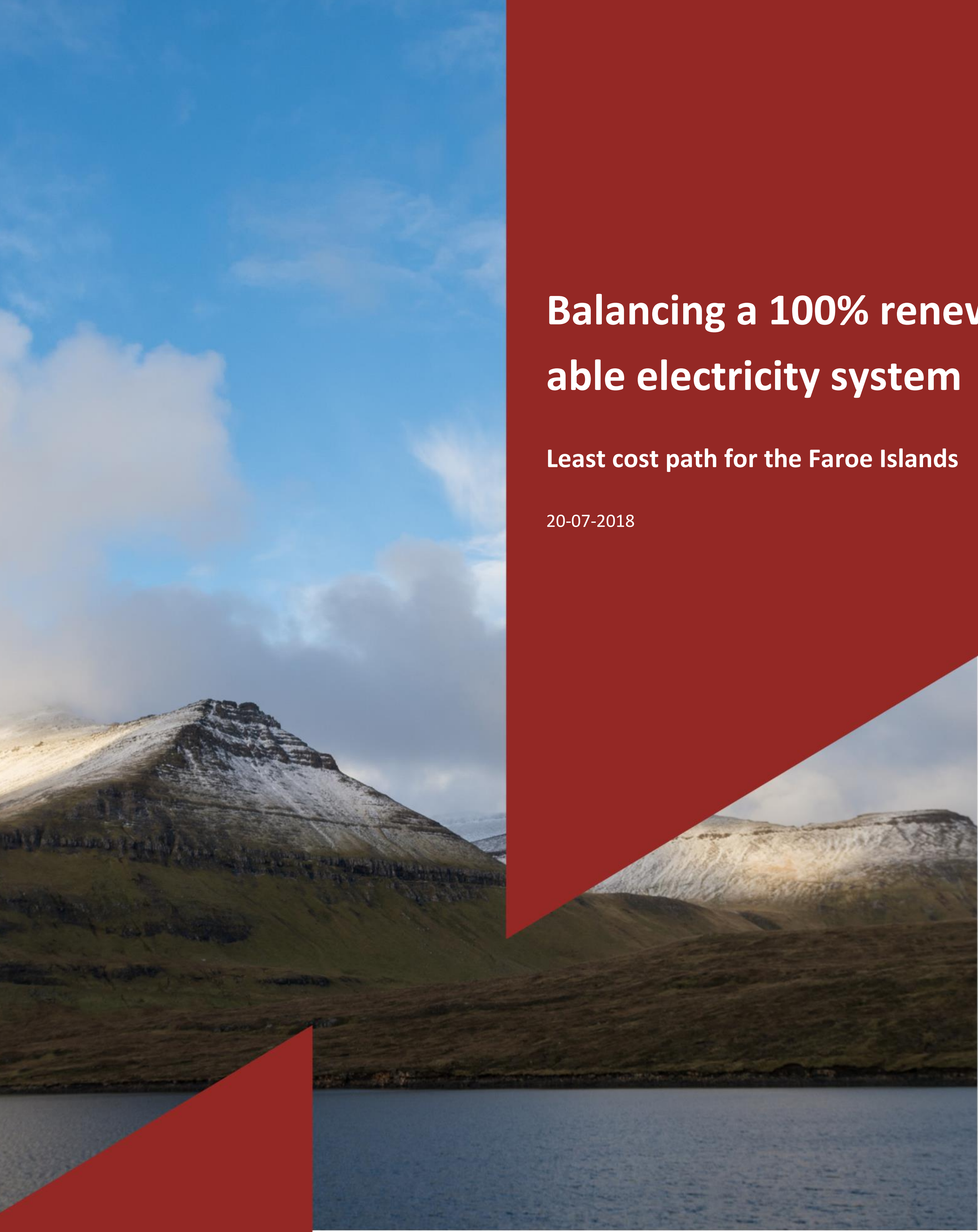

Balancing a 100% renewable electricity system

Least cost path for the Faroe Islands

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Ea Energy Analyses

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Foreword

This project is developed for SEV, the electricity utility of the Faroe Island, and Orka, from the Environment Agency Umhvørvisstovan. The focus is in studying least costs options to develop the Faroe Island electricity system into a 100 % renewable system.

A key challenge is to balance the variable wind and solar power generation in such a relatively small and isolated system.

Analyses are done with the open source electricity and heat model Balmorel. With given inputs about cost and performance of alternative technologies the model simultaneously finds the optimal dispatch of the system and points at the least cost investment in new generation, that can fulfil a goal of 100 % renewable energy in 2030. The model optimises the generation based on hourly resolution of the demand and generation.

In 2015 an action plan for how to increase the share of renewable energy was published (Faroese Ministry of Trade and Industry, 2015). The report included a range of recommendations and initiatives included studies of wind, solar and tidal power, analyses of district heating, storage system, and electric connection to Iceland.

1 Executive summary

The focus of this study was on how the expansions in hydro can contribute to the integration of wind and solar in the power system of the Faroe Islands. The specific expansion considered in this analysis consists of investment options for additional turbines for the Mýrarnar and the Heygadal lakes, the expansion of the reservoirs of both lakes and a pumping system, pumping water from the Heygadal lake to the Mýrarnar lake.

Four scenarios are considered. The Main scenario would represent the reference scenario in this study. Total electrification of the transport and heat sector is assumed along with the assumption of zero CO_2 emissions by 2030.

Two sensitivies are performed on the Main scenario. The first one looks at a situation with lower full load hours (FLHs) compared the Main assumptions. The second one considers the existing hydro reservoirs less flexible compared to Main.

Finally, a fourth scenario is set up where the results of the Norconsult report (Norconsult, 2018), "Hovedalternativet" are used and the hydro expansions in the Balmorel model is fixed to the numbers found in this study. The other capacities are model-optimized.

Main scenario

In the Main scenario, the model shows an investment path where all diesel generation is replaced by wind and solar by 2030. The solar generation capacity is then 75 MW and the wind capacity 141 MW. In order to balance all this renewable power, the model invests in about 48.5 MW additional turbine capacity and 7 GWh hydro reservoir expansion. The model also invests in a pump between the Mýrarnar and Heygadal lakes of 58 MW.

Lower solar

The scenario with lower FLSs for solar production shows lower solar capacities as the model finds the solar options less attractive with lower full load hours (64 MW compared to 75 MW in the Main scenario by 2030). In the generation, the difference is even larger. The total costs for this scenario are only marginally larger than for the Main scenario (2% increase).

Restricted hydro

The restricted hydro scenario sees only 25% of the existing hydro reservoirs as useable for the balancing of the power system. The model shifts a small amount of wind power (less predictable) to solar power and installs more pumping capacity. The total cost of this scenario is very close to the Main scenario.

Norconsult scenario

Compared to the Main scenario, the Norconsult scenario shows very high values of storage size. This can be explained by remembering that Balmorel looks at one year at a time and in these simulations only considers a "normal hydro year". The Main scenario therefore does not consider storing water during wet years for generation in dry years. Furthermore, the model has full foresight so does not have to keep hydro for reserves.

The Norconsult scenario will make zero emissions by 2030 in all likely scenarios, including a dry hydro year. This comes at a price of about 70 million DKK additional system cost (or about 11%) compared to the optimized scenario where the zero-emission restriction will be upheld in case of a normal hydro year.

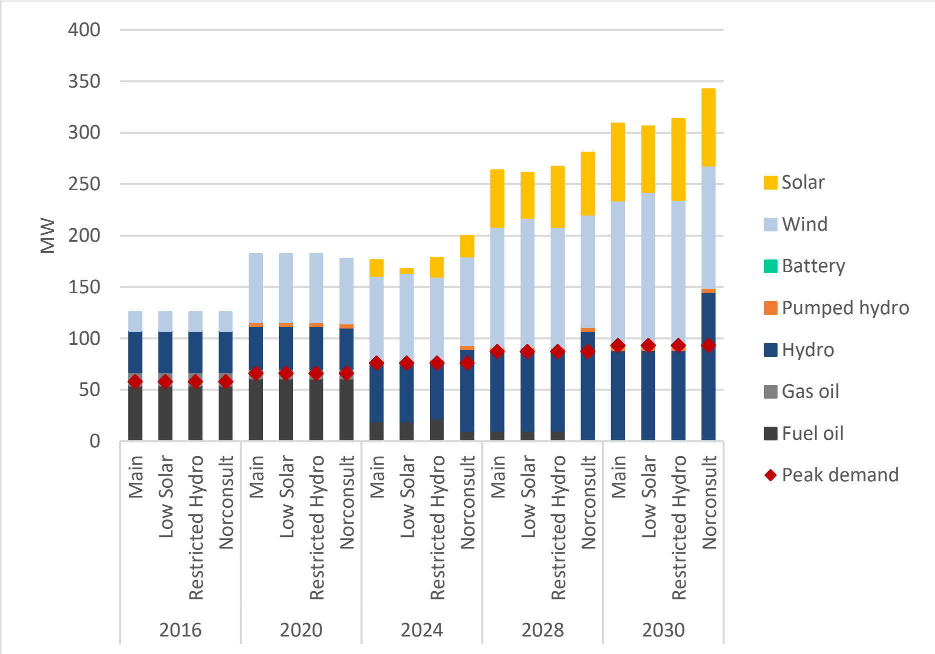

Figure 1: Total capacity for the 4 scenarios for selected years between 2016-2030. Peak demands are indicated. The orange pumped hydro technology represents the 'pumped hydro' project in Miðvatn, Suðuroy. All other hydro expansions (which also include pumping) are shown as dark blue 'hydro'.

