

Improved modelling of pumped hydro energy storage

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Thesis submitted for the degree of Doctor of Philosophy to the National
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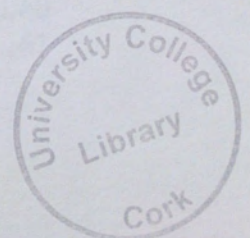


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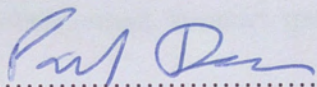
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Declaration

I hereby declare that this thesis is my own work and that it has not been submitted for another degree, either at University College Cork or elsewhere. Where other sources of information have been used, they have been acknowledged. Chapter 6 of this thesis, “Soft-linking of a power system model to an energy system model, was co authored with Alessandro Chiodi.

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Signature: 

Date: 15/5/2013

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Executive Summary

Rising greenhouse gas emissions, diminishing fossil fuel reserves and concerns over energy security have led to renewable energy targets that have spurred the growth of variable renewable generation sources such as wind and wave in many countries. The introduction of variable sources of electrical generation makes the operation and modelling of the power system more challenging. Pumped hydro energy storage is a flexible, fast acting generating source with the ability to store large amounts of electricity, and to facilitate the technical integration of variable renewable sources of generation. Recently, there has been resurgence in pumped hydro energy storage as many European countries strive for greater integration of renewables; however, the software tools and techniques used to traditionally model the power system need to be improved in order to capture the operation and role of flexible enabling technologies such as pumped hydro storage. Traditionally deterministic models that simulate the power system at hourly resolution are employed to assess the role and usefulness of pumped hydro storage. In this thesis, techniques are developed and presented to improve the current representation of pumped hydro energy storage, eliminating the weakness of perfect foresight assumption in model simulations. It is also demonstrated that higher temporal resolution simulations of the power system have the ability to capture important aspects of power system operation such as binding ramp rates. New techniques are also put forward for the improved modelling of large pumped storage in the context of wind forecast uncertainty, and it is shown that energy system models can benefit in the modelling of pumped hydro storage by soft-linking with power system models. Overall, this work shows that existing pumped hydro energy storage will play an ever more important role in Ireland as levels of installed wind capacity increase.

Thesis Outputs

Deane J.P, Ó Gallachóir B. P, McKeogh E.J. “Techno-Economic Review of Existing and New Pumped Hydro Energy Storage Plant.” – Renewable & Sustainable Energy Reviews, December 2009

Deane J.P, McKeogh E.J ,Ó Gallachóir B. P. “Derivation of Intertemporal Targets for Large Scale Pumped Hydro Energy Storage with Stochastic Optimisation”-IEEE Transactions on Power Systems- 2012. In review

Deane J.P, Chiodi A.,Gargiulo M., Ó Gallachóir B.P. “Soft-Linking of a Power Systems Model to an Energy Systems Model”- Energy- 2012

Deane J.P, Dalton G., Ó Gallachóir B.P. “Modelling the economic impacts of 500 MW of Wave Power in Ireland”. In press. Energy Policy 2012

Deane J.P., Drayton G., Ó Gallachóir B.P. “Sub-Hourly Modelling in Power Systems with Significant Levels of Renewable Generation”. IEEE Transactions on Power systems. In review 2012

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Conferences Papers and Invited talks

Deane J.P, Chiodi A, Gargiulo and Ó Gallachóir B. P “Modelling Electricity Generation; Comparing results from a Power System Model and an Energy System model-International energy Workshop-6th July 2011

Deane J.P, Dalton G, Ó Gallachóir B. P” Economic of Wave Energy in the Irish Power System”- Presentation at Ocean Energy Forum HMRC Cork May 2011.

Deane J.P, Chiodi A, Gargiulo and Ó Gallachóir B. P. “Comparing PLEXOS and TIMES”. ETSAP UCC Workshop, Nov 2010.

Deane J.P, McKeogh E.J, Ó Gallachóir B. P “Modelling the Power system with High Wind Energy penetration and large scale pumped hydro energy storage-Conference paper and presentation at 9th International Workshop on large scale integration of wind power into Power systems-Quebec October 2010

Deane J.P “The derivation of robust intertemporal targets for pumped hydro energy storage using stochastic optimisation using PLEXOS”-Presentation and Paper to PLEXOS European user Meeting-London 2010

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Units and Abbreviations

AI	All Island
AIGS	All Island Grid Study
CCGT	Combined Cycle Gas Turbine
CER	Commission for Energy Regulation
DP	Dynamic Programming
DQ	Dispatch Quantity
EDF	Électricité de France
EDP	Energias de Portugal
EU	European Union
GB	Great Britain
GW	Gigawatt
GWh	Gigawatt hour
MDT	Minimum Down Time
MEC	Maximum Export Capacity
MSL	Minimum Stable level
MSP	Market Scheduling and Pricing
MSQ	Market Schedule Quantity
MUT	Minimum Up Time
NI	Northern Ireland
NIAUR	Northern Ireland Authority for Utility Regulation
OCGT	Open Cycle Gas Turbine
PHES	Pumped Hydro Energy Storage
POR	Primary Reserve
RES-E	Renewable Electricity
ROI	Republic of Ireland
RR	Rounded Relaxation
SEM	Single Electricity Market
SEMO	Single Electricity Market Operator
SERG	Sustainable Energy Research Group
SMP	System Marginal Price
SOR	Secondary Reserve
T1	Tertiary 1 Reserve

T2	Tertiary 2 Reserve
TEPCO	Tokyo Electric Power Company
TER	Total Energy Requirement
TH	Turlough Hill
TSC	Trading and Settlement Code
TSO	Transmission System Operator
TW	Terawatt
UCED	Unit Commitment and Economic Dispatch

Chapter 1: Challenges for Power Systems with Significant Fluctuating Renewable Generation

Decarbonisation of the power sector is fast becoming a key policy objective underpinning European and global energy policy, and one that is seen to be crucial to achieving a sustainable future. The means of achieving high levels of decarbonisation are still being debated, but what is certain is that the power sector is set to undergo many changes over the coming decades. Within the EU, targets related to energy and climate change for the year 2020 are driven by the 20-20-20 initiative [1]. This package of policies aims to reduce greenhouse gas emissions by 20%, to increase the share of renewables in energy use by 20% and to improve energy efficiency by 20%. These and similar policy measures have spurred massive growth in renewable energy across the globe, mainly in the form of wind energy, with installed capacities of over 1700 GW predicted by the year 2030 [2]. While wind energy generation is a clean and relatively cheap power source, it is not without its drawbacks, particularly in the form of variability and predictability.

The introduction of wind energy and other variable fluctuating renewables such as wave energy into the electrical power system poses some significant challenges to the operation of the power system and to the modelling of the power system. Power system issues associated with wind energy's variability are well documented [3]-[7] and have been the focus of much research [8] and many integration studies [9]-[11]. Briefly, variability of power sources in a power system can cause issues for system balancing and make the commitment and dispatch of conventional power plant difficult, leading to inefficient dispatch and operation of power plant. It can also increase the requirement for system reserve. In general, the more variability within a power system, the more flexible the power system is required to be. Flexibility, in power system terms, is traditionally associated with quickly dispatchable generators. Balancing, however, is not simply about power plants, it must also consider other resources such as storage, demand-side management or response, and interconnection to

adjacent power systems for trade. Today, interconnectors are capable of providing a high level of flexibility to power systems. Pumped Hydro Energy Storage (PHES), which is described in detail in Chapter 2, is also a strong provider of flexibility due to its quick start-up times and flexible generation range.

The issue of variability for renewable resource can be mitigated to a certain extent by spreading the resource over a large geographical area. This has the effect of 'smoothing' out the variability. The benefits of having a geographical spread to a variable resource such as wind are well understood. Poorly correlated resources can smooth out the total net variability of the aggregated resource. On the other hand, if the resources are well correlated then the net variability of the aggregated resource would be expected to increase, which would not be beneficial to the power system as a whole [4]. Also, as different renewable energy technologies fluctuate over different timescales, a diverse portfolio of renewable generation options (i.e. wind, wave and solar, etc.) can be beneficial to the power system since the natural cycles of each generation type may complement one another. In Ireland, however, it is likely that wind energy will provide the bulk of our renewable energy for 2020 and beyond [12].

In Ireland, wind energy has a current installed MW capacity of 1800 MW and is projected to reach approximately 4100 MW by 2020 providing almost 40% of Ireland's electricity [13]. Ireland's power system is, by European standards, a relatively small synchronous system with current DC interconnection of 450 MW to Great Britain. Current thermal capacity in the Irish or All Island power system is 7.8 GW, and is primarily composed of gas fired power plant. In fact, Ireland is one of the most fuel dependant countries in Europe and relies heavily on gas for electricity generation. In 2005, the Irish Government undertook a detailed grid study to determine the most cost effective and technically suitable portfolio of power plants to meet Ireland's electricity demand in 2020. The All Island Grid Study (AIGS) [14] provided the technical foundation for the determination of a 40% target for RES-E by 2020. This means that Ireland will have one of the highest penetration levels of wind energy in the EU by 2020 (See Figure 1.1).

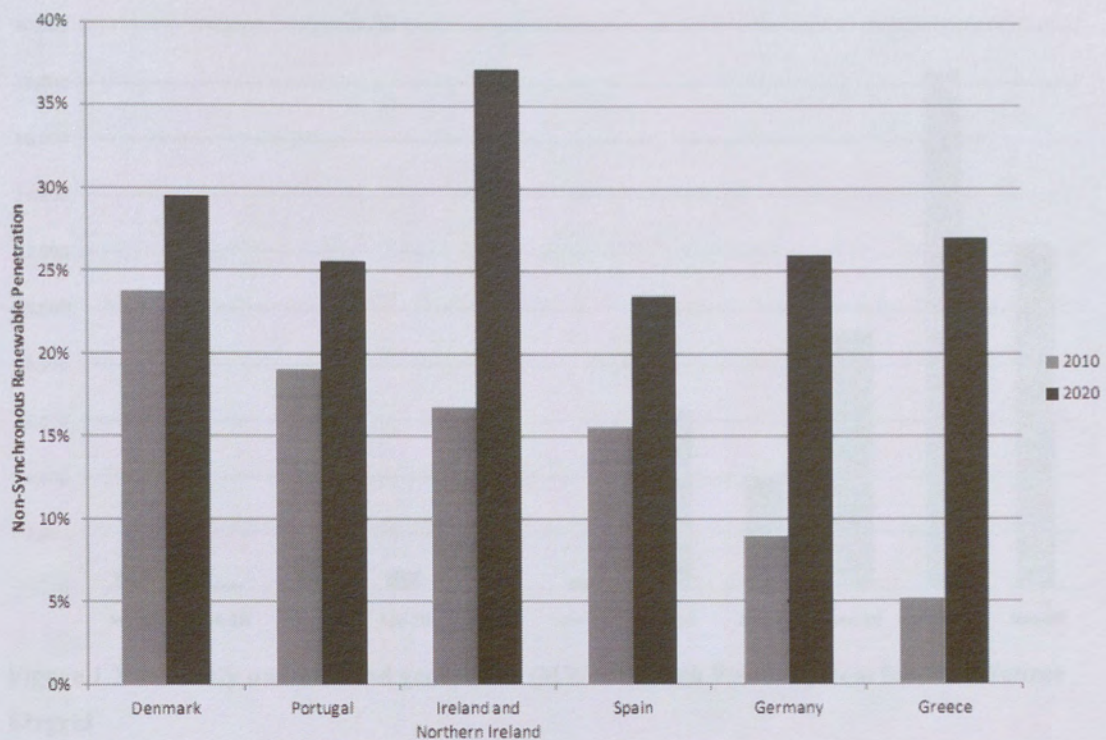


Figure 1.1: Non-synchronous renewable penetration (by annual energy) for the top six control areas in the EU in 2020-Source Eirgrid. Estimate based in data submitted by EU member States, June 2010

However, a lot has changed since the AIGS was undertaken and the recent drop in electricity demand resulting from the economic collapse has meant that wind power as a percentage of instantaneous demand is now one of the highest in the world [15]. In the power system, it is necessary for wind generation to be turned down at times to maintain system security. The reasons for this can be system-wide; for example, maintaining a minimum level of synchronous inertia, which results in wind curtailment. Figure 1.2 shows the unused wind generation in the All Island system for the year 2010.

1.5 Thesis in Brief

This is primarily a technical thesis that aims to improve on current methods for modelling PVDF within power system markets with a view to achieving a better understanding of the role and use of PVDF in order to plan future power systems. This is undertaken in a two-stage process, with a number of chapters focusing on a particular issue related to PVDF and variability. Initially, the role and drivers for PVDF are outlined in Chapter 2, which is a conceptual chapter. The more than practical of technical Chapters 3 to 6, in which direct preparation for



Figure 1.2: Monthly unused wind generation (MWh) in Irish Power System for 2010-Source Eirgrid

The rise in installed wind power capacity in Ireland and the expected increase in wind curtailment have led investors and speculators in the Irish energy sector to investigate the use of pumped hydro energy storage as a means of storing excess production from wind farms and selling it later when there is a shortage in demand. While there is a lot of interest in PHES, there has been little or no critical review of the software models used to simulate the operation of the electrical power system with PHES and wind power production. This thesis examines the modelling of PHES in the existing and future Irish power system, and investigates the assumptions and limitations of current modelling techniques.

1.0 Thesis in Brief

This is primarily a technical thesis that aims to improve on current methods for modelling PHES within power system models with a view to achieving a better understanding of the role and use of PHES in today's and future power systems. This is undertaken in a two stage process, with a number of chapters focusing on a particular issue related to PHES and variability. Initially, the role and drivers for PHES are established in Chapter 2, which is a non-technical chapter. The thesis then proceeds to technical Chapters 3 to 6, in which current practices for

modelling PHES and the full power system are scrutinised and improved upon. The key question therefore underpinning the research presented in Chapter 3 to Chapter 6 is as follows:

Do current methods for modelling PHES in power systems adequately capture the operation of PHES and, if not, how can they be improved?

The motivation for asking this question is significant for a number of reasons. If PHES has a role to play in facilitating Ireland's renewable future, it is vitally important that today's models are adequately able to capture and model current operation and use of PHES. This is also a salient point for future potential PHES projects as lead-in times for PHES development take many years; so decisions on the requirement for PHES need to be made well in advance of the development. Also, as will be shown throughout this thesis, even modestly small improvements in the modelling and operation of PHES can translate into differences of millions of Euro across the annual operation of the power system. The answer to the above research question is developed throughout the thesis, but, to put it succinctly, the case is made that current methods for modelling PHES in power systems **do not** adequately capture the operation of PHES. In general, most current models assume perfect foresight and simulate the power system at hourly resolutions, which has important implications in relation to power systems with pumped storage and high levels of wind energy.

The thesis, therefore, proceeds from establishing the drivers and uses of PHES to the modelling of PHES in the existing and future Irish power system with increased levels of renewable generation such as wind and wave energy. More specifically, in Chapter 2, the development and use of PHES in Ireland and abroad is presented. A review of past and future international PHES projects is presented and the drivers for building PHES and the role they play in power systems are investigated. Since much of the rhetoric around PHES in Ireland has focused on the fact that other European countries are building PHES to accommodate wind variability, it is important to provide the context for these PHES developments. It is shown in Chapter 2 that, while increased wind development is often cited as a driver for newer PHES construction, it is not the

only reason. Other factors such as multiple uses of storage and water shortages also come into play. These issues do not generally arise in Ireland; thus, lessons for PHES development abroad may not be readily transferable to Ireland. What is unique to Ireland is that the sole driver for the renewed interest in PHES is increased wind power production and the use of PHES primarily to reduce wind curtailment. Ireland's only PHES plant is Turlough Hill, built in 1974, and in the past number of years there have been a number of applications for the development of new PHES projects in Ireland. These are also discussed and presented in Chapter 2. Throughout Chapter 2, the costs for new PHES developments are also presented. It is important to note that the financial profitability of current or future PHES is not examined here. It is widely understood that current economics of PHES development are marginal and a review of previous research in this area is briefly presented in Chapter 3.

As mentioned previously, wind curtailment is expected to increase in Ireland as levels of variable renewable generation increase. The concept of using PHES to reduce wind curtailment is relatively simple: In times of excess wind generation, PHES can store excess generation and release it later when wind output is low or demand is high. While in theory this concept is straightforward, it is an oversimplification of a rather complex problem. PHES operates in a dynamic power system with interconnection and with numerous important technical constraints on the operation of thermal power plant and on the operation of PHES itself. These important constraints are introduced and discussed in Chapter 3 and range, for example, from the minimum stable level of a units operation, to minimum up and down times for thermal plant, to constraints on the operation of PHES itself such as rough running ranges and lower efficiencies at minimum output levels. These constraints limit the actual flexibility of thermal power plant and PHES, and they are revealed in this study to be important elements in relation to the modelling of the power system.

The work in this thesis shows that Turlough Hill will play an ever more important role in the operation of the Irish power system as more wind energy introduces further variability into the power system. It is the understanding of this role that is introduced in technical Chapter 4, in which the modelling of the

Turlough Hill, and indeed the full power system, is examined in closer detail at high temporal resolution in the projected 2020 Irish power system. This power system will have significant amounts of variability introduced by wind power production, and it is shown that hourly simulations of the power system will not capture important binding constraints such as ramp rates and start profiles of thermal power plant. This has consequences for total system costs and also for the perceived flexibility of the power system and PHES. The assumption of perfect foresight also has limitations in relation to modelling the power system correctly. A model that assumes perfect foresight of forced outages and wind power production will underestimate total system operation costs. This is because models that assume perfect foresight can take pre-emptive action before an actual outage or drop in wind power production occurs, thus providing an economically optimal solution to the operation of the power system (whereas, in reality, no such luxury of perfect foresight exists). In Chapter 4, the cost and implications of this perfect foresight assumption is examined and quantified in detail.

As will be shown in Chapter 2, some of the proposed PHES projects for Ireland are very large by today's standards. The modelling of larger PHES units is examined in close detail in Chapter 5, and it is shown that conventional methods of modelling and operation of large PHES are inadequate to correctly exploit the full potential of PHES. Large PHES systems need to be optimised over long time horizons and new methods are required to deal with the inherent uncertainty in wind power production over such long optimisation periods. Moreover, in a real operational environment the operator of PHES has no firm knowledge about future wind power production. Information is available in the form of wind power forecasts that have uncertainty associated with them. An operator thus has to make a decision '*here and now*' on the operation of PHES, which has consequences for the effectiveness of PHES' ability to store or generate electricity in the future. If too much capacity within the storage reservoir is used for generation '*now*,' it may compromise the storage's ability to generate at a later stage. When storage operation is examined in the context of this uncertainty, it is shown by this analysis that more conservative release decisions are made in

comparison to release decisions than are made under the assumption of perfect foresight

Chapter 6 assembles the knowledge developed in the technical Chapters 3 to 5 and establishes a soft-linking methodology of the power system model to the TIMES energy system model. It is shown that the low temporal resolution at which TIMES simulates the energy system is inadequate to capture the operation of PHES and the flexibility of thermal power plant. The motivation for this soft-linking is to provide a transfer of information from the power systems model strong points to the energy systems model weak points, and to use this information to improve and develop the understanding of results from the energy system model. Part of this motivation is derived from the view that one specific energy modelling tool cannot address all aspects of the full energy system in great detail, and that greater insights and progress can be gained by drawing on the strengths of multiple modelling tools rather than trying to incorporate them all into one comprehensive model

Finally, in Chapter 7, the impact of an Irish government target for 500 MW of wave energy is examined. Although this is not directly related to the modelling of PHES, it does give insight into how a diverse portfolio of renewable technology choices can impact on overall system variability and total system costs.

Chapters 2, 4, 5, 6, 7 of this thesis are either in review or have been accepted for publication in peer review journals. The chapters are presented as the text submitted for review with minor modification and formatting changes.

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Chapter 2: Techno-Economic Review of Existing and New Pumped Hydro Energy Storage Plant

Abstract: There has been a renewed commercial and technical interest in Pumped Hydro Energy Storage (PHES) recently with the advent of increased variable renewable energy generation and the development of liberalized electricity markets. During the next 8 years over 7 GW of PHES capacity will be added to the European network while projects are also planned in the USA and Japan. This chapter provides a review of existing and proposed PHES plant and discusses the technical and economic drivers for these developments. It reviews proposed PHES projects and shows that costs of building a new PHES plant vary widely. The chapter illustrates however that build costs vary widely and are highly site specific. This work highlights a key development in recent PHES plants that are increasingly moving to the use of variable speed technology. This technology, while incurring slightly higher capital costs, offers a greater range of operational flexibility and efficiency over conventional PHES. This paper has primarily been prompted by a lack of detailed information on PHES facilities worldwide and reviews current developments in the context of market and generation mix changes. The most recent large scale review of PHES facilities was undertaken by the American Society of Civil Engineers Hydro Power Task Committee on Pumped Storage in 1996. In the absence of data in the literature on new PHES plant development, this review draws primarily on publicly available information from utilities, government bodies and electricity regulators. In the same context this study is limited to a review region of the European Union, Japan and the United States as information on developments outside these areas is difficult to procure. This chapter also gives a review of locations and proposed timelines for new PHES development and provides a thorough up-to-date overview of the development trends of this technology.

1.0 Introduction:

PHES is currently the only commercially proven large scale (> 100 MW) energy storage technology with over 300 plants installed worldwide with a total installed capacity of over 95 GW[1]. In recent years there has been a flurry of interest in the technology resulting in the planning and building of a number of new plants in Europe and Japan. As of 2009, the European Union has an installed PHES capacity of 36 GW accounting for 4.3% of total generating capacity within the region. USA has an installed capacity of 21.8 GW with over 39 PHES plants and Japan with 34 plants (Plant with installed MW capacity > 200 MW) has an installed capacity of 21.8 GW. While PHES was previously developed in many countries to facilitate the integration of large baseload generation, there has been a recent renewed interest in the technology with an increase of variable renewable generation such as wind in many countries. This paper examines the drivers and costs behind both new PHES development and existing developments. The majority of information gathered on new PHES development for this review paper comes directly from developer web sites as there is a gap in this information in academic literature.

This paper is structured as follows. Section 2 introduces the technology and basic concepts of PHES. Section 3 reviews existing developments in the review region and details the owners of large PHES plant. Section 4 gives a general overview of proposed PHES and looks at the drivers for these developments. A detailed description of each proposed project is given on a country by country basis. Section 5 reviews the capital cost of new and exiting plant while section 6 concludes with some observations on current trends.

While there are a large number of PHES plant in planning or early development stages in countries like the USA, the authors limited this review to plants deemed to be likely or very likely to be built. The principal criteria used to make this assessment were (1) whether construction has commenced and (2) has the Environmental Assessment Stage of planning been completed.

2.0 Pumped Hydro Energy Storage

2.1 Technology

The fundamental principle of PHES is to store electric energy in the form of hydraulic potential energy. Pumping typically takes place mainly during off-peak periods, when electricity demand is low and electricity prices are low. Generation takes place during peak periods, when electricity system demand is high. Pumping and generating generally follow a daily cycle but weekly or even seasonal cycling is also possible with larger PHES plant.

The US Army Corps of Engineers distinguishes between two types of PHES [2] namely pure PHES and pump-back PHES. Pure PHES plants rely entirely on water that has been pumped to an upper reservoir from a lower reservoir, a river or the sea. Pure PHES are also known as 'closed-loop' or 'off-stream'. Pump-back PHES use a combination of pumped water and natural inflow to produce power/energy similar to a conventional hydroelectric power plant. Pump-back PHES may be located on rivers or valleys with glacial or hydro inflow. Figure 2.1 shows a schematic of both Pure and Pump-back PHES.

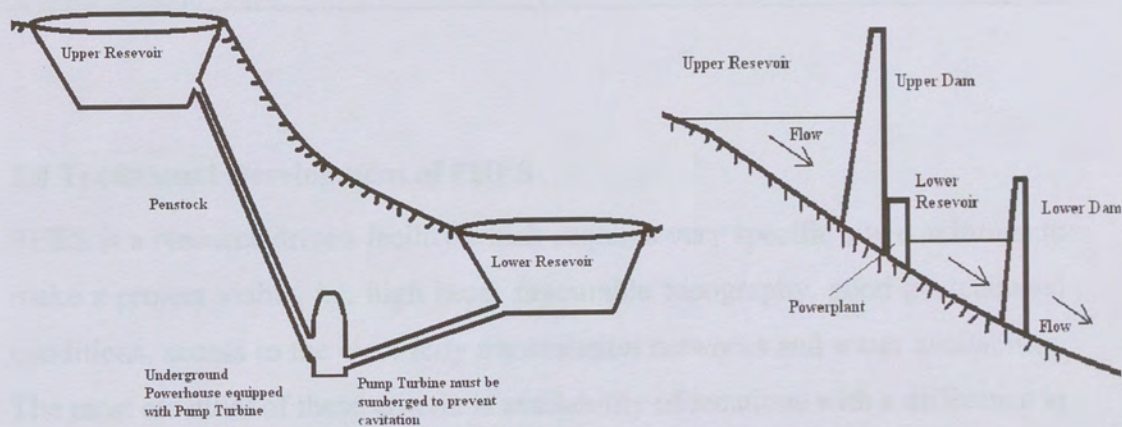


Figure 2.1: Pure PHES on left and Pump back PHES on right

The benefits of PHES to electrical system operations are well documented in textbooks and journals [3-8]. Its flexible generation can provide both up and down regulation in the power system while its quick start capabilities make it suitable for black starts and provision of spinning and standing reserve. A

summary review of the operational characteristic of PHES in comparison to conventional power plant is provided in Table 1.

Table 2.1: Typical Operating Characteristic of Generating plant [7]

	Nuclear Power Plant	Coal Fired Plant	Oil Fired Plant	Gas Turbine- Peaker	PHES
Normal Duty Cycle	Baseload	Baseload	Baseload- Midmerit	Peak Load	Peak- Midmerit
Unit Start up-Daily	No	No	Yes, hot	Yes	Yes
Load Following	No	Yes	Yes	Yes	Yes
Quick Start (10 minutes)	No	No	No	Yes	Yes
Frequency Regulation	No	Yes	Yes	No	Yes
Black Start	No	No	No	Yes	Yes

3.0 Traditional Development of PHES

PHES is a resource driven facility which requires very specific site conditions to make a project viable, i.e. high head, favourable topography, good geotechnical conditions, access to the electricity transmission networks and water availability. The most essential of these criteria is availability of locations with a difference in elevation and access to water. Some of the earliest PHES plants were built in the Alpine regions of Switzerland and Austria, regions that have a rich hydro resource and a natural complimentary topography for PHES. Prior to the emergence of liberalized electricity markets, PHES plants were built by state owned utilities as a system tool to supply energy in times of high demand and allow baseload power plants to operate at high efficiencies in periods of low

demand. PHES also provided for such power systems management tasks as balancing, frequency stability and black starts. PHES plants have been built in many countries such as the USA and Japan to act as fast response peaking plant to complement high inertia nuclear power plants, but more recently there has been a renewed interest in the technology as an integrator for variable wind power. Figure 2.2 shows that the development of PHES plants in the USA is strongly correlated to the development of nuclear power plants

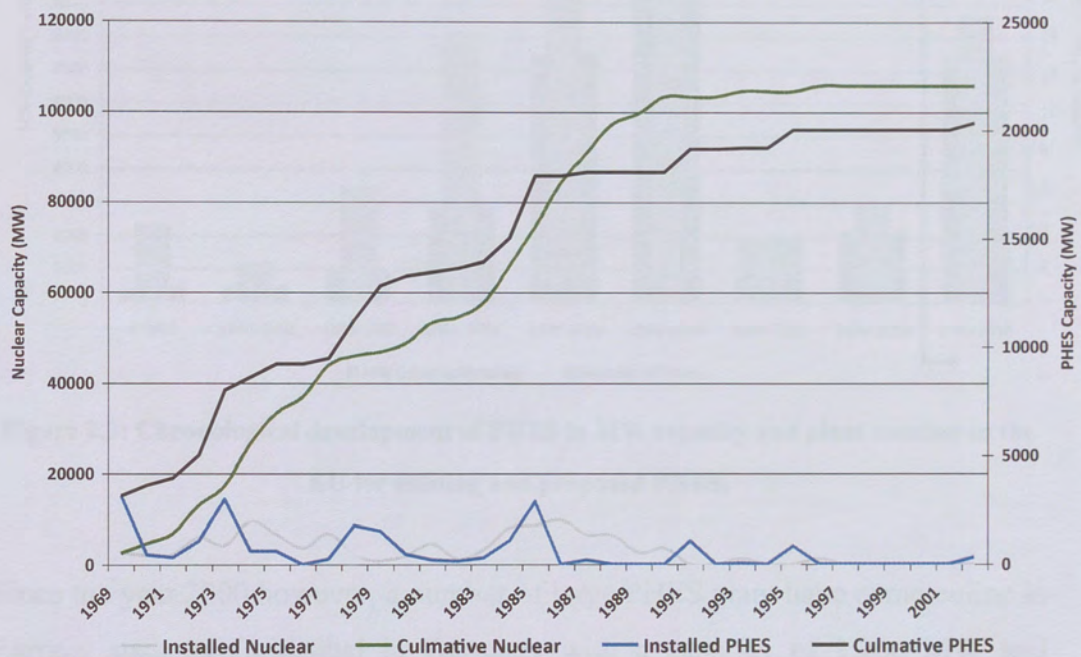


Figure 2.2: Development of Nuclear Power and Pumped Hydro Energy Storage in USA [9]

PHES development on a European level is also closely correlated to nuclear development however countries such as Austria with no nuclear generation, but a rich hydro resource developed PHES to primarily enhance the operation and efficiency of large scale hydro power plants.

The chronological development of PHES in many countries shows the majority of plants were built from 1960's to the late 1980's. This was in part due to a rush for energy security and nuclear energy after the oil crises in the early 70's. Fewer facilities were developed during the 90's; due to a natural saturation of the best available (most cost effective) locations and a decline in growth in nuclear development. Figure 2.3, with information gathered from individual plant

developers, shows the development of PHES in the Europe confirming the high level of construction in the 60's through to the 80's.

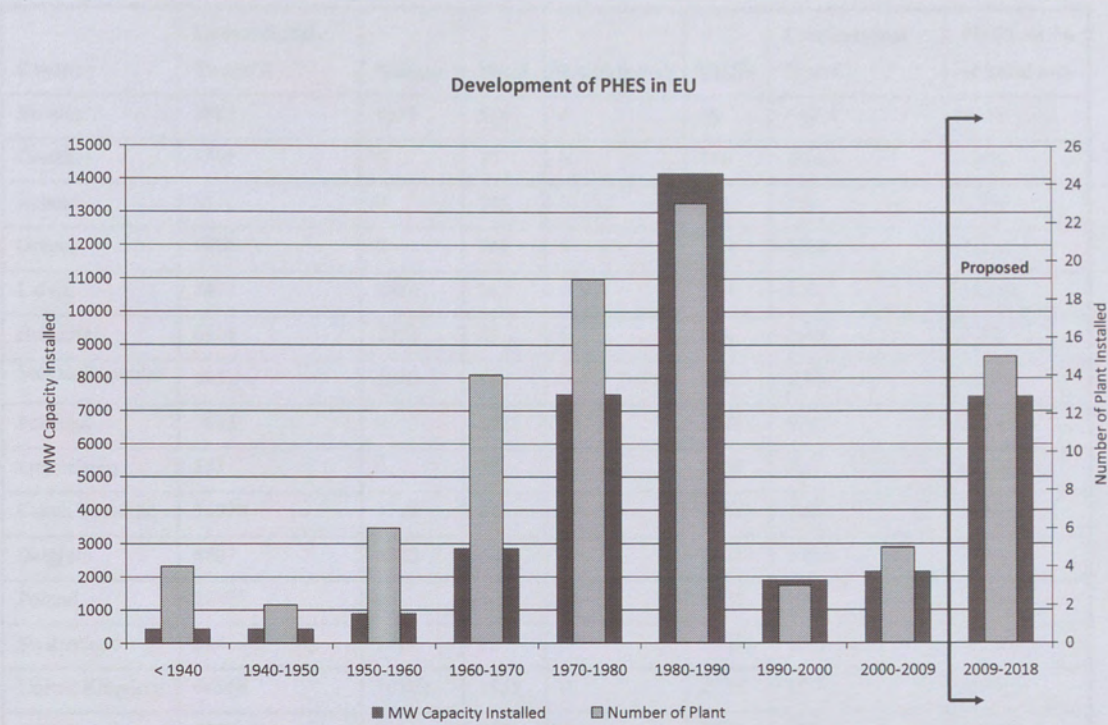


Figure 2.3: Chronological development of PHES in MW capacity and plant number in the EU for existing and proposed PHES.

Since the year 2000 however, a number of large PHES plant have come online in Europe, such as Goldisthal in Germany with a capacity of 1,060 MW and Kopswerk II with a capacity of 450 MW in Austria.

As shown in Table 2.2, PHES generally accounts for a small percentage of a country's generation portfolio in terms of installed capacity.

Table 2.2: Installed Generation Capacities (MW) in EU Member States (2006) [9] Japan (2008) [10] and USA (2007) [11]. PHES as a % of full installed capacity is also shown

Country	Conventional Thermal	Nuclear	Wind	Geothermal	PHES	Conventional Hydro	PHES as % of Total mix
Sweden	7882	9454	516	0	36	16234	0.1%
Croatia	1802	0	17	0	256	1804	6.6%
Ireland	5171	0	746	0	292	234	4.5%
Greece	9682	0	749	0	699	2436	5.2%
Latvia	2471	1183	31	0	760	117	16.7%
Bulgaria	6418	2722	27	0	864	1984	7.2%
Slovak Republic	3051	2640	5	0	916	1598	11.2%
Portugal	7685	0	1681	25	1048	4017	7.2%
Luxemburg	463	0	35	0	1100	40	67.2%
Czech Republic	11528	3760	44	0	1147	1028	6.6%
Belgium	8807	5825	212	0	1307	107	8.0%
Poland	29857	0	172	0	1406	925	4.3%
Switzerland	844	3220	12	0	1655	13355	8.7%
United Kingdom	64568	10969	1955	0	2726	1514	3.3%
Austria	6344	0	969	0	3580	8273	18.7%
Italy	65492	0	1902	671	4017	17055	4.5%
France	25672	63260	1412	0	4303	20822	3.7%
Germany	75176	20208	20622	0	4854	4141	3.9%
Spain	43659	7365	11736	0	5347	12967	6.6%
USA	776122	100266	16515	2214	21886	77885	2.2%
Japan	142000	49470	1880	520	24575	21465	10.2%

The country with the highest percentage of installed PHES worldwide is Luxemburg with 67%. Excluding Luxemburg the average installed capacity for the countries in the review region is approximately 6%. Countries with high installed capacities of PHES generally have a large amount of installed nuclear power capacity, like Latvia, Japan and the Slovak Republic or a rich hydro topography such as Croatia and Austria.



Figure 2.4: Existing PHES within the EU

On the worldwide scale the USA and Japan have the highest installed capacities of PHES. The USA has an installed capacity of 21,886 MW [9] of pumped hydro energy storage plants accounting for 2.1% of total installed generating capacity. 39 PHES plants are currently in operation with installed capacities ranging from 8 MW to over 2000 MW. The largest plant is the Virginia Electric & Power Co (now called Dominion) owned Bath plant with a capacity of 2,862 MW built in 1985. The 1,050-megawatt Helms pumped-storage project, operated by Pacific Gas and Electric Company in Fresno County, California with a head of 543 metres has the highest head in the United States. The largest federally owned pumped storage project is the Tennessee Valley Authority's 1,530 MW Raccoon Mountain project on the Tennessee River in Tennessee [9]. Major pumped storage plants (plants with installed capacity > 100 MW) in the USA are characterised by a mixture of pure pumped storage (17 plants), operating on daily cycles and pump-back facilities (12 plants) with large energy storage capacity operating on weekly or seasonal cycles. A number of pump-back facilities, such as Castaic (1,275 MW) also serve as part of irrigation and water regulation

schemes. The average size of a PHES plant in the United States is 520 MW. The majority of PHES plants were built in the period 1970-1980 when 14 facilities totalling a MW capacity of 9,636 MW were installed.

