ROLE OF DETAILED HYDRO POWER MODELLING IN INVESTIGATING POWER SYSTEM FLEXIBILITY

MASTER THESIS - ENERGY SCIENCE

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SUMMARY

In order to reach a 80% GHG emission reduction by 2050 (based on 1990 levels), a decarbonisation of 95% to 100% of the power supply sector will be necessary. Intermittent renewable energy sources (iRES) such as wind and solar are likely to become important components of such low-carbon power systems, but they require operational flexibility from non-iRES generators in the power system. From the few flexible and dispatchable renewable energy sources which are currently commercialized, hydro power has the largest installed capacity in Europe at the moment and could therefore be a significant provider of operational flexibility in future low-carbon power systems. However, hydro power is vulnerable to periods of drought, which may decrease the reliability of hydro power generation.

In this research, the effects of different natural inflow scenarios on a potential low-carbon European power system are investigated. This is done by including a detailed representation of hydro capacity (including details on hydro storages, natural inflow and complex configurations) in a European low-carbon power system model. In addition, the detailed representation of hydro plants is compared to a more simplistic method of modelling hydro capacity in order to investigate the added value of a detailed approach.

By including 68 detailed hydro power plants in the model, 32% of the total currently installed hydro capacity in Western Europe has been covered. The hydro power plants modelled in detail are clearly influenced by different natural inflow scenarios. Storage (STO) and Run-of-River (RoR) plants generate 79% and 72% more electricity on an annual basis in the maximum natural inflow scenario compared to the minimum natural inflow scenario. For PHS plants, this difference is 8%. These differences are mainly compensated for by gas turbines (GT) and natural gas combined cycle plants (NGCC). In the more simplistic hydro modelling method, these effects of alterations in natural inflow can not be accounted for.

In weeks with high iRES generation, all types of hydro plants (STO, RoR and PHS) provide for generation during hours without sun, both in the detailed and the lumped scenarios.

Based on this study, the main added value of detailed hydro modelling is the sensitivity of hydro plant dispatch to different natural inflow scenarios. If a higher share of the hydro capacity is included in the detailed hydro plant database, the effect of different natural inflow scenarios on total generation profiles is expected to be significant.

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ABBREVIATIONS

CCS	Carbon Capture and Storage
CSP	Concentrated Solar Power
DR	Demand Response
ECF	European Climate Foundation
ENSTO-E	European Network of Transimission System Operators for Electricity
EREC	European Renewable Energy Council
ESHA	European Small Hydro Association
EU	European Union
GEO	Global Energy Observatory
GHG	Greenhouse Gas
GWEC	Global Wind Energy Council
IEA	International Energy Agency
iRES	intermittent Renewable Energy Source
JRC	Joint Research Centre
MIP	Mixed Integer Programming
PHS	Pumped Hydro Storage
PwC	PriceWaterhouseCoopers
RES	Renewable Energy Source
rLR	Rounded Linear Relaxation
RoR	Run-of-River hydro power
STO	Storage hydro power
TES	Thermal Energy Storage
WWF	World Wildlife Fund

1. INTRODUCTION

1.1 BACKGROUND

If GHG emission rates will not be reduced significantly, the resulting global warming in the coming decades will have severe environmental and social consequences. Therefore, the European Union (EU) set targets to reduce GHG emission rates by 80% in 2050, compared to 1990 emission levels (European Commission, 2011). In order to reach the 80% GHG emission reduction by 2050, a decarbonisation of 95% to 100% (based on 1990 levels) of the power supply sector will be necessary (ECF, 2010). One of the ways to reach this decarbonisation in the power supply sector is through a power system including a high share of renewable energy technologies (RES). This RES can be supplemented with nuclear power plants and fossil fuelled power plants equipped with carbon capture and storage (CCS) (ECF, 2010). In general, a high share of renewable energy comes with a high share of intermittent renewable energy sources (iRES). By illustration, in the 80% renewable energy scenario for 2050 by ECF (2010), 49% iRES gneration is assumed on an energy basis. By comparison, the share of iRES in gross energy production in 2014 was less than 5% (Eurostat, 2016). These iRES, of which solar and wind energy are examples, generate electricity on a variable and relatively unpredictable basis. When the share of iRES is high, the system must therefore be able to respond to significant fluctuations in generation which can be difficult to predict, in addition to the fluctuations in demand. This increases the required operational flexibility and the required backup capacity of the power system (Brouwer, et al., 2016). Operational flexibility can be maintained through energy generation technologies providing spinning reserves (available within 5 minutes) and standing reserves (available within 1 hour), offering the ability to quickly change power output in order to meet fluctuating power demand), and through increased transmission capacity between regions, demand response options (DR) and storage (Alizadeh, et al., 2016; Brouwer, et al., 2016).

Of all the commercialized renewable power generation technologies, only a few can provide for standing and/or spinning reserves. These few technologies include hydro power, geothermal energy, concentrating solar power with thermal energy storage and biomass fired plants. In modelling low-carbon power systems with large shares of iRES, a sufficiently detailed representation of these technologies might therefore be important in giving an accurate representation of the operational flexibility of the generation mix.

From the four technologies mentioned, the focus is on modelling hydro power. Hydro power is dispatchable as well as flexible with most plants able to ramp up and down quickly and provide standing and spinning reserves (Locher, 2004; Brouwer, et al., 2016; Eurelectric, 2011). There are several reasons for the choice for this technology as focus of this study. To start with, it is currently the renewable energy source (RES) with the largest generation in Europe. In 2014, the installed hydro power capacity (excluding pumped hydro) in the EU-28 was 148.5 GW, producing 393 TWh net electricity in that year (Eurostat, 2016). It provided for 12% of total gross[1] electricity generation and for 42% of the renewable electricity generation in 2014 in the then EU-28 (Eurostat, 2016). This high share increases the chance that a more detailed representation of the technology in power system models has significant effects on the results. Moreover, some types of hydro power plants can be equipped with storage. Finally, from the currently commercialised dispatchable low-carbon

[1] Gross electricity generation includes the energy consumed by the power plants themselves, in plant auxiliaries and other transformers (Eurostat, 2016).

generation technologies mentioned, hydro power presents particular modelling challenges because of the large differences between hydro power technologies and significant differences between individual plants due to site-specific characteristics. Moreover, hydro generation is influenced by the water availability which may vary both between plants and over time. Finally, several studies mention that the unexploited economic capacity for hydro power plants in Europe is rather limited. For the EU-27 (current EU-28 excluding Croatia) JRC reports a maximum annual hydro power electricity generation potential of 470-610 TWh (JRC, 2014). However, expected electricity generation from hydro power plants is estimated lower, about 448 TWh/y from 194 GW installed capacity in EU-27 by 2050 (EREC, 2010). This is a relatively small increase compared to the generation of about 393 TWh in 2014. If future growth of the European hydro power sector will indeed be limited, a rigorous model of the current hydro power system would be roughly representative for future power systems as well.

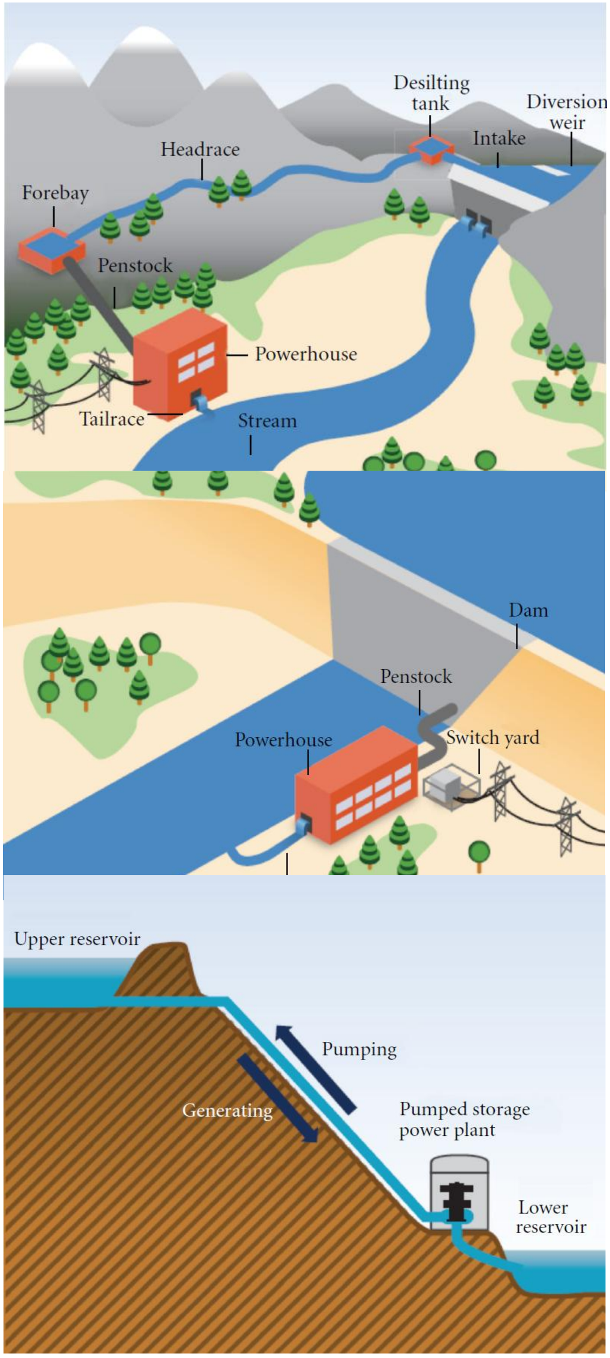

Figure 1 - Schematic representation of, from top to bottom, a) run-of-river b) storage c) pumped storage hydro power plant. Copy from Kaunda et al. (2012).

The three main types of hydro power plants are run-of-river, storage and pumped storage hydro power. There are no universally accepted quantitative definitions to distinguish between different types and therefore definitions used differ per country (Kaunda, et al., 2012). Here, a general description is given (Kaunda, et al., 2012; Eurelectric, 2011; IRENA, 2012).

Run-of-river (RoR) hydro power. With this type of hydro power generation, no significant impoundment is used, so limited or no storage is available in this type of plant. Electricity is generated from the current natural inflow from the river. Therefore the momentary power capacity is dependent on the river's flow regime. The conversion efficiency of a well-operated plant can be around 85%. Some run-of-river hydro power plants allow for storage for a few hours or a day and are therefore able to adjust to power demand to a certain extent. These plants are called 'pondage run-of-river hydro power plants'. An example of a pondage RoR plant (with a small reservoir) is given in figure 1a.

Storage (STO) hydro power. Storage hydro power systems essentially consist of a reservoir behind a dam. When needed, the potential energy in the water behind the dam can be released in order to generate electricity. The generation can take place at the dam toe or further downstream: the

reservoir is connected to the electricity generation unit through pipelines or tunnels.
Following the definition by ENTSO-E, a plant is a storage plant when it can withhold natural inflow for more then 400 hours (ENTSO-E, 2011). Obviously, STO hydro power is far less dependent on the natural flow regime than run-of-river schemes. Like for run-of-river schemes, the efficiency can be up to 85%. Reservoirs of STO plants are equipped with spillways, to allow the release of excess or flood water (J.E.Lindell, et al., 2004).

Pumped hydro storage (PHS). Pure pumped hydro storage systems do not generate renewable energy, but instead function as a storage facility. Water is pumped from a lower to a higher reservoir when excess energy is available. When the energy is needed, energy is generated out of the created difference in height. Usually, the round trip efficiency of the pump-turbine system is about 75% (F.Geth, et al., 2015), meaning that about three quarters of the energy used to pump the water to the head storage, can be regained. Besides pure PHS systems, it is possible that part of the energy is generated from natural inflows in the head storage and another part from water that was previously pumped up to the head storage. This form is called mixed PHS.

In current power system modelling work at Utrecht University (UU), no distinction is made between RoR and STO plants, nor are hydrological details such as reservoir volumes and natural inflow included for these plant types. In a recent study, hydro power is modelled as a fixed capacity per country (Brouwer, et al., 2016). Annual constraints on capacity factors are applied in order to match historic production levels.

The first limitation to this approach is that no detailed information on installed hydro storage capacity is available, since run-of-river and storage hydro capacity are lumped together. Secondly, as no hydrological details are included, no influence of water availability on hydro power generation capacity can be tested. According to Van Vliet et al. (2013) limited water availability (as a result of climate change) may have a significant negative impact on hydro power potential. The effect is estimated to be over 15% decrease in potential energy production for southern and southeast Europe for the period 2031-2060 compared to 1971-2000 (van Vliet, et al., 2013). Third, limitations to operational flexibility due to regulation of flow regimes are not accounted for. Finally, complex hydrological networks may prevent maximal resource usage (Huertas-Hernando, et al., 2016). This effect is also not taken in to account when a lumped approach is used. In the extensive review study on modelling hydro power by Huertas-Hernando et al (2016) it is recommended to include a sufficient level of hydrological details in modelling hydro power, to enable the modelling of the effects of water availability, flow regime regulations and complex hydro networks (Huertas-Hernando, et al., 2016).

However, most current databases on hydro power plants in Europe do not include detailed information on the reservoirs that the plants are connected to, nor do they present information on (average) water availability or other hydrological details (ENTSO-E, 2015; BFE, 2016; Wikipedia, 2016; Enipedia, 2016). The open source database of the Global Energy Observatory (GEO) does provide some hydrological data in combination with technical data on power plants, but these hydrological details are not complete nor are they always reliable. Data on water availability is very scarce on the GEO website (GEO, 2016).

The aim of this research is to investigate the effects of different natural inflow scenarios on a potential future European power system in which hydro plants are modelled in detail, and to compare this detailed hydro modelling approach to a more simplistic method of modelling hydro capacity.

Two research needs are identified. Firstly, a detailed hydro database is needed which can be used for European power system modelling, in which relevant technical details of different types of hydro power systems are linked to hydrological details associated with connected reservoirs, such as historic natural inflow data, maximum usable volume and available hydraulic head. Using these data, the effect of different natural inflow scenarios on both the hydro power system and the power system as a whole can be investigated. Secondly, the value of the more detailed approach of hydro power modelling should be compared to a more simplistic approach. It should be tested to what extent the results from power system modelling, in which this detailed approach is used, differ from results using the 'lumped capacity' approach. This would give an indication whether detailed modelling of hydro systems is actually useful in modelling the European power system. As the details will increase the simulation time of the model and require extra time for data collection, this involves a trade off.

1.2 Problem definition

The main question of the research is:

"How does a potential future European low-carbon power system respond to different natural inflow scenarios, and what is the added value of modelling the hydro power system in detail?"

The sub-questions are:

1) What are the relevant characteristics of significant run-of-river hydro, storage hydro and pumped hydro storage systems, which are currently operational?

2) How do different natural inflow scenarios applied on the hydro power system influence the model optimisation results of a potential future European low-carbon power system model?

3) How do the results from more detailed hydro power modelling differ from the results from a more simplistic hydro power capacity modelling approach, all other aspects held constant?

1.3 Scope

The geographical scope for the data collection part of this study was all present EU-28 countries, supplemented by Norway and Switzerland.

The geographical scope of the modelling part of this study is smaller. It is the same as the geographical scope used in the model by Brouwer et al. (2016), except that Scandinavia is excluded from this study. Thus, the included countries are: Austria, Belgium, France, Germany, Ireland, Italy, Luxembourg, the Netherlands, Portugal, Spain, Switzerland and the United Kingdom. The scope of the existing model was adopted since this model was used as a basis for the model used in this study. Scandinavia was excluded from the model scope because no local natural inflow data were available for this region, which were needed to connect to the involved reservoirs. It was decided not to estimate the natural inflow into Scandinavian reservoirs based on general data as this would greatly diminish the reliability of the results. After all, Scandinavia has significant hydro power capacity, accounting for 29% of the total installed hydro capacity within the region under the scope of the Brouwer et al. (2016) model (ENTSO-E, 2014)). As in the model by Brouwer et al., the countries are grouped into regions (see figure 2). The regions are:

- BRI – United Kingdom and Ireland
- GAL – France
- GER – Germany, Belgium, Luxembourg and the Netherlands
- HIS – Portugal and Spain
- ITA – Italy, Austria and Switzerland

The period under study is from 2016 until the year 2050. Only the electricity market is covered: neither heat or cold production/demand is treated in this research.

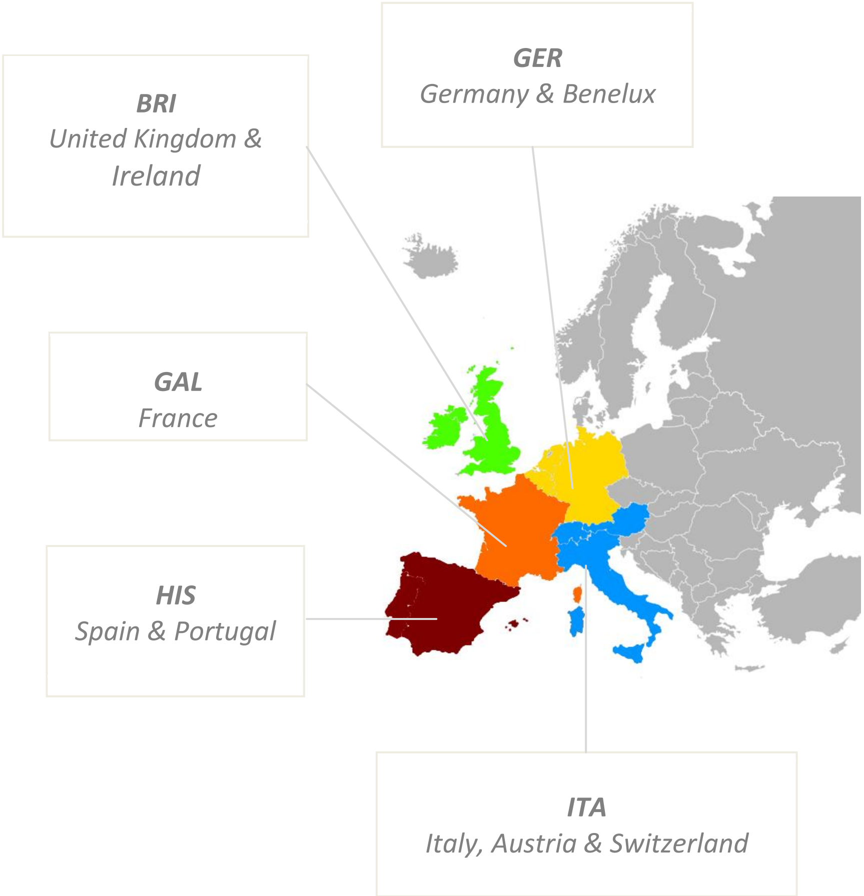

Figure 2 – Geographical scope of the model. Based on figure 1 from Brouwer et al. (2016).

1.4 DOCUMENT STRUCTURE

The next part of this document, chapter 2, describes the method of data collection for the database with detailed properties of the power plants. This part describes both data collection on the technical details of power plants as well as on the hydrological details. In chapter 3, the results of the data collection are described. Then, in chapter 4, the method used for the modelling are discussed. These methods describe the general model structure, additional model input (apart from the detailed plants) and model settings. In chapter 5, modelling results are given. Chapter 6 consists of the discussion, containing the limitations of the database and the model, discussion of the modelling results and validation of the modelling results. The conclusions are drawn in chapter 7.

2. METHOD – DETAILED HYDRO PLANT DATA

To be able to model the power plants in detail, a database of significant hydro power plants was set up by collecting raw data. The plants included in this list are referred to as 'detailed plants' in this study. In this section the data collection for the list of hydro power plants is described, as well as the generation of the natural inflow data for the included reservoirs. These natural inflow data were generated using an existing model developed by David Gernaat. Model set up and methods concerning modelling are discussed in chapter 4.

All of the three types of detailed power plants (STO, RoR, and PHS) are by definition connected to water bodies. For convenience, in this study, all of these water bodies are referred to as 'storages', even those of RoR plants. For STO plants, these 'storages' are mainly large with relatively little natural inflow, for RoR plants the 'storages' are small with large natural inflow (see 2.4 on the definition of plant type). Thus, the term 'storage' as used in this study, does not necessarily mean a large reservoir of a storage (STO) hydro plant.

To give more insight in the data collection method, a flow chart of the method concerning the detailed power plants is given in figure 3.

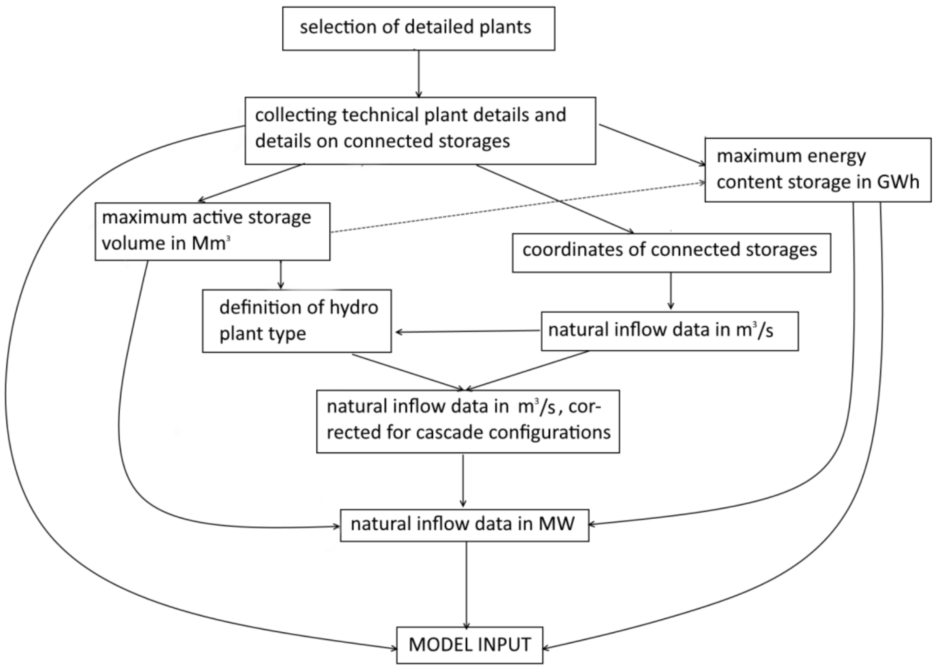

Figure 3 - Flow chart of data selection and data processing concerning the detailed power plants.

2.1 SELECTION OF DETAILED HYDRO POWER PLANTS AND DATA COLLECTION

First, the existing large power stations in the geographical scope had to be identified. For this purpose, lists containing individual plants derived from Wikipedia and Enipedia were used (Wikipedia, 2016; Enipedia, 2016). Additionally, an article by Geth et al. (2015) listing significant pumped hydro storage was used. The identified plants were combined in a database and sorted on installed capacity. Only plants reported as currently operational are included.

Then, detailed technical and hydrological data were collected for the largest plants in the list, with installed capacities typically higher than 250 MW.

To find the detailed data for the included plants plants, open source data were used. Data provided by plant operators and contractors were generally preferred, since they were considered most reliable. If these sources were not available, data provided by the Global Energy Observatory (GEO, 2016) and from scientific sources such as articles and books were used. Enipedia and Wikipedia were used only when no other available sources were found, because data on these websites was usually least specific: definitions used were sometimes unclear. If the active volume (that is the maximum volume available for power generation or pumping) was not available from operators or contractors, the Grand Database was used (GWSP, 2016). For storages not included in the Grand Database either, another internet source for the active volume was used. In some cases, estimations had to be made due to a lack of information.

In Appendix I, a table is given containing all data entries of the collected raw data together with a description.

2.2 Maximum energy content of storages connected to detailed plants

In PLEXOS, the energy model is used to define storage volumes, which means that storage volumes have to be defined in GWh and flows in MW. This is done because of limited data availability: there is not enough reliable information available to work with water flows in cubic meters per second, while the installed capacities of the turbines and pumps in MW are known. However, as the maximum content of the storages is not reported in GWh in many cases, this value has to be calculated. This is done assuming a linear relationship between volume (in cubic meters) and energy content (in GWh) of the storage. This is a simplification because the effects of decreasing head were thereby neglected. The energy storage content is based on average volume. In this section it is explained how this calculation was carried out for both head and tail storages. Head storages have been connected to all detailed plants and also to rest and lumped PHS plants. This is the highest storage providing water to the turbines. Tail storages have been connected to all detailed PHS plants, to some of the detailed STO and RoR plants (in case it was a head-tail storage, see 2.5 and Appendix IV) and all rest and lumped PHS plants. Tail storages collect the water that has been released by the turbines. In case of PHS plants, water can be pumped up from the tail storage to the head storage.

2.2.1 Simple head storage

The simple head storage is a head storage which is connected to one generator and to which no other storages or generators are connected. A schematic representation is given in figure 4. Flow 1 in figure 4 is the power at which the generator (GEN in the figure) is working. This is possible because the turbine efficiency is already included in the potential energy content of the head storage.

The amount of energy that can be generated by the generator starting with a full storage was calculated using one of the following equations, in order of preference:

1) $$E_{sto,head} = h_{turb,max} * P_{turb,max} * \frac{1\ GWh}{1000\ MWh}$$

2) $$E_{sto,head} = \rho * g * H * V_{sto,active} * \eta_t * \frac{1\ GWh}{3.6*10^6\ MJ}$$

3) $$E_{sto,head} = \frac{P_{turb,max} * V_{sto,active}}{Q_{turb,max}} * \frac{1\ GWh}{3.6\ TJ}$$

In which:

$E_{sto,head}$	= maximum energy content of the full head storage [GWh]
$h_{turb,max}$	= maximum hours of generation by turbines, starting with full head storage [h]
$P_{turb,max}$	= total installed capacity of the turbines [MW]
ρ	= density of water (assumed to be 1000 kg/m^3) [kg/m^3]
g	= gravitational acceleration (assumed to be 9.81 m/s^2) [m/s^2]
H	= average hydraulic head [m]
η_t	= turbine efficiency (87%, based on Geth et al. (2015) and Brouwer et al. (2016)) [-]
$V_{sto,active}$	= active volume of the storage in [Mm^3]
$Q_{turb,max}$	= water flow through the turbines at maximum capacity [m^3/s]

The first preferred method to calculate $E_{sto,head}$ is using equation 1. This method is considered most reliable because it is transparent, no additional assumptions are needed and only a few numbers are involved, which decreases uncertainty. However, this equation could be used only when $h_{turb,max}$ was specified by a reliable source. The second preferred source was the article by Geth et al. (2015), giving energy storage volumes directly. The method used by Geth et al. is equal to equation 6 and/or 7, and the use of open source data was avoided as much as possible by the authors (F.Geth, et al., 2015). Therefore, the data are considered reliable. If the plant is not described in Geth et al. (2015) either, equation 2 was used to calculate $E_{sto,head}$, using open source data. For the turbine efficiency (η_t), an estimated value of 0.87 was used, being an average of the values used by Geth et al. (2015) and Brouwer et al. (2016). If insufficient data could be found to use the equation 2, equation 3 was applied. This last method was regarded as least reliable. The reason for this is that the value $Q_{turb,max}$ does not seem highly trustworthy as it was often not clearly specified whether maximum flow processed by the turbines is given or maximum total flow is meant (including spillways).

