

JOINT PROGRAMME ON ENERGY STORAGE MECHANICAL STORAGE SUBPROGRAMME

TECHNOLOGICAL DEVELOPMENTS FOR PUMPED-HYDRO ENERGY STORAGE

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PREFACE

Today, everything seems to indicate that pumped hydro energy storage (PHES) is experiencing a second, or even third, youth (Fayolle and Lafon, 2008). Main drivers of such reemergence are mostly related with concerns on climate change and depletion of fossil fuels, which have been transposed into international agreements, regional directives, and national and local regulations (UN, 1998; EC, 2009). As a consequence of these concerns and associated regulations, there has been a strong deployment of renewable energy (REN) technologies, which is still ongoing.

Amongst all REN sources, wind seems to be at present the one with the largest economically feasible potential (Lu et al., 2009), but also with the highest variability (Wan, 2005; Taulan et al., 2009; Paradinas et al., 2012), and the most difficult to predict (Greaves et al., 2009; Hodge et al., 2012).

In this context, PHES "reemerges" as an excellent means to integrate wind power into the electric power system, not only because of its maturity and technically proven flexibility, but also because of its significant remaining potential (EURELECTRIC, 2011; IEA, Technology Roadmap, 2012; Lacal Arántegui et al., 2012). Within this new role, special attention is given to variable speed PHES (Schwery and Kunz, 2009; EPRI, 2013; HEA, 2013) and hydraulic short-circuit operation (Taulan et al., 2009; Lippold et al. 2012).

The objective of this report is to describe some current trends and future challenges on PHES in relation with its role in REN integration, with special emphasis on mechanical aspects of hydraulic machinery, power electronics devices used for variable speed operation, and utilities' operation strategies both in liberalized and centralized markets contexts.

The remainder of this document is organized as follows. In Chapter 1, after a brief introduction and historical background, the new generation of PHES is presented with particular focus on those equipped with variable-speed technology. Typical configurations of pumped-storage hydropower plants (PSHPs) are also briefly described, discussing their capability for providing grid support services, such as load-frequency regulation, inertia and short-circuit power. Chapter 2 focuses on reversible pump-turbines, discussing their operating limits and presenting the state-of art of the research on their unstable behavior. In chapter 3, the operating principle and some basic aspects of the electrical machines most widely used in PSPHs are described. In chapter 4, power electronics devices typically used in PSHPs for both start-up in pumping mode and variable speed operation are described in detail, along with some recent developments on variable speed drives. In chapter 5, utilities' operation strategies are reviewed in detail, and some future challenges to make the best possible use of PHES assets according to their new role are identified.

1 Pumped Storage Hydropower Plants: the new generation

1.1 Introduction

In the last decades, world electrical energy consumption has significantly increased with a rate that has reached 17.7% in 2010 and is predicted to double by 2025 (IEA, Key World Statistics, 2012). The increasing concern about environmental aspects has favored a corresponding rapid growth of the deployment of the renewable energy sources aimed at the progressive reduction of fossil fuel exploitation and dependence. In such a context hydropower is undoubtedly one of the most mature technologies with an electricity production of about 3,500 TWh in 2010 (16.3% of the world's electricity), greater than that of the other renewable sources combined (3.6%), but much smaller than that of the fossil fuel plants (67.2%) (IEA, Technology Roadmap, 2012) (Figure 1.1).



Figure 1.1 World electricity generation by fuel

In the EU-27 the hydropower generation was 323 TWh in 2010 (9.8% of the European electricity) and around 60% of electricity generation from renewable sources (EC, 2011). Even though today hydropower plays a key role in the green energy production, avoiding the combustion of 4.4 million barrels of oil equivalent daily, only 33% of potential hydro resources have been developed and the remaining technical potential is estimated to be very high (14,576 TWh/year) (IEA, Technology Roadmap, 2012) (Figure 1.2).



Figure 1.2 World hydropower technical potential (IEA, Technology Roadmap, 2012)

The highest percentage of undeveloped potential is located in Africa (92%), followed by Asia (80%), Oceania (80%) and Latin America (74%), even though this region is also characterized by two of the top ten hydropower producers in 2010 (Table 1.1) and by several countries with a very large share of electricity generation obtained by hydropower (Table 1.2) (IEA, Technology Roadmap, 2012).