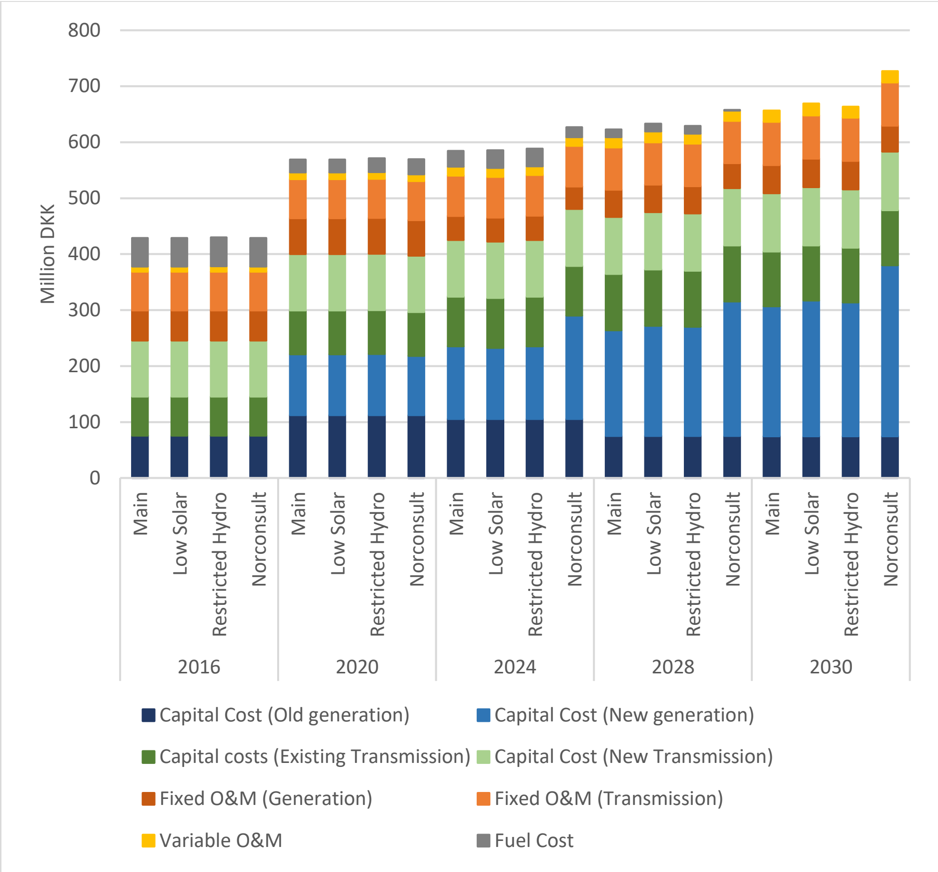

Figure 2: Total annual system costs for the 4 scenarios for selected years between 2016-2030. This graph includes both model results and assumptions for costs made by SEV. It should be noted that investments in existing and committed generation is not included in this graph.

2 Faroese system: Data and assumptions

In total, the electricity system in the Faroe Island consists of six isolated systems. Here we focus on the two largest systems: Main (45,400 inhabitants) and Suðuroy (4,600 inhabitants).

The remaining systems are Skúvoy (52 inhabitants), Stóra Dímun (7 inhabitants), Koltur (2 inhabitants), Fugloy (44 inhabitants) and Mykines (20 inhabitants).

2.1 Electricity demand

Annual electricity demand projections

In 2015, in Main and Suðuroy together, 314 GWh of electricity has been consumed. The projected *classic* electricity demand (excluding additional electrification in the heat and transport sectors) increases 2% annually due to economic growth and reaches 423 GWh in 2030. The classic demand projection, along with power demand projections for transport and heat are shown in Figure 3. In this analysis, the power and heat sector are assumed to be 100% electrified by 2030.

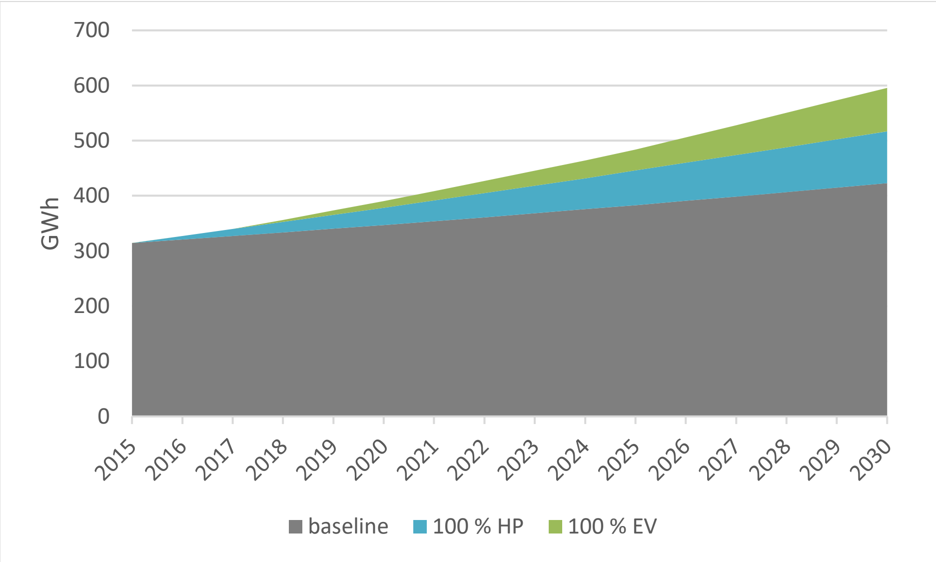

Figure 3: Prospected electricity demand between 2015-2030 for the Faroese power system.

Hourly demand profile

Separate hourly demand profiles are implemented for the Main and Suðuroy area. In Figure 4, Figure 5 and Figure 6 the variation profiles for the different types of demand. The hourly profiles are scaled to sum up to the total annual demand in each given year.

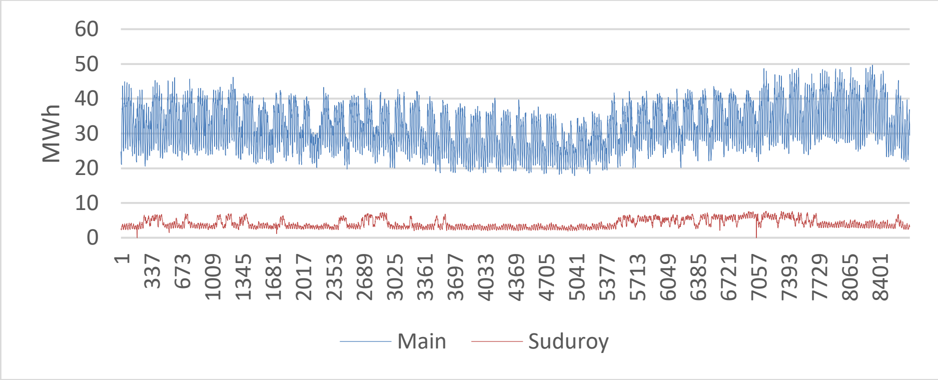

Figure 4: Hourly variation profiles for the Main and Suðuroy classical power demand for 2015. Same profile used in other years, scaled to match annual classical demand.

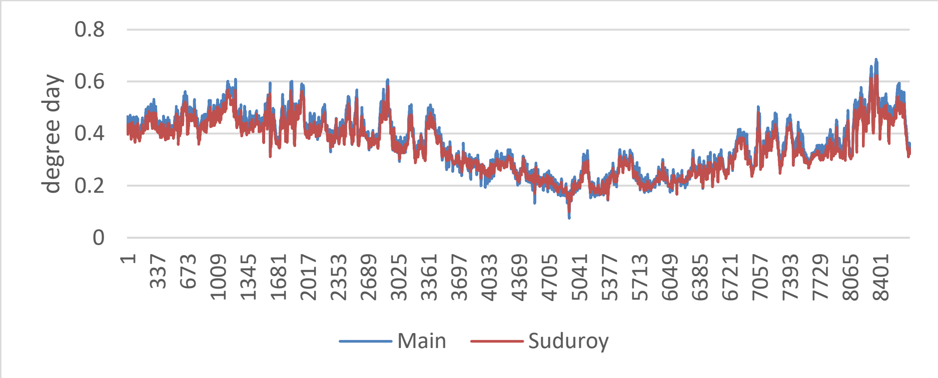

Figure 5: Hourly variation profile of the heat demand expressed in hourly fractions of degree days. Used in all years, scaled to match annual demand for heat.

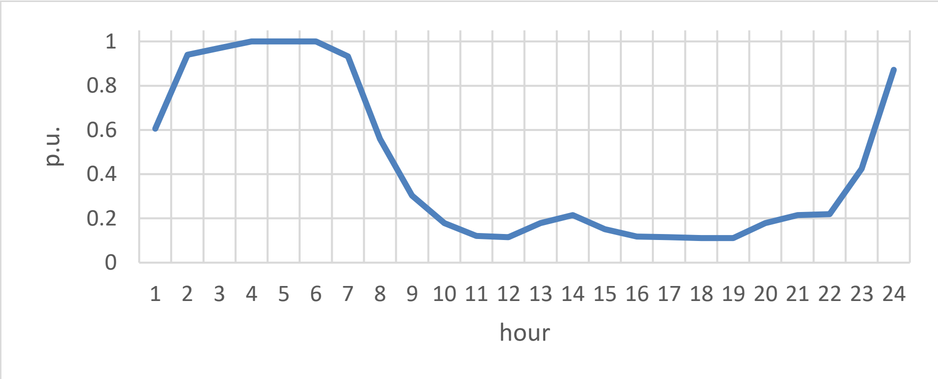

Figure 6: Daily hourly variation profile of the EV demand. This profile illustrates smart charging of electric vehicles. Used in all years, scaled to match annual demand for transport.

2.2 Existing and committed generation capacity

Existing capacity

The existing capacity currently in operation in the Faroe Islands is implemented in the model based on (SEV, 2017). An additional 2 MW wind farm not owned by SEV is also included. See Table 1.

MW	Main	Suduroy	Total
Fuel oil	40	14	54
Gas oil	10	3	13
Water	37	3	40
Wind	18		18
Total	**105**	**20**	**125**

Table 1. Existing generation capacity.

A lifetime is assumed for each existing unit after which the unit is decommissioned (commissioning data for each unit are known). This and other assumptions for existing capacity are shown in Table 2.

	Lifetime (years)	Fuel efficiency (%)	Fixed O&M (DKK15/kW)	Variable O&M (DKK15/MWh)
Fuel oil	30	42%	371	60
Gas oil	30	45%	1.046	60
Wind	25	100%	275	21
Hydro	60	100%	375	0

Table 2: Characteristics of existing capacity

Committed capacity

Three projects which are assumed highly likely to come into operation during the period modelled are also added to the model as input.

