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Research Paper

Transparent regional energy modelling for data-scarce arctic bidding zones: diagnostics for Northern Norway

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ABSTRACT

The transition toward low-carbon energy systems requires planning approaches capable of representing the spatial, climatic, and infrastructural heterogeneity of peripheral Arctic regions, where national-scale models often smooth over locally binding constraints and data limitations. This study investigates whether high-resolution regional energy system optimization can provide substantially different transition diagnostics and infrastructure priorities compared with aggregated national analyses, while also identifying the methodological implications of regional data scarcity. A transparent open-source optimization model was developed for Northern Norway for the period 2020–2050 using five-year planning intervals, 96 hourly seasonal time-slices, explicit interregional electricity trade representation, and reproducible regional downscaling procedures for buildings, transport, industry, heating, and power generation sectors. The results show that regional modelling reveals significantly stronger electricity demand dynamics than population-based national indicators suggest, with Northern Norway representing about 9% of the national population but approximately 13% of electricity consumption in the buildings sector, highlighting limitations of conventional downscaling approaches. The optimization further identifies hydropower as the structural backbone of the regional system while offshore wind becomes a major expansion technology option under constrained hydropower growth and sustained export assumptions; however, removing future export growth approximately halves total wind deployment and largely eliminates storage requirements, demonstrating the strong sensitivity of infrastructure outcomes to trade assumptions. Sensitivity analysis on offshore wind capacity factors additionally shows storage charging increases approaching 60% under higher renewable availability conditions, emphasizing the importance of temporal resolution for flexibility assessment. The study also demonstrates that the principal limitation for detailed regional industrial decarbonization modelling is not optimization capability but the absence of transparent and disaggregated industrial datasets. These findings show that transparent regional optimization models can expose infrastructure bottlenecks, reveal the consequences of modelling assumptions, and provide decision-relevant diagnostics that aggregated national energy models cannot capture.

1. Introduction

In the last two centuries, human activities have caused a rise in atmospheric greenhouse-gas concentrations, which have unequivocally warmed the planet, with the global mean surface temperature now substantially higher than in the late nineteenth century [1]. Limiting long-term warming to 2 °C or, preferably, to near 1.5 °C, therefore requires deep and sustained reductions in greenhouse-gas emissions across all sectors in the short term, making rapid transformation of the energy system a central feature of credible mitigation pathways [2]. Central elements of those transformation pathways are large-scale electrification of end-uses, rapid deployment of low-carbon electricity generation, improvements in energy efficiency, and expanded provision of temporal and operational flexibility through storage, sector coupling and demand-side measures [3].

Energy-system models are the primary tools by which researchers and policymakers explore these transformation pathways because they can represent technology-explicit portfolios, cost minimisation and trade-offs between investment, dispatch and flexibility under alternative assumptions [4]. The capacity of such models to deliver policy-relevant insight depends critically on their structural features: spatial

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Nomenclature

2 W	Two-wheelers vehicles
ACT	Activity
AEM	Anion Exchange Membrane
BAU	Business As Usual
BVKM	Billion vehicles per kilometre
C2A	Capacity to activity
CAP	Installed Capacity
CAPEX	Capital Expenditure
CCGT	Combined cycle gas turbine
CCS	Carbon Capture and Storage
CF	Capacity factor
CHP	Combined Heat and Power
CO_2	Carbon Dioxide
COP	Coefficient of Performance
COVID-19	Corona Virus Disease 19
DEM	Demand
DSD	Demand Specific Distribution
ENTSO-E	European Network of Transmission System Operators for Electricity
EU	European Union
FI	Input Flow (Equations)
FI	Finland (Bidding Zone)
FO	Output Flow
GDP	Gross Domestic Product
GHG	Greenhouse Gas
GW	Gigawatt
GWh	Gigawatt-hour
HDD	Heating degree days
HFO	Heavy Fuel Oil
HP	Heat Pump
IEA	International Energy Agency
IPCC	Intergovernmental Panel on Climate Change
JRC	Joint Research Centre
kWh	Kilowatt-hour
LCV	Light Commercial Vehicle
LNG	Liquid natural gas
LP	Linear Programming
MGO	Marine gas oil
MW	Megawatt
MWh	Megawatt-hour
NEC	Non energy consumption
NO3	Trøndelag bidding zone
NO4	Northern Norway
NZE	Net Zero Emissions
O&M	Operation and Maintenance
OPEX	Operational Expenditure
PEM	Proton Exchange Membrane
PJ	Petajoule
PV	Photovoltaic
RES	Renewable Energy Sources
ROR	Run of River
SE1	Sweden bidding zone 1
SE2	Sweden bidding zone 2
SMR	Small modular reactor
SOEC	Sulphur oxide exchange cell
SSB	Statistics Norway
TEMOA	Tools for Energy Modelling Optimization and Analysis
TLF	Time limiting factor
TSO	Transmission system operator
TWh	Terawatt-hour
UNFCCC	United Nations Framework Convention on Climate Change
VRE	Variable Renewable Energy

granularity, temporal resolution and the representation of network and operational constraints materially influence estimates of required storage, the value of flexibility options and the locational signals for investment [5]. These methodological sensitivities are especially consequential where climatic and geographic conditions depart markedly from temperate, densely populated baselines, because resource variability, seasonal demand swings and infrastructure fragility can interact to produce locally binding constraints that aggregate models typically smooth over [6].

The Arctic region exemplifies such departure: observed warming trends in high latitudes are larger than the global mean, a phenomenon commonly referred to as Arctic amplification, with attendant impacts on cryosphere dynamics, permafrost stability and ecosystem structure that have both local and global climate feedback [7]. Permafrost thaw, coastal erosion and changing freeze–thaw cycles already pose documented risks to the built infrastructure in high-latitude areas, risks that include ground subsidence under roads and pipelines, increased maintenance needs for generation assets, and altered access for fuel and equipment logistics [8].

Concurrently, Arctic and sub-Arctic territories may host significant renewable resources, for example favourable wind regimes and, seasonally, solar potential, while exhibiting system characteristics such as low population density, reliance on long transmission corridors or isolated micro-grids, and industry-concentrated loads that together create strong spatially heterogeneous trade-offs in planning and operation [9].

These interacting climatic, infrastructural and resource features therefore heighten the need for regionally focused, transparent energy-system modelling that can represent local resource variability, network bottlenecks, seasonal storage requirements and the vulnerability of physical assets to climate-driven change [5]. Open, reproducible modelling frameworks, and in particular technology-explicit optimisation tools that document data-processing and aggregation choices, are well suited to this task because they make the assumptions that drive results traceable and enable sensitivity analysis over temporal and spatial assumptions that determine policy-relevant diagnostics [3].

Building on this rationale, this study develops a regional application of a transparent optimisation framework for the Northern Norway (NO4) documenting the data-downscaling choices, temporal representation and proxy strategies used to construct a regional database and showing how those choices shape diagnostics for storage, network reinforcements and sector coupling relative to coarser national narratives.

In peripheral Arctic territories such as NO4, the combination of strong seasonality in demand, concentrated generation resources and constrained transmission corridors produces operational and planning challenges that are not resolved by aggregate national studies alone. A regionally focused, technology-explicit optimisation therefore offers two complementary advantages: it generates spatially and temporally resolved diagnostics that can identify locally binding constraints, and it makes transparent how data downscaling, temporal representation, and proxy assumptions determine the interpretation of those diagnostics by planners and system operators.

Against this background, this paper addresses a focused research question: to what extent does regional, high-temporal-resolution energy system optimisation alter transition diagnostics and infrastructure priorities compared with national-scale modelling in sparsely populated Arctic regions? Rather than proposing multiple long-term scenarios, the study examines how modelling choices related to spatial granularity, temporal resolution, and data downscaling shape policy-relevant insights for peripheral regions. The study situates a TEMOA (Tools for

Energy Model Optimization and Analysis) regional analysis of NO4 within this need for finer-grained evidence, emphasising reproducibility of data-processing workflows and the translation of model outputs into decision-relevant indicators for regional stakeholders. TEMOA is an established open-source bottom-up energy system optimisation framework which minimises system costs across multi-technology, multi-sectoral representations and has been used widely to support transparent, reproducible exploration of transition pathways [10].

Although open-source optimisation frameworks have been applied extensively at national scale, there remain three interrelated gaps that limit the policy relevance of such models for sparsely populated Arctic zones [11]. First, aggregate national models typically smooth temporal and spatial heterogeneity; this, risks understating the scale and timing of storage, flexibility and network reinforcements required to manage winter-dominated peaks and locally concentrated variable renewable output. Second, transparent, auditable methods for constructing regional input datasets, notably for industrial activity, district heating potential and site-specific capacity factors, are scarce; where regional micro-data are unavailable, the literature lacks widely accepted proxying procedures that preserve traceability and quantify structural uncertainty. Third, there is limited practice in linking regional optimisation outputs to spatially explicit investment signals or to network-level analyses that would make results actionable for transmission system operators, local planning authorities and industrial actors. These limitations are particularly acute in industrial sectors, where data confidentiality and aggregation practices often prevent meaningful regional characterisation, thereby constraining the ability of optimisation models to represent endogenous decarbonisation pathways.

Recent review studies on energy-system optimisation modelling identify limitations that closely align with the research gaps addressed in this work. In particular, the literature increasingly recognises that low-spatial-resolution national models systematically underrepresent regional heterogeneity in renewable resources, transmission bottlenecks, and seasonal demand variability, especially in peripheral or climatically extreme regions [12]. Recent reviews further highlight that many existing energy-system models still rely on highly aggregated or weakly documented regional datasets, with limited transparency regarding spatial downscaling procedures, proxy assumptions, and uncertainty propagation [13]. Similar concerns are raised regarding the integration of high temporal and spatial resolution within computationally tractable open-source optimisation frameworks, as well as the limited coupling between regional optimisation outputs and network-level planning tools [14]. The present study contributes to this literature by addressing these gaps simultaneously within a transparent regional implementation focused on a data-scarce Arctic bidding zone, explicitly documenting the methodological implications of data construction choices, temporal aggregation, and proxy-based assumptions for policy-relevant diagnostics.

This work contributes to the literature in four ways. First, it develops a transparent regional optimisation framework for a data-scarce Arctic bidding zone using reproducible downscaling procedures and openly documented proxy assumptions. Second, it evaluates how high temporal and regional resolution influence infrastructure diagnostics, storage requirements and trade patterns relative to aggregated national representations. Third, it systematically identifies structural data limitations affecting regional industrial decarbonisation modelling. Fourth, it demonstrates how regional optimisation can generate planning-relevant diagnostics for peripheral Arctic systems while remaining computationally tractable within an open-source framework. The contribution is therefore methodological and diagnostic rather than predictive: the paper shows how a regional open-source optimisation model can reveal locally binding constraints, assumption sensitivities, and data gaps that are smoothed over in aggregated national assessments. The remainder of the paper is organised as follows. Section 2 describes the model structure, regional system boundary, data-processing workflow, temporal representation, scenario design, and validation procedure. Section 3 presents the calibration results, system-development diagnostics, export and offshore-wind sensitivity analyses, and limitations. Section 4 summarises the main findings and implications for regional energy planning.

2. Methods

The methodological choices adopted in this study are guided by a diagnostic rather than predictive objective. The model is designed to examine how spatial disaggregation, temporal resolution, and data-construction assumptions influence system behaviour and infrastructure requirements at regional scale, rather than to forecast a single "most likely" transition pathway. As a result, particular emphasis is placed on transparency, reproducibility, and traceability of data-processing steps and proxy choices, so that model outcomes can be interpreted as conditional on clearly stated assumptions.

2.1. Modelling framework

The model is built on the open-source TEMOA framework, a bottom-up technology-rich energy system optimisation model [15]. TEMOA represents the entire energy system as a network of conversion processes: raw energy commodities (e.g. coal, oil, biomass) are transformed through intermediate carriers into final end-use services (electricity, transport fuels, heating, etc.) [15]. Each technology or process is characterised by technical, economic and environmental parameters as efficiency, capital cost and emissions rate [15]. All sectors and energy carriers are handled in an integrated manner, with investment decisions and operational dispatch chosen simultaneously. TEMOA minimises the total present value of system costs, hence, investment plus fixed and variable operation, over a multi-period horizon, subject to meeting exogenous end-use demands in each period [15]. In other words, the model chooses which technologies to build and how to operate them so as to meet all specified energy service demands at minimum discounted cost [10]. In the present application, these features are particularly relevant because they allow regional modelling assumptions, such as temporal aggregation, proxy-based demand construction, and capacity constraints, to be made explicit and systematically evaluated.

TEMOA is formulated as a linear programming problem, implemented in Python using the Pyomo algebraic modelling language [15]. The complete model, input database, and data-processing scripts are publicly archived in a permanent Mendeley dataset (https://doi.org/10.17632/kvw4kz9fwm.1) [16]and mirrored through GitHub for version control and transparency [17]. By design, TEMOA is intended to run in high-performance computing environments: the original developers explicitly targeted parallel execution to facilitate large-scale scenario and uncertainty analyses [10]. The open-source nature of the framework means it can employ a variety of solvers (e.g. CPLEX, Gurobi, GLPK) and be freely extended or modified for new objectives or stochastic extensions.

2.2. Model mathematical formulation

The following subsection consolidates the complete mathematical structure of the TEMOA optimisation problem as implemented in this study. The model is formulated as a deterministic, multi-period linear programme (LP), in which investment and dispatch decisions are chosen simultaneously to minimise total discounted system cost subject to physical, operational, and policy constraints.

Table 1 and Table 2 report the notation used to describe the mathematical formulation of the model.

All variables are continuous and non-negative.

2.3. Derived variable

The total activity of each technology in a given time-slice is the sum of all its output flows:

Table 1
Sets and indices.

Symbol	Description
$t \in T$	Planning periods: {2020, 2025, 2030, 2035, 2040, 2045, 2050}
$v \in V \subseteq T$	Technology vintages ($v \leq t$)
$s \in S$	Seasons: {winter, spring, summer, autumn}
$d \in D$	Time-of-day slices ($d \in \{1, \ldots, 24\}$)
$p \in P$	Technologies (processes)
$c, i, o \in C$	Commodities; i and o denote input and output subsets
P_{dem}	Demand-serving technologies
P_{stor}	Storage technologies
P_{base}	Baseload technologies
P_{res}	Primary resource technologies
P_{mult}	Multi-output technologies

Table 2
Decision variables.

Symbol	Description
$FO_{p,s,d,i,t,v,o}$	Commodity flow from technology p, input i, output o, vintage v, period t, season s, time-slice d
$FI_{p,s,d,i,t,v,o}$	Commodity flow into technology p
$CAP_{p,t,v}$	Installed capacity of technology p, vintage v, in period t

$$ACT_{p,s,d,t,v} = \sum_{i,o} FO_{p,s,d,i,t,v,o} \tag{1}$$

2.4. Objective function

The model minimises the total present value of system costs comprising annualised investment costs (InvCost), fixed operation and maintenance costs (FixOM), and variable operation costs (VarOM), all discounted to the base year:

$$\begin{aligned}\text{Minimise: TotalCost} = &\sum_{p,t,v} \text{InvCost}_{p,t,v} \cdot \text{CAP}_{p,t,v} \\ &+ \sum_{p,t,v} \text{FixOM}_{p,t,v} \cdot \text{CAP}_{p,t,v} + \sum_{p,s,d,i,t,v,o} \text{VarOM}_{p,t,v} \cdot \text{FO}_{p,s,d,i,t,v,o}\end{aligned} \tag{2}$$

2.5. Constraints

(C1) Capacity–Activity Constraint. The installed capacity of each technology must be sufficient to support its activity in every time-slice, given the capacity factor CF, the capacity-to-activity conversion factor C2A, and the time-limiting factor TLF, which accounts for technologies whose operational lifetime ends within a planning period:

$$CF_{s,d,t,v} \cdot C2A_t \cdot TLF_{p,t,v} \cdot CAP_{p,t,v} \geq ACT_{p,s,d,t,v} \forall p, s, d, t, v \tag{C1}$$

(C2) Supply–Demand Balance. For each end-use commodity c and each demand sector, the sum of all output flows meeting that demand must cover the exogenously specified annual demand, scaled by the demand shape distribution DSD:

$$\sum_{p,i,v} FO_{p,s,d,i,t,v,c} \geq DEM_{c,t} \cdot DSD_{s,d,c} \forall c \in Cdem_{s,d,t} \tag{C2}$$

(C3) Process Efficiency Constraint. Each technology cannot output more energy than it consumes, adjusted by the technology-specific efficiency EFF (output per unit of input):

$$FO_{p,s,d,i,t,v,o} \leq EFF_{i,t,v,o} \cdot FI_{p,s,d,i,t,v,o} \forall p, s, d, i, t, v, o \tag{C3}$$

(C4) Global Commodity Balance. For every intermediate commodity c (e.g. electricity, hydrogen, district heat), total production must equal total consumption in each time-slice, linking all processes in the network:

$$\sum_{p \in producers} FO_{p,s,d,\cdots,c} = \sum_{p \in consumers} FI_{p,s,d,c,\ldots} \forall c \in Cint_{s,d,t} \tag{C4}$$

(C5) Storage Season Balance. Storage technologies (batteries, pumped hydro, hydrogen tanks) are not subject to the instantaneous balance of (C4). Instead, their net energy input must equal their net energy output over the full season, ensuring no net creation of energy:

$$\sum_{s,d} FI_{p,s,d,t,v} \cdot \eta_{ch} = \sum_{s,d} FO_{p,s,d,t,v} \forall p \in Pstor_{t,v} \tag{C5}$$

where η_{ch} is the round-trip charging efficiency.

(C6) Emission Constraint. Aggregate greenhouse gas emissions from all processes in each period must not exceed the policy-specified cap EmisLim, consistent with Norway's climate targets (55% reduction by 2030 and 90–95% by 2050 relative to 1990):

$$\sum_{p,s,d,i,v,o} EF_{p,i,o} \cdot FO_{p,s,d,i,t,v,o} \leq EmisLim_t \forall t \tag{C6}$$

where $EF_{p,i,o}$ is the technology- and fuel-specific emission factor.