Besides the positive effects on climate mitigation, hydropower also presents other considerable advantages: it promotes price stability because, unlike fuel and natural gas, it is not subject to market fluctuations; it reduces environment vulnerability to floods; it contributes to fresh water storage for drinking and irrigation exploitations; it makes a significant contribution to development by bringing electricity, roads, industry and commerce to communities which can benefit future generations as hydropower projects are long-term investments with an average life span of 50–100 years.

Country	Hydro electricy [TWh]	Share of electricity generation [%]				
China	694	14.8				
Brazil	403	80.2				
Canada	376	62.0				
United States	328	7.6				
Russia	165	15.7				
India	132	13.1				
Norway	122	95.3				
Japan	85	7.8				
Venezuela	84	68.0				
Sweden	67	42.2				

 Table 1.1 Top ten hydropower producers in 2010 (IEA, Technology Roadmap, 2012)

Share of	Countries	Hydropower
hydropower		Generation
~ 100%	Albania, DR of Congo, Mozambique, Nepal,	54 TWh
	Paraguay, Tajikistan, Zambia	
>90%	Norway	126 TWh
>80%	Brazil, Ethiopia, Georgia, Kyrgyzstan, Namibia	403 TWh
>70%	Angola, Columbia, Costa Rica, Ghana,	77 TWh
	Myanmar, Venezuela	
>60%	Austria, Cameroon, Canada, Congo, Iceland,	351 TWh
	Latvia, Peru, Tanzania, Togo	
>50%	Croatia, Ecuador, Gabon, DPR of Korea, New	36 TWh
	Zealand, Switzerland, Uruguay, Zimbabwe	

Table 1.2 Countries with more than a half of their electricity generation from hydropower in 2010 (IEA,
Technology Roadmap, 2012)

Despites numerous examples of excellent, sustainable and safe exploitation of the water resources by hydropower, large hydro projects, which include a dam and a reservoir, encountered a substantial opposition in the latter end of the last century because of their environmental and social implications (landscape, wildlife, biodiversity, population settlement, health and water quality, etc..). This opposition was one of the main factors of the slowdown in the hydroelectricity generation between the late 1990s and the early 2000s (IEA, Technology Roadmap, 2012; IEA, Key World Statistics, 2012).

However, eliminating large hydropower projects from renewable energy programs will not reduce the power demand, which will be partially satisfied by thermal plants, thereby increasing the global level of greenhouse gas emissions. For instance, it was demonstrated that two PHES units combined with a thermal generation unit make it possible to reduce the excess emissions of the thermal unit by 60% (Nazari et al., 2010).

In such a context, a renewed interest in large PSHP and a huge demand for the rehabilitation is globally emerging both due to further increases in the corresponding share of renewable electricity production and due to the support, in terms of storage capacity, of a wider exploitation of other renewable energy sources such as wind and solar power.

Even though these renewable energy sources have largely increased in the last years, reaching in 2010 a share of 3.6% of the world electricity generation (IEA, Key World Statistics, 2012), this share would need to be greatly increased in order to significantly contribute to the reduction of greenhouse gas emissions (GHG). The European Union policy has made great efforts towards developing these resources in response to environmental concerns, but their unpredictable and intermittent characteristics have restrained their deployment because of the negative impact on power system security, stability, reliability and efficiency (ENTSO, 2010).

At present, the electricity grid is highly centralized with a complex system of energy productiontransmission characterized by a long distance between power plants and end-users and by a limited use of storage, whose installed capacity was about 127.9 GW in 2010 (2.5% of the world installed capacity) (EPRI, 2010). To ensure the security of the power system, a continuous balance between demand and supply should be guaranteed and this actually limits penetration in the grid of intermittent renewable energy sources, whose energy production is fluctuating, unpredictable and delocalized. For example, as regards the potential wind energy penetration in the electricity grid, an instantaneous increase up to 20% of the total energy production was estimated to be feasible without technical hitches for the grid stability. However, further increases in wind energy generation (up to 80%) are feasible only in isolated grids (smaller than 10MW), whereas greater electrical grids require energy storage to accept a wind energy penetration greater than 20% (Padron et al., 2011)

The development of a significant energy storage capacity is, therefore, a necessary solution to favour the deployment of the renewable energy sources not only in isolated grids, but also in interconnected grid systems, as demonstrated by several analyses carried out on a national scale (Anagnostopoulos & Papantonis, 2012; Steffen, 2012).

