FRAUNHOFER INSTITUTE FOR ENERGY ECONOMICS AND ENERGY SYSTEM TECHNOLOGY, IEE

# DEVELOPMENT OF EUROPEAN ENERGY SYSTEM SCENARIOS

## Report for HydroConnect Work Package 2.2

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# Abbreviations

**CCGT** combined-cycle gas turbines. 13, 14, 20, 21
**CCS** Carbon Capture and Storage. 13
**CHP** combined heat and power. 15, 20, 21, 29
**CLEQ** clustered-equivalent. 8, 9

**EEZ** Exclusive Economic Zone. 11, 31
**EQ** equivalent. 8, 9

**FanSi** Scenario fan simulator. 6, 32, 33

**GHG** Greenhouse gas. 7, 10, 14

**LP** linear programming. 7, 8

**NTCs** net transfer capacities. 12

**OCGT** open-cycle gas turbines. 13, 14, 20
**OEI** offshore energy island. 12, 26, 31

**PtX** Power-to-X. 13

**SCOPE SD** SCOPE Scenario Development. 6–8, 10, 12, 13, 32, 33
**solar PV** solar photovoltaics. 13, 14, 19, 21

**TYNDP** Ten-Year Network Development Plan. 12, 13

# 1 Introduction

Achieving climate-neutrality targets in Europe requires substantial deployments of variable renewable electricity generation in the transition to 2050. Pan-European power and energy systems face several cross-border and cross-sectoral integration challenges to facilitate an effective and efficient transition. Norwegian hydropower has a large storage capacity in existing reservoirs that can be used for large-scale balancing and energy storage integrated with continental Europe and the United Kingdom.
As a first step in the HydroConnect project's chain of modelling tools, Fraunhofer IEE's modelling and optimisation framework SCOPE Scenario Development (SCOPE SD) for integrated energy systems is used to compute relevant future European scenarios for Norwegian hydropower. The overall application of different models can be seen in Figure 1.

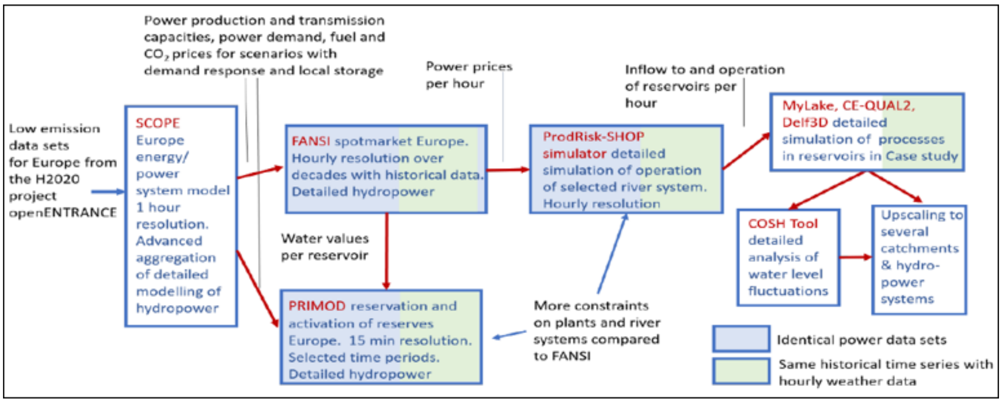



**Figure 1 SCOPE SD application in HydroConnect, illustration taken from project proposal.**

SCOPE SD provides scenarios for the medium-term (e.g. 2030) and long-term (e.g. 2050) for Europe's future power and energy system. The scenario development is based on recent scenario work (e.g. from the openENTRANCE project [1]) and input from the HydroConnect project (i.e. scenario workshops). A detailed hydropower model for the multi-reservoir hydro systems is employed to analyse hydropower's role in future European energy scenarios. Output from SCOPE SD is used directly as input in the Scenario fan simulator (FanSi) model and the PRIMOD model.

# 2
# Integrated energy system model SCOPE SD

The pan-European cross-sectoral capacity expansion planning framework SCOPE Scenario Development (SCOPE SD) is a bottom-up techno-economic partial equilibrium model. Recent mathematical formulations and applications of SCOPE SD can be found in [2, 3, 4, 5, 6]. Figure 2 illustrates the structure, components, and typical in- and output data of SCOPE SD (upper section) including the interactions of technology options (lower section) in the corresponding markets or policy instruments (middle section).

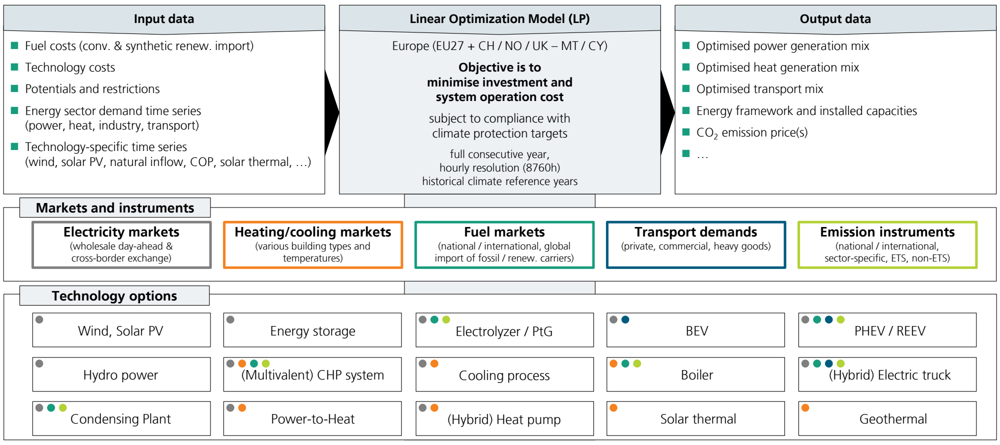



**Figure 2 Schematic overview of the pan-European cross-sectoral capacity expansion planning framework SCOPE SD, own illustration. Note that the different dot colours of the technology options indicate the (multi-fold) participation of technology options in the corresponding markets or policy instruments.**

## 2.1
## General model information

The modelling and optimisation framework develops coherent long-term low-carbon energy system scenarios for Europe for a given target scenario year in the future. By minimising the generation, storage, and cross-sectoral consumer technology investment and system operation cost, this large-scale linear programming (LP) approach has representations for the traditional power system as well as for all relevant bi- and multivalent technology combinations at the sectoral interfaces with the building, industry, and transport sectors.
Each market area, i.e. every European country, is represented by one node. All units (generation, storage, and cross-sectoral demand technology options), their most important parameters (costs, potentials, and operational characteristics), and their relevant interactions with each other are modelled in hourly resolution. By explicitly modelling national and pan-European fuel markets, it is possible to distinguish between the use of fossil fuels, on the one hand, and synthetic renewables, on the other hand, which are either imported from outside of Europe or produced domestically. In order to account for net-neutrality in future scenarios, national and international greenhouse gas (GHG) emission budgets are implemented as a driving force behind investments in low-carbon technologies.

SCOPE SD is implemented in MATLAB®. The resulting LP instances in this case study have been solved with the Barrier (interior point) algorithm of IBM ILOG CPLEX® 12.9 on a medium-range HPCC node (Intel XEON E5-2698v3 16 Cores @ 2.30 GHz, 256 GB RAM).

## 2.2 Detailed hydropower model

A critical aspect of the modelling approach is representing hydropower assets across Europe. Given the heterogeneous orography across the European continent, hydropower systems exist in many different structural shapes, and they are subject to very different natural inflow patterns, e.g. multireservoir systems with branched and parallel connections between turbine and pump units in alpine regions and long serial hydropower systems extending into multiple jurisdictions and participating in different markets at the same time. The SCOPE SD framework uses the deterministic hydropower modelling approach developed in [7, 8].
Figure 3 gives an overview of the detailed hydro reservoir model which features an operation planning tool for individual hydro plants and reservoirs based on the water domain. It allows for the modelling of multireservoir hydropower systems with parallel up- and downstream plant connections and hydraulic coupling.

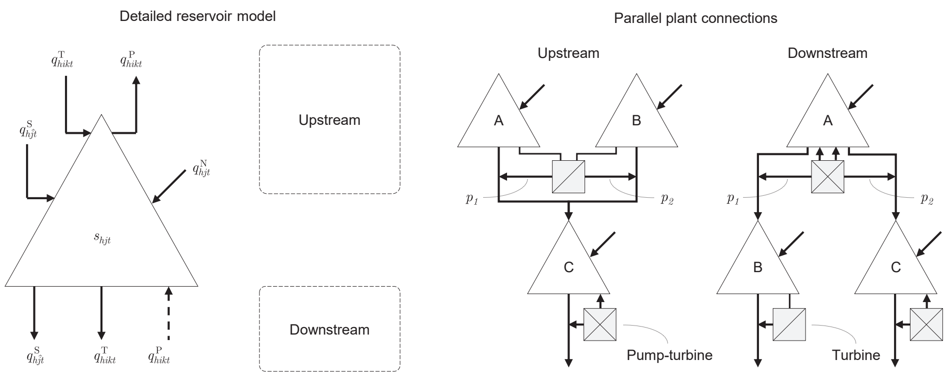



**Figure 3 Overview of the detailed hydro reservoir model and schematic illustration of parallel up- and downstream hydro plant connections, own illustration based on [7, 8].**

While the detailed modelling approach can be used in the SCOPE SD modelling framework, it is important to mention that this modelling approach is computationally prohibitive when analysing the integrated energy system of Europe in high spatial and temporal resolution.

## 2.3 Aggregated hydropower modelling approaches

To overcome computational tractability issues, the model can derive two aggregated modelling approaches: equivalent (EQ) and clustered-equivalent (CLEQ) [7, 8]. Figure 4 provides a schematic overview of the involved aggregation procedure from the detailed to the equivalent (EQ) to the clustered-equivalent (CLEQ) modelling approach based on the concept of an equivalent one-dam representation of each hydro system [9].

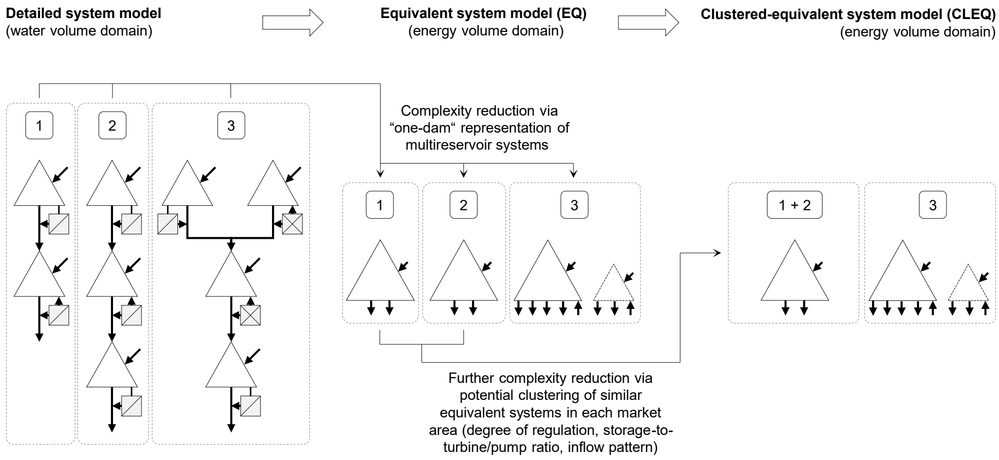



**Figure 4 Schematic overview of the aggregation procedure from the detailed to equivalent (EQ) to clustered-equivalent (CLEQ) modelling approach for three exemplary multireservoir hydropower systems, own illustration based on methodology in [7, 8].**

For different configurations of detailed hydropower systems, slightly different equivalent model types can be used to represent the hydropower system characteristics. Figure 5 summarises the different model types which differ due to available pumping capacity or the necessity to avoid overestimating the flexibility of pumped-hydro storage with a potential second synthetic reservoir.