(C7) Capacity Bounds. Upper and lower bounds on installed capacity can be imposed for any technology and period, reflecting physical, policy, or resource constraints:

$$CAP_{p,t}^{min} \leq \sum_{v} CAP_{p,t,v} \leq CAP_{p,t}^{max} \forall p, t$$

(C8) Demand–Activity Proportionality. End-use devices are constrained to operate in proportion to their demand profile: the activity in each time-slice must reflect the specified demand shape, preventing the model from unrealistically concentrating demand in low-cost periods:

$$ACT_{p,s,d,t,v} = DSA_{s,d,c} \cdot \sum_{s',d'} ACT_{p,s',d',t,v} \forall p \in Pdem_{s,d,t} \tag{C8}$$

(C9) Baseload Operation Constraint. Technologies designated as baseload generators (e.g. thermal plants) must maintain a constant output rate within each day segment and cannot ramp between time-of-day slices:

$$\frac{FO_{p,s,d,i,t,v,o}}{C2A_t} = const. \forall d \in D, \forall p \in P_{base} \tag{C9}$$

(C10) Resource Extraction Limit. Annual extraction of primary resources (domestic fuel production or imports) is bounded by a user-specified maximum for each technology and period:

$$\sum_{s,d,v} FO_{p,s,d,i,t,v,o} \leq ResLim_{p,t} \forall p \in Pres_t \tag{10}$$

(C11) Multi-output Split. For co-generation or multi-product processes, a fixed ratio is imposed among output commodities:

$$\frac{FO_{p,\cdots,o1}}{FO_{p,\cdots,o2}} = Split_{p,o1,o2} \forall p \in Pmulti_{t,v} \tag{11}$$

All decision variables are continuous and non-negative. Together, constraints (C1)-(C11) ensure that all end-use demands are satisfied by available technology outputs while respecting physical conversion limits, seasonal storage cycles, emission caps, and user-specified investment or resource bounds. The complete algebraic form including detailed indexing over vintages and time-slices is provided in the original TEMOA documentation [18] and in [10]. The formulation used here follows that reference without modification.

All of the above constraints as well as the objective are linear, so the model remains a linear programme. In summary, TEMOA solves a deterministic, multi-period LP: it chooses investment capacities and dispatch flows to minimise total system cost, subject to physical and policy constraints that link resources to final demands. The implementation used here is fully transparent and can be extended or

modified as needed for alternative objectives, stochastic scenarios, or additional.

While TEMOA has been extensively applied in national-scale studies, as shown in [19–21], as well as in the North Carolina instance by the developing research group in [22], its use at the regional level remains limited. Nevertheless, [23] reveals the importance of addressing this gap in the energy planning perspective.

Both the TEMOA-Piedmont and TEMOA-North Carolina implementations provide relevant reference frameworks for regional energy system analysis within the open-source TEMOA structure. The TEMOA-Piedmont model, developed by [23], applies the framework to the Italian Piedmont region, adopting a single regional node that covers all energy sectors. This configuration reflects the national structure of Italy's energy system, where electricity and other energy carriers are centrally managed and dispatched at the national level. Consequently, the regional disaggregation in TEMOA-Piedmont serves primarily to capture regional energy demand and technology characteristics rather than to represent autonomous regional energy operation or exchanges. In contrast, in the Norwegian context, where each bidding zone, including NO4, constitutes an operationally distinct part of the national power market with local generation constraints and cross-zone trading, a regional modelling approach can reveal dynamics that a national model would obscure.

The TEMOA-North Carolina model, developed by the North Carolina State University group [22], adopts a detailed temporal representation of system operation, dividing each model year into 96 time slices (24 h across four representative days, one per season). The present work follows a comparable approach, preserving the same hourly resolution and seasonal sampling to capture the diurnal and seasonal variability of supply and demand while maintaining computational tractability. This temporal structure is not treated as a neutral modelling choice, but as a core analytical dimension, since the representation of diurnal and seasonal variability materially affects storage needs, trade flows, and the valuation of flexibility options in sparsely populated Arctic systems. Both models thus share a consistent methodological basis in temporal structuring, while differing substantially in spatial focus and, consequently, the underlying energy system characteristics they aim to represent.

2.6. Regional scope and system boundaries

The geographical scope of the analysis corresponds to the NO4 region, the northernmost part of Norway. Throughout the manuscript, the terms Northern Norway and NO4 are used interchangeably to refer to the same bidding-zone-level model region. The term bidding zone is used when discussing electricity-market structures, whereas region refers to the modelled geographic system. The term node is reserved exclusively for model topology and network representations. This region was selected due to the combination of climatic, infrastructural and demographic characteristics that differentiate it from both national averages and other Nordic zones. Lying almost entirely above the Arctic Circle, NO4 experiences pronounced seasonality in both energy demand and renewable resource availability. Heating requirements dominate the winter energy balance, while solar irradiance, hydrological inflows and temperature-dependent electricity demand vary sharply between seasons. These patterns impose distinctive storage and flexibility needs that cannot be captured adequately by models calibrated at coarser spatial or temporal resolutions.

The population of NO4 is sparse and unevenly distributed, concentrated in a few coastal urban centres, such as Tromsø and Bodø, and scattered rural and insular settlements. This spatial distribution affects the shape and concentration of energy demand, as well as the design and utilisation of transmission and distribution infrastructure. Industrial activity, though geographically limited, plays an important role in determining local load profiles, particularly where process heat or electricity-intensive operations are located near hydropower resources.

From a system perspective, NO4 is part of the integrated Nordic electricity market and is physically interconnected with neighbouring zones, namely NO3 (Trøndelag), SE1 and SE2 (Sweden), and FI (Finland) [24]. These interconnections enable cross-border electricity exchanges that are fundamental for system reliability and economic optimisation. Historically, NO4 has been a net exporter of electricity, as reported in Fig. 1, primarily towards NO3, which is structurally in deficit, and to a lesser extent towards northern Sweden. This export behaviour reflects the dominance of hydropower generation in the region and its limited local demand base. Nonetheless, seasonal hydrological variability, coupled with future increases in electrification and renewable penetration, may alter these exchange patterns, highlighting the need for dynamic regional assessment.

The modelled system boundaries encompass the principal energy sectors relevant to the NO4 energy balance: Residential and Commercial, represented under the Buildings module, Industry, Power Generation, Transport, and Upstream supply. In addition, two cross-sectoral components are treated explicitly as model sectors: District Heating and Hydrogen Production. The inclusion of these modules allows the model to capture sector-coupling effects, such as the potential role of hydrogen in balancing electricity surpluses, or the substitution of direct electric heating with district heating in urban areas.

The whole representation of the energy system is reported in Fig. 2, where energy commodities are tracked consistently across extraction, transformation and final consumption stages, ensuring conservation of energy flows and enabling the quantification of conversion losses and emissions. The conceptual structure of the system representation follows a three-tier configuration: primary energy extraction and imports on the left, transformation and conversion technologies in the central block, and final energy demands on the right. Storage technologies, including hydro reservoirs, batteries and potential hydrogen storage, are integrated where relevant, allowing the temporal shifting of surplus generation and the mitigation of peak demands. Emissions are accounted for at process level according to technology-specific emission factors and are aggregated for reporting and potential constraint enforcement.

This delineation of scope and boundaries ensures that the model captures both endogenous dynamics within NO4, such as technology competition, resource utilisation and sectoral interactions, and exogenous interactions with neighbouring zones through interconnectors. It therefore provides a consistent basis for evaluating the adequacy, flexibility and sustainability of the regional energy system under alternative scenarios of demand growth, electrification, and renewable integration.

2.7. Data processing and downscaling

To construct a consistent regional database, national-level datasets, mainly from Statistics Norway, were downscaled to NO4 employing different proxies and methods.

2.8. Buildings

Residential and commercial energy demands, including heating, hot water, and electricity, were derived through a combination of energy data with demographic and economic indicators. Specifically, population and regional gross domestic product (GDP) (the latter from Eurostat, 2025) were used as scaling factors, while official electricity consumption statistics published by Statistics Norway served as proxies to extrapolate the remaining energy service demands, thereby allowing for the reconstruction of the total energy consumption in these sectors. Recent additions to [27] include total energy consumption in the residential sector for the year 2022, which falls amid the two historical years of this model, 2020 and 2025, allowing for the extrapolation of the remaining data. Table 3 reports population data and projections according to Statistics Norway, as they were used in the model for data disaggregation and as drivers for specific future demands.

Similarly, Table 4 summarises regional GDP values as per Eurostat

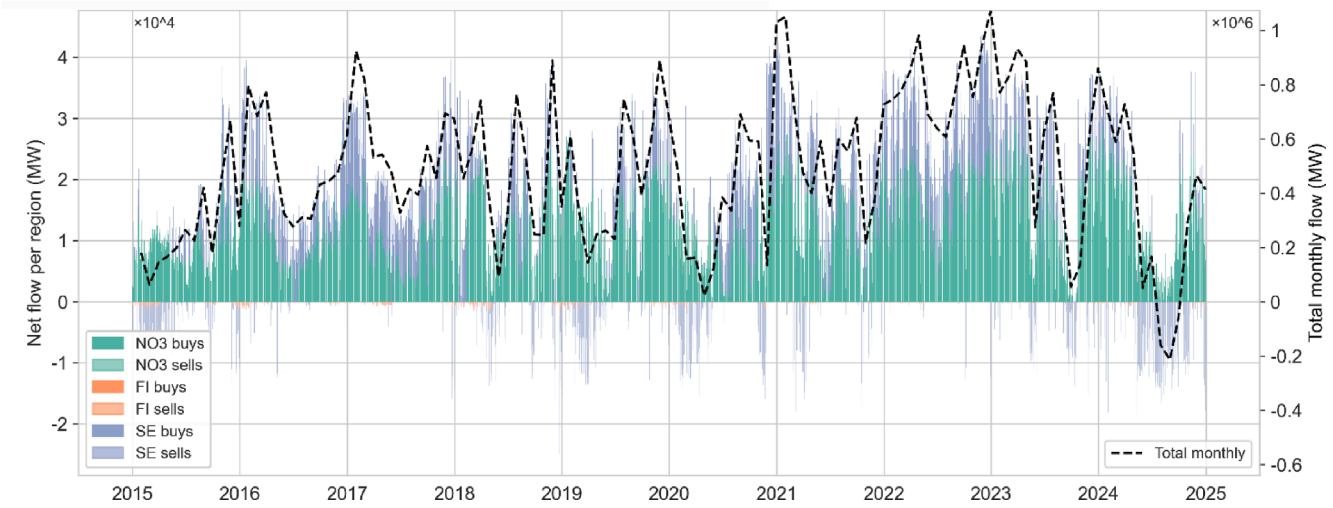

Fig. 1. Elaboration of data from [22]. The graph reports daily electricity flows from and to NO4 and the nearby connected territories, in MW, with positive values representing NO4 export (the region of interest "buys") and vice versa. The dotted line reports the monthly net total amount of the trades for NO4, resulting negative (net import) only for a short period of 2024.

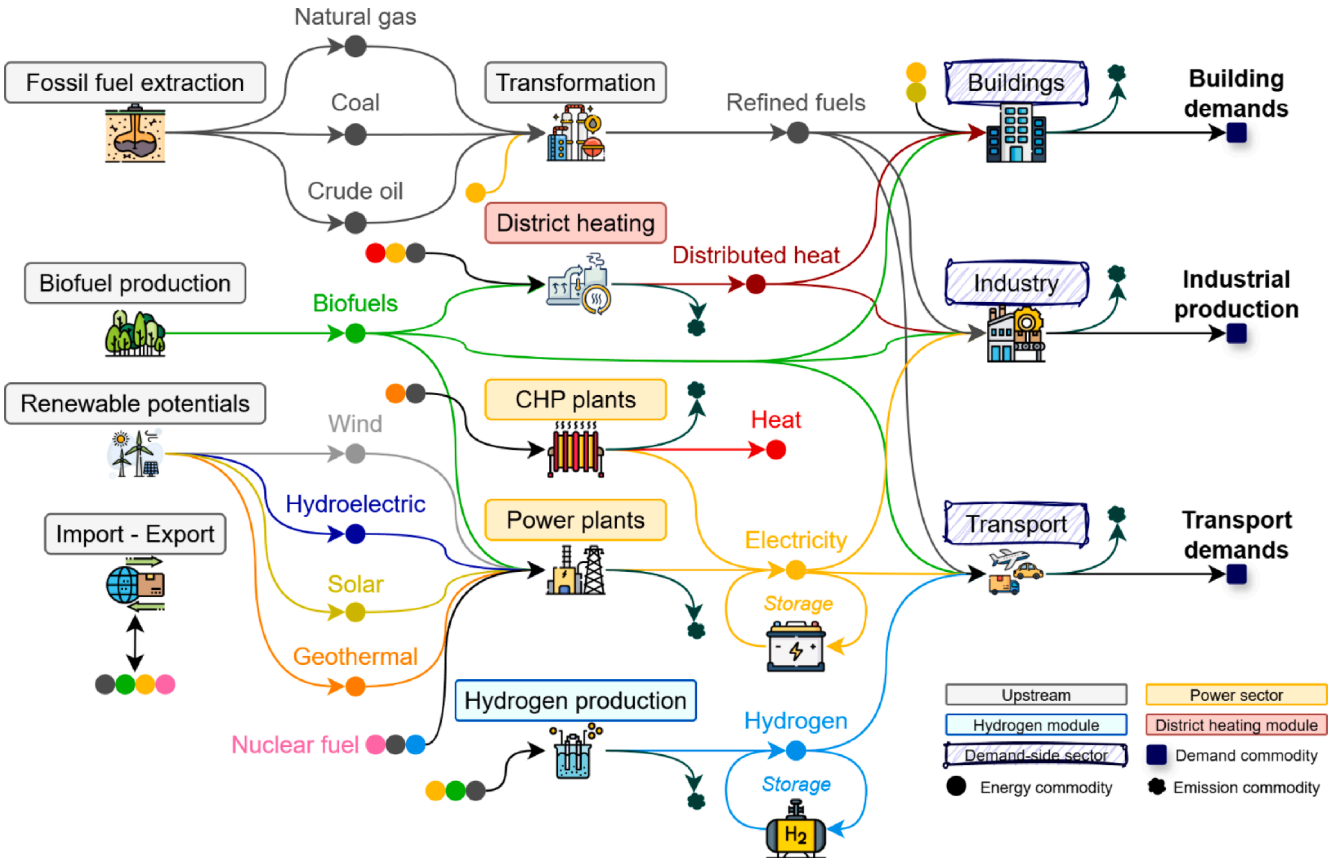

Fig. 2. Northern Norway reference energy system.

data for recent years up to the last available datum.

The procedure for implementing Buildings demands started with retrieving energy consumption data for the sector, and this was accomplished thanks to the combination of figures from the following tables. Initially, table number 11561 from [27], of which here is an extract reported as Table 5, was the main source of data for energy consumption both in residential and commercial subsectors. For both consumer groups, electricity is addressable as main energy vector with shares of over 70% for services and over 80% for households, and while on the residential side solid biomass, of which the large majority is wood, stands as secondary source, followed by district heating, commercial activities still rely considerably on diesel and other fossil fuels, as well as on district heating for a significant amount.

The limitation, as in the majority of the cases, is that this table refers to national framework, hence, table 14092, reporting electricity consumption by consumer group and region, from the same source was used as a proxy for deriving also the other consumptions. Here, this was reported as Table 6 after some calculations for a simplified view, in

Table 3
Population data projections by region and county, thousands, Statistics Norway.

Region	County	2020	2030	2040	2050	% in 2020
NO1	Viken	1241	1357	1440	1504	50.78%
	Oslo	693	742	784	809	
	Innlandet	371	377	383	387	
	Vestfold og Telemark	419	440	455	464	
NO2	Agder	307	324	337	346	5.72%
NO5	Rogaland	479	505	525	538	25.74%
	Vestland	636	660	681	694	
	Møre og Romsdal	265	270	274	275	
NO3	Trøndelag	468	494	512	522	8.73%
NO4	Nordland	241	240	239	236	9.03%
	Troms og Finnmark	243	245	249	249	
National total		**5367**	**5658**	**5884**	**6028**	

Table 4
Regional gdp, [26].

Year	2015	2016	2017	2018	2019	2020	2021
Nord-Norge [M€]	23 233	24 566	25 380	25 952	25 996	23 006	26 109

particular, since the source dataset includes monthly data, they were aggregated yearly and converted from MWh to PJ for coherence with the present document. Combining these two datasets, the weight of electricity consumed by households and tertiary services in Northern Norway over the total electricity consumption in the same categories for the whole country can be retrieved, also highlighting that the use of population as a proxy for data disaggregation might also be misleading, since NO4 hosts roughly 9% of the country's population, but its electricity consumption in buildings (i.e.: tertiary industry plus households in table 4) over the same datum at national level (i.e.: sum of "Electricity" for both categories in table 3) results in a 12.8% average share, almost 4 percentiles apart with respect to population weight.

This aspect was recently updated thanks to newly implemented data in [27], including table 14580 for energy usage in households by contents, year and region, here reported as Table 7. From this set of data, the total consumption per person could be multiplied by the actual population of the region to find total energy consumption in residential sector, now well in line with the total electricity consumption in the same sector from table 14092.

Energy consumption per person in Table 7, was multiplied by NO4 population in 2022, as per from table 01222 of [27], providing a total energy consumption for the residential sector of the region of 20.4 PJ. Comparing this number with the total energy consumption of the residential sector at national level, it was possible to estimate the weight of NO4 region in order to also obtain total energy consumption for the commercial sector, with the assumption of a similar proportion, hence deriving the demands for the buildings sector.

The former step is summarised in Table 8. This allows to have a total energy consumption for buildings sector (commercial plus residential) to be distributed in various end-use demands. To obtain this, two further steps are still needed: consider a share for each end-use such as space heating, water heating, electric appliances, etc. which was accomplished applying JRC data for Sweden (the closest geographic area with official data) [28]; accounting for system efficiency, since all data retrieved regard energy *consumption*, while the model needs energy *demand* as an input (i.e.: useful energy output from the specific technology).

The described steps lead to the composition of energy demands in the buildings sector as reported in the following Table 9. Starting from previously reported total energy consumption for residential and commercial, JRC shares can be used to obtain breakeven consumption by end-use. These, multiplied by efficiency, provide the actual energy

Table 6
Elaboration of table14,092 from [27] about electricity consumption by consumer group and region, in Northern Norway from 2020 to 2024 included, selecting main posts for consumer groups.

PJ	2020	2021	2022	2023	2024
Total	62.8	62.5	67.3	70.2	68.4
Primary industries	1.5	1.7	1.8	1.9	1.9
Secondary industries	32.9	30.7	35.4	36.8	35.7
Tertiary industries	11.2	12.1	12.7	13.5	13.5
Households	17.3	18.1	17.3	18.0	17.3

Table 7
Extract from table14,580 from [27], including all contents, year 2022, Northern Norway region.

Energy usage in households, by contents, year and region	Northern Norway 2022
Specific energy consumption (kWh per m^2 dwelling area)	*195*
Energy consumption per person (kWh)	*11 712*
Dwelling area (m^2)	*118*
People per household	*2.1*

Table 5
Extract from table11,561 of [27], considering data in petajoule, years from 2020 to 2024, final energy consumption for commercial and services and households only and detailed energy products only for non "all zero" posts.