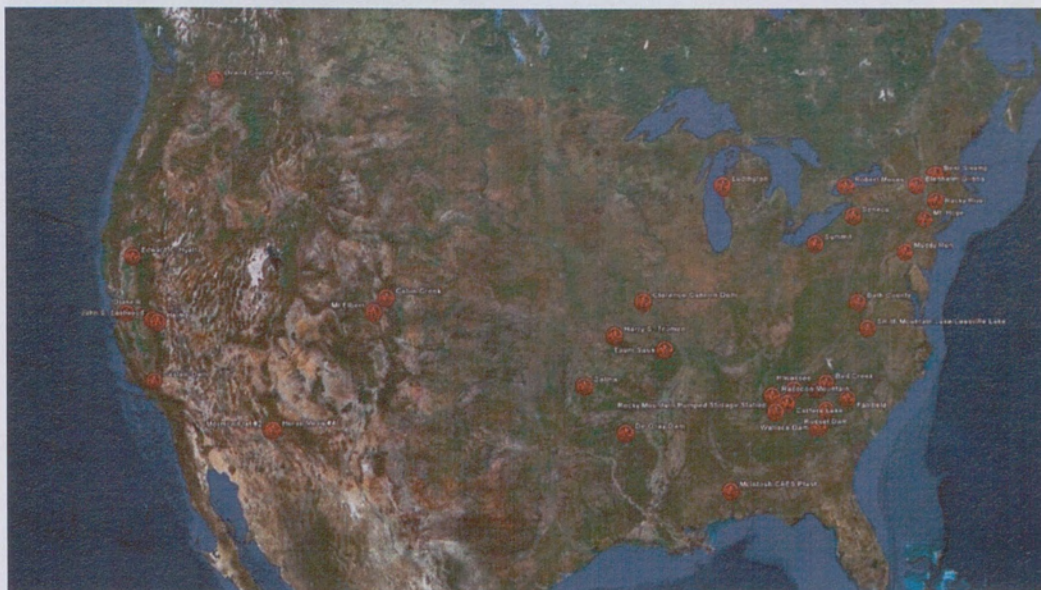


Figure 2.5: Existing PHES in the USA

Like the USA, Japan developed PHES to compliment nuclear power facilities, providing peak power in the evenings and pumping when demand is low. Japan has the third largest installation of nuclear power worldwide with a total of 53 units accounting for 47.9 GW installed capacity. Currently Japan has 34 PHES major plants with a total capacity of 24,575 MW [11]. Current installed capacities in Japan range from 200 MW to 1,932 MW.



Figure 2.6: Existing PHES in Japan

The majority of plants are pure pumped hydro storage schemes operating on a daily cycle characterised by large MW capacity and relatively short storage times, typically 5-10 hours. PHES installations account for 10.2% of full installed generating capacity.

In a European context the majority of PHES facilities are concentrated in the Alpine regions of France, Switzerland and Austria however Germany has the largest number of PHES plants with 23 operational plants ranging in capacity from 62.5 MW to 1,060 MW. Germany is second only to Spain in terms of installed MW capacity. Over 6,000 MW of PHES is installed on the Iberian Peninsula. Spain has 14 PHES plants with sizes ranging from 65 MW to 745 MW. The largest plant in currently in operation is the Iberdrola owned *Villarino* plant with a capacity of 745 MW. Portugal has 5 major PHES plants with an average capacity of 160 MW. PHES in Portugal and Spain are predominantly

pump-back type operating on major rivers or operating as part of larger hydro complexes or cascades. This type of facility can also play a number of important roles from irrigation to flood control. The largest PHES plant in the EU is the 1,800 MW EDF owned '*Grand Maison*' facility in the French Alps opened in 1987. The 1,728 MW Dinorwig plant in the UK was previously the largest PHES plant in Europe. Dinorwig can achieve full load from spinning in less than 20 seconds [12].

3.1 Ownership of Current PHES

While many PHES facilities were built before liberalized markets by State owned utilities, more recent times has been characterised by mergers and buy-outs of competing private companies. Table 2.3 details the current ownership of PHES in the review region.

Table 2.3: Majors owners of PHES in the review region*

Owner	Number of Operational Plants (2009)	Approximate Pumping Capacity (MW)
Iberdrola	10	3,327
TEPCO	9	6,801
Vattenfall	8	2,893
J-Power	7	4,970
EDP	6	969
EDF	6	4,978
Verbund	6	1,182
Endesa	5	1,577
E-on Wasserkraft	5	1,009
Schluchseewerk AG	5	1,740

*values are obtained from web sites of individual companies

The largest owner of individual PHES plant in the review region is Iberdrola [13] with a total of 10 operational plants in Spain and Portugal. TEPCO [14] and J-

Power [15] (also known as EPDC) are the largest owners of plant MW with a combined capacity of over 11,700 MW. EDF are the largest owner and operator of PHES plant in Europe on a MW basis. In the USA there is no clear major owner of PHES with the majority of the 34 plants being individually owned. The largest owner of PHES is the US Bureau of Reclamation with 4 plants totalling to an installed capacity of 340 MW. The California Department of Water Resources owns 3 plants with a total installed capacity of 800 MW.

4.0 New Developments

4.1 Technology Developments

While PHES is a relatively mature and established technology a number of recent innovations and improvements have been observed.

A number of proposed PHES plants (*Linthal 2015* and *Nant de Drance*) will use variable speed pump/turbine units. This technology is already employed in a number of existing PHES units in Japan. The advantage of variable speed pump/turbine units is that the variable speed pumped storage plants use asynchronous motor-generators that allow the pump/turbine rotation speed to be adjusted. This technology allows regulation of the amount of energy absorbed in pumping mode. This facilitates energy storage when power levels available on the network are low and in addition to reducing the number of starts and stops can help regulate the network frequency or voltage in pumping mode [16]. This technology also allows turbines to operate closer to their optimal efficiency point. This improved performance comes at extra costs for construction as the motor/generator/turbine shaft is longer and requires deeper excavation. A study in the USA [17] has estimated that this would increase the construction cost of a variable speed plant as opposed to a conventional PHES plant from approximately \$1000/kW to \$1050/kW.

In the area of improved efficiencies the Kannagawa PHES plant in Japan was the first plant to employ a 'splitter runner' which is a multi-blade turbine pump runner. Improvements in power generation and pump efficiencies of up to 4% are reported for this runner by TEPCO [18].

In the area of site development, J-POWER became the first company in the world in 1999 to build and operate a 30 MW sea-water PHES plant at Okinawa with a head of 136m. Research for the plant development started in 1981 and focussed on corrosion preventive measures [19]. Sea-water PHES may have several advantages over conventional PHES such as lower civil construction cost and greater site availability. Sea-water PHES technology has yet to develop a commercial track record however, with only one completed plant worldwide.

4.2 Drivers for New PHES Development

From a review of available public literature, developers of new PHES cite a number of key reasons for new developments, these can be summarised as follows.

- Government and regional targets for increased renewable energy are stimulating wind energy development in many countries. Increased variable generation is seen to drive the demand for system reserve and increase the value of PHES in ancillary services.
- A general growing demand for power and peak power in liberalized markets across Europe.
- Increased interconnection is cited as contributing to the value of PHES as developers have access to more potential markets and market opportunities.
- Security of supply. PHES is seen by many developers to contribute to a countries or regions security of supply.
- Reduce volatility or increase efficiency of current hydroelectric assets. Developers who already have existing hydroelectric or PHES assets are using newer more efficient equipment to increase the operational efficiency of existing plants.

Within the EU there is currently approximately 7,400 MW of new PHES development proposed, with a total investment cost of over 6 billion Euros. This constitutes approximately 20% increase in installed capacity of PHES in the EU.

Figure 2.7 [20] shows existing and planned PHES in the EU as well as current installed wind capacity and the percentage of PHES of total system capacity.

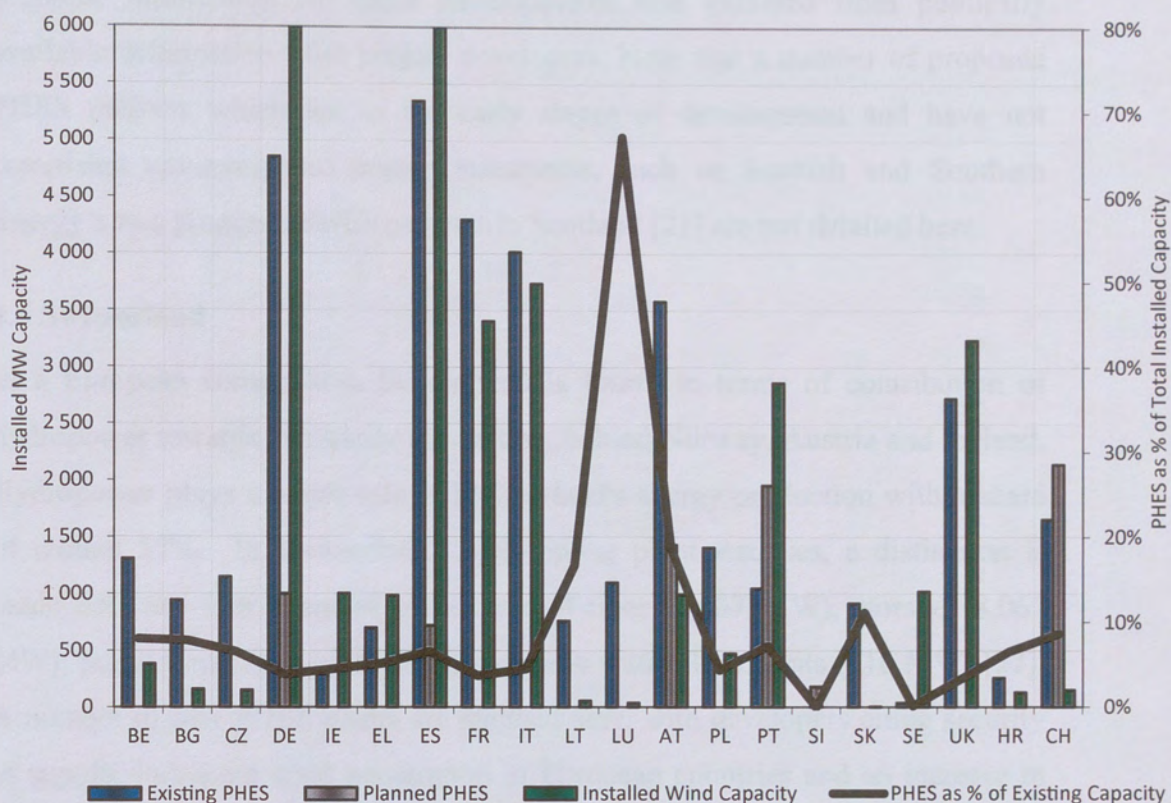


Figure 2.7: Installed PHES, Proposed PHES, Existing Installed Wind Capacity and % of PHES of Full Installed Capacity in the EU. Note for illustration purposes Germany (DE) and Spain (ES) installed wind capacity is limited to 6000 MW. Actual installed wind capacity in Germany is 23903 MW and 16740 MW in Spain

Switzerland has the highest amount of planned PHES at 2,014 MW. Table 2.4 details proposed PHES in Europe.

Table 2.4: Proposed PHES in Europe

Country	Proposed PHES (MW)
Switzerland (CH)	2,140
Portugal (PT)	1,956
Austria (AT)	1,430
Germany (DE)	1,000
Spain (ES)	720
Slovenia (SL)	180
Total	7,426

A review of new developments on a country by country basis is given in the next sections. Information for these developments was gathered from publically available information from project developers. Note that a number of proposed PHES projects which are in the early stages of development and have not completed environmental impact statements, such as Scottish and Southern Energy's two proposed PHES projects in Scotland [21] are not detailed here.

4.3 Switzerland

In a European comparison, Switzerland is fourth in terms of contribution of hydropower towards electricity production, behind Norway, Austria and Iceland. Hydropower plays a major role in Switzerland's energy production with a share of around 57%. In Switzerland's hydropower plant statistics, a distinction is made between four types of plants: run-of-river (3,667 MW), storage (8,067 MW), pumped storage (1,384 MW) and basic water flow plants (316 MW) [22]. A number of new PHES plants are planned here, with developers citing security of supply, increased wind penetration in European countries and an increase in demand in peak power in liberalized European markets as major incentives for development.

Axpo Group is developing the *Linthal 2015* PHES project which consists of two major expansion phases to the existing *Linth Limmer* complex [23]. The first phase *NESTIL* is a 140 MW pumping capacity and 110 MW turbine capacity plant that is being built into the existing complex. The construction of *NESTIL* began in 2005 and will take 4 years at an estimated cost of 100 million Swiss francs. The second phase *Linthal* is part of the same complex of reservoirs has a 1,000 MW pump/turbine capacity. Construction of *Linthal* is expected to take 5 year and has an estimated cost of 1 billion francs.

Construction started in 2008 at the 600 MW *Nant de Drance* PHES plant. The project is being developed by *Nant de Drance SA* a consortium of 3 companies Alpiq, CFF and FMV. The facility will use existing reservoirs at the *Vieux*

Emosson site. The project is expected to be completed in 2015 and cost of the project is estimated at 990 million Swiss francs [24].

Kraftwerke Oberhasli AG power company (KWO) is currently in the process of its 845 million Swiss franc investment and enhancement program (KWO Plus) of its existing hydroelectric facilities. This program includes the construction of the new 400 MW PHES *Gimsel 3* plant at a cost of 320 million Swiss francs. The plant will use existing reservoirs at the complex and compliment the existing 344 MW *Grimsel 2* PHES plant. Construction is expected to start on this facility in 2010 and end in 2014 [25]. Table 2.5 provides a summary of proposed PHES development and costs in Switzerland.

Table 2.5: Summary details of proposed PHES in Switzerland

Proposed Plant	Capacity	Published Cost	Project Developer	Operational Date
Linthal 2015(NESTIL)	140 MW	100 million Swiss francs	Axpo Group	2009-2010
Linthal 2015(Linthal)	1000 MW	1 billion Swiss francs	Axpo Group	2015
Nant de Drance	600 MW	990 million Swiss francs	<i>Nant de Drance SA</i>	2015
KWO Plus (Gimsel 3)	400 MW	320 million Swiss francs	Kraftwerke Oberhasli AG	2014

4.4 Portugal and Spain

In the European Union, Portugal is leading the resurgence in PHES with plans to build or upgrade up to 10 facilities adding approximately 2,000 MW of PHES to its current capacity of 980 MW. Portugal has a total installed generating capacity of 14916 MW with a total hydroelectric installation of 4,943 MW. Hydroelectric capacity factors for the past five years have been below average at 56% and

Portugal is exposed to volatility in hydroelectric production. In 2008 Portugal's imported balance for electricity was 19% with hydro resources supplying 11% of electricity while in 2007 the import balance was 15% with hydro supplying 18% of electricity [26]. This volatility along with ambitious government renewable energy targets and a relatively under exploited hydro resource is stimulating a renewed commercial interest in PHES development. Portugal is one of the few European countries with significant hydro potential (54%) to be developed [27]. Portugal has ambitious renewable energy goals. By 2010, renewable energy should represent 45% of the total consumption in the country. The installed wind energy capacity is expected to increase to 5,100MW by 2010. In this context the Portuguese government commissioned '*Plano Nacional de Barragens de Elevado Potencial Hidroelétrico*-'The National Program of High Hydroelectric Potential Dams' [28] (PNBEPH) in 2007. The PNBEPH identified and defined priorities for investments in large hydroelectric developments in the project horizon 2007-2020. The PNBEPH intends to reach a national hydro rated capacity above 7,000 MW in 2020 (70% of the national hydro potential). Particular emphasis was given in the PNBEPH to hydroelectric plants with pumping capacity given its ability to facilitate the integration of variable renewable generation. Wind power production and electricity demand in Portugal are highly uncorrelated with the windiest periods occurring at night time and early morning. Preliminary analysis within the PNBEPH indicated the ideal relationship between pumping capacity and wind power was in the order of 1.0 MW pumping capacity to 3.5 MW of wind power.

One of the largest new PHES plants to be built in Portugal (and Europe) is the *Alto Tâmega* complex [29]. This project is being built by the Spanish utility Iberdrola. This complex comprises of 4 dams (*Daivões, Gouaves, Padroselos, Alto Tâmega*) with a total generating capacity of 1,200 MW and a total pumping capacity of 900 MW. The company also recently won a tender to manage the existing *Aguieira* PHES plant (336 generating capacity and 270 pumping capacity) in Portugal until 2014 [30]. Iberdrola are also developing and expanding a similar complex in Spain at the *La Muela* complex which when completed in 2012 will have a total generating capacity of 1,710 MW and 1260 MW of pumping capacity. EDP (Energias de Portugal) are building 4 new PHES

plant in Portugal namely; *Baixo Sabor*, *Foz Tua* and *Fridão/Alvito* and expanding *Alqueva II*. EDP state that increased wind penetration is adding to the value of PHES through energy storage and ancillary services and making it attractive for investment. Increased interconnection with Spain (set to double to approximately 3 GW by 2014) and the liberalized Iberian electricity market (MIBEL) are also increasing the attractiveness of PHES for utilities and investors in Portugal [31]. Table 2.6 provides a summary of costs and MW capacities of proposed PHES in Spain and Portugal.

Table 2.6: Summary details of proposed PHES in Portugal and Spain

Facility	Size	Published Cost	Developer	Operational Date
Alto Tâmega Complex	1,200 MW Turbine Capacity 900 MW Pumping Capacity	1.7 billion Euros [³¹]	Iberdrola	2018
Baixo Sabor	170 MW	369 million Euro [³¹]	EDP	2013
Foz Tua	324 MW	340 million Euro [³¹]	EDP	2018
Fridão/Alvito*	256 MW + 136 MW	510 million Euro [³¹]	EDP	2016
Alqueva II (expansion)	240 MW	150 million Euro [31]	EDP	2012
La Muela II (extension)	720 MW	350 million Euro [31]	Iberdrola	2012

*Subject to the confirmation by INAG (the Portuguese Water Institute)

4.5 Austria

Hydroelectric power supplies approximately 55% of Austrian electricity [32] with an installed capacity of 11,853 MW of which 3.5 GW is PHES. Austria has 13 major PHES plants with the earliest plant, *Rodundwerk I* (198 MW) coming into full operation in 1952. The majority of PHES in Austria are situated in the west and south of the country in the Alpine regions. PHES in Austria, (as in the alpine regions of Switzerland) is characterised by large storage reservoirs with some glacial inflow and are generally connected by long underground penstocks into multi-stage hydroelectric complexes such as the Malta or Kaprun complexes. Major owners of PHES in Austria are the utilities Verbund, illwerke and Tiroler.

Liberalization of electricity markets, the rapid development of wind energy and increased electricity demand are cited as the main drivers for increased PHES development in Austria. In November 2008 the Vorarlberger Illwerke AG KOPS II (kopswerk) plant went into operation. KOPS II is located at the site of the existing KOPS plant. The project uses existing reservoirs and has a head of approximately 800m. The project cost approximately €360 million and took 3.5 years to build. Plant KOPS II has a full range of controllability of +/- 100 % in turbine operation and in pump mode using hydraulic short circuit [33]. Following the commissioning of KOPS II, Vorarlberger Illwerke has 1,700 MW of turbine output and 980 MW of pump capacity in the Austrian market [34].

Verbund are planning to build two new PHES Plant - *Reißeck II* and *Limberg II*. Verbund currently own and operate 6 PHES plants with a total pumping capacity of 1,182 MW and generating capacity of 1,621 MW [35]. *Limberg II* (480 MW capacity with a head of 360 m) is being built into the Kaprun Power Storage Complex and is expected to be completed by 2012 at a cost of €365 million. After the start of operations of *Limberg II*, the turbine output of the Kaprun Power Storage Complex will increase from 353 MW to 833 MW. The power output in the pump operation is set to climb from 130 MW to 610 MW [36]. *Reißeck II* with a planned installed capacity of 430 MW and a head of 595 m is being added to the Malta complex in Carinthia. The project will use existing reservoirs and resources and is estimated to cost €335 million. The project is

currently going through the environmental planning stage and is expected to be completed by 2014 [37].

Kelag are adding the 140 MW Feldsee PHES plant at a cost of €75 million to its Fragant hydro complex (334 MW) also in Carinthia. The new PHES plant will use existing reservoirs at a head of 532m. The project is expected to be completed by late 2009 [38]. A summary table of new Austrian PHES development is provided in Table 2.7.

Table 2.7: Summary details of proposed PHES in Austria

Facility	Size	Published Cost	Developer	Operational Date
<i>Reißeck II</i>	430 MW	335 million Euro	Verbund	2014
Limberg II	480 MW	365 million Euro	Verbund	2012
Feldsee	140 MW	75 million Euro	Kelag	2009

4.6 Germany

Germany with 23 operational PHES plants has the highest number of plants in Europe. In 2003 after 30 years of planning and 7 years of construction, Germanys largest pumped storage plant *Goldisthal* in Thuringia was put into operation. The plant, owned by Vattenfall has an installed capacity of 1,060 MW and a storage capacity of 8.5 GWh [39]. Currently one new PHES facility is planned for Germany. Schluchseewerk AG, owner of over 1,600 MW of PHES in Germany are in the planning phase of the 1,000 MW *Hornbergen II* project. This is an extension to the *Hotzenwaldgruppe* complex in southern Germany. The project is expected to be completed by 2014 and is estimated to cost €700 million. Increase in wind energy installations, increase in energy demand in the region and electrical grid congestion from the north to the south of Germany are cited as prime reasons for development of the plant [40].

4.7 Slovenia

Slovenia utility *Soške elektrarne Nova Gorica* (SENG) are in the final construction phase of the country's first PHES plant. The 520 meter head 180 MW Avče PHES plant is estimated to cost €91.4 million. SENG have secured loans from the European Investment Bank (EIB) for the construction of the project. The plant is scheduled to be completed at the end of 2009 [41].

4.8 USA

In the past fifteen years just one major PHES plant (Rocky Mountain 848 MW) was built in the USA. The most recent PHES build in the USA is the 40 MW Lake Hodges project in San Diego [42]. Recent renewed commercial interest in PHES is evident with companies such as Brookfield Power Corporation [43], Nevada Hydro Company, Symbiotic LLC [44] announcing pipelines of over 6000 MW of planned PHES plant [45]. At governmental level, Secretary of Energy Dr Steven Chu made positive comments [46] about the merits of PHES but has urged that new plants must not adversely effect local environment sensitivities and that lessons could be learned from European operators on this issue. According to official statistics from the Energy Information Administration there are currently no planned construction of PHES plants in the USA up to 2012 [47] however the Federal Energy Regulator Commission (FERC) has granted over 30 pre-permits¹ totalling over 22,000 MW of PHES. The majority of pre-permits were issued for potential locations in western USA states with high renewable portfolio standard targets, namely California-(20% target by 2010), Washington-(15% target by 2020), Nevada-(20% target by 2015) and Oregon-(25% target by 2025). A high number of pre-permit applications does not mean that projects will get build. Fifteen years ago the FERC had license applications for 18 GW of new pumped storage (42 plants with 31 in the west). However, deregulation, relatively cheap natural gas, and risk adverse private investors led nearly all developers to back out of construction [48]. Because of the need for significant elevation changes in pumped hydroelectric plan designs, the number of environmentally acceptable sites for future pumped hydroelectric facilities is very limited. Nevertheless,

¹ A preliminary permit, issued for up to three years, does not authorize construction; rather, it maintains priority of application for license (i.e., guaranteed first-to-file status) while the permittee studies the site and prepares to apply for a license. The permittee must submit periodic reports on the status of its studies. It is not necessary to obtain a permit in order to apply for or receive a license.

planning is underway to add new pumped hydro storage power plants to the USA grid [49]. As of 2009, one final Environmental Impact Statement has been submitted to the FERC for a pumped hydro scheme-The 500 MW (6,000 MWh storage) Lake Elsinore Advanced Pumped Storage Project (LEAPS). The FERC has estimated the cost of the project (not including Transmission line) to be approximately 1 billion USA dollars [50]. A construction date has not yet been given for the project. A study undertaken for the ERPI in 1988 [7] identified a number of reasons why the utilities in the USA were reluctant to pursue PHES. These reasons ranged from the availability of suitable sites, long lead times for licensing by regulatory agencies (4-6 years) and cost overruns in a number of PHES projects.

4.9 Japan

Although steady development of hydroelectric power plants is desired, Japan has used nearly all available sites for the construction of large-scale hydroelectric facilities, and so recent developments have been on a smaller scale [51]. In Japan's largest service area, the Tokyo Electric & Power Company (TEPCO) service area, the proportion of PHES as a percentage of the total capacity of the entire power network is determined based on a power network system analysis that aims to minimize the power generation cost of the entire power network taking into consideration the pattern of daily electricity usage. The current optimal proportion of PHES capacity as a percentage of the total capacity of the entire power network in TEPCO's service area is estimated to be 10 to 15% [52].

All PHES plants in Japan are owned and operated by the ten privately-owned regional electric power companies and J-Power who own 4.9 GW of PHES. A number of PHES plants are currently in the construction phase: Tokyo Electric & Power Company are currently in the construction phase of the *Kannagawa* plant which when completed in 2015 will be Japan's largest PHES plant with an installed capacity of 2,820 MW [53]. TEPCO also have the option to bring another 800 MW online at its *Kazunogawa II* plant to increase its capacity to 1,600 MW. *Kazunogawa* PHES is unique in that it has one of the world's largest ultra high head large capacity turbines (400 MW pump with a head of over 700 m) [54]. Kyushu Electric Power Company are in phase II of the construction of the *Omarugawa* PHES, currently 300 MW are operational. The plant is expected

to be completed by 2011 with a maximum capacity of 1,200 MW [55]. Table 2.8 provides a summary of proposed PHES development in Japan.

Table 2.8: Summary details of proposed PHES in Japan

Facility	Installed MW Capacity	Head	Operator	Completion Date
Kannagawa	2,820	653 m	TEPCO	2015
Kazunogawa II	1,600 (800 MW + Option to expand)	700 m	TEPCO	NA
Omarugawa	1,200	646 m	KEPC	2011

4.10 Ireland

Ireland's only PHES plant is Turlough Hill, built in 1974. It is a 'closed loop' PHES system with no hydro inflow. The plant is currently operated on a relatively simple cycle of pumping during the night and generating during the day. Since the building of Turlough Hill there has been further interest in PHES in Ireland. Plans for a second PHES facility were abandoned by NIE at the Camlough site in the mid 70's. Currently 2 facilities (Knocknagreenan -70MW and Lippagh Lough-70MW) are in the grid connection process with a further 275 MW currently outside of the process. A number of other projects are in feasibility assessment stages. Schemes in the public domain are *Organic Power's* application for a 45 MW PHES site in Derryduff, Co. Cork and preplanning is being submitted for a 480 MW sea water PHES site at Glinsk, Co. Mayo [57]. In May 2009, Spirit of Ireland [58] launched an ambitious campaign for energy independent for Ireland within 5 years using large scale coastal PHES coupled with wind energy. These projects demonstrate the sustained interest in the market for PHES.

5.0 Capital Cost for PHES and Current Trends

PHES plants are characterised by long asset life (typically 50 to 100 years), high capital cost, low operation and maintenance cost and round-trip efficiencies of

70-75%. The relatively low efficiencies and low cost of pumped hydro are more than compensated by the ability to avoid expensive peaking power. There are however limited siting possibilities for new pumped hydro resources [59]. Project costs for PHES are very site specific with some quoted costs varying from of €600-€3000/kW [60]. Furthermore capital costs depend not only on the installed power but also on the energy storage and MW capacity at any given site.

A study (7) undertaken by the EPRI of 14 PHES plant build in the USA from the years 1963 to 1985 found that build costs varied from under \$300/kW to over \$600/kW with an average cost of \$434/kW. The costs presented in the study are in January 1988 currency and exclude interest during construction and transmission costs. Figure 2.8 presents the costs detailed in the study. The study also noted that there was an observed increase in capital costs in “recent” builds in the USA (recent assumed to be 1980 +). This increase in costs was attributed to higher licensing costs, higher cost in providing more efficient and reliable plant and construction delays due to technical and financial problems.

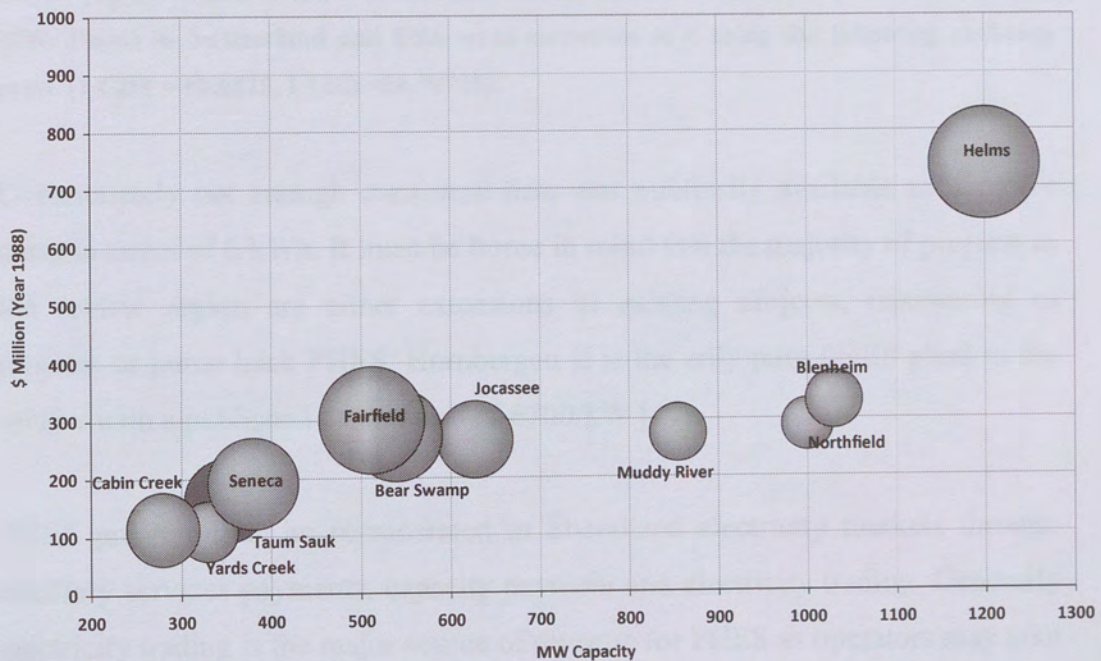


Figure 2.8: MW capacity and capital cost (ex transmission line and interest during construction) for 14 PHES Plant in the USA built between 1963 and 1985. Y-axis is full CAPEX cost in \$ US (1988). Size of bubble is indicative of relative cost per MW.

Figure 2.9 details the published capital costs and installed capacities for all proposed PHES plants in the review region, the majority of which are in Europe. A general linear trend is observed in the relationship between installed capacity and capital cost. Capital costs per MW for proposed PHES in the review region are between €470/kW and €2170/kW with an average cost of €888/kW.

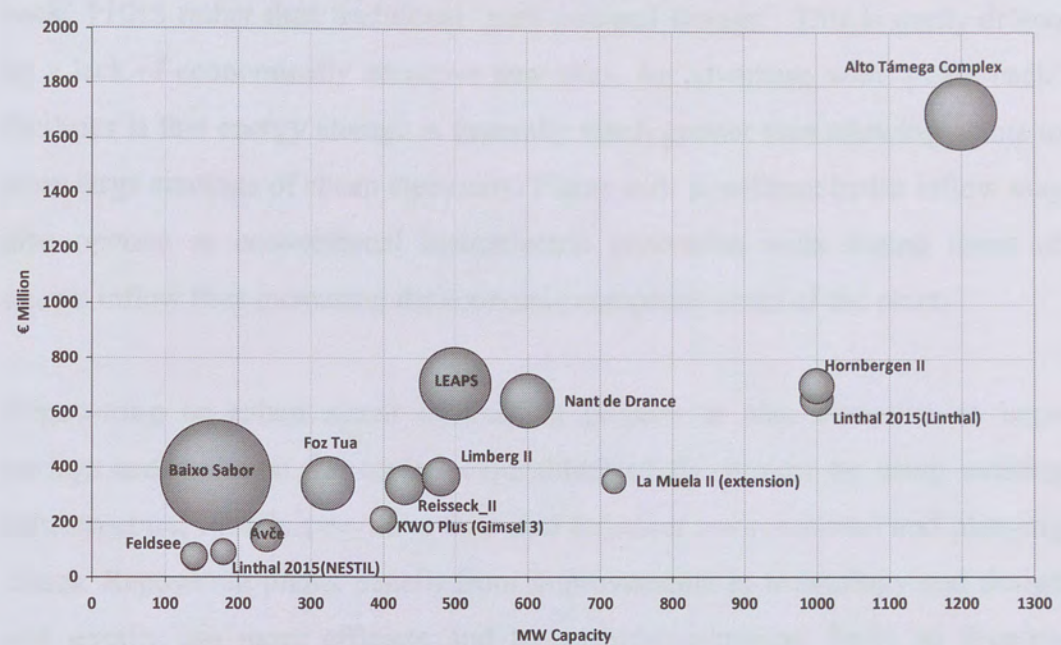


Figure 2.9: MW capacity and capital cost (ex transmission line) for proposed PHES in review region. Y-axis is full CAPEX cost. Size of bubble is indicative of relative cost per MW. Plants in Switzerland and USA were converted to € using the following exchange rates. (1 CHF = €0.6515, 1 USD =€0.70715).

Unfortunately not enough consistent data was publically available to compare costs in terms of €/kWh. It must be borne in mind that the majority of projects in the review region are either extensions to existing projects, repowering of projects or pump back PHES. Hornbergen II is the only pure PHES plant in the review with a published capital cost of €700/kW [40].

PHES projects may be remunerated in liberalized electricity markets through ancillary services payments, capacity payment and electricity trading. Generally electricity trading is the major source of revenue for PHES as operators may take advantage of energy arbitrage opportunities. For arbitrage pumping price has to be at least 25-30% lower than selling price to compensate for energy losses and significant volatility (not necessarily high energy prices) must be present in the wholesale price of electricity to make revenue. Increased wind generation in

many countries can naturally lend itself to increased price volatility in the wholesale market [60].

Current trends for new PHES plants in Europe show that developers operating in liberalized markets are tending to repower, enhance projects or build 'pump-back' PHES rather than traditional 'pure pumped storage'. This is partly driven by a lack of economically attractive new sites. An advantage with 'pump-back' facilities is that energy storage is generally much greater thus allowing plants to store large amounts of cheap electricity. Plants with significant hydro inflow may also operate as conventional hydroelectric generation units during times of excess inflow thus increasing the economic competitiveness of the plant.

Repowering or enhancement of existing projects is also attractive as large savings are made on the capital expenditure of the project by using existing infrastructure, usually reservoirs thus also reducing environmental and planning issues. Repowered plants benefit from improvements in technology and design and usually use more efficient and larger turbines/pumps. From an investor standpoint the internal rate of return for repower project is on average higher than new plants [61].

Developers of new PHES in the review region tend to have diverse generating portfolios usually with significant amounts of wind capacity. This is particularly true in Europe. In countries where wind energy is subsidised by government it may be economically favourable for co-owners of PHES and wind farms, as they may benefit for their using their own wind power to fill PHES reservoirs. For a market access perspective developers are tending to locate new PHES plants in areas with strong interconnection to neighbouring markets or regions to sell or purchase power.

6.0 Conclusion

This review papers details and presents over 7,000 MW of new and proposed PHES in Europe, Japan and the USA with a total proposed investment cost of approx €6.7 billion. The majority of new plants are proposed in Europe. While

there is considerable commercial interest in the USA, only one PHES plant has submitted a final environmental impact statement to the regulating authorities. Japan will continue to grow its PHES capacity over the next number of years but the available exploitable resource for economically viable PHES is dropping.

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Section A

1.6 Review of Power System Modelling

Modelling the operation of a power system is not a trivial problem. For example, a system with only 4 generators and 48 trading periods can have over 1.6×10^{13} possible combinations of unit/off decisions. Many optimisation solvers and computer models used to model the power system are unable to solve this problem in full (see [1] and [2]). A common feature of most of these solvers is that they solve the problem in a decomposed manner, solving the unit commitment and economic dispatch problem in a sequential way. In power systems

Chapter 3: Power Systems Modelling Review and Modelling Pumped Storage in the Current Power System

Abstract: When modelling power systems with fluctuating renewable sources such as wind power, it is important that the flexibility (or lack of flexibility) of generation units is captured correctly by the model. Failure to correctly describe a unit's flexibility in a model will overstate the full system's ability to absorb fluctuating renewable sources and lead to an undervaluation of inherently flexible generation source such as pumped hydro energy storage. The first section of this chapter presents a review of power systems modelling and introduces the power system modelling tool (PLEXOS) used for this analysis. The first section of this chapter concludes by reviewing previous research in Ireland and abroad on the topic of PHES.

In the second section, a detailed PLEXOS model of all generation units in the Irish power system for the year 2008 is developed. The All Island power system is then simulated for one market year and simulation results for the operation of PHES are compared to the actual historic dispatch. This is undertaken as a means of benchmarking the performance of the model in relation to the market and operational modelling of pumped storage. The objective of the section is to determine what level of technical detail is required in model development so as to adequately replicate the actual operation of existing PHES.