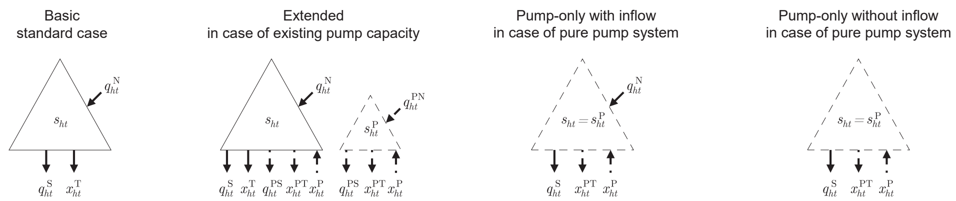



**Figure 5 Equivalent system model types for the aggregated representation of (multi-) reservoir hydropower systems, own illustration based on [7, 8].**

Depending on the application, the equivalent (EQ) hydropower system model can already provide a sufficient reduction of complexity and computational burden. However, analysing the European power and energy system requires the representation of a large number of hydropower systems (recall Figure 8) making further aggregation necessary. To that end, the core idea of the clustered-equivalent (CLEQ) hydropower system model is to harness the fact that the instances of the uniforming EQ model formulations can exhibit very similar characteristics. By clustering and merging these equivalent hydro units according to their coherent features, a further aggregation can be achieved [7].

# 3
# European energy system scenario variants

In the HydroConnect project, the SCOPE SD modelling and optimisation framework is used to compute relevant scenarios for Norwegian hydropower in the future. To analyse its role in future European energy scenario settings, a detailed hydropower model for the multi-reservoir hydropower systems is employed and several scenario variants reflecting essential uncertainties in the future are investigated. These include an increased Norwegian electricity demand, a reduced transport sector flexibility, higher public acceptance for onshore wind power, increased offshore wind deployments, realisation of offshore energy islands, and varying green hydrogen import prices from outside of Europe.
The following Figure 6 depicts an overview of the analysed **scenario streams** and the European scenarios investigated in the HydroConnect project. Note that a pan-European SCOPE SD simulation has been carried out for each of the 15 scenario combinations indicated below.

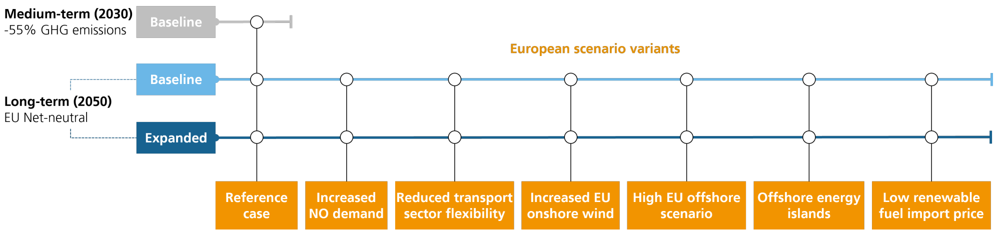



**Figure 6 Overview of the European scenario variants in the HydroConnect project, own illustration.**

In a medium-term scenario developed for 2030, GHG emissions are reduced by 55 % compared to 1990. The medium-term scenario primarily highlights the intermediate effects on the energy and power system in the transition to climate neutrality by 2050. In the long-term scenarios for 2050, Europe is modelled as a net-neutral system, implying that fewer GHG emissions are being produced than absorbed by the system. Note that this study only contains a pan-European GHG emission budget without any additional layer of the country- or instrument-specific budgets. The term "Europe" refers to the current 27 Member States of the European Union without Malta and Cyprus but including Norway, Switzerland, and Great Britain (recall Figure 2).
There are two different **scenario streams** defined for all European scenarios: **Baseline** and **Expanded**. The main difference between the two is that the Expanded cases assume an additional Norwegian hydropower turbine capacity of 11.2 $GW_{el}$ (and 5.2 $GW_{el}$ of pump capacity) and an increased interconnector cable capacity of 13 $GW_{el}$ for cross-border electricity exchange flows to and from Norway.

Based on a "reference case" for each of the scenario streams, a range of six further European scenario variants is investigated:

European energy system scenario variants

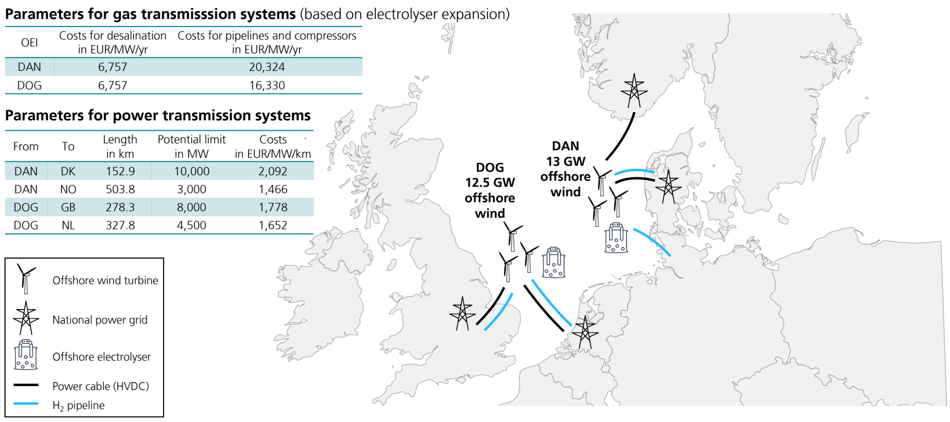
- **Increased Norwegian electricity demand (↑ NO demand):**
  the increase in electricity consumption for Norwegian data centres and new consumers (42 $TWh_{el}$/yr) is twice that of the reference case (21 $TWh_{el}$/yr)
- **Reduced transport sector flexibility (↓ Transport flex):**
  the share of flexible vehicle charging behaviour for electric vehicles in all considered market areas is only 20 % in the reference case
- **Increased onshore wind deployments (↑ EU Onshore):**
  a higher public acceptance of onshore wind in Norway and Europe leads to increased expansion potentials compared to the reference case, i.e. 1 228 vs. 908 $GW_{el}$ at the pan-European level, and 22 vs. 10 $GW_{el}$ in Norway
- **Increased offshore wind deployments (↑ EU Offshore):**
  there is a pan-European minimum offshore wind expansion of 446 vs. 284 $GW_{el}$, and 20 vs. 6 $GW_{el}$ in Norway
- **Increased offshore wind deployments plus offshore energy islands (↑ EU Offshore+OEI):**
  corresponds to the ↑ EU Offshore variant with the exception of two offshore energy islands at the Doggerbank (not connected to Norway) and in the Danish exclusive economic zone (EEZ) (connected to Norway)
- **Increased use of renewable hydrogen imports (↑ EU $H_2$ Imports):**
  the import price for renewable hydrogen from global markets is cheaper at 73 compared to 85 $EUR_{2018}/MWh_{th}$ in the reference case

# 4
# Input data and assumptions

To consider meteorological effects and past climate conditions, the historical meteorological reference year 2012 is used to derive weather-dependent input data. The choice for this year is mainly due to the fact that it features a two-week "Kalte Dunkelflaute" period (cold dark doldrums) and is, therefore, well-suited (e.g., see [10]) to represent extreme weather conditions of the integrated energy system in the future and their implication for design choices by the modelling framework.
Several data sources are used to determine the various energy demands in the end-use sectors. The final traditional electricity demand of every country in Europe is based on ENTSO-E data [11]. For the countries of Northern Europe, i.e. Denmark, Finland, Norway, and Sweden, electricity consumption is aligned with a recent analysis from Statnett [12] to reflect developments of new consumers, e.g. data centres. Final energy demand developments of the European transport and heating sectors are based on the EU Reference Scenario 2016 [13].

## 4.1
## Net transfer capacities and offshore energy islands

The SCOPE SD framework employs a transport model for cross-border electricity flows. The net transfer capacities (NTCs) are based on the 2040 transmission grid scenario "GCA 2040" of the Ten-Year Network Development Plan (TYNDP) 2018 [14]. Although SCOPE SD can model endogenous transmission expansion planning, this option is only allowed in the scenario "Increased offshore wind deployments plus offshore energy islands (↑ EU Offshore+OEI)". More specifically, this scenario considers two offshore islands and co-optimises their power transmission and gas pipeline infrastructure. Parameter assumptions for gas transmission systems as well as for power transmission systems can be seen in Figure 7.


**Parameters for gas transmisssion systems** (based on electrolyser expansion)

| OEI | Costs for desalination in EUR/MW/yr | Costs for pipelines and compressors in EUR/MW/yr |
|---|---|---|
| DAN | 6,757 | 20,324 |
| DOG | 6,757 | 16,330 |

**Parameters for power transmission systems**

| From | To | Length in km | Potential limit in MW | Costs in EUR/MW/km |
|---|---|---|---|---|
| DAN | DK | 152.9 | 10,000 | 2,092 |
| DAN | NO | 503.8 | 3,000 | 1,466 |
| DOG | GB | 278.3 | 8,000 | 1,778 |
| DOG | NL | 327.8 | 4,500 | 1,652 |



**Figure 7 Parameter assumptions for offshore energy islands (OEIs), own illustration.**

An overview of the NTCs between Norway and its neighbouring countries can be found in Table 1. The difference between 2030 Baseline and 2050 Baseline is only the additional "NorthConnect" connection between the UK and Norway with a capacity of 1 400 MW. In the 2050 Expanded scenarios, the connections "NordLink" between Germany and Norway (5 600 MW), "NorNed" between the Netherlands and Norway (1 400 MW), "Skagerrak" between Denmark and Norway (1 400 MW) and an expansion of "North-Connect" to now 5 600 MW are added. Furthermore, onshore AC transmission network reinforcements between Sweden and Norway are assumed, increasing the capacity to 6 000 MW.