PJ	Energy balance									
	Commerce and public services					Households				
	2020	2021	2022	2023	2024	2020	2021	2022	2023	2024
All energy products	125.3	133.6	126.0	129.3	129.3	168.0	176.7	159.1	167.6	167.7
Natural gas	0.6	0.6	0.4	0.4	0.4	0.1	0.1	0.1	0.1	
Liquefied petroleum gas (LPG) and ethane	1.3	1.4	1.7	2.3	1.6	0.1	0.1	0.2	0.3	0.2
Kerosene-type jet fuel	1.4	1.3	1.1	1.3	1.4					
Diesel not used for road transport	11.9	12.6	12.1	12.4	12.5					
Road diesel (excl. bio)		0.1								
Marine gas oil	1.6	1.7	1.9	1.7	1.9					
Gas oil/diesel oil	0.1			0.1						
Other oil products n.e.c.	0.1									
Solid biofuels	0.9	0.3	0.2	0.2		18.7	20.8	22.1	20.6	20.2
Liquid biofuels		0.5	1.0	2.1	2.2					
Biogas	0.5	0.5	0.5	0.5	0.8					
Non-renewable waste	0.7	0.6	0.3	0.5	0.5					
Electricity	93.9	99.4	93.0	91.9	93.2	143.8	149.5	130.8	139.8	140.6
District heating	12.3	14.8	13.9	15.9	15.3	5.3	6.2	5.9	6.9	6.7

Table 8
Share of no4 buildings energy and electricity consumption over national data. The total amount of consumed energy for commercial and services (bold figures) was derived applying the same share (%) retrieved for households.

	2022 NATIONAL	REGIONAL	%
Total energy consumption in households	161.0	20.4	12.7%
Total energy consumption in commercial and services	124.5	**15.8**	12.7%
Electricity consumption in households	130.9	17.3	13.2%
Electricity consumption in commercial and services	92.7	12.7	13.7%

demands for the sector.

Notably, the efficiency value considered is higher than 1. This derives from different assumptions: the first is to derive an average efficiency of space heating technologies used in households, which was accomplished considering their share as reported in table 10,571 of [27] on a national basis. This provides the value in table since the use of heat pumps (both air-coupled or geothermal ones) covers 36% of the cases, with COP between 2.5 and 3.5, and 44% of the cases are electric heaters, for which an efficiency of 80% was considered. The second assumption was to use this space heating systems efficiency for the entire sector, as the space heating covers more than 65% of the entire energy demand in the building sector. This is a strong assumption, but it is conservative because it may overestimate total demand. Electric appliances, the second-largest end-use category, usually have efficiencies between 80% and 90% or higher, which would imply lower useful-energy demands for that category. The final effect is therefore to test a system required to meet demands that may be slightly higher than strictly necessary, which is preferable to underestimating demand.

2.9. Power sector

The electricity generation resulting from model outcomes, is directly related to optimization choices performed by the process, as electricity is one of the possible energy vectors to be exploited to fulfil final demands. This is the reason why the demand for this commodity is inherently built through each sector's demands. Nevertheless, the technologies configuration of the sector and their historical power outputs must correspond to recorded data. On this regard, as previously mentioned, electricity consumption records represent the most detailed and reliable datasets available in Norwegian statistics, and therefore they were generally not problematic to obtain also at regional level. Conversely, significant data gaps emerged with respect to production for Northern Norway. In particular, from table 14,093 of [27], both thermal and hydropower generation data were only reported for a single temporal unit, July 2024, over the entire historical period 2020–2025 (continuously updated to the second to last month). The incompleteness of this dataset led to switching source for this sector, referring to [25]'s transparency platform which reports hourly electricity generation by production type at spot price region level. 2019′s figures, combined with installed capacities retrieved from the same source, were used to implement the base year electricity generation configuration, while 2020 and 2025 datasets, reported in Fig. 3 as monthly production, served as reference for historical years comparison and calibration.

As mentioned, [25] data were also used to retrieve the installed capacity by technology in the NO4 region, as well as the electricity export flows, which, as previously discussed, play a central role in the regional energy balance. In particular, to derive significant data for electricity trade with adjacent regions, both sources were considered and compared, in order to verify the robustness of input data. Respectively, data retrieved from tables 14,093 and 14,092 of [27] were elaborated to obtain the difference between total production and total consumption of electricity in the region, similarly to what has been done with [25]'s dataset, where total load was compared to total generation computed from all the active production technologies recorded, to be finally compared to the export of the region as reported by [27] itself, obtaining the Table 10 shown below.

The values in the table differ by non-negligible amounts, reflecting the complexity of electric grid management. This occurs because the calculations rely on datasets that may refer to different quantities. For example, the "Actual Load" reported by [25] equals the sum of all the power generated by the plants [25,27], while the "Total consumption" of electricity from [27] is defined as the Net consumption, hence excluding grid losses due to transmission and transformation (Statistics Norway). Moreover, the "Export" dataset obviously does not include all the traded electricity which would also imply imports from neighbouring bidding zones. Much closer gaps are observed in Table 11, comparing the surplus electricity from [25] (the "Entsoe difference" in Table 10), with the net traded one from the same source, which includes grid balancing exchanges through the year.

This surplus represents for the model perspective, the export potential of the region. In order to allocate this electricity to the trade with NO3, SE1 and SE2, and FI through SE1, [24] data about power lines were used as well as, from the same source, the historical data already mentioned.

Data from [24] reports a capacity of 700–1000 MW from NO4 to NO3, of 600 MW to SE1, of which 120 MW spill-over to FI and of 200 MW to SE2. Considering the maximum capacity, 56% of the flow can be allocated to NO3 and 44% to Sweden, of which 15% spills over to Finland. These shares were used to compose import and export capacities from nearby regions. For operational activity, import was not actually forced to any value, as it was chosen to leave the model free to optimize electricity import only when it really is convenient. This freedom could not be assured with exports since the model only produces what is needed to satisfy the demands. Export demands were therefore implemented to represent the historical outward flow of electricity from the region. In particular, the 2019′s figures from Table 12 were used for the base year's demand values of each region, and 2020 and 2025 data are implemented through driver and elasticity computation for corresponding years. The table also reports year by year values to show how these can be oscillating in time, therefore, building the export demand based on the time steps of the model may not properly reflect the dynamics of the grid and sensitivity analysis was performed on these input data to verify their influence on the power sector of the region in the long term.

Table 9
Energy demands for northern norway region derived from jrc shares and global system efficiency.

	Demands	JRC shares for Sweden or assumption*	NO4 consumption 2022 [PJ]	Performance	**NO4 demands 2022 [PJ]**
Households	Space cooling	0.0%	0.01	1.70	**0.01**
	Space heating	76.9%	15.69		**26.72**
	Water heating	8.0%	1.63		**2.78**
	Electric appliances	15.0%	3.06	0.85	**2.60**
Commercial	Space heating	50%*	7.88	1.70	**13.43**
	Water heating	10%*	1.58		**2.69**
	Electric appliances	40%*	6.31	0.85	**5.36**

*commercial and services demand shares are assumed.

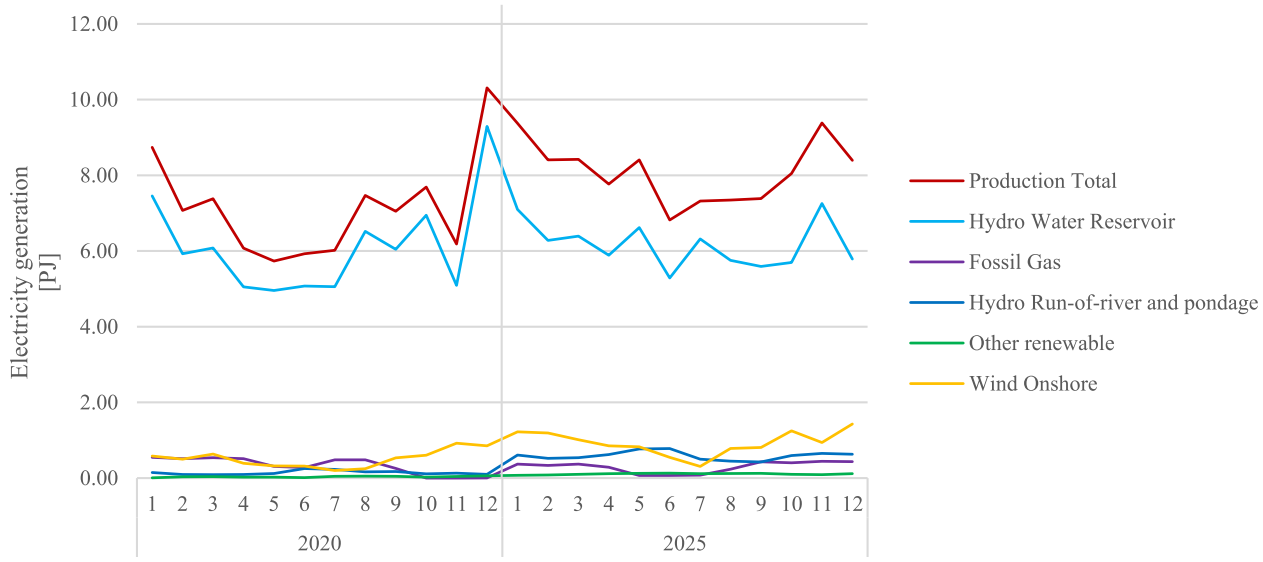

Fig. 3. Monthly electricity generation profiles for years 2020 and 2025 in northern norway, in pj, according to[25]'s Transparency Platform. Although the total production's profile is closely resembled by the hydropower generation's one (reservoir) for both years, in 2025 the distance between these two lines increases, marking a stronger intervention of other production technologies, in particular onshore wind and run-of-river hydropower.

Table 10
Difference between generation and consumption of electricity from the different available sources: total production from table14,093 and total consumption table 14,092 of [27], aggregated by year, produced the "SSB difference". Further data aggregation from [25]'s Transparency Platform for NO4 (Actual generation per generation unit and Total Load – Actual) produced the "Entsoe difference" and from the same platform, the "Export" was computed thanks to the Cross-border Physical Flow dataset, considering only the exiting fluxes from the region.

	SSB difference	Entsoe difference	Export
2020	22.0	18.4	21.5
2021	29.9	25.9	27.4
2022	41.1	39.5	37.4
2023	30.5	25.3	29.9
2024	17.4	12.8	20.9
2025	28.3	24.9	24.2

Table 11
Comparison between net traded electricity and production-load difference [25].

	Net trade Entsoe	Surplus
2020	17.9	18.4
2021	25.1	25.9
2022	36.7	39.5
2023	26.6	25.3
2024	13.5	12.8
2025	22.0	24.9

Table 12
Net export towards neighbouring bidding zone.

	NO3	FI	SE
2019	18.0	0.7	2.7
2020	12.1	1.0	4.9
2021	17.2	0.9	7.0
2022	22.1	1.5	13.1
2023	20.2	1.3	5.1
2024	16.1	0.8	−3.5
2025	18.1	0.6	3.2

2.10. Industry

The industrial sector represents the most critical diagnostic challenge for regional energy system modelling, due to structural limitations in data availability rather than to modelling capability. Official statistics are largely subject to confidentiality restrictions, and without specific agreements with industrial stakeholders, detailed information on production capacities and technology deployment cannot be accessed. As a result, the sector is represented primarily from an energy demand perspective, focusing on aggregated consumption of energy commodities rather than explicit technological characterization. Even this approach is constrained by limited regional data, with electricity consumption representing the only publicly available indicator. This representation is adopted deliberately to preserve internal consistency and transparency, acknowledging that greater technological detail would require confidential or plant-level data that are not publicly accessible at regional scale. The implications of these assumptions are therefore interpreted diagnostically rather than predictively. Accordingly, industrial results are discussed primarily in terms of energy balances and system implications rather than detailed techno-economic optimization. As shown in Table 13, electricity demand has therefore been used as a proxy to estimate the consumption of other energy carriers, under the assumption that the industrial structure of NO4 reflects the national average.

As a consequence of these data constraints, industrial decarbonisation in the model is implemented through exogenous assumptions rather than emerging endogenously from technology competition. While this limits the ability to explore detailed industrial transition pathways, it serves a diagnostic purpose: it reveals that, at present, the primary bottleneck for meaningful regional industrial decarbonisation modelling is not the optimisation framework itself, but the lack of transparent, disaggregated industrial data at subnational level. In this sense, the industrial sector highlights a structural gap between national reporting practices and the information requirements of regional energy planning models.

For this reason, industrial-sector results should not be interpreted as endogenous technology-transition pathways. In the present implementation, the model determines the system-level energy-balance implications of industrial demand and emissions constraints, but it does not endogenously identify plant-level fuel-switching, electrification, hydrogen uptake, carbon capture, or process-specific technology

Table 13
Breakeven of energy commodities consumption in industry sector. electricity data reflect national shares for each subsector, multiplied by the actual total consumption. these are then used to derive the remaining data.

PJ	Elc	Oil prod	Gas	Coal	DH & steam	W&w/Bio	Fuels	**Totals**
Mining	0.30	0.49	0.04	0.00	0.00	0.00	0.05	**0.88**
Food & beverages	2.02	0.22	0.72	0.00	0.21	0.04	0.13	**3.35**
Textile	0.05	0.00	0.01	0.00	0.00	0.00	0.00	**0.07**
Wood & paper	2.71	0.13	0.21	0.00	0.10	1.81	0.02	**5.00**
Petrochemical	6.35	0.46	9.25	2.64	0.60	0.67	0.07	**20.04**
Metals	18.93	0.12	0.62	3.35	0.03	0.01	0.03	**23.08**
Other	0.87	0.08	0.06	0.00	0.06	0.00	0.07	**1.15**
n.e.c.	1.66	0.11	0.09	0.00	0.09	0.03	0.11	**2.09**
	32.90*	**1.62**	**10.99**	**5.99**	**1.10**	**2.57**		**55.64**

*Source: Statistics Norway table 14,092.

replacement. Industrial decarbonisation is therefore treated as an externally imposed constraint under data scarcity, while the resulting electricity, fuel, and emissions implications are interpreted diagnostically. This distinction is important because the absence of disaggregated industrial activity data limits the model's ability to distinguish between alternative industrial transition mechanisms.

2.11. Transport

Transport sector is composed by various subgroups based on means of transfer: road, rail, navigation, aviation; and by purpose of transfer: passenger, freight. This scheme builds up a diversified and complex system for which data sources differ in resolution, definition and retrievability.

To begin with, road transport represents one of the components with the larger weight on the sector, and most of its data can be retrieved from [27]. The demands are compiled according to total traffic volumes retrieved from table 12,576 of [27], for Nordland, Troms and Finmark counties, composing the region, including also figures for Svalbard, often considered in NO4 statistics (Statistics Norway). These figures are reported in Million kilometres in the table and represent the aggregate road traffic volumes for each vehicle category, specifically: passenger cars, buses, vans and small lorries, heavy lorries and road tractors, divided by fuel type including petrol, diesel, electricity and different hybrid configurations. The figures reported in this statistic are exceptionally accurate since, as from Statistics Norway claim, they result from the aggregation of the mandatory odometer readings of vehicles of each category in 75% of the fleet, while the remaining 25% is estimated according to vehicle type. This is far from the usual sampling survey from which statistics are generally produced, increasing the reliability of data input for the model. The level of detail of this source will be useful for results comparison and model calibration in following sections, while for the demand composition, figures aggregated by vehicle category can suffice, constituting the road transport volume as a whole. These were converted in Bvkm and reported in Table 14.

Two-wheeled vehicles are not included in previous data since in Norway, contrary to other vehicles, these are not subject to mandatory odometer readings (Statistics Norway), for this reason no aggregate mileage is available for the region. Nevertheless, according to Norwegian vehicle register, a not-negligible fleet belongs to this category in Northern Norway, specifically, NO4's two-wheeled vehicles represent roughly 8% of the national fleet. Snow scooters are not included in this datum, even if half of the entire fleet resides in Northern Norway, since these are not road vehicles and are mainly used for entertainment purposes for which annual mileage can be poorly captured, and not enough data can be retrieved from the Norwegian authority for transport on this regard. On the other side, starting from a national statistic, the annual demand for two wheels transport was estimated as follows.

Statistics Norway table 03982, reporting domestic passenger transport by mode of transport, was used for motorcycles and mopeds. Because these figures are available only at national level, they were downscaled to the Northern Norway bidding zone using the ratio between regional private-car traffic volumes and national private-car traffic volumes as a proxy, assuming the average occupancy of two-wheeled vehicles equal to one, as reported in equation below, where $2W_{D.NO4}$ is the two-wheelers demand in the region, $CAR_{V.NO4}$ and $CAR_{V.NORWAY}$ are the traffic volumes for private cars respectively for the region and for the country, from Statistics Norway table 12576, $2W_{P.NORWAY}$ is the passenger transport value for the country given by above mentioned table 03982 and AO_{2W}, is the average occupancy of two-wheeled vehicles assumed equal to 1.

$$2W_{D.NO4} = \frac{CAR_{V.NO4}}{CAR_{V.NORWAY}} * \frac{2W_{P.NORWAY}}{AO_{2W}}$$

The corresponding values for the equation above are reported in Table 15, with the resulting demand for two-wheelers. Data are reported from 2019 to 2024 for completeness, and the demand was implemented considering the base year of the model 2019. Also, figures about national motorcycles in the table, are reported in the same unit of measure as other data since the average occupancy considered is equal to one.

As previously anticipated, non-road transport includes aviation, navigation and rail. For each of these, both passenger and freight demands, and respective technologies, exist and the majority of data in this regard can still be retrieved from [27].

Maritime transport demand was estimated separately for passenger and freight services. For passenger maritime transport, an initial assumption was made using Statistics Norway data: passenger movements were treated as national only, because international passenger transfers to and from Northern Norway were reported as null in table 04225 when selecting ports from Mo i Rana to Sveagruva and all destinations outside Norway.

Given this assumption, passenger transport is retrieved from table 11571 of [27], including all public routes and reported as "boat kilometres", which can be easily converted in Bvkm, the unit of

Table 14
Road transport demands for passenger and freight. sourced from table12,576 of Statistics Norway.

	2019 Demand [Bvkm]
Cars	3.172
Buses	0.029
LCV	0.558
Trucks	0.103

Table 15
Summary table for two-wheeled vehicles demand estimation, based on[27] data.

	Road traffic volumes – NO4 [Bvkm]					
	2019	**2020**	**2021**	**2022**	**2023**	**2024**
Private cars – National	35.5	33.9	35.1	35.3	35.7	35.4
Private cars – Regional	3.17	3.01	3.10	3.08	3.06	2.97
Motorcycles – National	1.53	1.56	1.59	1.51	1.38	1.34
Motorcycles – Regional	0.14	0.14	0.14	0.13	0.12	0.11

measurement used in the model. Unfortunately, this dataset does not include the entire maritime passenger traffic as it would require accounting also for private boats, non-regular transport services, touristic cruises, non-public passenger boats, and others, but such a statistic is not reported for Northern Norway. There is, in fact, a statistic that estimates the entire maritime passenger demand, which is table 03982, though this presents several criticalities: firstly, it does not presents region-based data, but only national ones, hence requiring disaggregation which adds uncertainty to input data; on the other hand, the figures here included are estimations based on aggregation of data, while table 11571 retrieves figures directly from observations. For this reason, the above-mentioned source was considered to obtain passenger demand.