For this reason, the European Union is carrying out a Climate and Energy policy, defined in the Strategic European Technology Plan (SET-Plan) (European Commission, 2011), one goal of which is to study more in depth the benefits of storage applications. In such a context, several studies (EPRI, 2010; Loisel, 2012; Rangoni, 2012) have been carried out to analyse the current status of the wide range of available technologies (mechanical, electromagnetic, chemical, thermal) in terms of technology maturity, efficiency, energy storage capacity, power discharged capacity, application size, cost of investment, life time and environmental impact.

All these analyses identify PHES as being the most cost-efficient large-scale storage technology currently available, with an efficiency range of 75-85% and competitive costs (600-1000 €/kW). In Europe, this technology represents 99% of the on-grid electricity storage (EPRI, 2010) with more than 7400 MW of new PSHPs proposed and a total investment cost of over 6 billion € (Deane et al., 2010). In spite of this boost provided by the increasing need for storage capacity, one of the major limits for the further development of PHES is the lack of suitable locations for the construction of new facilities. To overcome this problem, analyses to identify areas that could be quite easily modified in order to construct the reservoirs of the PHES were carried out (Connolly et al., 2010) and the possibility of exploiting the sea as lower reservoir (sea-water PSHPs) and of excavating underground reservoirs was considered (Pickard, 2011; Uddin, 2012). However, in the long-term perspective to fulfil the increasing storage capacity need, besides the installation of new PHES sites, it would be necessary to adapt and exploit the existing hydropower plants, as was achieved in France during the 1970s and 1980s to support the nuclear power reactors or as recently proposed in Greece to support REN penetration. To reach this aim, the existing hydropower and PHES plants should not only optimize turbine performance by means of innovative design criteria (see Chapter 2) so as to increase the corresponding storage efficiency and to achieve the required greater flexibility, but also modify their operation strategies in order to maximize the revenue from the day-ahead market and from the regulation services (see Chapter 5). The resulting storage capacity will also favour a different economical approach to investment in REN production based not only on the incentive mechanisms, but also on the techno-economic optimization of the plant operation. This would be aimed at maximizing returns by storing the amount of green production during the low demand periods and selling it to the system during the peak demand periods, thereby providing the required grid stability by means of a fast response time.

1.2 The new generation of pumped-storage hydropower plants

A PHES plant converts grid-interconnected electricity to hydraulic potential energy (so-called "charging"), by pumping the water from a lower reservoir to an upper one during the off-peak

periods, and then converting it back during the peak periods ("discharging") by exploiting the available hydraulic potential energy between the reservoirs like a conventional hydropower plant.

These plants require very specific site conditions to be feasible and viable, among which proper ground conformation, difference in elevation between the reservoirs and water availability. For these reasons, the earliest PSHPs were built in the Alpine regions of Switzerland and Austria whose ground conformation together with the presence of hydro resources was suitable for PHES.

The first PSHP, owned by state utilities, were built to supply energy during the peak periods, allowing the base-load power plants to operate at high efficiency, and to provide balancing, frequency stability and black starts. The period from the 1960s to the late 1980s was characterized by a significant development of these plants mainly due to the corresponding deployment of nuclear power plants whose great inertia was compensated by the PHES flexibility (Figure 1.3) (Deane et al., 2010).



Figure 1.3 Development of the PSHPs in EU

In the 1990s the reduced growth of the nuclear plants together with the increasing difficult identification of suitable locations significantly limited the further development of new PSHPs. For this reason, in 2006 the average percentage of PHES installed capacity was only about 6% of the full generation installed capacity in the majority of the world countries with the exception of Luxemburg (67%). This percentage was greater than 10% only for those countries characterized by a significant

availability of hydro sources (Croatia) or by a significant percentage of installed nuclear power capacity (Latvia, Japan and the Slovak Republic). USA and Japan still maintained the world highest installed PHES capacity with 20815 MW and 24575 MW respectively, whereas in the European context the largest number (23) of PSHPs are concentrated in Germany.

