

Analysis of Future Trends in the Nordic Power Sector

Afzal S. Siddiqui

Department of Computer and Systems Sciences

Stockholm University

and

Department of Mathematics and Systems Analysis

Aalto University

`asiddiq@dsv.su.se`

13 December 2024

Contents

1	Introduction	1
2	Framework for Analysis	1
2.1	Overview	1
2.2	ISO's Problem	2
2.3	Firm i 's Problem	3
2.4	Storage Operator's Problem	4
2.5	Transport Company's Problem	4
2.6	Industrial Consumer's Problem	5
2.7	Reformulation as a Single Optimisation Problem	5
3	Numerical Examples	6
3.1	Data	6
3.1.1	Transmission Network	6
3.1.2	Installed Generation Capacity	6
3.1.3	Thermal Generation	8
3.1.4	Hydro Generation	8
3.1.5	VRE Generation	9
3.1.6	Demand Parameters and Net Imports	11
3.2	Scenarios	11
3.2.1	Base 2018	12
3.2.2	Current 2023	14
3.2.3	Future 2035	17
3.2.3.1	Future 2035: Matching VRE Subscenario	18
3.2.3.2	Future 2035: NE Subscenario	22
3.2.3.3	Future 2035: LE Subscenario	24
	Appendix A Nomenclature	28
	Appendix B Mathematical Formulation	32
B.1	Mathematical Formulation for the ISO	32
B.2	Mathematical Formulation for Firm i	33
B.3	Mathematical Formulation for the Storage Operator	34
B.4	Mathematical Formulation for the Transport Company	34
B.5	Mathematical Formulation for the Industrial Consumer	34
B.6	Karush-Kuhn-Tucker (KKT) Conditions	35
B.6.1	KKT Conditions for the ISO	35
B.6.2	KKT Conditions for Firm i	35
B.6.3	KKT Conditions for the Storage Operator	36
B.6.4	KKT Conditions for the Transport Company	37
B.6.5	KKT Conditions for the Industrial Consumer	37

B.7 Equilibrium Problem and Single Equivalent Optimisation Problem	38
References	40

1 Introduction

This report outlines the theoretical framework for analysing the evolution of the Nordic power sector. Aligned with their ambitious climate goals, the Nordic countries—Denmark, Finland, Norway, and Sweden—have pledged to decarbonise their power sectors while simultaneously driving the electrification of their economies. As a result, the power sector is expected to increasingly depend on variable renewable energy (VRE) sources, such as wind and solar power, to meet not only electricity demand but also the energy needs of related sectors, including heating, industrial processes, and transport. Such an unprecedented transformation of the Nordic power sector will have both economic and environmental impacts. This technical report serves as background for the simulations reported in [Tangerås et al. \(2025\)](#).

In order to examine metrics such as electricity prices, social welfare, and CO₂ emissions under various plausible future scenarios, we adapt a bottom-up equilibrium model developed by [Hassanzadeh Moghimi et al. \(2023\)](#). In the subsequent sections of this document, we describe the modelling framework (Section 2) and provide details about the numerical results from the problem instances that capture salient features of future scenarios (Section 3). Appendices A and B specify the nomenclature and the mathematical formulation, respectively.

2 Framework for Analysis

2.1 Overview

We use an open-loop operational modelling framework to analyse electricity markets. To enhance tractability, the analysis treats both capacity-availability and operational decisions as if they were made at the same time. While operational decisions are adapted to each time period, those for capacity availability apply for the entire year. This approach is in contrast to a closed-loop model ([Wogrin et al., 2013](#)) in which capacity decisions anticipate the operational ones, which enables strategic behaviour to be captured more credibly. However, since we assume perfect competition, an open-loop perspective is sufficient. Thus, our setup is similar to the lower level of [Hassanzadeh Moghimi et al. \(2024\)](#) except that perfect competition and no explicit damage costs associated with CO₂ emissions are assumed. Moreover, any capacity expansion is handled exogenously, i.e., adapted to each future scenario’s requirements, rather than as endogenous decisions. The overall equilibrium model comprises an independent system operator (ISO), several¹ power companies, i.e., named “firms,” a storage operator, a transport company, and an industrial consumer (Figure 1). All agents are price takers, which means that the resulting equilibrium problem over a network may be reformulated as a single optimisation problem.

As is common in the literature on equilibrium modelling, a direct-current (DC) load-flow approach is taken to model the power flows. While flows among the zones of the four main Nordic countries are endogenous, net exchanges outside of the twelve modelled pricing zones are taken as exogenous. In the subsequent subsections, we detail each agent’s problem before specifying how

¹In a model of imperfect competition, the choice of how much to produce depends on the generation output of other power companies. Under perfect competition, however, no firm takes into account the behaviour of other market participants. Thus, the number of producers does not matter.

the resulting equilibrium problem may be reformulated as a single quadratic program (QP). The mathematical formulations of the problems and their corresponding Karush-Kuhn-Tucker (KKT) conditions for optimality are given in Appendix B, while Appendix A provides the relevant nomenclature.

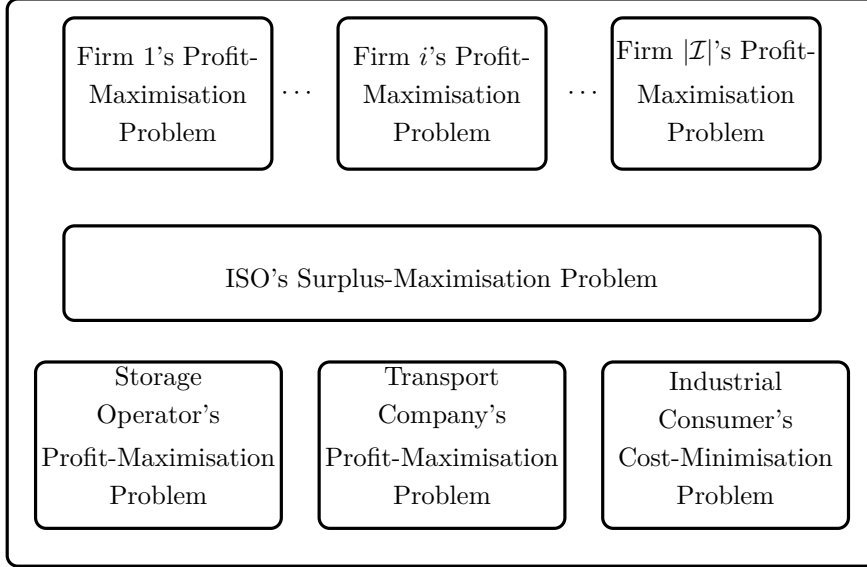


Figure 1: Equilibrium Framework for Analysis.

2.2 ISO's Problem

In conducting a surplus-maximising dispatch (Figure 2), 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). Under the Nash assumption, the ISO takes as given the decision variables of the firms, the storage operator, the transport company, and the industrial consumer, while it determines power flows, voltage angles, and consumption to maintain the system's energy balance without violating the thermal limits of transmission lines. The ISO maximises gross consumer surplus, i.e., the area under the inverse-demand function up to the quantity demanded, which is equivalent to a welfare-maximising redispatch yielded by adjusting consumption and transmission flows. Since the generation cost depends on decision variables that are not within the ISO's control, they are taken as exogenous by the ISO, i.e., the Nash assumption. Thus, it suffices to conclude that the ISO directly maximises gross consumer surplus as in (1).²

The ISO's principal constraint is to ensure energy balance (2), i.e., conventional consumption plus industrial consumption equals the sum of net generation, net discharge by the storage operator, net sales by the transport company, and net imports at each node and in each time period. Flows on all lines must stay within rated capacities (3). The DC load-flow approximation is used to model energy flows on alternating-current (AC) lines as proportional to the differences

²It could be argued that the ISO maximises consumer surplus, i.e., gross consumer surplus minus the cost of electricity purchases. However, since the latter depends on net generation and is outside the control of the ISO, i.e., the Nash assumption, it is treated as a constant when the ISO solves its own problem. Therefore, the term related to the cost of generation makes no difference to the ISO's optimal decision. Nevertheless, all metrics related to consumer surplus that are subsequently reported in this study follow the standard definition, viz., gross consumer surplus minus the cost of electricity purchases.

Maximise _{Γ^{ISO}}	Gross Consumer Surplus (1)
s.t.	Energy-Balance Constraint (2)
	Thermal Limit of Transmission Line (3)
	DC Load-Flow Constraint (4)
	Limit on Voltage Angle (5)

Figure 2: ISO's Surplus-Maximisation Problem.

in nodal voltage angles (4). Finally, voltage angles at nodes in the AC portion of the network must be within technical bounds (5).

2.3 Firm i 's Problem

Based on the Nash supposition, each firm $i \in \mathcal{I}$ maximises profit (Figure 3) by taking the decision variables of the ISO, the storage operator, the transport company, the industrial consumer, and every other firm as given when making its own decision to manage its fleet of power plants. Its objective function (6) is to maximise its overall profit, which depends on the equilibrium price and net sales of energy. From the ensuing revenue, we subtract the generation costs of thermal units and the price of CO₂ emission permits. Likewise, we subtract the amortised annual fixed operation and maintenance (O&M) capacity-availability costs for thermal, VRE, and hydro units. Price-taking behaviour in all generation is captured by treating the equilibrium price in (6) as exogenous. In this context of perfect competition, the firm index, i , is superfluous because asset ownership is inconsequential.

Maximise _{Γ^{i}}	Revenue from Net Electricity Sales
	- Cost of Thermal Generation
	- Cost of CO ₂ Emissions
	- Amortised Annual Fixed O&M Cost (6)
s.t.	Capacity Limit on Thermal Generation (7)–(8)
	Ramp Limit on Thermal Generation (9)
	Availability of VRE Generation (10)–(11)
	Hydro-Reservoir-Balance Constraint (12)
	Bound on Hydro Reservoir (13)
	Limit on Pumped-Hydro Charging (14)
	Capacity Limit on Hydro Generation (15)–(16)

Figure 3: Firm $i \in \mathcal{I}$'s Profit-Maximisation Problem.

Eq. (7) limits the production of thermal units based on available capacity, which itself is constrained by the installed generation capacity (8). Meanwhile, (9) represents the ramp limits of the thermal units. Eq. (10) states that the production of VRE units is limited by their availability factors and available capacity. In turn, available capacity is restricted by installed generation capacity (11). Constraints (12)–(16) account for the operation of the hydro units. Eq. (12) is the energy-balance constraint for hydro reservoirs, i.e., the water level in a period is equal to the water level in the previous period plus water charged to the reservoir, e.g., by

pumped-hydro units, and any exogenously occurring inflows. From these additions, the water spilled and turbinised for generation is subtracted. The reservoir level must stay between lower and upper limits as in (13). Charging by pumped-hydro units is modelled by (14), and (15) limits the generation of hydro units by their available capacity, which is restricted by their installed capacity (16).

2.4 Storage Operator’s Problem

As outlined in Virasjoki et al. (2020), a non-strategic standalone storage operator’s problem is to maximise its profit from net discharge of electricity from its battery capacity (Figure 4). Its objective function (17) is simply the revenue from net discharge of electricity at the nodal electricity price where losses in charging the battery are taken into account. The storage operator takes as given the decisions of all firms, the transport company, the industrial consumer, and the ISO when solving its problem. Its constraints (18), (19), (20), and (21) mirror the storage-related ones for firm $i \in \mathcal{I}$ (12), (13), (14), and (15), respectively, excluding natural inflows and spillage.

Maximise _{TES}	Revenue from Net Electricity Sales (17)
s.t.	Battery-Balance Constraint (18)
	Bound on Battery Capacity (19)
	Limit on Battery Charging (20)
	Limit on Battery Discharging (21)

Figure 4: Storage Operator’s Profit-Maximisation Problem.

2.5 Transport Company’s Problem

We capture the behaviour of a transport company that operates a fleet of electric vehicles (Figure 5). By running its fleet, the transport company purchases energy to charge its “battery” and is also able to make sales back to the grid, thereby earning the nodal electricity price (22). Thus, we loosely base the formulation on the vehicle model of Sioshansi (2012) but ignore attributes pertinent to plug-in hybrid vehicles. In effect, the fleet’s capacity is handled analogously to the storage operator’s battery. The transport company takes as given the decisions of all firms, the storage operator, the industrial consumer, and the ISO when solving its problem.

Maximise _{TC}	Revenue from Net Electricity Sales (22)
s.t.	Battery-Balance Constraint (23)
	Bound on Battery Capacity (24)
	Limit on Battery Charging (25)
	Limit on Battery Discharging (26)
	Consumption Balance (27)
	Requirement on Annual Consumption (28)
	Limit on Periodic Consumption (29)

Figure 5: Transport Company’s Profit-Maximisation Problem.

The constraints (23)–(26) mirror the storage operator’s (18)–(21). The only new constraints here are (27)–(29), which state that energy consumed by the fleet plus the energy sold back to the grid equals the energy discharged from the fleet’s “battery,” total annual energy consumed per node has to meet the annual requirement, and periodic energy consumption is within a range, respectively.

2.6 Industrial Consumer’s Problem

Under the Nash assumption, the industrial consumer considers the variables of the firms, the storage operator, the transport company, and the ISO as given, while it determines its hourly consumption of electricity as a price taker (Figure 6). The industrial consumer’s objective (30) is to minimise the annual cost of electricity consumption. Annually, it must purchase a minimum annual amount of electricity per node (31). There may also be restrictions on the minimum/maximum periodic consumption (32) and the maximum increase/decrease in periodic consumption (33) (Sundén, 2024).³

Minimise _{IC} Cost of Electricity Consumption (30) s.t. Requirement on Annual Consumption (31) Limit on Periodic Consumption (32) Limit on Periodic Changes to Consumption (33)

Figure 6: Industrial Consumer’s Cost-Minimisation Problem.

2.7 Reformulation as a Single Optimisation Problem

Since each optimisation problem, (1)–(5), (6)–(16), $\forall i \in \mathcal{I}$, (17)–(21), (22)–(29), and (30)–(33), is convex, it may be replaced by its KKT conditions as in Appendix B.6 to render a mixed-complementarity problem (MCP), (34)–(42), (43)–(63), $\forall i \in \mathcal{I}$, (64)–(71), (72)–(85), and (86)–(91). Next, this MCP can be recast as a single optimisation problem (Figure 7) 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 (92) with constraints that stem simply from the underlying optimisation problems, (2)–(5), (7)–(16), $\forall i \in \mathcal{I}$, (18)–(21), (23)–(29), and (31)–(33). As indicated in Appendix B.7, the objective function differs slightly from the social surplus of electricity-market operations due to the presence of the terms related to the CO₂ tax, which is treated as accruing to government revenue unless it is offset by any damage cost, and net imports from outside the Nordic region.

³Of course, if there are minimum periodic restrictions, then there may be an upper bound on how much the industrial consumer buys annually. However, the industrial consumer’s principal concern is to obtain the target, i.e., minimal, annual amount, which is precisely rendered by (31).

Maximiser	Gross Consumer Surplus
	- Cost of Thermal Generation
	- Cost of CO ₂ Emissions
	- Amortised Annual Fixed O&M Cost (92)
s.t.	ISO's Constraints (2)–(5)
	Firm i 's Constraints (7)–(16), $\forall i \in \mathcal{I}$
	Storage Operator's Constraints (18)–(21)
	Transport Company's Constraints (23)–(29)
	Industrial Consumer's Constraints (31)–(33)

Figure 7: Equivalent Optimisation Problem.

3 Numerical Examples

3.1 Data

All parameter values are based on 2018 data from [Hassanzadeh Moghimi et al. \(2023\)](#) and [Hassanzadeh Moghimi et al. \(2024\)](#). The parameters are described in Sections 3.1.1–3.1.6.

3.1.1 Transmission Network

The 2018 Nord Pool pricing zones for Denmark, Finland, Norway, and Sweden comprise 12 nodes (or, zones) and 19 transmission lines (Figure 8). Four of these transmission lines are DC (represented as dashed lines), and the remaining ones are AC. The lines' net transfer capacities (in MW) as reported by Nord Pool in 2018⁴ are used in each direction, and the susceptances (in S) are estimated given line lengths and power ratings ([Egerer, 2016](#)) (Tables 1–2).

