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The impact of climate change on the cost-optimal electricity system composition in Sweden

Master's thesis in Sustainable Energy Systems

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Abstract

Climate change has an impact on both the supply and demand of the electricity system. Amongst the affected areas are both electricity demand for temperature control and hydropower. The aim of this thesis is to support the understanding how the climate change impact on these two areas will impact the cost-optimal electricity system composition in a subregion of Sweden.

There is a large spread on reported magnitude of the climate change impact on the two areas depending on the utilised climate model, studied climate scenario, studied years, and used hydrological model. With a temperature increase of about 2°C, a maximum increase of yearly hydropower potential in Sweden of 20% is reported. The hydro inflow will be more spread out across the whole year with a lower, and earlier, spring flood. Electricity demand for temperature control during wintertime can decrease by 15% and increase by 70% during summertime. The absolute decrease in electricity demand wintertime is larger than the absolute increase during summertime.

Both the change in electricity demand and hydropower reduce the strain on the electricity system during wintertime, either by reducing the demand or introducing more available hydropower during the winter season. At the same time, the strain during summertime is increased as demand is increased, and available hydropower is reduced. While wintertime remains the dimensioning season in terms of generation capacity and energy required, the reduction in strain of the electricity system in wintertime does impact the cost-optimal composition. The change in electricity demand and hydropower production is investigated separately as well as in combination. The largest change in the cost-optimal composition is seen when both the electricity demand and the hydropower changes simultaneously, where a greater change in the two areas bring a larger change in the cost-optimal composition. For the case with the highest climate change impact, the installed capacity of offshore wind, which offers great amount of energy and generation capacity wintertime, is reduced by up to 15.4% while the installed capacity of solar power increases by up to 37.7%. With impacts on this scale, it is important to take climate change impact on hydropower and electricity demand for temperature control into consideration when planning future electricity systems.

1. INTRODUCTION

1.1. Background

Extreme weather events and climate have, both direct and indirect, influence on electricity demand and generation. The impact manifests itself both in varying demand due to indoor temperature control as well as varying generation due to the direct dependence on weather condition that varying renewable energy exhibits. Global warming changes the climate in a multitude of ways. Two of the factors closely related to electricity generation are increased air temperature and changed precipitation (IPCC, 2014). This changes the preconditions for the electricity system which need to be taken into consideration when designing systems supposed to last a long time. An assessment of the extent of impact caused by climate change provides opportunity to adapt, increasing resistance of the electricity system and ensuring security of supply.

There exist a plethora of studies assessing climate change impact on areas which are related to the electricity system, such as the potential of renewable energy. These studies have used climate projections from either global climate models (GCM) or regional climate models (RCM). Due to the wide range of climate models, climate scenarios and studied years the result of these studies tends to vary from each other. However, there exist common trends. Emodi et al., 2019, performed a scoping review of studies using GCMs. Emodi state that by end of the century Northern Europe will have an increased share of wind power and hydropower production while solar power production will decrease. Thermal generation units showed inconsistent results. The residential energy demand was found to be decreasing. The magnitude of these changes differ depending on study. Cronin et al., 2018, did a review of their own and reported the magnitude found in their studies. Hydropower potential could see increases ranging from 5-20% in Northern Europe. In Europe, average wind speeds could vary by ± 30% and changes in solar generation likely remain within ± 10%. Cronin found that thermal power plant output will decrease by 0.4-0.7% per degree of warming. In addition to having varying results depending on model used, there is geographical variation of these changes (Karnauskas et al., 2018; Mideksa & Kallbekken, 2010).

These studies certainly indicate that the European electricity system will be impacted and would benefit from having measures in place that accommodate and utilise the range of potential production. The impact of climate change on singular countries will vary, as supported by previous studies on singular countries (Pašičko et al., 2012; Seljom et al., 2011). Studies with a nation-scale geographical resolution helps determine climate change impacts on the electricity system of single countries. Identifying the extent of impact upon nation-scale electricity systems is a crucial part in enabling both policymakers and organisations active in the electricity market to make informed decisions.

1.2. Aim

The aim of this work is to provide an understanding of how the Swedish electricity system is coupled to climate change impact on electricity demand for indoor temperature control and hydropower. This is done by investigating how the cost-optimal composition of the electricity system varies when climate change impacts are introduced relative to a base case without these climate change impacts. The cost-optimal composition of the electricity system is achieved by using a linear-optimising model that minimises the total system cost as the objective function. Both hydro inflow and electricity demand have two characteristics; total yearly energy and the profile which distributes the energy across the year. Both of these are investigated in this thesis. The study covers a subregion of Sweden resembling bidding area SE3 in Sweden and the climate change impact represents what could happen when global warming reaches up to 3°C. More specifically, the work aims to answer the question if it is important to consider climate change impact on hydropower and electricity demand for temperature control when designing the future electricity system of Sweden.

1.3. Limitations

The investigation started by including wind data produced by two models created in the EURO-CORDEX project to see possible impact caused by changes in wind. However, the data set was determined too small to draw any conclusions with confidence. A broader data set is needed in order to increase the legitimacy of the data. Instead, wind data used in previous papers were used and no possible climate change impact on wind power was included in this thesis. The input data is described in section 3.3.

Linkages between the electricity system and other sectors such as the district heating system is not regarded in this work.

2. LITERATURE REVIEW

The focus of this study is changes in demanded electricity and hydropower. Literature is reviewed to create an understanding of how each of the areas currently operate and how climate change could impact each area. As stated in the aim, both hydropower and electricity demand have two characteristics. The first of these is the annual available hydropower potential, or hydro energy, and the annual demanded electricity. The second is the temporal aspect of these two, meaning how the annual energy is spread out in each hour of the year. As such, the literature review presents both the change in annual energy and the temporal aspect.

The reported results in the investigated literature differ between each study. This is due to researchers using different data, methodology, and boundaries. A few of the factors that impact the results are different climate and hydrological models as well as different climate scenarios and years. This work does not sort the findings into separate categories according to these factors as this work aims to investigate whether the climate change impacts is noticeable or not in a cost-optimal electricity system. To answer the aim, an approach where 'what-if' scenarios with the reported climate change impact on hydropower and electricity demand is used. The finding of each study is reported in a table close to the start of each subsection. Hydropower is presented in section 2.1 while electricity demand for heating and cooling is treated in section 2.2. How these findings are translated into model input data is explained in section 3.

2.1. Hydropower

From 1986 to 2018, hydropower in Sweden has on average provided 67.6 TWh annually. This data is retrieved from Statistics Sweden and the interannual variations can be seen in Figure 1. The hydro inflow usually peaks during summertime due to snow melting in northern Sweden where most of the hydropower is located and the lowest inflow is around March, prior to the spring flood (Energiföretagen, 2020). Bidding area SE3, which is similar but not identical to the investigated region explained in section 3.2, have 16% of the total installed generation capacity of hydropower in Sweden (Energimyndigheten, 2016). The total amount of installed hydropower capacity in Sweden is around 16 GW (Royal Swedish Academy of Engineering Sciences, 2016). The installed capacity of hydropower in bidding area SE3 is thus roughly 2.6 GW.

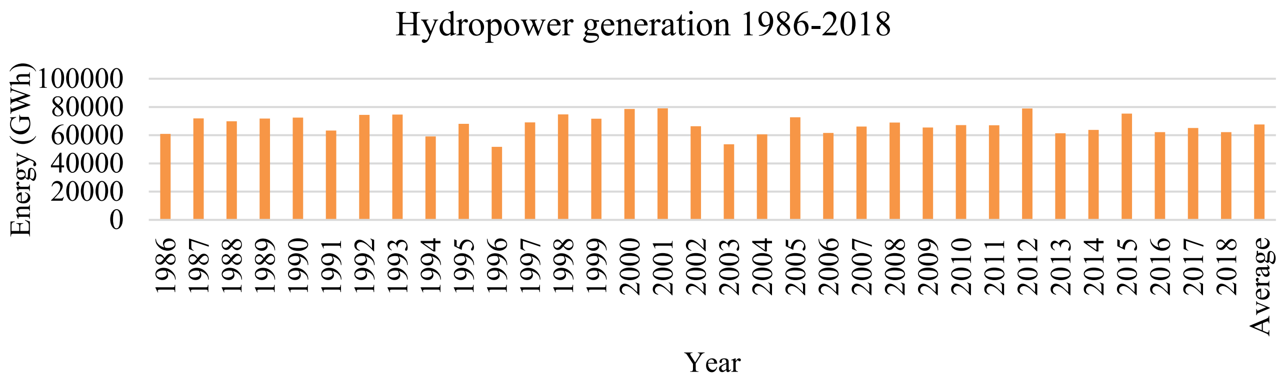

Figure 1 Hydropower generation in Sweden from 1986 to 2018. Statistics available from SCB (Statistics Sweden).

In Table 1 a quick summarisation of the findings on climate changes impacts to hydropower potential in Sweden can be seen. The first two papers described divide Sweden into three parts and the impact on whole of Sweden is therefore calculated by using the fact that most of the hydropower exist in northern Sweden. Each paper is described more in-depth in the following text. The investigated papers studied changes occurring with a temperature increase ranging from 1.5° to 3°C, the results presented in Table 1 being the largest change found in the corresponding paper.

Table 1 Summarisation of reported climate change impact on annual available hydro energy in Sweden found in different papers. These changes are reported for a temperature increase of 1.5°C to 3°C where a higher temperature increase generally yields a higher annual available hydro energy. The papers often cover a range of scenarios and models with varying degrees of change of the hydro energy. The values in the table refer to the maximum change reported in each paper.

	Northern Sweden	Middle Sweden	Southern Sweden	Whole of Sweden
Gode et al.	+24%	+10%	-2.7%	
Bergström et al.	+30%	-41%	-26%	+19%
Tobin et al.				+17%
Van Vliet et al.				+10%

Gode, 2007, was main author on a report performed by Swedish Elforsk that investigated climate change impact on the energy sector in Sweden. This report contains knowledge of several investigations. Climate data from several climate models created by SMHI show that the total yearly hydropower potential is going to increase in Sweden. Calculations were performed with the hydrological model HBV for years 2071-2100 and compared to reference years 1961-1990. Gode then used linear interpolation to give qualitative results for years 2011-2040 which have a temperature increase of 1-2°C in the tried climate scenarios. As previously mentioned, different scenarios and models give different results. In some combinations of climate scenario and climate model, a 0.9% to 2.7% decrease of inflow in southern Sweden is reported, while other combinations yield an increase of +6% to +8%. Northern and middle parts of Sweden have an increase in hydropower potential regardless combination of climate scenario and climate model. However, this increase varies between +4% to +24% in northern Sweden and +0.5% to +10% in middle part of Sweden depending on combination. Regarding the temporal aspect, it was stated that hydro inflow will increase in all of Sweden during autumn and winter. Northern Sweden will see an earlier spring flood and southern Sweden will experience a more spread out hydro-inflow during wintertime instead of a spring flood. The summer hydro-inflow will decrease in southern Sweden. No definite numbers on how the inflow will change week to week was reported. Compared to the yearly statistics in Figure 1, the reference period used in the paper by Gode is earlier and as such the changes reported might already have started as global warming is already occurring. However, as 'what-if' scenarios of are sought after, it is assumed that the changes mentioned can be applied to the hydropower data in Figure 1.

The same trends were identified by Bergström et al., 2001, but the magnitude differs. Bergström used one RCM for downscaling but retrieved climate data from two different GCM, yielding two cases. The investigated cases have a temperature increase of about 2.6°C. These two cases were used in two different setups of the used hydrological model HBV where the evapotranspiration was handled in two different ways. Southern Sweden saw results varying from +3% to -26% in annual hydro energy while northern Sweden had results varying from +23.0% to +30.0%. The hydro energy in the middle part of Sweden decreased, with results varying from -10.0% to -41.0%.

Northern Sweden has most of the hydropower with approximately 85% of the annual hydropower energy coming from bidding area SE1 and SE2. If the extremes are considered, a 41.0% decrease in middle and southern part of Sweden, and an increase of 30.0% in northern Sweden, it would result in an overall increase of 19% of annual available hydro energy in the whole of Sweden.

Tobin et al., 2018, used five RCM simulations from the EURO-CORDEX project and investigated changes of renewable energy resources in Europe. The spread across the climate models was substantial. In this work, the ensemble mean which Tobin reported is used. The ensemble mean in Sweden showed an increase of 10% to 17% in hydropower potential depending on the degree of warming from 1.5°C to 3.0°C respectively.

Van Vliet et al., 2013, used a hydrological modelling framework to evaluate the hydropower potential for years 2031-2060 and compared the result to reference year 1971-2000. The work was done for two emission scenarios, one considered a medium-high scenario and the other one with low scenario. In their work they found that hydropower potential increased by 8.0% to 10.0% in Sweden depending on scenario.

2.2. Demand changes due to heating and cooling

In Sweden most of the heating in multi-family residential buildings come from district heating. Only 7.6% of the heating demand, corresponding to 2.1 TWh, comes from electric space heating (Energimyndigheten (Swedish Energy Agency), 2017). On the other hand, single family dwellings use electric space heating to a higher degree as 47% of the heating demand, equals to 15.2 TWh, comes from electricity (Energimyndigheten, 2017). Buildings used for business and public areas mostly use district heating but approximately 4 TWh of electricity is consumed yearly for heating (Statens energimyndighet, 2020). In total, the yearly consumption of electricity meant for space heating is 21.3 TWh.

Comfort cooling does exist in Sweden but compared to space heating there is not as much information regarding the electricity consumption. As such, rough estimations on both the extent and intensity of electrical comfort cooling must be made. The Swedish Energy Agency made an investigation of public facilities including general offices and health care facilities (Swedish Energy Agency, 2010). In this report they state that comfort cooling is available in more than half of the investigated offices with an average consumption of 10 kWh/m2/year. Excluding electrical heating, this is equals to 11% of the electricity consumption in offices which is 93 kWh/m2/year. Another investigation made by the Swedish Energy Agency in 2016 stated that a total office area of 25.3 million m2 is heated with district heating (*Energistatistik För Lokaler 2016*, 2017). If it is assumed that comfort cooling is, or will be, installed to the same extent of area as the district heating in offices this would add up to a consumption of 253 GWh per year. Health care facilities have a lower consumption of comfort cooling at 3 kWh/m2/year. This is equals to 3.75% of their total electricity consumption excluding electricity for heating. The total area of health care facilities that was heated by district heating amounts to 16.2 million m2 (*Energistatistik För Lokaler 2016*, 2017). If the same assumption as for offices is applied, the electricity consumption for comfort cooling is 48.6 GWh. Based on these assumptions, the total electricity consumption for comfort cooling in public facilities in contemporary Sweden would thus add up to 301.6 GWh per year.

Information of comfort cooling in family residences is harder to come by. An estimation of the total cooled area together with a specific consumption can be used to get an estimated electricity consumption. This is made in section 3.5. In order to do a realistic assumption of the cooled area, it is important to know that in the investigated region there are almost 4.2 million residences, according to Statistics Sweden. These residences have a total area of almost 384 million m2 with 159 million m2 being multi-family residences.

In literature regarding climate change impact on heating and cooling demand the specific electrical consumption is not discussed to a great extent. Rather, it is discussed in terms of heating degree days (HDD) and cooling degree days (CDD). These days represents how large the need for either heating or cooling is or will be, but not the exact consumption required to satisfy this demand. In this review, HDD and CDD is investigated then used with a correlated specific electric consumption to get the impact on the electricity system. The structure of the text is the same as for the hydropower with an overview first then a more detailed description in the text. Table 2 shows a quick summarisation of changes to HDD and CDD found in literature. The papers studied investigate climate change impact occurring with a temperature increase ranging from 1° to 3°C.

Table 2 Summarisation of reported climate change impact on heating degree days (HDD) and cooling degree days (CDD) in different papers. These values are reported for a temperature increase from 1°C to 3°C. The papers often cover a range of scenarios and models with varying degrees of change in HDD and CDD. The values in the table refer to the maximum change in HDD and CDD reported in each paper.

	HDD	**CDD**
Gode et al.	-692	
Pilli-Sihvola et al.	-500	
Aebischer et al.	-400	+70

Gode et al. (2007) made a report on suspected decrease in heating demand and increases comfort cooling in Sweden. When calculating the changes in demanded energy Gode take more than change in HDD into consideration, such as increased efficiencies and change in solar irradiation. These are all valid points when trying to paint a descriptive future but to see changes in a cost-optimal electricity system and how the investment changes depending on climate change, a rougher consideration can be made which only focuses on the HDD and CDD changes. Of the investigation scenarios, IPCC scenario A2 (introduced in the Fourth Assessment Report representing a scenario with continuously increasing global population and, relative to other scenario families, slower technological change and economic development) gives the largest reduction in HDD as reported by (Persson & Strandberg, 2007). In years 2011-2040 the median HDD has been reduced by 692. Year 2011-2040 in scenario A2 with the used regional models corresponds to a temperature increase of 1-2°C summertime and 2-3°C wintertime (Jonsson, 2003). No changes in CDD were investigated.