- **Miðvatn project**: A wind turbine project in Suðuroy (10.8 MW in 2019, and an additional 3.6 MW in 2025 and in 2029, total = 18 MW). A pumped hydro installation is added to the close-by Miðvatn lake (6 MW pump and 4 MW turbines) in 2020. The reservoir size is assumed to be 253 MWh.
- **Sund 3 fuel oil generator**: Four fuel oil units totalling at 37 MW come into operation in 2020 (Main island), as of when two old 12.4 MW Sund generators will only be used as back-up generators and will no longer be included in the model.
- **Main wind**: 18 MW of onshore wind will be built in the Main region by 2019.

The total exogenous (manually entered and thus not model-invested) capacity is shown in Figure 7.

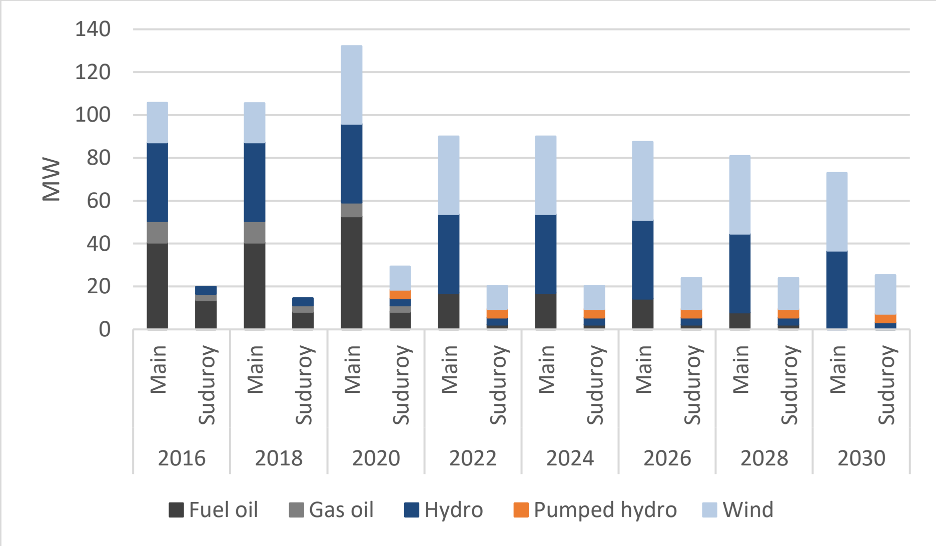

Figure 7: Exogenous capacity development between 2016-2030

Hydro

All hydro power in the Faroe Islands is modelled with reservoirs. The model has full foresight about the power demand, the hydro inflows, the wind speeds and the solar/tidal generation of the entire year it is optimizing, meaning the optimization takes place with full knowledge of the entire year and all hours of the year are optimized together. The model can therefore dispatch hydro power optimally to balance variations in residual demand (demand minus variable renewable energy). The six modelled hydro generators are described in Table 3. Average generation for several years is given by (SEV, 2017) The year 2006 is chosen as an average, "normal" hydro year. The Eiði value is scaled according to the expansion in capacity. For the normalized weekly inflow profile of the hydro plants data from 2006 is used as shown in Figure 8. Inflow is much higher in winter and spring then in summer and autumn. The Mýrarnar and Heygaværk hydro units have been modelled as cascading, meaning the water inflow to Heygaværk will depend on the generation in the Mýrarnar lake. Only 50% of the hydro reservoirs can be used for balancing, giving a conservative estimate of the flexibility of hydro.

	Generation MWh	Capacity MW	FLHs	Reservoir MWh	Reservoir % of gen.	Unloading hours
Fossa	21.757	6,30	3.453	2.700	12%	429
Mýrarnar	11.920	2,40	4.967	2.403	20%	1.001
Heygaværk	12.412	4,90	2.533	551	4%	112
Eiði	63.289	21,76	2.909	6.013	10%	276
Strond	2.678	1,40	1.913	22	1%	16
Botnur	4.629	3,30	1.403	441	10%	134

Table 3: Characteristics of hydro plants in the Faroe Islands

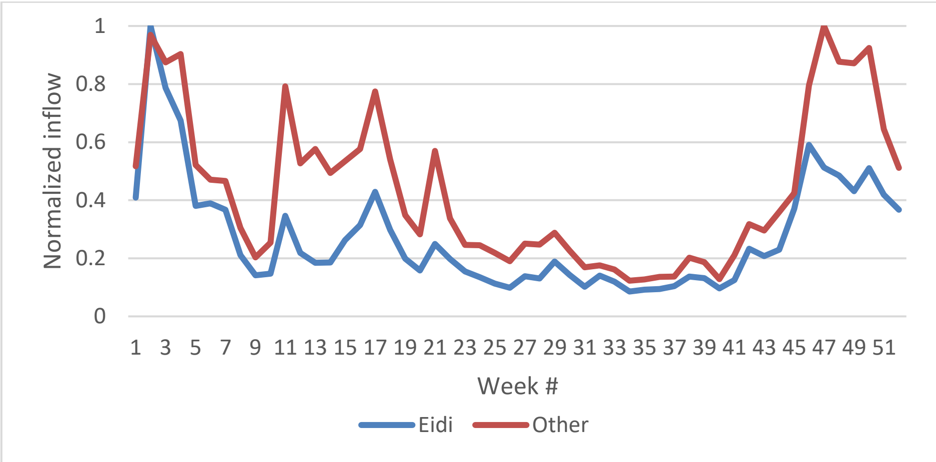

Figure 8: Weekly inflow profiles for hydro reservoirs 2006

Figure 9: Eiði hydro reservoir

2.3 Technology catalogue

The most suitable generation technologies for the Faroe Islands are collected in a generation technology catalogue which is used in the Balmorel model. This catalogue (Table 4) contains investment options the model can build in addition to the existing power plants to fulfil the electricity demand. Some technologies have assumed learning curves in their investment costs representing technological progress. Technologies relying on coal or natural gas are not considered for the Faroe Islands and neither is nuclear power. One scenario does consider a biomass technology (imported wood pellets). No additional hydro projects are considered here.

Annuity factor

When the model considers investing in additional generation capacity, it considers the annualized investment cost, additional fixed and variable O&M costs and fuel costs of the candidate technology. To obtain the annualized investment costs an annuity factor of 8.02% is used, corresponding to 5% discount rate over a lifetime of 20 years.

Model-based decommissioning

On top of the exogenous decommissioning as described above (manually taking units out after the end of their lifetime) the model is also allowed to endogenously (i.e. model-optimised) decommission units when their fixed costs are too high for them to remain in the optimal, least-cost solution. Endogenous decommissioning is allowed from 2022 onwards.

	Investment costs	Fixed O&M (DKK/kW)	Variable O&M (DKK/MWh)	Lifetime	Efficiency
Variable RE technologies	**(DKK/kW)**				
Wind (2020-'24)	8,924	190	52	20	-
Wind (2025-'29)	8,564	190	50	20	-
Wind (2030)	8,203	190	48	25	-
Solar PV (2020-'24)	5,890	68	0	25	-
Solar PV (2025-'29)	5,091	61	0	25	-
Solar PV (2030)	4,692	54	0	30	-
Tidal (2020-'29)	32,736	1,178	0	30	-
Tidal (2030)	23,064	876	0	30	-
Dispatchable technologies	**(DKK/kW)**				
Diesel (2020-'30)	21,726	371	60	30	43%
Wood (2020-'30)	21,307	899	0	30	31%
Pump Mýrarnar (2020-'30)*	1,634	50	0	30	70%
Turbine Mýrarnar (2020-'30)*	1,976	50	0	30	
Turbine Heygaværk (2020-'30)*	4,396	50	0	30	
Energy storage technologies	**(DKK/kWh)**				
Battery (2020-'30)	2,300	17	2	15	80%
Reservoir Mýr. (2020-'30)*	40	10	0	40	-
Reservoir Heyg.(2020-'30) *	105	0	0	40	-

*Table 4: Technology catalogue of investment options of the Balmorel model. * More information about investments in pumped hydro is given below.*

Wind

Wind power investments can be made by the model both on the Main island and Suðuroy, where the wind speed time series are from the Húsahagi wind farm and a measuring mast in Porkerishagi respectively (data provided by SEV; measuring height: 70.2 m; time period: August 2016 - July 2017). The average wind speeds for the two locations are 10.27 and 9.8 m/s. The Neshagi wind farm uses the wind speeds from the Húsahagi plant.

The power curve for the wind technologies in the model is based on an adapted version of the Enercon E44 turbine, which includes storm control functionality (Enercon, 2017). The power curve of the turbine is seen in Figure 11. This technology in the Main islands, results in full load hours for wind of 4,266, in Suðuroy the wind production has 4,136 full load hours. A restriction of 20 MW of additional wind installations per 2 years is applied.

Figure 10: Nesahagi wind farm

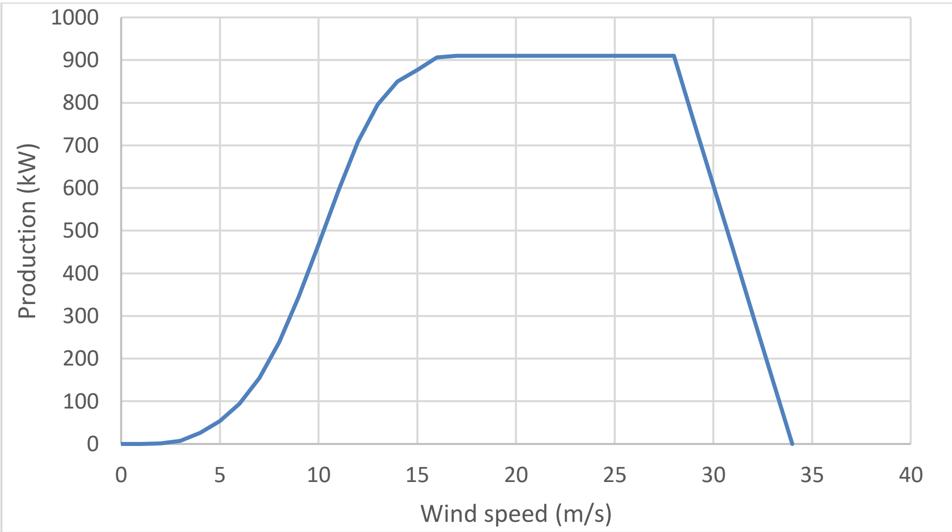

Figure 11: Wind technologies power curve

Solar

To gain information about the solar generation profiles in the Faroe Islands, the website Renewables Ninja was used. A learning curve was applied to the full load hours (FLH) of solar as shown in Table 5. A restriction of 20 MW of additional solar installations per 2 years is applied.

