The Value of Pumped Hydro Storage in a Decarbonized World

by

Anthony Fratto Oyler

B.S. Chemical Engineering,
B.S. Political Science,
University of Utah (2017)

Submitted to the Institute for Data, Systems, and Society
in partial fulfillment of the requirements for the degree of

Master of Science in Technology and Policy

at the

MASSACHUSETTS INSTITUTE OF TECHNOLOGY

June 2019

Signature redacted

Author

Technology and Policy Program
May 10, 2019

Signature redacted

Certified by

John Parsons
Senior Lecturer, MIT Sloan School of Management
Head of the MBA Finance Track and co-Director of the CANES Low Carbon Energy Center
Thesis Supervisor

Signature redacted

Accepted by

Noelle Selin
Director, Technology and Policy Program
Associate Professor, Institute for Data, Systems, and Society and
Earth, Atmospheric, and Planetary Science

The Value of Pumped Hydro Storage in a Decarbonized World

by
Anthony Fratto Oyler

Submitted to the Institute for Data, Systems, and Society
on May 10, 2019, in partial fulfillment of the
requirements for the degree of
Master of Science in Technology and Policy

Abstract

Countries around the world have pledged to decarbonize their electricity sector in order to address climate change. In this thesis we investigate the role of pumped hydro storage (PHS) in decarbonizing power generation in combination with a high penetration of low-carbon energy sources. PHS is the oldest storage technology and constitutes of 95 percent of storage capacity worldwide. We provide a technical and historical overview of PHS while noting assumptions about locational availability and environmental concerns that have progressed over the last several decades. This thesis uses a high PHS capacity country, Spain, as its case study.

First, this thesis establishes how PHS operates in a competitive wholesale market, confirming its use of daily arbitrage. Secondly, it shows the degree to which PHS effects the operation of other technology like nuclear, wind, and solar PV and its impact on greenhouse gas (GHG) emissions. This is incredibly important as further buildouts of renewables to meet decarbonization goals will result in high levels of curtailment. PHS can provide value by shifting curtailed energy to low renewable production periods and reducing the need for fossil fuel generation. This value is characterized by a total system cost analysis of meeting in 2030 demand by adding marginal PHS under alternative capacity scenarios. This thesis calculates the investment and operational costs of said marginal PHS. Furthermore, it asks whether these marginal PHS produce the lowest system cost, or whether investments in alternatives—such as solar PV or wind produces a lower system cost. Ultimately, this thesis shows that at expanded penetrations of wind and solar PV, and a firm baseload low-carbon resource, PHS is a lower system cost alternative to further reducing GHG emissions than building out additional renewables. If countries are to expand renewable capacity and they have the ability to expand PHS capabilities they should. To encourage this investment in competitive restructured markets, policy needs to allow PHS to operate within all sectors of electricity including generation, transmission, and distribution.

Thesis Supervisor: John Parsons
Title: Senior Lecturer, MIT Sloan School of Management
Head of the MBA Finance Track and co-Director of the CANES Low Carbon Energy Center

Acknowledgments

High school Anthony would not believe his future self would be submitting a thesis for a master's degree from MIT. And yet here we are, incredibly grateful.

All of my gratitude goes towards my parents who instilled in me a sense of passion for learning and responsibility. Most importantly they taught me to enjoy the little things. To recognize that it was the experiences I had with friends and family that I will remember most about my time at this Institution. They do not care where their children graduate from or the accolades they receive but simply that we are happy and doing the things we enjoy. Their unconditional love and support got me through the stressful nature of higher education. I will be continuously appreciative for everything they have done for me.

Thank you to my sister, Nicole, and my brother and best friend, Chase, who despite being across the country got me through each week with endless phone calls and texts. To my Aunt Mary, who makes leaving home hard every time. Nicole and I would not be the people we are today without you. To my grandmothers, Catherine and Jean, whose matriarchal love and values instilled a bedrock of support within our families.

To my friends in Utah, thank you for making an active effort to make sure we never stay out of touch and grounding me in what I truly care about. To my friends and roommates here in Boston, thank you for giving me a reason to love this city. Without any of you I would never have finished this thesis.

To my CEEPR, JP, and MITei student crew, thank you for getting me through long nights and weekends of PSets, research, and thesis writing.

I'd like to thank TPP for accepting me and giving me this incredible opportunity. To Barb, the literal heart of our Program, who made all of us feel unique and but most importantly heard. To the 18ers and 20ers, thank you for giving me my little own Cambridge family and for validating that TPP is the closest and liveliest program at MIT. And finally, my cohort of 19ers who I would not have survived without and who's individualistic personalities and incredible knowledge and leadership I know will leave the world better than they found it. Thank you for your friendship.

And lastly, I want to thank my advisor, mentor, and friend, Dr. John Parsons. Through him I learned the importance of proper questioning, communication, and critical thinking. I will never forget the first time I came into a meeting stressed and he asked the simple, but oft overlooked, question of "How are you doing." I answered in response to our research and he stopped me and said "No, how are YOU doing." His genuine interest and care for students is apparent and I hope to be half the professional he is one day.

THIS PAGE INTENTIONALLY LEFT BLANK

Contents

List of Figures

List of Tables

Chapter 1

Introduction

Climate change is arguably the most critical issue of this century. In response, numerous countries have pledged to reduce their greenhouse gas (GHG) emissions, with a large focus on decarbonizing the electricity sector through renewables [15]. Yet these low-carbon technologies lack flexibility as compared to fossil fuel plants. Primarily you see this with wind and solar which are weather and time dependent. This fluctuating nature does not allow for uninterrupted supply of power to the end user [63]. If low-carbon technology is to reach a majority share of electricity, as pledged, there will be forced curtailments during higher production periods. This will not only require massive capacity investments into low-carbon energy to meet daily demand but devalue said investments. One of the most commonly discussed and researched solutions to this challenge is energy storage.

The primary goal of this thesis is to determine the role of a specific storage technology, pumped hydro storage (PHS), in decarbonizing the electricity sector. The latest IPCC report gives limited time to mitigate GHG emissions [14]. Therefore, it is imperative for stakeholders to determine the best use of investments and regulation for the deployment of storage on the path to decarbonize. PHS is the only large scale storage technology implemented throughout the world, proven to work for over a 100 years.

This thesis performs two separate methods of valuating PHS, using a high PHS capacity country Spain, as a case study. In both methods I examine a full portfolio of capacity required to serve future demand in all hours of a given year. The first method evaluates the effects the current installed capacity of PHS has on low-carbon curtailment under a variety of energy mixes. This assumes the current PHS installed capacity is a sunk cost and provides value by optimizing low-carbon production and deterring GHG emissions that would have otherwise occurred if PHS had not been installed.

In the second method I determine the total system cost to meet demand by adding marginal PHS to the capacity mix. I calculate the investment needed to install the capacity plus the cost of operating the capacity. I ask whether these marginal PHS produce the lowest system cost, or whether investments in alternatives–such as solar PV or wind produces a lower system cost.

Through statistical analysis and optimization, this thesis addresses the following questions:

1. How does PHS work within the current electricity system?
2. To what degree does the current capacity PHS curb curtailment of low-carbon generation and promote lower GHG emissions?
3. Which low-carbon source does PHS primarily optimize?
4. Is PHS investment a least cost technology required to decarbonize?
5. How does policy and regulation play a role in PHS investment?

Selecting Spain is two-fold. For one it has ambitious decarbonization targets; a 100 percent renewable electricity grid by 2050 [79]. Secondly, Spain has the highest absolute PHS capacity of Europe and the fourth highest in the world, behind the U.S., China, and Japan [28]. While this thesis discusses the global history and role of PHS, it utilizes Spanish data to serve as a visual reference and to value PHS.

Chapter 2

Overview of Pumped Hydro Storage

The hallmark of energy storage, highlighted by numerous works, is its ability to address the concerns the electricity system endures under heightened wind and solar penetration [24, 33, 6, 76, 16].

First, renewables increase the variability of the net load, or the demand remaining after renewable generation. In certain hours, under high renewables, supply could momentarily exceed demand and in others fall just shy of demand. Storage can be used to offset this discrepancy, by "regulating up" when there is a supply shortfall by increasing its discharge and/or reducing charging. When there is excess supply, storage can "regulate down", reducing its discharge and/or increase charging. This is called frequency regulation.

Second, renewables affect ramping rate, the speed at which load-following units have to change their output. For example wind generation ramps up and down as quickly as wind speed changes. This can threaten the flexibility of the grid. Storage can mitigate large ramping rates by discharging or charging at a rate equivalent to wind.

Third is uncertainty. While forecasting wind and solar patterns has improved weather can change fairly quickly. Long duration storage can hold electricity to be used when wind and solar are suddenly unavailable. This is imperative for a resilient electricity system.

The final impact of increased penetrations of renewables is its affect on ramping range, the difference between the daily minimum and maximum demand. High renewable production hours reduces the minimum load such that it could force baseload generators, like nuclear, to scale-down their output or turn off. Baseload generators are not as flexible as renewables. Thus storage could transfer renewable generation to other time periods of the day. This would raise the minimum load and ensure baseload generators stay on so as to not incur the cost of reducing their output or turning them off. Alternatively, storage could act as the baseload power source itself. That is, energy harnessed from renewables could be stored and deployed during non production periods.

Ultimately this act of optimizing low-carbon energy sources is imperative for renewables to succeed at high penetration levels within a national power system [5].

Energy storage systems are categorized as follows [63]:

Table 2.1: Bulk Storage Systems

System	Type
Mechanical	Pumped Hydro (PHS) Compressed Air Energy (CAES) Flywheels
Electrical	Capacitors Superconducting magnetic energy (SMES)
Chemical	Metal-air Flow battery Lithium-ion battery Sodium-sulfur (NAS) battery Hydrogen energy

Of the storage technologies above only two serve as large-scale (> 100 MW) commercial, in-front-of-the-meter storage; PHS and CAES [72]. There are only two CAES facilities in the world [1] [85, 75]. Yet, there are over 350 PHS plants worldwide that account for 185 GW installed capacity [28]. That accounts for over 94 percent of global total installed storage [28]. PHS is the most mature storage technology, having served as a peaking power source throughout the 20th century.

2.1 Technical Characteristics

The energy that is extracted from the water of a PHS plant is potential energy contained within the mass of the water as a consequence of its elevation [9].

[1] A 110 MW and 290 MW plant in the U.S. and Germany, respectively

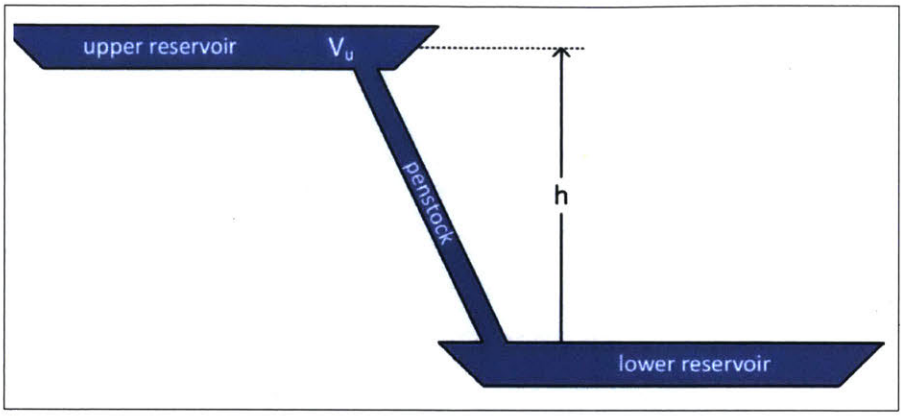


Figure 2.1: PHS Reservoirs

PHS is composed of two reservoirs, an upper and lower. They are separated by a height, h (m), as seen in Figure 2.1. This height, also known as the hydraulic head, is greater than the depth of the upper reservoir. The upper reservoir stores the potential energy as water, whose volume is V_u (m^3).

The total stored energy, E_t (J) in the reservoir is:

$$E_t = V_u \rho g h$$

Where ρ is the density of water, 1000 kg/m^3, and g is the gravitational acceleration in [m/s^2].

The energy density, e_v (J/m^3) of the stored water is:

$$e_v = \frac{E_t}{V_u} = \rho g h$$

In order to convert the gravitational potential energy to electricity, water falls from the high level reservoir into the lower reservoir through a penstock. The penstock can be above ground pipes or below ground shafts that are generally steel- or concrete-lined, roughly 5-10 m in diameter. From the penstock the water drives a pump-turbine that powers an electrical generator all within a "power house" [22].

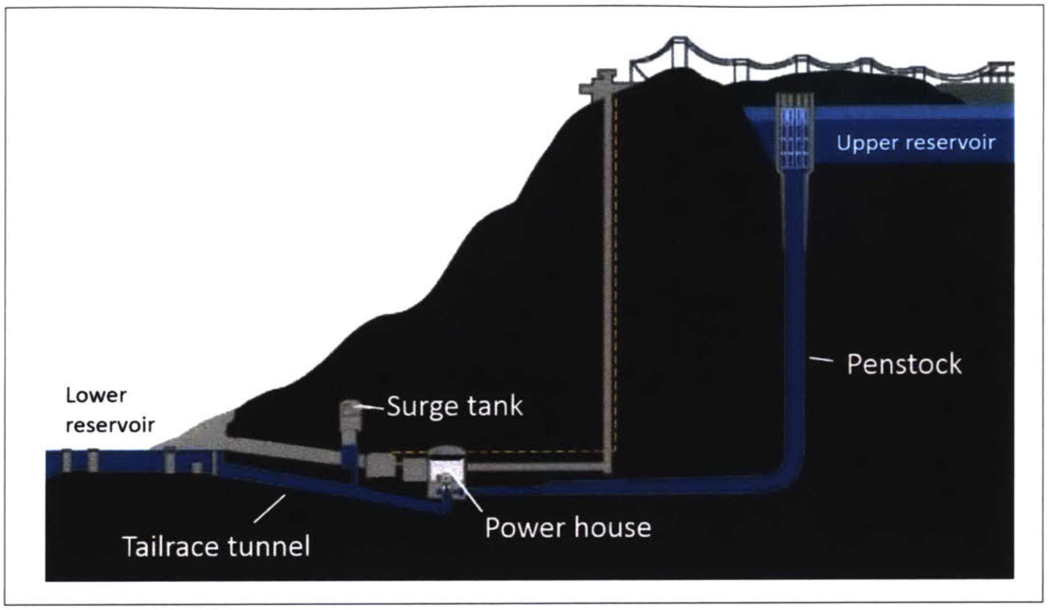


Figure 2.2: Components of a Typical PHS Unit

Additionally, a typical PHS unit will contain a tailrace tunnel. It has a larger diameter than the penstock and used to lower pressure and flow rate of water when being pumped to the upper reservoir. A surge tank also placed on a tailrace or penstock as extra storage space when there is a long penstock. These components are shown in Figure 2.2.

When it's generating, the turbine directs power towards the grid. However, when it's in storage mode the grid or some other external source, supplies power to pump the water from the lower reservoir into the upper reservoir.

The energy density of the stored water is also the hydrostatic pressure at the level of the lower reservoir and thus the energy density of the water at the turbine.

The rate at which energy is transferred to the turbine (from the pump) is the power, P (W), extracted from (delivered to) the water:

$$P = \rho Q g h$$

Where Q is the discharge/flow rate in [m^3/s]. [2].

However, this does not account for the round-trip efficiency, η, of PHS plants:

$$\text{efficiency} = \eta = \frac{\text{Generation}}{\text{Consumption}}$$

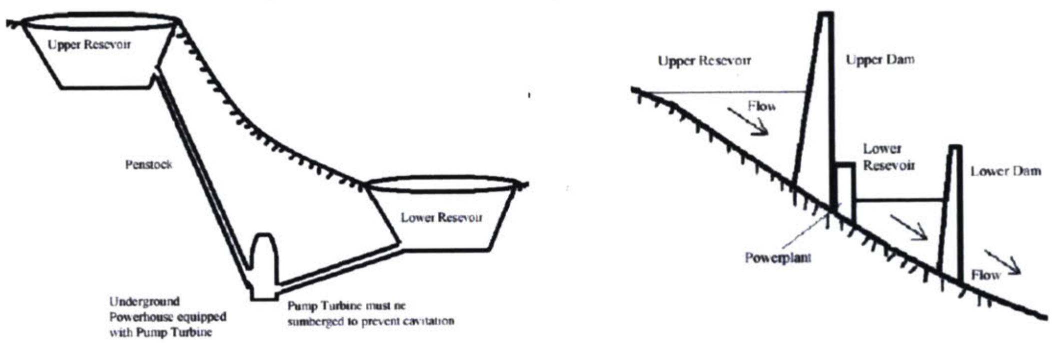
[2]The larger the cross-sectional area of a penstock the slower flow rate is. This translates to a smaller power value but lower loss of water.

Efficiency ranges between 65-85 percent depending on the age of the station and/or pump updates [47, 2, 22, 71].

Therefore the true nameplate capacity of PHS is, P [46]:

$$P = \eta p Q G H$$

There are two main kinds of pumping stations, pure and pump-back, as seen in Figure 2.3 courtesy of Deane et al. (2009).



a: Pure b: Pump-Back

Figure 2.3: PHS Schematic

Pure PHS generally do no have any natural inflows into the upper reservoir, and serve only as storage facilities [29]. They depend on water that has been pumped to the upper reservoir from the lower reservoir that sits on a stream or other body of water [22, 29]. This type of development relies entirely on pumped water as a source of energy. These projects allow for a daily or weekly cycle in order to generate 6 to 20 hours continuously at full output [29]. In addition to a daily/weekly cycle they can used as seasonal storage, i.e. water is pumped into the upper reservoir during the high flow season, with releases being made during low flow periods to back up generation of run-of-river plants.

Pump-back PHS are typical hydro reservoir plants in which a pumping unit has been installed [22]. This is done for two reasons. The first and the primary reason for installation, is to allow the plant to act as a peaking unit because the natural inflows are not large enough to do so on their own [29]. The second, similar to seasonal pure PHS, is to allow the hydro plants to firm up their capacity during periods of low flow [29].

2.1.1 New Developments

Despite a consistency in technology over the decades, PHS has seen recent innovations and improvements primarily in pump design [4, 22].

The traditional design is a reversible single-stage Francis pump-turbine, which acts as a pump in one direction (lower to upper reservoir) and as a turbine in the other (upper to lower reservoir) [4]. A layout of the Francis turbine and a cross-sectional schematic is shown in Figure 2.4 courtesy of Nazari-Heris et al. (2017) and Breeze (2014) [57, 10].

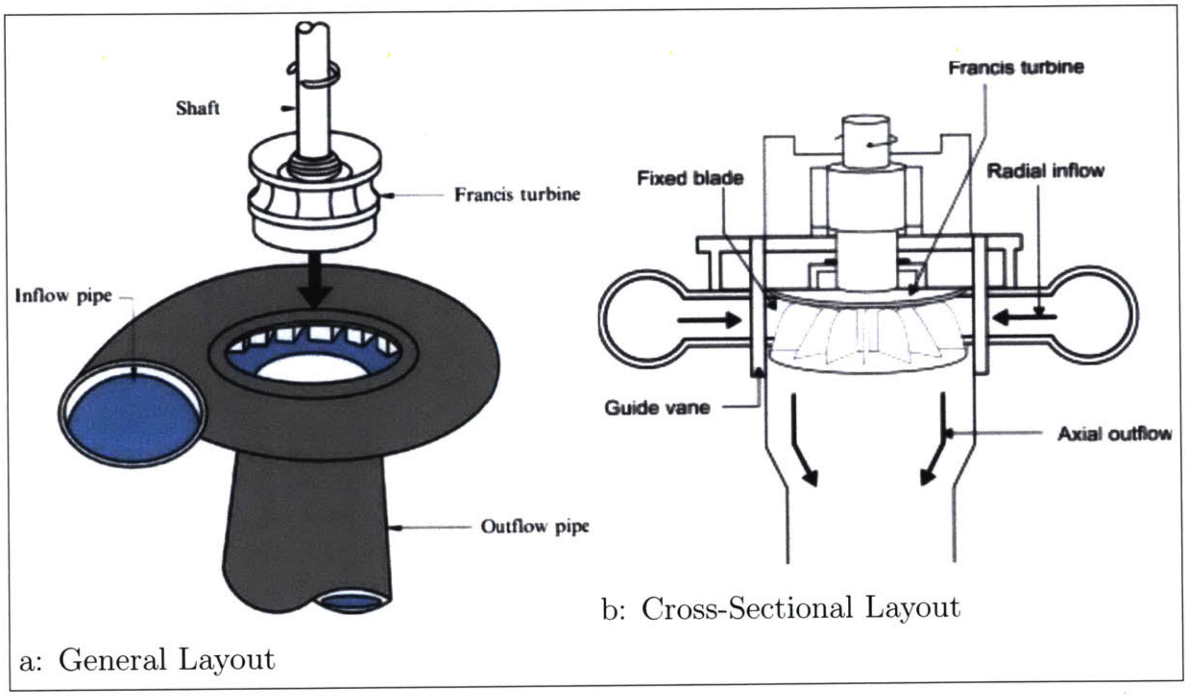


Figure 2.4: Francis Pump-turbine

Developed in 1855, its key characteristic is the fact that water changes direction as it passes through the turbine. Flow enters the turbine in a radial direction, flowing toward its axis, striking the turbine blades. The force exerted on the blades causes the turbine to spin and the rotation is converted into electricity by a generator [57, 10]. The water then exits along the direction of the axis [57, 10].

Over the years R&D on this turbine has allowed PHS to makes strides in efficiency as well as power output capability [4, 22]. However, there are still issues. When it is in pumping mode, traditional PHS can not regulate frequency and while in turbine mode it can not operate at peak efficiency [4, 22].

Enter the recently developed "variable speed" pump, a motor-generator that allow the pump/turbine rotation speed to be independently adjusted through a frequency converter [22]. A general design of Toshiba's is shown in Figure 2.5 [21].

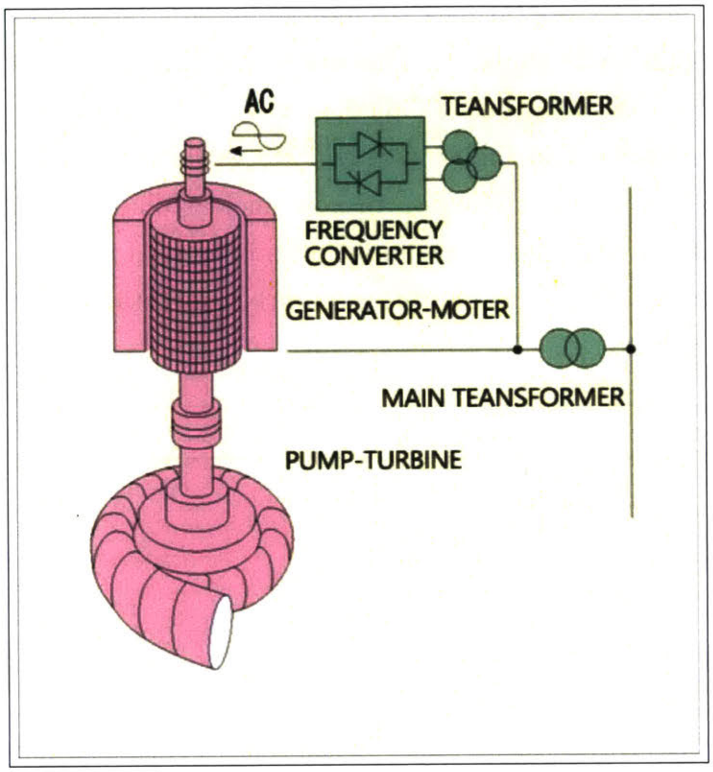


Figure 2.5: Variable Speed PHS System

In pumping mode, the control of speed allows for the regulation of the amount of energy consumed [4, 22]. In turbine mode, variable speed can optimize peak efficiency operation [4, 22]. This adds value to the system because not only would it reduce the number of start-stops, but provide another ancillary service through the regulation of frequency. This is incredibly useful for high variable renewable energy inputs during low consumption (i.e. wind at night) or during large ramping periods [4]. Thus a PHS with a variable speed pump would have additional ancillary service opportunities by selling regulation reserves at night [45].

2.2 History

The earliest PHS plant appeared in the Alpine regions of Switzerland, Austria, and Italy in the 1890s [84]. They expanded to Germany and the U.S. in the 1920s [85, 75].

The development of PHS remained relatively slow until the 1960s when utilities in many countries began to envision a dominant role for nuclear power. PHS was built primarily to complement nuclear as peaker plants, as well as storing the minimum technical output of coal-fired stations [22, 40]. By operating PHS alongside these baseload stations, nuclear and coal could operate at higher efficiencies [3]. This usage of PHS was seen not only in Spain but throughout Europe, the U.S., and Japan [86].

The 1990s saw a stagnation in the growth of PHS worldwide due to a variety of factors including, but not limited to, the reduction in new nuclear plants, environmental concerns, the competitiveness of gas turbines as peaking units (due to a drop in gas prices), trouble with identifying locations of new PHS plants, and market uncertainties with the restructuring of the power sector [4] [63, 2].

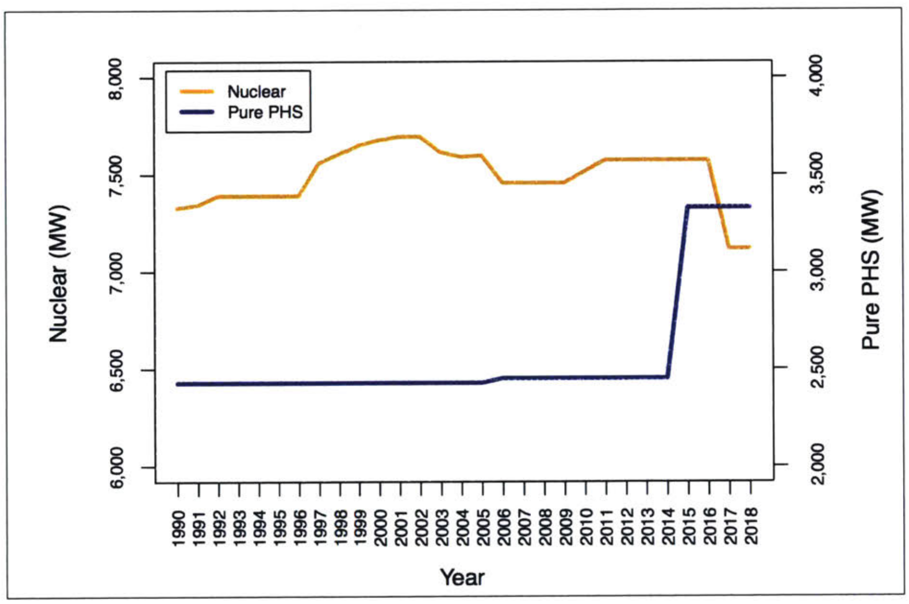


Figure 2.6: Spanish Nuclear and PHS Capacity, 1990-2018

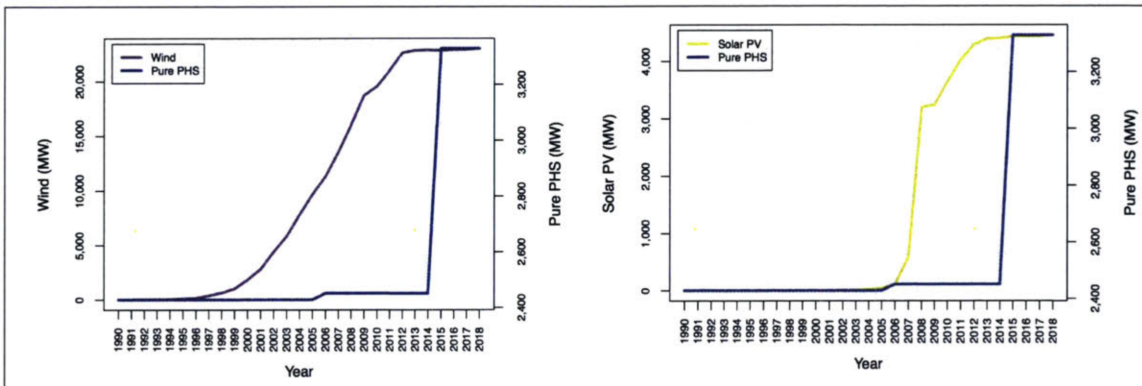
We see this stagnation in Spain in Figure 2.6 above, which compares nuclear capacity (primary y-axis) to pure PHS capacity (secondary y-axis) [5]. The seven nuclear reactors that

[3]Thermal power plants have a minimum requirement of operation that ranges from 10% (oil and open cycle gas turbines) to 50% for coal and 75% for nuclear [74]. Frequent start-stops cause wear and tear in the equipment that significantly affects their lifetime and life-cycle cost [64].

[4]PHS is classically defined between the generation and transmission sector. In structured wholesale market, reserve capacity and ancillary services are served by peaking power plants. It was unclear how PHS would participate in these new markets.

[5]Note the figure begins at 1990 as that is when the Spanish electricity operator, REE, makes yearly capacity data available.

operate in Spain today were installed in the 1980s, as were the pure PHS units [6]. Pure PHS and nuclear capacity remained relatively steady to one another for almost 25 years until the La Muela PHS plant was put online in 2015, and the Garona nuclear power plant was officially decommissioned in 2017 [7].



a: Wind and PHS

b: Solar PV and PHS

Figure 2.7: Spanish Renewable and PHS Capacity, 1990-2018

However, PHS has found a new role with variable renewable sources such as wind and solar. Spain's La Muela PHS plant began operation as wind and solar installations have taken off as seen in Figure 2.7 above, which compare the installed capacities of pure PHS to wind and solar PV respectively. Wind and solar capacity are graphed on the primary y-axis of their respective sub-figures, while pure PHS is graphed on the secondary y-axis. If Spain is to increase its renewable share to meet emission standards, storage like PHS will need to play an integral part.

2.3 Uses and Challenges

PHS sits atop storage technology as the most mature in terms of technology and manufacturing and marketing position [47, 36]. It is a versatile and valuable resource that can increase power system reliability, reduce customer costs, and facilitate high wind and solar

[6]Five additional nuclear plants were to be installed in Spain however a moratorium in 1984 placed a hold on their construction, and a 1994 act finalized their abandonment and cancelled long postponed plans for future projects [35]. No other new plants have since been planned.

[7]Small increases in the capacity of nuclear seen in the figure are from investments in uprates at the existing plants. [35]

integration [44, 63, 52, 41, 55, 56, 45, 47, 77, 23, 82]. By moving energy surplus production hours to high demand hours, PHS can reduce energy price volatility [45]. Additionally PHS serve as ideal ancillary services resources with fast ramp rates, fast startup and shutdown, and low cycling costs [45].

Therefore it is important to identify not only the uses and benefits PHS provides to the electricity market but the challenges that have been cited as deterrents to potential investments.

2.3.1 Role in the Electricity Market

There are two types of electricity markets: regulated and restructured. In both markets the lowest-cost generators are scheduled to serve the expected hourly load, and then are optimally dispatched based on additional technical, security, and economic constraints. This is done through marginal-cost-based economic dispatch in regulated markets and through cost-based-bids in restructured market (i.e. Spain).

2.3.1.1 Traditional Regulated Market

Traditional electricity markets function under a vertically integrated, regulated monopoly business model [60]. A utility operates and owns all the generation and network assets in a given region. They are required to meet all of the supply of the consumers of their area, as well as plan and implement the expansion of production and network capacity under the guidelines of the regulatory authority [60]. Consumers are assigned to the utility that serves their region and thus protected by the regulator for minimum standards of quality of service and remuneration. Remuneration is based on the cost of service, with a regulator approved rate of return for the utility to make a "just and reasonable" profit [60].

Under a regulated market, PHS would theoretically provide savings by limiting the need for expensive peaking plants. These savings would pay for the PHS plant. Additionally the utility, in coordination with the regulator, would have enough control over consumer remuneration prices to allow for the investment of PHS.

2.3.1.2 Restructured Market

The restructured market is inherently a wholesale, spot market for electricity in both generation and retailing [60]. The agents trading are generators, consumers, and different categories of supplier companies. In order to ensure competitiveness there must be unbundling, i.e. companies retain generation and retailing assets but are vertically separated from transmission and distribution services [60]. Asset and infrastructure expansions are based on individual company decisions that attempt to maximize earnings through power supply contracts. Thus, investment decisions are dependent on perceived economic and financial risk [60]. Regulating authorities are responsible for trying to achieve a minimization of system costs while respecting reliability and environmental objectives and constraints. Under the restructured market, real-time operations are overseen by a central System Operator (SO) [60].