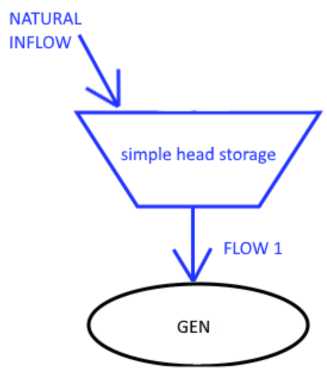

Figure 4 - Schematic representation of a simple head storage.

2.2.2 Simple tail storage

The simple tail storage is a tail storage which is connected to only one generator and to which no other storages are connected. For pumped storage plants, the maximum energy storage volume of the tail storage has to be defined in PLEXOS. A schematic representation of the simplest configuration of a PHS plant is given in figure 5.

$E_{sto,tail}$ for all relevant tail storages is calculated as tail storage data are not available in the study by Geth et al. (2015). Here $E_{sto,tail}$ is the amount of energy needed to pump the active water volume up to the head storage. An adapted version of the same formulas as for the head storage is used, in order of preference:

$$4) \qquad E_{sto,tail} = h_{pump,max} * P_{pump,max} * \frac{1\,GWh}{1000\,MWh}$$

$$5) \qquad E_{sto,tail} = \frac{\rho * g * H * V_{sto,active}}{\eta_p} * \frac{1\,GWh}{3.6 * 10^6\,MJ}$$

$$6) \qquad E_{sto,tail} = \frac{P_{pump,max} * V_{sto,active}}{Q_{pump,max}} * \frac{1\,GWh}{3.6\,TJ}$$

In which:

$E_{sto,tail}$ = energy needed to pump the maximum active volume of the tail storage up to the level of the head storage [GWh]
$h_{pump,max}$ = maximum hours of pumping, starting with full tail storage [h]
$P_{pump,max}$ = total installed capacity of the pumps [MW]
ρ = density of water (assumed to be 1000 kg/m^3) [kg/m^3]
g = gravitational acceleration (assumed to be 9.81 m/s^2) [m/s^2]
H = available hydraulic head [m]
η_p = pumping efficiency (87%, based on Geth et al. (2015) and Brouwer et al. (2016))
$V_{sto,active}$ = active volume of the storage in [Mm^3]
$Q_{pump,max}$ = water flow pumped up at maximum capacity [m^3/s]

The pumping efficiency is assumed to be 87%. This is based on the roundtrip efficiency of 76%, based on the values used in Geth et al. (2015) (75%) and Brouwer et al. (2016) (77%). Assuming that $\eta_t = \eta_p$ and using $\eta_{rt} = 76\%$, the pumping and turbine efficiencies come down to 87%, since the roundtrip efficiency of one pumping cycle is equal to (F.Geth, et al., 2015):

$$7) \qquad \eta_{rt} = \eta_t * \eta_p$$

Some of the pumped storage plants in the model use a river as tail storage. In that case, a fixed amount of 500 GWh of storage was applied as 'volume' of the tail storage which is large enough to function as a 'infinite' amount of energy in PLEXOS. The choice to model rivers functioning as tail storages as having infinite storage capacity is imitated from Geth et al. (2015).

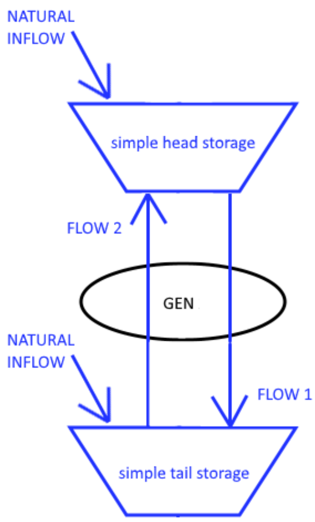

Figure 5 - Schematic representation of pumped storage plant with simple head and tail storage.

2.3 NATURAL INFLOW DATA

To calculate the effect of different natural inflow scenarios, hydrological data are needed for each storage. For generating the required natural inflow data, a model set up by David Gernaat was used. The model input consists of detailed geographical elevation maps combined with spatial precipitation data. From this input, the model calculates monthly average natural inflow into each grid cell by combining direct precipitation with surface run-off calculations. This way, the model generates natural inflow data for every pair of coordinates associated with the storages in the database described in section 2.1. Natural inflow is calculated by the model for all PHS plants, as no difference was made between closed loop and mixed PHS plants in the database. Therefore, closed loop PHS plants could not be excluded. The resulting natural inflow data consist of monthly average natural inflow numbers for each storage (head as well as tail storages) for the years 1971 – 2000. Natural inflow data generated by the natural inflow model are in m^3/s.

2.3.1 Natural inflow scenarios

Three scenarios are created from the available natural inflow data. The low discharge scenario is created by choosing the year with the least total natural inflow for each storage. The monthly natural inflow numbers of that year are used. The data from different years for each reservoir, are combined into one scenario, in this case the minimum natural inflow scenario.

The maximum natural inflow scenario is created following a procedure similar to that for the minimum natural inflow scenario, this time using the data from the year with maximum natural inflow for each storage separately and again combining the different year data for different storages into one scenario.

The average scenario is created by taking the 30 year average of each month (for example, the average of all January months) for each storage.

2.3.2 Conversion to energy inflow

For all storages in the detailed power plant list, the monthly average natural inflow in m^3/s must be converted to an inflow in terms of energy (in MW) as in PLEXOS the hydro model is defined in terms of energy. The maximum energy content of the storage (as described in section 2.2) as well as the active volume of the storage in cubic meters is used, following:

$$8)\quad P_{\text{in,natural,i}} = \frac{E_{\text{sto}}\, Q_{\text{in,natural,i}} \frac{1000\ \text{MWh}}{1\ \text{GWh}}}{V_{\text{sto,active}} \frac{1\ \text{h}}{3600\ \text{s}}}$$

In which:

$P_{in,natural,i}$	= natural inflow into storage in terms of energy in month i [MW]
E_{sto}	= maximum energy content of the storage [GWh]
$Q_{in,natural,i}$	= natural inflow into storage in terms of water flow in month i [m^3/s]
$V_{sto,active}$	= maximum active volume of water the storage can withhold [m^3]

2.4 Definition of plant types

There are three different types of power plants as as mentioned in the introduction: storage (STO) power plants, run of river (RoR) power plants and pumped hydro storage (PHS) plants. However, a clear definition to distinguish between run of river and storage hydro is not found as the definitions differ per country (Kaunda, et al., 2012). For consistency however, the same definition should be used for all plants in this study. Therefore, the definition given in the glossary by the ENTSO-E under 'Storage Hydro' is adopted here (ENTSO-E, 2011). Following this definition, if the head storage can withhold 400 or more hours of historic average natural inflow ($t_{withhold} \geq 400$ hours), it is defined as a 'storage hydro power plant' (STO). If it cannot ($t_{withhold} < 400$ hours), it is called a 'Run-of-River hydro power plant' (RoR). In this study, no distinction is made between pondage (2 hours < $t_{withhold}$ < 400 hours) and pure run-of-river plants ($t_{withhold}$ ≤ 2 hours). Also, the plant type is based on natural inflow only, not on inflow provided by an upstream plant.

To calculate the hours of natural inflow that each storage in the detailed plant database can withhold ($t_{withhold}$), the following equation is used:[2]

9) $$t_{withhold} = \frac{V_{sto,active}}{Q_{dis,av} * hourseconds}$$

In which:

$t_{withhold}$	= hours of average inflow which the storage can withhold [h]
$V_{sto,active}$	= maximum active volume of the storage in [m^3]
$Q_{dis,av}$	= 30 year average natural inflow into the head storage [m^3/s]
hourseconds	= seconds per hour (equal to 3600) [s/h]

$Q_{dis,av}$ is based on raw natural inflow data in m^3/s, derived from the natural inflow model developed by David Gernaat and described in section 2.3.

2.5 STORAGES IN COMPLEX CONFIGURATIONS

Some of the plants in the database are more complicated than having just a simple head storage and optionally a simple tail storage (the configurations discussed in section 2.2). In that case, the calculation of the energy content of the storages as well as the natural inflow in terms of energy have to be adjusted. Examples of storages in 'complex configurations', as they are referred to in this study, are:

- **Head-tail storage**, cascade configuration in which one storage is functioning as head and a tail storage at the same time.
- **Supplementary storage**, not connected to a generator but providing water to another storage that is connected to a generator.
- **Shared head storage,** used as a head storage by more than one generator.
- **Shared tail storage,** used as a tail storage by more than one generator.

These four configurations are illustrated and further described in Appendix IV. For the head-tail storage, a correction on the natural inflow data was necessary, which is explained in the next section.

[2] The outcomes for included plants are compared to the definitions of the same plants as given by the ENTSO-E Transparency Platform – Installed capacity per generation unit (ENTSO-E, 2015). Differences are observed in only three cases: for the Spanish plants Saucelle, Cedillo and Ribarroja. All three of them are defined as RoR plants using the method described, while ENTSO-E classifies them as STO plants. However, in the ENTSO-E Transparency Platform data, not a single Spanish hydro power plant is classified as RoR, which is remarkable. In this study, the method described here is used for all plants.

In some cases, the tail storage of a plant in the database also functions as a head storage for another plant in the database. This is called a cascade configuration. The connecting storage is referred to as head-tail storage in this study. The model generating the natural inflow data ignores the fact that the upstream power plant might withhold water as the catchment areas of the water facilities of the two plants might show overlap (see figure 6). Therefore, the natural inflow into the head-tail storage resulting from the natural inflow model might be overestimated. This is corrected for if the upper plant is defined as a STO plant (see definitions of plant types, section 2.4), because only in that case it is assumed to withhold a significant part of the total natural inflow of the head-tail storage.

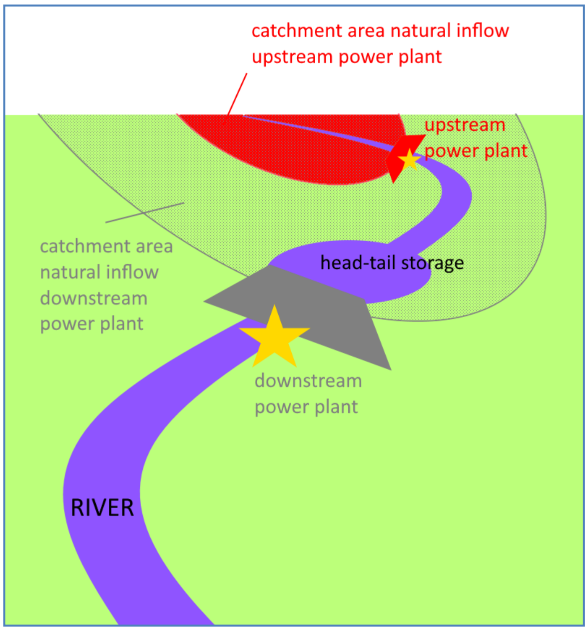

Figure 6 - Schematic representation of cascade configuration. The catchment areas of natural inflow available for the upstream and downstream hydro power plant show overlap. The head storage of the upstream power plant is not depicted.

The correction is carried out by subtracting the natural inflow of the higher water facility (of the upstream plant) from the natural inflow into the head-tail storage. The correction was carried out on raw natural inflow data in m^3/s. The corrected data were converted into flows in terms of energy (see 3.2), and then used as model input. Of course, during the model run, the downstream water facility is fed by the discharge of the upstream power plant as compensation.

3. RESULTS – DETAILED HYDRO PLANT DATA

3.1 DATA COLLECTION HYDRO PLANTS AND STORAGES

Not all existing plants could be included in this database due to a lack of time and because of limits to the complexity of the input given that additional inputs can considerably increase running times of the model. To show the capacity that is not included in the database, the capacity in the detailed input list of 68 power plants (including PHS) is given next to the total installed capacity per country (including PHS) in figure 7. For comparison, most recent figures for total installed capacity per country according to three different data sources are used: the IHA data from the 2016 Hydro power Status Report, the ENTSOE data for the year 2015 and most recent available data from the European Small Hydro Association (ESHA) (IHA, 2016; ESHA, 2015; ENTSO-E, 2015). For Switzerland, no ESHA data were available and data from the Swiss government were used instead (BFE, 2016).

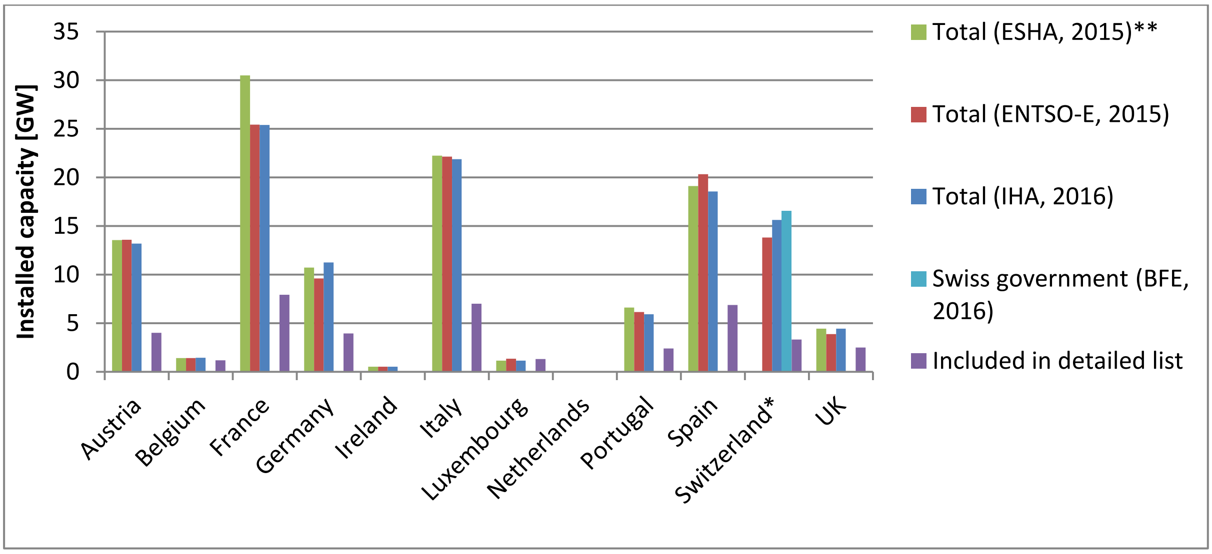

Figure 7 – Total hydro installed capacities (including PHS) per country according to several studies, compared to the installed capacity included in database. *For Switzerland, ENTSO-E data from 2014 were used (ENTSO-E, 2014). **From the ESHA, most recent available data were used for each country, the years differ among countries.

According to ESHA and BFE data, the total number of plants within the model geographical scope is 13638, covering a total installed capacity of 126.8 GW (ESHA, 2015; BFE, 2016). Of those 13638 plants, 1553 plants (11%) are large plants (with an installed capacity over 10 MW). Despite their relatively limited number compared to the total number of plants, the large plants cover 91% of total installed capacity (see Appendix II).

A list consisting of 105 plants and connected storages was composed, including plants in the EU-28 supplemented by Norway and Switzerland. Of these 105 plants, 68 plants with a total installed capacity of 40.4 GW lay within the model geographical scope (including Austria, Belgium, France, Germany, Ireland, Italy, Luxembourg, Netherlands, Portugal, Spain, Switzerland and the United Kingdom, see also section 1.3). The analysis of the results presented in the rest of this section is based on these 68 plants only, as they will be used in the second part of this study (the modelling).

With the 68 plants, only 0.5 % of the number of plants within the model geographical scope is included. However, they cover 32% of the total installed hydro capacity in the model geographical scope. This is caused by the fact that the database contains only the larger hydro plants. Of these 68 plants, 63 plants have an installed capacity higher than 250 MW and 5 plants have an installed capacity between 96 and 226 MW. These few plants with capacities smaller than 250 MW were included in the detailed plant database because they were connected to larger plants through complex configurations.

An analysis of the distribution of the capacities of the individual included power plants is shown in Figure 8.

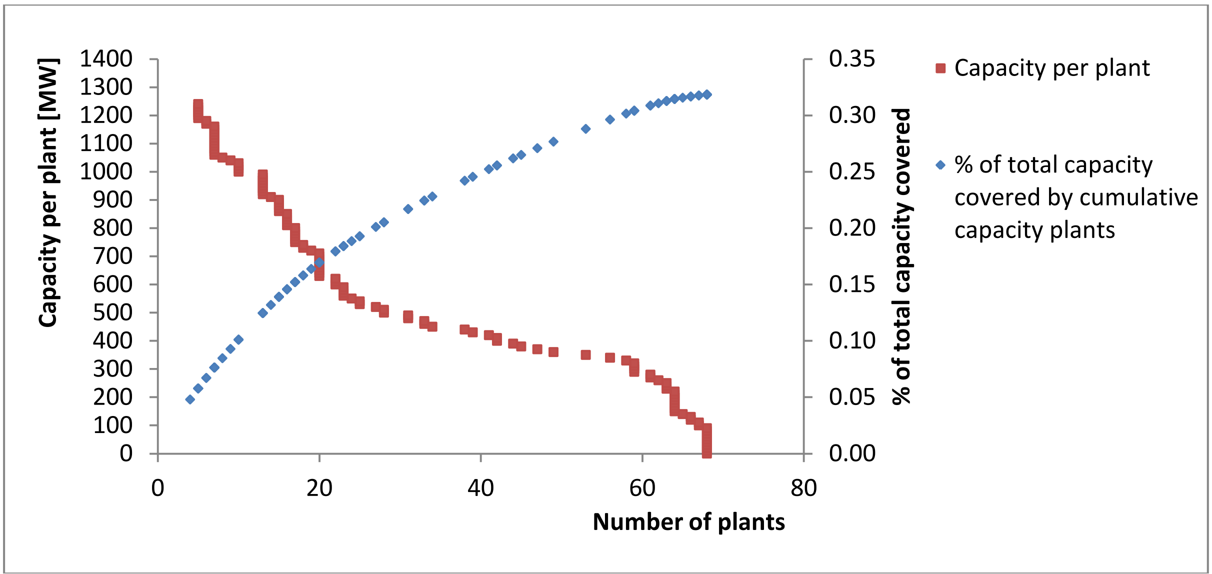

Figure 8 - Capacities of large hydro plants within the model geographical scope (including Austria, Belgium, France, Germany, Ireland, Italy, Luxembourg, Netherlands, Portugal, Spain, Switzerland and the United Kingdom), including pumped hydro generation capacity. The total installed hydro capacity within this area is 126.8 GW (ESHA, 2015; BFE, 2016).

The red curve in figure 8 shows that about 20 plants with a capacity over 600 MW have been included and only 6 with a capacity smaller than 250 MW. From the blue curve (percentage of total capacity) it can be concluded that some plants larger than the smallest ones in the list must be missing, since this curve will never reach 100% capacity coverage. This can be partly explained by the fact that some of the smaller plants have been included because of their connection to larger plants through complex configurations.

In figure 9, an overview of the installed capacity per plant category was given for each region. Next to it, the installed capacities of the plants included in the detailed plant database are depicted for each region. It shows that no small plants are included in the detailed plant database (as only the largest plants were included and modelled in detail). Also, from the different categories, PHS capacity is relatively best represented in the detailed scenarios. This is a result of the use of the article by Geth. et al (2015) as one of the starting points for the data collection. This article includes a fairly complete oversight of existing PHS plants. Hereby, besides the installed capacity of the plants, data availability has been one of the criteria for selecting the plants that were modelled in detail.

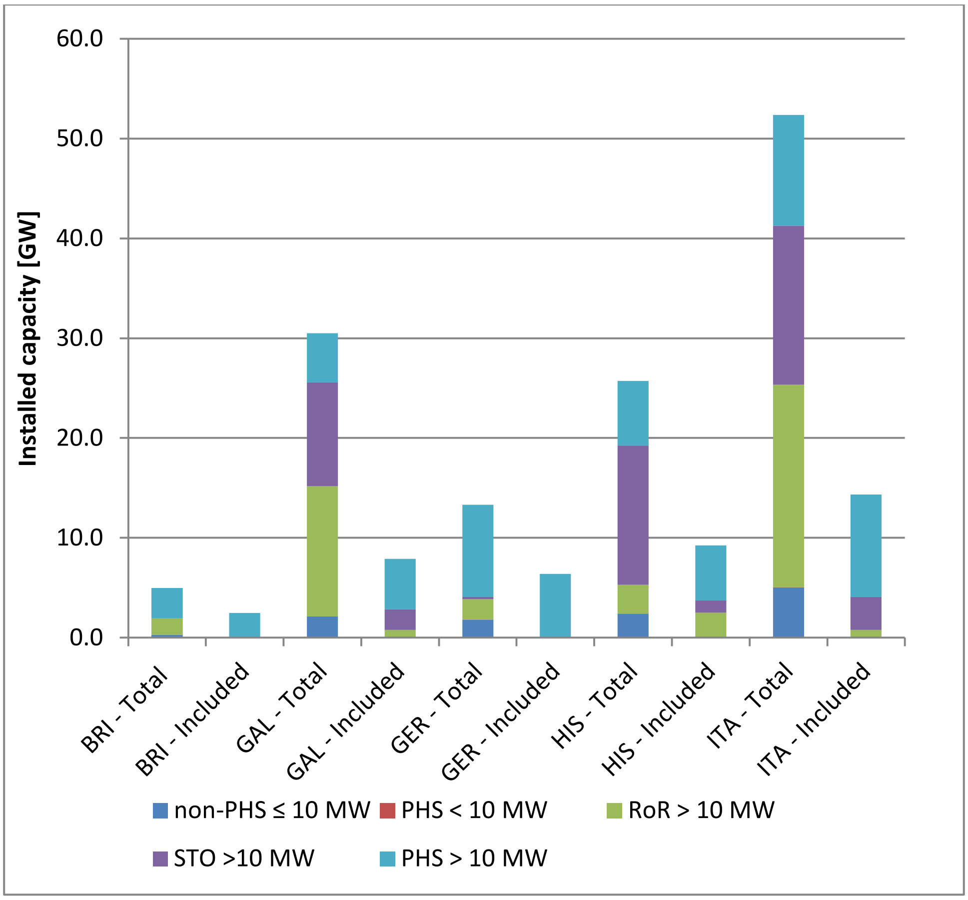

Figure 9 - Overview of total capacity vs. capacity included in the list of detailed hydro power plants, divided per plant category and per region.

In the original model, the total installed hydro capacity was assumed to be 9% of the total installed capacity and this capacity was allocated to the different regions based on an expert ranking by ECF (Brouwer, et al., 2016; ECF, 2010). It was divided in two categories: installed PHS capacity and installed non-PHS hydro capacity. In this study, the hydro capacity for each region was redefined based on installed capacity data per country using ESHA and BFE data (ESHA, 2015; BFE, 2016). The capacity thus derived deviates significantly from the capacity in the original model by Brouwer et al., as can be seen in figure 10.

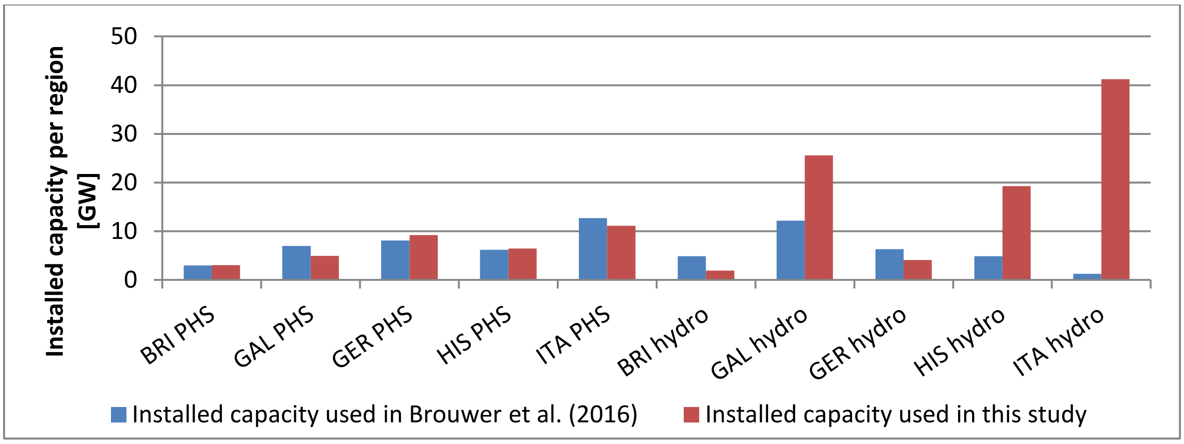

Figure 10 - Comparison of the installed PHS and non-PHS capacity per region as included in the model by Brouwer et al. (2016) and this study.

The total PHS capacity included in the model by Brouwer et al. (2016) is 37.0 GW (excluding Scandinavia, 80% bulk scenario), while in this study it is 34.8 GW. The difference for non-PHS hydro capacity is much larger: 29.5 GW maximum installed capacity in the Brouwer model, while it is 92.0 GW in this study. The largest differences are observed for hydro capacities in the regions GAL (France), HIS (Spain and Portugal) and ITA (Italy, Austria and Switzerland).

In Appendix V, two tables containing the most relevant data for the 68 detailed plants within the geographical model scope and the connected storages are given. A database containing the collected data of all 105 plants, including all data entries described in Appendix I, is only electronically available and not included in this document.

3.1.1 Storages connected to detailed plants

The head storages connected to the power plants included in the detailed database, have a total volume of 1.63 * 10^{10} m^3. Together, they represent a head storage volume ($E_{sto,head}$) of 8.9 TWh. The distribution of the storage volumes over the different types of plants is given in figure 11,

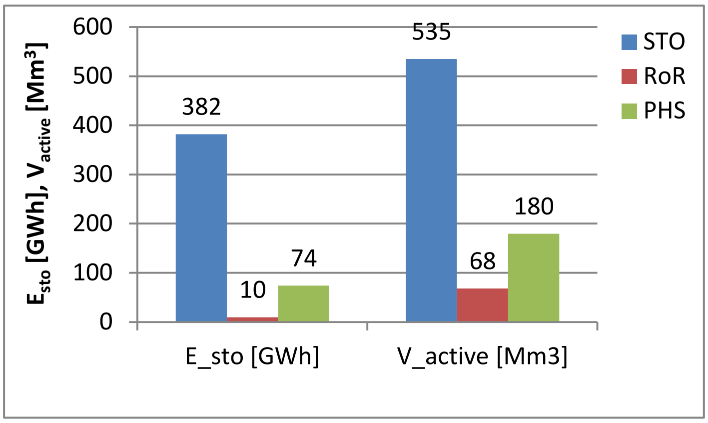

Figure 11 - Storage volumes of head storages connected to power plants in the detailed database, both in GWh and in Mm3, and averaged over the plants in each category. The number of included plants are 15, 10 and 43 for STO, RoR and PHS plants respectively.

expressed both in GWh and in Mm^3. As expected, detailed STO plants have the largest average storage capacity per plant (average of 382 GWh). They are followed by PHS plants (average of 74 GWh), and the storage capacity of RoR is lowest (average 10 GWh).

