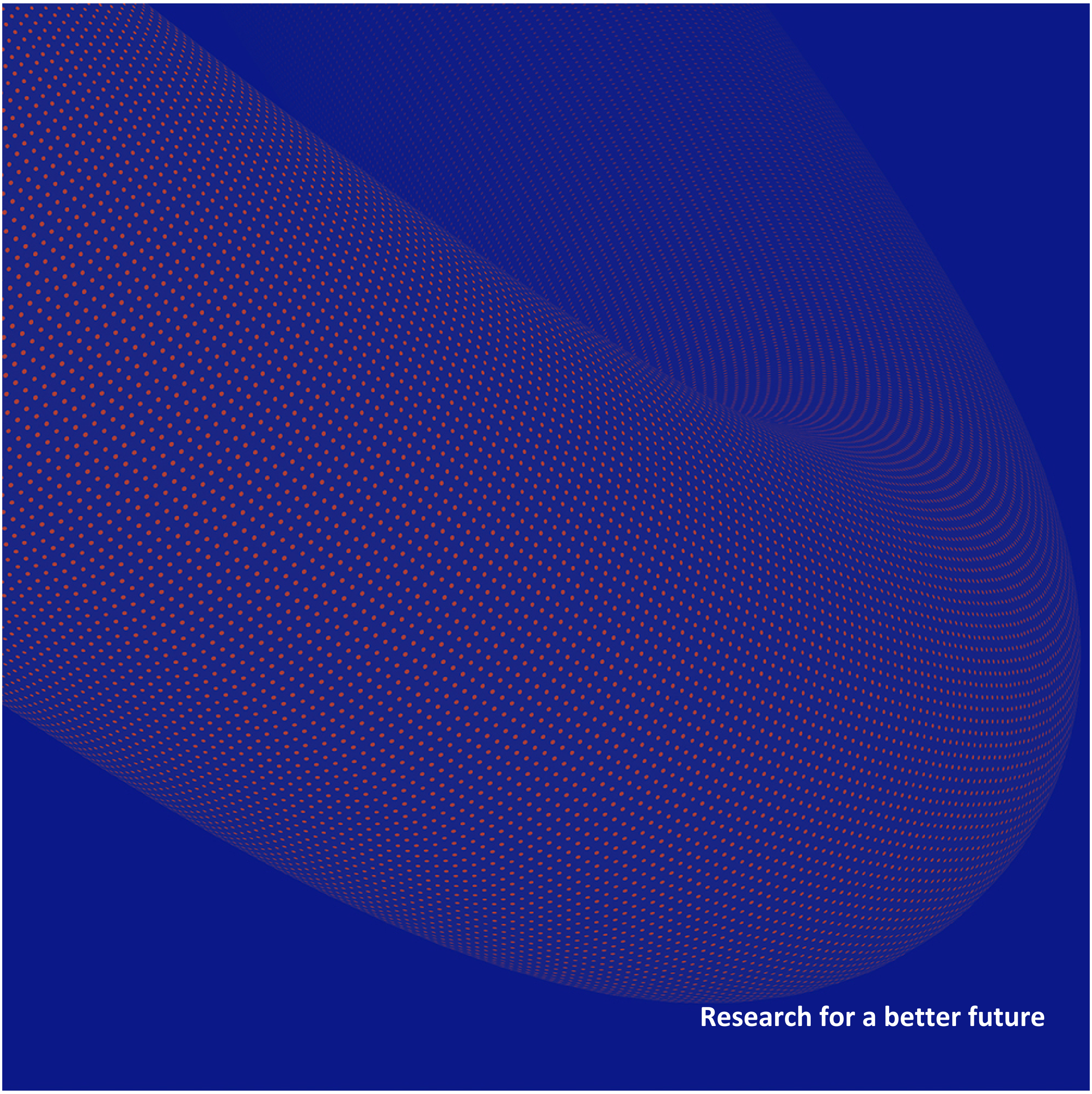
Documentation of IFE-TIMES-Norway v2

IFE/E-2021/005



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Summary:

The development of the energy system model IFE-TIMES-Norway started in 2017 in cooperation with Norwegian Water Resources and Energy Directorate (NVE). This report describes the model version 2 from November 2021, with several updates made throughout the model since previous model documentation (2020). The model is based on earlier versions of TIMES-Norway (2009) and MARKAL-Norway (1992). The model development is dynamic with continuously methodological developments.

IFE-TIMES-Norway is a long-term optimisation model of the Norwegian energy system that is generated by TIMES (The Integrated MARKAL-EFOM System) modelling framework. TIMES is a bottom-up framework that provides a detailed techno-economic description of resources, energy carriers, conversion technologies and energy demand. TIMES models provide investments and operational decisions that minimize the total discounted cost of a given energy system that meets the future demand for energy services. The total energy system cost includes investment costs in both supply and demand technologies, operation and maintenance costs, and income from electricity export to and costs of electricity import from countries outside Norway.

IFE-TIMES-Norway is a technology-rich model of the Norwegian energy system that is divided into five regions that corresponds to the current spot price areas of the electricity market. The model provides operational and investment decisions from the starting year, 2018, towards 2050, with model periods for every fifth year from 2020 within this model horizon. To capture operational variations in energy generation and end-use, each model period is split into 96 sub-annual time slices, where four seasons is represented by 24 hours each. The model has a detailed description of end-use of energy, and the demand for energy services is divided into numerous end-use categories within industry, buildings and transport.

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Contents

1 Introduction

IFE-TIMES-Norway is a long-term optimisation model of the Norwegian energy system that is generated by TIMES (The Integrated MARKAL-EFOM System) modelling framework in the VEDA interface. The Norwegian energy system model, TIMES-Norway, was developed in cooperation between the Norwegian Water Resources and Energy Directorate (NVE) and Institute or Energy Technology (IFE), starting in 2017, with a continuous development through several projects. This model development was based on restructuring and updates of earlier versions of TIMES-Norway that was deployed in another interface, the Answer interface. The first version of TIMES-Norway was available in 2009 which was built on the MARKAL-Norway (MARKAL is the predecessor of TIMES) model, that was developed from 1990. NVE and IFE has further developed the IFE-TIMES-Norway model into two different directions due to different modelling needs, and the model version of IFE is denoted IFE-TIMES-Norway.

The TIMES modelling framework is developed within the ETSAP (the Energy Technology Systems Analysis Program) IEA implementing agreement during several decades [1] and has a modular approach using the modelling language General Algebraic Modelling System (GAMS). GAMS translate a TIMES database into the Linear Programming (LP) matrix. This LP is submitted to an optimizer and result files are generated. Two different user faces are possible, Answer and VEDA [2]. IFE-TIMES-Norway applies the VEDA user interface, that is developed and maintained by KanOrs [3].

TIMES is a bottom-up framework that provides a detailed techno-economic description of resources, energy carriers, conversion technologies and energy demand. TIMES models minimize the total discounted cost of a given energy system to meet the demand for energy services for the regions over the period analysed at a least cost. The total energy system cost includes investment costs in both supply and demand technologies, operation and maintenance costs, and income from electricity export to and costs of electricity import from countries outside Norway [4-6].

IFE-TIMES-Norway is a technology-rich model of the Norwegian energy system divided into five regions corresponding to the current electricity market spot price areas. The model provides operational and investment decisions from the starting year, 2018, towards 2050, with model periods for every fifth year from 2020 within this model horizon. To capture operational variations in energy generation and end-use, each model period is divided into 96 sub-annual time slices, where four seasons is represented by a day of 24 hours.

The model has a detailed description of end-use of energy, and the demand for energy services is divided into numerous end-use categories within industry, buildings and transport. Note that energy services refer to the services provided by consuming a fuel and not the fuel consumption itself. For example, the heating demand in buildings is an energy service while the fuel used to heat the building is not. Each energy service demand category can be met by existing and new technologies using different energy carriers such as electricity, bio energy, district heating, hydrogen and fossil fuels. Other input data include fuel prices; electricity prices in countries with transmission capacity to Norway; renewable resources; and technology characteristics such as costs, efficiencies, and lifetime and learning curves.

This report describes the status of IFE-TIMES-Norway by December 2021 and is an update of the report of 2020 [7]. It is written for modellers used to the TIMES vocabular and the objective is to describe and document the content of the model in the present status. The focus of the recent model development in 2021 has been on road transport and buildings, thus this part is more detailed described than other parts of the documentation. A schematic view of general TIMES inputs and outputs is presented in Figure 1. How this is applied to IFE-TIMES-Norway is presented in Figure 2.

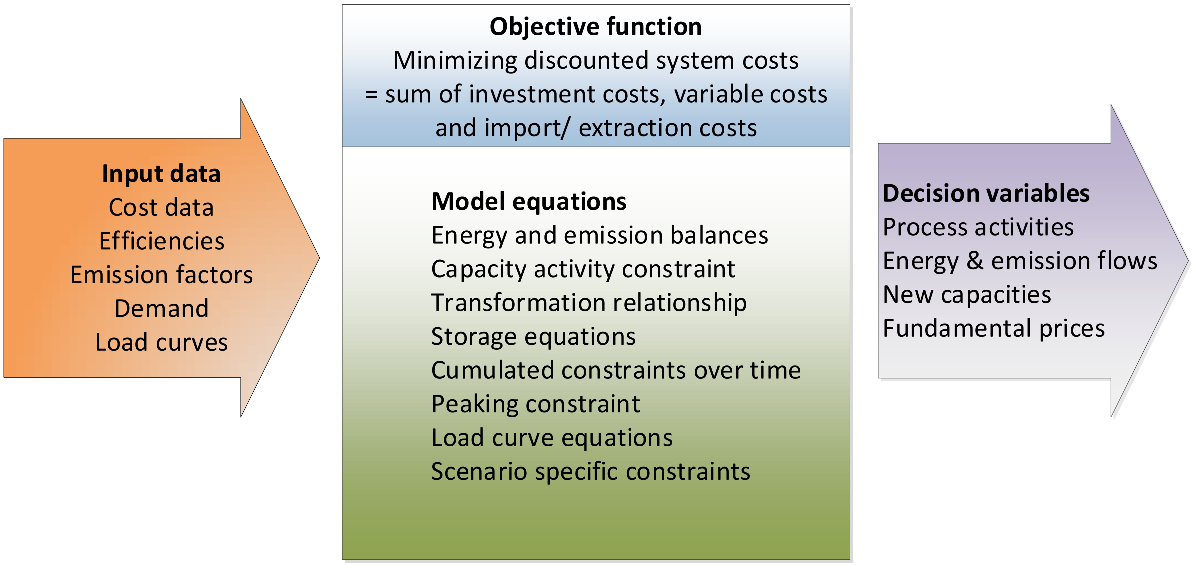

Figure 1 Schematic of TIMES inputs and outputs

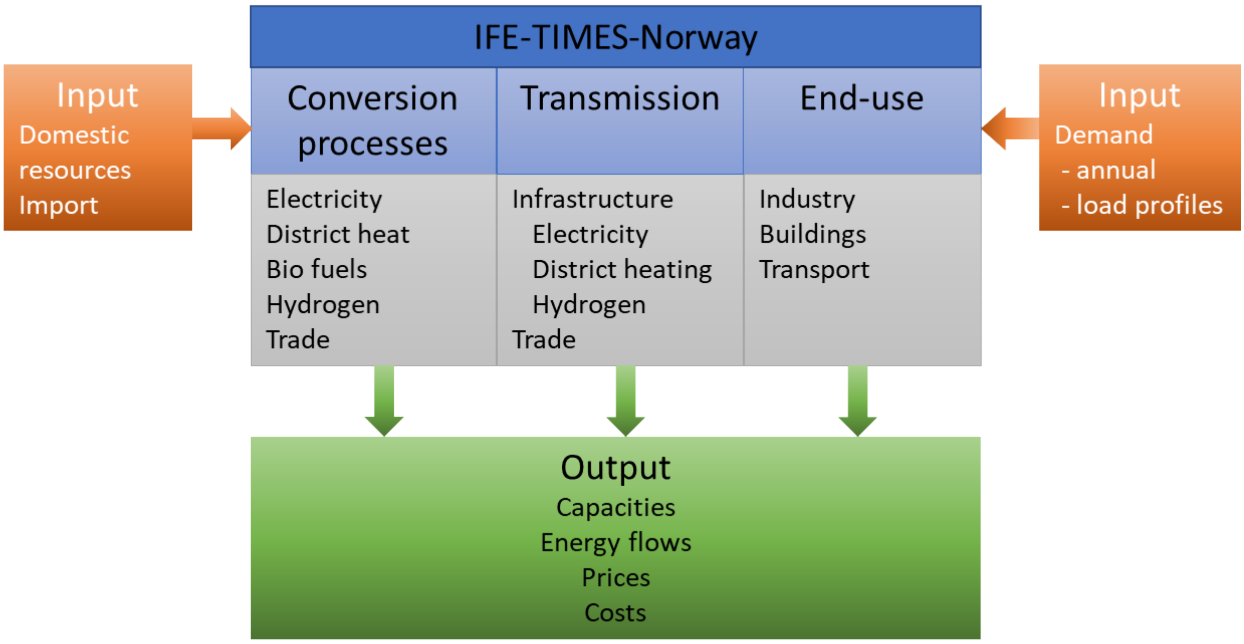

Figure 2 Schematic of IFE-TIMES-Norway

2 Model structure

The model input and design are structured in several excel files where each of these files are described in the following chapters. An overview of the main content of these files are presented in Figure 5

Model files	***Content***
SysSettings	Starting year, time periods, time slices, discount rate, units etc.
Power, DistHeating	Production technologies Production potentials/restrictions
Trade	Trade links & parameters (existing and new)
Fuels	Fuels definitions, prices, potentials (biomass, waste, waste heat) Technology specific delivery costs Hydrogen & bioenergy production technologies CO2 emissions
Industry, Buildings, Transport	Annual demand Demand technologies incl. potentials/limitations
Scen_Base_Profiles	TimeSlice profiles of demand & resources
Scen_Base_Assumptions	Norwegian biomass balance, electricity fee, electricity trade prices
SubRES_CCS	New technologies in different SubRES files
Scen_CO2_constraint Scen_Taxes	Different scenario files

Figure 5.

The overall model characteristics such as base year, time periods, regions, time-slices, discount rate (incl. year for discounting), units etc, is defined in the SysSettings file. The present data used are:

- Regions: NO1, NO2, NO3, NO4, NO5 (the five Norwegian electricity spot price regions), see Figure 3
- Start year 2018
- Times slices (see Figure 4)
  - 4 Seasons (Fall, Spring, Summer, Winter)
  - 24 hours per day (DayNite: 01, 02, 03,…., 24)
- Discount rate: 4%
- Discount year: 2018
- Currency: kNOK2016
- Activity unit: GWh
- Capacity unit: MW
- Commodity unit: GWh

Figure 3 Regions included in IFE-TIMES-Norway, NO1 to NO5

The currency of the model is kNOK2016 since that was the available data when the model was first developed. When adding new technologies, often more recent currencies are used, without recalculating to NOK2016. The reason for this is both that the difference in consumer price index is low (1.8% from 2016 to 2018) and that many data are rough estimates with much higher uncertainty than the change in KPI.

The modelling horizon is easily changed in the analyses. A usual set of modelling periods is presented in Figure 4, consisting of 5 year-periods after the initial two periods of 2018 and 2020. The times slice level can also be changed, but it requires more work, since different load profiles must be changed as well. The length of the four seasons is the same: 25% of a year. Spring is defined as March – May, Summer is June – August, Fall is September – November and Winter is December – February. The total number of annual time slices is 4 * 24 = 96.

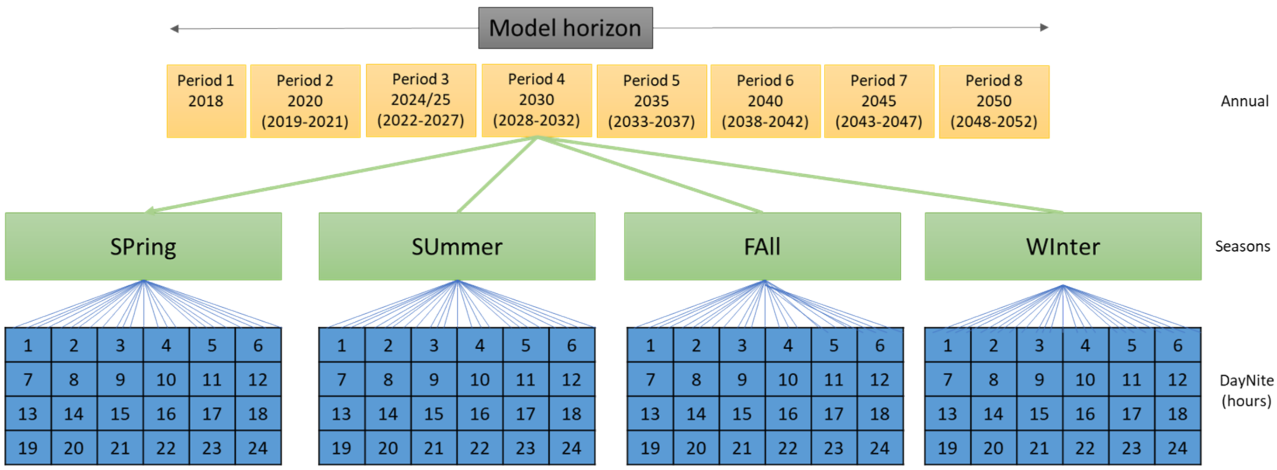

Figure 4 Time slice tree of IFE-TIMES-Norway (base version)

An overview of the different files included in IFE-TIMES-Norway is presented in Figure 5

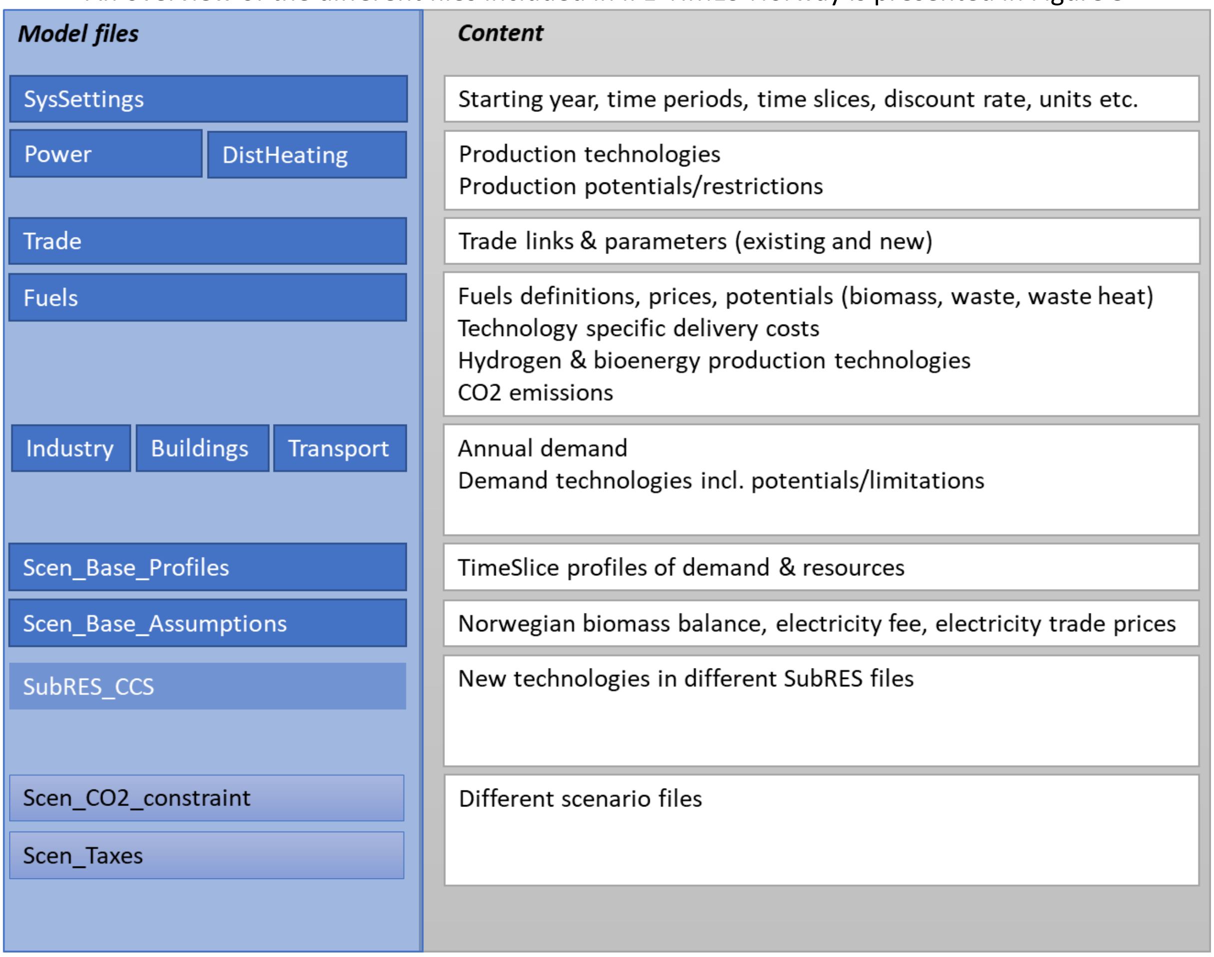

Figure 5. The model consists of six basic files representing the end-use sectors buildings, industry and transportation and the energy sectors power and district heating. In addition, all fuels are defined in “Fuels”. The power file includes hydro, wind and PV, while CHP is included in the DistHeating-file. No gas power or other thermal power plants are included.

Different scenario files are developed, and they are typically project specific and not further described here. SubRES files can only include new technologies, not included in base year templates. In IFE-TIMES-Norway, CCS and VVB (flexible hot water tank in buildings) is included as SubRES files. Electricity trade parameters are defined in the Trade-files.

Profiles are collected in the scenario file "Base profiles". This file includes profiles of demand, hydro power inflow, wind power, EV charging, heat pump efficiencies and solar capacity factors.

Assumptions often used in analyses are gathered in the scenario file "Base assumptions". This file includes energy taxes, CO_2-price, subsidies for EV, minimum requirement of zero emission trucks (EU), growth constraint for new vehicles, electricity trade prices and biomass balance. This is described in more detail in the sector chapters.

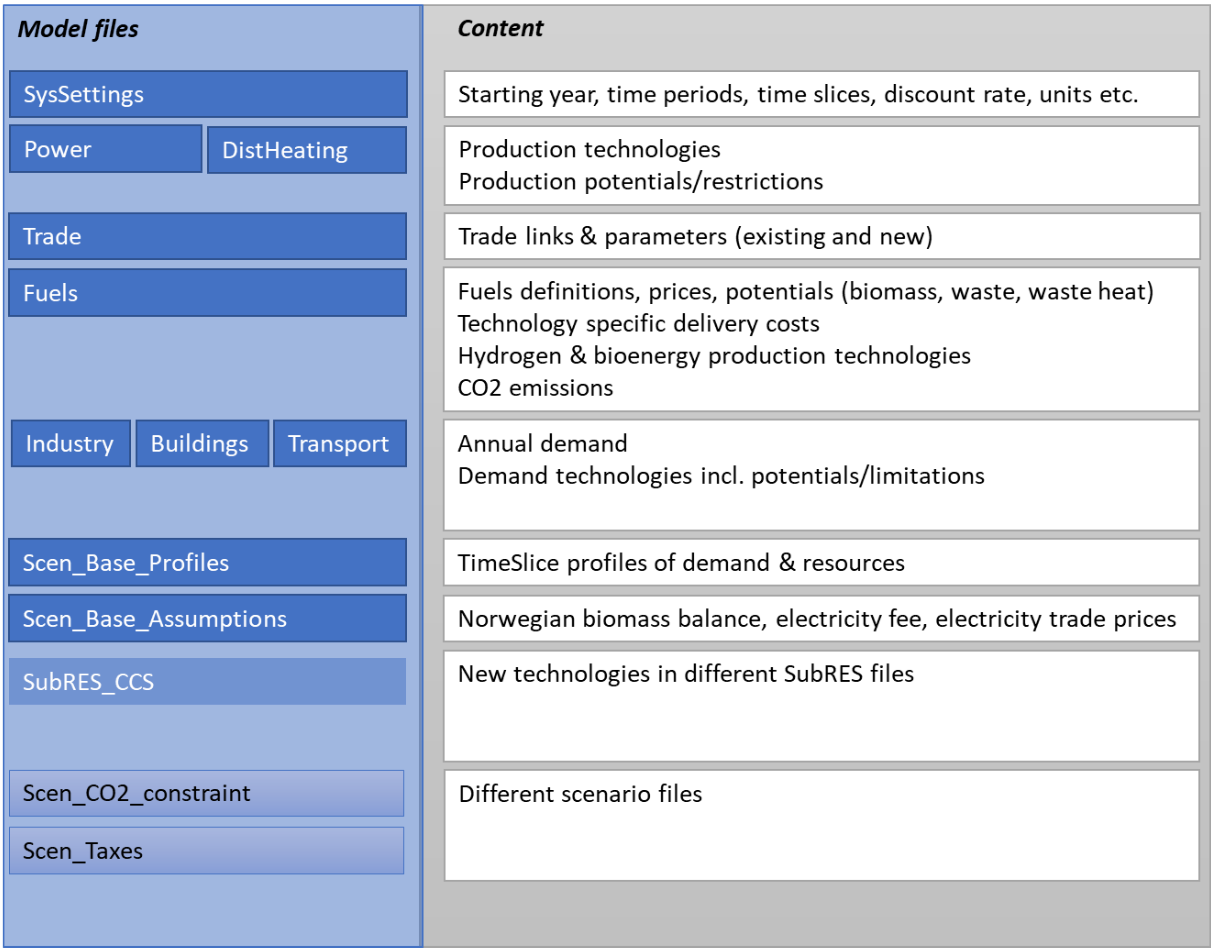

Figure 5 Overview of model files and main content

In the following, the model is described based on the functionality and the chapter headings are not always equal to the content of the files of the model. One example is the profiles that are described together with the technology and not in a separate chapter of Base_Profiles.

The investment costs in IFE-TIMES-Norway are aiming to include the entire cost of installation, including costs for land and the necessary land and infrastructure preparation costs. However, not always all the costs are possible to identify. For investments which needs considerable construction time, also costs of capital in form of interest cost during construction time are included.

The TIMES modelling framework can either be deterministic or stochastic, where the stochastic modelling approach can both consider short-term and long-term uncertainty [8]. IFE-TIMES-Norway is currently in several projects using stochastic programming to consider the short-term uncertainty of e.g. weather-dependent renewable electricity supply and heat demand. As illustrated in e.g. [9-12], a two-stage stochastic model can be used to provide investment decisions that explicitly value flexibility by considering a set of operational situations that can occur, due to the short-term uncertainty of weather-dependent supply and demand. The stochastic modelling approach is however not the focus of this version of model documentation, and the illustrated model results are based on a deterministic modelling approach.

3 Energy carriers

The main rule is that electricity commodities are defined in the power file, commodities in district heating in the DistHeating file and most other commodities in the fuels file. Internal commodities such as heating commodities and local PV production are included in the end-use files (Buildings or Industry).

The commodities produced in IFE-TIMES-Norway are electricity, district heat, hydrogen and some bio energy products. The power file includes electricity generation and is described in the power chapter of this report. Production of district heat is included in the file DistHeating and is described in the district heating chapter of this report.

Bio energy is used across all sectors and the production of some bio energy products is included in the fuels file.

Hydrogen is used in the transport and industry sectors and is included in the fuels file. The modelling of hydrogen is further described in the next chapter.