Section A

1.0 Review of Power Systems Modelling

Modelling the operation of a power system is not a trivial problem. For example, a system with only 4 generators and 48 trading periods can have over 1.6^{28} possible combinations of on/off decisions. Many specialist softwares and computer models used to model the power system are available and an overview is provided in [1] and [2]. A common feature of most models is that they all generally assume perfect foresight and approach the unit commitment and economic dispatch problem in a deterministic sense. In power systems,

modelling the unit commitment and economic dispatch problem means deciding the correct combination and power output of units for the reliable and economic operation of the power system. The problem takes account of fuel and carbon costs as well as system reserves (also known as ancillary services), which are required in the event of forced outages of power plants or transmission lines. Unit commitment, then, concerns the decision of what units to turn on or off; dispatch concerns the decision of what level to run units at once they are switched on. A standard approach, using mixed integer programming (MIP), to determining the optimal unit commitment and economic dispatch in a power system subject to technical and economic constraints is presented in [3]. The value of detailed unit commitment and dispatch modelling comes from the fact that it captures many of the technical constraints and limitations of thermal power plant and quantifies the implications for variable renewable generation. This feeds back into the determination of the technical suitability and flexibility of the power system. The unit commitment and dispatch problem can be relatively complicated to solve because the physical delivery of electricity is subject to the technical and economic constraints on generation. Some of these technical constraints introduce integer variables into the linear programming formulation in order to track the on/off state of a generation plant, enforcing important technical constraints like minimum stable generation, minimum up and down times and start costs. A brief description and definition of these important constraints is given below

Minimum Stable Level: Generators generally have a limited range of operation. This range of operation is between their minimum level, which is known as the minimum stable level (MSL), and its maximum generation capacity, or simply max capacity. MSL is typically around 40% of the maximum generation capacity of a plant. MSL is an important constraint as it forces units to come online in a ‘chunky’ manner. Often the need for a mid-merit plant to come online will require a baseload plant to scale back generation to allow the unit come on at its MSL or above. This also has important implication for wind curtailment as wind may also need to be curtailed to allow units come online at their MSL or above.

Minimum Up and Down Times: Thermal generators in particular have minimum running times, i.e. a minimum number of hours that, once the unit is 'committed,' it must run for, usually expressed in hours and typically in the range of 1-24 hours. Similarly, once a unit is shutdown there is sometimes a minimum cooling down period required before the unit can be restarted.

Start Cost and Time: Generators consume some power and fuel when starting. The amount needed is a function of how cold the units are, i.e. the time since they were last running. The terms 'cold,' 'warm,' and 'hot' start are used to describe the state of the unit. Generally it is easier and faster to restart a hot unit than a cold one. When a generating unit is started, it will run from a notional zero output to its MSL over a certain period of time. This often takes less than an hour and so the run-up period is usually ignored when simulating the system at an hourly level. However, this becomes an important constraint when modelling at sub-hourly resolutions.

Ramp Rates: The rate at which a generating unit can change its load level is limited by a number of factors including the rate that fuel and water for a steam turbine supply can be increased/decreased without taking pressures out of safe ranges, the amount of inertia in the machine itself, manufacturer recommendations, etc. When the ramp rate limit implies that the unit cannot run all the way from MSL to Max Capacity in a single simulation period, then the simulation needs to model the ramp rate as a constraint. Ramp limits are usually expressed as a maximum increase/decrease in megawatts per minute (MW/min).

Deterministic techniques for optimisation of power systems using linear programming/mixed integer programming and dynamic programming (DP) have traditionally been the tools of choice for many utilities when deciding unit commitment and economic dispatch in power markets. An overview of these methodologies is provided in [4]. In the past, MIP was considered in academia to be a better optimisation model, but the processing and time requirements to solve a problem using MIP were prohibitive and made this impractical for use in real-world scenarios. Recent innovations in CPU technology and improvements in the MIP algorithm [5] have meant that it is now possible to use MIP based software for market and real time operations. PJM (Pennsylvania-New Jersey-

Maryland Interconnection) in the USA, in partnership with AREVA, have developed a MIP solution for market operations and unit commitment, which has been in commercial use since 2005. CAISO (California ISO) is using a MIP solution in their new market since April 2009. SEMO (Single Electricity Market Operator in Ireland) can also operate a MIP unit commitment engine to determine operating schedules on the island of Ireland and currently there is an ongoing consultation on the full-time implementation of MIP in the market.

The use of MIP requires the need for specialist solvers. The solver used in this work is Xpress [6]. The function of the solver is to find the lowest cost feasible solution. This is done by stepping through a search space and testing the quality of each solution. The MIP solver has a number of distinct phases. First of these is the task to solve a relaxed or linear version of the problem. This is completed to get the lower bound on the overall solution. If, in this relaxed solution, the decision variables with integer constraints have integer values, then no further work is required. If one or more integer variables have non-integral solutions, a method known as 'Branch and Bound' is used. This method chooses one such variable and "branches," creating two new sub problems where the value of that variable is more tightly constrained. These sub problems are solved and the process is repeated until a solution that satisfies all of the integer constraints is found. An optimality gap is calculated as the percentage variance between the best current solution and the best lower bound from this phase.

While the process of modelling power systems deterministically with perfect foresight may provide lowest cost solutions for system dispatch, it also risks providing unrealistic results. This is especially true for power systems with significant levels of fluctuating renewable energy since the assumption of perfect foresight supposes that variable generation and wind production will do exactly what it is expected to do, without accounting for uncertainty. If uncertainty is accounted for, it is generally accepted that more conservative solutions should be chosen. While Monte Carlo simulations give optimal solutions for a number of scenarios assuming perfect foresight for each scenario, they cannot give insight into what decisions should be made now given the uncertainty in the inputs.

Stochastic optimisation modelling addresses a natural short-coming in deterministic techniques by allowing for the inclusion of uncertainty in the modelling process. This is especially important for large PHES that may require optimisation over long periods of time in the context of uncertainty. Stochastic optimisation of intertemporal targets is introduced and discussed in detail in Chapter 5. In brief, the goal of stochastic optimisation is, while accepting that uncertain inputs have definable probability distributions, to find a dispatch that is feasible for all possible data instances. Stochastic optimizations mimics real power system dispatches because the decision maker makes a decision based on information at hand, after which a random event occurs and then recourse has to be taken.

Another important issue in power systems modelling affected by the assumption of perfect foresight is that of forced outages (i.e. outages that occur to plant outside of scheduled maintenance), which are also assumed to be known. Again this deviates from the reality of actual power systems operation as a real forced outage is an unexpected event that occurs at some random time. The assumption of perfect in this case may give a false impression of the flexibility of the power system as the model can pre-empt the outage and therefore take evasive action against it. This issue and mitigations against it is discussed in greater detail in Chapter 4.

1.1 Previous PHES Research in Ireland

Pumped hydro energy storage has been the focus of much research In Ireland over the past ten years. In 2004, the Sustainable Energy Research Group (SERG) in UCC prepared a report on the ‘Study of Electricity Storage Technologies and Their Potential to Address Wind Energy Intermittency in Ireland’ [7]. This report reviewed available storage technologies (including PHES) and examined how each technology may be usefully employed to assist in dealing with variability. The report also presented an economic assessment of small scale PHES and hydrogen, reporting that total system capital cost is the most important variable driver of the attractiveness of storage systems. The report showed that pumped hydro systems may be viable in certain market environments. This refers specifically to small scale lower cost plants with favourable topographical

conditions. However, cost of storage capacity means that they are unlikely to fully compensate on a technical basis for the intermittency of wind.

In 2008, at University College Dublin [8], an investigation was carried out into the impact of balancing wind generation with storage for different levels of installed wind and storage under different operational strategies. Operational policies and possible revenues were examined. System marginal prices (SMP) from 2006 were chosen as a normal SMP and demand and wind profiles for 2010 were used to populate the model. The paper showed that a 24-hour optimisation period for PHES was the most effective and profitable operational time frame compared to longer time frames for the specific storage in question.

At the University of Limerick, research has been undertaken in full energy modelling and the technical potential of PHES to increase fluctuating renewable energy penetrations [9]. This research uses the energy-systems-analysis tool, *EnergyPLAN*, which accounts for all sectors that need to be considered for integrating large penetrations of renewable energy (the electricity, heat and transport sectors). Using *EnergyPLAN* a model of the Irish energy-system was constructed based on the year 2007. A technical optimisation in *EnergyPLAN* was used to analyse the technical potential of PHES. The analysis in this study compared different PHES operating strategies by simulating PHES in conjunction with large-scale wind penetrations on the Irish energy-system. This was done to illustrate the ability of each scenario to integrate increasing amounts of fluctuating renewable energy. It was concluded that increasing the PHES power capacity enables larger wind penetrations than increasing the PHES storage capacity. The analysis showed that, for example, a maximum feasible wind penetration of 60% could be achieved with approximately 6000 MW of PHES, with 50 GWh storage capacity assuming a double penstock. The model also assumed a minimum requirement of 30% of electricity to come from grid stabilising units. The research also developed a novel tool for prospecting for suitable locations for PHES and found that the potential for new sites was greater than had been expected [10].

In 2010, again at University College Dublin, [11] a study examined the unit commitment and dispatch of the Irish power system in 2020 using the WILMAR model running in deterministic mode. The model used assumptions based on the All Island Grid Study in relation to demand and Interconnection, and it looked at the Irish power system with and without PHES for increasing levels of wind from 17% to 80% of total electrical energy generated by wind. Taking into account the capital cost of storage, it was shown that storage is not viable from a system perspective until extremely high levels of wind power are seen on the system. A PHES unit of 500 MW with 10 hours of storage was used in this analysis. Levels of curtailment of wind were low for installed wind capacity of less than 6 GW. However, a sharp rise in curtailed wind was seen for higher levels of wind. At 7 GW of installed wind and above, a significant reduction in curtailment was seen with the inclusion of PHES. To meet 60% of our electricity needs from wind without any storage, 11650 MW of wind would need to be installed; whereas, by replacing conventional plant with 500 MW of storage, 11250 MW of wind needs to be installed.

In 2012, Connolly et al [12] examined the potential profit a 300 MW PHES unit would make under a number of operational strategies in 13 electricity spot markets. It was concluded that increased profits in terms of gains in energy arbitrage can be achieved if the storage is operated and optimised in a day-ahead strategy. The study also highlighted the riskiness in PHES investment as energy revenue streams were shown to be very volatile.

Outside of Irish Universities, Eirgrid have also undertaken research in this area. In 2009, they carried out an analysis of the potential benefit of pumped storage to Ireland [13]. The study examined how large scale pumped storage would operate in an Irish system based on a forecasted 2025 generation portfolio and demand. A broad range of scenarios were studied by varying the installed wind capacity, the level of interconnection to Britain and the amount of pumped storage capacity. The production costs, CO₂ emissions and amount of wind curtailment were determined for each scenario. These were combined with capital cost estimates to provide an overall comparison of the scenarios. Results were calculated in terms of the total cost to the Irish system. The study found that very

little curtailment of wind occurred up to 40% of electricity from renewables. Consequently, there was little value in adding large pumped storage at this penetration level. At higher wind levels, storage does contribute to avoiding wind curtailment and thus reduces production costs. However, when examined in the presence of increased interconnection, this benefit is lessened. The study indicated that the addition of both 1 and 2 GW of pumped storage provides a cost benefit to the system, assuming 10 GW of wind installed, but only when lower storage capital costs are assumed. However, if the greater capital cost is assumed, adding large pumped storage would be uneconomical.

A further Eirgrid study looking at the Economic Feasibility of Interconnection in Ireland [14] compared, in one of its scenarios, a 'Large Scale Pumped Storage' portfolio with 1500 MW of storage (135 MWh) to a base case scenario for the year 2025. Both scenarios achieved 40% renewable penetration in RoI (7.3 GW of wind for the Island), whereas the Large Scale Pumped Storage Scenario had less CCGT's and more OCGT's relative to the base case. GB portfolios were fixed for varying levels of interconnection from 400 MW to 1900 MW. The report indicated that, while lower levels of wind curtailment were achieved with large PHES and varying levels of interconnection relative to the Base Case, the Total System costs for the AI and GB system would increase. This study made no comment in relation to the economic feasibility of storage.

Many international studies have also specifically looked at the cost effectiveness of PHES to assist in integrating wind [15-18]. Outside of autonomous energy systems, where storage may be more essential, these studies have found that, for wind penetration levels of as much as 50%, the cost effectiveness of building new electricity storage is still low when considering the need for wind integration alone, due to the relatively higher cost of storage in comparison to other balancing options (excluding hydropower with large reservoirs and some pumped hydro). By storing electrical energy when renewable output is high and the demand low, and generating energy when renewable output is low and the demand high, the curtailment of renewable energy will be reduced and the baseload units on the system will operate more efficiently. When using storage to assist the integration of variable generation, storage should be viewed as a

system asset to balance all forms of variability including demand variations, as opposed to dedicating a storage unit to a single variable source. It is generally not cost effective to provide dedicated balancing capacity for variable generation in large power systems where the variability of all loads and generators is effectively reduced by aggregation, in the same way as it is not effective to have dedicated storage for outages of a certain thermal power plant, or to have specific plant following the variation of a certain load.

Section B

In this section, the PLEXOS software is described. A market model of Ireland's Single Electricity Market (SEM) is developed for the year 2008 to compare the simulated and actual market operation of PHES. Finally, an operational model of the Irish power system for 2008 is developed to contrast and compare the actual operation of PHES against its historic operational profile.

2.0 PLEXOS Software Description

The software used throughout this work to model the power system and solve the unit commitment and economic dispatch problem is PLEXOS [19]. Full details of model equations are shown in Appendix A. PLEXOS is a power systems modelling tool used for electricity market modelling and planning worldwide [20]-[26]. PLEXOS, normally a commercial modelling tool, is free to academic institutions for non-commercial research. This software was chosen because it is a flexible platform allowing user defined constraints. It is not a 'black box' and the users can browse and verify the equations of the problem via a diagnostic tool. The PLEXOS modelling tool is used by the Commission for Energy Regulation (CER) in Ireland to validate Ireland's Single Electricity market and has a history of use in Ireland [27].

PLEXOS co-optimises hydro, thermal, renewable, and reserve classes; and no heuristic or sequential approach is taken. Modelling is carried out using mixed integer linear programming that aims to minimize an objective function subject to the expected cost of electricity dispatch and a number of constraints. The

objective function of the model includes operational costs, consisting of fuel costs and carbon costs; start-up costs, consisting of a fuel offtake at start-up and a start cost; penalty costs for unserved energy and for failing to meet reserve requirements. Fuel consumption is calculated using piecewise linear function as in [28]. System level constraints consist of an energy balance equation ensuring supply (net pumping demand) meets regional demand at each period. Water balance equations ensure water flow within the pumped storage units is conserved and tracked. Constraints on unit operation include minimum and maximum generation, maximum and minimum up and down time and ramp up and down rates. Constraints in relation to each units ability to provide reserve are also included. Start-up/shutdown profiles and times are enforced via run-up rates. This means that units cannot ‘block load’ and cannot provide reserve or capacity during a start up period. Ancillary services are optimized using techniques set out in [28].

In chronological mode, PLEXOS solves for each period and maintains consistency across the full problem horizon. Temporal resolution settings in relation to solving are user defined and flexible. Users can choose interval lengths of one minute to one hour in hourly, daily or weekly periods over the full problem horizon (typically one year or more). For example, a model run with an optimisation length of one hour and period of one day with a horizon of one year will run 365 individual daily optimisations at a resolution of one hour each. To avoid issues with intertemporal constraints (i.e. unit commitment of large units and storage end levels) at the simulation step boundaries, a ‘look ahead’ period is used. ‘Look ahead’ means that the optimiser is given information about what happens ahead of the period of optimisation, and then solves for this full period (i.e. simulation period + look ahead period). However, only results for the simulation period are kept.

In PLEXOS, water in the PHES reservoir has no ‘value’ other than the value of the thermal generation it can replace. Thus, the optimisation will use all the water possible to minimize thermal costs. The use of the ‘look ahead’ period ensures the reservoir does not empty at the end of each simulation step by providing a natural shadow price equal to the dual variable of the water balance constraint

(See Appendix for full formulation). This represents the future value of water held in the storage and is used to initialize neighbouring simulation steps.

Within the model, maintenance schedules for generation units can be fixed exogenously if a known maintenance schedule is available, otherwise the model can determine an optimal maintenance schedule based on the annual maintenance rate and mean time to repair for each unit. The objective function of the maintenance scheduling formulation is to equalize the capacity reserves across all peak periods. Random outages for units are calculated based on Monte Carlo simulations. Outages occur at random times throughout the year with frequency and severity defined by forced outage rate, mean time to repair and repair time distribution. At simulation run time, PLEXOS dynamically constructs the linear equations for the problem using AMMO² software and a solver to solve the equations. In this work, Xpress MP [6] with a duality gap set to 0.2% is used.

Within the PLEXOS modelling tool, wind and other renewables are essentially treated as ‘free’ generation (i.e. the marginal cost is zero), although this can be changed by the user.

2.1 Market Modelling of PHES in the SEM

Over the past four years, the Commission for Electricity Regulation in Ireland has released a validated PLEXOS market model of the Single Electricity Market (SEM) [27]. The model has been shown each year to be capable of correctly simulating the operation of the SEM. In this section, the validated PLEXOS model of the SEM is expanded to include extra information in relation to the modelling of pumped storage, and one market year of simulations is undertaken to determine how simulated PHES operation compares to the actual market dispatch of PHES.

In a second step, the market model is further expanded and developed to an operational model by including important elements such as reserve classes and extra PHES operational constraints. Both the Market and Operational model

² AMMO performs a similar role in PLEXOS as other mathematical languages such as AIMMS, AMPL, or GAMS but is written exclusively for PLEXOS

were simulated for the year 2008 and results compared to actual historic outturns. The year 2008 was chosen because good quality data and information on wind production and reserve provision was available. Note, that in 2008 one of the four Turlough Hill units was out of service for most of the year. Both models were populated with individual generator characteristics, fuel prices, wind production profiles, outages rates and maintenance schedules. Interconnector flows from the period were also fixed based on actual historic flow. The models also used actual daily start costs and no load costs from the SEM. Figure 3.1 gives an overview of the generation portfolio for the period.

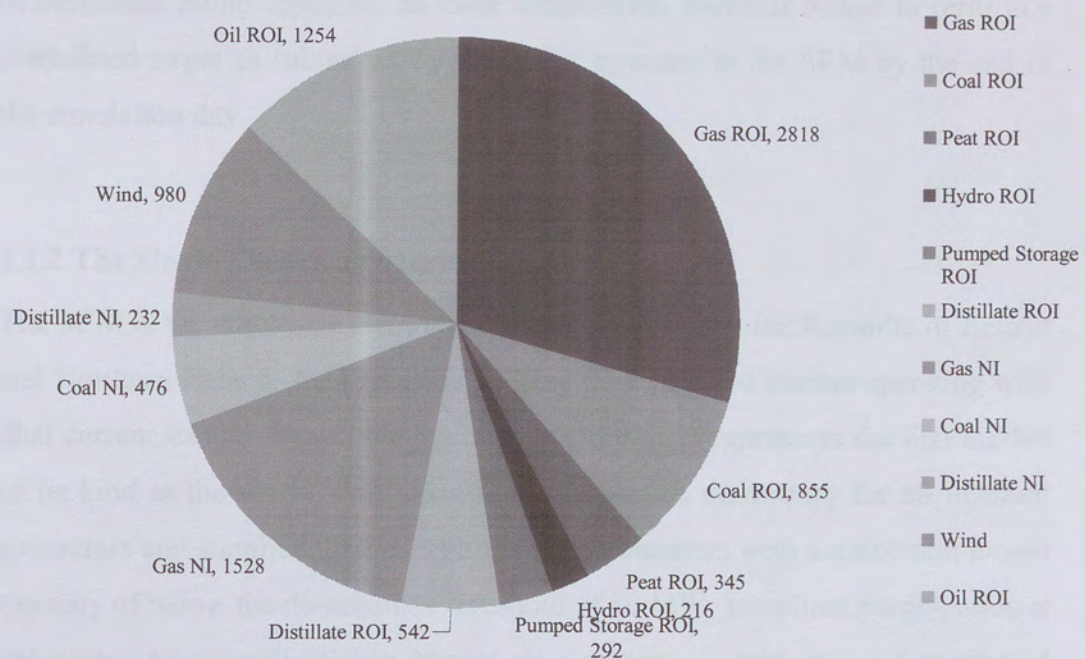


Figure 3.1: Total Generation Capacity (MW) by Fuel and Region for 2008 All Island System.

2.1.1 Market Operation of Pumped Hydro Energy Storage in Ireland

Turlough Hill is the sole pumped storage plant in Ireland and is capable of producing up to 292 MW of power. This is achieved when the four installed 73 MW Francis turbines supplied from a common penstock are operated as hydro units. The operation of Turlough Hill has three distinct modes. These are Spin, Min and Pump modes respectively. In Spin mode, up to two units can be synchronised onto the system without significant power production. Each unit can produce 5 MW in Spin mode. Min mode is where a unit is operating and

producing sizeable amounts of power, in the region of 40 MW to 73 MW. This type of mode provides both primary and secondary spinning reserve. In the third and final mode, Pump mode, the generators act as motors being supplied from other plant on line in the network. To act as motors each unit must draw 71.5 MW. The pumps cannot be used at intermediate values. This type of operation provides instantaneous primary reserve. The capacity of the reservoir is 1.59 GWh with a lower bound of 0.3 GWh on the lower reservoir. In the SEM, the market has a rather simplified view of Turlough Hill and basically models the units like hydro units, which are allowed to run from a zero level up to maximum capacity. In Pump mode, the units are also allowed to pump from a zero level up to maximum pump capacity. In these simulations, PHES is forced to refill to a predefined target as submitted by the PHES operator to the SEM by the end of the simulation day.

2.1.2 The Single Electricity Market (SEM)

The SEM is the wholesale electricity market operating in the Republic of Ireland and Northern Ireland. As a gross mandatory pool physical market operating with dual currencies and in multiple jurisdictions, the SEM represents the first market of its kind in the world. Participation in the pool is mandatory for all licensed generators and suppliers, the exception being generators with a maximum export capacity of below the de-minimus threshold of 10 MW, for whom participation is voluntary. As a result of this, almost all electricity is sold into and purchased from the pool. Under the pool arrangements, all generators and suppliers receive and pay the same price for electricity sold into and purchased from the pool. The Single Electricity Market Operator (SEMO) facilitates the continuous operation and administration of the SEM.

The Commission for Energy Regulation and Northern Ireland Authority for Utility Regulation (NIAUR) define the Trading and Settlement Code (TSC) as the trading and settlement rules and procedures for participation in the SEM. The implementation and operation of the TSC is carried out by SEMO, the Market Operator for the SEM. EirGrid issue Grid Codes, the codes by which the generation of electricity is regulated on a near real time basis. The grid codes

ensure the safety and power quality of the system and provide for ancillary services.

Participant generators within the SEM are required to submit offers into the pool for each generation unit, for each trading period (30 minutes), for each trading day. Offers consisting of commercial offer data and technical offer data, must be submitted by gate closure, which is at 10:00 on the day before the relevant Trading Day (i.e. 10:00 D-1), but may be submitted up to 28 days before gate closure. The technical offer data relates to the technical capabilities of the generator unit and consists of parameters such as ramp rates. Standard commercial offer data consists of no load costs, start-up costs and price quantity pairs.

- **No load costs:** This represents the elements of operating costs which are independent of the actual level of output.
- **Start-up costs:** This represents the costs associated with starting up the Generator Unit from cold, warm or hot states. A minimum of one and a maximum of three start-up costs are submitted.
- **Price Quantity Pairs:** The “quantity” represents the average MW level of energy to be supplied over a trading period. The price represents the minimum payment required for each MWh delivered. The price must increase with increasing quantity. A minimum of one and a maximum of ten price quantity pairs can be submitted.

Under the pool arrangements, all generator units receive, and all supplier units pay, the same energy component of price in a trading period, the System Marginal Price (SMP). The SMP is the price calculated by the Ex-Post Market Scheduling and Pricing (MSP) Software for every half hour trading period that will cover the cost of meeting the marginal cost of demand in the SEM. The MSP Software calculates the SMP in each Trading Period to:

- reflect the cost of the marginal MW required to meet demand in a trading period within the context of an unconstrained schedule. This is the **Shadow Price** component.

- recover operating costs associated with Start Up Costs and No Load Costs. This is the **Uplift** component.

The resultant formula for the derivation of SMP in a Trading Period is:

$$SMP = \text{Shadow Price} + \text{Uplift}$$

The SEMO uses a Market Scheduling and Pricing software package (MSP) to determine for each trading period both the SMP and the Market Schedule Quantity (MSQ). The MSP software takes max ramp rates, min stable generation and other technical details into account to produce a schedule that is as realistic as possible but does not consider provision of reserve.

The MSP Software gives individual consideration only to price maker generator units that are not under test. No other units are represented individually within the MSP Software. Based on the commercial and technical offer data provided by participants, the MSP software seeks to identify the lowest cost solution at which price maker generator units provide sufficient generation to meet demand that is not met by price taker and autonomous generator units

Under the SEM, dispatchable generator units are dispatched centrally by the TSO rather than autonomously by self dispatching. The TSO (EirGrid) dispatches generators during the trading day in real time. Although the MSP software produces a market schedule, this is based on an unconstrained system, ignoring transmission constraints and voltage and reserve requirements. The TSO must dispatch generator units taking system constraints and reserve requirements into account. The TSO must also consider real-time events such as generator outages and must respond to momentary changes in demand to keep supply and demand balanced throughout the day, which means the actual dispatch quantity (DQ) may deviate from the MSQ. An operational model of the Irish power system is developed and expanded in Section 2.2.

2.1.3 Pumped Storage in the SEM

The scheduling of Pumped Storage Units is performed by the MSP Software with the aim of minimising the total MSP production cost over all scheduled

generator units across a given optimisation time horizon (this runs from 06:00 on the Trading Day to 12:00 on the next day, i.e. 36hrs). It is important to note here that the objective function is not to maximise profit for PHES or any plant. The operators of a PHES site do not have control over the scheduling of the PHES units once it is declared as available. The unit is scheduled on the basis of the least cost for the overall system to meet demand during each trading period. To operate in the market, PHES units must submit Price Quantity Pairs, Start-Up Costs and No Load Costs for each unit, including Default Data, in all cases equal to zero. PHES participants submit additional Data Records to the commercial offer data and technical offer data in respect of each of its Pumped Storage Units (i.e. for each pump/turbine). These additional Data Records are:

- Commercial Offer Data
 - Target Reservoir Level at the end of the Trading Day;
- Technical Offer Data
 - Pumped Storage Cycle Efficiency, submitted as a single value for each Trading Day to apply to all Trading Periods within that Trading Day.
 - A Target Reservoir Level Percentage of 50%;
 - Maximum Storage Capacity expressed in terms of generation (MWh) for each Pumped Storage Unit within Trading Day.
 - Minimum Storage Capacity expressed in terms of generation (MWh) for each Pumped Storage Unit within Trading Day.

The MSP Software operates with the constraint that the Target Reservoir Level shall be used as a lower limit for the reservoir level at the end of the Trading Day, and that the MSP Software shall schedule each pump generator unit so the reservoir level at the end of the Trading Day is greater than or equal to the submitted Target Reservoir Level. For each run of the MSP Software, the Target Reservoir Level Percentage (50%) is multiplied by the Target Reservoir Level to derive a lower limit for the reservoir level at 12:00 on the following trading day and the MSP Software schedules each Pumped Storage Unit in such a way that the reservoir level at 12:00 on the following trading day is greater than or equal

to the resultant reservoir level. For all Pumped Storage Units that utilise the same reservoir for any Trading Day, the operator of the unit submits values of Maximum Storage Capacity, Minimum Storage Capacity and Target Reservoir Level.

2.1.4 Results for Market Model Simulations

The 2008 market model of the SEM was run for one full year (11th February 2008 to 11th February 2009) at half hourly resolution as per current SEM configuration. The historic market of dispatch profile of Turlough Hill and the modelled dispatch profile for the year are shown in Figure 3.2. It can be seen that the simulated profile of PHES follows quite closely the actual market profile. The total annual generation for the market and simulated model are shown in Table 3.1.



Figure 3.2: Actual and modelled market dispatch annual profile of Turlough Hill for simulation period

Table 3.1: Actual and modelled annual market generation from Turlough Hill

Actual Historic Dispatch	265 GWh
Modelled Dispatch	255 GWh

2.2 Operational Model of Irish Power System

As mentioned in the previous section, the MSP software produces a market schedule. This is based on an unconstrained system, ignoring transmission constraints and reserve requirements. The TSO must therefore dispatch generator units while taking system constraints and reserve requirements into account. In this section, the 2008 SEM model is expanded to include reserve and extra technical details that are shown to be important when modelling Turlough Hill. In this operational model, transmission is not modelled directly; however, the North-South tie line which connects the north and south of the country is included. This has a limit of 450 MW of flow in each direction. Other operational constraints are included, which draw on work carried out by Eirgrid. A minimum number of high inertia generators are required to be online at all times. Finally, one coal plant in the south of the country is required to be online at all time to support the 400 kV network.

As mentioned in Section 2.1 the SEM has a simplified description of the PHES. The actual operation of Turlough Hill is more complicated. In the Operational Model of the 2008 Irish Power system the following extra technical details are added to the PLEXOS model.

- **Rough Running Constraint:** This is a range of MW outputs that must be avoided. In the model, this range is from 5 MW to 40 MW. This band of output must be avoided to avoid cavitation and excessive vibration in the generator sets.
- **Fixed Speed Pumping:** The pumping units in the model are at a fixed speed. This means that pumping can only take place at one point (71 MW). A minimum pumping load constraint is therefore forced upon the model. However, in the PLEXOS software this will result in a zero contribution to reserve when pumping. This necessitates a dummy generator to model fixed speed pumps and contribution to reserve classes correctly.
- **Pumping/Generating Limits:** The PLEXOS software will allow PHES units to pump and generate at the same time. This may not be an issue if

the PHES unit has multiple penstocks or if is of the 'pump-back' type. However, Turlough Hill has one primary penstock; therefore, it can only perform one function at a time. A linear constraint is enforced in the model to ensure the plant is not pumping and generating at the same periods.

- **Minimum Generation:** When Turlough Hill is operating at minimum stable level of 5 MW, also known as Spin mode, the efficiency of the generators is modelled as 50%. A constraint is enforced that limits the number of units generating at this minimum stable level to 2 units at any one time. At all other times the generators are modelled at 100%. The efficiency in the pumping units is modelled at 70% at all times.
- **Spinning reserve:** Each generating unit can contribute 15 MW to POR (primary reserve), but this is capped at a total of 35 MW in total for all units. All units in generating mode are allowed to provide a maximum of 28 MW each to (SOR) secondary reserve. In Pump mode, all units are allowed to provide full pump capacity 71.5 MW to reserve. See next section for a more detailed account of reserve classes.

2.2.1 Reserve Classes and Pumped Storage

In Ireland's grid code, a number of reserve categories are defined [29]. Operating reserve, as defined in the Irish system, is divided into four parts: primary, secondary, tertiary 1 and tertiary 2. An overview of Ireland's operational reserve requirement is provided and contrasted with other systems in [30]. The primary driver for the requirement for operating reserve is the size of the largest in-feed. Within the model, the demand for operational reserve is calculated dynamically and is determined to be a 75%-100% of the All-Island largest in-feed as defined by [29]. Minimum requirement for each operational reserve class is also fixed. Operational reserve can only be supplied by units that are fully synchronized (i.e. they cannot contribute to reserve while on a start profile). Certain units can only provide reserve above a regulation point, which is 50% of their maximum export capacity as per [29]. Replacement reserve is modelled by keeping enough peaking units offline to cover requirement.

2.2.2 Methodology

A number of annual simulation scenarios were undertaken with varying degrees of technical constraints. All models were run with the same input data at 30 minute intervals at one-day (24 hrs) simulation periods for a horizon of one year. Each simulation has a look ahead of six hours as per current market set up in the SEM. All models were run for one full year (11th February 2008 to 11th February 2009). The only parameters that were changed were the constraints that were applied to the modelling of the PHES. The table below shows the technical constraints that were included in each simulation.

Table 3.1 Scenarios run for 2008 power system

	PHES related constraints			Thermal power plant constraints					Simplified network constraints
Scenario	Fixed Speed PHES	Efficiency at MSL	Rough Running Ranges	Start Costs	Min Stable Level	Ramp Rates	Min Up/Down Time	Start profiles	
RR	X			X	X	X	X	X	X
BASE	X	X	X	X	X	X	X	X	X
01	X		X	X	X	X	X	X	X
02	X			X	X	X	X	X	X
03				X	X	X	X	X	X

The model was firstly run using a technique commonly used by PLEXOS users called 'Rounded Relaxation' (RR). The RR algorithm integerizes or rounds up/down the unit commitment decisions in a multi-pass optimization. The result is an integer solution. Rounded Relaxation is a much faster solver than MIP as it uses a finite number of passes of linear programming rather than integer programming. The extent to which the method 'explores' the solution space is controlled by a setting that decides whether non-integers should be rounded up or down. This result is compared to a full detailed model MIP simulation that models all PHES operational constraints as defined in Table 3.2. Notably, the RR cannot model certain complex constraints such as rough running ranges or

reduced efficiency of PHES at MSL. Equally, the RR algorithm occasionally has difficulty with dealing with reserve, and it can produce infeasibilities in the optimiser.

2.2.3 Results

Results presented in Table 3.3 show the actual annual generation from Turlough Hill for the simulation period, as well as the model output generation for various technical scenarios as described above. It can be seen that the simulation results that best match the actual dispatch of Turlough Hill is the ‘Base Scenario,’ in which all technical constraints of Turlough are modelled. Table 3.3 also shows the % change in total system generation costs (start-up cost of all plant and total fuel consumption costs) relative to the actual modelled generation costs. The actual modelled generation costs were determined by forcing all generators in the model to follow their actual historic dispatch. This enables a determination of total generation costs for the system over that period. All model scenarios underestimate the total operational costs of the system.

Table 3.2: Results for scenario simulations

Scenario	Annual PHES generation (GWh)	Simulation run time	% Change in total annual cost relative to actual costs
Actual	346	-	-
RR	416	1.3 hours	-1.34%
Base	342	4.3 hours	-1.52%
01	361	3.4 hours	-1.61%
02	361	3.0 hours	-1.64%
03	363	3.0 hours	-1.63%

From the results above it can be seen that the modelling of a lower efficiency of PHES at its MSL has an impact on results and thus can be considered an important modelling constraint. The actual operational profile of Turlough Hill is shown in Figure 3.3 for a week in October compared to simulated results for the ‘Base Scenario’ as described in Table 3.2. As can be seen, the modelled daily operation of TH fits very well to the actual daily operation of the plant. Units

generate at peak times during the day but, importantly are kept online for most of the day to provide spinning reserve. It can also be seen that units provide important spinning reserve at peak times and do not produce at their maximum capacity in the week shown, and rarely at any point during the year. Due to the pumping losses inherent in PHES, it is generally more optimal to provide as much spinning reserve as possible when generating because provision of spinning reserve does not consume energy. This contrasts with the market operation of PHES, as described in Section 3.3, where the provision of reserve is not considered at all. In Pump mode, PHES is also a strong provider of spinning reserve and modelled pumping profiles match the actual pumping profiles very well. Figure 3.4 compares the actual operational profile of TH to simulated results where the rounded relaxation simulation method is used. It can be seen that the modelled operation of TH is more flexible (rough running ranges are not considered) and have a wider operational range. Thus, the RR scenario overestimates the annual production of Turlough Hill.

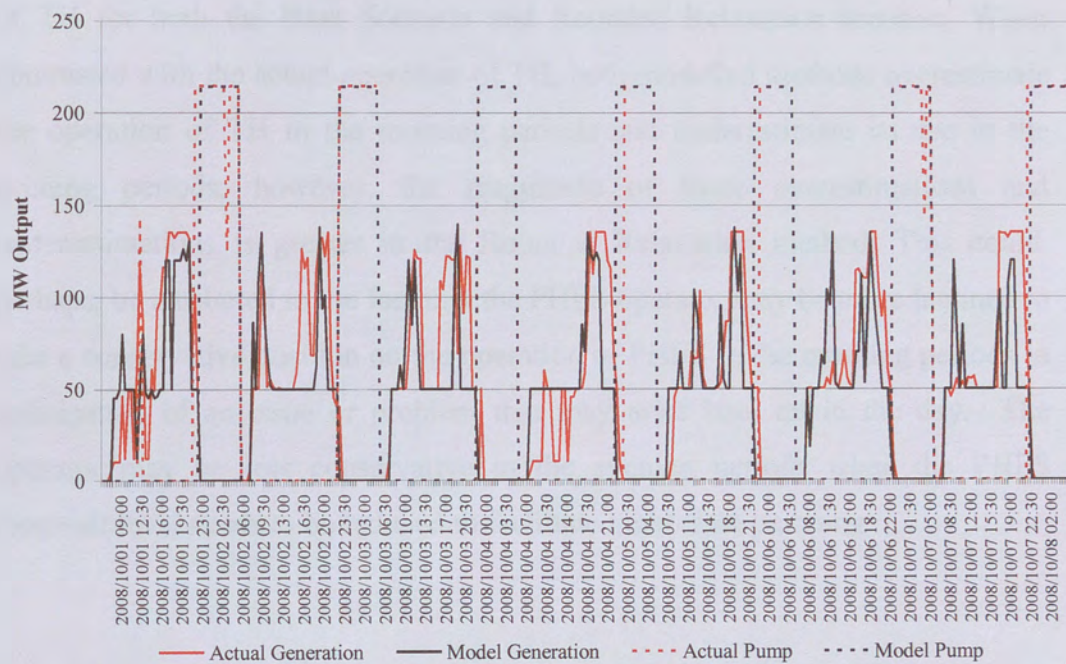


Figure 3.3: Actual and modelled TH dispatch (Base Scenario) for generation and pumping for a week in October.