3.1.2 Complex configurations

In section 2.5, possible complex configurations are explained. Here, the storages involed in the different types of complex configurations are listed. The names of the storages involved in complex configurations are:

- **Head-tail storages** included are: Grimsel, Galgenbichl, Laengental, Provvidenza, Val Grosina.
- **Supplementary storages** included are: Raeterichsboden, Grimsel, Pareloup, Longefan.
- **Shared head storages** included are: Grand Dixence Reservoir, Chevril.
- **Shared tail storage** included is: Lago della Piastra.

3.2 Natural inflow

3.2.1 Natural inflow in volume per second

In figure 12, the natural inflow data in m^3/s (averaged over all storages[3] which are included in the database containing the detailed plants) are depicted for the different natural inflow scenarios described in section 2.3.1. According to these data, natural inflow is generally higher during autumn and winter than during spring and summer months. The differences between natural inflow scenarios are small in the summer months. Further, the monthly average natural inflow in the maximum natural inflow scenario is incidentally lower than in the average scenario (September, November). The possibility of this outcome is a result of the method used: the year with respectively the lowest and highest total natural inflow was selected to get the monthly minimum and maximum natural inflow scenario data from. Therefore it is possible that the min and max scenarios do not show the lowest or the highest natural inflow respectively in each of the twelve separate months.

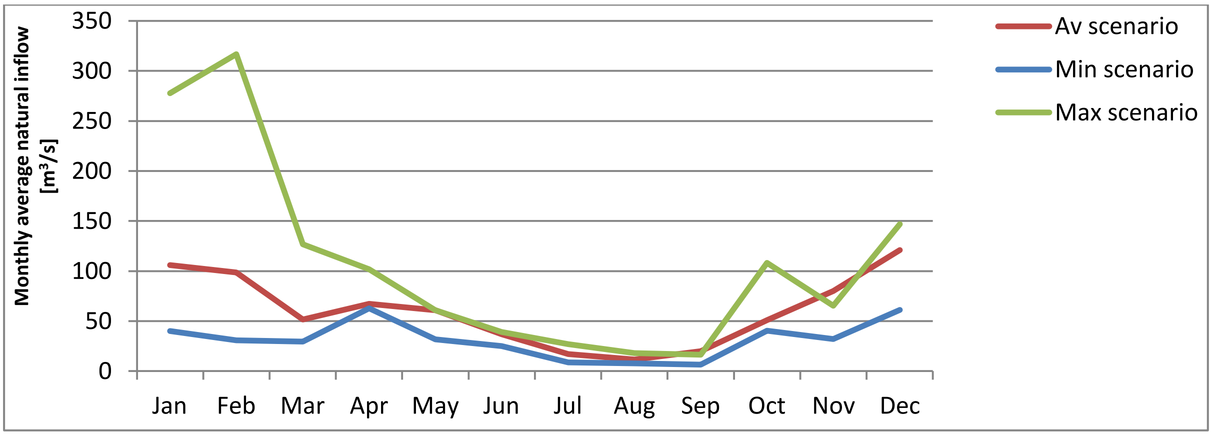

Figure 12 - Average monthly natural inflow, average over all included storages for different scenarios, in m^3/s.

In figure 13, the monthly average inflow data of the head storages are given as flow duration curves, sorted by the type of power plant to which the storages are connected. For the different types of hydro power plants, annual average data are given in table 1. The 30 year average natural inflow (in m^3/s) in the average scenario is highest for head storages of RoR plants (294.5 m^3/s), followed by STO plants (64.3 m^3/s). The overall natural inflow is lowest for PHS plant head storages (21.6 m^3/s). The PHS category consists of both PHS plants with very low natural inflow (practically closed loop) and PHS plants which are obviously of the 'mixed' type, that is, of which a significant part of the electricity production is generated from the natural inflow into the head storage, and not from water that was pumped upwards before.[4] The inclusion of these 'mixed' PHS plants causes an increase in 30-year average inflow numbers, averaged over all PHS plants. Absolute differences

[3] Note that in this study, the term 'storage' does not necessarily refer to a large reservoir of a storage hydro plant, as explained in the beginning of chapter 2. Head storages are connected to all detailed RoR, STO and PHS plants.

[4] As mentioned in section 2.3, natural inflow is calculated by the model for all PHS plants, as no distinction was made between 'closed loop' and 'mixed' PHS plants in the database. Therefore, PHS plants with both very low as well as with significant natural inflow numbers were included in natural inflow calculations.

between 30-year average inflow numbers calculated for the different natural inflow scenarios are highest for RoR plants, relative differences are highest for PHS plants.

Table 1 – Annual average natural inflow numbers per plant type, calculated for the three natural inflow scenarios. For the average natural inflow scenario, the data represent the 30-year averages over the available data. For the min and max natural inflow scenarios, the data represent the annual average natural inflow after selecting the data used in the min and max natural inflow scenarios (see section 2.3.1).

Annual average inflow [m3/s]	Min natural inflow scenario	Average natural inflow scenario (30-year average)	Max natural inflow scenario
STO	31.0	64.3	113.2
RoR	164.4	294.5	516.1
PHS	10.6	21.6	43.6
average all	*31.4*	*60.1*	*108.7*
% difference with respect to average natural inflow scenario			
STO	-52%	-	+76%
RoR	-44%	-	+75%
PHS	-51%	-	+102%
average all	*-48%*	-	*+81%*

To give some insight in the distribution of natural inflow over the different regions, the yearly average natural inflow per region and power plant type is given in figure 14. Only head storages are included in the calculation of given averages. In the region HIS (Spain and Portugal) natural inflow in the head storages is highest on average. Inflow in head storages connected to PHS plants in most regions is very low (< 1 m^3/s on average), indicating that modelling the included plants as closed-loop systems might be a justified simplification (in this study natural inflow in PHS storages is included). In HIS, inflow in included PHS plants is relatively large (128 m^3/s on average, based on the average inflow scenario). This is a result of the fact that the 3 PHS head storages with largest average natural inflow of included PHS storages (Muela II (855 m^3/s), Alqueva (478 m^3/s), and Alto Lindoso (56 m^3/s), all based on the average scenario) are all situated in this region.

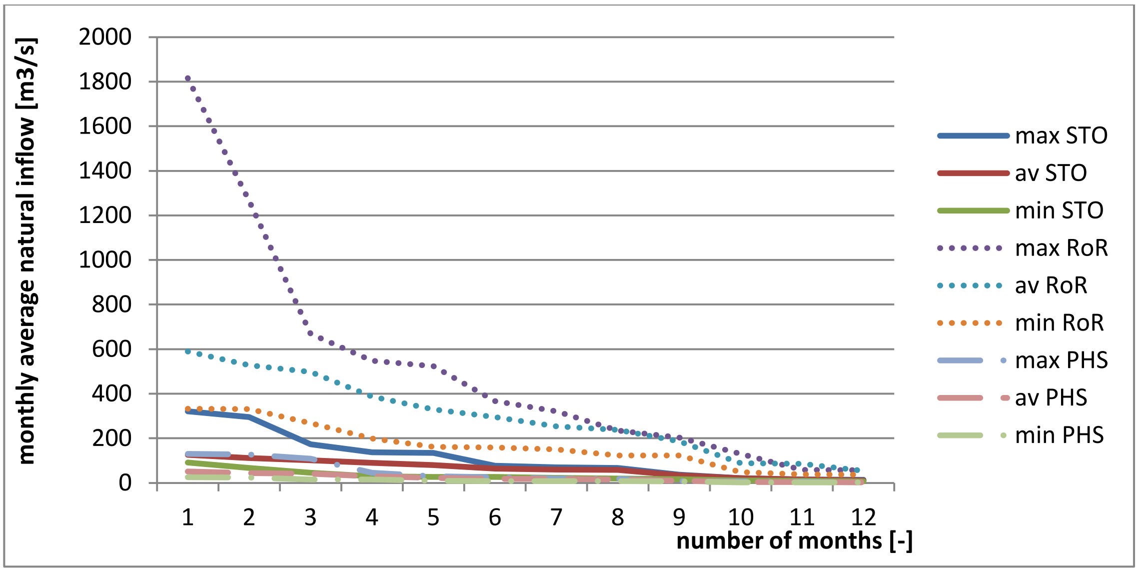

Figure 13 – Flow duration curve of monthly natural inflow, averaged over the head storages per power plant type.

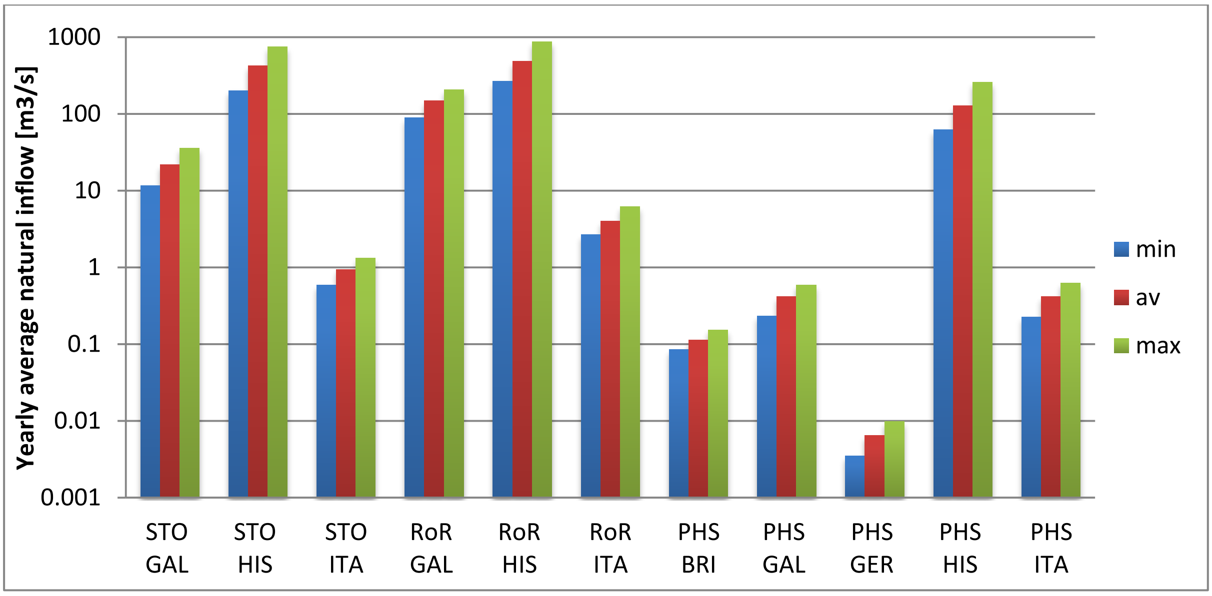

Figure 14 - Yearly average natural inflow for three natural inflow scenarios, per region and power plant type on a logarithmic scale. Only head storages are included.

3.2.2 Natural inflow in terms of energy

The natural inflow after conversion to inflow in terms of energy is given in figure 15. The pattern is similar to the pattern presented in figure 12, but small differences are observed, for example in August. This is logical, as for each separate storage, the conversion from natural inflow in terms of volume per second to natural inflow in terms of energy is a linear transformation, for which the scalar used is the ratio E_{sto} / $V_{sto,active}$ (see section 2.3.2). This ratio differs among storages

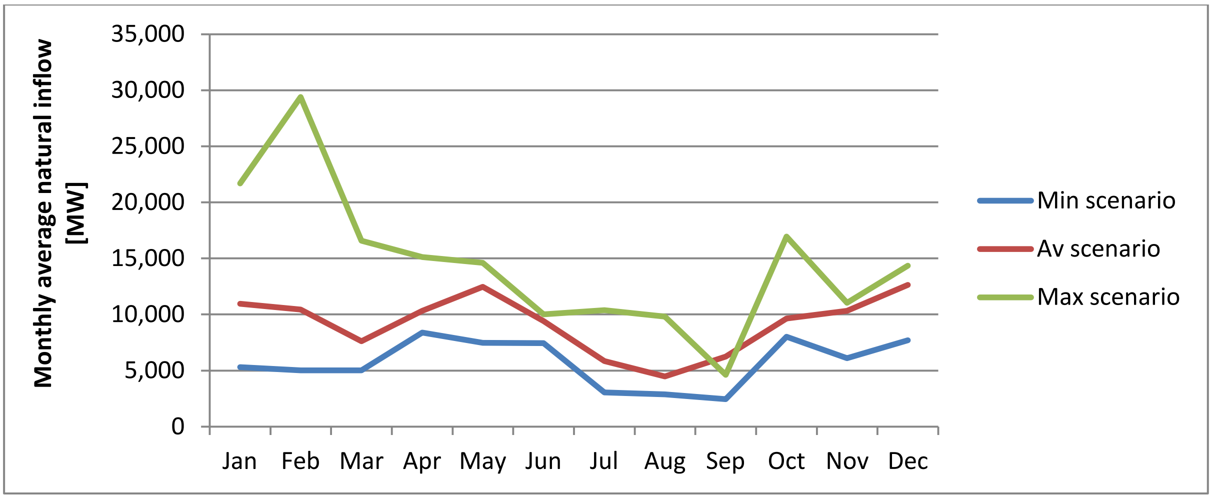

Figure 15 – Monthly average natural inflow, averaged over all included storages, for different natural inflow scenarios. Converted to natural inflow in terms of energy, in MW.

as it depends on specific site characteristics such as average hydraulic head. Combined with the fact that changes in inflow in m^3/s between scenarios are not equally distributed over all storages, this caused the differences between the graphs in figures 12 and 15.

In order to be able to relate annual total generation to annual natural inflow, total annual natural inflow numbers in terms of energy are presented in table 2 for the different plant types. Recall that the numbers of detailed STO, RoR and PHS plants included in the database are 15, 10 and 43 respectively (see Appendix II).

Total annual inflow in head storages of RoR plants in the average natural inflow scenario is 14.68 TWh, at an average of 1.47 TWh per plant. Total annual inflow in head storages of STO plants in the average natural inflow scenario is 7.41 TWh, at an average of 0.49 TWh per plant. For PHS plants, total and average annual inflow numbers are 7.73 and 0.18 TWh respectively.

It is observed that the relative differences in total inflow between the different natural inflow scenarios are similar for natural inflow in terms of energy compared to natural inflow in terms of volume per second. However, differences between the different detailed plant types in natural inflow expressed in terms of energy are smaller than when expressed in volume per second. For example, in terms of energy, the inflow in detailed RoR plants is only 8.2 times the inflow in detailed PHS plants (averaged over plants of this type). When inflow is expressed in volume per second, this difference is a factor 13.6 (see table 1). This is a logical result, caused by the different characteristics of the different types of power plants, like differences in average hydraulic head, influencing the ratio $E_{sto} / V_{sto,active}$.

Table 2 - Total annual energy inflow in head storages of detailed plants, per plant type, calculated for the three natural inflow scenarios. The numbers of detailed STO, RoR and PHS plants included in the database are 15, 10 and 43 respectively.

ANNUAL TOTAL INFLOW [TWh]	***Min natural inflow scenario***		***Average natural inflow scenario***		***Max natural inflow scenario***	
	Total [TWh]	Average over plants [TWh]	Total [TWh]	Average over plants [TWh]	Total [TWh]	Average over plants [TWh]
STO	3.48	0.23	7.41	0.49	13.28	0.89
RoR	8.38	0.84	14.68	1.47	25.79	2.58
PHS	4.26	0.10	7.73	0.18	14.58	0.34
total all	50.3	0.74	80.6	1.19	127.4	1.87
% difference with respect to average inflow scenario						
STO	-53%		0%		+79%	
RoR	-43%		0%		+76%	
PHS	-45%		0%		+89%	
total all	-46%		0%		+80%	

4. METHOD - MODELLING

4.1 MODEL SET UP

4.1.1 POWER SYSTEM MODEL USED AS BASIS FOR THIS STUDY

The model used in this study is based on a model built by A.S. Brouwer and others and is described in the article by Brouwer et al. (2016). This model was implemented in PLEXOS[5] and it will be shortly discussed here.

In the article by Brouwer et al. (2016), least-cost options for intermittent renewables in low-carbon power systems are investigated. In the study, three exogenously defined non-fossil generation capacity scenarios are defined (based on 40%, 60% and 80% RES of annual electricity generation). The model then optimizes the remaining fossil capacity by minimizing total system costs subject to current power system reliability expectations to make up the full generation mix (Brouwer, et al., 2016). The effect of various complementary options (including demand response (DR), interconnection capacity and energy storage on total system costs) was investigated. The energy storage option in the base scenarios consists of 39 GW of PHS capacity.

First, the investment decisions for the complementary fossil capacity is optimized using the long term (LT) plan. During this simulation phase, new fossil generators can be built and investments in other complementary options are made. Secondly, a medium term (MT) schedule is used to translate annual constraints, such as maximum annual capacity factors of hydro plants and planned outages, to weekly constraints (Brouwer, et al., 2016). The MT schedule simulates 25 periods per week (1300 per year). Finally, the short term (ST) schedule optimises unit commitment and economic dispatch decisions on an hourly basis. The target for the ST schedule is minimising the total generation cost while the following constraints are met:

- electricity supply equals electricity demand
- flexibility constraints of the generators
- limited transmission capacity of interconnectors
- balancing reserve requirements

More detailed information on the original model can be found in the article by Brouwer et al. (2016).

4.1.2 HYDRO CAPACITY: CATEGORIES AND SCENARIOS

The elements from the original model described in the previous section have been left unchanged for this study (model input is described in more detail in section 4.2 and Appendix III). However, hydro capacity in the original model has been replaced by total hydro capacity per region

[5] PLEXOS power system simulation software was developed by Energy Exemplar. Link to main website: www.energyexemplar.com.

as based on ESHA data (ESHA, 2015). The hydro plants providing for this installed capacity have been divided into 5 categories:

- **small non-PHS**: plants (non-PHS) with installed capacity ≤ 10 MW
- **small PHS**: plants (pure and mixed PHS) with installed capacity ≤ 10 MW
- **large STO**: storage plants with an installed capacity > 10 MW
- **large RoR**: run-of-river/pondage plants, with installed capacity > 10 MW
- **large PHS**: pumped hydro storage plants (pure and mixed), with installed capacity > 10 MW

The total capacity and number of plants included in each category are based on data provided by the ESHA and the ENTSO-E (ENTSO-E, 2015; ESHA, 2015). The method for this is described in section 4.2.2. Two different approaches are used: the lumped and the detailed approach.

In the lumped approach, the total capacity and number of plants for each of the five categories is implemented in the model. Detailed plants from the database are not included. There is no connection to natural inflow for any of the five categories. Instead, PHS plants are modelled using average storage sizes (based on Geth et al., 2015) without natural inflow (closed loop systems). For PHS plants, the maximum duration of generation and pumping is limited by the maximum energy content of the storage. Lumped RoR and STO plants are modelled using maximum annual capacity factors (see Appendix III). These plants are referred to as 'lumped plants' in this study.

In the detailed approach, the plants from the database are included. These plants are referred to as 'detailed plants' in this study. The detailed plants are connected to the storages also included in the database, which are fed by natural inflow defined by the natural inflow scenarios. The resting capacity and number of plants to match the total numbers and capacities, is calculated by subtracting the number and installed capacity of detailed plants from the total category size. This is done for each of the five categories. The method is explained in further detail in section 4.2.2). These resting plants are referred to as 'rest plants' in this study. The rest plants are modelled in the same way as the lumped plants (see previous paragraph): no rest plants are connected to natural inflow data. Average storage sizes are used for the closed loop PHS plants and maximum annual capacity factors are used for limiting the generation by RoR and STO plants.

An overview of each of the two approaches is given in figure 16.

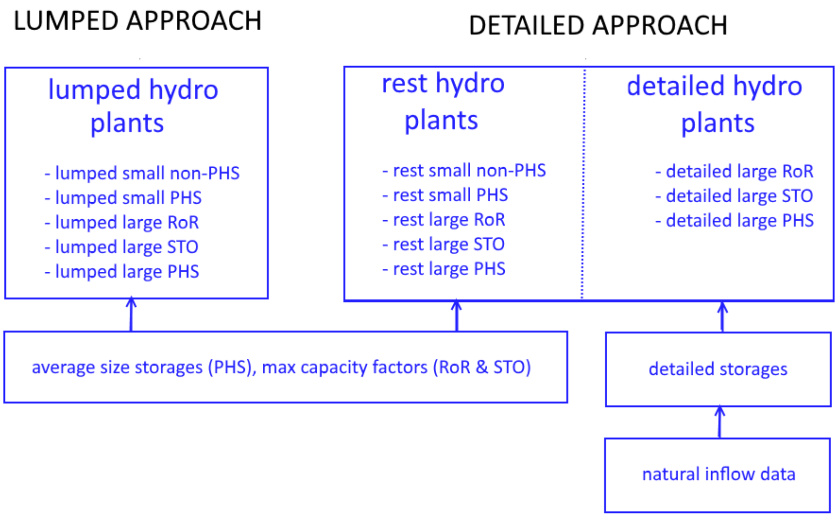

Figure 16 – Schematic overview of the two approaches used. Hydro plant categories are given, as well as main input data.

With the three natural inflow scenarios and the two different approaches, four different scenarios were created:

- **Detailed – min** scenario. Hydro capacity is covered by a combination of detailed and rest plants. The detailed plant storages are connected to the minimum natural inflow scenario.
- **Detailed – av** scenario. Hydro capacity is covered by a combination of detailed and rest plants. The detailed plant storages are connected to the average natural inflow scenario.
- **Detailed – max** scenario**.** Hydro capacity is covered by a combination of detailed and rest plants. The detailed plant storages are connected to the maximum natural inflow scenario.
- **Lumped** scenario. Hydro capacity is covered by lumped plants.

4.1.3 Long term plan runs

For the long term (LT) plan, the amount and composition of the newly installed capacity is analysed. This is done for all of the four scenarios introduced in section 4.1.2.

In the base case, the following plants[6] are allowed to be newly built during the LT plan:

- Biothermal plants
- Natural gas combined cycle plants with CCS (NGCC-CCS)
- Natural gas combined cycle plants without CCS (NGCC)
- Pulverized coal plants with CCS (PC-CCS)
- Gas Turbines (open cycle) (GT)

[6] Techno-economic parameters of these plant types are given in Appendix III.

A sensitivity analysis on the influence of the yearly CO_2 emission cap on newly built capacity portfolio is carried out. CO_2 emission caps were varied between 20 and 50 Mtonne/year.

An additional run is carried out in which hydro plants can be newly installed as well. In this run, the same type of hydro plant categories can be built as the hydro plant categories defined exogenously. In addition, existing large PHS plants can be equipped with a capacity increase. Parameters involved can be found in Appendix III.

The LT plan is carried out using rounded linear relaxation optimization[7]. The LT plan simulates 50 periods per month (600 per year).

4.1.4 Short term schedule runs

For the short term (ST) schedule runs, the expansion portfolio from the LT plan is used without new hydro capacity, with the 35 Mtonne/year CO_2 emission cap. It was chosen to exclude new hydro capacity in order to enable optimal comparison between the scenarios.

The ST schedule is simulated for the whole year using rounded linear relaxation. This was done to keep running times within bounds. From these runs, the total annual generation per plant type and the annual capacity factors of hydro plants will be investigated.

In addition, two weeks are selected to run the ST schedule using full mixed integer programming (MIP)[8]. As the focus of the study is on hydro generation and the flexibility of hydro plants, the two weeks are selected in which the generation of hydro plants and peak generation plants (NGCC and GT) together are highest and lowest respectively (based on the detailed scenario with average natural inflow). The differences between the different natural inflow scenarios as well as the differences between detailed scenarios with average natural inflow and the lumped scenario were investigated.

4.1.5 Indicators for evaluating the scenarios

For comparison between the different scenarios, mainly the following result indicators were used:

From the LT plan results:

- Investment decisions

From the ST schedule results:

- Total annual electricity generation
- Annual electricity generation of hydro plants (total and per category)
- Annual CO_2 emissions
- Annual capacity factors of different hydro plant categories

[7] In rounded Linear Relaxation (rLR), total system costs are minimised by finding a unit commitment optimality solution using linear relaxation. The linear relaxation unit commitment optimality solution is then rounded to an integer unit commitment while meeting constraints such as minimum down time and minimum stable level. The rLR heuristic aims to produce a solution of sufficent quality, without the need to run full mixed integer programming (MIP): running times in rLR are shorter than in MIP (Energy Exemplar, 2016).

[8] In full mixed integer programming (MIP), total system costs are minimised by finding the best combination of integer values for on/off decisions (unit commitment) in combination with the best economic dispatch solution, while meeting constraints such as minimum up time and minimum stable level. Running times are longer than for rLR.

- Total electricity generation profiles in two selected weeks (the weeks with minimum and maximum generation by hydro and peak (GT + NGCC) plants)
- Hydro electricity generation profiles and pump load in two selected weeks (the weeks with minimum and maximum generation by hydro and peak (GT + NGCC) plants)

4.2 Model input

4.2.1 Exogenously defined installed capacity

The model used in this study is based on the 80% RES generation scenario (59% iRES capacity) from the original model. In figure 17, an overview of installed capacities in the exogenously defined generation mix of all generators is given. The total exogenously defined capacity is 955 GW. In the lumped scenario, the exogenously defined hydro capacity exists entirely of lumped power plants. In the detailed scenario, the exogenously defined hydro capacity consists partly of detailed hydro power plants and partly of rest plants. The categories of lumped and rest plants are described further in the following section, 4.2.2.

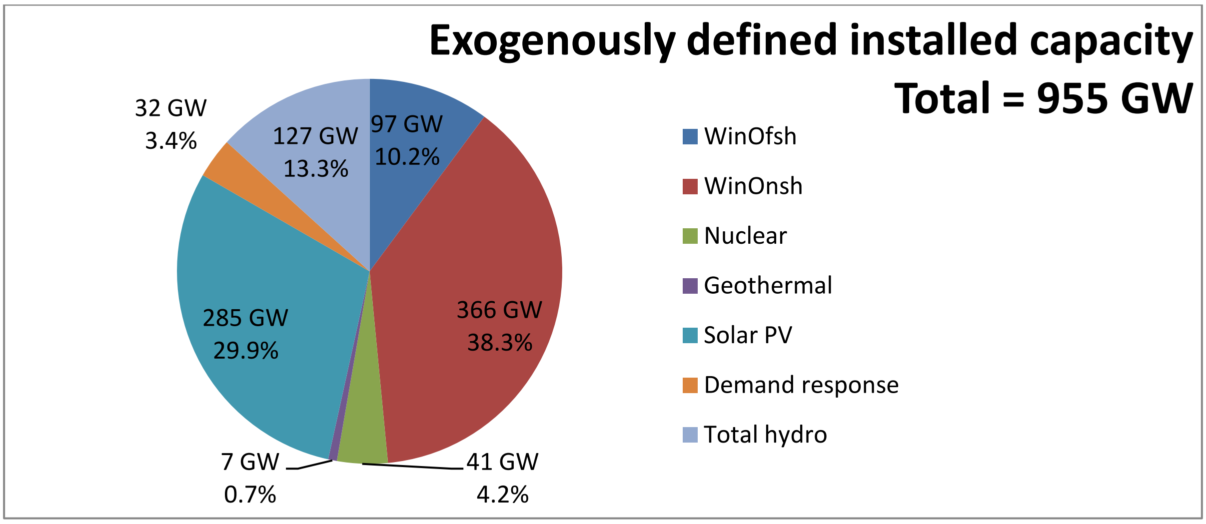

Figure 17 - Exogenously defined capacity divided per power plant type.