The electricity commodities are:

- ELC-HV (high voltage)
- ELC-LV (low voltage)
- ELC-REG (electricity from regulated hydropower)
- ELC-RUN (electricity from run-of-river)
- ELC-WIND (electricity from wind power)
- ELC-PV-RES (electricity from solar power in residential building)
- ELC-PV-COM (electricity from solar power in commercial buildings)
- ELC-CAR (electricity for battery powered cars, after charger, defined in transport file)
- ELC-VAN (electricity for battery powered vans, after charger, defined in transport file)
- ELC-HD (electricity for battery powered trucks, after charger, defined in transport file)

Electricity produced locally in residential buildings can only be used in the residential sector or sold to the low voltage grid. Similarly, electricity produced locally in non-residential buildings can only be used in the non-residential sector or sold to the low voltage grid.

The grid losses in the high voltage grid are assumed to be 2% and in the low voltage grid 7% and this is defined in the power file. A grid fee is added to the low voltage grid. Based on the average grid fee for households in the period 2012-2019, 273 NOK/MWh is used in the base case (constant in all project periods) [13]. The grid fees are included in the file “Power”. Electricity tax and VAT is defined in the file “Base_Assumptions”.

The grid fee for electricity produced by PV has been estimated based on discussions with NVE in 2020 concerning future structure of grid tariffs. It is assumed that the firm part of the grid fee will be ca. 80% and that local produced electricity must pay this fee. Due to less distribution losses, ca. 20% of the grid fee is deducted. Not all electricity produced by PV can be used by the producer, but a part will be transformed to the grid and used by other consumers. This part will have the same costs as other electricity. This cost is added as a seasonal flow cost, based on the assumptions in Table 1.

Table 1 Own consumption of electricity produced by PV

	Residential	Commercial
Winter	100%	100%
Spring	96%	100%
Summer	47%	47%
Fall	69%	100%

The district heating commodities are:

- LTH-DH1-GRID (district heat from large scale plants to grid)
- LTH-DH2-GRID (district heat from small scale plants to grid)
- LTH-GRID1-EX (district heat from large scale grid to heat exchanger in end-use sector)
- LTH-GRID2-EX (district heat from small scale grid to heat exchanger in end-use sector)

Commodities defined in the fuels file is presented in Table 2 with energy prices for those commodities being an exogenous input to IFE-TIMES-Norway (not produced in the model). Some products can both be produced in Norway and imported, such as biofuels and hydrogen. The prices in Table 2 present the exogenous price to the model in those cases. Emissions are connected to the use of fuel commodities and are included in the fuels file. The values used are presented in Table 3. In the base case, the energy prices are kept constant, while different price developments are defined in scenario files.

Prices of fossil fuels are divided in "production cost", CO2-tax and other taxes to facilitate analysis of different taxes. The "production cost" is defined in the Fuels-file of IFE-TIMES-Norway, and taxes are defined in the scenario file "Base_Assumptions". The taxes are based on rates of 2021 [14] and most of the energy production cost is based on Klimakur 2030 [15].

A general VAT of 25% is added to all costs in the residential sector. Investment costs in the residential sector is with VAT included. VAT of energy carriers is added as a flow delivery cost in the scenario file "Base_Assumptions". The flow delivery cost also includes a higher delivery cost due to smaller quantities of chips and pellets in the residential sector and in the commercial sector compared to industry. Electricity fee is added as a flow delivery cost in "Taxes". The fee is 0.546 øre/kWh in industry, 16.7 øre/kWh in commercial and 45.3 øre/kWh in residential (incl. VAT), based on Norwegian taxes 2021.

Table 2 Definitions of fuel commodities and prices in 2020, without VAT

Output Commodity		Cost (NOK/MWh)	CO2 taxes (NOK/MWh)	Other taxes (NOK/MWh)	Comments/references
BIO-COAL	Biocoal	1082		-	assumption
BIO-FOR	Biomass-forest	139		-	Statistics Norway
BIO-FUEL	Biomass-based fuel in transport	1234		407	Klimakur 2030; other taxes = "veibruksavgift"
BIO-GAS1	Biogas, cost class I	1000		-	estimated from Clean Carbon report 2019
BIO-GAS2	Biogas, cost class II	2000		-	estimated from Clean Carbon report 2019
BIO-WASTE	Biomass - residues	100		-	Assumption, cheaper than forest
BIO-WOOD	Biomass – wood	50			"selvhogst"
COAL	Coal and coal products (fossil)	273		0	Statistics Norway, industry coal 2019
FOS	Fossil fuel in transport (based on diesel)	675	157	356	Klimakur 2030; other taxes = "veibruksavgift"
GAS	Gas (based on LPG)	343	138	0	Klimakur 2030
IMP-H2	"Imported" Hydrogen produced by SMR with CCS	1000		-	Assumption, blue hydrogen trade price
LNG	Liquid natural gas for maritime	442	119	173	Klimakur 2030; other taxes = grunnavgift min.olje
MGO	Marine gas oil	440	157	173	Klimakur 2030; other taxes = grunnavgift min.olje
OIL	Oil (based on light distillate)	513	157	173	Light fuel oil without VAT; other taxes = grunnavgift min.olje
WASTE	Municipal waste	-273			NVE
WASTE-HEAT	Waste heat from industrial processes	1		1	

Table 3 Emission factors (ton CO2/MWh)

	FOS	OIL	COAL	GAS	WASTE	MGO	LNG
Emissions, t CO2/MWh	0.266	0.266	0.239	0.24	0.173	0.27	0.20

4 Conversion processes and transmission

4.1 Electricity

4.1.1 Hydropower

Hydropower is divided in reservoir and run-of-river technologies and has both existing plants and possibilities for investments in new capacity. Data and development of future potential for hydro power generation is based on information from NVE and is further described below. Table 4 summarizes the generation of existing and new hydropower plants.

Table 4 Hydropower generation in a normal year, TWh/year

	Total generation in existing plants in a normal year(TWh)	Additional generation (TWh)
Mean generation 1981-2010	135.6	
+ new generation 2017-2020	137.7	2.1
+ increased precipitation today	141.2	3.5
+ increased precipitation in 2040	144.0	2.8
+ under construction 2020-2025	146.8	2.8
New potential		
- Without increased precipitation	156.7	16.2
- With increased precipitation	163.4	6.6+16.2

The existing capacities and generation in a normal year is based on information from NVE in May 2020, and NVEs «Langsiktig kraftmarkedsanalyse 2019-2040» [16]. The normal annual hydropower generation in 2019 is 141 TWh. It is based on mean production in 1981-2010, including increased generation of 3.5 TWh today resulting from increased precipitation (included in 141 TWh).The generation in existing hydropower plants is assumed to increase further by 2.8 TWh (total 6.3 TWh) up to 2040, due to increased precipitation (from today until 2040), see [17].

A total of 2.8 TWh are under construction in the period 2020-2025. The distribution of new capacity per region and reservoir/run-of-river is based on data from NVE. Investments in new hydropower plants that are under construction per March 2020 are included in existing hydropower, based on [18]. In total, this results in 147 TWh hydropower production in 2040 by existing plants (including those under construction in 2020).

The potential for new investments in hydropower is based on information from NVE in March 2018 and is updated with investments in new projects in 2018-2020. In total, existing plants and potential new plants could result in 156.7 TWh, excl. increased precipitation. With increased precipitation of 6.3 TWh in 2040, the total hydropower production can be up to 163 TWh.

The new hydropower plants are divided in two technologies for reservoir power and three for run-of-river. The investment costs are based on LCOE of 0.5-2 NOK/kWh and the potential for the five technologies is added to the model as an activity bound per region.

The operating hours is included in the model as availability per season for reservoir technologies and an annual availability in combination of a share per time slice for run-of-river plants.

For new reservoir plants, the operating hours is reduced since new plants seem to increase the capacity more than the generation. The calculation of availability per season for new reservoir plants, is based on the Lysebotn project [19], where the capacity increased by 75% and the generation by 15%, resulting in an average availability of 65.7% of the original.

4.1.1.1 Model input based on EMPS simulations

We have calibrated the operational hydropower input data by using simulations by the EMPS power market model [20] that is provided by Sintef Energy. The simulations provided includes weekly weather-year data from 2000 to 2015 on unregulated inflow (GWh) and Norwegian hydropower generation (GWh), for each spot-price region.

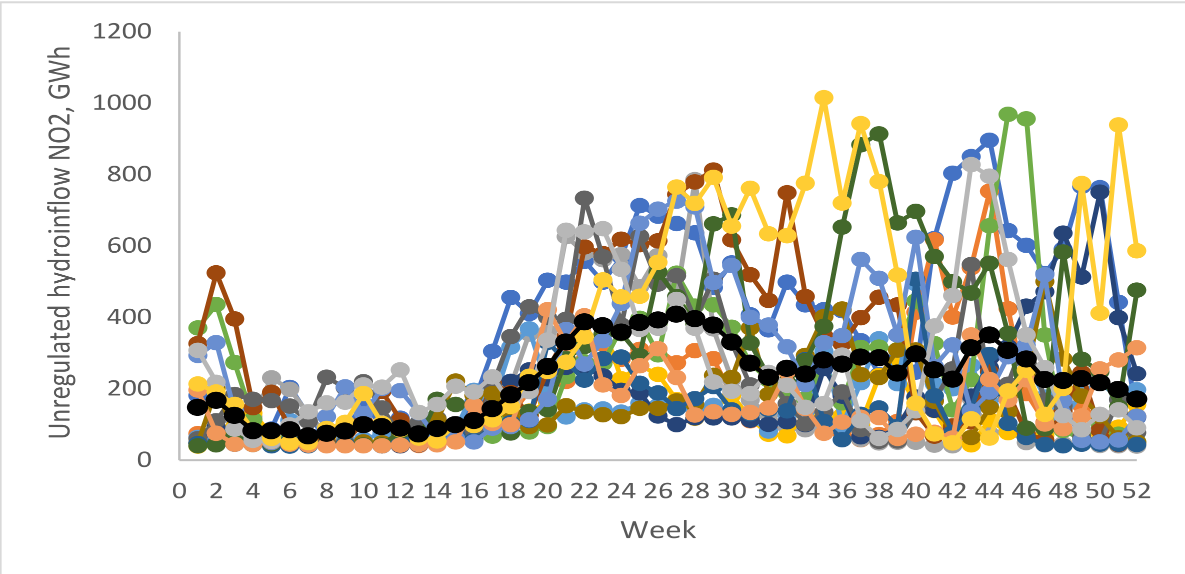

Figure 6 Illustration of unregulated hydro inflow in NO2 for weather years from 2000-2015, where the black line is the average.

First, we assume that the unregulated hydro inflow characteristics, as demonstrated in Figure 6, corresponds to the weekly hydropower generation of the run-of the river plants in IFE-TIMES-Norway. We have used the unregulated hydro inflow data to map how the unregulated hydropower generation is distributed within the four modelled seasons and to capture the annual variations in the power generation.

In the deterministic model version, weather-dependent operational hours are not considered in the run-of the river hydropower generation. However, unregulated hydro inflow has been used to map how the run-of-generation is distributed throughout the four seasons. The corresponding results and model input are shown in Table 5, and is based on an average of the simulated weather years.

Table 5 Model input on seasonal generation distribution of run-of the river plants in the five spot-price regions

	NO1	NO2	NO3	NO4	NO5
Winter	0.10	0.15	0.20	0.07	0.09
Spring	0.18	0.17	0.17	0.09	0.11
Summer	0.42	0.38	0.31	0.48	0.47
Fall	0.30	0.30	0.33	0.36	0.34
Total	1.00	1.00	1.00	1.00	1.00

For the stochastic model version, we however assume that the seasonal distribution and the annual operational hours are weather dependent. The stochastic scenarios, that are designed to capture this weather dependencies, take into account the seasonal generation for all weather years, that is illustrated for NO2 in Figure 7.

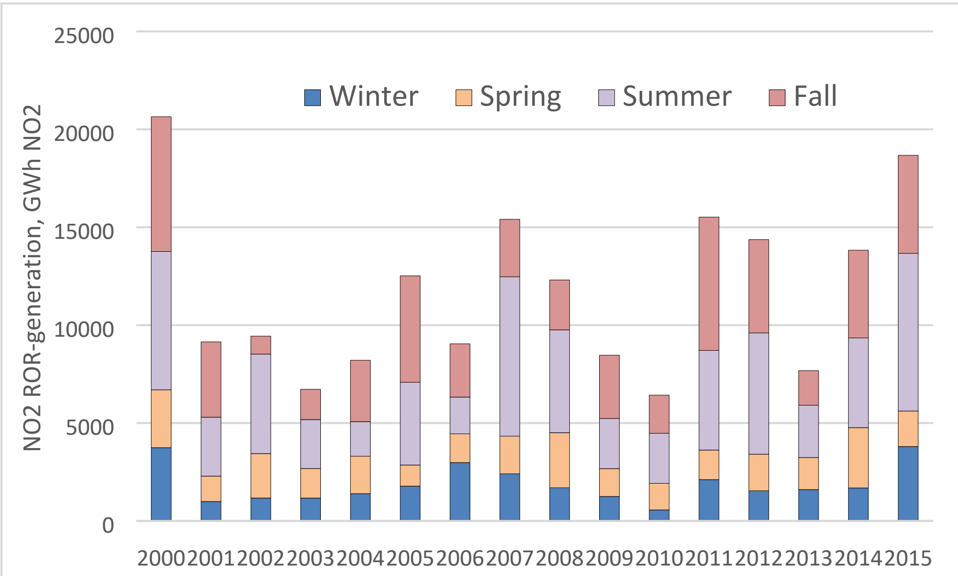

Figure 7 Seasonal ROR generation for NO2 for weather years from 2000 to 2015

Second, we assume that the regulated hydropower generation equals the Norwegian power generation minus the unregulated hydro inflow. The corresponding weekly generation characteristics for NO2 is illustrated in Figure 8.

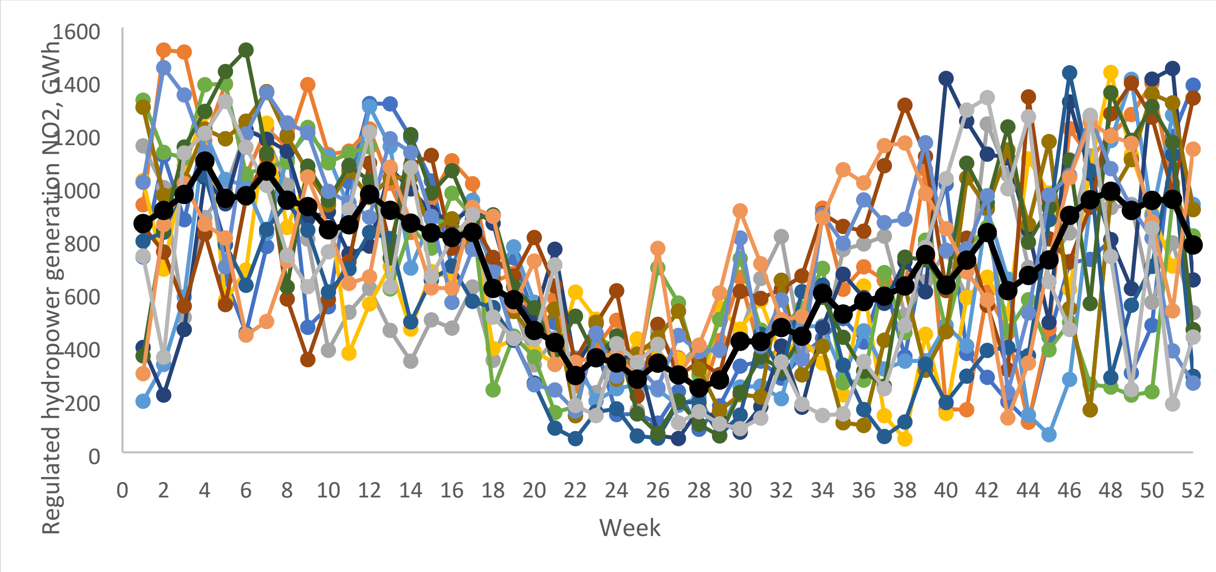

Figure 8 Illustration of regulated hydro power generation in NO2 for weather years from 2000 -2015, where the black line is the average.

For the deterministic model version, we use this information to derive the upper limit for operational hours the regulated hydropower generation can provide for each spot region, that is based on the average generation over the weather-years. See Table 6 for an overview of the corresponding model inputs. Note, as mentioned above, we assume that the operational hours for new regulated hydropower plants are 65.7% of the full load operational hours of the existing plants.

Table 6 Average full load operational hours of existing regulated hydropower.

Region	NO1	NO2	NO3	NO4	NO5
Hours	4071	4122	4620	4621	3844

For the stochastic model version, we consider that the operational hours are weather dependent. The stochastic scenarios, that are designed to capture this weather dependencies, take into account the annual generation from regulated plants vary for all weather years, as is illustrated for NO2 in Figure 9.

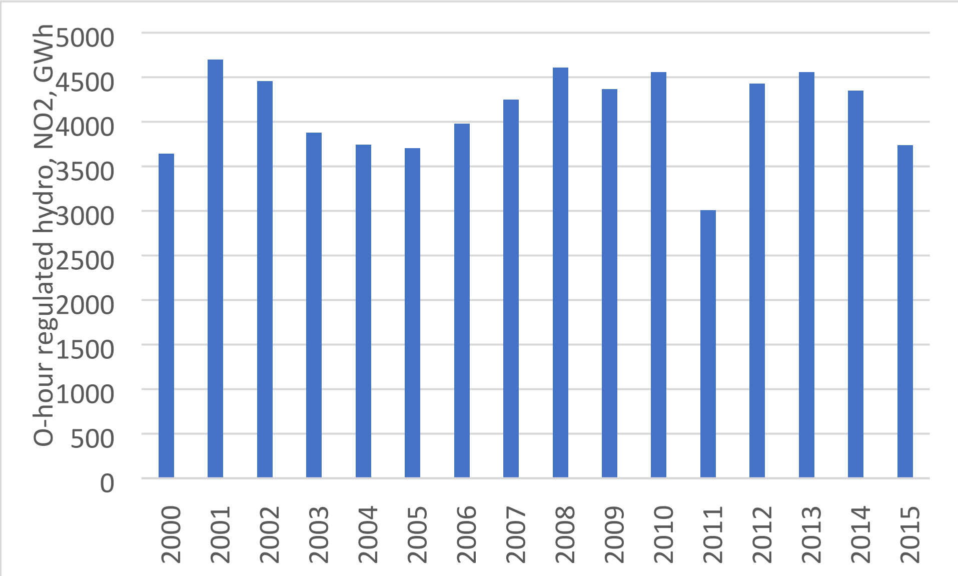

Figure 9 Weather-dependent operational hours of existing regulated hydropower plants for NO2 for weather years from 2000 to 2015

4.1.2 Wind power

Existing wind power plants are included with existing capacity and annual full load hours as presented in Table 7. The data are based on information from the wind power database of NVE [21]. The lifetime for all wind power plants is assumed to be 25 years. The variable operating and maintenance costs are 10 øre/kWh today, declining to 7.6 øre/kWh in 2050, based on [22].

Table 7 Data of existing wind power plants

Region	Full load (hours/year)	Installed capacity 2002-2020 (MW)	Decided to be installed 2021-2022 (MW)
NO1	3 758	224	25
NO2	3 565	1 391	50
NO3	3 469	1 906	345
NO4	3 373	724	50
NO5	3 758	-	40
Total		4 244	510

New wind power plants are modelled as 10 different classes: three levels of investment costs and three levels of full load hours and in addition a high cost/high potential alternative. The investment cost classes in 2020 are:

- Low 5300 NOK/kW
- Medium 10 600 NOK/kW
- High 17 700 NOK/kW

A technology learning rate of 24% from 2018 to 2035 is used, based on [22]. The investment costs are interpolated between the specified model periods and extrapolated from 2035.

The full load operational time for future wind power plants is divided in three classes:

- high (10% higher than the regional average of today)
- medium (average of today)
- low (10% lower than the regional average of today)

A wind power potential is calculated based on applications for wind power concessions downloaded from the database of NVE [23]. The wind power potential reflects the upper limit for wind power capacity as a total of classes 1-9 in IFE-TIMES-Norway. The potential is 48 TWh as shown by spot price region in Table 8. Note that the indicated wind power potential also includes existing wind power. The potential is equally divided in the 9 different wind power plant classes. The tenth class adds another 22 TWh of potential with the high cost and medium full load hours, in addition to plants included in the concession database.

Table 8 Wind power potential in a normal year, TWh/year.

	NO1	NO2	NO3	NO4	NO5	Norway
Consessions (class 1-9)	1.7	11.7	15.0	19.1	0.5	48
Additional potential (class 10)	0.6	4.7	5.3	11.1	0.2	22

Reinvestment in wind power plants is another possibility in IFE-TIMES-Norway. The investment cost is assumed to be 20% lower than the average cost of new wind power, due to less costs for infrastructure etc. The possible capacity of reinvestment is restricted to existing wind power plants in 2022.

4.1.3 PV

Photovoltaic electricity production is included as existing and new technologies in residential and non-residential buildings. PV parks are included as new technology with a start year of 2100 and no upper potential. When the start year is 2100, it means that the PV parks are not included in the analysis. However, when changing the start year, PV parks can be included. No opportunity for investments in PV in industry or agriculture are included yet but is to be updated in newer model versions. The existing capacity is calculated until the end of 2020 and is 47 MW in the residential sector and 79 MW in the commercial sector [24].

The investment costs in are based on NVE [25] and an overview of technology data of PV plants is presented in Table 9 .

Table 9 Technology data of PV plants

	Investment cost		Operation and maintenance cost		Life time
	NOK/kW		NOK/kW		years
	2018	**2030**	**2018**	**2030**	
Residential	11 500	5 750	58	29	30
Commercial	6 500	3 250	33	16.5	30
Park	6 000	3 000	30	15	30

PV production profiles are calculated based on profiles from renewables Ninja [26, 27]. Data is based on satellite photos from the period 2000-2018 and the cities Tromsø, Bergen, Trondheim, Kristiansand and Oslo represent the five regions of IFE-TIMES-Norway. Profiles for plants installed in the residential and commercial sector are calculated for 24 hours of a typical day in the four seasons. The tilt is assumed to be 30° south for residential PV-plants and 10°west/east for commercial plants.

A rough estimate of the maximum possible installation in buildings is calculated, see Table 10. In the residential sector, it is based on statistics on number of dwellings, assuming a capacity of 10 kWp per dwelling and assuming 20% of the dwellings not suitable (due to roof construction, shadowing etc.). In the commercial sector, statistics of existing non-residential buildings (excl. buildings in agriculture), assuming a capacity of 80 kWp per building and assuming 25% of the buildings not suitable (due to roof construction, shadowing etc.). This estimate is uncertain and should be updated.

Table 10 Region specific data of PV

	Annual share of full load hours		Potential (MW)	
	Residential	Commercial	Residential	Commercial
NO1	0.11	0.09	5 554	5 714
NO2	0.12	0.10	3 674	4 045
NO3	0.11	0.09	2 210	2 681
NO4	0.09	0.07	1 682	2 227
NO5	0.09	0.08	1 846	2 102
Norway			14 965	16 769

4.1.4 Transmission grid

The possibilities to invest and expand national transmission capacities between the regions are shown in Table 11, Table 12 and in Figure 10. The assumed investment cost of new capacity is also presented, where the investment cost varies due to the distance and technologies (cable vs. lines), based on project specific data [28-32]. New international transmission capacity to European countries is scenario specific and limited to maximum 1,400 MW. In the base template no new investments in international transmission are allowed.

Table 11 Investment cost for new transmission capacity (NOK/kW)

	NO1	NO2	NO3	NO4	NO5
NO1		841	2049		1216
NO2	841				1265
NO3	2049			3807	1195
NO4			3807		
NO5	1216	1265	1195		
SE3	1264				
DK1		5714			
DE		8750			
NL		8570			
UK		14285			14285

Table 12 Existing transmission capacity in 2020 (MW)

	NO1	NO2	NO3	NO4	NO5
NO1		3500	500		3900
NO2	3500				600
NO3	500			1200	500
NO4			1200		
NO5	3900	600	500		
SE1				700	
SE2			1000	300	
SE3	2145				
DK1		1632			
RUS					56
DE		1400			
NL		723			
UK		1400			

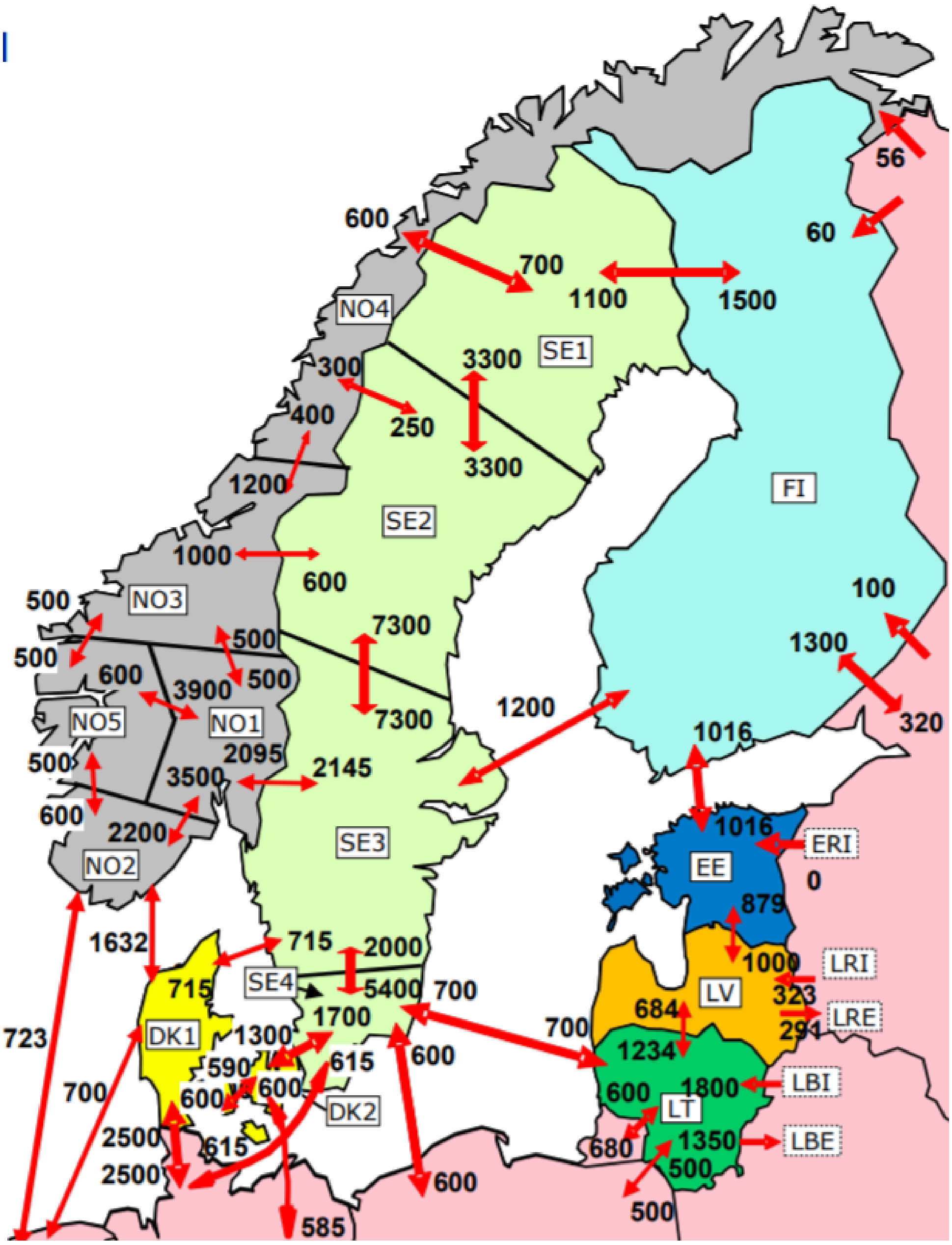

Figure 10 Net transmission capacities between regions, MW [33]

4.1.5 Electricity trade

IFE-TIMES-Norway needs exogenous input of electricity prices for countries with transmission capacity to Norway. Electricity trade prices are typically project specific, but a set of prices are included in the Base Assumptions-file. The prices for the base year are the average prices from 2018, from NordPool [34] and entso-e [35]. The future prices are a result from NVE, based on their analyses "Langsiktig Kraftmarkedsanalsye 2020-2040" [36]. The average power prices are presented in Table 13. The future prices are a result from NVE, based on their analyses "Langsiktig Kraftmarkedsanalsye 2020-2040" [36]. The average power prices are presented in Table 13. Figure 11 shows an example of the prices for export to Germany. Linear interpolation is used to estimate electricity prices between two given years until 2040. After 2040, the exogenous electricity prices are assumed to remain constant.