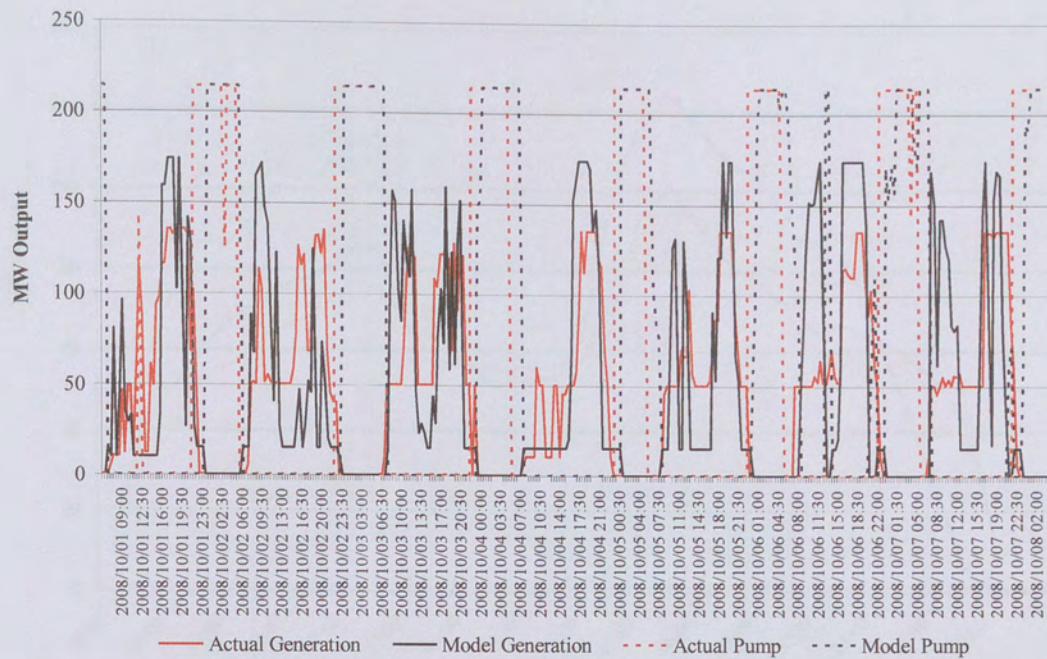


Figure 3.4: Actual and modelled TH dispatch (RR Scenario) for generation and pumping for a week in October.

Figure 3.5 compares the annual actual operational profile and modelled profiles of TH for both the Base Scenario and Rounded Relaxation scenario. When contrasted with the actual operation of TH, both modelled methods overestimate the operation of TH in the morning periods and underestimate its use in the evening periods; however, the magnitude of these overestimations and underestimations is greater in the Rounded Relaxation method. This could, perhaps, be attributed to the fact that the PHES operator may be more inclined to take a conservative position on the operation of PHES in the morning periods in anticipation of an issue or problem that may arise later on in the day. The operator may be less conservative in the evening periods when the PHES reservoir level needs to be reduced to facilitate night-time pumping.

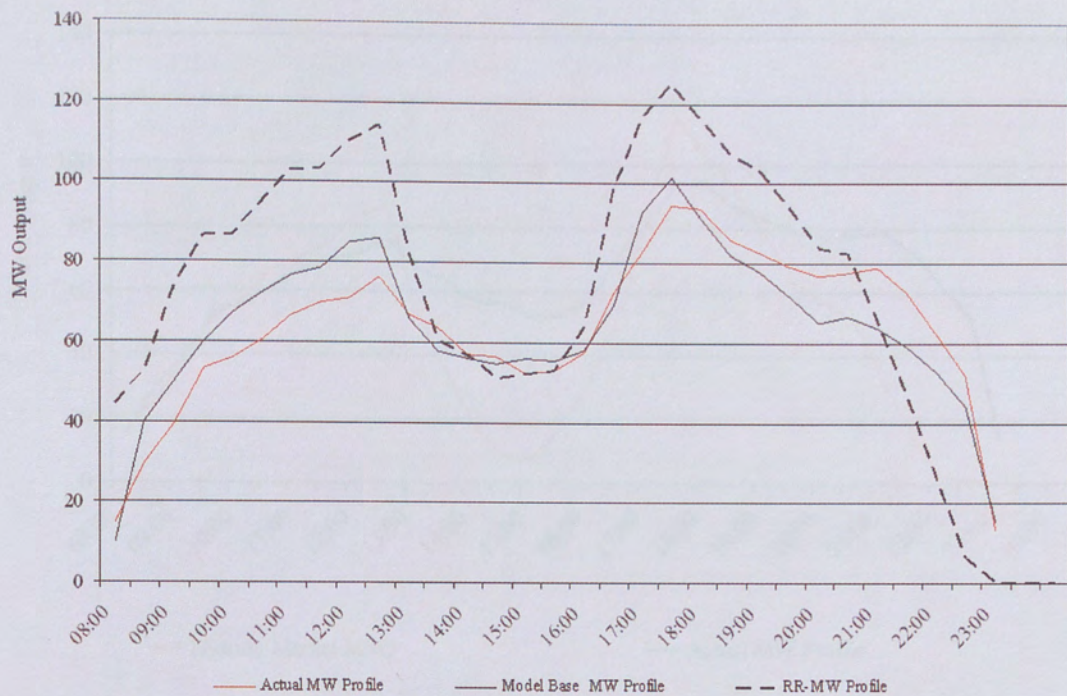


Figure 3.5: Annual profile of TH operation versus operational profile

3.0 Conclusion

This chapter introduced important elements of power system modelling and showed that the market and operational modelling of PHES in Ireland can produce quite distinct results. Figure 3.6 compares both the Market and actual Operational annual profiles of Turlough Hill for the target year. The importance of Turlough Hill in the provision of spinning reserve is a major modelling component and has a big impact on the operation profile of the plant, particularly during the mid afternoon when the units are kept online to provide reserve.

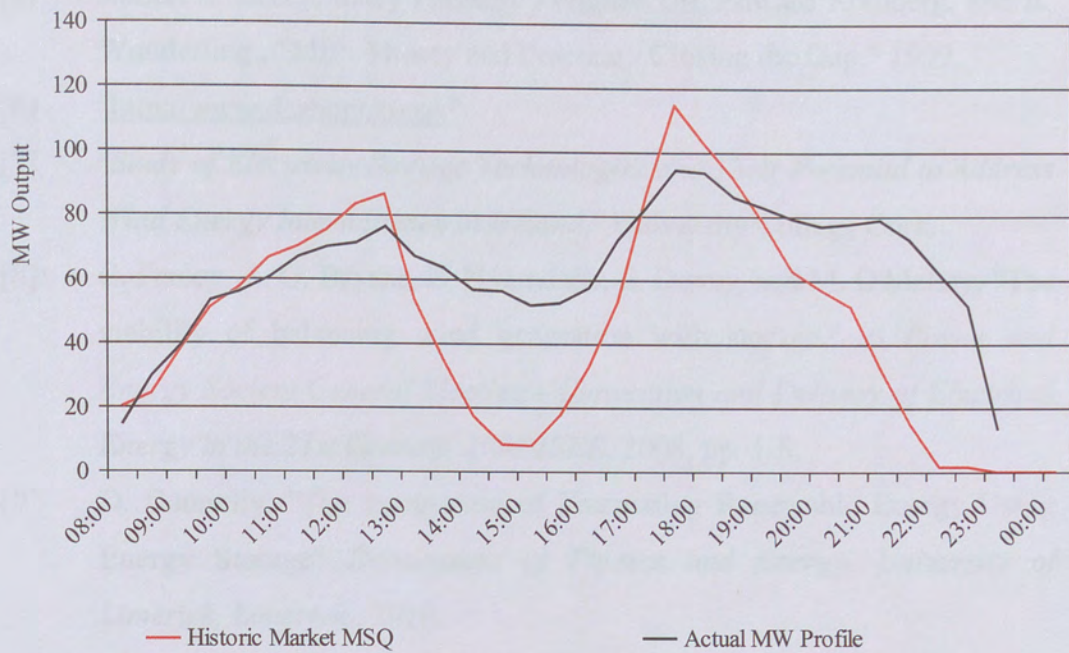


Figure 3.6: Market and Actual Operational Dispatch of Turlough Hill

To capture the actual operational modelling of PHES, it is important to include the modelling of reserve classes, as well as other constraints such as rough running ranges and reduced efficiency at lower operational levels.

4.0 References

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1.0 Introduction

Over 18 GW of wind power was installed globally in 2010 with a projected doubling in capacity over the next five years [1]. While wind energy generation is a clean and relatively cheap power source, it is not without its drawbacks, namely in the form of variability and non-dispatchability. Power system operators are challenged with wind energy's variability and non-dispatchability and have documented [2], [3] and have been the focus of much wind integration studies which are summarized in [4], [5]. The integration of variable renewable resources such as wind power will require numerous operational flexibility—namely capability to provide load following and regulation in wider operating ranges and at rates faster than are those of larger generation facilities that are currently experienced. In providing these capabilities, existing and planned thermal generation units will likely need to operate longer at low or minimum loading levels and provide more frequent start, stop, and cycling over the operating day [6]. To assess the future impact of wind power on systems, wind integration studies usually simulate a future power system with large penetrations of wind power production and evaluate the system impact in terms of costs. These studies generally use the energy balance and commitment and dispatch models to simulate the operation of the power system. A more robust approach to determine the impact of wind power on power systems is to use a more detailed approach to determine the impact of wind power on power systems.

Chapter 4: Sub-Hourly Modelling in Power Systems with Significant Levels of Renewable Generation

Abstract—The goal of this work is to determine the impact of sub-hourly modelling of a power system with significant amounts of wind generation and also to examine the cost of the perfect foresight assumption for forced outages of generation units. This paper presents the modelling of the Irish power system for a one year period. Results show that increased model resolution captures more variability in system load and is necessary to capture the inflexibilities of thermal units that lead to increases in total generation costs. This work also shows that a perfect foresight assumption on forced outages and wind power production underestimates total system generation costs.

1.0 Introduction

Over 38 GW of wind power was installed globally in 2010 with a projected doubling in capacity over the next five years [1]. While wind energy generation is a clean and relatively cheap power source, it is not without its drawbacks, namely in the form of variability and unpredictability. Power system issues associated with wind energy's variability and unpredictability are well documented [2], [3] and have been the focus of many wind integration studies which are summarized in [4], [5]. The integration of variable renewable resources such as wind power will require increased operational flexibility—notably capability to provide load-following and regulation in wider operating ranges and at ramp rates that are faster and of longer sustained duration than are currently experienced. In providing these capabilities, existing and planned thermal generation units will likely need to operate longer at lower minimum operating levels and provide more frequent starts, stops and cycling over the operating day [6]. To assess the future impact of wind power on systems, wind integration studies usually simulate a future power system with large penetrations of wind power production and evaluate the system impacts in term of costs. These studies generally use sophisticated economic unit commitment and economic dispatch models to simulate the operation of the power system. A standard approach to determining the optimal unit commitment and economic

dispatch in a power system subject to technical and economic constraints using mixed integer programming is given in [7]. Modelling the unit commitment and economic dispatch of a power system is not a trivial problem and to solve the problem sophisticated mathematical optimisation software and techniques are used to determine the least cost production schedule [8].

Many research and commercial models [9]-[12] have been used in recent wind integration studies [13]-[16]. A limitation with most of these studies and highlighted by [17] is that they run at hourly resolutions and impacts that occur inside the hour may be hidden. This means that start ups and ramp rates on conventional units are approximated by hourly rates. Recent work in [18] also highlighted the need to investigate hourly chronological simulation with sub hourly (5-15 minutes) simulation to investigate the fidelity of a models ability to capture the operation of the system. Although there is widespread interest in capturing these sub-hourly impacts in the modelling framework, it is not yet clear how important these impacts will be [19]. Note that while some studies undertake operational modelling that is performed on an hourly time step, they generally analyze sub-hourly wind and load data using statistical techniques to provide insight into the intra-hour impacts and variability characteristics [20].

The goal therefore of this paper is to investigate the value of sub-hourly unit commitment and dispatch modelling of an actual power system with a high level of wind penetration and to investigate the cost of a perfect foresight assumption for forced outages of units and of wind power production. This work presented in this paper is similar in concept to that of [21] in that a high resolution (15 minute) unit commitment and dispatch model is used to simulate a system. The work in this paper is different as it applies mixed integer linear programming (MILP) to solve the UCED problem (UC and ED are solved simultaneously) and aims to qualify and quantify the differences between high resolution simulations (i.e. 15 minutes) and hourly simulation results. This is important because in large power systems hourly simulation may have to be undertaken to keep the problem computational manageable so it is useful to understand the implication of higher resolution modelling. This work also investigates the cost of a perfect foresight

assumption for forced outages of units and also the cost of a perfect foresight assumption of wind power production.

Section II provides a review of the model used in this analysis. Section III presents the modelling methodology used in this analysis and the test system. Section IV presents the results and Section V draws conclusions. .

2.0 Software Model

The software used throughout this work to solve the unit commitment and dispatch problem is PLEXOS [22]. PLEXOS is a power systems modelling tool used for electricity market modelling and planning worldwide [23], [24], [25] and [6]. PLEXOS is commercial modelling tool but is free for non-commercial research to academic institutions. This software was chosen because it is a flexible platform allowing many user defined constraints. It is not a ‘black box’ and the users can browse and verify the equations of the problem via a diagnostic tool. The PLEXOS modelling tool is used by the Commission for Energy Regulation (CER) in Ireland to validate Ireland’s Single Electricity market and has a history of use in Ireland [26]. Detailed equations for the model are shown in Appendix A.

In this set-up PLEXOS co-optimises hydro, thermal, renewable, and reserve classes and no heuristic or sequential approach is taken. Modelling is carried out using mixed integer linear programming that aims to minimize an objective function subject to the expected cost of electricity dispatch and a number of constraints. The objective function of the model includes operational costs, consisting of fuel costs and carbon costs; start-up costs consisting of a fuel offtake at start up of a unit and a fixed unit start-up cost. Penalty costs for unserved energy and a penalty cost for not meeting reserve requirements are also included in the objective function. Fuel consumption is calculated using piecewise linear functions as in [27]. System level constraints consist of an energy balance equation ensuring supply (net pumping demand) meets regional demand at each simulation period. Water balance equations ensure water flow within pumped storage units is conserved and tracked. System operational constraints unique to this work are described in the next section. Constraints on

unit operation include minimum and maximum generation, maximum and minimum up and down time and ramp up and down rates. Constraints in relation to each unit's ability to provide reserve are also included. Start up/shutdown profiles and times are enforced via run up rates. This means that units cannot 'block load' and cannot provide reserve or capacity during a start-up period. This is shown in Figure 4.1 for an exemplarily 300 MW unit with a minimum stable level of 120 MW, a run up rate of 2 MW/minute and a ramp up rate of 3 MW/minute. The unit is committed at 01:00 and must then follow its start profile or run up rate of 2 MW/minute to the minimum stable level. Assuming a 15 minute simulation interval this takes 4 periods. Once the unit reaches minimum stable level it can ramp at a regular ramp rate of 3 MW/minute up to maximum capacity. This is in contrast to the block loading method where the unit can instantaneously come online at the minimum stable level.

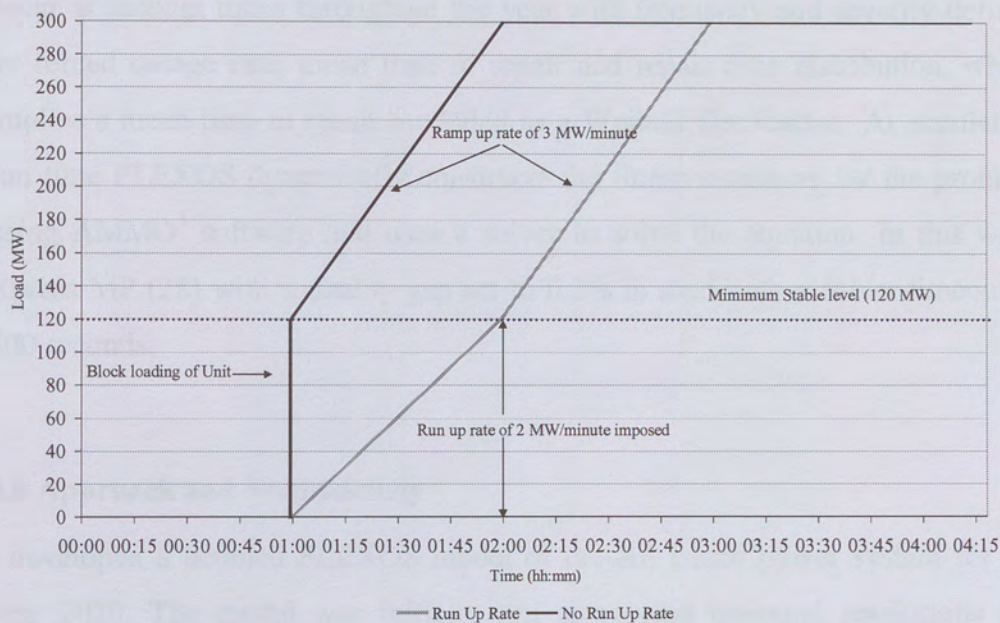


Figure 4.1: Example of run up rate and block loading for a thermal unit

Ancillary services within the model are optimized using techniques set out in [27]. In chronological mode PLEXOS solves for each period and maintains consistency across the full problem horizon. Temporal resolution settings in relation to solving are user defined and flexible. Users can choose interval lengths of 1 minute to multiple hours in hourly, daily or weekly steps over the full problem horizon (typically 1 year or more). For example, a model run with an optimisation length of 1 hour and period of 1 day with a horizon of 1 year will

run 365 individual daily optimisations at a resolution of 1 hour each. To avoid issues with intertemporal constraints (i.e. unit commitment of large units and storage end levels) at the simulation step boundaries a ‘*look ahead*’ period is used. Look ahead means that the optimiser is given information about what happens ahead of the period of optimisation and solves for this full period (i.e. simulation period + look ahead period) however only results for the simulation period are kept.

Within the model maintenance schedules for generation units can be fixed exogenously if a known maintenance schedule is available, otherwise the model can determine an optimal maintenance schedule based on the annual maintenance rate for each unit. The objective function of the maintenance scheduling formulation to equalize the capacity reserves across all peak periods. Random outages for units are calculated based on Monte Carlo simulations. Outages occur at random times throughout the year with frequency and severity defined by forced outage rate, mean time to repair and repair time distribution, which implies a mean time to repair modelled as a Weibull distribution. At simulation run time PLEXOS dynamically constructs the linear equations for the problem using AMMO³ software and uses a solver to solve the equation. In this work Xpress MP (28) with a duality gap set to 0.2% is used with a solver timeout at 300 seconds.

3.0 Approach and Methodology

I developed a detailed PLEXOS model of the All Island power system for the year 2020. The model was initially run at varying temporal resolutions (15 minute, 30 minute and 60 minute) under the assumption of perfect foresight for wind power and forced outages to investigate the effect of increased model resolution on results. The model was then re-run, firstly without the assumption of perfect foresight of outages and secondly without the assumption of perfect foresight of wind power production to determine the effect on results. Note that all model simulations share the same model inputs as well as maintenance and forced outages patterns and times.

³ AMMO performs a similar role in PLEXOS as other mathematical languages such as AIMMS, AMPL, or GAMS but is written exclusively for PLEXOS.

3.1 Test system

The 2020 generation portfolio is taken from EirGrid's (Ireland's transmission operator) All-Island Generation Capacity Statement 2012-2021 [29] which gives projections of generation capacity out to 2021. The 2020 power system includes approximately 8320 MW of synchronous generation (coal, peat and hydro plant, OCGT's, and CCGT's). In total the All Island system has 72 individual units with two interconnectors to Great Britain (GB) and one pumped storage plant comprised of 4 individual units. Details of the 2020 power system are provided in Figure 4.2. Further details of the system in relation to adequacy and reliability can be found at [29]. The system has 5200 MW of installed wind capacity which meets approximately 40% of annual electricity demand.

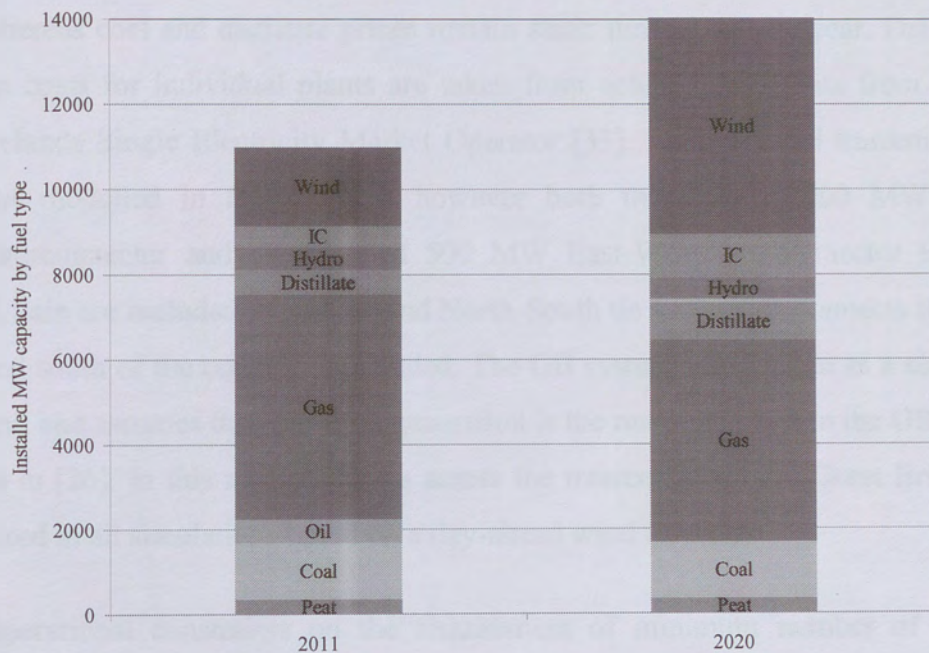


Figure 4.2: Generation portfolio for All Island System 2011 and 2020 [29]

3.2 Data sources and Model set up

The PLEXOS model was populated with individual unit characteristics and technical details such as minimum stable generation, load dependant heat rates, minimum up and down times, ramp rates, start up and shutdown profiles, regulation points and ranges for reserve provision (see section C for detailed

discussion of treatment of reserves). Technical details in relation to these parameters were taken from Irelands Commission for Energy regulation validated PLEXOS market model [26]. Information on the provision of each generation unit to reserve classes is taken from [30] and assumed to be the same for 2020. Annual and peak electricity demand assumptions for the All-Island system are also taken from [29]. Annual demand is estimated to be 41 TWh with a peak of 7.2 MW. The demand profile for 2020 was created in PLEXOS by mapping 2020 demand onto 15 minute demand from 2011 and linearly scaling it. Wind power production data for 2020 is taken from actual 15 minute metered wind generation 2011 [31] and scaled up directly to match 2020 installed wind capacity. All data was quality controlled before use. In periods where wind curtailment was occurring actual forecast data was used. The annual capacity factor for wind data is 31% which typical of an average wind year for Ireland. Fuel and carbon prices are taken from [32]. Seasonal gas prices are assumed whereas coal and distillate prices remain static throughout the year. Daily start-up costs for individual plants are taken from actual market data from SEMO, Irelands Single Electricity Market Operator [33]. Intra-regional transmission is not modelled in this analysis however both the existing 500 MW Moyle Interconnector and the planned 500 MW East-West interconnector to Great Britain are included as well as and North-South tie line which connects the north and south of the country is included. The GB system is modelled as a single gas unit and assumes that gas-fired generation is the marginal plant in the GB system as in [26]. In this analysis flows across the interconnectors to Great Britain are fixed in all simulations based on a day-ahead wind forecast.

Operational constraints on the requirement of minimum number of thermal generators online are assumed based on recent work by Eirgrid. A constraint restricting the amount of wind generation in the model in a given period is enforced based on [34]: This requirement states that the amount of wind generated, when added to imports, must not exceed 70% of the sum of system load and exports, ie $(Wind\ Gen + Import) / (System\ Load + Export) \leq 0.7$. Pumped storage is modelled as having 3 distinct phases which are as follows: 1) Pumping mode: the plant has 4 fixed speed pumps which draw a load of 71.5 MW each and can provide this full quantity to all reserve. 2) In spin mode each unit can provide 5 MW of power but no more than 2 units can at be in spin mode at any

one time. 3) In generation mode each unit can provide a minimum of 40 MW and up to a maximum of 73 MW. As all units share a common penstock they are not allowed to generate and pump at the same time. Water in the storage has no 'value' other than the value of the thermal generation it can replace. Thus the optimization will use all the water possible to minimize thermal costs. The use of the '*look ahead*' period ensures the reservoir does not empty at the end of each simulation step by providing a natural shadow price equal to the dual variable of the water balance constraint. This represents the future value of water held in the storage and is used to initialize neighbouring simulation steps.

3.3 Treatment of reserves

In the grid code of Ireland a number of reserve categories are defined [35]. Operating reserve, as defined in the Irish system, is divided into four parts: primary, secondary, tertiary 1 and tertiary 2. An overview of Irelands operational reserve requirement is provided and contrasted to other systems in [36]. In this model set up operating reserve requirement for 2020 are assumed to be the same as 2011 with minor additional reserve requirement due to wind as per [37]. The primary driver for the requirement for operating reserve is the size of the largest in-feed which is the East-West interconnector (500 MW). Within the model the demand for operational reserve is calculated dynamically and is determined to be 75% of the All-island largest in-feed as defined by [35]. A minimum requirement for each operational reserve class is also fixed. Operational reserve can only be supplied by units that are fully synchronized (i.e. they cannot contribute to reserve while on a start profile). Certain units can only provide reserve above a regulation point which is 50% of their maximum export capacity as per [35]. 50 MW of static reserve is provided by interruptible load and 100 MW of static reserve is held on the interconnectors. Replacement reserve is modelled by keeping enough peaking units offline to cover requirements. The value of reserve not met is fixed lower than the value of demand not met so the model has the option to draw down reserve to ensure demand is met.

3.4 Perfect foresight assumptions

In deterministic mode PLEXOS assumes perfect foresight of wind production, system demand and forced outages within the optimisation period but not in the look ahead period⁴. This means the optimisation engine can take ‘pre-emptive’ action before a forced outage or a sudden drop in wind power production occurs as the optimiser can ‘see’ perfectly what is going to occur a number of hours into the future—the look ahead period excepted. To re-create conditions of actual power system operation a number of simulations have been run where the model is firstly not allowed the perfect foresight assumption for forced outages and secondly for wind power production. This is done as follows and closely simulates the operation of actual power systems. This is shown in Figure 4.3. The configuration below is described for optimisation time steps of 1 hour; however the same configuration applies to the 30 minute and 15 minute simulations.

Firstly a day-ahead unit commitment is produced for all units based either on the day-ahead wind forecast or the actual wind production. The day-ahead unit commitment has knowledge of actual planned maintenance but no knowledge of forced outages.

Secondly a ‘real-time’ model configuration is run, where the unit commitment of large units from the day-ahead plan is ‘locked in’. In this real-time run PLEXOS is configured so it cannot see forced outages until they actually occur. This is done by limiting the actual optimisation length to one period and allowing a longer look-ahead period in which PLEXOS cannot see outages. In this way the system must react within the optimisation period to the forced outage.

⁴ A user-definable simulation setting allowed forced outages to be anticipated in the look-ahead period, but this setting is ‘off’ by default.

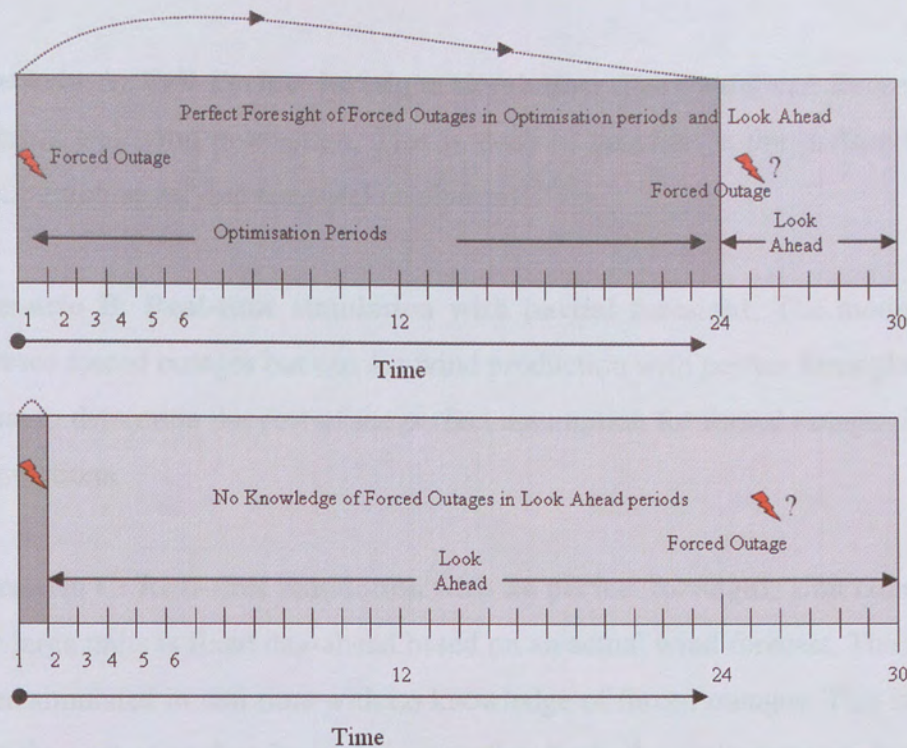


Figure 4.3: Optimisation periods and intervals for both the perfect foresight and real-time model configurations. Upper sketch assumes perfect foresight for the 24 hour period of the day. Lower sketch assumes perfect foresight for one period only.

There is an important assumption that must be considered when interpreting results of this analysis. The model assumes that the unit that is forced out will come back online before the end of the market day and does not recommit the full system. It is allowed however to recommit certain flexible CCGT units but it will generally try to follow the day ahead commitment as closely as possible. This deviates for the actual systems operation. In a real system if a large unit failed, the system operator would have information at hand on the extent of the outage and would thus make a decision on whether to recommit the system if the unit was predicted to be out for an extended period. The implication of this assumption is that the results presented here may overstate the actual costs of the perfect foresight assumption on forced outages.

4.0 Results

The detailed PLEXOS model of the 2020 All Island power system was run at 15 minute, 30 minute and 60 minute resolution with configurations as per Table 4.1 and for all scenarios listed below.

Scenario A: Full Perfect foresight simulation: The model can foresee forced outages and wind production. This is done to benchmark the perfect foresight assumption at varying temporal resolutions.

Scenario B: Real-time simulation with partial foresight: The model cannot foresee forced outages but can see wind production with perfect foresight. This is done to determine the cost of the perfect assumption for forced outages in model simulations.

Scenario C: Real-time simulation with no perfect foresight: Unit commitment for large units is fixed day-ahead based on an actual wind forecast. The model is then simulated in real time with no knowledge of forced outages. This is done to test the cost of perfect foresight assumption for both wind power production and forced outages.

Table 4.1: Optimisation configuration for each phase

Phase	Temporal Resolution	Optimisation Period	Optimisation Period 'Look ahead'	Optimisation Horizon
1	15 Minutes	1 day	6 hours	1 year
2	30 Minutes	1 day	6 hours	1 year
3	60 minutes	1 day	6hours	1 year

4.1 Full Perfect foresight simulation

Results in terms of total generation costs are presented in Table 4.2 for the full perfect foresight scenario at varying temporal resolutions. Total generation costs include full fuel consumption and start-up costs for the system. The full running time and problem size is also shown for each resolution. All simulations were executed on a workstation with Intel Xeon 3.0-GHz processors with 12 GB of RAM running Microsoft Windows 7 64 bit.

Table 4.2: Total generation costs for each optimisation configuration

	Total AI Generation Cost (€000)	Generation Cost Only (€000)	Full Simulation Run time (hrs)	Daily problem size (columns* rows* integers)
15 minute	1,668,862	1,570,885	26	54873*94027*6519
30 minute	1,661,086	1,575,186	15	28594*48394*3484
60 minute	1,653,853	1,581,601	8	15650*26245*1772

It can be seen that total annual generation costs are higher for the higher resolution simulations. The increase in cost is due to the models ability to capture more variability at higher temporal resolutions and also a better portrayal of the flexibility/inflexibility of thermal units is achieved at higher temporal resolutions. In general across all simulations the operation of baseload coal and peat generation units is not affected by simulation resolution. However as simulation resolution increases older and less flexible baseload CCGT units are unable to ramp sufficiently to meet changes in demand and newer more flexible mid merit CCGT units are cycled more frequently to respond to changes in load. At higher temporal resolution simulations start profiles of power plant become increasingly important. As units are not allowed to block load, the number of start ups and related costs for more flexible units increase. Total annual generation for thermal generation is shown in Table 4.3. Table 4.4 shows the number of start ups of units for each temporal resolution simulation for the year. The number of starts for pumped storage and open cycle gas units increases dramatically as simulation temporal resolution increases. This is an important insight in terms of the assessment of power system flexibility. These flexible resources are shown to be increasingly important as more variability in wind and demand and lack of flexibility in thermal units is captured by the model.

Table 4.3: Total annual generation (GWh)

	60 Minute Simulation	30 Minute Simulation	15 Minute Simulation
Base			
Load Gas	3825	3814	2817
Mid Merit			
Gas	13724	13734	14622
GAS			
OCGT	252	254	323
Coal	7975	7976	7984
Peat	2614	2616	2598
PHES	467	475	502

Table 4.4: Total Annual Number of start ups

	60 Minute Simulation	30 Minute Simulation	15 Minute Simulation
Base Load			
Gas	492	489	348
Mid Merit			
Gas	330	323	365
GAS OCGT	1245	1272	1433
Coal	155	155	161
Peat	133	133	133
PHES	4240	6479	10793

At 30-minute resolution simulations and even more so in 15-minute resolution simulations ramp rates become binding. This is evident in the development of shadow prices on the ramp constraints of units within the model. Figure 4.4 shows the annual average ramping up and down intensity for each category of generation. Ramping intensity is defined as the total sum of ramping throughout the year for all units in that category divided by the total ramping time for those units. The figure also shows the maximum average value for each category.

Midmerit gas units are ramped up and down significantly more in the higher resolution simulations.

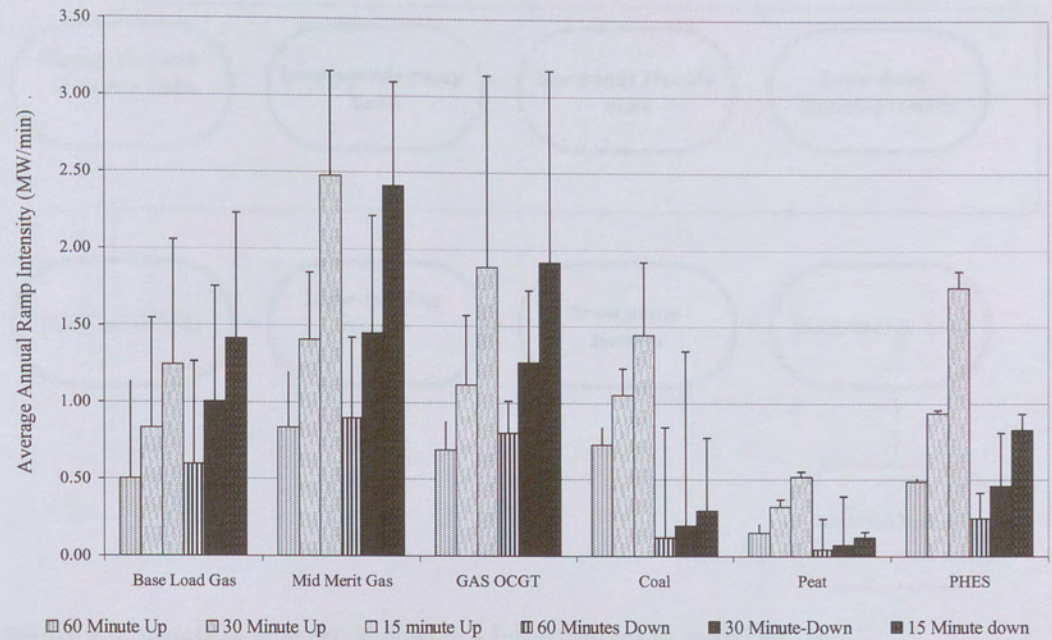


Figure 4.4: Annual average ramping intensity (up and down) for each simulation configuration for each generation type.