In recent years, after the liberalization of the market, the increasing interest in renewable energy sources has again turned public attention towards the PHES as a mature and large scale energy storage technology to support green energy production and to provide grid stability. In such a context, several new PHES have been planned in Europe for a total power capacity of 7426 MW (EC, 2009) and some of them will adopt the variable-speed reversible pump-turbines breakthrough technology (sect. 1.4.4.2), whose peculiarity is to improve the pump-turbine efficiency over a wider range of operating conditions and to improve the capability in grid regulation of the PHES (Ciocan et al., 2012; Henry et al., 2012).

Due to great interest towards such a technology, several new PHES have been constructed or are under construction in Europe and all around the world. Table 1.3 presents an overview of this new generation whereas Table 1.4-Table 1.7 present technical details on the most important PHES under construction equipped with the variable speed technology.

Two of the largest PHES under construction in Europe that are equipped with this technology are Nant de Drance and Linthal, located in the south west and the north east of Switzerland respectively. In both these power plants the use of the variable speed technology was justified by the wide head variation: in the power station of Nant de Drance, equipped with six variable speed units with a unit output of 157 MW (rated speed=428.6 rpm; speed range= \pm 7%), the gross head varies between 250 and 390 m; in the power station of Linthal, equipped with four variable speed units with a unit output of 250 MW (rated speed=500 rpm; speed range= \pm 6%), the gross head varies between 560 and 724 m (Table 1.4).

The use of the variable speed technology allows to enlarge the working field of the PHES in comparison with a conventional fixed speed configuration, as it can be seen in Figure 1.4, comparing these variable-speed PHES with the other recently installed by Alstom Power.

Table 1.5 reports the project features of another important installation, that is the PHES of Goldisthal, in Germany, equipped with two fixed units and two variable-speed units, whereas Table 1.6 and Table 1.7 reports the project features of the PHES of Frades II and of other variable speed PHES still under construction.

DHES	Head [m]	Power per	Runner	Speed [rpm]	Country	
I IIES		unit [MW]	diameter [m]	speed [1pm]	Country	
Afourer I	600	175		750.00	Morocco	
Afourer II		60		500.00	Morocco	
Alqueva I	71.1	129	-	136.40	Portugal	
Alqueva II	72	134		136.40	Portugal	
Baixo Sabor Jusante	35	18	3.948	150.00	Portugal	
Baixo Sabor Montante	100	77	4.112	214.29	Portugal	
Beni Haroun	680	90	2.205	750.00	Algeria	
Cruachan	396	106			UK	
Dniester	147.5	324	7.300			
Dos Amigos	38.1	28			USA	
Feldsee	548	73	1.919	1000.0	Austria	
Foz Tua	99	125	4.837	187.50	Portugal	
Grand Maison	955	152.5		600.00	France	
Grimsel II	400	90		750.00	Switzerland	
Guangzhou	535	306		500.00	China	
Hintermuhr	518	74	1.870	1000.0	Austria	
Hohhot	503/585	306		500.00	China	
Huizhou	630	300		500.00	China	
Kozjak	713.2	220	-	600.00	Slovenia	
Kops II (ternary)	723.1/818.2	162	2.800	500	Austria	
La Muela II	520	850	-	600.00	Spain	
Lam Ta Khong	360	260		428.60	Tahiland	
Lang Yashan	153	166	4.700	230.77	China	
Limberg II	288/436	240	3.920	428.57	Austria	
Pedreira		20	-	120.00	Brasil	
Salamonde II		207		166.70	Portugal	
Shahe		51		300.00	China	
Tierfehd (Nestil)	1066	142	2.263	600.00	Switzerland	
Tongbal	289	306	4.802	300.00	China	
Venda Nova II	410	191.6		600.00	Portugal	
Vianden M11	295	200	4.286	333.33	Luxemburg	
Yang Yang		258		600.00	South Korea	
Yecheon		408		400.00	South Korea	
Yixing	420	262	4.394	375.00	China	
Zarnowiec	128	188	6.008	166.67	Poland	
Zanghewan		255		333-33	China	