4.2.2 Rest and lumped plants

Lumped plants – number and capacity

As explained in section 4.1, detailed plants from the database are not included in the lumped scenarios. ESHA (2015) data are used directly as basis for the calculation of the installed capacity in each category per region, because this source distinguishes between small plants (≤ 10 MW) and larger plants (> 10 MW) and, within the larger plants, between pumped hydro plants and plants working with natural inflow (ESHA, 2015). Moreover, ESHA provides for the installed capacity as well as the number of plants in each of these groups. The installed capacity given for France by ESHA (2015) is rather high in comparison to ENTSO-E and IHA data. Still, this value is used for reasons of consistency and because it is not certain whether the other sources are more reliable.

To make the distinction between storage and run-of-river plants within the category of large plants (> 10 MW) provided by the ESHA (2015) data, the ratio between storage and run-of-river plants was calculated based on data from the transparency platform (ENTSO-E, 2015) for each separate region. This resulted in the categories ‘large RoR’ and ‘large STO’. For the installed capacity and number of plants in the ‘small PHS’ category, data from Geth et al. were used (F.Geth, et al., 2015). To determine the installed capacity and number of plants in the ‘small non-PHS’ category, the figures from the ‘small PHS’ category were subtracted from the figures for total small plants (non-PHS and PHS) provided by the ESHA database (ESHA, 2015).

Rest plants – number and capacity

In the detailed scenarios, rest plants were used to cover the capacity not included in the database. This remaining capacity is divided into the same five plant categories as in the lumped scenario, as explained in section 4.1. To calculate the number of rest plants in each category and region, the number of detailed plants is subtracted from the number of lumped plants in that category and region. This is done for installed capacity as well. This way, a number of rest plants and a total capacity of the rest plants are derived for all categories and regions. An average installed capacity per plant is derived by dividing the remaining capacity by the remaining number in each category and region.

The resulting figures per region and category are given in Appendix II, for lumped plants, plants included in the detailed plant database and rest plants. Economic parameters for all hydro and other plants are given in Appendix III.

Maximum energy content storages Lumped and Rest PHS plants

The average maximum energy content of storages of the rest and lumped PHS systems were based on the data from Geth et al. (2015). As a maximum energy content for the large rest and lumped plants, the average reported head storage size over all plants with generation capacity > 10 MW reported in the article was used: 12.8 GWh. As maximum energy content of small PHS plants, the same method was applied, this time using all reported plants in Geth et al. with a generation capacity ≤ 10 MW. The maximum energy content of storages of small lumped or rest PHS plants is 0.022 GWh. For the lumped and rest plants, head and tail storages are assumed to have equal volumes, following Brouwer et al. (2016).

4.2.3 Modelling storages

The spillway capacity of the storages is assumed to be infinite. Therefore, the usage of the storages will never be limited by a surplus of water. This is done because of limited data availability on spillway capacity. Further, in the ST runs, the initial energy content and end-of-the-year target energy content of the storages are defined as half the maximum energy content E_{sto}.

4.2.4 Maximum emission capacity

A maximum emission constraint was included in the LT scheme, just as in the model by Brouwer et al. (2016). The cap of the emission from the electricity generation sector in the geographical scope of the model (Western Europe) was set to 35 Mtonne CO_2-eq. per year, based on 96% reduction compared to 1990 reduction levels for the region under the scope. This number was based on data provided by UNFCC (UNFCC, 2014). The CO_2 net emissions in the Public Electricity and Heat Production sector database provided by UNFCC were used. The values for the year 1990 were added for the 12 countries within the model geographical sope, and 4% was taken of them to derive the 35 Mtonne CO_2-eq. emission cap. The cost of CO_2 produced above the maximum allowed amounts, is assumed constant at 70 €/tonne CO_2.

4.2.5 Reserves

The minimum balancing reserve requirements as implemented in the original model by Brouwer et al. (2016), have been maintained in this study. Three types of balancing reserves are accounted for:

- Spinning up reserves: available within 5 min, with a 1-h ahead forecast.
- Spinning down reserves: available within 5 min, with a 1-h ahead forecast.
- Standing up reserves: available within 60 min with a 12-h (wind) or 24-h ahead (solar PV) forecast.

The minimum reserve requirements are needed to decrease the risk for energy shortages or dump energy caused by errors in the prediction of generation by iRES sources (Brouwer, et al., 2016). As reserve requirements were calculated per scenario and per region, Scandinavia's share in total reserve requirements could be easily excluded for this study.

5. Results - Modelling

5.1 Long term plan results

From the LT plan results, the newly installed capacity was analysed for the three detailed scenarios and the lumped scenario. In all of the three detailed scenarios (average, minimum and maximum inflow), 211.4 GW gas turbine (GT) capacity is newly built, as well as 15.0 GW of NGCC capacity. Hereby, the total installed generation capacity (including the exogenously defined capacity) adds up to 1181 GW. The newly installed capacity per region is given in figure 18 for the three detailed scenarios.

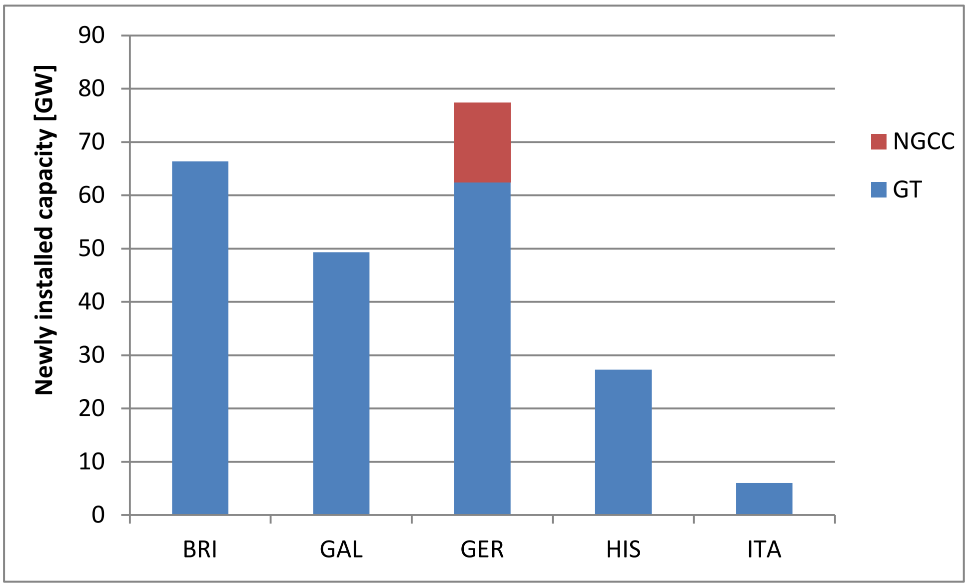

Figure 18 - Newly installed capacity during the LT plan, per plant type per region for the detailed scenarios (the results are the same for these 3 scenarios).

The LT plan results of the lumped scenario are very similar, the only differences are that 100 MW more GT is installed in GAL and 300 MW more GT is installed in GER compared to the lumped scenario. The small differences are possibly caused by rounding errors or by the difference in annual maximum capacity factor constraints between hydro plants (see further on in the ST schedule results).

In conclusion, no difference is observed between the natural inflow scenarios, and differences between the detailed and the lumped scenario are very small (about 0.5% and 0.02% difference in installed capacity in GER and GAL respectively).

5.1.1 Emission cap sensitivity analysis

The sensitivity of the newly built generation portfolio to varying emission caps was tested. In the base case, the maximum allowed emission capacity in the LT plan in PLEXOS was 35 Mtonne/year, based on 96% reduction compared to 1990 levels for the included countries. The maximum allowed yearly emissions were varied between 25 Mtonne/year and 50 Mtonne/year, representing 98% and 57% reduction compared to 1990 levels respectively.

The newly built capacity under the varying emission constraints turned out to be very similar to the base case for the detailed scenarios. In the lumped scenario however, some exchange is observed between GT (increasing from 8 to 22 GW newly installed) and NGCC turbines (decreasing from 218 to 205 GW newly installed) as the emission cap is increased. However, on a total of 1181 GW installed capacity, these changes are relatively small (about 1% of installed capacity was adjusted). The results of the emission cap sensitivity are given in Appendix VI.

5.1.2 Newly installed hydro plants

A second LT plan run was carried out in which hydro plants were allowed to be built in addition to the biothermal and fossil fuel fired power plants. Parameters for new hydro capacity are included in Appendix III. The newly installed capacity is depicted in figure 19. Only plant types of which new capacity has been built in at least one of the scenarios are included in figure 19 (so newly installed capacity of other plant types is zero in all scenarios). The total newly installed capacity is 235.4 GW in the detailed scenarios and 236.1 GW in the lumped scenario, which is slightly less than in the case in which no hydro was built (236.4 and 236.8 GW for detailed and lumped scenarios respectively). Small PHS plants have the highest share in the newly installed capacity. Less NGCC generator capacity is built (only 10 GW in comparison to 15 GW in the base case, and less GT (66 GW in comparison to 211 GW in the base case). In addition to building new plants, the LT plan was given the possibility to upgrade existing PHS plants (exogenously defined) by increasing the capacity. This is less expensive than building new PHS plants (see Appendix III), but the maximum number of units built is limited by the number of exogenously defined large PHS plants. In the results, some capacity increase by upgrading existing PHS plants occurs indeed. However, this capacity increase through upgrading is less than 3% of newly installed small PHS capacity. The newly installed small PHS capacity increases slightly with increasing natural inflow (0.6% increase in installed small PHS capacity in the high natural inflow scenario compared to the low natural inflow scenario).

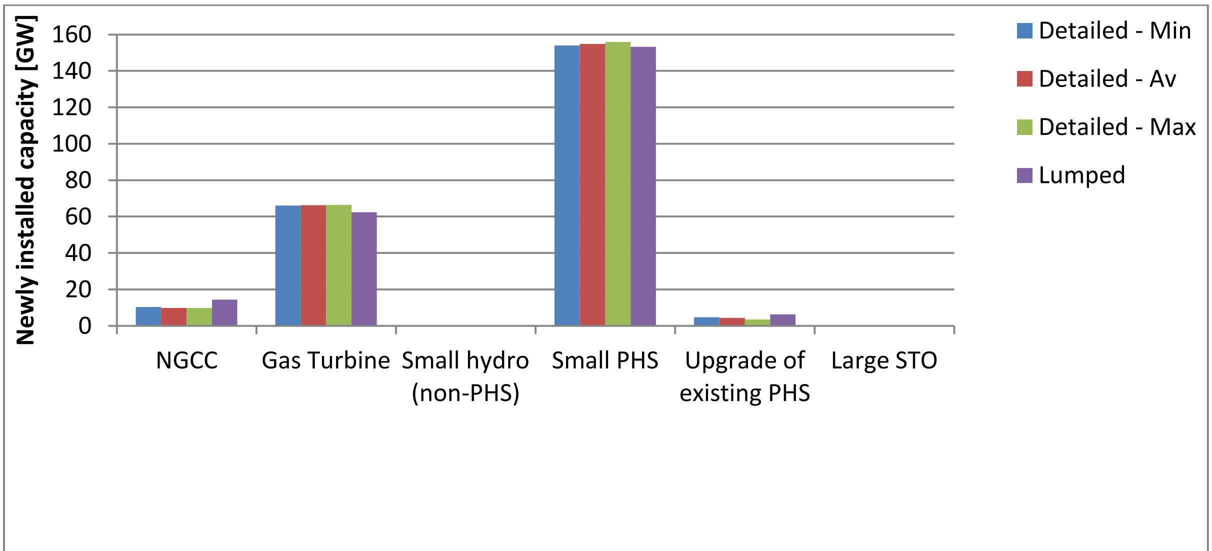

Figure 19 - Newly installed capacity, in case the option to build new hydro capacity is enabled. Results are depicted for the detailed scenarios (minimum, average and maximum natural inflow) and the lumped scenario.

5.2 SHORT TERM SCHEDULE RESULTS

In this section, the results of the short term schedule are presented. First, the results over the yearly runs are discussed (section 5.2.1). Then, the results of the week with maximum and minimum generation by hydro peak plants together are given, being the weeks beginning at 18/02/2050 and at 03/06/2050 respectively.

5.2.1 ST SCHEDULE RUNS OVER YEAR 2050 (RLR)

ANNUAL ELECTRICITY GENERATION PER PLANT TYPE

In figure 20, the model results for the total generation in the year 2050 are depicted. The total generation is 2570 TWh for the detailed scenarios (all natural inflow scenarios) and 2546 TWh in the lumped scenario. These figures include the generation (electricity output) from pumped hydro plants. The total pump load (electricity consumption by pumps) is 112 TWh in the detailed scenarios while it is only 88 TWh in the lumped scenario, causing a difference in total load and therefore explaining the difference of 24 TWh total generation between the detailed and lumped scenarios.

Concerning the detailed scenarios, it is observed that the detailed hydro plants produce more energy as the natural inflow increases (86 TWh in the minimum natural inflow scenario vs. 103 TWh in the maximum natural inflow scenario, an increase of 20%). Note that this difference is smaller than the difference in total annual natural inflow between the minimum and the maximum scenario in the head storages, which is 77.1 TWh. Possibly, a certain degree of saturation is reached with inflow higher than in the average natural inflow scenario. This would also explain the relatively small difference in hydro production in the max natural inflow scenario compared to the average natural inflow scenario (5% increase, compared to a 14% increase in hydro generation in the average natural inflow scenario compared to the minimum natural inflow scenario). Production by the rest plants remains practically the same (increasing from 500 to 503 TWh with increasing natural inflow). This is logical as the rest plants were not connected to natural inflow but instead modelled using maximum annual average capacity factors. The low electricity generation by hydro plants in the minimum average inflow scenario is compensated by nuclear (3 TWh increase), GT (13 TWh increase) and NGCC plants (3 TWh increase). The small differences in solar and wind generation between the scenarios are considered to be random effects of the rounded linear relaxation modelling process, as no curtailment of solar and wind generation occurs.

The share of total hydro generation (including both detailed and rest/lumped plants) in the lumped scenario is lower than in all the detailed scenarios (20% of total generation in the lumped scenario compared to 23 to 24% of total generation in the detailed scenarios). This decrease is compensated for by nuclear, GT and NGCC plants (respectively 47 TWh, 38 TWh and 24 TWh increase compared to the detailed average inflow scenario).

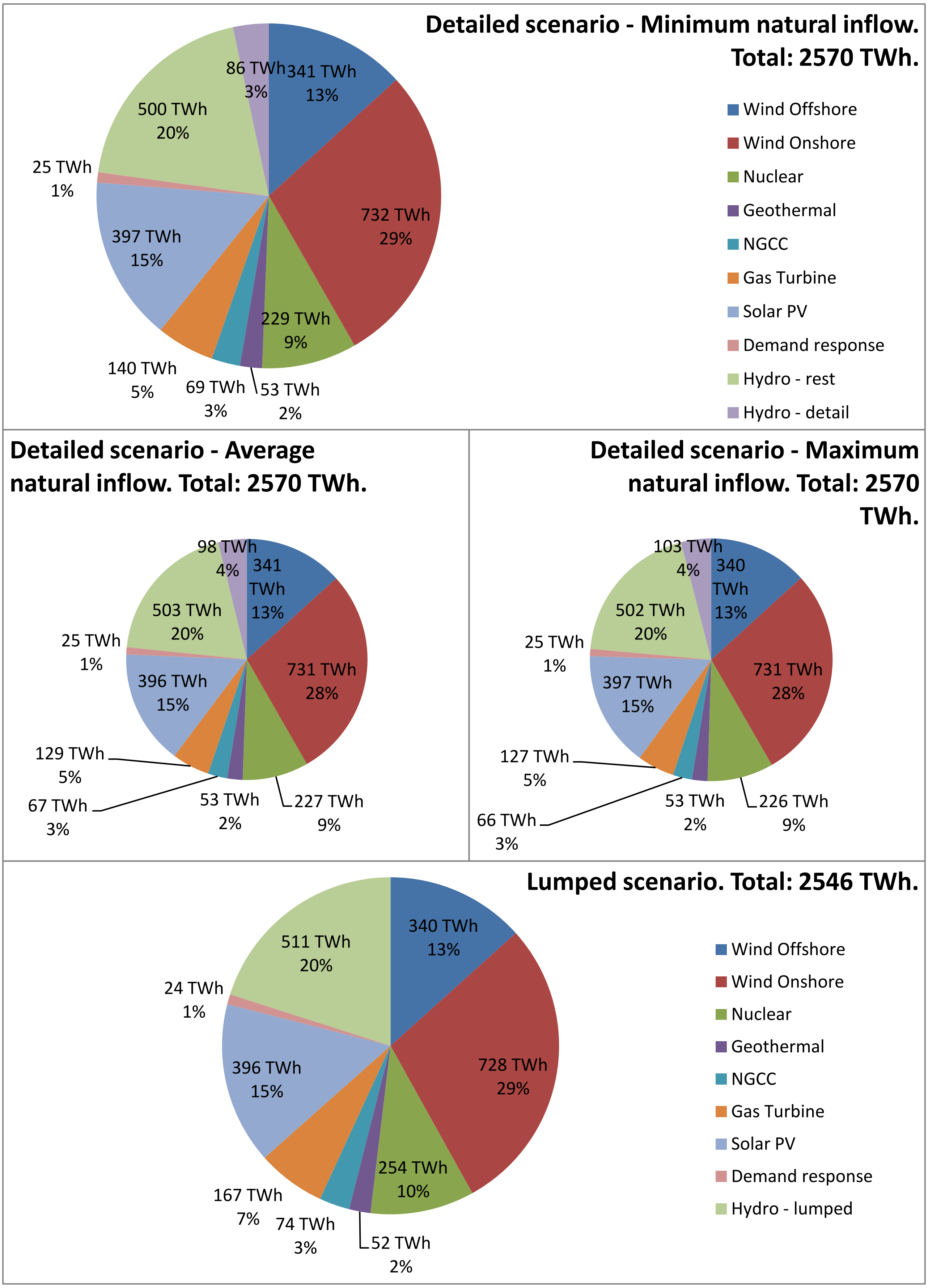

Figure 20 - Electricity generation in 2050.

In figure 21, the annual generation and pump load (the electricity consumed by pumps of PHS plants) of all hydro plant categories is given for all four scenarios. Total generation is higher in the three detailed scenarios compared to the lumped scenario. This might have been caused by an error in the model on capacity factors of large STO rest plants and small non-PHS rest plants (see next section). Indeed, the generation by large STO rest plants and small non-PHS rest plants in the detailed scenarios exceeds the generation of the same categories in the lumped scenario with 32%, despite the smaller installed capacity in the rest large STO category in the detailed scenario. Further, the total pump load in the lumped scenario is smaller than in the detailed scenarios. Small differences in total hydro generation (rest and detailed plants together) between the different natural inflow scenarios are observed, showing a slight increase (3%). However, the detailed STO and RoR plants show 79% and 72% increase in annual generation between the minimum and maximum natural inflow scenarios respectively. Detailed PHS plants are less affected by natural inflow and show an increase of only 8% in annual generation when comparing the maximum with the minimum natural inflow scenario.

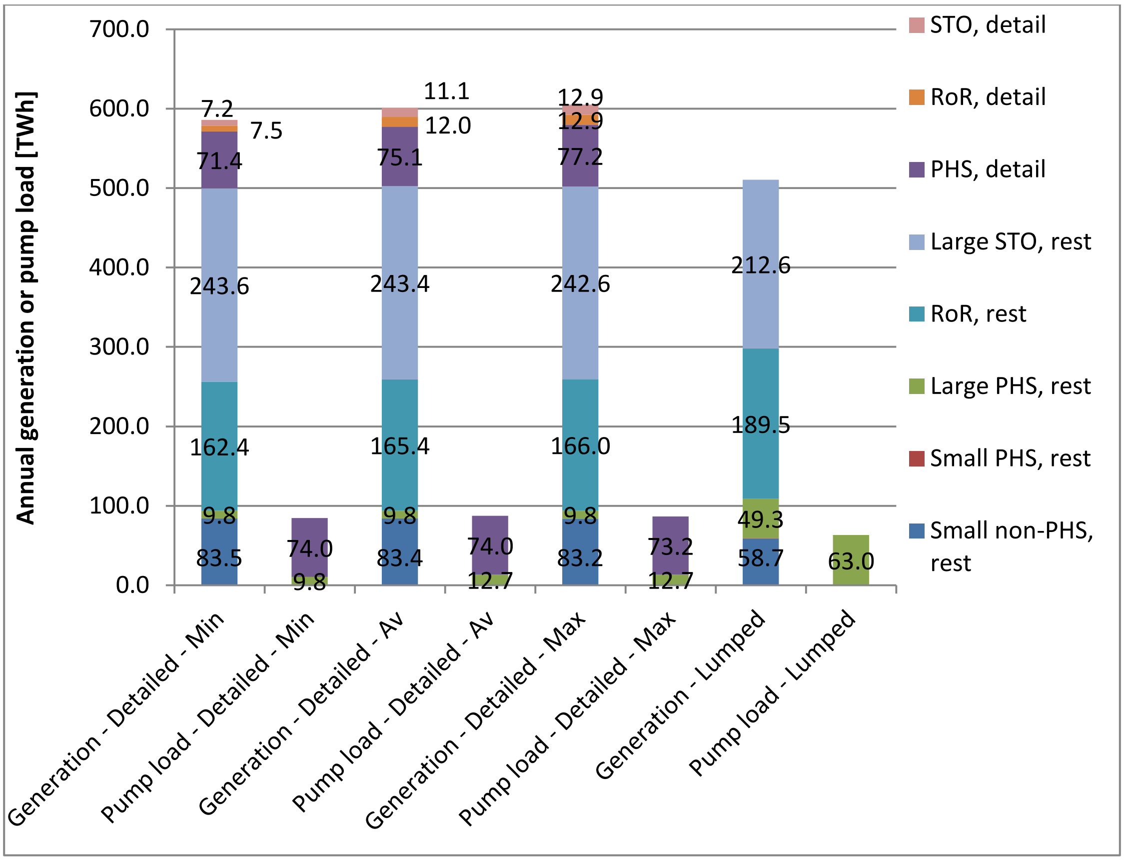

Figure 21 - 2050 annual generation of hydro plants, divided per scenario (x-axis) and per hydro plant category (stacked). The categories are listed in the legend, rest plant and detailed plants have been separated. No detailed plants are included in the lumped scenarios.

Capacity factors hydro plants

The annual capacity factors of lumped and rest plants are higher than expected. An error was made in the model concerning the Max Capacity Factor Year constraint in the detailed scenarios, which disabled the constraint for two categories: small non-PHS rest plants (Max Capacity Factor Year should be 46.25%) and large STO rest plants (Max Capacity Factor Year should be 50%). This is the cause of the high annual capacity factors for these categories in the detailed scenarios (82% for large STO rest plants and around 81% for small non-PHS rest plants). However, also for large STO and small PHS plants in the lumped scenario and for all RoR rest plants, the (correctly applied) constraints are violated. The reasons for this are unclear, possibly the solving method was not precise enough. Also for small PHS plants (both rest and lumped categories), the model output annual average capacity factor is higher than realistic, despite the modelling of the head and tail storages connected to them. For large PHS plants in the rest and lumped categories, capacity factors are much lower (around 22%).

For the detailed plants, the output capacity factors are more realistic. Recall that for the detailed plants, no input capacity factor constraints were applied. Instead, the output capacity factors from the modelling of the maximum storage volumes and limited natural inflow. Significant increases in capacity factors of the detailed plants are observed with increasing natural inflow, especially for STO and RoR detailed plants (both 74% increase in max inflow scenario with respect to min inflow scenario). Detailed PHS plants show a capacity factor increase of 8% in the maximum inflow scenario compared to the detailed inflow scenario.

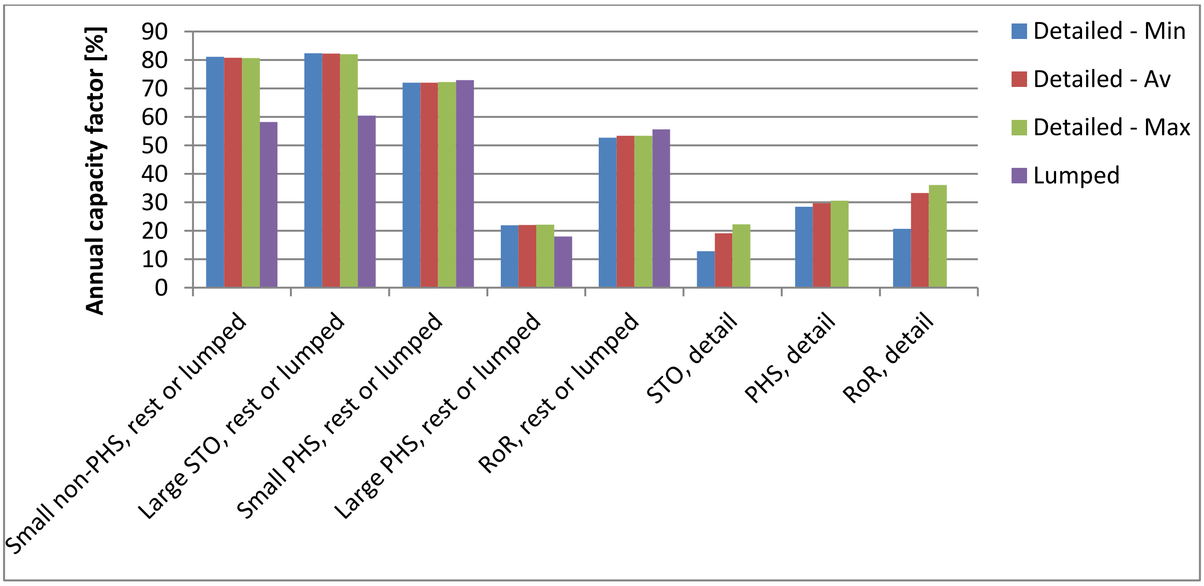

Figure 22 - Average annual capacity factors of hydro plants, divided per category and per scenario.

Annual CO_2 Emissions

The emission cap is 35 Mtonne CO_2/year net produced in the LT scheme. While the cap is met in the LT scheme, it is largely exceeded in the ST schedule. The resulting annual emissions produced were 86.1 Mtonne/year in the base case, with a price of 70 €/tonne CO_2. The net production of CO_2 in the system is highest in the lumped scenario. Within detailed scenarios, increases are observed with decreasing natural inflow (see table 3). When the CO_2 price was set to 160 €/tonne CO_2, still 85.0 Mtonne/year was produced in the detailed average scenario.

Table 3 - Annual CO_2 emissions in different scenarios, using a CO_2 shadow price of 70 €/tonne.