Pilli-Sihvola et al. (2009) did an investigation of climate change impact on cooling and heating for central and northern Europe. Amongst the investigated countries were Finland. Of the investigated scenarios and years, the maximum decrease in HDD was found in IPCC scenario A1B with a reduction of approximately 500 HDD in 2050. Pilli-Sihvola built a regression model and did a regression analysis of the electricity consumption based on, amongst others, HDD and CDD. It was found that HDD did have a statistical significance and that an increase of one unit of HDD increase electricity consumption by 0.03% in Finland. No significance was found for CDD and therefore no change in CDD was investigated. The global temperature increase in this scenario with the used model and years is 1°C, and in Finland the temperature increase varies from 1°C summertime and 1.7°C wintertime. As Finland features similar weather conditions and similar heating systems as Sweden, it can be assumed that the found correlation between HDD and electricity consumption holds true for Sweden.

Aebischer et al. (2007) present a thorough investigation of changes in HDD, CDD and the associated increase in energy consumption (Aebischer et al., 2007). A decrease of around 400 HDD and an increase of 70 CDD was reported for Stockholm at a temperature increase of 2°C. The presented correlation between specific electricity consumption for comfort cooling and CDD have a higher baseline than the specific electricity consumption in offices found by the Swedish Energy Agency. If the same linear increase in electricity consumption based on CDD is assumed, an increase of 70 CDD would increase the specific electricity consumption by 70%. This would, using the baseline value found by the Swedish Energy Agency, increase the specific electricity consumption of comfort cooling to 17 kWh/m2/year compared to the original 10 kWh/m2/year.

3. METHOD

In this section, the method employed to calculate the cost-optimal electricity system as well as how literature findings are utilised is covered. The first subsection provides a brief general information regarding what type of model is used and gives reference where to find more in-depth explanations of said model. In section 3.2 the investigated region is explained. Section 3.3 describes where input data is gathered from. Cases which are investigated are explained in section 3.6.

The aim of the thesis is to provide an understanding of how changes in hydropower and electricity demand would impact the electricity system. This is done by modifying existing input data in an electricity system model according to the findings in literature and comparing these cases with a base case without any modified input data. The relative change between the base case without climate change impact and the cases with climate change impact reveals which changes to the cost-optimal electricity system could happen due to climate change. How the modification to the original input data is done is explained for hydropower in section 3.4 and electricity demand in section 3.5. Previously mentioned, both the hydropower and electricity demand have two aspects; the annual energy and how this annual energy is spread out across a year.

3.1. Model description

The model used is the eNODE model, a one-node greenfield model which uses linear optimisation to minimise the system cost thus achieving the composition for a cost-optimal electricity system, subject to constraints and input data. Both investment in technologies and dispatch of these technologies are controlled by the eNODE model in order to achieve a cost-optimal electricity system. A time-resolution of three hours is used to limit the amount of computing needed. The eNODE model was developed by Göransson et al., 2017, and there are several papers written by Göransson that explains constraints and available technologies. No major functional changes are done to the eNODE model in this work and the reader is referred to the work done by Göransson if a more in-depth view of the model is sought after.

3.1.1. General model settings

To limit the temperature increase to a maximum of 2°C and strive for a maximum 1.5°C as per the Paris Agreement a limit on CO2 emission must be set. A scenario aiming for a limit of 1.5°C should have a CO2 limit of zero by 2050 if no negative emissions are allowed. If negative emission is allowed, this limit could be postponed somewhat. In this work it is assumed that zero emissions will be attained, and the CO2 limit is therefore zero for all tested cases.

As several different years are used, costs of technologies would normally vary between each year due to the nature of learning curves. To avoid this additional impact on the results, the price of technologies is fixed and set identical for each year and configuration, using cost data for 2050 as representative cost.

In this work, the installed capacity, and available storage, of hydropower is treated as brownfield. This means that the hydropower is set to a specific installed capacity and storage size where no new investment can be made by the model. In section 2.1 it was stated that the installed capacity of hydropower in bidding area SE3 was roughly 2.6 GW. The investigated region, EPOD region SE2 (see Section 3.2), is similar to bidding area SE3 and the installed hydropower capacity is set to 2.6 GW. The available storage size in EPOD region SE2 is set to 2474 GWh.

An annual hydrogen demand equals to 15% of the annual electricity demand is included. It is not farfetched that a hydrogen demand equals to 15% of the annual electricity demand would exist in 2050 as there are projects aiming to start hydrogen production in Sweden[1].

[1] One such example is the HYBRIT project which aims to produce fossil-free steel by using hydrogen instead of coke as reduction agent.

3.2. Investigated region

The investigated region is the EPOD region SE2 which is not the same as the whole of Sweden, and neither the same as bidding area SE2 commonly used. It is similar to bidding area SE3, but not exactly identical. The EPOD region SE2 consist of the greater part of southern Sweden, excluding the most southern part such as Skåne and Blekinge. Figure 2 shows the EPOD regions in Sweden and surrounding countries.

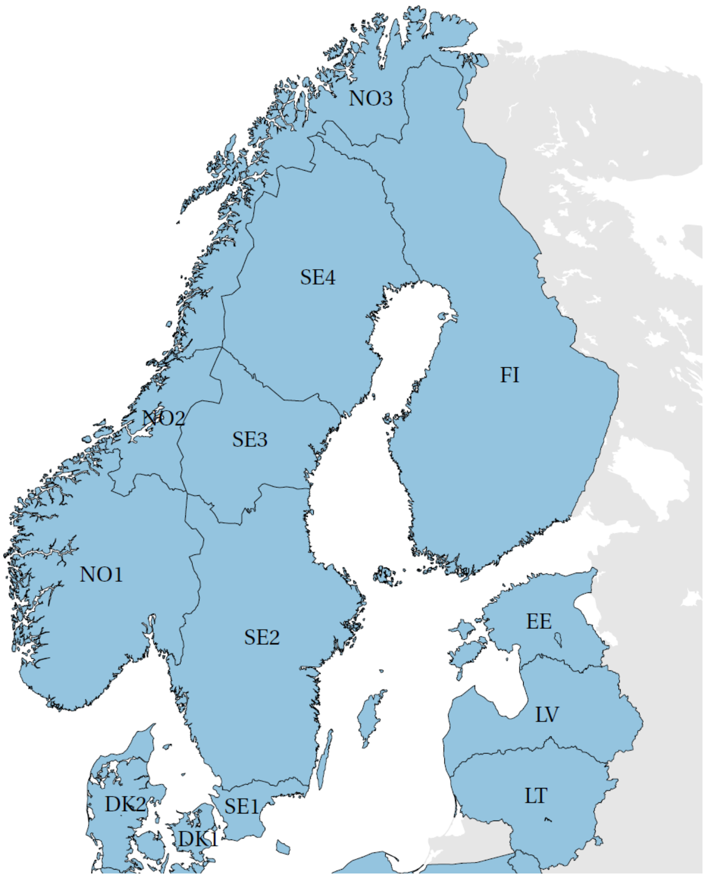

Figure 2 Figure showing the EPOD regions in Sweden. Credits to Joel Goop.

As the majority of the hydropower exist in the northern part of Sweden, it is only available to EPOD region SE2 as a means of imported hydropower. Most of the investigated cases will not allow any imported hydropower to SE2 to investigate climate change impact upon a single region. However, four configurations explained briefly in section 3.6 are performed with imported hydropower to showcase the effect when a larger amount of hydropower is existent.

3.3. Input data

The original electricity demand represents year 2015 and the original normalised demand profile is procured by European Network of Transmission System Operators for Electricity (ENTSO-E) and represents year 2012. The original annual demanded electricity and the original normalised demand profile, multiplied by this annual demand, is shown in section 3.5. Both wind and solar data are retrieved from MERRA-2 reanalysis data representing year 2012. The original hydro inflow profile represents a normal year and is retrieved from work by Göransson, 2014. Available yearly hydro energy is explained in section 2.1.

Investment cost for thermal generation units are retrieved from the International Energy Agency (*World Energy Outlook 2016*, 2016). Technology data for renewable technologies is gathered from The Danish Energy Agency, 2020. Data on energy storage technologies, such as batteries, is retrieved from a separate catalogue from The Danish Energy Agency, 2020.

3.4. Hydropower

The findings regarding hydropower in the literature review is in this section translated to model input data. Both the annual available hydro energy and the temporal aspect, the hydro inflow profile, is modified to represent how climate change could impact hydropower. First, the modifications to the annual available hydro energy will be explained. Secondly, the hydro inflow profile. The different configurations reveal 'what if' scenarios which can be used qualitatively in determining how large impact climate change on hydropower has on a cost-optimal electricity system.

Previous research considered; it seems that the annual available hydro energy could increase by up to 19% in Sweden depending on future scenario mentioned in section 2.1. In this work, several different scenarios will be tested to cover the range of possible changes. The total available hydro energy in Sweden will be increased by 4% steps up to a 20% increase, which from the original 67.6 TWh available to the whole of Sweden equals to 81.12 TWh. A simplification is made where the percentual increase in SE2 is assumed to be equals the percentual increase in the whole of Sweden. The equivalent increase in the investigated area SE2 is shown in Table 3 where the different versions, starting from the original, of the available **H**ydro **E**nergy is named HE0, HE1, ..., HE5.

Table 3 Annual available hydro energy for the whole of Sweden and EPOD region SE2.

	HE0	HE1	HE2	HE3	HE4	HE5
Sweden (TWh)	67.6	70.3	73.0	75.7	78.4	81.1
SE2 (TWh)	12.8	13.4	13.9	14.4	14.9	15.4

According to literature (Gode, Bergström) a changed hydro inflow profile can be expected with more inflow during wintertime and an earlier, smaller, spring flood. No specific numbers how the inflow will change week to week was found in literature. As such, the hydro inflow profile was modified by dividing the original hydro inflow profile into 52 weeks, multiplying each week with a unique factor, normalising the new profile, then smoothening the new profile using a moving average in order to create a resemblance of how the literature findings was interpreted. The used factors can be seen in Appendix B. Eight different hydro inflow profiles were constructed to gain insight whether the impact to the electricity system would be continuous or happen during a certain breakpoint. The hydro inflow profiles are used in a normalised format as input data. Each hydro inflow profile can be seen multiplied with the original available hydro energy, for the whole of Sweden, in Figure 3. This was done in order to showcase the magnitude of the inflow and the changes relative to the original profile. The changed hydro inflow profiles have an earlier, and lower, spring flood with a small increase of inflow during the rest of the year. Each of version of the **H**ydro **P**rofile is named HP0, HP1, …, HP8 where HP0 is the original hydro inflow profile which can be seen furthest in the back with the highest spring flood.

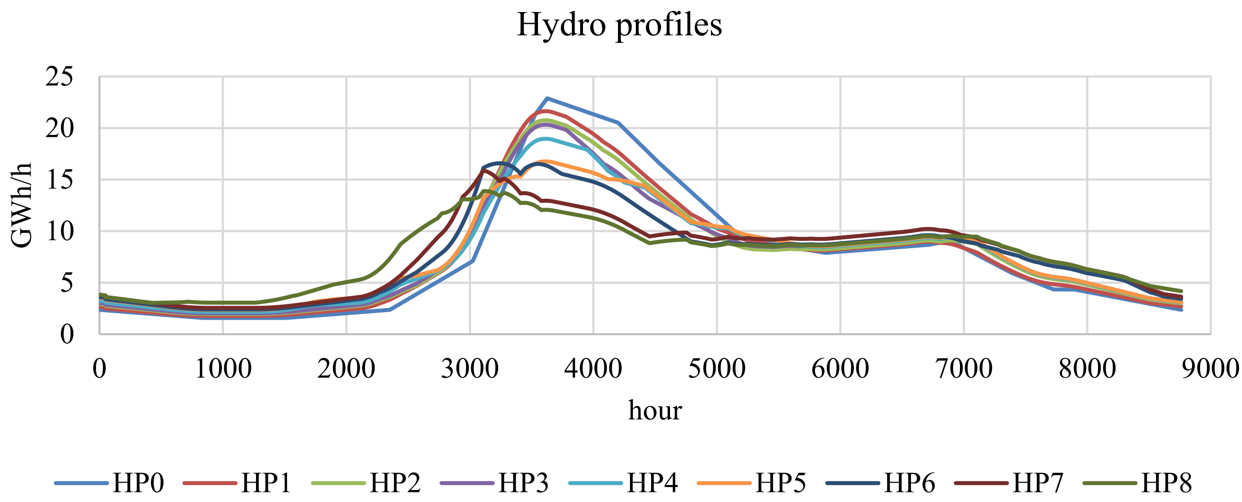

Figure 3 Hydro inflow profiles. The original inflow profile has a higher spring flood while the modified inflow profiles have a slightly lower and earlier flood. In this figure, the inflow profiles are multiplied with the original hydro energy of 67.6 TWh per year.

3.5. Demand changes due to heating and cooling

To be able to modify an electricity demand for temperature control, the electricity demand for comfort cooling in households for the base case must first be estimated. In the literature review of the electricity demand for temperature control, information regarding the total area of residences in the investigated region was presented. This information can be used to estimate the current electricity demand for comfort cooling in households. By assuming that all the single-family residences, 225 million square meters, have electrical comfort cooling and none of the multi-family residences have electrical comfort cooling. If the specific electricity consumption is assumed to be equal to the specific electricity consumption of offices, 10 kWh/m2, the electricity consumption would add up to 2.25 TWh per year for households. This is a rough estimate, and probably exaggerated, but will suffice to create 'what-if' scenarios that shows the relative change when climate change impact is introduced. The total electricity consumption for comfort cooling in public facilities and households in the investigated region is therefore almost 2.6 TWh per year in the base case, as the public facilities had an electricity consumption of 0.30 TWh per year which was shown in section 2.2.

As mentioned previously, the climate change impact on electricity demand for room temperature control varies depending on chosen data, methodology, and boundaries. To cover a range of reported climate change impact, from zero impact to the chosen maximum explained in the next paragraph, the impact on the electricity demand for temperature control is performed stepwise. First, the climate change impact on HDD and CDD must be translated to changes in electricity demand. The input data of annual electricity demand and the demand profile can then be modified to fit this identified climate change impact. In order to identify whether it is the changed annual electricity demand or the changed demand profile that has the highest impact on the cost-optimal electricity system composition the two changes are done separately.

By assuming that one unit of HDD results in a change in electricity consumption for heating by 0.03% as found by Pilli-Sihvola. A decrease in HDD of 500, which is in this investigation chosen as the maximum climate change impact, then corresponds to a decrease of electricity consumption for heating of 15%. A decrease in 15% of the current electricity consumption for heating is a decrease of 3.2 TWh, from 21.3 TWh to 18.1 TWh. Assume that an increase of 70 CDD results in an increase of electricity consumption for comfort cooling by 70%. This would increase the electricity consumption for comfort cooling by 1.8 TWh, from 2.6 TWh to 4.3 TWh. The change in total electricity demand per year is a decrease of 1.4 TWh. This obviously omits important factors such as efficiency increases, increased deployment of electrical appliances and so forth but interest in this paper is climate change and not impact from other sources.

The impact of these changes is tested by increasing the electricity demand for comfort cooling during April to September (summertime) and reducing the electricity demand for heating during December to February (wintertime). It is possible to compare the electricity demand during a specific time interval, such as the winter- and summertime, between two demand profiles. This is done by multiplying the (same) annual electricity demand with two different normalised demand profiles and comparing the electricity consumption in a specific time interval of each demand profile. As this is possible, a demand profile which reflects the climate change impacts on the electricity demand for temperature control can be constructed by modifying the original demand profile. The modified demand profile is constructed by splitting the original normalised demand profile into 52 weeks and multiplying each week, in the affected time interval, by a factor then normalising the new profile. The factor for each week is chosen as to make the difference between the modified and the original demand profile reflect the change in electricity consumption found in literature, for both winter- and summertime. Appendix C shows the factors used. As mentioned, the change is done stepwise to cover a range of climate change impact. The demand profile is changed in five steps. The final step has an increased electricity consumption of 1.8 TWh summertime, and reduced electricity consumption of 3.2 TWh wintertime. The steps in between are made at equal spacing with an electricity consumption change of 20%-units each step. See the demand profiles, multiplied with the original demand, in Figure 4 below. The original demand profile is in the back and has the highest peak demand. The final modified demand profile can be seen in the front with the lowest peak demand. In between those two, the four additional steps can be seen. The **D**emand **P**rofiles will be named DP0, DP1, …, DP5 where DP0 is the original demand profile.