Freight maritime transport needed a less straightforward process to obtain national and international demands. Initially, the figures about annual tonnes of goods moved from and to NO4 were retrieved from table 10916 of [27], including all the ports of the region for the years from 2018 to 2024, in order to check that the year 2019 does not constitute an outlier, both towards and from national and international destinations. The second step was to estimate the average route length for both. To accomplish this, data from table 10916, specifically total tonnes of goods shipped nationally and internationally in all Norway, were combined with data about transport work (tonnes km) from table 11403. In this case, an assumption was necessary, since there is not explicit indication about how many national and international travels a ship accomplishes, hence, the transport work, including cabotage, from ships in the Norwegian Ordinary Ship Register (NOR) was considered for national transport, while the transport work from ships in the Norwegian International Ship Register (NIS) and in foreign ship registers was accounted for international transport. Moreover, the total tonnage capacity divided by number of vessels was performed both for NO4 region and for Norway, from table 08203, to estimate an average tonnage per vessel for both domestic and foreign transport, respectively. Finally, data were combined to obtain demands for those two instances in 2019, in Bvkm. The explicit equation is reported for clarity, where $NAV_{D,FRG}$ represents the freight demand for maritime transport (national or international), $\sum_{p\in NO4} t_p$ is the sum of the tonnes of cargo, t, for each port, p, belonging to the NO4 region. $\frac{w_{NOR/NIS}}{load}$ is the work of transport, in tonnes km, of the ships included in the Norwegian Ordinary Ship Register, or in the Norwegian International Ship Register plus in the foreign registers, for domestic and international computations, respectively, divided by the corresponding total load transported. This parameter is computed on national data to obtain average travel distances. Finally, $\frac{totalcapacity}{numberofvessels}$ is considered to compute average tonnage per vessel, national figures are used for the average international shipping tonnage, regional (NO4) ones for national result. All data are referred to the year 2019.

$$NAV_{D,FRG} = \frac{\left(\sum_{p\in NO4} t_p\right) \bullet \frac{w_{NOR/NIS}}{load}}{\left(\frac{totalcapacity}{numberofvessels}\right)}$$

For rail transport, Statistics Norway table 13300 was used to obtain the number of passengers travelling within and through the region. The average travel length was estimated through table 10,484 by dividing transport work (passenger-km) by passenger counts for the Nordland Railway, the main rail connection between Northern Norway and southern Norway. This is an approximation because only about half of this line lies within the Northern Norway bidding zone. The only other railway connection is the Ofoten Line (Ofotbanen), which links Narvik to the Swedish border and historically served iron-ore transport to the port; today, the electrified single-track line carries both freight and passengers. Because table 13300 reports only 2020, 2023, and 2024, regional passenger demand for 2019 was derived from 2020 passenger flows from Nord-Norge to Nord-Norge, corrected using the ratio of Nordland Line passengers in 2019 to those in 2020 from table 10484. This value was multiplied by the average travel length and divided by the number of seats per train, adjusted by the occupied/vacant-seat ratio derived from seat-km and passenger-km data, and then converted to billions.

$$RAI_{D,PAS} = \frac{passengers2020_{NO4} \bullet \frac{passengers2019_{NordlandLine}}{passengers2020_{NordlandLine}} \bullet \overline{travellength}_{NordlandLine}}{seats_{in-use}}$$

Similar procedure was followed to obtain interregional demand, starting from number of passengers in 2020 from Nord Norge to all the other regions, applying again the mentioned steps.

Freight transport demand by rail was estimated starting from table 04780, considering the national transport work of goods, multiplied by the fraction representing NO4. This fraction was found through table 13299, which is similar to the one used previously for passengers, calculating the ratio of goods moved inside the region, from Nord Norge to Nord Norge, over the goods moved nationally, from the whole country to the whole country, and finally divided by the average load per train, set at 2800 tonnes [29]. Figures from table 13299 were used to estimate the exchanges between Nord Norge and the rest of the country, though unfortunately, no national statistics report goods movement from the single regions to outside the country to account for other external exchanges. Nevertheless, Ofoten Line activities are well reported due to their importance in the iron ore industry, for this reason, it is known that the length of the Norwegian side of the route is 43 km, and that the traffic is of about ten trains per day towards Narvik, transporting 6800 tonnes of goods, leading to carriage of about 25 Mt per year, consistent with the Narvik's port capacity. However, a more conservative figure was used, derived from the transport operating company LKAB, accounting, in the 2019 report, for two thirds of the export through Narvik, with a total delivered material of 24.8 Mt, resulting in $\sim$ 16.5 Mt of goods over 43 km in trains with 6800 tonnes of carriage each [30]. This amount is added to the previous interregional activity to compose international demand. In the equation below is the summary of what described, with the numerator of the first fraction representing the national work of transport, w_{Norway}, multiplied by the fraction of goods exchanged exclusively between NO4 and the rest of the country, over the entire exchanges happening in the country, representing the weight of the region. At the denominator, the regional tonnage per freight train mentioned above. The second fraction represents the Ofoten route's contribution, where $load_{Ofot}$ is the 16.5 Mt figure already discussed.

$$RAI_{D,FRG,INT} = \frac{\frac{\left(NO4 \xrightarrow{freight} Norway\right) - \left(NO4 \xrightarrow{freight} NO4\right)}{Norway \xrightarrow{freight} Norway} \bullet w_{Norway}}{ton/train_{REG}} + \frac{load_{Ofot} \bullet length_{Ofot}}{ton/train_{Ofot}}$$

Finally, aviation was considered, with table 08,503 reporting all the aircraft movements both for national and international routes, that have to be multiplied by the distance travelled. In order to obtain an average length of the flights, table 03,982 was used, considering total and domestic air transport both passenger and passenger km figures. Dividing the latter by the former the average distance travelled is obtained, with the approximation that this is the datum about the country and not the region and given the difference between figures of total air transport and domestic air transport, the same result can be computed for international flights. This way, passenger demand was achieved both for national and international travels. Below, the equation is reported, with $\#flights_{NO4}$ representing the aircrafts movements from NO4 to national and international destinations respectively for each demand, w_{Norway} being the passenger transport work in passenger km, divided by the total number of passengers, providing average travel length, different for domestic and international cases.

$$AVI_{D,PAS} = \#flights_{NO4} \bullet \frac{w_{Norway}}{passengers_{Norway}}$$

Freight transport required the elaboration of data from table 08505, reporting tonnage of carried goods from and to each Norwegian airport,

selecting the ones in the Northern Norway region, total carried goods are obtained for 2019. In order to estimate average travelled distances for national and international routes, two similar strategies were followed. For national case, the three main airports of Northern Norway region were considered: Bodø, Tromsø and Narvik (Evenes), the great circle distance was computed from each of these airports to Oslo's one, which constitutes the main national centre for freight transport [31], the average value of 1000 km was considered.

International case followed a similar procedure, considering only Narvik (Evenes) as NO4′s export hub, since it covered over 90% of regional freight transport abroad in the period 2019–2024 [27], and selecting main continental destinations for computing the average. In particular, Amsterdam Schiphol, Frankfurt Main, Copenhagen and Liège were chosen, leading to an average distance from Narvik of 1800 km. Concerning aircraft capacities, two common models were chosen for national and international routes, Boeing 737 and Airbus a310F, respectively. The equation below summarizes the terms composing the demand, with $\sum_{a\in NO4} t_a$ including the sum of tonnes from and to all the Northern Norway airports, a.

$$AVI_{D,FRG} = \frac{\left(\sum_{a\in NO4} t_a\right) \bullet avglength}{ton/aircraft}$$

The resulting demands from the transport section, obtained as described above, are reported in Table 16, in Bvkm.

2.12. Existing capacities

Existing capacities for the base year are computed differently for road and non-road technologies. For the former, table 11823 from [27], reporting registered vehicles per region, was considered to obtain Northern Norway engine-wise shares for the fleets of cars, buses, light commercial vehicles, trucks and two-wheeled vehicles. For these, technologies were created to match the existing registered vehicles in terms of engine type and class, the actual share of each technology was multiplied by the 2019 demand, increased by a 1% value to grant demand fulfilment even in case of data mismatches and neglected technologies (e.g.: paraffin engine cars were not included in the model because their share in the total fleet is of 0.0016%). This artificial increase in existing capacity does not affect the optimization process, as the model is going to exploit technologies only to precisely fulfil the demands, hence, exceeding capacity will not entail additional energy consumption.

Non-road technologies do not have a regional register; therefore, national energy balance statistics were used to obtain existing technologies and related capacities. Specifically, table 11562 from [27] was used for data about energy consumption by product in the transport sector, with details about rail, domestic aviation and domestic navigation data. Figures were converted to obtain energy content for each energy product (often reported as ktonnes consumed) and shares were computed for each of them over each non-road category. Domestic aviation and navigation data were also used for international technologies under the assumption of similar development. Moreover, maritime transport fuel shares have been slightly modified with respect to the balance reported in [27], again to ensure demand fulfilment. Specifically, Marine gas oil technologies shares were manually increased from 75.5% to 78.9%, to account for all the fuels individually weighing less than 3.5% in the sector. The resulting figures are reported in Table 17, where each line represents an additional technology, even though some of them share the same name, due to the fact that they satisfy different demand classes, do not share the same characteristics. For example, passenger and freight transport technologies are distinguished for efficiencies, costs, and load type. National and international freight vessels also have different load rates; therefore, the "Technology" column reports the fuel consumed by that specific instance, for clarity and concision.

Table 16
Demands for passenger and freight in 2019 for non-road transport in northern norway, estimated both for national and international routes.

			Demand 2019 [Bvkm]
Passenger	**Navigation**	National	2.13E-03
		International	–
	Aviation	National	5.76E-02
		International	1.64E-03
	Rail	Regional	1.03E-03
		National	3.76E-04
Freight	**Navigation**	National	1.83E-03
		International	2.91E-03
	Aviation	National	6.81E-04
		International	7.84E-05
	Rail	National	5.31E-04
		International	1.20E-04

2.13. Temporal and spatial resolution

The model covers the time horizon 2020–2050, with five-year interval time-steps. Within each year, demand and supply are represented using a time-slicing structure that captures seasonal variation and intra-day dynamics. Specifically, time is disaggregated into seasons (winter, spring, summer, autumn) made of 24 time-of-day blocks, which allow the reproduction of realistic generation and load patterns.

The selected 96-slice structure represents a compromise between chronological fidelity and computational tractability, consistent with several high-resolution long-term energy-system optimisation model applications identified in recent review literature [12]. It should be noted that, while this structure captures seasonal and diurnal variability, it cannot represent prolonged multi-day low-renewable events or hydrological stress periods, which may lead to underestimation of long-duration storage and backup requirements.

Spatial resolution is defined at the bidding-zone level, with interconnection flows represented through technical transfer capacities. Interconnected regions are included only through electricity exchanges: exports from Northern Norway are imposed as demands, whereas imports are left to the optimisation model when economically advantageous.

Temporal resolution was selected to represent daily variation in energy demand and renewable production. Averaging electricity generation and consumption over a full day could obscure peak demand, intra-day mismatch, and the intermittency of renewable resources. The selected time structure therefore represents demand and capacity factors through season-specific daily profiles and allows storage to be deployed when intra-day supply–demand mismatch makes it economically useful.

2.14. Model calibration

The model has been calibrated against historical datasets for years 2020 and 2025, with 2024 data representing the latter for databases not yet updated at the time of writing. The process consists mainly of introducing activity and capacity constraints over existing technologies and possibly the penetration of prospective ones whether historical data reflects this behaviour. The sources framework reflects closely what already presented for demands estimation and representation and the graphical comparison is reported in Fig. 4.

The scope of this comparison is to verify whether the model has been appropriately defined and tuned in order for service demands to be satisfied in a way that resembles as closely as possible what actually happened in reality. This check was performed through the comparison between the total amount of primary energy supplied to the system, hence excluding what resulted from a transformation process (e.g.: electricity, district heating), as reported by official data, and the same amount as resulted from the model.

On the other side of the spectrum of the Reference Energy System

Table 17
Road and non-road existing capacities, computed from actual vehicle fleets data or fuel consumption shares in the sector, as reported in[27].

	Demand class	Augmented Demand [Bvkm]	Technologies	Share	Existing capacity [Bvkm]
ROAD	Passenger cars	3.204E + 00	Electric cars	3.3%	1.04E-01
			Diesel cars	58.3%	1.87E + 00
			Gasoline cars	34.7%	1.11E + 00
			Gasoline hybrid cars	3.6%	1.16E-01
			Diesel hybrid cars	0.2%	6.58E-03
	Passenger 2-wheelers	1.384E-01	Gasoline 2-wheelers	98.0%	1.36E-01
			Electric 2-wheelers	0.5%	7.33E-04
	Freight light vehicles	5.634E-01	Diesel LCVs	79.3%	4.47E-01
			Gasoline LCVs	20.4%	1.15E-01
			Electric LCVs	0.3%	1.89E-03
	Freight heavy vehicles	1.042E-01	Diesel trucks	95.0%	9.90E-02
	Passenger buses	2.889E-02	Diesel buses	98.8%	2.85E-02
NON-ROAD	Rail passenger regional and national	1.423E-03	Diesel train	99.7%	1.42E-03
	Rail freight national	5.366E-04	Diesel train	100.0%	5.37E-04
	Rail freight international	1.437E-04	Electric train	100.0%	1.44E-04
	Air passenger national	5.813E-02	Kerosene aircraft	99.4%	5.78E-02
	Air passenger international	1.658E-03	Kerosene aircraft	99.4%	1.65E-03
	Air freight national	6.881E-04	Kerosene aircraft	99.4%	6.88E-04
	Air freight international	7.917E-05	Kerosene aircraft	99.4%	7.92E-05
	Maritime passenger national	2.154E-03	MGO ship	78.9%	1.70E-03
		2.154E-03	LNG ship	10.2%	2.21E-04
		2.154E-03	Gasoline ship	5.7%	1.23E-04
		2.154E-03	HFO ship	5.2%	1.11E-04
	Maritime freight national	1.844E-03	MGO ship	78.9%	1.45E-03
		1.844E-03	LNG ship	10.2%	1.89E-04
		1.844E-03	Gasoline ship	5.7%	1.06E-04
		1.844E-03	HFO ship	5.2%	9.52E-05
	Maritime freight international	2.935E-03	MGO ship	78.9%	2.31E-03
		2.935E-03	LNG ship	10.2%	3.01E-04
		2.935E-03	Gasoline ship	5.7%	1.68E-04
		2.935E-03	HFO ship	5.2%	1.52E-04

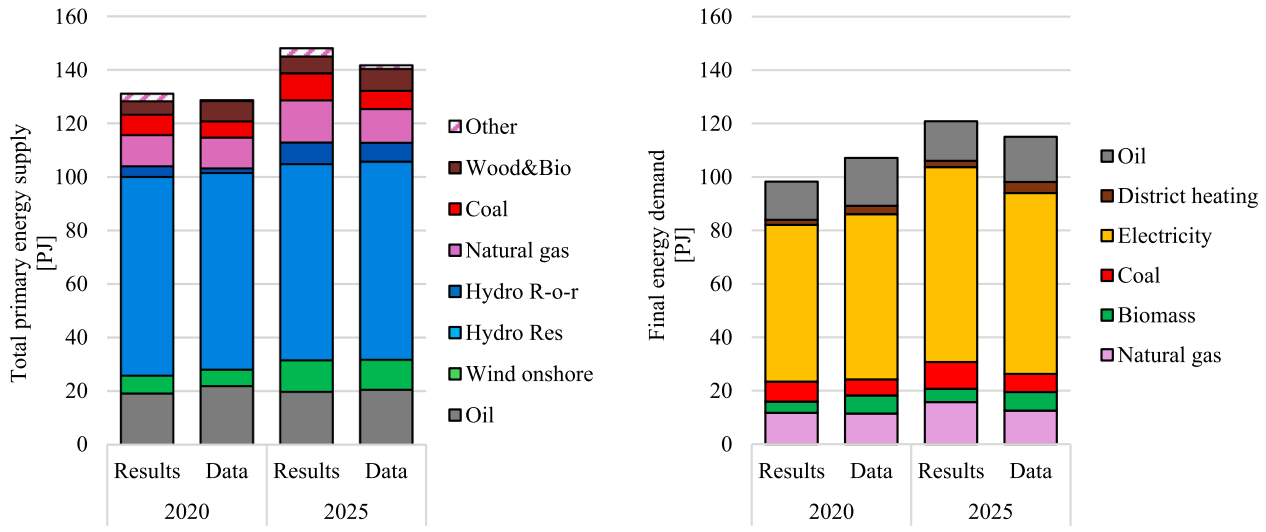

Fig. 4. Results-data comparison for years 2020 and 2025 for both total annual primary energy supply (left) and final energy demand (right), in pj. in the latter, "final" has the meaning of energy delivered to demands sectors.

with respect to total primary energy supply, is the final energy consumption, which accounts for the amount and the type of energy carriers consumed by the demand sectors to exploit the needed services, in other words, the technologies used and the "fuels" they consume. The comparison of the composition of total primary energy supply and final energy consumption mixes, between model results and historical data, provides feedback on the basic operation of the model and allows for full-horizon results analysis.

To strengthen the quantitative validation of the calibration procedure, additional error metrics were computed comparing model outputs against historical datasets for both Total Primary Energy Supply (TPES) and Final Energy Demand (FED) in years 2020 and 2025, and reported in Table 18.

Table 18
Quantitative error metrics of calibration parameters.

Weighted Absolute Percentage Error (WAPE)	2020	2025
TPES	*1.9%*	4.5%
FED	*8.3%*	5.0%

For TPES, the weighted absolute percentage error (WAPE) between model outputs and historical data equals approximately 1.9% for 2020 and 4.5% for 2025. Although some individual categories exhibit larger

deviations, particularly for smaller contributors such as “Other” energy carriers, the aggregate energy balance remains well reproduced by the model. The largest discrepancies are associated with categories characterized by low absolute values, where relatively small numerical differences translate into high percentage deviations.

For FED, the weighted absolute percentage error equals approximately 8.3% for 2020 and 5.0% for 2025. The model reproduces the overall composition of final energy demand reasonably well, particularly for dominant energy carriers such as electricity, oil products and natural gas. Remaining discrepancies are primarily linked to uncertainty in regional downscaling procedures and to the limited availability of disaggregated regional industrial data.

Overall, the validation exercise indicates that the model captures the main structural characteristics of the NO4 regional energy system while remaining consistent with the diagnostic purpose of the study. The calibration is therefore considered sufficient to support the interpretation of long-term infrastructure and flexibility diagnostics, while acknowledging that uncertainties associated with regional data construction propagate into model outputs.

In addition to annual energy-balance calibration, the temporal representation was checked against historical seasonal electricity patterns. Modelled electricity generation was extracted over the four representative seasonal profiles and compared with observed seasonal shares from the historical electricity datasets used for calibration. The comparison confirms that the model reproduces the dominant winter-demand and hydropower-led seasonal structure of the regional system, although it cannot represent multi-day extreme events or interannual hydrological variability. This comparison is reported in Fig. 5, and Table 19 also includes the percentage error computed with respect to historical data. Although the errors are not completely negligible, the shape of the curve is well preserved by the model, and the overall behaviour was considered well-represented. The temporal calibration is therefore assumed adequate for diagnostic comparison of seasonal trends, but not for adequacy assessment or investment-grade reliability analysis.