Scenario	CO_2 emissions [Mtonne/year]	Relative difference with detailed av
Detailed - min	91.77	+7%
Detailed - av	86.15	
Detailed - max	84.47	-2%
Lumped	110.57	+28%

5.2.2 ST SCHEDULE RUNS OVER WEEK (MIP)

TOTAL GENERATION AND PUMP LOAD

The week with maximum summed peak (GT and NGCC) and hydro generation, is the week starting at February 18th 2050.

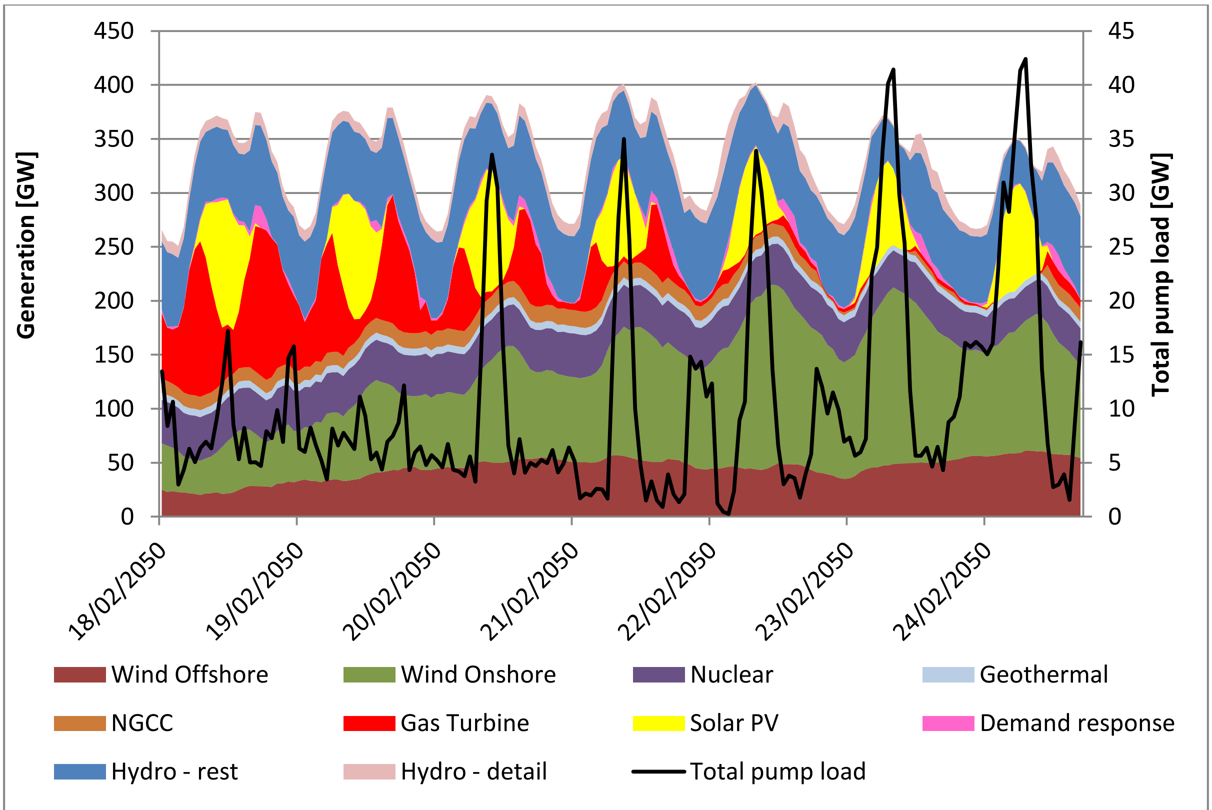

Figure 23 – Electricity generation profile in week with maximum generation by peak and hydro plants. Detailed scenario with average natural inflow. Next to electricity generation, the pump load (including both hydro and DR) is shown. Total generation in this week is 55.9 TWh, total pump load is 1.78 TWh.

In figure 23, the generation profile of the different plant types is given in the week with maximum generation by hydro and peak plants for the detailed scenario with average natural inflow. In this graph, 'hydro' includes all types of hydro plants (RoR, STO and PHS). Additionally, total pump load is given (including the 'pump load' by Demand Response (DR)). The total generation in this week for this scenario is 55.9 TWh, of which 12.8 TWh (23%) is generated by hydro plants and 7.1 TWh (13%) by peak plants (GT and NGCC). Total energy 'consumed by pumps' (including both PHS pumps and DR) in this week in this scenario is 1.78 TWh (of which 0.63 TWh from DR, that is 35%, the rest from PHS plants). Especially in the beginning of this week, the total generation by wind and solar PV is relatively low. It is observed that in this week, the total generation by hydro plants is never zero. In general, two peaks in pump load are observed each day. The first peak coincides with the daily peaks in generation by solar PV. The second peak falls in the night. On February 18th and 19th, the total pump load is relatively low as a result of the low generation by solar and wind.

In figure 24, the same results are shown for the lumped scenario. The general patterns are equal to those in the detailed average inflow scenario. The total generation in this week is 55.7 TWh, of which 10.9 TWh by hydro plants. The total Total energy 'consumed by pumps' (including both PHS pumps and DR) is 34% higher than in the detailed average inflow scenario: 1.57 TWh (of which 0.60 TWh from demand response, that is 38% of the total, the rest is consumed by PHS pumps).

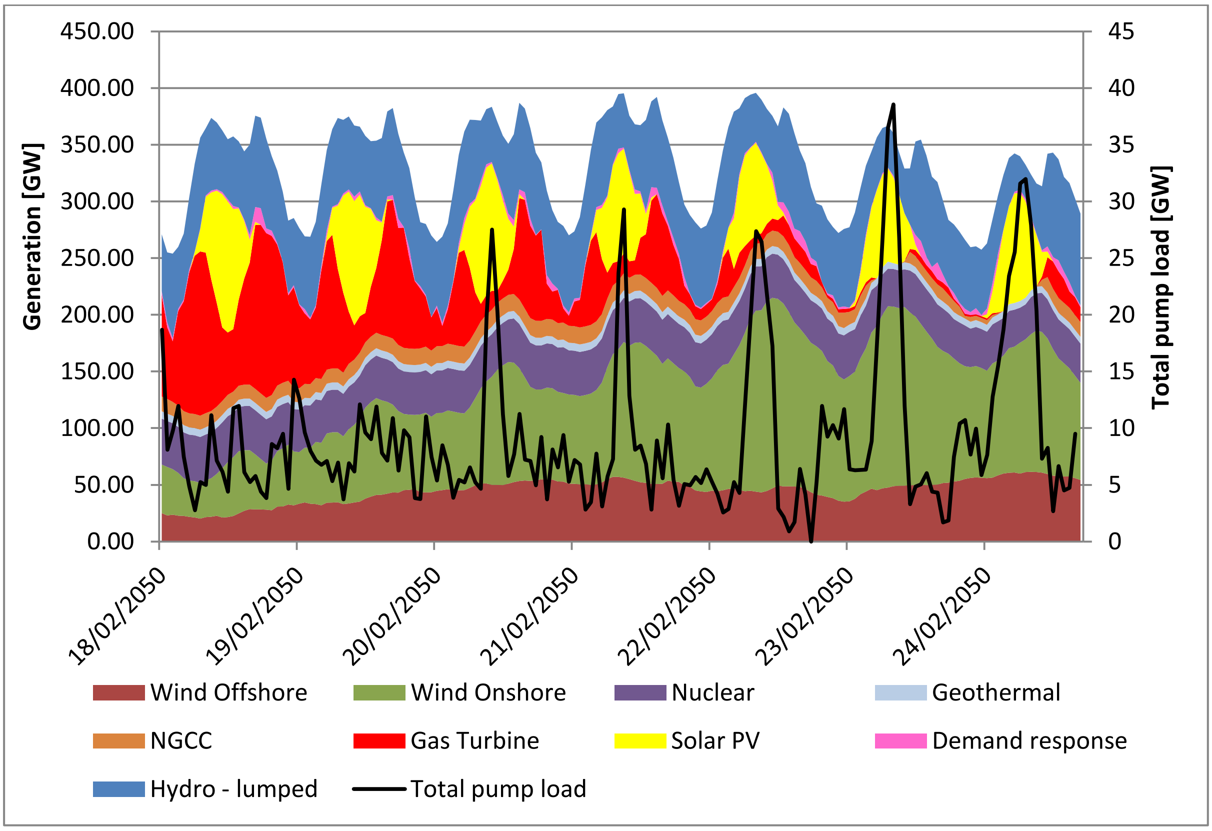

Figure 24 –Electricity generation in week with maximum generation by peak and hydro plants. Lumped scenario.

The week with minimum summed peak and hydro generation is the week starting at June 3rd 2050 for the detailed average inflow scenario. In this scenario, the total generation is 48.3 TWh, of which 10.7 TWh (22%) is generated by hydro plants and 0.5 TWh (1%) by peak plants (GT and NGCC). It is observed that the share in total generation of hydro is almost equal in comparison to the week of February 18th, while the share of peak plants (GT and NGCC) has been significantly decreased. The total energy consumed by pumps (including both PHS pumps and DR) is 2.38 TWh (of which 0.40 TWh (17%) is 'consumed' by DR 'pumps', the rest by hydro pumps. As shown in figure 25, most hydro plants are dispatched as peak plants in this week: during peaks in PV generation, the hydro generation is very small or even zero.

This also counts for the hydro generation in the lumped scenario in the same week, depicted in figure 26. The total generation in this week in the lumped scenario is 38.7 TWh, of which 9.7 TWh is generated by hydro plants and 0.9 TWh by peak plants. The total energy consumed by pumps is 1.91 TWh, of which 0.40 (21%) is 'pumped' by DR.

When comparing the figures for the detailed average scenarios with the lumped scenarios, it is concluded that the patterns are similar. The most significant differences observed are those in dispatch of gas turbines and total pump load. In the next section, hydro generation and pump load are analysed separately.

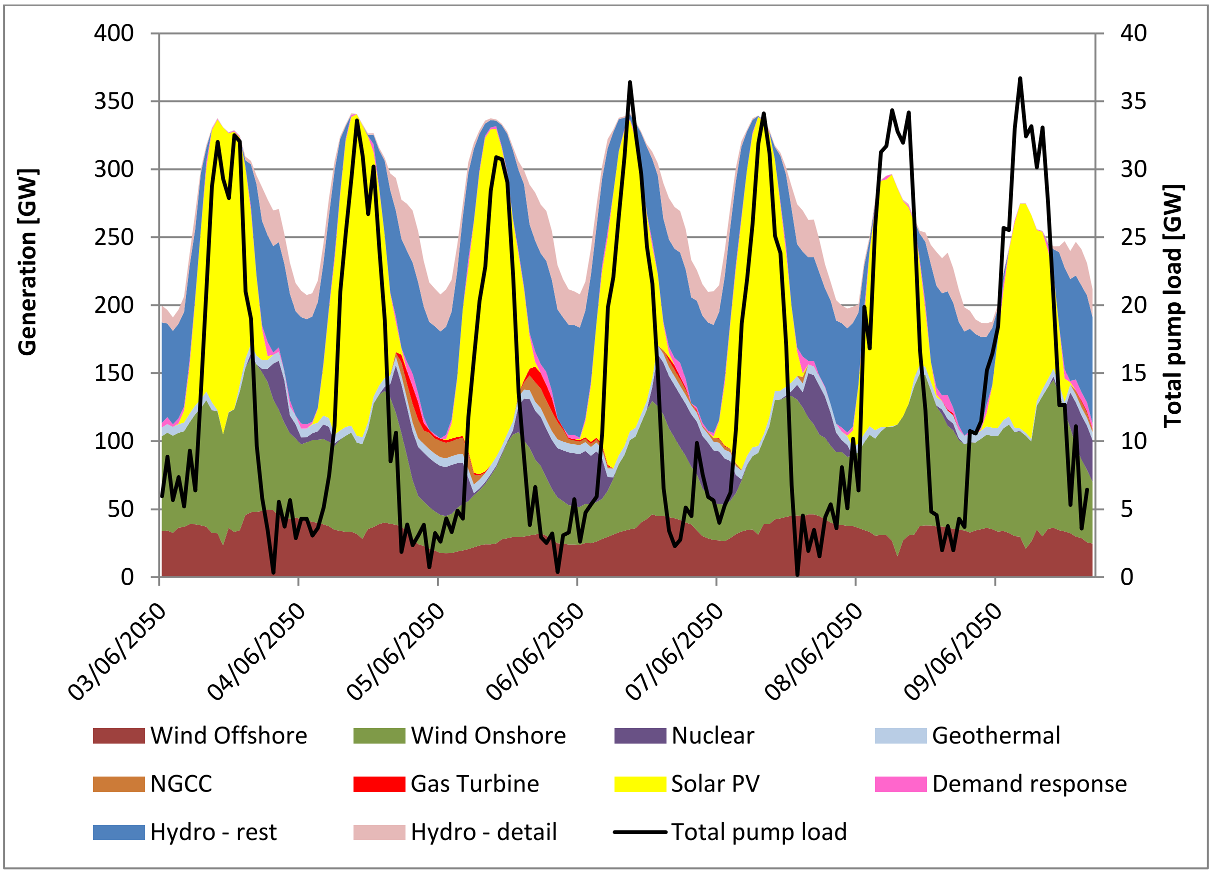

Figure 25 - Electricity generation in week with minimum generation by peak and hydro plants. Detailed scenario, average natural inflow.

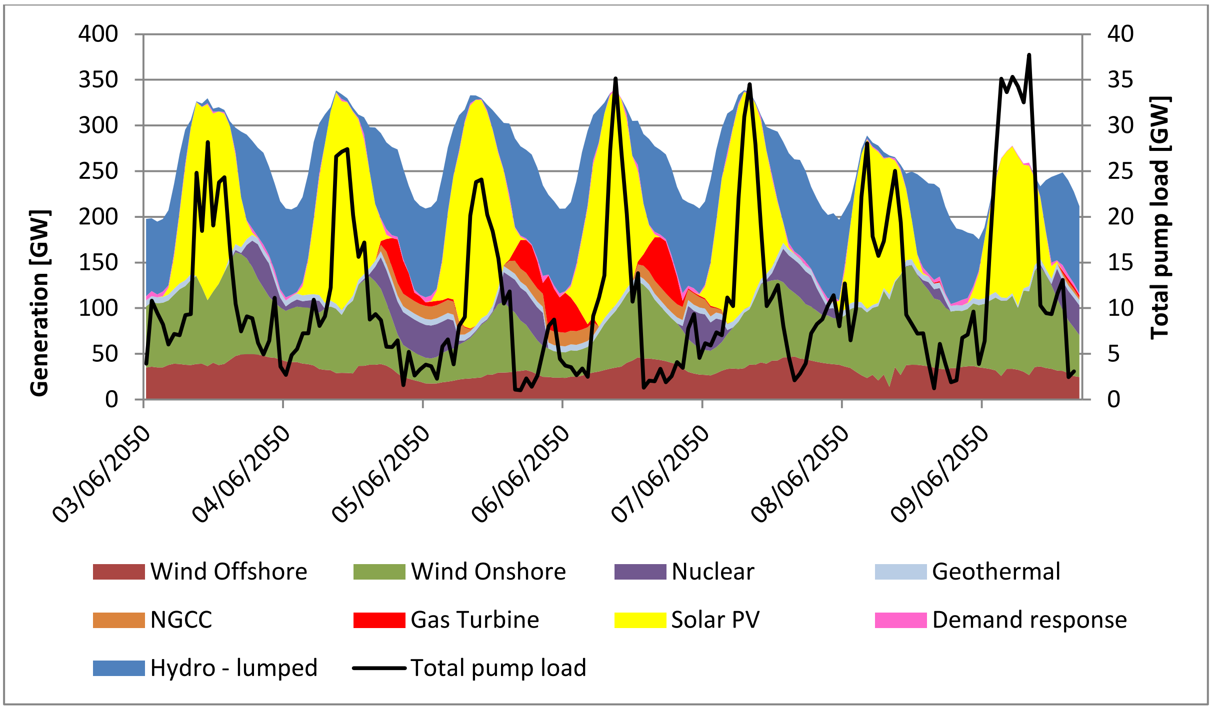

Figure 26 - Electricity generation in the week with minimum generation by peak and hydro plants. Lumped scenario.

HYDRO GENERATION AND PUMP LOAD

In figures 27 and 28, the electricity generation of detailed hydro plants divided per category is given for the week with maximum and minimum summed peak and hydro generation respectively.[9] The first observation is that the generation pattern differs among different plant categories, especially between PHS and non-PHS plants. From February 18th untill February 22nd, RoR and STO plants are generating at rather constant levels, while PHS generation is fluctuating. Later in the same week however, RoR and PHS plants show very low generation during mid day as a result of the peak in solar PV generation. Further, in the week with maximum generation by peak plants and hydro plants, the relative differences between the different natural inflow scenarios are larger for RoR than for PHS and STO plants (see table 2).

[9] As all detailed plants belong to the large category (installed capacity per unit > 10 MW) 'large' is not mentioned in the figures as part of the category name.

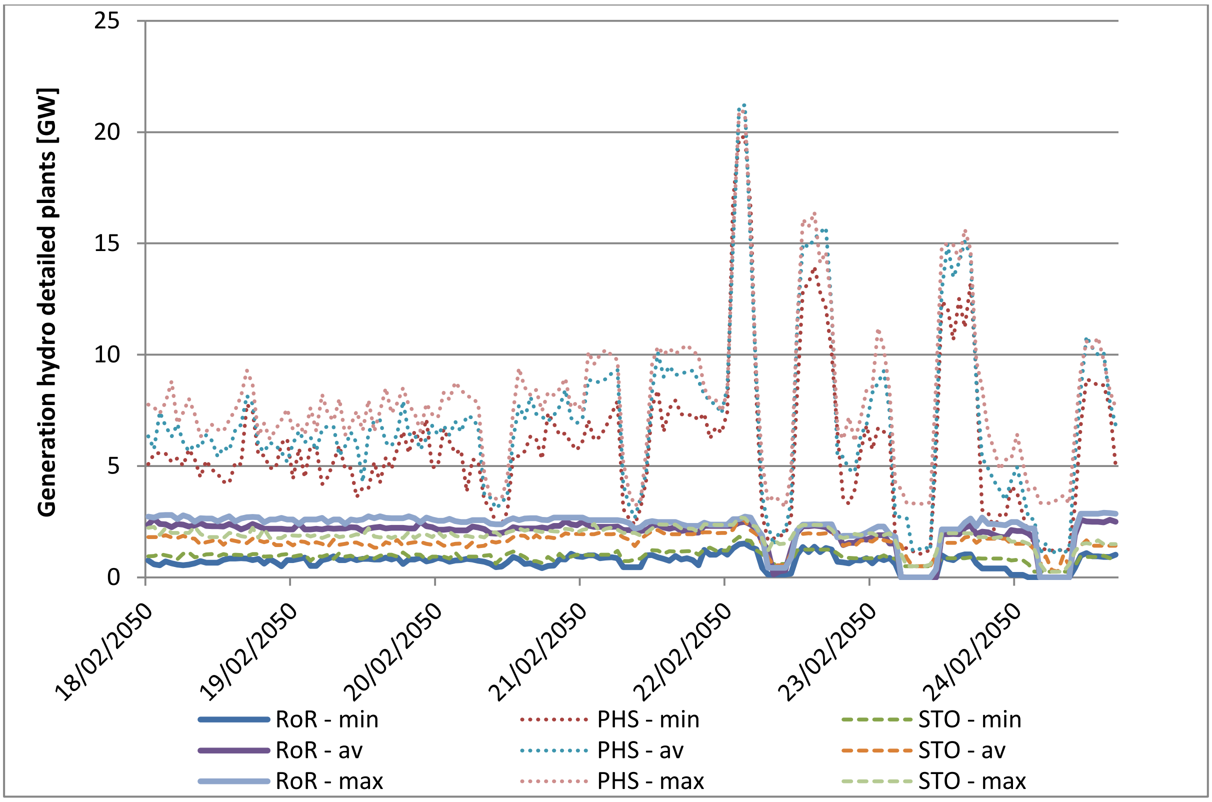

Figure 27 - Electricity generation by detailed hydro plants in the week with highest generation by hydro + peak plants.

In the week starting at June 3rd, like in the second half of the week starting at February 18th, all types of detailed plants are generating very low amounts of electricity in the middle of the day. Large relative differences in generation by RoR plants are observed in this week (see table 4). The generation by both RoR and PHS plants is highest in the average inflow scenario. This is probably caused by the effect of a temporarily higher natural inflow in the average scenario over the maximum scenario (see also section 3.2 on natural inflow results).

Table 4 - Relative differences between natural inflow scenario's for different types of detailed plants in weeks with highest and lowest summed generation of peak and hydro plants.

	Week of 18/02/2050			Week of 03/06/2050		
	RoR	**STO**	**PHS**	**RoR**	**STO**	**PHS**
minimum	35.5%	58.1%	83.9%	7.8%	91.2%	99.3%
average	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
maximum	114.4%	116.5%	114.4%	8.4%	118.9%	99.0%

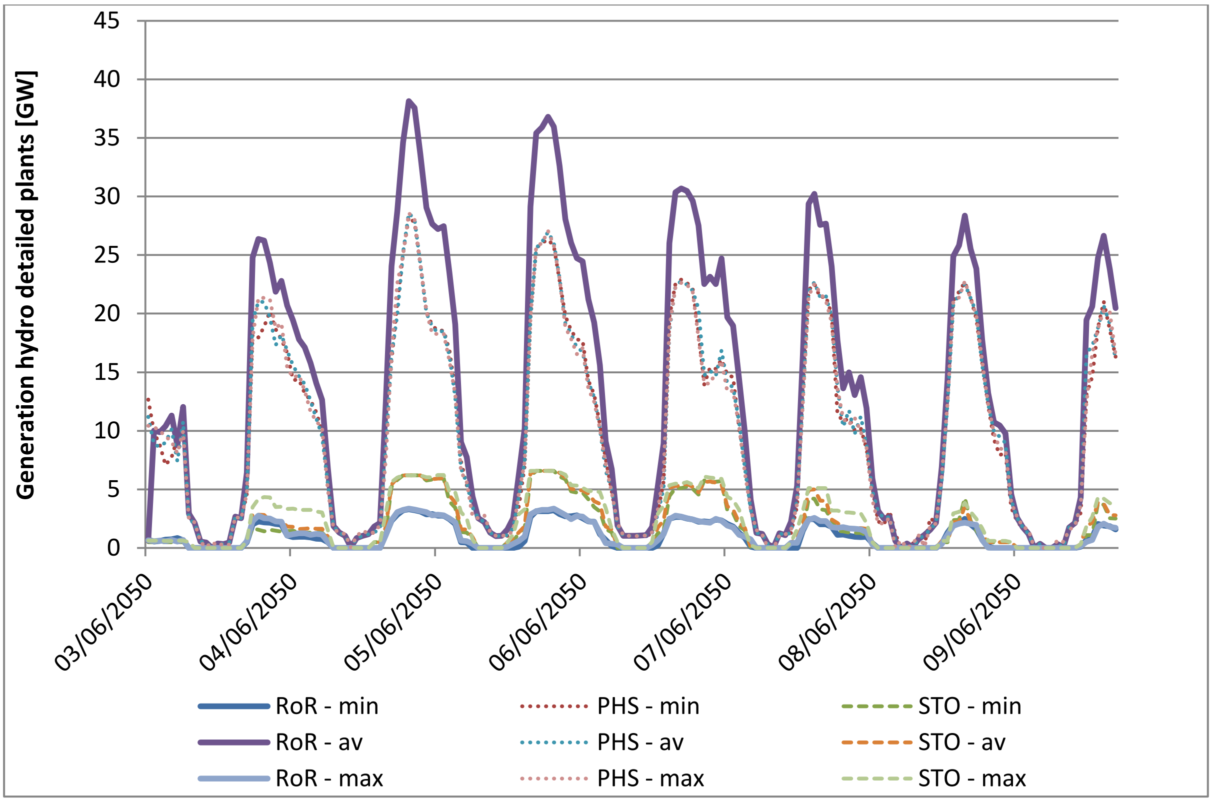

Figure 28 - Electricity generation by detailed hydro plants in the week with lowest generation by hydro + peak plants.

To be able to compare the detailed approach with the lumped apporach, in Appendix VII the generation profiles of rest plants from the detailed scenarios, as well as hydro generation in the lumped scenario are given. Especially in the week of February 18th, the generation profiles of detailed (figure 27) and rest plants (figure 31 in Appendix VII) differ significantly. In this week, the rest RoR rest plants in the detailed scenario are generating on a fluctuating basis, while the detailed RoR plants in the same week show rather constant generation. This could be caused by the detailed modelling, but as only 10 detailed RoR and 15 detailed STO plants are included in the detailed model, on a total of 707 and 677 plants respectively, the differences might also be caused by an increased flexibility through a larger total number of plants in the rest category. The rest STO plants are generating on a rather constant basis. In the lumped scenario, both RoR and STO plants generation profiles are irregular.

In conclusion, for the week of February 18th, the differences in generation profiles of hydro plants between detailed and lumped scenarios, are clearly visible. These differences are smaller for the week of June 3rd.

The total electricity consumed by pumps of PHS plants in both weeks discussed is given for all different scenarios in table 5. Over the whole year 2050, the electricity consumed by PHS plants in the lumped scenario is lower than in the detailed scenarios (see table 5). The electricity consumed by PHS plants in the week starting on February 18th is lower than the electricity consumed by PHS plants observed in the week starting on June 3rd. This can be explained from the higher iRES generation in the latter week, causing a higher surplus energy generation at peak generation time: the middle of the day. This idea is confirmed by the pump load patterns for the two weeks given in Appendix VII, as figure 31 in Appendix VII shows high pump load peaks during middays.

Summarising, relative differences in generation between natural inflow scenarios are largest for detailed RoR plants. The difference between generation patterns of different types of detailed hydro plant types are largest on days with high generation of peak and hydro plants. These days, the differences between lumped and detailed hydro plant generation profiles are significant as well. However, these difference might be caused by different numbers of plants included per category. When hydro plants are needed for peak generation only, as is the case in the week of June 3rd, the generation patterns do not differ much between types of plants nor between detailed and lumped scenarios. Further, during periods with high iRES generation, electricity consumed by PHS pumps is higher than in periods with low iRES generation (especially during the middle of the day) and natural inflow scenarios do not largely influence pump load by PHS pumps.

Table 5 – Electricity consumed by pumps of PHS plants, for both the detailed scenarios and the lumped scenario. Absolute pump electricity consumption as well as relative differences in pump load among natural inflow scenarios are given. For the lumped scenario, relative differences are calculated as the deviation from total (rest + detailed) electricity consumed by PHS pumps in the average scenario. PHS capacities included in the categories are given in Appendix II.

	week starting at 18/02/2050				**week starting at 03/06/2050**			
	Rest PHS [GWh]	Detailed PHS [GWh]	Rel. diff. rest PHS	Rel. diff. detailed PHS	Rest PHS [GWh]	Detailed PHS [GWh]	Rel. diff. rest PHS with respect to Av	Rel. diff. detailed PHS with respect to Av
Min	180	1035	+1%	+4%	324	1654	+1%	0%
Av	178	995	-	-	322	1659	-	-
Max	182	958	+3%	-4%	326	1649	+1%	-1%
Lump	989		-16%		1521		-16%	

6. Discussion

The first part of this chapter (section 6.1), deals with the limitations of both the database and the modelling part. In the second part, section 6.2, the model results are discussed. Finally, in section 6.3 the model results are compared to data from reality and the newly installed hydro capacity in the LT plan is compared to a study on future PHS storage potential.