In a restructured market PHS can play a role in two forms: ancillary services and energy arbitrage [27]. The specifics of each are outlined below [27, 3]:

Storage Service	Description
Ancillary Services	Functions by generating, transmission, and distribution system equipment to support basic services of energy supply and power delivery
Operating Reserves	Resources at the ready to inject or removing energy into the system
Event	Resources standing ready to inject energy into the power system when a major disturbance occurs
Contigency (Spinning)	Generation capacity that is online but unloaded that can respond within 10 minutes to compensate for generation outages
Ramping	Resources that offset output ramping, i.e. wind generation's output ramps up or down quickly as wind speed changes quickly so resources as ramping service must increase or decrease proportionally with wind generation output changes.
Non Event	Constantly injecting or removing energy from the power system
Regulating (Frequency)	Moment-to-moment reconciliation of the difference between supply and demand to maintain the stability and accuracy of the AC frequency. As more variable generation resources are added the electric supply will vary along with demand.
Following	The generation required to during the transition hours of the daily electric demand cycle, i.e. when demand increases in the morning as people begin their day and when it diminishes in the evening as people begin to go to bed.
Voltage Support	Maintaining the necessary voltage level and stability for the electric grid. *PHS not used for voltage support*
Black Start	The first to power up to re-energize the grid after a blackout as per a long-term contract
Energy Arbitrage	Charging storage when energy is plentiful and inexpensive and returning that energy to the power system when it is scarce and expensive
Daily/Weekly	Buying electricity to pump water to the upper reservoir at low prices (i.e. when low-carbon sources are the marginal plant) and generating electricity at high prices. Can generate between 6 to 20 hours continuously at full output
Seasonal	Water is pumped into the upper reservoir during the high flow season, with releases being made during low flow seasons where they are more likely needed (less hydro run-of-river and reservoir sources, higher electricity demand, etc.)

Figure 2.8: Energy Storage Grid Benefits

For PHS to make economic sense as energy arbitrage, the ratio of the cost of charging the energy to discharging must exceed the round-trip efficiency, η. That is the energy price in pumping mode needs to be at least (1-η) lower than the selling price to cover *variable O&M*

costs (VOC) [47]. Generally this economic rationale is expressed as the *marginal revenue* (MR), the difference between the selling price of produced energy (P_{sell}) and the cost of pumping (P_{buy}). The MR must be at least equal to or greater than the VOC.

$$MR = P_{sell} - P_{buy} \geq VOC$$

where

$$P_{buy} < \eta P_{sell}$$

2.3.2 Challenges: Locations and Environmental Impacts

It was, and still is, a common misconception that suitable locations to construct new PHS facilities were limited as few assessments of PHS potential were conducted [8] [20, 8, 39, 69, 85, 2]. Additionally, environmental impacts have historically been of serious concern. Extensive lobbying from environmental groups caused many PHS projects to be cancelled [84]. Conventional PHS construction would sometimes require damming a river to create a reservoir. This in turn disrupts the natural aquatic ecosystem, can trap and kill fish, and destroy the terrestrial habitat and landscape of the area now flooded [85, 84].

Solutions to these problems take multiple forms. The first is adapting current infrastructure. This includes retrofitting existing hydropower plants with pumping mechanisms (i.e. pump-back PHS) and upgrading older pure PHS systems to have higher efficiency turbines (older generations have around 70 percent, newer ones up to 85 percent) [47, 2, 22].

The second solution is optimizing non-traditional locations. This not only grows PHS capacity but limits environmental impacts. This could include utilizing off-stream systems, which would not require damming a river and thus pose fewer problems for aquatic ecosystems [85]. Or PHS could use already made reservoirs, such as underground reservoirs, groundwater systems and abandoned quarries and mines. This would also avoid impacts to existing water bodies and ecosystems [85].

In 2009 there was a capacity of around 130 GW of PHS [85]. This has increased by over 40 percent in the last decade [28]. Recent studies have shown that PHS site potential locations are much more common than originally thought [85, 20, 19].

[8] For example the most comprehensive assessment of PHS conducted in the United States was by the Army Corps of Engineers in 1982. According to Yang et al. (2011), "no comprehensive assessment of PHS potentials has been conducted in the United States since." [83, 85].

Chapter 3

Spanish Energy System

3.1 Overview

Table 3.1 shows peninsular Spain's current electricity capacity and generation mix.[1]

The country has nearly 100 MW of capacity spread among a diverse mix of resources, including a large set of nuclear plants, a significant amount of hydro and wind facilities, a smaller set of solar facilities, and a large set of coal plants, natural gas combined-cycle plants and cogeneration plants, and others. In 2018, Spain's electricity demand on the peninsula totaled approximately 253.5 TWh. 14 percent of demand was supplied by the country's hydro resources, 5.5 percent of which was pure PHS. Low-carbon generation (i.e. renewables, nuclear, and cogeneration) account for roughly 56 percent of total installed capacity and 72 percent of generation to meet demand. Renewables themselves account for 44 percent of total installed capacity they only account for 39 percent of generation to meet demand.

In terms of trends Spain's oil units have all but disappeared while coal has begun to fall. Nuclear and natural gas combined-cycle (CCGT) units have remained fairly steady since the 90s. Since the beginning of the millennium solar PV and wind has grown dramatically [30].

Spain has always had a build of excess capacity thanks mainly to their high capacities of thermal plants and hydro. This is still the case today as is evident from the capacity factors for the fossil fuel-fired units displayed in Table 3.1. The natural gas CCGT, coal, and cogeneration units have average capacity factors of 12 percent, 42 percent, and 58 percent respectively.

[1] I restrict my analysis to Spain's peninsular system, i.e., excluding the Balearic and Canary islands as well as the African coastal cities of Ceuta and Melilla. However, my accounting includes the power delivered from the peninsula over the Balearic HVDC link and delivered over the transmission network between Portugal and France. It does not include self-consumption from PV or other generation located behind the meter.

Table 3.1: Spain's Electricity Capacity and Generation Mix in 2018

		Installed Capacity (MW)	Share	Generation & Demand (GWh)	Share	Capacity Factors
		[A]	[B]	[C]	[D]	[F]
	Spanish Generation (Peninsula)					
[1]	Hydro	17,047	17%	34,097	13%	23%
[2]	Pure PHS Turbine	3,329	3%	2,009	1%	7%
[3]	Nuclear	7,117	7%	53,198	21%	85%
[4]	Coal	9,562	10%	34,882	14%	
[5]	Combined Cycle	24,562	25%	26,403	10%	12%
[6]	Wind	23,091	23%	48,902	19%	24%
[7]	Solar PV	4,460	5%	7,363	3%	19%
[8]	Solar Thermal	2,304	2%	4,424	2%	22%
[9]	Bio	858	1%	3,546	1%	47%
[10]	Cogeneration	5,729	6%	28,975	11%	58%
[11]	Other	575	1%	3,029	1%	60%
[12]	**Total**	98,634		246,828		
[13]	PHS Pumping			(3,201)		
[14]	Baleric HVDC Link			(1,233)		
[15]	Interconnection Balance			11,102	4%	
[16]	**Spanish Demand (Peninsula)**			253,496		

Source: Red Eléctrica de España (REE) National Statistical Series (March 2019)

Notes:

[1] Hydro includes reservoirs, run-of-river, and mixed PHS units which REE aggregates in their yearly statistical data set

[11] Includes waste, residual energy, mining sub-products, fuel gas, oil, and geothermal

[13] Includes the consumption of both mixed and pure PHS units

[D] Generation share is the share of the total demand

3.2 Hydro

Spain's hydro resources (including pure PHS) have accounted for 20 percent of total installed capacity (20 GW) since 2015 when an additional 3 GW were installed [30]. The decade prior it varied between 16-20 percent [30].

Hydro inflows for reservoirs and run-of-rivers can fluctuate each season and year, thus annual hydroelectric generation sits between 5-15 percent (20-40 TWh) of total demand. 2017 was a historically dry year for Spain, at around 7 percent with an hydroelectric index 0.5 [2]. Hydro generation in 2018 was higher than average, accounting for 13 percent of electricity demand with an index of 1.3 [30, 32].

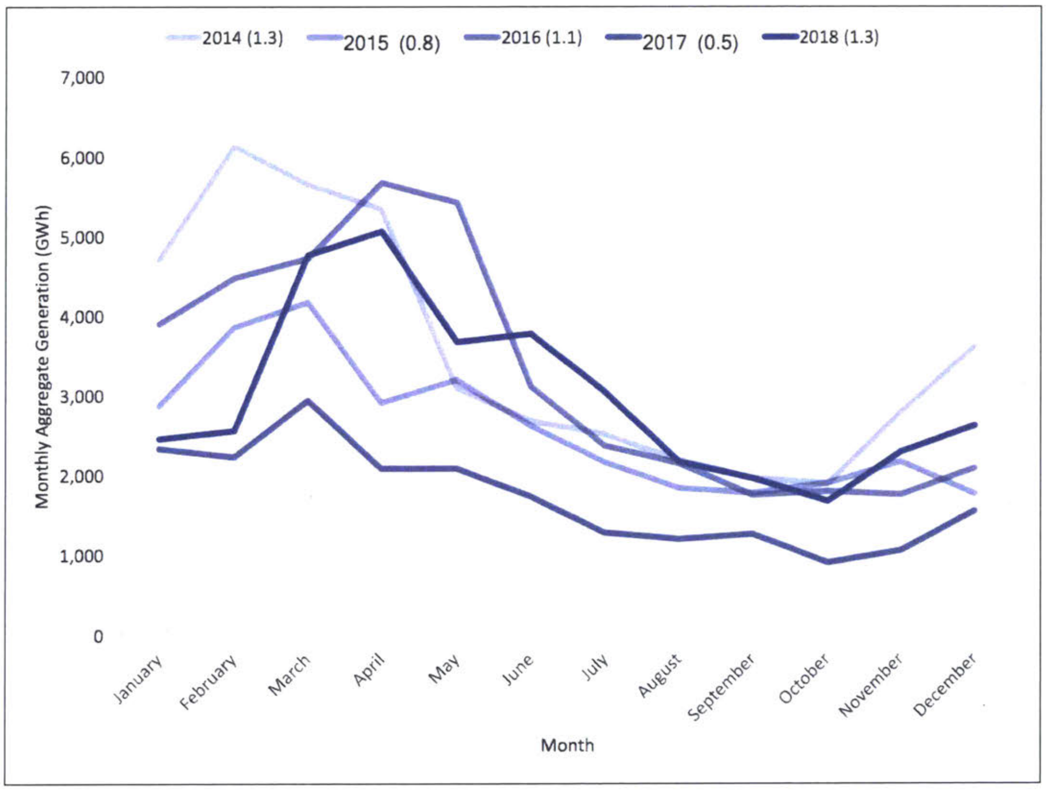


Figure 3.1: Monthly Generation of Aggregate Hydro Resources in Spain 2014-2018

Historically, the months of winter and spring are periods in which there is a greater contribution of hydroelectric power generation due to high rainfall and snow melt in those

[2]The hydroelectric index is the quotient between the producible energy and average producible energy of hydro resources. Producible energy is defined by REE as maximum quantity of electricity that theoretically could be produced considering the water supplies registered during a specific period of time, and once the supplies used for irrigation or uses other than the generation of electricity have been subtracted. An index of 1.0 constitutes an "average" hydro year.

months as seen in Figure 3.1 [31, 30]. The aggregate generation of all hydro resources are graphed by month for the last five years. We indicate their hydro electric index to show the difference in water supplies/inflow has on their generation. Note that no matter the index, the generation of any given year starts to rise in November or December, peaks between February and April, and begins to fall after that.

Spain classifies hydro resources as hydro UGH, non-UGH, and pure pumping. Hydro UGH are power stations belonging to the same hydroelectric basin and market bidding individual. They also contain pumping units that can be used as storage (i.e. pump-back) [3]. When there is a water surplus, the power station will function as a conventional power station, but still maintains the ability to store energy by pumping water from the lower to the upper reservoir.

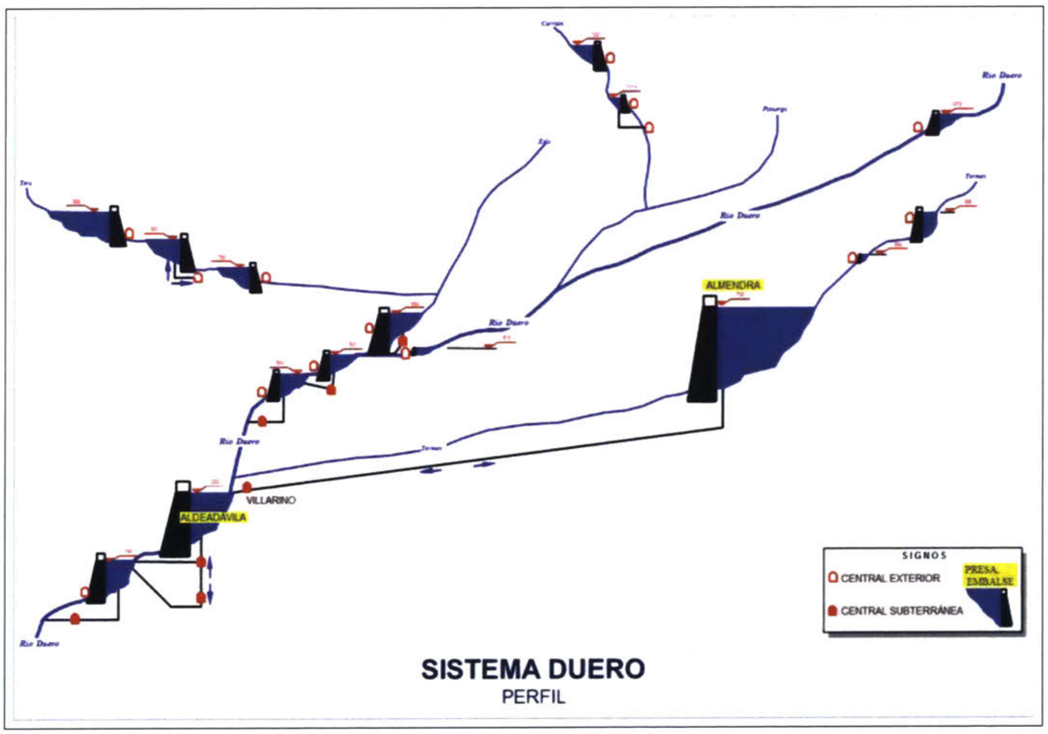


Figure 3.2: Dureo Hydro Plant, Castilla y León, Spain

One example of a hydro UGH and pump-back system can be found in the Duero Basin in Castilla y León, Spain. There are two highlighted reservoirs in the above figure, Almendra (upper) and Aldeadávila (lower). Not only can they store water and have relevant natural inflows, but can pump water as indicated by the blue arrows.

[3]Spain's translation refers to them as "mixed pumping" units, however in keep with literature we will continue to identify them as "pump-back" PHS.

Non-UGH are small (average 14 MW) run-of-river hydro plants that do not belong to a large basin.

Finally there are the pure PHS units.

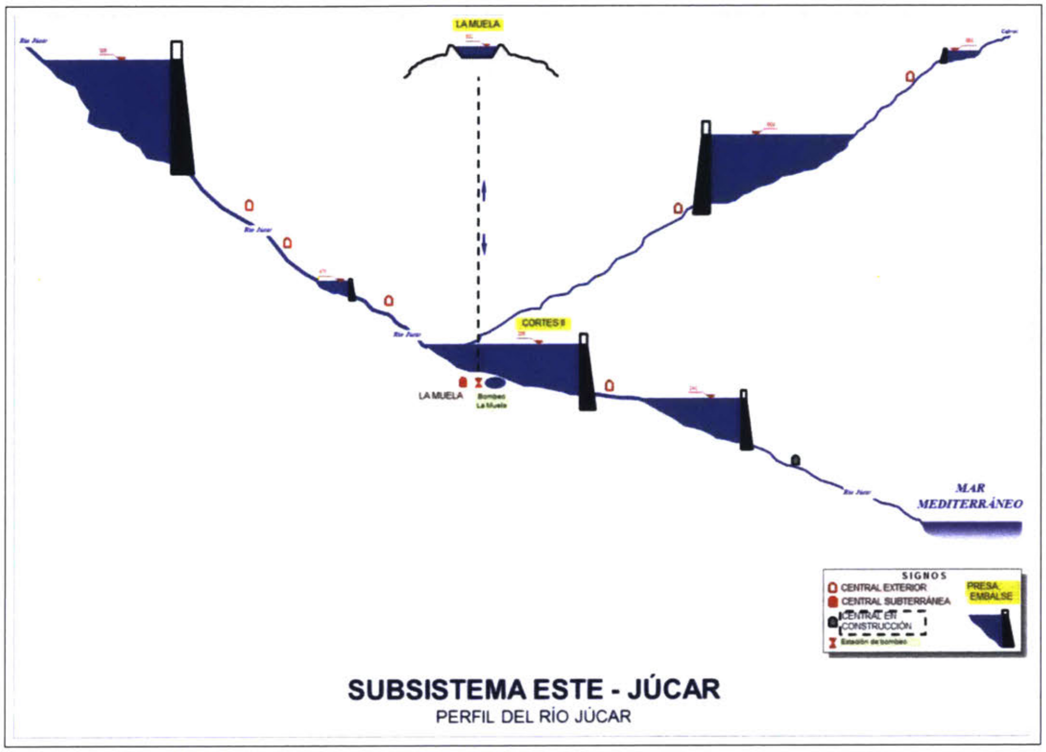


Figure 3.3: La Meula Pure Pumping Plant, Valencia, Spain

We can see this pure pumping at the La Muela pumping plant in Figure 3.3 . The upper reservoir is artificial (i.e. no natural inputs) that pumps up from the lower basin/river reservoir of Cortes II.

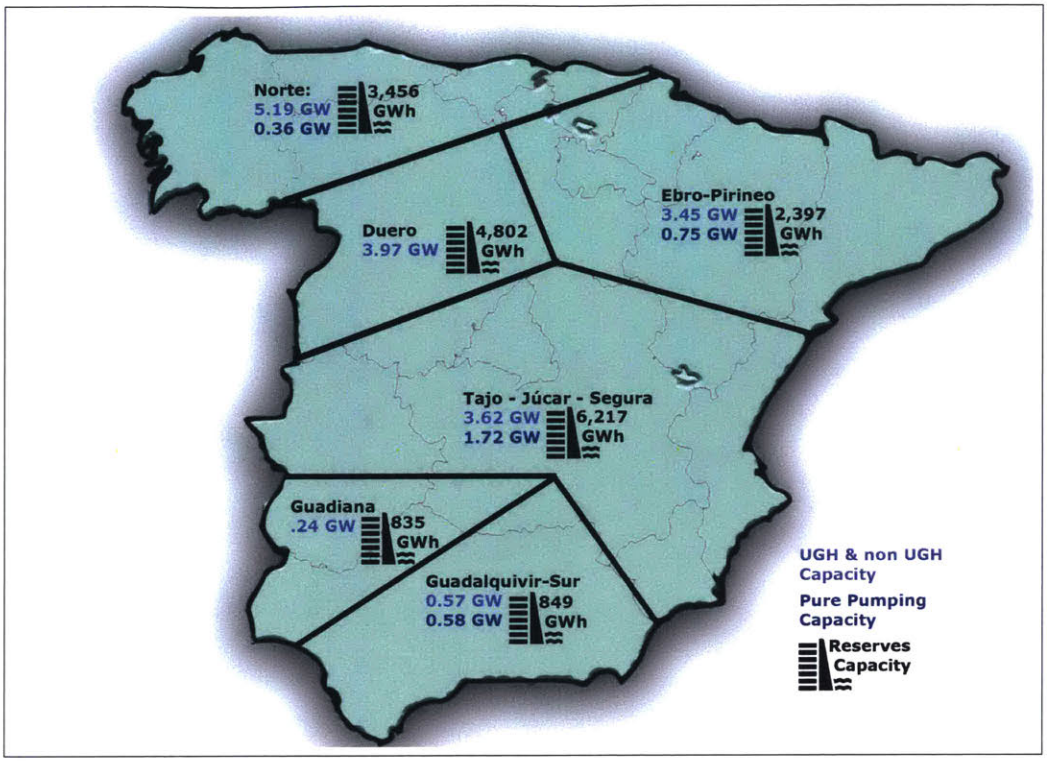


Figure 3.4: Installed Hydropower Capacity and Reserves by basin as of 12/31/17

Hydropower capacity of UGH and non UGH units is identified by basin regions in accordance with the river that feeds them as shown in Figure 3.4 [4]. I've noted each of the seven basin's maximum hydroelectric reserve. The hydroelectric reserve, as defined by REE, is "[T]he quantity of electricity that could be produced in the reservoir's own power station and in all the power stations situated downstream, with the total drainage of its current usable water reserves at that time and providing that drainage occurs without natural contributions. The annual regime reservoirs are those in which the fill and drainage cycle occurs over a one-year period. Hyper-annual regime reservoirs are those which allow the variations in rainfall to be offset in cycles of more than one year." The reserve number listed is a total of both annual and hyper-annual regimes.

According to REE's Renewable Energy Report these reserve levels are not associated with pure PHS units but rather natural inflow units such as UGH, non UGH, and mixed PHS. We were unable to identify through REE or e·SIOS, pure PHS hydroelectric reserve levels.

[4]Royal Decrees 1/2001, 125/2007, and 29/2011 established the River Basin Districting and Territory for Spain.

3.3 Electricity Market

In 1997 under the Electric Power Industry Law, Spain's electricity sector was "liberalised", i.e. it became a restructured market. Under Royal Decree 2019/1997 the specifics for electricity supply and purchase of that market were established.

Two entities oversee the market, the SO, Red Electrica de Espanaa (REE), and the market operator (MO), Operador de Mercado Iberico Espanol (OMIE). OMIE manages the energy markets, i.e. the day-ahead and intraday offers and bids. REE manages the rest of electricity system which includes ancillary services and their markets as well as transmission grid operation.

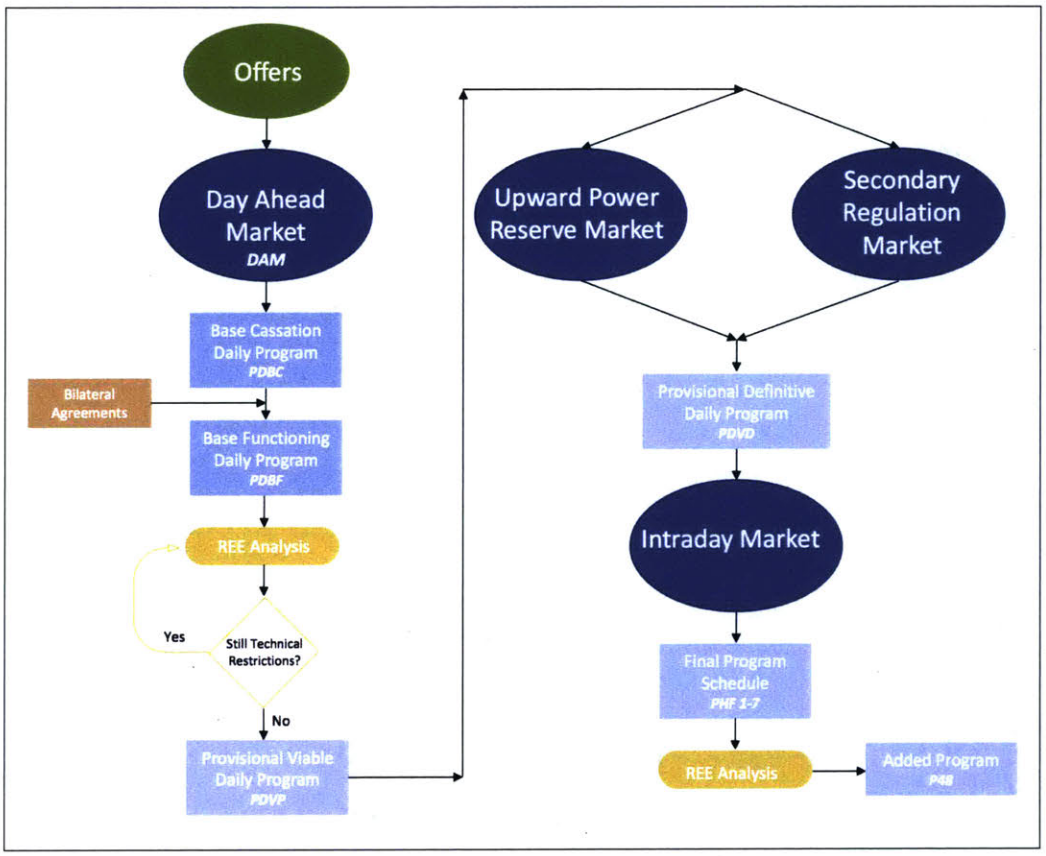


Figure 3.5: Operation of Centralized Spanish Electricity Market

The operation of the Spanish electricity market, visualized in the above schematic, is as follows [66, 48]:

For a given hour final dispatch of electricity begins 24 hours prior in the day-ahead market (DAM). This market is governed by pure economic principles, the cheapest facilities in merit order will meet the demand of that hour. The DAM in combination with separate bilateral agreements form the "el Programa Base de Funcionamiento" (PDBF) or the Base Functioning Daily Program. REE then conducts an analysis of the committed energy with respect to technical constraints of the facilities, security of supply, and reliability. The resulting schedule after this market is called "el Programa Diario Viable Provisional" (PDVP) or the Provisional Viable Daily Program.

Once the PDVP is available, two markets are launched consecutively. The first is the additional upward power reserves market, utilized whenever the REE considers an insufficient amount of upward reserves. The other market is the secondary regulation band market, which allows REE to select resources that will provide regulating reserves.

At this point the intraday market begins with seven sessions of "Programa Horario Final" (PHF), or the Final Program Schedule. They serve as adjustments to the PDVP based on predicted deviations between electricity generation and demand that was originally planned for in the DAM [5]. After the intraday markets complete, the final schedule is published, "Programa Agregado P48" (P48), or the Added Program P48.

The proceeding Chapter 4 analysis of PHS operation only focuses on pure PHS. That is due to the fact that production data for pump-back PHS is included Hydro UGH production. Both REE and the individual plants do not identify what production in a hydro UGH plant is from natural water inputs or the operation of the pumping unit.

[5] After the first two intraday markets, REE launches a call for bids to participate in the tertiary regulation market. The tertiary regulation is used to replenish the secondary reserves that are used in real time. This market is not formally established until there is an actual need for tertiary regulation.

Chapter 4

PHS Operation

An important question I first sought to answer was if data supports the theory behind how PHS operates in the energy arbitrage market and ancillary services. While rather benign, a useful part of open data is actually being able to visualize and back up expected operation.

Although REE provides granular hourly unit commitment data within all their electricity markets, it is difficult to ascertain the actual role PHS serves in ancillary services. As described in Section 3.2, after the PDVP market both the regulation and reserve market is launched. Yet there is no data on the final settling on those two markets (referred to PDVD). Rather it jumps straight into the intraday, PHF markets. As such it is not possible to determine what PHS was specifically used in ancillary services.

Therefore my analysis centers only on energy arbitrage. Future work would attempt to classify the specific usage of PHS in today's ancillary services market and how that may change in the future under a high penetration of renewables.

4.1 Utilization Rate and Productivity Index

The utilization rate of PHS is the ratio of consumption of PHS to the final consumption of the entire system. That is to what degree does PHS play in total electricity demand? A relatively high utilization rate would indicate that PHS is being used to store excess generation.

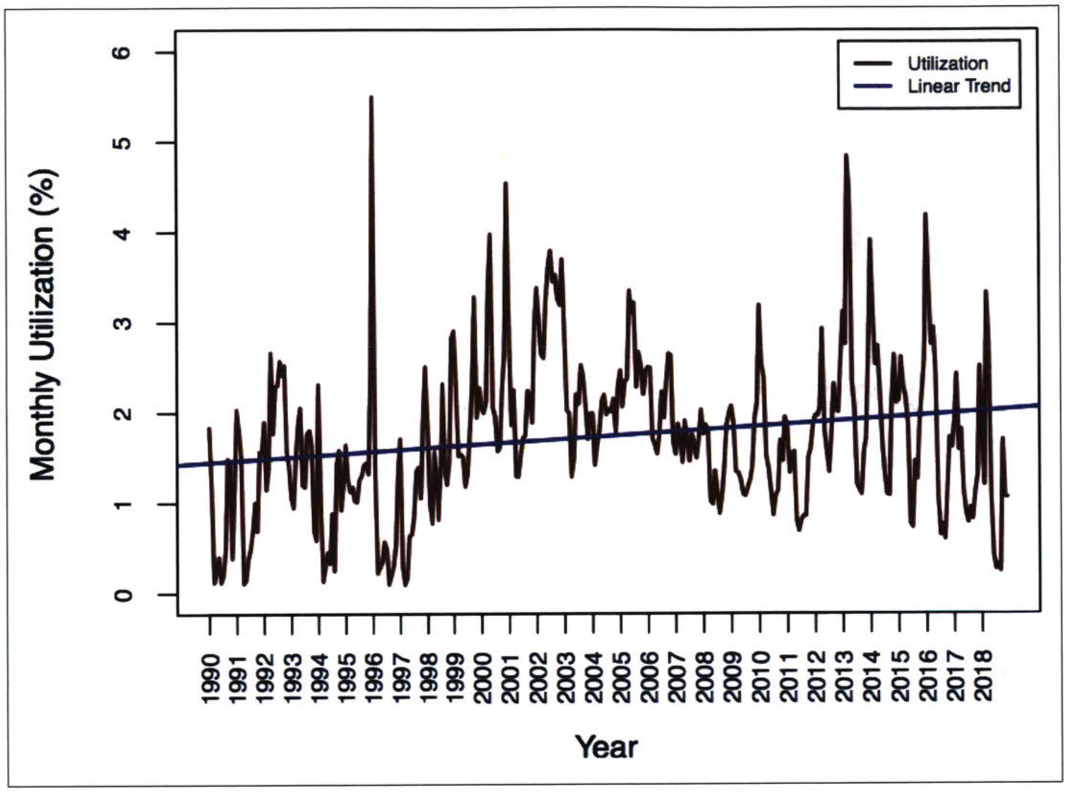


Figure 4.1: Monthly Utilization Rate for PHS 1990-2018.

Figure 4.1 plots the historical utilization rate of PHS from 1990 until 2018. Hourly data from REE is not provided until 2014 and thus monthly is the most granular data available for long historical purposes.

The utilization rate ranges from .09 percent to 5.50 percent, with an average of 1.72 percent. This is similar to results found by Kougias (2017) in their analysis of PHS utilization, where they identified Spain with an average utilization rate of 1.75 percent, and 1.8 percent for all European Union (EU) PHS countries. The linear trend in Figure 4.1 shows a small sustained increase in PHS utilization. This again reaffirms what Kougias (2017) found that Spain has experienced a sustained increase in utilization rates over the past 25 years. This makes sense as PHS capacity has slightly increased and a greater share of renewables have penetrated the market.

The productivity index is a useful indicator of PHS operational efficiency. It is the fraction of energy produced to energy consumed. Up until recently PHS pump-turbines generally had a round-trip efficiency of 70 percent. As mentioned in Section 2.3.2, new pump-turbines are around 85 percent [47, 2, 22].

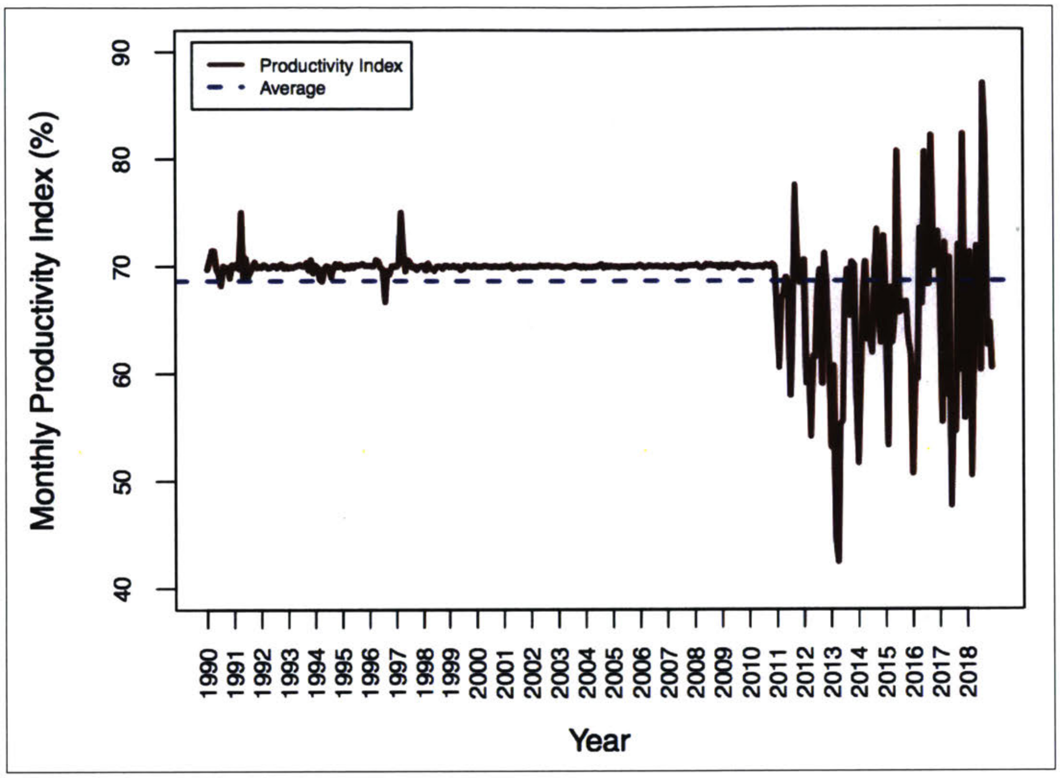


Figure 4.2: Monthly Productivity Index for PHS 1990-2018.