Table 1.3 The New Generation of PHES

DHEC	Nant de	Linthal	Tehri
r nllð	Drance 2019	2015	2016
Rotational Synchronous speed [rpm]	428.6	500.0	230.77
Speed range	±7%	±6%	±6%
Head variation [m]	250/390	560/724	830/740
Nominal output per unit [MW]	157	250	255
Maximum pump discharge per unit [m ³ /s]	56	-	-
Maximum turbine discharge per unit [m³/s]	60	-	-
Generator Mode [MVA]	175	280	278
Motor mode [MW]	172	250	
Runner diameter [m]	6.009	4.230	

Table 1.4 The new generation of PHES equipped with the variable-speed technology

PHES	Goldisthal
Rotational Synchronous speed [rpm]	333
Speed range (2 units)	+4%/-10%
Head variation [m]	279.2/334.0
Nominal output per unit [MW]	265
Maximum pump discharge per unit [m³/s]	80
Maximum turbine discharge per unit [m³/s]	103
Runner diameter [m]	4.593

Table 1.5 The Goldisthal project

PHES	Frades II
Rotational Synchronous speed [rpm]	375
Speed range (2 units)	+2%/-7%
Head [m]	413.64/431.8
Nominal output per unit [MW]	383
Generator Mode [MVA]	419.5
Motor mode [MW]	372
Maximum turbine discharge per unit [m ³ /s]	100
Runner diameter [m]	4.52

Table 1.6 The Frades II project

ригс	Venda	Omarugawa	AVCE	Grimsel
PILS	Nova III	III		III
Rotational Synchronous speed [rpm]	-	600	600	-
Speed range	-	±4%	±4%	-
Max Head [m]	-	688/720	521	580
Nominal output per unit [MW]	380	310	185	200
Generator Mode [MVA]	420	319	195	-
Motor mode [MW]	380	310	185.25	-
Maximum turbine discharge per unit [m³/s]	-	-	40	-
Maximum pump discharge per unit [m³/s]	_	44.1	34	-

Table 1.7 Under construction variable- speed PHES



Figure 1.4 Alstom experience with PSP projects.

It is interesting to highlight that in the great part of these plants the design priority was given to flexibility in pumping mode, maximizing the pump operating range, whereas in other cases, such as the PSHP of Tehri under-construction in India (four variable-speed units of 255MW; rated

speed=230.77rpm; speed range= \pm 6%) the hydraulic design was optimized to increase the global plant efficiency (Table 1.4). These different design strategies, aimed at maximizing the plant revenue, are due to the different electricity market regulations and in particular to the existence (or not) of a remunerative regulation market, that could significantly affect the definition of the plant management strategies (Chapter 5).

As regards the power converter technology, significant advances have been made in recent years, as for example the 100 MVA variable speed frequency converter provided by ABB for the PSHP of Grimsel 2 (Switzerland), enabling a wider variable speed pumping (\pm 12%) but not generating. However, to increase the voltage range and to reduce cost, size and losses still remain the main challenges to face in order to develop a \pm 100% power converter.

Even if these plants represents the starting point of a new generation of PHES, the possibility in terms of speed variation is limited to about $\pm 10\%$ due to the lack of full variable-speed design criteria, allowing the pump-turbine to operate at a high efficiency in a wide range of rotation velocities, and to the lack of a full power converter technology, enabling a full-range variable speed turbining and pumping (Table 1.4 - Table 1.7).

As regards the mechanical equipment, Computational Fluid Dynamics (CFD) has allowed significant advances to the understanding of the reasons of the unstable behaviour of the pump-turbines that prevent PHES from operating at low load (Chapter 2). However, innovative design criteria allowing electricity production in the whole operating range (o-100% of the peak power) still have to be developed and certainly represents the future challenge for the development of a new generation of pump-turbine.

1.3 Unconventional pumped-storage hydropower plants

In recent years, to favour the spread of large scale storage, in addition to the renewed interests in conventional PHES projects, new storage concepts have been proposed and developed on the basis of the possible exploitation of unconventional lower reservoirs. In such a context, two of the most interesting proposals are undoubtedly sea-water and underground PHES, exploiting sea and underground caverns respectively.