**Table 1 Overview of NTC capacities between Norway and its neighbouring countries in the Baseline (BL) and Expanded (EX) scenarios in alphabetical order.**

| Country 1 | Country 2 | 2030 BL 1 → 2 | 2030 BL 2 → 1 | 2050 BL 1 → 2 | 2050 BL 2 → 1 | 2050 EX 1 → 2 | 2050 EX 2 → 1 |
|---|---|---|---|---|---|---|---|
| DEU | NOR | 1 400 | 1 400 | 1 400 | 1 400 | 7 000 | 7 000 |
| DNK | NOR | 1 132 | 1 132 | 1 132 | 1 132 | 2 532 | 2 532 |
| FIN | NOR | 150 | 130 | 150 | 130 | 150 | 130 |
| GBR | NOR | 1 400 | 1 400 | 2 800 | 2 800 | 5 600 | 5 600 |
| NLD | NOR | 700 | 700 | 700 | 700 | 2 100 | 2 100 |
| NOR | SWE | 3 695 | 3 995 | 3 695 | 3 995 | 6 000 | 6 000 |

## 4.2 Thermal power generation

For large thermal power plants, a distinction is made between existing or planned plants and new to-be-built ones. In the former category, projections are made using specific lifetime assumptions for the existing and already planned thermal power plants from the PLATTS database [15]. Note that this only affects the remaining nuclear production capacities in Finland (2.8 GW), France (1.75 GW), the Czech Republic (2.0 GW), Romania (0.7 GW), and Slovakia (0.88 GW). In addition, nuclear production capacities amounting to 3.5 GW are assumed in Sweden [16]. In the latter category, SCOPE SD can make investment decisions for open-cycle gas turbines (OCGT) and combined-cycle gas turbines (CCGT), both with or without possible cogeneration of heat and power. Further note that all new to-be-built thermal power plants use hydrogen as their primary fuel source. The price assumptions for green hydrogen from non-European export countries are based on Fraunhofer IEE's Power-to-X (PtX) atlas [17], which contains a broad assessment of global production and export sites. Solutions involving Carbon Capture and Storage (CCS) technologies are not considered.

## 4.3 Renewable power generation

For renewable power generation, rooftop and utility-scale solar photovoltaics (solar PV) as well as onshore and offshore wind technology potentials are based on Fraunhofer IEE's internal "satellite models", which combine land-use data [18] with numerical weather prediction information based on the historical meteorological reference year. The European onshore wind capacities are scaled to the capacities of the "Distributed Energy 2050" scenario of the TYNDP 2022 [10], while the slightly more conservative "Distributed Energy 2040" scenario is used for the offshore wind capacities. In the countries of Northern Europe, i.e. Denmark, Finland, Norway, and Sweden, solar PV capacities are adjusted to the values from the Nordic Grid Development Perspective 2021 [19].

As previous mentioned, only green hydrogen is permitted in the model's hydrogen sector. Following the classification of different types and origins of hydrogen in [7], green hydrogen is defined as a result of GHG-neutral production based on water electrolysis powered entirely by renewable electricity from wind and solar PV.

## 4.4 Heat generation

Detailed information on the modelling and input data of heat generation technologies including heat pumps, thermal storage, district heating, and industrial heat generation can be found in [4, 5], which also feature a detailed overview of the required time series data for renewable generation, end-use demands for electricity and heat, and passenger transport demands. Moreover, note that the conventional electricity load profiles in Europe from published ENTSO-E data [20] are adjusted by corrections of today's heat-dependent electricity consumption since the modelling framework has explicit representations of the thermal demand sectors and decides on the optimal supply mix.

## 4.5 Cost assumptions

The assumed investment costs of different technologies in these calculations are based on Fraunhofer IEE's internal database, which is under continuous development in several research projects, and a current version can be found in [4]. An overview of different cost assumptions for selected renewable technologies in 2050 can be found in Table 2.

**Table 2 Overview of investment costs, fixed operation costs, and depreciation periods for selected renewable technologies in 2050.**

| Technology | Investment cost in $EUR_{2018}$/kW | Fixed operation cost in $EUR_{2018}$/kW/yr | Depreciation period in yr |
|---|---:|---:|---:|
| Solar PV (rooftop) | 676 | 0.055 | 25 |
| Solar PV (utility-scale) | 300 | 0.055 | 25 |
| Onshore wind (low specific) | 1 355 – 1 767 | 0.054 | 25 |
| Onshore wind (high-specific) | 1 000 – 1 415 | 0.054 | 25 |
| Offshore wind | 2 800 | 0.177 | 20 |
| CCGT | 750 | 30.0 | 30 |
| OCGT | 420 | 8.0 | 30 |
| Li-Ion (6 h storage ratio) | 372 | 3.72 | 8 |
| Electrolysis | 470 | 35.7 | 20 |
| Methanation | 300 | 9.0 | 20 |

Furthermore, cost assumptions for different (fossil) fuels can be found in Table 3.

**Table 3 Overview of fuel costs for 2030 and 2050.**

| Fuel | Unit | 2030 | 2050 |
| --- | --- | --- | --- |
| Natural gas (2035 fossil, 2050 renewable) | $EUR_{2018}/MWh_{th}$ | 26.74 | 106.33 |
| Uranium | $EUR_{2018}/MWh_{th}$ | 3.55 | 3.55 |
| Hard coal | $EUR_{2018}/MWh_{th}$ | 8.06 | 7.08 |
| Lignite | $EUR_{2018}/MWh_{th}$ | 1.87 | 1.87 |
| Oil | $EUR_{2018}/MWh_{th}$ | 38.51 | 29.72 |
| Hydrogen-Import | $EUR_{2018}/MWh_{th}$ | 20.60 | 85.00 |
| PtL-Import | $EUR_{2018}/MWh_{th}$ | 159.20 | 124.40 |
| $PtCH_4$-Import | $EUR_{2018}/MWh_{th}$ | 159.20 | 124.40 |

For the long-term scenario year 2050, centralised power plants, including combined heat and power (CHP) backup boilers, no longer use natural gas but only hydrogen ($H_2$). In addition to imports from outside Europe, it is possible to produce hydrogen domestically using electrolysis. Instead of fossil fuels, renewable liquid fuels and also hydrogen are used in the transport sector in addition to electric vehicles. Natural gas, which is modelled as renewable methane ($CH_4$) in 2050, is only used in decentralised boiler systems.
Investment decisions incorporate different weighted average cost of capital, which depend directly on the assumed interest rate. These interest rates are given in Table 4.

**Table 4 Interest rates for different types of investment decision makers in 2030 and 2050.**

| Interest rates | Unit | 2030 | 2050 |
| --- | --- | --- | --- |
| Decentralised (e.g. private households) | % | 3 | 6 |
| Centralised (e.g. district heating) | % | 6 | 6 |
| Industry | % | 10 | 6 |

## 4.6 Hydropower data base

The representation of multi-reservoir hydropower systems across Europe is based on Fraunhofer IEE's internal database, which contains hydropower plants from and reservoir parameters of over 874 hydropower systems, with more than 2 951 single hydro plants and 3 657 individual hydro reservoirs gathered from public data. The parameters of hydropower systems in Norway are updated in close consultation with SINTEF based on their detailed models.
Figure 8 shows the internal database containing hydropower plants and reservoir parameters of over 874 hydropower systems gathered from public data. Alongside plant- and reservoir-specific data, the database includes complex hydraulic connections, couplings, and information on cross-border market participation.

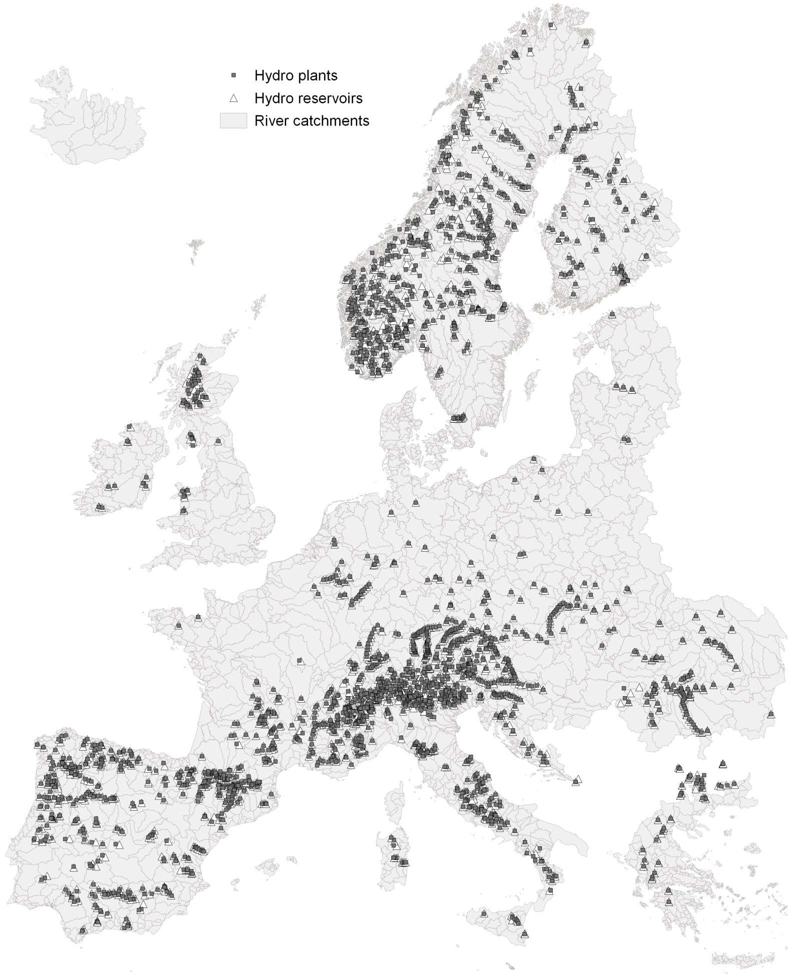



**Figure 8 Overview of explicitly covered and modelled hydropower systems across Europe (3 657 hydro reservoirs and 2 951 hydro plants in total), own illustration based on updated data sets developed in [8].**

Public availability of reservoir inflow data is particularly challenging. The modelling approach employs a generic approach to generate natural inflow profiles of every single hydro reservoir in the considered market areas. The core idea is to infer natural inflows from past climatic and meteorological conditions, i.e. historical runoff data, to create reservoir-specific natural inflow profiles that are then adjusted to individual hydropower plant production data. For a more detailed description of the spatial and temporal interpolation based on the global atmospheric reanalysis ERA-Interim [21, 22], it is referred to [7, 8].

Table 5 gives an overview of the modelled hydropower systems across Europe in HydroConnect's **Baseline** cases.