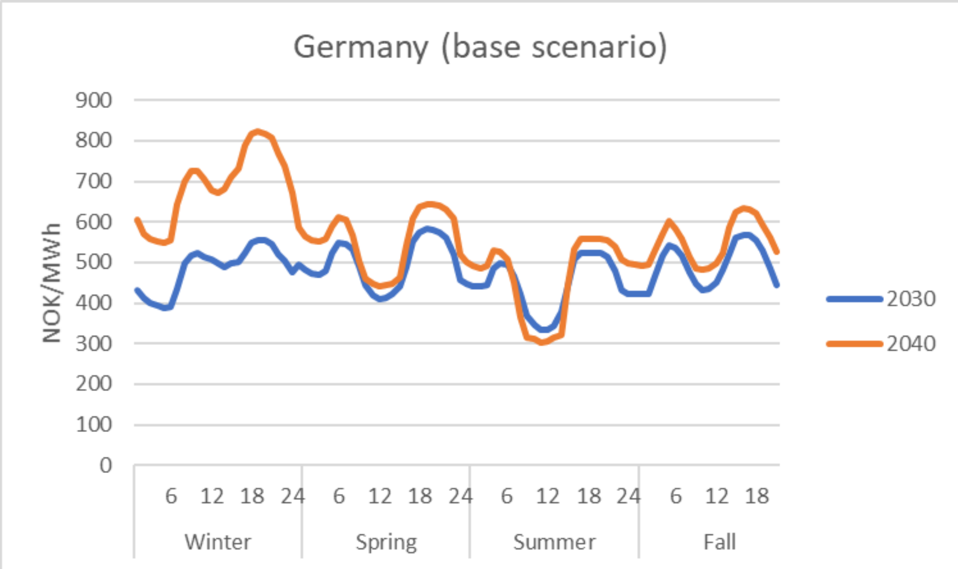

Figure 11 Electricity prices for export to Germany in base scenario in 2030 and in 2040.

Table 13 Average power trade prices [36]

Year	Sweden	Finland	Denmark	Germany	The Netherlands	UK
2022	37	37	35	44	44	54
2025	42	41	43	49	47	56
2030	37	35	47	47	45	48
2040	41	41	44	46	46	51

4.2 District heating

4.2.1 Background

District heating has been modelled as one system with several heating plant alternatives in each electricity spot area. To better cover the diversative of different district heating systems, two sizes are introduced – large and small/local district heating grids. This facilitates the incorporation of different specific investment costs of large and small systems and assumptions of technologies to be available for local systems.

In a model like IFE-TIMES-Norway, all buildings have the same costs and availability to use different technologies, if no restrictions are applied. Therefore, a market share often is used, to improve the modelling of actual possibilities and/or different costs or efficiencies.

4.2.2 Statistics

Use of energy for production of heat in district heating plants has increased from 0.5 TWh in 1985 to 8 TWh in 2019, see Figure 12 (Statistics Norway). In addition to energy used for heat production, 0.7 TWh was used for electricity production and 0.8 TWh was cooled to air. Use of district heating was in total 6.6 TWh in 2019, including grid losses. End-use of district heating was in total 5.9 TWh, and of this, commercial buildings used 3.4 TWh, dwellings 1.5 TWh and industry 0.8 TWh, see Figure 13.

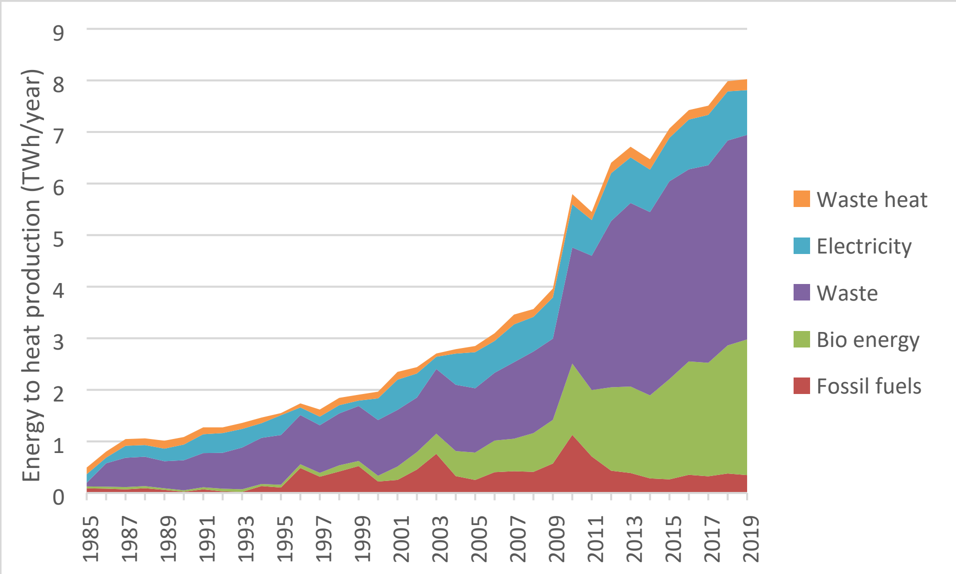

Figure 12 Energy used for heat production in district heating plants 1985-2019, TWh/year

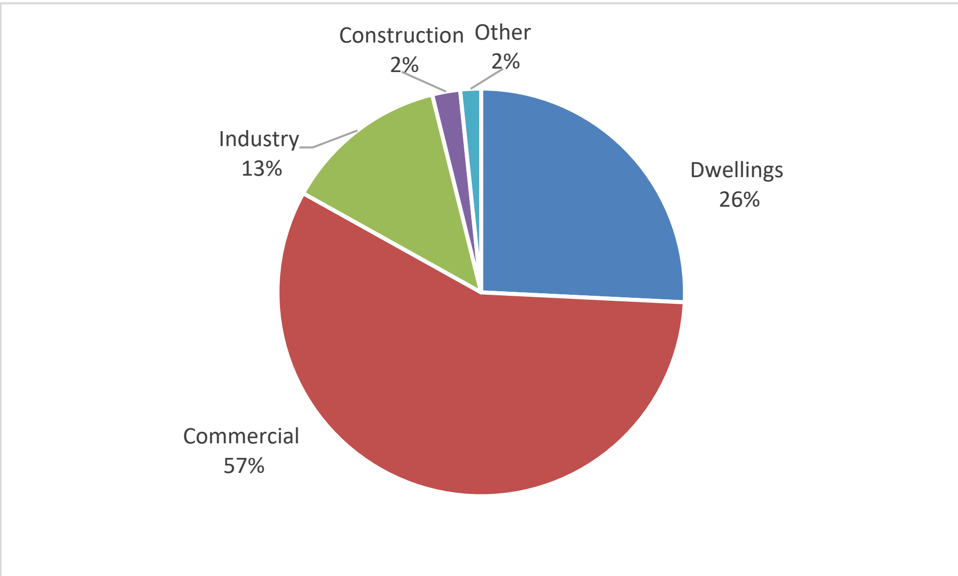

Figure 13 Use of district heating per end-use sector in 2019

Information on a plant level can be found at fjernkontrollen.no, were most of the district heating companies report data. Most of district heating is produced in market spot price area NO1, 3.3 TWh in 2019, and the second largest area is NO3, see Figure 14.

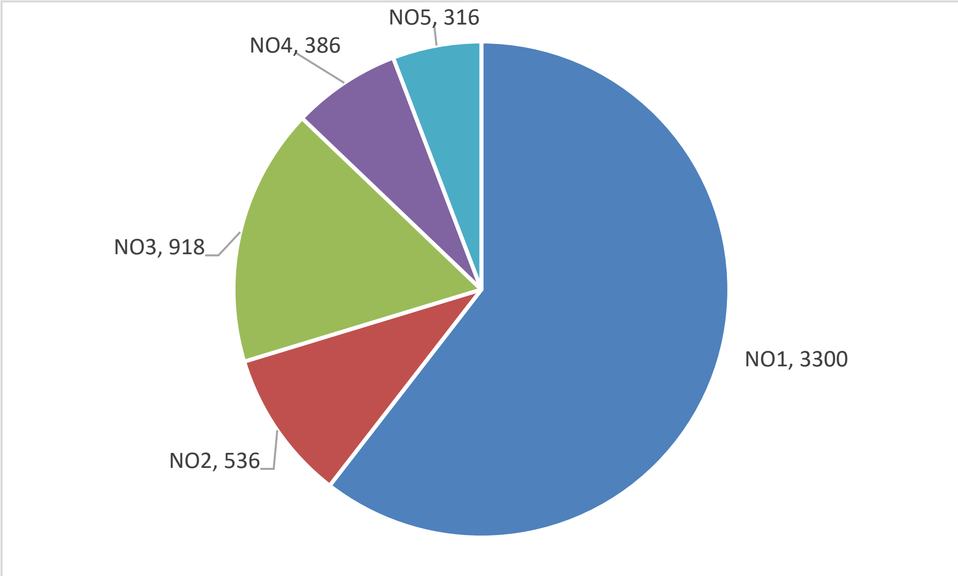

Figure 14 District heating production per market spot price area in 2019 (fjernkontrollen.no), GWh/year

Only one site produces more than 1 TWh/year (Oslo) and two more produce more than 300 GWh/year (Trondheim and Bergen). The number of plants delivering 100-300 GWh/year was 8 in 2019 (Hamar, Tromsø, Kristiansand, Ålesund, Lillestrøm, Fornebu, Forus, Drammen). In total 11 plants produce 3.8 TWh/year. If it is assumed that it is only smaller plants that do not report to fjernkontrollen.no, the production from plants with an annual production less than 100 GWh/year can be estimated to 2.8 TWh produced at 90-100 plants. Based on this, the definition of large and small/local district heating systems in the TIMES model is that large grids produce more than 100 GWh and small/local district heating systems produce <100 GWh/year.

4.2.3 Estimate of maximum potential for district heating

One way of estimating a maximum potential for district heating is to base it on an assumption that all commercial buildings and dwellings in areas with high enough density can be connected to a district heating system (large or small/local). Statistics Norway publish data on people living in "tettbygde strøk" (densely populated areas) and the definition of these areas are "at least 200 people live in an area of houses with less than 50 m apart". With this definition 18% of people in Norway live in areas that cannot be connected to local or large district heating systems. The share differs in the five Norwegian el price regions, see Table 14.

It could be argued that the share of commercial buildings and multi-family houses is higher in densely populated areas than in sparsely populated areas, than the population figures give as a result, but there are also other barriers that is not considered, so all-in-all it is considered as a reasonable assumption.

Table 14 Population in densely and sparsely populated areas

	Electricity price area	Densely populated area	Sparsely populated area
East	NO1	86 %	14 %
South	NO2	84 %	16 %
Middle	NO3	74 %	26 %
North	NO4	72 %	28 %
West	NO5	80 %	20 %
Norway		82 %	18 %

Another assumption made, based on information from major Norwegian district heating companies, is that single-family houses cannot be connected to a district heating system. This is a simplification and is not true in all cases, but as a model assumption it is justified since it often not is profitable to connect dwellings to a district heating grid. On the other hand, it is assumed that all multifamily houses within densely populated areas are possible to connect to a heat grid, but this is probably a minor overestimation.

Buildings with a central heating system can be connected to a district heating grid at lower costs than buildings with point source heating. It is assumed that only the buildings with central heating can be connected. The basic assumption is that the share of central heating is 58% of existing commercial buildings and in new buildings 90%, 38% of existing multifamily houses and 88% of new multifamily houses. In single-family houses the share of central heating is 12% in both existing and new dwellings, but this has no influence on the use of district heating, since it is assumed that they cannot be connected to a district heating grid.

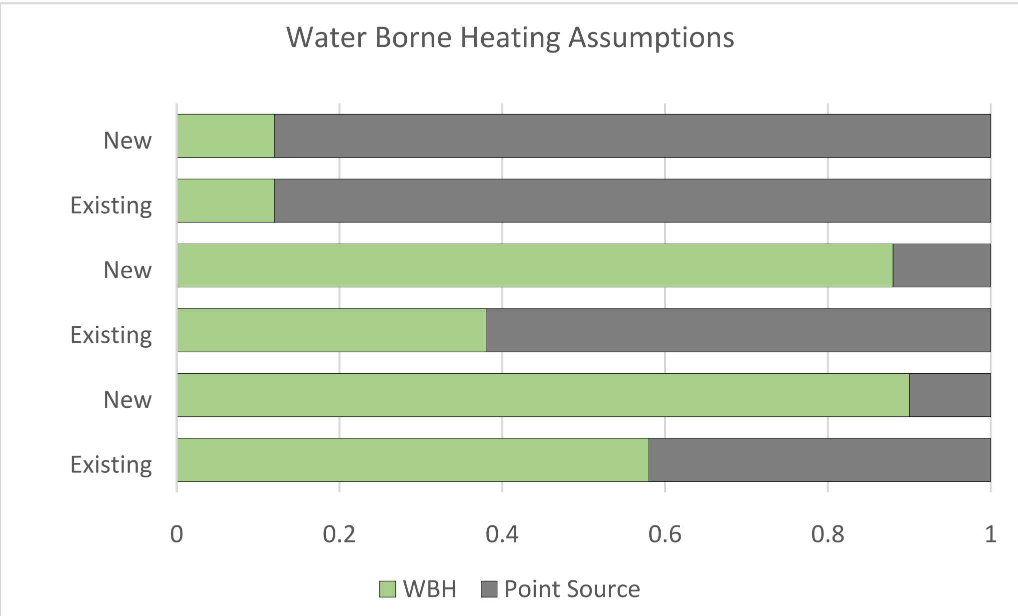

Figure 15 Share of water borne heating (WBH) and point source heating in buildings

Definition of large and small district heating systems is based on that “large” systems are applicable in cities and “small/local” systems otherwise. The estimate of people living in “cities” is not well founded but based on different statistics and knowledge of district heating grids of today. Statistics used for the calculations are statistics of inhabitants in the centre of cities divided by total inhabitants of the region, see resulting share in Table 15.

Table 15 Share of large district heating systems per electricity price area

	Electricity price area	mill. persons in «cities»	Share living in «cities»
East	NO1	1.47	65 %
South	NO2	0.61	50 %
Middle	NO3	0.28	38 %
North	NO4	0.18	37 %
West	NO5	0.30	47 %
Norway		2.83	53 %

The maximum share of connections to large or local district heating grids per type of dwelling and commercial building is presented in Table 16. In this table, “buildings” refer to both multi-family houses and commercial buildings.

Table 16 Share of maximum connection to large and small/local district heating grids per region

	El. price area	**Single-family houses**	**Buildings with point source heating**	**Buildings with waterborne heating Large**	**Buildings with waterborne heating Local**
East	NO1	0%	0%	56 %	30 %
South	NO2	0%	0%	42 %	42 %
Middle	NO3	0%	0%	28 %	46 %
North	NO4	0%	0%	27 %	46 %
West	NO5	0%	0%	38 %	42 %
Norway		0%	0%	44 %	38 %

An illustration of the possible share of small, large and no district heating system is presented in Figure 16.

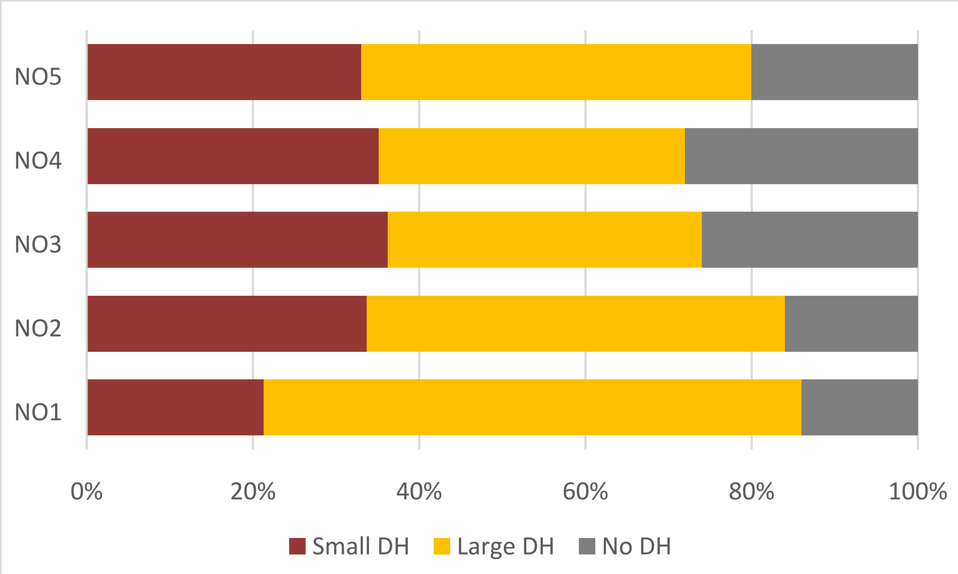

Figure 16 Share of small, large and no district heating systems per market spot price area

With these possible maximum shares for connection with local or large district heating grids, a total upper potential can be calculated to 10-11 TWh in 2030–2050.

Table 17 Maximum potential of use of large and small/local district heating in 2030 (GWh/year)

	El. price area	Single-family houses	Buildings with point source heating	Multi-family houses with central heating Large	Multi-family houses with central heating Local	Commercial buildings with central heating Large	Commercial buildings with central heating Local
East	NO1	0	0	660	360	2 150	1 170
South	NO2	0	0	280	280	1 040	1 030
Middle	NO3	0	0	110	180	410	670
North	NO4	0	0	60	110	280	480
West	NO5	0	0	100	110	400	450
Norway		0	0	1 210	1 040	4 270	3 800

In Figure 17, the use of district heating in 2019 is compared with the maximum potential in 2030 based on the above calculations. The potential in industry, construction and others is assumed to increase at a similar rate as in commercial buildings. In total, the potential in 2030 will be 13 TWh compared to the use of district heating in 2019 of almost 6 TWh.

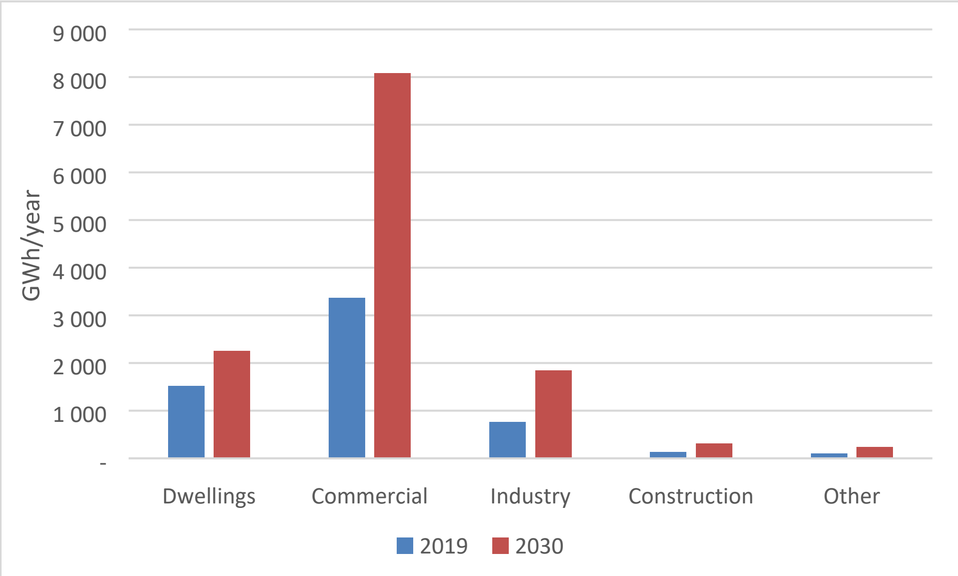

Figure 17 Use of district heating in 2019 and calculated maximum potential in 2030 per end-use sector (GWh/year)

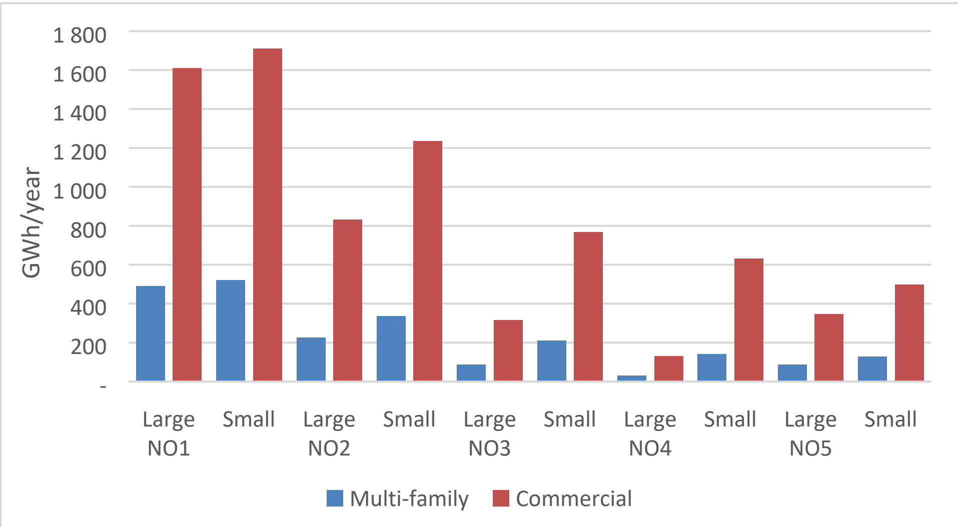

Figure 18 Calculated maximum potential in 2030 of large- and small-scale district heating per market spot price area

4.2.4 Heating technologies

District heating plants produces heat distributed to a district heat grid. Heat from the grid is input to district heat exchangers within the end-use sectors building and industry. The different types of existing and possibilities for new investments in district heating boilers and CHP with used data is presented in Table 18. Cost reductions due to technology learning are based on [22].

Table 18 District heating plants and grid

Technology	Investment cost 2018 (NOK/kW)	Market share (maximum)	Efficiency	Life time (years)
Fossil boiler - large - small	 763 963		 92% 92%	 20 20
Waste boiler (large)	25 310			20
Biomass boiler - large (wet fuel) - small (dry fuel)	 6613 5883		 89% 90%	 20 20
Electric boiler - large - small	 533 790		 98% 98%	 20 20
Heat pump - large - small	 8099 8099	 50% 50%	 2.8 2.8	 20 20
Heat recovery - large - small	 12303 12303	 20% 20%	 5 5	 20 20
CHP	29 247		3.2	20
Grid - large - small	 3159 3159		 89% 89%	 60 60

Municipal waste can only be used in large district heating plants, and it is assumed that the volumes of today will be constant until 2050. It could be argued both for an increase due to increased population and a decrease due to more recycling of materials and less use of resources. The municipal waste must be used since it is not allowed to deposit waste anymore.

CCS

CCS in waste incineration in district heating plants with CHP is included as a possibility in SubRES files: SubRES_CCS and SubRES_CCS_Trans, with region specific data in the Trans-file. In addition, the Scen_CCS file is needed to force in used of waste incineration plants and avoid double counting of stock.

All technology data is added to the capture process since separate data of capture and transport/storage is not available. Technology data [15] is based on the reports «Kvalitetssikring (KS1) av KVU om demonstrasjon av fullskala fangst, transport og lagring av CO2» from 2016 and «Kvalitetssikring (KS2) av KVU om demonstrasjon av fullskala fangst, transport og lagring av CO2 Rapport fase 1 og 2» from 2018 [37, 38]. The following data are used:

- Captured CO2 295 kt per year and from 2030 332 kt CO2 per year
- Efficiency 77% and from 2030 87%

- Investment costs 9700 mill. NOK increased by 30% in the KS2-report to 12610 mill NOK, resulting in specific costs of 32059 kNOK/kt CO2
- Operating costs 349 mill NOK per year resulting in specific costs of 1319 kNOK/kt CO2

The starting year in NO1 is assumed to be 2025 and in the other regions 2030. The investment costs are different in different regions and year, but this differentiation is not based on literature, it is only an assumption to facilitate incorporation of site-specific data in the future.

Heat and electricity consumption are added to the capture process based on the same source as above [39] and also here is the operating cost used in the model is halved.

4.3 Bio energy

Bio energy can be imported as bio coal, biofuel, biomass or bio wood, but limitations are added in the base case. The model includes production of bio chips/pellets, biofuel and bio coal from biomass.

In the fuels file, regional limitations of wood resources based on the use of today is included. A total of 5.9 TWh/year is available at a low cost, corresponding to the actual use that to a large extent is self-harvesting.

Biomass can be used as raw material in the wood industry or as energy resources, see Figure 19. The energy resources include use as chips/pellets in heating plants, conversion to biofuel or conversion to bio coal. The technology data for conversion from biomass to biofuel or bio coal is based on information from NVE [15] and presented in Table 19.

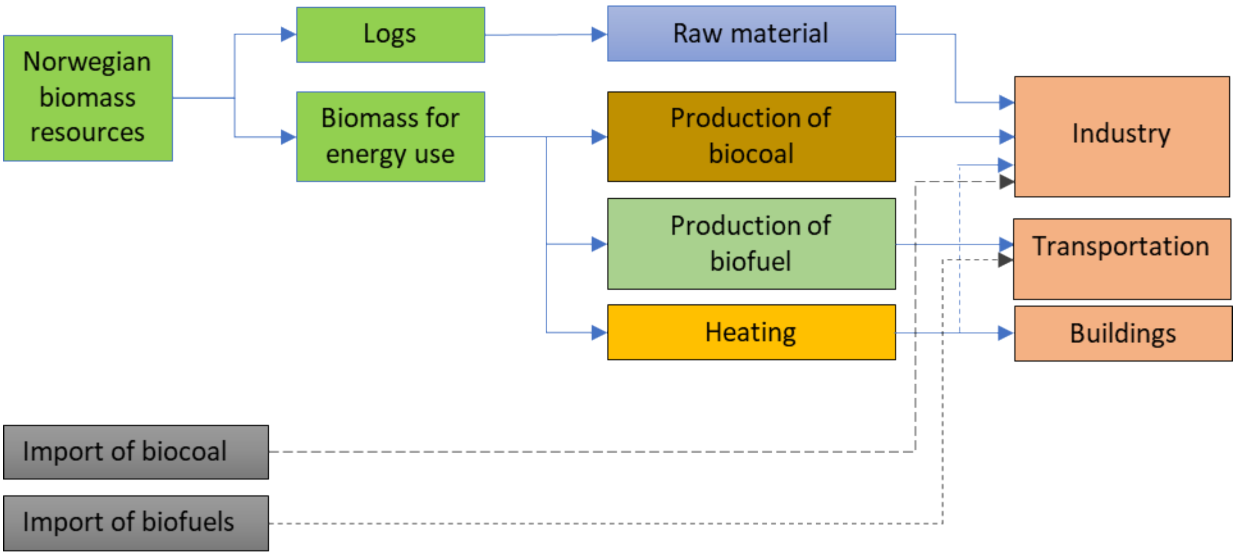

Figure 19 Schematic overview of biomass resources, conversion processes and end-use

Table 19 Technology data for conversion of biomass to biofuel or bio coal

	Efficiency	Life time (years)	Investment cost (NOK/MW)	Fixed O&M cost (NOK/MW)	Variable O&M cost (NOK/GWh)
Biofuel	58%	30	86 000	2500	250
Bio coal	25%	30	10 000		41

Various bioenergy products can be produced from Norwegian raw materials or be imported. Consumption of bioenergy resources and possible future potential is estimated and graphically presented in Figure 20. Other bioenergy resources may also be possible to use as raw material for production of biofuels, but here the focus is on solid biomass. In the future, it may be possible to use marine biological resources for production of various bioenergy products, but this has not been considered here.