Since one of the main problems limiting a significant spread of PHES is the identification of suitable sites, the idea of exploiting unconventional lower reservoirs certainly represents a possibility for a further exploitation of this storage technique. Moreover, these plants are characterized by lower civil construction costs due to the need of constructing a single reservoir instead of the two required by conventional PHES. However, in spite of several and recognized advantages deriving from these new

storage concepts, there are also important barriers (technological, economic, regulatory, environmental, social and other acceptance, etc.) actually limiting their intensive deployment. Next, pilot projects as well as feasibility studies regarding these unconventional storage solutions will be summarized.

As regards <u>sea-water PHES</u>, Japan pioneers in building the first demonstration plant in the northern part of Okinawa Island. This project, whose construction was performed from 1991 to 1999, commenced operation in 1999 and it was tested for 5 years in order to demonstrate the feasibility of a seawater pumped storage power generation technology.

Figure 1.5 and Figure 1.6 report a view and a plan view of the power plant, whereas Figure 1.7 reports a sectional view of the waterways. The upper reservoir, located 500 m away from the seashore at the elevation of 150m, is clearly identifiable because of its octagonal shape. The outlet of the tailrace was protected from the waves by tetra-pods. Table 1.8 reports the main specifications about the Okinawa power plant, whereas much more details can be found in (Fujihara et al., 1998) and in (Hino and Lejeune, 2012).

The most interesting aspects of the construction of this seawater PSHP are undoubtedly the challenging problems that have been faced due to the need on one side of pumping-up sea water and on the other of mitigating the environmental impact of this type of plants on the seawater ecosystem.



Figure 1.5 View of the Seawater Pumped-storage Power Plant, Okinawa Pref. in Japan (Fujihara et al., 1998)



Figure 1.6 Plan view of the seawater PHES in Okinawa (Japan) (Fujihara et al., 1998)



Figure 1.7 Sectional view of the waterways of the Okinawa Project (Hino and Lejeune, 2012)

Okinawa Yanbaru Power Plant		Specification
Power plant	Max. Output	30 MW
	Max. Discharge	26 m ³ /s
	Effective head	136 m
Upper regulating pond	Туре	Excavated type, Rubber sheet-lined
	Max. embarkment height	25 M
	Crest circumference	848 m
	Max. Width	251.5 m
	Total storage capacity	0.59x106 m ³
	Max. depth	22.8 m
Waterway	Penstock	Inside dia. 24 m Length 314 m
	Tailrace	Inside dia. 27 m Length 205 m

Table 1.8 Main specifications of the Okinawa Project

As regards the mechanical equipment, studies were carried out to define structural features of mechanical equipment for seawater applications and measures for preventing corrosion and adhesion of marine organisms (Fujihara et al., 1998).

A binary set was preferred to other configurations (see sect. o) and the assembly was designed in order to take out easily the runner from below for maintenance work, whereas in the zones of supposed water stagnation the pump-turbine was coated with anti-pollution type dirt-prevention paint.

As regards the environmental impacts, the most significant impact factors were identified by a study committee:

- Outflow of muddy water from the construction area into the gullies and sea area near the river mouth
- Reduction of habitat area duet to land changes
- Noise and vibration from heavy equipment
- Damages to small animals from construction vehicles and accidents to falling down into roadside gutters

And proper countermeasures were carried out to significantly reduce these factors, such as water chemical treatments, low-noise machinery, animal intrusion prevention nets, etc. (Hino and Lejeune, 2012).

As a consequence of the positive results obtained by the Okinawa plant, other possible seawater projects have been considered and feasibility studies have been proposed in the last years (Pina et al., 2008; McLean and Kearney, 2014; Alterach et al., 2014).

As regards **<u>underground PHES</u>**, the first idea of exploiting a disused mine as an underground reservoir dated from 1960 (Harza, 1960) and it was developed by several studies and technical reports but not accompanied by functioning pilot projects (Pickard, 2011).

This storage concept presents several advantages in comparison with conventional PHES, as for example the higher possibility of social acceptance and the larger number of potential sites.