Table 1: AC Transmission Lines' Thermal Capacities in Positive Direction (in MW) and Susceptances (in S).

Line	ℓ_1	ℓ_2	ℓ_3	ℓ_4	ℓ_5	ℓ_6	ℓ_7	ℓ_8	ℓ_9	ℓ_{10}	ℓ_{11}	ℓ_{12}	ℓ_{13}	ℓ_{14}	ℓ_{19}
\bar{K}_ℓ	3500	500	3900	600	1200	1500	700	3300	600	250	7300	2145	5400	1300	500
B_ℓ	1628	898	1275	1346	317	460	688	798	981	302	1081	822	1226	1578	487

Table 2: DC Transmission Lines' Thermal Capacities in Positive Direction (in MW).

Line	ℓ_{15}	ℓ_{16}	ℓ_{17}	ℓ_{18}
\bar{K}_ℓ	680	1200	1632	590

3.1.2 Installed Generation Capacity

Generation capacities (in GW) by firm and zone (Table 3) are based on the 2014 data of [Virasjoki et al. \(2018\)](#) with updates from firms' websites and relevant databases⁵ as collated by [Hassanzadeh Moghimi et al. \(2023\)](#). Installed capacities for thermal, VRE, and hydro plants are specified below. The thermal plants are indexed u_1 – u_{14} in order coal, gas, combined-cycle gas

⁴<https://www.nordpoolgroup.com/48fea6/globalassets/download-center/tso/max-ntc.pdf>

⁵https://data.open-power-system-data.org/conventional_power_plants/

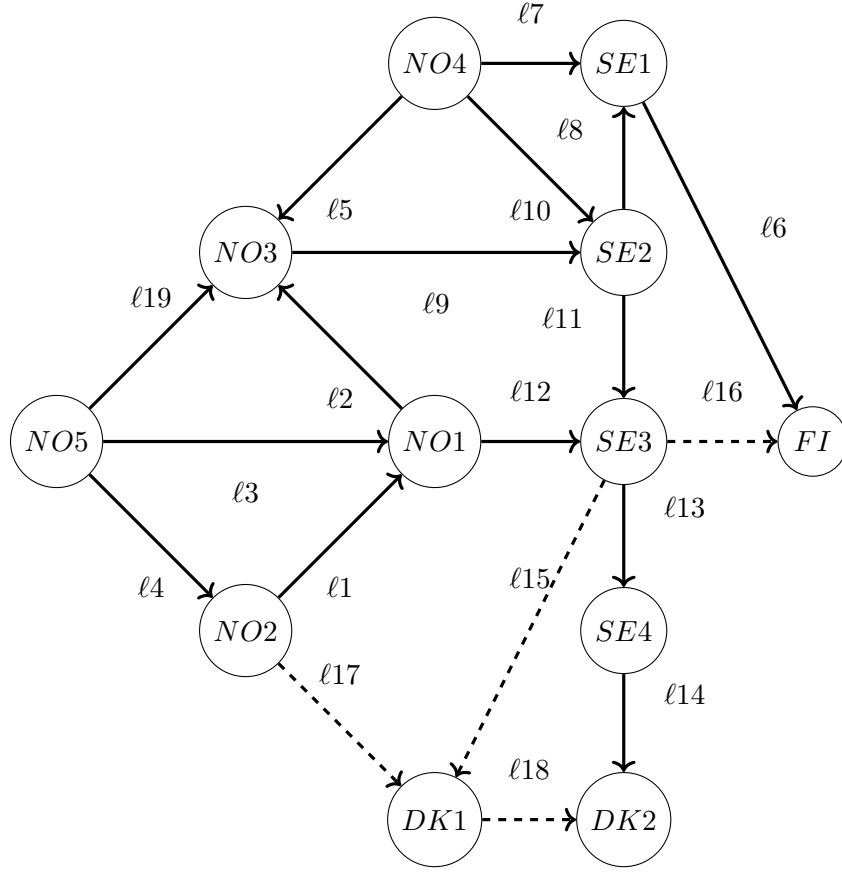


Figure 8: Nordic Test Network.

turbine (CCGT), oil, biomass, nuclear, peat, waste, CHP coal, CHP waste, CHP gas, CHP oil, CHP peat, and CHP biomass. For units $u9$ – $u14$, only the notional power-only capacities of the combined heat and power (CHP) plants are included. As mentioned previously, since this study assumes perfect competition, the firm index is irrelevant but retained to reflect the structure of the original database from [Hassanzadeh Moghimi et al. \(2023\)](#).

Table 3: Installed Capacities by Zone and Unit (in GW).

Zones	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	–	–	–	–	–	–	–	–	–	–	5.6	0.2	1.6
	FI	$i4$	0.3	–	–	–	–	1.5	–	–	0.1	–	0.3	–	–	0.1	–	–
$i6$		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	

3.1.3 Thermal Generation

Thermal plants' operating costs (in €/MWh), CO₂ emission rates (in t/MWh), and ramp rates as proportions of installed capacities (unitless) are based on information available from firms' websites, relevant databases,⁶ and national authorities (Table 4).⁷ The notional power-only capacities of CHP units u_9 – u_{14} are also included with costs estimated as per Virasjoki et al. (2018) and supplemented by data from Finnish authorities.⁸ We use the 2020 U.S. EIA's Annual Energy Outlook⁹ to estimate amortised annual fixed O&M costs (in €/MW) of thermal technologies by applying a 5% per annum interest rate and a thirty-year lifetime for all technologies. These costs range from €6,968/MW for gas to €121,316/MW for nuclear. In lieu of modelling the EU Emissions Trading System (ETS), we simply use the average EU ETS permit price for 2018 (roughly €15/t) as an effective tax on CO₂ emissions.¹⁰

Table 4: Thermal Generation Costs (in €/MWh), Amortised Annual Fixed O&M Costs (in €/MW), Emission Rates (in t/MWh), and Ramp Rates (–).

Unit	$C_{i,n,t,u}$	$C_{i,n,u}^{\text{ava}}$	$P_{i,n,u}$	R_u^{up}
Coal u_1	32	40,456	0.83	0.2
Gas u_2	65	6,968	0.50	0.5
CCGT u_3	48	14,092	0.37	0.5
Oil u_4	67	14,092	0.72	0.7
Biomass u_5	59	14,092	0.00	0.2
Nuclear u_6	21	121,316	0.00	0.1
Peat u_7	22	14,092	1.09	0.1
Waste u_8	22	14,092	0.94	0.1
CHP Coal u_9	37	40,456	0.83	0.1
CHP Waste u_{10}	22	14,092	0.94	0.1
CHP Gas u_{11}	57	6,968	0.50	0.1
CHP Oil u_{12}	33	14,092	0.72	0.1
CHP Peat u_{13}	22	14,092	1.09	0.1
CHP Biomass u_{14}	27	14,092	0.00	0.1

3.1.4 Hydro Generation

Hydro units are categorised as follows:

1. Run of river (ROR)
2. Reservoirs (RES)
3. Pumped hydro (PHS)

Since ROR units have no reservoirs, they rely solely on exogenous inflows for power generation. In cascaded watersheds, each plant is treated separately and is assumed to have its own natural inflow. The inflow series for each plant aggregates to the annual production and has the same profile as that of every other plant in the watershed.

⁶https://data.open-power-system-data.org/conventional_power_plants/

⁷https://energia.fi/en/newsroom/publications/district_heating_statistics.html

⁸https://www.stat.fi/index_en.html

⁹https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_AE02020.pdf

¹⁰[https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:52019DC0557R\(01\)&from=EN](https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:52019DC0557R(01)&from=EN)

Data sources for the generation capacities (in GW), reservoir volumes (in GWh), and periodic natural inflows (in GWh) are the firms' websites, e.g., Kemijoki,¹¹ Vattenfall,¹² PVO,¹³ and Fortum,¹⁴ as well as those of relevant authorities, e.g., Finnish Energy^{15,16} and NVE.^{17,18} Cumulative hydro generation capacities are reported in the final column of Table 3. As for reservoir volumes, we allocate them based on capacity shares (Table 5). Furthermore, initial and terminal reservoir levels are taken from 2018 data.¹⁹ Inflows to reservoirs are estimated from the annual production of the affiliated units and seasonal production profiles, e.g., see Figure 9 for a reservoir in *SE1*. Similarly, the annual production of ROR units is distributed periodically based on the inflow profiles. Since hourly inflow data are not available at the plant level, they need to be estimated on a weekly basis using data from Nord Pool.²⁰ Hydro plants are assumed to have zero operating costs and no CO₂ emissions in generation. Run-of-river hydro plants are assumed to have zero fixed O&M costs, but the reservoir-enabled ones have amortised annual fixed O&M costs of €29,796/MW using a 5% per annum interest rate and a thirty-year lifetime based on estimates from the U.S. EIA.²¹ Finally, pumped-hydro units are assumed to be 73% efficient at pumping water back into their reservoirs (Debia et al., 2021).

Table 5: Firms' Hydro Reservoir Volumes by Zone and Type (in GWh).

Zones	Firm	RES	PHS
<i>SE1 – SE4</i>	<i>i1</i>	16878	
	<i>i4</i>	5952	
	<i>i10</i>	2533	
	<i>i16</i>	4105	
	<i>i17</i>	1626	
	<i>i18</i>	2457	
<i>FI</i>	<i>i6</i>	1268	
	<i>i8</i>	4262	
<i>NO1 – NO5</i>	<i>i10</i>	33215	2823
	<i>i11</i>	5505	
	<i>i12</i>	4328	681
	<i>i13</i>	4782	95
	<i>i14</i>	3347	130
	<i>i15</i>	9392	421
	<i>i21</i>	26234	701

3.1.5 VRE Generation

Data on VRE capacities for the main firms are collected from their websites, i.e., following the procedure for hydro capacities described in Section 3.1.4. Fringe firms' capacities are obtained

¹¹<https://www.kemijoki.fi/toimintamme/voimalaitokset-ja-tuotanto.html>

¹²<https://powerplants.vattenfall.com>

¹³<https://www.pohjolanvoima.fi/tuotamme-sahkoa-ja-lampoa/vesivoima/vesistojen-saannostely/>

¹⁴<https://www.fortum.com/about-us/our-company/our-energy-production/our-power-plants/hydro-power-plants>

¹⁵https://energia.fi/tilastot/sahkotilastot/sahkontuotanto_ja_kaytto

¹⁶https://energia.fi/en/newsroom/publications/district_heating_statistics.html

¹⁷<https://www.nve.no/konsesjonssaker/>

¹⁸<https://www.nve.no/energiforsyning/kraftmarkedsdata-og-analyser/om-magasinstatistikken/>

¹⁹<https://data.nordpoolgroup.com/power-system/reservoir>

²⁰<https://data.nordpoolgroup.com/power-system/production>

²¹https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_AE02020.pdf

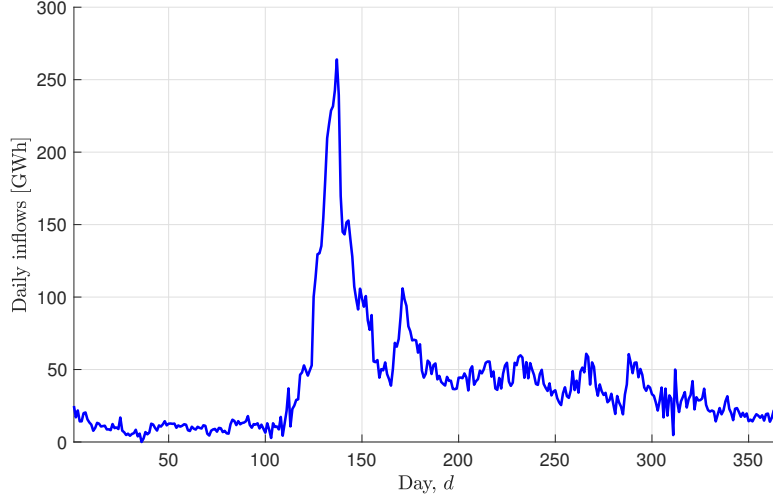


Figure 9: Daily Estimated Hydro Inflows to a Reservoir in *SE1* (in GWh).

from relevant authorities, viz., NVE,^{22,23} Energinet,^{24,25} and Svenska kraftnät.²⁶ We calculate availability factors, e.g., Figure 10 for zones *FI* and *SE3*, using the ratio of the actual production to the installed capacity. Due to its negligible installed capacity, Norway is assumed to have no solar production. VRE plants are assumed to have zero operating costs and no CO₂ emissions in generation. The amortised annual fixed O&M costs of a 150 MW PV plant and a 200 MW onshore wind plant are €15,184/MW and €26,260/MW, respectively, using a 5% per annum interest rate and a thirty-year lifetime based on estimates from the U.S. EIA.²⁷

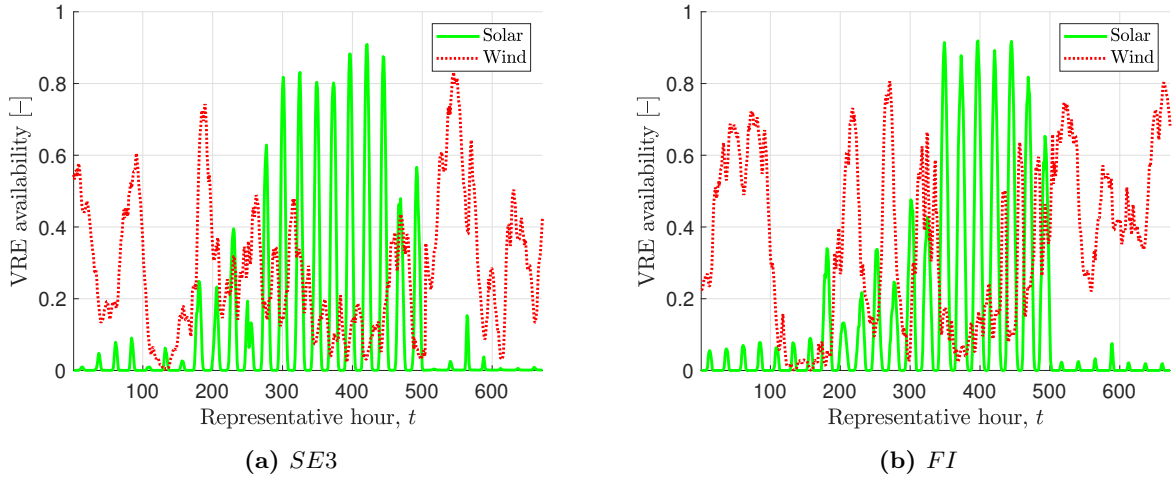


Figure 10: VRE Availability in Representative Weeks (-).

²²<https://www.nve.no/energiforsyning/kraftproduksjon/vindkraft/vindkraftdata/>

²³<https://www.nve.no/energiforsyning/kraftproduksjon/solkraft/?ref=mainmenu>

²⁴<https://www.energidataservice.dk/tso-electricity/GridCapacityMapT50>

²⁵<https://www.energidataservice.dk/tso-electricity/CapacityPerMunicipality>

²⁶<https://www.svk.se/om-kraftsystemet/kraftsystemdata/elstatistik/>

²⁷https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_AEO2020.pdf

3.1.6 Demand Parameters and Net Imports

Electricity prices (in €/MWh) and consumption (in MWh) are taken from Nord Pool.²⁸ The price elasticity of the linear inverse-demand functions is assumed to be -0.065 (Neamtu, 2016) at the observed (consumption_{*n,t*}, price_{*n,t*}) pair for each node *n* and hour *t*. Based on the definition of price elasticity of demand, we calculate the slope of the inverse-demand function, $D_{n,t}^{\text{slp}}$, as $-\text{price}_{n,t}/(\epsilon \times \text{consumption}_{n,t})$, where ϵ is the assumed price elasticity of demand at the observed (consumption_{*n,t*}, price_{*n,t*}) pair. Subsequently, we use the point-slope equation of a line to calculate the vertical intercept of the inverse-demand function, $D_{n,t}^{\text{int}}$, as $\text{price}_{n,t} + D_{n,t}^{\text{slp}} \times \text{consumption}_{n,t}$. Energy transfers outside of the four Nordic countries are treated as exogenous net imports and are taken as reported on Nord Pool’s website.²⁹

We reduce the scale of our problem instances by clustering the data into four weeks of 168 hours each. Thus, instead of 8,760 time steps as in a full year of operation, we have a total of 672 time steps. The clusters are based on minimising the normalised seasonal-weekly values for consumption, price, and wind availability. As the criterion for representativity, we deploy the seasonal-weekly values of averages and standard errors. Hence, the representative week for each season minimises the Euclidean distance from that season’s centroid (Mignon, 2008).