Figure 4.2 plots the historical productivity index rate of PHS from 1990 until 2018. Interestingly it stays relatively consistent between 1990 to 2010 with a range of 66.67 to 75.00 percent and an average of 69.9 percent. This is as expected, if PHS efficiency is around 70 percent. However after 2011 it becomes measurably volatile. With the productivity index ranging between 42.45 and 86.96 percent and an average of 65.04 percent.

That, according to REE, is based on a shift in available data [1]. Up until 2011, there was no individual information of the plants, and the turbine generating mode was assumed to be at 70 percent of pumping consumption. As of 2011 REE had information on both the pumping consumption and the turbidity of the pure PHS. However, for the pump-back PHS it is not possible to distinguish between generation from natural water inputs and pumped water turbine. So, for these pump-back plants, REE's system estimates the daily pumping generation by applying 70 percent to the daily pumping consumption of the plant as long as it has had production on that day.

That being said I assume all PHS in Spain operates with a round-trip efficiency of 70 percent.

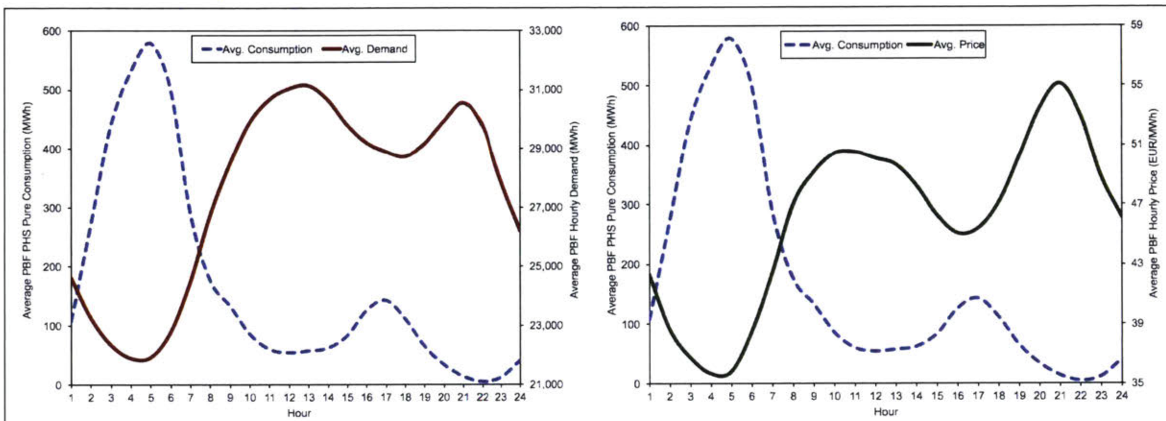
[1]This is not information published by REE but was given upon further investigation

4.2 Daily Energy Arbitrage

Diving deeper into the data it becomes apparent that PHS currently plays a dominant role within energy arbitrage, as one would intuitively assume.

This is especially true on a daily basis where the price of electricity fluctuates per the required demand and the available technology.

Averaging the hourly price over an entire 24 hour day from 2014-2017, one can visually see the relationship between demand (and thus price) and the energy input/output of pure PHS.

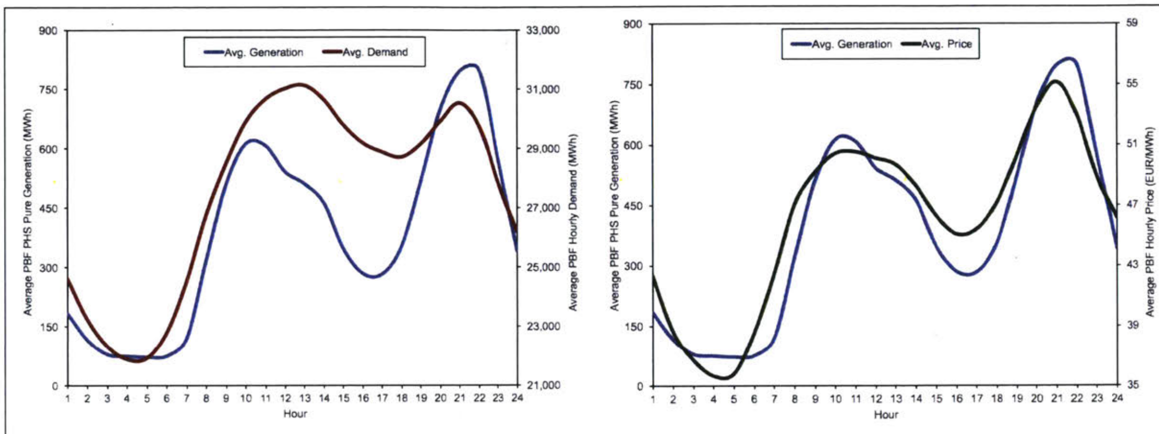


a: Consumption & Demand b: Consumption & Price

Figure 4.3: Average Hourly Day Trend in PBF Market of PHS Consumption

In Figure 4.3 a, the dotted blue line plotted on the primary axis is the average hourly consumption of pure PHS units in the PBF Market. It has a high peak, where it consumes the most energy during the middle of the night, between hours 1-7. It has another peak, although relatively small in comparison to the previous, between hours 15-19. Hourly demand, is the solid red line, plotted on the secondary axis. Compared to the consumption line, demand is the exact inverse. Figure 4.3 b, shows the same inverse relationship but instead of demand it plots the average marginal price of electricity on the secondary axis.

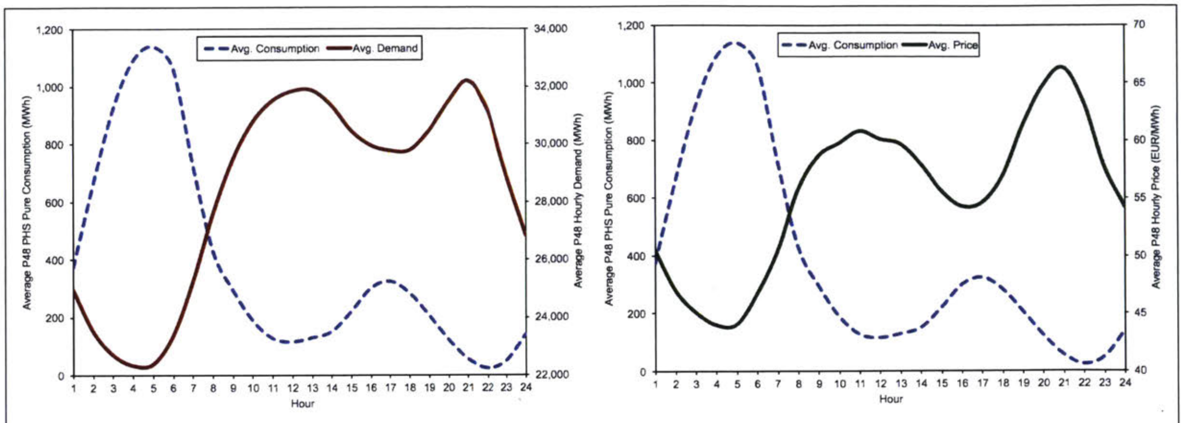
This makes sense. Starting at around hour 21 until hour 5 (of the next day) electricity demand falls as people begin to go to bed and stay asleep. Electricity prices are low and thus it behooves PHS to buy this cheap electricity to pump water to store energy. After hour 5 people begin to wake up and electricity demand increases as people go about their day. There is a peak in demand during the work day, hours 10-14. PHS consumption significantly decreases as electricity prices are high during this increased demand period. There is a relative dip in demand and prices, and thus a small peak in consumption, from hours 15-19 as people head home. And then there is relative uptick in demand and prices during hours 19-21 when the sun goes does and more lights are turned on, people eat dinner, and other general social activities take place that require increased electricity usage.



a: Generation & Demand   b: Generation & Price

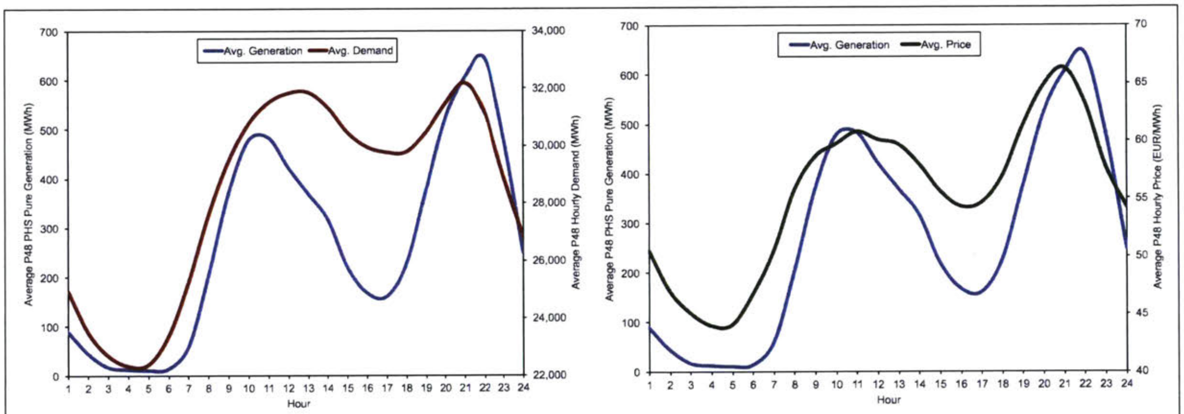
Figure 4.4: Average Hourly Day Trend in PBF Market of PHS Generation

In Figure 4.4 a and b, the blue solid line plotted on the primary axis is the average hourly generation of pure PHS units in the PBF Market. It follows the same general peak and valley trend of demand and prices. Therefore when demand and prices are increasing, hours 5-11 and 16-21, PHS turbines generate electricity to be sold. While in the early morning (hours 1-5), middle of the work day (hours 11-16), and late evening (hours 21-24), demand and prices decrease therefore making more economic sense for the PHS to consume the cheap electricity and store energy rather than sell it.



a: Consumption & Demand b: Consumption & Price

Figure 4.5: Average Hourly Day Trend in P48 Market of PHS Consumption



a: Generation & Demand b: Generation & Price

Figure 4.6: Average Hourly Day Trend in P48 Market of PHS Generation

Figures 4.5 and 4.6 and plots the same relationships with similar trends as to Figures 4.3 and 4.4 but under the P48 market. P48 sees a higher degree of PHS generation and consumption as well as market demand and prices. Reguant (2014) has shown in their analysis of Spanish bidding data, that roughly 80 percent of the electricity allocated in the centralized market of Spain is sold through the day-ahead, PBF market. Financial contracts are also indexed at the day-ahead price. Therefore the PBF market can be seen as a minimum "reference" point and P48, after all the proceeding markets and constraints would have, on average, a higher degree of values.

In summation, there is a distinct relationship between both the hourly demand and price of the electricity with PHS operation.

4.2.1 Pricing Regression

Based off the preceding conclusion, I wanted to quantify what price of electricity would determine PHS operation. This required determining the causal relationship between price and the status of PHS (i.e. generating, consuming, or neither), and thus inform us if there was a discernible price distinction between PHS operation in order to take advantage of price volatility.

The status of each individual PHS is described by the continuous variable, X_i, which is the amount it is generating or consuming. The outcome of interest, a measure of the final hourly price in the market, is denoted as Y_i. The question of interest is whether Y_i is affected by the status of the PHS units. That causal relationship in turn highlights whether or not the final market price needs to meet a certain threshold for a PHS unit to consume as opposed to generate.

Y_{0i} is the final hourly price of the market had the unit been turned off, irrespective of whether it was actually generating or consuming. While Y_{1i} is the final hourly price of the market had the unit been generating or consuming. The difference between the two is the causal effect of the unit generating or consuming, i.e. the expected value of Y_i conditional on X_i. It is represented by the following equation:

$$E[Y_i|X_i] = E[Y_{1i} - Y_{0i}|X_i]$$

To quantify this relationship, I set up an ordinary least squares regression (OLS) between market price and the operational status of PHS. In OLS notation you can adapt the previous equation to:

$$E[Y_i|X_i] = \beta_0 + \beta_1 X_i$$

Ultimately, what we are solving for is our estimates of β_0 and β_1, expressed as $\hat{\beta}_0$ and $\hat{\beta}_1$. In most cases, the slope estimate, $\hat{\beta}_1$, is of primary interest. It tells us the amount by which Y_i changes when X_i increases by one unit.

However in this case we are interested in the intercept, $\hat{\beta}_0$, which is the predicted value of Y_i when X_i is 0. This is important because when analyzing PHS consumption units, the $\hat{\beta}_0$ indicates the price when they are not consuming. Thus this translates into the minimum price for said unit to be in generating mode.

The proceding tables report the intercept values of each units over 35,000 observations (i.e. each hour of 2014-2017). The value in the parenthesis below the estimator is the standard error of the regression. The small standard errors demonstrates the importance of a large data pool, as the precision of the estimator increases as the data size, n, increases [2]. The p-values reported within the following regression tables are all less than 1 percent. While this shows the results have a degree of statistical significance, it is important to not place too high of a value on that. It simply reinforces there is an observable relationship between the final price of the market and whether or not a unit was generating or consuming.

Note the tables do not include regression estimates of the actual treatment effect, $\hat{\beta}_1$ as we are not concerned with the change in generation nor consumption values has on price but only its operational status.

The following tables and figures capture the OLS regression of the final hourly price in the PBF and P48 market on PHS generation and consumption.

4.2.1.1 PBF Pure PHS

Table 4.1: Regression of Hourly Pure PBF Generation on Hourly PBF Pricing

	Dependent variable:							
	Price							
	AGUG	CHIPG	GUIG	MLTG	MUEL	SLTG	TJEG	UFBG
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Max. Pump	43.145***	46.049***	44.729***	44.311***	44.893***	45.111***	44.323***	44.592***
	(0.100)	(0.110)	(0.089)	(0.094)	(0.089)	(0.088)	(0.090)	(0.108)
Observations	35,064	35,064	35,064	35,064	35,064	35,064	35,064	35,064
Adjusted R^2	0.066	−0.00002	0.040	0.041	0.033	0.027	0.055	0.013
Note:								*p<0.1; **p<0.05; ***p<0.01

Table 4.2: Regression of Hourly Pure PBF Consumption on Hourly PBF Pricing

	Dependent variable:							
	Price							
	AGUB	CHIPB	GUIB	MLTB	MUEB	SLTB	TJEB	UFBB
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Min Gen	48.639***	47.392***	46.735***	47.659***	48.726***	46.750***	46.865***	47.264***
	(0.080)	(0.082)	(0.083)	(0.082)	(0.079)	(0.083)	(0.083)	(0.084)
Observations	35,064	35,064	35,064	35,064	35,064	35,064	35,064	35,064
Adjusted R^2	0.203	0.102	0.046	0.117	0.212	0.049	0.055	0.075
Note:								*p<0.1; **p<0.05; ***p<0.01

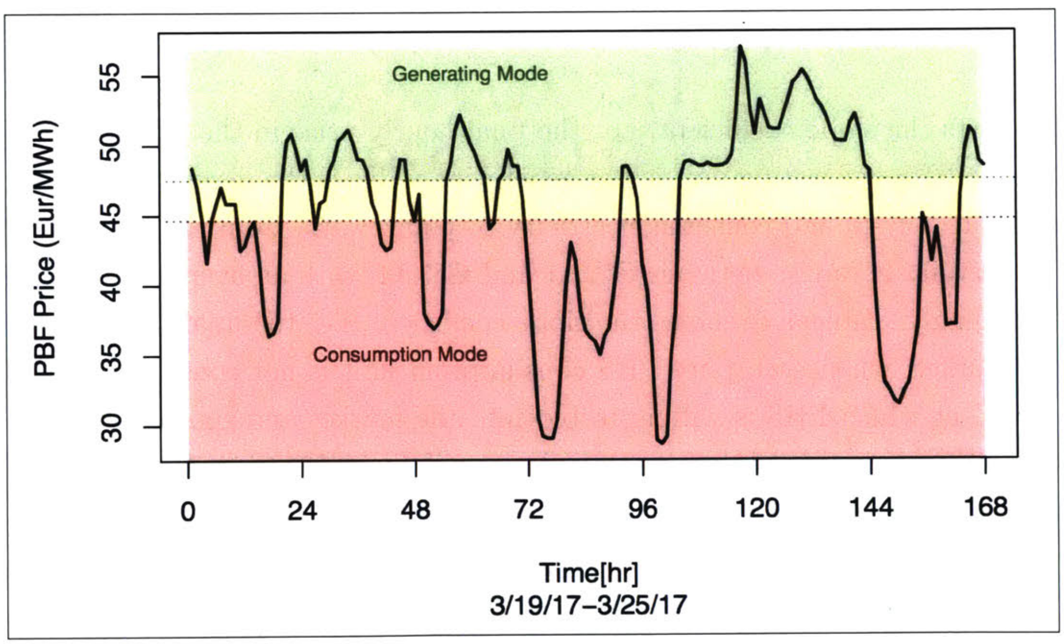
[2] As n approaches infinity, standard error converges to $\frac{1}{\sqrt{n}}$

Table 4.1 reports the slope coefficient, i.e. the final hourly price in the day-ahead PBF market, when each pure PHS generating unit is not generating. This is the maximum price at which PHS is willing to buy-in and consume electricity to pump water from the lower reservoir to the upper reservoir. It ranges between €43.15 and €46.05, with an average price of €44.64.

Correspondingly, Table 4.2 reports the slope coefficient, i.e. the final hourly price in the day-ahead PBF market, when each pure PHS consumption unit is not consuming. This is the minimum price at which PHS is willing to bid into the market and generate electricity, i.e. release water from the upper reservoir to the lower reservoir. It ranges between €46.73 and €48.73, with an average price of €47.50.

To visualize the above values, refer to Figure 4.7 which plots the real day-ahead PBF hourly prices of a week in March, 2017 and identifies whether or not a pure PHS unit would be generating (green) or consuming (red) based off the historical regression. The yellow indicates the value between the two regression coefficients where theoretically the unit could be pumping, generating, or neither.

Figure 4.7: Weekly PBF Market Curve with Corresponding Pure PHS Operation



4.2.1.2 P48 Pure PHS

Table 4.3: Regression of Hourly Pure P48 Generation on Hourly P48 Pricing

	Dependent variable:							
	Price							
	AGUG	CHIPG	GUIG	MLTG	MUEL	SLTG	TJEG	UFBG
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Max. Pump	52.870***	53.865***	54.734***	54.035***	52.508***	54.425***	54.486***	55.143***
	(0.098)	(0.094)	(0.088)	(0.089)	(0.090)	(0.089)	(0.088)	(0.086)
Observations	35,064	35,064	35,064	35,064	35,064	35,064	35,064	35,064
Adjusted R^2	0.055	0.030	0.014	0.039	0.111	0.023	0.023	0.004
Note:						*p<0.1; **p<0.05; ***p<0.01		

Table 4.4: Regression of Hourly Pure P48 Consumption on Hourly P48 Pricing

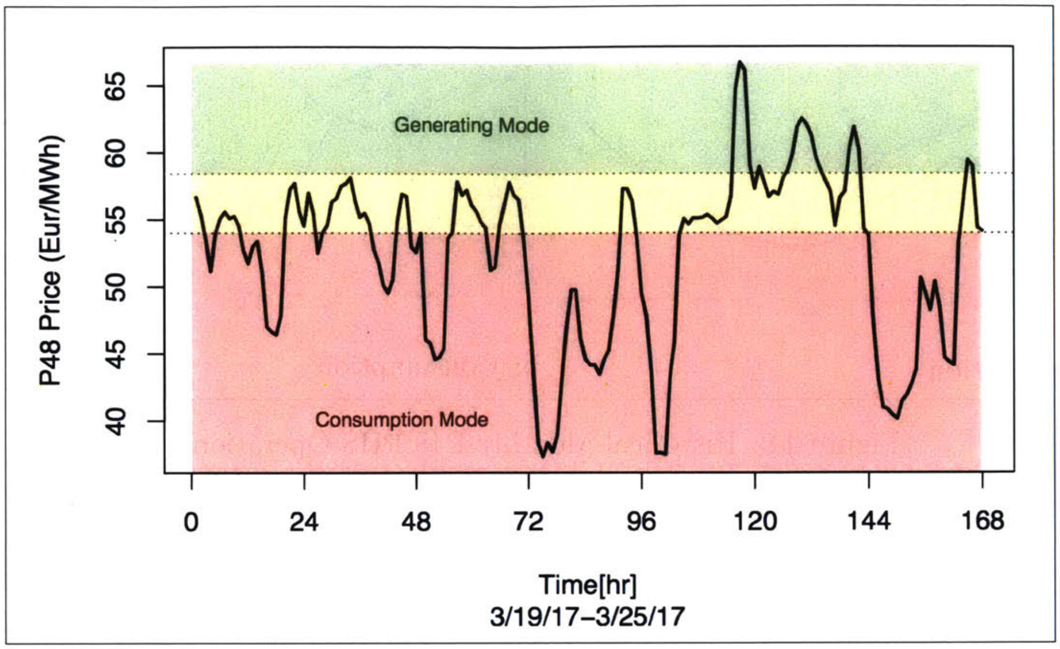
	Dependent variable:							
	Price							
	AGUB	CHIPB	GUIB	MLTB	MUEB	SLTB	TJEB	UFBB
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Min Gen	59.997***	57.615***	57.301***	58.739***	59.381***	57.780***	57.609***	59.005***
	(0.087)	(0.083)	(0.082)	(0.080)	(0.089)	(0.083)	(0.082)	(0.088)
Observations	35,064	35,064	35,064	35,064	35,064	35,064	35,064	35,064
Adjusted R^2	0.220	0.141	0.130	0.227	0.174	0.140	0.151	0.159
Note:						*p<0.1; **p<0.05; ***p<0.01		

Table 4.3 reports the slope coefficient, i.e. the final hourly price in the closing P48 market, when each pure PHS generating unit is not generating. This is the maximum price at which PHS is willing to buy-in and consume electricity to pump water from the lower reservoir to the upper reservoir. It ranges between €52.51 and €55.14, with an average price of €54.01.

Correspondingly, Table 4.4 reports the slope coefficient, i.e. the final hourly price in the closing P48 market, when each pure PHS consumption unit is not consuming. This is the minimum price at which PHS is willing to bid into the market and generate electricity, i.e. release water from the upper reservoir to the lower reservoir. It ranges between €57.30 and €60.00, with an average price of €58.43.

To visualize the above values, refer to Figure 4.8 which plots the real closing P48 hourly prices of a week in March, 2017 and identifies whether or not a pure PHS unit would be generating (green) or consuming (red) based off the historical regression. The yellow indicates the value between the two regression coefficients where theoretically the unit could be pumping, generating, or neither.

Figure 4.8: Weekly P48 Market Curve with Corresponding Pure PHS Operation

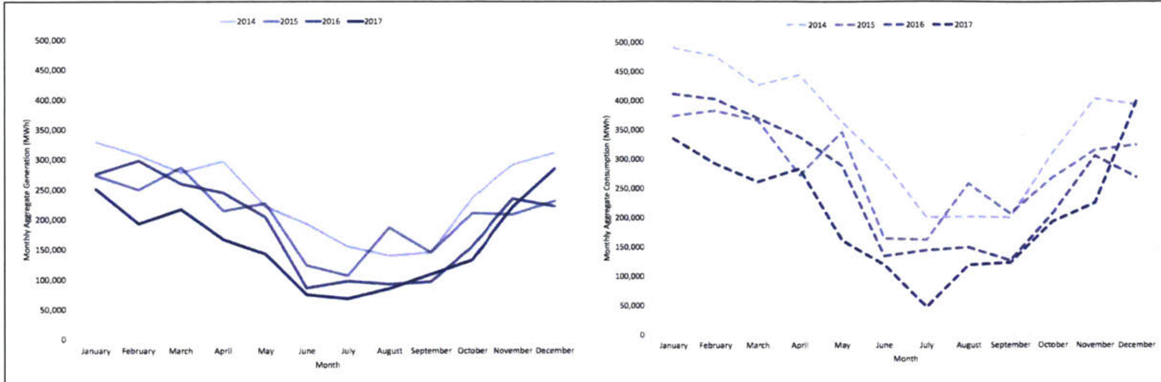


Jumping from the PBF to P48 Market we see an increase in final hourly price which translates to increased maximum consumption and minimum generation price threshold.

The bottom line is that the data shows pure PHS takes advantage of energy arbitrage by selling generation at high prices, and consuming electricity to store at low prices.

4.3 Seasonal Trends

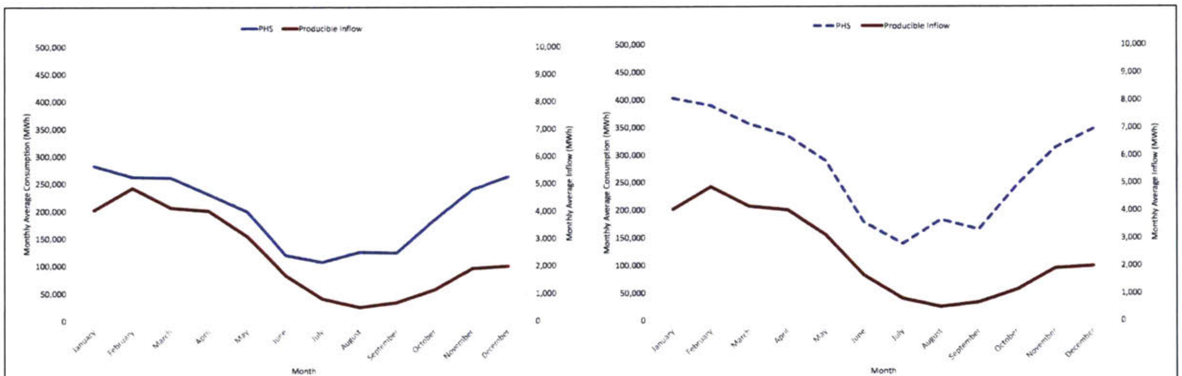
As discussed in Section 2.1 PHS can not only optimize its generational dispatch and consumption on a daily period but throughout the year.



a: Generation b: Consumption

Figure 4.9: Historical Monthly P48 PHS Operation

PHS does exhibit a seasonal pattern as seen in Figure 4.9. This graphs the aggregate monthly P48 generation (a) and consumption (b) from 2014-2017, by year. Maximum generation and consumption occur during the wet periods of winter and spring months, and minimums during the dry summer and early fall. This likely indicates PHS close connection with hydro inflows.



a: Generation b: Consumption

Figure 4.10: Average Monthly P48 PHS Operation & Producible Hydroelectric Energy

Figure 4.10 graphs the average monthly P48 generation (a) and consumption (b) of PHS on the primary-axis. The secondary axis is the monthly average "producible hydroelectric energy", i.e. the maximum quantity of electricity that could theoretically be produced considering the water inflows. Whereas our daily analysis in the previous section showed

PHS operation close relationship with hourly demand and pricing, this shows the level of PHS operation in any given month is related to the water inflows of the season.

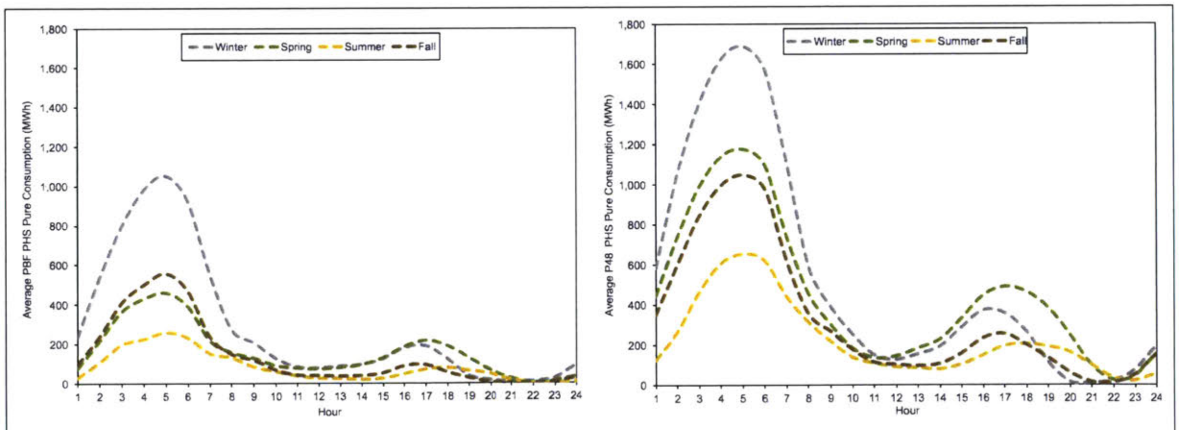
However, the fact that generation and consumption keep along an identical pattern, only separated by a degree of efficiency (i.e. consumption is about 30 percent more than generation), tells us that their operation may be following a seasonal trend but not necessarily seasonal arbitrage. If there were a pattern of seasonal arbitrage we'd expect high consumption seasons to translate into increased generation during low consumption periods. As there is no reservoir level data for PHS units I can not fully determine if they are holding water from one season to the next.

4.3.1 Daily Arbitrage by Season

I can however observe the daily arbitrage within the context of the season.

Figure 4.11 graphs the average hourly consumption of PHS over an entire 24 day from 2014-2017 by season, for both PBF and P48 markets. Each dotted line refers to a season where, winter is defined as December-February, spring is March-May, summer is June-August, and fall is September-November.

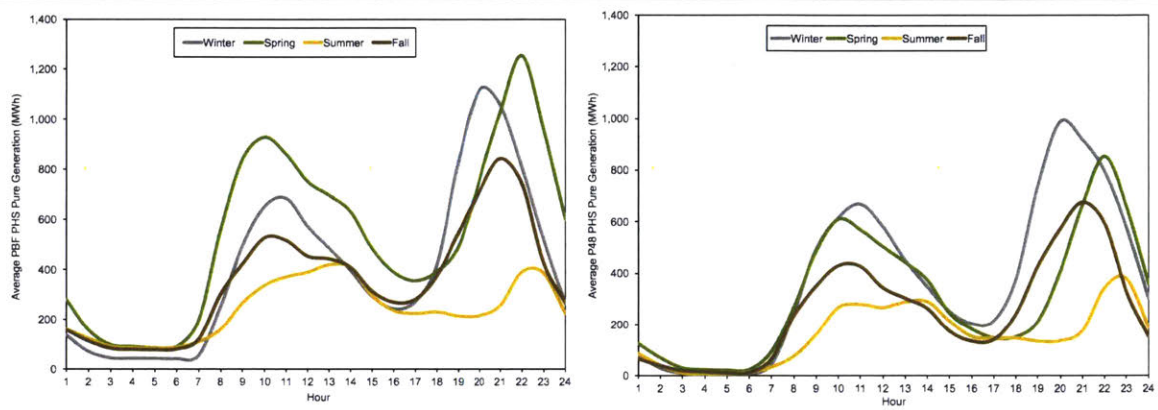
During the winter seasons (dotted grey line), PHS, on average, consumes more especially during the middle of the night. While the summer season (dotted yellow line) shows a markedly less amount of consumption. Spring (dotted green line) and fall (dotted brown line) are consistent with one another and lie in the middle of winter and summer.



a: PBF Market b: P48 Market

Figure 4.11: Seasonal Daily Average of Hourly PHS Consumption

Figure 4.12 graphs the average hourly generation of PHS over an entire 24 day from 2014-2017 by season, for both PBF and P48 markets. The spring (solid green line) and winter (solid grey line) seasons see high amounts of generation within the PBF and P48 market during the morning and evening. The fall (solid brown line) is close behind and once again the summer (solid yellow line) has the lowest generation.