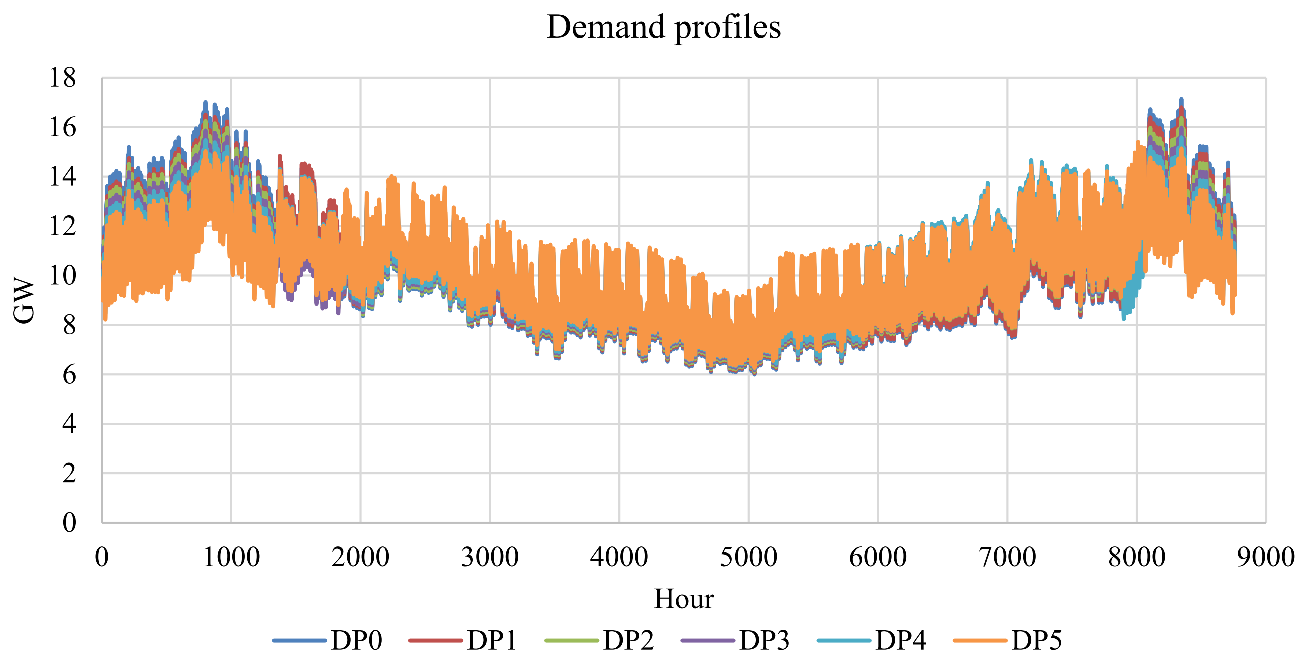

Figure 4 Demand profiles with the original annual demanded energy. The highest peak during wintertime in the original demand profile is 17 GW, while the highest peak in DP5 is roughly 15 GW.

As mentioned, the annual electricity demand and the demand profile is changed separately. The electricity demand is simply tested in one step as the change in annual electricity demand was quite small compared to the total electricity demand. As such, the annual electricity demand is tested at 92.5 TWh and at 91.1 TWh. This electricity demand does not take the additional consumption of electricity meant for hydrogen production into account which was 15% of the electricity demand. With this additional 15% consumption, the total annual electricity demand is 106.4 TWh without any reduction and 104.8 TWh with the reduction. The configurations with the original electricity demand **D**emanded **E**nergy will be called DE0, and the reduced electricity demand DE1.

3.6. Investigated configurations

There are four type of changes present in this investigation.

- Changes to total annual demanded energy
- Changes to demand profile
- Changes to total annual hydro inflow energy
- Changes to hydro inflow profile

The total number of possible configurations are 648. To limit this, only the extreme points of the profiles are investigated together with differentiating hydro energy and electricity demand. All the profiles are tested with the original pair of energies, HE0 and DE0, to reveal whether any potential changes happen gradually or at a certain breakpoint.

Table 4 Investigated configurations. All combinations of hydro inflow profile and electricity demand profiles are tested with the original pair of energies, HE0 and DE0. Only the extreme points (marked in dark grey in the upper part of the figure) in profiles are tested with the other combinations of energies.

	HP0	HP1	HP2	HP3	HP4	HP5	HP6	HP7	HP8
DP0									
DP1									
DP2									
DP3									
DP4									
DP5									

		HE0		**HE5**	
		HP0	HP8	HP0	HP8
DE0	DP0				
	DP5				
DE1	DP0				
	DP5				

In addition to this, four configurations are tested where traded hydropower, henceforth called imported hydropower, is allowed. The capacity of the imported hydropower is set to 7 GW and represents the hydropower available for import from EPOD regions SE3 and SE4 to SE2. The four investigated configurations are the extreme points with the original hydro energy and electricity demand.

4. RESULTS

The results are divided up into sections that describes the impact of hydro, demand, and combined changes. Main take-aways are presented first, followed by a base case with original configurations that the upcoming configurations will be compared to. Hydro and demand changes comes next and is presented as changes relative to the base case. Afterwards, combined changes are presented in section 4.5 and lastly these changes together with imported hydropower are presented in section 4.6.

Only the results from the extreme points will be presented below as the changes occurring in the investigated parameters from one extreme point to the other is almost linear. The linearity enables interpolation between the extreme points. This is shown in Appendix A where the profile of either demand or hydro is changed in between the extreme points.

4.1. Main take-aways

Wintertime remains as the dimensioning season when climate change impact relating to a temperature increase of 1.5-3°C is introduced. However, the climate change impact reduces the strain on the electricity system during wintertime. A less demanding wintertime results in less investments in offshore wind. As the installed amount of offshore wind is decreased, it no longer provides sufficient generation capacity and energy during summertime. This is solved by increased investments in solar power in the form of solar photovoltaics (SPV). Change in the composition of the cost-optimal electricity system is therefore seen. Solar power has a lower levelized cost of electricity compared to offshore wind power. As such, changes that makes the wintertime easier to handle, make the system cheaper. Of the investigated cases without available imported hydropower, the maximum impact on the system cost per demanded energy is a reduction by 8.5%. This is found when both aspects of the electricity demand and hydropower are changed to the maximum.

Climate change impact on the temporal aspect, the profiles, of both electricity demand and hydro inflow have a larger impact than the climate change impact of annual energy of either of these. Of the electricity demand and the hydro inflow, the changed demand profile has a larger impact on the electricity system, when imported hydropower is not allowed. The change in demand profile decreases the need of generation capacity during wintertime. As previously mentioned, this results in reduced investments in offshore wind and increased investments in solar power. Investments in peak generation units decrease with a changed demand profile. Changes in the hydro inflow profile also reduces the strain on the electricity system during wintertime. The climate change impact on hydropower increases the available hydropower during wintertime, and as such reduces the need of other electricity generation units. If the changes between increased annual hydro energy of 2.6 TWh and decreased annual electricity demand of 1.4 TWh are compared, the increased hydro energy have a larger impact on the system cost per energy unit. In addition to changes in generation capacity, small changes in the investments of storage technologies are seen. Battery investments are reduced while hydrogen storage capacity increases. Battery storage is more suited to cover a need of power capacity while hydrogen storage is cheaper per energy stored. Both storages are sized in wintertime in the investigated cases. With less power capacity being needed wintertime, less battery storage is invested in. However, there is still a need of energy storage wintertime. Reduced investments in battery storage decreases the energy storage capacity in the electricity system. In order to keep the energy storage capacity in the electricity system sufficiently large, investments are made in hydrogen storage. Worth noting is that the change of investments in storage does not impact the system cost as much as change of investments in electricity generation capacity.

An overview of the system cost of the investigated configurations can be seen in Table 5. As is seen the least costly configuration is with an increased annual available hydro energy, reduced total electricity demand, and with a maximum change on the hydro inflow and electricity demand profile.

Table 5 Average system cost per demanded energy of that case. The presented cases are the extreme points of the different configurations.

System cost (Euro/MWh)		**HE0**		**HE5**	
		HI0	HI8	HI0	HI8
DE0	DP0	59.6	57.9	59.1	57.6
	DP5	57.0	55.2	56.5	54.8
DE1	DP0	59.5	57.8	59.0	57.5
	DP5	56.9	55.1	56.4	54.7

4.2. Base case

The base case heavily relies on wind power both in terms of generation capacity and energy. The installed generation capacities can be seen in Figure 5. Offshore wind has 15.6 GW of installed capacity and onshore wind has 3.8 GW, a total of 19.4 GW wind power. Solar PV has 7.1 GW installed and hydropower is, as mentioned in section 3.1.1, capped at 2.6 GW. In total, the system has 37 GW installed capacity with 29.1 GW of renewables and 7.9 GW non-renewable electricity generation capacity.

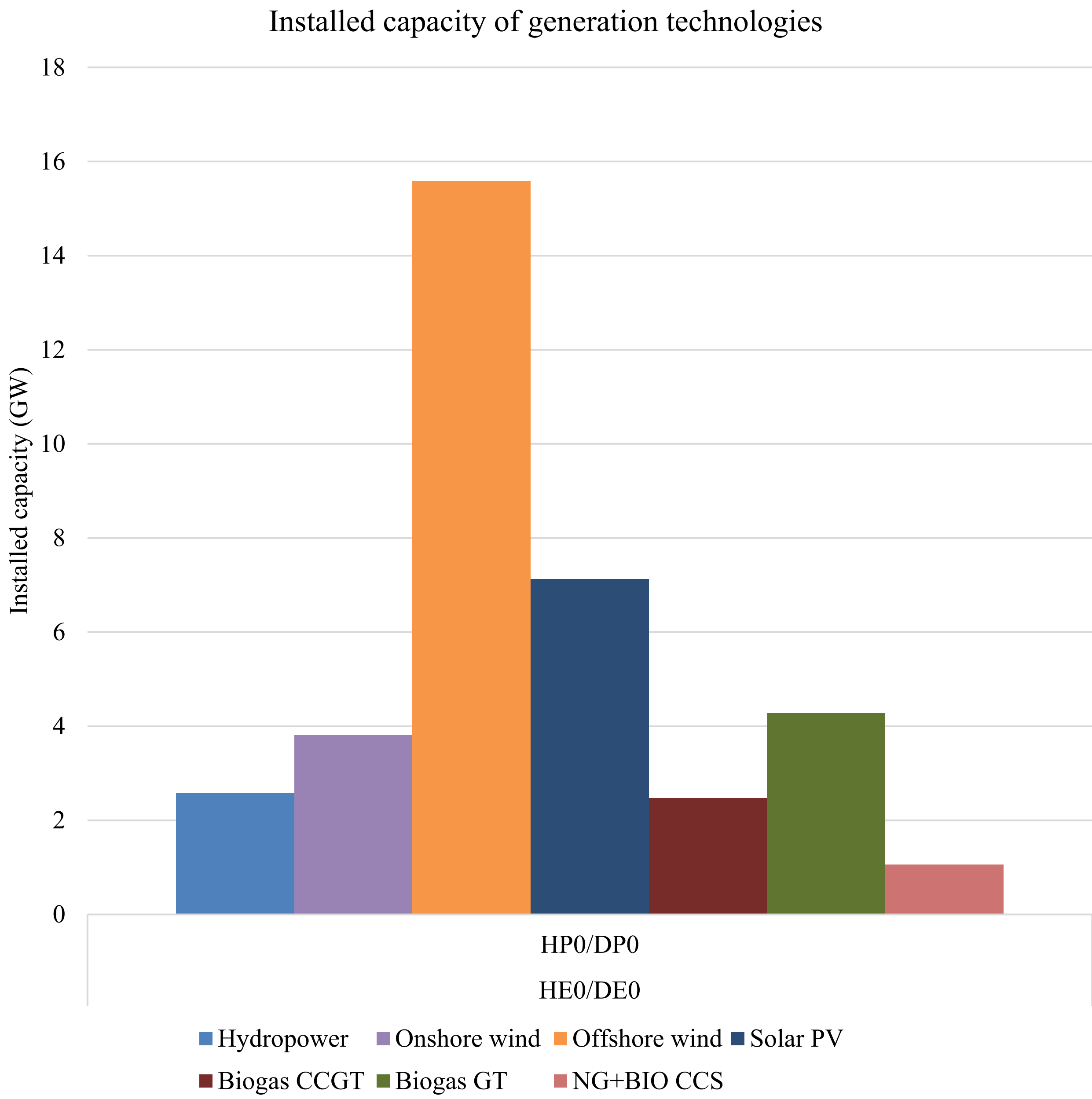

Figure 5 Installed generation capacities in the base case.

In terms of annual generated electricity, offshore wind is on top as can be seen Figure 6. A total of 75.1 TWh is generated annually from offshore wind and 6.4 TWh from onshore wind, in total 81.5 TWh wind energy per year. Hydropower adds 13 TWh and solar power 6.4 TWh. As such the system has a total of 100.9 TWh of renewable energy per year. Additional 8.8 TWh is produced from non-renewables.

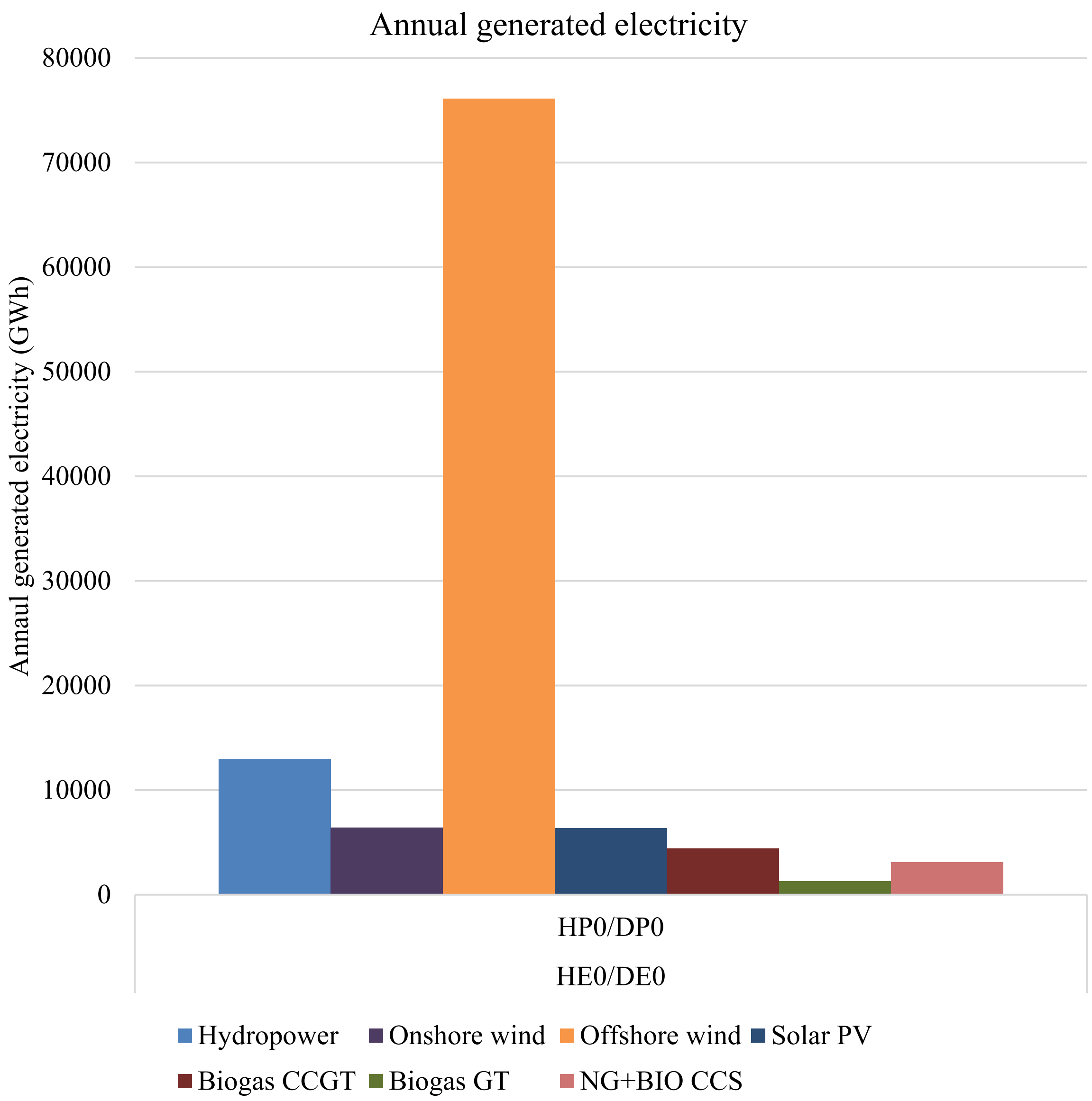

Figure 6 Annual generated electricity from each technology in the base case.

The total demanded electricity was 92.5 TWh and an additional 13.9 TWh from the added hydrogen demand, a total of 106.4 TWh. The generated electricity is still larger than the demanded by 3.3 TWh. This energy is lost due to conversion losses in battery storage and losses in the electrolyser. Investments in storage technologies can be seen in Figure 7. Hydrogen storage have a size of 180.5 GWh while the battery storage size is 50 GWh.