3.2 Scenarios

We conduct three scenarios (with a few additional subscenarios) defined as follows:

- *Base 2018* establishes a baseline using installed generation capacities from 2018 and a CO₂ price of €15/t
- *Current 2023* closely aligns with the Base 2018 scenario while accounting for significant changes in the Nordic countries’ electricity markets since 2018 such as (i) an increase in the CO₂ price to the 2023 EU ETS average of €83.66/t,³⁰ (ii) the use of estimated 2023 fuel costs for thermal plants,³¹ (iii) a derating of 881 MW to the nuclear capacity at Ringhals and an upgrade of 1600 MW to the nuclear capacity at Olkiluoto (excluding the winter and spring seasons since the additional capacity came online on 1 May 2023 but experienced operational issues in May and June),³² (iv) the use of 2025 U.S. EIA estimates for amortised annual fixed O&M costs,³³ (v) an exogenous increase in VRE capacity (onshore wind and solar along with some offshore wind³⁴ as summarised in Table 12) to a total of 44 GW, and (vi) an increase in the vertical intercepts of the 2018 inverse-demand functions by 5% to ensure adequate calibration
- *Future 2035* is identical to the Current 2023 scenario except for (i) full extra 1600 MW capacity availability for Olkiluoto during the entire year, (ii) an exogenous increase to

²⁸<https://data.nordpoolgroup.com/reports>

²⁹<https://data.nordpoolgroup.com/reports>

³⁰<https://www.umweltbundesamt.de/en/press/pressinformation/new-record-revenue-in-emissions-trading-more-than>

³¹These vary by unit but range from a mild increase of 21% for nuclear to a twofold increase for gas.

³²https://www.tvo.fi/material/sites/tvo/pdf/kjqs0hi5r/TV0_Financial_Statements_2023.pdf

³³https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_AEO2025.pdf

³⁴The 2018 VRE availability factors are retained, cf. Figure 10, except that offshore wind’s availability factor is assumed to be 1.5 times that of onshore wind’s with a ceiling of 1.0.

the *FI–SE1* transmission capacity by 900 MW in the direction to *SE1* and 800 MW in the direction to *FI*,³⁵ (iii) an exogenous increase to onshore capacity of 3.4 GW in *SE1–SE4*, (iv) an exogenous annual demand of 31 TWh with constant hourly consumption for industrial processes in *SE1–SE4* with a concomitant increase in onshore capacity, (v) an exogenous annual demand of 36 TWh with constant off-peak hourly consumption for electric vehicles in *SE1–SE4* with a concomitant increase in onshore capacity, and (vi) an exogenous battery capacity of 10 GWh each in *SE3* and *SE4*

Moreover, within each scenario, we implement several cases including a do-nothing (DN) case without additional capacity adoption. Other cases involve varying industrial capacity, storage capacity, and transport capacity as indicated in the description of the Future 2035 scenario. Key metrics used to compare the results are social surplus (SS), CO₂ emissions, and average zonal prices. For sake of completeness, SS equals the sum of consumer surplus (CS), producer surplus (PS), the storage operator’s battery surplus (BS), the transport company’s surplus (TS), merchandising surplus (MS), and government revenue (GR) minus the cost of industrial consumption (HC), which are reported as they appear in the following subsections. Full mathematical definitions of these surplus components are provided in Appendix B.7. Each problem instance takes under a minute to solve 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.

3.2.1 Base 2018

We conduct a single DN case for 2018 in order to establish a credible baseline for the subsequent analyses. The summary results are indicated in Table 6. Based on key metrics, the modelled outputs are roughly in line with the observations for 2018. For example, the average modelled electricity price is €41.88/MWh compared with the observed average price of €42.04/MWh in the representative weeks. Modelled CO₂ emissions are 28.2 Mt compared with the observed level of 35.1 Mt for both power and heat generation in 2017.³⁶ In terms of modelled total generation and hydro generation, we obtain 398 TWh and 212 TWh, respectively, cf. the observed values of 398 TWh and 213 TWh in 2018.³⁷

Table 6: Numerical Results for the Base 2018 Scenario (in Billion € Unless Indicated).

Metric \ Case	DN
SS	139.359
CS	128.051
PS	10.526
MS	0.359
GR	0.423
CO ₂ Emissions (Mt)	28.200
Average Price (€/MWh)	41.884

³⁵<https://www.fingrid.fi/en/grid/construction/aurora-line/>

³⁶<https://www.nordicenergy.org/wordpress/wp-content/uploads/2020/04/Tracking-Nordic-Clean-Energy-Progress-2020.pdf>

³⁷<https://data.nordpoolgroup.com/reports>

Zonal breakdowns of average prices, consumer surplus, and producer surplus are provided in Tables 7–9. Regional variations in production mixes can be gleaned from these decompositions, e.g., *DK2*, *FI*, and *SE4* have relatively high prices due to their heavier reliance on fossil-fuelled technologies. The installed VRE capacities by type and by zone are given in Table 10. Approximately, the Nordic region had a total of 16 GW of installed VRE capacity in 2018.

Table 7: Average Zonal Prices in the Base 2018 Scenario (in €/MWh).

Zone \ Case	DN
<i>DK1</i>	41.31
<i>DK2</i>	43.42
<i>FI</i>	46.36
<i>NO1</i>	40.59
<i>NO2</i>	40.90
<i>NO3</i>	42.23
<i>NO4</i>	41.95
<i>NO5</i>	36.70
<i>SE1</i>	41.64
<i>SE2</i>	41.69
<i>SE3</i>	42.16
<i>SE4</i>	43.67
Nordic	41.88

Table 8: Zonal Consumer Surplus in the Base 2018 Scenario (in Billion €).

Zone \ Case	DN
<i>DK1</i>	6.22
<i>DK2</i>	4.28
<i>FI</i>	29.27
<i>NO1</i>	12.03
<i>NO2</i>	11.94
<i>NO3</i>	8.65
<i>NO4</i>	6.28
<i>NO5</i>	5.49
<i>SE1</i>	3.22
<i>SE2</i>	5.24
<i>SE3</i>	27.71
<i>SE4</i>	7.73
Nordic	128.05

Table 9: Zonal Producer Surplus in the Base 2018 Scenario (in Billion €).

Zone \ Case	DN
<i>DK1</i>	0.46
<i>DK2</i>	0.22
<i>FI</i>	1.34
<i>NO1</i>	0.64
<i>NO2</i>	1.73
<i>NO3</i>	0.64
<i>NO4</i>	0.58
<i>NO5</i>	1.29
<i>SE1</i>	0.74
<i>SE2</i>	1.46
<i>SE3</i>	1.25
<i>SE4</i>	0.19
Nordic	10.53

Table 10: Zonal VRE Installed Capacity in the Base 2018 Scenario (in GW).

Zone \ Type	Offshore	Onshore	Solar
<i>DK1</i>	–	4.379	0.620
<i>DK2</i>	–	1.194	0.284
<i>FI</i>	–	1.859	0.159
<i>NO1</i>	–	–	0.068
<i>NO2</i>	–	0.748	–
<i>NO3</i>	–	0.872	–
<i>NO4</i>	–	0.396	–
<i>NO5</i>	–	–	–
<i>SE1</i>	–	0.666	0.001
<i>SE2</i>	–	0.851	0.008
<i>SE3</i>	–	2.170	0.100
<i>SE4</i>	–	1.562	0.041
Nordic	–	14.698	1.282

3.2.2 Current 2023

In the Current 2023 scenario, we conduct two cases: DN and generation expansion (GE). The former does not allow for exogenous VRE capacity expansion, whereas the latter increases VRE capacity to reflect 2023 patterns (Table 12). Not surprisingly, the combination of a higher CO₂ price and fuel costs in the DN case leads to an exorbitantly high average electricity price for the Nordic region of €108.68/MWh, cf. the actual average in 2023 of €58.59/MWh. Although the social-surplus levels are not directly comparable due to the shifting of the demand functions, the overall impact on the power system under the DN case of the Current 2023 scenario is to reduce CO₂ emissions (Table 11) from the Base 2018 scenario (Table 6) and to increase (decrease) the relative share of producer surplus (consumer surplus).

Table 11: Numerical Results for the Current 2023 Scenario (in Billion € Unless Indicated).

Metric \ Case	DN	GE
SS	149.027	152.910
CS	115.313	134.438
PS	32.162	15.992
MS	0.774	2.193
GR	0.778	0.287
CO ₂ Emissions (Mt) Average	9.304	3.436
Price (€/MWh)	108.677	56.372

Actual VRE capacity increased to 44 GW in 2023 across the Nordic region (Table 12), cf. 16 GW in 2018. In particular, the Swedish zones, *SE1–SE4*, exhibit the largest increase in VRE capacity, which more than triples from its 2018 level (Table 10). This relatively large volume of generation expansion causes the average Nordic electricity price to drop to €56.37/MWh, which is in line with the observed average electricity price (Table 14). Indeed, total VRE generation more than doubles to 96.653 TWh (Table 13) from its 2018 level of 37.428 TWh. As a result, social surplus improves vis-à-vis the Current 2023 DN case with a corresponding transfer to consumers from producers. The GE case also induces CO₂ emissions to drop further due to VRE expansion.

Table 12: Zonal VRE Installed Capacity in Case GE of the Current 2023 Scenario (in GW).

Zone \ Type	Offshore	Onshore	Solar
<i>DK1</i>	1.250	4.022	2.577
<i>DK2</i>	1.044	0.755	0.948
<i>FI</i>	0.044	6.650	1.018
<i>NO1</i>	–	0.384	0.267
<i>NO2</i>	–	1.425	0.233
<i>NO3</i>	–	2.112	0.042
<i>NO4</i>	–	1.159	0.004
<i>NO5</i>	–	–	0.056
<i>SE1</i>	–	3.000	0.027
<i>SE2</i>	–	6.823	0.168
<i>SE3</i>	0.028	3.941	2.604
<i>SE4</i>	0.165	2.266	1.174
Nordic	2.531	32.538	9.117

Table 13: Zonal VRE Generation in Case GE of the Current 2023 Scenario (in TWh).

Zone \ Type	Offshore	Onshore	Solar
<i>DK1</i>	4.634	10.277	2.653
<i>DK2</i>	3.996	2.048	1.122
<i>FI</i>	0.204	20.806	1.083
<i>NO1</i>	–	–	–
<i>NO2</i>	–	3.383	–
<i>NO3</i>	–	2.035	–
<i>NO4</i>	–	2.418	–
<i>NO5</i>	–	–	–
<i>SE1</i>	–	5.277	0.020
<i>SE2</i>	–	17.133	0.143
<i>SE3</i>	0.102	9.569	2.353
<i>SE4</i>	0.579	5.572	1.247
Nordic	9.515	78.518	8.621

Table 14: Average Zonal Prices in the Current 2023 Scenario (in €/MWh).

Zone \ Case	DN	GE
<i>DK1</i>	108.14	66.03
<i>DK2</i>	109.34	70.52
<i>FI</i>	119.49	73.55
<i>NO1</i>	105.94	58.70
<i>NO2</i>	107.25	59.30
<i>NO3</i>	111.31	49.43
<i>NO4</i>	110.41	46.05
<i>NO5</i>	94.44	41.94
<i>SE1</i>	109.40	44.55
<i>SE2</i>	109.10	43.61
<i>SE3</i>	108.84	56.87
<i>SE4</i>	110.46	65.91
Nordic	108.68	56.37

On the basis of the price changes, the consumer surplus under GE recovers its zonal values to reach a share of social surplus that is near parity with the Base 2018 social-surplus share, cf. Tables 15 and 8. Conversely, the zonal producer-surplus values decline under GE to near their Base 2018 shares, cf. Tables 16 and 9.

Table 15: Zonal Consumer Surplus in the Current 2023 Scenario (in Billion €).

Zone \ Case	DN	GE
<i>DK1</i>	5.59	6.37
<i>DK2</i>	3.89	4.35
<i>FI</i>	26.16	29.90
<i>NO1</i>	10.87	12.52
<i>NO2</i>	10.78	12.52
<i>NO3</i>	7.77	9.40
<i>NO4</i>	5.64	6.88
<i>NO5</i>	5.11	6.00
<i>SE1</i>	2.90	3.54
<i>SE2</i>	4.71	5.79
<i>SE3</i>	24.92	29.22
<i>SE4</i>	6.98	7.93
Nordic	115.31	134.44

Table 16: Zonal Producer Surplus in the Current 2023 Scenario (in Billion €).

Zone \ Case	DN	GE
<i>DK1</i>	1.16	0.68
<i>DK2</i>	0.35	0.27
<i>FI</i>	4.63	2.97
<i>NO1</i>	1.75	1.02
<i>NO2</i>	4.82	2.68
<i>NO3</i>	1.81	0.78
<i>NO4</i>	1.60	0.68
<i>NO5</i>	3.53	1.48
<i>SE1</i>	2.06	0.89
<i>SE2</i>	4.07	1.97
<i>SE3</i>	5.84	2.12
<i>SE4</i>	0.54	0.44
Nordic	32.16	15.99

3.2.3 Future 2035

In the Future 2035 scenario, we conduct four cases with varying degrees of demand expansion corresponding to the simulation results reported in Chapter 9 of [Tangerås et al. \(2025\)](#): DN, additional demand from the industrial consumer (IC), additional demand from both the industrial consumer and the transport company (IC+TC), and additional demand from both the industrial consumer and the transport company with a storage operator (IC+TC+ES). The first case, DN, refers to the exogenous changes to the generation and transmission assets in the near future, viz., (i) full extra 1600 MW capacity availability for Olkiluoto during the entire year, (ii) an exogenous increase to the *FI–SE1* transmission capacity by 900 MW in the direction to *SE1* and 800 MW in the direction to *FI*, and (iii) an exogenous increase to onshore capacity of 3.4 GW in *SE1–SE4*. In particular, the latter component involves increases to onshore capacity by 0.571

GW, 1.846 GW, 0.834 GW, and 0.151 GW in zones *SE1*, *SE2*, *SE3*, and *SE4*, respectively, cf. Table 12.

In the IC case, we allow for annual electricity demand for industrial processes in zones *SE1*, *SE2*, *SE3*, and *SE4* of 14.3 TWh, 1.1 TWh, 14 TWh, and 1.6 TWh, respectively, that is complemented by a corresponding increase in onshore capacity, e.g., by 8.13 GW at *SE1*, to ensure that the resulting additional generation output at the average availability factor throughout the year matches the industrial requirement. Moreover, the ensuing consumption must be constant throughout the year, viz., 1632 MWh in each hour for *SE1*.

Next, in the IC+TC case, all of the features of the IC case pertaining to industrial consumption and matching VRE capacity are included together with additional consumption and matching VRE capacity for electric vehicles. Specifically, the transport company has annual consumption of 1.73 TWh, 3.25 TWh, 23.89 TWh, and 7.19 TWh in zones *SE1*, *SE2*, *SE3*, and *SE4*, respectively. This consumption is assumed to occur uniformly during the off-peak hours of each day, viz., 00:00–06:00 and 20:00–24:00.

In the IC+TC+ES case, we allow for 10 GWh of energy storage each in zones *SE3* and *SE4* on top of the aforementioned demands from industry and transport as well as the matching VRE capacity from the IC+TC case. The technology is assumed to have a 1% hourly self-discharge rate. Otherwise, there are no efficiency losses in either charging or discharging, and we do not impose either a maximum charging/discharging rate or any minimum state-of-charge restriction.