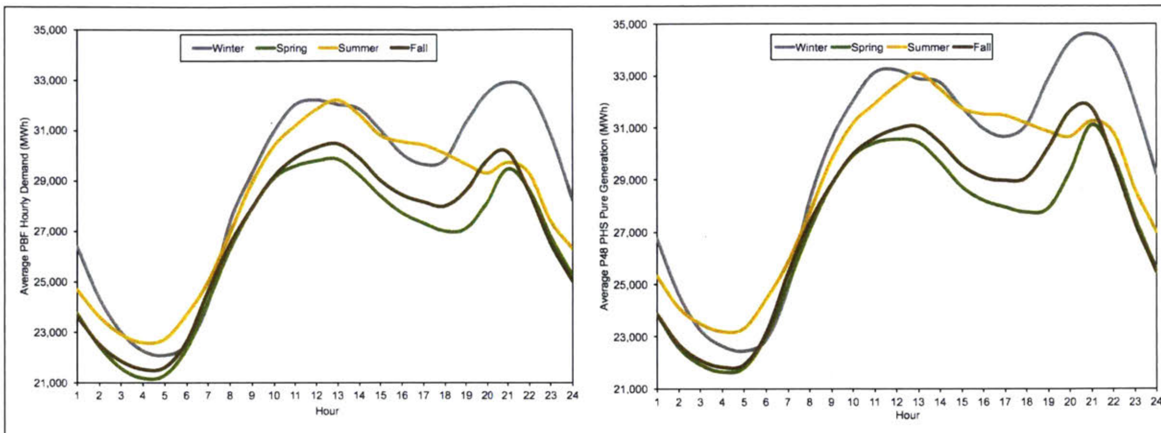
a: PBF Market b: P48 Market

Figure 4.12: Seasonal Daily Average of Hourly PHS Generation

All of the above figures follow a similar 24 hour pattern that was described in the daily arbitrage analysis. That is, peaks of electricity consumption occur during low demand periods, i.e. the middle of the night and between later afternoon and late evening. PHS turbine generation is during high demand hours, i.e. morning, work period, and evening.

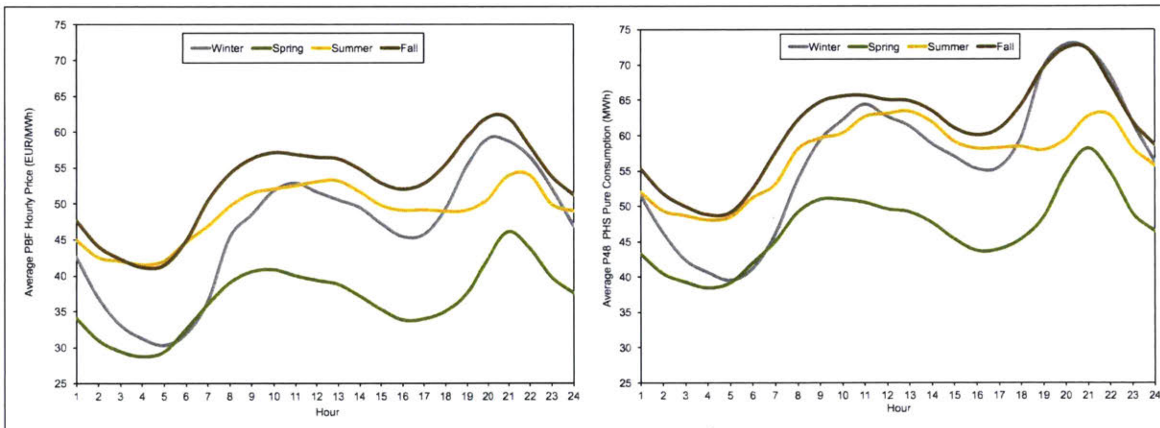
That being said there is a discrepancy between actual seasonal consumption and generation with seasonal demand and prices. Figures 4.13 and 4.14 plot the average hourly demand and price, respectively, by season for PBF and P48 Markets.

The demand curves in Figure 4.13 follow a generally inverse relationship to PHS consumption (Figures 4.3 and 4.5) as we would expect. However there is not as visible of difference between the seasons as there was in PHS consumption (Figures 4.3 and 4.5). The same can be said for price (Figure 4.14).



a: PBF Market b: P48 Market

Figure 4.13: Seasonal Daily Average of Hourly Demand



a: PBF Market b: P48 Market

Figure 4.14: Seasonal Daily Average of Hourly Price

Seasonal operation is most likely defined not just by demand and price but other factors like the amount of renewable generation or hydro inflow during those seasons, as early alluded through Figure 4.10.

Seasons with high electricity demands and high renewable penetration, i.e. winter and wind in the case of Spain, will cause PHS in winter months to consume more electricity during low electricity demand hours and high wind penetration in order to prepare for the high electricity demand in the evenings. The spring sees a high influx of water into the system and can generate high volumes during peak hours without having to consume as much. The summer on the other hand sees little inflow and the lowest penetration of wind. As such PHS keeps a low generation and consumption profile. Solar has higher production over the summer during the day yet little if any electricity is consumed by PHS during those hours within the summer. This will most likely change in our future forecasting model when solar capacity expands so much so that it may need PHS consumption to help mitigate curtailment.

Further work could be done to discern and describe these relationships through various OLS regressions.

Chapter 5

Decarbonizing the Electricity Sector - Renewable Energy Policy

Since the Paris Climate Accord, renewable energy targets have been a primary policy objective on the national and local stage throughout the world.

According to the "Global Status Report" by the Renewable Energy Policy Network for the 21st Century (REN21), more than 150 countries had national renewable power-related targets in place at the end of 2017 [1] [1]. Around half of those targets was for 50 percent or more of electricity to be from renewables [1].

The countries of the European Union (EU) have had some of the most aggressive targets. The EU committed to reduce GHG emissions in the EU 20 percent by 2020, 40 percent by 2030, 60 percent by 2040 and 80 percent by 2050, as compared to 1990 levels [18]. The targeted reductions in the sectors covered by the EU's Emissions Trading Scheme (ETS), including the electricity sector, are greater still. They call for a reduction of 21 percent by 2020 and 43 percent by 2030, as compared to 2005 levels [18].

However, the targeted reduction in the ETS sector are EU-wide commitments, and individual country emissions may decline by more or less depending upon cross-country trading within the EU-wide cap. Spain, under their new government has done just that.

In November of 2018 the Spanish Government released an outline of their planned climate and energy legislation. In it they called to switch their electricity system entirely to renewable sources by 2050 and completely decarbonize the rest of economy soon after (i.e. transport, buildings, etc.) [79]. By 2050 they plan to cut emissions by 90 percent from 1990 levels [79].

[1] REN21 is a multi-stakeholder network that is built on an international community of over 900 experts from governments, inter-governmental organisations, industry associations, non-governmental organisations, and science and academia

To do this, they promised to install additional wind and solar PV capacity, banning new licenses for fossil fuel drilling and fracking, and allocating a fifth of the budget toward policies and action that mitigate climate change [79].

In February of 2019, the Spanish Government further solidified their plan to meet Paris Climate Accord through their draft National Climate and Energy Plan as required by the EU. In it, they target a total of 50.3 GW and 37 GW of wind and solar capacity by 2030 through a €50 billion of investment [2] [73].

5.1 Future Energy Mix

For the purpose of my analysis, it is important stick with one baseline scenario in order for Spain to meet its electricity targets. At the time this thesis was written, the progressive Spanish government was relatively new and facing a snap general election April 28th. Therefore, I was not reliant on their current draft climate and energy policy or plan.

The proceeding analyses use use a capacity and generation mix based on the Distributed Generation (DG) scenario located in the Ten-Year Network Development Plans (TYNDP) 2018 [80]. The TYNDP was developed by the European Network of Transmission System Operators for Electricity (ENTSO-E) in collaboration with their sister organization responsible for natural gas transmission systems. The DG scenario was used as one base case scenario in the report by Spain's Commission of Experts [17]. The Commission had been tasked in 2017 with informing Spain's Inter-ministerial Working Group's development of a future Law on Climate Change and the Energy Transition.

The reason for choosing the year 2030 is two-fold. For one the next major energy targets for Spain are 2030. Secondly both the ENTSO-E TYNDP and Spain's Commission of Experts report analyze 2030 and serve as useful reference points.

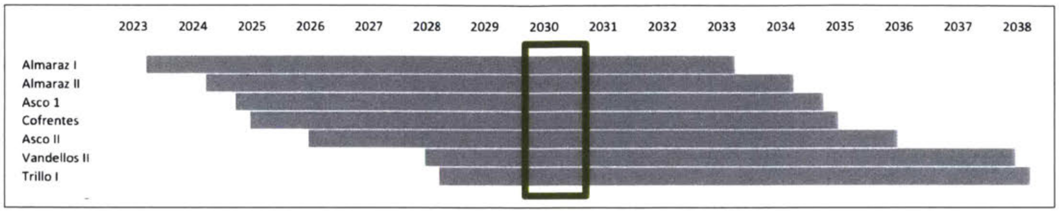
It is important to note that the energy mix with respect to nuclear could be drastically different. This is important as PHS was originally built to complement nuclear not renewables. All current nuclear plants in Spain are coming up on their 40 year design life before 2030. They are all eligible for 10 year extensions upon approval from the Spanish government.

Figure 5.1 visualizes the 40th and 50th anniversary dates of commercial operation. The end of the 40-year design lives are all reached before 2030, in the years from 2023 to 2028

[2]The plan calls for a total of €236 billion investment which primarily goes towards energy efficiency, transmission, and transport measures [73]

on the left-hand-side. A 10-year life extension would extend past 2030 as seen on the far right-hand-side.

Figure 5.1: Overlapping Windows of a 10-year Life Extension for Each Nuclear Reactor



At the beginning of 2019, the Spanish government in coordination with the executives of the three companies that operate nuclear facilities in Spain (Iberdrola, Endesa, and EDP) agreed the plants would close as early as 2025 but no later than 2035 [7]. Thus 2030 is a midway point between two nuclear scenarios in Spain.

Chapter 6

Valuation of PHS

In order to identify the value PHS provides to the Spanish electricity system we perform two separate evaluations:

1. The effect the current PHS capacity has on curtailment of low-carbon generation under a variety of future energy mix scenarios.

2. Total system cost of improving and/or adding PHS capacity to a future baseline portfolio as compared to alternative technologies (i.e. solar PV and wind) assuming nuclear is still installed

Key to these valuations is understanding the dispatch of renewables in a decarbonized scenario. Renewables have a time profile of availability that does not necessarily match with the time profile of demand. Therefore investments in high capacities of renewables may be helpful in some hours and markedly less so in others [43, 25, 67, 12]. As countries discuss reaching 60, 80, and even 100 percent of electricity to be met by renewables they will see those "beneficial hours" have an increase in curtailment. That is there will be such a large capacity of renewables that during rich resource periods the energy produced by wind and solar will be greater than the actual demand during that hour.

This high curtailment will result in an increased cost of a marginal unit of renewable generation. This will further devalue said investment in the renewables while still leaving you with periods unable to be met by renewables and only thermal plants (i.e. when the wind doesn't blow, sun doesn't shine). Thus storage can potentially provide value by taking that curtailed energy and redistributing to hours in which renewables can not fully meet the demand profile.

6.1 Impact of Renewable Resource Availability

According to the REN21 report, only six countries in the world have 20 percent or more share of electricity generation from "variable renewable energy" (i.e. solar PV and wind), Spain being one of them [1]. As countries continue to pledge low-carbon growth and limiting greater emissions the effect of resource availability is likely to be an important factor to consider.

I illustrate this point with a 2030 scenario for hourly load and hourly resource factors. For hourly load I take the hourly trend profile of 2017 and scale it up to match the aggregate ENTSO-E TYNDP DG 2030 forecasted load of 295 TWh [80].

I then use historic and calendar hourly wind and solar PV capacity factor profiles to determine their potential 2030 generation [30].

Figure 6.1: Correspondence Between the Hourly Wind Resource Factor and the Hourly Load, 2030 Forecast Scenario

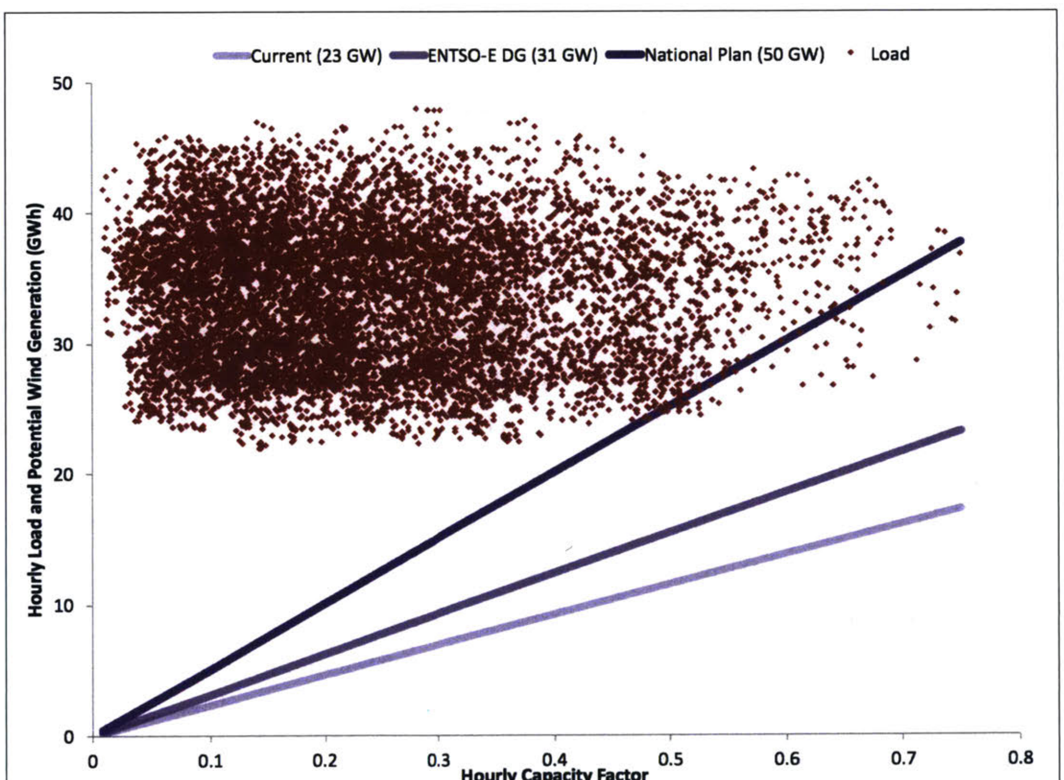
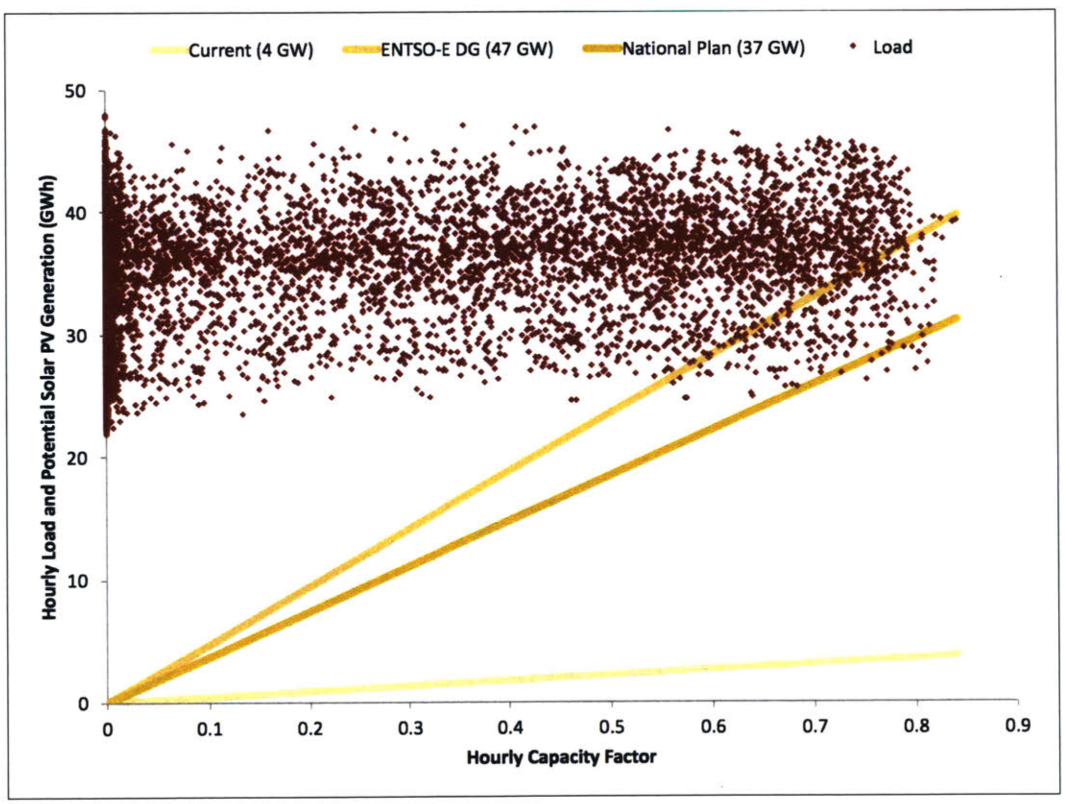


Figure 6.1 shows the correlation between the hourly wind resource factors and load in 2030. The hourly wind resource factor varies from just under 1 percent up to 75 percent. The

hourly load varies between 22-48 GWh. Overlaid on the data are three lines that show the potential hourly generation that would be produced at three different levels of installed wind capacity. The lowest line is the potential hourly generation with the current installed wind capacity, around 23 GW. The middle line is the potential hourly generation with an installed capacity of 31 GW. This is the expected installed capacity under the ENTSO-E DG 2030 Scenario. Finally, the top line is the potential hourly generation with an installed capacity of 50 GW. That is the targeted capacity Spain has placed within their draft National Energy and Climate Plan required by the EU in order to meet the Paris Accord [73] [1]. In this final case, there are many hours where the load falls below the line, indicating that the potential wind generation alone is greater than the hourly load.

Figure 6.2: Correspondence Between the Hourly Solar PV Resource Factor and the Hourly Load, 2030 Forecast Scenario



As for Figure 6.2 the hourly solar PV resource factor varies from 0 percent up to 84 percent, while the hourly load still varies between 22-48 GWh. The three lines show the potential hourly generation that would be produced at different levels of installed solar PV

[1]see Table 2.2 pg 41

capacity. The lowest line is the potential hourly generation at the current installed capacity, roughly 4 GW. The top line is the potential hourly generation with an installed capacity of 47 GW, which is the expected installed capacity under the ENTSO-E DG 2030 Scenario. Finally, the middle line is the potential hourly generation with an installed capacity of 37 GW, which is the targeted capacity Spain has placed within their draft National Energy and Climate Plan [73]. In both future scenarios, i.e. the top two lines, there are multiple hours where the load falls below them, thus again when the potential solar PV generation is greater than the hourly load.

Note that the lines in both Figures 6.1 and 6.1 are anchored to the left-hand-side at zero. As more capacity is installed, the potential generation increases only when the resource factors are high (i.e. to the right-hand-side). As more capacity is installed and the line pivots up, increasing volumes of the potential generation must be curtailed or an increasing volume of storage is required. If Spain were to rely on wind or solar generation to supply demand hours to the left-hand-side, they would either need enormous amounts of installed capacity or storage (or both). The cost of serving those hours is more expensive than the cost of serving units of load located on the right in the Figures.

Figure 6.3: Net Load Duration Curves, 2030 Forecast Scenarios

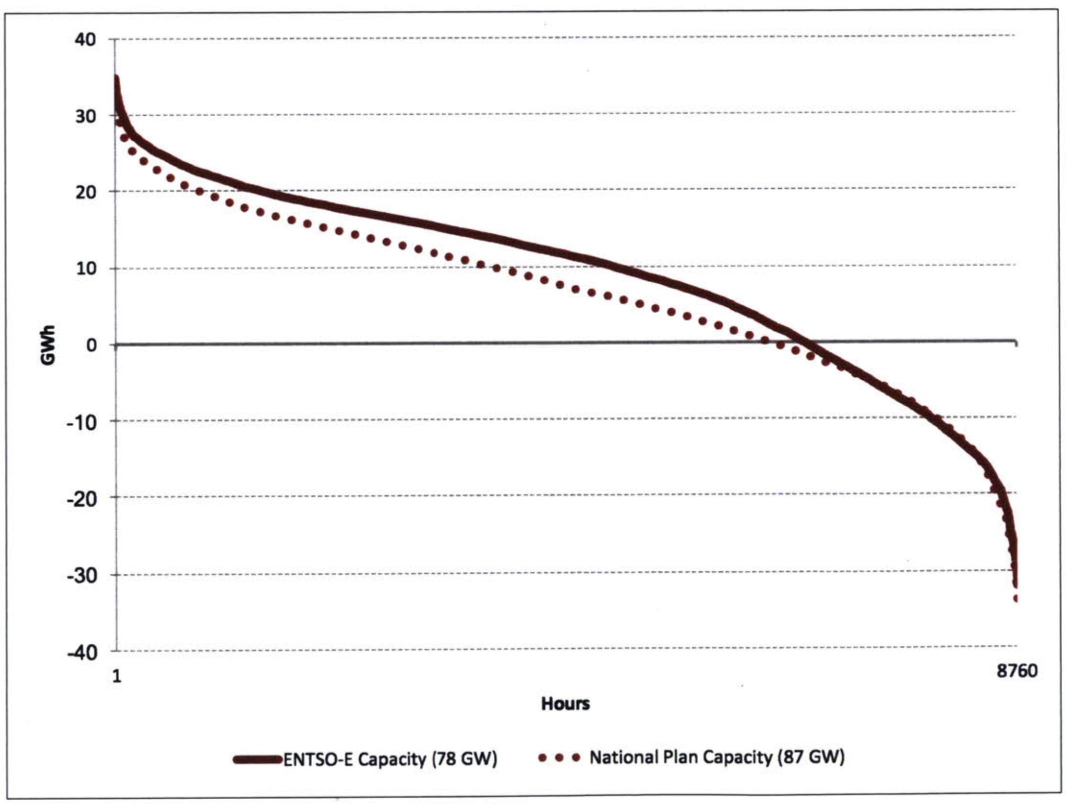


Figure 6.3 simply reinforces curtailment by aggregating wind and solar PV potential generation scenarios. Both lines show a net load duration curve for the ENTSO-E DF 2030 scenario in which the aggregate load is 295. Net load in each hour is the load minus the aggregate potential renewable generation under two capacity mixes. This generation includes hydro run-of-river, solar PV, wind, solar thermal and other renewables. It does not include hydro reservoir.

The top line is under the ENTSO-E DG capacities [2]. The aggregate renewable generation if no curtailment occurs, is more than 219 TWh, almost 75 percent of total load. The maximum hourly net load is 35 GWh. The curve goes negative at hour 6702. That is, in 2058 hours or nearly 24 percent of hours in the year, there is more available generation from renewable facilities than there is load. There is roughly 19 TWh of renewable generation curtailed or 9 percent of total low-carbon generation.

The second, bottom line shows the net load duration curve calculated using the wind and solar PV capacity from Spain's National Plan (around 9 GW more of aggregated renewables) [73]. The fraction of hours when available renewable generation exceeds load now climbs from 24 to 27 percent. There is 20 TWh of low-carbon generation curtailed or 8 percent of total low-carbon generation [3]. Note neither load accounts for the interconnection Spain has with France, Portugal, Morocco, and the Balearic Islands.

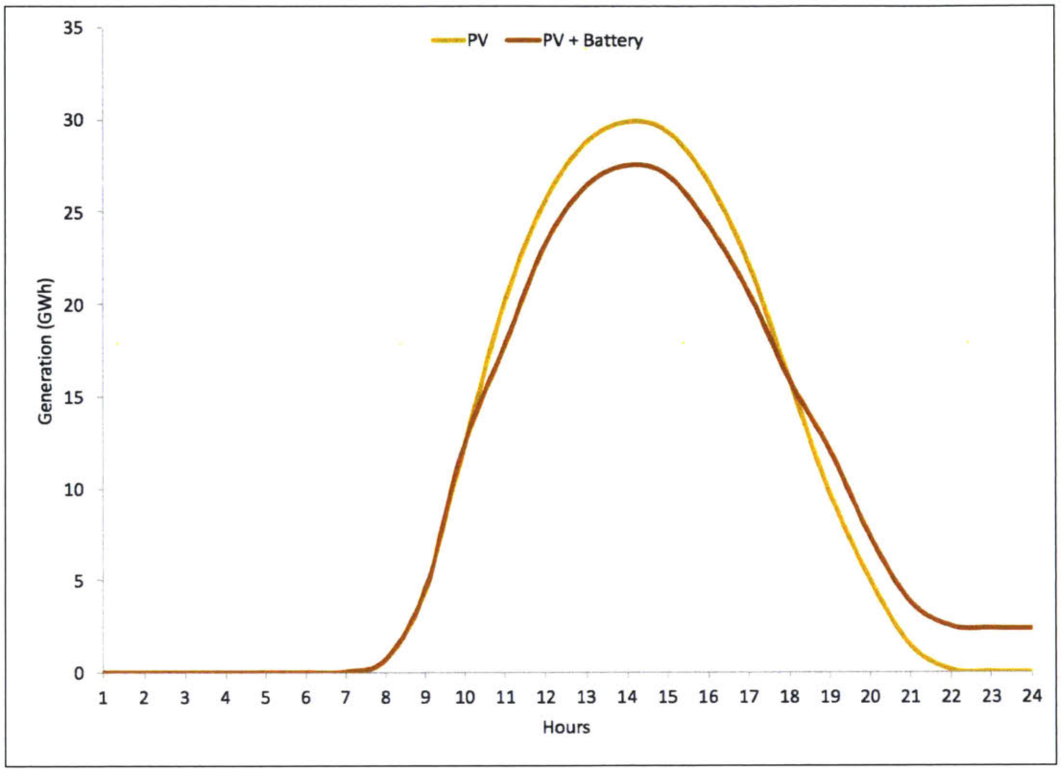
As discussed at the beginning of this thesis, storage can move these curtailed low-carbon generation into hours where load exceeds the available low-carbon generation. For the Spanish system in 2030, there are four main sources of storage, (i) PHS, (ii) hydro reservoirs, (iii) batteries, and (iv) integrated storage at solar thermal facilities.

The chemical battery installations envisioned in ENTSO-E's DG 2030 scenario are intended to smooth the solar PV generation, capping the peak and adding generation in later hours [80]. However the battery capacity envisioned is relatively small to solar PV. Thus even assuming an optimistic efficiency of 90 percent and storage time of 6 hours the battery can only make a modest shift in the daily profile of solar PV generation as Figure 6.4 illustrates.

[2]These are outlined in system cost analysis section in Table 9.1

[3]This is a lower percentage as compared to the top line as wind makes up the majority of potential generation and has a more favorable calendar pattern of resource availability to load. This is contrasted with solar PV who largely generates during the middle of the day when demand is low and thus more likely to be curtailed

Figure 6.4: Average Hourly Generation Profile of Solar PV with and without Battery Use, 2030 Forecast Scenario



The largest source of storage on the Spanish system is through the management of hydro flow using reservoirs and PHS. Reservoirs are more difficult to model due to their season flexibility and complex dynamic stochastic optimization problem.

However, in the case of PHS, they have higher capacities and storage lengths then chemical batteries and allow Spain to minimize the deterioration in the net capacity factor of renewables like solar PV and wind. Every time curtailed low-carbon generation is moved to another hour results in an efficiency loss, which reduces the net addition to generation produced by incremental investment in solar PV capacity.

Chapter 7

Methodology and Model Description

In order to analyze the curtailments and capacity of future scenarios I used an optimized least-cost hourly dispatch model. Optimization methods range from simple Excel spreadsheets to GAMs or Julia. I utilized GenX, a model developed at MIT based on Julia programming [42].

Gen X can jointly optimize the following objectives for a target year [42]:

- **Capacity expansion planning** (e.g., investment and retirement decisions for a full range of centralized and distributed generation, storage, and demand-side resources);
- **Hourly dispatch** of generation, storage, and demand-side resources;
- **Unit commitment** decisions and **operational constraints** for thermal generators; **Commitment of generation, storage, and demand-side capacity** to meet system operating **reserves requirements**;
- **Transmission network power flows** (including losses) and network expansion decisions;
- **Distribution network power flows, losses, and network reinforcement decisions**;
- **Interactions between electricity and heat markets**.

The technologies as well as the characteristics and constraints that can be included in this model are: [42]:

Category	Technology Options	Characteristics and Constraints
Thermal	CCGT, OCGT, coal, biomass, biogas, etc.	Capacity, fuel price, heat rate, emissions rate, min dispatch, min down and on time, outage periods, ramp up/down limits, start up costs and fuel consumption
Nuclear	Conventional nuclear, flexible nuclear (NACC), nuclear with heat storage	Fuel price, heat rate, min dispatch power, min down and on time, outage periods, ramp up/down limits
VRE	Solar, wind, run of river	Hourly capacity factor, min down and on time, outage periods, ramp up/down limits
Hydro	Reservoir	Energy to Power ratio, hourly water inflow, initial reservoir level, min dispatch power, min down and on time, outage periods, ramp up/down limits
Storage	Generic storage or specific types like pumped hydro, CAES, batteries, etc. Heat storage is also doable	Energy to Power ratio, charge and discharge efficiencies, self-discharge rate, min and max duration
Demand Side Resources	Reschedulable/shiftable load (in different levels), price responsive/curtailable load	Cost of demand curtailment per type of customer, size of demand response as a % of total demand per type of customer

Figure 7.1: Modeling Technologies in GenX

At the foundation of this model is that it is a least-cost optimization. This is shown mathematically below courtesy of Jenkins et al. (2017) [42]:

$$
\begin{aligned}
\min \Bigg\{ & \sum_{z \in \mathcal{Z}} \sum_{y \in \mathcal{G}} \left((\pi_{y,z}^{INVEST} \times \Omega_{y,z}^{size} \times \Omega_{y,z}) + (\pi_{y,z}^{FOM} \times \Omega_{y,z}^{size} \times (\overline{\Delta_{y,z}} + \Omega_{y,z} - \Delta_{y,z})) \right) \\
& + \sum_{z \in \mathcal{Z}} \sum_{y \in \mathcal{G}} \sum_{t \in \mathcal{T}} \left(((\pi_{y,z}^{VOM} + \pi_{y,z}^{FUEL}) \times \Theta_{y,t,z}) + (\pi_{y,z}^{VOM} \times \Pi_{y,t,z}) + (\pi_{z}^{HEAT} \times \nu_{y,t,z}) \right) \\
& + \sum_{z \in \mathcal{Z}} \sum_{t \in \mathcal{T}} \sum_{s \in \mathcal{S}} \left(n_s^{slope} \times \Lambda_{s,t,z} \right) \\
& + \sum_{z \in \mathcal{Z}} \sum_{y \in \mathcal{G}} \sum_{t \in \mathcal{T}} \left(\pi_{y,z}^{START} \times \chi_{y,t} \right) \\
& - \sum_{z \in \mathcal{Z}} \sum_{y \in \mathcal{G}} \sum_{t \in \mathcal{T}} \left(\pi_{z}^{HEAT} \times \epsilon_{y,t,z} \right) \\
& + \sum_{t \in \mathcal{T}} \left(\pi^{unmet} (r_t^{+,unmet} + r_t^{-,unmet}) \right) \\
& + \sum_{l \in \mathcal{L}} \left(\pi_l^{TCAP} \times \Delta \varphi_l^{max} \right) \\
& + \sum_{z \in \mathcal{V}} \left(\pi_z^{DCAP} \times (\Delta \lambda_z^{W} + \Delta \lambda_z^{I}) \right) \Bigg\}
\end{aligned}
$$

Figure 7.2: GenX Cost Minimization Equation

In words, this is the minimization of costs associated with [42]:

1. Where and how to invest on capacity;

2. How to dispatch that capacity;

3. Which consumer segments to serve or curtail;

4. How to cycle and commit thermal units subject to unit commitment decisions;

5. How much heat to produce and sell to heat markets;

6. How to provide operating reserves;

7. Where and how to invest in additional transmission network capacity to increase power transfer capacity between zones;

8. Where and how to invest in reinforcements of distribution network capacity.

I used this model to discern the least cost marginal plant for each hour in 2030 under technical constraints, unit commitments, and reserve requirements. It does not include capacity expansion or retirements as we are not trying to plan out the optimal mix in Spain in 2030 but rather quantify the value PHS adds to the system. Therefore installed capacity is set and GenX does not retire or build-out plants unless capacity is manually changed.