**Table 5 Overview of hydropower systems modelled in HydroConnect's Baseline cases, own compilation based on Fraunhofer IEE's hydropower model and database.**

| Market area | Total capacity in GW | | | Total storage capacity in TWh | | Number of | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Turbine (T) | Pumped hydro turbine (PT) | Pump (P) | Equivalent storage+ | Equivalent pumped storage+ | Detailed hydro plants | Detailed hydro reservoirs | Equivalent hydro systems | Clustered eq. hydro systems |
| AUT | 8.32 | 5.54 | 4.49 | (3.26) | (1.04) | 176 | 236 | 61 | 14 |
| BEL | 0.11 | 1.30 | 1.20 | (0.02) | (0.01) | 13 | 24 | 11 | 3 |
| BGR | 2.21 | 1.40 | 0.93 | (2.73) | (0.26) | 27 | 39 | 12 | 4 |
| CHE | 12.30 | 6.50 | 5.51 | (10.32) | (2.14) | 153 | 207 | 68 | 14 |
| CZE | 1.09 | 1.15 | 1.13 | (0.34) | (0.03) | 23 | 38 | 15 | 7 |
| DEU | 4.67 | 10.30 | 9.06 | (0.33) | (0.06) | 150 | 185 | 40 | 7 |
| ESP | 11.44 | 10.81 | 9.19 | (18.33) | (4.18) | 405 | 458 | 94 | 17 |
| EST | <0.01 | - | - | (<0.01) | - | 2 | 4 | 2 | 1 |
| FIN | 3.23 | - | - | (5.30) | - | 113 | 133 | 27 | 6 |
| FRA | 18.11 | 6.08 | 4.82 | (8.47) | (0.75) | 296 | 358 | 56 | 15 |
| GBR | 1.34 | 4.14 | 3.90 | (1.44) | (0.08) | 64 | 88 | 22 | 10 |
| GRC | 2.93 | 0.52 | 0.52 | (2.07) | (0.24) | 19 | 35 | 16 | 5 |
| HRV | 3.15 | 0.28 | 0.25 | (2.42) | (0.02) | 28 | 41 | 14 | 4 |
| HUN | 0.07 | - | - | (<0.01) | - | 4 | 8 | 4 | 2 |
| IRL | 0.24 | 0.72 | 0.72 | (0.09) | (<0.01) | 14 | 24 | 10 | 6 |
| ITA | 17.58 | 6.84 | 6.87 | (11.49) | (0.33) | 484 | 608 | 137 | 16 |
| LTU | 0.13 | 1.60 | 1.74 | (0.04) | (0.01) | 3 | 5 | 2 | 2 |
| LUX | 0.05 | - | - | (<0.01) | (<0.01)* | 5 | 6 | 3 | 2 |
| LVA | 1.55 | - | - | (0.07) | - | 4 | 8 | 4 | 3 |
| NLD | 0.05 | - | - | (<0.01) | - | 5 | 10 | 5 | 2 |
| NOR | 34.70 | 1.37 | 1.04 | (83.32) | (2.53) | 408 | 553 | 145 | 145× |
| POL | 0.55 | 1.76 | 1.65 | (0.12) | (0.05) | 18 | 32 | 14 | 8 |
| PRT | 5.19 | 4.22 | 3.28 | (4.76) | (0.99) | 65 | 70 | 13 | 9 |
| ROU | 7.63 | 1.00 | 1.00 | (2.64) | (<0.01) | 98 | 163 | 65 | 8 |
| SVK | 1.85 | 1.62 | 1.62 | (0.53) | (0.06) | 34 | 42 | 9 | 5 |
| SVN | 1.57 | 0.58 | 0.62 | (0.02) | (<0.01) | 35 | 37 | 4 | 2 |
| SWE | 16.56 | - | - | (32.69) | - | 221 | 243 | 21 | 21× |
| ALL | 156.63 | 67.71 | 59.50 | (190.81) | (12.81) | 2867 | 3655 | 874 | 338 |

+ Total storage and pumped hydropower storage capacity figures can merely be used as an indication since structural and inflow information is vital to the allocation of storage among the hydropower systems in one market area.

* The pumped storage reservoir capacity is geographically located in market area LUX, but the total pump turbine and pump capacities participate in the market area DEU.

× Given the focus on Nordic hydropower, there is no clustering of equivalent hydropower system units in Norway and Sweden in the context of the HydroConnect project.

Table 6 gives an overview of the modelled hydropower systems across Europe in HydroConnect's **Expanded** cases. Compared to Table 5, the only changes result from additional turbine and pump units in Norway, which also increase the equivalent total and pumped-hydro storage capacities.

**Table 6 Overview of hydropower systems modelled in HydroConnect's Expanded cases, own compilation based on Fraunhofer IEE's hydropower model and database.**

| Market area | Total capacity in GW | | | Total storage capacity in TWh | | Number of | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Turbine (T) | Pumped hydro turbine (PT) | Pump (P) | Equivalent storage+ | Equivalent pumped storage+ | Detailed hydro plants | Detailed hydro reservoirs | Equivalent hydro systems | Clustered eq. hydro systems |
| AUT | 8.32 | 5.54 | 4.49 | (3.26) | (1.04) | 176 | 236 | 61 | 14 |
| BEL | 0.11 | 1.30 | 1.20 | (0.02) | (0.01) | 13 | 24 | 11 | 3 |
| BGR | 2.21 | 1.40 | 0.93 | (2.73) | (0.26) | 27 | 39 | 12 | 4 |
| CHE | 12.30 | 6.50 | 5.51 | (10.32) | (2.14) | 153 | 207 | 68 | 14 |
| CZE | 1.09 | 1.15 | 1.13 | (0.34) | (0.03) | 23 | 38 | 15 | 7 |
| DEU | 4.67 | 10.30 | 9.06 | (0.33) | (0.06) | 150 | 185 | 40 | 7 |
| ESP | 11.44 | 10.81 | 9.19 | (18.33) | (4.18) | 405 | 458 | 94 | 17 |
| EST | <0.01 | - | - | (<0.01) | - | 2 | 4 | 2 | 1 |
| FIN | 3.23 | - | - | (5.30) | - | 113 | 133 | 27 | 6 |
| FRA | 18.11 | 6.08 | 4.82 | (8.47) | (0.75) | 296 | 358 | 56 | 15 |
| GBR | 1.34 | 4.14 | 3.90 | (1.44) | (0.08) | 64 | 88 | 22 | 10 |
| GRC | 2.93 | 0.52 | 0.52 | (2.07) | (0.24) | 19 | 35 | 16 | 5 |
| HRV | 3.15 | 0.28 | 0.25 | (2.42) | (0.02) | 28 | 41 | 14 | 4 |
| HUN | 0.07 | - | - | (<0.01) | - | 4 | 8 | 4 | 2 |
| IRL | 0.24 | 0.72 | 0.72 | (0.09) | (<0.01) | 14 | 24 | 10 | 6 |
| ITA | 17.58 | 6.84 | 6.87 | (11.49) | (0.33) | 484 | 608 | 137 | 16 |
| LTU | 0.13 | 1.60 | 1.74 | (0.04) | (0.01) | 3 | 5 | 2 | 2 |
| LUX | 0.05 | - | - | (<0.01) | (<0.01)* | 5 | 6 | 3 | 2 |
| LVA | 1.55 | - | - | (0.07) | - | 4 | 8 | 4 | 3 |
| NLD | 0.05 | - | - | (<0.01) | - | 5 | 10 | 5 | 2 |
| NOR | 38.27 | 9.00 | 6.27 | (87.13) | (11.97) | 420 | 553 | 145 | 145× |
| POL | 0.55 | 1.76 | 1.65 | (0.12) | (0.05) | 18 | 32 | 14 | 8 |
| PRT | 5.19 | 4.22 | 3.28 | (4.76) | (0.99) | 65 | 70 | 13 | 9 |
| ROU | 7.63 | 1.00 | 1.00 | (2.64) | (<0.01) | 98 | 163 | 65 | 8 |
| SVK | 1.85 | 1.62 | 1.62 | (0.53) | (0.06) | 34 | 42 | 9 | 5 |
| SVN | 1.57 | 0.58 | 0.62 | (0.02) | (<0.01) | 35 | 37 | 4 | 2 |
| SWE | 16.56 | - | - | (32.69) | - | 221 | 243 | 21 | 21× |
| ALL | 160.20 | 75.34 | 64.73 | (194.62) | (22.25) | 2879 | 3655 | 874 | 338 |

+ Total storage and pumped hydropower storage capacity figures can merely be used as an indication since structural and inflow information is vital to the allocation of storage among the hydropower systems in one market area.

* The pumped storage reservoir capacity is geographically located in market area LUX, but the total pump turbine and pump capacities participate in the market area DEU.

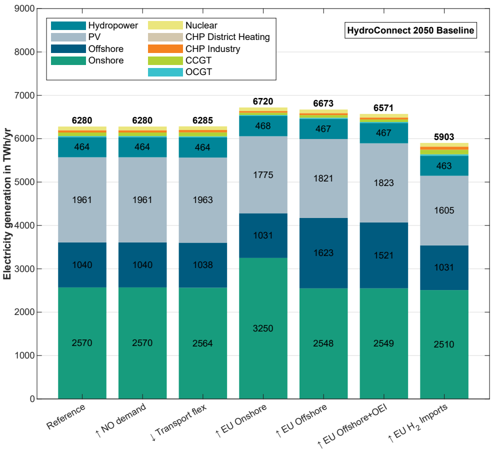
× Given the focus on Nordic hydropower, there is no clustering of equivalent hydropower system units in Norway and Sweden in the context of the HydroConnect project.

# 5 Results

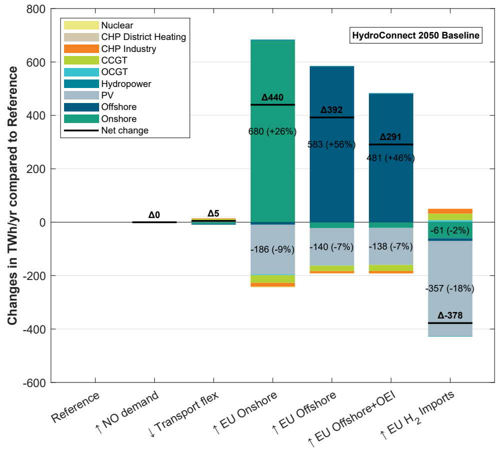


## 5.1 European energy system

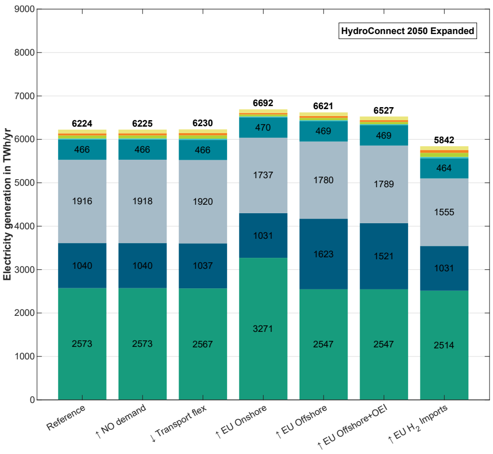
To substantiate the impacts of the different scenarios on the European electricity system and markets, Figure 9 shows the optimised (net) electricity generation balances in the climate neutral scenarios for Europe. For each scenario in both scenario streams, the absolute figures in $TWh_{el}$/yr are given in Figure 9a and Figure 9c, while Figure 9b and Figure 9d indicate the absolute and relative changes in the various scenarios compared to the corresponding reference cases.