Finally there is a slight increase in annual wind curtailment of 0.2% from the 60 minute simulation to the 15 minute simulation.

4.2 Real-time simulation with partial foresight

In this scenario all models have perfect knowledge of wind production but cannot foresee forced outages of thermal units. The unit commitment of large units is based on a day-ahead plan with knowledge of maintenance but no knowledge of forced outages. When a forced outage occurs in the real-time model simulations, the model can react in a number of ways, depending on which is most economical at the time as shown in the sequence in Figure 4.5.

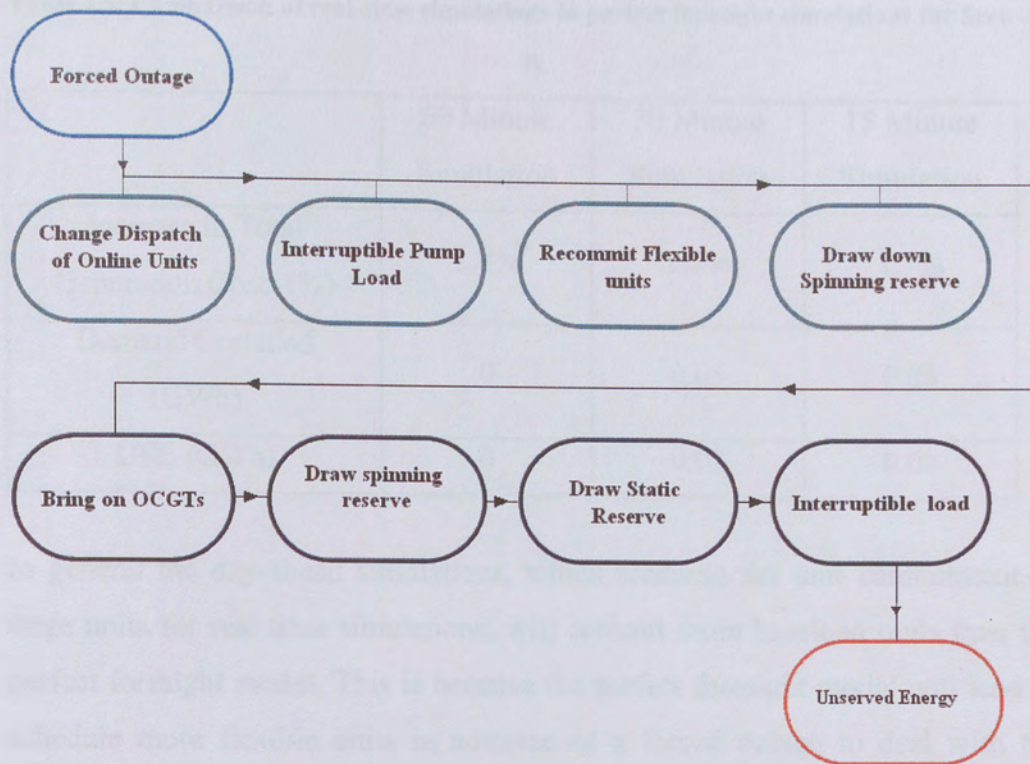


Figure 4.5: Sequence of events following a forced outage in model set up.

Initially the model can change the dispatch of units already online or choose not to de-commit certain flexible units and thus deviate from the day-ahead unit commitment. It may also find it more economical to stop pump storage from pumping. As there is a penalty on reserve not being met the model will always try and meet reserve requirement. It will however allow brief shortages if it is more economical than bringing on extra units. At all cost the model will try to meet demand as the penalty for unserved energy is very high. Table 4.5 shows the increase in annual total system costs relative to the perfect foresight assumption where the model has full knowledge of the same unforced outages for the same temporal resolution. Table 4.5 also shows levels of unserved energy and curtailed demand over the year.

Table 4.5: Comparison of real-time simulations to perfect foresight simulations for Scenario

B.

	60 Minute Simulation	30 Minute Simulation	15 Minute Simulation
Increase in Total Generation Costs (%)	1.8%	1.7%	1.7%
Demand Curtailed (GWh)	0	0.05	0.08
USE (GWh)	0	0.02	0.03

In general the day-ahead simulations, which schedule the unit commitment of large units for real time simulations, will commit more baseload units than the perfect foresight model. This is because the perfect foresight model will tend to schedule more flexible units in advance of a forced outage to deal with the outage in an economically optimal manner. The real-time simulations cannot take pre-emptive action and therefore have to manage the outages by adjusting the dispatch or commitment of units in real time. This is shown in Figure 4.6 and Figure 4.7 for a sample day where a 380 MW CCGT unit fails unexpectedly for a 12 hour period. Note for clarity only generation categories that are affected by the outage are shown. The outage period is shown in the dark rectangle.

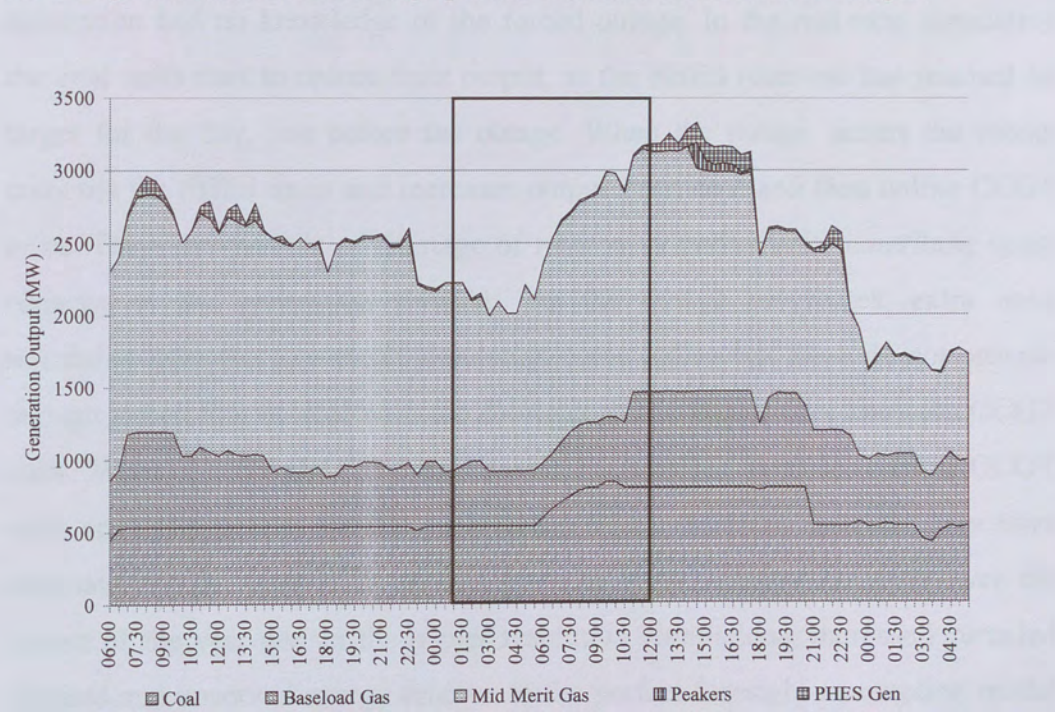


Figure 4.6: Sample period of outage for perfect foresight model simulation

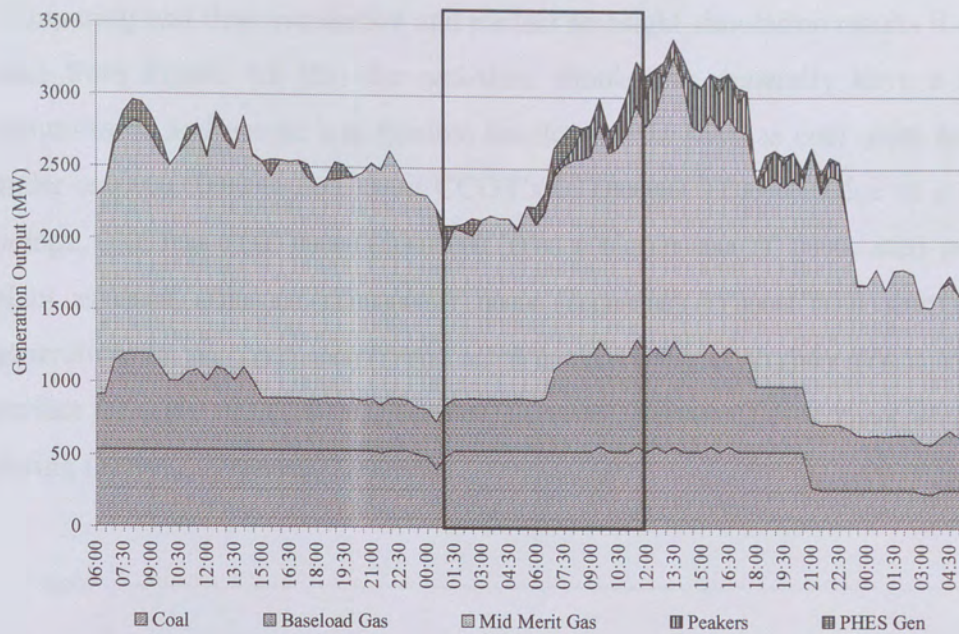


Figure 4.7: Sample period of outage for real-time model simulation.

With the perfect foresight model simulation, the model has one extra CCGT unit already online before the outage occurs and then schedules an extra coal unit to come online soon after the outage. The perfect foresight model can then deal with the outage by increasing the generation of these units. In the real-time model simulation these specific units are scheduled to be offline as the day-ahead simulation had no knowledge of the forced outage. In the real-time simulation the coal units start to reduce their output, as the PHES reservoir has reached its target for the day, just before the outage. When the outage occurs the model commits the PHES units and increases output from coal and then online CCGT units. There are periods of shortage of reserve as online units contribute spare capacity to the generation shortfall. As the outage progresses, extra units scheduled from the day-ahead simulation come online but these do not provide enough generation to deal with the shortage so the model then commits OCGT units. When the failed CCGT unit comes back online at midday extra OCGT units are again needed for the peak as the PHES reservoir does not now have adequate energy reserve. In all this leads to higher generation costs over the course of the year and in the higher resolution simulations, increased curtailed demand and unserved energy relative to the perfect foresight assumption model simulations.

Comparing real-time simulation and perfect foresight simulation results it can be seen from Figure 4.8 that the real-time simulations generally have a higher commitment and use of less flexible baseload plant such as coal units and will under-commit flexible mid-merit CCGT's in absence of knowledge of a forced outage. The real-time simulation will have a higher use of quick start peaking plant as these units are committed more frequently to deal with shortfalls in generation. In all cases examined PHES generation was slightly lower than the perfect foresight model simulations as pumping was interrupted more frequently during the year to reduce demand.

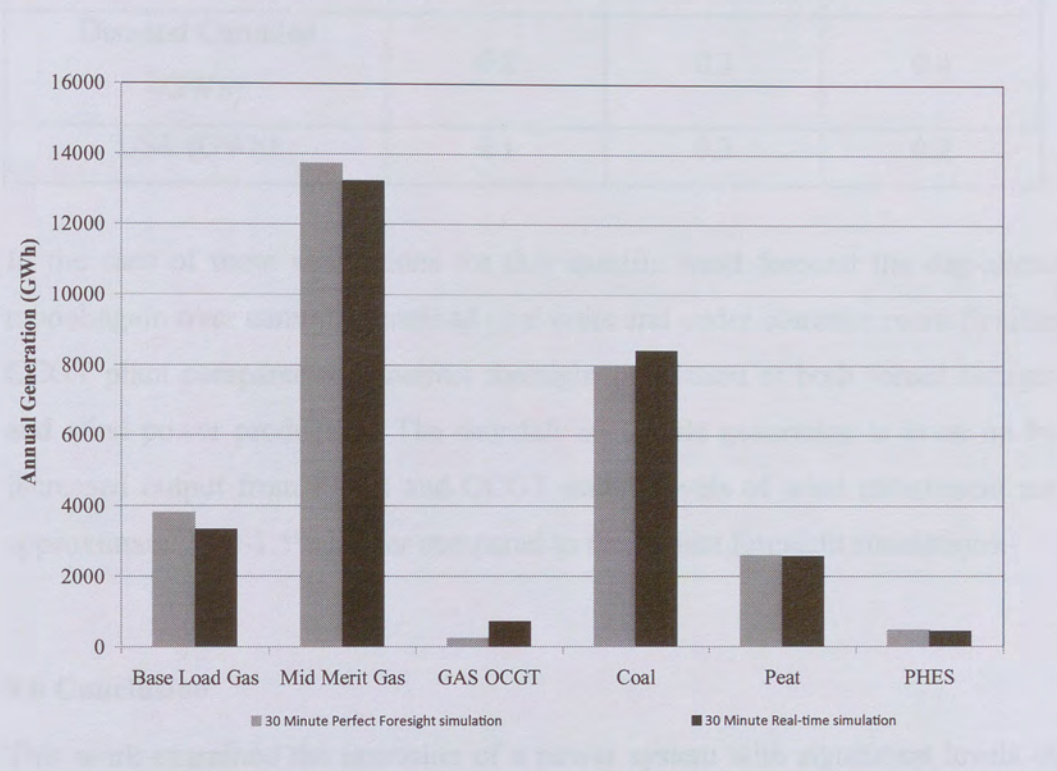


Figure 4.8: Annual generation for 30 minute simulations for perfect foresight and real-time simulations.

4.3 Real-time simulation with no perfect foresight of wind and outages

In this final scenario the unit commitment for large thermal plant are determined based on a day-ahead schedule with a day-ahead forecast of wind power production and no knowledge of forced outages (as in section B). The wind forecast is based on a year of actual day-ahead concurrent forecasts from Eirgrid. The real-time simulations were run with the actual wind power production and same forced outages as the perfect foresight simulations. The increase in total annual generation cost relative to the perfect foresight assumption for the same

temporal resolution is shown in Table 4.6 and reflects the cost increases associated with the absence of perfect wind power forecasting.

Table 4.6: Comparison of real-time simulations to perfect foresight simulations for Scenario C

	60 Minute Simulation	30 Minute Simulation	15 Minute Simulation
Increase in Total Generation Costs (%)	2.8	2.8	2.7
Demand Curtailed (GWh)	0.2	0.3	0.4
USE (GWh)	0.1	0.2	0.2

In the case of these simulations for this specific wind forecast the day-ahead model again over commits baseload coal units and under commits more flexible CCGT plant compared to a perfect foresight simulation of both forced outages and wind power production. The shortfall in flexible generation is made up by increased output from PHES and OCGT units. Levels of wind curtailment are approximately 1.2-1.5% higher compared to the perfect foresight simulations.

5.0 Conclusion

This work examined the operation of a power system with significant levels of wind generation under a number of technical modelling assumptions relating to temporal resolution and assumptions on perfect foresight of outages and wind. It is shown that increased model temporal resolution is required to capture important aspects of power system flexibility such as inflexibility of thermal plant during start-up and ramping rates of plant. The associated increase in total system generation costs for a 15 minute resolution simulation relative to an hourly perfect foresight simulation was approximately 0.9%. The cost of the perfect foresight assumption in relation to forced outages and wind power production were also examined and shown to be approximately 1.7%-2.8% greater than the perfect foresight assumption for each respective simulation temporal resolution.

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Chapter 5: Derivation of Intertemporal Targets for Large Pumped Hydro Energy Storage with Stochastic Optimisation

Abstract-this paper models large pumped hydro energy storage in a future power system where variable generation, primarily in the form of wind generation is the dominant source of power generation. The research question posed is how to formulate day-ahead and week-ahead reservoir targets for pumped hydro energy storage in the context of wind forecast uncertainty. A methodology in the form of a storage management strategy is presented that uses historic wind production data, wind forecasts and stochastic optimisation methods to derive intertemporal targets for large pumped hydro energy storage that reduce overall system costs when compared to targets derived using a conventional method.

1.0 Introduction

The extent to which any power system can accommodate variations in electrical supply is governed to a large degree by its flexibility. Pumped Hydro Energy Storage (PHES) is often cited as a potential technical facilitator for large scale wind energy integration due to its inherent flexibility, quick start characteristics and its ability to store excess energy [1]. During the next 8 years, over 7 GW of PHES may be added to the European network [2] with a predicted doubling of PHES capacity within Europe by 2050 [3] indicating a renewed interest in this technology. As wind penetration levels increase, curtailment, in addition to other power system issues, is likely to become more prominent [4]. By storing electrical energy when renewable output is high and the demand low, and generating when renewable output is low and the demand high, the curtailment of RE will be reduced, and the baseload units on the system will operate more efficiently [5]-[6]

In this paper, the modelling of large PHES in a power system with significant wind penetration is addressed and in particular the challenges associated with the determination of end of day and end of week targets for large energy storages in an environment with wind forecast uncertainty. Two important background

assumptions for this work are 1): The problem is addressed from a Transmission System Operator (TSO) point of view. The TSO is mandated with the safe, secure, reliable, economical and efficient operation of the transmission and power system. 2) Large closed-loop PHES is considered, this means that the energy capacity of the storage is large. A number of these large systems are proposed worldwide [7]-[8].

Section II provides a review of current modelling techniques while section III presents the modelling methodology used in this analysis and the test system. Section IV presents the results and Section V draws conclusions.

2.0 Pumped Hydro Energy Storage Modelling

In contrast with thermal generation, whose operation is decoupled in time (except large baseload plant with high start-up/shutdown cost), PHES systems are coupled in time that is, a decision today affects operating costs in the future. For example the decision to release or hold water today may inhibit or enhance the ability to capture and store excess generation in the future. Therefore modelling of PHES systems should take into consideration wind power forecasts and thermal unit commitments as these interdependencies are fundamental to actual system operation.

A large body of work is available on the optimisation of hydro-thermal systems [9]-[11] and stochastic optimisation has been applied to hydro thermal problems in the past [12]-[14]. The work presented in this paper is similar in concept however stochastic optimisation is applied to the operation of a pumped storage plant in a power system with significant wind energy installation and as such historic wind power production profiles are used in place of historic hydro inflows to determine week-ahead targets for the storage.

Previous work in this area has generally focussed on the stochastic modelling and joint optimisation of wind and hydro systems as in [15] and [16]. A number of papers have investigated the operation of PHES and large PHES in power systems with significant amount of wind energy [17]-[21] where PHES is modelled deterministically. In operational mode PHES can either operate on a fixed cycle which is common [22] (i.e. refill the reservoir at the end of each day,

week etc) or on a free cycle, similar to [21] where the value of storage is based on the marginal value of water held in the storage. These techniques may not be appropriate for larger PHES in systems with significant renewable generation for the following reasons: A fixed cycle takes no account of wind generation at the end of the cycle and, as shown later, may not exploit the storage to its full potential. Secondly in modelling a ‘free cycle mode’ a large storage will not attain its bounds within a short optimisation period (for example 1-2 days) and the reservoir may empty within the first few simulation steps. Therefore for larger PHES systems the entire power system has to be optimised over longer periods such a week, month or year. The question raised in this paper is how to deal with the inherent uncertainty in longer optimisation periods in power systems with significant wind power production. In this paper therefore we are concerned with the derivation of robust end of day and end of week targets for the storage. PHES is free to ‘react’ to actual wind power production during the day, however it is constrained to finish each day at a predefined targets as described in detail in Section III. It is the derivation of these daily and weekly targets that is the core goal of this paper.

3.0 Approach and Methodology

The methodology presented here specifically deals with closed-loop PHES (i.e. no hydro inflow) in power systems with high wind penetration. In this paper we built a PLEXOS model of a test power system and used it to solve medium and short-term PHES constraints in two-stages to derive intertemporal targets for storage. Wind power production is the only stochastic variable. Demand is assumed to be known with certainty. Weekly end storage levels are derived using stochastic optimisation and historic wind data. Daily end storage levels are derived using stochastic optimisation and wind forecasts. Stochastic optimisation is only applied to storage end levels. A detailed methodology is provided in Section C below. Firstly the test system is presented in section A and the modelling software is detailed in section B.

3.1 Test system

The test system presented, while satisfying security of supply standards, is not intended to be an optimal portfolio, and is merely used as a test bench for

modelling techniques. The test system modelled is based on a potential portfolio for the All-Island system (AI) as in report [23]. Electricity demand for the island of Ireland in 2035 is assumed to be approximately 42 TWh with a peak of 7.4 GW. Generation units and unit capacity used are detailed in Table 5.1. The system has one 500 MW PHES with 10 GWh of storage. One year of half hourly regional wind farm capacity factors (in time series format) from Ireland for 2008 were scaled up to match 2035 wind capacity values. This analysis does not consider detailed modelling of transmission issues, frequency and inertia issues of voltage stability. In this analysis however instantaneous wind penetration levels in the AI system are limited to 70% [24]. Pumped storage is modelled as 2 individual 250 MW generating and pumping units with a minimum stable generation level of 40 MW on each unit. The units are not allowed to pump and generate at the same time. Spinning reserve and replacement reserve are modelled. It is assumed that each PHES unit can contribute up to 100 MW to spinning reserve in generation mode and a full 250 MW in pumping mode. The demand for spinning reserve is set by the largest unit online with allowance for wind capacity as per [25].

Table 5.1: Test portfolio characteristics

Type of Generation	Capacity AI (GW)	No of Units	Max Capacity of Units (MW)	Ramp rates MW/Min
Wind	8.4	-	-	-
CCGT	5.4	12	450	10
OCGT	2.0	20	100	6
Interconnector to Great Britain	2.0	4	500	-
Pumped Storage	0.5	2	250	20

3.2 PLEXOS Model

The software used throughout this work to solve the unit commitment and dispatch problem is PLEXOS [26]. Full details of model equations are shown in appendix. PLEXOS is a power systems modelling tool used for electricity market modelling and planning worldwide [26]-[30] and recently in wind integration studies [31] and energy storage studies [32]. PLEXOS is commercial modelling tool but is free for non-commercial research to academic institutions. This software was chosen because it is a flexible platform allowing user defined constraints. It is not a 'black box' and the users can browse and verify the equations of the problem via a diagnostic tool. The PLEXOS modelling tool is used by the Commission for Energy Regulation (CER) in Ireland to validate Ireland's Single Electricity market and has a history of use in Ireland [33].

In this set-up PLEXOS co-optimises hydro, thermal, renewable, and reserve classes and no heuristic or sequential approach is taken. Modelling is carried out using mixed integer linear programming that aims to minimize an objective function subject to the expected cost of electricity dispatch and a number of constraints. The objective function of the model includes operational costs, consisting of fuel costs and carbon costs, start up costs consisting of a fuel offtake at start-up and a cost, penalty cost for unserved energy and a penalty cost for not meeting reserve requirements. Fuel consumption is calculated using piecewise linear function as in [34]. System level constraints consist of an energy balance equation ensuring supply (net pumping demand) meets regional demand at each period. Water balance equations ensure water flow within the pumped storage units is conserved and tracked. Constraints on unit operation include minimum and maximum generation, maximum and minimum up and down time and ramp up and down rates. These are provided in more detail in Appendix A. Constraints in relation to each unit's ability to provide reserve are also included. Ancillary services are optimized using techniques set out in [34]. In chronological mode PLEXOS solves for each period and maintains consistency across the full problem horizon. Temporal resolutions settings in relation to solving are user defined and flexible. To avoid issues with intertemporal constraints at the simulation step boundaries a '*look ahead*' period is used. Look ahead means that the optimiser is given information about what happens ahead

of the period of optimisation and solves for this full period (i.e. simulation period + look ahead period) however only results for the simulation period are kept. In stochastic mode PLEXOS uses two-stage stochastic optimisation. The classic two stage stochastic linear problem with recourse is described in [35].

In this analysis stochastic settings specifically force non-anticipativity on the PHES volume levels only to derive weekly and daily targets. The model is free to derive intra day levels. This means daily and weekly end volume levels for the PHES are identical for all scenarios of wind power production for these periods. Non anticipativity is not a hard constraint but there is a penalty for not meeting it in the objective function (see appendix). Softening this constraint allows the model to deviate from a unique volume in case of unserved energy. A detailed description of the model formulation in linear programming format is provided in Appendix A. Note the same formulation is used in all steps of this process; time and optimisation intervals change as per Table 5.2 described in the next section.

3.3 Proposed Methodology

A two step methodology or strategy for operation of the PHES is proposed which aims firstly to derive weekly and secondly daily end level storage targets for a large PHES from a system operator point of view. PHES is free to operate in an optimal fashion within the day. The methodology also provides a technique for the ‘bridging’ of the daily and weekly targets. The targets are derived from reservoir end volume levels (GWh) during model simulations of the complete power system. The decomposition of the targets from weekly to daily targets is based on wind power forecasts. The modelling process also considers forced outages, maintenance and ancillary services for all plant. Note non-anticipativity is forced on storage end volumes only and not on any other units.

Step one of the process for the methodology uses low resolution optimisation interval lengths over long optimisation periods of time, while step two uses high resolution optimisation interval lengths over shorter optimisation periods of time. All model runs are for a one year optimisation horizon as detailed in Table 5.2 and Figure 5.1.

Table 5.2: Optimisation configuration for each phase

Phase	Optimisation Interval	Optimisation Period	Optimisation Period ‘Look ahead’	Optimisation Horizon
Step 1- Weekly targets: low resolution	6 hrs	1 year	0 days	1 year
Step 2 Daily targets: high resolution	2 hrs	1 day	6 days	1 year

3.3.1 Stochastic Method

Figure 5.1 provides a schematic overview of the two step approach for the stochastic method.

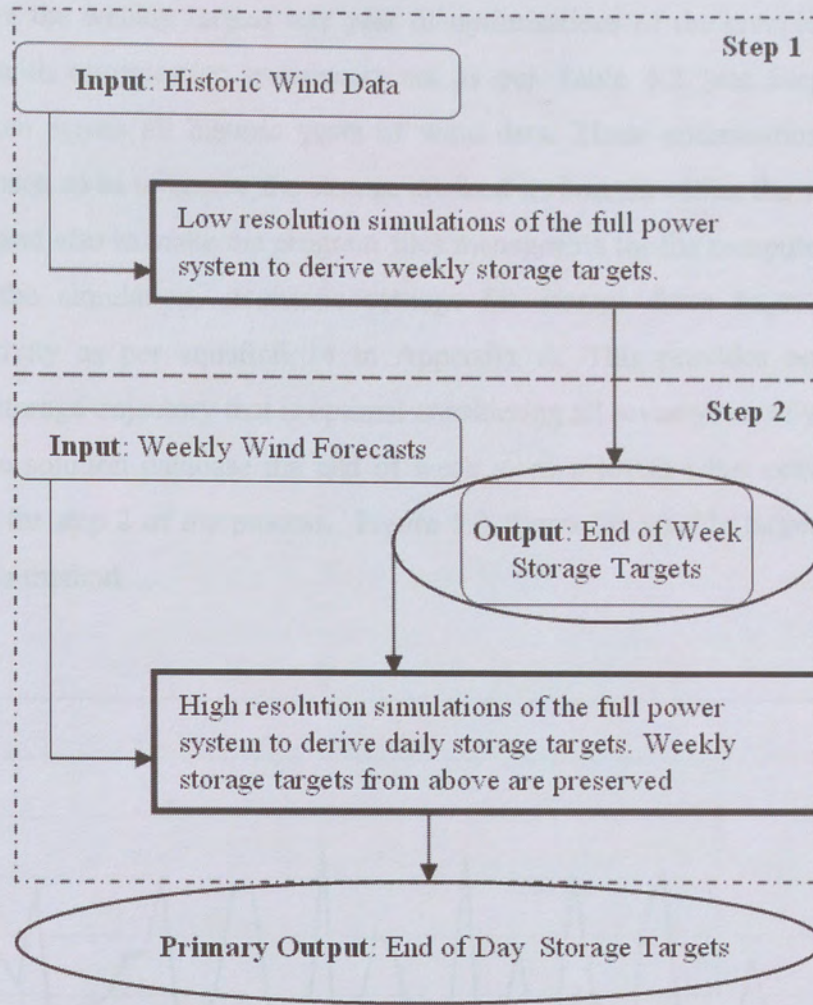


Figure 5.1: Schematic of two stage approach to development of targets for PHES in high wind systems.

Step one of the process aims to derive weekly targets (end of week) for the PHES storage. For large PHES storages, targets have to be derived in advance of knowing what the wind power production will be in the future. In reality, long range wind forecasts for periods up to a year are not available so in this analysis actual historic wind production data for the AI System is used to develop hourly annual profiles of wind power in time series format. 7 years of data are used as this was the full wind data set available. The data was quality controlled and checked against local meteorological stations for consistency. It is assumed that each one of these 7 years of wind data represents a possible scenario of wind production for the target year. The scenarios are equally weighted. In this analysis discrete scenarios are used and it is assumed that the range of actual historic wind data presented captures and reflects the uncertainty inherent in annual wind production.

To derive the weekly targets one year of optimisations of the complete power system with optimisation parameters set as per Table 5.2 (see Step 1) was undertaken across all historic years of wind data. These optimisation settings were chosen so as to ensure the storage attained its bounds within the simulation horizon and also to make the program files manageable for the computer system. Within the simulation, stochastic settings for storage force trajectory non-anticipativity as per equation 14 in Appendix A. This provides one unique weekly storage trajectory that is optimal considering all seven years of wind data. From the solution database the end of week storage levels were extracted and retained for step 2 of the process. Figure 5.2 shows the weekly targets derived using this method.

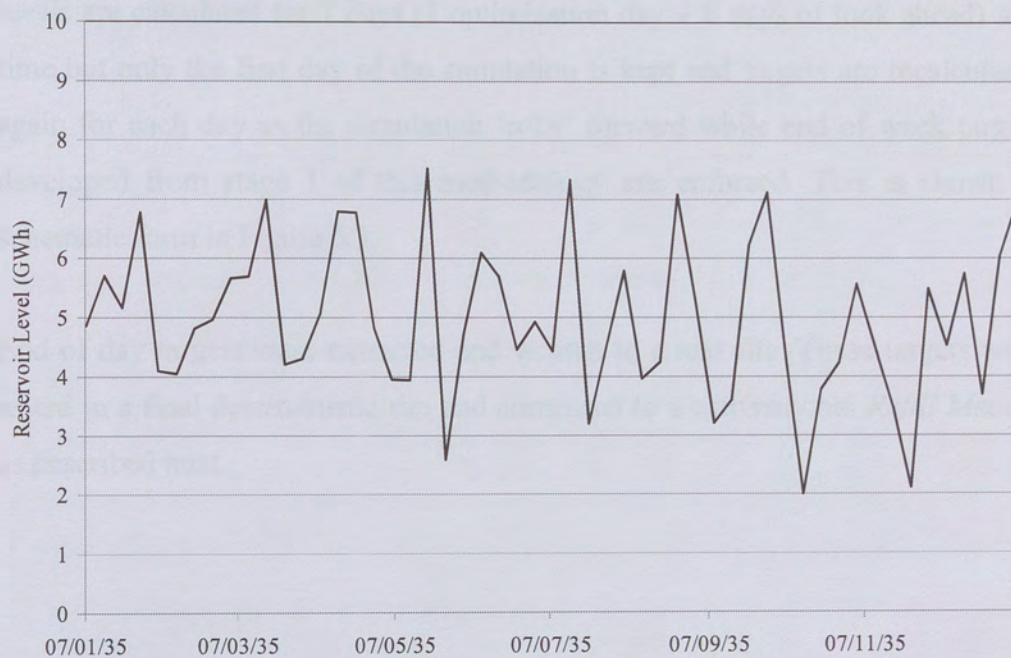


Figure 5.2: Weekly target for PHES derived using stochastic method

Step two of the methodology aims to derive daily targets for PHES while preserving the weekly targets determined in step one. Daily storage targets should be set so as to give PHES adequate flexibility to deal with daily variability in the power system but also ensure that PHES finishes each day in a position to manage the next day's and number of day's variability and unpredictability of wind.

Daily storage targets for each day of the week are developed in the context of weekly wind power forecasts. In this analysis 3 individual 7 day wind energy forecasts are used. The forecast error is simulated by Auto Regressive Moving Average (ARMA) series similar to [36] that are established by tuning the statistical characteristics to those of actual 5 day forecasts supplied by Eirgrid.

In Step 2 the full power system was again optimised forcing the end volume levels for the pumped storage reservoir to be the same across the full range of wind forecast scenarios for the end of each day while also ‘hitting’ the discrete end of week targets as developed in step 1. As per Table 5.2 a year of daily optimisations with a 6 day look ahead is used. This ensures the optimisation can ‘see’ the end of week storage target and rolls forward towards it. End volume levels are calculated for 7 days (1 optimisation day + 6 days of look ahead) at a time but only the first day of the simulation is kept and targets are recalculated again for each day as the simulation ‘rolls’ forward while end of week targets developed from stage 1 of this methodology are enforced. This is shown in schematic form in Figure 5.3.

End of day targets were extracted and written to a text file. These targets were tested in a final deterministic run and compared to a conventional *Refill Method* as described next.

5.3.3 Weekly Refill Method

A simple weekly ‘Refill’ method is also put forward as a more conservative approach. This method is put forward as simply storage optimisation targets are calculated on a weekly basis [21]. In this method the reservoir is simply refilled to the full level at the end of each week. End of day storage targets are set as 0.95 of the weekly target. This is done to ensure that the reservoir is not overfilled due to forecast errors. The weekly target is calculated as the difference between the weekly wind energy forecast and the weekly demand. The weekly target is then divided by the weekly storage capacity to give the weekly refill target.

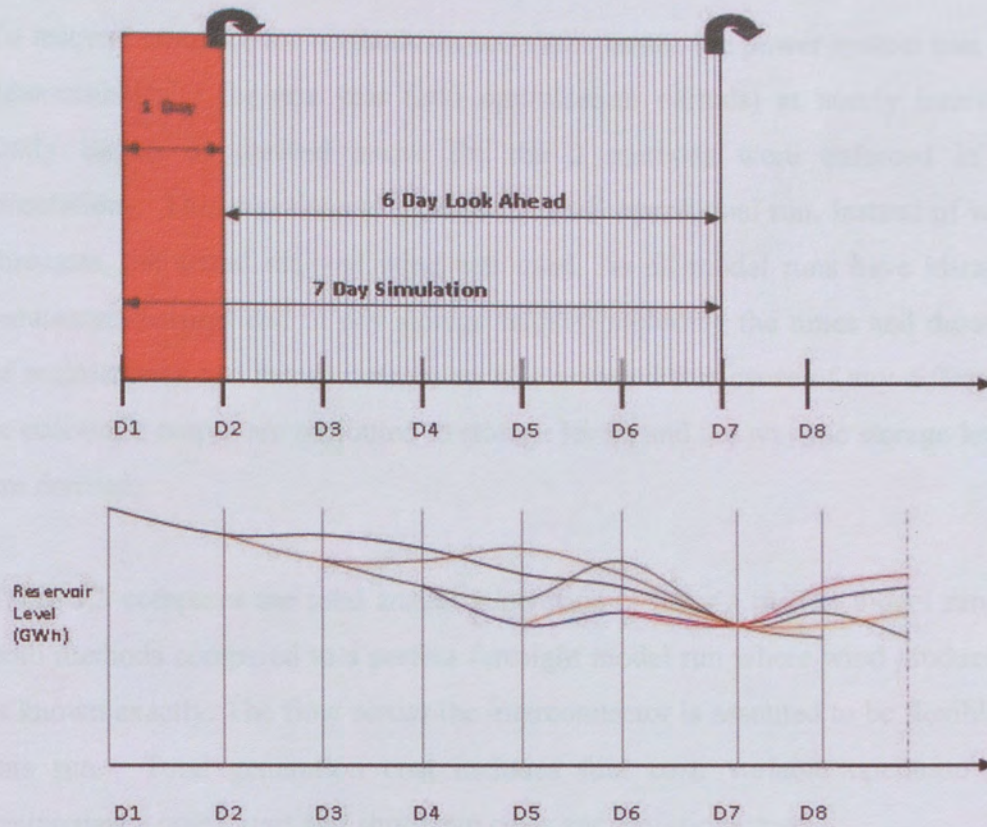


Figure 5.3: Schematic of ‘look ahead’ period on top with rolling reservoir levels on bottom. X-axis is days of simulation.

All simulations were executed on a workstation with an Intel Xeon 3.0-GHz processors with 12 GB of RAM running Microsoft Windows 7 with 64 bit and the Xpress MP MIP [37] solver with a relative optimality criterion of 0.2%. The longest stochastic simulation was 27 hours

3.3.2 Weekly Refill Method

A simple weekly ‘*Refill*’ method is also put forward as a means for comparison. This method is put forward as many storage operators balance large reservoirs on a weekly basis [22]. In this method the reservoir is simply returned to its full level at the end of each week. End of day storage targets are set as the simple average of individual deterministic simulations of each day ahead wind forecasts.