7.1 Model Structure and Constraints

On the highest level, Gen X minimizes the addition of investment and operational costs to meet demand minus any heat market sales, subject to a number of constraints.

Conventional models, according to the GenX authors, ignore four major features of electricity capacity planning:

1. **Unit commitment constraints**: This includes ramping ramps, start-up/shut-down decisions, minimum stable loads, and reserve requirements;

2. **Variability of renewable resources and demand**: Not mapping out the annual hourly profile;

3. **Transmission and distribution network infrastructure**;

4. **Integration with adjacent markets**: Electricity demand's relationship with the demand of transport and heating energy and their respective markets.

Therefore GenX is designed to take into account these features at the users discretion in order to "determine the mix of electricity generation, storage, and demand-side resource investments and operational decisions to meet electricity demand in a future planning year at lowest cost" [42].

Unit commitment constraints provide measurable value in capacity planning as opposed to a simple supply stack model. Palmintier et al. (2011) found that models including unit-commitment decisions in combination with ramping and minimum power commitments, more accurately valued operational flexibility [58]. I perform a similar comparison and our analysis in Appendix A between our baseline model and one that includes individual and combination of thermal unit constraints.

For the purpose of this thesis and work, I ignore the last two features. The transmission and distribution network infrastructure option in GenX is useful for evaluating the potential value and impact of distributed energy resources (DERs). DERs are deployed at different voltage levels and locations in the distribution network. Modeling the transmission and distribution network infrastructure aids in identifying the trade-offs between siting DERs at difference locations. In this work I only look at large centralized resources and the value they provide to the system as a whole. I treat the Spanish electricity system as one node without transmission or distribution limitations.

As for integration with other sectors it is true that for a city, state, country etc. to decarbonize it will have to electrify a large share of final energy demand (cite). This includes transportation, heating, and industrial processes which will then have to be planned and operated by the electricity sector. Modeling will need to capture these interactions. Yet I assume the high penetration of renewables countries like Spain are committing are with respect to the current electricity sector.

The following section will provide a high level view of demand balance and unit commitment constraints. Of importance to note is that I do not allow for the model to optimize new build-outs or retirements of technology. I am not optimizing the capacity planning itself but rather the operation of set installed technologies in 2030.

7.1.1 Demand Balance

$$\underbrace{\sum_{y\in\mathcal{H}}\Theta_{y,t,z}+\sum_{y\in\mathcal{D}}\Theta_{y,t,z}+\sum_{y\in\mathcal{ND}}\Theta_{y,t,z}}_{\text{Generation from thermal, dispatchable, and non dispatchable sources}}+\underbrace{\sum_{y\in\mathcal{O}}(\Theta_{y,t,z}-\Pi_{y,t,z})}_{\text{Charging and discharging of storage}}+\underbrace{\sum_{y\in\mathcal{DR}}(-\Theta_{y,t,z}+\Pi_{y,t,z})}_{\text{Reschedulable load: Shifting demand or satisfying shifting load (not used)}}-\overbrace{\sum_{y\in\mathcal{HO}}\Pi_{y,t,z}}^{\text{Generation from heat storage sources (not used)}}+\underbrace{\sum_{y\in\mathcal{W}}\Theta_{y,t,z}}_{\text{Generation from hydro reservoir sources}}+\overbrace{\sum_{y\in\mathcal{AN}}(\Theta_{y,t,z}+\eta^{heat}_{y,z}(\sigma_{x,t,z}+\nu_{y,t,z}))}^{\text{Generation from Nuclear Air CC sources (not used)}}$$

$$+\underbrace{\sum_{s\in\mathcal{S}}\Lambda_{s,t,z}}_{\text{Demand curtailment (not used)}}-\underbrace{\sum_{l\in\mathcal{L}}(\varphi^{map}_{l,z}\times\Phi_{l,t})}_{\text{Power flows into or out of zone (not used)}}-\underbrace{\frac{1}{2}\sum_{l\in\mathcal{L}}(\mid\varphi^{map}_{l,z}\mid\times\beta_{l,t}(\cdot))}_{\text{Power losses in transmission networks (not used)}}-\underbrace{\ell_{z,t}}_{\text{Distribution losses (not used)}}=\underbrace{D_{t,z}}_{\text{Electricity demand}}$$

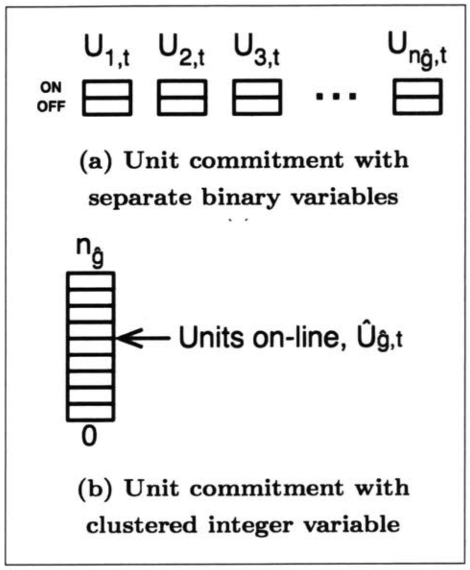
Figure 7.3: GenX Demand Balance Constraint

The demand balance constraint of the model, Figure 7.3, ensures that electricity demand is met at every hour in each zone. As shown in the equation, electricity demand, $D_{t,z}$, at each hour for each zone must be equal to the sum of generation ($\Theta_{y,t,z}$) of thermal plants ($\mathcal{H}$), dispatchable renewables ($\mathcal{D}$) [1], non-dispatchable renewables ($\mathcal{ND}$) [2], and hydro-reservoir ($\mathcal{W}$). Additionally, PHS and any other storage technology ($\mathcal{O}$) could be charging ($\Pi_{y,t,z}$) or generating ($\Theta_{y,t,z}$) during this time and must be taken into account. Rescheduled load (i.e. shifting demand ($\mathcal{DR}$)), generation from heat storage ($\mathcal{HO}$) and nuclear air combined cycle ($\mathcal{AN}$) technologies, demand curtailment ($\Lambda_{y,t,z}$), and power losses in transmission ($\beta_{l,t}$) and distribution ($l_{z,t}$) are not used within my model and thus their respective constraints do not matter. As there is only one load, the power flows in and out of zones ($\Phi_{l,t}$) is not required.

[1] Generation can be curtailed, i.e. large-scale renewables. I assign solar PV and wind to this category

[2] Generation cannot be curtailed and are considered must run. I include bio, cogeneration, solar thermal, and hydro run-of-river in this category

7.1.2 Unit Commitment



(a) Unit commitment with separate binary variables

(b) Unit commitment with clustered integer variable

Figure 7.4: Unit Commitment Approaches

GenX uses an integer clustering technique to model commitment and operation constraints as opposed to a binary technique where a unit is either on or off. In the clustered unit commitment technique, as shown in Figure 7.4 courtesy of Jenkins et al. (2017), generators are clustered by type and zone, and the integer commitment state variable for each cluster varies from zero to the number of units in the cluster. Thus this problem scales with the number of units of a given type in each zone, rather than by the number of discrete units, significantly improving computational efficiency [59, 42].

Unit commitments are further constrained by [3]:

1. **Startup/Shutdown**: The maximum number of plants that can be committed ($v_{y,t,z}$), started ($\chi_{y,t,z}$), or shutdown ($\xi_{y,t,z}$), at any given time, is given by the net installed generation capacity of the cluster y in zone z. The startup events are further optimized in the original minimization equation in Figure 7.2 which takes into account the start-up cost, $\pi^{START}_{y,z}$, of turning on a thermal plant.

2. **Maximum and Minimum Power**: Requires that clustered thermal generators' output ($\Theta_{y,t,z}$) must be between maximum ($\rho^{max}_{y,t,z}$) and minimum ($\rho^{min}_{y,z}$) output levels of the committed technologies. The maximum output is the aggregate installed capacity

[3]see Jenkins (2017) for in depth analysis of the decision variables, model inputs, and restrictions

of committed technologies while minimum power of each clustered technology is set by the model user.

3. **Ramping**: How fast thermal units can adjust their power output in a given hour. For clusters of thermal generators, the hourly change in output must be constrained to reflect limits on the rate of change in the output of committed (online) generators, as well those that are starting-up and shutting-down.

7.2 Model Inputs and Assumptions

I assume Spain is a one zonal network in which demand of the entire country is aggregated together, and all generating units in the country can meet said demand.

As such there are four main inputs for GenX that require detail and attention: hourly load, fuels, generators, and variability of resources. Each are examined in the sections below. Additionally I describe the optimization of hydro reservoir and storage technologies as they play an important role in Spain.

7.2.1 Load

For hourly load I take the hourly trend profile of 2017 and scale it up to match the aggregate ENTSO-E DG 2030 forecasted load. I exogenously account for the power delivered from the peninsula over the Balearic HVDC link and the power delivered over the transmission network to France and Portugal according to ENTSO-E 2030 DG Scenario. This is largely under the assumption Spain will use its interconnection to export low-carbon generation and reduce curtailment.

7.2.2 Fuels

The base fuel cost of nuclear, coal, and natural gas is from ENTSO-E's TYNDP Annex II, Table 1 [4].

By taking the carbon content of each fuel from the 2006 IPCC Guidelines for National Greenhouse Gas Inventories Chapter 2 (Table 2.2) I integrate the ENTSO-E TYNDP forecasted carbon price in 2030 (Annex II Table 1) into the respective base fuel price.

[4] The coal mix in current Spanish units differs between hard or soft, domestic or imported. However all contain some percentage of imported hard coal [54]. As imported hard coal has the highest coal content highest we assume it is the most expensive, marginal fuel [38]

All renewables and storage have no fuel costs assigned to them. This includes biogas and biomass for simplicity sake as they account for around 1 percent of Spanish production.

7.2.3 Generators

Start up fuel requirements are taken from the European Commission's Joint Research Centre's (JRC) ETRI report of the respective technologies. As is the base variable O&M costs. In addition to the base variable O&M cost of each technology I include the additional costs specific to Spain. By fuel type these include:

1. **Nuclear**: The "Empresa Nacional de Residuos Radiactivos S.A." (ENRESA) fee. Translated to the Spanish Radioactive Waste Management Organisation, ENRESA is a state company responsible for spent fuel, radioactive waste management and decommissioning activities. Additionally, nuclear plants pay a per MWh fee to the Consejo de Seguridad Nuclear (CNS), or the Nuclear Safety Council. The CNS was created through regulation to oversee and minimize potential radiological risks [61]. The fee received from nuclear operators goes towards studies, reports, inspections, evaluations, etc. Lastly I apply local environmental taxes based on each plant's location and assign the uranium combustion tax.

2. **Coal**: The "logistics and management" cost identified in Resolution 1736 in EUR/MT [54].

3. **Natural Gas**: "Access PVP Transport Network," "Regasification'", and "Exit to Consumer" tariffs as per Royal Decree 949/2001 and outlined by Enagás, the Spanish energy company and TSO, which owns and operates the nation's gas grid and regasification terminals [**BOEEnagas'Tariffs**, 26].

4. **Taxes**: Additionally, all thermal units have a 7 percent revenue tax and a 0.5 EUR/GJ Network Access tax. Coal and natural gas pay a 0.65 EUR/GJ "Green Tax" as carbon emitters [49, 50, 65].

Start up costs are from the JRC ETRI report while ramping, start-up and down time, and minimum power from DIW Berlin's Current and Prospective Costs of Electricity Generation Report [13, 68].

For data on the thermal efficiency and heat rate of large plants, I take advantage of the thermal power dataset reported by Spain's Ministry of Agriculture and Fisheries, Food and Environment (MAPAMA) Royal Decree 815/2013. The Decree was in response to the European Union Directive 2010/75/EU on industrial emissions which allowed for Member States to prepare a National Transition Plan (PNT) (applicable during January 1, 2016 to June 30, 2020), on combustion facilities whose nominal thermal potential was 500MWth or greater [5] [53].

Only three natural gas CCGT unit efficiencies are reported. Therefore the other CCGT units are all assigned a standard efficiency of 55 percent.

As for the rewnewable resources, variable O&M costs are retrieved from the JRC report.

I assume that the bids of the generator are equal to their marginal cost of production.

7.2.4 Variability

All renewables have an hourly capacity factor profile (i.e. variability) that matches the historic profiles from 2014-2017 except for Hydro UGH Reservoirs and PHS. Bio, cogeneration, solar thermal, and hydro run-of-rivers generate according to their hourly capacity factor profile. They are non-dispatchable meaning generation curtailment is not allowed. Thus by merit order they will always meet the hourly demand first. Solar PV and wind are also modeled according to their hourly capacity factor profile but are dispatchable, i.e. they can be curtailed. This allows me to measure low-carbon curtailment.

Coal and natural gas units are assumed to all be operational throughout the year and thus have a variability of one [6].

I model nuclear variability according to plant outages as well as operation and maintenance schedules based on historical norms. I take the average monthly un-availability factor of nuclear units published by REE and apply it to all nuclear plants. That is if the un-availability of nuclear is 13 percent in March, all seven nuclear plants will operate at 87 percent of max capacity throughout March in 2030.

7.2.5 Hydro Operation

Hydro UGH reservoirs are modeled separately from run-of-river and effectively treated as storage plants by GenX. The only difference is that they do not charge but rather receive

[5] The PNT was integrated into Spanish regulation with Royal Decree 815/2013. It is important to note some of the power plants are aggregated (for example C.T. as Pontes is PGR1 + PGR2 + PGR3 + PGR4, C.T. Teuel (Andorra) is TER1 + TER2 + TER3, etc.).

[6] As there is excess capacity of natural gas (historical capacity factors are near 20 percent) we do not view this as a problem

exogenous inflows to their storage reservoirs, reflecting stream-flow inputs.

Reservoir hydro resources are parameterized by the following:

1. **Generation efficiency** (η): I assume to be 100 percent.

2. **Power to energy ratio** (μ_{stor}): Found by taking the total aggregate power capacity of hydro UGH (roughly 14 MW) and dividing it by the total max reservoir storage capacity (around 18.5 GWh). [30].

3. **Initial energy level** (w^{level}): , The fraction of the max reservoir storage capacity that you start with. I use 0.42 which is the historical average of the last 5 years. [30]. Note the model is run such that the final hourly capacity level has to be within 0.5 percent of the original.

4. **Energy inflows** (ρ): I use the REE reported "Producible hydroelectric energy." Defined earlier as the maximum quantity of electricity that theoretically could be produced considering the water supplies registered during a specific period of time, and once the supplies used for irrigation or uses other than the generation of electricity have been subtracted.

At any given hour the amount of stored energy in the reservoir, Γ_t, is the value of stored energy from the previous hour, Γ_{t-1}, minus the electricity generated, Θ_t, plus the hourly inflow, ρ_t.

The maximum stored energy level, Γ_{max} must be less than or equal to the energy capacity of the reservoir. Electricity production must be less than or equal to both the net installed power capacity AND the current energy reservoir level. Refer to Section 5.15 of Jenkins (2017) for the complete optimization equations and constraints.

Effectively GenX optimizes the best times to release water and generate electricity. In my future scenario hydro largely does not generates during two different types of hours:

1. When solar PV generation is so high it is meeting the net load, i.e. the middle of the day when solar resource factors are high and demand is generally low [7].

2. When CCGT generation is high, i.e during high net load hours because there is low penetration of renewable generation.

[7]Net load in this case is the load remaining after non-dispatchable renewables

You can further explore this relationship visually in Appendix B where I graph the hydro UGH reservoir generation vs net load, nuclear generation, solar PV, wind, and CCGT during the first week of our baseline future scenario.

Note that I essentially model all seven hydro basins in Spain (which include dozens of reservoirs) as, for visualization purposes, one giant bathtub. This is a major assumption. The number of reservoirs, whether or not they are in series or parallel to another, and their initials inflows will change the energy level of said reservoir at hour t. Because REE only reports the aggregate energy inflow, aka producible hydroelectric energy, I cannot accurately depict the optimization of each reservoir.

7.2.6 Storage Operation

I model two separate storage technologies, chemical batteries and PHS. The only difference in GenX's optimization strategy of them is the following parameters:

1. **Roundtrip efficiency** (η): How much can be generated per the electricity consumed to store. For chemical batteries I assume a roundtrip efficiency of 80 percent in 2030. Current PHS capacity is modeled at 70 percent while future capacity additions are modeled at 85 percent.

2. **Power to energy ratio** (μ_{stor}): The inverse of their cycle, or the number of hours it would take to fully discharge a full state of charge for a given technology. I assume chemical batteries can keep a full charge for 6 hours and PHS 24 hours.

At any given hour the amount of stored energy is the value of stored energy from the previous hour minus the power generated plus the power consumed. It is constrained by the fact that the amount of stored energy must be less than or equal to the capacity of the storage times the number of hours the energy can be stored. Additionally, the power generated by storage can never be more than the amount of the energy stored. Refer to Section 5.12 of Jenkins (2017) for the complete optimization equations and constraints.

The GenX optimization seeks the best time for storage to generate vs consume in order to minimize system cost. Therefore it is not necessarily trying to generate at high electricity prices for arbitrage but to bring down the amount of CCGT required to meet load.

You can further explore this relationship visually in Appendix C and D where I graph the battery and PHS generation vs net load, nuclear generation, solar PV, wind, and CCGT during the first week of the baseline future scenario.

Note I model pure PHS separately from pump-back PHS. This is in order to account to some degree the duality of operation of hydro UGH reservoir plants that have pumping capabilities. Thus I constrain the aggregate hourly production of hydro UGH reservoirs and pump-back PHS to be no more than the maximum electricity generating capacity of hydro UGH reservoirs. This allows ensures I do not overestimate generation by these two technologies.

Chapter 8

Value of Current PHS Capacity in a Decarbonized World

8.1 Introduction

As established, Spain has a high installation of PHS in relation to other countries. As such it is important to first quantify the low-carbon generation value the current capacity PHS provides to the system. This chapter seeks to answer two questions:

1. To what degree does the current capacity PHS curb curtailment of low-carbon generation and promote lesser GHG emissions?
2. Which low-carbon source, nuclear, wind, or solar PV does PHS primarily optimize?

I do this by examining four scenarios where renewable capacity has increased, each under two different portfolios; with and without the current installment of PHS:

- **Scenario A-1**: ENTSO-E DG 2030 electricity capacity mix (keeping PHS capacity to current value);
- **Scenario A-2**: Same as Scenario A-1 except nuclear has been phased out;
- **Scenario A-3**: Same as Scenario A-2 except solar PV capacity has been increased so that emissions are equivalent to Scenario A-1;
- **Scenario A-4**: Same as Scenario A-2 except wind capacity has been increased so that emissions are equivalent to Scenario A-1;

This portfolio of capacities is detailed below in Table 8.1 [1]. This valuation is treated on curtailment of low generation alone as opposed to system cost as the PHS has already been built.

Table 8.1: Portfolios of Capacities Analyzing effects of PHS

		A - 1 - i [A]	A - 1 - ii [B]	A - 2 - i [C]	A - 2 - ii [D]	A - 3 - i [E]	A - 3 - ii [F]	A - 4 - i [G]	A - 4 - ii [H]
	Installed Capacity (MW)								
[1]	Nuclear	7,117	7,117	-	-	-	-	-	-
[2]	Wind	31,000	31,000	31,000	31,000	31,000	31,000	63,379	63,379
[3]	Solar PV	47,157	47,157	47,157	47,157	1,127,810	1,127,810	47,157	47,157
[4]	Natural Gas CCGT	23,746	23,746	23,746	23,746	23,746	23,746	23,746	23,746
[5]	PHS	-	6,480	-	6,480	-	6,480	-	6,480
	Generation Potential (GWh)								
[7]	Nuclear	58,961	58,961	-	-	-	-	-	-
[8]	Wind	64,934	64,934	64,934	64,934	64,934	64,934	132,758	132,758
[9]	Solar PV	89,210	89,210	89,210	89,210	2,133,541	2,133,541	89,210	89,210
[10]	Subtotal	213,105	213,105	154,145	154,145	2,198,475	2,198,475	221,968	221,968
[11]	Natural Gas CCGT	208,014	208,014	208,014	208,014	208,014	208,014	208,014	208,014

Notes:
[1] - [5] = Are chosen
[7] = Capacity multiplied by hourly availability factor and aggregated together
[8] - [9] = Capacity multiplied by hourly resource factor and aggregated together
[11] = Capacity multiplied by 8760 hours

8.2 Results and Discussion

Table 8.2 reports the dispatch results for the four scenarios under their two portfolios. Table 8.2 only shows generation for nuclear, solar, wind and natural gas CCGT units along with generation and consumption from PHS and battery storage since these are the only items allowed to vary across the portfolios.

[1]The solar PV and wind capacities in Scenario A - 3 and 4 were determined by increasing the respective capacities in Scenario A - 1 until the emissions matched our emissions of Scenario A - 2

Table 8.2: Dispatch Results for Alternative Capacity Scenarios and Portfolios

		A-1-i	A-1-ii	A-2-i	A-2-ii	A-3-i	A-3-ii	A-4-i	A-4-ii
		[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]
	Generation (GWh)								
[1]	Nuclear	53,636	56,180	-	-	-	-	-	-
[2]	Wind	53,959	61,181	58,632	63,307	34,203	34,644	113,125	122,467
[3]	Solar PV	80,122	86,601	84,561	87,974	143,363	174,027	75,957	81,172
[4]	Subtotal	187,717	203,962	143,192	151,281	177,566	208,671	189,082	203,639
[5]	Natural Gas CCGT	43,446	31,829	87,829	82,087	53,197	31,173	41,996	31,823
[6]	Total	231,163	235,791	231,022	233,368	230,764	239,845	231,078	235,462
	Curtailment (GWh)								
[7]	Nuclear	5,325	2,781	-	-	-	-	-	-
[8]	Wind	10,976	3,754	6,303	1,628	30,731	30,290	19,633	10,291
[9]	Solar PV	9,087	2,608	4,650	1,236	1,990,177	1,959,514	13,253	8,038
[10]	Total	25,388	9,143	10,952	2,864	2,020,909	1,989,804	32,886	18,329
	Storage Generation (GWh)								
[11]	PHS	-	10,831	-	5,640	-	20,465	-	10,227
[12]	Batteries	3,959	3,903	3,166	3,075	4,390	4,484	3,599	3,601
	Storage Consumption (GWh)								
[13]	PHS	-	15,473	-	8,057	-	29,235	-	14,610
[14]	Batteries	4,888	4,819	3,908	3,797	5,420	5,535	4,443	4,446
	Storage Losses								
[15]	PHS	-	4,641.81	-	2,417.06	-	8,770.49	-	4,382.98
[16]	Batteries	929	916	743	721	1,030	1,052	844	845
[17]	Total	929	5,557	743	3,138	1,030	9,822	844	5,228
	Net Generation								
[18]	Subtotal, N+S+W-losses	186,789	198,405	142,450	148,143	176,537	198,849	188,238	198,411
[19]	Total , N+S+W+CC-losses	230,234	230,234	230,279	230,229	229,734	230,022	230,234	230,234
[20]	**GHG Emissions (MtCO2eq)**	15.96	11.69	32.25	30.15	20.10	11.69	15.44	11.69

Notes:

[1] - [3] = Output of GenX minimum cost dispatch

[4] = [1] + [2] + [3]

[5] = Output of GenX minimum cost dispatch

[6] = [4] + [5]

[7] - [9] = Shortfall of actual generation in [1]-[3] relative to potential from previous table

[10] = [7] + [8] + [9]

[11] - [14] = Output of GenX minimum cost dispatch

[15] = [13] - [11]

[16] = [14] - [12]

[17] = [15] + [16]

[18] = [4] - [17]

[19] = [6] - [17]

[20] = Output of GenX minimum cost dispatch

Emissions from cogeneration plants are excluded as they are recorded under industrial sector

Row [18] shows the net generation from the three low-carbon technologies minus total losses from storage. Row [19] shows the net generation from the four technologies: i.e., actual total generation minus total losses from storage.

Comparing columns [B] to [D] we see that nuclear plays a large role in this future scenario as emissions almost triple if nuclear is phased out without substitute low-carbon capacity replacing it. This is because natural gas CCGT units substitute.

Table 8.3 reports the changes in curtailment and emissions within each of the scenarios when PHS is installed:

Table 8.3: Comparing the Impact of Current PHS Capacity than without

		A - 1	A - 2	A - 3	A - 4
		[A]	[B]	[C]	[D]
	Δ Curtailment with PHS (GWh)				
[1]	Nuclear	(2,544)	-	-	-
[2]	Wind	(7,222)	(4,675)	(441)	(9,342)
[3]	Solar PV	(6,479)	(3,413)	(30,664)	(5,215)
[4]	Total Low Carbon	(16,245)	(8,088)	(31,105)	(14,557)
[5]	Natural Gas CCGT	11,616	5,743	22,024	10,173
	Δ Capacity Factor with PHS (%)				
[6]	Nuclear	4.32	-	-	-
[7]	Wind	11.12	7.20	0.68	7.04
[8]	Solar PV	7.26	3.83	1.44	5.85
[9]	Total Low Carbon	7.62	5.25	1.41	6.56
[10]	Natural Gas CCGT	(5.58)	(2.76)	(10.59)	(4.89)
	Δ GHG Emissions with PHS				
[11]	MtCO2eq	(4.27)	(2.10)	(8.41)	(3.74)
[12]	%	(26.76)	(6.52)	(41.83)	(24.25)
[13]	**Monthly Utilization Rate of PHS (%)**	1.87	0.29	6.68	1.94

Notes:

[1] - [5] = Change in energy curtailed with PHS than without from previous table
[6] - [10] = Change in capacity factor with PHS than without from previous table
[11] - [12] = Change in emissions with PHS than without from previous table
[13] = Amount of energy PHS consumes as share of total load

Each column of Table 8.3 represents the difference between each scenario with and without PHS. Row [4] is the decrease in the amount of energy curtailed from low-carbon generation through the use of PHS. Row [5] is the amount of CCGT that is no longer required because of PHS. Row [9] shows that the capacity factors of low-carbon sources increases with the use of PHS. Additionally, emissions significantly decreases with PHS than without. If a ton of CO_2 in 2030 is \$50 than depending on the energy mix scenario we are saving at minimum €105 million (Scenario A - 2) to upwards of €421 million (Scenario A - 4).

Comparing Scenarios 1 and 2, columns [A]-[B], in Table 8.3 two major things stand out.

First, the reduction of low-carbon curtailment and CCGT generation in row [4] and [5], respectively, is not equivalent. That is the addition of PHS under an energy mix that includes nuclear (Scenario A - 1) has a greater effect on curtailment reduction than without nuclear (Scenarios A - 2-4). Under column [A], row [4], 16,245 GWh of low-carbon generation was no longer curtailed when current PHS capacity was included in an energy mix with nuclear. While in row [5], CCGT production decreased by 11,616 GWh. Those numbers are almost halved in column [B] when nuclear is no longer in the energy mix.

In row [9], we see that any change in low-carbon curtailments affects low-carbon capacity factors. By including PHS in Scenario A - 1, the capacity factor of low-carbon production increases by 7.62 percent. Including PHS in Scenario A - 2 only increases the capacity factor by 5.25 percent.

Why is that? PHS is not being utilized as much when nuclear is no longer in the energy mix. Row [13] is the monthly utilization rate of PHS for each scenario, i.e. what percentage of total load is from PHS consumption. The monthly utilization rate of PHS under Scenario A - 1 is 1.87 percent, while it drops to 0.29 percent in Scenario A - 2. The only difference between moving from Scenario A - 1 to Scenario A - 2 is the removal of nuclear capacity.

This makes sense due to the operating constraints of nuclear. Nuclear cannot be quickly turned on and off nor does it have any sort quick ramping capabilities. It can be counted on to meet demand over long periods of time. That is why it operates as a baseload source. So, in a future scenario where nuclear exists and solar PV and wind capacity has increased (i.e. Scenario A - 1) nuclear is likely to be kept on while curtailing wind and solar PV production is necessary. This in turn causes the aggregated capacity of these low-carbon sources to over-meet load.

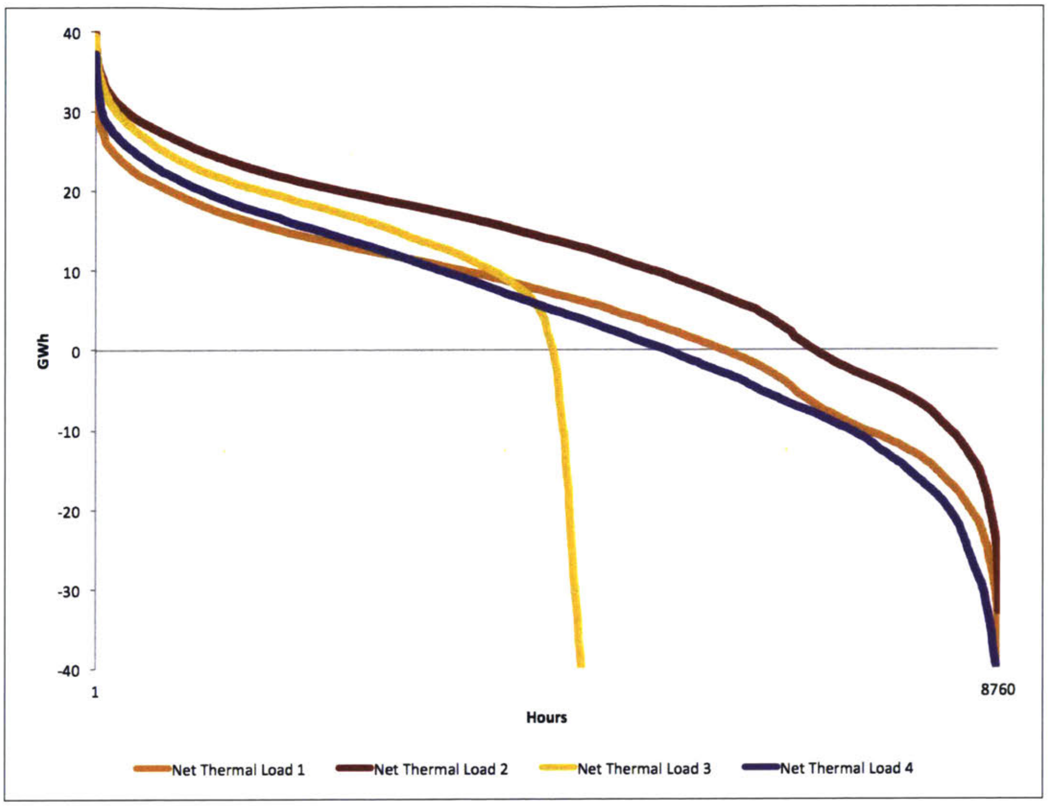


Figure 8.1: Net Thermal Load under each Scenario

In Scenario A - 2 the sum of low-carbon production will not require as much curtailment as there is no nuclear. This is visualized in Figure 8.1. Figure 8.1 graphs the net thermal load for each of the four scenarios. That is the load after the production of our low-carbon energy sources. You can see that under Scenario A - 1 (the orange line), low-carbon production meets the load roughly 1000 hours more than Scenario A - 2 (the red line). Thus, the inclusion of PHS in Scenario A - 1 mitigates curtailment to a higher degree than Scenario A - 2.

That leads to the second point. More CCGT is used in both Scenario A - 1 and 2 without PHS than with. Yet, without nuclear in Scenario A - 2 (and absent emission requirements), CCGT take its place as a flexible baseload source. Emissions almost double. Therefore, in combination with a lower PHS utilization rate, emissions only reduce by 6.5 percent in Scenario A - 2 with the addition of PHS. However, in Scenario A - 1, by using PHS at a higher rate to shift otherwise curtailed low-carbon generation, it offsets CCGT's production and lowers emissions by almost 27 percent.

This promotes my reasoning to implement a quasi-limit on emissions in Scenarios A - 3 and A - 4 by building out our solar PV and wind fleet so that it matches the emissions of

Scenario A - 1.

When comparing Scenario A - 3 and 4 (columns [C] and [D]) to Scenario A - 2 (column [B]), we see that utilization rate of PHS in row [13] is higher. Because solar PV largely generates only during the day and during low demand hours it requires a larger capacity build-out to meet our emissions requirement of Scenario A - 1. Thus, at such a high capacity it meets the net thermal load around 50 percent of the hours as seen in Figure 8.1. Scenario A - 3, represented by the yellow line, sharply drops below a net thermal load of 0 before any of the other scenarios.