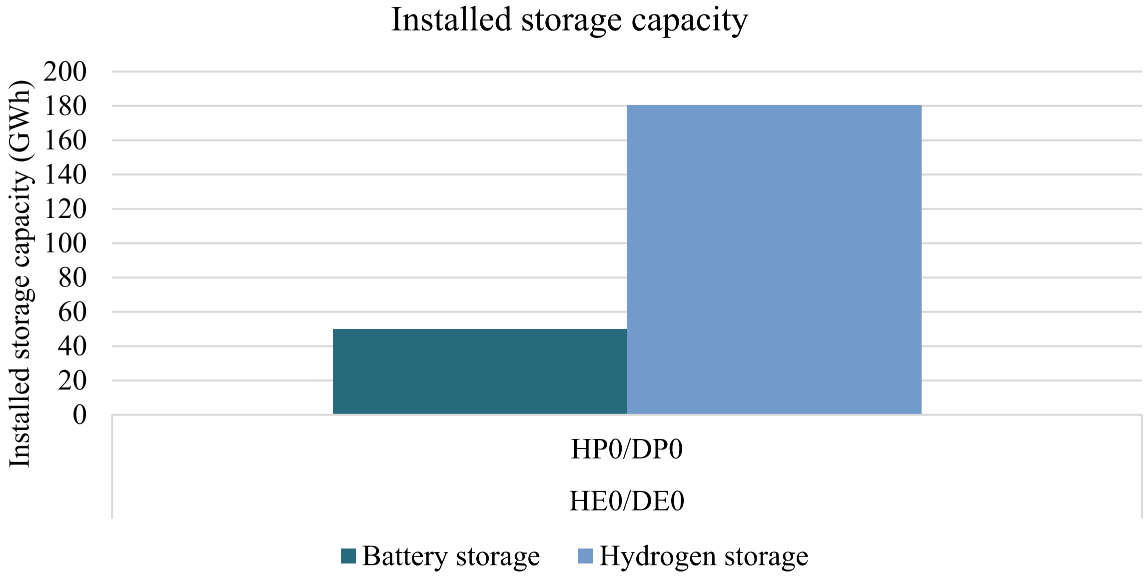

Figure 7 Investments in storage technologies in the base case.

4.3. Hydropower impact

The impact of hydropower can be studied by looking at the results from the configurations belonging to the first row in Table 5. Both a changed hydro energy and a changed hydro inflow leads to a reduction in system cost. Solely increasing the annual hydro energy by 20% leads to a decrease of the average system cost by 0.5 Euro/MWh, while changing the hydro profile to the maximum, HP8, have a larger decrease in the average system cost by 1.7 Euro/MWh. The combined effect of a maximum increased annual hydro energy and maximum changed hydro inflow profile yields a reduction of 2.0 Euro/MWh, a decrease of 3.4% in the system cost compared to the original configuration. This reduction in system cost comes from a change in investments where offshore wind investments are reduced and investments in SPV are increased.

Figure 8 shows how the installed capacity of generation technologies differ depending on the hydro inflow profile and annual hydro energy. Hydro profile 8 was characterised by a drastically lower, and earlier, spring flood and more inflow during the rest of the year. The increased inflow of hydro during wintertime increases the extent hydropower can be utilised during wintertime without depleting the hydro storage. This reduces the need of other generation technologies during wintertime. As such, offshore wind investments are reduced. When only considering the hydro profile change, investments in offshore wind decreases by 0.8 GW, equal to 5.1%. The same behavior is seen when the hydro energy is increased with the original hydro inflow profile. A higher amount of hydro energy is introduced across the whole year, including wintertime. This once again reduces the need of other generation technologies during wintertime, in turn reducing investments in offshore wind. The impact on the electricity system composition stemming from a changed hydro energy is not as large as the impact caused by a changed hydro inflow profile. This is explained by taking into consideration that the annual hydropower available in EPOD region SE2 is relatively small, meaning a percentual increase of the annual available hydro energy by 20% is in absolute terms still quite small. Hydro inflow profile and hydro energy changes combined reduces investments in offshore wind by 1.1 GW, equal to 7.1%. The reduction in offshore wind enables a larger share of solar power as the need for generation capacity and energy persist during summertime. The combined impact of hydro energy and hydro inflow increases investments in SPV by 0.7 GW, equal to 10%. Investments in peak generation units, Biogas GT, remain stable across all configurations. The investments in the remaining thermal generation units, Biogas CCGT and Biogas + NG CCS, varies. Biogas + NG CCS experiences reduction in investments with the hydro profile changes and this reduction is amplified when an increased hydro energy is introduced. A reduction exceeding half of the investments in the base case is seen. Investments in Biogas CCGT increases with a changed hydro profile and even more so together with an increased hydro energy. Biogas CCGT has a lower running cost and faster ramping rate than Biogas + NG CCS. The increase in investments in Biogas CCGT indicate that more flexible thermal generation becomes more competitive when climate change impact on hydro power is introduced. The cycling of Biogas CCGT increases during wintertime when climate change impacts are introduced while the operation of Biogas + NG CCS becomes more stable during wintertime. This means that Biogas CCGT partly replaces Biogas + NG CCS but also adds some dispatchable generation capacity. Investments in onshore wind remain stable throughout all the configurations.

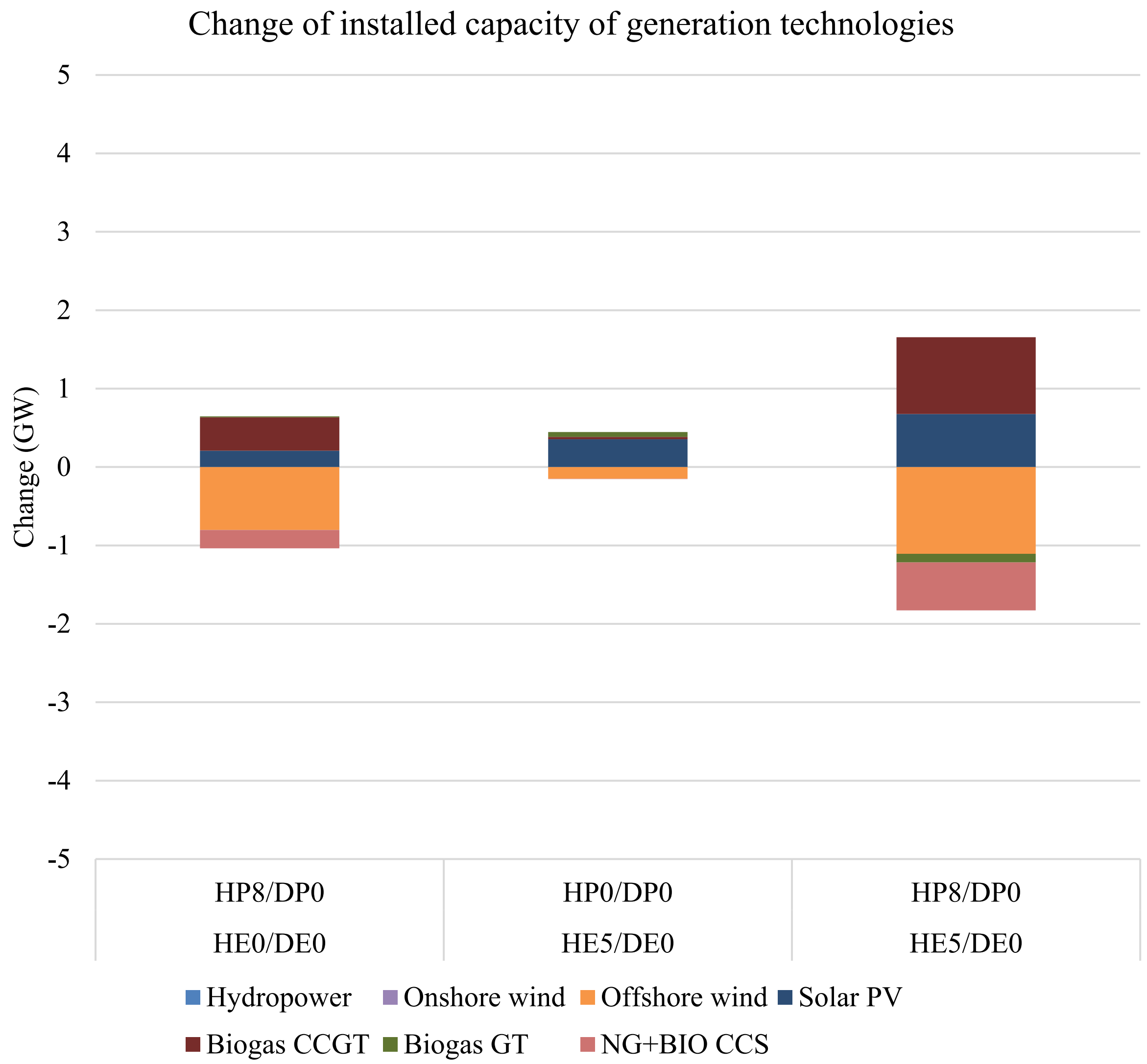

Figure 8 Installed capacity of generation technology in three different configurations. The left bar is a configuration where only the hydro inflow profile is changed. The middle bar is a configuration where solely the annual hydro energy is changed. The rightmost bar is a configuration where both the hydro inflow profile and annual hydro energy have been changed to the maximum.

The use of the hydro storage changes with a changed hydro inflow. The hydro storage level with both the original and maximum changed hydro inflow profiles are depicted in Figure 9. A more intense, and earlier, emptying of the hydro storage is done to relieve the stress of other generation technologies during parts of wintertime that are demanding. This earlier emptying of the hydro storage can be performed without compromising the availability of hydropower during spring as the spring flood is earlier. The lower intensity of the spring flood is seen as the charging of the hydro storage takes a longer time.

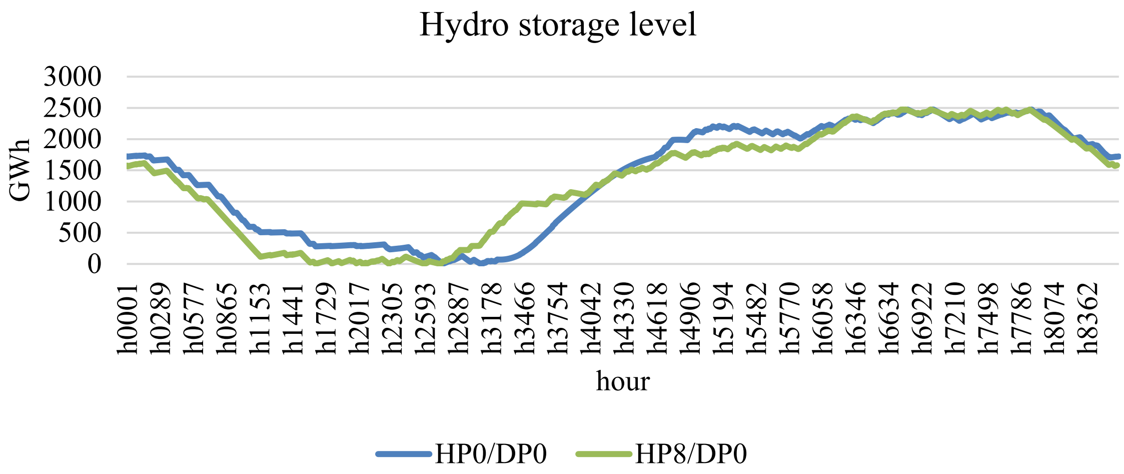

Figure 9 Hydro storage level with the original hydro energy. Original hydro inflow profile is seen in blue and maximum changed hydro inflow profile is seen in green.

4.4. Demand changes due to heating and cooling impact

Both a change in electricity demand profile and a change in total electricity demand reduces the system cost. Of these two, the largest decrease in average system cost comes from the changed demand profile. A maximum changed demand profile, DP5, lowers the average system cost with 2.6 Euro/MWh. The combined impact of changed annual electricity demand and demand profile lowers the average system cost by 2.7 Euro/MWh, equal to 4.5%. As for the hydropower, the change in system cost comes largely from changes in installed generation capacities.

Figure 10 shows the installed generation capacities in three different configurations. The combined impact of changed demand profile and demanded energy reduces investment in offshore wind by 1.4 GW, equal to 9%. This is greater than what was seen with a changed hydropower. Solar PV investments are increased by 2.2 GW, equal to +32%. Biogas GT investments decrease by 1.4 GW. Biogas CCGT investments reduces by 0.9 GW and investments in Biogas + NG CCS increases by 0.6 GW. As explained, the reduction in offshore wind stems from a less demanding wintertime. The increase in solar power investments happen as there is a void in generation capacity and energy during summertime left behind by the decrease in offshore wind. In addition to having an impact on the wintertime electricity demand, the change in demand profile increases the electricity demand during summer. This results in additional investments in SPV. This was not seen with a changed hydropower as the hydropower mostly had an impact on the need of generation capacity during wintertime. In addition to reduced investments in offshore wind, the need for peak generation units during wintertime is decreased which is why Biogas GT investments decreases.

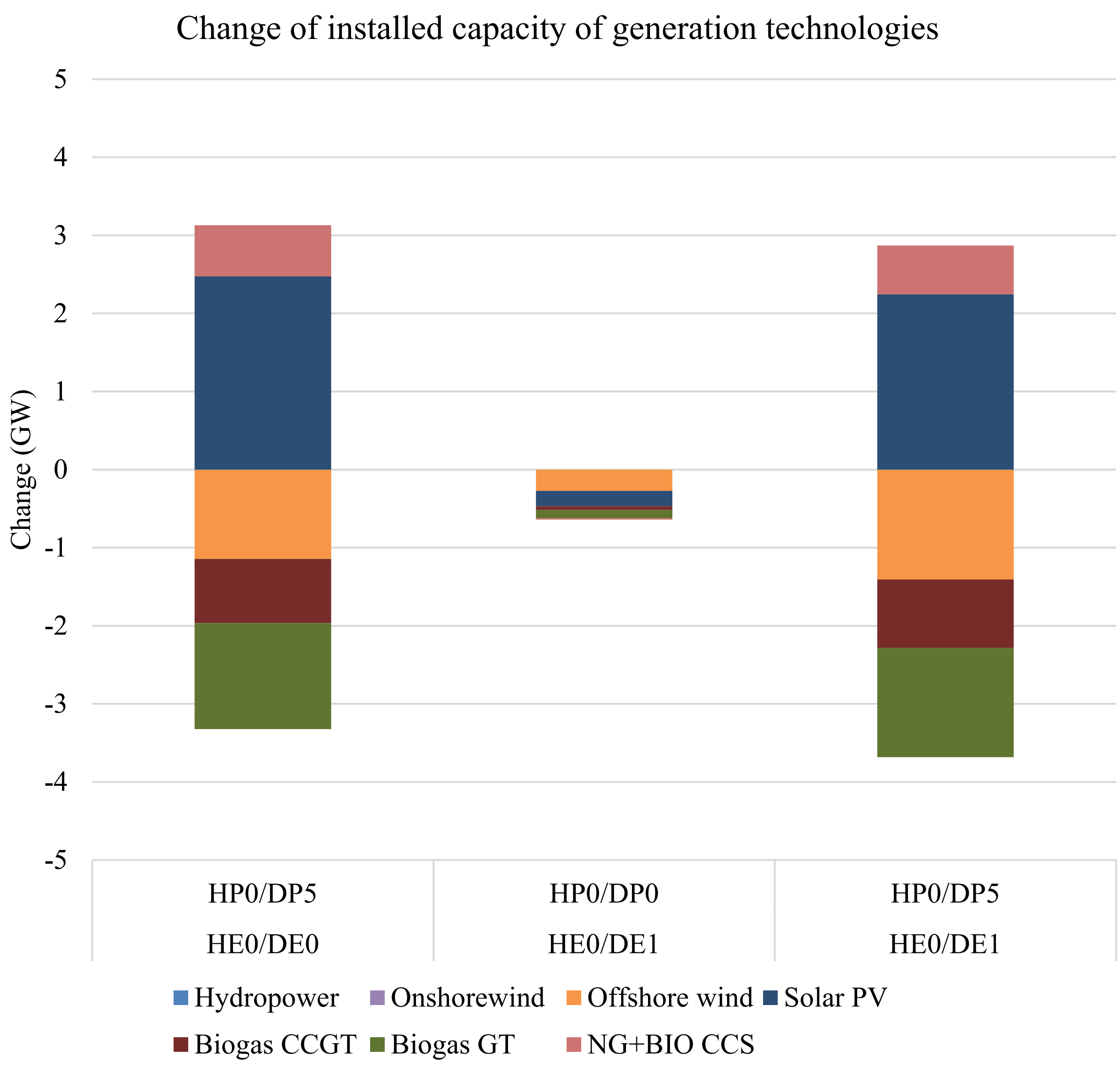

Figure 10 Installed capacities with different configuration regarding the demanded electricity. The left bar is a configuration where only the electricity demand profile is changed. The middle bar is a configuration where solely the annual electricity demand is changed. The rightmost bar is a configuration where both the electricity demand profile and annual electricity demand have been changed to the maximum.