Years	Full load hours
2015-2019	830
2020-2024	880
2025-2029	889
2030	905

Table 5: Solar full load hours in the Faroe Islands

Tidal

Three tidal locations are considered in the model: Vestmannasund, Skopunarfjørður and Leirviksfjørður (all in the Main system). The tidal speeds are very complementary when combined, power can be generated at all hours (Figure 12). The full load hours for tidal generation are: 3,695, 2,873, 2,349 for Vestmannasund, Skopunarfjørð and Leirviksfjørð respectively.

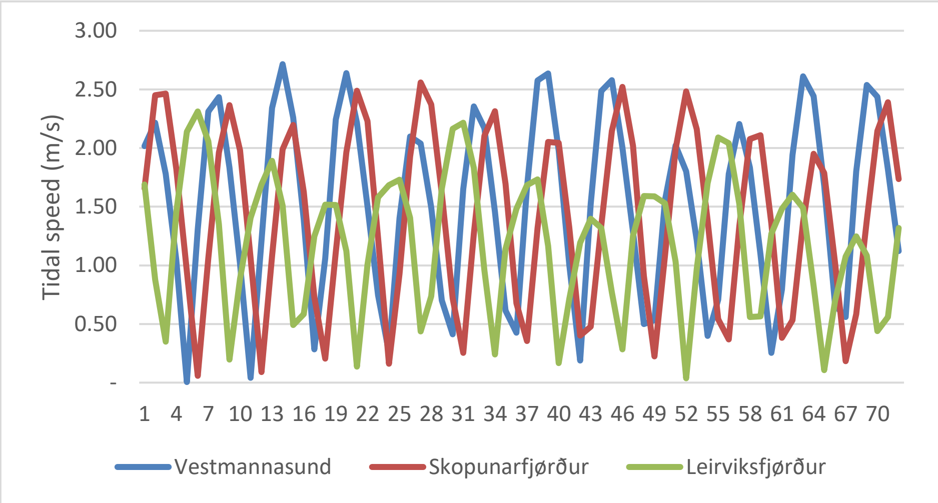

Figure 12: Tidal speeds for the 3 locations modelled (first three days)

Biomass

Biomass plants are considered a mature technology and as controllable units they can contribute to the security of supply. In this regard, imported wood pellets have the advantage to be easily storable over a longer period and so the wood pellets themselves represent an energy storage. In a renewable energy system in the Faroe Islands, wood pellet plants must be understood as balancing means.

Over the whole life cycle zero CO_2 emissions can be assumed and biomass is considered as a renewable technology. Wood pellets need to be imported. Nevertheless, biomass plants have the potential to be an economically responsible solution to avoid over-investment and spilling of variable, uncontrollable generation technologies in a 100% renewable energy system.

Pumped hydro

The model can expand the existing Mýrarnar and Heygadalcascade with additional turbine capacity and expansion of the reservoir size for both hydro plants. Additionally, the model can invest in a pump, pumping water from the Heygadalback up to Mýrarnar. The round-trip efficiency of the pumping is 70%. The investment costs for the hydro expansions are based on (Norconsult, 2018). Where only 50% of the existing reservoirs will be used actively for balancing purposes, the model will be able to use the full expansion of the hydro reservoirs invested in.

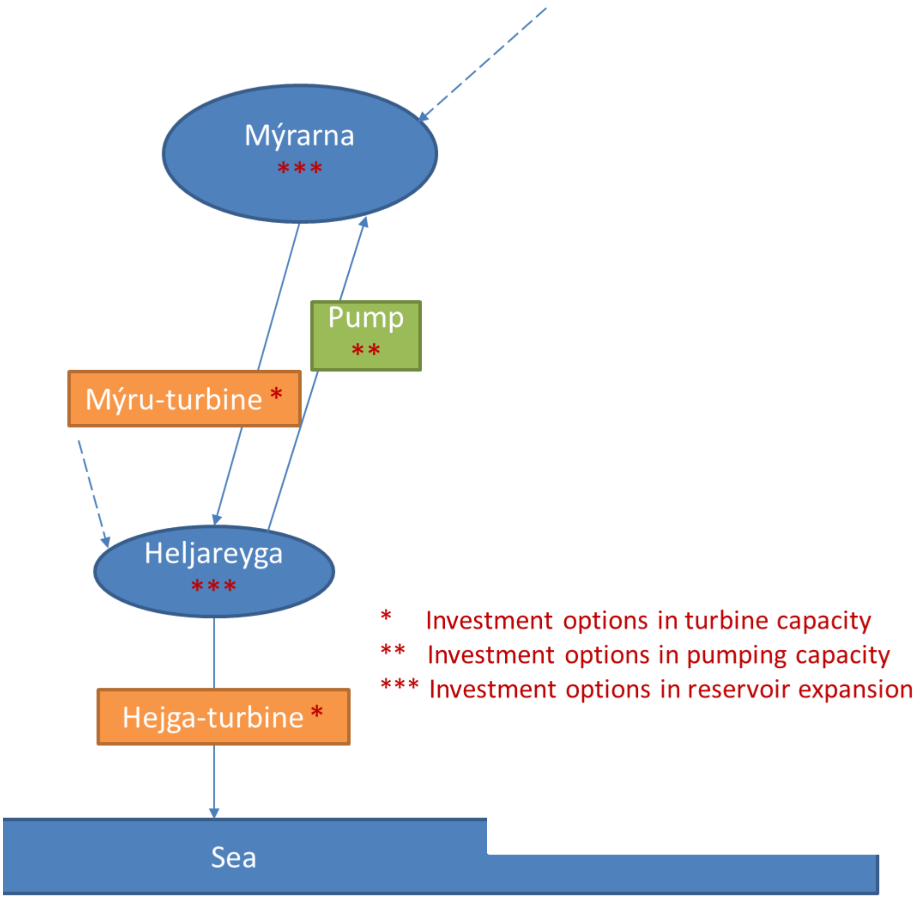

Figure 13: Investment options for hydro and pumped hydro in the Mýrarnar and Heygadal cascading hydro units.

2.4 Transmission capacity

Currently, the two regions, Main and Suðuroy, are not connected and function as two independent systems. The model is allowed to invest in a transmission cable between the two regions however. The investment cost is assumed 14 million DKK per MW.

2.5 Fuel prices

The Faroese fuel prices are generally higher than in Europe due to transport costs. To the fuel oil and gas oil prices, a 7 DKK/MWh offset is applied compared to European (Danish price), representing 2.7 DKK/MWh import/environmental duty + 4.3 DKK/MWh freight cost.

Shipping costs for biomass is heavily dependent on the volume. A volume of 66 TJ/year is assumed.

Figure 14 shows a prospect of fuel prices until 2030.

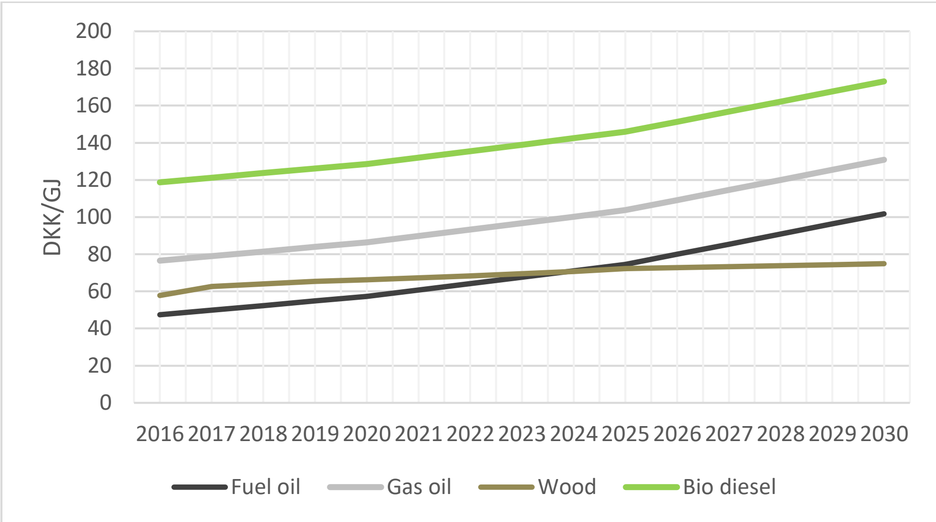

Figure 14: Prospect of fuel prices in the Faroe Islands between 2016-2030.

2.6 CO_2 emissions policy

The Faroese power sector expansion will be driven by increasing demands as well as an ambition to reduce CO_2 emissions by 2030 to zero (100% renewable power sector). In Figure 15, CO_2 emissions are shown from 2016 to 2030. The limit on emissions is only enforced from 2020 where the model is allowed to invest in generation capacity.