6.1 Limitations of the study

6.1.1 Database

The most important limitations on the database quality are listed below.

- The plants from the database include only about one third of the total installed hydro capacity within the geographical scope of the model. In the detailed scenarios, the rest of the existing hydro capacity is lumped. This limits the influence of the effects of the natural inflow scenarios on the results for the power system as a whole, as well as the differences between the detailed and the lumped scenario.
- Norway, Sweden and Denmark have been excluded from the model scope because no natural inflow data were available for this region. A significant amount of hydro generation capacity is present in Norway and Sweden (respectively 31 TW and 16 TW installed capacity including PHS) (ENTSO-E, 2014). Also, in Norway the energy storage capacity is large (11 TWh energy storage capacity in 2011 has been reported) (JRC, 2013). For comparison, the total storage capacity included in head storages of the detailed plants in this model is less than 0.5 TWh. For these reasons, inclusion of Nordic countries in the model geographical scope might have significant effects on the results, also for the regions currently included because of interconnection between Nordic countries and the other regions in the model.
- Only power plants which are currently operational have been included, disregarding the age of the plant. Plants which are under construction at the moment are ignored. These things decrease the accuracy of the representation of the 2050 hydro power plant portfolio.
- The data reliability of the open source data on which the modelling of the detailed power plants is based, is not always guaranteed. Especially the data on hydrological details was sometimes barely available or of doubtful quality. The active volume and hydraulic head for example were not always clearly defined and therefore had to be estimated in some cases. This has led to increased uncertainty of storage energy content for some of the storages and therefore also an increased uncertainty in natural inflow in terms of energy in some cases, as the latter is based on the ratio between energy content and volume of the storage.
- Simplifications of hydro plant systems were made during the data collection. Often, not all storages connected to the power plants were included, underestimating total storage capacity. Also, when more than one storage was modelled (supplementary storage), only one value for the hydraulic head was used to base the energy content of the other storages on. This may as well under- or overestimate the total available energy storage capacity of the hydro power plant.

- No other uses of the water than for hydroelectricity have been accounted for, which may have led to an overestimation of water availability in some cases.
- The natural inflow data are generated as monthly averages. In reality, significant daily and even (sub-)hourly changes in natural inflow may occur due to rainfall. These fluctuations might have significant effects on the water availability, especially in case of small storages with a daily generation cycle (for seasonal storages, daily or hourly changes are less important).
- The minimum and maximum natural inflow scenarios were based on the years with respectively the lowest and highest total natural inflow per storage. So for each storage, the data from a complete year were used in each scenario. This was done because it was considered to be more realistic than picking the minimum or maximum inflow for each storage for each month separately. However, the chosen approach has two drawbacks. The first is that the differences between the scenarios are smaller than when minima and maxima would have been used per month instead of per year. The second is that, due to this approach, it was possible that in the average scenario the inflow in a certain month could be higher than in the maximum scenario, causing unexpected effects in outcome for that month.
- As the energy hydro model was used in PLEXOS, all natural inflow data had to be converted into energy inflows. For this, the calculated energy content and the volume of the storage were used. As a result, any uncertainties in the volume and energy content of the storages reflect in the natural inflow values as well.

6.1.2 MODEL

Some of the model limitations mentioned in Brouwer et al. (2016) also count for this study, as this article was based on the same model as this study. The limitations most relevant for this study are the ones influencing flexibility requirements:

- Heat and transport sections are excluded. For this reason, no flexibility provided by power-to-heat, heat storage and electricity storage in vehicles is accounted for (Brouwer, et al., 2016).
- The regions used in the study are relatively large, which might underestimate flexibility requirements due to spatial smoothing (Brouwer, et al., 2016).

Further limitations of this specific model are:

- In the ST schedule, CO_2 emission caps were not met. This means that the generation by fossil fuelled power plants is allowed to be too high, leading to an underestimation of the load that has to be met by RES and iRES plants.
- The ST schedule runs over the year were carried out using rounded linear relaxation optimization. As this method is less reliable than full mixed integer programming, this has lead to an increased uncertainty of the model results. Moreover, during the run in PLEXOS, infeasibilities occurred on nuclear plants, for unknown reasons. The infeasibilities were repaired by the solver, resulting in a few hours per year in which the generation of nuclear plants was negative. Significant negative peaks (< -0.1 MW) occurred on average 10 times in the year per region, with an average value of about -600 MW. The total amount of 'negative' energy values (energy 'consumption') in the average scenario over the year 2050 was 30 GWh, which is small in comparison to the 'positive' generation of nuclear plants of 269.6 TWh. Therefore, the

influence on total system results is expected to be relatively small. However, it may have decreased flexibility requirements or need for energy curtailment during times of high iRES production.

HYDRO MODELLING

In this part, specific limitations of the hydro modelling are discussed.

- There are limits to the detailed modelling of complex configurations when the energy hydro model is used in PLEXOS. No correct calculation for the energy content of a storage being both a tail storage of a pumped hydro plant as well as a head storage of a downstream plant could be carried out in this energy model. This could have been avoided using the volume hydro model in PLEXOS. However, in this study, not enough data were collected for using this model. Using the energy hydro model, the problem rises that the same volume of water may represent different amounts of energy, as it could be used to be pumped upwards by the PHS plant as well as for electricity generation by downstream turbines. In PLEXOS, these two amounts are forced equal, in which the energy potential of the water for the downstream plants is chosen as the dominant value. This may have led to over- or underestimation of the available amount of water available for the PHS plants to pump upwards. This is a problem for the PHS plants Grimsel 2, Galgenbichl, Kühtai and Provvidenza, with a total installed capacity of 898 MW. This is 2.6% of the total PHS capacity in the model, and 3.0% of included detailed PHS capacity. Therefore, the influence of this inaccuracy on the results in this study will be relatively small.
- To calculate the total installed capacity of the hydro rest plants, total installed hydro capacity data provided by the ESHA were used (ESHA, 2015). The installed capacity of hydropower in France is significantly higher than the other sources investigated, namely the ENTSO-E and the IHA (IHA, 2016; ENTSO-E, 2015). This might be due to the inclusion of small hydro plants by the ESHA that are not included by the other sources. If this is the case, the choice for the ESHA would be the best one. The other possibility is that the installed capacity for France is overestimated by the ESHA and thereby also in this study.
- The total installed capacity of large non-PHS plants (based on ESHA data) was divided into RoR and STO plant capacity using a ratio based on ENTSO-E data. Such a combination of different data sources involves uncertainty and may have caused the size of the different categories to deviate from reality. However, it was the best approximation that could be made given the available data.
- Simplifications have been made in the hydro modelling. No correction for changes in efficiency due to changes in water level (hydraulic head) was made. Instead, average hydraulic head is used. However, as in most of the cases the average hydraulic head was largely exceeding the maximum difference in hydraulic head, this effect is expected to be relatively small.
- Evaporation losses from storages are not included in the model. Evaporation losses of hydropower plants are estimated to be 22.3 $m^3/GJ_{produced}$ (Marence, et al., 2012), which would correspond to 9% loss based on data of included storages. Indirect CO_2-equivalent emissions from hydropower plants are not taken into account. They are estimated to be 6 tonne CO_2-eq/GWh for STO plants by JRC (2014). Given the generation by STO plants of around 250 TWh/year, this would make a difference of approximately 1.5 Mtonne CO_2-eq/year.

- The spillways have very large capacity, allowing instant emptying of storages. This does not reflect reality, in which spilling must occur more gradually due to limited spilling capacity. This overestimated the flexibility of the storage content and underestimates possible negative effects of flooding. In reality, flooding can be a factor limiting the hydro production potential (Kaunda, et al., 2012).
- The fact that flow regime regulations are not taken into account in this model contributes to overestimating the flexibility of the flows and thereby of plant operation. This does not count for most PHS plants, as they generally do not release large amounts of water.
- According to the model results, small PHS plants are generating energy as well as store energy during the same hour. The reason for this has not been found. It is the explanation why the capacity factors of this type of plants are so high: around 70% in all scenarios. However, as the total generation and pump load by small PHS plants is very small (both being 0.6 TWh over the year in all scenarios), this inaccuracy is negligible.

Unfortunately, some errors were discovered in the hydro modelling which could not be corrected anymore due to time constraints.

- The calculation of the maximum energy content of storages of PHS plants is not totally correct. The maximum energy contents of head storage was defined as 'the maximum amount of energy that can be generated from a full storage', calculated using a turbine efficiency of 87%. The energy content of the tail storage was defined as 'energy needed to pump the maximum active volume up to the head storage', using a pump efficiency of 87%. However, for PHS plants in PLEXOS, the turbine efficiency applied is 100% and the pump efficiency applied was 76%. Therefore, the correct method would have been to define the maximum energy content of the head storage in PLEXOS as the total potential energy of the water (not accounting for 87% efficiency of the turbines). The maximum energy content of the tail storage should have been calculated using the ratio energy content per unit of volume of the head storage. As a result of this, the maximum energy content of the simple tail storages of PHS plants has been overestimated by 32%. This obviously contributes to inaccuracy of the model results, but as the charging/discharging cycles are mostly limited by the energy content of the head storage, the error in the model results might be relatively small.
- An error has been made in modelling the maximum capacity factors of rest STO plants and small rest hydro plants in the detailed hydro models. During the runs, the capacity factors of these two categories were not constrained. Indeed, the annual average capacity factors of these categories are around 80% instead of the intended maximum of 50% (rest STO) and 46.25% (small rest hydro). Therefore, the generation by those two categories has been overestimated significantly. Apart from that, resulting capacity factors for rest RoR plants are also higher than the maximum annual capacity factor constraint (around 56% instead of the intended 46.25%), despite correct implementation in this case. The unrealistically high capacity factors should be considered in interpreting the results.

6.2 Validation of model results

In this section, two aspects of the model results are validated. First, for the detailed plants, the capacity factors resulting from the model are compared to the real historic capacity factors of the same plants, which were collected in the database. Second, the capacity PHS plants built in the LT plan is compared to a European PHS capacity potential study by JRC (2013).

The average capacity factor based on historic values for included RoR power plants is 24.3%. The annual average capacity factors for detailed RoR plants resulting from the model vary between 21% and 36% (low and high natural inflow scenarios, respectively). The capacity factor of 24.3% from the collected data lies within this range. For STO plants, the capacity factor based on historic values is 21.8%. The model gives an annual average capacity factor between 13% and 22% for detailed STO plants, which is plausible. For detailed PHS plants, the average capacity factor based data from reality is only 13%. The capacity factors of the same detailed PHS plants from the results are higher: between 28 and 31%. This may be caused by the high amount of iRES capacity implemented in the model, largely exceeding the current installed iRES capacity.

In the LT plan, about 155 GW small PHS capacity was installed. This number is compared to a study on European PHS potential energy storage capacity by JRC (JRC, 2013). In the model, the small PHS plants have an installed capacity of 10 MW and a storage capacity of 0.022 GWh. Therefore, 155 GW of those plants corresponds to 341 GWh storage capacity. The total realisable new storage capacity for plants with one new storage in the geographical scope of the model according to the JRC study is almost 3500 GWh, about ten times as high. According to these figures, the amount of plants built in the LT scheme is realisable regarding the storage capacity needed.

6.3 DISCUSSION ON MODEL RESULTS

In the week of June 3rd, production by iRES plants is high and low solar PV production is compensated by hydro plants. During periods of high iRES production like the middle of the day, total demand is met using wind and solar energy only. On four out of seven days of this week, total hydro generation is zero during midday even for RoR plants. This effect (no hydro generation during midday) is also observed on June 23rd in the week with minimum residual demand presented in the results in the article by Brouwer et al. (2016). During periods with low solar production (night), hydro plants generate the largest share of energy produced by non-iRES sources. Therefore, according to these results, hydro power is an important technology in providing for the required flexibility in systems with high iRES penetration.

Two remarks have to be made on this observation. To start with, the total hydo generation in the detailed scenarios has been overestimated due to the unconstrained capacity factors of STO rest plants and small non-PHS rest plants. This possibly overestimates the role of hydro power in providing for the required flexibility as the resulting total hydro generation is higher than realistic. Moreover, one could question the value of these results as RoR plants are considered to have limited possibilities to adapt to changes in demand due to their low storage capacity (Kaunda, et al., 2012). Concerning detailed RoR plants, there are two reasons why zero generation by RoR plants during periods of peak iRES electricity production is possible in this study. First, as no difference was made between pure and pondage RoR, the RoR plants which are modelled in detail have relatively large storage capacities compared to the natural inflow (until 400 hours of natural inflow could be withhold). The second reason is that all types of plants, including RoR plants, were modelled with infinite spilling capacity, allowing RoR plants to spill water when no generation was needed. Concerning the rest and lumped RoR plants, economic dispatch decisions were constrained by maximum ramp up and down parameters and a minimum stable level, but the plants can still be ‘switched off’ unconstrained. As the total share of RoR in installed capacity is more than 31%, it would be interesting to improve these inaccuracies in future power system models including hydro power. A first step would be to make a distinction between pondage and pure RoR capacity. More realistic spillway capacities would improve the dispatch results of detailed pure and pondage RoR. If a lumped approach is chosen, the implementation of a Minimum Capacity Factor per day (pure RoR) and/or per week (pondage RoR) might enable modelling pure and pondage RoR plants in a more realistic way.

The results also indicate that the water availability is an important factor influencing the dispatch of plants other than hydro. The difference in annual generation by the detailed hydro plants between the low and the high natural inflow scenarios is 20%, and this difference is covered up by peak plants (in this model: GT and NGCC plants). If all hydro plants would be modelled as detailed plants, the effects of the different natural inflow scenarios on the total generation profile are expected to be significant. The effects of natural inflow might be further increased by running the model for several years in a row.

7. CONCLUSION

This study investigates the effects of detailed hydro power modelling under different natural inflow scenarios and compares the detailed approach to a more simplistic method of modelling hydro capacity. In the detailed approach, 68 individual hydro power plants in Western Europe and the storages connected to them are modelled, supplemented by rest capacity (divided in categories of plant types) to meet the total installed hydro capacity. These individual hydro power plants and the rest capacity are implemented in an existing model of the Western European low-carbon power system in 2050, with a high share of iRES (59% of installed generation capacity). This model was set up by A.S. Brouwer and others (Brouwer, et al., 2016) and is evaluated using the PLEXOS power system simulation tool. Three scenarios for average monthly natural inflow into the storages are set up, based on data generated by a hydrological model developed by David Gernaat. The more simplistic method consists of using 5 lumped categories of power plant types, a total number of plants as well as an average installed capacity per plant being assigned to each of these categories. The lumped categories were implemented in the same power system model by Brouwer et al., to enable comparison between model results of the detailed and lumped cases.

The study is divided in two parts. The first part is on collecting data on individual hydro power plants and storages. The second part is on the PLEXOS model. Model results of the detailed approach were compared between different natural inflow scenarios. Also, a comparison between the detailed approach and the more simplistic method of modelling hydro capacity was made.

Data availability on hydrological details which are relevant for hydro power generation, such as active volume of connected storages, available hydraulic head and volume of water used per generated unit of energy, is rather low and scattered at the moment. The added value of this database in comparison to existing databases, is that both technical details on the power plant itself and details on the connected storages (such as volumes, average hydraulic heads, maximum flow through turbines) have been included. Moreover, the database is supplemented by monthly average natural inflow data in m^3/s over the last 30 years for each of the included storages. This opens up the possibility to model a large amount of hydro plants in a relatively high level of detail. The database set up in this study consists of 105 hydro power plants (with a total installed capacity of 62.0 GW, of which 35.8 GW (mixed) PHS capacity), located in the EU-28 supplemented by Norway and Switzerland. Of those hydro plants, 68 are located within the geographical scope of the model (with a total installed capacity of 40.4 GW of which 29.7 GW is pumped hydro storage (PHS), 7.4 GW is storage plants (STO) and 3.3 GW Run-of-River (RoR) capacity). Within the geographical scope of the model, 32% of the currently existing hydro capacity is included in the database as the total existing installed hydro capacity within the model scope is 126.8 TW (ESHA, 2015).

Concerning the results from the natural inflow data generation in storages included in the model, it is observed that:

- Head storages of RoR plants show the highest natural inflow on average (294 m^3/s), based on the average natural inflow scenario. Head storages of included STO plants have next highest average natural inflow in the average scenario (64 m^3/s). Head storages of PHS plants show low average natural inflow (22 m^3/s). For most head storages of PHS plants, average natural inflow is even below 1 m^3/s. This indicates that modelling PHS plants as closed loop systems (excluding natural inflow data) would be a justified simplification in most cases (in this model the natural inflow data of PHS plants were included).

- On average, head storages included in the model receive 46% less natural inflow in minimum and 80% more in the maximum natural inflow scenario compared to the average natural inflow scenario, expressed in terms of energy.

Concerning the PLEXOS modelling part, conclusions are drawn from both the long term (LT) plan and the short term (ST) schedule. During the LT plan (1 year time horizon, steps of 1 week), investment decisions are optimised for power plants complementing the exogenously defined capacity. In the ST schedule unit commitment and dispatch decisions are optimised using a one hour time step.

In the LT plan base case, the detailed plant portfolio is used with average natural inflow. Only fossil and biothermal plants can be built in the base case and the maximum allowed emission capacity is 35 Mtonne/year (based on a 96% reduction compared to 1990 levels for the included countries). Differences between natural inflow scenarios and between the detailed and lumped approach of hydro modelling are investigated. Also, a CO_2 emission cap sensitivity is carried out on the base case. Further, an additional run is set up in which investments in new hydro capacity are enabled. The conclusions based on the LT plan are:

- In the base case (no new hydro, CO_2 emission cap 35 Mtonne/year), most capacity built consists of GT plants (211.4 GW), supplemented by some NGCC capacity (15 GW). No biothermal, CCS or coal fired plants have been newly installed in this simulation.
- No significant (larger than 1%) differences in capacity built is observed between the natural inflow scenarios nor between the detailed scenario and the lumped scenario for the base case. Based on these results, it can be concluded that the detailed approach does not influence the expansion portfolios significantly.
- The effect of varied emission caps on the newly built capacity is negligible for both the detailed scenario with average natural inflow and the lumped scenario.
- During the LT plan run in which the building of new hydro capacity was enabled, about 155 GW of small PHS plants were installed and less GT capacity was built (66 GW) as well as less NGCC (about 10 GW) compared to the base case. Also, a capacity increase of 4.4 GW of existing PHS plants was observed as a result of this simulation. Here, the newly installed capacity of small PHS plants increases slightly with increasing natural inflow, but as this difference in installed small PHS capacity is less than 1%, this effect is not significant.

Next, the ST schedule is carried out with a time horizon of a year, using rounded linear relaxation as unit commitment optimality method. Yearly results for different natural inflow scenarios are compared between the detailed scenarios, as well as between the detailed approach and the lumped approach. The conclusions drawn from these runs are:

- The effects of the natural inflow scenario on hydro generation of detailed plants in the ST schedule are significant (20% increase in hydro generation by detailed plants in the high natural inflow scenario compared to the low natural inflow scenario). This increase is mainly caused by

RoR and STO plants (showing an increase of 74% in capacity factor with increasing natural inflow).

- Both total hydro generation and hydro pump load are lower in the lumped scenario then in all detailed scenarios. This might have been caused by an error in the model, as a result of which the capacity factors of large rest STO plants and small non-hydro plants were left unconstrained. As the total share of detailed plants is limited and capacity factors of rest plants are higher than those of detailed plants, the difference between low and high natural inflow scenarios in total hydro generation (including rest plants) is only 3%.

Next to the ST schedule runs for the whole year, some runs over the week were carried out, using full mixed integer programming (MIP) as unit commitment optimization tool. The weeks with minimum and maximum summed generation by hydro power plants and peak plants (gas turbines and NGCC plants) are selected. The conclusions drawn based on these runs are:

- The generation by detailed RoR and STO plants, is strongly affected by natural inflow scenarios.
- In the week with minimum total generation by hydro and peak plants (in which iRES generation is relatively high) the generation patterns between different types of hydro plants (for detailed as well as rest and lumped plants) do not differ much. In this week, all hydro plant profiles show peaks during night and periods of low generation during midday, because of solar PV generation.
- In the week with maximum total generation by hydro and peak plants (and relatively low generation by iRES plants), generation profiles of the different types of detailed hydro plants are different. Detailed RoR plants and STO plants are generating at rather constant levels (about 2.5 and 2 GW respectively between 18/02/2050 and 22/02/2050), while generation by detailed PHS plants is fluctuating (roughly between 3 and 10 GW between 18/02 and 22/02/2050).
- In contrast to detailed RoR plants, rest RoR plants in the detailed scenario (supplementing installed capacity of detailed plants in the detailed approach) and lumped RoR (in the lumped approach) plants show irregular generation profiles (generation by those RoR plants roughly fluctuating between 18 and 33 GW (rest) and 20 and 34 GW (lumped)). This could be a result of the hydrological constraints because of the detailed modelling, but also of the larger number of plants in the rest and lumped groups, causing a larger relative flexibility as a large number of power plants which can be switched of at the same time. When comparing generation profiles of rest and lumped STO plants, it is observed that STO plants generate on a far more fluctuating basis than rest STO plants. This might be caused by the maximum annual generation capacity factor which is implemented on the lumped STO plants but (by mistake) not on the rest STO plants. Due to these differences in category size and applied annual capacity factors between the different scenarios, no sound conclusions can be drawn on the influence of using a lumped approach with respect to generation profiles.

In summary, it is concluded that investment decisions are not or hardly not affected by different natural inflow scenarios. Investment decisions resulting from the LT plan are similar for detailed and lumped scenarios. Annual generation by detailed hydro plants, however, is increased by 20% on average in the high inflow scenario compared to the low inflow scenario. Largest relative differences are observed for RoR and STO plants (79% and 72% respectively).

Based on these results, the main added value of detailed hydro modelling is the sensitivity of hydro plant dispatch to different hydro scenarios. If a higher share of the hydro capacity would have been included in the detailed hydro plant database, the effect of different natural inflow scenarios on total generation profiles is expected to be significant. As the lumped plants were not connected to natural inflow data, effects of different inflow scenarios can not be investigated using the lumped approach.

Recommendations for future research

- Investigating the effects of making a distinction between pure and pondage RoR.
- Investigating the effects of implementing limited spillway capacity.
- Run the model for more subsequent years to see the effect of several years with low or high natural inflow.
- Including Scandinavia, because of the large amounts of hydro capacity installed in that region.
- Extending the database including detailed hydro plants to enable investigation of the effects of a larger share of detailed plants within the model.

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Appendix I – Description of database entries

This appendix consists of a table containing all entries of the raw data collected for the database, accompanied by a description.

Table 6 - Entries of raw data and description.

Station ID	ID number of power plant.
Country	Country in which the plant is located.
Operator	The (main) operator of the plant.
Group	If the power plant is part of a group of plants, for example all using the same storages, the name of this group is mentioned.
Station name (second name)	The name of the power plant, and potentially an alternative name between brackets.
Location	A geographical name of a nearby town or the area in which the power plant is located.
River	The river which provides for the major part of the water supply to the system.
LAT power station	Latitude of point location of power plant in decimal degrees.
LON power station	Longitude of point location of power plant in decimal degrees.
Number of turbines	The number of turbines installed
Number of pumps	The number of pumps installed (these may be the same units as the turbines, in case of reversible pump-turbines). If it was not reported, the number of turbines was assumed equal to the number of pumps.
Turbine/pump type	The type of turbines/pumps installed (Francis, Kaplan or Pelton)
Capacity turbines [MW]	The total capacity installed for turbine mode.
Capacity pumps [MW]	The total capacity installed for pumping mode. For PHS plants: when no pump capacity was found, it was assumed that the installed pump capacity equals the turbine capacity.
Start-up time, black start [s]	The amount of seconds the power plant needs to start up from standstill (found for a small number of plants).
Start-up time, spinning [s]	The amount of seconds the power plants need to start up from spinning (found for a small number of plants).

Max. generation time [h]	The maximum number of hours generating at full capacity, starting with full head storage.
Max. pumping time [h]	The maximum number of hours pumping at full capacity, starting with full tail storage.
Annual generation [GWh]	The annual electricity generation of the power plant, including the generation for which water that was pumped up earlier was used (in case of pumped storage). If available, an average value is used, for example given by the operator. Otherwise, the generation in the year 2007 is used, retrieved from Enipedia. If the plant was commissioned after 2007 and no other reliable data were available, the 2020 estimated value from Enipedia was used.
Annual consumption by pumps [GWh]	The annual electricity consumption by the pumps (found for a small number of plants).
Average capacity factor turbines [-]	The capacity factor of the turbines was calculated to use for model validation.[10] As it was based on annual generation which was sometimes found for one year only, these numbers are not very reliable.
Average capacity factor pumps [-]	The capacity factor of the pumps was calculated as well.[10] As it was based on annual electricity consumption by pumps which was sometimes found for one year only, these numbers are not very reliable.
Opening date	The year in which the plant was first commissioned.
Year latest modernization	The year in which the last modernization was completed.
Head storage	The name of (one of) the head storage(s) from which the water is used by the power plant. In few cases, more than one storage was specified for one power plant. In many cases, simplifications were made regarding the amount of storages involved in the system. This was done because of limited time.
Grand ID corresponding dam (head storage)	If the dam withholding the storage is in de Grand Dam Database, the Grand ID of this dam is given here.
LAT head storage	Latitude of point location of the head storage in decimal degrees. The point location is generally chosen close to the middle of the dam withholding the water volume.

[10] The historic capacity factor was calculated using the following formula: $CF_{turb,hist} = \frac{E_{gen,hist\ annual}}{P_{turb,max} * yearhours}$, in which CF_{hist} = historic capacity factor of the turbines [-], $E_{gen,hist.\ annual}$ = historic annual electricity generation by turbines [MWh/year], $P_{turb,max}$ = total installed capacity of the turbines [MW], yearhours = hours per year (24*365.25) [h/year]. The formula for the pump capacity factor is similar, using consumed instead of generated energy and the $P_{pump,max}$ instead of $P_{turb,max}$.