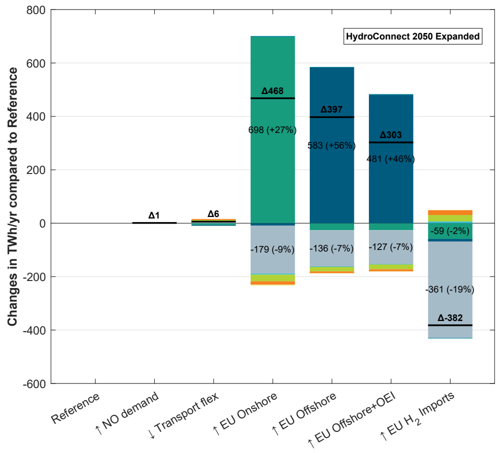

**(a) Baseline case**




**(b) Changes w.r.t. Baseline reference scenario**




**(c) Expanded case**



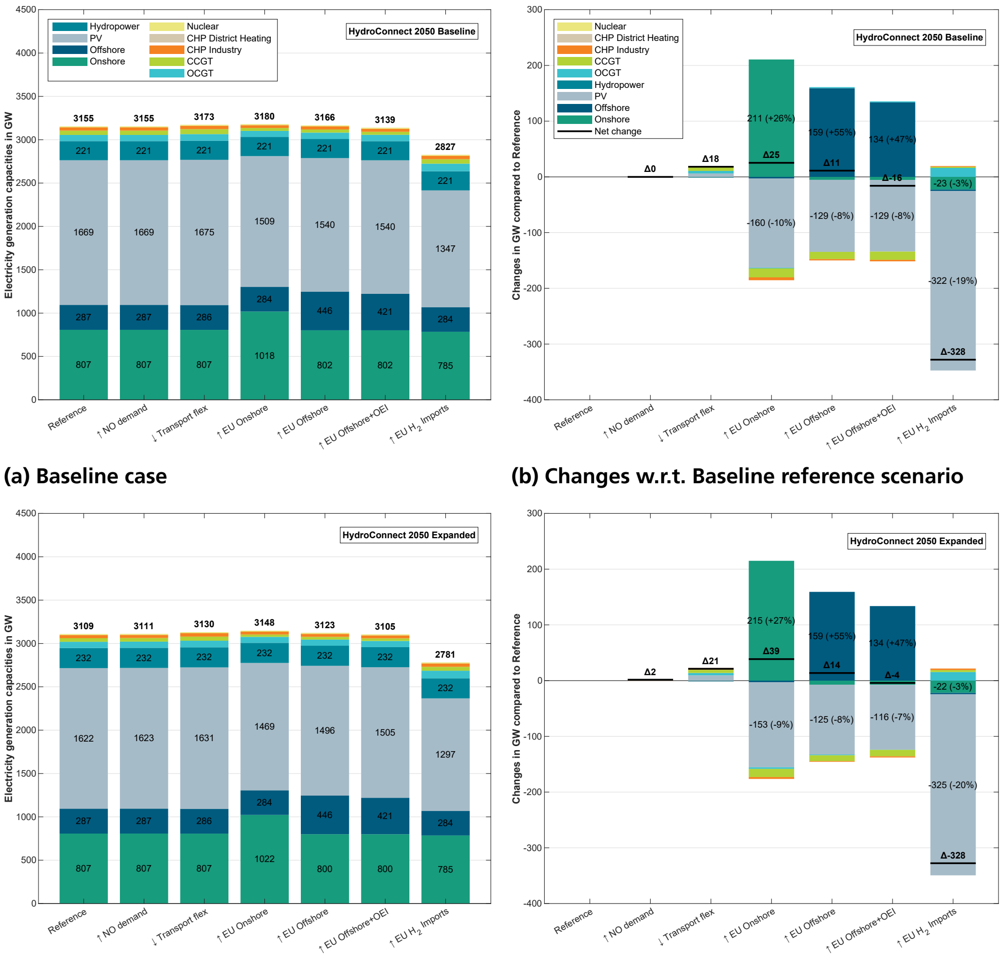

**(d) Changes w.r.t. Expanded reference scenario**

**Figure 9 European power generation balance for HydroConnect's Baseline and Expanded cases, own illustration based on own calculations. Note that other generation, e.g. waste or geothermal, are not included in the figures above.**

As expected for a net-neutral setting, the electricity production primarily comes from renewable power generation sources, including on- and offshore wind, solar PV, and hydropower.

The scenarios with higher wind capacities result in higher wind production volumes. In the scenarios with cheaper hydrogen imports, the electricity balance decreases because less electricity has to be used for domestic hydrogen production. Since there is no endogenous expansion of hydropower systems and due to the limitation of existing natural inflow volumes, an increase in electricity production from hydropower is only possible to a limited extent by better utilisation of storage capacities.
Thermal power plants only play a minor role in the cost-optimised integrated energy system, and the endogenous thermal capacity expansions are, to large extent, new CHP units for district heating and industrial applications. These thermal power plants are mostly required to maintain firm capacity during a few hours of the year when all other flexibility options are exhausted. Recall that due to the requirements of net-neutrality, all OCGT and CCGT units, as well as their CHP versions, are fired by green hydrogen. The electricity produced from remaining nuclear power plants in Europe is assumed to be $CO_2$-neutral.

Besides the European electricity generation balance, it is also worth looking into the capacity expansion decisions for each scenario in Figure 10. Again, for each scenario, the absolute figures in $GW_{el}$ are given in Figure 10a and Figure 10c, while Figure 10b and Figure 10d indicate the absolute and relative changes in the various scenarios compared to the corresponding reference cases.




**(a) Baseline case**

**(b) Changes w.r.t. Baseline reference scenario**

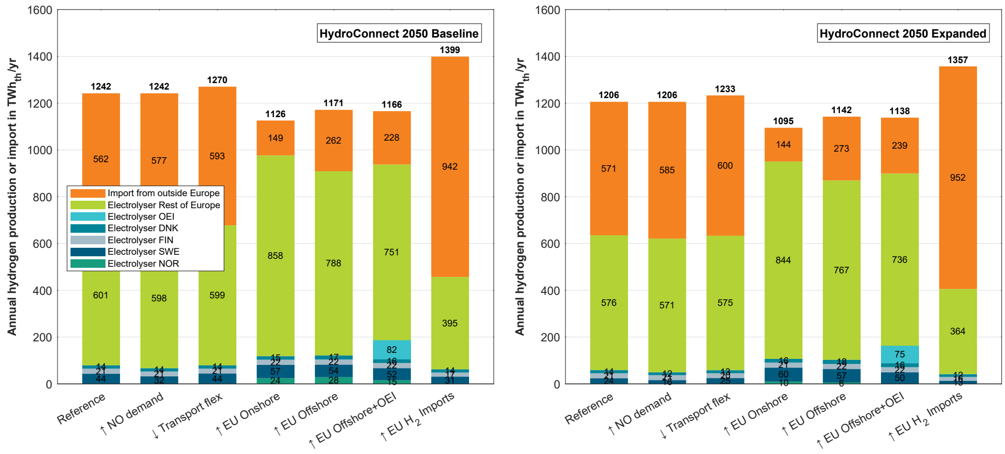
**(c) Expanded case**

**(d) Changes w.r.t. Expanded reference scenario**

**Figure 10 European power generation capacities for HydroConnect's Baseline and Expanded cases, own illustration based on own calculations. Note that other generation, e.g. waste or geothermal, are not included in the figures above.**

While the obtained capacity expansion results generally correspond to the electricity production figures from Figure 9, there are some noteworthy aspects. For the lower hydrogen import price scenario, the largest change in installed capacity corresponds to solar PV installations. The remaining thermal generation stack shows a heterogeneous picture. While CCGT and industry CHP units exhibit increased electricity outputs for a low import price, those increases do not translate into an increased capacity deployment but rather a higher capacity factor. The main reason for this is that the underlying multivalent flexible CHP systems, see e.g. [6], are still essential to supply the heating demands and that the CCGT units remain competitive in some market areas to provide firm capacity. The increase in wind capacity in the corresponding scenarios with more wind power is straight-forward (recall Figure 9).

Pan-European hydrogen demands are shown in Figure 11. The numbers on top of the bars indicate the total demand. It can be covered by imports from outside of Europe or by domestic production via electrolysers.



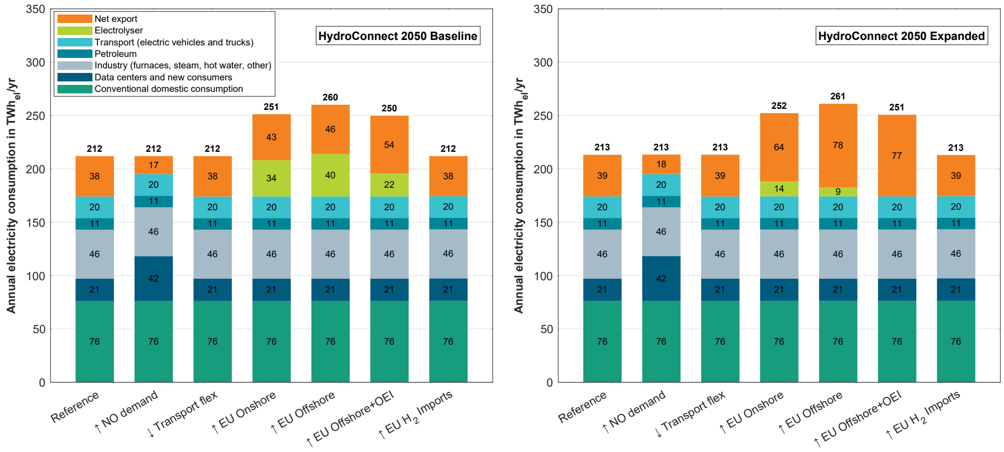

**(a) Baseline case** **(b) Expanded case**

**Figure 11 Pan-European $H_2$ demand for HydroConnect's Baseline and Expanded cases, own illustration based on own calculations.**

The highest hydrogen demands occur with a global hydrogen breakthrough leading to cheap imports and more economically attractive hydrogen solutions to supply various end-use demands. Norway only becomes a hydrogen producer when it builds additional wind capacities. If more wind capacity is built, this reduces the demand for hydrogen since less hydrogen is then needed for electricity production.

## 5.2
## Norwegian energy system

Norway's electricity balance strongly depends on domestic wind expansions and electrolysers. Figure 12 shows Norway's electricity balance for the HydroConnect **Baseline** and **Expanded** cases. The electricity consumption indicates seven categories: *conventional domestic consumption*, *data centres and new consumers*, *industry*, *petroleum*, *transport*, *electrolysers*, and *net export*. Note that the demands of transport and industry, as well as conventional domestic consumption, are assumed to be constant for all considered model runs.

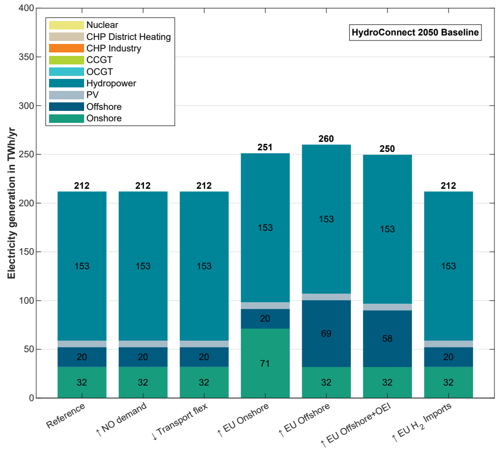



**(a) Baseline case** **(b) Expanded case**

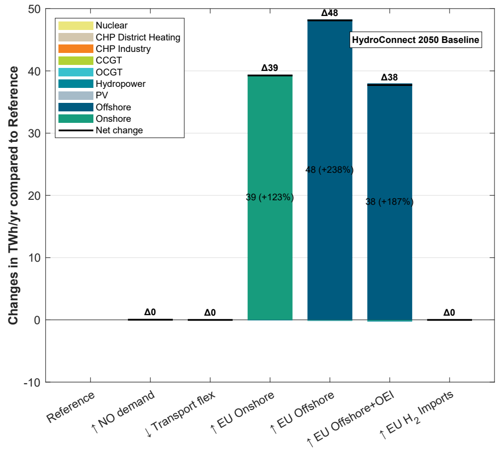
**Figure 12 Norway's electricity consumption for HydroConnect's Baseline and Expanded cases, own illustration based on own calculations. Note that other generation, e.g. waste or geothermal, are not included in the figures above.**

The most considerable changes in Norway's electricity balance result from changes in the cross-border electricity exchange and the expansion of domestic electrolyser capacity for hydrogen production. The scenario with increased electricity consumption shows that a substantial increase in electricity demand for new consumers directly translates into a reduction of net exports from Norway to its power system neighbours.
The scenarios with reduced transport sector flexibility and lower import prices for hydrogen imports do not show significant changes for Norway compared to the reference case. However, the scenarios with more onshore and offshore wind deployments in Norway lead to an expansion of domestic electrolyser capacity. When comparing the **Baseline** and **Expanded** cases, the market clearing outcomes further show that exporting the additional electricity production from domestic wind power plants via interconnector cables is more favourable than producing hydrogen.