Norway has large biomass resources related to the forest. About 11 mill. m^3 timber was felled for sale in 2018 [40], approx. 22 TWh, but there is potential to increase it to approx. 31 TWh within what is called the balance quantity and is sustainable felling. The annual forest growth is estimated at approx. 50 TWh.

When timber is felled, there are usually biomass resources left on the felling field that can be used for energy production (GROT) with an estimated energy content of 6 TWh/ year based on current felling. Another resource that can be used for energy production is wood waste (recycled chips), which is estimated at 3 TWh. Wood consumption in households was 5.6 TWh in 2018 according to Statistics Norway (5.1 TWh in 2019). In total, possible Norwegian bioenergy resources from solid biomass are estimated to 46 TWh (incl. biomass used as raw material).

Today's consumption of solid biomass as raw material in the wood industry (lumber, paper, fibreboards, etc.) is estimated to about 11 TWh. Combustion of biomass in boilers in district heating plants, industry and buildings was 2.7 TWh in 2018 and wood consumption in households was 5.6 TWh [41]. A total of 7 TWh was exported and 1 TWh was imported [40]. Industrial use of charcoal was approx. 0.5 TWh. In total, the current consumption of biomass is about 26 TWh.

In 2018, 4.4 TWh of biofuel and 48 TWh of fossil fuels (diesel, petrol, gas) were used. If this amount were to be produced from solid biomass with an efficiency of 58% biofuel per biomass, the need would be 91 TWh biomass.

Today's use of biogas is approx. 0.2 TWh and the potential for increased biogas production in Norway is estimated to 2.7 TWh. A realistic potential is estimated at about 2 TWh and a theoretical one at about 4 TWh in [42]. In [43] the potential for biogas is 4 TWh in 2020. Klimakur 2030 states the potential for biogas to be from 2.3 to 5 TWh / year [15], based on a study by [44]. This study is the most recently and detailed at is used to divide the potential in two price classes: 1.2 TWh at a price of 1 NOK/kWh and 1.5 TWh at a price of 2 NOK/kWh.

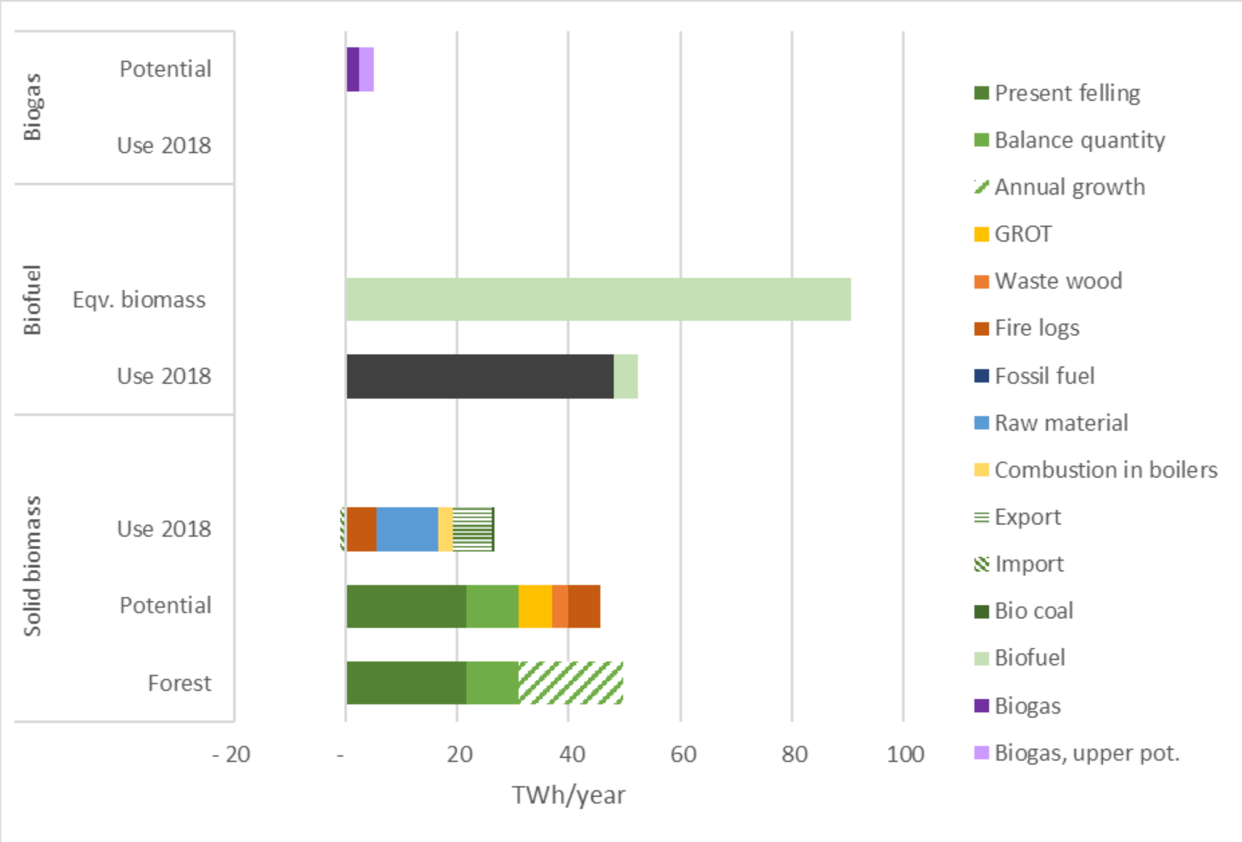

Figure 20 Biomass potentials and use, TWh/year

In the Base_Assumptions file, limitation of biomass is included. The limit is 15.7 TWh in 2018-2020, increasing to 31 TWh from 2030. A limitation of biogas is also added, 0.4 TWh in 2018-2020 increasing to 3 TWh in 2030. The production process of biogas is not included in the model yet.

Limitations of use of imported biofuel and bio coal are also included in the Base_Assumptions file. From 2035, no import of biofuels is possible, and with linear increased limitations from 2025 to 2035. Bio coal can be unlimited imported until 2035, and after 2035 it must be produced from Norwegian biomass resources.

The use of municipal waste is limited per region in line with the consumption of today. It is assumed to be constant at this level during the modelling horizon, due to lack of data. Increased population can argue for increased volumes of waste, but more recycling will reduce the waste available for energy purposes.

4.4 Hydrogen

Hydrogen can be produced and used in many different manners and many of them are still only in (early) developing stage. In IFE-TIMES-Norway are included the technologies which are considered relevant for Norway and are illustrated in Figure 21. The commodity H2-CENT is assumed to be low pressure hydrogen available directly after production (electrolyzer). For storage and usage in transport segment it needs to be compressed into the commodity H2-COMP, which is assumed a compression level of 250 bar. In commodity H2-TRA the hydrogen is in addition both distributed and handled by filling infrastructure, which might increase the pressure further.

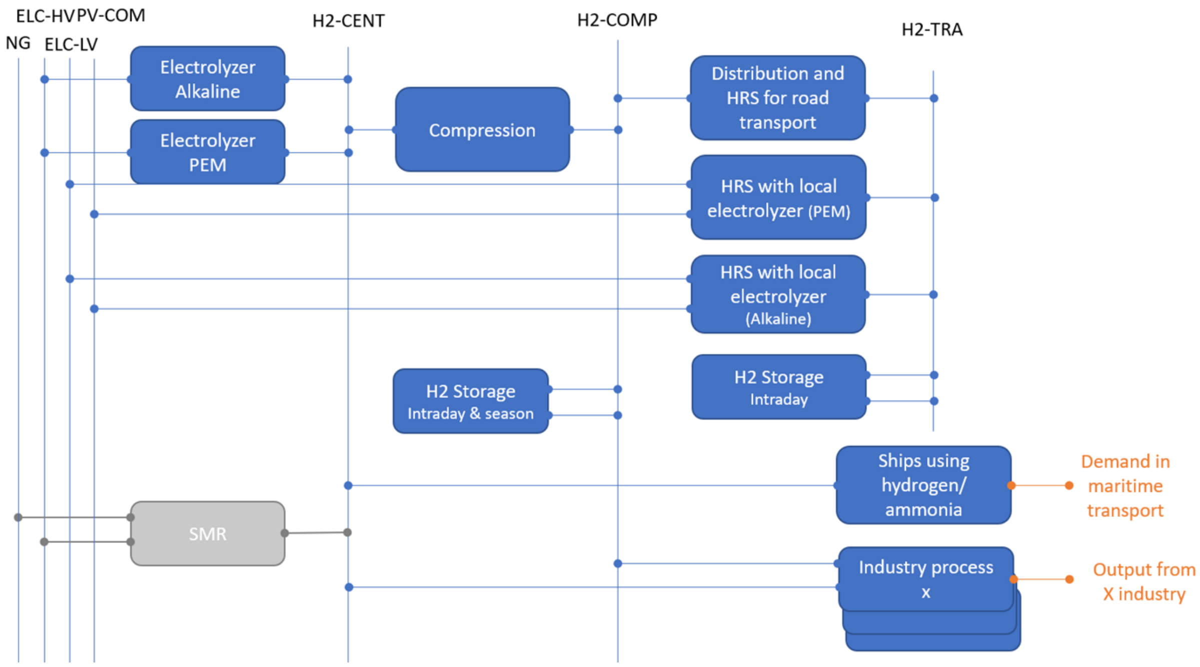

Figure 21 RES of hydrogen system presented in IFE-TIMES-Norway. The grey box shows technology not yet added to the model.

In the present version of the model, hydrogen is produced with electrolyzer and in further work the intention is to include production by steam reforming of natural gas (SMR) with CCS.

4.4.1 With electrolyzer

Hydrogen from electrolyzer is assumed to be produced in each region either large scale (centralized) or small scale (distributed) and cost wise are represented by a 20 MW_{el} and 3 MW_{el} installed capacity, respectively. The costs are provided both for alkaline and PEM electrolyzer and are build up from three parts: electrolyzer, compressor skid and other costs. The other costs cover engineering, control systems, interconnection, commissioning, and start-up costs. In Table 20 are shown the aggregated investment costs, while in Table 21 used efficiency and lifetime of the electrolyzers are presented. The lifetime for electrolyzers is usually presented in operational hours and its end of lifetime is based on when its efficiency drops below a set threshold due the degradation of the fuel cell. In IFE-TIMES is set a fixed lifetime in years based on the plants capacity factor of 95%.

In the model is made the distinction between PEM and Alkaline electrolyzer by allowing hourly (Daynite) variation in operation of PEM electrolyzer, while Alkaline is allowed to vary between seasons.

Table 20 The cost for the different electrolyzers for different years shown in NOK per installed kW_{el}

		2018	2030	2050
20 MW el	PEM	17400	11400	5400
	Alkaline	11700	7500	4900
3 MW el	PEM	31800	18100	10200
	Alkaline	34700	18800	13400

Table 21 Efficiency of large electrolyzer and compression stage

	Alkaline			PEM		
Efficiency (%)	67%	68%	75%	58%	66%	71%
Lifetime (h)	79 000	100 000	132 000	63 000	79 000	132 000

The yearly OPEX costs are built up for a differentiated value between electrolyzer types and a separate value for the compressor and is shown in Table 22. The noticeable difference between large and small scale electrolyzer is due to small scale electrolyzer includes a compressor to provide high pressure hydrogen to the commodity H2-TRA.

Table 22 Assumed OPEX costs in $kNOK/MWh_{H2}$

		2018	2030	2050
20 MW el	PEM	383	251	120
	Alkaline	257	165	108
3 MW el	PEM	900	476	290
	Alkaline	1115	572	419

The large-scale and distributed electrolyzers are in addition to CAPEX and OPEX distinguished by electricity source; where large-scale electrolyzer is assumed to consume power from the high-voltage grid and the distributed electrolyzers are dependent on the low-voltage distribution grid for which are included grid tariff on top off the electricity cost. On the other side, for the distributed electrolyzers it is also added an option to use power from PV production from panels installed at commercial buildings.

In Appendix A, a more detailed explanation is made of how costs and technical values has been selected for the electrolyzers and references to publications used in the selection process.

4.4.2 Storage

The storage of hydrogen is assumed to be at 250 bars. Cost for such storage is taken from [45] and is 6300 NOK/kg.

Storage within a day is available both for centralized and compressed hydrogen commodity (H2-COMP) and for local hydrogen production for transport (H2-TRA). On the other hand, seasonal storage is only enabled in connection centralized compression unit units.

4.4.3 Hydrogen refuelling station (HRS)

Necessary infrastructure for filling hydrogen provides a cost in addition to hydrogen production and in certain studies it accounts for about half the total hydrogen cost for the customer. Costs for HRS can vary greatly depending on size, pressure, degree of utilization and design. An overview from some sources is shown in Table 23. In [4], the cheapest 700 bar solution costed almost 40 NOK / kgH2 and the most expensive 350 bar solution costs slightly above 35 NOK / kgH2. At the same time as [7] shows that a large scale (1000 kg / day) 700 bar HRS can be as low as 32 NOK / kgH2, while if either HRS is smaller or has a lower utilization rate, costs increase. Based on available literature, an average cost of 40 NOK / kgH2 is assumed for start year.

Table 23 Cost for HRS from different sources

		Light-duty vehicles	Heavy-duty vehicles	
		[46]	[47]	[48]
Pressure (bar)		700	350	350 & 700
Currency		USD_{2017}	USD_{2017}	NOK_{2018}
Cost per kg_{H2}	Max	7	5.5	66
	Min	3.8	1	32

In addition, a reduction in cost is expected over time. In [7], the cost reduction is connected to the increase of HRS increases globally. An increase from 375 HRS in operation 2018 globally to approximately 5,000 and 10,000 stations, the costs may decrease by 40% and 45% respectively. In IFE-TIMES-Norway, it is assumed that by 2030 there will exist 5,000 HRS stations globally and in 2040 there will be 10,000 HRS stations globally.

4.4.4 Hydrogen transport and trading

Hydrogen can in theory be transported both long and short distances. In practice, cost-effective long-distance transport of hydrogen is a relatively immature technology that is expensive and requires large-scale demand volume to motivate building of hydrogen pipelines, alternative transport solution with liquified hydrogen. The latter has thus notable cost and energy efficiency penalties.

Therefore, trade in hydrogen has only been added for adjacent geographical areas within Norway and the costs for it are based on the distance between the main cities within each region. The distance between regions and costs of transport are shown in Table 24. The cost calculations are based on transport of hydrogen in a 40-foot tube trailer by truck and a total daily delivery of 2000 kg hydrogen transported in several tube trailers.

Table 24 Distance between regions and transport costs used in trading of hydrogen

From		To		Distance (km)	Transport costs (NOK/kg_{H2})
NO1	Oslo	NO2	Kristiansand	320	15
		NO3	Trondheim	490	23
		NO5	Bergen	460	22
NO2	Kristiansand	NO1	Oslo	320	15
		NO5	Bergen	470	22
NO3	Trondheim	NO1	Oslo	490	23
		NO4	Tromsø	1100	49
		NO5	Bergen	700	32
NO4	Tromsø	NO3	Trondheim	1100	49
NO5	Bergen	NO1	Oslo	320	15
		NO2	Kristiansand	470	22
		NO3	Trondheim	700	32

The hydrogen used in the transport sector can either be produced in large scale and distributed or be produced locally, as illustrated in Figure 22. The costs of distribution of hydrogen within a region will be affected by its size. The distance and connected costs of distribution are developed using a simple method based on the distance between regions showed in Table 24. As a first step, a distance (D) is calculated as the average between a region of interest and all adjacent regions. The main cities in each region are assumed to be roughly in the centre of the region and that the D can be simplified as distance between centre points between two circular regions, as shown in Figure 22. In the second step, it is assumed that regions have approximately same size and that initial large-scale production of hydrogen will be close to the main city of each region. A part of hydrogen demand for road transport will be relatively close to the production site and defined as an average distance of D/6 (short distance), while other part of demand will be on average distance of D/3 (long distance), as shown in Figure 22. The average distance between regions, the short and long distance of distribution and costs for distribution in IFE-TIMES-Norway is presented in Table 25 and are based on a 40-foot tube trailer that distributes 500 kg per day.

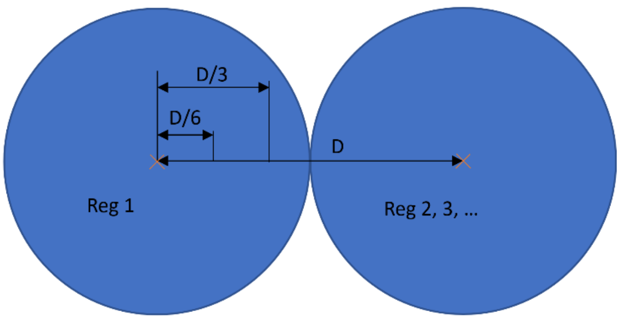

Figure 22 Illustration of how distance of distribution within regions are developed.

Table 25 Values used to calculate distribution costs with each region and the distribution costs itself.

Region		Average distance to other regions, D (km)	Long transport within region		Short transport within region	
			D/3	NOK/kg	D/6	NOK/kg
NO1	Oslo	423	141	9	71	6
NO2	Kristiansand	395	132	9	66	6
NO3	Trondheim	763	254	14	127	9
NO4	Tromsø	1100	367	19	183	11
NO5	Bergen	497	166	10	83	7

As the hydrogen demand will increase over time, it is assumed that several large-scale production sites will be available in each region and by that the distance of distribution reduced. This development is modelled by assuming that in 2030 only 50% of hydrogen for transport can be supplied through short distance distribution, while the share increases to 100% by 2050. This variable is set exogenous, but is strongly dependent on the model results, which makes it a central parameter for sensitivity analysis of the hydrogen supply chain for the transport sector. The distribution costs of hydrogen are defined in such a detailed matter to be able to analyze the role of locally produced hydrogen.

5 End-use demand

5.1 Industry

5.1.1 Structure and demand projection

The industry sector is divided in the following sub-sectors:

- ALU - Aluminium industry
- METAL - Metal industry (production of other raw metals)
- CHEM - Chemical industry
- WOOD - Wood industry (production of pulp & paper, sawmills)
- MIN - Mineral industry
- Light - Light industry (food, metal products…..)
- Petro - Petroleum industry (power from onshore to offshore activities)
- Data - Data centres
- AGR&CON - Agriculture and construction

Each sub-sector has a demand of heat, electricity (for non-heating purposes) and/or raw materials. The demand is defined by the energy balance of 2018 and the projection is based on known development the next coming years and mainly an assumption of constant energy demand after that, see Figure 23 and Figure 24. Some increased demand of new activities such as data centres is included in the demand projections.

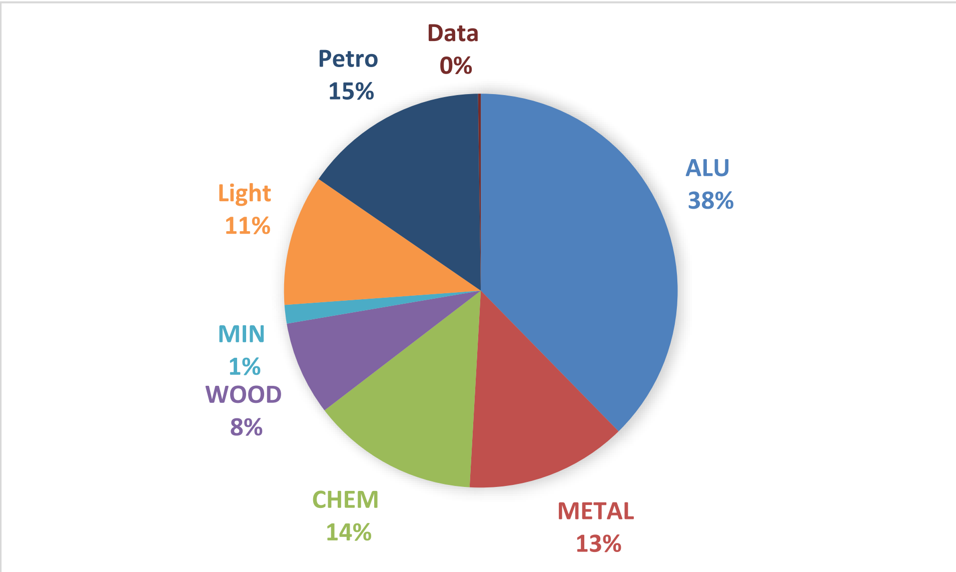

Figure 23 Share of electricity for non-heating purposes by sub-sector of total use in industry in 2018, TWh/year

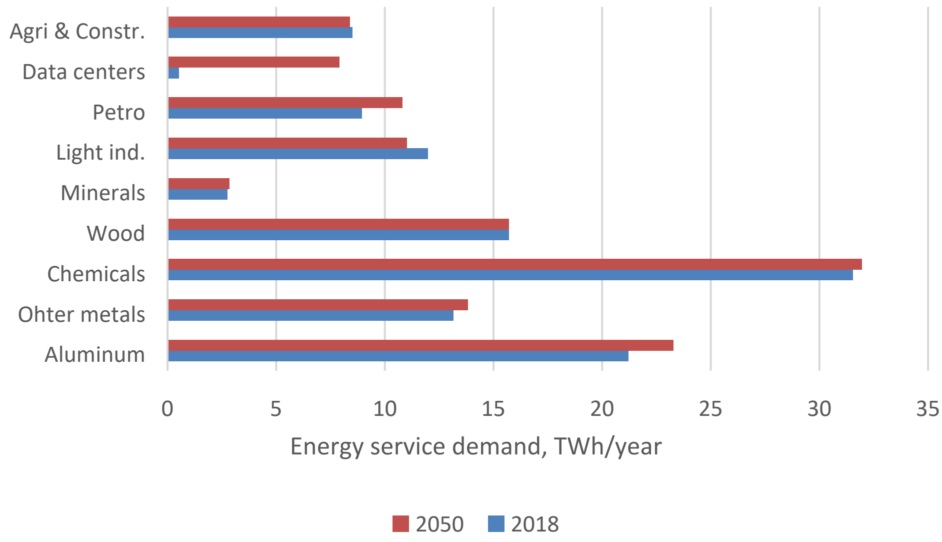

Figure 24 Total energy service demand in 2018 and 2050, TWh/year

The load profile of all industry sub-sectors but light industry is assumed to be flat, i.e. continuous operating time all year. In light industry, a daily load profile is added, see Figure 25, assuming no seasonal variation. It is set to be equal to the profile of commercial buildings [49, 50].

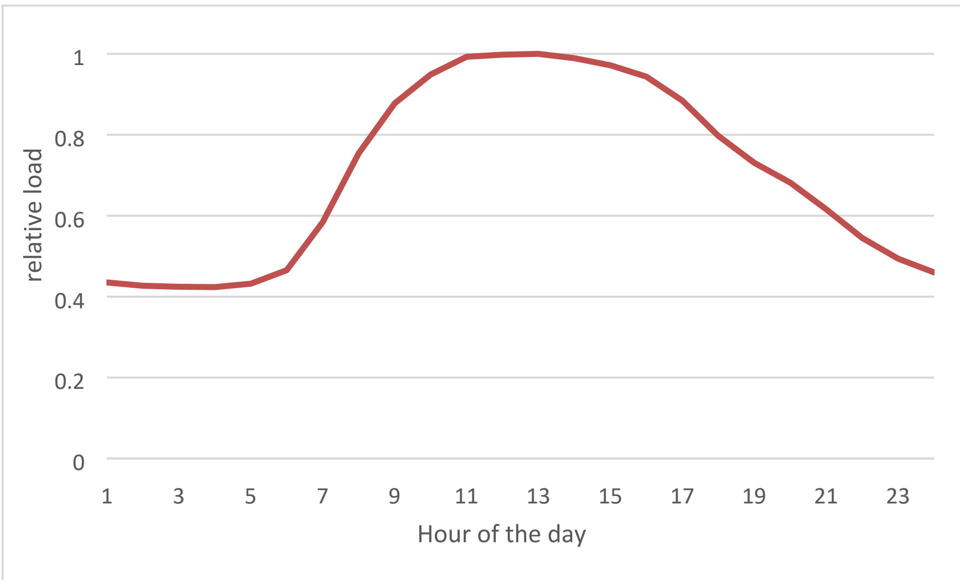

Figure 25 Load profile per day in light industry

5.1.2 Demand technologies

The electricity for non-heating purposes is modelled as one technology using ELC-HV in all industry sub-sectors except light industry, agriculture and construction that are using ELC-LV.

All industries can use fossil energy or electricity for heat production. Biomass can be used in wood, mineral and light industry. In addition, district heat and heat pumps can be used in light industry, with an upper limitation. The technology data (investment costs, efficiencies, life time) are based on [22]. Agriculture and construction are modelled with a share of energy carriers. In 2018, the share is fixed in accordance with the energy balance and in 2040 an upper limit is applied.

Use of coal as raw material in other metals and chemical industry has the possibility to be replaced by hydrogen, with an upper bound of use based on available literature (uncertain data). In the base case, this possibility is restricted to Yara in NO2 and use in a few reduction processes.

5.1.3 CCS

CCS in cement production is included as a possibility in SubRES files: SubRES_CCS and SubRES_CCS_Trans, with region specific data in the Trans-file.

The technology data for the CCS processes are based on the case studies of Breivik and Klemetsrud and all technology data are included in the CAP-processes. This could later be divided by costs and efficiencies at the plant and for transportation and storage. Storage might also be one process for Norway, with trade between the regions, but this is not implemented.

Technology data are based on the reports «Kvalitetssikring (KS1) av KVU om demonstrasjon av fullskala fangst, transport og lagring av CO2» from 2016 and «Kvalitetssikring (KS2) av KVU om demonstrasjon av fullskala fangst, transport og lagring av CO2 Rapport fase 1 og 2» from 2018 [37, 38]. The middle alternative of Norcem Breivik is used and the data are:

- Captured CO2 400 kt per year
- Efficiency 85%
- Investment costs 9500 mill. NOK increased by 20% in the KS2-report to 11400 mill NOK, resulting in specific costs of 21 375 kNOK/kt CO2
- Operating costs 349 mill NOK per year resulting in specific costs of 873 kNOK/kt CO2

All technology data is added to the capture process, since the reports do not differ between costs for capture and costs for transport/storage, but this can easily be changed, if data are available.