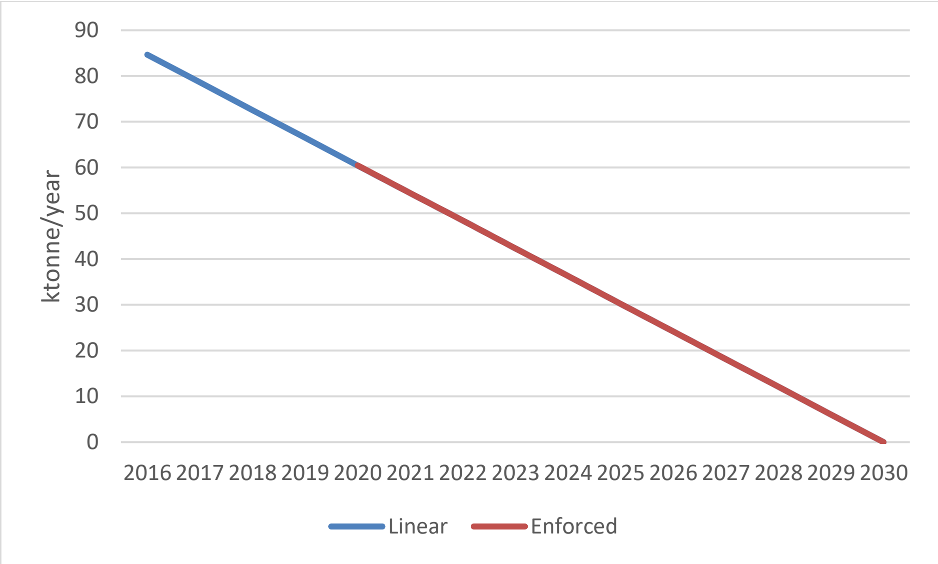

Figure 15: CO_2 limit in the model between 2016-2030.

3 Balmorel

The Balmorel power system model is an economic and technical partial equilibrium model that simulates the power system and least-cost dispatch. The model optimises the production at the existing and planned production units and simultaneously simulates investments in new generation and transmission. Investments are also made on a cost-minimising basis and they can include constraints on availability of fuels, cap on transmission investments, etc.

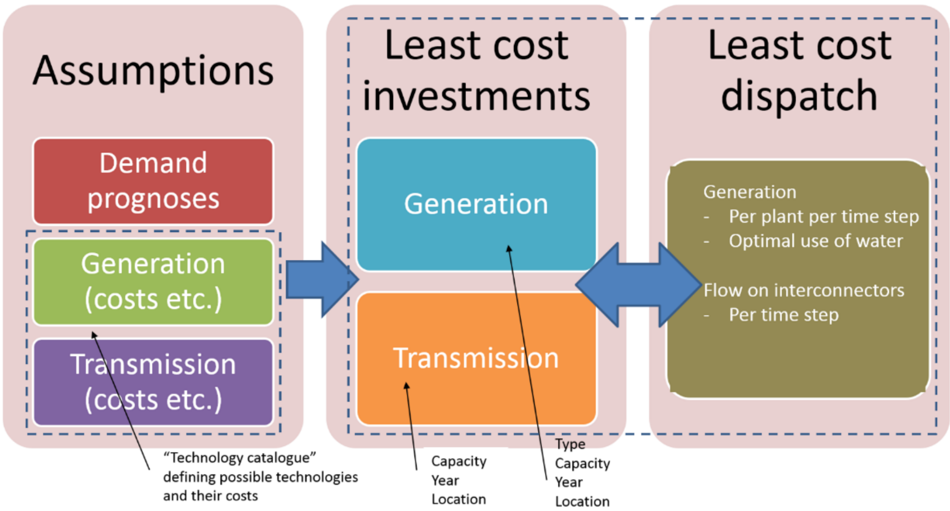

Figure 16: Output of Balmorel model is least-cost investment in generation and transmission infrastructure with an optimal dispatch.

Balmorel is a deterministic model that finds optimal solutions based on given inputs. All information is used in the form of "perfect foresight" within a given year. This simplification gives two important benefits:

- It is easy to compare alternative scenarios. All solutions are least-cost, and any difference in the results is a result of the change in input.
- Computation time is significantly decreased.

The model is flexible and can be used in several different setups:

- Optimal dispatch with a certain specification of generation and transmission (fixed system)
- Investment optimization for generation and transmission
- Use extra detailed information about power system dynamic, e.g. unit commitment of specific plants and information about ramp rates, minimum generation levels and minimum hydro flow.
- A limited number of time steps can be used to represent the year, or a full hourly resolution can be used.

The Balmorel model is open source[1] and applied by a number of universities, research institutions, interest organization, energy companies, transmission system operators and consultant companies.

[1] See www.eaea.dk/balmorel

4 Scenarios

The scenarios employed in this project cover different realistic prospects and restrictions against the background of the 100 % renewable target in 2030. The renewable energy target is here formulated as zero CO_2 emission. An overview is provided in Table 6.

Scenarios	
Main	
Main	The main scenario assumes 100% electrification of the transport and heat sectors and zero CO_2 emissions by 2030.
Alternative scenarios	
Low solar	The low solar scenario simulates the same parameters as the **Main scenario**, except for an assumption on lower full load hours for solar generation (650 instead of 830 in 2016)
Restricted hydro	The restricted hydro scenario is similar as the **Main scenario**, but assumes that only 25% of the hydro reservoirs can be used actively for storing water for generation (instead of 50%)
Norconsult	In the Norconsult scenario, the only difference from the **Main scenario** is that the expansion of hydro (turbines/pumps/reservoir expansion) is fixed to the same capacities as assumed in the "Hovedalternativet" of the Norconsult study. (Norconsult, 2018)

Table 6. Overview of the analysed scenarios.

Norconsult hydro expansion

The Norconsult scenarios sees a large expansion in turbine capacity for hydro as well as pumping and reservoir expansion.

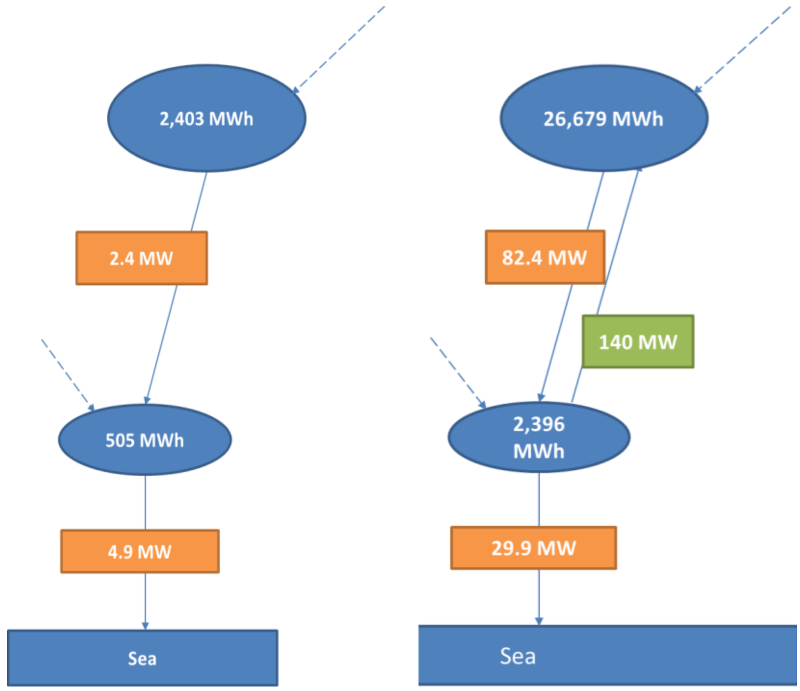

Figure 17: Existing hydro cascade with Mýrarnar and Heygadal (left) and resulting capacities after expansion in the Norconsult Hovedalternativet (right)

5 Results

For the year 2016, the model computes an electricity generation mainly based on hydro (36%), diesel generators (40%) and wind power (24%). These numbers can be compared to the statistics of 2015: hydro (43%), diesel (40%) and wind 17%). Curtailment of wind power may be the cause of the lower share of wind power and the high diesel generation.

In this chapter several key results will be compared for the four scenarios:

- Main
- Low solar
- Restricted hydro
- Norconsult

All of them include 100% electrification of heat and transport sector and 0 tonne CO_2 emissions by 2030. The comparison shows the impact of key assumptions (on solar full load hours) and decisions on how to operate or invest in hydro power (Restricted hydro and Norconsult scenarios respectively).

5.1 Generation capacity

To supply demand in all simulated years, the model will use existing and committed technologies and will additionally invest in new power generation capacity to comply with CO_2 limitations, to accommodate increasing electricity demand and to compensate decommissioning of old units. Figure 18 shows the total generation capacity. This includes existing and committed capacity as well as new investments.

The hydro expansion for the Norconsult scenario is much more ambitious than the expansion seen in the other scenarios. Decreasing solar full load hours results in slightly less solar capacity and compensated with more wind power capacity. Reducing the flexibility of hydro to only 25% of the reservoir has negligible impact on the capacities.

Figure 19 shows the model-based investments for each simulated year. The expansion of hydro in the Norconsult scenario is also included even if it is fixed capacity.

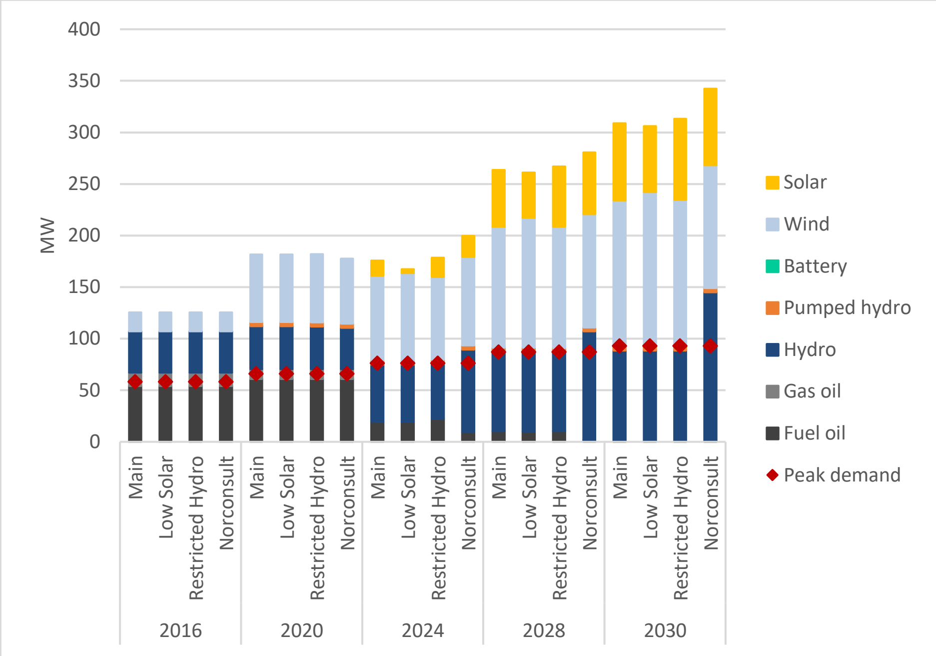

Figure 18: Total capacity for the 4 scenarios for selected years between 2016-2030. Peak demands are indicated. The orange pumped hydro technology represents the 'pumped hydro' project in Miðvatn, Suðuroy. All other hydro expansions (which also include pumping) are shown as dark blue 'hydro'.