The assumption of matching VRE capacity to meet the additional industrial and transport demands is further tested via subscenarios. In particular, each case (besides DN) is implemented for three subscenarios: matching VRE capacity expansion (as described in the preceding three paragraphs and implemented in Section 3.2.3.1), no VRE capacity expansion beyond that in the DN case (subscenario NE in Section 3.2.3.2), and limited VRE capacity expansion in zones *SE1–SE2* to go along with the matching VRE capacity expansion in zones *SE3–SE4* that enables a suitable compromise for the additional electricity end uses (subscenario LE in Section 3.2.3.3), which is the basis of the discussion in the main report (Tangerås et al., 2025).

3.2.3.1 Future 2035: Matching VRE Subscenario

Not surprisingly, the additional capacity in the DN case lowers the average Nordic electricity price to €46.53/MWh from €56.37/MWh in the GE case of the Current 2023 scenario, cf. Tables 17 and 11. This reduction in prices is to the benefit of consumers at the expense of producers, and the bolstered CO₂-free capacity further curbs emissions by nearly 2 Mt. The zonal impacts in Table 18 are also intuitive with a general price decrease that is more pronounced in *SE1–SE4* and *FI* compared to the GE case of the Current 2023 scenario (Table 14). In a similar vein, the benefits to consumers (Table 19) and losses to producers (Table 20) accrue disproportionately in Finland and in the Swedish zones vis-à-vis the GE case of the Current 2023 scenario (Tables 15 and 16). For reference, total consumption by price-elastic demand in the Nordic region is 409.904 TWh.

Table 17: Numerical Results for the Future 2035 Subscenario with Matching VRE (in Billion € Unless Indicated).

Metric \ Case	DN	IC	IC+TC	IC+TC+ES
SS	153.443	152.837	152.057	152.188
CS	139.331	139.069	138.494	138.958
PS	11.058	11.738	13.518	13.024
MS	2.933	3.005	3.219	2.927
GR	0.121	0.142	0.165	0.123
HC	–	1.117	1.235	1.177
TS	–	–	-2.105	-1.760
BS	–	–	–	0.093
CO ₂ Emissions (Mt) Average Price (€/MWh)	1.449 46.528	1.701 46.939	1.972 49.250	1.465 48.221

Table 18: Average Zonal Prices in the Future 2035 Subscenario with Matching VRE (in €/MWh).

Zone \ Case	DN	IC	IC+TC	IC+TC+ES
<i>DK1</i>	58.03	58.50	61.14	59.57
<i>DK2</i>	61.62	61.15	65.26	63.34
<i>FI</i>	52.09	52.34	54.63	53.01
<i>NO1</i>	53.42	52.91	52.51	52.78
<i>NO2</i>	54.44	54.23	54.74	54.81
<i>NO3</i>	54.67	54.77	54.12	54.53
<i>NO4</i>	42.47	44.80	45.39	44.35
<i>NO5</i>	41.34	41.94	43.54	44.89
<i>SE1</i>	28.86	27.66	29.13	28.41
<i>SE2</i>	17.06	17.61	20.64	20.01
<i>SE3</i>	41.49	44.04	49.97	47.08
<i>SE4</i>	52.84	53.31	59.96	55.89
Nordic	46.53	46.94	49.25	48.22

Table 19: Zonal Consumer Surplus in the Future 2035 Subscenario with Matching VRE (in Billion €).

Zone \ Case	DN	IC	IC+TC	IC+TC+ES
<i>DK1</i>	6.54	6.53	6.52	6.54
<i>DK2</i>	4.47	4.48	4.46	4.48
<i>FI</i>	31.83	31.81	31.68	31.81
<i>NO1</i>	12.75	12.78	12.82	12.82
<i>NO2</i>	12.71	12.72	12.70	12.70
<i>NO3</i>	9.25	9.25	9.27	9.26
<i>NO4</i>	6.96	6.91	6.90	6.92
<i>NO5</i>	6.01	6.00	5.97	5.95
<i>SE1</i>	3.71	3.73	3.71	3.72
<i>SE2</i>	6.26	6.25	6.21	6.22
<i>SE3</i>	30.61	30.37	30.07	30.28
<i>SE4</i>	8.24	8.24	8.18	8.26
Nordic	139.33	139.07	138.49	138.96

Table 20: Zonal Producer Surplus in the Future 2035 Subscenario with Matching VRE (in Billion €).

Zone \ Case	DN	IC	IC+TC	IC+TC+ES
<i>DK1</i>	0.50	0.51	0.51	0.50
<i>DK2</i>	0.19	0.18	0.18	0.17
<i>FI</i>	1.79	1.80	1.92	1.81
<i>NO1</i>	0.92	0.90	0.88	0.88
<i>NO2</i>	2.43	2.42	2.45	2.45
<i>NO3</i>	0.87	0.88	0.87	0.87
<i>NO4</i>	0.62	0.66	0.67	0.65
<i>NO5</i>	1.46	1.48	1.54	1.60
<i>SE1</i>	0.52	0.54	0.59	0.56
<i>SE2</i>	0.54	0.58	0.78	0.74
<i>SE3</i>	0.89	1.42	2.54	2.21
<i>SE4</i>	0.33	0.36	0.60	0.58
Nordic	11.06	11.74	13.52	13.02

Next, we explore the inclusion of demand by the industrial consumer. Although the system is able to meet the requirement for the IC case on aggregate thanks to the provision of matching VRE capacity expansion, there is a slight increase in the average price to €46.94/MWh and an indication of increased congestion (Table 17) relative to the DN case. Price-elastic consumption is almost unchanged from the DN case at 409.552 TWh. Consequently, the greater need for flexibility to balance expanded VRE output also causes an uptick in emissions, presumably from fossil-fuelled plants, and a mild surplus transfer from consumers to producers. More important, the cost to the industrial consumer is €1.12 billion. The zonal impacts vis-à-vis the DN case are also limited with the notable exception of zone *SE3*, which experiences the highest price increase (Table 18) and additional surplus for its producers (Table 20). The latter outcome may be attributed to the relative lack of flexible generation in that zone, primarily due to its reliance on nuclear power. Given the prices in the Swedish zones, it is possible to estimate

whether the installed VRE capacity will be economically viable. For example, the 2025 U.S. EIA capacity-availability and amortised investment costs for onshore wind are €29,754/MW and €53,604/MW, respectively.³⁸ Thus, the total annualised capital cost per MW is €83,358. Dividing this target by the number of hours in a year (8,760) and *SE1*'s average availability factor for onshore wind (0.201) yields a levelised cost of €47.34/MWh, which is not covered by the €27.66/MWh price in *SE1*. While *SE2* has a higher average availability factor (0.287), its levelised cost (€33.16/MWh) also exceeds its modelled price. Yet, zones *SE3* and *SE4* with similar availability factors have high-enough modelled prices to support such VRE capacity expansion.

In the IC+TC case, the transport company's electrified fleet is incorporated into the analysis. We assume that since the transport company essentially has no flexibility over its charging/discharging decisions, the fleet's storage operations are disregarded along with the possibility to sell energy back to the grid. In effect, the transport company is modelled as having inflexible demand during the aforementioned off-peak hours for charging its fleet, e.g., constant consumption of 474 MWh in zone *SE1* during each of the 3,650 off-peak hours of the year. Each zone's additional electricity requirements are complemented by a corresponding exogenous increase in zonal onshore capacity, e.g., an increase of 0.98 GW in zone *SE1*. As in the IC case, while the aggregate balance of the system is maintained, e.g., the price-elastic consumption is relatively unchanged at 408.168 TWh, the introduction of further inflexible generation and consumption tends to increase the average price to €49.25/MWh with a net transfer of surplus from consumers to producers along with an increase in CO₂ emissions (Table 17). Further examining prices (Table 18), consumer surplus (Table 19), and producer surplus (Table 20) at the zonal level, we observe a similar trend as that in the IC case, viz., a more apparent impact in *SE3* and *SE4*. Likewise, onshore capacity investment would be supported by the modelled prices in *SE3* and *SE4*. The increase in the merchandising surplus also reveals potentially greater network congestion, while the transport company pays €2.11 billion over the year to meet its electricity requirements.

The inclusion of a storage operator rounds out the analysis. By conducting pure arbitrage in the IC+TC+ES case, the storage operator earns a modest battery surplus of €93 million over the year, which facilitates the integration of electric vehicles and eases some network congestion along with reducing CO₂ emissions (Table 17). As expected, social surplus experiences a mild increase relative to the IC+TC case, and the average Nordic electricity price slightly decreases to €48.22/MWh, which is largely driven by the price decreases in zones *SE3* and *SE4* (Table 18). In a power system with large shares of inflexible generation and consumption, storage can absorb "excess" VRE output for local temporal reallocation. However, other zones that would have benefited from this VRE generation need to utilise their own resources to a greater extent, thereby leading to the observed regional impacts for consumers and producers (Tables 19–20). For example, price-elastic consumption increases slightly from the IC+TC case to 408.732 TWh.

³⁸https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_AE02025.pdf

3.2.3.2 Future 2035: NE Subscenario

For reference, we repeat the IC case without the matching increases to onshore capacity in *SE1–SE4*, i.e., the demand for industrial processes is to be met by the installed capacity available in the DN case. Referring to this as the IC-NE case, Table 21 summarises that the increased demand can be met but at a social-surplus loss and a substantial increase in the average price to €87.23/MWh. This is the result of a decrease in price-elastic consumption to 384.250 TWh, which is a decrease of approximately 25 TWh from the DN case. Consequently, the residual 6 TWh of industrial consumption is met by increased generation. The zonal impacts without matching VRE capacity expansion are indicated in Tables 22–24.

Table 21: Numerical Results for the Future 2035 Subscenario NE (in Billion € Unless Indicated).

Metric \ Case	IC-NE	IC+TC-NE	IC+TC+ES-NE
SS	151.603	148.025	148.034
CS	123.491	116.288	116.435
PS	29.554	38.118	37.982
MS	1.086	1.087	0.839
GR	0.170	0.283	0.205
HC	2.698	3.395	3.374
TS	–	-4.357	-4.090
BS	–	–	0.033
CO ₂ Emissions (Mt)	2.029	3.387	2.448
Average Price (€/MWh)	87.226	107.574	107.464

Table 22: Average Zonal Prices in the Future 2035 Subscenario NE (in €/MWh).

Zone \ Case	IC-NE	IC+TC-NE	IC+TC+ES-NE
<i>DK1</i>	88.73	104.02	104.52
<i>DK2</i>	92.02	107.26	107.56
<i>FI</i>	91.39	107.03	107.43
<i>NO1</i>	86.54	106.65	107.01
<i>NO2</i>	85.74	106.84	107.01
<i>NO3</i>	85.57	107.76	107.87
<i>NO4</i>	85.21	107.17	107.51
<i>NO5</i>	81.93	103.96	104.00
<i>SE1</i>	83.85	106.00	106.49
<i>SE2</i>	82.98	105.62	106.38
<i>SE3</i>	89.93	112.71	110.95
<i>SE4</i>	92.83	115.86	112.86
Nordic	87.23	107.57	107.46

Table 23: Zonal Consumer Surplus in the Future 2035 Subscenario NE (in Billion €).

Zone \ Case	IC-NE	IC+TC-NE	IC+TC+ES-NE
<i>DK1</i>	5.93	5.66	5.66
<i>DK2</i>	4.08	3.92	3.91
<i>FI</i>	28.48	27.26	27.22
<i>NO1</i>	11.56	10.87	10.86
<i>NO2</i>	11.55	10.80	10.80
<i>NO3</i>	8.43	7.86	7.86
<i>NO4</i>	6.12	5.71	5.70
<i>NO5</i>	5.31	4.95	4.95
<i>SE1</i>	3.15	2.94	2.93
<i>SE2</i>	5.12	4.77	4.76
<i>SE3</i>	26.42	24.67	24.83
<i>SE4</i>	7.35	6.89	6.96
Nordic	123.49	116.29	116.46

Table 24: Zonal Producer Surplus in the Future 2035 Subscenario NE (in Billion €).

Zone \ Case	IC-NE	IC+TC-NE	IC+TC+ES-NE
<i>DK1</i>	1.14	1.41	1.42
<i>DK2</i>	0.43	0.55	0.55
<i>FI</i>	4.74	5.90	5.93
<i>NO1</i>	1.44	1.75	1.76
<i>NO2</i>	3.94	4.95	4.96
<i>NO3</i>	1.44	1.84	1.84
<i>NO4</i>	1.34	1.70	1.71
<i>NO5</i>	3.05	3.91	3.91
<i>SE1</i>	1.89	2.43	2.44
<i>SE2</i>	4.42	5.73	5.76
<i>SE3</i>	5.02	7.01	6.82
<i>SE4</i>	0.71	0.93	0.90
Nordic	29.55	38.12	37.98

Compared to the IC+TC case, the consequences of the additional consumption by the transport company are more severe when VRE capacity is fixed as in the DN case. Indeed, the IC+TC-NE case in Table 21 indicates that a “light” electrification plan is still feasible without dedicated VRE capacity expansion, but it causes the average electricity price to soar to €107.57/MWh and leads to a 66% increase in CO₂ emissions vis-à-vis the IC-NE case. This involves a decrease in price-elastic consumption of approximately 39 TWh from the DN case to 370.500 TWh along with an increase of 28 TWh in generation from the DN case. Other zonal distortions without matching VRE capacity expansion are further exacerbated from the IC-NE case (Tables 22–24).

Inclusion of energy storage without the matching VRE capacity to support the newly electrified sectors in the IC+TC+ES-NE case leads to a slight decrease in the average Nordic electricity price due to temporal arbitrage (Table 21). In effect, storage alleviates the inflexibility posed by

the consumption patterns of industrial processes and transport, which is especially relevant for zones *SE3* and *SE4* (Table 22). As a result, price-elastic consumption is slightly higher than in the IC+TC-NE case at 370.600 TWh. Nevertheless, the impact is again uneven and is largely to the benefit (detriment) of consumers (producers) as indicated in Tables 23–24.

3.2.3.3 Future 2035: LE Subscenario

To find an amenable result for the industrial consumer, we implement an intermediate case, IC-LE, with limited VRE expansion in zones *SE1–SE2* to go along with the matching VRE expansion in zones *SE3–SE4* as before. By doing so, we aim to find a suitable compromise such that prices are neither too high nor too low. We find that allowing for VRE expansion in those two zones that is sufficient to meet 45% of the additional demand from industrial processes renders average *SE1–SE2* prices in the €40/MWh range, i.e., high enough to be economically viable (Tables 25–28).

Table 25: Numerical Results for the Future 2035 Subscenario LE (in Billion € Unless Indicated).

Metric \ Case	IC-LE	IC+TC-LE	IC+TC+ES-LE
SS	152.700	151.923	152.050
CS	135.986	135.669	135.649
PS	16.089	17.897	18.019
MS	2.048	2.326	2.025
GR	0.141	0.161	0.109
HC	1.563	1.657	1.646
TS	–	-2.474	-2.203
BS	–	–	0.097
CO ₂ Emissions (Mt)	1.691	1.926	1.300
Average Price (€/MWh)	54.519	56.327	56.515

Table 26: Average Zonal Prices in the Future 2035 Subscenario LE (in €/MWh).

Zone \ Case	IC-LE	IC+TC-LE	IC+TC+ES-LE
<i>DK1</i>	63.72	65.19	64.60
<i>DK2</i>	67.08	69.15	68.22
<i>FI</i>	62.45	64.91	63.95
<i>NO1</i>	55.20	54.63	55.77
<i>NO2</i>	56.07	55.85	57.65
<i>NO3</i>	51.23	51.45	52.95
<i>NO4</i>	49.80	53.09	54.50
<i>NO5</i>	45.04	46.86	48.02
<i>SE1</i>	44.79	47.18	48.02
<i>SE2</i>	40.60	41.89	42.74
<i>SE3</i>	55.57	59.30	57.88
<i>SE4</i>	62.67	66.42	63.87
Nordic	54.52	56.33	56.52

Table 27: Zonal Consumer Surplus in the Future 2035 Subscenario LE (in Billion €).