Electricity consumption is added to the capture process, based on information from [39]. Since the operating cost of the KS-reports includes energy use, the operating cost in the model is halved, but this cost needs to be further checked.

5.2 Buildings

5.2.1 Structure

The building sector of TIMES-Norway is divided in residential single-family and multi-family houses and in non-residential/commercial buildings for each of the model regions. All buildings are divided in existing and new buildings. The existing buildings have a stock of equipment in the start year. The end-use demand is divided in central heating (HC), point source heating (H), hot water (W) and electricity specific demand (E).

A schematic overview of the systems in residential and commercial buildings is presented in Figure 26 and Figure 27. Oil boiler is only available in before 2020. Solar collectors are added as a possible technology with start year 2100. Demand for hot water is added to demand for space heating in buildings with central heating, while it is separated in two in buildings with point source heating.

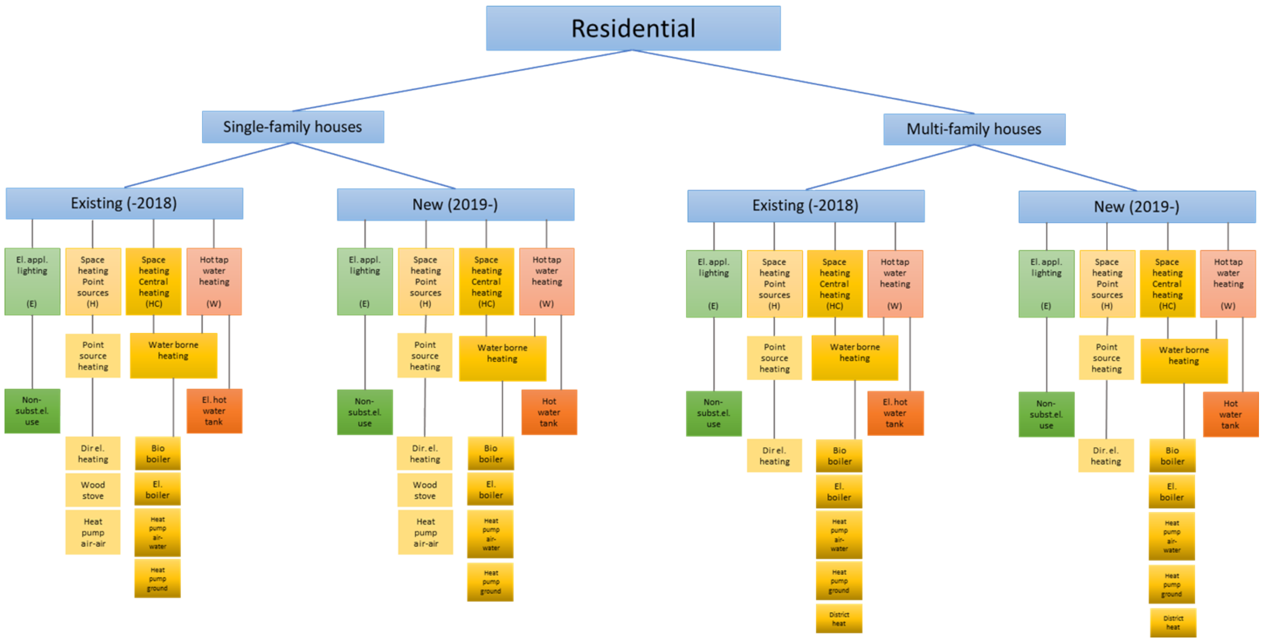

Figure 26 Schematic overview of the energy system in residential sector

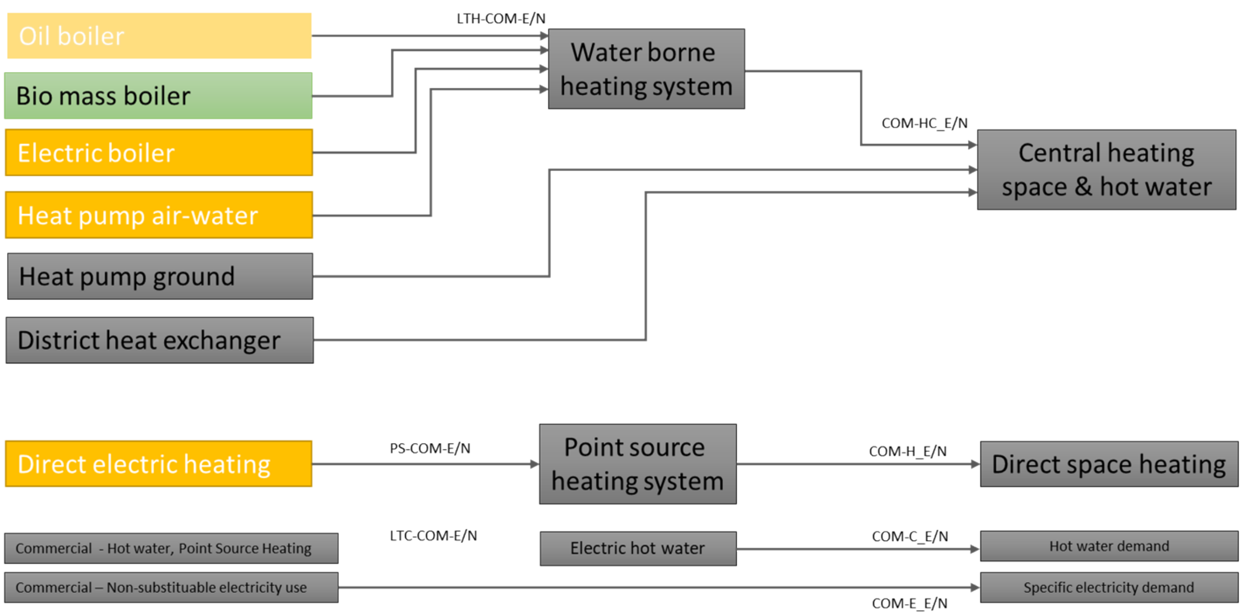

Figure 27 Schematic overview of the energy system in commercial buildings

Heating is divided in central heating (water borne system) and "point source" heating based on data from the FlexBuild project [51]. The assumptions regarding the share of point source and central heating in the building sectors are presented in Table 26.

Table 26 Share of point source and central heating in the building sectors

	Point sources	Central heating
Multi-family houses, existing	62 %	38 %
Multi-family houses, new	12 %	88 %
Single-family houses, existing	88 %	12 %
Single-family houses, new	88 %	12 %
Commercial buildings, existing	37 %	63 %
Commercial buildings, new	10 %	90 %

District heating and ground source heat pumps are connected directly to heating demand in order to get the same profile as the demand (if a building has district heat it cannot have any other heating source when modelled as this). Biomass boilers are modelled on a seasonal level, since they normally are more difficult to operate on an hourly level with rapid on/off.

5.2.2 Demand projections and load profiles

The demand projections in residential and non-residential buildings are based on data from previous work in the FlexBuild project [51], see Figure 28. It is based on the scenario “Energy Nation”.

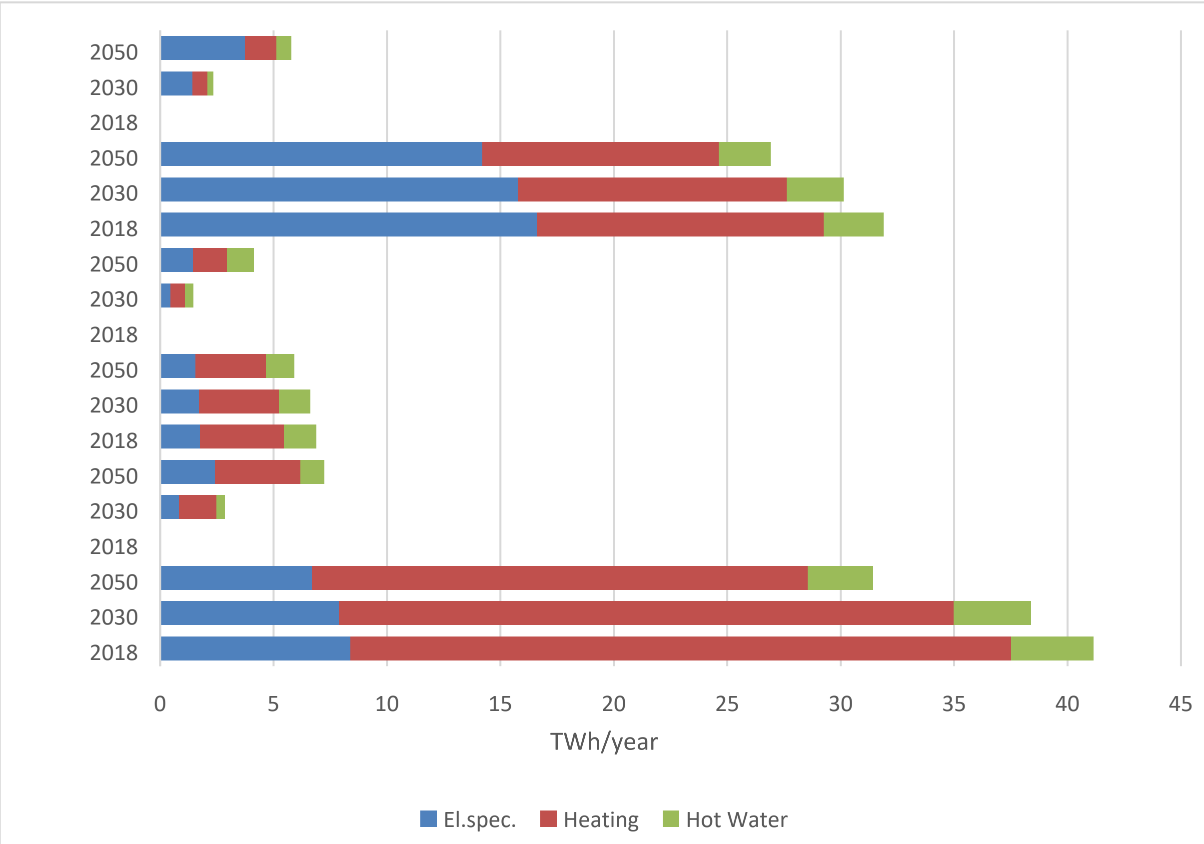

Figure 28 Projections of energy service demand in residential and commercial buildings, 2018, 2030 and 2050, TWh/year

The load profiles, the sub-annual hourly load variations, are based on input from [49, 50]. In the base model, we assume that the load profiles are the same for all years and for existing and new buildings. The heating profiles differs between regions and for central heating/ point source heating. The profile for non-substitutional electricity is the same for all residential buildings and all non-residential buildings. Examples of load profiles in region NO1 is presented in Figure 29, Figure 30 and Figure 31.

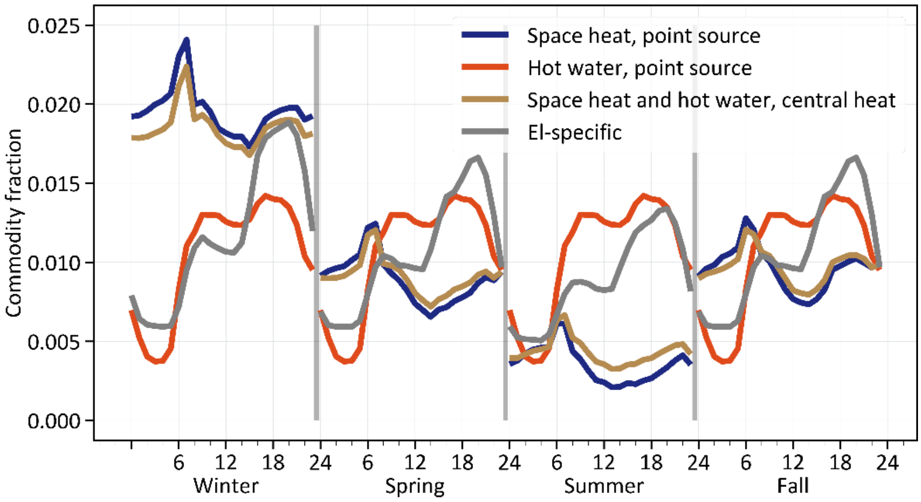

Figure 29 Load profile for residential single-family house in model region NO1.

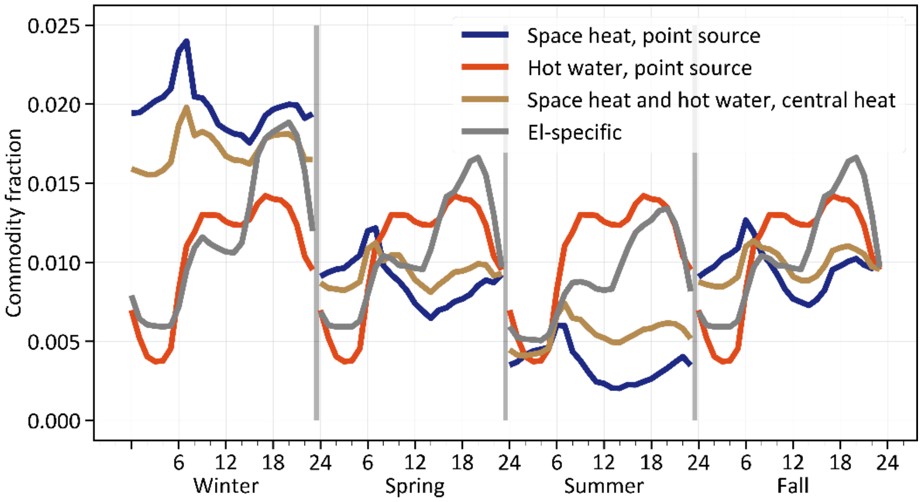

Figure 30 Load profile for residential multifamily house in model region NO1.

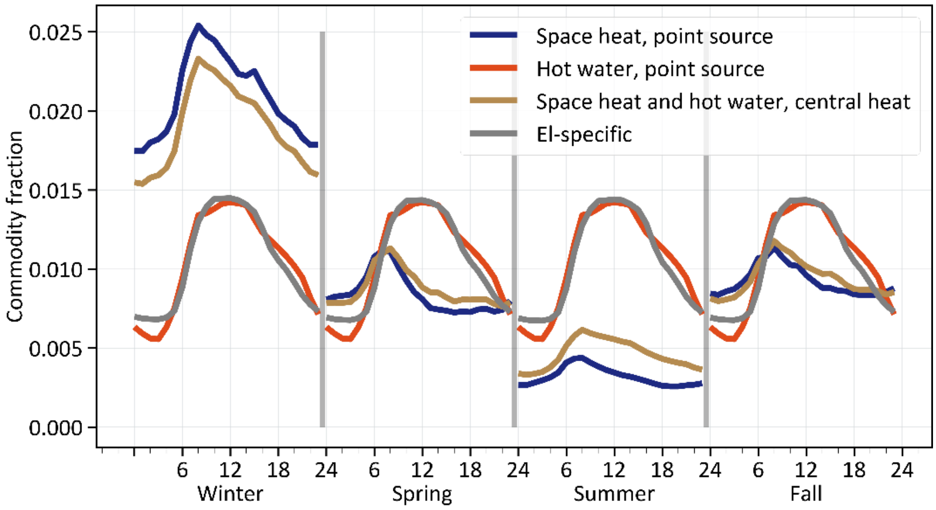

Figure 31 Load profile for commercial buildings in model region NO1.

5.2.3 Demand technologies

5.2.3.1 Heating equipment

The investment and operational costs, annual full load hours, efficiencies, life times and technology learning rates are based on [22] and presented in Table 27. Equipment in the residential sector includes VAT 25%.

Existing oil boilers have 2 years lifetime, and it cannot be invested in new oil boilers, and oil boilers can consequently not be used from 2020. Stock of existing heating equipment is calculated based on energy use in 2018 and full load hours from [22].

The efficiency and the availability of heat output of air-air heat pumps and air-water heat pumps depends on the outdoor temperature [52] and is therefore modelled on DayNite level for each of the five regions, see Figure 32. The nominal COP_{33N} for air-water and COP_{13N} for air-air used is an average of rated COP's of commercially available heat pumps in each category.

Table 27 Technology data of heating equipment in buildings

Description	Efficiency /COP	Market Share	LIFE	INVCOST	INVCOST 2035	FIXOM	VAROM
			years	NOK/ kW	NOK/kW	NOK/ kW	NOK/ MWh
Residential Multi-family							
Central heating							
Biomass boiler	0.81		15	7 897	7 739	919	8 96
Electric boiler	0.98		20	1 546	1 546	540	1 35
Solar collector	1.00	0.10	25	5 714	4 000	38	
District heat exchanger	0.99		50	482	482	-	-
Heat pump water-water	3.0	0.56	20	15 643	12 514	40	15
Heat pump air-water		0.39	15	6 790	5 432	40	15
Point sources							
Heat pump air-air		0.27	15	6 872	5 498	30	
Wood stove	0.4		25	3 002	3 002	45	
Direct electric heating	1.00		25	2 042	2 042	31	12 5
Electric water heater	0.98		20	4 500	4 500		
Residential Single-family							
Central heating							
Biomass boiler	0.81		15	12 876	12 618	919	8 96
Electric boiler	0.98		20	4 046	4 046	540	1 35
Solar collector	1.00	0.10	25	10 715	7 501	38	
Heat pump water-water	3.0	0.28	20	20 523	16 419	40	15
Heat pump air-water		0.36	15	17 966	14 373	40	15
Point sources							
Heat pump air-air		0.27	15	6 872	5 498	30	
Wood stove	0.4	0.5	25	3 002	3 002	45	
Direct electric heating	1.00		25	2 042	2 042	31	12.5
Electric water heater	0.98		20	4 500	4 500		
Commercial							
Central heating							
Biomass boiler	0.84		15	7 897	7 739	510	7.3
Electric boiler	0.98		20	1 546	1 546	32	1
Solar collector	1.00	0.05	25	5 714	4 000	20	
District heat exchanger	0.99		50	918	918		
Heat pump water-water	3.0	0.3	20	15 643	12 514	32	12
Heat pump air-water		0.4	15	6 790	5 432	32	12
Point sources							
Direct electric heating	1.00		25	1 226	981	15	8
Electric water heater	4.00		25	3 000	3 000	60	8.00

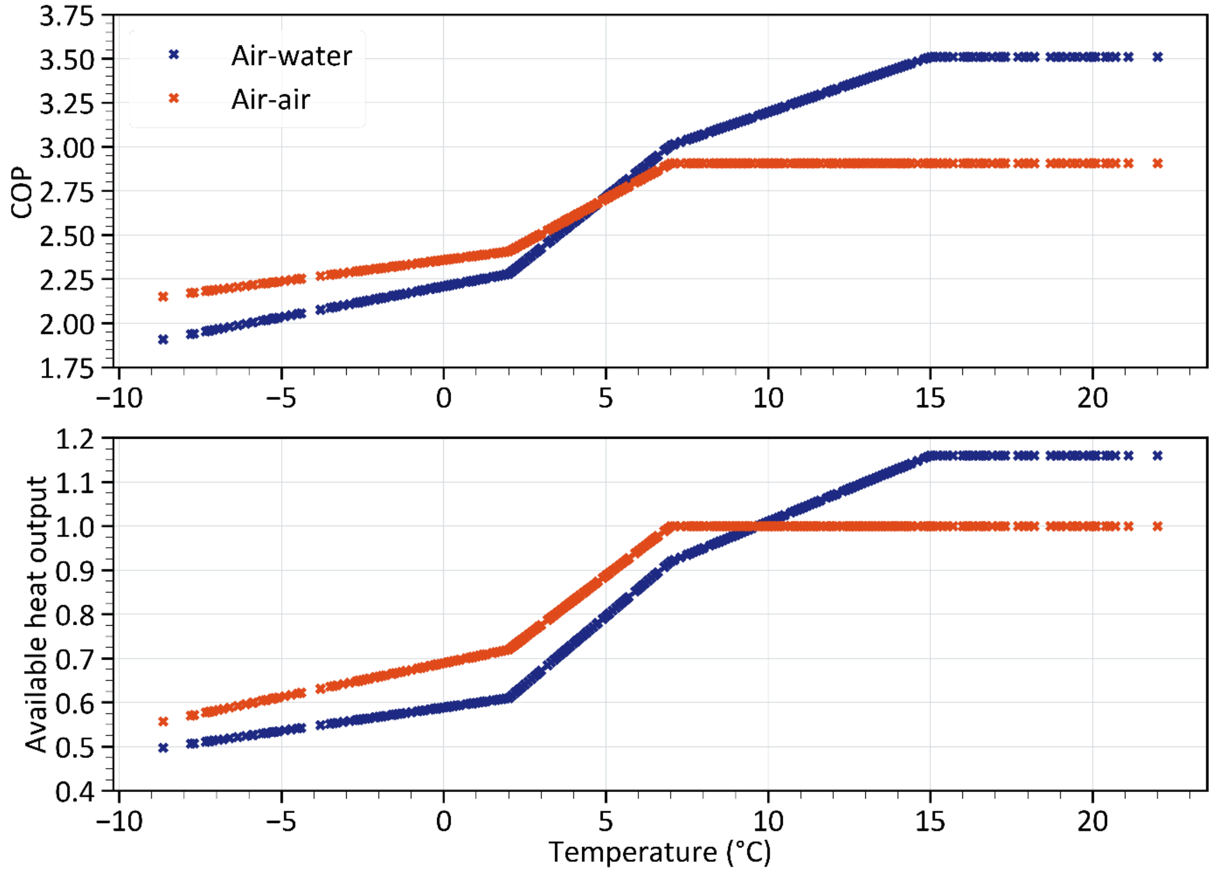

Figure 32 Temperature dependent COP and heat output of nominal capacity for air-water and air-air heat pumps.

A maximum market share is added for heat pumps (see Table 28) and district heating, see 4.2.3. NVE has estimated coverage and prevalence for three types of heat pumps in three types of buildings, see Table 28.

Table 28 Market share of heat pumps

	Heat pump type	Air-to-air	Air-to-water	Water-to-water
Coverage	Old buildings	40 %	65 %	80 %
	New buildings	50 %	75 %	90 %
Prevalence	Single-family houses	90 %	90 %	21 %
	Multi-family houses	0 %	60 %	70 %
	Commercial	0 %	80 %	70 %
Max market share	Existing dwellings	27 %	54 %	26 %
	New dwellings	34 %	62 %	30 %
	Existing commercial	-	52 %	56 %
	New commercial	-	60 %	63 %

Wood stoves can only be used in winter hours 16-24, fall and spring hours 18-22, in order to reflect actual use of wood firing, see Figure 33. The efficiency of wood stoves is lower than actual, to reflect that not all produced heat is useful (some is used for extra comfort, part of the time the temperature is above the needed comfort temperature etc.). Wood stoves can only cover 50 % of heat demand.

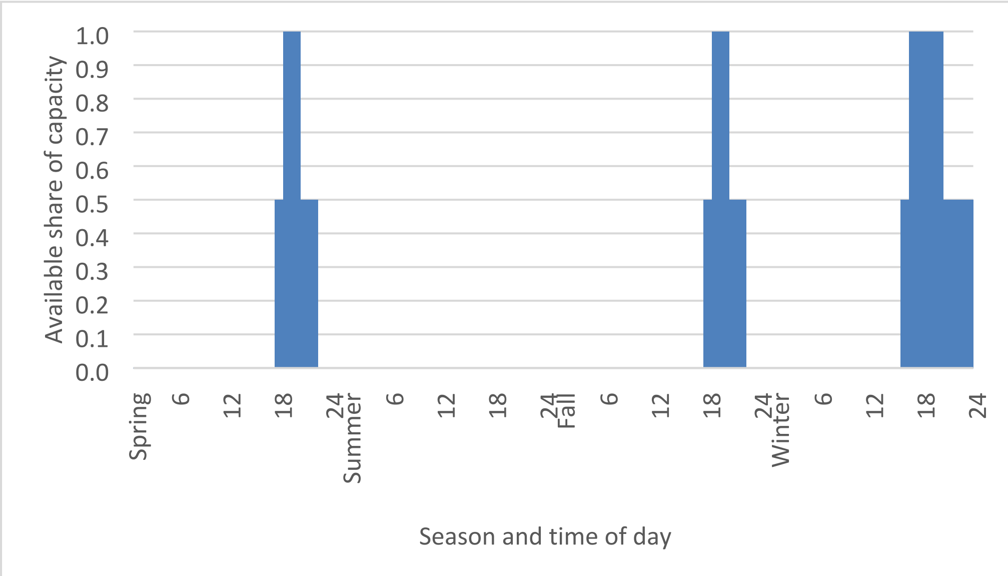

Figure 33 Illustration of available share of capacity for wood stoves per season and time of day (hour).

5.3 Road Transport

5.3.1 Structure

The road transport is divided into six different types and are listed in Table 29 together with a short description. Further below is described more in detail why and how trucks are subdivided in three segments.

Table 29 Description of the different road transport demand types

Type	Name in TIMES	Description
Cars	TCAR	Vehicles transporting up to 9 persons including driver. Taxis, and ambulances are also included in this group.
Vans	TVAN	Vehicles designed for carriage of goods with gross vehicle weight below 3.5 ton. It corresponds the Norwegian Public Roads Administrations vehicle group N1. In addition are included motorhomes and combined cars (an outdated government definition of vehicles designed for both person and goods transport).
Trucks	TTRUCK-S	Trucks with registered total gross weight including trailer between 3.5 and 50 ton, all distances (S as in Small)
	TTRUCK-LS	Trucks with registered total gross weight including trailer above 50 ton and for short haulage (<300km) (LS as in Large and Short)
	TTRUCK-LL	Trucks with registered total gross weight including trailer above 50 ton and for long haulage (>300km) (LL as in Large and Long)
Bus	TBUS	Vehicles transporting 10 persons or more.

The demand for heavy-duty trucks is divided into three as its size and daily milage is central parameters for energy consumption and feasibility for different propulsion systems. They will also have different demand for fast charging, if electrified. In Table 30, it is shown how the daily truck milages in Norway are distributed and by colours divided in three parts. Engine size above 500 hp is typically used in tractor units with semi-trailer, but also for trucks who provides more demanding services. It can for example be a road-train set-up with max 24 m length and total gross weight of 60-ton, mass transport to/from construction sites or other special purpose vehicles.

Table 30 Distribution of trucks daily mileage for vehicles 5-year-old and newer [53].

Engine power (HP)	Up to 100 km	100-200 km	200-300 km	300-400 km	400-500 km	500 km and over	Total
100-199	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%	0.2%
200-299	2.5%	2.2%	1.1%	0.6%	0.2%	0.2%	6.8%
300-399	2.8%	2.8%	1.1%	0.7%	0.2%	0.2%	7.8%
400-499	4.7%	4.4%	2.9%	1.0%	0.6%	2.2%	15.8%
500-599	12.4%	8.3%	6.6%	4.1%	5.3%	17.6%	54.3%
600-699	2.1%	1.1%	0.9%	0.6%	0.8%	2.7%	8.2%
700+	2.0%	0.9%	0.7%	0.5%	0.7%	2.4%	7.2%
Total	26.6%	19.8%	13.2%	7.5%	7.6%	25.3%	100.0%

The transport demand overview, its forecast and fleet composition for Norway is prepared by the Norwegian Institute of Transport Economics (TØI) through their Freight Transport model (GTM based on its Norwegian Acronym) and stock-flow cohort model of the Norwegian vehicle fleet (BIG based on its Norwegian Acronym). It is essential to easily transfer data from TØI's forecasts, especially BIG model as it provides the decomposition of the heavy-duty transport fleet into trucks and tractor units, as well as into different sizes. The vehicle sizes are divided in BIG based on registered total gross weight including trailer and its decomposition for year 2018 is shown in Table 31.