4.5. Combined impact

Previously seen trends in decrease offshore wind and increased SPV is seen once again when the climate change impact on electricity demand and hydropower is combined. Figure 11 shows the installed generation capacities in three configurations that combine the impact of profile changes, energy changes, and a mix of both. The strain on the electricity system during wintertime is even lower when the impact of electricity demand and hydropower is combined compared to when the cases were investigated separately. A combined change results in a reduction of 2.4 GW, equal to 15.4%, in offshore wind capacity and an increase of 2.5 GW, equal to 37.7%, in SPV capacity. The combined impact of electricity demand and hydropower leaves Biogas CCGT investments mostly stable and reduces both Biogas + NG CCS and Biogas GT investments. This differs from the changes seen in the previously presented cases as changed hydropower and changed electricity demand had differentiating impact on thermal generation units.

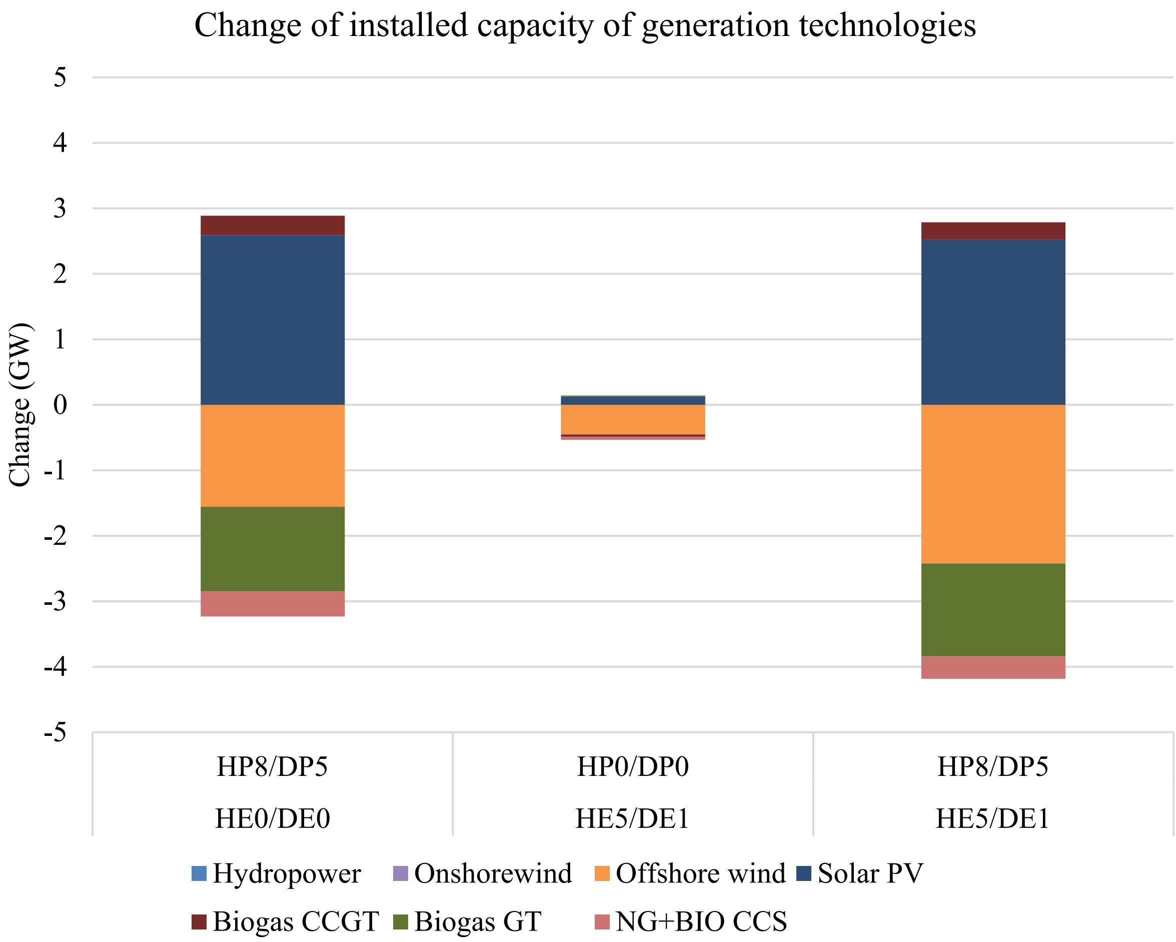

Figure 11 Installed capacity of generation technology in configurations that combine electricity demand and hydropower changes. The left bar is a configuration with original energies and changed profiles. The middle bar is a configuration where the energies have been changed. The rightmost bar is a configuration where both the profiles and the energies been changed to the maximum.

In the base case, the high investments in offshore wind was primarily made to satisfy the demand for generation capacity during wintertime, not the energy demand. This is shown by looking at the annual electricity generation, shown in Figure 12, for the combined impact of electricity demand and hydropower and comparing this change to the change in investments. The reduction in offshore wind capacity was 15.4%, but the reduction in used energy from offshore wind is only 10.6%, from 76 TWh to 68 TWh. In addition to this, the used energy from onshore wind has increased by 27%, from 6.4 TWh to 8.1 TWh. Investments in SPV increased by 37.7%, but the used energy from SPV has increased by 54%. Less electricity from renewable sources are now curtailed as the capacities are less oversized.

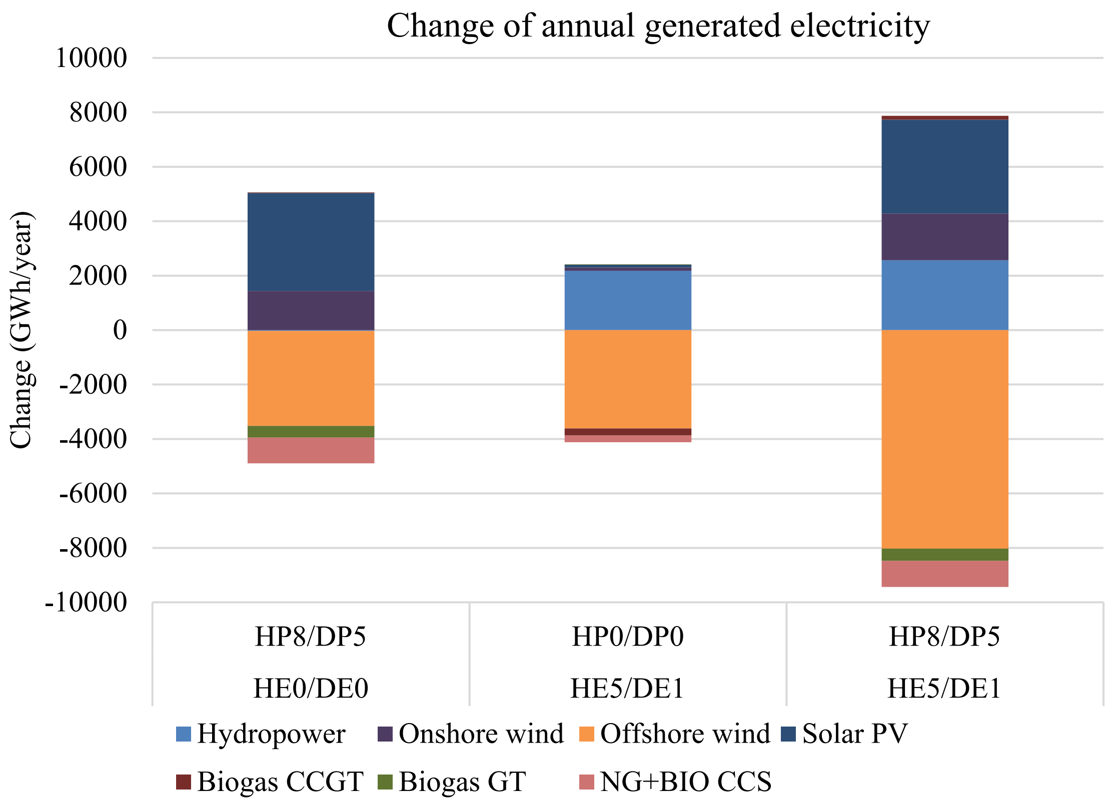

Figure 12 Annual generated electricity in the combined configurations. The left bar is a configuration with original energies and changed profiles. The middle bar is a configuration where the energies have been changed. The rightmost bar is a configuration where both the profiles and the energies been changed to the maximum.

Investments in storage technologies can be seen in Figure 13. A higher utilisation rate of wind power together with an increase in investments in hydrogen storage satisfies the electricity demand wintertime that is no longer fulfilled by an oversized offshore wind. Battery storage is great in terms of delivering power and in the base case, batteries were invested in because of the need of generation capacity during wintertime. However, the climate change impact on electricity demand and hydropower reduces the need of generation capacity. As such, investments in battery storage experiences reduction in all configurations, although the reduction in battery power is not as great as the reduction in peak load.

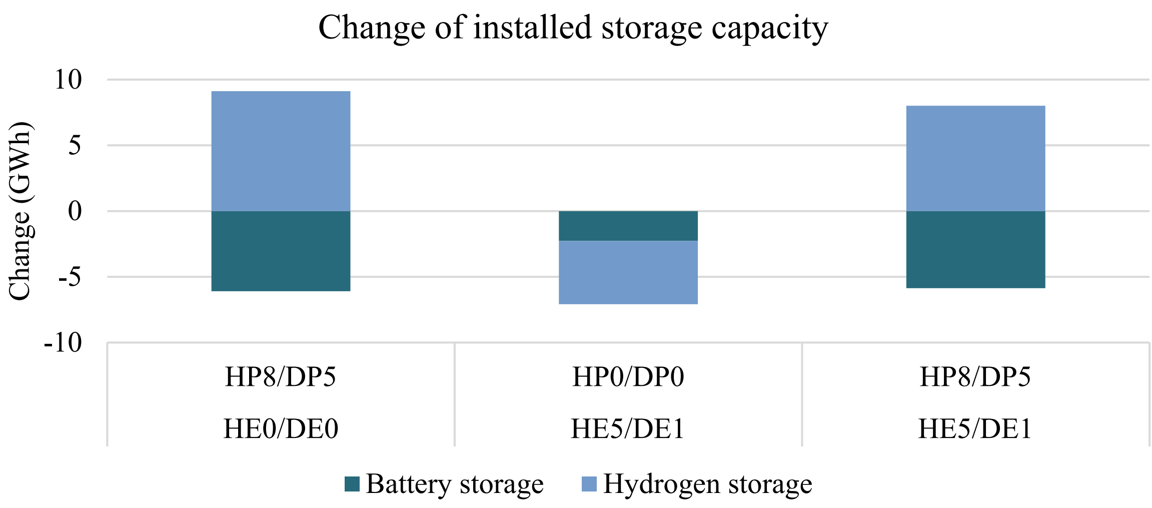

Figure 13 installed storage capacity in the combined configurations. The left bar is a configuration with original energies and changed profiles. The middle bar is a configuration where the energies have been changed. The rightmost bar is a configuration where both the profiles and the energies been changed to the maximum.

The combined impact of changed hydropower and electricity demand does bring small changes to the electricity price. This happens mainly in the zero price hours and in the bulk electricity price, as depicted in Figure 14.

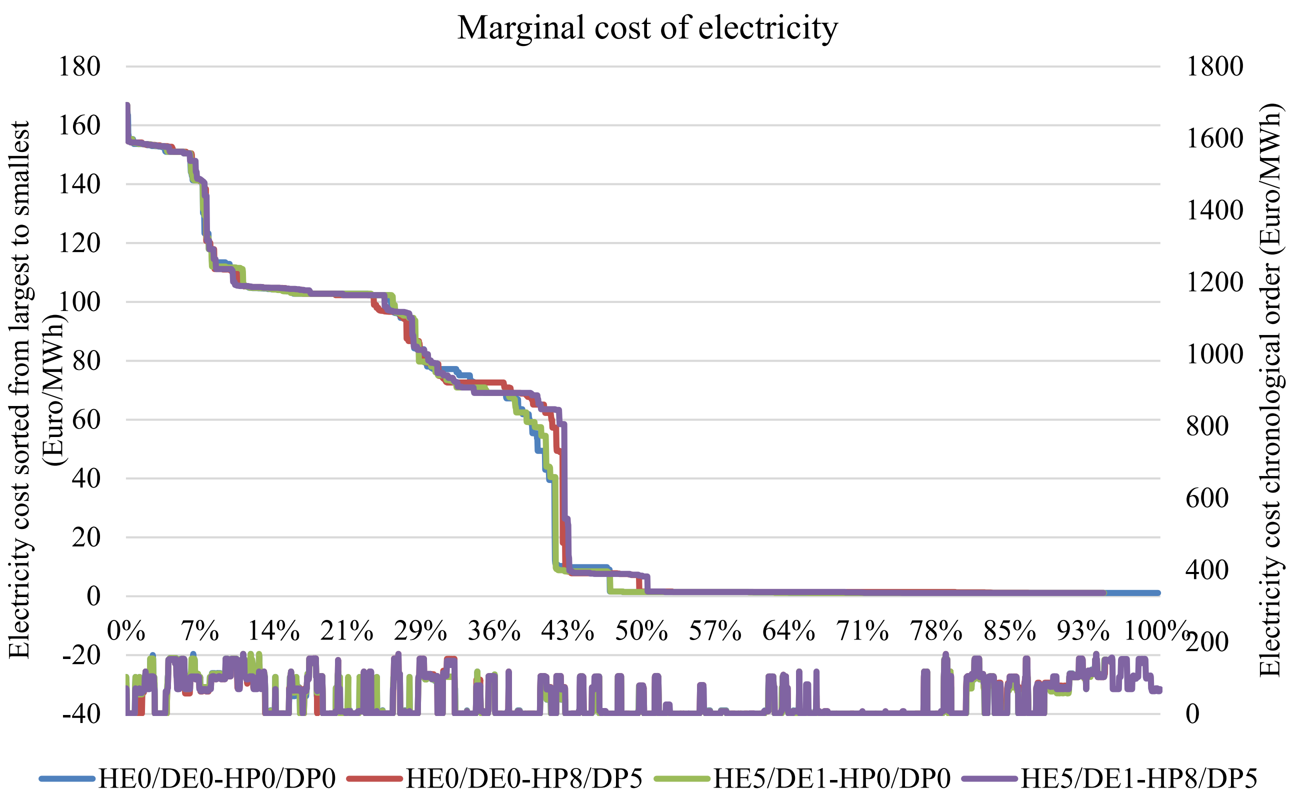

Figure 14 Electricity price (marginal cost of electricity) with the combined impact of changed hydropower and electricity demand. The left axis belongs to the electricity cost duration curve shown above while the right axis belongs to the chronological ordered electricity cost shown below.

4.6. Imported hydropower

The four configurations present in the first quadrant in Table 5 were investigated where 7 GW of imported hydro power from northern Sweden was allowed. These four configurations include a base case with no climate change impact, two different configurations where the changed profiles of the hydro inflow and electricity demand is tested by themselves, and lastly a configuration that tests the combined impact of these two. No changes in available hydro energy or reduced electricity demand was tested with imported hydropower allowed. By using imported hydropower in these four configurations, the impact of the changed hydropower is larger than previously seen.

The system cost is much lower compared to previously as large amount of low-cost hydropower has been introduced to the system. A decreasing system cost with different configurations of electricity demand and hydro inflow profiles can be seen in Figure 15. With imported hydropower, the changed hydro inflow profile has a greater impact as can be observed in the system cost. The increased available hydropower has replaced almost all installed capacity of slower thermal generation units. Even the peak generation units have been reduced in all configurations compared to the base case without imported hydropower. The difference between configurations in installed capacity of offshore wind and solar power is greater than without imported hydropower. Investments in offshore wind reduces by 3.8 GW, equal to 28% of what is seen without any climate change impact. SPV investments goes from non-existent to 6.4 GW installed capacity. Most of the change to the investments stems from the change in hydro inflow profile, but solely the changed hydro inflow profile is not enough to introduce solar power in the system. It is rather the combined effect of changed hydro inflow and electricity demand profile that needs to exist to promote solar power.