Zone \ Case	IC-LE	IC+TC-LE	IC+TC+ES-LE
<i>DK1</i>	6.42	6.44	6.44
<i>DK2</i>	4.40	4.41	4.42
<i>FI</i>	30.93	30.77	30.85
<i>NO1</i>	12.71	12.75	12.72
<i>NO2</i>	12.65	12.66	12.59
<i>NO3</i>	9.35	9.34	9.30
<i>NO4</i>	6.81	6.74	6.72
<i>NO5</i>	5.94	5.91	5.89
<i>SE1</i>	3.54	3.52	3.51
<i>SE2</i>	5.84	5.83	5.81
<i>SE3</i>	29.36	29.25	29.33
<i>SE4</i>	8.03	8.03	8.07
Nordic	135.99	135.67	135.65

Table 28: Zonal Producer Surplus in the Future 2035 Subscenario LE (in Billion €).

Zone \ Case	IC-LE	IC+TC-LE	IC+TC+ES-LE
<i>DK1</i>	0.63	0.60	0.62
<i>DK2</i>	0.23	0.22	0.22
<i>FI</i>	2.56	2.69	2.64
<i>NO1</i>	0.93	0.91	0.92
<i>NO2</i>	2.52	2.50	2.59
<i>NO3</i>	0.81	0.82	0.84
<i>NO4</i>	0.75	0.80	0.82
<i>NO5</i>	1.60	1.68	1.72
<i>SE1</i>	1.08	1.21	1.24
<i>SE2</i>	1.94	2.09	2.13
<i>SE3</i>	2.57	3.67	3.55
<i>SE4</i>	0.48	0.72	0.74
Nordic	16.09	17.90	18.02

Similarly, with the inclusion of the transport company, the intermediate case, IC+TC-LE, is implemented, thereby allowing VRE expansion in *SE1–SE2* sufficient to meet 55% of the additional demand from industrial processes and the transport company. It should be noted that we retain matching VRE expansion in zones *SE3–SE4* as before. This case yields average *SE1–SE2* prices in the €45/MWh range (Tables 25–28). For sake of comparison, the installed VRE capacity in this case is given in Table 29, cf. Table 12 for the DN case of the Current 2023 scenario, which corresponds to total VRE generation of 162.069 TWh (Table 30). Due to the planned VRE capacity expansion from 2023, the additional transmission capacity between *SE1* and *FI*, the limited VRE capacity expansion in *SE1–SE2*, and the matching VRE capacity expansion in *SE3–SE4*, price-elastic consumption emerges relatively unchanged at 403.664 TWh vis-à-vis its level of 402.076 TWh in the GE case of the Current 2023 scenario. Prices exceed €200/MWh during the IC+TC-LE case of the Future 2035 scenario in 0.149%, 0.149%, 1.488%,

and 3.423% of the hours in zones $SE1$, $SE2$, $SE3$, and $SE4$, respectively. For reference, in the Current 2023 scenario's GE case, only $SE4$ experiences such events during 1.339% of the hours.

A thermal plant's shadow price, i.e., $\beta_{i,n,u}^{\text{ava}}$ from (8), reflects the marginal value of an infinitesimal increase in installed capacity. In the IC+TC-LE case of the Future 2035 scenario, it is €157,625/MW for a nuclear plant in $SE3$ and €10,039/MW for a gas-fired plant in $SE4$. As for VRE capacity, the corresponding shadow price, i.e., $\beta_{e,i,n}^{\text{ava}}$ from (11), is €44,017/MW, €55,767/MW, €83,337/MW, and €91,198/MW in zones $SE1$, $SE2$, $SE3$, and $SE4$, respectively, for onshore wind, which would appear to trigger adoption given its amortised investment cost. The corresponding values for solar are €12,518/MW, €13,125/MW, €19,401/MW, and €26,213/MW in zones $SE1$, $SE2$, $SE3$, and $SE4$, respectively, which do not align with its amortised investment cost. Finally, the shadow prices for offshore wind are €29,907/MW and €37,809/MW in $SE3$ and $SE4$, respectively, which would also not be profitable given its amortised investment cost.

Table 29: Zonal VRE Installed Capacity in the Future 2035 Subscenario LE's IC+TC-LE Case (in GW).

Zone \ Type	Offshore	Onshore	Solar
$DK1$	1.250	4.022	2.577
$DK2$	1.044	0.755	0.948
FI	0.044	6.650	1.018
$NO1$	–	0.384	0.267
$NO2$	–	1.425	0.233
$NO3$	–	2.112	0.042
$NO4$	–	1.159	0.004
$NO5$	–	–	0.056
$SE1$	–	8.583	0.027
$SE2$	–	9.621	0.168
$SE3$	0.028	20.379	2.604
$SE4$	0.165	5.992	1.174
Nordic	2.531	61.084	9.117

Table 30: Zonal VRE Generation in the Future 2035 Subscenario LE's IC+TC-LE Case (in TWh).

Zone \ Type	Offshore	Onshore	Solar
$DK1$	4.633	10.276	2.652
$DK2$	3.976	2.033	1.113
FI	0.204	20.805	1.083
$NO1$	–	–	–
$NO2$	–	3.383	–
$NO3$	–	2.035	–
$NO4$	–	2.418	–
$NO5$	–	–	–
$SE1$	–	15.097	0.020
$SE2$	–	23.740	0.137
$SE3$	0.101	49.483	2.352
$SE4$	0.573	14.714	1.240
Nordic	9.488	143.984	8.598

Exploring the impact of energy storage in this subscenario, as before, an intermediate case, IC+TC+ES-LE, is implemented. This involves limited VRE expansion in zones *SE1–SE2*, thereby allowing sufficient VRE expansion to meet 55% of the additional demand from industrial processes and the transport company along with matching VRE expansion in zones *SE3–SE4* as before. The results yield average *SE1–SE2* prices in the €45/MWh range (Tables 25–28).

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 $n \in \mathcal{N}$.

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

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

$\ell^{\text{AC}} \in \mathcal{L}^{\text{AC}} \subset \mathcal{L}$ AC transmission line.

$\ell^{\text{DC}} \in \mathcal{L}^{\text{DC}} \subset \mathcal{L}$ DC transmission line.

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

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

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

$n^{\text{AC}} \in \mathcal{N}^{\text{AC}} \subset \mathcal{N}$ AC node.

$n^{\text{DC}} \in \mathcal{N}^{\text{DC}} \subset \mathcal{N}$ DC node.

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

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

$u \in \mathcal{U}_{i,n}$ Thermal unit 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 $n \in \mathcal{N}$.

Parameters

$A_{n,t}^e$ Availability factor for VRE unit $e \in \mathcal{E}_{i,n}$ at node $n \in \mathcal{N}$ at time $t \in \mathcal{T}$ (-).³⁹

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

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

$C_{i,n,t,u}$ Cost of generation for thermal 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).

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

$D_{n,t}^{\text{slp}}$ Slope of inverse-demand curve at node $n \in \mathcal{N}$ at time $t \in \mathcal{T}$ (€/MWh²).

$E_n^{\text{in,ES}}$ Charging inefficiency of storage operator's battery at node $n \in \mathcal{N}$ (-).

$E_n^{\text{in,TC}}$ Charging inefficiency of transport company's fleet at node $n \in \mathcal{N}$ (-).

³⁹“(-)” refers to a unitless item.

$E_{i,n,w}^{\text{sto}}$	Self-discharge rate of hydro unit $w \in \mathcal{W}_{i,n}$ of firm $i \in \mathcal{I}$ at node $n \in \mathcal{N}$ (-).
$E_n^{\text{sto,ES}}$	Self-discharge rate of storage operator's battery at node $n \in \mathcal{N}$ (-).
$E_n^{\text{sto,TC}}$	Self-discharge rate of transport company's fleet at node $n \in \mathcal{N}$ (-).
$F_{i,n,w}$	Pumped-hydro inefficiency of hydro unit $w \in \mathcal{W}_{i,n}$ of firm $i \in \mathcal{I}$ at node $n \in \mathcal{N}$ (-).
$\bar{G}_{i,n,u}$	Maximum generation capacity of thermal unit $u \in \mathcal{U}_{i,n}$ of firm $i \in \mathcal{I}$ at node $n \in \mathcal{N}$ (MW).
$\bar{G}_{i,n}^e$	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).
$I_{i,n,t,w}$	Natural inflow to hydro unit $w \in \mathcal{W}_{i,n}$ belonging to firm i at node n in period t (MWh).
$\bar{K}_\ell / \underline{K}_\ell$	Capacity of 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).
$Q_{i,n,w}$	Generation efficiency of hydro unit $w \in \mathcal{W}_{i,n}$ of firm $i \in \mathcal{I}$ at node $n \in \mathcal{N}$ (-).
$\bar{R}_{i,n,w} / \underline{R}_{i,n,w}$	Maximum/minimum reservoir volume of hydro unit $w \in \mathcal{W}_{i,n}$ of firm $i \in \mathcal{I}$ at node $n \in \mathcal{N}$ (MWh).
$\bar{R}_n^{\text{ES}} / \underline{R}_n^{\text{ES}}$	Maximum/minimum battery capacity of storage operator at node $n \in \mathcal{N}$ (MWh).
$\bar{R}_n^{\text{TC}} / \underline{R}_n^{\text{TC}}$	Maximum/minimum fleet capacity of transport company at node $n \in \mathcal{N}$ (MWh).
$R_{i,n,w}^{\text{in}}$	Maximum charging rate for hydro unit $w \in \mathcal{W}_{i,n}$ of firm $i \in \mathcal{I}$ at node $n \in \mathcal{N}$ (-).
$R_n^{\text{in,ES}} / R_n^{\text{out,ES}}$	Maximum charging/discharging rate of storage operator's battery at node $n \in \mathcal{N}$ (-).
$R_n^{\text{in,TC}} / R_n^{\text{out,TC}}$	Maximum charging/discharging rate of transport company's fleet at node $n \in \mathcal{N}$ (-).
$R_u^{\text{up}} / R_u^{\text{down}}$	Ramp-up/ramp-down rate for thermal unit $u \in \mathcal{U}_{i,n}$ (-).
S	Cost of CO ₂ emissions (€/t).
T_t	Duration of period t (h).
V	Scaling factor for power flow (-).
X_n^{ind}	Minimum annual industrial electricity requirement at node $n \in \mathcal{N}$ (MWh).
$\hat{X}_{n,t}^{\text{ind}} / \check{X}_{n,t}^{\text{ind}}$	Maximum/minimum relative periodic industrial electricity consumption at node $n \in \mathcal{N}$ at time $t \in \mathcal{T}$ (-).

\bar{X}_n^{ind}	Maximum relative periodic increase in industrial electricity consumption at node $n \in \mathcal{N}$ (-).
$\underline{X}_n^{\text{ind}}$	Maximum relative periodic decrease in industrial electricity consumption at node $n \in \mathcal{N}$ (-).
X_n^{TC}	Minimum annual electricity requirement for transport company at node $n \in \mathcal{N}$ (MWh).
$\hat{X}_{n,t}^{\text{TC}}/\check{X}_{n,t}^{\text{TC}}$	Maximum/minimum relative periodic electricity consumption for transport company at node $n \in \mathcal{N}$ at time $t \in \mathcal{T}$ (-).
$\bar{Y}_{i,n,w}$	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

Primal variables

$a_{i,n,u}/a_{i,n}^e/a_{i,n,w}$	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).
$f_{\ell,t}$	Power flow on transmission 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).
$g_{i,n,t}^e$	Generation by 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).
$g_{n,t}^{\text{TC}}$	Transport company's electricity sales 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).
$q_{n,t}^{\text{ind}}$	Industrial consumption at node $n \in \mathcal{N}$ at time $t \in \mathcal{T}$ (MWh).
$q_{n,t}^{\text{TC}}$	Transport company's consumption at node $n \in \mathcal{N}$ at time $t \in \mathcal{T}$ (MWh).
$r_{i,n,t,w}^{\text{in}}$	Energy pumped into hydro unit $w \in \mathcal{W}_{i,n}$ of firm $i \in \mathcal{I}$ at node $n \in \mathcal{N}$ at time $t \in \mathcal{T}$ (MWh).
$r_{n,t}^{\text{in,ES}}$	Energy charged into storage operator's battery at node $n \in \mathcal{N}$ at time $t \in \mathcal{T}$ (MWh).
$r_{n,t}^{\text{in,TC}}$	Energy charged into transport company's fleet at node $n \in \mathcal{N}$ at time $t \in \mathcal{T}$ (MWh).
$r_{i,n,t,w}^{\text{out}}$	Energy produced from hydro unit $w \in \mathcal{W}_{i,n}$ of firm $i \in \mathcal{I}$ at node $n \in \mathcal{N}$ at time $t \in \mathcal{T}$ (MWh).

$r_{n,t}^{\text{out,ES}}$	Energy discharged from storage operator's battery at node $n \in \mathcal{N}$ at time $t \in \mathcal{T}$ (MWh).
$r_{n,t}^{\text{out,TC}}$	Energy discharged from transport company's fleet at node $n \in \mathcal{N}$ at time $t \in \mathcal{T}$ (MWh).
$r_{i,n,t,w}^{\text{sto}}$	Energy stored in hydro unit $w \in \mathcal{W}_{i,n}$ of firm $i \in \mathcal{I}$ at node $n \in \mathcal{N}$ at time $t \in \mathcal{T}$ (MWh).
$r_{n,t}^{\text{sto,ES}}$	Energy stored in storage operator's battery at node $n \in \mathcal{N}$ at time $t \in \mathcal{T}$ (MWh).
$r_{n,t}^{\text{sto,TC}}$	Energy stored in transport company's fleet at node $n \in \mathcal{N}$ at time $t \in \mathcal{T}$ (MWh).
$v_{n,t}$	Voltage angle at node $n^{\text{AC}} \in \mathcal{N}^{\text{AC}}$ at time $t \in \mathcal{T}$ (rad).
$z_{i,n,t,w}$	Energy spilled from hydro unit $w \in \mathcal{W}_{i,n}$ of firm $i \in \mathcal{I}$ at node $n \in \mathcal{N}$ at time $t \in \mathcal{T}$ (MWh).

Dual variables

$\beta_{i,n,u}^{\text{ava}} / \beta_{e,i,n}^{\text{ava}} / \beta_{i,n,w}^{\text{ava}}$	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).
$\beta_{i,n,t}^e$	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).
$\beta_{i,n,t,u}^{\text{up}} / \beta_{i,n,t,u}^{\text{down}}$	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).
$\eta_{\ell^{\text{AC}},t}$	Shadow price of energy flow on AC line $\ell^{\text{AC}} \in \mathcal{L}^{\text{AC}}$ 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).
$\bar{\kappa}_{n^{\text{AC}},t} / \underline{\kappa}_{n^{\text{AC}},t}$	Shadow price of maximum/minimum voltage angle at node $n^{\text{AC}} \in \mathcal{N}^{\text{AC}}$ at time $t \in \mathcal{T}$ (€/rad).
$\lambda_{i,n,t,w}^{\text{bal}}$	Shadow price of energy 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 $t \in \mathcal{T}$ (€/MWh).
$\lambda_{n,t}^{\text{bal,ES}}$	Shadow price of energy stored in storage operator's battery at node $n \in \mathcal{N}$ at time $t \in \mathcal{T}$ (€/MWh).
$\lambda_{n,t}^{\text{bal,TC}}$	Shadow price of energy stored in transport company's fleet at node $n \in \mathcal{N}$ at time $t \in \mathcal{T}$ (€/MWh).
$\lambda_{i,n,t,w}^{\text{h}}$	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).