Table 31 Million vehicle km distribution across vehicle registered total gross weight for different vehicle types for year 2018 based on data from BIG [54]

Registered total gross weight including trailer	Trucks	Tractor units	Total	Share of total
3.5-7.5 ton	38	0	38	2%
7.5-12 ton	97	0	97	4%
12-20 ton	130	2	132	6%
20-30 ton	105	13	118	5%
30-40 ton	49	10	59	3%
40-50 ton	113	14	127	5%
50-60 ton	147	41	188	8%
60 + ton	1066	478	1544	67%
Sum	**1743**	**558**	**2302**	**100%**

In IFE-TIMES, it is assumed that all vehicles with registered total gross weight including trailer above 50 ton corresponds to vehicles with engine size above 500 hp. The match is not perfect but provides a rational and simple linkage to BIG model. The vehicle km for vehicles above 50-ton gross weight is divided into two equal parts to represent short and long haulage. Information from TØI results in a trend with less smaller trucks and more heavy trucks, see Figure 34.

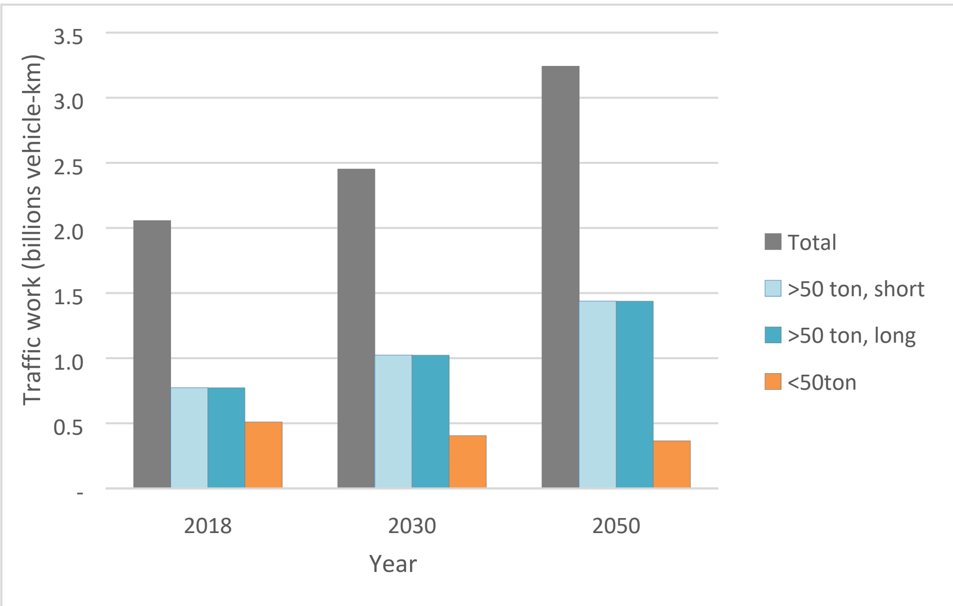

Figure 34 Development in demand of traffic work of three types of trucks, 2018, 2030 and 2050 (bill. vehicle-km / year)

5.3.2 Demand

The demand towards 2050 is based upon the projections made in the national transport plan (NTP) 2022-2033 [55] and is shown in Figure 35. Only national data of demand for buses in passenger-km are available from NTP, and therefore data from TØIs BIG-model on vehicle-km is used for the base year. The division on regions is based on population per region. The projection is based on relative change in passenger-km from NTP.

The total heavy freight transport is based on data from NTP 2022-2033 and is divided in the three truck classes of IFE-TIMES-Norway as described in the previous paragraph. The division of data per region and the relative development from 2018 to 2050 is based on county data of NTP 2022-2033.

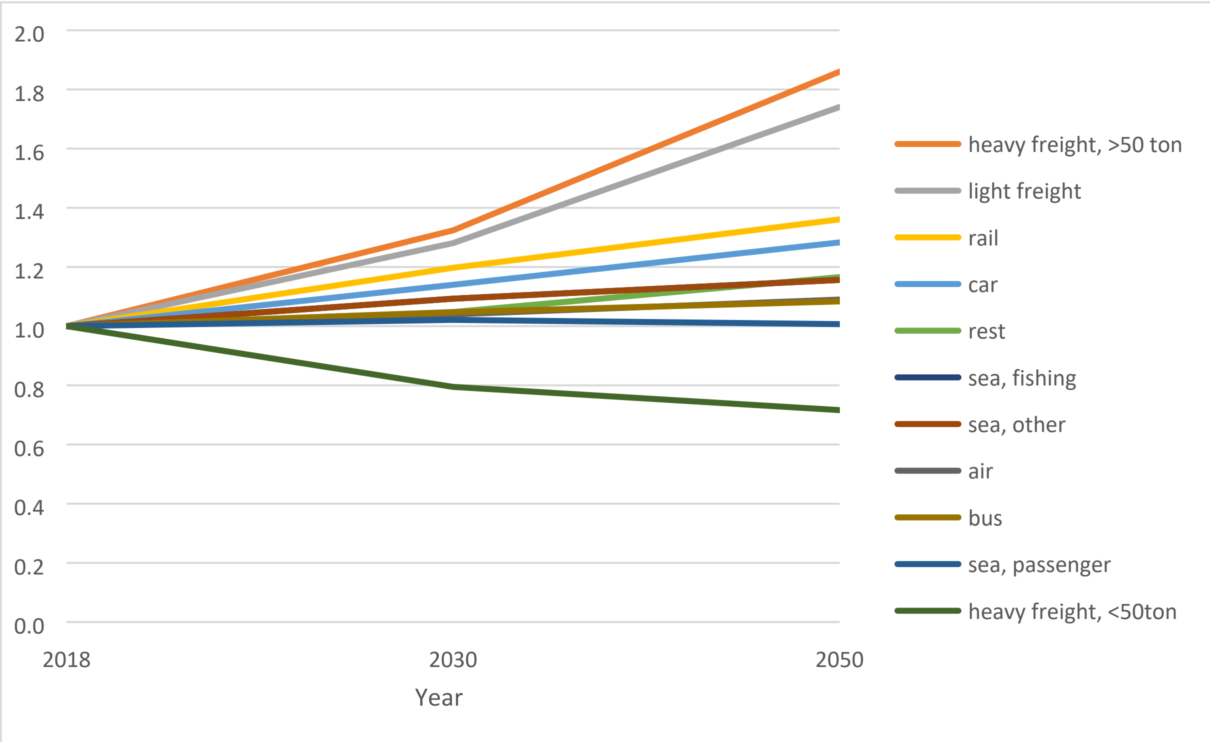

Figure 35 The relative change of demand for the default scenario (NTP) in 2018, 2030 and 2050

5.3.3 Available powertrains

In IFE-TIMES-Norway, various technologies or powertrains can be used to satisfy the transport demand. The powertrains included in IFE-TIMES-Norway are internal combustion engine (ICE), plug-in hybrid with ICE, battery electric, fuel cell electric and gas-powered ICE. A more detailed description of each powertrain is presented in Table 32.

Table 32 Description of powertrains, how they are defined in IFE-TIMES-Norway and input commodities.

Power trains	Description of powertrain	Powertrain definition in TIMES	Commodity used
ICE	Within this category is aggregated ICE using petrol and diesel. In addition, hybrid vehicles which are not plug-in are included here. They can use fossil fuel, biofuel or a mix	XXX-ICE	FOS BIO-FUEL
Plug-in hybrid	In similarity with ICE powertrain, both petrol and diesel engines are considered. In addition, a share of energy can be supplied by electricity.	XXX-PLUG	FOS BIO-FUEL ELC-LV
Battery	Battery electric vehicle are modelled to be charged by electricity provided from charging infrastructure	XXX-ELC	ELC-CAR
Fuel cell	Fuel cell and battery hybrid system entirely powered by hydrogen. Hydrogen production and handling is modelled separately in IFE-TIMES-Norway.	XXX-H2	H2
Gas powered ICE	Based on liquid or compressed biogas used in ICE for urban busses.	XXX-GAS	GAS

Various of the powertrains have several commodities as input and limitations are set for some of them of how small or big share they can be of the total input. An overview of set limitations is shown in Table 33. Biofuels represented 12% of volumetric fuel demand for road transport in 2018 [56], it is simplified in IFE-TIMES-Norway to also represent the energy demand covered by biofuels in the starting year. Norwegian law requires to reach at least 20% share of biofuels by 2020 including minimum 4% of advanced biofuels, which are allowed to be double counted in the legislation [57]. This implicates an actual blending with minimum 16% of biofuels in 2020 and it is fixed to this limit in the model. While the upper limit is allowed to reach 100% by year 2040.

The share of electricity usage in plug-in vehicles depends on a wide range of parameters and is difficult to estimate. In IFE-TIMES-Norway, the data presented in [58] of 30% electricity share, based on measured data from www.spritmonitor.de, are used. As shown in Table 33, the value is assumed to be constant in IFE-TIMES-Norway until 2050.

Table 33 Share of commodities for certain powertrains.

		Start year	2020	2040	2050
BIO-FUEL input for ICE	Max	12%	19%	100%	
	Min	12%	19%	19%	
Electricity input in plug-in hybrid	Max	30%			30%

When considering the specific conditions in the Norwegian transport sector and current technological development, not all the powertrains are considered of relevance for all the different demands. In Figure 36 Matrix of powertrains applied for the different road transport demandFigure 36**,** an overview of which powertrains are considered for each type of road transport demand is presented. Battery powertrain is defined for large trucks with long haulage but is usually not included in reference scenarios as per today it is uncertain whether such a solution would be technically feasible.

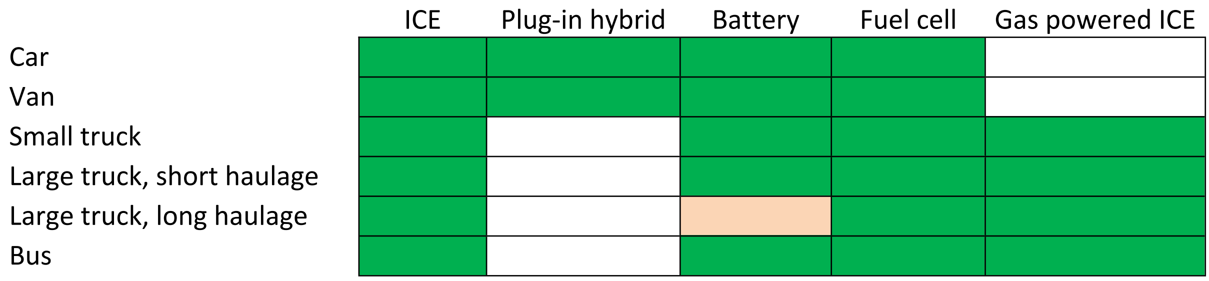

Figure 36 Matrix of powertrains applied for the different road transport demand

Some technologies of vans and busses are limited to give a more realistic development in certain model scenarios, see Table 34. Battery vehicles are highly efficient with low maintenance and fuel costs. However, for heavy-duty applications their current limited range is a strong drawback and can oppose limits of their penetration in heavy-duty segments. Based on the technical performance of the vehicles in current demo projects in Norway, a market penetration of approx. 1% can be achieved [53]. However, rapid technology increase is expected. A forecast to the trucks market share is shown in Table 34.

Table 34 Upper market share limitations of vans and buses

Technology	Market share		
	2018	**2030**	**2040**
Battery electric vans		15%	100%
Plug-in vans		15%	100%
Biogas busses		10%	50%
Battery electric Small truck	0%	100%	
Battery electric Large truck, short haulage	0%	100%	
Battery electric Large truck, long haulage	0%		

5.3.4 Existing stock

The existing fleet of vehicles at the start year is modelled as a stock of ICE powertrains, which linearly decreases to zero during a time span equivalent to the vehicle's lifetime. The only exception is the rapid increase in fleets of battery and plug-in hybrid powertrains for TCAR, which has emerged only during the last years. These are defined more specifically as past investments using PASTI and based on the road traffic volumes provided by Statistics Norway [59]. For battery vehicles data between 2012 and 2019 is used, while for plug-in hybrids available data spans between 2016-2019.

The distribution of the transport demand and corresponding vehicle fleet is assumed to be constant over time as per distribution shown in Table 35. In the same Table 35, it is also shown how existing stock of battery vehicles are distributed with a greater density in the southern parts of Norway.

Table 35 Distribution of transport demand and existing stock of battery vehicles over regions

	Transport demand	Battery vehicle distribution
NO1	42%	51%
NO2	24%	21%
NO3	16%	10%
NO4	9%	3%
NO5	9%	15%
Total	100%	100%

5.3.5 Input values

Where possible, data for Klimakur 2030 are used, as this source is being the knowledge ground for studies of how to reduce greenhouse gas emissions in Norway and to have a consistent method for many input data for transport segment in IFE-TIMES-Norway. The disadvantage is that it only presents data for ICE and battery powertrain, while data for other sources needs to be complemented from other sources. When data is complemented, it is more important to simulate the relative change in the parameters between the powertrains than absolute values. Therefore, relative change in parameters with base in ICE powertrain is used for complementary data. Exception has been made for investment costs for trucks, where data from TØI are used as basis.

5.3.5.1 Fuel consumption

In this chapter the different processes/powertrains for the different technologies are presented.
The fuel consumption is taken for vehicles in 2020 and applied for start year, which makes the modelled fuel consumption for start year slightly higher than reality. The fuel consumption of existing stock is based on the one of new cars in the start year, but with slightly increased fuel consumption to match the CO2 emissions for 2018. See last part in this chapter for the comparison. No adjustments are made to the fuel/energy consumption of EV stock.

Passenger cars (TCAR)

The statistics of cars sold during 2017 and 2018 shows approx. even split between small and compact cars and medium, large and luxury cars [60]. The fuel consumption for TCAR-ICE and TCAR-ELC in 2020 is based on the average value of a small and a large representative car in Klimakur 2030 – teknisk notat [15]. The chosen representative cars are VW Golf for a small car and VW Tiguan for a large car. Golf is available both with ICE and battery while Tiguan is available only with ICE. The study however discomposes each car and set an imaginary battery propulsion in VW Tiguan. The weakness of Klimakur 2030 report is that it does not include other relevant powertrains such as plug-in hybrid and hydrogen cars. To have a complete and a consistent dataset, relative relationships between different powertrains and years are taken from an extensive analysis of drivetrains made in modelling program Autonomie by Argonna national laboratory [61]. When applying trends from [61]; the fuel consumption relationship between powertrains and development over time is based in a midsize car, at low technology development and at high cost prediction. In addition, the energy consumption is based on average value from the two driving cycles used in the simulation, Urban Dynamometer Driving Schedule and Highway Federal Emissions Test. The energy demand for fuel cell vehicles is interpreted as very optimistic, thus the fuel consumption of fuel cell cars in start year and in future is taken from Danish Teknological Institut [58]. An overview of the values used are shown in Table 36.

Table 36 Energy consumption for passenger cars (TCAR)

Name in TIMES	Start year		2050	
	kWh/km	Source	kWh/km	Source
TCAR-ICE	0.57	Average small and big car from [15]	0.39	31% improvement from 2020 according [61]
TCAR-ICE_0	0.64	15% increase from new investment		
TCAR-ELC	0.19	Average small and big car from [15]	0.12	12% improvement from 2020 according [61]
TCAR-ELC_0	0.19	Same as new investment		
TCAR-PLUG	0.42	Relative improvement from ICE according to [61]	0.32	24% improvement from 2020 according [61]
TCAR-PLUG_0	0.47	15% increase from new investment		
TCAR-H2	0.33	[58]	0.28	[58]

Vans (TVAN)

There is less literature available regarding vans in comparison with passenger cars, but in large extent they are similar in size. Especially when considering that max gross vehicle weight (GVW) for both types are 3.5 tons and that 71% of total vans vehicle km in Norway during 2019 was made with small vans with max payload of 1 ton [62].

The fuel consumption of ICE and battery vehicles are based on the average value of light and heavy van specified in Klimakur 2030. The light van in Klimakur 2030 is defined to be below 1.7 ton GVW and heavy vans above that limit and below 3.5 ton. It is comparable, even if not the same definition as in SSB.

In Table 37, the final values used for powertrains for TVAN in IFE-TIMES-Norway are shown.

Table 37 Energy consumption for vans (TVAN)

Name in TIMES	Start year		2050	
	kWh/km	Source	kWh/km	Source
TVAN-ICE	0.59	Average of light and heavy van from [15]	0.40	Same improvement as for TCAR-ICE
TVAN-ICE_0	0.73	25% increase from new investment		
TVAN-ELC	0.19	Average of light and heavy van from [15]	0.12	Same improvement over time as for TCAR-ELC
TVAN-PLUG	0.42	Same relative improvement as for TCAR-PLUG relative to TCAR-ICE	0.32	Same improvement over time as for TCAR-PLUG
TVAN-H2	0.33	Same relative improvement as for TCAR-H2 relative to TCAR-ICE	0.28	Same improvement over time as for TCAR-H2

Trucks (TTRUCK-S, TTRUCK-LS and TTRUCK-LL)

For trucks and tractor units it is challenging to find a complete dataset which represents the fuel consumption for all the powertrains used and adapted for the Norwegian conditions. Several factors make the Norwegian usage pattern unique, for example: (i) higher max GVW in comparison with EU and USA as default max GVW is 50 tons and in some exceptions up to 60 tons (ii) mountainous landscape with few highways results in low average speed with frequent up and downhills.

The efficiency of ICE vehicles is based on empiric data from almost 900 000 working days in trucks with engines between 200 to 700+ horsepower. This data was gathered in LIMCO project led by TØI and shared with IFE. The received data was than weighted against how the daily milage is distributed in the national fleet (Table 30) and for each truck type as defined previously.

For zero-emission heavy-duty technologies there is present only a limited amount of experience, which results in a great variation in expected fuel consumption. For example, relative improvement in fuel consumption versus ICE for a battery truck from Klimakur 2030 is similar to fuel cell truck presented by Fulton et.al. [63]. To include the difference in energy loss between a battery and a fuel cell technology, their relative advantage versus ICE are based on Fulton et.al. [63]. A shortage in the work of Fulton et.al. is lack of electric long-haul truck, such as example Tesla Semi. To estimate the improved energy efficiency of such a truck in Norway, the relative improvement for a short-haul truck from fuel-cell to battery is used as reference.

It shall be noticed that for long-haul vehicles in [63] with electric and hydrogen powertrain the advantage to ICE is notably reduced. This dynamic is based in the fact at steady long-haul driving, the efficiency of ICE increase, while the possibility to regenerate power in electric driveline decreases.

Two long-term trends in goods transport can contribute to reduce the emissions per transported ton of goods and the cost of transport; (i) the emissions and cost per ton goods are reduced if more goods are transported per vehicle which encourages the use of bigger vehicles and (ii) the steady increase in the energy efficiency of the vehicles. The first trend forces the energy consumption per vehicle up as the average vehicle becomes heavier and the second trend decreases the energy consumption per vehicle. As there lies an uncertainty on how the future heavy-duty market will develop with contradicting trends regarding the fuel consumption per vehicle, the energy efficiency for trucks is set constant from start year until 2050.

The values used in IFE-TIMES-Norway based on the sources and assumptions mentioned above is shown in Table 38.

Table 38 Energy consumption for trucks

Name in TIMES	Start year	
	kWh/km	Source
TTRUCK-S-ICE	3.58	Aggregated data from LIMCO [15, 64]
TTRUCK-S-ICE_0	3.94	10% increase from new investment
TTRUCK-S-ELC	1.12	Relative improvement from ICE in a short-haul truck according [63]
TTRUCK-S-H2	1.72	Relative improvement from ICE in a short-haul truck according [63]
TTRUCK-LS-ICE	4.83	Aggregated data from LIMCO [64]
TTRUCK-LS-ICE_0	5.31	10% increase from new investment
TTRUCK-LS-ELC	1.51	Relative improvement from ICE in a short-haul truck according [63]
TTRUCK-LS-H2	2.32	Relative improvement from ICE in a short-haul truck according [63]
TTRUCK-LL-ICE	4.19	Aggregated data from LIMCO [64]
TTRUCK-LL-ICE_0	4.61	10% increase from new investment
TTRUCK-LL-ELC	2.30	Relative improvement as from H2 to ELC short-haul truck according to [63]
TTRUCK-LL-H2	3.48	Relative improvement from ICE in a long-haul tuck according [63]

Buses (TBUS)

The Norwegian Institute of Transport Economics have had close follow up of the national public transport system and its experience of zero-emission technology. Their work published in [53, 65] provides fuel consumption for the complete set of technologies currently (2016-2019) and short/middle term with improved ICE engine and more mature battery technology in 2025. Due to the bus segments limited role in the transport sectors total energy consumption, no analysis was made for trends beyond 2025. An overview of the values used is shown in Table 39.

Table 39 Energy consumption for busses (TBUS)

Name in TIMES	Start year		2025	
	kWh/km	Source	kWh/km	Source
TBUS-ICE	4.20	[53]	4.10	[53]
TBUS-ICE_0	4.83	15% increase from new investment		
TBUS-GAS	5.38	Increase relative to ICE Euro IV according to [65]	5.25	Increase relative to ICE Euro IV according to [65]
TBUS-GAS_0	6.18	15% increase from new investment		
TBUS-ELC	2.30	[53]	2.10	[53]
TBUS-H2	3.33	[53]	3.33	[53]

CO_2 emissions in start year

The CO_2 emissions in the start year are adjusted to match the national emissions from road transport in 2018. As in IFE-TIMES-Norway, the existing stock of vehicles are modelled relatively course, and thus there is a small mismatch in numbers, as shown in Table 40.

Table 40 Comparison of CO_2 emissions from road transport in 2018 from Statistics Norway (SSB) [66] and IFE-TIMES-Norway start year

		Statistics Norway	IFE-TIMES-Norway
		Mill. ton CO2	Mill. ton CO2
Car		**4,83**	**4,89**
Light transport		**1,4**	**1,25**
Heavy transport		**2,95**	**3,01**
	TTRUCK-S		0,50
	TTRUCK-LS		1,02
	TTRUCK-LL		0,88
	BUS		0,61
Total emission from road transport except 2 wheelers		**9,18**	**9,16**
2-wheelers		**0,13**	
Total emission from road transport		**9,31**	**9,16**

5.3.5.2 Maintenance costs

The maintenance costs (see Table 41) are based on values specified in Klimakur 2030 [15] for ICE and battery powertrains and adapted to gas, plug-in and fuel cell vehicles. In Klimakur 2030 they are maintained constant until 2030, and in IFE-TIMES-Norway they are also assumed constant until 2050. The only exception for the rule is fuel cell vehicles, and this is explained more in detail below.

The maintenance cost for gas buses is assumed to be the same as for ICE. For plug-in vehicles an average maintenance cost between ICE and battery vehicles is assumed, motivated by decreasing wear of the brake system, but a remaining complex powertrain with many rotating parts. For fuel cell vehicles, in start year, the same maintenance cost is set as for plug-in vehicles, but the maintenance cost based on fuel cell technology remains a novel technology and might require closer follow up in near term, while in the long term the maintenance level is assumed to be comparable with EV.

In Klimakur 2030, the maintenance costs for heavy-duty trucks are not differentiated between battery and ICE powertrains, thereby also no differentiation is made in IFE-TIMES-Norway.

Table 41 Maintenance costs in NOK/km

	Year	ICE	Plug-in hybrid	Battery	Fuel cell	Gas
TCAR	Start year	0.62	0.45	0.28	0.45	
	2030				0.28	
TVAN	Start year	0.65	0.46	0.28	0.46	
	2030				0.28	
TTRUCK-S	Start year	0.98		0.98	0.98	
TTRUCK-LS	Start year	0.98		0.98	0.98	
TTRUCK-LL	Start year	0.79		0.79	0.79	
TBUS	Start year	2.20		1.60	1.90	2.20
	2030				1.60	

5.3.5.3 Investment cost

The VAT and purchase fees are included only for cars due to it is expected to present in best ways the cost exposed to the buyer of the vehicle.

Passenger cars (TCAR)

In TØI report “360 graders analyse av potensialet for nullutslippskjøretøy", the car sales is divided into several car type segments and the cost of each segment (small, compact, medium size, large and luxury). The two largest segments of cars sold is compact and medium size cars standing for 43% and 27% of the sales, respectively. [60]

The purchase price of ICE and EV vehicles are based on Klimakur 2030 [15]. The costs are just as fuel consumption based on a representative car and the costs used in IFE-TIMES-Norway is an average value between a small and a large car. For more detail information about the representative cars see chapter “5.3.5.1 Fuel consumption”.

For powertrains other than ICE and battery, the costs are taken from TØI report “360 graders analyse av potensialet for nullutslippskjøretøy" based on weighted purchase cost from all the car segments. Klimakur 2030 provides cost development between 2020 and 2030. TØI report “360 graders analyse av potensialet for nullutslippskjøretøy" provides costs in 2019 and 2025. The costs from TØI report are adjusted to start year and 2030, respectively.

The summary of the used costs for TCAR in IFE-TIMES-Norway excluding VAT and fees is shown in Table 42.

The VAT of 25% is assumed to be paid both for ICE and plug-in vehicles, while the one-time fee is assumed to be 91160 NOK for ICE and 2877 NOK for Plug-in vehicle based on values provided by [60]. To include these values in TIMES, the fees are added upon the vehicle cost and thereafter converted to input for TIMES considering the vehicles average annual mileage.

Table 42 Investment costs for TCAR exclusive taxes and fees

Name in TIMES	Start year		2030	
	NOK	Source	NOK	Source
TCAR-ICE	229,100	Average small and large car [15]	241,643	Average small and large car [15]
TCAR-ELC	480,500	Average small and large car [15]	248,489	Average small and large car [15]
TCAR-PLUG	306,381	Trend relative to ICE from [60]	287,546	Trend relative to ICE from [60]
TCAR-H2	765,167	Trend relative to ICE from [60]	370,661	Trend relative to ICE from [60]

Vans (TVAN)

Klimakur 2030 provides cost for a large and small van for both ICE and battery powertrains. While for other powertrains is applied the same relative cost trends as for TCAR based on the similarities between TVAN and TCAR discussed in chapter “5.3.5.1 Fuel consumption”. The summary of the costs for TVAN in IFE-TIMES-Norway is shown in Table 43.

The one-time fee is indicated to be 24 000 NOK for small vans and 69 000 for large vans for ICE vans [15]. In IFE-TIMES-Norway, an average of 46 500 NOK per ICE vehicle is used. For plug-in vehicles, the fee is assumed to be so low that it is assumed to be neglectable.

Table 43 Investment costs for TVAN exclusive taxes and fees

Name in TIMES	Start year		2030	
	NOK	Source	NOK	Source
TVAN-ICE	230,500	Average small and large van [15]	236,240	Average small and large van [15]
TVAN-ELC	506,000	Average small and large van [15]	248,489	Average small and large van [15]
TVAN-PLUG	308,254	Trend relative to ICE from [60]	281,116	Trend relative to ICE from [60]
TVAN-H2	769,842	Trend relative to ICE from [60]	362,373	Trend relative to ICE from [60]

Trucks (TTRUCK-S, TTRUCK-LS and TTRUCK-LL)

The investment cost for 2020 and 2030 are based on data received from TØI. They have built up the dataset through cost decomposition of different parts of the vehicle. In addition, a premium cost is added for novel powertrains. This additional cost can at least to some part be assigned to R&D. The costs of 2020 are quality checked by known truck OEM.