2.15. Technology database

The technology portfolio considered in this study encompasses both existing and prospective options that are particularly relevant for the NO4 region. The former have been described and quantified previously, while prospective alternatives are introduced in the following.

Concerning the electricity generation, hydropower constitutes the backbone of the system, reflecting the dominant role of Norway’s extensive hydro resources. In Northern Norway, both run-of-river and large reservoir plants are present, with the latter playing a fundamental role in providing flexibility and balancing capacity to the entire Nordic grid [32]. Alongside hydropower, wind power is emerging as an increasingly significant technology. Onshore wind farms have already been developed in exposed coastal and mountain areas, where high wind speeds and relatively low population density reduce conflicts related to urban land use, although environmental and indigenous land-use concerns remain significant. Offshore wind, although less developed to date, is included in the model as a prospective option, acknowledging the region’s vast maritime areas and favourable wind regimes [33]. This source is also envisioned as a promising capacity expansion alternative for enhancing power production to meet the expectedly increasing demand of electricity[34]. Solar photovoltaic is also represented, albeit with lower relevance compared to wind and hydro, given the latitude and the resulting highly seasonal production profile; nevertheless, during summer months with long daylight hours, PV generation can complement other renewables.

Conventional generation is limited in NO4 as in the entire country but remains relevant for system reliability. Natural gas covers the vast majority of thermal power plants in Norway (Statistics Norway) and in the model, a small gas turbine plant is represented reporting the actual thermal power production, with the addition of a combined cycle (CCGT), where waste heat can be recovered to supply the district heating network through sector coupling. Nevertheless, the role of such technologies is projected to remain limited, as their deployment is endogenously constrained under stringent decarbonization scenarios. Heating technologies are modelled with particular attention to the Arctic context, where space heating represents a major share of demand. Electric boilers and high-efficiency heat pumps form the core of the modelled options, complemented by biomass-based systems that remain locally important, especially in rural areas with access to forest resources.

A distinct feature of the model is the explicit representation of district heating as a separate module, which is, however, tightly coupled with electricity generation through sector coupling. As mentioned, the waste heat from CCGT plants, but also from prospective high-enthalpy geothermal facilities, can be recovered and fed into the district heating network. This recovered heat, alongside to the one produced with this purpose, is then distributed to residential and commercial buildings, as well as to industrial users, both for space heating and water heating purposes, thereby improving overall system efficiency and reducing the need for additional fuel consumption for heat production. The explicit modelling of these couplings allows the system to exploit synergies

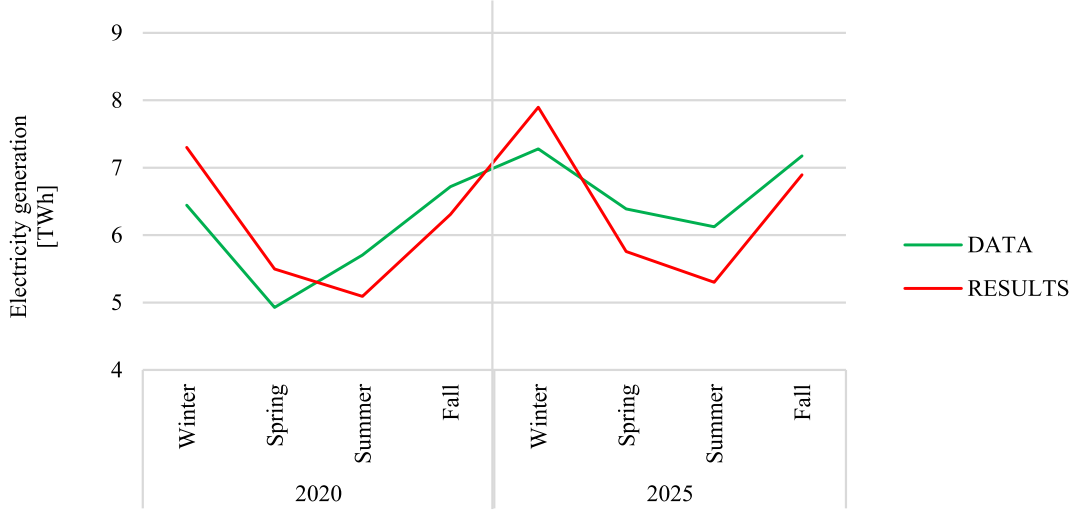

Fig. 5. Comparison between seasonal electricity generation in years 2020 and 2025 as per the model outcome and historical data, in TWh.

Table 19
Percentage error of model results with respect to historical data regarding electricity generation on seasonal base for years 2020 and 2025.

	2020				2025			
	Winter	Spring	Summer	Fall	Winter	Spring	Summer	Fall
Error	13%	12%	−11%	−6%	8%	−10%	−13%	−4%

between electricity and heat supply, a critical dimension for decarbonization in cold-climate regions such as NO4.

Storage technologies are also represented, mainly as a prospective option, since as for now, no relevant plant is present in the region, while information about the country in general reports the reliance on pumped hydro storage solutions existing only in the southern side of Norway [35] and reservoir hydro as a de facto energy storage. Nevertheless, their growing importance in a system increasingly dominated by variable renewables could shift the management of the power grid towards peak production phases, charging storages, and peak load ones requiring discharging towards consumption hotspots. Batteries are modelled as well as hydrogen technologies, alongside pumped hydro, with longer duration. In case of chemical storage, electrolysers convert surplus renewable electricity into hydrogen, which can subsequently be stored and re-electrified or used directly in other energy applications, creating a potential seasonal balancing option for NO4 [36].

Transport sector evolution requires the introduction of different lower carbon alternatives, that are expected to enter the framework at different times, according to technology development. Electric cars are already part of the fleet, and expected to grow in the market, while heavier road vehicles extensively relying, as of today, on diesel engines, will have the option of electric and hydrogen alternatives, the latter starting from year 2030, as for cars and buses. Maritime transport is integrated, from 2030, with innovative propellant engines, specifically methanol fuel cells, ammonia fuel cells, hydrogen ICE and dual fuelled systems. Finally, aviation's future technologies include synthetic kerosene from 2030 and fuel cell hydrogen aircrafts from 2040 [37]. All these technologies are clearly intended as possible choices for the model optimization process, and including each of them in the technological framework does not involve their certain deployment in the sector.

Each technology is characterized by a consistent set of techno-economic parameters, including investment, operating and fixed costs (CAPEX, OPEX and FIXOM), lifetimes, performance parameters (efficiency and COP), capacity factors and so on. In this context, CF can have a constant or variable value for each technology, useful especially for renewable energy sources, providing intermittent and outputs with oscillating intensity. For this reason, a particular effort was made to derive realistic capacity factor profiles for hydropower, wind, and solar resources in Northern Norway, reflecting both seasonal variability and the hourly resolution required to capture extreme Arctic conditions.

Similarly to what has been done with capacity factor profiles for renewables, energy demand in the building sector was represented with hourly profiles that account for the pronounced seasonality of the region. Space heating dominates winter demand, with sharp peaks during the coldest periods, while electricity demand is more evenly distributed across the year, albeit still influenced by seasonal variations in lighting and appliance use. These detailed demand and supply profiles were essential to reproduce the specific temporal dynamics of the NO4 system and are described thoroughly in the following section.

A high-level detail of all the technologies in the model is reported in Table 20.

Table 20
Summary of technologies included in the model by sector. fuel technologies also inform about which energy carriers are available for the specific sector.

Sector	Fuel technologies		Production / End-use technologies		Trade
Buildings	Diesel blending	Geothermal	Space cooling	Water heating: 5 technologies	–
	District heating	Natural gas	Space heating: 9 technologies	Appliances: 3 efficiency classes	
	Electricity	Wood			
Industry	Electricity	Natural gas	Mining & quarrying	Wood & paper	–
	District heating	Coal	Food & beverages	Petrochemicals	
	Petroleum products	Wood & waste wood	Textiles	Metals	
				Other and non-energy use	
Power	Hydro	Nuclear	Onshore wind	Geothermal (high enthalpy)	Import: Finland, Sweden, NO3
	Wind	Natural Gas	Offshore wind	Solid biomass	Export: Finland, Sweden, NO3
	Solar PV	Hydrogen	Hydro (RoR, reservoir)	Nuclear SMR	
	Geothermal	Biomass	Solar PV	Hydrogen fuel cell	
			Thermal		
District Heating	Biofuels & biogas	Fossil gas			–
	Coal	Waste heat			
	Oil	Waste incineration			
	Electric boiler	Wood waste			
Transport	Ethanol	Methanol	Passenger: Cars; Motorcycles; Buses; Rail		–
	Electricity	Heavy fuel oil	Aviation: Domestic & intl. Flights		
	H_2 compressed	Marine gas oil	Maritime: Domestic		
	Kerosene & *syn*-kerosene	Blended fuels	Freight: Vans, Trucks, Agri-machinery; Rail; Aviation; Shipping		
	Ammonia				
Hydrogen	Electricity	Biomass	Steam reforming (gas, biomass)	Oil partial oxidation	–
	Natural gas	Oil	Gasification (coal, biomass)	Electrolysis (alkaline, PEM, SOEC, AEM)	
	Coal				
Upstream	–	–	Extraction: Offshore fixed, FPSO, Hub riser, Subsea		Imports: Fuels
			Refining: Oil refinery		Exports: Oil, Gas
Storage	–	–	Pumped hydro	Redox-flow battery	–
			Li-ion battery	H_2 storage tanks	

2.16. Hourly load profiles and capacity factors

In order to represent hourly variations in energy demand for heating (both space and water) in the building and industry sectors of the NO4 region, synthetic load profiles were constructed. These profiles were normalized so that, for each subsector, the sum of all hourly values across the year equals unity, thereby ensuring consistency with the annual energy demand data introduced in the model.

To disaggregate annual heating demand into hourly temporal profiles, heating degree days (HDD) were leveraged as a climatic proxy for seasonal heating requirements. These are widely used to capture wintertime heating demand in energy system studies since HDD-based indicators have been shown to correlate strongly with energy demand for space heating in residential and tertiary sectors [38]. HDD were retrieved by an open data source [39] and computed for the Tromsø weather station (18.91E, 69.68 N) from December 1st, 2022, to November 30th, 2025. These data were used to determine the weight of each season over the annual heating demand, in order to distribute demand shares accordingly.

Four distinct seasonal patterns were considered (winter, spring, summer, and autumn), reflecting the marked seasonal asymmetries of the Arctic environment, where the absence of daylight in winter and continuous daylight in summer strongly influence both residential and service sector demand, also for what concerns lighting, included in the electricity profile discussed ahead. Within each season, hourly load distributions were shaped according to the typical operating patterns of the relevant end-uses sectors, services, households and industry. Given the lack of publicly available regional hourly demand data for Northern Norway, intra-day demand profiles were derived from the literature and adapted to ensure behavioural and sectoral consistency. While absolute load levels are calibrated using official statistics, hourly shapes are intended to capture representative demand dynamics rather than replicate observed time series, hence, to represent structurally consistent intra-day patterns that are compatible with sectoral behaviour, climatic conditions, and empirical evidence from comparable Nordic and European contexts [40].

Fig. 6 illustrates the seasonal and diurnal distribution of heating demand across the year, distinguishing among the sectors including this demand. The resulting profiles highlight the strong intra-day variability for the different loads, with complementary behaviours between households and other sectors, due to daily occupancies linked to working hours. These daily patterns are reproduced similarly in all the seasons, while their specific weight determines the distribution throughout the year. This weight is reported in the same figure for each season and as already mentioned, derives from the average distribution of heating degree days over the year.

Corresponding profiles for electricity are reported in Fig. 7. Differently from the heating demand, in this case daily profile are built on real observations for the specific spot price region NO4, retrieved from's *Transparency Platform.*

Specifically, aggregated actual-load figures for the Northern Norway electricity bidding zone were used for 2019, with hourly records from 1 January to 31 December expressed as power output (MW). Values were assumed constant within each hour, converted to MWh, and summed over the year. For each month, 24 hourly average values were computed and then converted into seasonal profiles. These seasonal hourly values were normalised by the annual total to obtain demand-distribution shares. Because averaging produces a distribution that slightly exceeds 100%, a uniform reduction factor of 0.91 was applied to preserve the profile shape while satisfying the model distribution constraint. The resulting profile, shown in Fig. 6, is flatter than the heating-demand profile because it aggregates all sectors and is applied only to electricity demands associated with purely electric end uses, such as residential lighting and industrial auxiliary systems. The remaining electricity consumption, which represents the majority of total electricity use, is determined endogenously by the model through technology competition.

Seasonal weights are naturally included in the source dataset, and the profile is consistent with those reported in the previous figure, confirming the annual behaviour of the system and, since the latter derives from actual observed data, providing robustness to the degree-days methodology described above.

From the perspective of the TEMOA-NO4 model, these differentiated demand patterns are crucial in capturing the temporal dynamics of energy use in the northern Norwegian context. The residential sector introduces a relatively flexible and weather-sensitive demand profile, while services and industry contribute with more rigid and concentrated loads. This combination shapes the requirements for system balancing, storage deployment, and the integration of intermittent renewable generation, particularly wind power, which is projected to increase substantially in the region. By embedding such detailed temporal profiles, the model is able to represent more accurately the potential stresses on the system and the opportunities for flexibility that may not be visible in models with more aggregated demand representations.

On the other hand, these hourly distributed demands must be satisfied with energy supply that can match their behaviour. Capacity factors, particularly for renewables, have to be shaped along daily profiles according to the estimated availability of the natural resource in the selected area.

The hourly capacity-factor profiles implemented in the TEMOA-NO4 runs were derived by dividing technology-specific hourly electricity generation by the corresponding reported installed capacity (i.e. hourly output ÷ nameplate capacity), using the [41] time series as the primary empirical input and then aggregating the resulting 8760-hour series into seasonal mean hourly patterns. This 8760-based approach is a standard, transparent procedure for producing time-resolved availability patterns

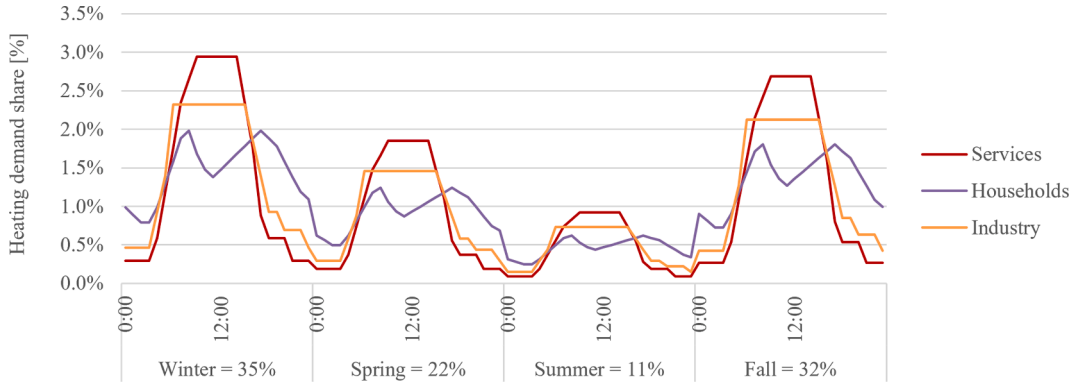

Fig. 6. Hourly profile breakeven of heating demand for its relevant sectors as percentage of total demand. season-specific weight derives from degree-days observed data[39] for the Tromsø weather station of the last three years.

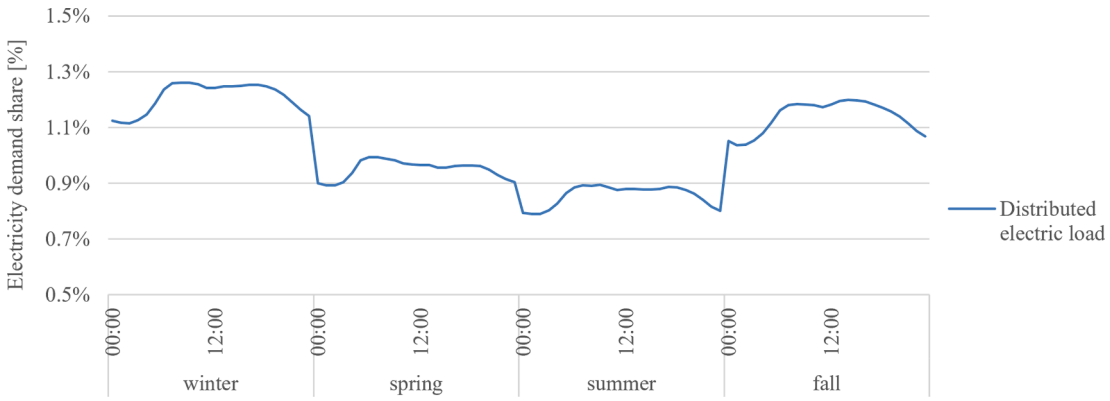

Fig. 7. Hourly profile distribution of electricity demand along the four seasons in the northern norway region as percentage of total demand.

for variable generation: it directly reflects observed hourly resource availability and the operational behaviour of the fleet in the reference year, and it is widely used in planning studies as a baseline for generating representative intra-annual profiles. [42] For hydropower, the same generation-over-capacity calculation implicitly captures operational choices and reservoir effects visible in the hourly record (seasonal storage discharge patterns, peaking behaviour), which is important in the Norwegian context where reservoirs and flexible dispatch materially shape hourly hydro output [43].

After obtaining hourly capacity factors for the last available year, the series were averaged within the conventional four seasons to produce seasonal 24-hour profiles that preserve both diurnal structure and seasonal shifts in resource availability.

These seasonal profiles were then applied to the model's representative time slices so as to expose the optimisation to realistic temporal mismatch between demand and variable supply. Using national hourly generation and installed capacity in this way is technically defensible when regional, site-level data are unavailable because it preserves the empirical temporal structure of the fleet; however, it is not free from limitations. The national average can mask spatial heterogeneity (coastal vs inland wind regimes, localized hydrological patterns, or specific micro-climates in Arctic latitudes), therefore this step should be read as a pragmatic approximation rather than a direct measurement of NO4 local resource dynamics.

For wind, it is common to find materially higher capacity factors offshore than onshore because of generally stronger and more persistent wind regimes and larger modern turbine ratings; empirical and review literature report typical onshore capacity factors in the low-to-mid 30 s (%) for Norway and higher values offshore, supporting the decision to scale offshore onshore-derived profiles upward when a region exhibits strong offshore potential [44].

In this implementation, an uplift of 20% (multiplying factor: 1.2) with respect to the onshore hourly profile was applied to represent offshore yield advantages. This increase is conservative compared, for example, to the assessments published by [45], which instead show a net increase of 20 percentage points in the transition from onshore to offshore wind power, but it remains an assumption and has to undergo sensitivity testing in future studies. All the resulting profiles are reported in Fig. 8, were wind technologies highlights a consistent capacity throughout the year, which possibly allows for a continuous power output during the day and across the seasons.