$\lambda_{i,n,t,w}^{\text{in}}$	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 $t \in \mathcal{T}$ (€/MWh).
$\lambda_{n,t}^{\text{in,ES}} / \lambda_{n,t}^{\text{out,ES}}$	Shadow price of charging/discharging rate of storage operator's battery at node $n \in \mathcal{N}$ at time $t \in \mathcal{T}$ (€/MWh).
$\lambda_{n,t}^{\text{in,TC}} / \lambda_{n,t}^{\text{out,TC}}$	Shadow price of charging/discharging rate of transport company's fleet at node $n \in \mathcal{N}$ at time $t \in \mathcal{T}$ (€/MWh).
$\lambda_{n,t}^{\text{sup,TC}}$	Shadow price of energy released from transport company's fleet at node $n \in \mathcal{N}$ at time $t \in \mathcal{T}$ (€/MWh).
$\lambda_{i,n,t,w}^{\text{ub}} / \lambda_{i,n,t,w}^{\text{lb}}$	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 $t \in \mathcal{T}$ (€/MWh).
$\lambda_{n,t}^{\text{ub,ES}} / \lambda_{n,t}^{\text{lb,ES}}$	Shadow price of maximum/minimum battery capacity owned by storage operator at node $n \in \mathcal{N}$ at time $t \in \mathcal{T}$ (€/MWh).
$\lambda_{n,t}^{\text{ub,TC}} / \lambda_{n,t}^{\text{lb,TC}}$	Shadow price of maximum/minimum fleet capacity owned by transport company at node $n \in \mathcal{N}$ at time $t \in \mathcal{T}$ (€/MWh).
λ_n^{ind}	Shadow price of minimum annual industrial electricity consumption at node $n \in \mathcal{N}$ (€/MWh).
$\hat{\lambda}_{n,t}^{\text{ind}} / \check{\lambda}_{n,t}^{\text{ind}}$	Shadow price of maximum/minimum periodic industrial electricity consumption at node $n \in \mathcal{N}$ at time $t \in \mathcal{T}$ (€/MWh).
$\bar{\lambda}_{n,t}^{\text{ind}}$	Shadow price of maximum increase in periodic industrial electricity consumption at node $n \in \mathcal{N}$ at time $t \in \mathcal{T}$ (€/MWh).
$\underline{\lambda}_{n,t}^{\text{ind}}$	Shadow price of maximum decrease in periodic industrial electricity consumption at node $n \in \mathcal{N}$ at time $t \in \mathcal{T}$ (€/MWh).
λ_n^{TC}	Shadow price of minimum annual electricity consumption for transport company at node $n \in \mathcal{N}$ (€/MWh).
$\hat{\lambda}_{n,t}^{\text{TC}} / \check{\lambda}_{n,t}^{\text{TC}}$	Shadow price of maximum/minimum periodic electricity consumption for transport company at node $n \in \mathcal{N}$ at time $t \in \mathcal{T}$ (€/MWh).
$\bar{\mu}_{\ell,t} / \underline{\mu}_{\ell,t}$	Shadow price of positive/negative transmission capacity of line $\ell \in \mathcal{L}$ at time $t \in \mathcal{T}$ (€/MWh).

Appendix B Mathematical Formulation

B.1 Mathematical Formulation for the ISO

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

$$\begin{aligned}
\text{s.t. } q_{n,t} + q_{n,t}^{\text{ind}} &= \sum_{i \in \mathcal{I}} \sum_{u \in \mathcal{U}_{i,n}} g_{i,n,t,u} + \sum_{i \in \mathcal{I}} \sum_{e \in \mathcal{E}_{i,n}} g_{i,n,t}^e + \sum_{i \in \mathcal{I}} \sum_{w \in \mathcal{W}_{i,n}} (Q_{i,n,w} r_{i,n,t,w}^{\text{out}} - F_{i,n,w} r_{i,n,t,w}^{\text{in}}) \\
&\quad + r_{n,t}^{\text{out,ES}} - E_n^{\text{in,ES}} r_{n,t}^{\text{in,ES}} + g_{n,t}^{\text{TC}} - E_n^{\text{in,TC}} r_{n,t}^{\text{in,TC}} \\
&\quad - \sum_{\ell \in \mathcal{L}_n^+} V T_t f_{\ell,t} + \sum_{\ell \in \mathcal{L}_n^-} V T_t f_{\ell,t} : \theta_{n,t}, \forall n, t
\end{aligned} \tag{2}$$

$$\mu_{\ell,t} : -T_t \underline{K}_{\ell} \leq V T_t f_{\ell,t} \leq T_t \overline{K}_{\ell} : \bar{\mu}_{\ell,t}, \forall \ell, t \tag{3}$$

$$T_t f_{\ell \text{AC},t} = T_t B_{\ell \text{AC}} (v_{n_{\ell}^+,t} - v_{n_{\ell}^-,t}) : \eta_{\ell \text{AC},t}, \forall \ell^{\text{AC}} \in \mathcal{L}^{\text{AC}}, t \tag{4}$$

$$\underline{k}_{n \text{AC},t} : -\pi \leq v_{n \text{AC},t} \leq \pi : \bar{k}_{n \text{AC},t}, \forall n^{\text{AC}} \in \mathcal{N}^{\text{AC}}, t \tag{5}$$

Here, $\Gamma^{\text{ISO}} \equiv \{q_{n,t} \geq 0, f_{\ell,t} \text{ u.r.s.}, v_{n \text{AC},t} \text{ u.r.s.}\}$ and ‘‘u.r.s.’’ stands for ‘‘unrestricted in sign.’’ The lower-case Greek letters adjacent to the constraints refer to the corresponding dual variables. At optimality, the dual variables reflect the shadow prices of the constraints. For example, the dual variable, $\bar{\mu}_{\ell,t}$, linked with (3) captures the marginal impact on the maximised gross surplus from an infinitesimal increase in the effective transmission limit, $T_t \overline{K}_{\ell}$. Some dual variables have non-negative signs, e.g., if the associated constraints are inequalities, whereas others are u.r.s., i.e., they are free to take on any sign, because their corresponding constraints are equalities.

B.2 Mathematical Formulation for Firm i

$$\begin{aligned}
\text{Maximise}_{\Gamma^i} \sum_{n \in \mathcal{N}} \sum_{t \in \mathcal{T}} &\left[\theta_{n,t} \left(\sum_{u \in \mathcal{U}_{i,n}} g_{i,n,t,u} + \sum_{e \in \mathcal{E}_{i,n}} g_{i,n,t}^e + \sum_{w \in \mathcal{W}_{i,n}} Q_{i,n,w} r_{i,n,t,w}^{\text{out}} - \sum_{w \in \mathcal{W}_{i,n}} F_{i,n,w} r_{i,n,t,w}^{\text{in}} \right) \right. \\
&\quad \left. - \sum_{u \in \mathcal{U}_{i,n}} (C_{i,n,t,u} + S P_{i,n,u}) g_{i,n,t,u} \right] - \sum_{n \in \mathcal{N}} \sum_{u \in \mathcal{U}_{i,n}} C_{i,n,u}^{\text{ava}} a_{i,n,u} \\
&\quad - \sum_{n \in \mathcal{N}} \sum_{e \in \mathcal{E}_{i,n}} C_{e,i,n}^{\text{ava}} a_{i,n}^e - \sum_{n \in \mathcal{N}} \sum_{w \in \mathcal{W}_{i,n}} C_{i,n,w}^{\text{ava}} a_{i,n,w}
\end{aligned} \tag{6}$$

$$\text{s.t. } g_{i,n,t,u} \leq T_t a_{i,n,u} : \beta_{i,n,t,u}, \forall n, t, u \in \mathcal{U}_{i,n} \tag{7}$$

$$a_{i,n,u} \leq \overline{G}_{i,n,u} : \beta_{i,n,u}^{\text{ava}}, \forall n, u \in \mathcal{U}_{i,n} \tag{8}$$

$$\beta_{i,n,t,u}^{\text{down}} : -T_t R_u^{\text{down}} a_{i,n,u} \leq g_{i,n,t,u} - g_{i,n,t-1,u} \leq T_t R_u^{\text{up}} a_{i,n,u} : \beta_{i,n,t,u}^{\text{up}}, \forall n, t, u \in \mathcal{U}_{i,n} \tag{9}$$

$$g_{i,n,t}^e \leq T_t A_{n,t}^e a_{i,n}^e : \beta_{i,n,t}^e, \forall e \in \mathcal{E}_{i,n}, n, t \tag{10}$$

$$a_{i,n}^e \leq \overline{G}_{i,n}^e : \beta_{e,i,n}^{\text{ava}}, \forall e \in \mathcal{E}_{i,n}, n \tag{11}$$

$$r_{i,n,t,w}^{\text{sto}} = (1 - E_{i,n,w}^{\text{sto}}) T_t r_{i,n,t-1,w}^{\text{sto}} + r_{i,n,t,w}^{\text{in}} - r_{i,n,t,w}^{\text{out}} - z_{i,n,t,w} + I_{i,n,t,w} : \lambda_{i,n,t,w}^{\text{bal}}, \forall n, t, w \in \mathcal{W}_{i,n} \tag{12}$$

$$\lambda_{i,n,t,w}^{\text{lb}} : \underline{R}_{i,n,w} \leq r_{i,n,t,w}^{\text{sto}} \leq \overline{R}_{i,n,w} : \lambda_{i,n,t,w}^{\text{ub}}, \forall n, t, w \in \mathcal{W}_{i,n} \tag{13}$$

$$r_{i,n,t,w}^{\text{in}} \leq R_{i,n,w}^{\text{in}} \overline{R}_{i,n,w} : \lambda_{i,n,t,w}^{\text{in}}, \forall n, t, w \in \mathcal{W}_{i,n} \tag{14}$$

$$Q_{i,n,w} r_{i,n,t,w}^{\text{out}} \leq T_t a_{i,n,w} : \lambda_{i,n,t,w}^{\text{h}}, \forall n, t, w \in \mathcal{W}_{i,n} \tag{15}$$

$$a_{i,n,w} \leq \overline{Y}_{i,n,w} : \beta_{i,n,w}^{\text{ava}}, \forall n, w \in \mathcal{W}_{i,n} \tag{16}$$

Here, $\Gamma^i \equiv \{a_{i,n,u} \geq 0, a_{e,i,n}^e \geq 0, a_{i,n,w} \geq 0, g_{i,n,t,u} \geq 0, g_{i,n,t}^e \geq 0, r_{i,n,t,w}^{\text{in}} \geq 0, r_{i,n,t,w}^{\text{out}} \geq 0, r_{i,n,t,w}^{\text{sto}} \geq 0\}$

$0, z_{i,n,t,w} \geq 0\}$.

B.3 Mathematical Formulation for the Storage Operator

$$\text{Maximise}_{\Gamma^{\text{ES}}} \sum_{n \in \mathcal{N}} \sum_{t \in \mathcal{T}} \theta_{n,t} (r_{n,t}^{\text{out,ES}} - E_n^{\text{in,ES}} r_{n,t}^{\text{in,ES}}) \quad (17)$$

$$\text{s.t. } r_{n,t}^{\text{sto,ES}} = (1 - E_n^{\text{sto,ES}})^{T_t} r_{n,t-1}^{\text{sto,ES}} + r_{n,t}^{\text{in,ES}} - r_{n,t}^{\text{out,ES}} : \lambda_{n,t}^{\text{bal,ES}}, \forall n, t \quad (18)$$

$$\lambda_{n,t}^{\text{lb,ES}} : \underline{R}_n^{\text{ES}} \leq r_{n,t}^{\text{sto,ES}} \leq \overline{R}_n^{\text{ES}} : \lambda_{n,t}^{\text{ub,ES}}, \forall n, t \quad (19)$$

$$r_{n,t}^{\text{in,ES}} \leq R_n^{\text{in,ES}} \overline{R}_n^{\text{ES}} : \lambda_{n,t}^{\text{in,ES}}, \forall n, t \quad (20)$$

$$r_{n,t}^{\text{out,ES}} \leq R_n^{\text{out,ES}} \overline{R}_n^{\text{ES}} : \lambda_{n,t}^{\text{out,ES}}, \forall n, t \quad (21)$$

Here, $\Gamma^{\text{ES}} \equiv \{r_{n,t}^{\text{in,ES}} \geq 0, r_{n,t}^{\text{out,ES}} \geq 0, r_{n,t}^{\text{sto,ES}} \geq 0\}$.

B.4 Mathematical Formulation for the Transport Company

$$\text{Maximise}_{\Gamma^{\text{TC}}} \sum_{n \in \mathcal{N}} \sum_{t \in \mathcal{T}} \theta_{n,t} (g_{n,t}^{\text{TC}} - E_n^{\text{in,TC}} r_{n,t}^{\text{in,TC}}) \quad (22)$$

$$\text{s.t. } r_{n,t}^{\text{sto,TC}} = (1 - E_n^{\text{sto,TC}})^{T_t} r_{n,t-1}^{\text{sto,TC}} + r_{n,t}^{\text{in,TC}} - r_{n,t}^{\text{out,TC}} : \lambda_{n,t}^{\text{bal,TC}}, \forall n, t \quad (23)$$

$$\lambda_{n,t}^{\text{lb,TC}} : \underline{R}_n^{\text{TC}} \leq r_{n,t}^{\text{sto,TC}} \leq \overline{R}_n^{\text{TC}} : \lambda_{n,t}^{\text{ub,TC}}, \forall n, t \quad (24)$$

$$r_{n,t}^{\text{in,TC}} \leq R_n^{\text{in,TC}} \overline{R}_n^{\text{TC}} : \lambda_{n,t}^{\text{in,TC}}, \forall n, t \quad (25)$$

$$r_{n,t}^{\text{out,TC}} \leq R_n^{\text{out,TC}} \overline{R}_n^{\text{TC}} : \lambda_{n,t}^{\text{out,TC}}, \forall n, t \quad (26)$$

$$q_{n,t}^{\text{TC}} + g_{n,t}^{\text{TC}} = r_{n,t}^{\text{out,TC}} : \lambda_{n,t}^{\text{sup,TC}}, \forall n, t \quad (27)$$

$$\sum_{t \in \mathcal{T}} q_{n,t}^{\text{TC}} \geq X_n^{\text{TC}} : \lambda_n^{\text{TC}}, \forall n \quad (28)$$

$$\check{\lambda}_{n,t}^{\text{TC}} : \check{X}_{n,t}^{\text{TC}} X_n^{\text{TC}} \leq q_{n,t}^{\text{TC}} \leq \hat{X}_{n,t}^{\text{TC}} X_n^{\text{TC}} : \hat{\lambda}_{n,t}^{\text{TC}}, \forall n, t \quad (29)$$

Here, $\Gamma^{\text{TC}} \equiv \{g_{n,t}^{\text{TC}} \geq 0, q_{n,t}^{\text{TC}} \geq 0, r_{n,t}^{\text{in,TC}} \geq 0, r_{n,t}^{\text{out,TC}} \geq 0, r_{n,t}^{\text{sto,TC}} \geq 0\}$.

B.5 Mathematical Formulation for the Industrial Consumer

$$\text{Minimise}_{\Gamma^{\text{ind}}} \sum_{n \in \mathcal{N}} \sum_{t \in \mathcal{T}} \theta_{n,t} q_{n,t}^{\text{ind}} \quad (30)$$

$$\text{s.t. } \sum_{t \in \mathcal{T}} q_{n,t}^{\text{ind}} \geq X_n^{\text{ind}} : \lambda_n^{\text{ind}}, \forall n \quad (31)$$

$$\check{\lambda}_{n,t}^{\text{ind}} : \check{X}_{n,t}^{\text{ind}} X_n^{\text{ind}} \leq q_{n,t}^{\text{ind}} \leq \hat{X}_{n,t}^{\text{ind}} X_n^{\text{ind}} : \hat{\lambda}_{n,t}^{\text{ind}}, \forall n, t \quad (32)$$

$$\underline{\lambda}_{n,t}^{\text{ind}} : -\underline{X}_n^{\text{ind}} X_n^{\text{ind}} \leq q_{n,t}^{\text{ind}} - q_{n,t-1}^{\text{ind}} \leq \overline{X}_n^{\text{ind}} X_n^{\text{ind}} : \overline{\lambda}_{n,t}^{\text{ind}}, \forall n, t \quad (33)$$

Here, $\Gamma^{\text{ind}} \equiv \{q_{n,t}^{\text{ind}} \geq 0\}$.