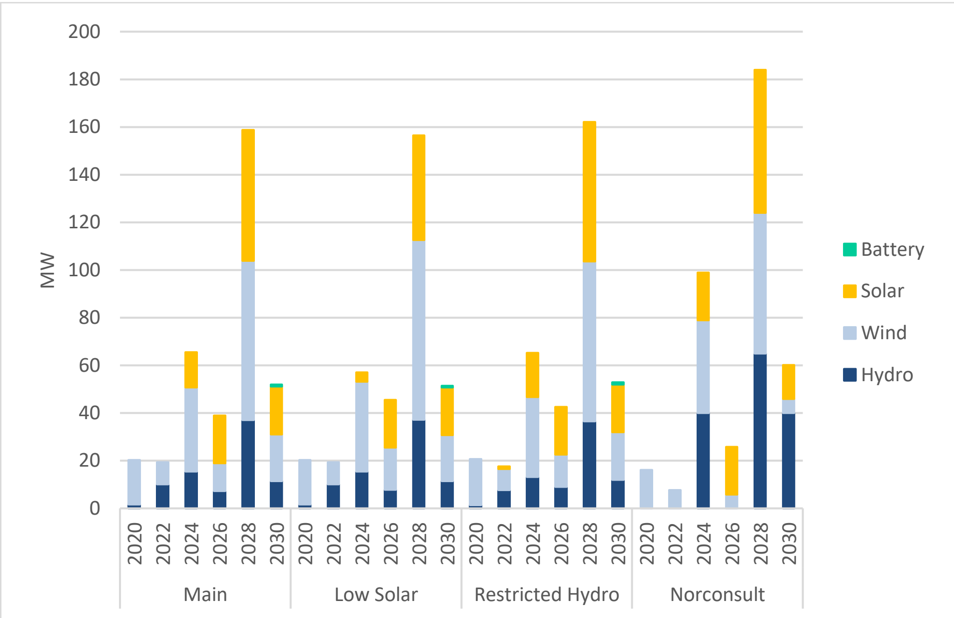

Figure 19: Invested capacity for the 4 scenarios in each simulated year between 2016-2030. The expansion of hydro in the Norconsult scenario is also included even if it is fixed capacity.

5.2 Hydro and pumped hydro expansion

The flexibility of hydro generation is especially important for an islanded system such as the Faroe Islands. The model adds flexibility by investing in hydro pumps as well as in increased turbine capacity and expansion of the reservoir size. The invested capacities for new turbines, pumps and for reservoir expansion are shown in Table 7.

		Generation capacity (MW)	Pumping capacity (MW)	Storage volume (MWh)
Main	**Mýrarnar**	47,5	58	5.698
	Heygadal	0,9	-	1.332
Low Solar	**Mýrarnar**	47,2	63	7.127
	Heygadal	1,5	-	1.821
Restricted Hydro	**Mýrarnar**	46,0	60	6.477
	Heygadal	2,5	-	1.540
Norconsult	**Mýrarnar**	80,0	140	24.276
	Heygadal	25,0	-	1.845

Table 7: Model-based investments in hydro/pumped hydro capacity in the Mýrarnar and Heygadal cascade by 2030. The expansion of hydro in the Norconsult scenario is also included even if it is fixed capacity.

An overview of the total storage capacity by 2030 is shown in Figure 20. For the Main scenario the total useable storage capacity is about 13.5 GWh where the Norconsult scenario has a capacity of 32.5 GWh.

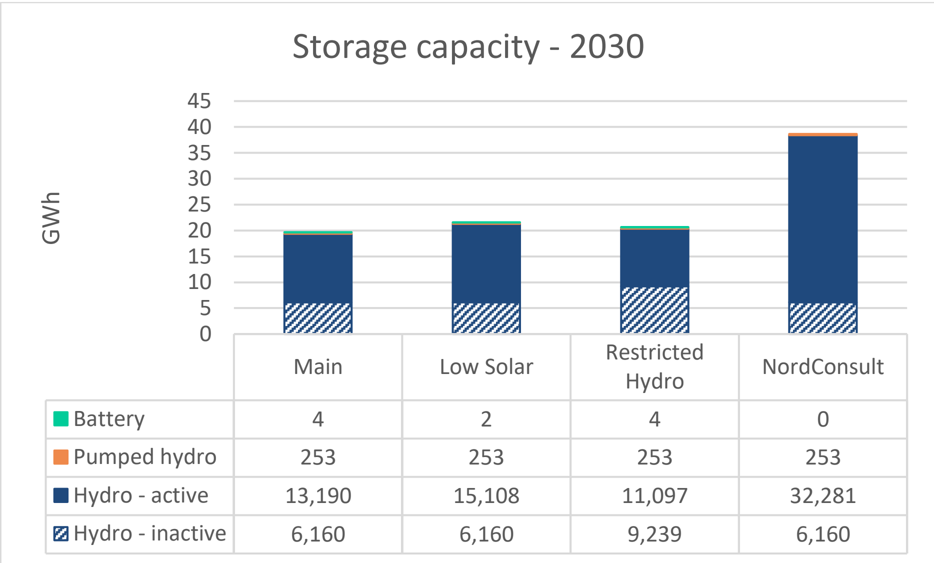

Figure 20: Total storage capacity in the Faroese power system for the 4 scenarios by 2030. Striped area represents the hydro reservoirs which cannot be used for balancing the system.

5.3 Annual generation

The annual generation for the different scenarios is shown in Figure 21. For the Main scenario, the generation mix is 74% wind generation, 16% hydro and 11% solar generation by 2030. The total hydro generation in 2030 is less compared to the generation in 2016 (94 GWh vs 117 GWh) due to pumping losses from the Heygadal to Mýrarnar pump. This is also illustrated in Figure 22, where the generation for each year stays constant, expect for the Mýrarnar plant which includes pumping losses.

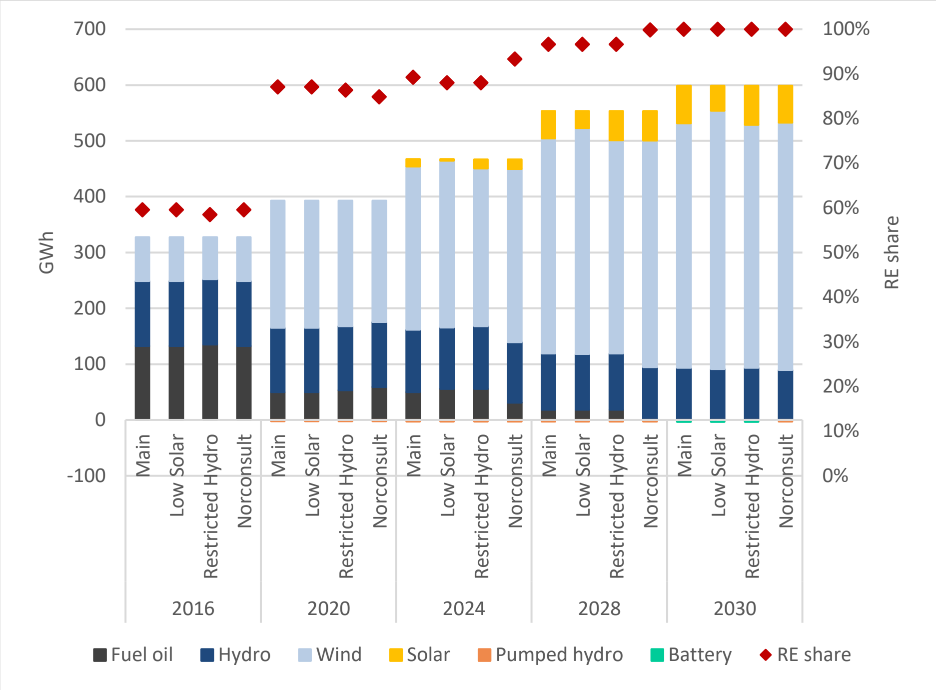

Figure 21: Annual power generation for the 4 scenarios for selected years between 2016-2030. RE shares are indicated.

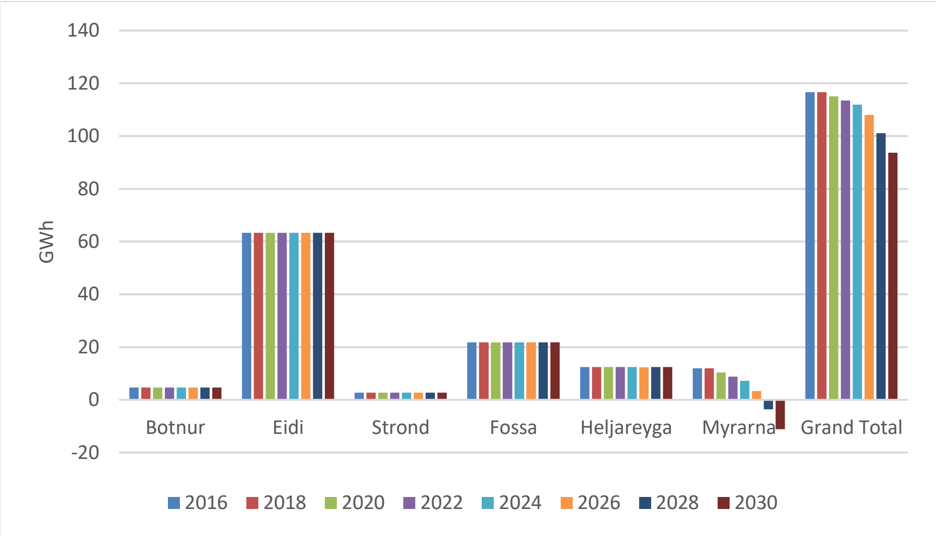

Figure 22: Annual generation of hydro plants in the Main scenario for all simulated years between 2016-2030

In the Low solar scenario, as expected due to less capacity as well as lower full load hours, the balance solar/wind generation is tilting further towards wind generation. The Norconsult scenario which has a high hydro pumping capacity sees more losses and reduces the annual hydro generation slightly.