There is such a large number of solar PV curtailments, PHS is being utilized at a higher rate to help shift said curtailment. Yet the production is so high because of such a large solar PV capacity, that PHS can only shift a relatively small portion of the curtailment. Therefore, the inclusion of PHS only increases the capacity factor of solar PV of Scenario A - 3 by 1.44 percent (row [8]). Wind's capacity factor only improves by less than one percent because PHS is being used primarily on solar PV.

Wind keeps a relatively consistent daily profile as compared to solar PV. As such a large buildout of wind in Scenario A - 4 is not required as it was with solar PV in Scenario A - 3. PHS increases the capacity factor of wind in Scenario A - 4 by roughly the same amount as Scenario A - 2 and uses the rest of the time to shift solar PV curtailment.

8.3 Conclusion

Rows [4] and [9] of Table 8.3 shows that across the scenarios, the inclusion of PHS reduces the amount of low-carbon curtailment with respect to potential generation. This increases low-carbon capacity factors, while decreasing fossil fuel generation and related emissions. Yet some energy mixes value PHS more than others.

Scenario A - 3 sees the lowest capacity factor increase from 8.32 percent to 9.78 percent, a change of 1.41 percent. Solar PV capacity is so large in order to lower emissions, that any reduction in curtailment by PHS is small in comparison to the total energy curtailed.

In Scenario A - 2 we see the inclusion of PHS increase low-carbon capacity factors from 92.89 percent to 98.14 percent, an increase of only 5.25. While Scenario A - 2 has the highest carbon capacity factors, it is because nuclear is no longer in the energy mix. There is a lower need for curtailment as otherwise curtailed solar PV and wind that we saw in Scenario A - 1 is now being deployed to meet load. However, because nuclear operates as a baseload plant and solar PV and wind are variable, Scenario A - 2's utilization of renewables is not equivalent to the would-be production of nuclear. Therefore, CCGT generation, and in response emissions, is almost doubled in order to replace would-be nuclear production. In a decarbonized world, this is the opposite effect we would like to see.

As such the scenarios that benefit the greatest from the inclusion of PHS are Scenarios A - 1 and A - 4. In these scenarios PHS lowers curtailment with respect to potential generation of low-carbon energy the most and thus raises their capacity factors. The capacity factor of low-carbon sources of Scenario A - 1 goes from 88.09 percent to 95.71 percent, an increase of 7.62 percent. In Scenario A - 4, the capacity factor of low-carbon sources goes from 85.09 percent to 91.75 percent, an increase of 6.56 percent.

Ultimately Scenario A - 1, as compared to the other three scenarios, sees the largest increase in its low-carbon capacity factor with the inclusion of PHS. That is, when all three major low-carbon sources are installed (nuclear, solar PV, and wind), they are most likely to meet the demand if PHS is used to shift their hourly generation throughout the day. When comparing Rows [7-9] of Scenario A - 2, 3, and 4 (Columns [B-D]), the buildout of wind in combination with PHS improves the capacity factors of low-carbon generation the most.

This can be summarized into three major points:

1. PHS provides measurable value in regards to low-carbon curtailment and emissions mitigation than without under a variety of future energy scenarios.

2. A healthy diverse energy mix of low-carbon energy sources provides the most value in increasing their capacity factors [2]. This is in line with other academic findings. Sepulveda et al. (2018) found that the least-cost strategy to decarbonize electricity includes one or more firm low-carbon resource (i.e. nuclear, bioenergy, or natural gas with carbon capture and sequestration) in combination with a healthy mix of solar, wind, storage, and demand flexibility [70].

3. When nuclear is phased out, wind is the most favorable technology in regards to capacity required to meet equivalent emissions as opposed to solar PV. Wind will utilize PHS more effectively, by not requiring such a large build-out to compensate for the hours in which CCGT must meet the remaining load. This is line with academic research as well. Rehman et al. (2015) went through more than 35 studies and found that the integration of wind and PHS was the most economically and technically competitive combination of renewable resource with PHS [63]. In these studies PHS was able to

[2] The importance of extending the life of nuclear power plants in Spain was emphasized by Fratto et al. (2018)

effectively exploit abundant wind potential and substitute conventional peak supply [63]. That being said the literature on PV-PHS systems were few and far between but showed what we expected, PHS effect is only a small number of hours during the day (i.e. during high solar penetration) [63].

Future work should examine the optimal mix of these resources to decarbonize and what role PHS would play in some 2050 scenario in which no emissions are allowed.

Chapter 9

System Cost of Additional PHS Capacity in a Decarbonized World

9.1 Introduction

This second analysis (Scenario B) addresses the system cost to serve hourly load in 2030 given expected hourly resource factors. I consider alternative portfolios of solar PV, wind and PHS capacities, holding constant the capacity of the other technologies, including nuclear, natural gas CCGT, hydro, solar thermal and other renewables, cogeneration, and batteries.

I start with a baseline portfolio of capacities that is identical to Scenario A - 1 (Table 8.1 Column [A]) as further detailed in Table 9.1. I continue to assume nuclear is in the baseline energy mix for two reasons:

1. As previously discussed the latest it will be phased out is 2035 thus in 2030 it is completely realistic all seven plants are still operational.
2. Firm low-carbon energy is an important aspect to optimizing PHS and lowering carbon emissions. If we are to envision a future scenario whose focus is deep decarbonization, I believe it is important to use the full healthy mix of low-carbon generating sources rather than a less optimal solution as the baseline [70].

Table 9.1: 2030 Baseline Portfolio of Capacities and the Resulting Generation

		Installed Capacity (MW)	Share	Generation & Demand (GWh)	Share	Capacity Factors
		[A]	[B]	[C]	[D]	[F]
	Spanish Generation (Peninsula)					
[1]	Hydro	18,059	18%	39,190	13%	25%
[2]	PHS Turbine	6,491	7%	10,831	4%	19%
[3]	Nuclear	7,117	7%	56,180	19%	90%
[4]	Coal	847	1%	-	0%	0%
[5]	Combined Cycle	23,746	24%	31,829	11%	15%
[6]	Wind	31,000	31%	61,181	21%	23%
[7]	Solar PV	47,157	48%	86,601	29%	21%
[8]	Solar Thermal	2,419	2%	4,022	1%	19%
[9]	Bio	2,550	3%	11,871	4%	53%
[10]	Cogeneration	8,500	9%	38,901	13%	52%
[11]	Batteries	2,358	2%	3,903	1%	19%
[12]	**Total**	150,244		344,511		
[13]	PHS Pumping			(15,473)		
	Battery consumption			(4,819)		
[14]	Baleric HVDC Link			(1,377)		
[15]	Interconnection Balance			(27,819)		
[16]	**Spanish Demand (Peninsula)**			295,023		
	Ancillary Calculations					
[17]	Storage losses			5,557		
[18]	Subtotal, N+W+S-losses			198,404		
[19]	Total, N+W+S+CC-losses			230,234		
[20]	GHG Emissions (MtCO2eq)			11.69		

Notes:

[1A] Hydro capacity includes reservoirs, run-of-river

[1C] Does not include mixed PHS

[2] Both mixed and pure PHS units

[13] Includes the consumption of both mixed and pure PHS units

[D] Generation share is the share of the total demand

I consider five alternative portfolios to the baseline:

- **Scenario B - 1**: Increasing the efficiency of one marginal MW of PHS capacity from 70 percent to 85 percent;
- **Scenario B - 2**: Increasing the efficiency of all currently installed PHS capacity from

70 percent to 85 percent;

- **Scenario B - 3**: Adding one MW of pure PHS capacity at 85 percent efficiency in which you connect two existing reservoirs [1];
- **Scenario B - 4**: Adding one MW of pure PHS capacity at 85 percent efficiency in which you build one new reservoir and connect it to an existing reservoir [2];
- **Scenario B - 5**: Converting one MW of existing hydro UGH reservoir that does not have pumping capabilities into a mixed pumping unit [3].

Alternatively, I consider additional solar PV and wind capacity installations that would result in equivalent emissions from the above portfolios [4].

Table 9.2 shows the installed capacities and generation potential of the efficiency improvement portfolios (Scenarios B - 1 & 2).

[1]The European Commission's JRC Report: *Assessment of the European potential for pumped hydropower energy storage* found that Spain has around 6,500 MW of this kind of capacity even accounting for environmental, transport, and infrastructure constraints [37]

[2]The European Commission's JRC: *Assessment of the European potential for pumped hydropower energy storage* found that Spain has around 31,750 MW of this kind of capacity even accounting for environmental, transport, and infrastructure constraints [37]

[3]Roughly 11,000 MW of hydro UGH reservoir does not have a pump installed on it. Assuming all of the remaining hydro UGH reservoirs can be converted into a mixed pumping unit may not be necessary feasible but has become a promising opportunity worldwide. Within the U.S. the Los Angeles Department of Water and Power (LADWP) and the U.S. Bureau of Reclamation are considered adding a pumping station to the Hoover Dam in order to increase the dam's capacity factor [51]

[4]I do not consider additional nuclear as Spain will not be adding to their existing fleet

Table 9.2: Set of Alternative Capacity Portfolios that Improve PHS Capacity Efficiency Benchmarked to our Baseline Portfolio

		B - 1 - PHS [A]	B - 1 - W [B]	B - 1 - S [C]	B - 2 - PHS [D]	B - 2 - W [E]	B - 2 - S [F]
	Installed Capacity (GW)						
[1]	Nuclear	7,117	7,117	7,117	7,117	7,117	7,117
[2]	Wind	31,000	31,000	31,000	31,000	31,950	31,000
[3]	Solar PV	47,157	47,157	47,157	47,157	47,157	49,361
[4]	Natural Gas CCGT	23,746	23,746	23,746	23,746	23,746	23,746
[5]	PHS	6,480	6,480	6,480	6,480	6,480	6,480
	Generation Potential (GWh)						
[7]	Nuclear	58,961	58,961	58,961	58,961	58,961	58,961
[8]	Wind	64,934	64,935	64,934	64,934	66,925	64,934
[9]	Solar PV	89,210	89,210	89,210	89,210	89,210	93,378
[10]	Subtotal	213,105	213,106	213,106	213,105	215,095	217,274
	Natural Gas CCGT	208,014	208,014	208,014	208,014	208,014	208,014

Notes:

[1] - [5] = Are chosen
[5A] = Capacity remains the same but efficiency of 1 MW has improved
[5D] = Capacity remains the same but efficiency of all 6,480 MW has improved
[7] = Capacity multiplied by hourly availability factor and aggregated together
[8] - [9] = Capacity multiplied by hourly resource factor and aggregated together
[11] = Capacity multiplied by 8760 hours

Scenario B - 1 is represented by Columns [A]-[C] in Table 9.2. Column [A] is improving the efficiency of one MW of PHS from 70 percent to 85 percent, while [B] and [C] adds additional capacity to wind (0.20 MW) and solar PV (0.45 MW) to ensure the same GHG emissions as [A].

scenario B - 2 is represented by Columns [D]-[F] in Table 9.2. Column [D] goes further than Column [A], improving the efficiency of all PHS capacity from 70 percent to 85 percent. Again, in [E] and [F] we add additional capacity to wind (950.13 MW) and solar PV (2,203.52 MW) to ensure the same GHG emissions as [D].

Note that in both Scenarios B - 1 an B - 2, the capacity of PHS itself is not improving, rather its generation to consumption ratio. So if it consumes one MW of electricity to pump water, rather than generating 0.7 MW of electricity it can now generate up to 0.85 MW of electricity.

Table 9.3 shows the installed capacities and generation potential of the capacity addition portfolios (Scenarios B - 3 to 5).

Table 9.3: Set of Alternative Capacity Portfolios that Add Marginal PHS Capacity Benchmarked to our Baseline Portfolio

		B - 3 - PHS	B - 3 - W	B - 3 - S	B - 4 - PHS	B - 4 - W	B - 4 - S	B - 5 - PHS	B - 5 - W	B - 5 - S
		[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]
	Installed Capacity (GW)									
[1]	Nuclear	7,117	7,117	7,117	7,117	7,117	7,117	7,117	7,117	7,117
[2]	Wind	31,000	31,251	31,000	31,000	31,251	31,000	31,000	31,234	31,000
[3]	Solar PV	47,157	47,157	47,708	47,157	47,157	47,708	47,157	47,157	47,667
[4]	Natural Gas CCGT	23,746	23,746	23,746	23,746	23,746	23,746	23,746	23,746	23,746
[5]	PHS	6,481	6,480	6,480	6,481	6,480	6,480	6,480	6,480	6,480
	Generation Potential (GWh)									
[7]	Nuclear	58,961	58,961	58,961	58,961	58,961	58,961	58,961	58,961	58,961
[8]	Wind	64,934	65,459	64,934	64,934	65,459	64,934	64,934	65,425	64,934
[9]	Solar PV	89,210	89,210	90,252	89,210	89,210	90,252	89,210	89,210	90,175
[10]	Subtotal									
[11]	Natural Gas CCGT	208,014	208,014	208,014	208,014	208,014	208,014	208,014	208,014	208,014

Notes:
[1] - [5] = Are chosen
[7] = Capacity multiplied by hourly availability factor and aggregated together
[8] - [9] = Capacity multiplied by hourly resource factor and aggregated together
[11] = Capacity multiplied by 8760 hours

Scenario B - 3 is represented by Columns [A]-[C] in Table 9.3. Column [A] adds one MW of pure PHS capacity at 85 percent efficiency in which you connect two existing reservoirs. Columns [B] and [C] adds additional capacity to wind (250.62) MW) and solar PV (551.31 MW), respectively, to ensure the same GHG emissions as [A].

Scenario B - 4 is represented by Columns [D]-[E] in Table 9.3. They are identical to Scenario B - 3, and its respective columns. The only difference is that the MW of pure PHS added is to build one new reservoir and connect it to an existing reservoir. So the two scenarios will diverge when comparing the cost of the two PHS designs.

Scenario B - 5 is represented by Columns [G]-[I] in Table 9.3. Column [G] adds one MW of PHS at 85 percent efficiency by converting one MW of existing hydro UGH reservoir that does not have pumping capabilities into a mixed pumping unit. Columns [H] and [I] add additional capacity to wind (234.26 MW) and solar PV (510.49) , respectively, to ensure the same GHG emissions as [G].

9.2 Results and Discussion

Table 9.4 reports the dispatch results for the improved PHS efficiency portfolios (Scenarios B - 1 and B - 2) and their alternatives. Table 9.5 reports the dispatch results for all the additive marginal PHS capacity portfolios (Scenarios B - 3, B - 4, and B - 5) and their alternatives. The tables only show generation for nuclear, solar, wind and natural gas CCGT units along with generation and consumption from hydro and battery storage since these are the only items allowed to vary across the portfolios.

Table 9.4: Minimum Cost Dispatch Results for Set of Alternative Capacity Portfolios that Improve PHS Capacity Efficiency Benchmarked to our Baseline Portfolio

		B - 1 - PHS	B - 1 - W	B - 1 - S	B - 2 - PHS	B - 2 - W	B - 2 - S
		[A]	[B]	[C]	[D]	[E]	[F]
	Generation (GWh)						
[1]	Nuclear	56,180	56,180	56,180	56,137	56,068	55,663
[2]	Wind	61,161	61,181	61,181	60,589	63,017	60,223
[3]	Solar PV	86,621	86,601	86,602	86,268	86,506	89,961
[4]	Subtotal	203,962	203,963	203,963	202,994	205,591	205,847
[5]	Natural Gas CCGT	31,829	31,829	31,829	30,273	30,265	30,262
[6]	Total	235,791	235,792	235,792	233,267	235,856	236,109
	Curtailment (GWh)						
[7]	Nuclear	2,781	2,781	2,781	2,824	2,893	3,298
[8]	Wind	3,774	3,754	3,754	4,345	3,907	4,712
[9]	Solar PV	2,588	2,608	2,609	2,942	2,704	3,417
[10]	Total	9,143	9,143	9,143	10,111	9,504	11,426
	Storage Generation (GWh)						
[11]	PHS	10,832	10,831	10,831	13,281	10,970	11,526
[12]	Batteries	3,903	3,903	3,903	2,939	3,925	3,989
	Storage Consumption (GWh)						
[13]	PHS	15,473	15,473	15,473	15,624	15,671	16,465
[14]	Batteries	4,819	4,819	4,819	3,629	4,846	4,924
	Storage Losses						
[15]	PHS	4,641	4,642	4,642	2,343	4,701	4,939
[16]	Batteries	916	916	916	689	921	936
[17]	Total	5,557	5,557	5,557	3,033	5,622	5,875
	Net Generation						
[18]	Subtotal, N+S+W-losses	198,405	198,405	198,405	199,961	199,969	199,972
[19]	Total , N+S+W+CC-losses	230,234	230,234	230,234	230,234	230,234	230,234
[20]	**GHG Emissions (MtCO2eq)**	11.69	11.69	11.69	11.12	11.12	11.12

Notes:

[1] - [3] = Output of GenX minimum cost dispatch

[4] = [1] + [2] + [3]

[5] = Output of GenX minimum cost dispatch

[6] = [4] + [5]

[7] - [9] = Shortfall of actual generation in [1]-[3] relative to potential from previous table

[10] = [7] + [8] + [9]

[11] - [14] = Output of GenX minimum cost dispatch

[15] = [13] - [11]

[16] = [14] - [12]

[17] = [15] + [16]

[18] = [4] - [17]

[19] = [6] - [17]

[20] = Output of GenX minimum cost dispatch

Emissions from cogeneration plants are excluded as they are recorded under industrial sector

Table 9.5: Minimum Cost Dispatch Results for Set of Alternative Capacity Portfolios that Add Marginal PHS Capacity Benchmarked to our Baseline Portfolio

		B-3-PHS	B-3-W	B-3-S	B-4-PHS	B-4-W	B-4-S	B-5-PHS	B-5-W	B-5-S
		[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]
	Generation (GWh)									
[1]	Nuclear	56,331	56,146	56,046	56,331	56,146	56,046	56,324	56,149	56,056
[2]	Wind	61,339	61,679	61,044	61,339	61,679	61,044	61,372	61,600	61,024
[3]	Solar PV	86,684	86,552	87,353	86,684	86,552	87,353	86,638	86,601	87,329
[4]	Subtotal	204,353	204,376	204,442	204,353	204,376	204,442	204,335	204,349	204,409
[5]	Natural Gas CCGT	31,305	31,438	31,437	31,305	31,438	31,437	31,315	31,464	31,462
[6]	Total	235,658	235,815	235,879	235,658	235,815	235,879	235,650	235,813	235,871
	Curtailment (GWh)									
[7]	Nuclear	2,631	2,815	2,915	2,631	2,815	2,915	2,637	2,813	2,905
[8]	Wind	3,596	3,781	3,891	3,596	3,781	3,891	3,562	3,825	3,910
[9]	Solar PV	2,526	2,658	2,900	2,526	2,658	2,900	2,571	2,609	2,847
[10]	Total	8,752	9,254	9,706	8,752	9,254	9,706	8,770	9,246	9,662
	Storage Generation (GWh)									
[11]	PHS	10,636	10,881	11,022	10,636	10,881	11,022	10,646	10,878	11,005
[12]	Batteries	3,866	3,911	3,927	3,866	3,911	3,927	3,866	3,911	3,925
	Storage Consumption (GWh)									
[13]	PHS	15,194	15,544	15,745	15,194	15,544	15,745	15,207	15,540	15,722
[14]	Batteries	4,772	4,829	4,848	4,772	4,829	4,848	4,773	4,828	4,845
	Storage Losses									
[15]	PHS	4,558	4,663	4,723	4,558	4,663	4,723	4,562	4,662	4,716
[16]	Batteries	907	917	921	907	917	921	907	917	921
[17]	Total	5,464	5,581	5,645	5,464	5,581	5,645	5,469	5,579	5,637
	Net Generation									
[18]	Subtotal, N+S+W-losses	198,889	198,796	198,797	198,889	198,796	198,797	198,866	198,770	198,772
[19]	Total , N+S+W+CC-losses	230,194	230,234	230,234	230,194	230,234	230,234	230,181	230,234	230,234
[20]	**GHG Emissions (MtCO2eq)**	11.55	11.55	11.55	11.55	11.55	11.55	11.56	11.56	11.56

Notes:

[1] - [3] = Output of GenX minimum cost dispatch
[4] = [1] + [2] + [3]
[5] = Output of GenX minimum cost dispatch
[6] = [4] + [5]
[7] - [9] = Shortfall of actual generation in [1]-[3] relative to potential from previous table
[10] = [7] + [8] + [9]
[11] - [14] = Output of GenX minimum cost dispatch
[15] = [13] - [11]
[16] = [14] - [12]
[17] = [15] + [16]
[18] = [4] - [17]
[19] = [6] - [17]
[20] = Output of GenX minimum cost dispatch
Emissions from cogeneration plants are excluded as they are recorded under industrial sector

Row [18] in both tables shows the net generation from the three low-carbon technologies: i.e., total generation from nuclear, wind and solar minus total losses from storage. Row [19] in both tables shows the net generation from the four technologies: i.e., total generation minus total losses from storage. As one can see, the values in row [19] are all approximately identical to one another and to the baseline portfolio results in Table 9.1. The only exception is alternative PHS capacity portfolios (Columns [A], [D], and [G] in Table 9.5. This makes sense because altering PHS to the baseline changes the amount of consumption vs generation. But in all the other cases, the only variation across the portfolios is how much of the demand is served by each technology. Together, they must serve the same net load.

Comparing the GHG emissions in the baseline portfolio shown in Table 9.1 against the GHG emissions in the five sets of alternative portfolios, we see that they fall by 0.001 percent in Scenario B - 1, 4.909 percent in Scenario B - 2, 1.228 percent in Scenarios B - 3 and B - 4, and 1.148 percent in Scenario B - 5. Examining the "marginal case" scenarios, that is all of them except Scenario B - 2, we see the greatest reduction in GHG emissions in Scenarios B - 3 and B - 4. That is where one MW of 85 percent pure PHS capacity has been added to the energy mix.

Again, I did not change or constrain the amount of CCGT capacity across alternative portfolios only solar PV and wind. Spain already has excess capacity, especially of CCGT. So installing more PHS, solar PV, or wind capacity in the alternative portfolios limits/squeezes out the CCGT generation not the capacity itself.

9.2.1 Cost Inputs

A key input to complete the system cost anaylsis is the cost of capacity and generation for PHS, solar PV, wind and CCGT in 2030. It is important to note that any future forecast for costing will have its differing assumptions, doubts, etc. As such I am very clear for the costs inputs so that any other reader could theoretically place in their own inputs. I have chosen to present the results primarily using values published by the European Commission's JRC ETRI report and by ENTSO-E's TYNDP [13, 81].

Tables 9.6 and 9.7 shows the inputs, which are all quoted in €2013.

Table 9.6: Inputs for the Cost of Electricity for PHS

		Input [A]		Unit Factor [B]	Present Value Factor [C]	Levelized Cost (€/MWh) [D]
	PHS - efficiency					
[1]	Life	60	years			
[2]	Capital Cost (Investment)	275	€/kW	0.544	0.071	10.65
[3]	Fixed O&M	4.125	€/kW/y	0.544	1.000	2.24
[4]	Variable O&M	0	€/MWh	1.000	1.000	0.00
[5]	Capacity Factor	0.21				
[6]	Discount Rate	7%				
[7]	**Total Cost**					12.89
	PHS - existing reservoirs connect					
[8]	Life	60	years			
[9]	Capital Cost (Investment)	650	€/kW	0.544	0.071	25.17
[10]	Fixed O&M	9.75	€/kW/y	0.544	1.000	5.30
[11]	Variable O&M	0	€/MWh	1.000	1.000	0.00
[12]	Capacity Factor	0.21				
[13]	**Total Cost**					30.47
	PHS - build one new reservoir					
[14]	Life	60	years			
[15]	Capital Cost (Investment)	1500	€/kW	0.544	0.071	58.08
[16]	Fixed O&M	22.5	€/kW/y	0.544	1.000	12.23
[17]	Variable O&M	0	€/MWh	1.000	1.000	0.00
[18]	Capacity Factor	0.21				
[19]	**Total Cost**					70.31

Notes:

Column [A] = Unless otherwise stated, inputs are from JRC ETRI projections for 2010-2050, 2030

[5], [12], and [18] = By assumption, at historical value

[6] = By assumption

Column [B]

[2] & [3], [9] & [10], [15] & [16] = 1/(CapacityFactor*8,760).

Column [C]

[2] = 60-year annuity factor = 1/(1-(1+R)^-T)/R = 1/(1-(1+[A5])^-[A1])/[A5]

[9] = 60-year annuity factor = 1/(1-(1+R)^-T)/R = 1/(1-(1+[A5])^-[A8])/[A5]

[10] = 60-year annuity factor = 1/(1-(1+R)^-T)/R = 1/(1-(1+[A5])^-[A14])/[A5]

Column [D]

[2], [3] & [4], [9] [10] & [11], [15], [16] & [17] = [A] * [B] * [C].

Table 9.7: Inputs for the Cost of Electricity for Other Technologies

		Input		Unit Factor	Present Value Factor	Levelized Cost (€/MWh)
		[A]		[B]	[C]	[D]
	Solar PV					
[1]	Life	25	years			
[2]	Capital Cost (Investment)	640	€/kW	0.571	0.086	31.35
[3]	Fixed O&M	10.88	€/kW/y	0.571	1.000	6.21
[4]	Variable O&M	0	€/MWh	1.000	1.000	0.00
[5]	Capacity Factor	0.20				
[6]	Discount Rate	7%				
[7]	Total Cost					37.56
	Onshore Wind					
[8]	Life	25	years			
[9]	Capital Cost (Investment)	866.67	€/kW	0.439	0.086	32.65
[10]	Fixed O&M	19.067	€/kW/y	0.439	1.000	8.37
[11]	Variable O&M	0	€/MWh	1.000	1.000	0.00
[12]	Capacity Factor	0.26				
[13]	**Total Cost**					41.02
	NGCC					
[14]	Life	30	years			
[15]	Thermal Efficiency	0.55				
[16]	Capital Cost (Investment)	850	€/kW	0.134	0.081	9.20
[17]	Fixed O&M	21.25	€/kW/y	0.134	1.000	2.85
[18]	Variable O&M	8.768	€/MWh	1.000	1.000	8.77
[19]	Fuel Cost	31.7	€/MWh-th	1.818	1.000	57.64
[20]	Emissions Charge	50	€/tCO2eq	0.367	1.000	18.37
[21]	Capacity Factor	0.85				
[22]	**Total Cost**					96.83

Notes:

Column [A] = Unless otherwise stated, inputs are from JRC ETRI projections for 2010-2050, 2030

[5], [12] = By assumption, at historical value

[6] = By assumption

[19] = 8.8/0.27778. ENTSOE's TYNDP DG2030 scenario as reported in Annex II Methodology: Scenario Report gives a fuel price of €8.8/GJ.

[20] = ENTSOE's TYNDP DG2030 scenario as reported in Annex II Methodology

[21] = By assumption

Column [B]

[2] & [3], [9] & [10], [16] & [17] = 1/(CapacityFactor*8,760).

[15] = By current units

[19] = 1/ThermalEfficiency = 1/[A15]

[20] = 56,100*0.001*0.0036/ThemalEfficiency=.20196/[A15]

MAPAMA (2017) reports the CO2 intensity of natural gas as 56,100 kgCO2/TJ thermal.

Column [C]

[2] = 25-year annuity factor = 1/(1-(1+R)^-T)/R = 1/(1-(1+[A5])^-[A1])/[A5]

[9] = 25-year annuity factor = 1/(1-(1+R)^-T)/R = 1/(1-(1+[A5])^-[A8])/[A5]

[10] = 30-year annuity factor = 1/(1-(1+R)^-T)/R = 1/(1-(1+[A5])^-[A14])/[A5]

Column [D]

[2], [3] & [4], [9] [10] & [11], [15] - [20] = [A] * [B] * [C].

Table 9.6, rows [1]-[4] of column [A] are the raw inputs for the cost of improving PHS efficiency with a new turbine, i.e. Scenarios B - 1 and B - 2. Rows [8]-[11] are the inputs for connecting two existing reservoirs, i.e. Scenarios B - 3 and B - 5. I assume this is the same for both pure PHS and mixed PHS connecting hydro UGH reservoirs. Rows [14]-[17] are the inputs for building one new reservoir for pure PHS, i.e. Scenario B - 4. These are taken directly from the ETRI Report [13]. The capacity factors are based off historical averages over the last decade from REE national historical stats [30].

Table 9.7, rows [1]-[4] of column [A] are the raw inputs for the cost of solar PV and rows [14]-[17] are the inputs for wind. These are taken directly from the ETRI Report [13]. The capacity factors are based off historical averages over the last decade from REE national historical stats [30].

Rows [20]-[26] are the inputs for the CCGT, including an attributed cost for GHG emissions. Variable O&M cost includes both value from the ETRI report as well as the appropriate taxes/fees outlined in Section 7.2.3. The fuel cost of is from ENTSO-E's TYNDP Appendix II [81]. A carbon price of €50/tCO2eq is also from ENTSO-E's TYNDP DG2030 scenario and additionally used in the Commission of Experts' (2018) report [81, 17].

The final result in the above tables is the Levelized Cost of Electricity (LCOE), a common metric for evaluating investment choices across alternative generation technologies. It is the average cost across the hours of electricity delivered using a discount rate to capture the time value of money and risk.

The main issue with LCOE is that it assumes every unit of electricity is like every other unit of electricity. Yet that is not the case. For example solar PV really only serves electricity during the high solar penetration periods and thus comparing its LCOE to CCGT that has the capability to provide electricity throughout the entire day is not entirely accurate. Another example is the difference between peak and off-peak load. It is more expensive to serve peak load because it requires capital investments that are paid off over fewer hours of the year. Other typical examples involve ancillary services, such as frequency regulation, reactive power or fast acting reserves. Consequently, electricity systems usually consist of investments in a portfolio of technologies that together provides the full array of services at lowest cost. Technologies with high LCOEs coexist alongside technologies with low LCOEs because they serve different portions of load, and the cost differential is inherent in serving them. Indeed, different units of the same technology are often used to serve different loads and therefore operate with different LCOEs.

9.2.2 System Cost

Rather than simply comparing fixed LCOE's, which takes the capacity factors as fixed and exogenously specified, I look at system cost which takes into account the time profile of demand and renewable resources and the use of the technologies in the full portfolio that serves the full load. Thereby I endogenously determine the capacity factor as a result of the optimal dispatch given under the specified capacities. These will differ across the set of alternative portfolios chosen and allow for comparison.

First, I compare the system costs within the two kinds of portfolios, efficiency improvements and capacity additions. Within each alternative set (i.e. PHS vs wind vs solar PV), the total GHG emissions are constant, so that a comparison across the portfolios within the set answers which portfolio is the cheapest way to achieve the targeted GHG emission reductions. I then compare across our types of portfolios.

Table 9.8 shows the calculation of the cost of the incremental low-carbon capacity and generation for the first two alternative efficiency portfolios, Scenarios B - 1 and B - 2:

Table 9.8: Relative System Costs for Set of Alternative Capacity Portfolios that Improve PHS Capacity Efficiency Benchmarked to our Baseline Portfolio

			B - 1 - PHS	B - 1 - W	B - 1 - S	B - 2 - PHS	B - 2 - W	B - 2 - S
			[A]	[B]	[C]	[D]	[E]	[F]
[1]	Incremental Capacity	(MW)	0.15	0.20	0.44	972.00	950.13	2,203.52
[2]	Incremental Low Carbon Generation	(GWh)	0.32	0.32	0.32	1,556.20	1,567.54	1,567.54
[3]	Incremental Capacity Factor		24%	18%	8%	18%	19%	8%
[4]	Incremental Unit Cost	(€/MWh)	11.05	58.12	90.59	14.81	56.63	92.49
[5]	Incremental System Cost, gross annual	(€ millions)	0.00	0.02	0.03	23.05	88.78	144.99
[6]	**Incremental System Cost, gross PV 60 years**	(€ millions)	0.05	0.26	0.40	323.59	1,246.34	2,035.53
[7]	**Difference to PHS**	(€ millions)		0.21	0.35		922.75	1,711.94
				425%	710%		285%	529%

Notes:

[1]
[A] = (1*0.85)-(1*0.7)
[B] = Table 11 [2B] - Table 10 [6A]
[C] = Table 11 [2C] - Table 10 [7A]
[D] = (6480*0.85)-(6480*0.7)
[E] = Table 11 [2E] - Table 10 [6A]
[F] = Table 11 [2F] - Table 10 [7A]
[2] = Table 13 [18] - Table 10 [18]
[3] = [2]/([1]*8.760)
[4] = Calculated using LCOE in Tables 15 & 16, substituting the capacity factor from [3].
[5] = [2]*[4]/1,000
[6] = PV(7%,10,-[5])
[7X]= [6X]-[6A]

- Row [1] is the incremental low-carbon capacity for each portfolio relative to the Baseline portfolio;
- Row [2] is the incremental low-carbon generation for that portfolio over the low-carbon generation in the Baseline Portfolio; this reflects the impact of dispatch, including curtailment;
- Row [3] is the capacity factor for this incremental capacity; in each case, I calculate the capacity factor incorporating the total net impact on generation from all low-carbon technologies and compare that against the potential generation from the increased capacity;
- Row [4] is the average unit cost for this generation given this capacity factor, and assuming the same pattern of generation for the full 60-year life of the PHS improvement and 25-years for the wind and solar [5]. PHS has the lowest cost as compared to equivalent wind and solar PV improvements in both Scenario B - 1 and B - 2;
- Row [5] is the incremental gross annual system cost associated with this incremental capacity; this does not reflect any savings from displaced CCGT; it simply asks what is the annual cost of this incremental generation produced with this capacity;
- Row [6] calculates the present value of this annual cost over the 60 year life of the PHS improvement. Note PHS pump/turbine efficiency improvements are the lowest system cost compared to the alternative solar PV and wind additions in both Scenarios B - 1 and B - 2;
- Row [7] calculates for each of the wind and solar pv alternatives the difference between their gross incremental system cost and the PHS improvement's gross incremental system cost.