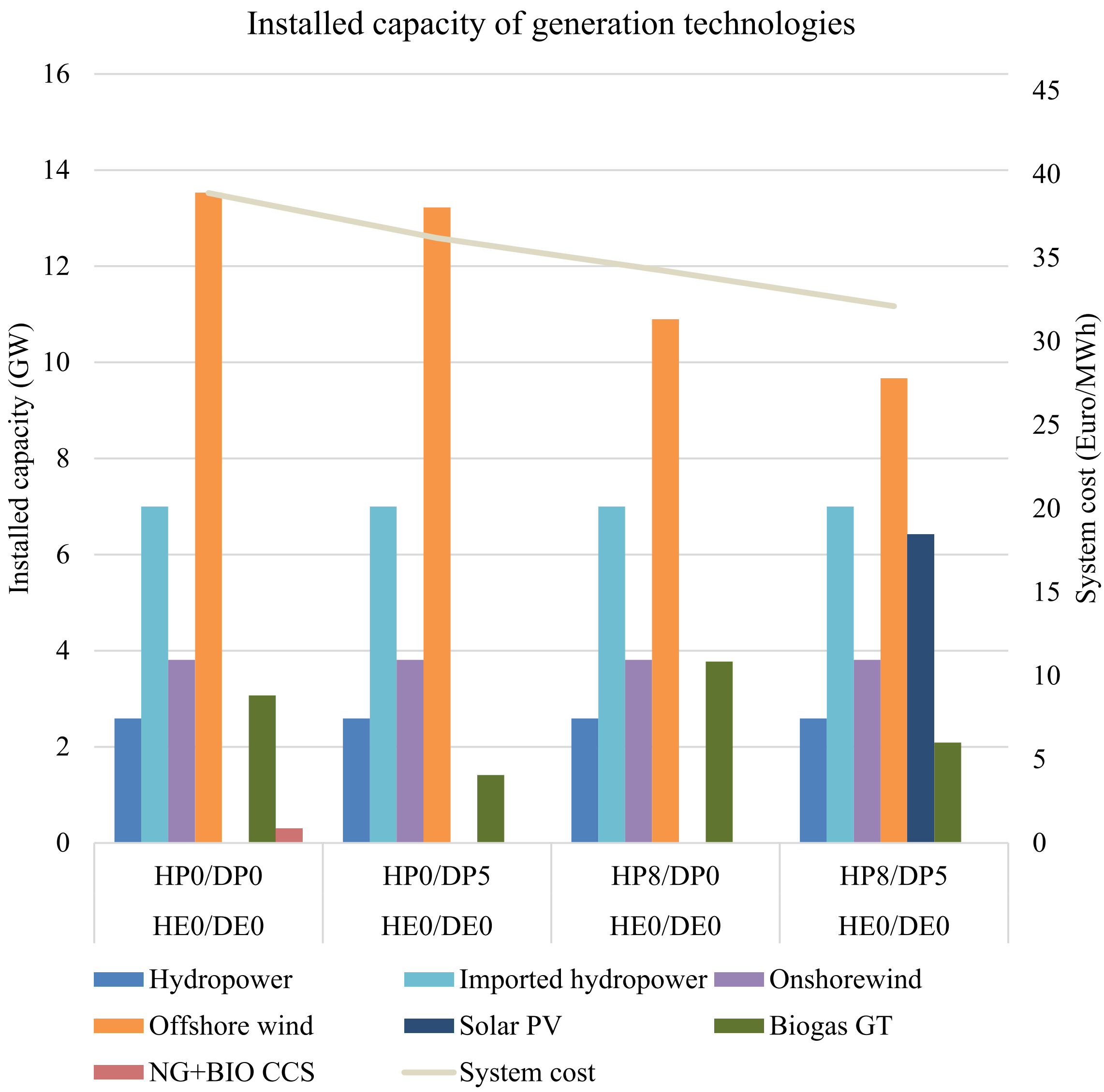

Figure 15 Installed generation capacity with imported hydropower. To the left is the configuration without any climate change impact. To the outmost right is the configuration with climate change impact on both hydro inflow profile and electricity demand profile.

From Figure 16 it is seen that large amounts of offshore wind are still generated. It can also be seen that the imported hydro has, in the cases with changed hydro inflow profile, enabled almost a doubling of utilised onshore wind energy. At the same time, the decrease in generated electricity from offshore wind between the configuration without climate change impact and the configuration with maximum changed profiles is around 13 TWh yearly. This can be compared to the cases without imported hydropower where the change in hydro inflow and electricity demand profile decreased used offshore wind energy by 3.5 TWh. When solar power is introduced, it contributes 6.9 TWh annually.

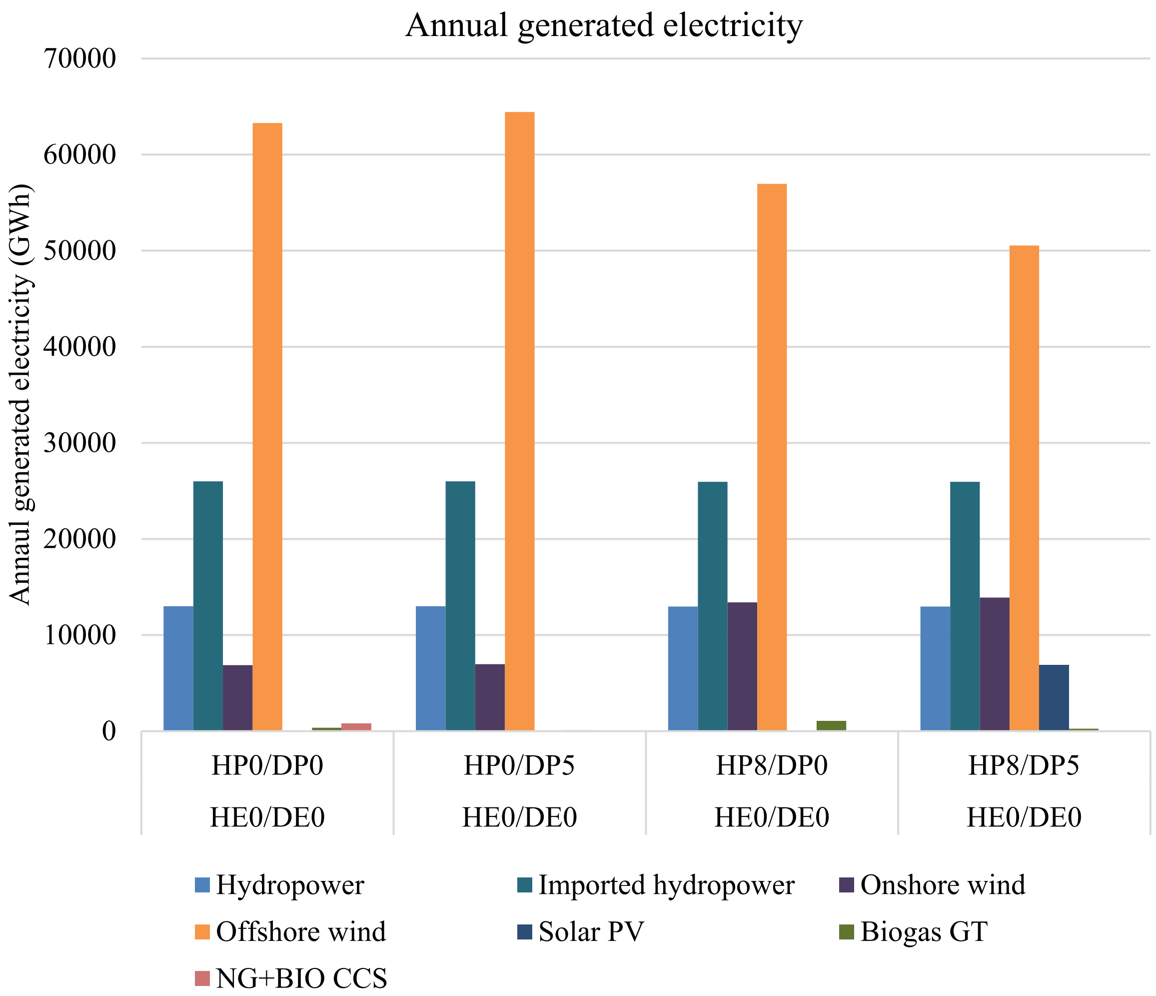

Figure 16 Annual electricity generation with imported hydropower. To the left is the configuration without any climate change impact. To the outmost right is the configuration with climate change impact on both hydro inflow profile and electricity demand profile.

Installed storage capacity is reduced significantly with imported hydropower compared to no imported hydropower, as is seen in Figure 17. This decrease happens as the imported hydropower can act as an energy storage, replacing hydrogen and battery storage. Figure 17 shows how the baseline hydrogen storage is now 88.2 GWh instead of 180.5 GWh as was the case without imported hydropower. A different trend than previously is also identified. The hydrogen storage is decreased in all configurations with climate impact, which was not the case without imported hydropower. In addition, the changed electricity demand profile supports higher amounts of battery storage, even without any installed solar power. In the combined case which does have solar power installed, the amount of battery storage decrease.

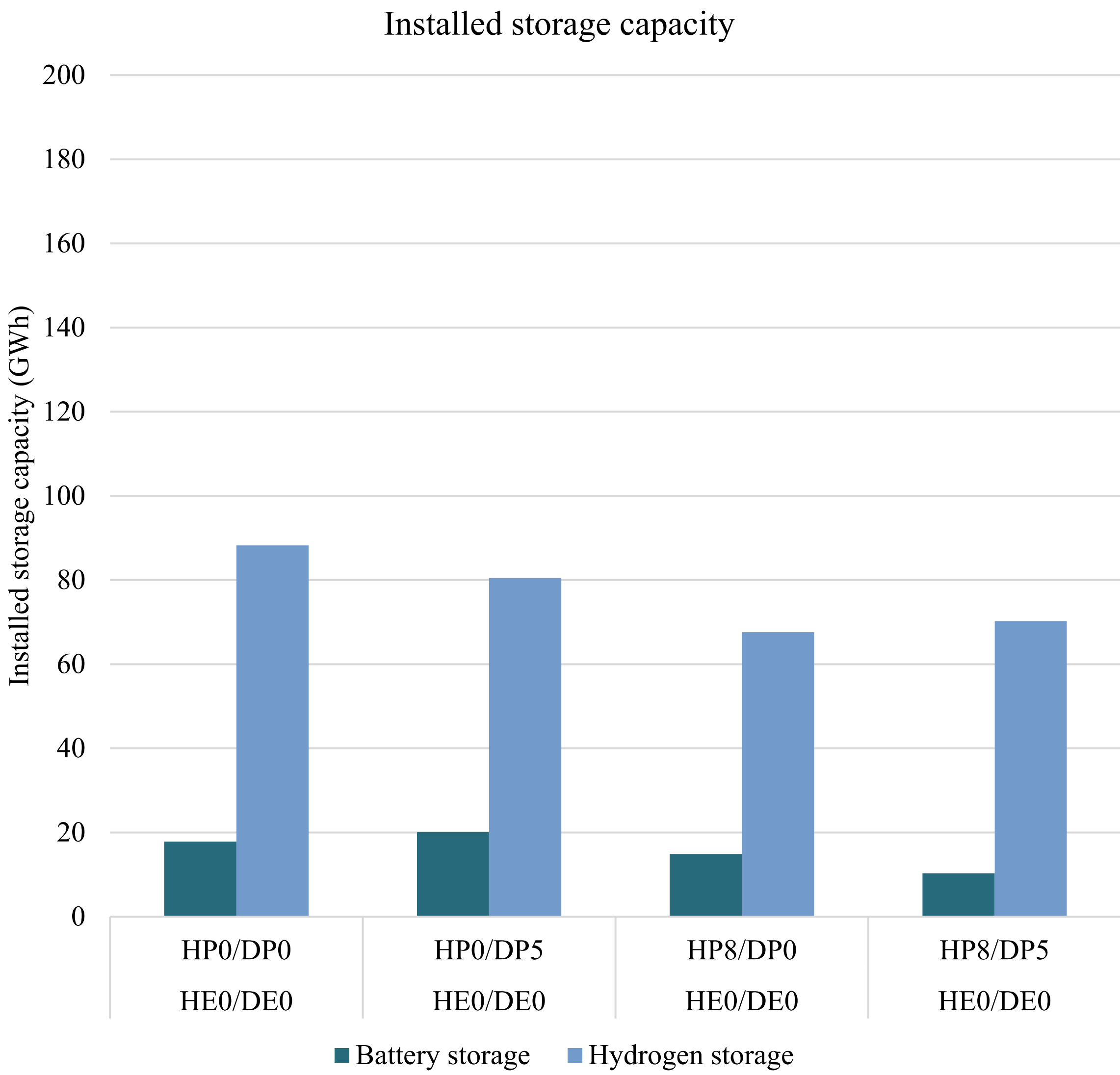

Figure 17 Installed storage capacity with imported hydropower. To the left is the configuration without any climate change impact. To the outmost right is the configuration with climate change impact on both hydro inflow profile and electricity demand profile.

With the imported hydropower a clear difference between the different configurations can be seen on the electricity price, shown in Figure 18. The configuration without any climate change impact has a higher amount of high price hours during wintertime and large amounts of zero price hours summertime. The zero price hours during summertime happens as the hydropower is dispatched as to not overflow the hydro storages when the spring flood arrives. The high cost hours exist as the available hydropower wintertime is not enough to cover all the demanding hours. The configuration with maximum changed profiles shows a much more stable price throughout the year because the previously mentioned issues have been resolved. Figure 18 shows how the summer months have a higher amount of non-zero price hours with the changed profiles compared to the original profiles.

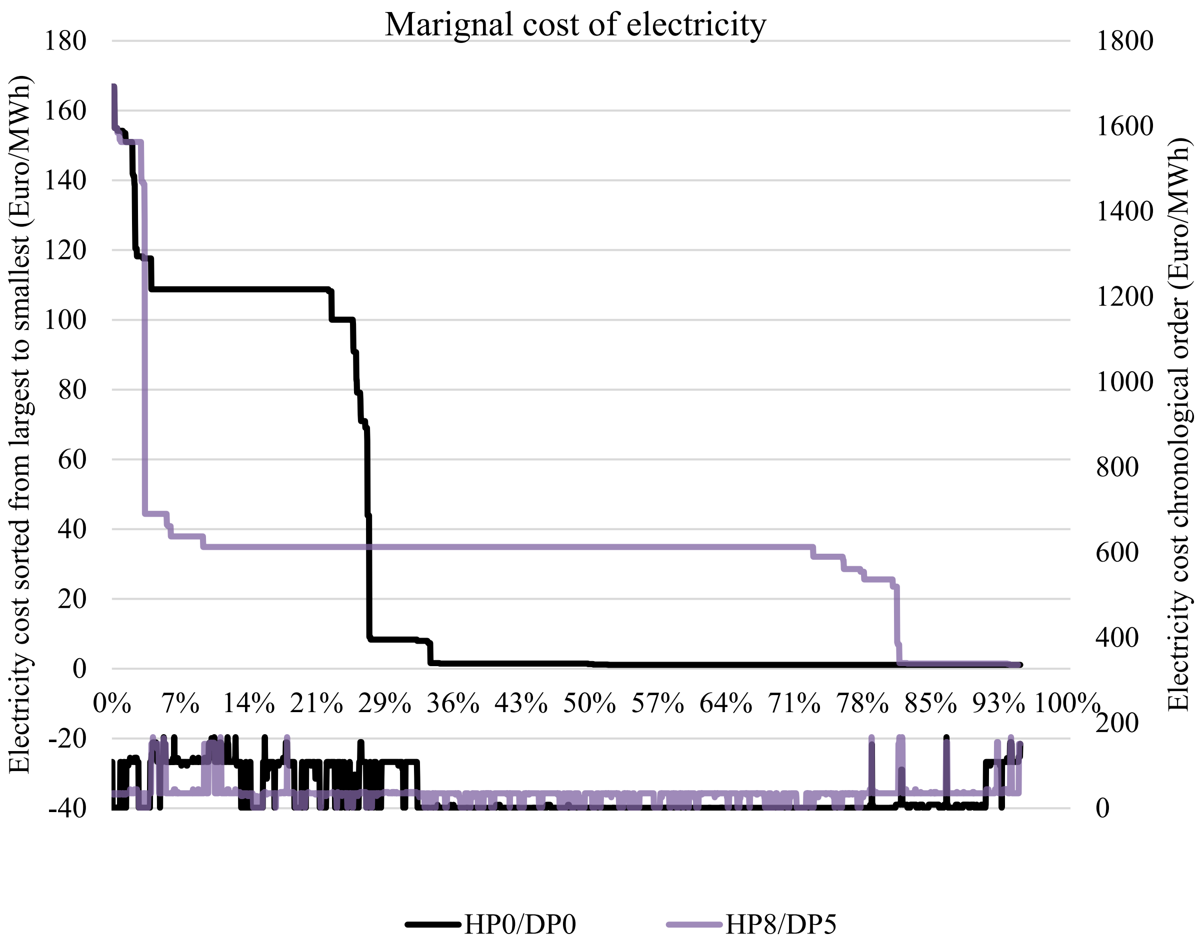

Figure 18 The electricity cost (marginal cost of electricity) with imported hydropower. The left axis belongs to the electricity cost duration curve shown above while the right axis belongs to the chronological ordered electricity cost shown below.

5. DISCUSSION AND CONCLUSION

The investigated changes on hydropower are based on literature that covers a global air temperature increase of 1.5°C to 3°C compared to pre-industrial levels while the impact on changed electricity demand is based on literature using a temperature increase of 1° to 3°C compared to pre-industrial levels. Changes that will occur if global warming of 2°C is reached can therefore be assumed to be covered by what has been investigated in this work.