4.0 Results

To test and compare the methods on economic terms, the power system was run deterministically for one year (365 optimisation periods) at hourly intervals. Daily targets as derived above for the 2 methods were enforced in all simulations. This was done to replicate a ‘real’ operational run. Instead of wind forecasts, the actual realized wind was used. As all model runs have identical parameters (except end of day storage targets) including the times and duration of maintenance and forced outages so it is assumed that cause of any difference in economic output are attributed to storage levels and the way the storage levels are derived.

Table 5.3 compares the total annual generation cost for a market model run for both methods compared to a perfect foresight model run where wind production is known exactly. The flow across the interconnector is assumed to be flexible in this run. Total generation cost includes fuel cost, variable operation and maintenance costs, start and shutdown costs and emissions costs.

Table 5.3: Relative increase in Annual Total system costs relative to perfect foresight case (%)

Stochastic Method	Refill Method
+0.12%	+0.28%

While the difference in % terms is small, the total annual system operation cost for the simulation is high, (approximately 2 billion Euros for this system), thus the annual savings that the stochastic method would provide over the refill strategy are approximately 3.3 million Euro. The stochastic method is a more sophisticated strategy of operation than the conventional strategy; however its implementation cost is not excessive other than the cost of including stochastic programming. All other resource, such as historic wind profiles and wind forecast should be available to a system operator.

Table 5.4 compares the total annual generation for each generation category for a scenario where flow on the interconnector to GB is flexible. Table 5.5 compares the annual generation for each generation category in the AI system for a

scenario where the flow on the interconnector is fixed day ahead based on a wind forecast.

Table 5.4: Annual generation (GWh) for AI units for flexible Interconnector flow scenario

	Refill Method	Stochastic method	Perfect Foresight
OCGT Generators	191	181	170
Pumped Storage Units	435	452	408
CCGT Generators	20138	19967	19919
Renewables	23042	23214	23331
Pump Load	580	602	544
Import to AI	2882	3387	2824
Export from AI	3824	4113	3623
Demand	42285	42486	42485
Wind Curtailment (%)	2.04%	1.31%	0.82%
Total Annual Generation Costs (M €)	€2,104	€2,101	€2,098

Table 5.5: Annual generation (GWh) for ai units for Fixed Interconnector flow scenario

Category	Refill Method	Stochastic method	Perfect Foresight
OCGT Generators	527	365	286
Pumped Storage Units	472	662	584
CCGT Generators	22677	22891	22922
Renewables	21229	21241	21263
Pump Load	630	883	779
Import to AI	2327	2327	2327
Export from AI	4118	4118	4118
Customer Load	42484	42485	42485
Wind Curtailment (%)	9.75%	9.70%	9.61%
Total Annual Generation Costs (M €)	€2,148	€2,146	€2,140

Looking firstly at the flexible IC flow scenario (Table 5.4), it can be seen that when uncertainty is accounted for in wind forecasts the generation level for thermal generation increases relative to a perfect foresight case. Total annual system costs is lowest (as expected) for the perfect foresight however the stochastic method for deriving PHES targets provides lower costs than the refill method. One of the reasons for this is that the stochastic method better exploits interconnector import capacity (imports into the AI are higher for stochastic optimisation) as the storage end level is co-optimized in association with interconnection across all scenarios of wind forecasts leading to better coordination of interconnection and storage strategies. This is not surprising as pumped storage and interconnection have similar flexible characteristics within the power system and should 'compete' closely to provide flexibility. The operation of pumped storage under uncertainty also leads to a higher capacity factor compared to a perfect foresight operation and also reduced wind curtailment when compared to the refill method.

Looking at the scenario when interconnector flow is fixed and is scheduled day ahead (Table 5.5), it is shown again stochastic optimisation of PHES targets provides the lowest increase in costs relative to a perfect foresight determination of PHES targets. When interconnector flows are fixed the magnitude of the savings are greater. This is because the interconnector is no longer allowed to provide the same level of flexibility. In the stochastic method, the capacity factor of the PHES is increased and the model exploits CCGT's more often whereas the refill method uses less CCGT's and calls on OCGT more often thus leading to higher total system costs.

A weekly dispatch of generation for the AI system under a fixed IC flow scenario for both the stochastic method and refill method is shown in Figure 5.4 and Figure 5.5. Imports and exports are the same for both scenarios and are not shown. It can be seen that the daily and weekly targets derived by the stochastic method allow greater flexibility in PHES operation allowing it to pump in the early week when wind generation is high, thus reducing wind curtailment and system costs and also enabling it to generate in the latter part of the week.

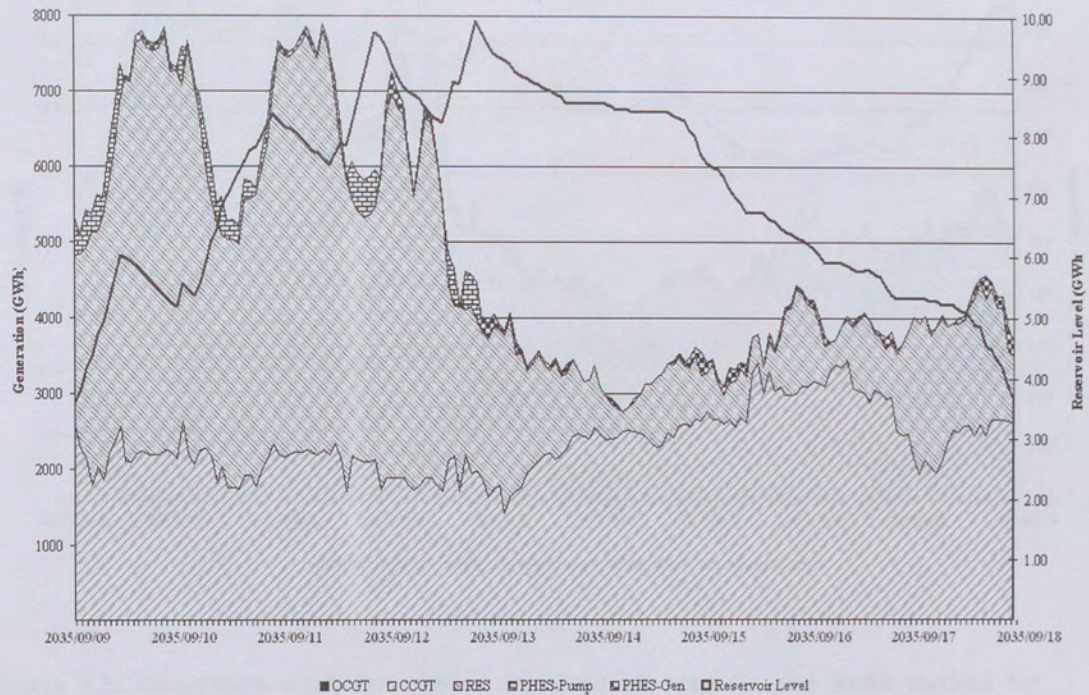


Figure 5.4: Generation stack for a week for fixed IC scenario and stochastic method for deriving PHES targets. Generation levels are shown on left y-axis. Reservoir levels are shown on right y-axis.

Figure 5.5 shows the same week and IC scenario but for the refill method. When the storage reservoir is recycled each week it limits its flexibility of storage to pump in times of high wind production. The storage is also constrained to recycle back to its full level at the end of the week when wind generation is lower. This method would be suitable for thermal generation dominated systems but in this case, where there is significant wind generation it can be seen to be a poor operational strategy.

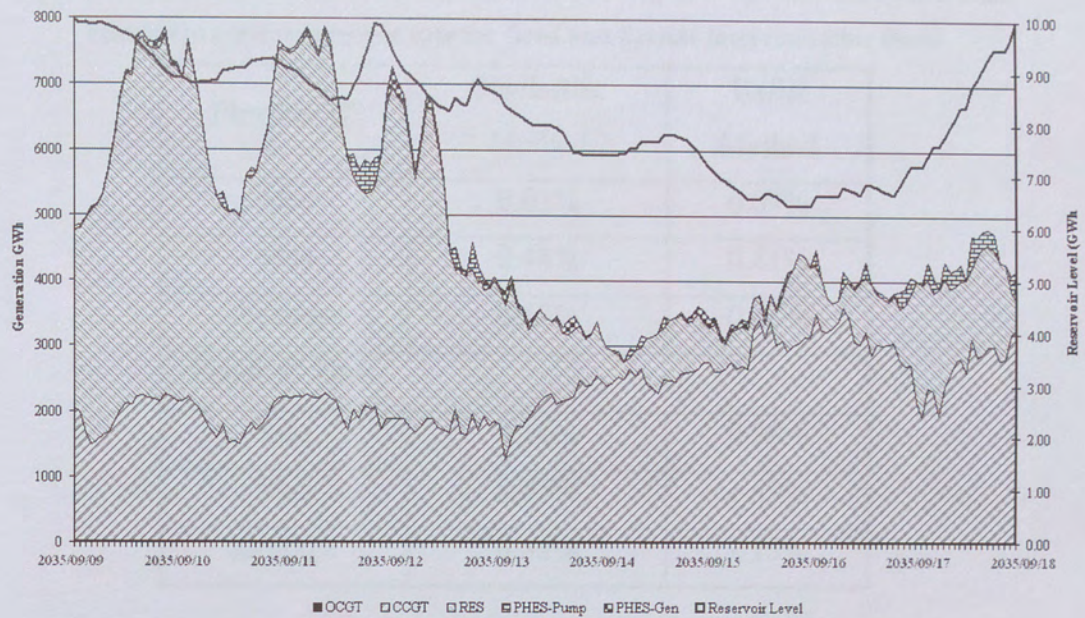


Figure 5.5: Generation stack for a week for fixed IC scenario and Refill method for deriving PHES targets. Generation levels are shown on left y-axis. Reservoir levels are shown on right y-axis

4.1.1 Sensitivity Analysis

To determine the sensitivity of total system costs to a variation in wind power profiles a number of extra simulations were undertaken. The simulations followed the same methodology as describe above, however each of the individual historic 7 years of wind data was used to develop the wind forecasts thus testing the sensitivity of results to each wind profile. Table 5.6 presents results of this analysis.

Table 5.6: sensitivity analysis showing relative increase (%) in annual total system costs relative to perfect foresight case for fixed and flexible interconnector flows

Flexible IC	Stochastic Method	Refill Method
Min	0.03%	0.07%
Max	0.48%	0.81%
Average	0.19%	0.38%
Fixed IC Flow		
Min	0.34%	0.96%
Max	0.97%	1.69%
Average	0.58%	1.15%

Results of the sensitivity analysis show that the stochastic method provides lower total system costs and on average produces costs that are 0.19% higher than a perfect forecast determination of targets compared to a conventional refill method which are on average 0.38% higher for a flexible IC scenario.

5.0 Conclusion

This paper has described and presented a methodology for deriving intertemporal targets for pumped hydro energy storage units that need to be optimised over long periods of time due to their large energy capacity. The methodology allows for the fact that these decisions have to be made in the context of uncertainty and stochastic optimisation is presented as a means of deriving end targets for storage in the context of wind forecast uncertainty. The papers shows that daily and weekly end volumes for PHES derived using stochastic optimisation provide lower total system generation cost than a conventional refill method. This is primarily because (in cases where interconnection scheduling is flexible) the stochastic optimisation method is better able to coordinate the efficient operation of the PHES units and interconnector to provide lowest operational cost. In cases where interconnector flow are scheduled day ahead the stochastic method better exploits cheaper generation such as CCGTs to provide corrective adjustment to deviations from the expected wind forecast.

6.0 Acknowledgements

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Chapter 6: Soft-Linking of a Power Systems Model to an Energy Systems Model

Abstract: In this chapter a soft-linking methodology that employs detailed simulation outputs from a dedicated power systems model to gain insights and understanding of the generation electricity plant portfolio results for the electricity sector from a separate energy systems model is presented. The methodology is applied and results are discussed. The motivation for this soft-linking is to provide a transfer of information from the power systems model strong points to the energy systems model and use this information to improve and develop understanding of energy systems model results. Part of this motivation is derived from a view that one specific energy modelling tool cannot address all aspects of the full energy system in great detail and greater insights and progress can be gained by drawing on the strengths of multiple modelling tools rather than trying to incorporate them all into one comprehensive model. The methodology takes an optimized generation portfolio for a specific year from an energy systems model and undertakes a detailed high resolution chronological simulation of the same portfolio in the power systems model with added degrees of technical detail. Results presented here show that in the absence of key technical constraints, an energy systems model can potentially undervalue flexible resources, underestimate wind curtailment and overestimate the use of baseload plant.

1.0 Introduction

Motivated by the need to reduce CO₂ emissions many European and Global governments have developed or are developing roadmaps and strategies to low carbon economies by the year 2050 [1-3]. The year 2050 is seen as a key year and much work has been undertaken on techno-economic modelling of entire energy systems out to this year. Energy systems modelling helps to identify technologies capable of having the greatest impact on CO₂ emissions and highlights technologies which potentially offer the lowest technical and financial risk in the face of a range of possible future demand scenarios. While a large

range of dedicated energy systems models exist [4] they generally concur that relative to today's levels, increased levels of renewable energy along with other low carbon measures will be required by 2050 in order to meet stringent emission reductions [5-7]. Global wind power capacity installed by the end of 2009 was capable of meeting roughly 1.8% of worldwide electricity demand and that contribution could grow to in excess of 20% by 2050 [8]. The power system challenges surrounding the stochastic nature of wind, predictability and integration into electrical grids have been well documented [8-11]. Greater integration of variable renewables will require power systems to be increasingly flexible. In order to assess how suitable power systems are to levels of fluctuating renewable energy, high resolution chronological modelling is required to model the highly temporal variation of wind power output in association with the sometimes intertemporally constrained thermal power plant. Many detailed assessments of wind power integration in various regions around the world have been undertaken and are summarized in [12]. In general dedicated power systems models, run at hourly or sub-hourly resolutions, are used to undertake these types of studies as these models are capable of capturing the temporal variation of wind and its effect on the entire power system on a short time scale. Load flow modelling (both D.C. and A.C.) are also utilized to analyse network impacts of wind power integration but these are not the focus of this chapter.

While power systems and energy systems models both address the modelling of complex systems, they are fundamentally different in their focus and application. Power systems models focus solely on the electrical power system and sometimes the gas network but do not consider the rest of the energy system. The primary inputs are generally exogenous in nature, including electricity load, fuel prices and power plant technical limits. Energy systems models examine the full energy system however the electrical power system is by contrast completely endogenous and driven by the combined behaviour of supply sectors that provide primary fuels and end-use sectors driven by exogenous energy service demands. The focus is typically to provide a technology rich basis for estimating energy dynamics over a medium and long-term, multiple period time horizon. Because of the exclusive focus on electricity generation within power systems models, the

problem description can be at a higher resolution when compared to full energy systems model, which have to handle a much broader range of problems and sub-systems. Typically a power systems model can model from hourly to 5-minute or higher resolution while energy systems models may have a limited number of temporally-independent “timeslices” which can be a disadvantage when looking at power systems with levels of fluctuating renewable energy.

The benefit of higher resolution within power systems and energy systems modelling has been recognized where it was shown that optimal investment decisions derived from models can vary significantly depending on the timeslice selection used [13,14]. In [15] the author has developed a temporal UK MARKAL model to investigate the role of electricity storage. The UK temporal MARKAL model has 20 annual timeslices compared to six in most standard MARKAL databases. In [16] the authors have developed a high resolution temporal TIMES model by dividing each year into 4 seasons, with 3 days per season and 24 hours per day. The results show that the increase in temporal resolution allows for more constraints to be taken into account, such as renewable resource availability, operational constraints, electricity demand dynamics and others.

The work presented in this chapter is different as it is intended to present a methodology to soft-link a power systems model to an energy systems model. The motivation for this soft-linking is to provide a transfer of information from the power systems model strong points and use this information to improve and develop model results within an energy systems model. Part of this motivation is also derived from accepting the situation that perhaps one specific modelling tool cannot model everything and greater insights and progress can be gained by drawing on the strengths of other modelling tools rather than trying to incorporate them all into one comprehensive model. Power systems models are better suited to high resolution modelling of the electrical power system while energy systems models provide a more comprehensive overview of the entire energy sector including the long term resource mix problem and electrical demand elasticities. While some power systems models are capable of long-term capacity expansion the demand and growth for electricity is generally exogenous,

as are fuel prices. The focus of this current methodology therefore is to use the high resolution economic unit commitment and dispatch capability of a power systems model to examine results from an energy systems model and gain insight into important features of power system design and operation, with a particular focus on how variable renewable generation impacts on the system. These insights can then be used to better interpret or improve results from the energy systems model. Such features of interest are system reliability, system flexibility, CO₂ emissions modelling and curtailment of renewable resources.

In this methodology one specific year is chosen from the energy systems model results and examined in greater detail in a power systems model. The energy systems model used in this analysis is the *Irish TIMES* model which is developed using the TIMES modelling tool. The power systems modelling tool used is *PLEXOS for Power Systems* [17] and a model of the Irish power system in PLEXOS is presented in this analysis. These tools and models are explained in greater detail in Section 3. Both models are tested on the Republic of Ireland energy system and focus on the electrical power system within the full energy system.

While electricity generation in Ireland in 2005 accounted for approximately 18% of total final consumption, results for the year 2050 under a mitigation 80% carbon reduction target (relative to 1990 levels)⁵ show this increasing to approximately 33% of total final consumption with a greater electrification in the heating sectors and transport on the pathway to 2050 [18]. This is coupled with a projected marked increase in wind generation as shown in Figure 6.1.

⁵ -86.5% relative to 2005 levels

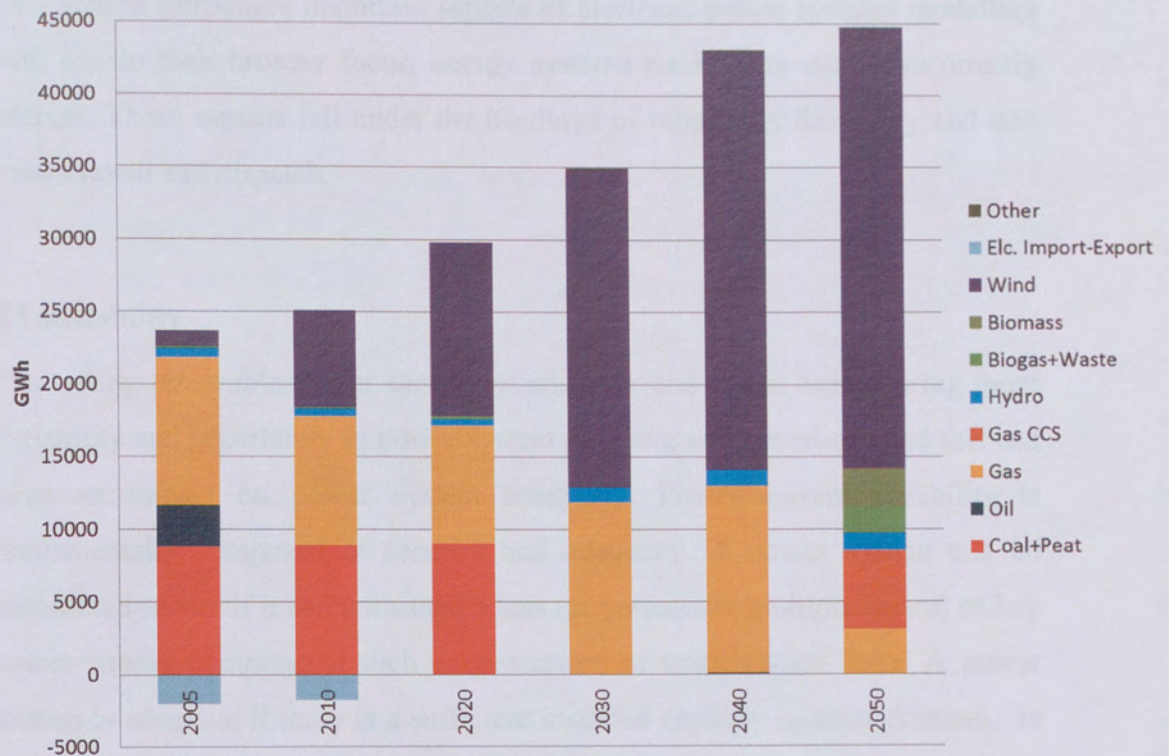


Figure 6.1: Electricity production under an 80% (rel. to 1990) carbon reduction scenario for Republic of Ireland [18]

This increase in electrification and increase in wind generation may pose significant challenges for the power system. The research in this chapter is can therefore be considered relevant as it aims to determine whether the electrical portfolios generated in the Irish-TIMES model are technically feasible and aims to gain insight into the appropriateness of the derived generation portfolio. Note that while this methodology is presented here for the Irish TIMES model it could also be applied to other countries and models which may have high projected levels of variable renewable generation in future power systems.

This chapter is thus structured as follows. Section 2 introduces important aspects of the power and energy system features and discusses the common ground between the two, and how one can improve on the other. Section 3 discusses the soft-linking methodology and introduces the two models used in this analysis. Section 4 presents results of the analysis.

2.0 Research focus and issues addressed

This section introduces important aspects of electrical power systems modelling that, due to their broader focus, energy systems models are unable to directly address. These aspects fall under the headings of reliability, flexibility and unit commitment and dispatch.

2.1 Reliability

Fluctuating renewable power such as wind, solar and ocean energy bring more variability and uncertainty to power system planning and operations and this can have an impact on power system reliability. Power system reliability is fundamentally composed of security and adequacy. A power system can be considered secure if it can withstand a loss (or potentially multiple losses) of key power supply components such as generators or transmission links. A power system is adequate if there is a sufficient installed capacity to meet demand. In general a number of key metrics are used to assess reliability. An overview of these can be found in [12]. Briefly these are Loss of Load Probability (LOLP) which is a measure of the probability that demand will exceed the capacity of the system in a given period and the Loss of Load Expectation (LOLE) which is number of times in a given period that the load will be greater than the demand. LOLE can be used to set a security standard, generally given as a number of hours per year. If this is exceeded in, it indicates the system has a higher than acceptable level of risk. Expected Unserved Energy (EUE) is also a useful metric as it takes account of the extent of the shortages.

Power systems models are capable of explicitly calculating these metrics as they can process detailed temporal information on maintenance outages, forced outages rates, mean time to repair modes and load information. They can iterate through all units in the system, accumulating the unit outages and calculating their respective probabilities of outages. Power systems model are also capable of detailed modelling of ancillary services for system reserves and can optimize the provision of reserves for each period of the simulation. Simply put, system reserve modelling means that units must hold spare generation capacity online in order to meet an unforeseen outage of largest in feed, this type of quick response reserve is generally called spinning reserve as it is provided by units that are already online. Replacement reserve is also required which can be provided by

both online and offline units as long as the units offline can start up with the required timeframe. And further, critical to the accurate valuation of renewable generation integration is the modelling of downward type reserves i.e. the ability of thermal generation to unload in the event that the variable renewable generation suddenly spikes upward. It is this lack of downward reserves that has proven to be the key limiting constraint for renewables integration for some regions [19]. Energy systems models do not explicitly derive these indices and instead use heuristic rules for capacity margins, and do not address the downward reserve requirements at all.

2.2 Unit Commitment and Dispatch

The security-constrained unit commitment and dispatch problem involves deciding the correct combination and power output of units for the economic and reliable operation of the power system, taking into account fuel and carbon costs, and reserve requirements required in case of forced outages of power plants or transmission lines and against demand uncertainty. Unit commitment being the decision of which units to turn on or off and dispatch being the decision of what level to run units at once they are on. A large number of commercial and non-commercial models are available for modelling the power system and power markets and are summarized in [20]. The value of detailed unit commitment and dispatch modelling is that it captures many of the technical constraints and limitations of thermal power plant and quantifies the implications for variable renewable generation in terms of its impact on the probability of the system running short of generation and/or reserve requirements. This feeds back into the determination of the technical suitability and flexibility of the power system. While power systems models can model the unit commitment and dispatch problem at high resolutions (1 minute to 1 hour), energy systems model generally assume a lower timely resolution for which the problem is solved. This is done so as to keep the problem size manageable. The unit commitment and dispatch problem can be relatively complicated to solve because the physical delivery of electricity is subject to the technical and economic constraints on generation. Some of these technical constraints may introduce integer variables into the linear programming formulation in order to track the on/off state of generation plant in time and to enforce important technical constraints minimum stable

generation, minimum up and down times and start costs as a function of unit temperature.

2.3 Flexibility

Electrical Power systems must also be adequately flexible and contain flexible resources to manage variability in the residual load. Flexibility, in power system terms, is traditionally associated with quickly dispatchable generators. Balancing however is not simply about power plants, it must also consider other resources such as storage, demand-side management or response, and interconnection to adjacent power systems for trade [21]. Within actual power system operation, technical constraints such as minimum stable generation, ramps rates and minimum up and down times restrict the flexibility of power plant and can affect renewable energy curtailment and emissions outputs. Modelling in the absence of these technical constraints can lead to very heavy cycling of baseload plants (as shown in results section), give a false impression of the capability of the system to integrate renewables and specifically an incorrect evaluation of wind curtailment.

The assessment of power system reliability and flexibility is important in the context of energy model results because while the model may correctly derive a least cost generation portfolio with consideration to broad technical and emission constraints, the resultant portfolio may not be technically suitable when examined in the context of higher resolution temporal modelling.

3.0 Soft-Linking Methodology

A methodology is presented that employs detailed modelling of the unit commitment and dispatch of the electrical power system, derived from an energy systems model, in a dedicated power systems model to provide insight and feedback to the energy systems model. The power systems model is populated with an electrical portfolio, fuel prices and demand from the energy systems model while the energy systems model is enhanced with output from the power systems model. The goal of the methodology is ultimately to have an improved understanding of the energy systems model's results in relation to the electrical

power sector and to understand what elements of the power system are important.

The power systems and energy systems modelling tools used in this analysis and the energy systems model are presented below before a detailed description of the soft-linking methodology.

3.1 Power Systems Modelling Tool: PLEXOS for Power Systems

In this analysis the PLEXOS modelling tool is used to build and solve a model of the Irish power system. PLEXOS is a power systems modelling tool used for electricity market modelling and planning worldwide. PLEXOS is a commercial modelling tool but is provided by Energy Exemplar free for non-commercial research to academic institutions. Modelling is generally carried out using deterministic or stochastic programming techniques that aim to minimize an objective function or expected value subject to the modelled cost of electricity dispatch and to a number of constraints including availability and operational characteristics of generating plants, licensing environmental limits, and fuel costs, operator and transmission constraints. The model solves using linear or mixed integer linear programming. Importantly from a research perspective PLEXOS is a transparent model, with the mathematical formulations available to the user via diagnostics.

In this analysis we are concerned with short-term deterministic modelling. This means that the model assumes perfect foresight in relation to wind production and forced outages of plant. When modelling in short term mode (typically a full year of daily half-hourly optimizations of the power system) PLEXOS models every trading period and maintains chronological consistency across the full optimization horizon. The tool models generator start ups and shutdowns and tracks the status of units across time. Within the modelling unit commitment process on/off decisions for each unit must be made. This is necessary to correctly model technical parameters for generators such as minimum stable generation, minimum up and down times. The inclusion of these technical constraints introduces integer decision variables. The presence of the integer variables means that the problem cannot be solved as a linear model. PLEXOS

uses mixed integer programming (MIP) to solve these problems. MIP means the modelling tool can realistically replicate the actual operation of generator in the physical market as all technical constraints can be modelled and obeyed. To avoid issues with intertemporal constraints at the simulation step boundaries a '*look ahead*' period is used. Look ahead means that the optimiser is given information about what happens ahead of the period of optimisation and solves for this full period (i.e. simulation period + look ahead period) however only results for the simulation period are kept. Within the model maintenance schedules for generation units can be fixed exogenously if a known maintenance schedule is available, otherwise the model can determine an optimal maintenance schedule based on the annual maintenance rate and mean time to repair for each unit. The objective function of the maintenance scheduling formulation to equalize the capacity reserves across all peak periods. Random outages for units are calculated based on Monte Carlo simulations. Outages occur at random times throughout the year with frequency and severity defined by forced outage rate, mean time to repair and repair time distribution. At simulation run time PLEXOS dynamically constructs the linear equations for the problem using AMMO⁶ software and uses a solver to solve the equation. In this work Xpress MP (22) with a duality gap set to 0.2%. Within the PLEXOS modelling tool, wind and other renewables are essentially treated as 'free' generation (i.e. the marginal cost is zero) although this can be changed by the user, therefore PLEXOS will use as much renewable generation as possible to reduce overall system costs subject to the technical constraints applied to the system. In PLEXOS, demand is represented as a chronological time series at 30 minutes resolution. The PLEXOS modelling tool is used by the Commission for Energy Regulation (CER) in Ireland to validate Ireland's Single Electricity market and thus has a history of use in Ireland [23].

3.2 Energy Systems Modelling Tool: TIMES

TIMES (The Integrated MARKAL-EFOM System) is one of the tools developed and used by the Energy Technology Systems Analysis Programme (ETSAP), an implementing agreement of the International Energy Agency (IEA). It combines

⁶ AMMO performs a similar role in PLEXOS as other mathematical languages such as AIMMS, AMPL, or GAMS but is written exclusively for PLEXOS

all the advanced features of MARKAL (Market Allocation) models, and to a lesser extent of EFOM (Energy Flow Model Optimization) models. The equations of the initial MARKAL model appear in [24] and numerous improvements on the model have been developed since then for various applications [25-28]. The full technical documentation of the TIMES model is available in [29]. TIMES is a technical economic model generator for local, national or multi-regional energy systems, which provides a technology-rich basis for estimating energy dynamics over a long-term, multi-period time horizon. It is usually applied to the analysis of the entire energy sector, but may also applied to study in detail single sectors (e.g. the electricity sector). TIMES is a deterministic linear programming model generator that computes a dynamic inter-temporal partial equilibrium on integrated energy markets. The objective function to maximize is the total surplus. In the simplest case this is equivalent to minimizing the total discounted energy system cost while respecting environmental and many technical constraints.

The key inputs to TIMES are the demand component (energy service demands), the supply component (resource potential and costs), the policy component (scenarios) and the techno-economic component (technologies and associated costs to choose from). The model is driven by exogenous demand specified by the list of each energy service demanded (disaggregation), actual values in the base year (calibration) and values for all milestone years till 2050 (projection).

Figure 6.2 shows an overview of a TIMES model. Each economic sector is described by technologies, each of which is characterized by its economic, technological and environmental parameters.

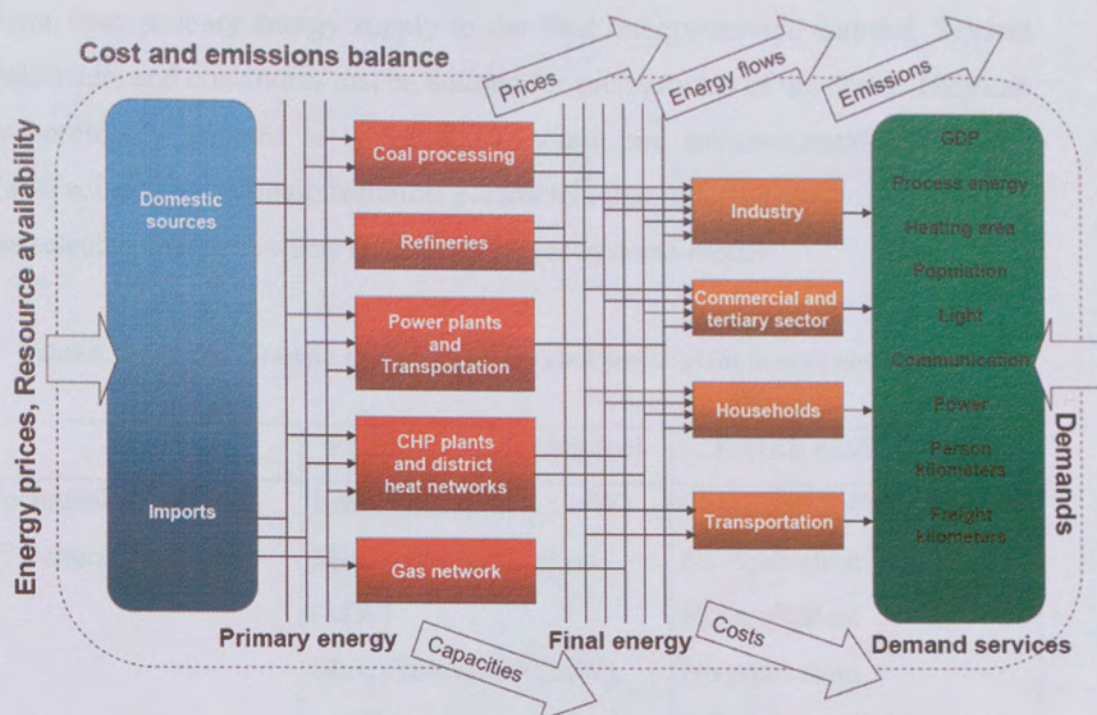


Figure 6.2 - Overview of TIMES Modelling Tool [29]

TIMES is mainly used for medium and long term modelling, but it is theoretically possible to use this tool also for shorter term analysis. Each time period is usually divided by sub-period, commonly called timeslice. The timeslice represent the “mesh” of each period and the definition depends strongly to the computing capacity and the time-scale. Long-medium term optimizations (20-50 years of time horizon) rarely use more than 12 timeslices. For example the model used in this chapter work, the Irish TIMES model, has a 2005-2050 time horizon while each period is sub-divided by 12 timeslices, commonly defined by day, night and peak hours for four season.

In the TIMES model net electricity demand profiles are not imposed exogenously, but rather are endogenously evaluated to optimally provide the energy service demand for each sector. The electricity generation sector is commonly characterized by various voltage levels (commonly three or four) in which each voltage level of the network is modelled by an equivalent simplified system composed of lines, transformers, infrastructure for electricity transport and distribution. Power plants are described by processes grouped as base year or post-base year capacities. Each plant is moreover characterized by input and output commodities that fit into the energy system composing the whole energy

chain from primary energy supply to the final energy service demand. Several parameters and constraints can be defined for each process of the chain. They can be commonly grouped as technical, economic and environmental parameters. Table 6.1 details the main technical parameters that describe power plant in both the selected energy systems model and power systems model.

Table 6.1: Main parameters that characterize each power plant in each modelling tool

	PLEXOS modelling tool	TIMES modelling tool
Technical parameters of Generation Plant	Installed Capacity (MW) Min. stable generation (MW) Max. Generation (MW), Up/Down Ramp Rates (MW/min) Heat rates, (GJ/MWh) Min. up and down times (hrs) Maintenance rates, repair time and failure rates (%)	Capacities (MW), No equivalent No equivalent No equivalent Efficiencies, (%) No equivalent Availability factors (%)
Economic parameters	Fuel and emission costs (€/GJ) Variable O&M Start costs (€)	Fuel and emission costs (€/GJ) O&M costs (fix and variable), No equivalent
Environmental parameters	Emissions (CO ₂ Only)	Emissions (CO ₂ Only)

Within TIMES most of renewable technologies (e.g. wind energy or solar PV) are commonly treated with efficiencies of 100% while the availability of the resource is inserted as capacity or activity constraint. The load fluctuation due to the resource variability (that represents the fuel for the process) is modelled by a timeslice dependent definition of average availability factors generating different generation profiles.

3.3 Soft-Linking Methodology

The soft-linking methodology is described using a number of steps listed below and illustrated in Figure 6.3. It is assumed that the energy systems model is already developed and available. Note that before the soft-linking approach can be correctly employed it is important that both models share certain common inputs. Depending on how the energy systems model is developed these inputs may already be the same. These particular inputs are electricity profile shape and renewable generation profiles. This aspect is discussed in more detail in Section 3.4.2

The steps in the soft-linking methodology are as follows:

1. Select the model, the scenario and the target year of the analysis for the energy systems model and execute the model.
2. Extract results from the energy systems model for the target year of interest for the electricity generation portfolio and populate the power systems model with this generation portfolio. Additional technical detail and data such as minimum stable generation, ramp rates and start costs, failure and maintenance rates are included in the power systems model. Fuel prices and carbon prices from the energy systems model are also provided to the power systems model.
3. Convert the annual electricity demand profile for the target year from the energy systems model into a half hourly chronological profile. This is done by taking an existing actual electricity half hourly demand for the region of interest and scaling it using quadratic optimisation so that the annual demand for electricity and peak demand for electricity are equal to the demand from the energy systems model, a function that is provided by PLEXOS. In this way a detailed chronological demand profile is developed and input into the power systems model. In this current use of the methodology it is assumed that the historic electricity demand profile is representative of a future demand profile. This may not always be the case as outlined in Section 3.4.2
4. Initially run the power systems model for the target year using this data at half-hourly resolution without any additional technical constraints such as

minimum stable generation, ramp rates and start costs. This is done to investigate the impact of increasing the chronological resolution of model.