B.6 Karush-Kuhn-Tucker (KKT) Conditions

B.6.1 KKT Conditions for the ISO

$$0 \leq q_{n,t} \perp - \left(D_{n,t}^{\text{int}} - D_{n,t}^{\text{slp}} q_{n,t} \right) + \theta_{n,t} \geq 0, \forall n, t \quad (34)$$

$$f_{\ell,t} \text{ u.r.s.}, T_t \eta_{\ell^{\text{AC}},t} + V T_t \bar{\mu}_{\ell,t} - V T_t \underline{\mu}_{\ell,t} + V T_t \theta_{n_{\ell^+},t} - V T_t \theta_{n_{\ell^-},t} = 0, \forall \ell, t \quad (35)$$

$$v_{n^{\text{AC}},t} \text{ u.r.s.}, - \sum_{\ell \in \mathcal{L}_n^+} T_t B_{\ell^{\text{AC}}} \eta_{\ell^{\text{AC}},t} + \sum_{\ell \in \mathcal{L}_n^-} T_t B_{\ell^{\text{AC}}} \eta_{\ell^{\text{AC}},t} + \bar{\kappa}_{n^{\text{AC}},t} - \underline{\kappa}_{n^{\text{AC}},t} = 0, \\ \forall n^{\text{AC}} \in \mathcal{N}^{\text{AC}}, t \quad (36)$$

$$\theta_{n,t} \text{ u.r.s.}, q_{n,t} + q_{n,t}^{\text{ind}} - \sum_{i \in \mathcal{I}} \sum_{u \in \mathcal{U}_{i,n}} g_{i,n,t,u} - \sum_{i \in \mathcal{I}} \sum_{e \in \mathcal{E}_{i,n}} g_{i,n,t}^e - r_{n,t}^{\text{out,ES}} + E_n^{\text{in,ES}} r_{n,t}^{\text{in,ES}} \\ - g_{n,t}^{\text{TC}} + E_n^{\text{in,TC}} r_{n,t}^{\text{in,TC}} - \sum_{i \in \mathcal{I}} \sum_{w \in \mathcal{W}_{i,n}} \left(Q_{i,n,w} r_{i,n,t,w}^{\text{out}} - F_{i,n,w} r_{i,n,t,w}^{\text{in}} \right) \\ + \sum_{\ell \in \mathcal{L}_n^+} V T_t f_{\ell,t} - \sum_{\ell \in \mathcal{L}_n^-} V T_t f_{\ell,t} = 0, \forall n, t \quad (37)$$

$$0 \leq \underline{\mu}_{\ell,t} \perp T_t \underline{K}_{\ell} + V T_t f_{\ell,t} \geq 0, \ell, t \quad (38)$$

$$0 \leq \bar{\mu}_{\ell,t} \perp T_t \bar{K}_{\ell} - V T_t f_{\ell,t} \geq 0, \ell, t \quad (39)$$

$$\eta_{\ell^{\text{AC}},t} \text{ u.r.s.}, T_t B_{\ell^{\text{AC}}} \left(v_{n_{\ell^+},t} - v_{n_{\ell^-},t} \right) - T_t f_{\ell^{\text{AC}},t} = 0, \forall \ell^{\text{AC}} \in \mathcal{L}^{\text{AC}}, t \quad (40)$$

$$0 \leq \underline{\kappa}_{n^{\text{AC}},t} \perp \pi + v_{n^{\text{AC}},t} \geq 0, \forall n^{\text{AC}} \in \mathcal{N}^{\text{AC}}, t \quad (41)$$

$$0 \leq \bar{\kappa}_{n^{\text{AC}},t} \perp \pi - v_{n^{\text{AC}},t} \geq 0, \forall n^{\text{AC}} \in \mathcal{N}^{\text{AC}}, t \quad (42)$$

The KKT conditions have standard economic interpretations. For example, (34) indicates that the marginal utility of electricity consumption is equal to the nodal electricity price if consumption is strictly positive. However, if the nodal electricity price exceeds the marginal utility of electricity consumption, then consumption is zero.

B.6.2 KKT Conditions for Firm i

$$0 \leq a_{i,n,u} \perp C_{i,n,u}^{\text{ava}} + \beta_{i,n,u}^{\text{ava}} - \sum_{t \in \mathcal{T}} T_t \beta_{i,n,t,u} - \sum_{t \in \mathcal{T}} T_t R_u^{\text{up}} \beta_{i,n,t,u}^{\text{up}} - \sum_{t \in \mathcal{T}} T_t R_u^{\text{down}} \beta_{i,n,t,u}^{\text{down}} \geq 0, \\ \forall n, u \in \mathcal{U}_{i,n} \quad (43)$$

$$0 \leq a_{i,n,t}^e \perp C_{e,i,n}^{\text{ava}} + \beta_{e,i,n}^{\text{ava}} - \sum_{t \in \mathcal{T}} T_t A_{n,t}^e \beta_{i,n,t}^e \geq 0, \forall e \in \mathcal{E}_{i,n}, n \quad (44)$$

$$0 \leq a_{i,n,w} \perp C_{i,n,w}^{\text{ava}} + \beta_{i,n,w}^{\text{ava}} - \sum_{t \in \mathcal{T}} T_t \lambda_{i,n,t,w}^{\text{h}} \geq 0, \forall n, w \in \mathcal{W}_{i,n} \quad (45)$$

$$0 \leq g_{i,n,t,u} \perp C_{i,n,t,u} + S P_{i,n,u} - \theta_{n,t} + \beta_{i,n,t,u} + \beta_{i,n,t,u}^{\text{up}} - \beta_{i,n,t+1,u}^{\text{up}} + \beta_{i,n,t+1,u}^{\text{down}} - \beta_{i,n,t,u}^{\text{down}} \geq 0, \\ \forall n, t, u \in \mathcal{U}_{i,n} \quad (46)$$

$$0 \leq g_{i,n,t}^e \perp -\theta_{n,t} + \beta_{i,n,t}^e \geq 0, \forall e \in \mathcal{E}_{i,n}, n, t \quad (47)$$

$$0 \leq r_{i,n,t,w}^{\text{in}} \perp F_{i,n,w} \theta_{n,t} - \lambda_{i,n,t,w}^{\text{bal}} + \lambda_{i,n,t,w}^{\text{in}} \geq 0, \forall n, t, w \in \mathcal{W}_{i,n} \quad (48)$$

$$0 \leq r_{i,n,t,w}^{\text{out}} \perp -Q_{i,n,w} \theta_{n,t} + \lambda_{i,n,t,w}^{\text{bal}} + Q_{i,n,w} \lambda_{i,n,t,w}^{\text{h}} \geq 0, \forall n, t, w \in \mathcal{W}_{i,n} \quad (49)$$

$$0 \leq r_{i,n,t,w}^{\text{sto}} \perp \lambda_{i,n,t,w}^{\text{bal}} - (1 - E_{i,n,w}^{\text{sto}}) T_t \lambda_{i,n,t+1,w}^{\text{bal}} + \lambda_{i,n,t,w}^{\text{ub}} - \lambda_{i,n,t,w}^{\text{lb}} \geq 0, \forall n, t, w \in \mathcal{W}_{i,n} \quad (50)$$

$$0 \leq z_{i,n,t,w} \perp \lambda_{i,n,t,w}^{\text{bal}} \geq 0, \forall n, t, w \in \mathcal{W}_{i,n} \quad (51)$$

$$\lambda_{i,n,t,w}^{\text{bal}} \text{ u.r.s., } r_{i,n,t,w}^{\text{sto}} - (1 - E_{i,n,t,w}^{\text{sto}})^{T_t} r_{i,n,t-1,w}^{\text{sto}} - r_{i,n,t,w}^{\text{in}} + r_{i,n,t,w}^{\text{out}} + z_{i,n,t,w} - I_{i,n,t,w} = 0, \quad (52)$$

$$\forall n, t, w \in \mathcal{W}_{i,n}$$

$$0 \leq \beta_{i,n,t}^e \perp T_t A_{n,t}^e a_{i,n}^e - g_{i,n,t}^e \geq 0, \forall e \in \mathcal{E}_{i,n}, n, t \quad (53)$$

$$0 \leq \beta_{e,i,n}^{\text{ava}} \perp \bar{G}_{i,n}^e - a_{i,n}^e \geq 0, \forall e \in \mathcal{E}_{i,n}, n \quad (54)$$

$$0 \leq \beta_{i,n,t,u} \perp T_t a_{i,n,u} - g_{i,n,t,u} \geq 0, \forall n, t, u \in \mathcal{U}_{i,n} \quad (55)$$

$$0 \leq \beta_{i,n,u}^{\text{ava}} \perp \bar{G}_{i,n,u} - a_{i,n,u} \geq 0, \forall n, u \in \mathcal{U}_{i,n} \quad (56)$$

$$0 \leq \beta_{i,n,t,u}^{\text{up}} \perp T_t R_u^{\text{up}} a_{i,n,u} + g_{i,n,t-1,u} - g_{i,n,t,u} \geq 0, \forall n, t, u \in \mathcal{U}_{i,n} \quad (57)$$

$$0 \leq \beta_{i,n,t,u}^{\text{down}} \perp T_t R_u^{\text{down}} a_{i,n,u} + g_{i,n,t,u} - g_{i,n,t-1,u} \geq 0, \forall n, t, u \in \mathcal{U}_{i,n} \quad (58)$$

$$0 \leq \lambda_{i,n,t,w}^{\text{in}} \perp T_t R_{i,n,w}^{\text{in}} \bar{R}_{i,n,w} - r_{i,n,t,w}^{\text{in}} \geq 0, \forall n, t, w \in \mathcal{W}_{i,n} \quad (59)$$

$$0 \leq \lambda_{i,n,t,w}^{\text{h}} \perp T_t a_{i,n,w} - Q_{i,n,w} r_{i,n,t,w}^{\text{out}} \geq 0, \forall n, t, w \in \mathcal{W}_{i,n} \quad (60)$$

$$0 \leq \beta_{i,n,w}^{\text{ava}} \perp \bar{Y}_{i,n,w} - a_{i,n,w} \geq 0, \forall n, w \in \mathcal{W}_{i,n} \quad (61)$$

$$0 \leq \lambda_{i,n,t,w}^{\text{ub}} \perp \bar{R}_{i,n,w} - r_{i,n,t,w}^{\text{sto}} \geq 0, \forall n, t, w \in \mathcal{W}_{i,n} \quad (62)$$

$$0 \leq \lambda_{i,n,t,w}^{\text{lb}} \perp r_{i,n,t,w}^{\text{sto}} - \underline{R}_{i,n,w} \geq 0, \forall n, t, w \in \mathcal{W}_{i,n} \quad (63)$$

Firm $i \in \mathcal{I}$'s KKT conditions also have straightforward economic interpretations. For example, (46) states that if thermal generation is strictly positive, then the nodal electricity price equals the marginal cost of generation plus the cost of CO₂ permits and any capacity rents. By contrast, if the marginal cost of generation plus the cost of CO₂ permits and any capacity rents exceeds the nodal electricity price, then thermal generation is zero. Moreover, (44) indicates that if VRE capacity is made available, then its marginal value of generation capacity plus its amortised annual fixed O&M capacity cost equals the sum of its capacity's availability-factor-adjusted shadow prices over the year. In particular, if VRE plant e at node n belonging to firm i is fully dispatched at its available capacity during period t , i.e., $g_{i,n,t}^e = T_t A_{n,t}^e a_{i,n}^e$, then we have $\theta_{n,t} = \beta_{i,n,t}^e \geq 0$ from (47) and (53). Likewise, if the capacity made available for this plant is at its installed capacity, i.e., $a_{i,n}^e = \bar{G}_{i,n}^e$, then $C_{e,i,n}^{\text{ava}} + \beta_{e,i,n}^{\text{ava}} = \sum_{t \in \mathcal{T}} T_t A_{n,t}^e \beta_{i,n,t}^e$ from (44) and (54). Hence, in such a situation, the nodal electricity price, $\theta_{n,t}$, must be high enough to cover the availability-weighted periodic share of the amortised capital costs, $C_{e,i,n}^{\text{ava}} + \beta_{e,i,n}^{\text{ava}}$.

B.6.3 KKT Conditions for the Storage Operator

$$0 \leq r_{n,t}^{\text{in,ES}} \perp E_n^{\text{in,ES}} \theta_{n,t} - \lambda_{n,t}^{\text{bal,ES}} + \lambda_{n,t}^{\text{in,ES}} \geq 0, \forall n, t \quad (64)$$

$$0 \leq r_{n,t}^{\text{out,ES}} \perp -\theta_{n,t} + \lambda_{n,t}^{\text{bal,ES}} + \lambda_{n,t}^{\text{out,ES}} \geq 0, \forall n, t \quad (65)$$

$$0 \leq r_{n,t}^{\text{sto,ES}} \perp \lambda_{n,t}^{\text{bal,ES}} - (1 - E_n^{\text{sto,ES}})^{T_t} \lambda_{n,t+1}^{\text{bal,ES}} + \lambda_{n,t}^{\text{ub,ES}} - \lambda_{n,t}^{\text{lb,ES}} \geq 0, \forall n, t \quad (66)$$

$$\lambda_{n,t}^{\text{bal,ES}} \text{ u.r.s., } r_{n,t}^{\text{sto,ES}} - (1 - E_n^{\text{sto,ES}})^{T_t} r_{n,t-1}^{\text{sto,ES}} - r_{n,t}^{\text{in,ES}} + r_{n,t}^{\text{out,ES}} = 0, \forall n, t \quad (67)$$

$$0 \leq \lambda_{n,t}^{\text{ub,ES}} \perp \bar{R}_n^{\text{ES}} - r_{n,t}^{\text{sto,ES}} \geq 0, \forall n, t \quad (68)$$

$$0 \leq \lambda_{n,t}^{\text{lb,ES}} \perp r_{n,t}^{\text{sto,ES}} - \underline{R}_n^{\text{ES}} \geq 0, \forall n, t \quad (69)$$

$$0 \leq \lambda_{n,t}^{\text{in,ES}} \perp R_n^{\text{in,ES}} \bar{R}_n^{\text{ES}} - r_{n,t}^{\text{in,ES}} \geq 0, \forall n, t \quad (70)$$

$$0 \leq \lambda_{n,t}^{\text{out,ES}} \perp R_n^{\text{out,ES}} \bar{R}_n^{\text{ES}} - r_{n,t}^{\text{out,ES}} \geq 0, \forall n, t \quad (71)$$

The storage operator's KKT conditions reflect the logic of arbitrage. For example, (65) states that if there is positive discharge from the battery, then the nodal electricity price equals the marginal value of stored energy plus any shadow price on the discharging rate. Otherwise, if marginal value of stored energy plus any shadow price on the discharging rate exceeds the nodal electricity price, then the discharge is zero.