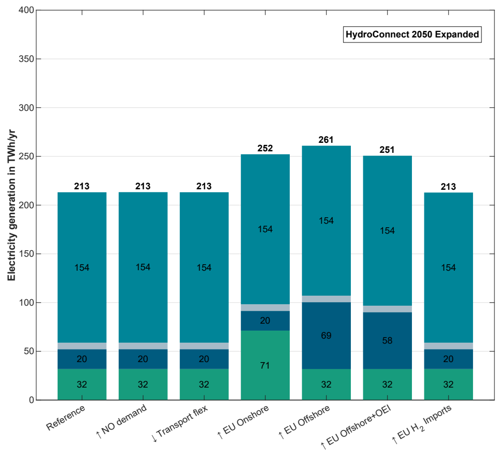
As a subset of the European power generation balance (recall Figure 9), Figure 13 shows the power generation balance in Norway.



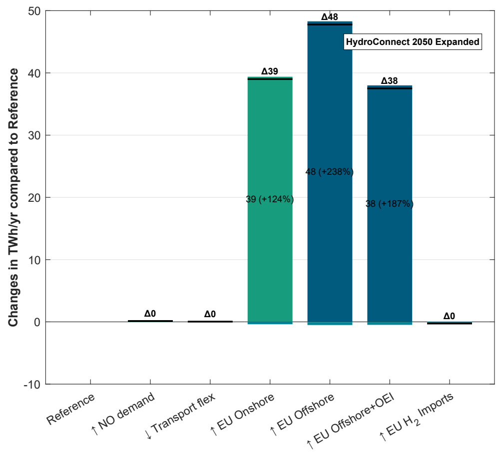

**(a) Baseline case**




**(b) Changes w.r.t. Baseline reference scenario**




**(c) Expanded case**

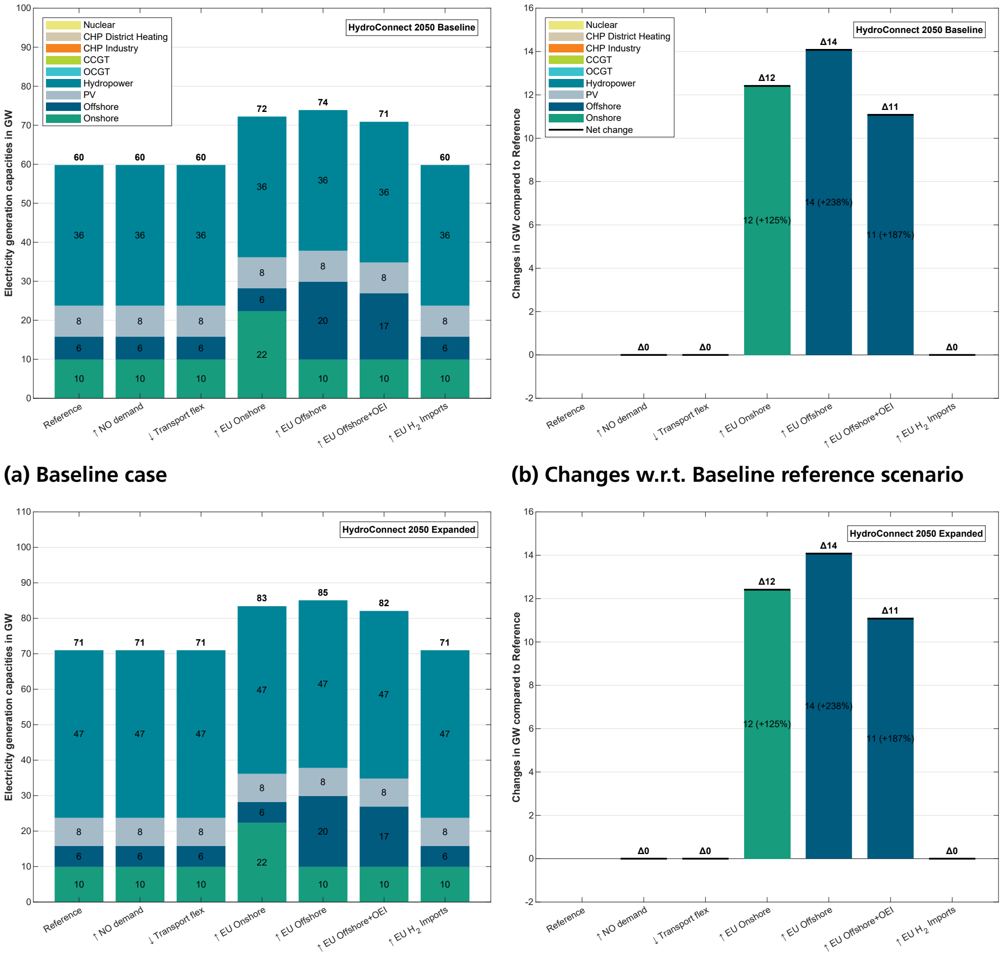



**(d) Changes w.r.t. Expanded reference scenario**

**Figure 13 Norwegian power generation quantities for HydroConnect's Baseline and Expanded cases, own illustration based on own calculations. Note that other generation, e.g. waste or geothermal, are not included in the figures above.**

The total sum of electricity generation aligns with the sum of electricity consumption from Figure 12. As a consequence of the increased wind capacities in the corresponding scenarios, their electricity production also increases. Electricity production from hydropower is only mildly affected in all scenarios due to the aforementioned reasons.

As a subset of the European power generation capacities (recall Figure 10), Figure 14 shows the power generation capacities in Norway. These differ only in the scenarios with more wind capacity and with offshore energy islands according to the assumptions (recall Figure 6).




**(a) Baseline case**

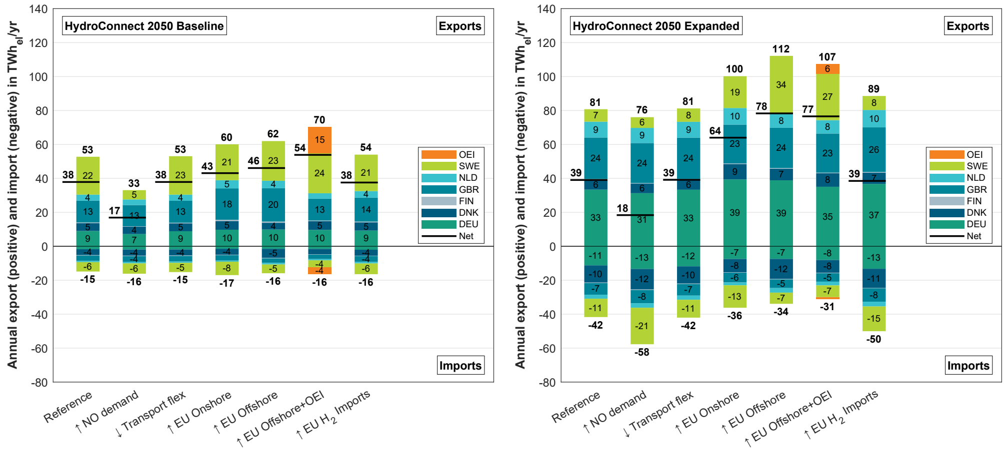
**(b) Changes w.r.t. Baseline reference scenario**

**(c) Expanded case**

**(d) Changes w.r.t. Expanded reference scenario**

**Figure 14 Norwegian power generation capacities for HydroConnect's Baseline and Expanded cases, own illustration based on own calculations.**

Norway continues to be a net exporter of electricity. The import and export balances in Figure 15 show a breakdown of Norway's resulting net exports. Norway has connections to Sweden, the Netherlands, Great Britain, Finland, Denmark, Germany, and the Danish OEI.



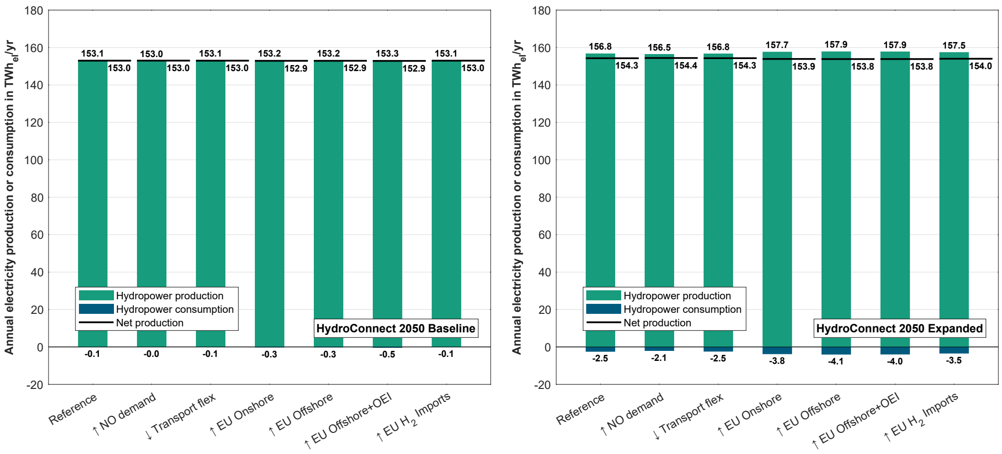

**(a) Baseline case** **(b) Expanded case**

**Figure 15 Norway's import and export balance for HydroConnect's Baseline and Expanded cases, own illustration based on own calculations.**

Ranging from 18 to 78 $TWh_{el}$/yr, net exports are predictably higher for the **Expanded** cases when compared to 17 to 54 $TWh_{el}$/yr in the **Baseline** cases. Moreover, Norway has the most significant net exports when domestic wind power is deployed. The lowest net exports occur if Norway's non-flexible domestic electricity consumption increases. While most electricity is exported to Sweden and Great Britain in the **Baseline** cases, additional interconnector cable capacities in the **Expanded** cases primarily increase exports to and, less so, imports from Germany.

## 5.3 Norwegian hydropower systems

Hydropower production in Norway remains in high demand and at stable levels. Figure 16 shows the respective production and consumption for all considered cases.