5. Subsequently run the power system model with increasing level of technical constraints in order to determine the impact these technical parameters on model results.
6. Compare results between the two models, determine the differences and examine the reliability and flexibility of the power system. Detailed information from the power systems model solving of the unit commitment and dispatch problem can shed light on the role each plant type provides in relation to system operation.
7. Determine the implications of low wind production years on the reliability of the derived portfolio from the energy system model by running the power systems model with a number of different years of wind production profiles.

Figure 6.3 details a graphical representation of the methodology .Depending on differences that arise and insights that are gained, the energy systems model inputs or technical parameters can be adjusted to aim for improvement of results.

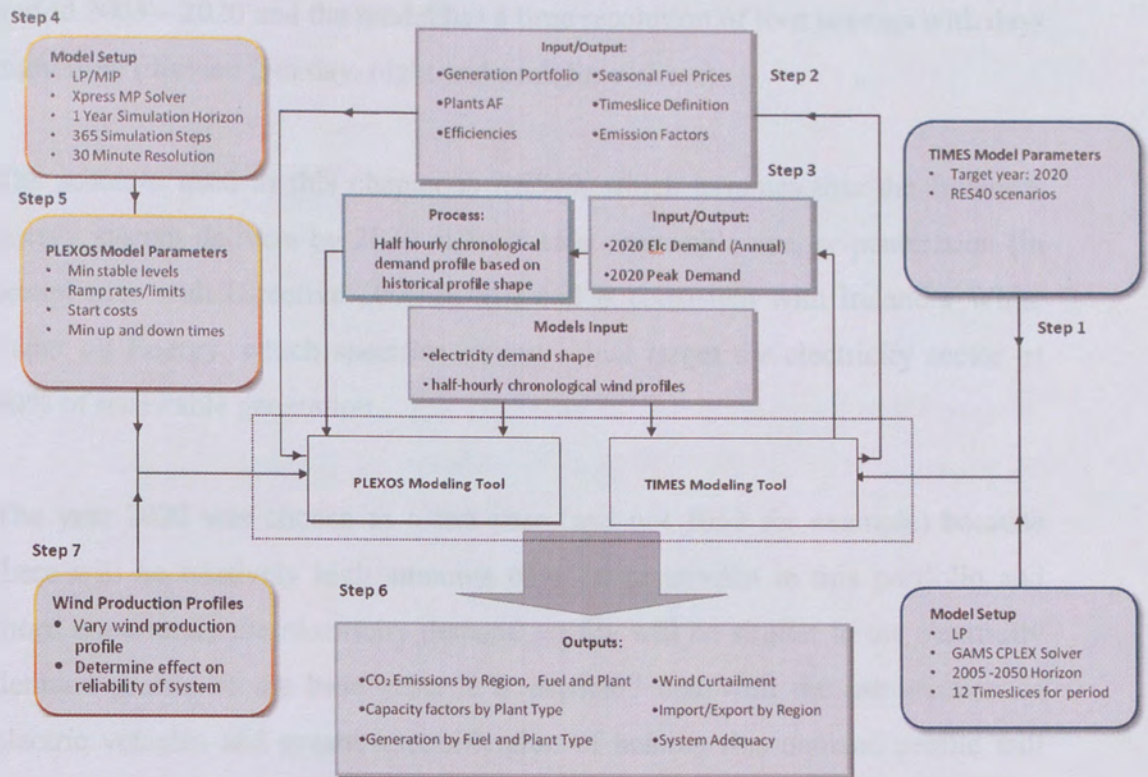


Figure 6.3-Flow chart of soft-linking methodology

3.4 Application of Methodology

To demonstrate the soft-linking methodology as outlined above, we applied soft-linking in Ireland to an energy systems model, Irish TIMES and an equivalent power systems model. This section describes the model and how the soft-linking methodology was applied.

3.4.1 The Irish TIMES model: details and configuration

The Irish TIMES model [30] is an energy systems model for the Republic of Ireland developed by University College Cork (UCC), Sustainable Energy Research Group in collaboration with the ESRI (Economic and Social Research Institute). The Irish TIMES model has been developed to build a range of medium (to 2020) [31] and long term (to 2050) energy and emissions policy scenarios in order to inform policy decisions. Irish TIMES was originally extracted from the Pan European TIMES model that includes EU27, Iceland, Norway, Switzerland and Balkans countries and then updated with local and more detailed data and assumptions [32]. The time horizon used here is the

period 2005 – 2020 and the model has a time resolution of four seasons with day-night time (divided into day, night and peak time-slices).

The scenario used in this chapter is *RES40*, which assumes that the Ireland's energy system delivers by 2020 at least 16% renewable energy penetration (in compliance with Directive 2009/28/EC) and is consistent with Ireland's White Paper on Energy, which specifies an individual target for electricity sector of 40% of renewable generation.

The year 2020 was chosen as a test year (and not 2050 for example) because there will be relatively high amounts of wind generation in this portfolio and more importantly the electricity demand profile will be similar to the electricity demand profile of the base year. It is expected that with the introduction of electric vehicles and greater electrification of heating this demand profile will change. The development of these new demand profiles is a target for future research and this point is discussed further in Section 6.

3.4.2 Model inputs and configuration

To produce consistent outputs in both models certain common inputs have been imposed. Firstly in both models the same electricity demand shape profile is used and is based in this instance on pre-economic recession 2007 electricity demand profile for Ireland. This assumption defines the likely chronological demand shape for the year 2020 under the *RES40* scenario. This specific scenario indicates that electrification between end-use sectors will not affect largely the load curve given the limited impact of electricity for heating purposes and for transportation. Within the Irish TIMES model the load curves for energy service demands, indicated as commodity fraction (COM_FR), have been recalibrated to follow globally the expected profile. Furthermore given the importance of accurate wind resource assessment estimation, both models initially use wind production data from the same year. In this analysis wind production data from the year 2008 was used. The average capacity factor for wind generation for the year was 31.7%. The long term time weighted annual average from 2002 to 2009 was 32.2% with a range of 34.7% to 29.1% [33]. The Irish TIMES model used this data segregated into 12 timeslices. This was done by summing up the half

hourly production of each time period within each timeslice definition. The power systems model used a half-hourly chronological profile of the same data, both giving the same total energy production. This analysis does not consider detailed modelling of transmission issues, frequency and inertia issues of voltage stability however to reproduce operational constraints within the Irish power system the instantaneous level of wind generation is limited to 70% [34].

Table 6.2 details the optimized generation portfolio from the Irish-TIMES model for the year 2020 subject to demand and energy constraints. This generation portfolio was input into the PLEXOS model along with detailed technical parameters as set out in Table 6.2.

According to the Irish TIMES model the total electricity requirement⁷ for the year was 29.8 TWh with a peak electricity demand of 4.9 GW. For the PLEXOS model technical information and characteristic of plants not available in TIMES (i.e. number of individual units, ramp rates, and minimum stable generation) are based on actual performance of plants within the current Irish power system [35]. Within the PLEXOS model pump storage is modelled as having 3 distinct phases and is modelled on the current pumped storage station in Ireland. These phases are: 1) Pumping mode: the plant has 4 fixed speed pumps which draw a load of 71.5 MW each and can provide this full quantity to all reserve. 2) In spin mode each unit can provide 5 MW of power but no more than 2 units can at be in spin mode at any one time. In this mode the efficiency of the generation units is 50%. 3) In generation mode each unit can provide a minimum of 40 MW and up to a maximum of 73 MW. As all units share a common penstock they are not allowed to generate and pump at the same time. The pumped storage system is closed loop with no inflow. The reservoirs have capacity for approximately 1.24 GWh of energy storage and so the system can generate at full load for 4.2 hours. Water in the storage has no 'value' other than the value of the thermal generation it can replace. Thus the optimization will use all the water possible to minimize thermal costs. In this model set up, the upper reservoir is forced to refill by the end of each trading day (06:00). In TIMES, electricity storage is modelled as a single process technology. This process is characterized by the capacity that describes

⁷ All the electricity sent out of power plants. This value is equivalent to the sum of final electricity consumption and grid losses.

the volume of the storage, and the activity, i.e. the storage content. In Irish TIMES, pumped storage is set as timeslice storage, which means its operation is optimized between timeslices. The maximum capacity of the reservoir is the same as the PLEXOS model 2020 is 292 MW with the same overall efficiency of 70%.

Table 6.2: Generation portfolio from Irish TIMES model for the year 2020 and equivalent PLEXOS model input

Category	Description	From Irish TIMES							PLEXOS Additional Parameters			
		Capacity (MW)	TIMES Efficiency (%)	Max Availability Factors (%)	O&M Costs (€/Mwh)	Fuel Cost (€/GJ)	CO ₂ Emission Factor (kg/GJ)	Number of Plant	Heat Rates (GJ/MWh)	Min Stable Generation(MW)	Ramp Rates (MW/min)	Min up/down times (hrs)
Gas	Combine Cycle	1422	47.5	57	0.04	4.4	56.1	4	7.5	150	12	4
	Combine Cycle-new	1664	55.1	85	1.53	4.4	56.1	4	6.5	220	30	4
	Gas Turbine	200	40	55	2.05	4.4	56.1	1	9	110	15	4
Coal	Steam Turbine Hard Coal	840	39.5	87	0.04	2.9	95	3	9.1	180	4	8
Peat	Steam Turbine Lignite	347	41.5	87	0.04	1.1	110.6	3	8.6	80	2	8
Distillate	Gas Turbine Distillate Oil	496	38	55	2.05	4.0	77.4	8	9.4	10	10	1
Biogas	Internal Combustion Biogas Plant	22	33.5	57	0.04	4.7	56.1	1	10.7	5	5	8
Waste	CHP: Steam Turbine Municipal waste	21	25	60	2.56	0.3	85.9	1	14.4	5	5	8
Wind	On-Shore wind	4305	100	31.7	NA	0.0	0.0	1	3.6	NA	NA	NA
Hydro	Hydro Dam Plant	215	100	25.5	NA	0.0	0.0	15	3.6	2	10	NA
	Run of River Plant	19	100	25.5	NA	0.0	0.0	1	3.6	0	NA	NA
Storage	Storage Hydro Plant	292	70	13.8	NA	-	0.0	4		5	50	NA
Total		9843										

To assess the methodology a series of yearly model runs (scenarios) were undertaken in the power systems model with added degrees of technical complexity. This was done to assess and quantify the added benefit of each of these parameters to the modelling process. The first of these scenarios (*Scenario Simple*) was a simple unit commitment and dispatch simulation with no technical constraints other than maximum generation capacity of each individual plant. A second scenario (*Scenario Start Costs*) added the start costs of each plant to the problem formulation. A third model scenario (*Scenario MSG*) also added

minimum stable generation, a fourth added ramp rates (*Scenario Ramp Rates*) for each plant while a final scenario (*Scenario Reserve*) added full modelling of upward reserve requirement. This final scenario can be interpreted as the most complete model of the power system and the one that provides the most realistic results in terms of power system operation. Therefore the differences between this scenario and the results from the energy systems model are the most important. These scenarios are summarized in Table 6.3 while Table 6.1 gives an overview of both model parameters and their equivalence for both models. A series of simulations were also undertaken in the power systems model to determine the effect of low wind production years to investigate the robustness of the derived power system. This was done by using actual historic wind power production data from the year 2010 which historically was a low wind production year in Ireland with an annual capacity factor of 24%.

Table 6.3: Summary of Individual Model Scenarios for power systems model simulations

Scenario “Simple”	Scenario “Start Costs”	Scenario “MSG”	Scenario “Ramp rates”	Scenario “Reserve”
Simple case with only maximum capacity of generators	Added start costs for each plant	Added minimum stable generation for each plant	Added ramp rates limits for each plant	Added spinning and replacement reserve requirements

4 Results

This section presents and discusses a selection of results in two main sections, where firstly the impact on generation reliability is discussed and then the differences between both model outputs for the electricity sector are presented. As the focus of this work is on the soft-linking methodology, the results are used only to show how this methodology can be employed and should not be taken as definitive.

All simulations were undertaken on a Dell laptop with two 2.39 GHz processors. The longest TIMES simulation took 40 seconds. The longest PLEXOS simulation was the 'Reserve' scenario and took approximately 5.5 hours of run time

4.1 Reliability

The power systems model PLEXOS is able to assess generation adequacy of any modelled power system by the evaluation of PASA (Projected Assessment of System Adequacy) reliability indices. Table 6.4 details results of this assessment and shows the generation portfolio developed in the Irish TIMES model to be reliable as the loss of load expectation and expected unserved energy are very low. Note that the parameter Firm Generation Capacity takes account of the capacity credit of wind rather than its full nameplate capacity. The portfolio was also tested under a low wind production year. It was found that the portfolio was reliable with only a marginal increase in expected unserved energy.

Table 6.4: Result of reliability and security analysis for the given portfolio

Property	Value
Peak Load (MW)	4947
Generation Capacity (MW)	9843
Firm Generation Capacity (MW)	6399
Capacity Reserves (MW)	1452
Capacity Reserve Margin (%)	29
Expected Unserved Energy (MWh)	84.3
Loss of Load Expectation (days)	0.02

4.2 Unit Commitment and Dispatch

Table 6.5 details the annual capacity factors for both model runs and each scenario simulation. The result presented here are for the 'typical' wind year and not the low wind year. Looking firstly at the results from the energy systems model and the 'Simple' scenario from the power systems model, it can be seen that results are broadly similar. However as more technical detail is added to the power systems model the results for certain plant diverge indicating the significance and importance of technical portrayal in modelling the electrical power system.

Results of the detailed unit commitment and dispatch show that the power systems model commits more of the less efficient CCGT units (CC-00) than the energy systems model across all technical scenarios examined. This is because these units come online when the newer CCGT units (CC-01) are out for maintenance or forced outages and are an important source of flexibility for the system. The energy model exploits the coal powered plant to its full capacity whereas in the power systems model these units are used less particularly with the inclusion of more technical parameters as the start cost gets incorporated into the objective function and coal generation is a 'pulled back' to allow gas and other generation to come online and run above their minimum stable level. As shown in Figure 6.4 the distillate fuelled plants, while having a low capacity factor in the energy systems model run are shown to provide an import peaking ability and this value is only seen when higher levels of technical detail are modelled in the power systems model. Also pumped storage is an important contributor to spinning reserve and is brought online more often to provide this service. Likewise the value of the pumped storage plant only becomes apparent when this level of detail is included in the power systems model. In relation to wind energy it can be seen that wind production is lower in the power systems model scenarios than the energy system model run indicating that wind curtailment occurring. Results of the power systems model show annual wind curtailment to rise from 7% for the simple scenario to 8% for the 'Reserve' scenario whereas The Irish TIMES model shows no wind curtailment. This stresses the importance of the correct modelling of flexible resources such as storage in the determination of system flexibility and suitability for renewable energy integration. Results for the low wind year simulations were broadly

similar however as annual wind generation was lower an increase in thermal generation was seen.

Table 6.5: Annual capacity factors (%) for target year (2020) for both models and each power system model scenario

	Irish-TIMES Results	PLEXOS Results				
Fuel Type/Description		Scenario "Simple"	Scenario "Start Costs"	Scenario "MSG"	Scenario "Ramp rates"	Scenario "Reserve"
Gas-CC	0%	16%	15%	16%	16%	21%
Gas-New	55%	54%	57%	58%	59%	58%
Gas-Turbine	0%	1%	1%	1%	1%	1%
Coal	87%	84%	73%	69%	69%	67%
Peat	87%	87%	83%	81%	81%	75%
Distillate	0%	2%	16%	17%	17%	12%
Biogas	57%	57%	57%	57%	57%	57%
Waste	60%	60%	60%	60%	60%	60%
Wind	32%	28%	28%	28%	28%	27%
Hydro	26%	23%	23%	23%	23%	23%
Hydro-ROR	26%	26%	26%	26%	26%	26%
Storage	0%	0%	4%	7%	7%	10%

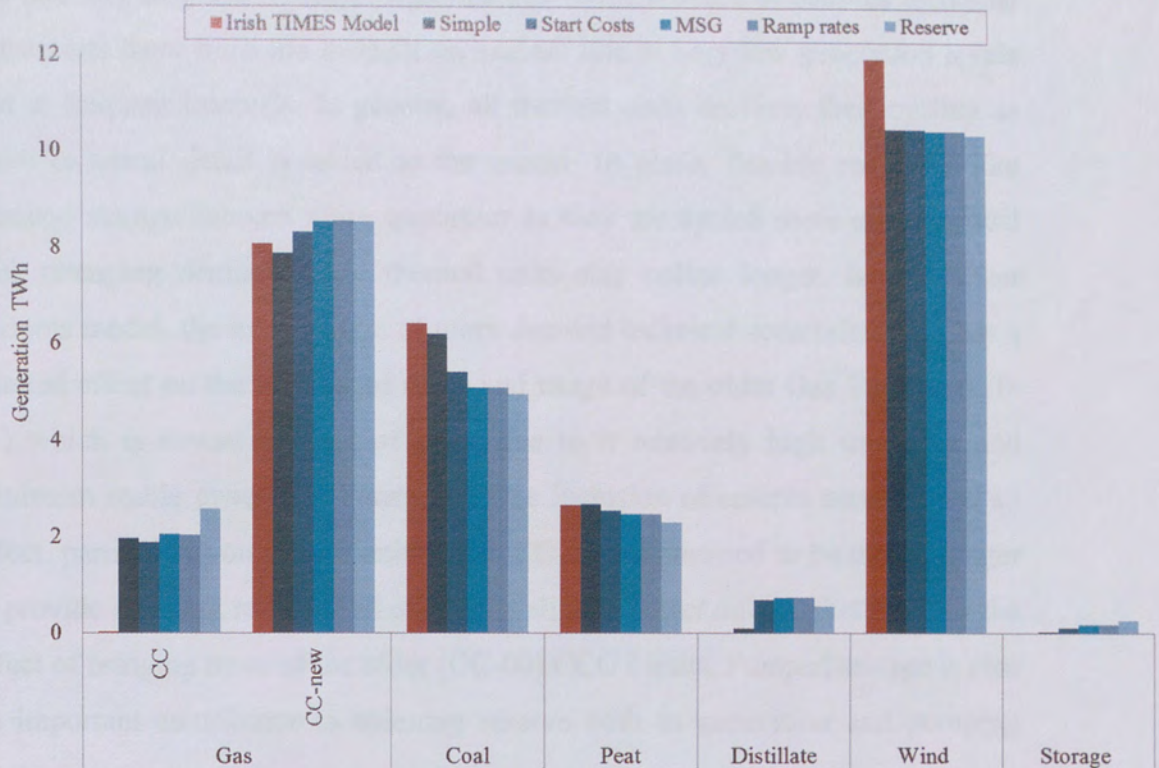


Figure 6.4: Annual generation (TWh) for target year for both models and each power system model scenario

4.3 Flexibility

Results of the detailed unit commitment and dispatch of the power system were also used to assess the flexibility of the generation portfolio developed by the Irish TIMES model and understand what technical details are important when modelling an electrical power system. Insights gained from this type of analysis can be useful in understanding why results differ between the two models. Table 6.6 firstly looks at the number of ‘start ups’ for each category of unit under each scenario of added technical detail. This is a useful metric as it gives an overview as to what units are cycling to meet variable demand and changes in wind power production and informs on what units are important for delivering system flexibility. Note that the TIMES model cannot report the number of start-ups of units throughout the year so only results for the power systems model are shown. The total number of starts changes significantly as more technical detail is added to the model, particularly for the less efficient gas CCGT units (CC-00) which the model cycles very heavily in the absence of either a start cost constraint or minimum stable generation constraint. The number of starts for the open-cycle

gas (GT-00) units also changes significantly. In the absence of detailed technical constraints these units are brought on and off line at very low generation levels and at frequent intervals. In general, all thermal units decrease their cycling as more technical detail is added to the model. In place, flexible resources like pumped storage become more important as they are cycled more often to deal with changing demand while thermal units stay online longer. In the power systems model, the introduction of more detailed technical constraints also has a marked effect on the number of starts and usage of the older Gas Turbine (GT-01) which is almost put out of merit due to its relatively high start cost and minimum stable generation constraint. The inclusion of reserve services has an effect, particularly on CCGT units. Gas CC-01 are required to be online longer to provide spinning reserve and operate at slightly lower output, this also has the effect of bringing more of the older (CC-00) CCGT units. Pumped storage is also an important contributor to spinning reserve both in generation and pumping mode.

Table 6.6: Detailed number of start ups for each thermal generation and storage for each power system model scenario

Category	Scenario “Simple ”	Scenario “Start Costs”	Scenario “MSG”	Scenario “Ramp rates”	Scenario “Reserve ”
Gas-CC	1246	191	188	190	309
Gas-New	601	282	296	284	244
Gas- Turbine	363	6	6	6	8
Coal	153	114	112	114	117
Peat	141	120	117	116	123
Distillate	1817	742	756	765	828
Storage	3246	3990	4966	4873	4131
Number of Starts	7567	5445	6441	6348	5760

Examining Tables 6.6 and Table 6.5 in detail, it can be seen that the most important technical constraint (i.e. the constraint that causes a marked change in results from one scenario to another) is start costs as this has the effect of reducing the cycling of mid-merit gas units plant and forces the use of more flexible units. The issue of starting up and turning off plant frequently is more so an important issue for mid-merit plant (i.e. gas CCGT units) rather than baseload plant as the lower fuel cost of coal and peat generally means that the model will schedule them at their maximum capacity. The introduction of the minimum stable generation constraint has less impact although it does force some coal units offline to allow for gas units to come online above their minimum stable level. A test scenario was undertaken enforcing only the minimum stable level constraint in the absence of start costs and it was seen that the start cost constraint had a more marked effect on results and did not reduce the number of start ups to the same degree as the start cost. The introduction of ramp rates has a limited consequence for results. Most plants in the model are able to ramp from minimum stable level to max generation within a half hour so it has little effect. However it is planned to look at a 10 minute unit commitment and dispatch as part of further research to determine the impact of ramp rates. The introduction of reserve requirements force units contributing to spinning reserve to hold spare generating capacity to contribute to the specified requirement for this service. This has important consequences for pumped storage plant.

4.4 CO₂ Emissions

Table 6.7 shows the annual CO₂ emissions for both model runs and each scenario simulation. Looking at the power system scenario with full technical and reserve requirements (scenario 'Reserve') it is seen that the Irish-TIMES model has a greater estimation of total annual emissions. This is because it has a higher level of coal and peat generation compared to the power systems model. The power systems model has higher emissions from gas plant but is offset by higher reduction in emissions from the coal and peat plant. In the absence of technical constraints the power systems model produces higher emissions as the baseload peat and coal plants are allowed to run longer.

Table 6.7: Annual CO2 emissions (Mt) for target year for both models and each power system model scenario

Fuel Type	Irish TIMES Model	PLEXOS Power Systems Model				
		Scenario "Simple"	Scenario "Start Costs"	Scenario "MSG"	Scenario "Ramp rates"	Scenario "Reserve"
Gas-CC	0.01	0.83	0.80	0.87	0.86	1.10
Gas-New	2.95	2.88	3.05	3.13	3.13	3.12
Gas- Turbine	0.00	0.01	0.01	0.01	0.01	0.01
Distillate	0.00	0.06	0.48	0.51	0.52	0.38
Coal	5.77	5.36	4.74	4.46	4.46	4.35
Peat	2.48	2.54	2.42	2.37	2.36	2.20
Waste	0.14	0.14	0.14	0.14	0.14	0.14
Total	11.35	11.81	11.63	11.47	11.47	11.29

5.0 Conclusions and Discussion

A soft-linking methodology that can be used to verify and gain insight into electricity sector results from energy systems models using a power systems model has been presented and detailed. Results for one specific year have been presented. The work in this chapter shows that the soft-linking methodology provides important insights into results and provides a useful method to crosschecking the technical appropriateness of the optimized power system results arising from an energy systems model. In this particular analysis it was shown that while the optimized portfolio from the Irish TIMES model was a reliable and adequate power system, the value of key flexible elements namely storage were undervalued. It was also shown while the energy systems model does not use the older CCGT gas units (CC-00) or distillate fired units they are an important element in the system. Wind curtailment was approximately 8% higher than expected and emissions were higher than reported when compared to detailed results from the power systems model. These insights could only be gained by the addition of key technical criteria to the modelling process such as imposing start costs, minimum stable generation levels and reserve requirements on the model. In relation to these constraints it was shown in this analysis that

start costs have a marked effect on the modelling of the power system and has important implication on the modelling of CO₂ emissions.

6.0 Future Work

Future work will involve applying the soft linking methodology to other target years with significant amounts of installed wind capacity such as 2050 and determining the best method of feeding insights from the results of the soft-linking methodology back into the energy system model to improve results. An important element of this work will involve the development of accurate chronological electricity demand profiles which will consider the changes that may occur to the demand profile over coming years. These include changes in demand and electricity usage due to the introduction of electric vehicles and the electrification of heating. Higher resolution power systems modelling (current resolution is 30 minutes) will also be investigated to determine the effect this has on ramp rates of thermal power plant. A further important modelling challenge will be the modelling of interconnection to other regions such as Great Britain and Northern Ireland. It is expected that these extra loads and generation centres coupled with wind and renewable energy variability will pose further significant modelling challenges and increase the value of this soft linking methodology particularly in the determination of imports and export of electricity from one region to another.

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Chapter 7: Modelling the economic impacts of 500 MW of Wave Power in Ireland

Abstract: This paper investigates the impacts of including 500 MW of wave power into Ireland's electricity generation portfolio in the year 2020. One year of detailed market simulations are undertaken to determine the impact on wholesale electricity prices, system operation costs and CO₂ emissions with and without this installed wave power under a number carbon prices assumptions. In both scenarios (with and without wave energy), Ireland's installed renewable capacity is fixed such that 40% of Ireland's electricity in 2020 is from renewable source. The likely revenue a wave energy device would earn in the market is also investigated and compared with what is required to achieve 500 MW installed capacity. It is shown that in general the inclusion of wave energy has a negligible effect on wholesale electricity prices, reduces total system cost in Ireland and can increase CO₂ emissions on the island of Ireland under certain carbon price assumptions.

1.0 Introduction

Over the past decade concerns related to climate change, rising fuel prices and security of supply have motivated policy makers worldwide to promote measures that support large increases in renewable energy. Within the European Union the primary policy instrument related to energy and climate change is the Climate and Energy package [1]. This package sets a series of targets to be met by 2020, known as the "20-20-20" targets. These targets are a reduction in EU greenhouse gas emissions of at least 20% below 1990 levels, a 20% of EU energy consumption to come from renewable resources and a 20% reduction in primary energy use compared with projected levels, to be achieved by improving energy efficiency. Ireland's EU targets related to energy and climate change for the year 2020 are also driven by the EU 20-20-20 initiative. Directive 2009/28/EC sets out a target of 16% renewable energy for Ireland for 2020. National targets for electricity, heating and transport are respectively 40% RES-E, 12% RES-H and 10% RES-T. The Irish government also recently set a target for 80% CO₂ emission reduction target by the year 2050 based on 1990 levels.

In many jurisdictions and countries around the world wind energy is expected to make up the bulk of renewable energy targets. This is evident from ambitious targets set by many countries for wind energy installations [2]. Apart from hydro power wind energy is seen by many to be the most commercial form of renewable energy and over the past ten years, global wind power capacity has grown at an average cumulative rate of over 30% with global installations standing at more than 120 GW [2]. Wave energy on the other hand is still in its infancy and does not yet share the commercial success of wind energy. However a very large global resource for wave energy exists and is estimated to be 32,000 TWh/yr [3]. While both technical unconstrained resources for wind and wave are very high, both power sources share the common issue of variability that can make their large scale integration into electrical grids challenging. Variability occurs at various time scales; for example wind can have seasonal variations as well as diurnal and hourly changes. Generally, very short-term fluctuations in the intra-minute and inter-minute timeframe are small relative to installed capacity. In this analysis related to power system modelling it is the hourly and daily variations that are important.

Power system issues associated with wind energy's variability are well documented [4] and have been the focus of many wind integration studies which are summarized in the following [5]. Variability of power sources in a power system can cause issues for system balancing and make the commitment and dispatch of conventional power plant difficult. In general the more variability within a power system the more flexible the power system is required to be. Wave energy, as it is largely generated by winds is also a variable power source. However fluctuations of wave energy are expected to be different to wind fluctuations, as waves in deep water lose their energy only slowly and the energy can hence travel long distances. Wave energy is subject to cyclic fluctuation, dominated by wave periods and wave heights. This lets power levels vary both on a daily and monthly basis, with seasonal variations being less in more temperate zones [6]. The issue of variability for renewable resource can be mitigated to a certain extent by having the resource spread over a large geographical area. This has the effect of 'smoothing' out the variability. The

benefits of having a geographical spread to a variable resource such as wind are well understood. Poorly correlated resources can smoothen out the total net variability (net variability is the demand minus the variable renewable generation) of the aggregated resource. On the other hand if the resources are well correlated then the net variability of the aggregated resource would be expected to increase and this would not be beneficial for the power system as a whole. Also as different renewable energy technologies fluctuate over a different time-scale, a diverse portfolio of renewable generation options (ie wind, wave and solar etc) can be beneficial for the power system as the natural cycles of each generation type may compliment each other [7].

Previous work on combining wind and wave energy has investigated the correlation of wind and wave time series off the coast of Ireland [8]. The study found that West and South coasts of Ireland generally experience wave systems, which are dominated by (from an energy point of view) large swell systems, generated by remote wind systems, which have little correlation with the local wind conditions. This means that the smoothing effect due to the integration of poorly correlated diversified sources reduced the combined variability. The paper concluded by stating that the potential benefits of the integration of wind and wave resources, where the climate of the location is appropriate, are too important to be neglected.

The focus of this paper is quantify these benefits in terms of the impacts on wholesale electricity prices and power system operation by modelling Irelands SEM (single electricity market) with and without 500 MW of wave energy and quantifying the differences. The paper complements previous work in the area of tidal energy in Ireland [9]. The approach and software used in this analysis is similar. However, we use an updated model of the All Island Single Electricity Market (SEM), PLEXOS_IE, which includes all new power plant anticipated to come online in the Irish system in the year 2020. The year 2020 is chosen as a test year for the simulations as Ireland has renewable energy target for 2020.

In addition to investigating the impacts on market prices, this paper also models the revenue received by wave power generators operating within the market

under a range of carbon prices. This builds on previous work [10] which investigated the performance and economic viability of the Pelamis wave energy converter (WEC) using 2007 wave energy data from various global locations based on annual energy output, cost of energy, internal rate of return and net present value. An Excel based model, NAVITAS, was developed (which is also used in this paper), which estimated the annual energy output of the Pelamis for each location, and produced financial results dependent on various input parameters. It was shown that while some study locations looked attractive for development from a cost of energy and annual energy output point of view, results were highly influenced by initial costs and the number of devices. Section 2 of this paper introduces renewable and ocean energy policy in Ireland. Section 3 introduces the single electricity market in Ireland and details the software and data used to model the market and market rules that determine the wholesale price of electricity. Section 4 presents results and discussion.

2.0 Context

The Irish Government has set a goal to make Ireland a world leader for research, development and deployment of ocean energy technologies. Ireland has an estimated wave energy resource of 21 TWh and an ambition to achieve at least 500 MW installed generating capacity from ocean energy by 2020 [11]. In order to achieve the ambition, the Department of Communications, Energy and Natural Resources established a renewable energy feed-in-tariff (REFIT) scheme for wave energy of €220/MWh. The department is supporting research for the development and demonstration of projects and is preparing a strategic environmental assessment of marine energy in Ireland [12]. In addition the Sustainable Energy Authority of Ireland (SEAI) is developing a National Wave Energy Test Site in the west coast of Ireland for near-shore, mid-water and deep water devices. The purpose of the wave energy test site is to provide a location for the temporary mooring and deployment of wave energy machines so that their performance in generating electricity and their survivability can be tested and demonstrated in open ocean conditions. It is proposed for the site to operate for up to 20 years with devices on site intermittently throughout the year. Further detail on the policies in place and the gaps that exist in order to meet the 500 MW target are presented and discussed in [13].

3.0 Methodology

This paper examines the inclusion of 500 MW of wave energy into the All Island generation mix in 2020 with levels of wind energy installation estimated to deliver Republic of Ireland (ROI) national renewable energy targets. The effect of additional wave energy is evaluated in the context of wholesale electricity prices in the All Island single electricity market, system operational costs, CO₂ emissions and the financial viability of a 500 MW wave project.

This analysis draws upon two main resources to develop a 2020 power systems model of the SEM. The first is Ireland's Commission for Energy Regulation (CER) validated electricity market model for 2009 which presents a large number of actual generator technical constraints operating within the SEM [14]. The model used in that exercise has been previously used to validate and model the SEM [14]. This model is expanded in this study by the authors to the year 2020 and considers new power plant that will be constructed in this period. Secondly, Eirgrid's (The Irish Transmission system operator) Generation Adequacy Report (GAR) [15] is used to estimate electricity demand and estimated peak electricity load for 2020. The GAR is also used to assess what power plant will be in operation in 2020 in the SEM. These resources are presented and discussed below. The study assumes that there are no significant rules changes to the SEM or to the broader market by 2020.

3.1 PLEXOS Software Modelling Tool

The software tool PLEXOS [16] is used in this analysis. PLEXOS, developed by Energy Exemplar, is a sophisticated power systems modelling tool that uses mixed integer optimisation techniques to determine the least cost unit commitment and dispatch solution to meet demand while respecting generator technical-economic constraints. This software is used in this analysis as PLEXOS was chosen by the CER to simulate and forecast the operation of the SEM in its first three years of operation. The PLEXOS software has been shown that it is capable of correctly modelling the SEM [14].

3.2 Single Electricity Market.

All electricity from a wave farm generating power in Ireland with a capacity greater than 10 MW will have to be sold into the SEM. This section briefly describes the SEM and market rules. A detailed description of these rules can be found at [17].

Since November 2007, Ireland and Northern Ireland are combined in the All Island Single Electricity Market. The SEM is a centralized or gross pool market with 48 trading periods per day (24 hours) with the first period at 06.00. Electricity is bought and sold through the pool under a market clearing mechanism. Generators receive the System Marginal Price (SMP) for their scheduled dispatch quantities, capacity payments for their actual availability, and constraint payments for changes in the market schedule due to system constraints. The SMP is the price calculated by the market software for every half hour trading period that will cover the cost of meeting the marginal cost of demand in the SEM. Suppliers purchasing energy from the pool pay the SMP for each trading period, capacity costs, and system charges. The SEM market rules are set out in the Trading and Settlement Code [17]. The SEM is designed around a single unconstrained marginal pricing structure, i.e. the price determined within the market ignores transmission and reserve constraints but respects generator physical abilities. The system marginal price is made up of a shadow price component and an uplift component. Shadow prices form the basis of the SMP calculation for each half hour trading period. However, paying for generation at shadow prices will mean that generator units will not recover the full costs of production as the shadow price does not reflect the start up and no load costs of the unit. The shadow price only reflects the cost of supplying an infinitesimal change in demand. As a result, situations can arise where units do not recover their “full” costs over a continuous period of running. The uplift element of the SMP pertains to the recovery by generator units of their production costs. Uplift is a mechanism of adding to the marginal-cost-based market price so that no generator makes a loss when both fixed and variable costs are considered. Uplift is an ex-post calculation and does not affect the optimal dispatch. Wind is currently modelled as a price taker in the SEM. A price taker cannot set the SMP, it merely receives (or takes) whatever the SMP is set at during the trading period.

Wave energy is also expected to be modelled as a price taker and is so in this analysis. Generators within the SEM may also earn capacity payments, however these are not considered within this analysis.

3.3 Modelling Process

We built a PLEXOS model for Ireland PLEXOS_IE, using the validated CER 2009 model as a starting point. We configured PLEXOS_IE to undertake one year (2020) of daily optimizations at half hourly resolutions as in the SEM. The simulation proceeds by using the PLEXOS software tool to solve these steps in chronological sequence, using the Xpress MP solver [18]. Two scenarios are run; one without wave energy and a second with wave energy. PLEXOS_IE is populated with individual generator technical characteristics such as maximum and minimum generation levels, maximum ramp rates (up and down), start costs, heat rates, mean time to failure and mean time to repair. These are presented in detail in appendix A. Within the developed 2020 model the Great Britain (GB) power system and interconnection to the SEM is modelled as in (14). Both the current Moyle interconnector and proposed East-West Interconnector are modelled with a total capacity of 1000 MW. GB is modelled as a single gas generator. Historically, gas-fired generation has predominantly been the marginal plant type on the GB system, and there has correspondingly been a correlation between the cost of gas-fired generation (including carbon) and the GB power price. We used the annual and peak electricity demand assumptions in ROI and Northern Ireland from EirGrid's median demand forecast from the Generation Adequacy Report 2011-2020 which predicts an All Island demand of 42546 GWh with a peak demand of 7399 MW. This demand for 2020 is mapped to half hours based on the historic half hourly load shape in ROI and NI from 2007. The load shape for 2008 was available but the shape was heavily skewed compared to typical demand profiles, due to the impact of the global economic crisis reducing demand in the latter part of the year.