B.6.4 KKT Conditions for the Transport Company

$$0 \leq g_{n,t}^{\text{TC}} \perp -\theta_{n,t} + \lambda_{n,t}^{\text{sup,TC}} \geq 0, \forall n, t \quad (72)$$

$$0 \leq q_{n,t}^{\text{TC}} \perp \lambda_{n,t}^{\text{sup,TC}} - \lambda_n^{\text{TC}} + \hat{\lambda}_{n,t}^{\text{TC}} - \check{\lambda}_{n,t}^{\text{TC}} \geq 0, \forall n, t \quad (73)$$

$$0 \leq r_{n,t}^{\text{in,TC}} \perp E_n^{\text{in,TC}} \theta_{n,t} - \lambda_{n,t}^{\text{bal,TC}} + \lambda_{n,t}^{\text{in,TC}} \geq 0, \forall n, t \quad (74)$$

$$0 \leq r_{n,t}^{\text{out,TC}} \perp -\lambda_{n,t}^{\text{sup,TC}} + \lambda_{n,t}^{\text{bal,TC}} + \lambda_{n,t}^{\text{out,TC}} \geq 0, \forall n, t \quad (75)$$

$$0 \leq r_{n,t}^{\text{sto,TC}} \perp \lambda_{n,t}^{\text{bal,TC}} - (1 - E_n^{\text{sto,TC}})^{T_t} \lambda_{n,t+1}^{\text{bal,TC}} + \lambda_{n,t}^{\text{ub,TC}} - \lambda_{n,t}^{\text{lb,TC}} \geq 0, \forall n, t \quad (76)$$

$$\lambda_{n,t}^{\text{bal,TC}} \text{ u.r.s.}, r_{n,t}^{\text{sto,TC}} - (1 - E_n^{\text{sto,TC}})^{T_t} r_{n,t-1}^{\text{sto,TC}} - r_{n,t}^{\text{in,TC}} + r_{n,t}^{\text{out,TC}} = 0, \forall n, t \quad (77)$$

$$0 \leq \lambda_{n,t}^{\text{ub,TC}} \perp \bar{R}_n^{\text{TC}} - r_{n,t}^{\text{sto,TC}} \geq 0, \forall n, t \quad (78)$$

$$0 \leq \lambda_{n,t}^{\text{lb,TC}} \perp r_{n,t}^{\text{sto,TC}} - \underline{R}_n^{\text{TC}} \geq 0, \forall n, t \quad (79)$$

$$0 \leq \lambda_{n,t}^{\text{in,TC}} \perp R_n^{\text{in,TC}} \bar{R}_n^{\text{TC}} - r_{n,t}^{\text{in,TC}} \geq 0, \forall n, t \quad (80)$$

$$0 \leq \lambda_{n,t}^{\text{out,TC}} \perp R_n^{\text{out,TC}} \bar{R}_n^{\text{TC}} - r_{n,t}^{\text{out,TC}} \geq 0, \forall n, t \quad (81)$$

$$\lambda_{n,t}^{\text{sup,TC}} \text{ u.r.s.}, q_{n,t}^{\text{TC}} + g_{n,t}^{\text{TC}} - r_{n,t}^{\text{out,ES}} = 0, \forall n, t \quad (82)$$

$$0 \leq \lambda_n^{\text{TC}} \perp \sum_{t \in T} q_{n,t}^{\text{TC}} - X_n^{\text{TC}} \geq 0, \forall n \quad (83)$$

$$0 \leq \hat{\lambda}_{n,t}^{\text{TC}} \perp \hat{X}_{n,t}^{\text{TC}} X_n^{\text{TC}} - q_{n,t}^{\text{TC}} \geq 0, \forall n, t \quad (84)$$

$$0 \leq \check{\lambda}_{n,t}^{\text{TC}} \perp -\check{X}_{n,t}^{\text{TC}} X_n^{\text{TC}} + q_{n,t}^{\text{TC}} \geq 0, \forall n, t \quad (85)$$

The transport company's KKT conditions are similar to those of the storage operator when it comes to management of the fleet's battery. One difference is that the incentives for endogenous consumption are captured by (73), which states that if there is positive electricity consumption by the fleet, then the marginal value of stored energy equals the sum of shadow prices on consumption, cf. (83)–(85). Otherwise, if the marginal value of stored energy exceeds the sum of shadow prices on consumption, then the fleet's electricity consumption is zero.

B.6.5 KKT Conditions for the Industrial Consumer

$$0 \leq q_{n,t}^{\text{ind}} \perp \theta_{n,t} - \lambda_n^{\text{ind}} + \hat{\lambda}_{n,t}^{\text{ind}} - \check{\lambda}_{n,t}^{\text{ind}} + \bar{\lambda}_{n,t}^{\text{ind}} - \underline{\lambda}_{n,t}^{\text{ind}} - \bar{\lambda}_{n,t+1}^{\text{ind}} + \underline{\lambda}_{n,t+1}^{\text{ind}} \geq 0, \forall n, t \quad (86)$$

$$0 \leq \lambda_n^{\text{ind}} \perp -X_n^{\text{ind}} + \sum_{t \in T} q_{n,t}^{\text{ind}} \geq 0, \forall n \quad (87)$$

$$0 \leq \hat{\lambda}_{n,t}^{\text{ind}} \perp \hat{X}_{n,t}^{\text{ind}} X_n^{\text{ind}} - q_{n,t}^{\text{ind}} \geq 0, \forall n, t \quad (88)$$

$$0 \leq \check{\lambda}_{n,t}^{\text{ind}} \perp -\check{X}_{n,t}^{\text{ind}} X_n^{\text{ind}} + q_{n,t}^{\text{ind}} \geq 0, \forall n, t \quad (89)$$

$$0 \leq \underline{\lambda}_{n,t}^{\text{ind}} \perp \underline{X}_n^{\text{ind}} X_n^{\text{ind}} + q_{n,t}^{\text{ind}} - q_{n,t-1}^{\text{ind}} \geq 0, \forall n, t \quad (90)$$

$$0 \leq \bar{\lambda}_{n,t}^{\text{ind}} \perp \bar{X}_n^{\text{ind}} X_n^{\text{ind}} - q_{n,t}^{\text{ind}} + q_{n,t-1}^{\text{ind}} \geq 0, \forall n, t \quad (91)$$

Intuitively, (86) states that if industrial consumption is strictly positive, then the nodal electricity price equals the shadow prices on annual electricity consumption, maximum/minimum periodic consumption, and maximum increase/decrease in periodic consumption. However, if the sum of said shadow prices is less than the nodal electricity price, then industrial consumption is zero.

B.7 Equilibrium Problem and Single Equivalent Optimisation Problem

$$\begin{aligned}
& \text{Maximise}_{\Gamma} \sum_{n \in \mathcal{N}} \sum_{t \in \mathcal{T}} \left[\left(D_{n,t}^{\text{int}} q_{n,t} - \frac{1}{2} D_{n,t}^{\text{slp},2} q_{n,t}^2 \right) - \sum_{i \in \mathcal{I}} \sum_{u \in \mathcal{U}_{i,n}} (C_{i,n,t,u} + SP_{i,n,u}) g_{i,n,t,u} \right] \\
& \quad - \sum_{i \in \mathcal{I}} \sum_{n \in \mathcal{N}} \left(\sum_{u \in \mathcal{U}_{i,n}} C_{i,n,u}^{\text{ava}} a_{i,n,u} + \sum_{e \in \mathcal{E}_{i,n}} C_{e,i,n}^{\text{ava}} a_{i,n}^e + \sum_{w \in \mathcal{W}_{i,n}} C_{i,n,w}^{\text{ava}} a_{i,n,w} \right) \quad (92) \\
& \text{s.t. (2) - (5)} \\
& \quad (7) - (16), \forall i \in \mathcal{I} \\
& \quad (18) - (21) \\
& \quad (23) - (29) \\
& \quad (31) - (33)
\end{aligned}$$

where Γ comprises the ISO's decisions, Γ^{ISO} , all of the firms' decisions, Γ^i , $\forall i \in \mathcal{I}$, the storage operator's decisions, Γ^{ES} , the transport company's decisions, Γ^{TC} , and the industrial consumer's decisions, Γ^{ind} .

Social surplus (SS) differs from (92) because it equals the sum of consumer surplus (CS), producer surplus (PS), the storage operator's battery surplus (BS), the transport company's surplus (TS), merchandising surplus (MS), and government revenue (GR) minus the cost of industrial consumption (HC), where:

- $CS = \sum_{n \in \mathcal{N}} \sum_{t \in \mathcal{T}} \left(D_{n,t}^{\text{int}} q_{n,t} - \frac{1}{2} D_{n,t}^{\text{slp},2} q_{n,t}^2 \right) - \sum_{n \in \mathcal{N}} \sum_{t \in \mathcal{T}} \theta_{n,t} q_{n,t}$, i.e., gross consumer surplus minus the cost of electricity purchases.
- $PS = \sum_{i \in \mathcal{I}} \sum_{n \in \mathcal{N}} \sum_{t \in \mathcal{T}} \theta_{n,t} \left(\sum_{u \in \mathcal{U}_{i,n}} g_{i,n,t,u} + \sum_{e \in \mathcal{E}_{i,n}} g_{i,n,t}^e + \sum_{w \in \mathcal{W}_{i,n}} (Q_{i,n,w} r_{i,n,t,w}^{\text{out}} - F_{i,n,w} r_{i,n,t,w}^{\text{in}}) \right) - \sum_{i \in \mathcal{I}} \sum_{n \in \mathcal{N}} \sum_{t \in \mathcal{T}} \sum_{u \in \mathcal{U}_{i,n}} (C_{i,n,t,u} + SP_{i,n,u}) g_{i,n,t,u} - \sum_{i \in \mathcal{I}} \sum_{n \in \mathcal{N}} \sum_{u \in \mathcal{U}_{i,n}} C_{i,n,u}^{\text{ava}} a_{i,n,u} - \sum_{i \in \mathcal{I}} \sum_{n \in \mathcal{N}} \sum_{e \in \mathcal{E}_{i,n}} C_{e,i,n}^{\text{ava}} a_{i,n}^e - \sum_{i \in \mathcal{I}} \sum_{n \in \mathcal{N}} \sum_{w \in \mathcal{W}_{i,n}} C_{i,n,w}^{\text{ava}} a_{i,n,w}$, i.e., revenues from electricity sales minus the costs of generation, CO₂ permits, and capacity O&M.
- $BS = \sum_{n \in \mathcal{N}} \sum_{t \in \mathcal{T}} \theta_{n,t} \left(r_{n,t}^{\text{out,ES}} - E_n^{\text{in,ES}} r_{n,t}^{\text{in,ES}} \right)$, i.e., the arbitrage profit from the battery's net discharge.
- $TS = \sum_{n \in \mathcal{N}} \sum_{t \in \mathcal{T}} \theta_{n,t} \left(g_{n,t}^{\text{TC}} - E_n^{\text{in,TC}} r_{n,t}^{\text{in,TC}} \right)$, i.e., arbitrage profit from the fleet's net sales.
- $MS = \sum_{n \in \mathcal{N}} \sum_{t \in \mathcal{T}} \theta_{n,t} \left(\sum_{\ell \in \mathcal{L}_n^-} V T_{t\ell,t} - \sum_{\ell \in \mathcal{L}_n^+} V T_{t\ell,t} \right)$, i.e., the revenues from net imports at each node.
- $GR = \sum_{i \in \mathcal{I}} \sum_{n \in \mathcal{N}} \sum_{t \in \mathcal{T}} \sum_{u \in \mathcal{U}_{i,n}} SP_{i,n,u} g_{i,n,t,u}$, i.e., revenues from sales of CO₂ permits.
- $HC = \sum_{n \in \mathcal{N}} \sum_{t \in \mathcal{T}} \theta_{n,t} q_{n,t}^{\text{ind}}$, i.e., the cost of electricity purchases of the industrial consumer.

The payment terms for electricity purchases in CS and HC plus the revenue terms in PS plus BS and MS plus the net revenue from battery arbitrage in TS equal zero via energy balance (2), and the cost of CO₂ permits in PS cancels with GR. Thus, $SS = \sum_{n \in \mathcal{N}} \sum_{t \in \mathcal{T}} \left(D_{n,t}^{\text{int}} q_{n,t} - \frac{1}{2} D_{n,t}^{\text{slp}} q_{n,t}^2 \right) - \sum_{i \in \mathcal{I}} \sum_{n \in \mathcal{N}} \sum_{t \in \mathcal{T}} \sum_{u \in \mathcal{U}_{i,n}} C_{i,n,t,u} g_{i,n,t,u} - \sum_{i \in \mathcal{I}} \sum_{n \in \mathcal{N}} \sum_{u \in \mathcal{U}_{i,n}} C_{i,n,u}^{\text{ava}} a_{i,n,u} - \sum_{i \in \mathcal{I}} \sum_{n \in \mathcal{N}} \sum_{e \in \mathcal{E}_{i,n}} C_{e,i,n}^{\text{ava}} a_{i,n}^e - \sum_{i \in \mathcal{I}} \sum_{n \in \mathcal{N}} \sum_{w \in \mathcal{W}_{i,n}} C_{i,n,w}^{\text{ava}} a_{i,n,w}$.⁴⁰

⁴⁰In 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 (2) and (37), subtract $X_{n,t}$ from $q_{n,t}$.
- Calculate the cost of exogenous net imports to the Nordic region, $IX = \sum_{n \in \mathcal{N}} \sum_{t \in \mathcal{T}} \theta_{n,t} X_{n,t}$.
- Subtract IX from $CS + PS + BS + TS + MS + GR - HC$ to yield $SS = \sum_{n \in \mathcal{N}} \sum_{t \in \mathcal{T}} \left(D_{n,t}^{\text{int}} q_{n,t} - \frac{1}{2} D_{n,t}^{\text{slp}} q_{n,t}^2 \right) - \sum_{i \in \mathcal{I}} \sum_{n \in \mathcal{N}} \sum_{t \in \mathcal{T}} \sum_{u \in \mathcal{U}_{i,n}} C_{i,n,t,u} g_{i,n,t,u} - \sum_{i \in \mathcal{I}} \sum_{n \in \mathcal{N}} \sum_{u \in \mathcal{U}_{i,n}} C_{i,n,u}^{\text{ava}} a_{i,n,u} - \sum_{i \in \mathcal{I}} \sum_{n \in \mathcal{N}} \sum_{e \in \mathcal{E}_{i,n}} C_{e,i,n}^{\text{ava}} a_{i,n}^e - \sum_{i \in \mathcal{I}} \sum_{n \in \mathcal{N}} \sum_{w \in \mathcal{W}_{i,n}} C_{i,n,w}^{\text{ava}} a_{i,n,w} - \sum_{n \in \mathcal{N}} \sum_{t \in \mathcal{T}} \theta_{n,t} X_{n,t}$.

References

- Chen, Y., M. Tanaka, and A.S. Siddiqui (2018), “Market Power with Tradable Performance-Based CO₂ Emission Standards in the Electricity Sector,” *The Ener. J.* 39(6): 121–146.
- Debia, S., P.-O. Pineau, and A.S. Siddiqui (2021), “Strategic Storage Use in a Hydro-Thermal Power System with Carbon Constraints,” *Ener. Econ.* 98: 105261.
- Egerer, J. (2016), *Open Source Electricity Model for Germany (ELMOD-DE)*, https://www.diw.de/documents/publikationen/73/diw_01.c.528927.de/diw_datadoc_2016-083.pdf.
- Hashimoto, H. (1985), “A Spatial Nash Equilibrium Model,” in Harker, P.T., editor, *Spatial Price Equilibrium: Advances in Theory, Computation and Application*, pp. 20–40, Springer.
- Hassanzadeh Moghimi, F., H. Ek Fälth, L. Reichenberg, and A.S. Siddiqui (2023), “Climate Policy and Strategic Operations in a Hydro-Thermal Power System,” *The Ener. J.* 44(5): 67–94.
- Hassanzadeh Moghimi, F., T.K. Boomsma, and A.S. Siddiqui (2024), “Transmission Planning in an Imperfectly Competitive Power Sector with Environmental Externalities,” *Ener. Econ.* 134: 107610.
- Mignon, V. (2008), *Économétrie : Théorie et applications*, Economica.
- Neamtu, I.D. (2016), *Wind Power Effects and Price Elasticity of Demand for the Nordic Electricity Markets*, Department of Economics and Business Economics, Aarhus University, https://pure.au.dk/portal/files/104558637/PhD_dissertation_Ioana_Neamtu.pdf.
- Sioshansi, R. (2012), “Modeling the Impacts of Electricity Tariffs on Plug-In Hybrid Electric Vehicle Charging, Costs, and Emissions,” *Oper. Res.* 60(3): 506–516.
- Sundén, D. (2024), *Till vilket elpris som helst?*, <https://lakevilleconsulting.se/wp-content/uploads/2024/02/Sunden-2024-Till-vilket-elpris-som-helst.pdf>.
- Tanaka, M. (2009), “Transmission-Constrained Oligopoly in the Japanese Electricity Market,” *Ener. Econ.* 31(5): 690–701.
- Tangerås, T., P. Holmberg, and C. Le Coq (2025), *Investeringar i elproduktion för en hållbar energiomställning*, SNS Konjunkturråd.
- Virasjoki, V., A.S. Siddiqui, B. Zakeri, and A. Salo (2018), “Market Power with Combined Heat and Power Production in the Nordic Energy System,” *IEEE Trans. Power Syst.* 33: 5263–5275.
- Virasjoki, V., A.S. Siddiqui, F. Oliveira, and A. Salo (2020), “Utility-Scale Energy Storage in an Imperfectly Competitive Power Sector,” *Ener. Econ.* 88: 104716.
- Wogrin, S., B.F. Hobbs, D. Ralph, E. Centeno, and J. Barquín (2013), “Open versus Closed Loop Capacity Equilibria in Electricity Markets under Perfect and Oligopolistic Competition,” *Math. Program.* 140: 295–322.