5.4 Hourly operation of hydro in 2030

It is interesting to look more in depth how the hydro cascade of Heygadal to Mýrarnar is operated. One way of looking at the annual allocation of hydro generation is to look at the water levels of the reservoirs in each hour.

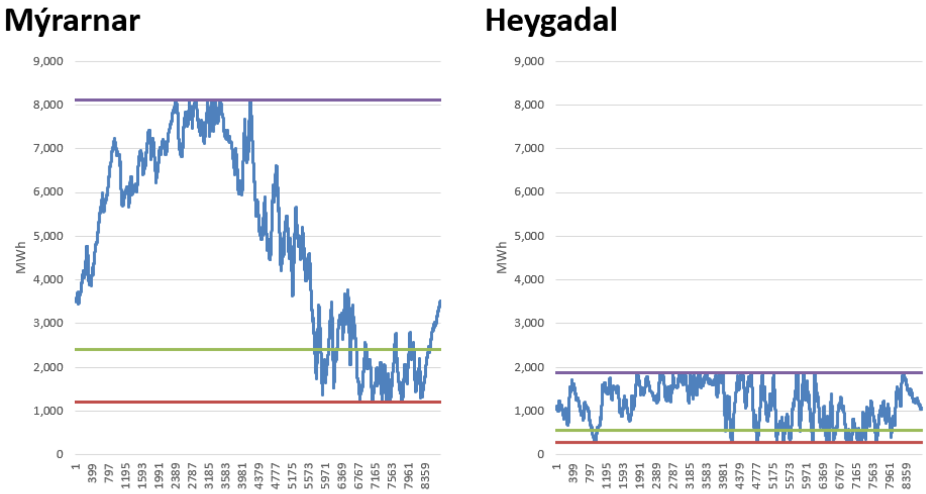

Figure 23: Water levels in the reservoirs of Mýrarnar and Heygadal in the Main scenario in 2030. Green line: Original reservoir size, Red line, minimum fill (level cannot go below), Purple line: Investments in reservoir expansion. Blue line water level for each hour.

Figure 23 shows that the hydro operation has a clear seasonal aspect to it. Where most of the water gets stored in winter and used during the summer months. This seasonal trend can be observed especially in the upper reservoir.

Additionally, the water is also used for short term balancing of the variable wind and solar generation and for following the hourly demand profile. This is also found in Figure 24, which shows hydro generation for an average week.

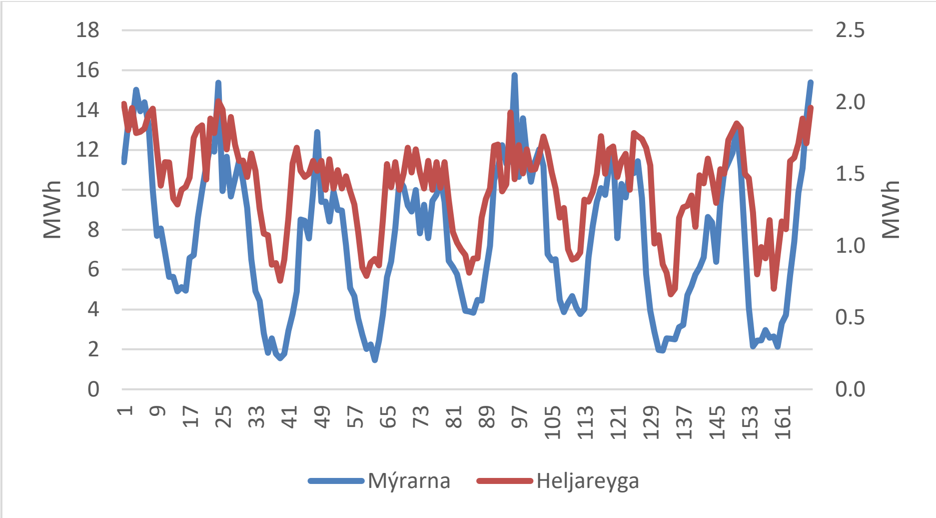

Figure 24: Hourly generation of two hydro units for an average week in the Main scenario in 2030. Mýrarnar (left) and Heygadal (Right).

Figure 25, shows the water levels of 2030 for the Norconsult scenario. Note the magnitude of the reservoir size is much large compared to the Main scenario. Optimized dispatch does not require the large size of the Mýrarnar reservoir in a normal hydro year. The hydro level is maximum 14,5 GWh, which is still higher than the reservoir size in the Main scenario.

It should be noted that the model only considers a normal hydro year and is not able to look ahead more than one year and store water in a dry year to safe it for a wet year. To store water in between years, a large reservoir size might be useful.

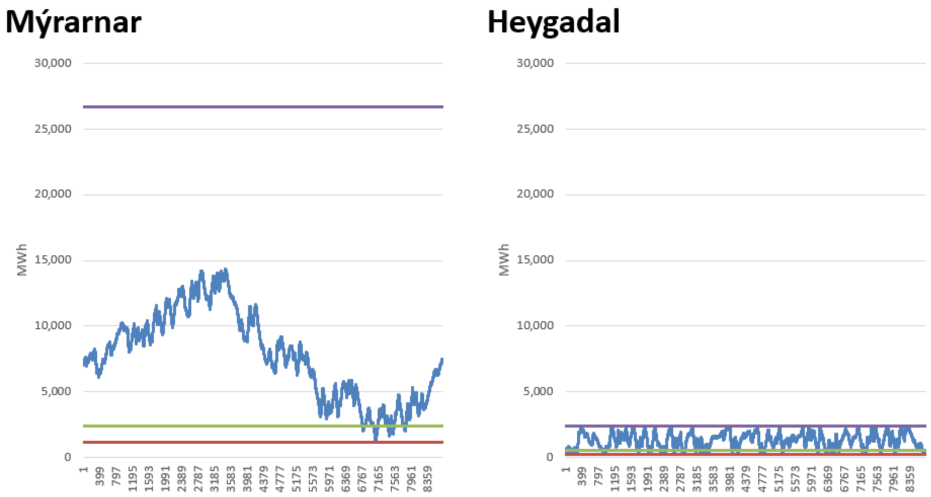

Figure 25: Water levels in the reservoirs of Mýrarnar and Heygadal in the Norconsult scenario in 2030. Green line: Original reservoir size, Red line, minimum fill (level cannot go below), Purple line: Investments in reservoir expansion. Blue line water level for each hour.

5.5 Transmission capacity

In 2016, the two regions in the Faroe Islands are not connected and all demand is provided by local generation. The model is however allowed to invest in transmission capacity between the two regions. The results are shown in Figure 26. By 2030, all scenarios show an optimal investment between 5-6 MW.

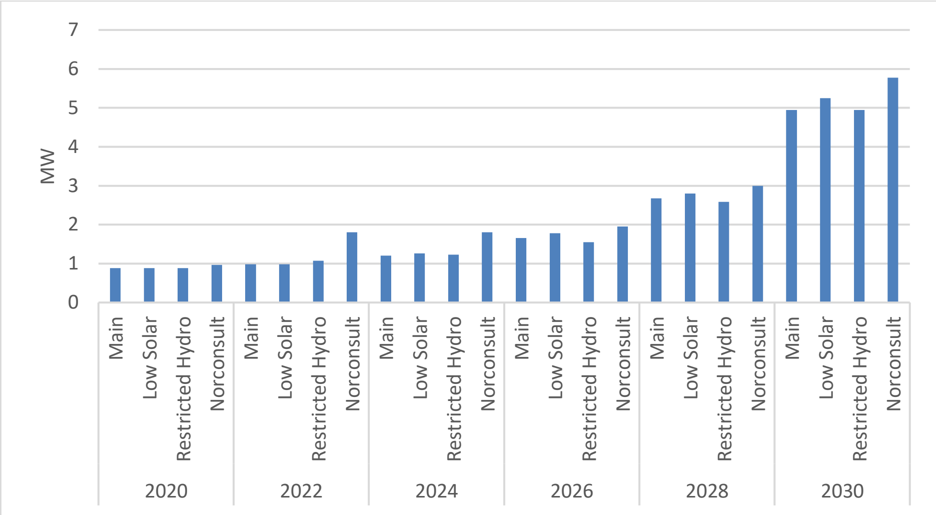

Figure 26: Invested (and total) capacity for the 4 scenarios in each simulated year between 2016-2030.

5.6 CO_2 emissions

The simulations are all run with a requirement to decrease CO_2 emissions over time to zero emissions by 2030. Figure 27 shows the resulting CO_2 emission of the power systems in the four scenarios modelled as well as the imposed CO_2 restriction. Due to cheap wind generation, the CO_2 limit is not binding in 2020. This means that the shift from fuel-oil generation to wind production is market driven.

By 2024, also solar becomes competitive and in the Main and the Norconsult scenarios, the emissions are lower than required. Both an assumption of lower solar full load hours and decreased hydro flexibility result in conditions which make the emission restriction binding. In later years, the large flexibility in the Norconsult scenario, results in very low emissions.