The total system cost is reduced in all the modified configurations. This reduction in system cost stems from a reduction in investments in offshore wind. The reduction in offshore wind is made possible by the investigated climate change impacts. The investigated climate change impacts reduce the need of investments in generation capacity by alleviating the strain on the electricity system during wintertime, which is the dimensioning season in terms of generation capacity. The strain is reduced in two different ways. Climate change impacts on the electricity demand for heating and cooling reduces the peak electricity demand during wintertime as the heating demand is reduced and increases electricity demand during summer where solar power is available. Climate change impact on the hydropower make more hydropower available for dispatch during wintertime, which reduces the need of other sources of electricity generation capacity. When investments in offshore wind are reduced, there is no longer sufficient generation capacity nor energy during summer. This deficit of generation capacity is satisfied by increased investments in solar photovoltaics. The combined impact of electricity demand and hydropower changes, without imported hydropower, reduces investments in offshore wind by up to 15.4%, reduces investments in peak units by 35%, and increases investments in solar power by up to 37.7%. In addition, the utilised energy from onshore wind power increase up to 27%. This happens as offshore wind no longer is as oversized to satisfy the demand of generation capacity meaning less wind power needs to be curtailed.

A larger hydropower capacity and more available hydro energy in the form of imported hydropower from Northern Sweden makes thermal generation units almost obsolete, but a certain capacity of peak units is still required. Climate change impact will decrease investments in offshore wind and introduce investments in solar power, similar to the case with no imported hydropower. The difference is that no solar power capacity exists when there is no climate change impact, and neither changes in hydropower nor electricity demand can solely enable investments in solar power. It is rather the combined impact of both change in hydropower and electricity demand that enables solar power to become sufficiently competitive.

Storage technologies have a key role in a highly renewable electricity system. This is true without any introduced climate change impact and remains true when climate change impact is introduced. Small changes in the sizing of storages is observed where hydrogen storage is slightly more favored than battery storage when climate change impact is introduced. Battery storage is great in satisfying peak demand as it can operate opportunistic with discharging occurring at high electricity price hours. However, as mentioned previously, the climate change impact reduces the peak demand and as such reduces the need of battery storage. Instead, investments in hydrogen storage, suitable to store large energy volumes, are increased.

The results with imported hydropower show how the marginal cost of electricity could be affected by climate change when trade exists between regions. The electricity price during winter was reduced while the summer electricity price increased when climate change impact was introduced. As such, climate change impact could prove more challenging for technologies that rely on wintertime to receive return on their investments.

Generation capacity is one of the primarily dimensioning variables concerning the cost-optimal composition of an electricity system. In this work both the chosen time resolution of three hours and the method used regarding construction of the electricity demand profile has a high impact on the needed generation capacity. A more detailed time resolution could result in a need of higher generation capacity as certain peak hours become more apparent. If the amount of these peak hours is significant, they could impact the composition of a cost-optimal electricity system. When constructing the changed electricity demand profile, a unique factor for each week was used to change the demand. However, this method does not capture possible changes in inter-weekly variations in the electricity demand stemming from possible changes in temperature fluctuations. If temperature fluctuations would change, this would impact the requirements of the electricity system as both the need of generation capacity and energy demand would be impacted. Future work on the subject of climate change impact on the electricity system should further refine how the need of generation capacity could change. In addition to how the need of generation capacity is expressed, future work needs to take into consideration how this generation capacity is satisfied. As seen in the results, the utilised model satisfied majority of the generation capacity need by large investments in offshore wind. The solution can be seen as overly specified as it heavily relies on the input wind data and does not consider that the available wind might change from one year to another. Future work should therefore investigate how the capacity contribution from wind power might vary between years and determine to what extent it is reasonable to rely on wind power as a provider of generation capacity rather than energy.

The work aimed to answer the question if it is important to consider climate change impact on hydropower and electricity demand for temperature control when working with future electricity systems. Results show that the composition of the cost-optimal electricity system does vary to a significant degree when climate change impact is introduced. As such, the answer to the question is that climate change impact on these two areas will have an impact on the cost-optimal electricity system composition that should not be ignored. The requirements on the electricity system today might not be the requirements on the electricity system in the future.

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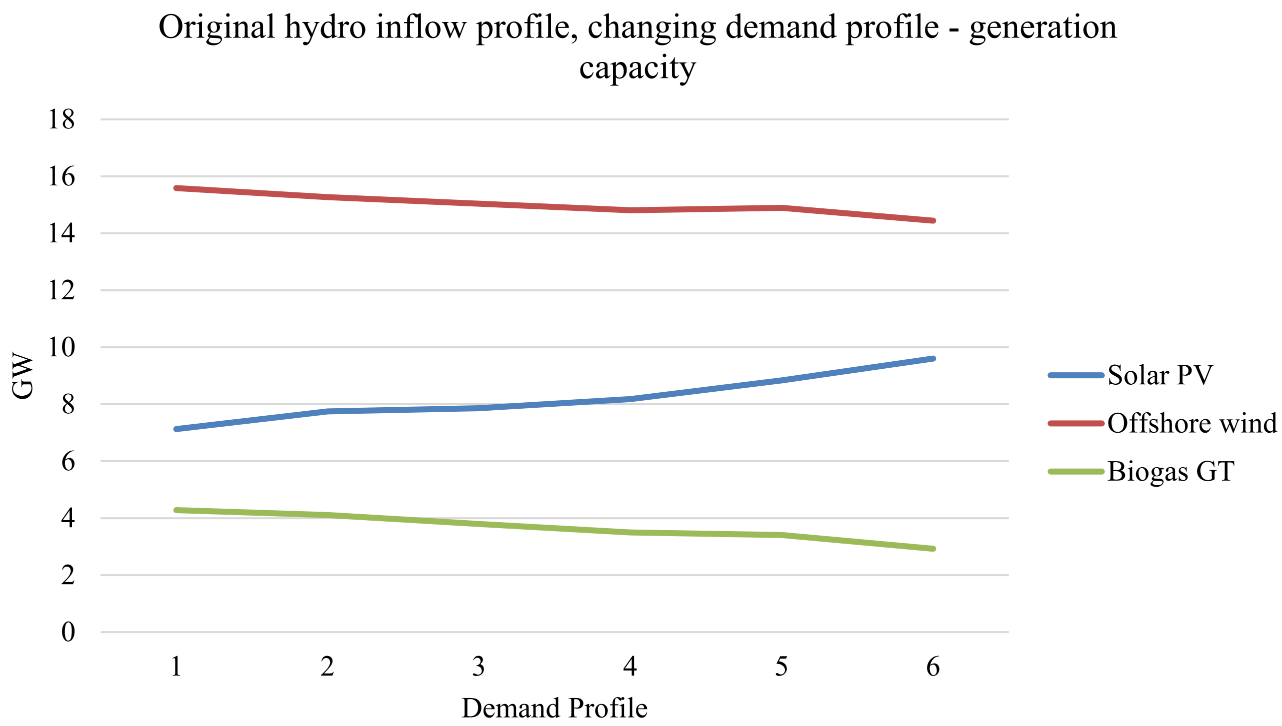
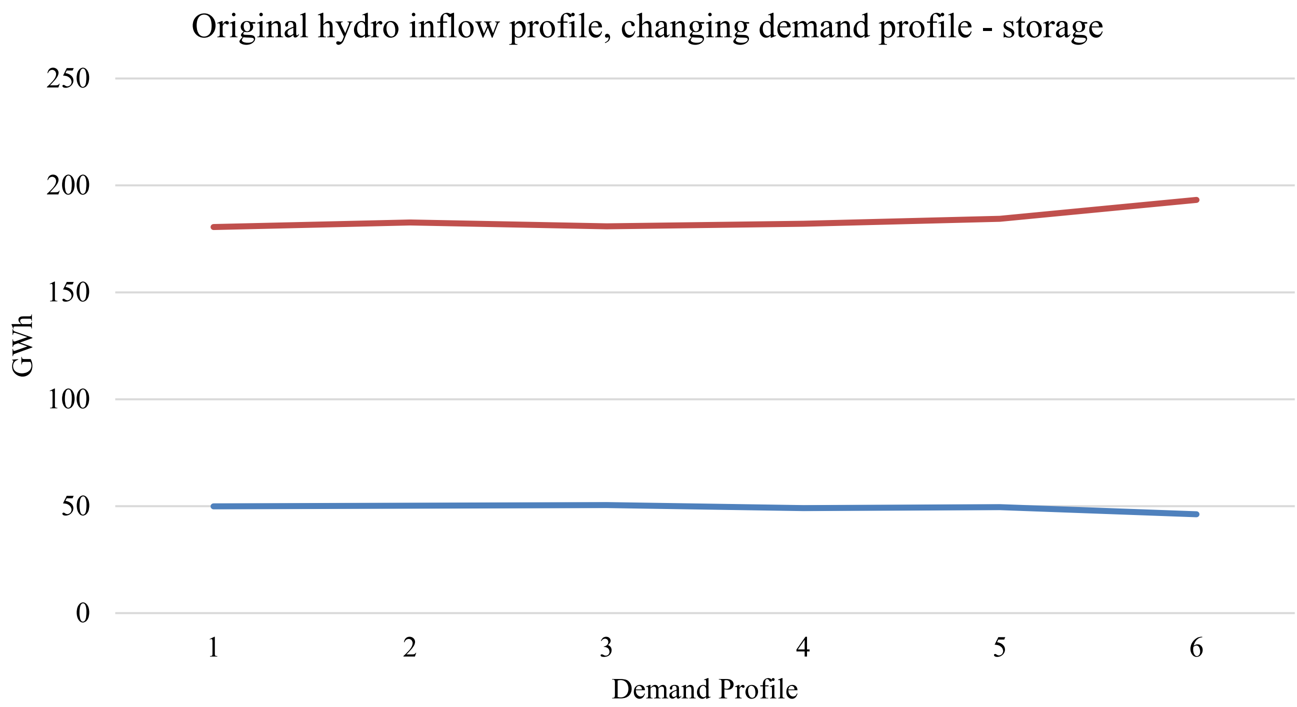
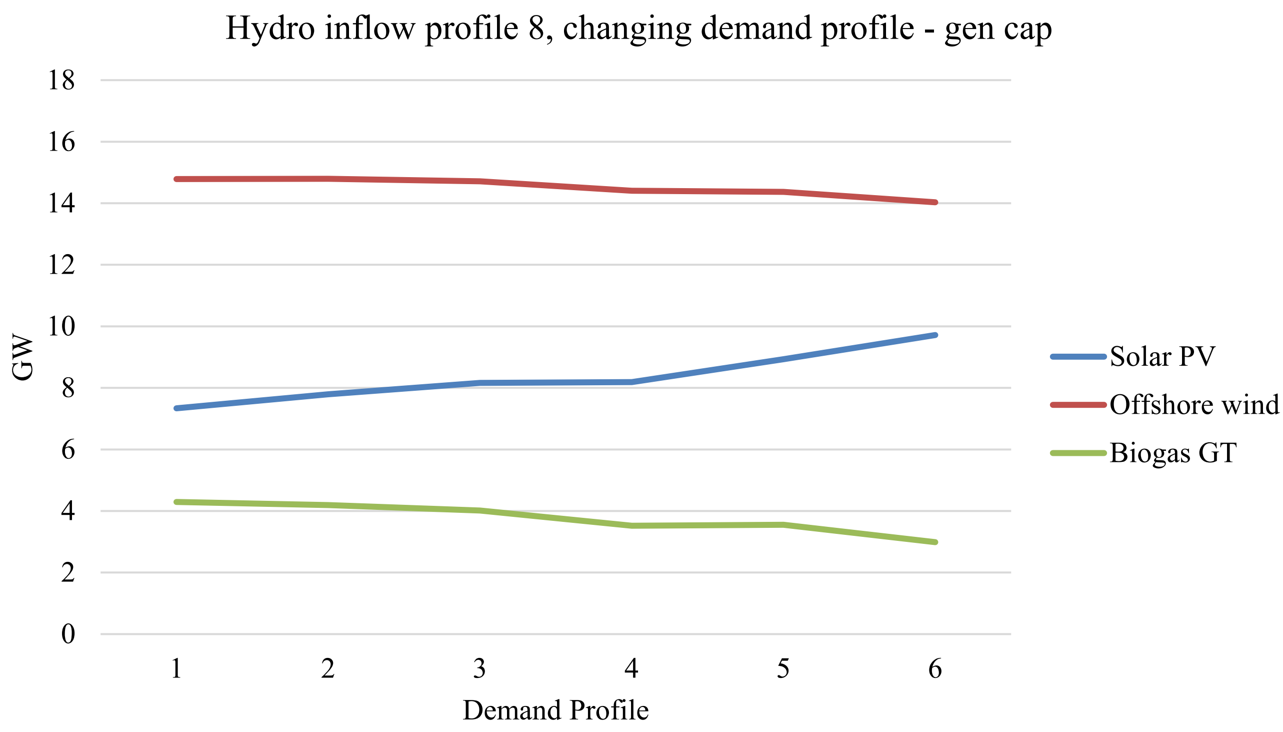
APPENDIX A



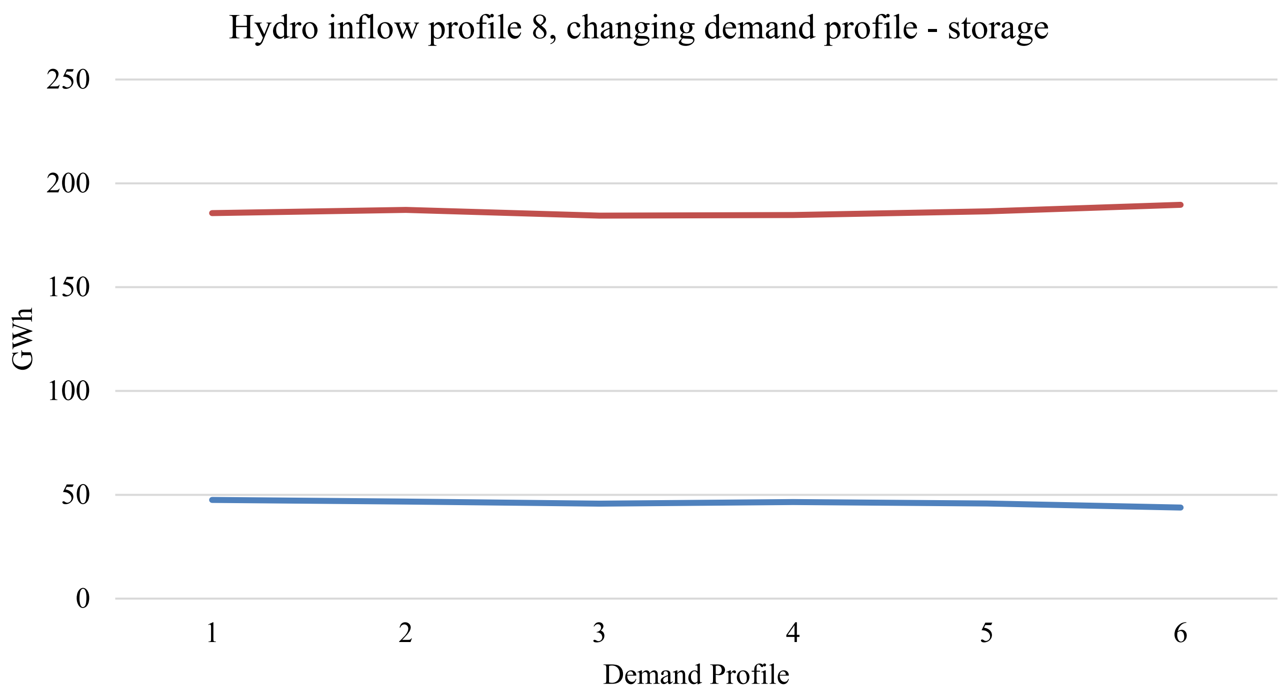
Appendix A Figure 1 Static hydro inflow profile 0, changing electricity demand profile



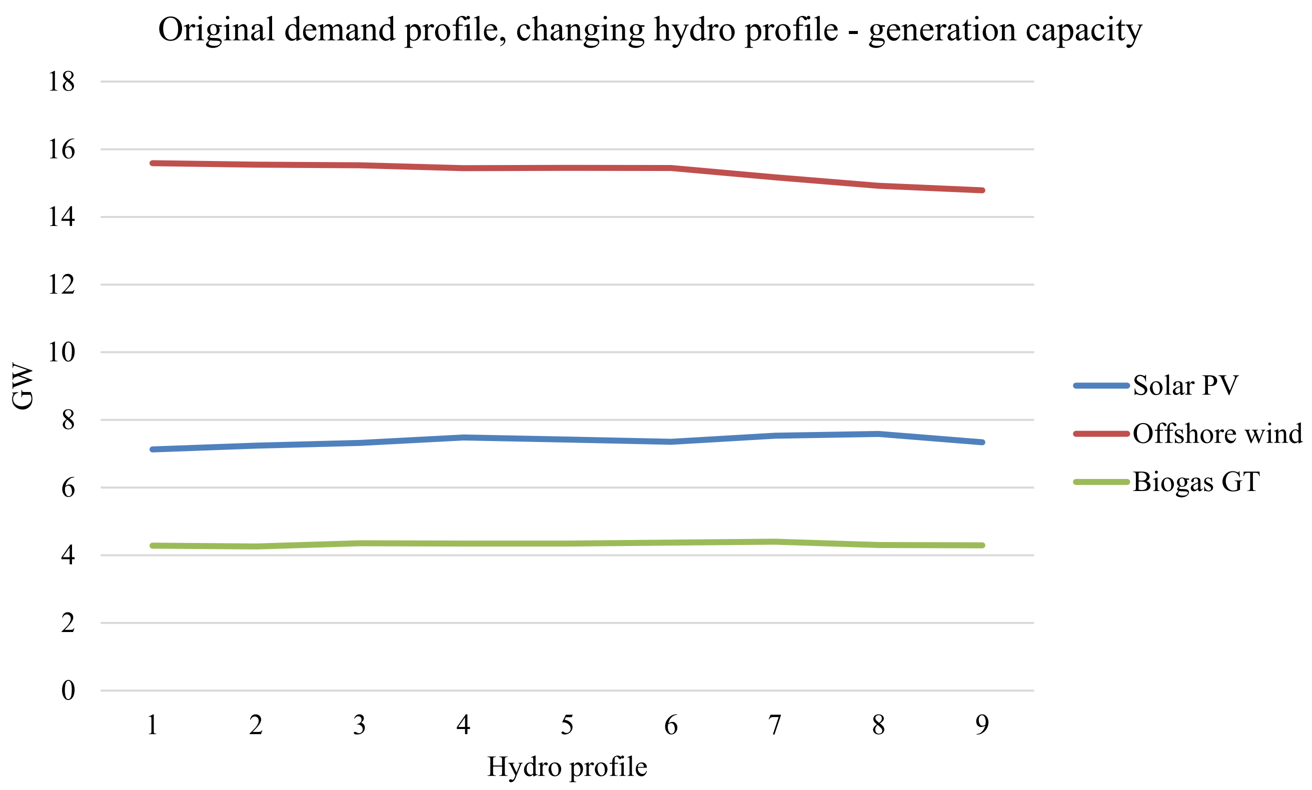
Appendix A Figure 2 Static hydro inflow profile 0, changing electricity demand profile.