LON head storage	Longitude of point location of the head storage in decimal degrees. The point location is generally chosen close to the middle of the dam withholding the water volume.
Active volume head storage [Mm^3]	The active (usable) water volume in t.he head storage. If no usable volume was found, but the surface area and the minimum and maximum water levels under operation were, the usable water volume was estimated using these data (see formula 1 in Method). If required data were not found, the total volume was used. All data are retrieved from open source data on internet, or from the Grand Database. [11]
Tail storage	The name of (one of) the tail storage(s) from which the water is used by the power plant.
Grand ID corresponding dam (tail storage)	If the dam withholding the tail storage is in de Grand Database, the Grand ID of this dam is given here.
LAT tail storage	Latitude of point location of the tail storage in decimal degrees. The point location is generally chosen close to the middle of the dam withholding the water volume.
LON tail storage	Longitude of point location of the tail storage in decimal degrees. The point location is generally chosen close to the middle of the dam withholding the water volume.
Active volume tail storage [Mm^3]	The active (usable) water volume in the tail storage. If no usable volume was found, but the surface area and the minimum and maximum water levels under operation were, the usable water volume was estimated using these data (see formula 1 in Method). If required data were not found, the total volume was used. All data are retrieved from open source data on internet or from the Grand Database.
Average hydraulic head [m]	Hydraulic head is the pressure difference between the high and low end of a vertical water column. The available hydraulic head is the theoretically available pressure difference minus pressure losses due to friction in pipes (Cengel, et al., 2012). In practice, the available hydraulic head fluctuates with fluctuating water levels. This effect is not taken into account in this study because of limited data availability and to limit calculation times of the model. Instead, average available hydraulic head is used. Often,

[11] In one case (Lago di Molveno) no (active) volume could be found, but the surface area was found. Here, the active water volume was estimated using: $V_{sto,active} = A * \Delta h$, in which: $V_{sto,active}$ = active volume of storage [m3], A = surface area of the storage [m2], Δh = difference between minimum and maximum water level [m]. For Δh, 10 m was assumed in this case.

	this average available hydraulic head of a plant was reported clearly. If it was not, one of the following assumptions was made, depending on the available data. The assumptions are, listed in order of preference: $H_{av} = \frac{H_{max} + H_{min}}{2}$, $H_{av} = H_{max} - \frac{1}{2}\Delta\mathrm{h}$, $H_{av} = H_{max}$. In which: H_{av} = average hydraulic head available [m], H_{max} = maximum hydraulic head available [m], H_{min} = minimum hydraulic head available [m], Δh= difference between minimum and maximum water level [m].
Maximum total flow rate turbines [m3/s]	The maximum flow rate through the turbines, working at full capacity. This is the total flow through all the turbines together. However, in several cases, it was not clearly specified whether the total flow rate found referred to the maximum flow rate used for electricity generation, or the maximum flow rate including spillways. Therefore, these data are regarded as rather unreliable.
Maximum total flow rate pumps [m3/s]	The maximum flow rate through the pumps, working at full capacity. This is the total flow through all the pumps together.
Name of power plant from which the natural inflow is used	If the power plant uses the water natural inflow of another power plant directly, the name of the other plant is mentioned here.
Competitive use of water head storage	Competitive use of the water in the head storage, except for electricity generation.
Remarks	Any relevant remarks. For example if daily or seasonal storage is concerned.
Sources	The sources of the data given. If internet sites were used, URLs linking directly to the information were given.

APPENDIX II – NUMBERS AND CAPACITIES LUMPED AND REST PLANTS

Here, the numbers and capacities included in the rest categories and lumped categories are given. The numbers are based on the plants from the database within the geographical scope of the model.

TOTAL EXISTING PLANTS (LUMPED SCENARIO)

Regions	non-PHS ≤ 10 MW	PHS < 10 MW	RoR > 10 MW	STO >10 MW	PHS > 10 MW	TOTAL
Total installed capacity [MW]						
BRI	299	0	1631	0	3036	4966
GAL	2110	0	13048	10392	4940	30490
GER	1797	22	2022	251	9209	13301
HIS	2391	10	2892	13965	6460	25718
ITA	4985	45	20299	15937	11105	52371
TOTAL	11582	77	39892	40545	34750	**126846**
Average capacity per plant [MW]						
BRI	1.21		30.2	30.2	607.2	-
GAL	0.92		80.8	80.8	548.9	-
GER	4.22	3.7	25.3	25.3	279.1	-
HIS	0.50	5.0	52.4	52.4	403.8	-
ITA	1.15	5.0	55.5	55.5	137.1	-
Number of plants [-]						
BRI	246	0	54	0	5	305
GAL	2301	0	161	129	9	2600
GER	426	6	80	10	33	555
HIS	4752	2	55	267	16	5092
ITA	4342	9	366	287	81	5085
TOTAL	12068	17	717	692	144	**13638**
Source used	ESHA (2015), Geth et al. (2015)	Geth et al. (2015)	ESHA (2015), ENTSO-E (2015)	ESHA (2015), ENTSO-E (2015)	ESHA (2015)	

PLANTS INCLUDED IN DETAILED PLANT DATABASE

Regions	non-PHS ≤ 10 MW	PHS < 10 MW	RoR > 10 MW	STO >10 MW	PHS > 10 MW	TOTAL
Total installed capacity [MW]						
BRI	0	0	0	0	2488	2488
GAL	0	0	768	2075	5068	7911
GER	0	0	0	0	6391	6391
HIS	0	0	2501	1239	5507	9247
ITA	0	0	0	4090	10255	14345
TOTAL	0	0	3269	7404	29738	**40381**
Number of plants [-]						
BRI	0	0	0	0	3	3
GAL	0	0	2	6	6	14
GER	0	0	0	0	7	7
HIS	0	0	6	2	8	16
ITA	0	0	2	7	19	28
TOTAL	0	0	10	15	43	**68**

PANTS NOT INCLUDED IN DETAILED PLANT DATABASE (REST)

Regions	**non-PHS ≤ 10 MW**	**PHS < 10 MW**	**RoR > 10 MW**	**STO >10 MW**	**PHS > 10 MW**	**TOTAL**
Total installed capacity [MW]						
BRI	299	0	1631	0	548	2478
GAL	2110	0	12280	8317	0*	22707
GER	1797	22	2022	251	2818	6910
HIS	2391	10	391	12726	953	16471
ITA	4985	45	19531	12651	850	38026
TOTAL	11582	77	35857	33909	5170	**86593**
Average capacity per rest plant [MW]						
BRI	1.21		30.2		274.0	-
GAL	0.92		77.0	67.9	0.0	-
GER	4.22	3.7	25.3	25.3	108.4	-
HIS	0.50	5.0	7.9	48.1	119.2	-
ITA	1.15	5.0	53.7	45.0	13.7	-
Number of plants [-]						
BRI	246	0	54	0	2	302
GAL	2301	0	159	123	3**	2586
GER	426	6	80	10	26	548
HIS	4752	2	49	265	8	5076
ITA	4342	9	364	280	62	5057
TOTAL	12068	17	707	677	98	**13567**

APPENDIX III – INPUT PARAMETERS PLEXOS

In this appendix, input parameters are given. In table 7, input parameters on rest/lumped and detailed plants are listed. Also, interconnection capacity figures used and techno-economic parameters on plants other than hydro and newly installed plants are given. All costs are in $€_{2012}$ values.

Table 7 - Input parameters for rest/lumped and detailed hydro power plants.

GENERATOR PROPERTIES	**small non-PHS rest/lumped**	**lumped/rest plants large RoR**	**lumped/rest plants large STO**	**lumped/rest plants PHS (small and large)**	**detailed plants RoR**	**detailed plants STO**	**detailed plants PHS**	**Data source**
Units	From Appendix II, per region	From Appendix II, per region	From Appendix II, per region	From Appendix II	Number of turbines	Number of turbines	Number of turbines	see Appendix IV
Max Capacity	Average for category per region	Average for category per region	Average for category per region	Average for category per region	Max capacity per turbine	Max capacity per turbine	Max Capacity per turbine	see Appendix II, Appendix IV
Min Stable Level	20 % of Max Capacity	20 % of Max Capacity	20 % of Max Capacity	20 % of Max Capacity	20 % of Max Capacity	20 % of Max Capacity	20 % of Max Capacity	Brouwer et al. (2016)
Max Ramp Up	4.1 % of Max Capacity	4.1 % of Max Capacity	4.1 % of Max Capacity	4.1 % of Max Capacity	Max ramp up reported or 4.1 % of Max Capacity	Max ramp up reported or 4.1 % of Max Capacity	Max ramp up reported or 4.1 % of Max Capacity	Brouwer et al. (2016)
Max Ramp Down	Equal to Max Ramp up	Equal to Max Ramp up	Equal to Max Ramp up	Equal to Max Ramp up	Equal to Max Ramp up	Equal to Max Ramp up	Equal to Max Ramp up	-
Firm Capacity	80% of Max Capacity	80% of Max Capacity	80% of Max Capacity	80% of Max Capacity	80% of Max Capacity	80% of Max Capacity	80% of Max Capacity	Brouwer et al. (2016)
Pump Load	-	-	-	Equal to Max Capacity	-	-	Pump capacity per Pump Unit	see Appendix IV
Pump Units	-	-	-	1	-	-	Number of pumps	see Appendix IV
Pump Efficiency (%)[12]	-	-	-	76	-	-	76	Geth et al. (2015), Brouwer et al. (2016)
Head Storage[13]	-	-	-	Average head storage (size: 12.8	Name of (main) head storage	Name of (main) head storage	Name of (main) head storage	Geth et al. (2015) and see Appendix IV

[12] In PLEXOS, Pump Efficiency is the roundtrip efficiency.

[13] For all storages included (both rest/lumped plants as for the detailed plants), the initial volume of the storages is set at half the maximum storage capacity in the ST schedule. Additionally, a target is set on the volume of the storage at the end to prevent that storages of RoR/STO plants are left empty at the end of the year. The storages of detailed plants are connected to natural inflow data. Storages of rest/lumped PHS plants are modelled without natural inflow (closed-loop systems).

				GWh for large, 0.044 GWh for small PHS)				
Tail Storage[8]	-	-	-	Average tail storage (size: 12.8 GWh for large, 0.044 GWh for small PHS)	Name (main) tail storage, ony included if the storage is part of a complex configuration	Name (main) tail storage, ony included if the storage is part of a complex configuration	Name (main) tail storage	Geth et al. (2015) and see Appendix IV
VO&M Charge (€$_{2012}$/MWh)	3	5	3 if Max Capacity > 100 MW, else: 5	0	5	3 if Max Capacity * Number of Turbines > 100 MW, else: 5	0	JRC (2014)
Max Capacity Factor Year (%)	46.25%	46.25%	50%	-	-	-	-	Assumption [14] / Appendix IV
FO&M Charge (€/kW/year)	1.5% of Build Cost	1.5% of Build Cost	1.0 % of Build Cost if Max Capacity > 100 MW, else: 1.5% of Build Cost	1.5% of Build Cost	1.5% of Build Cost	1.0 % of Build Cost if Max Capacity * Number of Turbines > 100 MW, else: 1.5% of Build Cost	1.5% of Build Cost	JRC (2014)
Equity Charge (€$_{2012}$/kW/year)	245.4	245.4	245.4	245.4	-	245.4	245.4	Brouwer et al. (2016)
Forced Outage Rate (%)	5	5	5		5	5		Brouwer et al. (2016)
Mean Time to Repair (hrs)	50	50	50		50	50		Brouwer et al. (2016)
Build Cost (€$_{2012}$/kW)	4167	5204	2037 if Max Capacity > 100 MW, else: 3120	1389	5204	2037 if Max Capacity > 100 MW, else: 3120	1389	JRC (2014), discounted from €$_{2013}$ values (discount rate 8%)
WACC (%)	8	8	8	8	8	8	8	Brouwer et al. (2016)
Economic Life (years)	60	60	60	60	60	60	60	JRC (2014) (Technical Lifetime, see discussion)

Interconnection capacity

The interconnection capacity between regions was assumed to be equal to the medium scenario from Brouwer et al. (2016). Included interconnection capacity is given in table 8. It is assumed that 2% percent loss occurs during transport over the transimission lines (Brouwer, et al., 2016).

[14] Based on 1.25 times the average yearly capacity factor per category given in JRC report (JRC, 2014).

Table 8 - Transmission lines and maximum interconnection capacities between regions.

Transmission line	Maximum interconnection capacity [GW]
Bri <> Gal	12.8
Bri <> Ger	4.9
Gal <> Ger	19.9
Gal <> His	27.4
Gal <> Ita	13.1
Ger <> Ita	6.6

TECHNO-ECONOMIC PARAMETERS PLANTS OTHER THAN HYDRO

Table 9 - Techno-economic parameters of power plants other than hydro (Brouwer et al., 2016).

Generator type	Build cost [€$_{2012}$/kW]	Fixed O&M cost [€$_{2012}$/kW]	Variable O&M cost [€$_{2012}$/MWh]	Full load efficiency [% LHV]	Lifetime years
Gas Turbine (GT)	438	10	0.8	42	30
Natural Gas Combined Cycle (NGCC)	902	11	1.2	63	30
Pulverized coal (PC)	2088	29	4.6	49	40
NGCC with CCS (NGCC-CCS)	1349	15	2.1	56	30
PC with CS	2847	33	5.6	41	40
Nuclear power	4841	103	0.0	33	50
Wind onshore	1402	37	0.0		25
Wind offshore	2655	83	0.0		25
Solar PV	700	17	3.1	45	40
Biomass power plant	1644	37	0.0		40

Table 10 – Additional parameters of newly installed hydro plants, deviating from parameters from table 7. Build cost and FO&M and VO&M of all types except 'existing PHS capacity increase' are assumed equal to those included in table 7.

Hydro plant type	**Max Capicity [MW]**	**Roundtrip efficieny [%]**	**Lifetime**	**Max units built [-]**	**Build cost [$€_{2012}$/kW]**	Fixed O&M cost [$€_{2012}$/kW]
RoR	0.7	90	60	-	see table 7	see table 7
Large STO	70	90	60	-	see table 7	see table 7
Small non-PHS	10	90	60	-	see table 7	see table 7
Large PHS	250	90	60	-	see table 7	see table 7
Small PHS	50	90	60	-	see table 7	see table 7
existing PHS capacity increase	50	90	60	Total number of large PHS plants exogenously defined	254.63	3.82

APPENDIX IV – COMPLEX CONFIGURATIONS

In this appendix, the complex configurations of the detailed plants are treated. The configurations are depicted in illustrations and the method to implement these configurations in the model is described.

COMPLEX CONFIGURATIONS DETAILED PLANTS

There are a few configurations in the model that are more complicated than the simple head or tail storage.

- **Head-tail storage**, one storage functioning as head and a tail storage at the same time.
- **Supplementary storage**, not connected to a generator but providing water to another storage that is connected to a generator.
- **Shared head storage,** used as a head storage by more than one generator.
- **Shared tail storage,** used as a tail storage by more than one generator.

To model the energy flows between storages and generators in these configurations, additional input like flow factors is needed. The different configurations and the method used to implement them are described here in detail.

CASCADE CONFIGURATIONS WITH HEAD-TAIL STORAGE

A head-tail storage is both a tail storage for an upstream plant and a head storage for a downstream plant. The configuration is illustrated in figure 29. Both storages are treated as a head storage, and for both the energy content is calculated using the method for head storages described in section 2.2.1. However, the maximum amount of energy that can be generated in GEN 1 using one cubic meter of water may differ from the maximum amount of energy generated in GEN 2 using the same volume of water. This is caused by, among other things, differences in available hydraulic head and turbine configuration. To correct for this difference, a flow factor has been used in PLEXOS. This was calculated using the linear relationship between volume and energy content of the storage assumed in this model, using previously calculated maximum energy content and maximum volume of each storage:

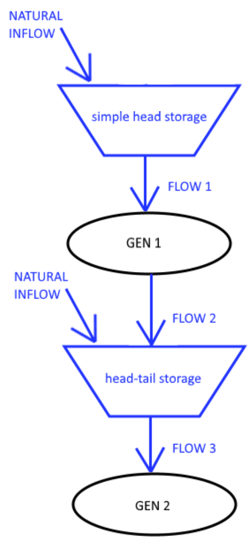

Figure 29 - Schematic representation cascade system with head-tail storage.

10) $$FF = \frac{P_{Flow\,2}}{P_{Flow\,1}} = \frac{E_{sto,head-tail}\;V_{sto,active,head}}{V_{sto,active,head-tail}\;E_{sto,head}}$$

In which:

FF = flow factor scaling the inflow from GEN 1 to the head-tail storage [-]

P_{Flow1} = energy flow from the simple head storage into GEN 1 [MW]

P_{Flow2} = energy flow from GEN 1 into the head tail storage [MW]

$E_{sto,head}$ = maximum energy storage of the simple head storage (to provide GEN 1 with energy) [GWh]

$E_{sto,head-tail}$ = maximum energy storage of the head-tail storage (calculated as simple head storage to provide GEN 2 with energy) [GWh]

$V_{sto,active,head}$ = maximum active volume of the simple head storage [Mm^3]

$V_{sto,active,head\text{-}tail}$ = maximum active volume of the head-tail storage [Mm^3]

SUPPLEMENTARY STORAGE

If the generator is fed by water from more than one storage, a supplementary storage is built in the model. This supplementary storage has a natural inflow of its own and is connected to the main head storage by means of a Waterway object in PLEXOS. The main head storage is on its turn providing water to the generator directly.

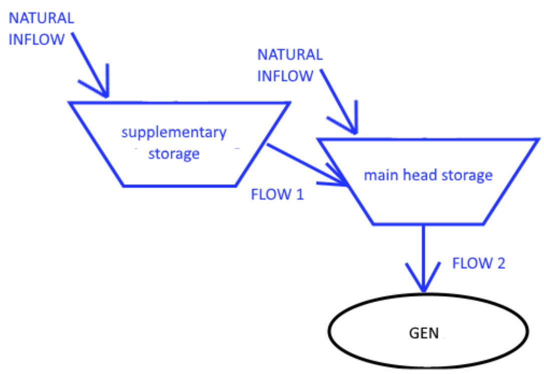

Figure 30 - Schematic representation of supplementary storage configuration.

If the supplementary storage has no other connections than one to the main head storage, the energy content per unit of storage volume of the supplementary storage is the same as in the main head storage. In that case, no flow factor needs to be applied on FLOW 1.

However, when the supplementary storage has another function as well, as head or tail storage of another generator, the energy content per unit of storage volume may differ from that ratio in the main head storage. In that case, the following equaion is applied:

11) $$FF = \frac{E_{sto,head,main} \; V_{sto,active,sup}}{V_{sto,active,main} \; E_{sto,head,sup}}$$

In which:

FF = flow factor scaling the inflow from the supplementary storage to the main head storage [-]

$E_{sto,head,sup}$ = maximum energy storage of the supplementary head storage [GWh]

$E_{sto,head,main}$ = maximum energy storage of the main head storage [GWh]

$V_{sto,active,sup}$ = maximum active volume of the supplementary storage [Mm^3]

$V_{sto,active,main}$ = maximum active volume of the main head storage [Mm^3]

SHARED HEAD STORAGE

A shared head storage is a water volume which is used as a head storage by more than one generator. If the generators differ in properties like the available hydraulic head, which is mostly the case, the same amount of water in the shared storage represents different amounts of stored energy for the different plants. This issue is solved by choosing one of the generators as reference generator. On this generator, the amount of energy in the shared storage modelled in PLEXOS is based. The flows to the other storages are corrected for

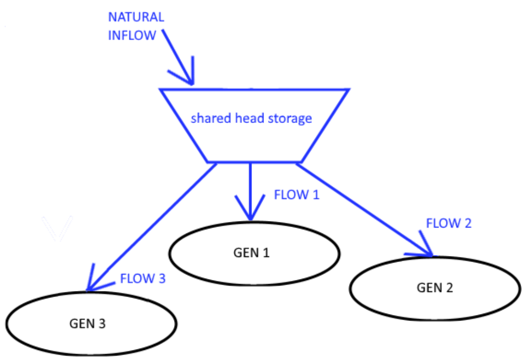

Figure 31 - Schematic representation of a shared storage configuration.

using the equation:

12) $$FF = \frac{E_{sto,head,non-ref}}{E_{sto,head,ref}}$$

In which:

$E_{sto,head,shared}$	= maximum energy content of the storage, calculated as energy provision for one of the non-reference generator(s) [GWh]
$E_{sto,head,ref}$	= maximum energy content of the storage, calculated as energy provision for the reference generator [GWh]

The flow factor thus derived was used in PLEXOS as '*Generator.Head Storage*' flow factor for the non-reference storages.

Shared tail storage

A shared tail storage is a water volume that is used as a tail storage by more than one generator. The method used was the same as for the shared head storage. The flow factors thus derived for the non-reference generators were used in PLEXOS as a '*Generator.Tail Storage*' flow factor for the non-reference storages.

APPENDIX V – DATABASE DETAILED HYDRO PLANTS

In this appendix, a list of the power plants which are modelled in detail is given. Two separate tables are given: table 11, containing collected technical data, and table 12, containing data on the storages connected to the plants. Note that total capacities are given here, not the capacity per turbine or pump unit as used as PLEXOS input. In table 12 very high values for $t_{withhold}$ occur for pumped storage plants, because the head storages of these plants often have very low natural inflow and $t_{withhold}$ directly depends on this natural inflow (see section 2.4 on definition of plant types).

Table 11 - Technical data of power plants included in detailed scenarios.

Name power station (second name)	Country	Region	Turbine units	Total max capacity turbines [MW]	Pump units	Total max capacity pumps [MW]	Category
Aldeadavila	Spain	HIS	8	1242	8	400	PHS > 10 MW
Almendra (Villarino)	Spain	HIS	6	810	6	728	PHS > 10 MW
Alqueva I II	Portugal	HIS	4	519	4	434	PHS > 10 MW
Alto Lindoso Dam	Portugal	HIS	2	630	2	630	PHS > 10 MW
Anapo	Italy	ITA	4	500	4	600	PHS > 10 MW
Bemposta	Portugal	HIS	4	430			RoR > 10 MW
Bieudron	Switzerland	ITA	3	1269			STO > 10 MW
Bitsch (Biel)	Switzerland	ITA	3	340			RoR > 10 MW
Brevieres	France	GAL	3	96			STO > 10 MW
Cedillo	Spain	HIS	4	473			RoR > 10 MW
Cheylas (MR)	France	GAL	2	460	2	480	PHS > 10 MW
Chiotas Piastra	Italy	ITA	8	1184	8	606	PHS > 10 MW
Conzere-Mondragon (Bollene)	France	GAL	6	348			RoR > 10 MW
Coo-Trois-Ponts	Belgium	GER	6	1164	6	1035	PHS > 10 MW
Cruachan	UK	BRI	4	400	4	400	PHS > 10 MW
Dinorwig	UK	BRI	6	1728	6	1650	PHS > 10 MW
Domenico Cimarosa (Presenzano)	Italy	ITA	4	1000	4	1029	PHS > 10 MW

Edolo	Italy	ITA	8	1000	8	1120	PHS > 10 MW
Ffestiniog	UK	BRI	4	360	4	300	PHS > 10 MW
Fionnay	Switzerland	ITA	6	290			STO > 10 MW
Galgenbichl	Austria	ITA	2	120	2	116	PHS > 10 MW
Genissiat	France	GAL	6	420			RoR > 10 MW
Gento-Sallente	Spain	HIS	4	446	4	468	PHS > 10 MW
Goldisthal	Germany	GER	4	1053	4	1053	PHS > 10 MW
Grand Maison Dam	France	GAL	12	1790	8	1160	PHS > 10 MW
Grimsel 2	Switzerland	ITA	4	348	4	352	PHS > 10 MW
Grosio	Italy	ITA	4	428			RoR > 10 MW
Hausling	Austria	ITA	2	360	2	360	PHS > 10 MW
Innertkirchen 1 (MR)	Switzerland	ITA	5	255			STO > 10 MW
Kaunertal	Austria	ITA	5	392			STO > 10 MW
Kops II	Austria	ITA	3	525	3	480	PHS > 10 MW
Kuhtai	Austria	ITA	2	289	2	250	PHS > 10 MW
La Bathie	France	GAL	6	546			STO > 10 MW
La Muela I	Spain	HIS	4	628	4	555	PHS > 10 MW
La Muela II	Spain	HIS	4	852	4	852	PHS > 10 MW
Limberg I II	Austria	ITA	4	592	4	604	PHS > 10 MW
Malgovert	France	GAL	4	332			STO > 10 MW
Markersbach	Germany	GER	7	1046	7	1046	PHS > 10 MW
Mequinenza	Spain	HIS	4	324	4		STO > 10 MW
Miranda	Portugal	HIS	4	370			RoR > 10 MW
Monteynard	France	GAL	4	364	0		STO > 10 MW
Montezic	France	GAL	4	910	4	870	PHS > 10 MW
Nendaz	Switzerland	ITA	6	390	0		STO > 10 MW
Oriol (Alcantara II)	Spain	HIS	4	915	0		STO > 10 MW
Picote I + II	Portugal	HIS	4	441	0		RoR > 10 MW
Pouget (MR)	France	GAL	5	440	1	33	PHS > 10 MW
Premadio	Italy	ITA	6	226	0		STO > 10 MW

Provvidenza	Italy	ITA	3	141	3	141	PHS > 10 MW
Revin Pumped Storage	France	GAL	4	720	4	720	PHS > 10 MW
Ribarroja	Spain	HIS	4	263	0		RoR > 10 MW
Rodundwerk I II	Austria	ITA	5	493	5	317	PHS > 10 MW
Roncovalgrande (Delio)	Italy	ITA	8	1040	8	784	PHS > 10 MW
Rottau	Austria	ITA	4	730	4	290	PHS > 10 MW
Rovinas Piastra	Italy	ITA	1	134	1	125	PHS > 10 MW
Sackingen	Germany	GER	4	360	4	300	PHS > 10 MW
San Fiorano	Italy	ITA	2	560	2	210	PHS > 10 MW
San Giacomo	Italy	ITA	6	448	6	448	PHS > 10 MW
San Massenza I	Italy	ITA	15	350	2	350	PHS > 10 MW
Saucelle	Spain	HIS	6	525	0		RoR > 10 MW
Serre-Poncon	France	GAL	4	380	0		STO > 10 MW
Silz	Austria	ITA	2	500	0		STO > 10 MW
Super-Bissorte	France	GAL	5	748	4	630	PHS > 10 MW
Tajo De la Encantada (El Chorro)	Spain	HIS	4	380	4	360	PHS > 10 MW
Tierfehd	Switzerland	ITA	6	441	6	140	PHS > 10 MW
Vianden	Luxembourg	GER	11	1296	11	1050	PHS > 10 MW
Villarodin	France	GAL	2	357	0		STO > 10 MW
Waldeck II	Germany	GER	2	480	2	476	PHS > 10 MW
Wehr (Hornbergstufe)	Germany	GER	4	992	4	1000	PHS > 10 MW

Table 12 - Data on storages connected to power plants included in detailed scenarios. * The active volume for the "River" tail storage is manually set to 500 Mm^3 and the other numbers are based on this artificial value.