2.17. Model assumptions

Building on the calibration of the historical years, the modelling framework is extended to the entire time horizon. The assumptions underpinning the projected system evolution over future years are primarily linked to the development of key demand drivers, namely gross domestic product (GDP) and population. With respect to economic activity, GDP growth is represented through a constant annual rate, adjusted to match the average growth observed for Norway over the period 2019–2024, as reported by the [46]. This approach was adopted to ensure continuity with recent, empirically observed trends, while avoiding the introduction of speculative structural changes in economic dynamics. Population evolution, in contrast, follows the main alternative published [27], which provides an official and internally consistent demographic outlook. The combined use of these two drivers allows demand growth to be anchored to established macroeconomic and demographic trajectories, minimising reliance on assumptions that are not directly supported by verifiable data. The resulting time series are subsequently normalised and reported in Table 21, serving as exogenous inputs driving the evolution of energy demand within the modelling framework.

Following the assumptions outlined regarding the evolution of key

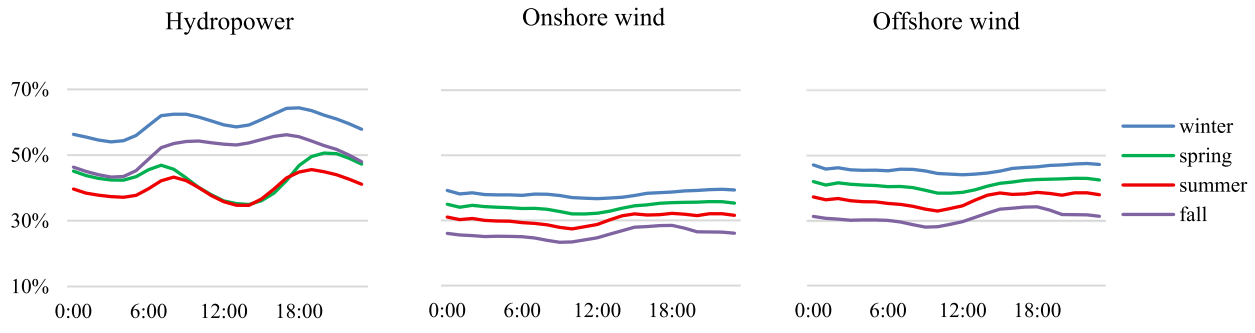

Fig. 8. Hydropower, onshore and offshore wind capacity factor profiles by season.

Table 21
Drivers' evolution for the entire time horizon. figures are normalized with respect to 2019 values, and 2020 gdp contraction derives directly from recorded data for norway.

	GDP	Population
2019	1.000	1.000
2020	0.884	1.000
2025	1.183	1.006
2030	1.260	1.008
2035	1.341	1.011
2040	1.428	1.013
2045	1.521	1.012
2050	1.620	1.008

demand drivers in this model, legally binding climate policy targets were introduced as exogenous constraints on system outcomes. For the 2030 horizon, the model implements a greenhouse gas emissions reduction target of at least 55 % below 1990 levels, consistent with Norway's enhanced Nationally Determined Contribution under the Paris Agreement and aligned with the European Union's Fit for 55 legislative framework, which Norway participates in through the European Economic Area agreement. This 2030 target is established in Norwegian law via the Climate Change Act and successive autonomous submissions to the UNFCCC [47]. For the longer-term horizon, the model adopts a 90–95 % reduction target for 2050 in line with Norway's long-term climate strategy, which aims to transform the economy into a low-emissions society by mid-century. These explicit emissions constraints are used as modelling boundaries rather than predictions, serving to anchor the system trajectory to internationally communicated policy commitments without implying that any specific pathway will necessarily be realised.

Nevertheless, several sources of long-term uncertainty remain outside the scope of the present modelling framework. In particular, the deterministic structure of the model does not explicitly represent uncertainty associated with climate-change impacts on hydrological regimes, renewable resource variability, future electricity-market dynamics, or socio-political constraints affecting infrastructure deployment and public acceptance. These factors may substantially influence the feasibility and timing of specific transition pathways, especially in Arctic and peripheral regions characterised by strong climatic sensitivity and constrained transmission development. Accordingly, the results should be interpreted as conditional system diagnostics under the selected assumptions rather than predictive forecasts of future regional energy evolution.

Moreover, a comprehensive summary of data gaps and limitations is gathered in Table 22, to further clarify the model input framework.

Beyond the data gaps catalogued in Table 22, several modelling choices required the use of proxy assumptions to bridge the gap between available data and model requirements. Table 23 provides a systematic overview of these assumptions, together with the rationale for their adoption and an assessment of how each one may influence model outputs. This structured presentation is intended to support a diagnostic reading of the results: where an assumption introduces a directional bias, the corresponding model outputs should be interpreted taking into account the stated caveat, and the magnitude of the effect should be weighed against the sensitivity analyses reported in the Results section.

The assumptions catalogued above range in their potential impact on results. The most consequential, as demonstrated by the sensitivity analyses presented in Section 3, are the offshore wind capacity-factor uplift (assumption 8) and the export trajectory (assumption 9), both of which are first-order drivers of wind deployment and storage requirements. The proxy assumptions affecting demand estimation in buildings (1–6) and industry (10) introduce moderate structural uncertainty that is bounded by the calibration exercise but cannot be fully resolved without improved regional data. The remaining assumptions (11–17) have more limited aggregate impact and affect sub-components of the system that carry smaller weights in the overall energy balance. Future work addressing the data gaps identified in Table 22 would allow the proxy assumptions in Table 23 to be progressively replaced with empirically grounded regional inputs, thereby reducing the conditional nature of the results.

Table 22
Data gaps and current treatments implemented in the model.

Data gap	Current treatment	Model implication	Priority for future work
Industrial technology configuration	Energy-wise representation based on national average downscaling	Industrial decarbonisation cannot be endogenous	Confidential industrial survey/ stakeholder data
Hourly industrial load profiles	Aggregated demand representation	Limited temporal accuracy for industrial flexibility	Sector-specific load profiles
Offshore wind resource profiles	Scaled wind capacity-factor assumptions	Offshore wind capacity sensitive to assumptions	Site-specific offshore wind datasets
Internal grid constraints	Bidding-zone transfer capacities	No power-flow or congestion modelling	Coupling with network model
District-heating potential	Proxy-based regional allocation	Limited spatial siting interpretation	Municipal heat-demand mapping
Hydrogen demand and infrastructure	Scenario/ technology assumptions	Hydrogen role remains exploratory	Regional hydrogen infrastructure assessment

3. Results and discussion

Before discussing individual sectors in detail, four key findings emerge from the regional optimisation results:

i. regional modelling reveals a stronger growth in electricity demand than suggested by national-scale outlooks, driven by electrification and export dynamics;
ii. offshore wind emerges as a robust but assumption-dependent expansion option;
iii. temporal mismatch between variable renewable generation and demand materially affects storage requirements and trade flows, even in a hydropower-dominated system; and
iv. limitations in industrial data availability constrain the representation of endogenous decarbonisation pathways, highlighting data availability as a critical bottleneck for regional energy planning.

The following sections discuss these findings in detail and relate them to existing national assessments and policy-relevant implications. To clarify how these results should be interpreted, the analysis is deliberately conducted under a single internally consistent projection rather than through a conventional scenario-based analysis. This choice reflects a deliberate methodological position adopted in this study: while scenario frameworks are widely used to explore divergent long-term energy futures, their application at a highly disaggregated regional scale, such as Northern Norway, currently relies on assumptions whose empirical support is limited, inconsistent, or rapidly evolving. In particular, key drivers shaping alternative futures, including industrial development in the neighbouring regions or increasing deployment of data centres, which could possibly drive the demand for electricity generation and export considerably, cannot at present be quantified in a stable or verifiable manner for the region considered [48]. Moreover, the simplified representation of the Northern Norway industrial sector, will need to undergo significant reorganization once reliable technology data are going to be available, deeply affecting possible outcomes. Under these conditions, the construction of

Table 23
Proxy assumptions adopted in TEMOA-NO4, their rationale, and assessed effects on model outputs.

#	Sector	Proxy Assumption	Data Used as Proxy	Rationale	Effect on Model Results	Likely Bias Direction
1	Buildings – Residential	Population share (9.03% of national) used as initial downscaling factor for energy demands	Statistics Norway table 01,222	Default disaggregation in absence of regional energy statistics	Systematic underestimation risk: NO4′s actual electricity share in buildings is ~ 12.7% of national (vs. 9% population share); corrected in the final workflow using per-capita consumption data	Underestimation (before correction); corrected using table 14,580
2	Buildings – Residential	Per-capita energy consumption (2022) × regional population to obtain total residential energy	Table 14580 (Statistics Norway)	Direct regional datum available; used as anchor for total residential consumption	Sets the base-year demand level; static per-capita value applied across the horizon introduces uncertainty if consumption patterns change	Neutral for base year; potential underestimation if per-capita consumption grows faster than assumed
3	Buildings – Commercial	Same regional weight as residential (12.7%) applied to derive total commercial energy	Residential/national ratio from tables 14,092 and 11,561	No regional commercial energy data available; proportionality assumed between sectors	If commercial energy intensity in NO4 differs from the national average, commercial demand will be over- or underestimated; GDP driver partially compensates over time	Uncertain; commercial sector more volatile than residential
4	Buildings – Residential	Swedish end-use shares (JRC-IDEES 2021) for space heating, water heating, and appliances	JRC database for Sweden	No equivalent Norwegian regional end-use breakdown available; Sweden is the closest geographic and climatic proxy	Space heating share in Arctic context may be higher than Swedish average; could slightly underestimate space heating demand and the role of heat-related technologies	Modest underestimation of space heating demand
5	Buildings – Commercial	End-use split assumed: 50% space heating, 10% water heating, 40% appliances	Expert assumption	No official regional or national commercial end-use split available for Norway	Large uncertainty in commercial demand composition; if appliance share is higher, electricity demand increases; if space heating dominates, district heating and heat pump deployment may be underrepresented	Unknown; high structural uncertainty
6	Buildings – All	National average heating technology shares (heat pump COP, electric heater efficiency) used to compute aggregate sector efficiency	Table 10571 (Statistics Norway)	Regional technology-fleet breakdown for heating unavailable	Overall sector efficiency may be overestimated if NO4 has lower heat pump penetration than the national average, leading to a conservative (high) estimate of useful-energy demand	Conservative overestimation of demand (preferable to underestimation)
7	Power – Hydropower and onshore wind	National average hourly capacity factor profiles, derived from ENTSO-E Transparency Platform generation and installed capacity data	ENTSO-E 2019 hourly generation series	Regional, site-specific CF data for NO4 unavailable; national profiles preserve the empirical temporal structure	Spatial heterogeneity masked: coastal vs. inland wind regimes, localised hydrological patterns, and Arctic micro-climates not captured; may over- or underestimate seasonal variability and storage needs	Uncertain; national profiles are a pragmatic approximation
8	Power – Offshore wind	Offshore capacity factors assumed as 1.2 × the onshore profile (20% multiplicative uplift)	Onshore ENTSO-E profiles scaled upward	Offshore wind datasets for NO4 unavailable; literature supports materially higher offshore CFs due to stronger, more persistent offshore wind regimes	This assumption is a primary driver of offshore wind economics and deployment; sensitivity analysis shows storage charging increases up to ~ 60% when the multiplier rises to 1.3×; offshore wind installed capacity is inversely sensitive to this parameter (higher CF → less capacity needed for same energy)	Conservative relative to empirical literature (which reports ~ 20 percentage-point net increase); deployment risk of underestimation
9	Power – Electricity exports	Historical 2019 export flows used as base-year demand; projected forward using GDP/population drivers and elasticity	ENTSO-E cross-border flow data; table 10	Export flows strongly determined by external market conditions; no regional export forecast available	Exports are a first-order driver of generation expansion: removing future export growth halves total wind deployment and eliminates storage requirements (as shown in the no-export sensitivity case); any error in export trajectory propagates strongly into offshore wind, storage, and grid results	Uncertain; the sensitivity analysis bounds the range of outcomes
10	Industry	Electricity consumption (known from regional statistics) used as proxy to derive consumption of all other energy carriers (oil, gas, coal, district heat, biomass)	Table 14092 (Statistics Norway); national energy balance by subsector	No regional industrial energy breakdown by carrier available; electricity is the only publicly accessible regional indicator	Industrial energy-carrier mix may differ significantly if NO4′s industrial structure (metals- and aquaculture-intensive) deviates from the national average; non-electricity carriers could be over- or underestimated;	Uncertain; metals industry suggests higher electricity and coal shares; other carriers may be overestimated

(*continued on next page*)

Table 23 (*continued*)

#	Sector	Proxy Assumption	Data Used as Proxy	Rationale	Effect on Model Results	Likely Bias Direction
		via national average sectoral shares			industrial decarbonisation cannot emerge endogenously	
11	Transport – Two-wheelers	Regional/national private-car traffic volume ratio used to downscale national two-wheeler passenger demand to NO4	Table 12576 (Statistics Norway – car volumes); table 03,982 (national motorcycles)	No regional two-wheeler traffic statistic available; car traffic assumed to be a structural proxy for motorised mobility patterns	If recreational or seasonal use of two-wheelers differs from car patterns in Arctic context, demand is misestimated; quantitative impact on total transport energy is minor	Low impact; small share of total transport
12	Transport – Maritime freight	NOR/NIS ship register transport-work data (national) used to estimate average route lengths; regional vessel tonnage ratio applied for capacity allocation	Tables 11403, 08,203 (Statistics Norway)	No NO4-specific maritime freight route statistics available; national register separates domestic and international fleets	If NO4 shipping routes are systematically shorter (coastal cabotage) or longer (deep-sea exports via Narvik) than the national average, freight demand estimates shift accordingly	Moderate uncertainty; Narvik port activity partially corrected with LKAB-specific data
13	Transport – Rail passenger	Nordland Railway used as representative route for average travel distance; 2020 data corrected to 2019 using line-level passenger ratio	Table 10484 (Statistics Norway)	Only available sub-regional rail dataset with both passenger counts and transport work	Approximately half of the Nordland Railway lies outside NO4; average travel distance may differ from the actual NO4 share; rail demand is a minor system component	Low impact; minor share of total transport energy
14	Hourly profiles – Space heating	Heating degree days (HDD) from the Tromsø weather station used to define seasonal demand weights for all of NO4	BizEE degreedays.net; 2022–2025 data	Single-point climatic observation chosen as representative of the bidding zone	Inland areas (e.g. southern Nordland) may experience colder winters; coastal areas may have milder conditions; seasonal demand distribution may be slightly distorted relative to the true spatial average	Modest; directional uncertainty varies by sub-region
15	Hourly profiles – Intra-day demand shapes	Nordic and European literature profiles adapted for sector-specific intra-day patterns (households, services, industry)	Published energy system studies for comparable contexts	No observed regional hourly demand data publicly available for NO4	Actual intra-day variability for NO4 unknown; uncertainty affects storage dispatch timing and peak demand representation; cannot be quantified with available data	Uncertain; likely most material for storage sizing and short-term flexibility assessment
16	Hourly profiles – Electricity	ENTSO-E national actual-load profile for NO4 bidding zone used; 0.91 uniform reduction factor applied to satisfy normalisation constraint	ENTSO-E Transparency Platform 2019 hourly load	Direct empirical data for NO4 electricity load available at bidding-zone level	Profile reflects the mix of all sectors aggregated; NO4 load may be more industry-dominated than the national average; temporal mismatch between supply and demand is slightly simplified	Low; directly calibrated on observed NO4 data
17	Power – Transfer capacities	Cross-border transfer capacity allocated as 56% to NO3 and 44% to Sweden (of which 15% spills to Finland), based on rated line capacities	ENTSO-E principles for Nordic transfer capacities [25]	Static allocation chosen in absence of dynamic market-flow model	Actual flow distribution depends on price differentials and market conditions; static allocation may misrepresent seasonal or annual flow dynamics; internal grid constraints within NO4 not modelled	Moderate; partially mitigated by free-optimisation of import flows

multiple scenarios would risk amplifying uncertainty through arbitrary or weakly substantiated assumptions rather than providing additional analytical insight. The resulting projection should therefore be interpreted as a diagnostic baseline, conditional on explicitly stated assumptions, rather than as a forecast. Its value lies in identifying structural system responses and infrastructure implications that arise from regionalisation and temporal resolution choices, and that can inform future scenario development as more robust regional data become available.

Fig. 9 presents the evolution of total primary energy consumption in the system up to 2050, highlighting a marked decline in the contribution of coal and oil during the early years of the projection. This trend reflects the stringent climate objectives incorporated in the modelling, including Norway's alignment with Fit for 55 targets, which seeks substantial reductions in emissions through rapid decarbonisation of energy supply and consumption. Coal, in particular, disappears from the energy mix in this projection, while oil's share contracts sharply as transport and other sectors electrify. Simultaneously, there is a clear expansion of wind energy, increasingly becoming a core element of the energy supply mix, consistent with external forecasts that identify wind power as a key scalable option to meet growing electricity needs in Norway [34].

A clear feature of the presented result, is a sharp increase in total energy supply from year 2020 to year 2025, followed by a consequent decrease again. The first side of this dynamic must be attributed to the COVID-19 effect of decreasing consumption in the former year, which gets to be restored in 2025, while the successive decrease, as described above, is due to the efficiency needs given by emissions reduction targets.

In the intermediate decades, natural gas initially supports the energy transition, providing flexibility and balancing capacity while renewable generation capacity is expanded. However, its relative contribution declines over time as wind scales up and non-fossil alternatives gradually enter the mix. Within this context, geothermal and nuclear energy appear only as modest contributors in the later years of the projection, a pattern that can be traced to two empirically supported constraints: the lack of data about actual geothermal resource potential in Norway, as reported the literature [49], makes unlikely to have a strong reliance on this source for energy supply, moreover, so far this has only been used for direct production of heat through heat pumps (*shallow geothermal*) rather than for electricity production (*high enthalpy*), for which the

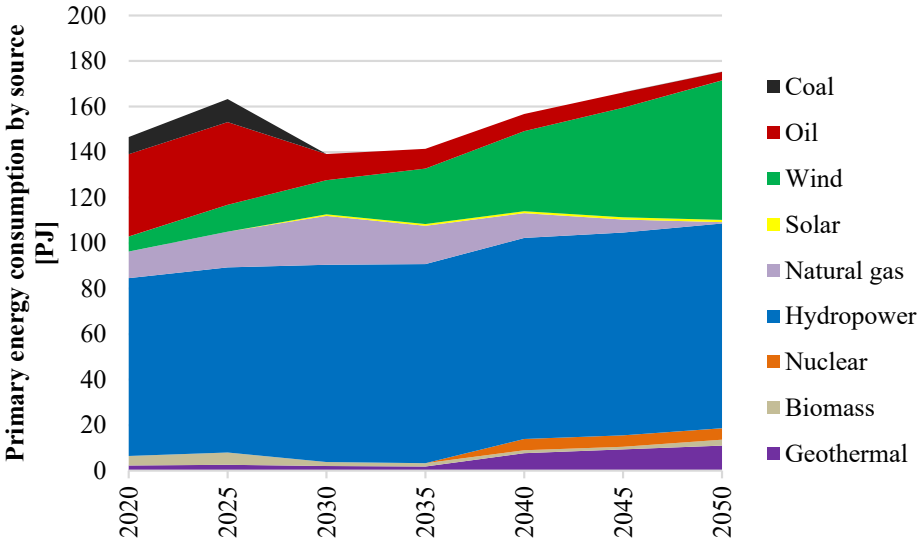

Fig. 9. Total annual primary energy supply of the system, intended as the total amount of not-transformed commodities to all the sectors (excluding exports), in PJ.

geographic area of Norway is not considered suitable, allowing for a low penetration in the energy supply chain. Nevertheless, the country's expertise in deep wells management deriving from the vast oil&gas industry, is being exploited in pilot projects to extract heat from deep sources, opening the possibility for this technology to have a role in the future of Norway's energy system [50]. On the other side, the absence of a substantial domestic nuclear industry or operational fleet translates in a lack of know-how of the country for a more significant nuclear deployment within the modelling period, which would require long lead times and significant institutional capacity building not currently evidenced in Norwegian energy planning [51].