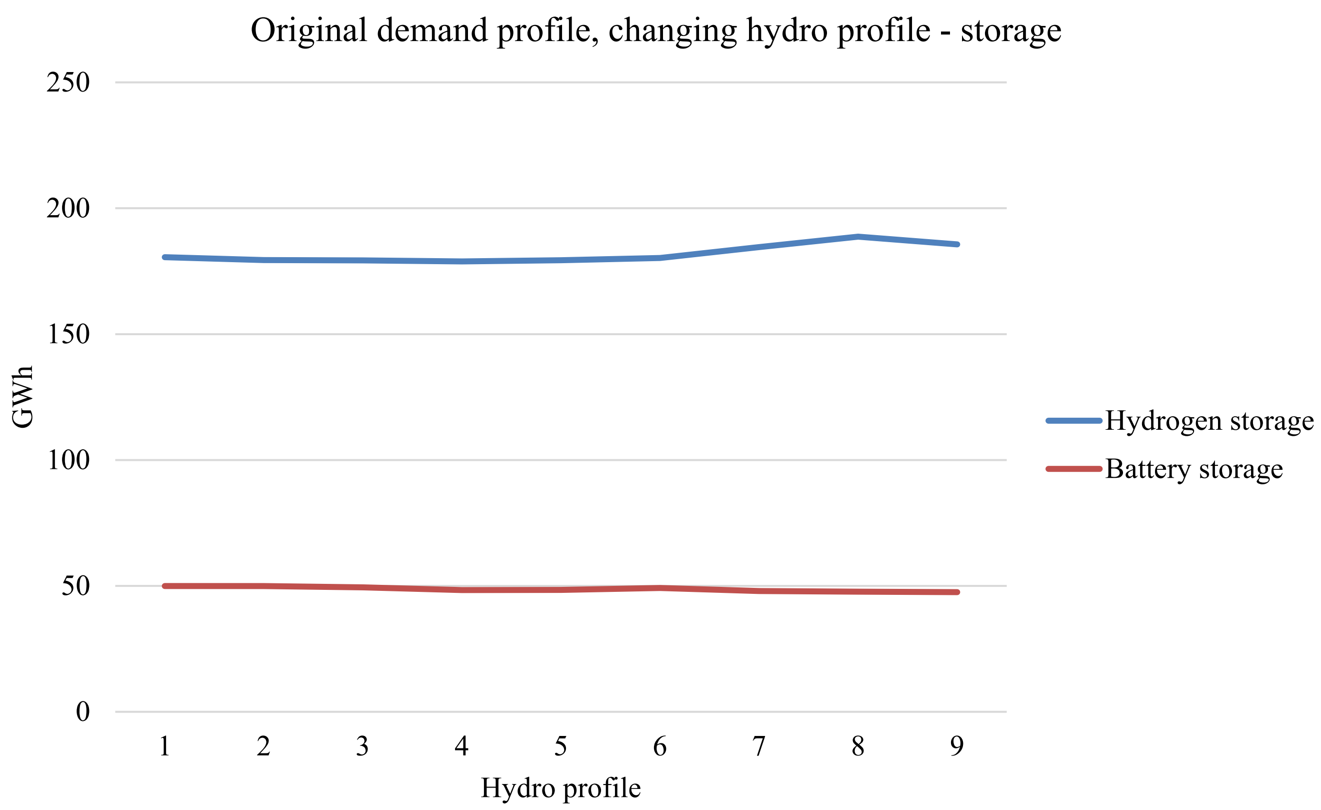
Appendix A Figure 3 Static hydro inflow profile 8, changing electricity demand profile



Appendix A Figure 4 Static hydro inflow profile 8, changing electricity demand profile

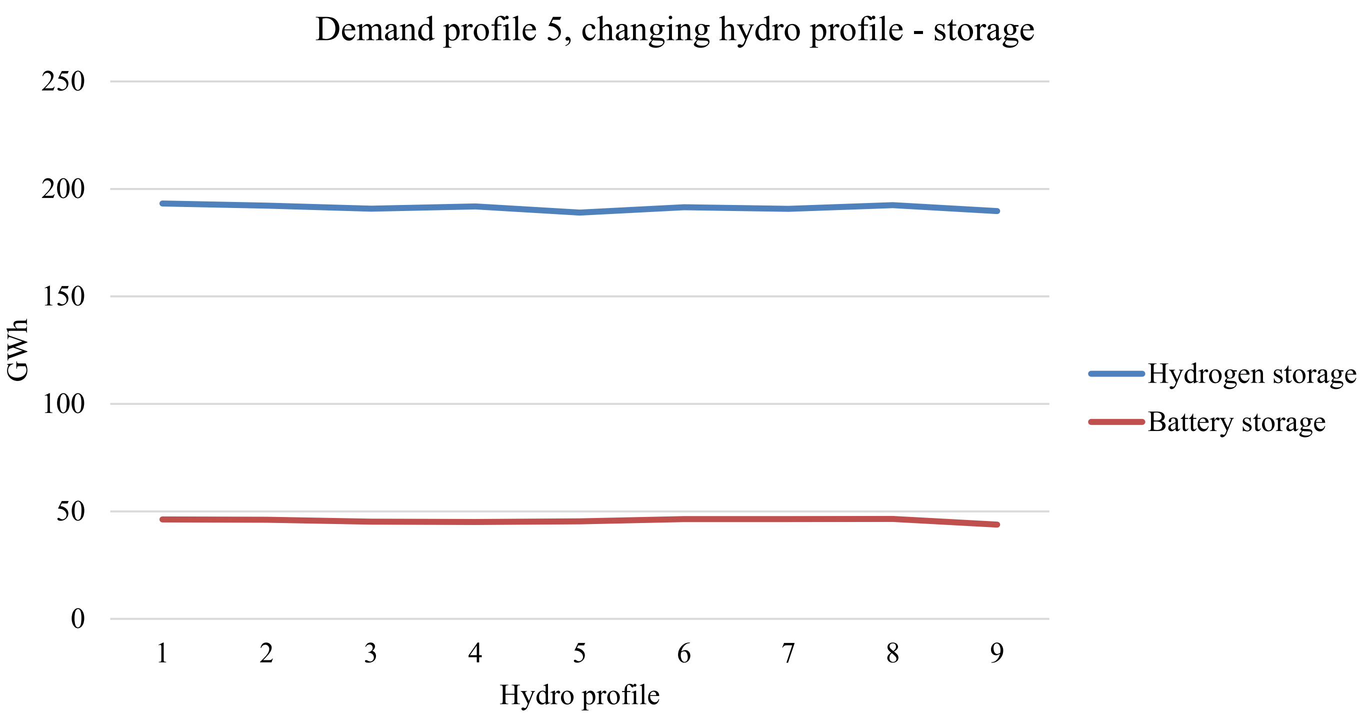


Appendix A Figure 5 Static electricity demand profile 0, changing hydro inflow profile.



Appendix A Figure 6 Static electricity demand profile 0, changing hydro inflow profile.

Appendix A Figure 7 Static electricity demand profile 5, changing hydro inflow profile.



Appendix A Figure 8 Static electricity demand profile 5, changing hydro inflow profile.

APPENDIX B

	HP1_factor	HP2_factor	HP3_factor	HP4_factor	HP5_factor	HP6_factor	HP7_factor	HP8_factor
Week 1	1.1	1.2	1.2	1.3	1.5	1.5	1.6	1.6
Week 2	1.1	1.2	1.2	1.3	1.4	1.5	1.5	1.5
Week 3	1.1	1.2	1.2	1.3	1.4	1.5	1.5	1.6
Week 4	1.1	1.2	1.2	1.3	1.4	1.4	1.5	1.7
Week 5	1.1	1.2	1.2	1.3	1.5	1.5	1.6	1.9
Week 6	1.1	1.2	1.3	1.4	1.5	1.5	1.6	1.9
Week 7	1.1	1.2	1.3	1.4	1.5	1.5	1.6	1.9
Week 8	1.1	1.2	1.3	1.4	1.5	1.5	1.6	2
Week 9	1.2	1.3	1.3	1.4	1.6	1.6	1.7	2.1
Week 10	1.2	1.3	1.4	1.5	1.7	1.6	1.7	2.3
Week 11	1.2	1.3	1.3	1.5	1.7	1.6	1.7	2.4
Week 12	1.2	1.3	1.3	1.5	1.7	1.6	1.7	2.5
Week 13	1.2	1.3	1.3	1.4	1.7	1.6	1.7	2.5
Week 14	1.3	1.4	1.5	1.6	1.9	1.8	1.9	2.8
Week 15	1.3	1.4	1.4	1.6	1.8	1.7	1.9	2.9
Week 16	1.2	1.2	1.2	1.3	1.4	1.5	1.8	2.4
Week 17	1.2	1.2	1.2	1.2	1.2	1.5	1.8	2.1
Week 18	1.3	1.3	1.4	1.3	1.4	1.7	2	1.9
Week 19	1.3	1.3	1.3	1.2	1.3	1.6	1.6	1.4
Week 20	1.2	1.1	1.1	1	1	1.1	1	0.9
Week 21	1.1	1	1	0.9	0.8	0.8	0.7	0.7
Week 22	1	0.9	0.9	0.8	0.7	0.7	0.6	0.5
Week 23	0.9	0.9	0.9	0.8	0.7	0.7	0.6	0.5
Week 24	0.9	0.9	0.8	0.8	0.7	0.7	0.6	0.5
Week 25	0.9	0.8	0.8	0.8	0.7	0.7	0.6	0.5
Week 26	0.9	0.8	0.8	0.8	0.8	0.7	0.5	0.5
Week 27	0.9	0.8	0.8	0.8	0.8	0.7	0.6	0.5
Week 28	0.9	0.8	0.8	0.8	0.8	0.7	0.6	0.6
Week 29	0.9	0.8	0.8	0.8	0.8	0.7	0.7	0.7
Week 30	0.9	0.8	0.8	0.9	0.9	0.7	0.8	0.7
Week 31	1	0.9	0.9	1	1	0.9	0.9	0.9
Week 32	1	0.9	0.9	1	1	1	1	1
Week 33	1	0.9	1	1	1	1	1.1	1
Week 34	1	1	1	1	1	1	1.1	1
Week 35	1	1	1.1	1.1	1.1	1.1	1.2	1.1
Week 36	1	1	1.1	1.1	1.1	1.1	1.2	1.1
Week 37	1	1	1.1	1.1	1.1	1.1	1.2	1.1
Week 38	1	1	1.1	1.1	1.1	1.1	1.2	1.1

Week 39	1	1	1.1	1.1	1.1	1.1	1.2	1.1
Week 40	1	1	1.1	1.1	1.1	1.1	1.2	1.1
Week 41	1	1	1.1	1	1.1	1.1	1.1	1.1
Week 42	1	1.1	1.1	1.1	1.1	1.1	1.2	1.1
Week 43	1	1.1	1.2	1.2	1.2	1.2	1.2	1.3
Week 44	1	1.1	1.2	1.2	1.2	1.3	1.4	1.4
Week 45	1	1.1	1.2	1.2	1.2	1.4	1.5	1.4
Week 46	1.1	1.2	1.2	1.2	1.2	1.5	1.6	1.6
Week 47	1.1	1.2	1.2	1.2	1.2	1.5	1.6	1.6
Week 48	1.1	1.2	1.2	1.2	1.2	1.5	1.5	1.5
Week 49	1	1.2	1.2	1.2	1.2	1.5	1.6	1.6
Week 50	1	1.1	1.2	1.2	1.2	1.5	1.6	1.6
Week 51	1	1.2	1.2	1.2	1.2	1.4	1.5	1.6
Week 52	1.1	1.2	1.3	1.3	1.3	1.4	1.5	1.7

APPENDIX C

	DP1_factor	DP2_factor	DP3_factor	DP4_factor	DP5_factor
Week 1	0.97	0.95	0.93	0.91	0.88
Week 2	0.97	0.95	0.93	0.91	0.88
Week 3	0.97	0.95	0.93	0.91	0.88
Week 4	0.97	0.95	0.93	0.91	0.88
Week 5	0.97	0.95	0.93	0.91	0.88
Week 6	0.97	0.95	0.93	0.91	0.88
Week 7	0.97	0.95	0.93	0.91	0.88
Week 8	0.97	0.95	0.93	0.91	0.89
Week 9	1.01	0.95	0.93	0.97	0.97
Week 10	1.01	0.95	0.93	0.97	0.97
Week 11	1.01	0.96	0.94	0.98	0.97
Week 12	1.01	1.02	1.02	1.04	1.06
Week 13	1.01	1.01	1.02	1.03	1.06
Week 14	1.01	1.01	1.02	1.03	1.06
Week 15	1.01	1.01	1.02	1.03	1.06
Week 16	1.01	1.01	1.02	1.03	1.06
Week 17	1.01	1.01	1.02	1.03	1.06
Week 18	1.01	1.02	1.03	1.04	1.06
Week 19	1.01	1.03	1.03	1.05	1.06
Week 20	1.01	1.02	1.03	1.04	1.06
Week 21	1.01	1.02	1.03	1.04	1.06
Week 22	1.01	1.02	1.03	1.04	1.06
Week 23	1.01	1.02	1.03	1.04	1.05
Week 24	1.01	1.02	1.03	1.04	1.04
Week 25	1.01	1.02	1.03	1.04	1.04
Week 26	1.01	1.02	1.03	1.04	1.04
Week 27	1.01	1.02	1.03	1.04	1.04
Week 28	1.01	1.02	1.03	1.04	1.04
Week 29	1.01	1.02	1.03	1.04	1.04
Week 30	1.01	1.02	1.03	1.04	1.04
Week 31	1.01	1.02	1.03	1.04	1.05
Week 32	1.01	1.02	1.03	1.04	1.08
Week 33	1.01	1.02	1.03	1.04	1.08
Week 34	1.01	1.02	1.03	1.04	1.08
Week 35	1.01	1.02	1.03	1.04	1.07
Week 36	1.01	1.04	1.05	1.06	1.06
Week 37	1.01	1.04	1.05	1.06	1.06
Week 38	1.01	1.04	1.05	1.06	1.06

Week 39	1.01	1.05	1.06	1.07	1.06
Week 40	1.01	1.05	1.06	1.07	1.06
Week 41	1.01	1.05	1.06	1.07	1.06
Week 42	1.01	1.05	1.06	1.07	1.06
Week 43	1.01	1.05	1.06	1.07	1.06
Week 44	1.01	1.05	1.06	1.07	1.06
Week 45	1.01	1.05	1.06	1.07	1.06
Week 46	1.01	1.03	1.05	1.06	1.06
Week 47	1.01	1.02	1.06	1.03	1.06
Week 48	1	0.95	1.01	0.91	1
Week 49	0.98	0.95	0.93	0.91	0.88
Week 50	0.98	0.95	0.93	0.91	0.88
Week 51	0.98	0.95	0.93	0.91	0.88
Week 52	0.98	0.95	0.93	0.91	0.88