Name power station (second name)	Name head storage	Name tail storage	Active volume head storage [Mm^3]	Max capacity head storage [GWh]	30 year average natural inflow head storage [MW]	$t_{withhold}$ head storage [hour]	Active volume tail storage [Mm^3]	Max capacity tail storage [GWh]	30 year average natural inflow tail storage [MW]
Aldeadavila	Aldeadavila	River*	56.6	18.7	597.10	31	500.0	220.3	1584.28
Almendra	Almendra dam reservoir	River*	2648.6	2155.5	166.74	12927	500.0	220.3	1584.28

(Villarino)									
Alqueva I II	Alqueva	Pedrogao	3150	5.8	1.94	2964	54.0	10.7	237.94
Alto Lindoso Dam	Alto Lindoso	Touvedo	390	237.0	89.41	2651	15.5	12.6	137.15
Anapo	Anapo upper reservoir	Anapo lower reservoir	5.6	4.0	0.01	356992	7.3	7.2	4.48
Bemposta	Bemposta		14.43	2.3	253.43	9			
Bieudron	Grand Dixence reservoir		400	1764.3	16.16	109148			
Bitsch (Biel)	Gibidum		9.2	16.3	45.49	358			
Brevieres	Chevril		230	407.1	17.99	22631			
Cedillo	Cedillo		260	26.4	175.65	150			
Cheylas (MR)	Flumet	Cheylas	4.7	2.9	0.36	7936	7.9	6.5	361.34
Chiotas Piastra	Lago del Chiotas	Lago della Piastra	27.3	17.0	0.29	58681	9.0	29.7	18.83
Conzere-Mondragon (Bollene)	Canal Donzere-Mondragon		0.2	0.0	0.64	17			
Coo-Trois-Ponts	Coo 1, Coo 2	Coo Beneden	8.5	5.8	0.01	863166	8.5	6.0	0.10
Cruachan	Cruachan	Loch Awe	10	10.0	1.13	8829	10.0	11.0	92.46
Dinorwig	Marchlyn Mawr	Llyn Peris	6.7	8.6	0.04	219376	5.4	11.6	4.59
Domenico Cimarosa (Presenzano)	Cesima	Presenzano Lower	6	7.0	0.09	74683	6.0	9.3	0.13
Edolo	Avio, Benedetto	Lago Edolo	17.04	4.9	0.68	7143	1.3	5.1	163.86
Ffestiniog	Stwlan	Tan-y-Grisiau	1.7	1.3	0.04	30547	5.1	4.9	1.09
Fionnay	Grand Dixence reservoir		400	1764.3	16.16	109148			
Galgenbichl	Koelnbrein	Galgenbichl	205	2.9	0.06	46205	4.4	1.3	0.38
Genissiat	Genissiat		56	8.9	166.31	53			
Gento-Sallente	Gento	Sallente	3	0.9	0.51	1765	5.0	5.9	1.02
Goldisthal	Goldisthal-oberbecken	Goldisthal-Oberes S	12	8.4	0.01	584232	19.0	18.1	1.15
Grand Maison Dam	Grand Maison	Verney	132	34.8	0.62	55721	15.6	0.8	0.69

Grimsel 2	Oberaar	Grimsel	61	53.4	3.06	17448	95.0	53.4	0.17
Grosio	Val Grosina		1.2	1.7	4.30	387			
Hausling	Zillergruendel	Stillup	68.7	11.2	0.39	28386	6.6	15.1	13.61
Innertkirchen 1 (MR)	Gelmersee		14	21.9	5.01	4381			
Kaunertal	Gepatsch		140	278.8	11.07	25196			
Kops II	Kops	Rifa	42	2.3	0.02	116867	1.3	3.1	19.97
Kuhtai	Finstertal	Laengental	60	2.7	0.02	142590	3.0	8.9	4.32
La Bathie	Roselend		187	567.2	13.33	42561			
La Muela I	Muela upper reservoir	Cortes de Pallas	20	24.5	0.01	1882871	116.0	193.8	358.86
La Muela II	Muela upper reservoir	Cortes de Pallas	20	24.5	0.01	1882871	116.0	193.8	358.86
Limberg I II	Mooserboden	Wasserfallboden	85.4	72.8	0.36	202953	81.2	97.1	5.16
Malgovert	Chevril		230	407.1	17.99	22631			
Markersbach	Markersbach-oberbecken	Markersbach-unterbecken	6.3	4.0	0.00	838338	8.0	7.2	1.80
Mequinenza	Mequinenza		1533.8	170.1	174.12	977			
Miranda	Miranda		6.66	0.8	198.67	4			
Monteynard	Monteynard		275	77.9	45.60	1708			
Montezic	Monnes_l'Etang	Couesques	30	36.4	2.03	17891	56.1	74.7	296.20
Nendaz	Grand Dixence reservoir		400	1764.3	16.16	109148			
Oriol (Alcantara II)	Alcantara		3162	970.1	452.44	2144			
Picote I + II	Picote		13.43	2.3	273.70	9			
Pouget (MR)	Villefranche-de-Panat	River*	10.9	0.7	0.20	3562	500.0	220.3	1584.28
Premadio	Cancano_San Giacomo	Val Grosina	187	285.4	4.71	60587	1.2	1.7	4.30
Provvidenza	Lago di Campotosto	Provvidenza	217	147.2	0.93	158240	1.7	2.6	3.02
Revin Pumped Storage	Marquisades	Whitaker	8.3	3.6	0.01	299345	9.0	7.0	4.74
Ribarroja	Ribarroja		206.9	13.2	141.92	93			
Rodundwerk I II	Latschau	Rodund	2.24	1.8	0.06	31046	2.1	2.3	55.80

Roncovalgrande (Delio)	Lago Delio	Lago Maggiore	10	17.7	0.04	421485	425.0	984.6	1343.75
Rottau	Galgenbichl	Moell	4.4	1.3	0.38	3403	0.5	1.7	367.90
Rovinas Piastra	Lago della Rovina	Lago della Piastra	1.2	2.0	1.55	1290	9.0	29.7	18.83
Sackingen	Eggbergbecken	River*	2.1	2.1	0.04	54191	500.0	220.3	1584.28
San Fiorano	Lago d'Arno	Sellero	38.8	130.4	4.27	30508	0.6	2.7	315.44
San Giacomo	Provvidenza	Piaganini	1.69	2.6	3.02	867	0.8	1.7	26.80
San Massenza I	Molveno	Lago Santa Massenza	32.7	44.8	6.84	6551	2.1	3.8	3.85
Saucelle	Saucelle		181.5	35.6	355.47	100			
Serre-Poncon	Serre-Poncon		1270	383.6	64.58	5941			
Silz	Laengental		3	8.9	4.32	2059			
Super-Bissorte	Bissorte	Pont des Chevres	39.5	3.2	0.10	32406	1.5	5.4	184.93
Tajo De la Encantada (El Chorro)	Tajo de la Encantada upper	Tajo de la Encantada	4	1.0	0.00	873726	4.0	4.3	51.19
Tierfehd	Limmern	Tierfehd	92	0.7	0.01	45838	0.3	0.5	20.42
Vianden	Vianden upper	Vianden lower	10.8	5.2	0.01	483553	6.8	7.4	0.12
Villarodin	Le Mont Cenis		332.2	689.9	5.51	125198			
Waldeck II	Oberbecken Waldeck II	Affoldener See	4.4	3.4	0.02	174496	7.6	7.9	104.51
Wehr (Hornbergstufe)	Hornbergbecken	Wehrabecken	4.4	7.9	0.07	113544	4.1	8.1	12.48

Appendix VI – Results charts LT emission cap sensitivity

In this appendix, two result charts for the emission cap sensitivity analysis in the LT plan are given. Figure 32 gives the results of the detailed (average inflow) scenario, figure 33 of the lumped scenario. The results are given per power plant category built.

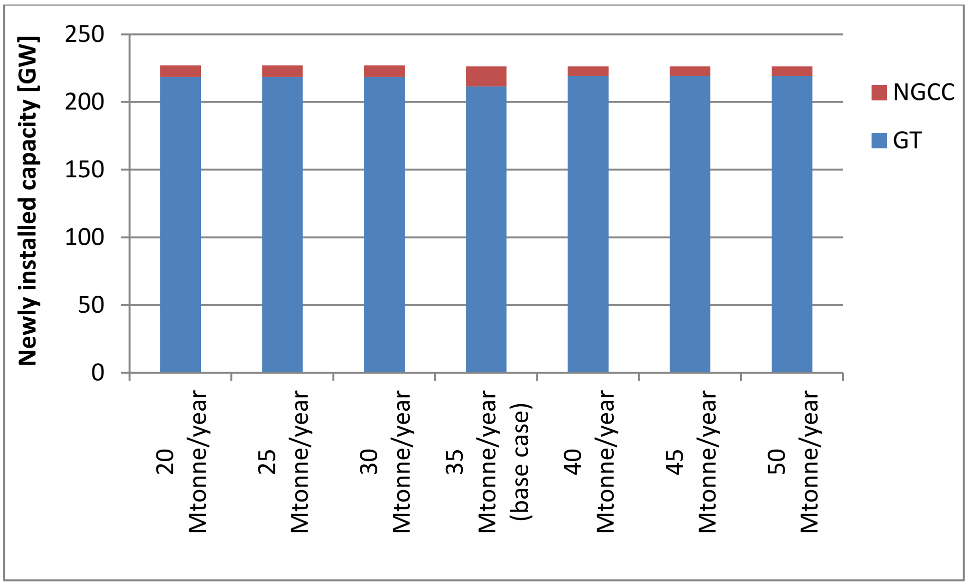

Figure 32 - Emission cap sensitivity analysis on the detailed (average inflow) scenario.

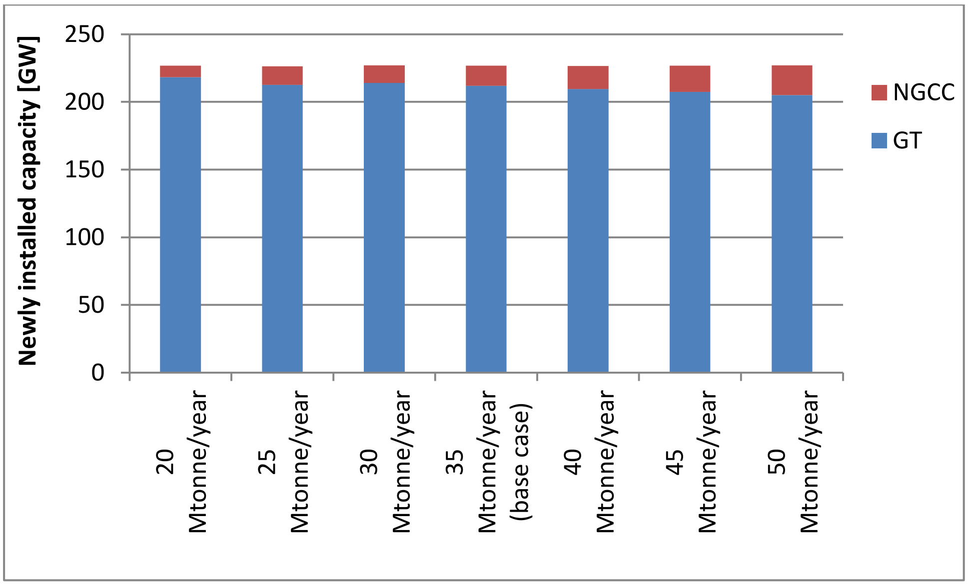

Figure 33 - Emission cap sensitivity analysis on the lumped scenario.

Appendix VII – Result charts of ST schedule, runs over week

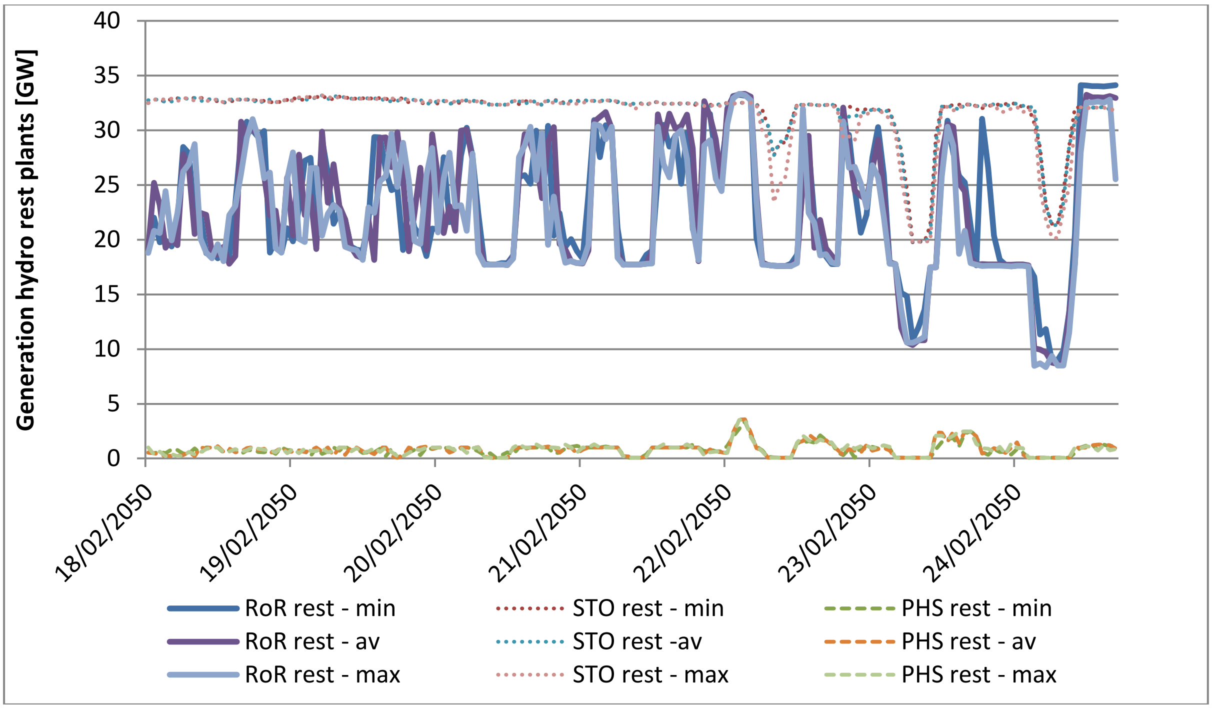

Figure 34 - Generation of hydro rest plant in the detailed scenarios, in the week with maximum total generation by hydro and peak (GT and NGCC) plants.

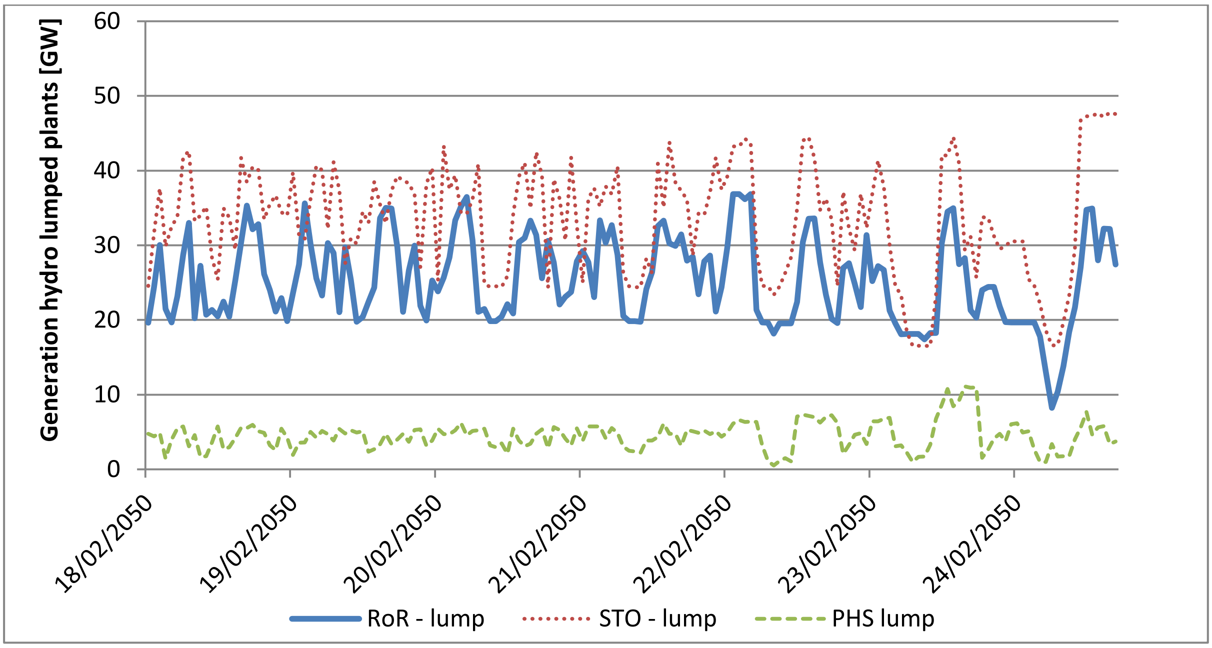

Figure 35 - Generation of hydro plants in the lumped scenario, in the week with maximum total generation by hydro and peak (GT and NGCC) plants.

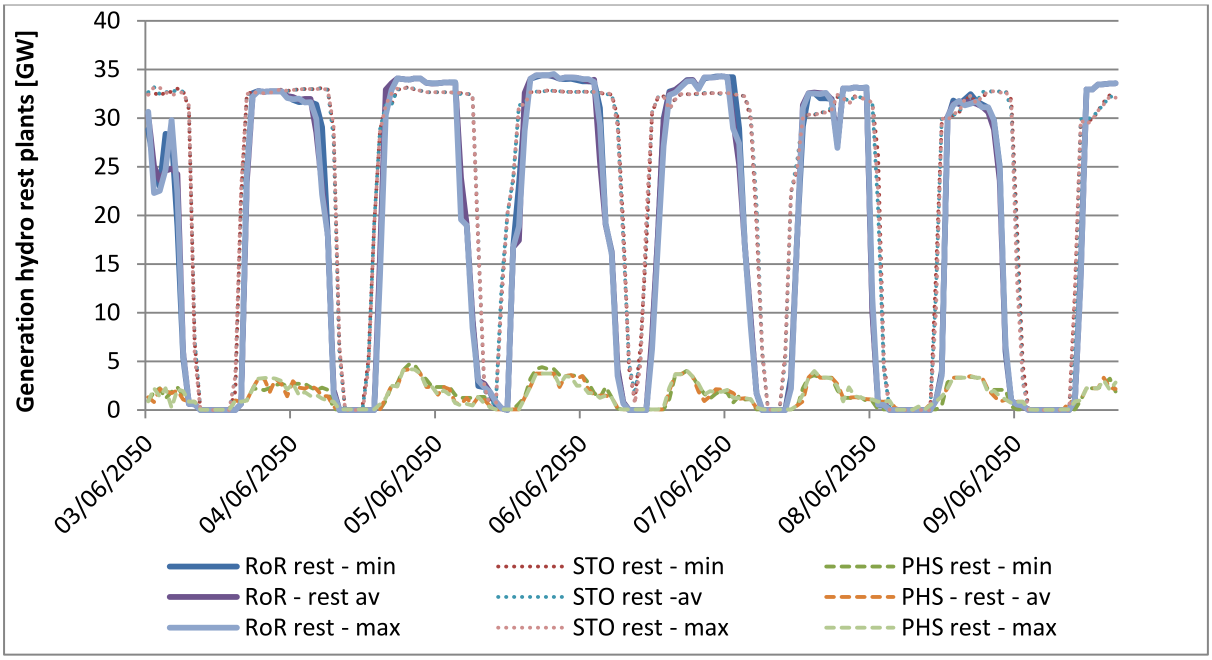

Figure 36 - Generation of hydro rest plant in the detailed scenarios, in the week with minimum total generation by hydro and peak (GT and NGCC) plants.

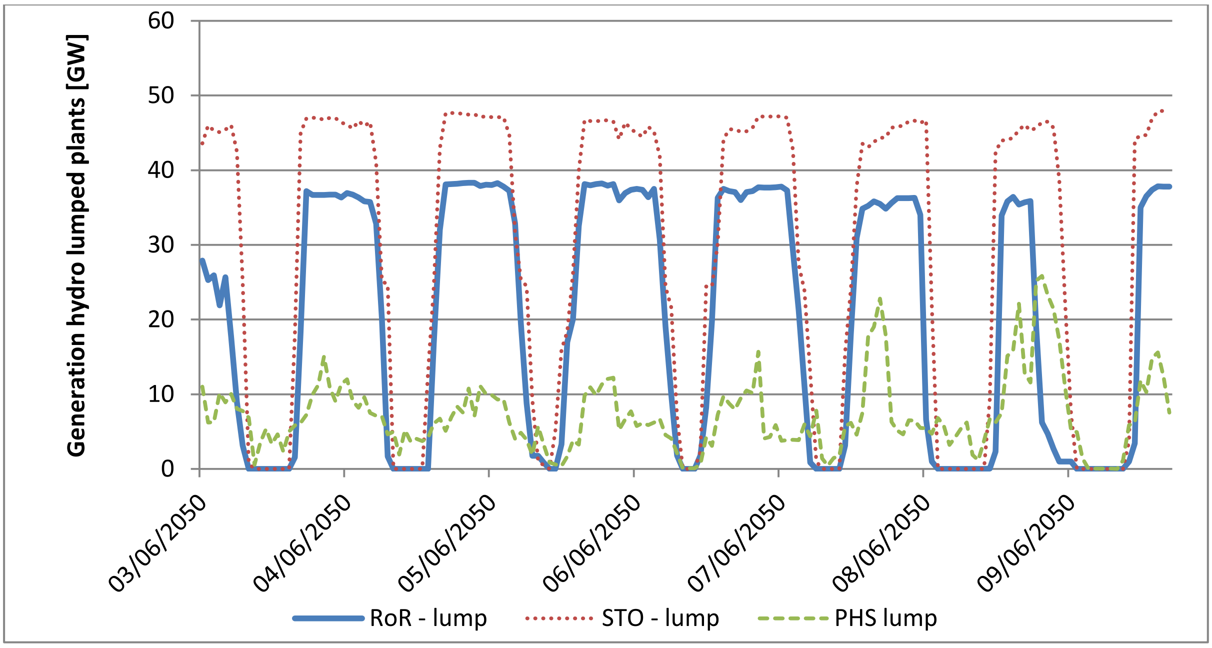

Figure 37 - Generation of hydro rest plant in the lumped scenario, in the week with minimum total generation by hydro and peak (GT and NGCC) plants.

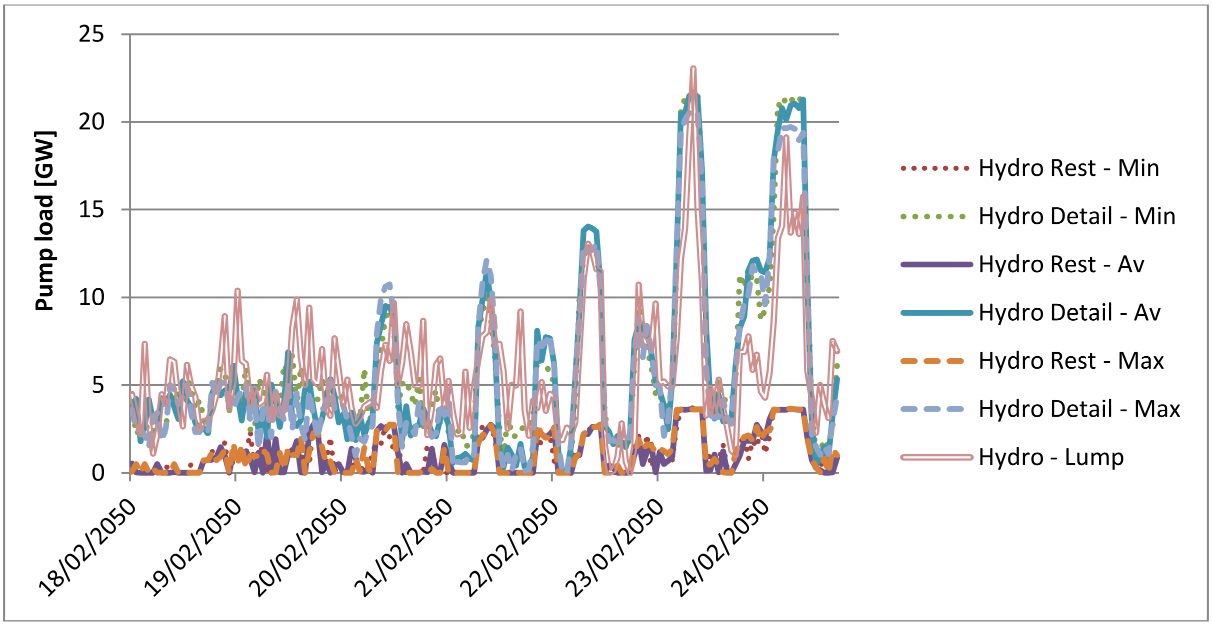

Figure 38 - Hydro pump load in the week starting on February 18th 2050.

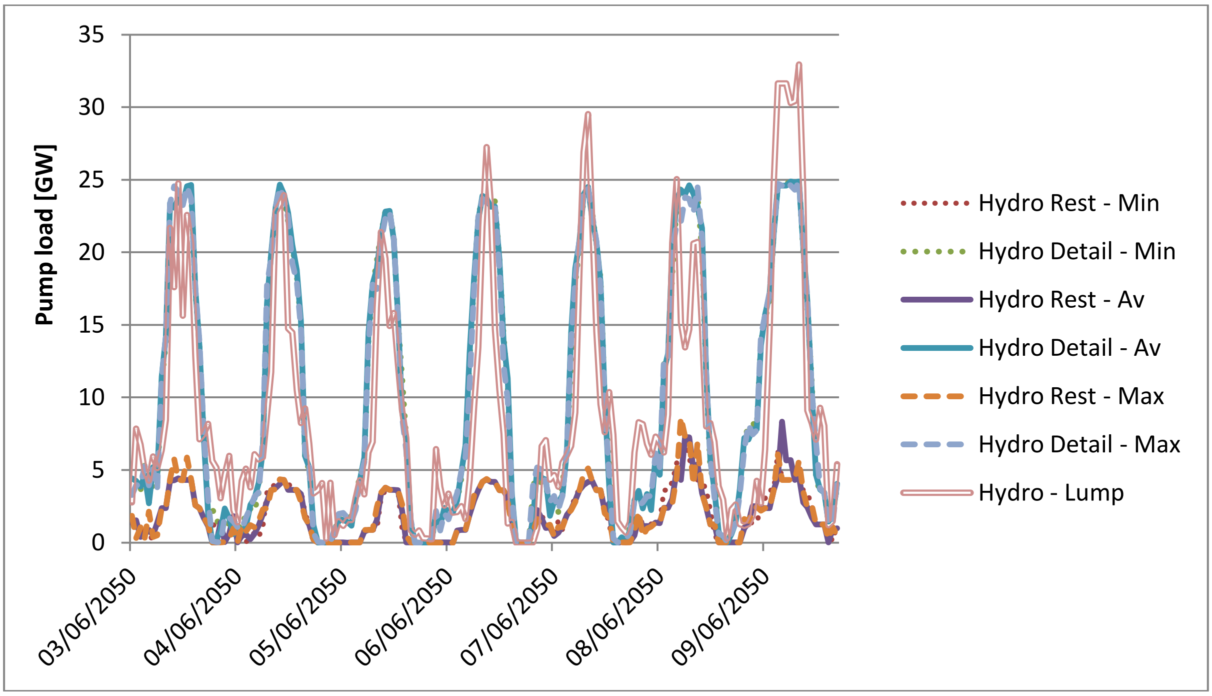

Figure 39 - Hydro pump load in the week starting on June 3rd 2050.