Fig. 10 illustrates the projected oil and natural gas export trajectory from the region, showing a substantial decline towards 2050. This outcome mirrors the forecasts from [34], which indicates that Norwegian oil and gas exports are expected to decrease significantly over the modelling period, with oil exports falling to a fraction of current levels and natural gas exports roughly halving by mid-century. This contraction reflects both diminishing global demand for fossil fuels under deep decarbonisation pathways and structural shifts within the Norwegian energy export portfolio as renewable electricity and alternative energy carriers become comparatively more important. It must be underlined that the decreasing demand for these commodities export has been implemented as an exogenous constraint, rather than being an intrinsic optimization choice, since the emissions happening outside from the regional borders are not affected by the limitations described previously.

3.1. *Power production and storage*

The electricity-generation mix in Fig. 11 illustrates the region's continued reliance on hydropower, which remains the backbone of the

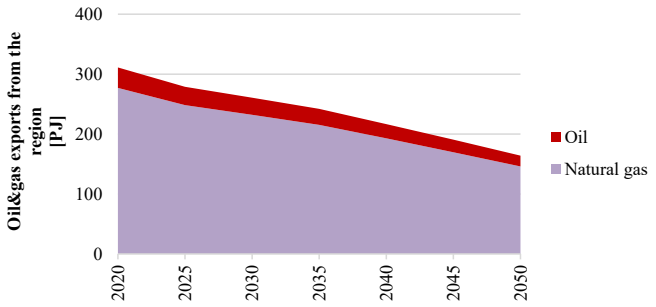

Fig. 10. Oil and natural gas annual export projection for future years, in PJ.

Northern Norway system. Wind power is present from the early model years through onshore technologies, while offshore wind provides the main additional expansion option under the assumed growth in electricity demand and sustained export requirements. Fossil gas is progressively phased out, whereas geothermal and nuclear technologies play only modest roles in later periods. Photovoltaic generation remains extremely limited because of Arctic solar conditions, while electricity exports remain explicitly represented to reflect the historical surplus-producing role of the region.

By 2050, however, the system undergoes a substantial transformation, with a significant portion of the electricity provided by wind power, moreover, as represented in Fig. 12, a modest contribution of the storage technologies is provided, to compensate for electricity dispatchment from renewable sources. However, the latter could also be underestimated since recent studies have highlighted the importance of robust storage planning methodologies under renewable uncertainty and extreme operating conditions [52].

In order to further understand the impact of hourly profiles on the behaviour of the power system, the results of power production in the grid are also reported as daily profiles for the years 2025 and 2050, in Fig. 13. The development of the system is visible as the contribution of thermal power production disappears (thin black lines in 2025), while offshore wind (green band) strongly penetrates the energy mix with stable power output, thanks to reliable values of the capacity factor in this environment. Hydropower (grey areas) enhance its role as first energy supplier, and the remainder is satisfied with imports (light blue dashed areas) and storage discharge in peak hours. It can also be appreciated that electricity storage technologies are charged in low demand hours where the power generation allows for it.

The general increase in power generation reflects the growing demand included in the model through drivers and elasticity. It is noticeable that this growth is also attributed to the exports of the region, and this choice follows what reported in the [53] for the reinforcement of the Norway-Sweden grid lines, especially between NO4 and SE1 and SE2 as the possible increase in electricity demand of the latter region could drive a significant development of the interregional connections, that must in any case match the internal grid implementations planned by national TSOs. Nevertheless, these implications should not be interpreted as direct transmission-planning recommendations or investment-grade congestion assessments. The present model represents interregional exchanges through aggregated transfer capacities at the bidding-zone level and does not explicitly simulate internal network constraints or power-flow dynamics. Accordingly, the discussion regarding possible

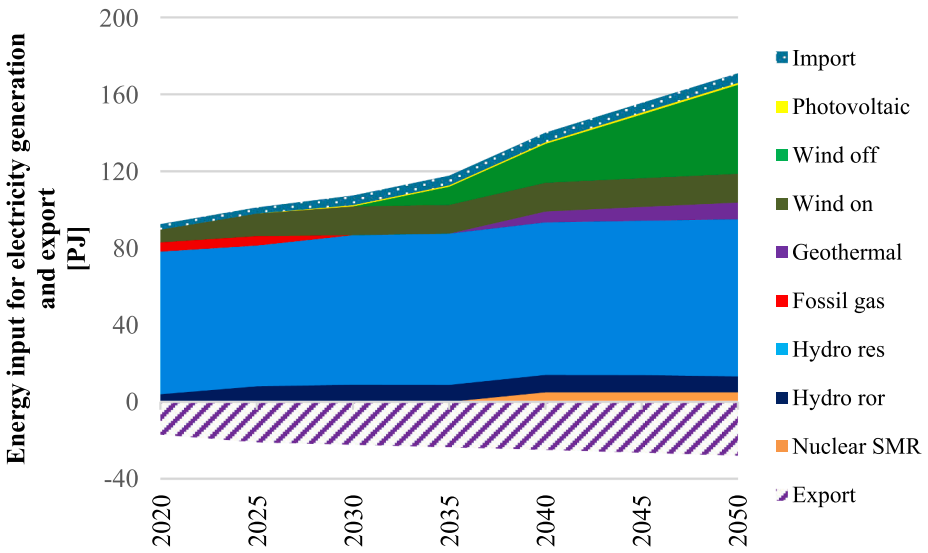

Fig. 11. Annual energy mix development of power generation in no4 region, from 2020 to 2050, in PJ.

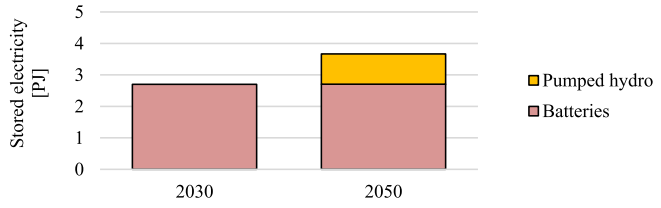

Fig. 12. Annual electricity storage uses in the region by technology, in PJ.

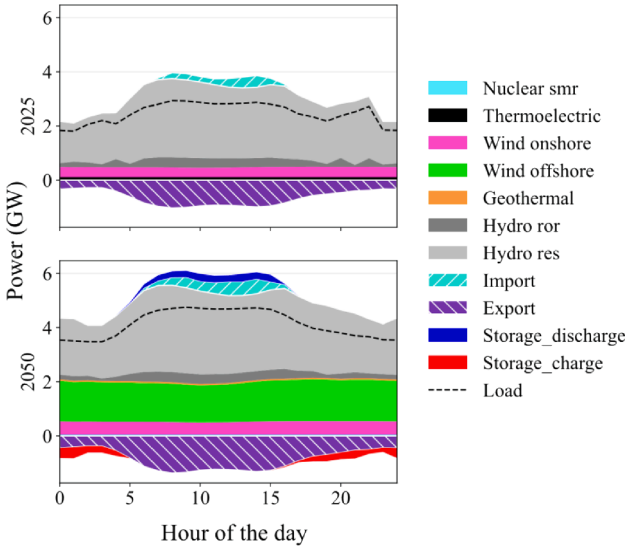

Fig. 13. Hourly profiles result for current year and 2050 depicting the evolution of power system and configuration of demand satisfaction, in GW.

reinforcement needs should be interpreted as a system-level diagnostic consistent with publicly available ENTSO-E and Nordic TSO planning scenarios, rather than as a deterministic identification of specific corridor investments. The merely noticeable contributions from nuclear and geothermal represent the secondary role these technologies are expected to cover, with the possibility to penetrate further in the system only in the second half of the current century.

Because offshore wind contributes substantially to the baseline case, additional sensitivity analyses were conducted to test whether its role depends on export assumptions and capacity-factor assumptions.

To isolate the effect of export assumptions, future export-driven electricity demand was set to zero after the calibration period. This choice leads to a milder development of the power generation sector, confirming that export assumptions are a major driver of long-term generation expansion, as depicted in Fig. 14.

Removing future export growth substantially reduces the required expansion of the power-generation sector. In this sensitivity case, the combined contribution of onshore and offshore wind in 2050 is reduced by approximately half relative to the baseline export-growth case, and storage deployment becomes negligible under the adopted temporal representation. This confirms that export assumptions are a first-order driver of wind expansion and storage requirements. The result should therefore be interpreted as a diagnostic sensitivity rather than as a prediction that storage will or will not be required in Northern Norway.

Moreover, to further contribute to the robustness of the presented results, the offshore wind capacity factor assumption is discussed in the following, with a sensitivity analysis over its values with respect to the onshore wind ones, spanning from 1, standing for offshore CF equal to onshore CF, to 1.3, standing for a 30% increase in the offshore capacity factors over the inland ones. This sensitivity analysis tests how offshore wind deployment, storage operation, and import dependence respond to alternative offshore wind capacity-factor assumptions.

A comprehensive representation of this sensitivity analysis is depicted in Fig. 15, with the left column showing in bright colours only the technologies recording an integral contribution variation higher than 3% with respect to the (a) case, a threshold considered meaningful for the present aim. The primary outcome emerging from this case-by-case comparison, is that offshore wind contribution variation to power generation (left column) remains below the threshold in all cases, showcasing the same activity level even with capacity factors equal to onshore wind. Moreover, looking at the rightmost column, it is possible to notice that with a growing capacity factor, for the same electricity produced, the needed installed capacity decreases. Also, onshore wind itself is not further installed due to capacity limitations imposed in the model.

Consequent observations reveal the dynamics highlighted by the storage, showing increases in charge phases (negative values as it is accounted as consumption) getting close to 60% in the case of the highest capacity factors, carrying the effects of this uncertainty assessment, and enhancing its contribution to the system with the growing availability of the offshore wind, especially regarding the cumulative supply of energy reported in the central column. The central graphs

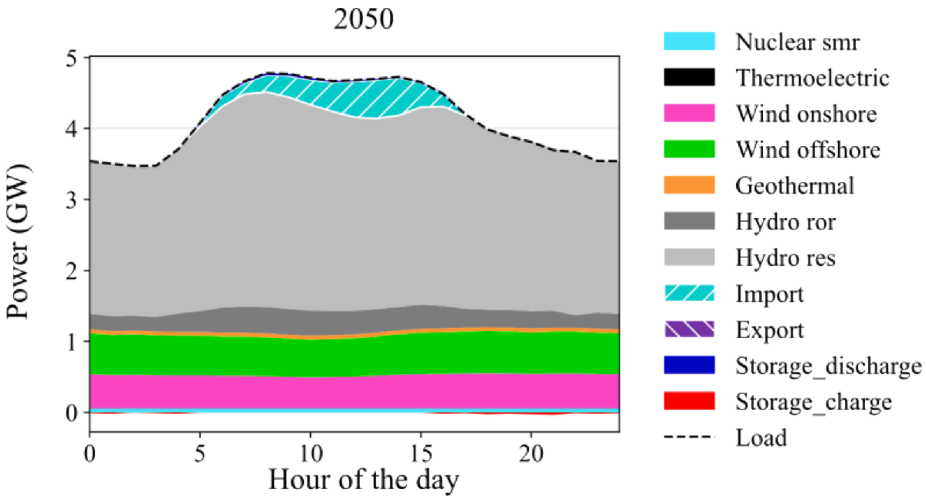

Fig. 14. Hourly profile results for 2050 in case of zero electricity export demand for future years, in GW.

account for the entire time horizon, providing an exhaustive metric about the technology participation to the electricity mix and underlining their role also beyond the single year (which is shown on the left as representative of the developed system).

This result highlights how the increasing availability of producible energy in low demand hours, could encourage the feasibility of storage system used for shifting towards peak hours, mitigating the need for additional supply as, for example, imports.

The adopted temporal resolution (96 time slices, constructed from four representative days with hourly detail) introduces well-known limitations in energy system optimization models that may influence the results, particularly for variable renewable energy (VRE) integration and storage operation. The use of a small set of representative days inherently reduces the ability of the model to capture chronological variability and inter-day correlations, which have been shown to be critical for accurately representing both the adequacy and operation of storage systems [5].

In particular, this aggregation approach does not preserve multi-day sequences of low renewable generation or prolonged dry periods affecting hydropower availability, which can lead to an underestimation of required storage capacity and system flexibility needs.

Similarly, extreme events and tail distributions of demand and generation are not explicitly represented, potentially biasing both capacity expansion and dispatch outcomes [5]. Previous studies have demonstrated that limited temporal sampling can lead to systematic distortions in storage utilization patterns, including overestimation of short-term cycling and underrepresentation of long-duration storage requirements, due to the absence of sustained imbalance periods.

While representative-day approaches are widely used to reduce computational burden, their implications on model outcomes, especially in high-renewable scenarios, are documented as non-negligible [5], and results related to storage deployment and VRE integration should therefore be interpreted with caution in light of these methodological constraints.

3.2. District heating

District heating in Norway is an established but comparatively limited component of the national heat supply; it is markedly less widespread than in Sweden, where district-heating systems supply a very large share of urban heat demand [54].

Although district heating occupies only a niche role in much of Norway's building stock, it is nonetheless present and has been explicitly represented in the regional TEMOA-NO4 model. National statistics for district-heating production and consumption are published by [27], and the model therefore uses their aggregated, national-level data as its principal input. Using these national aggregates to disaggregate to a sparsely populated region introduces methodological uncertainty: Northern Norway population and settlement patterns are increasingly dispersed as one moves northwards, and district heating is primarily an urban phenomenon, so long transmission distances and low density can make heat network economics, and hence any fine spatial disaggregation, less reliable [55].

That caveat notwithstanding, the decision to include district heating in the regional model is defensible on prospective grounds. If the NO4 region or adjacent regions experience industrial expansion or the emergence of large thermal point sources (for instance new industrial facilities, data centres or expanded waste-to-energy capacity), the technical and economic case for local heat networks can change rapidly because such facilities provide low-cost residual heat that can be integrated into district systems. Recent Norwegian studies and technology-centre reports emphasise the sizeable potential to recover industrial and data-centre waste heat for district networks and show how industrial clusters can underpin local network viability [56].

Fig. 16 presents modelled district-heating commodity consumption for the complete time horizon, highlighting a relative lack of convenience in this technology diffusion, at the current conditions. Between 2030 and 2050 the low-emission constraints allow for a growth in the contribution of recovered waste heat and biofuels, at the expenses of wood, gradually abandoned. Electricity remains a minor contributor while waste represents the main source for the purpose.

3.3. Buildings

National statistics and recent reviews indicate that Norway's building heat supply is characterised by a strong reliance on electricity (including heat pumps), while the country's use of district heating, as previously mentioned, is small relative to neighbours such as Sweden [57].

In the model outputs displayed in Fig. 17, electricity clearly dominates the energy supplied to buildings, with district heating and geothermal slightly complementing this framework, solid biofuels, diesel and natural gas appear as much smaller components, decreasing along the time horizon; this pattern is consistent with national trends and regional data about electricity consumption, nevertheless, it must be noticed that the electricity consumption for heating purposes is not explicit nor disaggregated from other appliances use. For this reason, even though the electricity share in the sector reflects statistics, the actual amount of energy consumption could differ with assumptions for demand estimation.

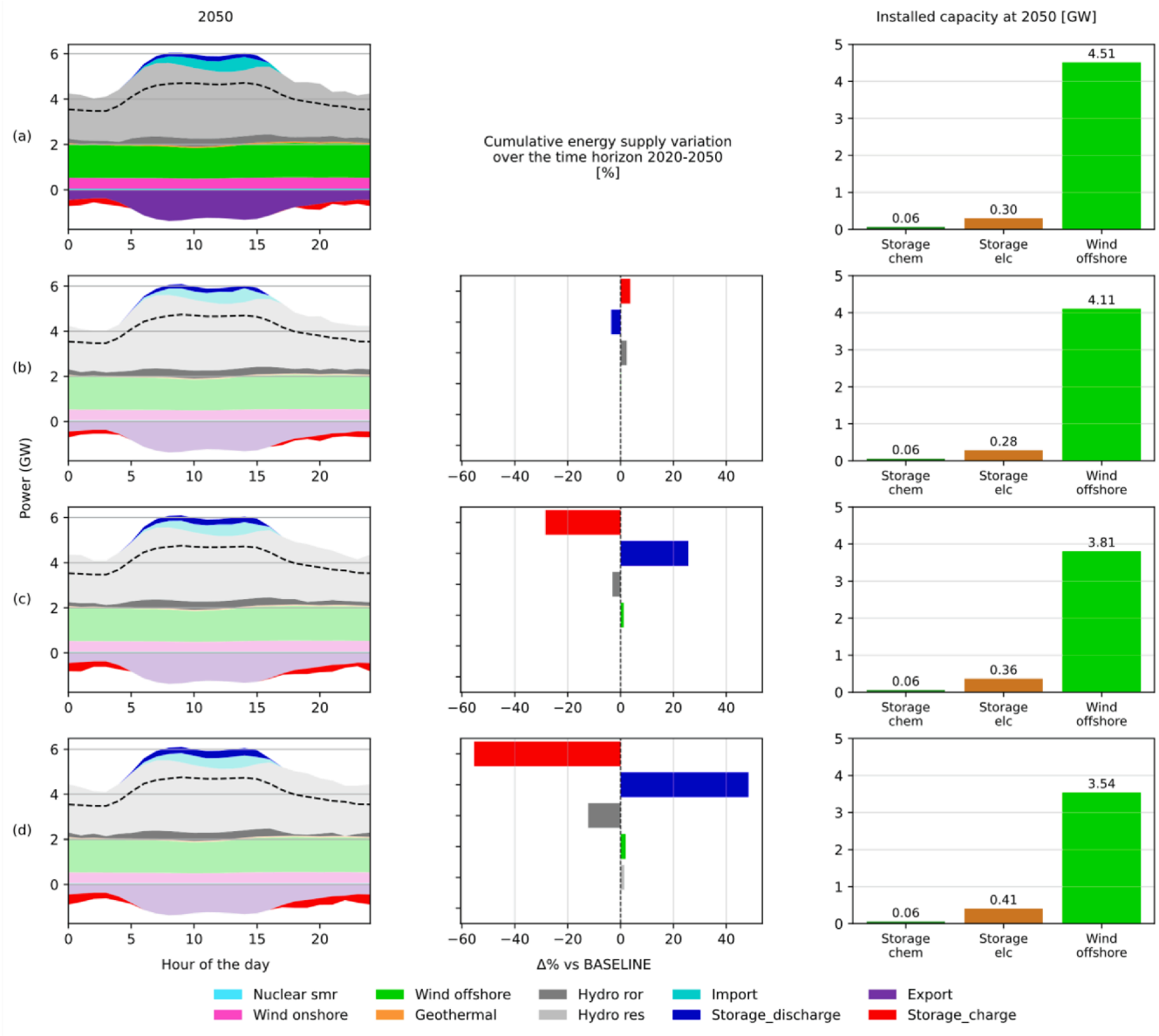

Fig. 15. Offshore wind's cfs sensitivity analysis results. the left column reports the hourly profiles for electricity production in 2050 for (a) offshore cfs equal to onshore cfs, (b) offshore cfs have a multiplying factor of 1.1 with respect to onshore cfs, (c) multiplying factor is 1.2, (d) multiplying factor is 1.3. the mid column accounts for the variation, over the entire time horizon (2020–2050), of the cumulative provided energy from a certain technology (legend's colour code) with respect to the (a) case. Right column represents the installed capacity of storage and wind offshore technologies in 2050.