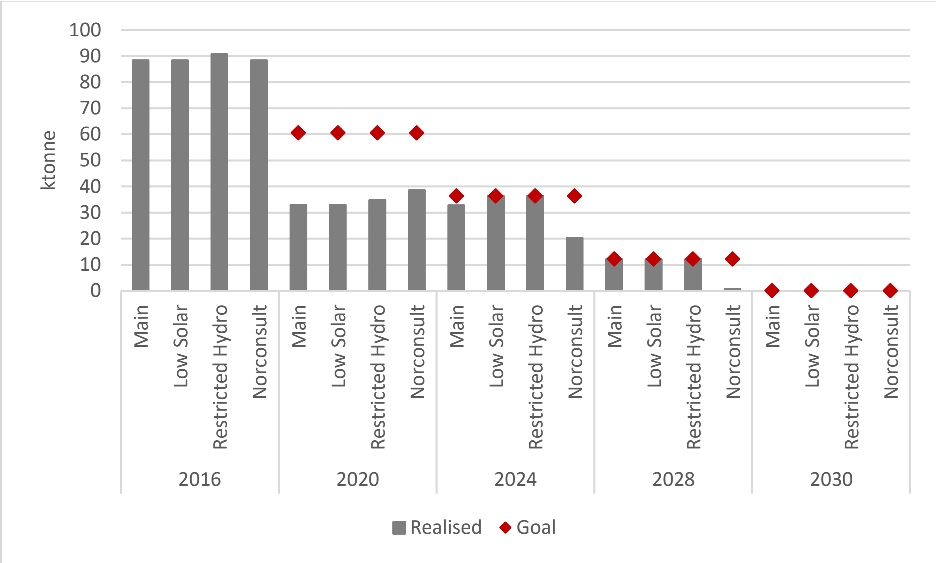

Figure 27: CO_2 emissions for the 4 scenarios for selected years between 2016-2030. CO_2 limits are indicated.

5.7 Total costs and cost of generation

The total system costs of the four scenarios is compared in Figure 28. This graph includes both model results and input from SEV on projected costs. An overview of the information contained in the categories of the system costs are indicated in Table 8. It should be noted that investments in existing and committed generation is not included in Figure 28.

Capital Cost (Old generation)	SEV input (Generation afskrivninger + renter)
Capital Cost (New generation)	Balmorel results
Capital Cost (Reservoir)	Balmorel results
Capital costs (Existing Transmission)	SEV input (Transmission afskrivninger + renter)
Capital Cost (New Transmission)	Balmorel results + SEV input (New transmission)
Fixed O&M (Generation)	Balmorel results
Fixed O&M (Transmission)	SEV input (Transmission materiale + løn)

Table 8: Cost categories and the information they contain

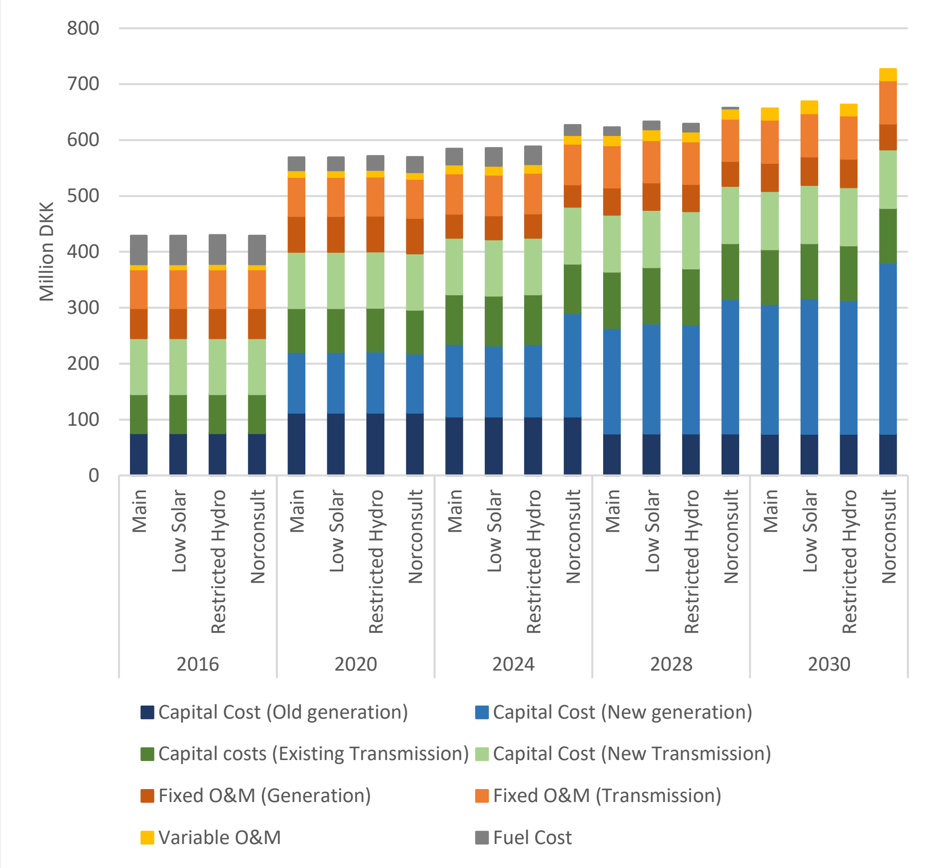

Figure 28: Total annual system costs for the 4 scenarios for selected years between 2016-2030. This graph includes both model results and assumptions for costs made by SEV. It should be noted that investments in existing and committed generation is not included in this graph.

The economic results show that over the years, fuel costs are decreased while fuel oil is replaced by wind and solar generation. Capital costs increase due to investments in new generation (investments costs for existing generation is not included).

The Low solar and the Restricted hydro scenarios are very similar to the Main scenario in terms of total costs (+2% and +1% increase respectively), where the Norconsult scenario is about 11% higher in costs due to expensive investments in large pumped hydro expansions. The total investment costs per year are illustrated in Appendix A.

Figure 29 shows the cost of generation by dividing the total system costs by the electricity generated that year. The graph shows a decrease in costs of generation over the years.

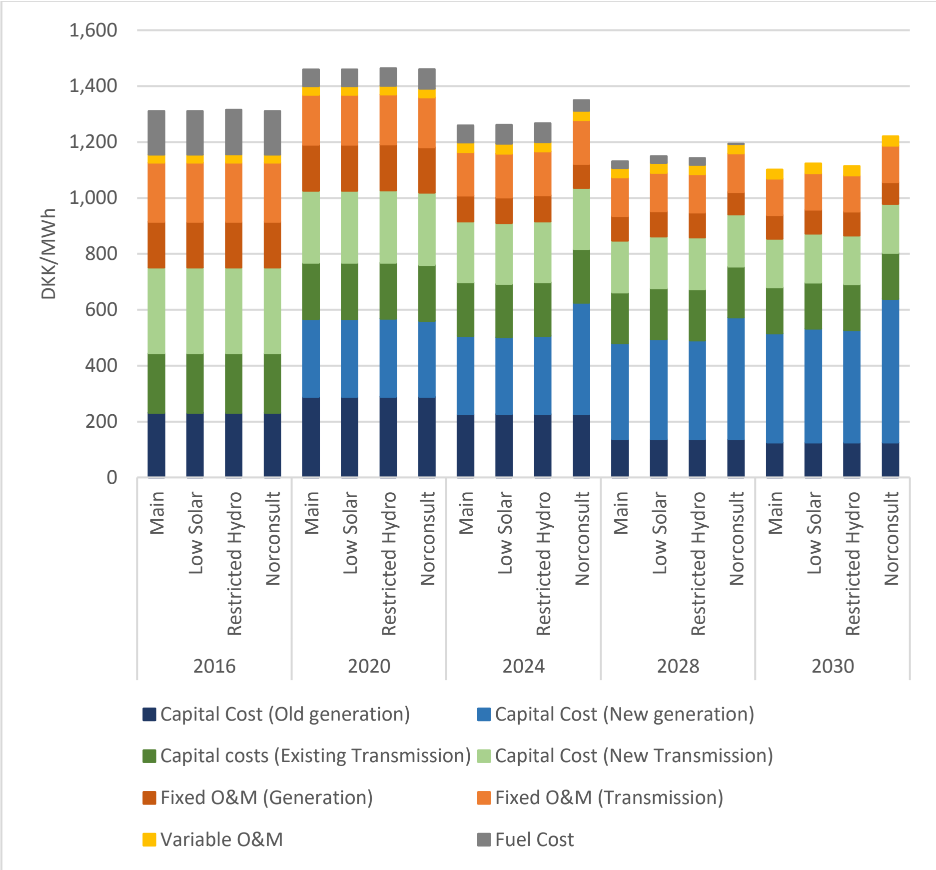

Figure 29: Cost of generation for the 4 scenarios for selected years between 2016-2030. This graph includes both model results and assumptions for costs made by SEV. It should be noted that investments in existing and committed generation is not included in this graph.

6 Discussion and further analyses

This study represents the second Balmorel study of the Faroe Island electricity system. The focus of the analysis is the hourly energy balance and how hydro and pumped hydro can aid the integration of variable renewable energy sources in a zero-emissions power system. With this perspective, the optimal dispatch and investment path is computed.

Storage

In (Dansk Energi, 2017) the need for storage is described for different scenarios. The needed storage capacity varies from 20 to 60 GWh. In the Main scenario with a strong expansion of electric vehicles, is it shown that with a system dominated by wind (130 MW wind, 30 MW solar), 60 GWh storage is needed. This can be reduced to 46 GWh if more solar power is added (121 MW wind, 95 MW solar) and further to 22 GWh if tidal energy is used (72 MW wind, 30 MW solar, 60 MW tidal). A challenge for the economy of such a system is that the storage will only have one yearly cycle: Full loaded in March to June, and without load in October.

In our study, the Main scenario with total electrification has 141 MW wind and 75 MW solar). The required (useable) storage capacity by 2030 is about 13.5 GWh, which includes the existing hydro reservoirs small amounts of battery storage, and the pumped hydro system in Suðuroy and 7 GWh of reservoir expansions in the Mýrarnar and Heygadal reservoirs. Lower solar full load hours would increase the storage size needed for balancing to about 15 GWh. Limiting the hydro use of existing hydro would not make the model invest in more reservoir, but adds slightly more pumping capacity.

Compared to the Main scenario, the Norconsult scenario shows very high values of storage size. This can be explained by remembering that Balmorel looks at one year at the time and in these simulations only considers a “normal hydro year”. The Main scenario therefore does not consider storing water during wet years for generation in dry years. Furthermore, the model has full foresight so does not have to keep hydro for reserves.

The Norconsult scenario will make zero emissions by 2030 in all likely scenarios, including a dry hydro year. This comes at a price of about 70 million DKK additional system cost (or about 11%) compared to the optimized scenario where the zero emission restriction will be upheld in case of a normal hydro year.

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