3.3.1 Wind and Wave Data

We use normalized wind profiles from 12 regions around Ireland for the year 2008. The regions are shown in Figure 1. The profiles were originally prepared

by Eirgrid for use in the 2009 SEM validation exercise and comprise of half hourly metered wind power data from existing wind farms in Ireland (14). It is assumed in this analysis that this wind data adequately represents a typical wind year. The average capacity factor for wind generation for the year 2008 was 31.7%. The long term time weighted annual average from 2002 to 2009 was 32.2% with a range of 34.7% to 29.1%. (15). The authors accept that in general it is better to undertake modelling of power systems with significant wind energy penetration with a number of years of wind data so as to account for the effect of annual variability. Unfortunately unavailability of good quality concurrent wind and wave data made this impossible for this exercise.

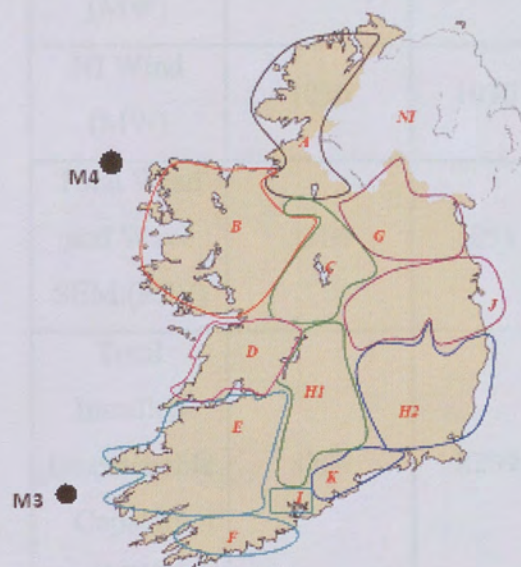


Figure 7.1: Wind Regions and buoy locations (M3 and M4) (14)

Installed wind capacities in each region are scaled up from current installed capacities to deliver the ROI RES-E targets of 40% of electricity generation with and without the contribution of wave energy. Note that ROI's target of 40% renewable electricity is also made up of contribution from hydro and biomass. These are included in the estimation of 40% targets. Offshore wind capacity and installed wind capacity in Northern Ireland (NI) is held constant for both scenarios as detailed in Table 1 as these are independent fixed targets. We used wave data from the M3 and M4 buoys, [19], owned by the Marine Institute [20]. Data was quality controlled and checked for consistency before use. A de-rating

of 10% was applied to the wave device to take into account array losses, availability and electrical losses. This value was estimated by the authors.

Table 7.1: Installed Wind Capacities and Wave capacity

Wind Region	Scenario 1: No wave energy (MW)	Scenario 2: With 500 MW of Wave (MW)
Wave ROI (MW)	0	500
ROI Wind (MW)	4076	3521
NI Wind (MW)	1030	1030
Total Wind and Wave SEM (MW)	5106	5051
Total Installed Dispatchable Capacity (MW)	8209	8209
RES % ROI*	40%	40%

Monthly generation (GWh) and monthly capacity factors (%) for wind and wave outputs are shown below for the target year. It can be seen that monthly capacity factors are well correlated showing similar seasonal trends. Note that due to the higher annual capacity factor of wave energy 555 MW of installed wind capacity is required to meet the equivalent energy produced by 500 MW of wave energy. It can be seen that while both scenarios produce the same amount of energy over the course of the year the combined wind and wave scenario produce more

energy that a wind alone in the winter months whereas the wind alone scenario produce less energy over the summer months.

Table 7.2 details the percentage of time of the year when wind power output is greater than the combined wave and wind power output. Also shown are the periods when the combined wave and wind power output is greater than wind alone output.

Table 7.2: Monthly details of average outputs when combined wind and wave output is greater than wind alone output

	% of Year when Combined Wave and Wind Output is greater than wind alone output	% of Year when Wind alone is greater than Combined Wave and Wind Output
Jan	5.4%	3.1%
Feb	4.1%	3.9%
Mar	4.8%	3.7%
Apr	3.7%	4.5%
May	1.9%	6.6%
Jun	3.2%	5.0%
Jul	1.7%	6.8%
Aug	3.3%	5.2%
Sep	5.2%	3.0%
Oct	5.1%	3.4%
Nov	3.8%	4.4%
Dec	5.7%	2.6%
Sum	47.9%	52.1%

Combined wind and wave output is on average higher than wind alone output for approximately 48% of the year generally during the winter and autumn months when wave output is high. Another interesting point about the wind and wave relationship is that when it is very windy (i.e. the hourly capacity factor for wind is greater than 60%) the wind alone output is generally higher than the combined wind and wave output. Contrarily when the wind alone output is very low the combined wind and wave output is slightly higher.



Figure 7.2: Monthly wind (S1) and wind and wave generation (S2) (GWh) for target year. Scenario 1 is shown in black for wind only-scenario. Scenario 2 is shown in a red line for wave and wind combination.



Figure 7.3: Monthly wave and wind capacity factors (%)

To put the 40% renewable energy target for ROI in context, Figure 7.4 shows the projected weekly wind energy generation (from Scenario 2) as a percentage of weekly All Island demand. Note that as a result of wind energy’s strong output in the winter and autumn months, there will be a requirement at times for more thermal generation online during the summer months than winter months, even though the demand in winter is higher.

	Coal	Gas	Oil	Renewables
Percentage of Total Demand	20%	40%	10%	30%

These percentages are based on output of the EIA Commission’s PRIMES model 2015-2030 and are added to the model to the price of the fuel. To check the consistency of the results to carbon price two extra carbon price cases have also been run. These prices are €15 and €45 per tonne.

4.5 Results and Discussion

The detailed PRIMES-2030 model was run with and without 100 MW of wind capacity. The results show that the 100 MW of wind capacity would reduce the total cost of the system by 10%.

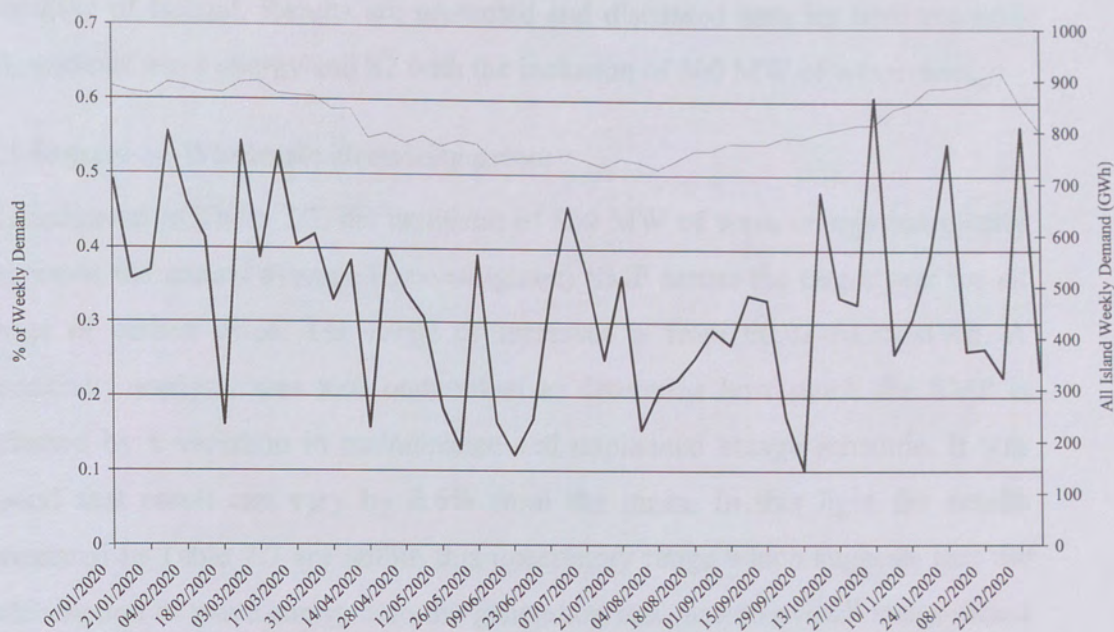


Figure 7.4: Weekly wind energy generation as a percentage of weekly All Island electricity demand for 2020

3.3.2 Fuel and CO2 prices

Fuel prices are taken from a recent Eirgrid economic analysis [21] and are provided in Table 7.3. Fuel prices are held constant across all simulations.

Table 7.3: Delivered Fuel prices including Carbon Cost

	Coal	Low Sulphur Fuel Oil	Gas	Distillate Oil	Peat
Purchase Price (€cents/net GJ)	212	640.2	702	1206	318

CO2 price assumptions are based on outputs of the EU Commission’s PRIMES model 2009 of €30/tonne and are added in the model to the price of the fuel. To check the sensitivity of the results to carbon prices two extra carbon price cases have also been assessed. These prices are €15 and €45 per tonne.

4.0 Results and Discussion

The detailed PLEXOS-IE 2020 model was run with and without 500 MW of installed wave capacity while maintaining a 40% annual RES-E target for the

Republic of Ireland. Results are presented and discussed here for both scenario S1, without wave energy and S2 with the inclusion of 500 MW of wave energy.

4.1 Impact on Wholesale electricity prices

As indicated in Table 7.7, the inclusion of 500 MW of wave energy marginally increases the annual average (time weighted) SMP across the target year for all cases of carbon price. The range of increases is from €0.02-€0.35/MWh. A sensitivity analysis was also undertaken to determine how much the SMP is effected by a variation in maintenance and unplanned outage schedule. It was found that result can vary by 0.6% from the mean. In this light the results presented in Table 7.7 are within this uncertainty range which suggests that the introduction of wave energy into the generation mix, has an overall insignificant impact of wholesale electricity prices compared to a wind only scenario for the fuel price examined.

Table 7.7: Annual time weighted values for system marginal price (SMP), uplift and shadow price.

	Carbon €15/t		Carbon €30/t		Carbon €45/t	
	No Wave	500 MW Wave	No Wave	500 MW Wave	No Wave	500 MW Wave
SMP €/MWh	56.44	56.79	63.30	63.32	71.56	71.64

The marginal increase in SMP for the wave scenario is primarily due to the monthly variation of wave generation and its impact on thermal plant. Over the summer months, due to the lower generation of wave, more thermal generation is required and the marginal cost of this generation is higher relative to the wind only scenario.

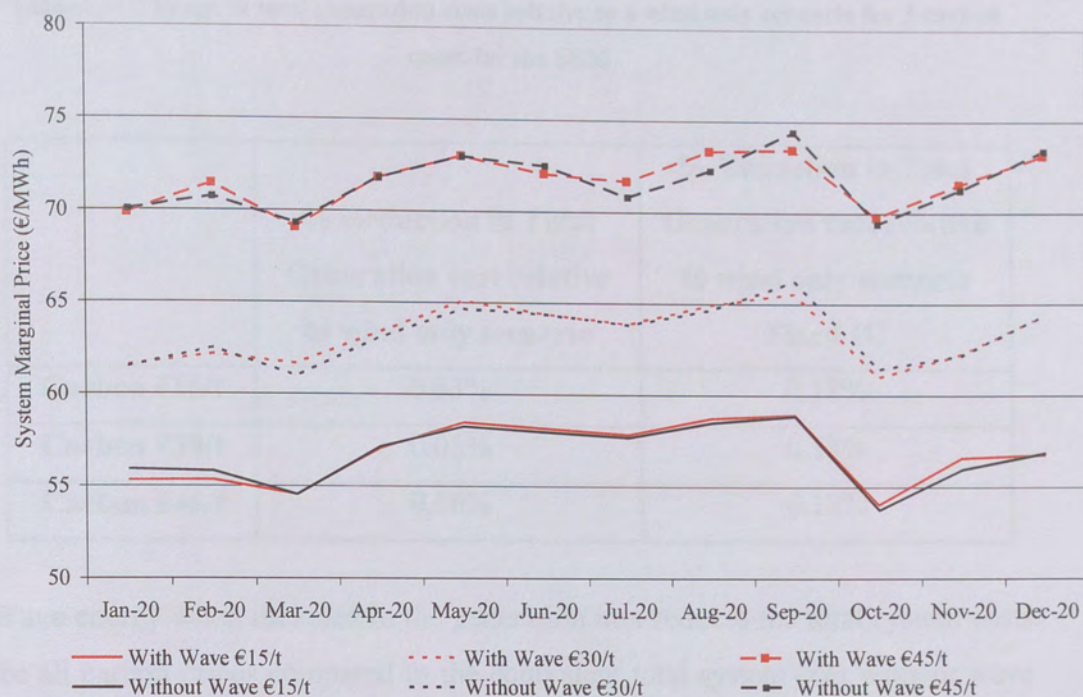


Figure 7.5: Monthly variation of SMP for both Scenarios and 3 cases of carbon price

4.2 System Impacts and Costs

The impact on SEM system operation costs were also examined. It must be borne in mind that the SEM is an unconstrained market schedule and does not consider transmission or system constraints. Deviations from the market schedule due to these constraints are covered in the market by balancing costs which in 2009 were reported to be €3/MWh [25]. The results presented in Table 7.8 exclude these costs but do give insight into the possible effects of wave energy on the Irish system. Note that total system costs are the sum of generation costs, and start-up costs. The generation cost comprises of both fuel costs and carbon costs. To test the sensitivity of results a large number of simulations were run with varying outage and maintenance schedules and result showed that total generation cost could vary by 0.07% from the mean. Another set of simulations was also run where the interconnector flows between GB and the AI were fixed for each scenario (Fixed IC). This was done to isolate the effect of import and export flows from the SEM and also to investigate how results would change if interconnector flows were scheduled ‘day ahead’.

Table 7.8: Change in total generation costs relative to a wind only scenario for 3 carbon cases for the SEM

	% Reduction in Total Generation cost relative to wind only scenario	% Reduction in Total Generation cost relative to wind only scenario Fixed IC
Carbon €15/t	0.63%	0.18%
Carbon €30/t	0.05%	0.18%
Carbon €45/t	0.16%	0.18%

Wave energy when included in the generation mix reduces the total system costs for all carbon prices compared to the equivalent total system cost without wave energy in the SEM. Reductions in SEM total system costs range from approximately €8.1m to €0.73m with the largest difference for the €15/tonne carbon case when interconnector flows are not fixed. The inclusion of wave energy generally reduces the system marginal price in winter months and increases the price in summer months relative to a wind only scenario. This has the effect of reducing imports in winter and reducing exports in summer relative to a wind only scenario. Figure 7.6 shows the monthly variation of total generation cost for the scenario without fixed interconnection flow. The introduction of wave energy reduces the overall need for peaking plant and some mid merit plant to generate during the winter months. This reduction in costs is enough to offset the higher cost of generation during the summer months when wave energy is at is lowest.

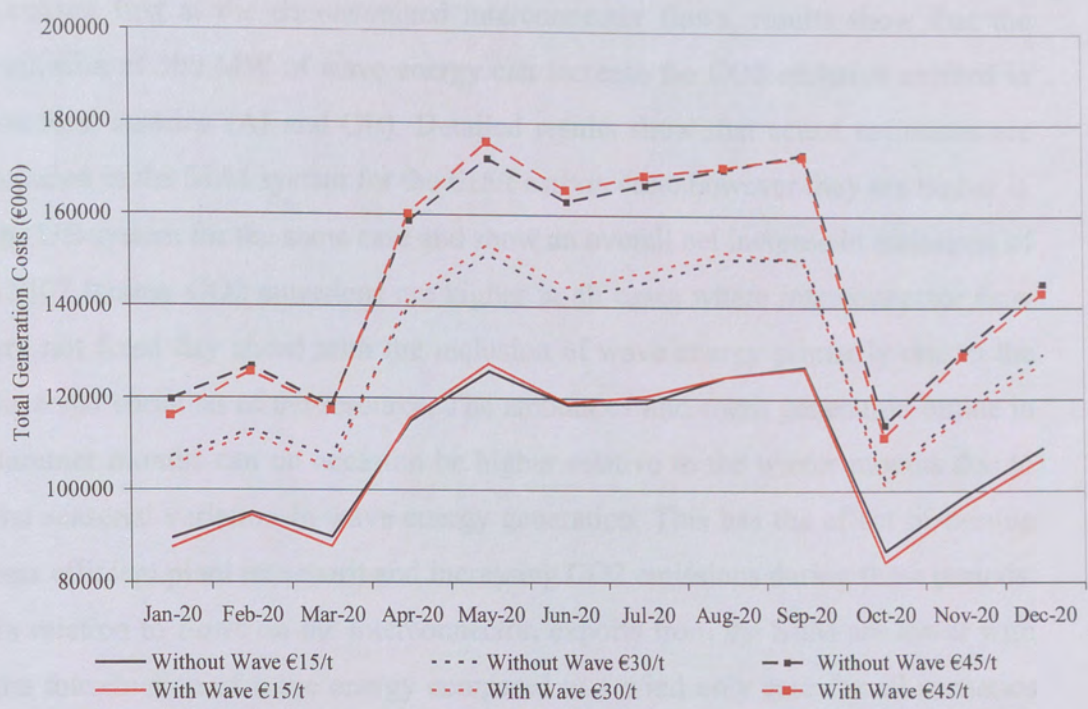


Figure 7.6: Monthly total generation costs for both scenarios and all carbon cases.

The change in CO2 system emission was also examined in scenarios with and without wave energy (Table 7.9). The emissions are counted by comparing the difference in tonnes of CO2 emission in the SEM and GB system relative to the wind only case. An extra case was also run where the interconnector flow were fixed for each case of carbon price to simulate a situation where IC flows were fixed day ahead. Note that a ‘-’ negative number means a reduction in emissions relative to a wind only case.

Table 7.9: Change in CO2 emissions relative to a wind only scenario for 3 carbon cases for full system

	% Change in Emissions relative to wind only scenario	% Change in Emissions relative to wind only scenario -Fixed IC
€15/t	0.01%	0.10%
€30/t	0.01%	-0.11%
€45/t	0.30%	-0.02%

Looking first at the unconstrained interconnector flows, results show that the inclusion of 500 MW of wave energy can increase the CO₂ emission emitted in the total systems (AI and GB). Detailed results show that actual emissions are reduced in the SEM system for the €15/t carbon case, however they are higher in the GB system for the same case and show an overall net increase in emissions of 15807 tonnes. CO₂ emissions are higher in all cases where interconnector flow are not fixed day ahead with the inclusion of wave energy primarily due to the seasonal variation of the resource. The amount of mid-merit generation online in summer months can on occasion be higher relative to the winter months due to the seasonal variation in wave energy generation. This has the effect of bringing less efficient plant into merit and increasing CO₂ emissions during these periods. In relation to flows on the interconnector, exports from the SEM are lower with the introduction of wave energy compared to a wind only case for all scenarios and imports are also lower. This is because at times when wind output is high the wind and wave combination is generally at a slightly lower output, thus limiting the potential for export to GB. This has the effect of increasing thermal generation in GB and increasing CO₂ emission relative to a wind only case. Imports to SEM are also reduced as at times when wind output is very low as the combined wind and wave output is slightly higher thus reducing the need for imports. When interconnector flows for each carbon case are fixed the emissions in the GB system are equal for each case and it is possible to see the effect on the SEM only. Results show that for higher carbon prices case the inclusion of wave energy can reduce CO₂ emissions in the SEM.

5.0 Conclusion

This paper has examined the effect of the inclusion of 500 MW of wave power into Ireland's generation mix relative to a scenario in which wind energy meets the bulk of Ireland's renewable energy target for electricity of 40%. Results show that the introduction of wave energy has a negligible effect on wholesale electricity prices as defined by the system marginal price of electricity. However, the results do not reflect the cost increase which would be passed on to the consumer via public service levy. The analysis also showed that wave energy has a much stronger seasonal bias than wind energy and this bias has some important implications for system operational cost. In all cases examined, the inclusion of

wave energy reduced total system operation costs relative to a wind only scenario, although the reductions were small. CO₂ emissions modelling showed that due to the seasonal bias of wave energy production relative to a wind only scenario, the inclusion of wave energy has the potential to increase CO₂ emission in the Island of Ireland, although that increase would be marginal. Note also that due to the unavailability of good quality concurrent wind and wave data only one year of simulations were undertaken. More robust conclusions would be obtained from further analysis of a number of years of concurrent data.

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Chapter 8: Conclusions and Future Work

This thesis has investigated the role, operation and modelling of PHES in power systems with significant levels of variable renewable generation. It was shown in Chapter 2 that there is considerable interest in the development of PHES projects in Europe and abroad with renewable energy integration being cited as one of the primary drivers for its development. Chapter 3 benchmarked the historic operation of Ireland's only PHES facility, Turlough Hill, against the simulated operation of the plant using a power system model developed using the PLEXOS software. It was shown that when technical characteristics such as reduced efficiency at minimum stable operation level, reserve provision and rough running ranges are included, the model can simulate the historic operation of the plant very well. Chapter 3 focussed on the Irish power system in 2008 which had relatively low levels of installed wind capacity. Chapter 4 instead focussed on the year 2020 when Ireland is expected to produce almost 40% of its electricity from wind generation. The issue of perfect foresight of forced outages and wind power production in power system modelling was addressed and it was shown that total system costs are underestimated when these issues are not accounted for. It was also shown the higher resolution temporal modelling of the power system is required to correctly account for ramp rates of thermal plant which are not captured in hourly modelling of the power system. Finally Chapter 4 showed that Turlough Hill will play an ever more important role in the future Irish power system as levels of wind generation increase. The modelling of larger pumped hydro storage was addressed in Chapter 5 where new techniques and methodologies were put forward for the operation of larger PHES plant in the context of wind forecast uncertainty. It was shown that stochastic optimisation of intertemporal targets using historic wind data and wind power forecasts provided lower overall total system costs when compared to traditional techniques. Chapter 6 presented a soft-linking technique to improve the interpretation of results for the electricity sector from an energy system model by using high resolution simulations from a power system model. It was shown that for the system examined, the energy system model underestimated the use and value of flexible resources such as pumped hydro energy storage. It was also demonstrated that the energy system model was unable to correctly capture

levels of wind curtailment predicted by the power system model. Finally in Chapter 7 the impact of the Irish government's targets of 500 MW of wave energy was briefly examined. It was shown that the inclusion of wave energy into the Irish generation mix has the potential to reduce overall system operation costs when compared to a wind only scenario, however the magnitude of these savings were small.

In summary this thesis has developed techniques and methodologies which permit the answering of questions which could not heretofore be answered. These range for example from the impact of binding ramp rates of thermal units to assessing the contribution of PHES to the operational flexibility of the power system. Questions in relation to the operation of large PHES in the context of wind uncertainty are also resolved. Overall this thesis has shown the value of PHES to the power system as a whole, rather than solely as a technology to absorb excess wind production. PHES facilitates the integration of wind energy in more subtle and indirect ways, by increasing overall system flexibility thereby allowing thermal plant to operate more efficiently. This important aspect can only be captured by high resolution (sub hourly) modelling of the complete power system.

Future work will focus on the development and implementation of the soft-linking methodology developed in Chapter 6 with a focus on improved modelling and representation of residential electrical heating loads, smart metering technologies and electrical vehicles in power system models in order to better inform on results from energy system models. Work is also currently ongoing on 5 minute temporal modelling of the 2020 Irish power system using the PLEXOS software to determine the insights and benefits of this level of technical modelling.

Appendix A

PLEXOS Detailed Equations: Deterministic Versions:

Indices

j	Generation Unit
t	Time period.
stor	Index related specifically to pumped storage unit
RES^{up}	Upper Storage Reservoir
RES_{low}	Lower storage Reservoir

Variables

V_{jt}	Integer on/off decision variable for unit j at period t
X_{jt}	Integer on/off decision variable for pumped storage pumping unit j at period t
U_{jt}	Variable that = 1 at period t if unit j has started in previous period else 0
P_{jt}	Power output of unit j (MW)
H_{jt}	Pump load for unit j period t (MW)
W_{int}	Flow into reservoir at time t (MWh)
W_{outt}	Flow out of reservoir at time t (MWh)
W_t	Volume of storage at a time t (MWh)

Parameters (make lower Case)

vl	Penalty for loss of load (€/MWh)
vs	Penalty for Reserve not met
use	Unserved Energy (MWh)
usr	Reserve not met (MWh)
D	Demand (MW)
obj	Objective Function
n_{jt}	No load cost unit j in period t (€)

c_{jt}	Start cost unit j in period t (€)
m_{jt}	Production Cost unit j in period t (€)
e_{stor}	Efficiency of pumping unit (%)
$pmax_j$	Max power output of a unit j (MW)
$pmin_j$	Mini stable generation of unit j (MW)
$pmpmax_{stor}$	Max pumping capacity of pumping unit
J_j	Available units in each generator
J_{stor}	Number of pumping units
MRU_j	Maximum ramp up rate (MW/min)
MRD_j	Maximum ramp down rate (MW/min)
MUT_j	Minimum up time (hrs)
A_p	Number of hours a unit must initially be online due to its MUT constraint (hrs)
W_{INT}	Initial Volume of reservoir (GWh)
W	Maximum volume of storage (GWH)

Objective Function:

$$OBJ = \min \sum_{t \in T} \sum_j c_{jt} U_{jt} + n_{jt} V_{jt} + m_{jt} P_{jt} + vl_{use_t} + vs_{usr_t} \quad (1)$$

The objective function in PLEXOS is to minimise the start up cost of each unit (start cost (€)* number of starts of a unit) + the no load cost of each online unit + production costs of each online unit + the penalty for unserved load+ the penalty of unserved reserve.

The objective function is minimised within each simulation period. The simulation solution must also satisfy the constraints below:

Energy Balance Equation:

$$\sum_{t \in T} P_{jt} - H_{jt} + use_t = D_t \quad (2)$$

Energy balance equation states that the power output from each unit at each interval minus the pump load from pumped storage units for each interval + unserved energy must equal the demand for power at each interval. (Note that line losses can also be included here but is not shown). As the penalty for unserved energy is high and part of the objective function, the model will generally try to meet demand.

Operation Constraints on Units:

Basic operational constraints that limit the operation and flexibility of units such as maximum generation, minimum stable generation, minimum up/down times and ramp rates.

$$-V_{jt} + U_{jt} \geq -1 \quad \forall t=1 \quad (3)$$

$$V_{jt} - V_{jt+1} + U_{jt+1} \geq 0 \quad (4)$$

These two equations define the start definition of each unit and are used to track the on/off status of units.

$$P_{jt} - P_{\max j} V_{jt} \leq 0 \quad (5)$$

Max Export Capacity: A units power output cannot be greater than it maximum export capacity.

$$P_{jt} - P_{\min j} V_{jt} \geq 0 \quad (6)$$

Minimum Stable Generation: A units output must be greater than it minimum stable generation when the unit is online.

$$H_{jt} - P_{mp \max stor} X_{jt} \leq 0 \quad (7)$$

Pumping load must less than maximum pumping capacity for each pumping unit

$$V_{jt} + X_{jt} \leq 1 \quad \text{where } j \in stor \quad (8)$$

$$V_j \leq J_j \quad X_j \leq J_{Stor} \quad j \in J \quad (9)$$

These constraints limits a pumped storage unit from pumping and generating at same time.

$$A_{p,j} \geq V_{j,t} - V_{j,t-1} \forall t..t - MUT_j - 1 \quad (10)$$

$$V_{j,t} \geq A_{p,j} - \sum_t^{t-MUT_j+1} V_{j,t} / MUT_j \forall t$$

Minimum Up Times⁸: (Note the following text is directly from the PLEXOS Help files). The variable **A_p** tracks if any starts have occurred on the unit inside the periods preceding **p** with a window equal to MUT. **i.e.** if no starts happen in the last MUT periods then **A_p** will be zero, but if one (or more) starts have occurred then **A_p** will equal unity. The MUT constraints then sets a lower bound on the unit commitment that is normally below zero, but when a unit is started, the bound rises above zero until the minimum up time has expired. This fractional lower bound when considered in an integer program forces the unit to stay on for its minimum up time.

$$A_{p,j} \geq V_{j,t-1} - V_{j,t} \forall t..t - MDT_j + 1$$

$$V_{j,t} \leq 1 + \sum_t^{t-MDT_j+1} V_{j,t} / MDT_j - A_{p,j} \forall t$$

Minimum Down Times: The variable **A_p** tracks if any units have been shut down inside the periods preceding **p** with a window equal to MDT. **i.e.** if no units are shutdown in the last MDT periods then **A_p** will be zero, but if one (or more) shutdown then **A_p** will equal unity. The MDT constraints then set an upper bound on the unit commitment that is normally above unity, but when a unit is stopped, the bound falls below unity until the minimum down time has expired.

⁸ PLEXOS Help Files

$$P_{jt} - P_{j,t-1} - MRU_j V_{jt} - p_{\min j} U_j \leq 0 \quad (12)$$

$$p_{\min j} P_{jt} + P_{jt} - P_{j,t-1} - P_{jt} (MRD_j - p_{\min j}) \leq 0 \quad (13)$$

Maximum Ramp up and down constraints: These constraints limit the change in power output from one time period to another.

Water Balance Equations:

These equations track the passage of water from the lower reservoir to the upper reservoir. In this set-up there is no inflow and water volume is conserved.

$$W_{tR} + W_{out,tR} - W_{in,tR} = W_{INT,R} \quad \forall t = 1, R \in RES_{Up}, RES_{low}$$

$$W_{t,RES^{up}} + W_{out,RES^{up}} - W_{in,RES^{up}} = 0$$

$$e_{stor} H_{jt,RES^{up}} - W_{in,RES^{up}} = 0$$

$$P_{stor,t} - W_{out,t,RES^{up}} = 0 \quad (10)$$

PLEXOS Equations: Stochastic Versions

Indices

- j Generation Unit
- t Time period (Optimisation interval as in Table 2)
- stor Index related specifically to pumped storage unit
- s Stochastic Scenario (stage 1 has 7 scenarios, while stage 2 has 3 scenarios)
- RES^{up} Upper Storage Reservoir
- RES_{low} Lower storage Reservoir

Variables

- V_{jt} Integer on/off decision variable for unit j at period t
- X_{jt} Integer on/off decision variable for pumped storage pumping unit j at period t

U_{jt}	Variable that = 1 at period t if unit j has started in previous period else 0
P_{jt}	Power output of unit j (MW)
H_{jt}	Pump load for unit j period t (MW)
W_{int}	Flow into reservoir at time t (MWh)
W_{outt}	Flow out of reservoir at time t (MWh)
W_t	Volume of storage at a time t (MWh)

Parameters

vl	Penalty for loss of load (€/MWh)
use	Unserved Energy (MWh)
vs	Penalty for Reserve not met
usr	Reserve not met (MWh)
D	Demand (MW)
obj	Objective Function
k_s	Probability of scenario s
n_{jt}	No load cost unit j in period t (€)
c_{jt}	Start cost unit j in period t (€)
m_{jt}	Production Cost unit j in period t (€)
e_{stor}	Efficiency of pumping unit (%)
$pmax_j$	Max power output of a unit j (MW)
$pmin_j$	Mini stable generation of unit j (MW)
$pmpmax_{stor}$	Max pumping capacity of pumping unit
J_j	Available units in each generator
J_{stor}	Number of pumping units
MRU_j	Maximum ramp up rate (MW/min)
MRD_j	Maximum ramp down rate (MW/min)
MUT_j	Minimum up time (hrs)
A_p	Number of hours a unit must initially be online due to its MUT constraint (hrs)
W_{INT}	Initial Volume of reservoir (GWh)
W	Maximum volume of storage (GWH)
δ	Penalty price if storage end volume for upper reservoir deviates from unique solution-penalty for non respecting non-anticipativity. (€)

θ_t Deviation of storage level from a unique solution at period t. Measure of non compliance with non-anticipativity. (MWh)

Objective Function:

$$OBJ = \text{Min} \sum_{s \in S} \sum_{t \in T} k_s \cdot c_{jt} \cdot U_{jt} + k_s \cdot n_{jt} \cdot V_{jt} + k_s \cdot m_{jt} \cdot P_{jt} + k_s \cdot v_{luse_t} + k_s \cdot v_{s.usr_t} + k_s \cdot \delta \theta_t \quad (1)$$

The objective function in PLEXOS is to minimise the start up cost of each unit (start cost (€)* number of starts of a unit) + the no load cost of each online unit + production costs of each online unit + the penalty for unserved load+ the penalty of unserved reserve. The last terms in the objective function deals with the cost of non compliance for non-anticipativity for storage levels as set out in equation 14. The penalty is set to a high value so in general the model will meet the non-anticipativity unless there is risk of very high prices or unserved energy. The objective function is minimised within each simulation period. The simulation solution must also satisfy the constraints below:

Energy Balance Equation:

$$\sum_{s \in S} \sum_{t \in T} P_{jst} - H_{jst} + use_t = D_{ts} \quad (2)$$

Energy balance equation states that the power output from each unit at each interval minus the pump load from pumped storage units for each interval + unserved energy must equal the demand for power at each interval.. As the penalty for unserved energy is high and part of the objective function, the model will generally try to meet demand.

Operation Constraints on Units:

Basic operational constraints that limit the operation and flexibility of units such as maximum generation, minimum stable generation, minimum up/down times and ramp rates.

$$-V_{jst} + U_{jst} \geq -1 \quad \forall t = 1 \quad (3)$$

$$V_{jst} - V_{jst+1} + U_{jst+1} \geq 0 \quad (4)$$

These two equations define the start definition of each unit and are used to track the on/off status of units.

$$P_{jst} - P^{\max}_j \cdot V_{jst} \leq 0 \quad (5)$$

Max Export Capacity: A units power output cannot be greater than it maximum export capacity.

$$P_{jst} - P^{\min}_j \cdot V_{jst} \geq 0 \quad (6)$$

Minimum Stable Generation: A units output must be greater than it minimum stable generation when the unit is online.

$$H_{jst} - P^{\max}_{mp\ stor} \cdot X_{jst} \leq 0 \quad (7)$$

Pumping load must less than maximum pumping capacity for each pumping unit

$$V_{jst} + X_{jst} \leq 1 \text{ where } j \in stor \quad (8)$$

$$V_j \leq J_j \quad X_j \leq J_{stor} \quad j \in J \quad (9)$$

These constraints limits a pumped storage unit from pumping and generating at same time.

$$A_{p,j} \geq V_{j,t} - V_{j,t-1} \forall t..t - MUT_j - 1 \quad (10)$$

$$V_{j,t} \geq A_{p,j} - \sum_t^{t-MUT_j+1} V_{j,t} / MUT_j \forall t$$

Minimum Up Times⁹: (Note the following text is directly from the PLEXOS Help files). The variable A_p tracks if any starts have occurred on the unit inside the periods preceding p with a window equal to MUT . i.e. if no starts happen in the last MUT periods then A_p will be zero, but if one (or more) starts have occurred then A_p will equal unity. The MUT constraints then sets a lower bound on the unit commitment that is normally below zero, but when a unit is started,

⁹ PLEXOS Help Files

the bound rises above zero until the minimum up time has expired. This fractional lower bound when considered in an integer program forces the unit to stay on for its minimum up time.

$$A_{p,j} \geq V_{j,t-1} - V_{j,t} \forall t..t - MDT_j + 1$$

$$V_{j,t} \leq 1 + \sum_t^{t-MDT_j+1} V_{j,t} / MDT_j - A_{p,j} \forall t$$

Minimum Down Times: The variable A_p tracks if any units have been shut down inside the periods preceding p with a window equal to MDT. **i.e.** if no units are shutdown in the last MDT periods then A_p will be zero, but if one (or more) shutdown then A_p will equal unity. The MDT constraints then set an upper bound on the unit commitment that is normally above unity, but when a unit is stopped, the bound falls below unity until the minimum down time has expired.

$$P_{jst} - P_{js,t-1} - MRU_j \cdot V_{jst} - p_j \cdot U_j \leq 0 \quad (11)$$

$$p_{\min j} \cdot P_{jst} + P_{jst} - P_{js,t-1} - P_{jst} \cdot (MRD_j - p_{\min j}) \leq 0 \quad (12)$$

Maximum Ramp up and down constraints: These constraints limit the change in power output from one time period to another.

Water Balance Equations:

These equations track the passage of water from the lower reservoir to the upper reservoir. In this set-up there is no inflow and water volume is conserved.

$$W_{stR} + W_{out,stR} - W_{in,stR} = W_{INT,R} \quad \forall t = 1, R \in RES_{Up}, RES_{low}$$

$$W_{st,RES^{up}} + W_{out,s,RES^{up}} - W_{in,s,RES^{up}} = 0$$

$$e_{stor} \cdot H_{jst,RES^{up}} - W_{in,stRES^{up}} = 0$$

$$P_{stor,st} - W_{out,st,RES^{up}} = 0 \quad (13)$$

$$-W_{s_n t RES^{up}} + W_{s_n t + 1 RES^{up}} + \theta_{st} = 0 \quad \forall n \in S \quad (14)$$