In IFE-TIMES, it is assumed that a continues development of investment costs for new drivetrains (fuel cells and batteries) continues also after 2030, while investments in ICE and GAS powertrains are assumed to be constant. Fulton et.al. [63] predicts that by 2050 the fuel cell and battery trucks investment costs will reach almost parity with ICE and their relative cost differences are applied.

A simplification has been made by assuming the same investment cost for TTRUCK-LS and TTRUCK-LL, where it would be reasonable to assume that trucks who drive longer would need larger batteries and hydrogen tanks, thus be more expensive relative to ICE. As battery and fuel cell trucks still are in their infancy, it is hard to find such a distinction in the literature. It shall be noted that battery vehicles are not included for TTRUCK-LL in a typical reference scenario due to the uncertainty of its technical feasibility.

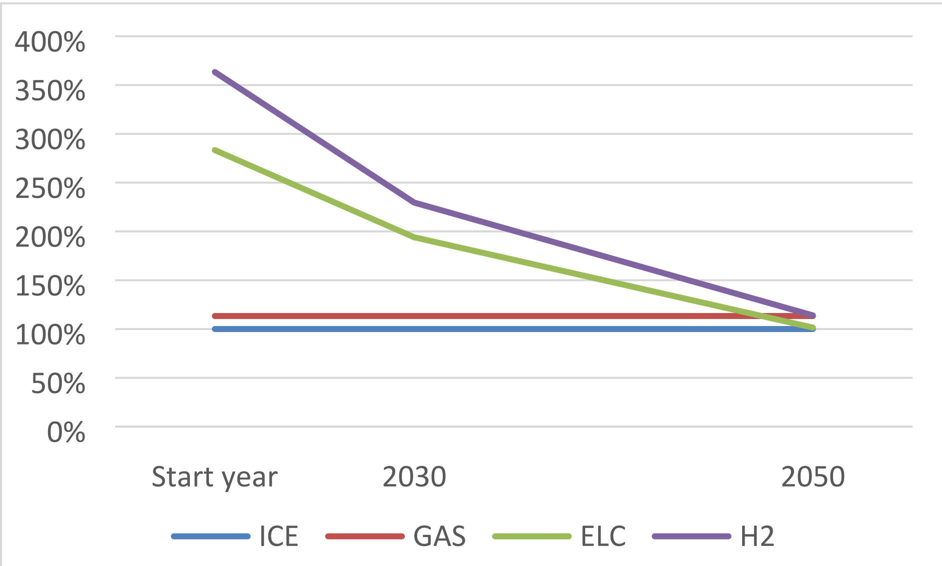

Figure 37 Investment cost development for TTRUCK-S

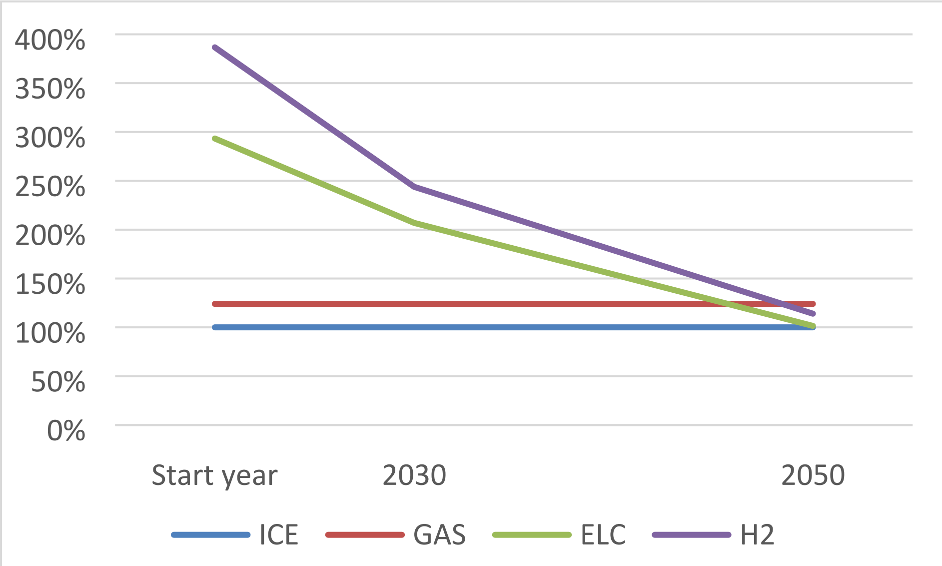

Figure 38 Investment cost development for TTRUCK-LS & LL

By 2020 the large-scale deployment of battery and hydrogen powertrains are still lacking, however strong activity within this field is noted with announcements of introduction of several models during the coming year. Therefor the starting year at which they can be deployed in the model has been adjusted as presented in Table 44.

Table 44 Starting year for investment in battery and hydrogen powered trucks and tractor units.

Type of truck and powertrain	Starting year
TTRUCK-S-ELC &TTRUCK-LS-ELC	2022
(TTRUCK-LL-ELC)	2025
TTRUCK-S-H2	2025
TTRUCK-LS-H2 & TTRUCK-LL-H2	2025

Buses (TBUS)

The investment cost of bus until 2025 is based on TØI report "Klima-og miljøvennlig transport frem mot 2025" [67]. The cost trend of ICE bus and the relative cost to ICE for the other powertrains in 2050 is based on cost development of urban buses from Fulton et.al. [63] from UCDavis. The summary of the used costs for TBUS in IFE-TIMES-Norway is shown in Table 45.

Table 45 Investment costs for TBUS exclusive taxes and fees

Name in TIMES	NOK	Source
	Start year	
TBUS-ICE	2,000,000	[67]
TBUS-GAS	2,200,000	[67]
TBUS-ELC	4,500,000	[67]
TBUS-H2	8,000,000	[67]
	2025	
TBUS-ICE	2,000,000	[67]
TBUS-GAS	2,200,000	[67]
TBUS-ELC	3,000,000	[67]
TBUS-H2	4,000,000	[67]
	2050	
TBUS-ICE	2,116,000	Relative change from 2025 according to [63]
TBUS-GAS	2,435,000	Trend relative to ICE from [63]
TBUS-ELC	2,116,000	Trend relative to ICE from [63]
TBUS-H2	2,290,000	Trend relative to ICE from [63]

5.3.5.4 Lifetime and annual mileage

Lifetime and annual mileage are two additional input variables used in IFE-TIMES-Norway and which are correlated. In general, vehicles annual mileage is highest the first years and drops considerably with age. In addition, vehicles of a given purchase year are continuously phased out from the fleet. In IFE-TIMES-Norway, these parameters are simplified with a constant annual mileage each year and with equal lifetime for each type of vehicles.

To find a fixed representative values for a continuous process of vehicle phase-out and reduced mileage over time, Statistics Norway data was used to look at how the share of annually mileage where accumulating with the age of vehicles, see Figure 39. The lifetime of vehicles in IFE-TIMES-Norway is set to a threshold of age at which approx. 90% of the yearly road traffic volume is covered.

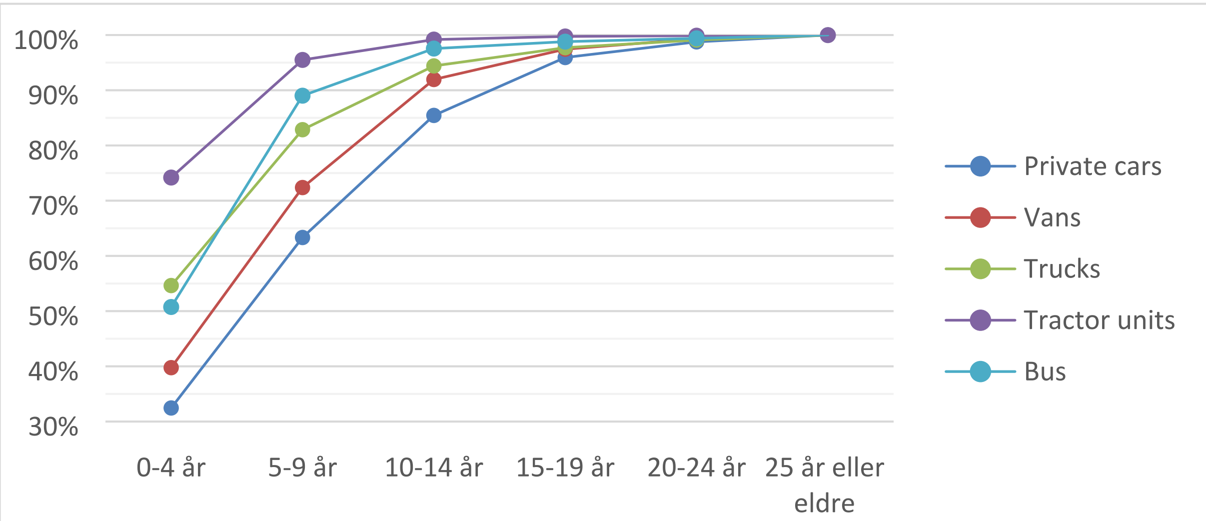

Figure 39 Accumulated traffic volume of each vehicle type depending of age, based on data from [62]

Same Statistics Norway database, which is used to select vehicle lifetime, offers both the road traffic volume in absolute values and an average yearly mileage per vehicle. From this data, it was possible to find the number of vehicles in each time bin. The average annual mileage is based on the road traffic volume divided by the number of vehicles, including only traffic volume and vehicles during the assumed vehicle lifetime in IFE-TIMES-Norway. The resulting annual mileage per vehicle is shown in Table 46.

The available dataset from Statistics Norway is distinguishing trucks between tractor units and all other trucks, while IFE-TIMES follows another division of trucks where both regular trucks and tractor units can be of either TTRUCK-LS and TTRUCK-LL type, depending on their typical daily mileages. To define the values for TTRUCK-LL, it is assumed that trucks drive a bit higher annual mileage and that their lifetime is a bit shorter than tractor units, hence some of the tractor units have lower annual mileages and by that sorted under TTRUCK-LS. While for TTRUCK-S and TTRUCK-LS the opposite is made based on the data provided for the rest of the trucks. The assumptions are shown in Table 46.

The simplification of vehicle lifetime and average annual mileage has some shortcomings, such as underestimating usage of newly invested vehicles (new technology) and overestimated usage of vehicles at the end of its lifetime in IFE-TIMES-Norway (old technology). In addition, omitting usage of old and very old vehicles which are past the lifetime set in IFE-TIMES-Norway.

Table 46 Lifetime and annual mileage used in IFE-TIMES-Norway

Vehicle type	Lifetime (years)	Average annual mileage (km)
TCAR	17	13 200
TVAN	15	15 300
TTRUCK-S	15	30 000
TTRUCK-LS	13	35 000
TTRUCK-LL	6	90 000
TBUS	10	41 800

5.3.6 Growth limitation

By default, TIMES select the technology to invest in based on the lowest lifetime cost option available. It means that once a new technology becomes the cheapest option, the entire investment in new capacity is shifted to this new technology. A 100% switch between vehicle powertrains from one year to another is assumed as unrealistic for vehicle sales and thereby a limitation is placed on how large increase in new capacity can be made for the different powertrains. These limitations are made with the help of NCAP, GROWTH user constrain.

The calibration of the growth constrain is inspired by TØI analysis made by stock-flow vehicle fleet model [68]. The year-to-year growth of a technologies market share will vary as new technologies tend to conquest a market first with early movers, then the majority is onboarding, and at last the laggards are adopting. It makes the new technologies market share to have a S-form, as seen in Figure 40. On the other hand, the growth constraint functionality in TIMES is based on a constant year-to-year growth limitation value, which provides an exponential growth of market share over time.

To make the best possible approximation for the growth constrain; the initial investment in the new technology is allowed to be relatively large share of the total new investments and the annual growth rate is selected to fit best where the new technology share of new investments increase most rapidly. The average growth increase is selected as the averaged year-to-year growth value when new investment share of zero emissions is increased from 10% to 90% for the three technologies shown in Figure 40. The growth constrain is adopted to both electric and hydrogen powertrains, while it is assumed that the growth for individual technologies and vehicle types can be double as fast. It is especially relevant for trucks as they are subdivided into several subcategories and that they are the most relevant pretendent for both battery and fuel cell technology in the road transport.

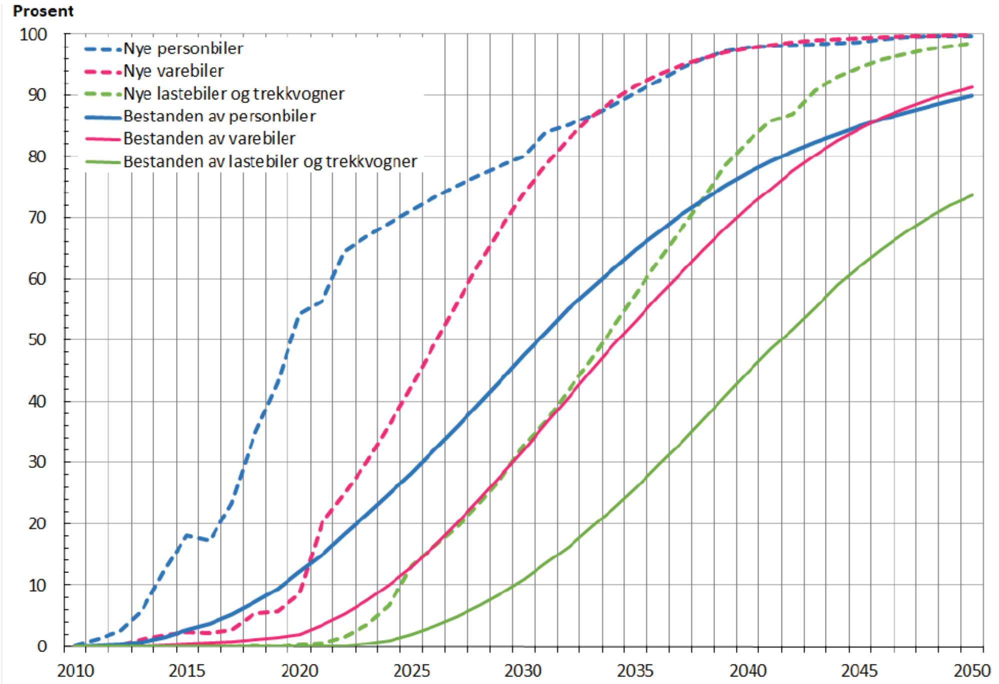

Figure 40 The zero emission vehicles share of new investment and fleet in the fast decarbonization scenario presented in [68]

This growth constrain is also adopted to conventional technologies, to limit a possible high fluctuation in their market share as well. So, for technologies with existing stock, the user constrain comes into force two years after the stock is defined either by STOCK or PASTI variable in TIMES. Thereby these technologies can calibrate what is a typical amount of new investments in each technology before the user constrain is applied. While for technologies without an existing stock, a predefined first investment is allowed, so called seed value. It is sized to represent 10% of total new investment needed within one modelling period.

5.3.7 Charging infrastructure for EV's

All electrical vehicles are depending on having available charging infrastructure, which brings an additional cost to the system in comparison with current well-established petrol filling station infrastructure. For private vehicles and vans, three different chargers are included: Residential, Commercial and Fast charging. The Commercial charging is defined as slow charging that it is done close to commercial buildings, with intention to represent that the car is charged at work. The typical usage pattern over a day is shown in Figure 41. For vans, the same type of charger is assumed and that the charging is occurring at home or at commercial buildings.

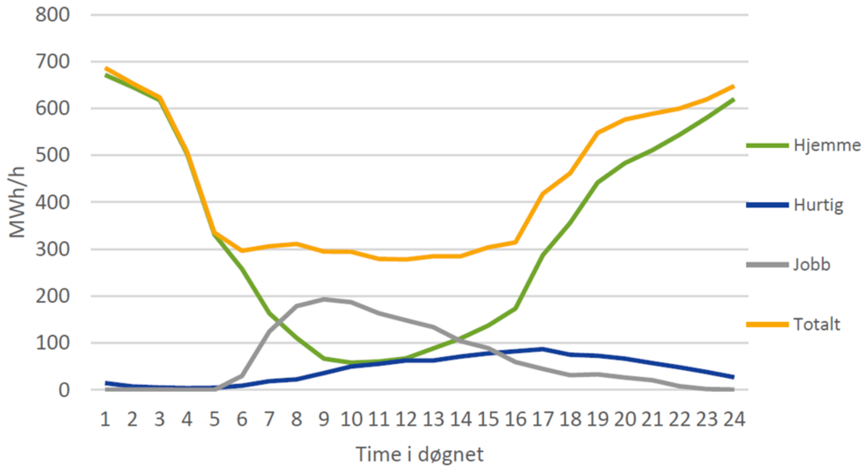

Figure 41 Total power demand from EV charging and disaggregated for different charging locations. [69]

For heavy-duty vehicles, both slow and fast charging are considered. Both profiles are shown in Figure 42 and share between slow and fast charging for each truck type is shown Table 47. As majority of trucks below total GVW of 50 ton drives short distances, they are assumed to mainly utilize slow chargers. TTRUCK-LS (total GVW ≥50 ton & <300 km/day) are assumed to entirely depend on slow chargers. On the other hand, TTRUCK-LL (total GVW ≥50 ton & >300 km/day) are assumed to depend equally much on slow and fast chargers.

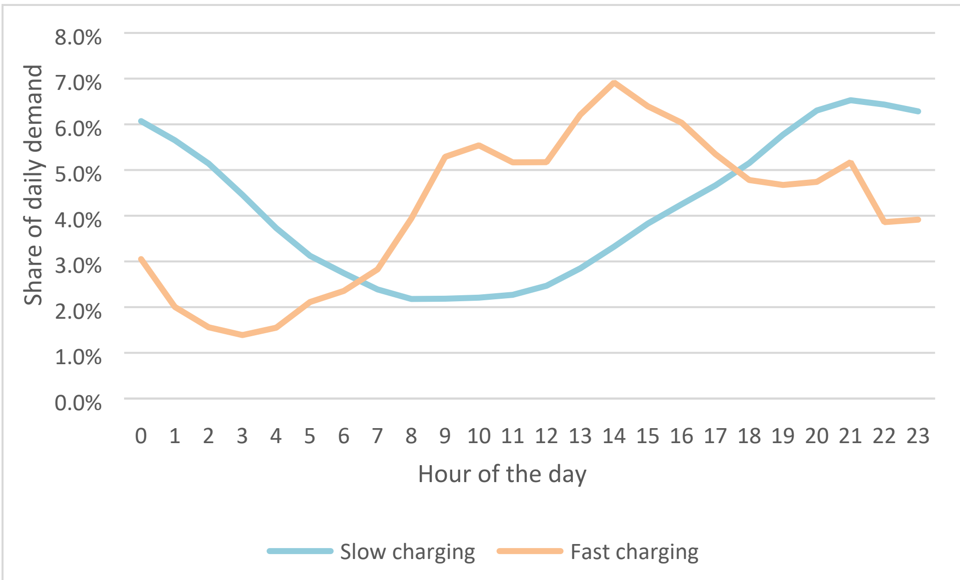

Figure 42 Slow and fast charging profiles based on data gathered within Limco project [70]

Table 47 Share of energy supplied to electric trucks from slow and fast chargers.

	Slow charging	Fast charging
TTRUCK-S	75%	25%
TTRUCK-LS	100%	
TTRUCK-LL	50%	50%

The costs of charger are based on data published in Klimakur 2030 report [15]. For residential and commercial charger, the cost of a charger is based on a <11kW installation with assumed average output of 7kW. For fast charging it is assumed costs of 50kW charger at start year which is fully replaced by 150kW charger in 2025.

For heavy-duty charging, there is limited data. In Klimakur is provided a cost of a 50 kW charger, which represent a slow charger. The cost from Klimakur 2030 report is complemented with a grid connection fee, as the first chargers installed at a logistic central or similar will probably not need grid enforcement. But when larger volumes will need to be deployed, a need for grid reinforcement will be required. There are very limited data for fast charging of heavy-duty truck, so their costs are expected to be closer to costs and performance of 350 kW light duty charger than a pantograph type chargers currently installed to serve fixed route electric busses. As buses consist for such a small share of road traffic, they are utilizing same charging infrastructure as trucks in the model and with flat charging demand profile.

The main charger unit, either it is onboard or external, rectifies electricity from AC to DC, transform it between different voltage levels, in addition energy is required for its control unit. Empiric studies shows that a low power output built-in charger for EV's has an efficiency of approx. 80% [71, 72]. Various producers of fast chargers specifies an efficiency of approx. 90% at optimal temperature of approx. 25°C, but is considerably lower at low temperatures [73].

A slow charger will typically be installed to charge a specific vehicle for a long period of time (8-12 h). When including days when the vehicle will need only limited charging or if it is standing still, the chargers overall utilisation rate will be further reduced. On the other hand, a fast charger will be serving many vehicles, but only for a limited amount of times. As such charger is designed for a peak demand which occurs occasionally, while low demand periods, e.g., nights, are reoccurring frequently, it will also face relatively low utilisation rates. The annual utilisation rate for fast chargers is inspired by vehicle passage counts at Hanestad and Gol and how they vary throughout the year. While for slow charging, the annual utilisation rate was set to 25%, which means that each charger in average charges vehicles for 6 hours every day.

The lifetime is assumed and needs to be reviewed later.

Table 48 Type of chargers used in IFE-TIMES-Norway and their characteristics. Based on [15, 71, 73] and own assumptions.

	Year	Light-duty			Heavy-duty	
Type of charger		Residential	Commercial	Fast charging	Slow charging	Fast charging
Commodity used		ELC-LV-RES	ELC-LV-COM	ELC-LV-COM	ELC-LV-COM	ELC-LV-COM
Effecincy		80%	80%	90%	90%	90%
Equipment and installation cost (NOK/kW)	2018	2857	2857	7000	5000	3400
	2025			3000		
Grid connection fee (NOK/kW)	2018			5000	2000	1000
	2025			2000		
Lifetime (year)		15	15	15	15	15
Utilisation factor		25%	25%	30%	25%	30%

5.4 Non-road transport

5.4.1 Structure and demand

Other transport than road transport is transport by rail, sea and air. In addition, a category gathering the rest of transport demand is included in "other transport". Demand is modelled as an energy demand (GWh/year) in these categories. The demand projection is presented in Figure 43.

Energy use of domestic air transport in the base year is divided in the five regions based on population in 2018. Development in passenger km in NTP 2022-2033 [55] is used to demand projection. Sea transport is divided in passenger transport, fishing and other sea transport. The projection of passenger sea transport is based on the development of passenger km in NTP 2022-2033 [55]. For the two other sea transport categories, the total development of freight transport by sea is used. The projection of rail transport is 50% based on development of passenger transport and 50% on freight transport. The rest category is assumed to develop as the increase in population of Statistics Norway 2020 (MMMM alternative).

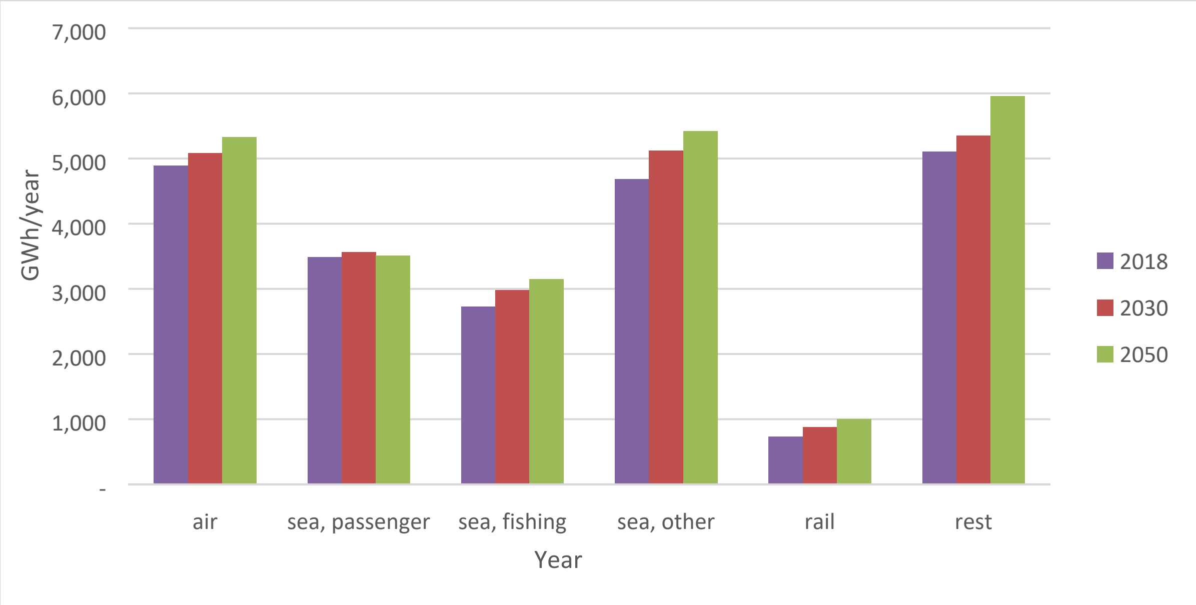

Figure 43 Energy demand of non-road transport in 2018, 2030 and 2050, TWh/year

5.4.2 Modelling of rail, air and other transport

Energy use in rail transport and other transport is modelled as a share of different energy carriers. In the regions NO1, NO2 and NO5, 100% of electricity is used by the railway. In region NO3, the electricity share for railway is 8% and in NO4 the electricity share is 4%. This share is kept fixed until 2050. When electricity is not used, railway can use an optional mix of fossil and biofuel.

In other transportation, only fossil fuel blended with 5% biofuel can be use in the base year. From 2040 a maximum share of 67% electricity and 100% biofuels can be used, linearly increased from the base year. The efficiency of electricity is assumed to be three times better than the use of liquid fuels.

Air transport uses fossil fuels in the base year and a minimum share of 10% biofuels is included in 2020, increasing to 30% in 2050. Electricity can be used in air transport after 2025, linearly increasing to 20% in 2040. Air transport using electricity is assumed to be twice as effective as fossil or biofuels. Cost data is not included in the modelling of air transport.

5.4.3 Maritime transport

The current energy demand and emissions from maritime sector in the start year is received from Statistics Norway divided between coastal transport and fishing. To estimate potential for decarbonisation, it is crucial to disaggregate as maritime transport varies greatly in ship designs and sizes as well as operation patterns. These variating parameters are affecting how well different zero-emission fuels and technologies can penetrate the different ship segments.

From the fuel bunkering data, it is not trivial to track how large share of the fuel bunkered in Norway is used for this purpose, as the maritime sector is very international. Vessels can easily change land of operation or bunker abroad while having main activity in coastal transport or fishing in national waters. Another shortcoming is the ability to distinguish what type of vessel is bunkering as common bunkering infrastructure can be used, including fishing vessels. Additional protocol needs to be implemented to disaggregate the data to fishing and other vessels. So, the data provided gives both uncertainty if the bunkered fuel is used for domestic transport and fishing and how large share of it is used by fishing vessels. It has resulted that energy consumption and emissions for fishing vessels has variated strongly between different methods used by Statistics Norway as well as by other sources. [74, 75]

The ship movement and by that indirectly their energy demand and emissions can also be monitored through Automatic Identification System (AIS) data. It can provide data for all vessels within a given geographical area, such as the Norwegian exclusive economic zone (in Norwegian: Norsk Økonomisk Sone or NØS). However, not all of them are operating for coastal transport. There are other shortcomings of AIS data, as the requirement of installing it applies only for certain size vessels. For fishing vessels, the limit goes at 15 meters and the large majority of fishing vessels are by that excluded from the AIS dataset [15].