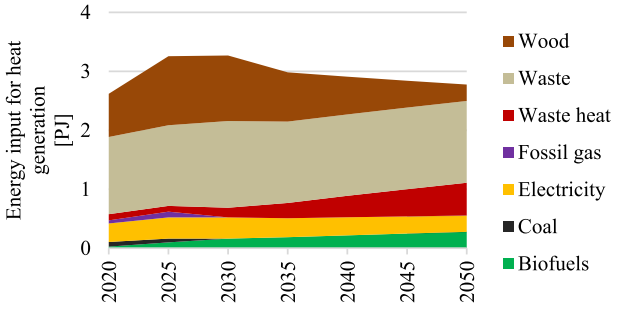

Fig. 16. Annual resource consumption for district heating production, in PJ.

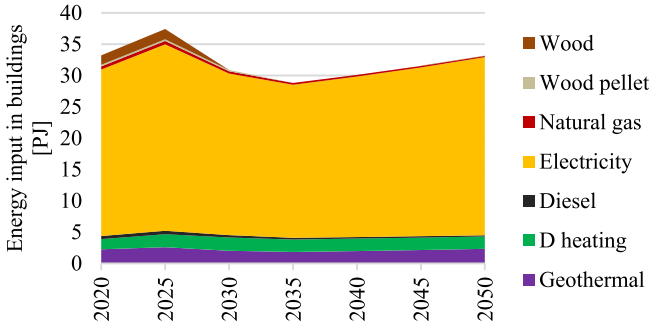

Fig. 17. Buildings' annual energy consumption by energy carrier, in PJ.

The modest contribution of district heating and biomass in the charts aligns with policy and market signals in Norway, for example, the 2020 prohibition on fossil fuels as base-load space heating and the continuing growth of electrification, which together limit the role of fossil and some networked heating solutions in many contexts [58].

The buildings energy consumption also show a peak for 2025, as previously observed also in total primary energy supply, due to the mentioned GDP values (Table 21) being affected by COVID-19 pandemic in 2020 and going back to usual growth in 2025, causing commercial activities and services to be strongly reactivated before the following strict emissions cut. This dynamic is more easily observable from Fig. 18, where the final energy demand of the sector is represented in its different components, for both residential and commercial compartments. In this view, it is noticeable how all the service demands encounter a growth in 2025, leading to the peak seen previously, and then stabilize on a linear increment that, combined with the increasing efficiency of the technologies exploited, explains the trend of the total energy consumption.

3.4. Transport

Trasport sector is one of the most dynamic of the region's economy, and currently the most relying on fossil fuels yet. For this reason, it displays the widest changes throughout the modelled time horizon, as represented in Fig. 19, with a progressively less important role of diesel, especially in the road freight and passenger transport, being replaced by electricity, which also cause the efficiency of the entire system to grow largely, though for these technologies a reducing efficiency factor has been used to better represent arctic conditions [59]. Also, hydrogen slowly penetrates the sector, mainly to cover public transport demand and LCVs in the later years of the horizon, substituting a considerable fraction of gasoline engines. Regarding the maritime transport, marine gas oil and HFO are substituted by liquid natural gas and ammonia starting from 2030, underlining a possible criticality of the system to match emissions target in time, since the mentioned transition is not yet happening at the expected pace. Finally, aviation, which is the most hard-to-abate aspect of the sector, mainly keeps the same technology configuration until 2045, and then introducing synfuels to respect the most stringent emission limits.

Transport-sector transformation remains necessary even though its energy consumption is relatively low compared with other sectors, because its emission intensity is high. In 2020 and 2025, transport accounted for 8.7% and 8.2% of total primary energy supply, respectively, but slightly more than 22% of carbon dioxide emissions. It was therefore the second-largest emitting sector after industry, which accounted for 36.6% and 44% of energy consumption and 46.9% and 63% of total carbon dioxide emissions in the same years. Sectoral

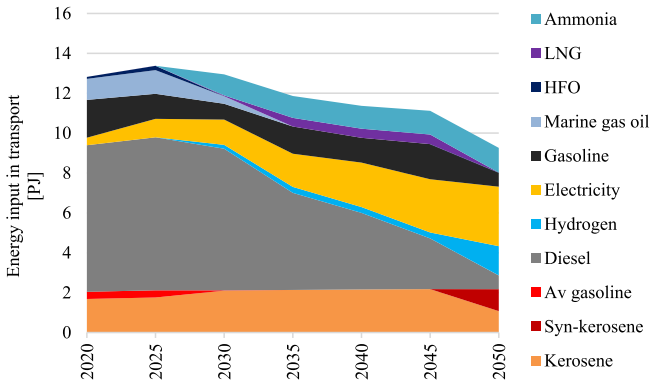

Fig. 19. Annual fuel consumption in transport sector, in PJ.

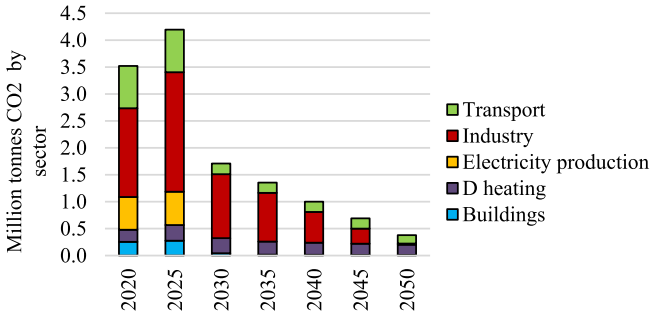

Fig. 20. Annual co2 emission breakeven by sector, in $MtCO_2$.

emissions are reported in Fig. 20, highlighting the effort required to meet the 55% emissions-reduction target by 2030, which the model indicates is not achieved under the adopted assumptions.

3.5. National model comparison

A useful external benchmark for national-scale expectations is DNV's Energy Transition Outlook: Norway 2024, in which DNV projects substantial growth in national electricity demand toward mid-century, similarly to what highlighted by the present work results, even though the report foresees a generally stable overall energy demand, while these results address a slow but constant growth led by economical drivers.

Direct comparison between DNV's national outlook and the TEMOA-NO4 regional results must be treated cautiously because of scale and scope differences. Nevertheless, juxtaposing the two offers instructive contrasts. DNV's assessment emphasises a strong national electrification

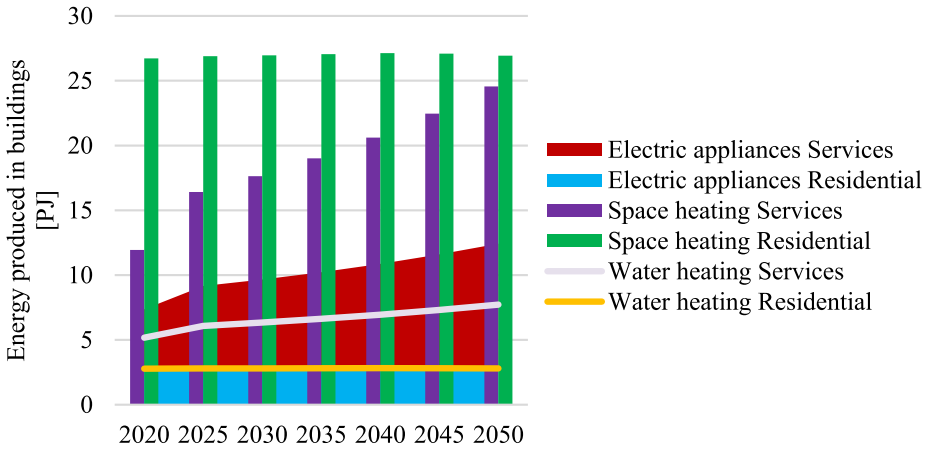

Fig. 18. Annual final energy demand in buildings by end use, in PJ.

trend and a large increase in electricity demand by 2050; similarly, TEMOA-NO4 finds a pronounced rise in regional electricity generation and exports in the decarbonisation scenarios, with offshore wind and existing hydropower forming the backbone of supply. The concordance on the direction of travel (electricity growth, renewables expansion) supports the credibility of the regional scenarios when viewed as a spatially concentrated expression of national dynamics [34].

Importantly, the regional model surfaces decision-relevant subtleties that national models, including DNV's aggregated assessment, are not configured to diagnose. In TEMOA-NO4, seasonal and diurnal mismatches materially affect storage requirements, the timing and scale of grid reinforcements, and the trade-offs between local flexibility (e.g. batteries, pumped hydro) and cross-border exchanges. These are operational and siting considerations that national models typically represent only in aggregate. Scholarly work on regionalisation confirms that such heterogeneities can alter optimal portfolios and infrastructure priorities [11].

In plain terms: where DNV provides a robust national narrative about electrification and overall sectoral transformation, TEMOA-NO4 offers granular diagnostics about how those transitions might play out locally in a peripheral Arctic region, for instance, highlighting potential congestion or the need for targeted reinforcement of specific corridors between NO4 and SE1/SE2, and thus supplies complementary evidence that can inform regional permitting, TSO planning and local adaptation strategies.

The practical value of the model lies in identifying which planning conclusions are robust and which are assumption driven. For regional planners, the results indicate that three issues require priority attention before investment-grade decisions can be made: the treatment of future export obligations, the quality of offshore wind resource assessment, and the availability of disaggregated industrial activity data. The model therefore functions as a screening and diagnostic tool: it does not prescribe specific investments, but it identifies which assumptions most strongly control infrastructure outcomes and where improved data would reduce planning uncertainty.

3.6. *Regional versus national modelling: Key insights from the NO4 case study*

Although the preceding sections discuss individual modelling outcomes in detail, an important integrating question is what additional insights emerge from regional-scale modelling that would be difficult or impossible to identify using national-level analyses. Drawing on the results presented in previous Sections, Table 24 summarises the principal differences highlighted by the Northern Norway case study across six analytically relevant dimensions, complementing the qualitative comparisons already offered in the National model comparison subsection with quantitative references where the model provides them.

The principal contribution of the regional perspective is not the identification of fundamentally different decarbonisation technologies since the broad direction of travel (electrification, renewables expansion, fossil-fuel phase-out) is consistent with national-scale narratives such as the DNV Energy Transition Outlook. Rather, it is the exposure of constraints and sensitivities that become obscured under national aggregation. In the NO4 case, regional modelling reveals a stronger electricity demand intensity than population-based indicators alone suggest, identifies electricity exports as a first-order driver of offshore wind deployment and storage requirements, and demonstrates that industrial decarbonisation assessments are currently constrained not by the optimisation framework but by the availability of disaggregated data. These findings illustrate that regional optimisation provides complementary planning diagnostics at the level of infrastructure sizing, sensitivity attribution, and data-gap identification that cannot be inferred directly from national-scale results, and that become particularly consequential for peripheral Arctic systems where locally binding constraints are masked by national averages.

4. Conclusions

This study developed a transparent regional energy system optimisation model for Northern Norway, applying the open-source TEMOA framework to a sparsely populated Arctic bidding zone characterised by strong seasonal variability, constrained transmission corridors, and limited regional data availability. Rather than producing a predictive transition scenario, the work adopted a diagnostic perspective aimed at evaluating how spatial granularity, temporal resolution, and data-construction assumptions influence regional energy-system planning outcomes.

The results show that regional modelling can reveal structurally important dynamics that remain partially hidden in aggregated national-scale analyses. In particular, the model identifies substantially stronger electricity-demand growth than population-based indicators

Table 24
Key differences between national-scale and regional-scale energy-system perspectives, as revealed by the NO4 case study. Quantitative references are drawn from the results reported in the preceding sections; section and table numbers correspond to those of the main manuscript.

Aspect	Typical national-scale interpretation	Regional insight from NO4	Quantitative reference
Electricity demand	Demand broadly follows population share, used as the primary downscaling indicator	Buildings-sector electricity consumption reaches approximately 12.7% of the national total, roughly 4 percentage points above the 9.0% population share, implying an intensity premium of ~ 40% over the national per-capita average	Table 8; population share from Table 3
Offshore wind	One of several renewable expansion options, competing on cost with onshore wind and other technologies	Becomes the dominant generation expansion pathway under sustained export assumptions; when future export demand is removed, the combined onshore and offshore wind contribution in 2050 is approximately halved relative to the baseline	Fig. 14 (export sensitivity)
Storage	Moderate and broadly predictable flexibility requirement, driven mainly by VRE penetration	Storage charging increases by up to ~ 60% under the highest offshore wind capacity-factor assumption (CF multiplier 1.3); conversely, storage deployment becomes negligible when future export demand is removed	Fig. 15 (CF sensitivity)
Electricity trade	Represented through aggregated national or cross-border exchange statistics	Historical net exports of ~ 21.5 PJ in 2020; first-order driver of long-term generation expansion, removing future export growth halves wind deployment and eliminates storage requirements	Table 10; Fig. 14
Hydropower	National balancing resource managed at grid level; its regional concentration is not resolved	Structural backbone of the regional system throughout the entire horizon, providing the majority of dispatchable generation and enabling flexible response to variable offshore wind and storage demand	Fig. 11; Fig. 13
Industrial decarbonisation	Technology pathways, carbon prices and efficiency improvements drive endogenous sectoral transitions	Electricity consumption (~32.9 PJ/yr, approximately 52% of total regional electricity use in 2020) is the only publicly available disaggregated regional indicator; decarbonisation pathways cannot emerge endogenously due to data confidentiality constraints	Table 6; Table 13

alone would suggest, reflecting the combined effects of electrification, industrial consumption, and persistent export dynamics. Historical data indicate that NO4 represents approximately 9% of Norway's population while accounting for roughly 13% of national electricity consumption in the buildings sector, highlighting the limitations of population-only downscaling approaches.

The analysis further shows that temporal and spatial representation materially influence infrastructure diagnostics. Under the assumptions represented in the model, hydropower remains the structural backbone of the regional electricity system, while offshore wind emerges as a robust expansion option under constrained hydropower growth and sustained export requirements. At the same time, the results indicate that storage deployment and electricity trade patterns are highly sensitive to the temporal representation of renewable variability and demand peaks. The selected 96-slice structure captures seasonal and intra-day variability but cannot fully represent prolonged low-renewable events or hydrological stress periods, which may lead to underestimation of long-duration flexibility requirements.

One of the criticalities highlighted by the study concerns the industrial sector. The analysis demonstrates that the main limitation for detailed regional decarbonisation modelling is not the optimisation framework itself, but the lack of transparent and disaggregated regional industrial datasets. Due to confidentiality restrictions and limited regional reporting, industrial energy balances had to be reconstructed using proxy assumptions derived from electricity consumption and national-average sectoral structures. Consequently, industrial decarbonisation pathways are represented diagnostically through exogenous assumptions rather than emerging endogenously from technology competition. This result highlights a structural mismatch between current statistical reporting practices and the information requirements of regional energy-system optimisation models.

The work also contributes methodologically by documenting a transparent regionalisation workflow for energy-system modelling in data-scarce Arctic regions. In contrast with many existing regional studies where data processing and aggregation procedures remain weakly documented, the present work explicitly reports the proxy assumptions, downscaling procedures, temporal aggregation choices, and calibration strategies used to construct the NO4 database. This transparency allows the interpretation of results as conditional on clearly stated assumptions and facilitates future sensitivity analyses and model extensions.

Model calibration against historical data for 2020 and 2025 shows reasonable agreement with observed energy balances. Weighted absolute percentage errors remain below 5% for total primary energy supply and between approximately 5% and 10% for final energy demand composition, indicating that the model reliably reproduces the principal structural characteristics of the regional energy system despite significant data limitations.

Nevertheless, several limitations remain. As demonstrated by the no-export sensitivity case conducted, export flows strongly influence generation expansion patterns and their exogenous representation constitutes a major bias over the model outcomes, particularly regarding the deployment of offshore wind. Similarly, the results suggest that further knowledge about offshore wind capacity factor development could significantly affect storage implementation in the region and installed capacity needs, also influencing grid management choices. The aggregated representation of transmission topology also prevents the direct identification of local congestion patterns or investment-grade reinforcement requirements. Furthermore, the deterministic structure of the model does not capture uncertainty associated with climate change impacts, hydrological variability, or future market dynamics.

Future work should focus on a systematic comparison between the present regional modelling framework and an equivalent national-scale energy system optimisation model developed independently from the regional database construction process. Such a comparison would allow a more rigorous evaluation of how spatial aggregation influences infrastructure planning, technology deployment pathways, electricity trade patterns, and flexibility requirements in Arctic and peripheral regions. In particular, directly comparing regional and national model outputs could help quantify which system dynamics remain hidden or underestimated in aggregated representations, especially regarding transmission bottlenecks, renewable integration challenges, and industrial electrification patterns. This would further strengthen the diagnostic role of regional optimisation modelling by clarifying under which conditions increased spatial and temporal resolution provides additional planning value relative to national-scale approaches. Finally, extending the temporal representation to include representative stress periods or multi-day low-renewable events would improve the evaluation of long-duration storage and system adequacy.

Overall, the study demonstrates that transparent regional optimisation modelling can provide planning-relevant diagnostics for Arctic energy systems while simultaneously exposing the structural data limitations and methodological trade-offs that shape those diagnostics. In this sense, the principal contribution of the work is not the production of a single optimal transition pathway, but the demonstration of how regional, open-source modelling can reveal locally binding infrastructure constraints, flexibility requirements, and data gaps that aggregated national analyses inherently smooth over.

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CRediT authorship contribution statement

Alessandro Balbo: Writing – review & editing, Writing – original draft, Software, Methodology, Investigation, Formal analysis, Data curation, Conceptualization. **Matteo Chiesa:** Writing – review & editing, Supervision, Conceptualization. **Laura Savoldi:** Writing – review & editing, Supervision, Methodology, Conceptualization.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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