The table does not show any of the savings from avoided natural gas CCGT capacity or operating expenses, which is why we refer to it as a gross cost. The calculations are based entirely on the single forecast scenario I used and does not include an assessment of risk over variables such as demand, resource availability, and the reliability of each type of capacity.

Table 9.9 shows the calculation of the cost of the incremental low-carbon capacity and generation for the second three alternative marginal PHS capacity addition portfolios, Scenarios B - 3, B - 4, and B - 5:

[5] I.e. this a static analysis that uses 2030 as a representative year. This ignores dynamic factors.

Table 9.9: Relative System Costs for Set of Alternative Capacity Portfolios that Add Marginal PHS Capacity Benchmarked to our Baseline Portfolio

			B - 3 - PHS	B - 3 - W	B - 3 - S	B - 4 - PHS	B - 4 - W	B - 4 - S	B - 5 - PHS	B - 5 - W	B - 5 - S
			[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]
[1]	Incremental Capacity	(MW)	1.00	250.62	551.31	1.00	250.62	551.31	1.00	234.26	510.49
[2]	Incremental Low Carbon Generation	(GWh)	484.04	390.81	392.42	484.04	392.42	390.81	461.55	365.39	366.97
[3]	Incremental Capacity Factor		5526%	18%	8%	5526%	18%	8%	5269%	18%	8%
[4]	Incremental Unit Cost	(€/MWh)	0.12	59.92	92.44	0.27	59.67	92.82	0.12	59.90	91.53
[5]	Incremental System Cost, gross annual	(€ millions)	0.06	23.42	36.28	0.13	23.42	36.28	0.06	21.89	33.59
[6]	**Incremental System Cost, gross PV 60 years**	(€ millions)	0.79	328.75	509.28	1.82	328.75	509.28	0.79	307.29	471.57
[7]	**Difference to PHS**	(€ millions)		327.97	508.50		326.94	507.47		306.51	470.78
				41679%	64622%		18004%	27946%		38952%	59828%

Notes:

[1]

[A], [D], and [G] = Chosen, one marginal MW of capacity

[B] = Table 12 [2B] - Table 10 [6A]

[C] = Table 12 [2C] - Table 10 [7A]

[E] = Table 12 [2E] - Table 10 [6A]

[F] = Table 12 [2F] - Table 10 [7A]

[H] = Table 11 [2H] - Table 10 [6A]

[I] = Table 11 [2I] - Table 10 [7A]

[2] = Table 14 [18] - Table 10 [18]

[3] = [2]/([1]*8.760)

[4] = Calculated using LCOE in Tables 15 & 16, substituting the capacity factor from [3].

[5] = [2]*[4]/1,000

[6] = PV(7%,10,-[5])

[7X]= [6X]-[6A]

The rows are calculated similarly to Table 9.8. Therefore the most important comparisons are in rows [4] and [6]. Row [4] shows that the unit cost of adding one MW of PHS, whether by connecting two existing reservoirs (Scenario B - 3), building one new reservoir (Scenario B - 4), or converting a current hydro UGH reservoir to pumping capabilities (Scenario B - 5), is cheaper than the alternative of adding wind or solar PV. Row [6] shows the total system cost of adding one MW of PHS, in all three scenarios, is significantly cheaper than the alternative of adding wind or solar PV.

9.3 Conclusion

The bottom line from Table 9.8 is improving the efficiency of one MW of PHS by installing a new turbine/pump (Scenario B - 1) decreases emissions by 0.0001 MtCO2eq at the lowest system cost. It saves over €355,000 relative to the alternative of expanding the scale of solar PV penetration, and saves almost €212,000 relative to the alternative of expanding the scale of wind penetration. Improving the efficiency of all current Spanish PHS by installing a new turbine/pump (Scenario B - 2) decreases emissions by 0.574 MtCO2eq at the lowest system cost. It saves over €1.7 billion relative to the alternative of expanding the scale of solar PV penetration, and saves almost €1 billion relative to the alternative of expanding the scale of wind penetration. In comparing Scenario B - 1 and B - 2, within rows [4] of columns [A] and [D], it is cheaper on an incremental unit cost basis to improve the efficiency of one marginal MW of PHS than the entire current capacity.

The bottom line from Table 9.9 is by adding one MW of PHS by either connecting two existing reservoirs (Scneario B - 3) or building one new reservoir (Scenario B - 4), reduces GHG emissions for electricity by 0.144 MtCO2eq to the baseline. However on an incremental unit and total system cost basis, connecting two existing reservoirs is about half the cost of building one new reservoir. We see that in rows [4] and [6] of columns [A] and [D]. That being said each scenario saves roughly €508 million relative to the alternative of expanding the scale of solar PV penetration, and saves around €327 million relative to the alternative of expanding the scale of wind penetration. Converting a current hydro UGH reservoir to pumping capabilities (Scenario B - 5), reduces GHG emissions for electricity by 0.134 MtCO2eq. Its incremental unit and system cost is equivalent to Scenario B - 3. However, it only saves over €470 million relative to the alternative of expanding the scale of solar PV penetration, and saves over €306 million relative to the alternative of expanding the scale of wind penetration.

In summation all scenarios show that under an energy mix that includes nuclear, improving the efficiency of or adding PHS is the lowest system cost than the alternative of adding additional low-carbon sources. Scenario B - 1, in which one current MW of PHS efficiency is improved, has the lowest total system cost of all five scenarios. Scenarios B - 3 and B - 5, have the lowest incremental unit costs of all five scenarios. Whereas Scenario B - 3 has the biggest difference in total system cost from adding marginal MW of PHS capacity than adding wind or solar PV equivalents.

Note that these system costs effectively only looked at Scenario A - 1 of previous valuation. It is imperative that future work should look at differing energy mixes, i.e. when no nuclear exists or additional wind and solar PV is added similar to Scenarios A - 2, 3, and 4. This would be incredibly important for Spain as it looks past 2035 when no nuclear exists. These simulations would help determine if its cost effective to add more solar PV, wind, or PHS.

From the Chapter 8 results, in which PHS had the biggest impact on an energy mix that included nuclear, it is entirely plausible that under a limited emissions scenario and an energy mix that doesn't have nuclear, PHS will not lower the system cost as much as it did in our above analysis. If I used Scenario A - 2 as a baseline instead, it may be cheaper to build out wind while utilizing the current PHS installed rather than building more PHS storage or even solar PV.

Additionally, another important scenario to look at is if no emissions are allowed and nuclear is phased out. Increasing PHS capacity will likely provide some value rather than excessively building out solar and wind. Thus it would be relevant to find the optimal mix of wind, solar, hydro, and PHS to properly meet all of demand.

Chapter 10

Policy and Regulation

10.1 Energy Arbitrage Risk in a Decarbonized World

One concern with PHS (and all storage for that matter) is its potential effect on arbitrage revenue if it, alongside low cost renewables, can completely meet the demand of a system.

As described in Section 2.3.1, for PHS to make economic sense within arbitrage, the ratio of the cost of charging the energy to discharging must exceed the round-trip efficiency, η. That is the energy price in pumping mode needs to be at least (1-η) lower than the selling price to cover variable O&M costs [47]. The last decade has seen a majority of electricity markets experiencing decreased spreads in electricity pricing [47, 24]. This is due to the increased penetration of renewables, availability of cheaper coal, stark decline in natural gas prices, and increased combustion turbine efficiency [47, 24]. This decreasing spread in prices can be seen in the following final hourly price in Spain's market in Figure 10.1.

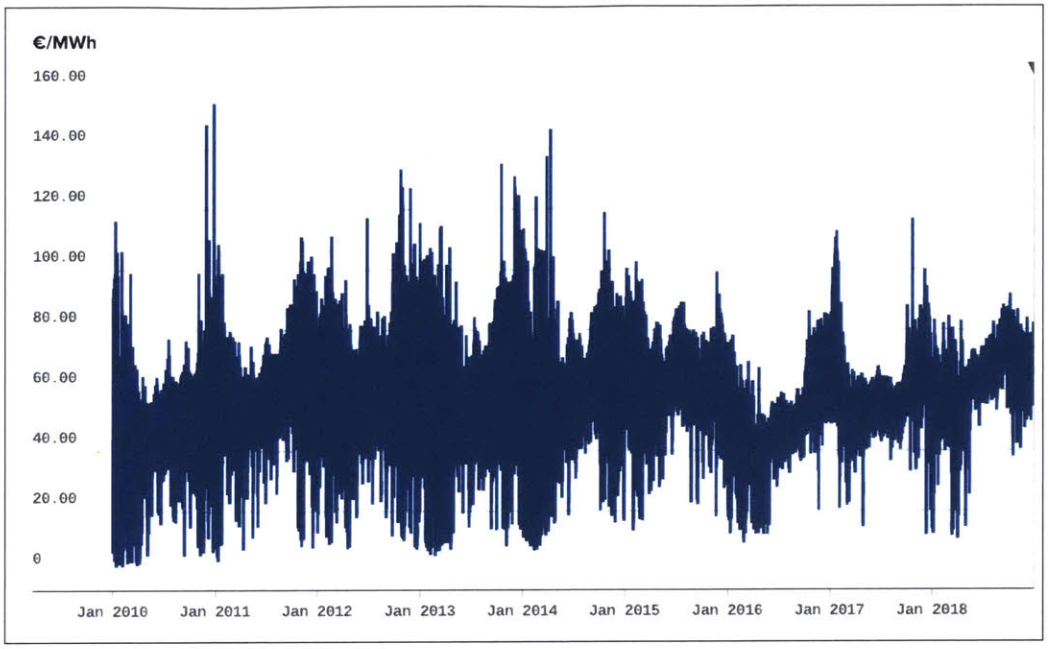


Figure 10.1: Final Hourly Price (€/MWh) in Spain, 2010-2018

Therefore reduction in peak/off peak spread could hurt PHS profitability in the energy arbitrage market as a bidding customer [1]. The National Renewable Energy Laboratory (NREL) outlines such a future scenario in which you have storage capacity, like PHS, that is large enough to flatten the net system load [27]. This would occur when, during low demand times and high variable energy production, energy is used to pump water to the upper reservoir to be stored. Thus, during traditionally peak demand hours, stored water is enough to meet said demand in conjunction with the other cheap O&M sources (renewables, nuclear, etc.). As a result, the entire day would see an equivalent net load. While this would not affect a regulated market, it could arguably impact a restructured competitive market. This scenario could essentially eliminate the need for expensive peaking plants to meet demand as there is no longer a price difference in marginal plants meeting the resulting demand. NREL argues that there would be no large price gap for the PHS plant to make the required profit to earn back their investment [27].

However, I contend there is a flaw in this concern. Even in a world limited by emissions or no emissions, there will always be the ability to use arbitrage. For example in years where we assume a high cost of carbon, CCGT and coal will most likely become more expensive.

[1] Additionally it has been argued that the EU Emissions Trading System (EU ETS) did not result in high carbon prices, thus CCGT and OCGT units have become the competitive alternative of PHS in the balancing markets [2]

PHS will always be able to bid into the market and use energy arbitrage to its advantage as long as they bid under the cost of using a fossil fuel plant. They could essentially serve as the marginal price setting plant.

Moreover, PHS can play a larger role in ancillary services. Increased penetration of variable renewables will increase the need for ancillary services and also likely result in increased ancillary service prices. If current and new PHS plants have variable speed pumps they will have increased ability to serve flexibility, ramping, regulation, and spinning reserves. Recent studies that run "co-optimized" energy arbitrage and ancillary services models indicate profitability of PHS plants would rise by 33 percent, with ancillary services accounting for 40 percent of the profits [2]. Additionally, it has been argued that it may be beneficial for the system operator to have some level of control over PHS in order to optimize energy and ancillary services [27]. If the system operator knows the full costs for PHS as well as the capabilities and limitations, they can use their operational and forecasting knowledge to schedule the pumping, generation, and ancillary service in the most beneficial way [27].

10.2 Investment Support

The question remains if PHS is a highly useful, cost effective, and mature proven technology why isn't used it more widely used. New reservoir possibilities as discussed in 2.3.2 should assuage the original environmental and geographical concerns and the preceding valuations of PHS showed it as a lower system cost option in decarbonizing the electricity sector.

Most likely the reason can be traced back to the biggest shift in the policy and regulation of electricity, the liberalization of major electricity markets. As mentioned PHS was built largely to complement thermal facilities in the 1970s and 80s. Generation, transmission, and distribution development, operation, and maintenance decisions were made largely by central regulation authorities [11, 60]. At the time PHS clearly had a role in ensuring a security of supply by complimenting nuclear and coal generation, and whose need and value could be easily determined from a central authority [2].

Security of supply is arguably an even more pressing issue as we trend towards a higher reliance on intermittent renewable generation. Yet, since electricity market liberalization began occurring there has been a decreased growth in PHS development in those markets.

[2]We are not arguing that centralised decision-making is the best way of considering or delivering the highest social value. That was actually a major reason electricity systems were deregulated: that markets could more efficiently realize complex needs and outcomes of the electricity sector in a increased welfare maximizing manner than a centralized monopoly could [11, 60].

Figure 10.2 from Barbour et al. (2016) shows the capacity (in GW) of PHS that has been commissioned in different market environments in various regions. They find that over 95 percent of PHS came into existence under monopoly market conditions while the rest was were commissioned under restructured market conditions [5] [3].

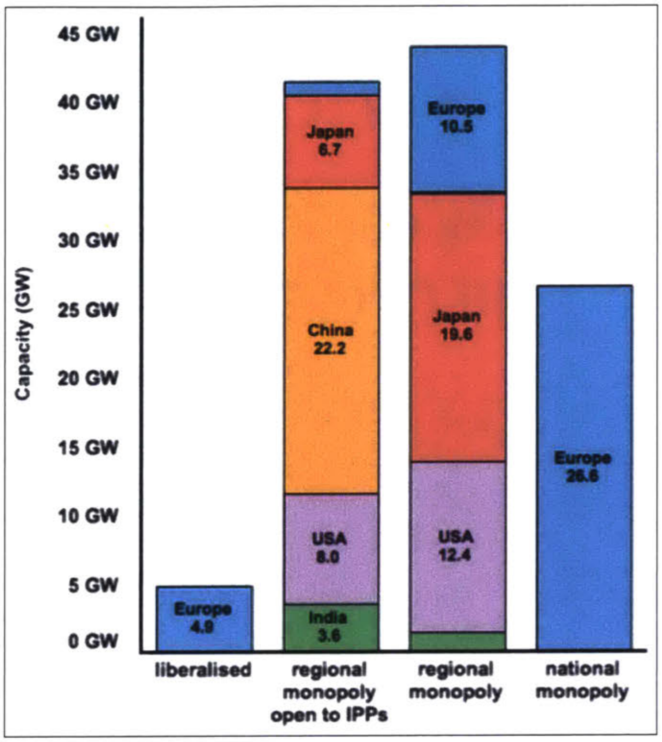


Figure 10.2: PHS Capacity Commissioned under Different Market Structures

I believe the revenue options those market support are the reason there is a lack of PHS investment in restructured markets. As a point of a refresher from section 2.3.1, in a regulated market, PHS can make revenue through "cost-of-service" business models. The cost of a project is remunerated through rates that cover both the project's capital and operating costs, approved by the regulator. Under a restructured market PHS can directly participate in the competitive energy market. Units in this market derive their revenue by discharging at peak electricity usage times when prices are high and charge during off-peak times when prices are low.

Under cost-of-service business models it is entirely reasonable that PHS plants can be built and properly remunerated. However new PHS plants, that have high capital costs and long time frames, have a concern of regulatory and financial uncertainty under restructured

[3]This is only under the five major PHS regions, China, U.S., Japan, Europe, and India.

competitive market places. The issue policy and regulators must face is how to encourage investment in and properly reward new PHS plants under competitive markets as they seek to decarbonize.

The biggest barrier to new PHS entry is their varied benefits across the energy sector. This allows for them to be classified as generating, transmission, or distribution assets yet not as "all of the above". Many of these benefits are in the form of "avoided costs". So in order for the owner of a PHS plant to benefit financially they themselves must be the ones originally bearing the cost that is avoided. For example, companies that own fossil fuel generating plants may not invest more in PHS unless the avoided cost of emissions is greater than the cost of using their fossil fuel plants [4]. Another example is that PHS can help avoid the purchase of transmission or distribution infrastructure by storing energy that may not be needed in the system at any given hour or by relieving the start-shut cycles of thermal generators in the grid. Yet in a restructured market PHS plants are assigned as generating assets thus the savings they provide to the transmission and distribution sector are not necessarily recouped by the owner of the PHS.

As such you could use policy to create market based incentives to develop PHS in a restructured market. This has been a common tool in the past two decades to encourage investment in certain technologies like renewables through feed-in tariffs, renewable portfolio standards, investment subsidies, soft loans and tax incentives. However again the issue traces back to the high upfront capital costs of PHS. Wind and solar PV have only taken off with incentives after R&D improvements have allowed their entire supply chain costs to go down. PHS capital costs are so dependent on a civil engineering, per-project basis that the market incentives used to reduce costs along the entire supply chain that worked for wind and solar PV does not seem applicable.

Barbour et al. finds that countries seeing the largest PHS development are those that allow PHS to be owned and operated by vertically integrated companies that own and operate transmission and distribution like China, India, Switzerland, and Japan. They also find new PHS has a higher likelihood of being developed where economies are expanding rapidly and there is no overcapacity of electricity generation, i.e. China and India. Therefore PHS is being used to fill a gap in peak-time electricity requirements. This is in contrast to the competitive markets in the U.S. and Europe, where there already is sufficient generating capacity to meet peak demand (i.e. CCGT in Spain).

[4]This leads to the case for why a carbon price should be high in order to promote bulk storage such as PHS.

Current PHS plants can obviously participate in multiple electricity market services, i.e. ancillary and energy arbitrage. The question still remains is it enough to encourage investment in new PHS? Vertically integrated utilities can accrue the benefits of their investments in PHS through generation as well as transmission and distribution.

Ultimately a policy need needs to be developed that allows storage to participate in the generating competitive market as well as the uncompetitive regulated transmission and distribution market. That is you could use the cost-of-service business for PHS in a restructured market as transmission and distribution projects are. Critics would argue this would give PHS an unfair advantage to other units that particpate in the competetive market. That is completely true. But in a world in which we need some degree of PHS to decarbonize I would rather address the incentive problem and provide a better investment landscape for PHS.

Another possible solution is having the national or local governments commission a PHS system themselves. Once again, if the goal is to decarbonize the electricity sector, the value PHS provides is piece of the larger puzzle by serving as a lower cost investment than large fleets of wind or solar. Sundararagavan and Baker (2011) found that the interest rate was the factor that had the greatest impact on the annualised total storage cost for PHS. Therefore a government has a better ability to borrow money at a lower rate than a private entity and could theoretically build the PHS plants themselves [78].

Chapter 11

Conclusion

As countries seek to decarbonize their electricity sector it is imperative that they examine the full range of technology options and capabilities of their system and location. This includes PHS which can help integrate high future penetrations of low-carbon energy. Many countries haven't fully explored PHS options since the buildout of their nuclear fleets. New analysis needs to be done on whether or not there is PHS potential within electricity grids. New variable speed pumps allow PHS to operate more efficiently and optimize their consumption and generating modes. Utilizing alternative locations like former mines or underground reservoirs mitigate the environmental impact building a brand-new reservoir for PHS can have.

This thesis presents a review of PHS and seeks to quantify its value in a decarbonized world with Spain, a high PHS capacity country, as its case study. Chapters 1 through 3 present an overview of PHS as well as the Spanish energy system for context.

Using the open-sourced data available to us, Chapter 4 characterizes PHS operation within daily energy arbitrage as well as seasonal trends. It confirmed that there is a distinct relationship between both the hourly demand and price of the electricity with that of PHS operation. When demand and prices are increasing (morning and late afternoon to early evening) PHS turbines generate electricity to be sold. When demand and prices decrease (middle of the night, work day, and late evening), PHS consumes cheap electricity and stores energy rather than sell it. By performing a linear OLS regression I determined that on average PHS consumes when the electricity price is below €44.64 and generates when the electricity price is above €47.50 in the day-ahead market. Whereas in the final scheduling market PHS consumes when the electricity price is below €54.01 and generates when the electricity price is above €58.43.

Additionally, Chapter 4 identifies PHS' seasonal pattern in that maximum generation and consumption occur during the wet periods of winter and spring months, and minimums during the dry summer and early fall. This likely indicates PHS close connection with hydro inflows.

Future work could focus on regressions of PHS operation with prices, hydro inflows, net thermal load, and renewable generation by season.

Chapter 5 provides an overview of future Spanish decarbonization policies through the integration of renewables. Chapter 6 illustrates that the effect of resource availability is likely to be an important factor to consider in future energy mixes. As countries surpass majority shares of electricity met by renewables, they will see larger shares of curtailment during high production and low demand hours. Storage can provide value by taking that curtailed energy and redistributing to hours in which renewables cannot fully meet the demand profile.

Using a least cost optimization model that employs unit commitment constraints, Chapter 8 considers the effect the current PHS capacity has on curtailment of low-carbon generation under a variety of 2030 energy mix scenarios. I find that that the inclusion of PHS increases the total low-carbon factor across all energy mixes while lowering GHG emissions. The biggest impact PHS has on improving low-carbon capacity factors is when nuclear is a part of the energy mix. If nuclear is phased out, it is more beneficial (in terms of lowering curtailment) to build out wind, as opposed to solar PV, to be utilized by PHS.

Chapter 9 uses the least optimization model to addresses the system cost to serve a 2030 scenario of high low-carbon capacity that includes nuclear. It considers the total system cost when improving the efficiency of PHS turbine/pump or adding a marginal MW of PHS capacity to lower GHG emissions. It compare that cost to the cost of solar PV and wind capacity installations that would result in equivalent GHG emissions.

I find that improving the efficiency of one MW of PHS by installing a new turbine/pump is around €200,000 cheaper than the next alternative. Additionally, improving the efficiency of all current PHS capacity is €1 billion less than the next cheaper alternative.

I find that adding a marginal MW of new pure PHS capacity to the energy mix is roughly €325 million less than the next cheaper alternative. While adding a marginal MW of new pump-back PHS capacity to the energy mix is over €305 million less than the next cheaper alternative.

The system cost valuation only looked at portfolios that included nuclear. Future work should look at the system cost under differing energy mixes, i.e. when no nuclear exists or additional wind and solar PV is added.

Finally, Chapter 10 examines the market concerns and barriers to increased PHS investments. PHS does have high upfront capital costs. This can be easily remunerated in a traditional market. Yet competitive restructured markets worry over the lack of energy arbitrage in a decarbonized future with high renewable penetration and a strong utilization of PHS. Chapter 10 notes that concerns are unnecessary as PHS will always be able to make returns by acting as the marginal unit under high carbon prices. It concludes that restructured markers can still encourage PHS investment by valuing its role across the generation, transmission, and distribution sector while optimizing its performance in both the energy arbitrage and ancillary services market.

Bibliography

[1] Renewable Energy Policy Network for the 21st Century. "Renewables 2018: Global Status Report". In: *National Bureau of Economic Research Working Paper* (2018). URL: http://www.ren21.net/wp-content/uploads/2018/06/17-8652_GSR2018_FullReport_web_-1.pdf.

[2] G. Ardizzon, G. Cavazzini, and G. Pavesi. "A new generation of small hydro and pumped-hydro power plants: Advances and future challenges". In: *Renewable and Sustainable Energy Reviews* 31 (2014), pp. 746–761. URL: https://www.sciencedirect.com/science/article/pii/S1364032113008575.

[3] Energy Storage Association. *Grid Operations Benefits*. URL: http://energystorage.org/energy-storage/energy-storage-benefits/benefit-categories/grid-operations-benefits.

[4] Energy Storage Association. *Variable Speed Pumped Hydroelectric Storage*. URL: http://energystorage.org/energy-storage/technologies/variable-speed-pumped-hydroelectric-storage.

[5] Edward Barbour et al. "A review of pumped hydro energy storage development in significant international electricity markets". In: *Renewable and Sustainable Energy Reviews* 61 (2016), pp. 421–432. URL: https://www.sciencedirect.com/science/article/pii/S1364032116300363?.

[6] Marc Beaudin et al. "Energy storage for mitigating the variability of renewable electricity sources: An updated review". In: *Energy for Sustainable Development* 14 (2010), pp. 302–314. URL: https://www.sciencedirect.com/science/article/pii/S0973082610000566.

[7] Isla Binnie. *Spain plans to close all nuclear plants by 2035*. Reuters. 2019. URL: https://www.reuters.com/article/us-spain-energy/spain-plans-to-close-all-nuclear-plants-by-2035-idUSKCN1Q212W.

[8] Frede Blaabjerg et al. "The future of electronic power processing and conversion". In: *IEEE Transactions on Power Electronics* 20 (2005), pp. 715–720.

[9] Paul Breeze. *Hydropower*. Academic Press, 2018. ISBN: 978-0-12-812906-7.

[10] Paul Breeze. *Power Generating Technologies*. Academic Press, 2014. ISBN: 978-0-08-098330-1.

[11] Constantin Brod, Robert Hull, and Karen Turner. "Brod, Constantin and Hull, Robert and Turner, Karen (2018) The Case for Pumped Storage Hydro in the UK's Energy Mix". In: *Discussion Paper* (2018). URL: https://strathprints.strath.ac.uk/66242/8/Brod_etal_IPPI_2018_Pumped_Storage_Hydro_in_the_UKs_Energy_Mix.pdf.

[12] James Bushnell and Kevin Novan. "Setting With The Sun: The Impacts Of Renewable Energy On Wholesale Power Markets". In: *UC Berkeley Haas Energy Institute Working Paper* 292 (2018). URL: https://ei.haas.berkeley.edu/research/papers/WP292.pdf.

[13] The Joint Research Centre. "ETRI 2014. Energy Technology Reference Indicator projections for 2010-2050". In: *Joint Research Center Scientific and Policy Reports* (2014). URL: http://publications.jrc.ec.europa.eu/repository/bitstream/JRC92496/ldna26950enn.pdf.

[14] Intergovernmental Panel on Climate Change. "Fifth Assessment Report". In: (2014). URL: https://www.ipcc.ch/report/ar5/.

[15] United Nations Framework Convention on Climate Change. "Paris Agreement". In: (2015). URL: https://treaties.un.org/doc/Treaties/2016/02/20160215%2006-03%20PM/Ch_XXVII-7-d.pdf.

[16] Jaquelin Cochran et al. "Integrating Variable Renewable Energy in Electric Power Markets: Best Practices from International Experience, Summary for Policymakers". In: *National Renewable Energy Laboratory* (2012). URL: https://www.nrel.gov/docs/fy12osti/53730.pdf.

[17] "Comisión de Expertos de Transición Energéti. Análisis y Propuestas Para la Descarbonizació". In: (2018).

[18] European Commission. *EU climate action*. URL: https://ec.europa.eu/clima/citizens/eu_en.

[19] D. Connolly, S. MacLaughlin, and M. Leahy. "Development of a computer program to locate potential sites for pumped hydroelectric energy storage". In: *Energy* 35 (2010), pp. 375–381. URL: https://www.sciencedirect.com/science/article/pii/S036054420900437X.

[20] D. Connolly et al. "The technical and economic implications of integrating fluctuating renewable energy using energy storage". In: *Renewable Energy* 43 (2012), pp. 47–60. URL: https://www.sciencedirect.com/science/article/pii/S0960148111006057#bib4.

[21] Toshiba Energy Systems & Solutions Corporation. *Toshiba Energy - Hydropower*. URL: https://www.toshiba-energy.com/en/renewable-energy/product/.

[22] J.P. Deane, B.P. Ó Gallachóir, and E.J. McKeogh. "Techno-economic review of existing and new pumped hydro energy storage plant". In: *Renewable and Sustainable Energy Reviews* 14 (2009), pp. 1293–1302. URL: https://www.sciencedirect.com/science/article/pii/S1364032109002779.

[23] Paul Denholm and Maureen Hand. "Grid flexibility and storage required to achieve very high penetration of variable renewable electricity". In: *Energy Policy* 39 (2011), pp. 1817–1830. URL: https://www.sciencedirect.com/science/article/pii/S0301421511000292.

[24] Paul Denholm et al. "The Role of Energy Storage with Renewable Electricity Generation". In: *National Renewable Energy Laboratory* Technical Report - 6A2-47187 (2010). URL: https://www.nrel.gov/docs/fy10osti/47187.pdf.

[25] Organisation for Economic Co-operation, Development, and the Nuclear Energy Agency. "The Full Costs of Electricity Provision". In: (2018). URL: https://www.oecd-nea.org/ndd/pubs/2018/7298-full-costs-2018.pdf.

[26] Ministry of Economy. "17027 Resolution of September 7, 2001". In: (2001). URL: https://www.boe.es/boe/dias/2001/09/07/pdfs/A33888-33904.pdf.

[27] Erik Ela et al. "The Role of Pumped Storage Hydro Resources in Electricity Markets and System Operation". In: *National Renewable Energy Laboratory* Conference Paper - 5500-58655 (2013). URL: https://www.nrel.gov/docs/fy13osti/58655.pdf.

[28] Department of Energy Office of Electricity Delivery and Energy Reliability. *DOE Global Energy Storage Database.* URL: http://www.energystorageexchange.org/.

[29] U.S. Army Corps of Engineers. "Hydropower". In: *Engineering and Design: Engineering Manual* EM 1110-2-1701 (1985), pp. 25–38. URL: http://www.plainwater.com/wp-content/uploads/2018/03/EM-1110-2-1701.pdf.

[30] Red Eléctrica de España (REE). *National statistical series.* URL: https://www.ree.es/en/statistical-data-of-spanish-electrical-system/statistical-series/national-statistical-series.

[31] Red Eléctrica de España (REE). *Renewable Energy in the Spanish Electricity System 2017 Report.* URL: https://www.ree.es/sites/default/files/11_PUBLICACIONES/Documentos/Renewable-2017.pdf.

[32] Red Eléctrica de España (REE). *The Spanish Electricity System 2018: Preliminary Report.* URL: https://www.ree.es/sites/default/files/11_PUBLICACIONES/Documentos/InformesSistemaElectrico/2019/Avance_ISE_2018_en.pdf.

[33] James M. Eyer and Garth P. Corey. "Energy Storage for the Electricity Grid: Benefits and Market Potential Assessment Guide". In: *Sandia National Laboratories* Sandia Report (2010). URL: https://www.sandia.gov/ess-ssl/publications/SAND2010-0815.pdf.

[34] Natalia Fabra and Juan Toro. "Price wars and collusion in the Spanish electricity market". In: *International Journal of Industrial Organization* 23 (2005), pp. 155–181.

[35] Anthony Fratto-Oyler and John Parsons. "The Climate and Economic Rationale for Investment in Life Extension of Spanish Nuclear Plants". In: *MIT Center for Energy and Environmental Policy Research Working Paper* 692 (2018). URL: http://ceepr.mit.edu/publications/working-papers/692.