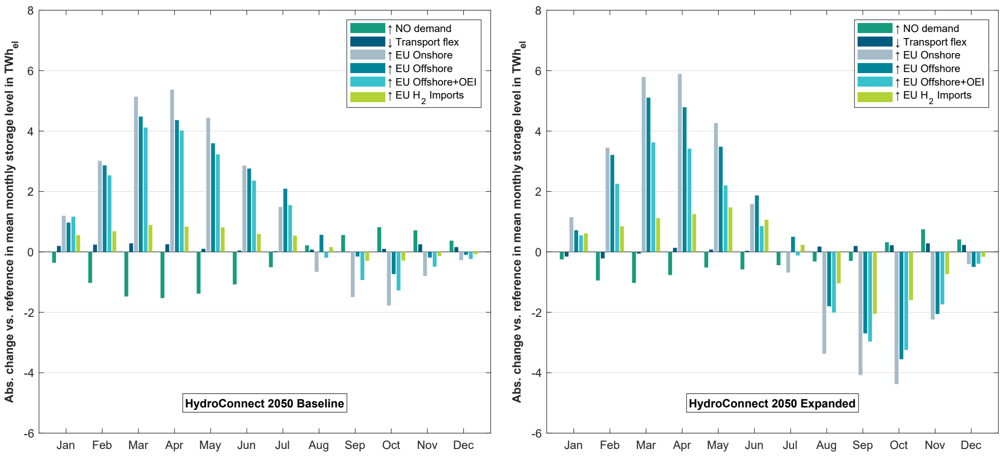



**(a) Baseline case** **(b) Expanded case**

**Figure 16 Norway's hydropower production and consumption for HydroConnect's Baseline and Expanded cases, own illustration based on own calculations.**

The difference in electricity production from hydropower is very small in the **Baseline** cases, with almost no electricity consumption via the pumped storage facilities. However, in the **Expanded** cases, additional pump and turbine units lead to increased hydropower production and consumption, although the net electricity production remains at similar levels when comparing both **scenario streams**. Furthermore, Norwegian hydropower pumping volumes are at their highest levels with more wind power deployments in Norway and other parts of Europe.

The impact on Norway's reservoir filling levels is substantial and depends on the scenario, as can be seen in Figure 17.

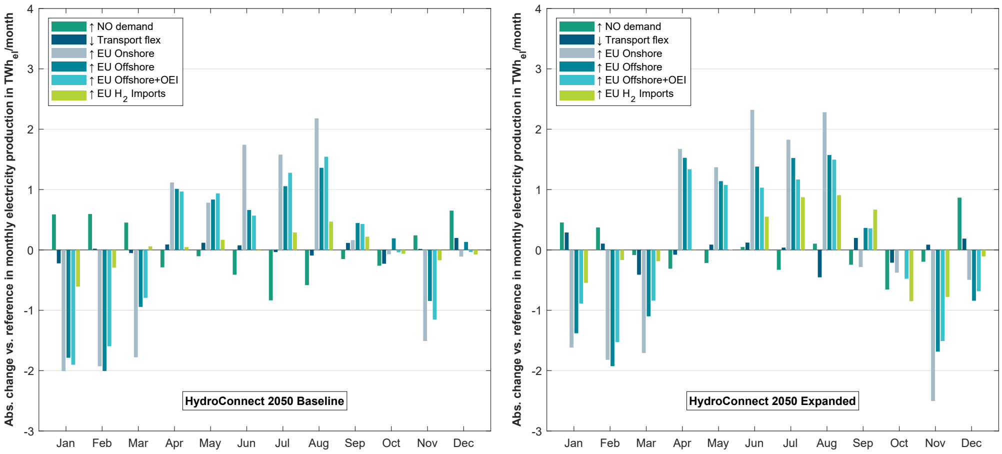



**(a) Baseline case** **(b) Expanded case**

**Figure 17 Norway's hydropower storage level change for HydroConnect's Baseline and Expanded cases, own illustration based on own calculations.**

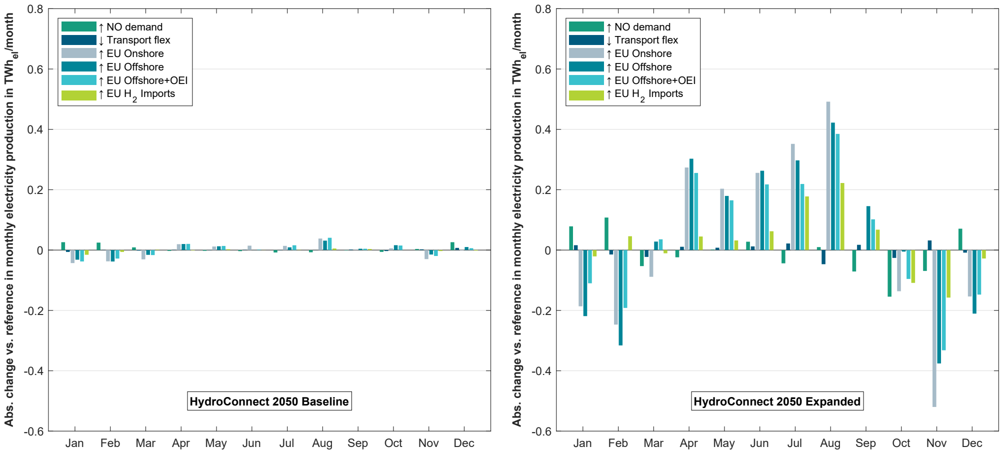
The European scenario impacts the storage level trajectories throughout the considered year. All other things being equal, larger wind power deployments in Norway and Europe lead to higher reservoir filling levels (plus 6 $TWh_{el}$) until summer for both scenario streams. Conversely, the increased Norwegian demand scenario exhibits lower reservoir filling levels. The opposite yet milder effect can be observed for the second half of the year. Lower reservoir filling levels in the year's second half are more pronounced in the **Expanded** cases, which is mainly due to additional pumping and cross-border electricity exchange capacities.

A deeper reasoning is shown by looking at Norway's hydropower turbine production changes (Figure 18), Norway's hydropower pump turbine production changes (Figure 19), and Norway's hydropower pump consumption changes (Figure 20).
Note that, in the **Expanded** cases, there are more differences between the variants due to the additional Norwegian hydropower turbine capacity of 11.2 $GW_{el}$. It should also be noted that there is more pump capacity (5.2 $GW_{el}$) in the **Expanded** cases, which is why more turbines are defined as pump-turbines here.



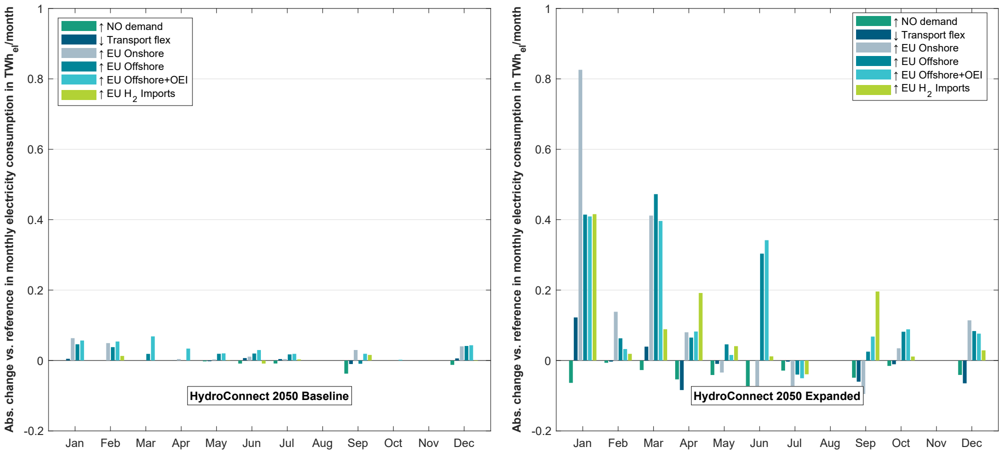

**(a) Baseline case** **(b) Expanded case**

**Figure 18 Norway's hydropower turbine production change for HydroConnect's Baseline and Expanded cases, own illustration based on own calculations.**




**(a) Baseline case** **(b) Expanded case**

**Figure 19 Norway's hydropower pump turbine production change for HydroConnect's Baseline and Expanded cases, own illustration based on own calculations.**



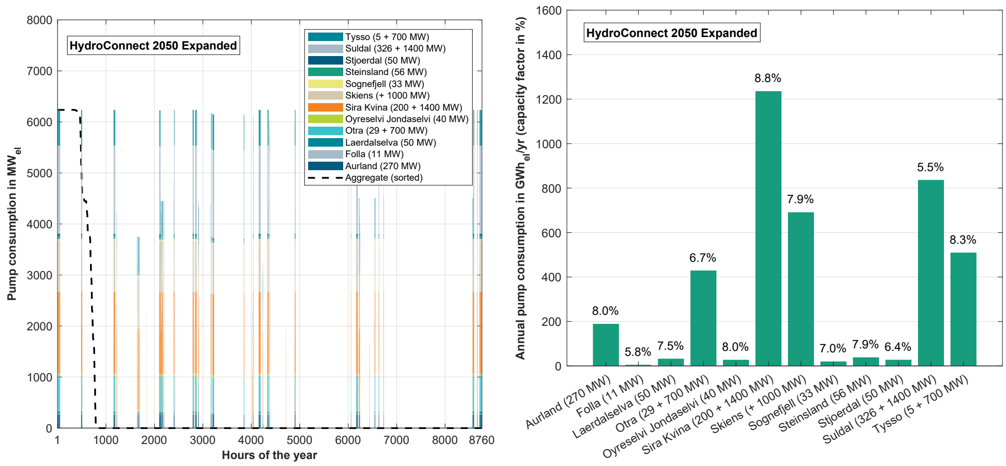

**(a) Baseline case** **(b) Expanded case**

**Figure 20 Norway's hydropower pump consumption change for HydroConnect's Baseline and Expanded cases, own illustration based on own calculations.**

The use of additional pumping capacities in Norway is very low. There are a few reasons and additional aspects explaining this effect: First, a possible factor is spatial aggregation, especially due to congestion situations between Norwegian price zones which are not represented in the model. However, an equivalent of each considered detailed hydropower system in Norway (145) and Sweden (21) is modelled (recall Tables 5 und 6), which is why an (storage) aggregation error in the model is not expected. Second, additional pumping capacities compete with other flexibility sources in Norway and behind interconnectors, i.e. flexible heat pumps, electric vehicle charging, hybrid CHP units, battery storage – but most importantly, also reduced use of conventional hydro storage in Norway (without the pumping losses).

Results

Finally, Figure 21 shows Norway's hydropower pump consumption schedules and annual pump consumption (including capacity factors) for HydroConnect's **Expanded** ↑ EU Offshore+OEI case. They further confirm the observed results by indicating that the additional pumping capacities are used throughout the year, often at full capacity, but only at low capacity factors in total.




**(a) Pump consumption schedule** **(b) Annual pump consumption and utilisation**

**Figure 21 Norway's hydropower pump consumption schedules and annual pump consumption (including capacity factors) for HydroConnect's Expanded Offshore case, own illustration based on own calculations.**

## 5.4
## Offshore energy islands

Figure 22 shows the detailed results for the OEI for each of the two islands in each of the two scenarios. The figures show for what application the electricity production from offshore wind is used and how the electrolysers are operated. Most of the wind power from the Danish EEZ island feeds the offshore electrolysis units while more than a quarter of the wind power from the Doggerbank is exported to the onshore power system. The Doggerbank electrolysers draw their electricity directly from the connected offshore wind farms. By contrast, the electrolysers on the Danish EEZ island also draw on electricity imports from the onshore system.