In [76], the emissions from AIS data where reviewed within NØS. When only considering vessels spending 80% or more of their time inside NØS and adding an estimate of 240 kton CO_2 equivalents for fishing vessels not covered by the AIS system [77], a close match was achieved with emissions data provided by Statistics Norway as seen in Table 49. The AIS data is presented per ship-type, which is seen as too detailed resolution for the IFE-TIMES model. Therefore, the maritime sector is aggregated to three ship types, divided by colours, and numbering in the same table.

Table 49 Comparison of CO2 emissions from maritime sector based on bunkering and AIS data (compensated for fishing vessels without AIS equipment with 240 kton). Also shown how the different ship types are aggregated in IFE-TIMES

	Statistics Norway (kton CO_2)	DNV GL (kton CO_2)	Share of emissions	Grouping
Passanger ships		831	27%	1
High speed ferries		139,8	5%	1
Cruise		19	1%	1
Fishing vessels		526+240	25%	2
Offshore vessels		711	23%	3
Other special use vessels		117	4%	3
Aquaculture		148	5%	3
Freight ships		199	6%	3
Wet & dry bulk		159	5%	3
6.3.1.0 Navigation - coastal traffic etc.	2713		88%	
6.3.2.0 Navigation - fishing	378		12%	
Sum	**3091**	**3090**		

In the AIS data above, emissions from cold ironing in harbours are not included.

To arrive to decomposition of the maritime fleet energy demand, following simplifications are made:

- The emissions for each ship type for coastal transport and national fishing as presented in Table 49 **is proportional** to the energy demand provided by Statistics Norway. So, the lower emissions due to usage of LNG is overseen.
- The natural gas consumption is assumed to be equal between passenger vessels and other ship types.

- In Statistics Norway, the energy demand for fishing industry also included electricity consumption of 224 GWh in 2018. This demand is excluded as it most probably is assigned to fishing farms or other onshore infrastructure.

The main fuels used in the maritime sector today is liquid (MGO and MDO) and gas (LNG) based fossil fuels. Alternative propulsion fuels considered in IFE-TIMES are batteries and hydrogen for short distance trips and ammonia for deep-sea trips. Liquide hydrogen is also a potential fuel for use in maritime sector, but as it is largely overlapping the usage of ammonia, the latter is chosen to represent hydrogen derivates in deep-sea shipping.

The technology options in IFE-TIMES-Norway and the max share of each technology are shown in Table 50. Due to hydrogen and ammonia immaturity as a maritime fuel, they are only available from 2025. The max market share of each technology for passenger vessels are based on work developed in HyInfra project [78], while for the other two ship types they are based on best guess when considering the ship sizes and trip lengths.

Table 50 Max share of each fuel to serve the maritime demand. Linear interpolation is used for years between inputs

Group	Type of vessel	Year	Fuel used/propulsion system				
			ICE	LNG	Battery	H2	Ammonia
1	Passenger vessels	2018	no limits	0%	0%		
		2025				0%	0%
		2030		86%	49%	13%	38%
		2040					
2	Fishing vessels	2018	no limits	0%	0%		
		2025				0%	0%
		2030			5%	5%	5%
		2040		50%	25%	25%	50%
3	Other vessels	2018	no limits	0%	0%		
		2025				0%	0%
		2030			5%	5%	5%
		2040		90%	10%	10%	90%

Input values

The current fossil fuels are consumed onboard in large and highly efficient (~45-50%) internal combustion engines (ICE). For future fuels, ammonia is also assumed to be consumed in ICE while hydrogen in PEM fuel cells. For both of these new fuels, the energy efficiency is assumed to be similar to conventional ICE. On the other hand, systems based on battery systems is assumed to have efficiency of 80%.

Since hydrogen to Ammonia pathway is not yet included in IFE-TIMES, the additional efficiency lost from hydrogen to ammonia is included in form of relative efficiency reduction of 17%.

As an intent to represent the investment costs related to energy consumption by the maritime sector, a typical ship type was selected for group 1 based on energy consumption [79] and 3 based on largest emissions or energy consumption (Table 50). A representative size and its investment costs were identified as well as the fleet size of the specific vessel. Thereafter based on assumed energy consumption for the specific vessel type a cost per demand in GWh was identified. The assumptions and results can be seen in Table 51.

Fishing vessels size varies greatly and with that also their costs and energy demand. It was not possible to identify how the energy demand is distributed among the different sizes of the vessels and thereby impeding to couple investment costs to energy demand. Thereby, they are assigned the same investment cost as passenger vessels per annual energy consumptions. Even higher value could be expected as not all fishing vessels can work constantly throughout the year as for example ferries or offshore vessels and thereby a lower energy demand per vessel.

Table 51 Investment costs for representative ship technology for maritime demand group 1 and 3

Group	1	3
Type of vessel	Passenger vessels	Other vessels
Example design	Ro Ro Ferry	Platform Supply Vessel (Offshore vessel)
Size [77]	1900 GT (PBE 70)	5080 DWT
Fleet size [77]	203	122
Annual energy consumption (GWh)	856	987
Specific energy consumption (GWh/ship)	4.2	8.1
CAPEX (kNOK/ship)	100'000 [80]	180'000 [81]
CAPEX (kNOK/(GWh/year))	23'728	22'260

Regarding investment in propulsion systems using other fuels, DNV-GL estimates that investment in an LNG ship is 20% more expensive [82]. For the other fuels and propulsion systems, it is very hard to obtain their additional investment costs and their costs are assumed to be 50% higher than for conventional ICE system today. By 2030 their extra costs are assumed to be reduced to 20% higher than ICE.

The lifetime of all ship groups is assumed to be 25 years. Even if ships can live considerably longer, their capacity factors in average are assumed to be higher for newer vessels and that older ships to large degree are sold to other countries. With the ship's long lifetime, it is usual to make retrofits and consider their second-hand. In this simplified approximation to the maritime demand, these aspects are overseen.

6 Results

Results of analyses made in the ITEM project are presented here, based on the assumptions presented in this report. A CO2 tax of 590 NOK/ton CO2 is applied from 2020 increasing to 5 000 NOK/ton CO2 in 2030 and 10 000 NOK/ton CO2 from 2040 to 2050. CCS is not included in the analyses. These results are included in this report as an example of results of analyses with the IFE-TIMES-Norway model. The results highly depend on assumptions and input data to the model and is normally discussed and analysed in more detail than presented here. Scenarios presented here are:

- Fast – fast electrification of transport (main scenario in the figures below)
- BEV – fast with a possibility to use batteries for all heavy road transport
- High industry demand – in line with projections of NVE and Statnett
- Slow – similar to present policy

6.1 Electricity

In a normal year, the total electricity production increases from 145 TWh in 2018 to 223 TWh in 2050 in the Fast scenario, see Figure 44. Hydro power generation increase with 10 TWh from today until 2050, wind power increase with 41 TWh, and PV with 27 TWh. The power trade with neighboring countries is around 20 TWh/year in 2025-2050.

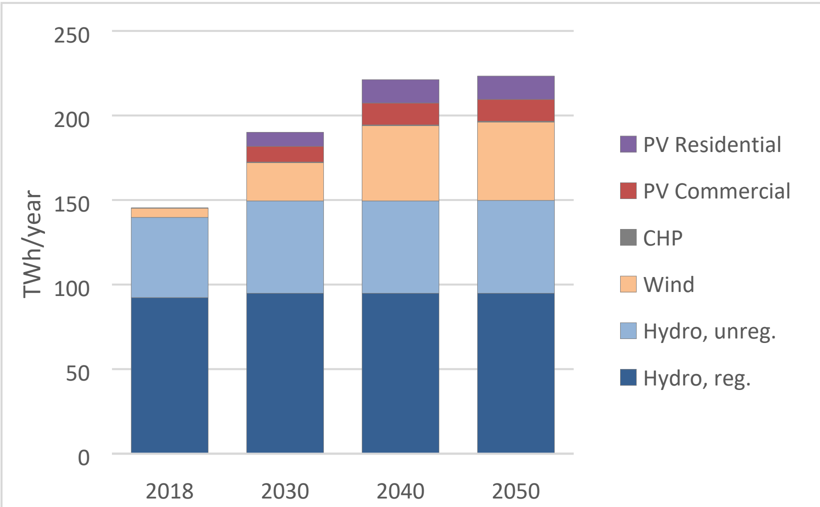

Figure 44 Electricity production, TWh/year

The electricity uses by end-use sector from 2018 to 2050 is presented in Figure 45. Total use of electricity increases by 48-218 TWh in the analyses presented here. Buildings show a slight decrease, while industry increase the electricity about 31 TWh in the base case and about 46 TWh in the high industry demand scenario. Hydrogen production will in these analyses use 15-23 TWh electricity in 2050 (the lower value if all heavy road transport can use battery electric vehicles). Direct use of electricity for transportation is here about 19-25 TWh in 2050.

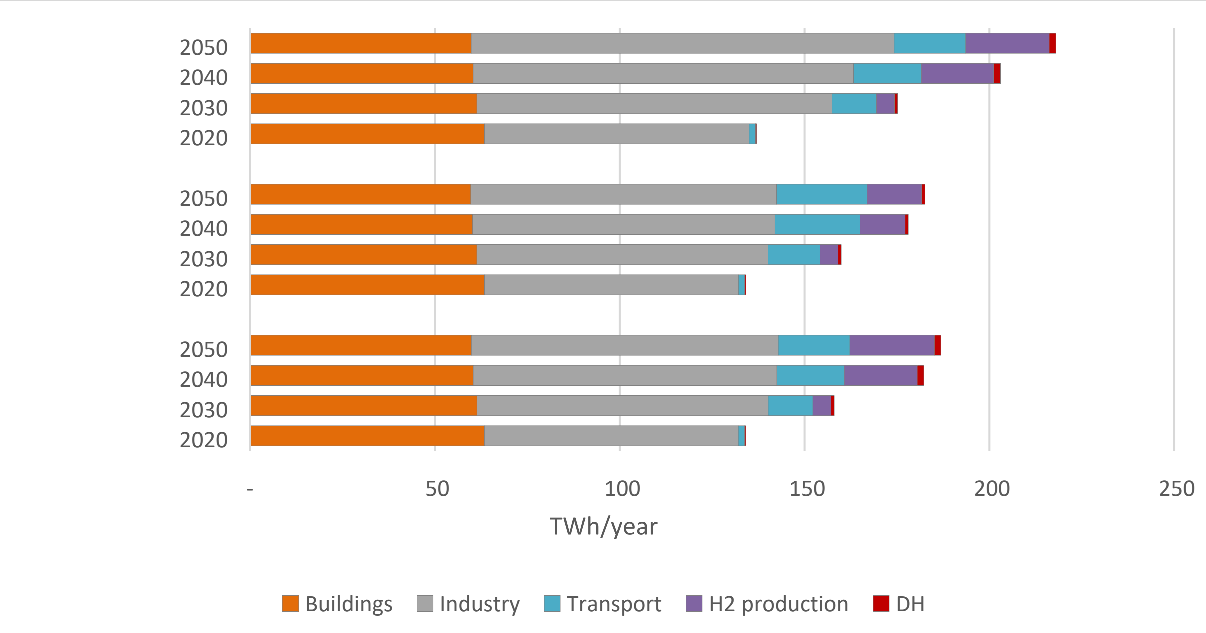

Figure 45 Electricity use per sector, TWh/year

6.2 Overall energy use

The energy use by energy carrier and end-use sector for the Fast scenario is presented in Figure 46. The energy use of buildings increases by 2% from 2018 to 2050, in industry it increases by 9% and in transport the decrease is 33%.

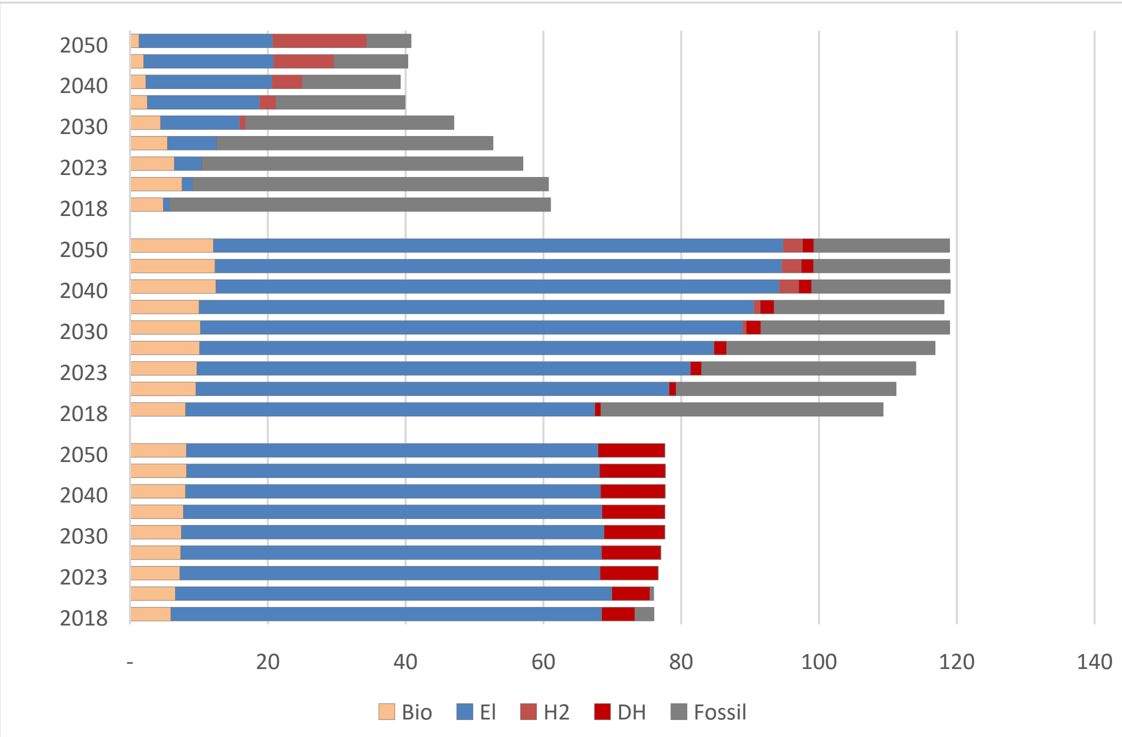

Figure 46 Energy use by energy carrier and end-use sector in the Fast scenario, TWh/year

6.3 Road transport

An example of the use of energy carriers in heavy road transport is presented in Figure 47. Energy use for trucks will in all scenarios analysed decrease. This is due to improved energy efficiency of new vehicles, particularly battery electric vehicles (BEV). As earlier mentioned, the Fast scenario assumes that BEV cannot be used for long, heavy transportation, while Fast-BEV allows use of BEV also for the long, heavy transportation. In the Slow scenario, fossil fuel will be a considerable share of energy use of trucks up to 2045 and even in 2050, some use of fossil fuels remains. Use of biofuel increases, blended in fossil fuels. The use of biogas increases and shows a maximum in 2030-2035 with 1.2 TWh/year. BEV is slowly introduced in 2023 and reach a high share from 2030 and forward. Hydrogen is introduced in 2045 and dominates in 2050. In the fast scenario, hydrogen trucks are coming in use in 2035 and the use of hydrogen is 4.4 TWh in 2050. If this is produced be electrolysis, the electricity use will be 6.5 TWh. Electricity use for BEVs and production of hydrogen for trucks will be about 10 TWh in 2050. Use of fossil fuels will be low in 2035 and totally phased out from 2040 and forward. The total energy use, if hydrogen is produced by electrolysis, is almost the same as today. If BEV can be used also for the long, heavy transports, total energy use is reduced by 4 TWh compared to today, due to the higher efficiency of BEVs.

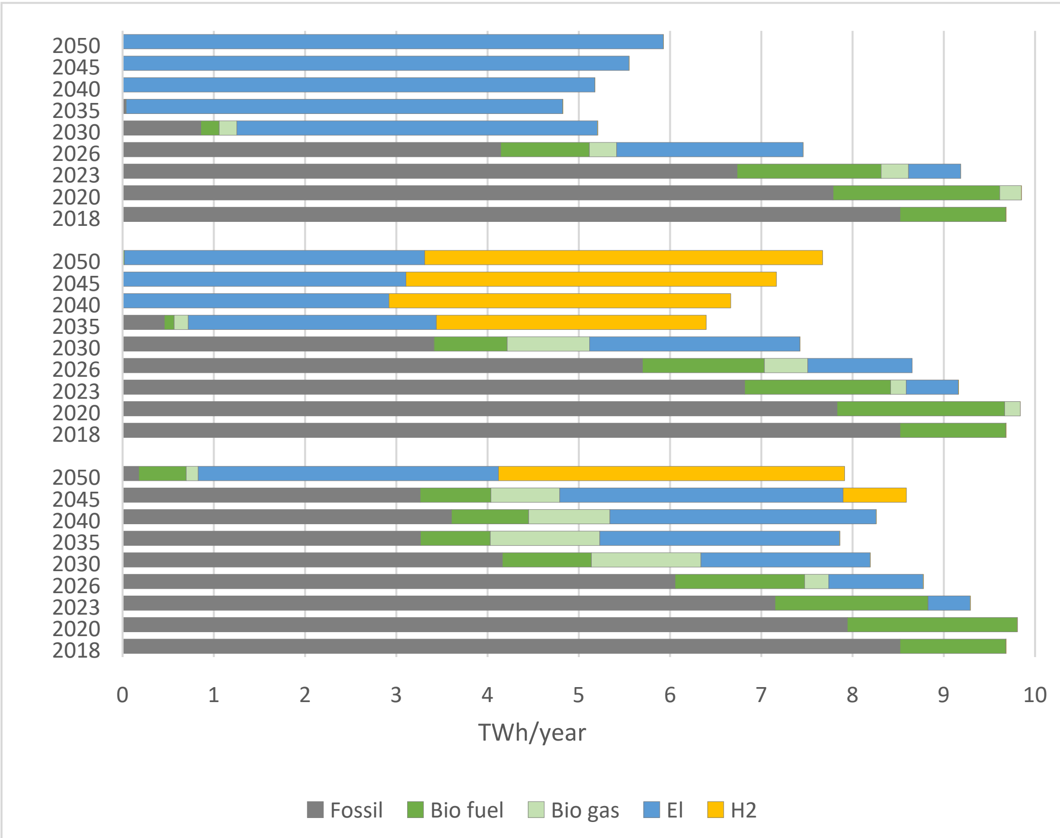

Figure 47 Energy by energy carrier for the scenarios Slow, Fast and Fast-BEV (TWh/year)

6.4 CO2 emissions

IFE-TIMES-Norway does not include all Norwegian GHG emissions, emissions from offshore petroleum activities are excluded as well as non-energy related emissions. The decrease in CO2 emissions in the two example analyses is presented in Figure 48. With a low CO2 tax (Slow scenario), the CO2 emissions is reduced by 75% or 19 million tons of CO2 from 2018 to 2050. With higher CO2 taxes (Fast scenario), the reduction is 82% or 21 million tons of CO2/year.

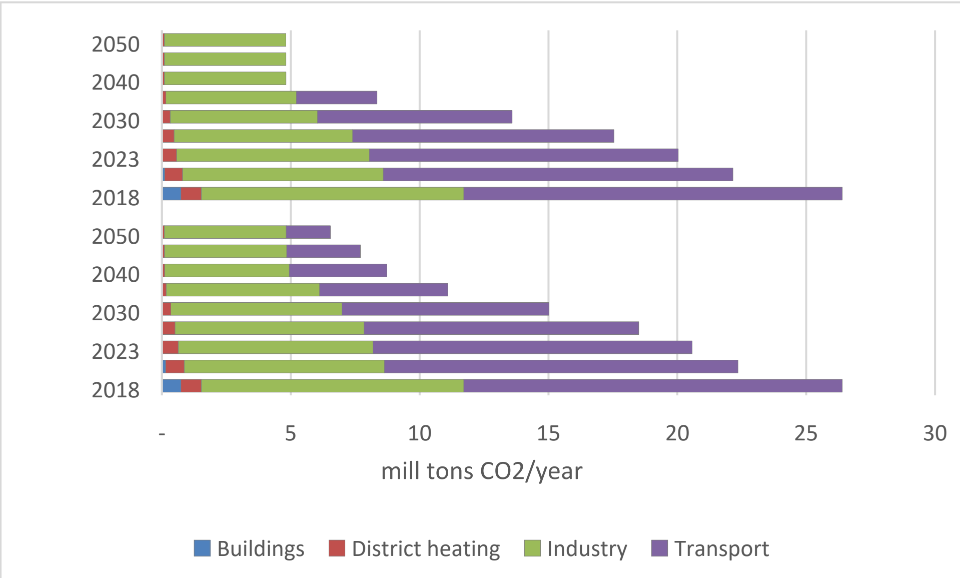

Figure 48 CO2 emissions in analyses with low and high CO2 tax, million tons of CO2/year

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Appendix A – Basis for input values for electrolyzer

Hydrogen from electrolyzer is assumed to be produced in each region either centralized or distributed manner. The costs are provided both for alkaline and PEM electrolyzer and necessary compressor unit to compress it to 250 bar pressure.
The centralized unit is based on costs expected from a 20 MW_{el} installed capacity while costs for the decentralized unit are based on a 3 MW_{el} size electrolyzer.
The costs are composed from three parts: electrolyzer, compressor skid and other costs. The costs of electrolyzer is taken from [83] and represents costs for the electrolyzer and necessary auxiliaries such as:

- Transformer(s), rectifier(s), control panel with PLC;
- Water demineralizer/deionizer;
- Electrolyser stack(s);
- Gas analysers, separators and separating vessels;
- Scrubber or gas purifier system & recirculating pump;

An important distinction between PEM and Alkaline electrolyzers is the output pressure. The traditional Alkaline electrolyzers work usually at atmospheric pressure, while some electrolyzer designs provide self-pressurization up to 30 bar. On the other side PEM systems can self-pressurerize the hydrogen for up to 80 bar in commercial products. [84] In TIMES the cost of Alkaline electrolyzer is included a dry piston compressor which provides 15 bar output pressure, while the output pressure for PEM is assumed to be 55 bar.
The costs for compressor is based on a cost per installed kW capacity based on data from [85] and refined in [48]. The required compressor capacity to reach the set pressure is based on adiabatic compression defined as

$$W = \left[\frac{\gamma}{\gamma - 1}\right] * P_0 * V_0 * \left[\left(\frac{P}{P_0}\right)^{\frac{\gamma-1}{\gamma}} - 1\right]. \quad \text{(A-1)}$$

Where P_0 is the initial pressure (Pa), V_0 is the initial specific volume (m^3/kg), P is the end pressure (Pa), and γ=1,41 is the adiabatic coefficient [86]. In addition, a mechanical efficiency of 70% is added and a compressor redundancy is set to 3 x 50%.

The other cost consists of [87]:

1. Engineering costs
2. Distributed Control System (DCS) and Energy Management Unit (EMU)
3. Interconnection, commissioning, and start-up costs

The other costs are expected to follow scale of economy; hence they are assumed to be 45% and 36% of CAPEX for 3 MW_{el} and 20 MW_{el} electrolyzer unit respectively.
Civil work costs are not included, which are here defined as construction of foundation, industrial buildings, lighting, water supply, fencing, security. Neither cost of land nor the option to extend the technical lifetime of the electrolyzer by only replacing the stack has been included in the model.
The development of costs is expected to decrease with time and are usually correlated with increased production volumes of the equipment. The reduction in price of electrolyzer is presented in [84] as a span between a max and minimum costs per kW_{el}. As current investment costs are based on a separate publication and are differentiated on size of the plant, only the trends of future costs are used. In IFE-

TIMES-Norway the cost development is based on the trend of the average costs. All the electrolyzer costs and expected reduction is shown in Table A-1.

Table A-1 Cost span of electrolyzers from [84] and price reduction for the average cost.

		Alkaline			PEM		
		Today	2030	Long-term	Today	2030	Long-term
Upper	USD_{2019}/kW_{el}	1400	850	700	1800	1500	900
Lower	USD_{2019}/kW_{el}	500	400	200	1100	650	200
Average	USD_{2019}/kW_{el}	950	625	450	1450	1075	550
Price reduction average price	-	0%	34%	53%	0%	26%	62%

The cost development of compressor is based on cost decrease factors presented in [46] where it is assumed that at production of 5 000 hydrogen refuelling stations (HRS) the hydrogen compressor could decrease with 53% and at production volume of 10 000 hydrogen refuelling stations (HRS) the decrease will be 60%. These production volumes are assumed to occur in 2030 and 2050 respectively and to represent also the reduction in compressor costs for middle and large-scale hydrogen production unit. It shall be noted that there are big technological differences between a compressor serving light-duty vehicle HRS (as referred to in the source) and large-scale hydrogen production unit, in addition prediction in future cost development is in general connected to large uncertainties.

In Table A-2 is summarized the cost used for each component (electrolyzer, compressor and other costs) and the sum of them used as input value in IFE-TIMES-Norway.

Table A-2 The cost for the different electrolyzers for different years shown in NOK per installed kW_{el}

			2018	2030	2050
20 MW el	PEM	Electrolyzer -	7406	5497	2777
		Compressor -	935	440	374
		Other costs	3170	2256	1198
		Total costs	**11511**	**8192**	**4349**
	Alkaline	Electrolyzer -	5925	3879	2821
		Compressor -	2318	1089	927
		Other costs -	3132	1888	1424
		Total costs	**11375**	**6857**	**5173**
3 MW el	PEM	Electrolyzer -	12363	9175	4636
		Compressor -	3118	1466	1247
		Other costs	9289	6385	3530
		Total costs	**24770**	**17026**	**9413**
	Alkaline	Electrolyzer -	9924	6498	4726
		Compressor -	3767	1770	1507
		Other costs	8214	4961	3739
		Total costs	**21905**	**13229**	**9972**

The efficiency consists of two parts: i) the actual efficiency of the electrolyzer and ii) the electricity required to compress the hydrogen up to previously mentioned pressure and including the mechanical inefficiency. The values of efficiency for each part and the summarized value of efficiency used in IFE-TIMES-Norway is shown in Table A-3. An interval of efficiency of the electrolyzer is provided by [84] and in IFE-TIMES-Norway is used the middle value.

Table A-3 Efficiency of electrolyzer, compression stage and the summarized efficiency used in IFE-TIMES-Norway

		Alkaline			**PEM**		
		Today	2030	Long-term	Today	2030	Long-term
Efficiency of electrolyzer	Upper	70%	71%	80%	60%	68%	74%
	Lower	63%	65%	70%	56%	63%	67%
	Middle	66.5%	68.0%	75.0%	58.0%	65.5%	70.5%
Energy lost during compression as share of the energy in the compressed hydrogen	kWhel/ kWhH2	4.4%	4.4%	4.4%	1.9%	1.9%	1.9%
Summarized		65%	66%	73%	57%	65%	70%

The yearly OPEX costs for each component and a complete cost for the entire electrolyzer unit are shown in Table A-4.

Table A-4 Assumed OPEX costs

Equipment	Share of CAPEX
Electrolyzer	3%
H2 compressor	6%

An expected range of lifetime of the electrolyzer today and in future is presented in [84], the range and a middle value, which is used in IFE-TIMES-Norway, is shown in Table A-5.

Table A-5 Assumed lifetime of electrolyzer stack in hours, differentiated by electrolyzer type and time of production [84]

	Alkaline			**PEM**		
	Today	**2030**	**Long-term**	**Today**	**2030**	**Long-term**
Upper	90 000	100 000	150 000	90 000	90 000	150 000
Lower	60 000	90 000	100 000	30 000	60 000	100 000
Middle	75 000	95 000	125 000	60 000	75 000	125 000

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