[36] Ludovic Gaudard and Franco Romerio. "The future of hydropower in Europe: interconnecting climate, markets and policies". In: *Environmental Science Policy* 37 (2014), pp. 172–181. URL: https://www.sciencedirect.com/science/article/pii/S1462901113001858.

[37] M. Gimeno-Gutiérrez and R. Lacal-Arántegui. "The Role of Pumped Storage Hydro Resources in Electricity Markets and System Operation. A GIS-based assessment of pumped hydropower storage potential". In: *Joint Research Center Scientific and Policy Reports* (2013). URL: https://setis.ec.europa.eu/sites/default/files/reports/Assessment_European_PHS_potential_pumped_hydropower_energy_storage.pdf.

[38] Darío R. Gómez and John D. Watterson. "Chapter 2 Stationary Combustion". In: *IPCC Guidelines for National Greenhouse Gas Inventories* (2006). URL: http://www.ipcc-nggip.iges.or.jp/public/2006gl/pdf/2_Volume2/V2_2_Ch2_Stationary_Combustion.pdf.

[39] Adolfo Gonzalez et al. "Study of electricity storage technologies and their potential to address wind energy intermittency in Ireland". In: *Sustainable Energy Authority of Ireland* (2004). URL: http://www.seai.ie/Grants/Renewable_Energy_RD_D/Projects_funded_to_date/Wind/Study_of_Elec_Storage_Technologies_their_Potential_to_Address_Wind_Energy_Intermittency_in_Irl.

[40] Melanie Guittet et al. "Study of the drivers and asset management of pumped-storage power plants historical and geographical perspective". In: *Energy* 111 (2016), pp. 560–579.

[41] T. Hino and A. Lejeune. "Pumped storage hydro power developments". In: *Comprehensive Renewable Energy* 6 (2012), pp. 405–434. URL: https://www.sciencedirect.com/science/article/pii/B9780080878720006168.

[42] Jesse D. Jenkins and Nestor A. Sepulveda. "Enhanced Decision Support for a Changing Electricity Landscape: The GenX Configurable Electricity Resource Capacity Expansion Model". In: *MIT Energy Initiative Working Paper* 1 (2017). URL: https://energy.mit.edu/wp-content/uploads/2017/10/Enhanced-Decision-Support-for-a-Changing-Electricity-Landscape.pdf.

[43] Paul Joskow. "Comparing the Costs of intermittent and dispatchable electricity generation technologies". In: *American Economic Review Papers and Proceedings* 61.3 (2011), pp. 238–421. URL: https://www.aeaweb.org/articles?id=10.1257/aer.101.3.238.

[44] Gareth Kear and Ralph Chapman. "'Reserving judgement': Perceptions of pumped hydro and utility-scale batteries for electricity storage and reserve generation in New Zealand". In: *Renewable Energy* 57 (2013), pp. 249–261.

[45] Brendan Kirby. *Co-optimizing Energy and Ancillary Services from Energy Limited Hydro and Pumped Storage Plants.* URL: http://www.consultkirby.com/files/Preprinted_HydroVision_2012-_Cooptimizing_Energy_AS_from_Energy_Limited_PS_Plants.pdf.

[46] Ranziska Koch, Andrea Reiter, and Heike Bach. "Energy: Simulation of Hydropower Generation and Reservoir Management". In: *In Regional Assessment of Global Change Impacts* (2016), pp. 279–286.

[47] Ioannis Kougias and Sandor Szabo. "Pumped hydroelectric storage utilization assessment: Forerunner of renewable energy integration or Trojan horse?" In: *Energy* 140 (2017), pp. 318–329. URL: https://www.sciencedirect.com/science/article/pii/S0360544217314822#bib12.

[48] Daniel Leston. "PHES modeling in long term oriented studies of the secondary regulation band market in the Spanish electricity system". In: *Universidad Pontificia Comillas, Erasmus Mundus Joint Master in Economics and Management of Network Industries Thesis* (2015).

[49] *Ley 15/2012, de 27 de diciembre.* URL: https://www.boe.es/boe/dias/2012/12/28/pdfs/BOE-A-2012-15649.pdf.

[50] *Ley 38/1992, de 29 de diciembre.* URL: https://www.boe.es/buscar/act.php?id=BOE-A-1992-28741.

[51] Peter Maloney. *Los Angeles considers $3B pumped storage project at Hoover Dam.* Utility Dive. 2018. URL: https://www.utilitydive.com/news/los-angeles-considers-3b-pumped-storage-project-at-hoover-dam/528699/.

[52] Zeng Ming, Zhang Kun, and Liu Daoxin. "Overall review of pumped-hydro energy storage in China: status quo, operation mechanism and policy barriers". In: *Renewable and Sustainable Energy Reviews* 17 (2013), pp. 35–43. URL: https://www.sciencedirect.com/science/article/pii/S1364032112003589.

[53] Alimentación y Medio Ambiente Ministerio de Agricultura y Pesca. "Plan Nacional Transitorio (PNT) Español Directiva 2010/75/UE Grandes Instalaciones de Combustión". In: (2013), pp. 1–25. URL: http://www.mapama.gob.es/es/calidad-y-evaluacion-ambiental/temas/medio-ambiente-industrial/prevencion-y-control-integrados-de-la-contaminacion-ippc/grandes-instalaciones-combustion/default.aspx.

[54] Energy Ministry of Industry and Tourism. "1736 Resolution of February 13, 2013". In: (2013). URL: https://www.boe.es/boe/dias/2013/02/18/pdfs/BOE-A-2013-1736.pdf.

[55] Anton Mitteregger and Gerhart Penninger. "Austrian pumped storage power stations supply peak demands". In: *World Pumps* 16 (2008), pp. 20–21.

[56] M.E. Nazari, M.M. Ardehali, and S. Jafari. "Pumped storage unit commitment with considerations for energy demand, economics, and environmental constraints". In: *Energy* 35 (2010), pp. 4092–4101. URL: https://www.sciencedirect.com/science/article/pii/S0360544210003452.

[57] Morteza Nazari-Heris and Behnam Mohammadi-Ivatloo. "Chapter 6 - Design of Small Hydro Generation Systems". In: *Distributed Generation Systems* (2017), pp. 301–332.

[58] Bryan Palmintier. "Incorporating Operational Flexibility into Electric Generation Planning". In: *MIT Engineering Systems Doctor of Philosophy Thesis* (2013). URL: https://dspace.mit.edu/handle/1721.1/79147.

[59] Bryan Palmintier and Mort Webster. "Impact of Unit Commitment Constraints on Generation Expansion Planning with Renewables". In: *IEEE Power and Energy Society General Meeting* (2011), pp. 1–7. URL: https://ieeexplore.ieee.org/document/6038963.

[60] Ignacio J. Pérez-Arriaga. *Regulation of the Power Sector.* Springer, 2013. ISBN: 978-1-4471-5034-3.

[61] *Real Decreto 1836/1999, de 4 de diciembre.* URL: https://www.boe.es/buscar/pdf/1999/BOE-A-1999-24924-consolidado.pdf.

[62] Mar Reguant. "Complimentary Bidding Mechanisms and Startup Costs in Electricity Markets". In: *Review of Economic Studies* 81 (2014), pp. 1708–1742.

[63] Shafiqur Rehman, Luai M. Al-Hadhrami, and Md. Mahbub. "Pumped hydro energy storage system: A technological review". In: *Renewable and Sustainable Energy Reviews* 44 (2015), pp. 586–598. URL: https://www.sciencedirect.com/science/article/pii/S1364032115000106#bib36.

[64] Orvika Rosnes. "The impact of climate policies on the operation of a thermal power plant". In: *Energy* 29 (2008), pp. 1–22.

[65] *Royal Decree 14/2010.* URL: http://www.boe.es/boe/dias/2010/12/24/pdfs/BOE-A-2010-19757.pdf.

[66] Angel Garcia Sanchez. "Análisis del Mercado Eléctrico Peninsular. Herramienta informática". In: *Universidad Carlos III Madrid* (2013).

[67] Richard Schmalensee. "The Performance of US Wind and Solar Generating Units". In: *National Bureau of Economic Research Working Paper* 19509 (2013), pp. 238–421. URL: https://www.nber.org/papers/w19509.

[68] Andreas Schröder et al. "Current and Prospective Costs of Electricity Generation until 2050". In: *Data Documentation* 68 (2013). URL: https://www.diw.de/documents/publikationen/73/diw_01.c.424566.de/diw_datadoc_2013-068.pdf.

[69] Marco Semadeni. "Energy storage as an essential part of sustainable energy systems: a review on applied energy storage technologies". In: *Swiss Federal Institutes of Technology, Centre for Energy Policy and Economics* (2003). URL: `http://e-collection.ethbib.ethz.ch/view/eth:26428`.

[70] Nestor A. Sepulveda et al. "The Role of Firm Low-Carbon Electricity Resources in Deep Decarbonization of Power Generation". In: *Joule* 2.11 (2018), pp. 2403–2420. URL: `https://www.sciencedirect.com/science/article/pii/S2542435118303866`.

[71] Fernando J. de Sisternes, Jesse D. Jenkins, and Audun Botterud. "The value of energy storage in decarbonizing the electricity sector". In: *Applied Energy* 175 (2016). URL: `https://www.sciencedirect.com/science/article/pii/S0306261916305967`.

[72] N. Sivakumara et al. "Status of pumped hydro-storage schemes and its future in India". In: *Renewable and Sustainable Energy Reviews* 50 (2013), pp. 208–213. URL: `https://www.sciencedirect.com/science/article/pii/S1364032112006090?via`.

[73] Government of Spain. "Borrador del Plan Nacional Integrado de Energia y Clima 2021-2030". In: (2019). URL: `https://ec.europa.eu/energy/sites/ener/files/documents/spain_draftnecp.pdf`.

[74] Iain Staffell and Richard Green. "Is there still merit in the merit order stack? The Impact of dynamic constraints on optimal plant mix". In: *IEEE Trans Power Syst* 31 (2016), pp. 43–53.

[75] Bjarne Steffen. "Prospects for pumped-hydro storage in Germany". In: *Energy Policy* 15 (2012), pp. 420–429. URL: `https://www.sciencedirect.com/science/article/pii/S0301421512001693`.

[76] Florian Steinke, Philipp Wolfrum, and Clemens Hoffmann. "Grid vs. storage in a 100% renewable Europe". In: *Renewable Energy* 50 (2013), pp. 826–832. URL: `https://www.sciencedirect.com/science/article/pii/S0960148112004818`.

[77] Patrick Sullivan, Walter Short, and Nate Blair. "Modeling the benefits of storage technologies to wind power". In: *Wind Engineering* 32 (2008), pp. 603–615.

[78] Sandhya Sundararagavan and Erin Baker. "Evaluating energy storage technologies for wind power integration". In: *Solar Energy* 86.9 (2012), pp. 2707–2717. URL: `https://www.sciencedirect.com/science/article/pii/S0038092X12002253`.

[79] Ministerio para la Transición Ecológica. *The Spanish Climate Change and Energy Transition Law: A supporting document for journalists.* 2018.

[80] European Network of Transmission System Operators. "TYNDP Annex I: Country Level Results". In: *Ten Year Network Development Plan – Scenario Report* (2018). URL: `https://docstore.entsoe.eu/Documents/TYNDP%20documents/entsos_tyndp_2018_Scenario_Report_ANNEX_I_Country_Level_Results.pdf`.

[81] European Network of Transmission System Operators. "TYNDP Annex II: Methodology". In: *Ten Year Network Development Plan – Scenario Report* (2018). URL: https://docstore.entsoe.eu/Documents/TYNDP%20documents/TYNDP2018/Scenario_Report_ANNEX_II_Methodology.pdf.

[82] Bart C. Ummels, Engbert Pelgrum, and Wil L. Kling. "Integration of large-scale wind power and use of energy storage in The Netherlands' electricity supply". In: *IET Renewable Power Generation* 2 (2008), pp. 34–46. URL: https://ieeexplore.ieee.org/document/4463799/authors#authors.

[83] U.S. Army Engineer Institute for Water Resources. "An Assessment of Hydroelectric Pumped Storage". In: *U.S. Government Printing Office* (1982).

[84] Chi-Jen Yang. "Chapter 2 - Pumped Hydroelectric Storage". In: *Storing Energy* (2016), pp. 25–38.

[85] Chi-Jen Yang and Robert B. Jackson. "Opportunities and barriers to pumped-hydro energy storage in the United States". In: *Renewable and Sustainable Energy Reviews* 15 (2011), pp. 839–844. URL: https://www.sciencedirect.com/science/article/pii/S1364032110003072.

[86] Sufang Zhang, Philip Andrews-Speed, and Pradeep Perea. "The evolving policy regime for pumped storage hydroelectricity in China: A key support for low-carbon energy". In: *Applied Energy* 150 (2015), pp. 15–24. URL: https://www.sciencedirect.com/science/article/pii/S0306261915004055.

Appendix

Appendix A: Unit Commitment Constraints on Dispatch Modeling

Unit commitment models range in their simplicity and constraints. For example one can easily create a least cost dispatch scenario in Excel which takes into account maximum power capacity and variable O&M costs in order to meet the marginal demand. However unit commitment models like GenX attempt to emulate the constraints system operators deal with. These include [1]:

- Start up costs: The overall cost to start up the unit (€/technology);
- Start up fuel: The initial amount of fuel required to start up (MMBtu/start). Start up fuel times the cost of fuel will go into the general start-up cost;
- Minimum power: Minimum stable power output per unit of installed capacity for each technology (% of installed capacity);
- Ramping: Maximum ramp-up or ramp-down rate per time step (% of installed capacity);
- Up/Down times: Minimum time the thermal plant has to be on before shutting down / Minimum time the thermal plant has to off before it can restart (hrs);

Additionally, GenX attempts to optimize storage and hydro reservoirs in order to minimize cost.

I wanted to test what effect each of these unit commitment constraints as well as the optimization of storage (battery and PHS) and hydro reservoirs had on the GenX model.

[1]Note these apply to thermal units, variable resources do not having startup/shut down times, fuel requirements, minimum power etc.

As a reference point I used the Baseline Scenario portfolio as per Table 9.1. Table 11.1 shows the results of zeroing out all the above constraints (Benchmark Case - Column [A]) of that portfolio and then applying each constraints individually. Note that the hourly storage and hydro operation of the Baseline Scenario was applied as exogenous to the hourly load. That is they are locked-in and do not adjust to minimize cost. Therefore they are identical across thermal constraints. I do not report the other renewable generation nor the HVDC link and interconnection balance as they were the same throughout all cases.

		Benchmark	Thermal Unit Commitment Constraints						Optimization		All
		No Constraints	Up/Down times	Startup Fuel	Startup Cost	Ramp rates	Minimum Power	All Previous Constraints	Optimizing Storage	Optimizing Hydro	Constraints + Optimization
		[A] (*TWh*)	[B] (*TWh*)	[C] (*TWh*)	[D] (*TWh*)	[E] (*TWh*)	[F] (*TWh*)	[G] (*TWh*)	[H] (*TWh*)	[I] (*TWh*)	[J] (*TWh*)
[1]	**Demand**	295.02	295.02	295.02	295.02	295.02	295.02	295.02	295.02	295.02	295.02
	Generation										
[2]	Nuclear	52.73	52.73	52.73	52.63	56.06	52.69	54.90	56.18	56.00	56.18
[3]	NG CCGT	31.54	31.54	31.54	31.64	32.15	30.99	33.49	31.83	32.20	31.83
[4]	Coal	0.00	0.00	0.00	0.00	0.04	0.59	0.33	0.00	0.03	0.00
[5]	Wind	63.50	63.53	63.50	63.50	61.02	63.43	60.74	61.32	61.13	61.18
[6]	Solar PV	88.02	88.00	88.02	88.02	86.52	88.09	86.32	86.46	86.42	86.60
[7]	Hydro Reservoir	25.84	25.84	25.84	25.84	25.84	25.84	25.84	25.84	25.84	23.40
[8]	Pumped Hydro	10.83	10.83	10.83	10.83	10.83	10.83	10.83	10.83	10.83	10.83
[9]	Battery	3.90	3.90	3.90	3.90	3.90	3.90	3.90	3.90	3.90	3.90
	Consumption										
[10]	Storage	-20.29	-20.29	-20.29	-20.29	-20.29	-20.29	-20.29	-20.29	-20.29	20.29
[11]	**Emissions (MtCO2)**	**11.55**	**11.55**	**11.55**	**11.59**	**11.82**	**11.92**	**12.70**	**11.69**	**11.87**	**11.69**

Note: Because the other variable energy sources, as well as the HVDC Link and Interconnection Balance are consistent throughout I do not report them

Figure 11.1: Unit Commitment Effects on Dispatch

In Table 11.1:

- Benchmark: Column [A] has no unit commitment constraints nor does it optimize storage or hydro [2];
- Thermal Constraints:
  - Column [B] is the Benchmark but now includes startup/shutdown times for thermal units;
  - Column [C] is the Benchmark but now includes startup fuel requirements for thermal units;

[2] Again the optimized storage and hydro from the original baseline portfolio run were applied exogenously, i.e. locked-in

- Column [D] is the Benchmark but now includes startup costs for turning on a thermal unit;
- Column [E] is the Benchmark but now includes ramp-up and ramp-down rates for thermal units;
- Column [F] is the Benchmark but now includes minimum power output requirements for thermal units;
- Column [G] includes all the aforementioned constraints combined;

- Optimization Constraints:
  - Column [H] is Column [G] but allows for storage to be optimized. Note only hydro reservoir generation is exogenously locked-in;
  - Column [I] is Column [G] but allows for hydro reservoir to be optimized. Note only storage generation and consumption is exogenously locked-in;

- All Constraints + Optimization:
  - Column [J] is Column [G] but allows for storage and hydro to be optimized. Therefore it is all constraints and optimizations included, i.e. the Baseline Result as seen in Table 9.1;

The first two unit commitment constraints of up/down times (Column [B]) and Startup fuel (Column [C]) do not affect thermal generation or emissions in aggregate. However, up/down times do affect wind and solar PV curtailment as seen when looking at rows [3] and [4] from columns [A] to [B].

Most likely the long minimum up/down times of nuclear plants force them to run during the middle of the day in low demand hours. Thus high solar PV production coupled with high thermal output coincides with these these low demand periods. As a result, some of the available solar PV is curtailed.

The startup cost constraint (Column [D]) appears to favor CCGT over nuclear generation. This makes sense as we apply a start-up cost to CCGT but not to nuclear. Therefore, it's cheaper to leave the CCGT on more than constatly shift between turning it on-and-off and incurring a cost each time it comes back online.

Ramping rates (Column [E]) affect both thermal and renewable generation as it requires increased operation of more flexible units. Wind and solar PV are curtailed as nuclear, CCGT, and even coal are utilized more. Because there are no minimum power or up/down time constraints nuclear is the highest capacity, lowest marginal cost unit and as such will be used the most.

Minimum power constraints (Column [F]) once again affect both thermal and renewable generation. Nuclear dispatches at a slightly lower amount than our benchmark Column ([A]) reference. This is likely due to the fact that nuclear plants have a larger installed capacity and minimum stable power. Thus for them to be turned the net load must be high enough to rationalize them turning on. Whereas CCGT has smaller maximum and minimum stable loads and will be utilized more when that constraint is considered.

Combining all the thermal constraints together increases the utilization of thermal units as compared to the benchmark case. These thermal units are required to be on longer than without the constraints, which in combination with low demand periods and high renewable penetration cause wind and solar PV curtailments to increase. Interestingly the coal is dispatched higher. That is likely traced back to the ramping constraint which in combination with minimum power and and startup costs forces coal to have significantly higher run times.

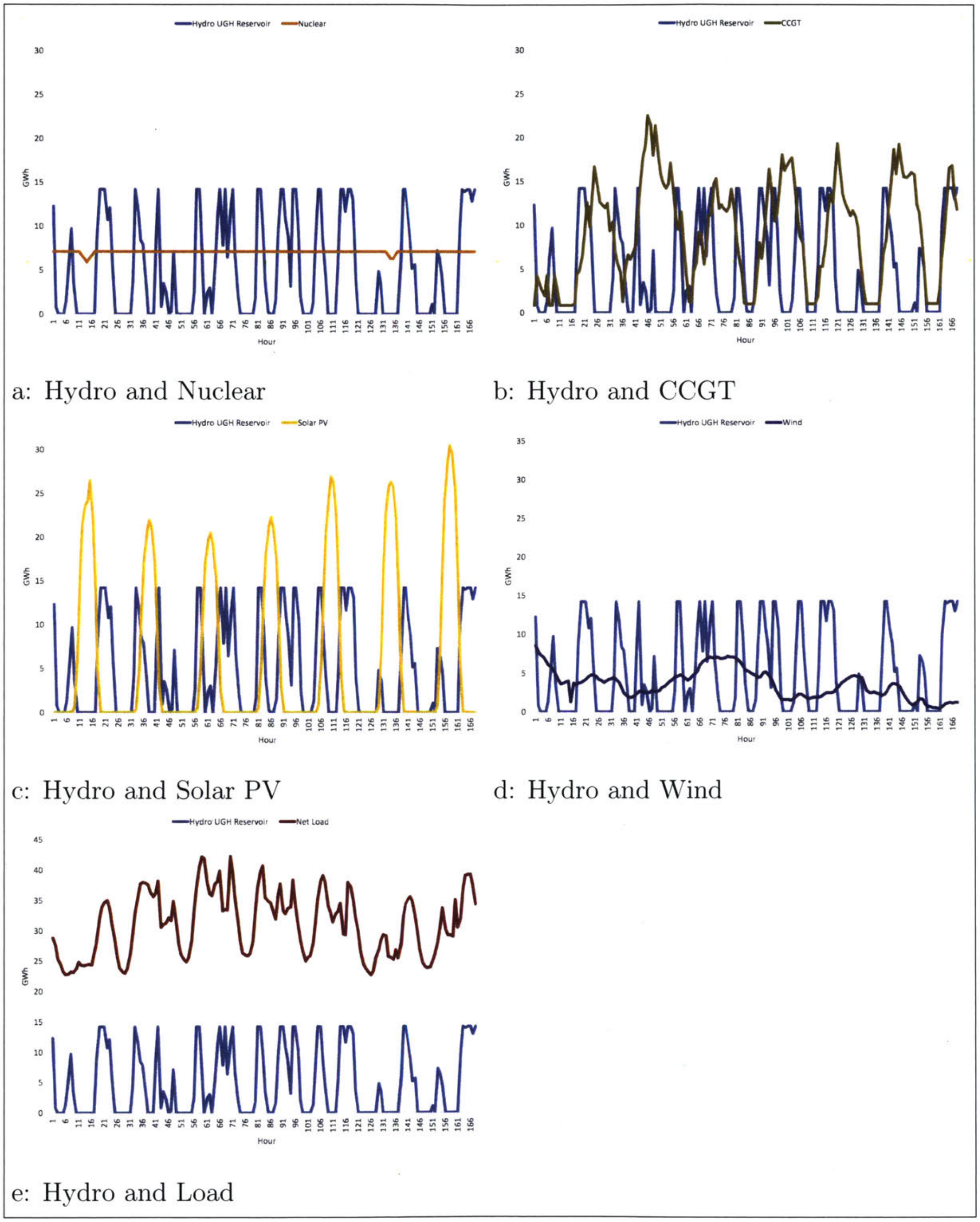
Moving from [G] to [H] and [I], and [J] allowing for the optimization of storage and hydro reduces CCGT generation while increasing low-carbon generation.

Ultimately when comparing the simple dispatch case (Benchmark Column [A]) to the baseline (Column [J]) which includes all units commitment constraints and an optimization of hydro and storage, firm low-carbon sources like nuclear is deployed more while renewables are curtailed to a greater degree.

Therefore including unit commitment constraints are important in attempts to replicate the true system operation. However, assuming a limited number of constraints is perfectly reasonable in some scenarios. For example in most day ahead markets, like the PDBF in Spain, technical constraints are not considered when committing generating units. More so the majority of the real-time market is settled in the day-ahead market [62, 34].

Another example is in Fratto et al. (2018) where they show the large reduction in costs of extending the life of nuclear plants in Spain as opposed to building out an equivalent solar PV and wind fleet. By abstracting out unit commitment constraints, they likely underestimated the value saved by extending nuclear which does nothing more than emphasize their point.

Appendix B: Hydro Dispatch Comparison in GenX



a: Hydro and Nuclear

b: Hydro and CCGT

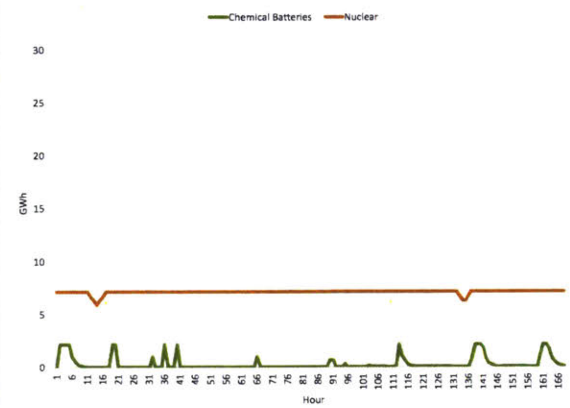
c: Hydro and Solar PV

d: Hydro and Wind

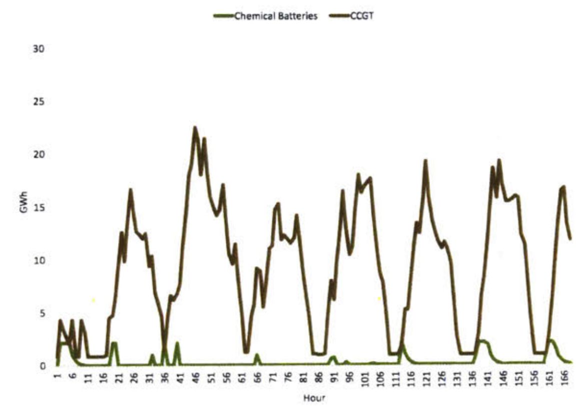
e: Hydro and Load

Figure 11.2: GenX Hydro Generation Dispatch Comparison, 2030 Forecast Scenario (hr 1-168)

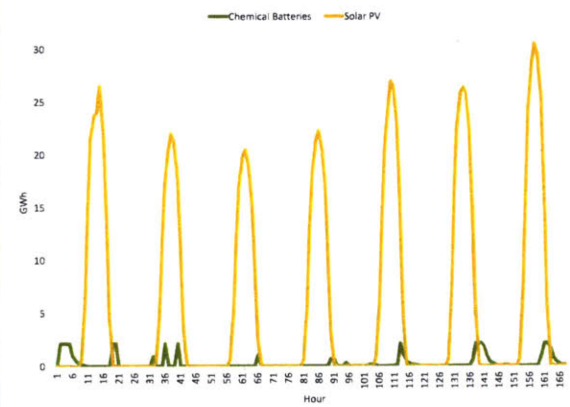
Appendix C: Battery Dispatch Comparison in GenX



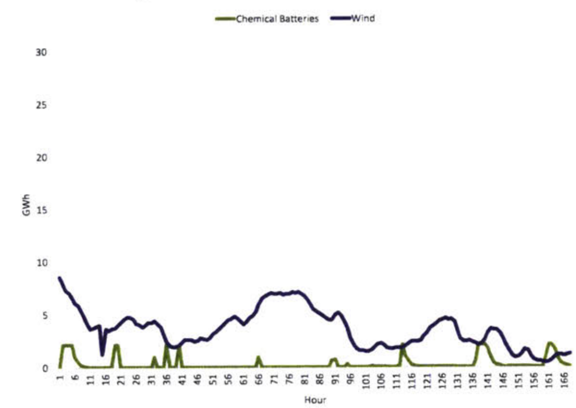
a: Battery and Nuclear



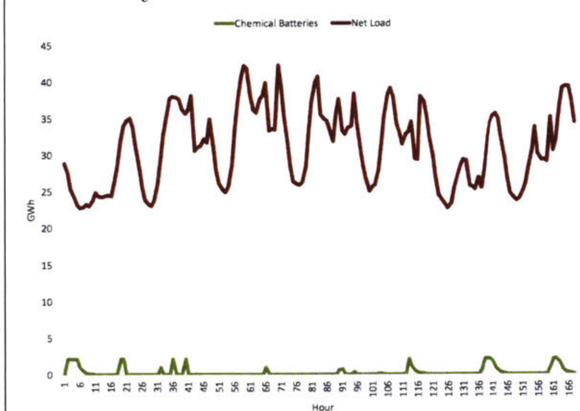
b: Battery and CCGT



c: Battery and Solar PV



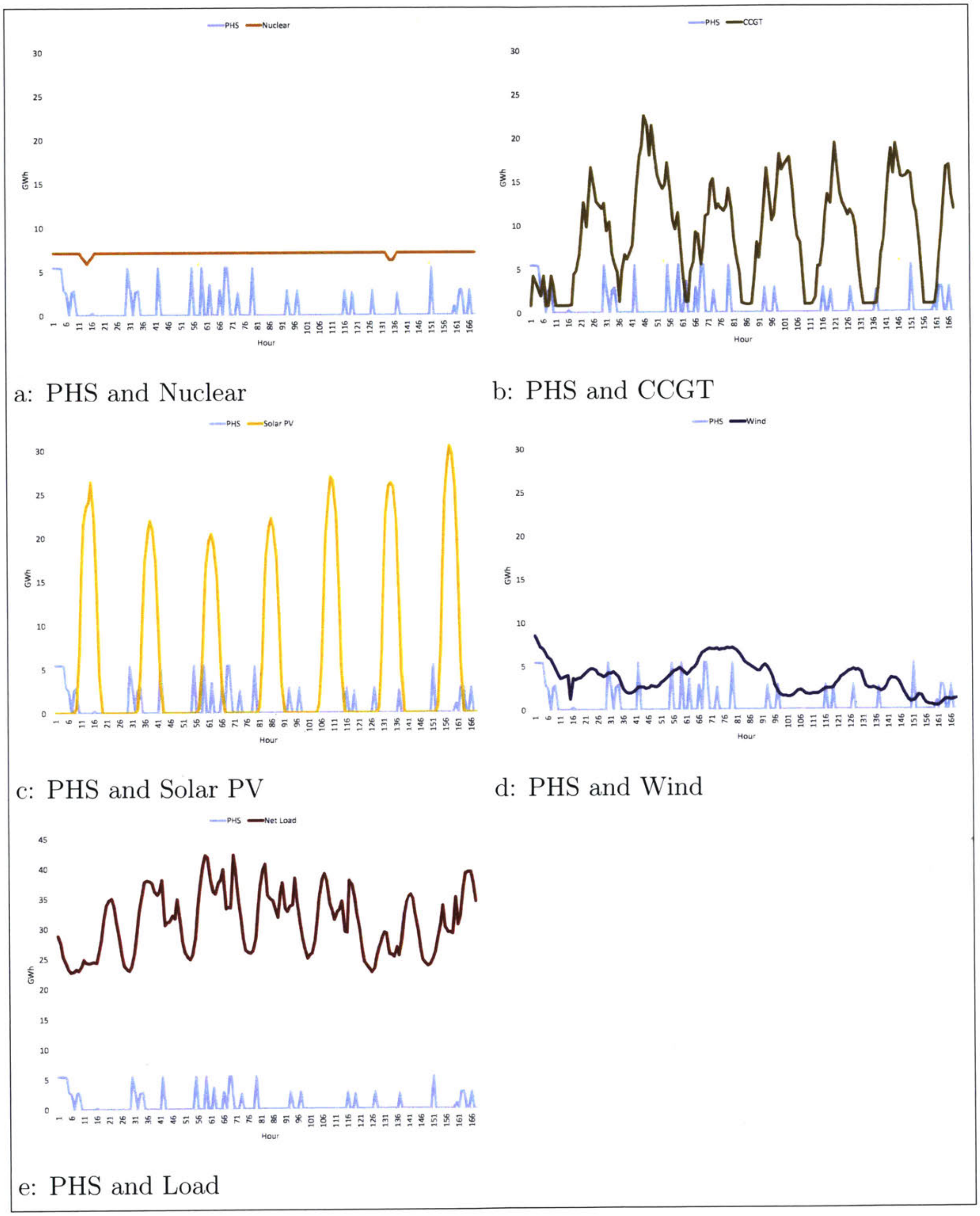
d: Battery and Wind



e: Battery and Load

Figure 11.3: GenX Battery Generation Dispatch Comparison, 2030 Forecast Scenario (hr 1-168)

Appendix D: PHS Dispatch Comparison in GenX



a: PHS and Nuclear

b: PHS and CCGT

c: PHS and Solar PV

d: PHS and Wind

e: PHS and Load

Figure 11.4: GenX PHS Generation Dispatch Comparison, 2030 Forecast Scenario (hr 1-168)