**Danish EEZ** energy island in the **Baseline** case:

| **Offshore wind is used for …** | | **Electrolyzers are operated by …** | |
|---|---|---|---|
| Electrolyzers | 94,77% | Offshore wind | 63,77% |
| Curtailment | 0,03% | Import from DK | 24,38% |
| Export to DK | 5,21% | Import from NO | 11,86% |
| Export to NO | 0,00% | | |

**Danish EEZ** energy island in the **Expanded** case:

| **Offshore wind is used for …** | | **Electrolyzers are operated by …** | |
|---|---|---|---|
| Electrolyzers | 94,45% | Offshore wind | 71,82% |
| Curtailment | 0,04% | Import from DK | 22,75% |
| Export to DK | 5,51% | Import from NO | 5,43% |
| Export to NO | 0,00% | | |

**Doggerbank** energy island in the **Baseline** case:

| **Offshore wind is used for …** | | **Electrolyzers are operated by …** | |
|---|---|---|---|
| Electrolyzers | 72,01% | Offshore wind | 95,62% |
| Curtailment | 0,01% | Import from GB | 1,59% |
| Export to GB | 14,98% | Import from NL | 2,79% |
| Export to NL | 13,00% | | |

**Doggerbank** energy island in the **Expanded** case:

| **Offshore wind is used for …** | | **Electrolyzers are operated by …** | |
|---|---|---|---|
| Electrolyzers | 72,44% | Offshore wind | 96,07% |
| Curtailment | 0,01% | Import from GB | 1,48% |
| Export to GB | 15,36% | Import from NL | 2,45% |
| Export to NL | 12,18% | | |

**Figure 22 Different characteristics of offshore energy islands, own illustration based on own calculations.**

# 6
# Summary and next steps in the project

Norway's hydropower production and flexibility contribute to a climate-neutral Europe as Norway is a net exporter of electricity. The scenario variants do not demonstrate large changes in the Norwegian power system. Interconnectors and domestic on- and offshore wind expansion potentials and targets determine future energy export volumes, i.e. electricity exports via interconnectors and the attractiveness of hydrogen production. One of the next immediate steps in the HydroConnect project is transferring the result data from the SCOPE SD modelling framework at Fraunhofer IEE to the downstream models at SINTEF and NTNU via the openENTRANCE nomenclature, see Chapter 7. In particular, output data from SCOPE SD will be used to analyse the use of Norwegian hydropower in even greater detail using the FanSi model.
With the established model setup and linkage, it is possible to investigate new sensitivities based on the **Baseline** and **Expanded** reference cases. Given the current political debate, additional sensitivities concerning offshore energy islands or future hydrogen and e-fuel import price uncertainties could be interesting avenues for future research.

# 7
# Transfer of data in the HydroConnect model chain

The following section summarises the relevant data which is passed to SINTEF's power system model FanSi as a result of the modelling runs carried out with SCOPE SD at Fraunhofer IEE (recall Figure 1). The list below distinguishes the categories "Scenario streams", "European scenario variants", "Market areas", "Market area-specific variables", "Time series variables", and "System-wide variables", all of which are combined with each other.

- **Scenario streams**
  2030 Baseline
  2050 Baseline
  2050 Expanded

- **European scenario variants (only 2050)**
  Reference case
  Increased Norwegian demand
  Reduced transport sector flexibility
  Increased EU onshore wind
  High EU offshore scenario
  Offshore energy islands
  Low renewable fuel import price

- **Market areas (i.e. countries)**
  Austria
  Belgium
  Bulgaria
  Switzerland
  Czech Republic
  Germany
  Denmark
  Spain
  Estonia
  Finland
  France
  United Kingdom
  Greece
  Croatia
  Hungary
  Ireland
  Italy
  Lithuania
  Luxembourg
  Latvia
  The Netherlands
  Norway
  Poland
  Portugal
  Romania
  Slovakia
  Slovenia
  Sweden

Transfer of data in the HydroConnect model chain

- **Market area-specific variables**

Efficiency | Gas | Fossil | CCGT | w/ CHP in %
Efficiency | Gas | Fossil | CCGT | w/o CHP in %
Efficiency | Gas | Fossil | OCGT | w/ CHP in %
Efficiency | Gas | Fossil | OCGT | w/o CHP in %
Efficiency | Hydrogen | Electrolyzer in %
Efficiency | Hydrogen | OCGT | w/o CHP in %
Efficiency | Oil | ST | w/o CHP in %
Capacity | Electricity | Coal in GW
Capacity | Electricity | Coal | CCGT | w/o CHP in GW
Capacity | Electricity | Coal | CCGT | w/ CHP in GW
Capacity | Electricity | Coal | OCGT | w/ CHP in GW
Capacity | Electricity | Lignite in GW
Capacity | Electricity | Lignite | CCGT | w/o CHP in GW
Capacity | Electricity | Lignite | CCGT | w/ CHP in GW
Capacity | Electricity | Lignite | OCGT | w/ CHP in GW
Capacity | Electricity | Gas in GW
Capacity | Electricity | Gas | OCGT | w/o CHP in GW
Capacity | Electricity | Gas | CCGT | w/o CHP in GW
Capacity | Electricity | Gas | CCGT | w/ CHP in GW
Capacity | Electricity | Gas | OCGT | w/ CHP in GW
Capacity | Electricity | Nuclear in GW
Capacity | Electricity | Oil in GW
Capacity | Electricity | Oil | CCGT | w/o CHP in GW
Capacity | Electricity | Solar in GW
Capacity | Electricity | Electrolyzer in GW
Capacity | Electricity | Wind in GW
Capacity | Electricity | Wind | Onshore in GW
Capacity | Electricity | Wind | Offshore in GW
Capacity | Electricity | Hydro in GW
Capacity | Electricity | Other in GW
Capacity | Electricity | Biomass in GW
Capacity | Electricity | Geothermal in GW
Secondary Energy | Electricity | Coal in EJ/yr
Secondary Energy | Electricity | Lignite in EJ/yr
Secondary Energy | Electricity | Gas in EJ/yr
Secondary Energy | Electricity | Nuclear in EJ/yr
Secondary Energy | Electricity | Oil in EJ/yr
Secondary Energy | Electricity | Solar in EJ/yr
Secondary Energy | Electricity | Electrolyzer in EJ/yr
Secondary Energy | Electricity | Wind in EJ/yr
Secondary Energy | Electricity | Wind | Onshore in EJ/yr
Secondary Energy | Electricity | Wind | Offshore in EJ/yr
Secondary Energy | Electricity | Hydro in EJ/yr
Secondary Energy | Electricity | HydroPSgen in EJ/yr
Secondary Energy | Electricity | HydroPScon in EJ/yr
Secondary Energy | Electricity | Other in EJ/yr
Secondary Energy | Electricity | Biomass in EJ/yr
Secondary Energy | Electricity | Geothermal in EJ/yr
Final Energy | Electricity | Heat in EJ/yr
Final Energy | Electricity | Transportation in EJ/yr
Final Energy | Electricity | Cooling in EJ/yr
Final Energy | Electricity | Other (excl. Heat, Cooling, Transport) in EJ/yr
Variable Cost | Electricity | Coal in $EUR_{2018}$/MWh
Variable Cost | Electricity | Lignite in $EUR_{2018}$/MWh

Variable Cost | Electricity | Gas in $EUR_{2018}$/MWh
Variable Cost | Electricity | Gas | OCGT in $EUR_{2018}$/MWh
Variable Cost | Electricity | Gas | CCGT in $EUR_{2018}$/MWh
Variable Cost | Electricity | Gas | CCGT | w/ CHP in $EUR_{2018}$/MWh
Variable Cost | Electricity | Gas | OCGT | w/ CHP in $EUR_{2018}$/MWh
Variable Cost | Electricity | Nuclear in $EUR_{2018}$/MWh
Variable Cost | Electricity | Oil in $EUR_{2018}$/MWh
Maximum Discharge | Electricity | Energy Storage System | Lithium-Ion in GW
Maximum Charge | Electricity | Energy Storage System | Lithium-Ion in GW
Maximum Storage | Electricity | Energy Storage System | Lithium-Ion in GWh
Network | Electricity | Maximum Flow in GW
Emissions | $CO_2$ in Mt $CO_2$/yr
Opportunity value | Electricity | Electrolyzer in $EUR_{2018}$/MWh

Transfer of data in the HydroConnect model chain

- **Time series variables**

Active Power | Electricity | Reservoir and Run of River in GWh/h
Active Power | Electricity | Biomass in GWh/h
Active Power | Electricity | Wind | Onshore in GWh/h
Active Power | Electricity | Wind | Offshore in GWh/h
Active Power | Electricity | Solar in GWh/h
Active Power | Electricity | Hydro | Pumped Storage | Turbine in GWh/h
Active Power | Electricity | Energy Storage System in GWh/h
Active Power | Electricity | Net Export in GWh/h
Active Power | Electricity | Wind | Onshore | Curtailment in GWh/h
Active Power | Electricity | Wind | Offshore | Curtailment in GWh/h
Active Power | Electricity | Solar | Curtailment in GWh/h
Active Power | Electricity | Gas | w/o CHP in GWh/h
Active Power | Electricity | Oil | w/o CHP in GWh/h
Active Power | Electricity | Net Import in GWh/h
Active Power | Electricity | Gas | OCGT | w/o CHP in GWh/h
Active Power | Electricity | Load in GWh/h
Active Power | Electricity | Export in GWh/h
Active Power | Electricity | Boiler | Backup | Resistive heater in MWh/h
Active Power | Electricity | Gas | CCGT | w/ CHP | Backup | Heat pump in MWh/h
Active Power | Electricity | Gas | CCGT | w/ CHP | Backup | Resistive heater in MWh/h
Active Power | Electricity | Gas | OCGT | w/ CHP | Backup | Resistive heater in MWh/h
Active Power | Electricity | Heat pump | Backup | Resistive heater in MWh/h
Final Energy | Electricity | Hydro | Pumped Storage | Pump in GWh/h
Final Energy | Electricity | Energy Storage System in GWh/h
Final Energy | Electricity | Electrolyzer in GWh/h
Final Energy | Electricity | BEV in GWh/h
Final Energy | Electricity | PHEV in GWh/h
Final Energy | Electricity | Truck in GWh/h
Final Energy | Electricity | Heat pump in GWh/h
Final Energy | Electricity | Cooling in GWh/h
Final Energy | Electricity | Load Curtailment in GWh/h
Final Energy | Electricity | Load | Controlled in GWh/h
Final Energy | Electricity | Load | Uncontrolled in GWh/h
Final Energy | Transp. | Passenger | Road | Electric | Battery | Controlled in GWh/h
Final Energy | Transp. | Passenger | Road | Electric | Battery | Uncontrolled in GWh/h
Opportunity value | Heat pump | Backup | Resistive heater in $EUR_{2018}$/MWh
Opportunity value | Boiler | Backup | Resistive heater in $EUR_{2018}$/MWh
Opportunity value | Gas | CCGT | w/ CHP | Backup | Heat pump in $EUR_{2018}$/MWh
Opportunity value | Gas | CCGT | w/ CHP | Backup | Resistive heater in $EUR_{2018}$/MWh
Opportunity value | Gas | OCGT | w/ CHP | Backup | Resistive heater in $EUR_{2018}$/MWh

Transfer of data in the HydroConnect model chain

- **System-wide (i.e. European) variables**

  Price | Uranium in $EUR_{2018}/MWh_{th}$ (fuel import)
  Price | Lignite in $EUR_{2018}/MWh_{th}$ (fuel import)
  Price | Hard coal in $EUR_{2018}/MWh_{th}$ (fuel import)
  Price | Oil in $EUR_{2018}/MWh_{th}$ (fuel import)
  Price | Natural gas in $EUR_{2018}/MWh_{th}$ (fuel import)
  Price | Hydrogen in $EUR_{2018}/MWh_{th}$ (endogenous result, trade-off between endogenous domestic production decisions and fuel import)

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