From a technical point of view, even though the construction of an underground storage reservoir is possible, the main limit is the need of competent rock, especially at reservoir depths.

Madlener and Specht (2013) presented an extremely interesting techno-economical analysis of the possible construction of underground PHES in Abandoned Coal Mines in the Ruhr area (Germany).

In this area, the geological conditions resulted not to be optimal and might be uneconomical with the exception of the use of tubular underground drift grids for the intake of water.

As regards the investment costs, the profitability depends from the realizable head. In case of low heads, the cost rate for the extension of the lower reservoir, in order to increase the accumulation capacity, dominates in comparison with other expenses. However, the relative cost rate decreases with increasing heads.

Apart from the higher construction cost of the lower reservoir, the analysis of Madlener and Specht (2013) highlighted expected higher maintenance and repair costs in comparison with conventional PHES and a possible lower service life. However, the possibility of placing the lower reservoir directly below the upper reservoir certainly reduces the length of headrace and/or tailrace and hence the corresponding costs.

An interesting <u>unconventional pumped hydro project</u>, proposed in Estonia (Project ENE 1001, 2010), is that of Muuga whose completion is expected in 2020. Table 1.9 reports some details of the proposed project (Project ENE 1001, 2010).

The peculiarity of this project is that it combines two different unconventional reservoirs: the sea as upper reservoir and underground chambers, resulting from granite excavations, as lower reservoir (Figure 1.8).

Muuga Plant	
Max. Plant Output	500 MW
Max. Unit Output	1X100 MW pump-turbine
	2x175 MW pump-turbine
	1x50 MW Francis turbine
Average Operation Height	500 m
Max. Discharge	110 m ³ /s
Diameter of delivery conduit	7.0 m
Max. Water velocity	3.1 m/s
Water consumption (by 12-hour operation full capacity)	4.75 Mm ³

Table 1.9 Main specification of Muuga Project



Figure 1.8 Schematic diagram of the seawater Muuga PHES (Project ENE 1001, 2010).

As for underground PHES, the total volume of the lower underground reservoir define the number of hours of plant operation at the nominal capacity, that is 12 hours for the Muuga project. The technological and environmental needs deriving from the use of seawater will require to adopt proper countermeasures on the basis of the Okinawa project experience. More details about civil works and technical solutions can be found in the description of the project (Project ENE 1001, 2010).

To conclude this section, it is worth mentioning a proposal of unconventional PHES, presented by De Boer et al. (2007) about an **inverse offshore pump accumulation station** (IOPAC), that is a seawater PSHP combined with an offshore wind power plant.

The idea is to station the plant on an artificial island, called the "Energy Island", consisting of a ring of dikes enclosing a seawater reservoir, approximately 6 km long and 4 km wide (Figure 1.9). According to proposed scenario, the reservoir would be dredged to a depth of 50 meters below sea level with a capacity of 30 GWh and a maximum generation capacity between 2000 and 2500 MW. The island will be built from the sand, obtained from deepening the reservoir.



Figure 1.9 Sketch of the inverse offshore pump accumulation station (de Boer et al., 2007)

The operating principle of the station is the following one. When the wind power exceeds the request, the station pumps the water out of the reservoir. Otherwise in shortage conditions, the floodgates are opened and the sea water flows into the turbines, producing the requested power difference (Figure 1.10).



Figure 1.10 Sketch of the cross Section of the station (de Boer et al., 2007)

A possible site location has been found in the Netherland coast, where the presence of a layer of clay on a right depth (50 m below the sea level) and with a good thickness (40 m) should prevent the groundwater entering in the inner reservoir by percolating through the substrata. Bentonite walls, already feasible till a depth of 60 m, should prevent seawater leakage.

An in-depth analysis of the technical, economical and ecological aspects of this project is still under investigation.

1.4 Power plants configurations

Several machine configurations have been used throughout the history of pumped storage. These configurations differ in the number of hydraulic and electric machines used. In general, they can be classified as:

- Binary set: One pump-turbine and one electrical machine (motor/generator)
- Ternary set: One turbine, one pump and one electrical machine (motor/generator)
- Quaternary set: One turbine driving one generator and one pump driven by one motor.

Each configuration has its own advantages and disadvantages. In what follows, these configurations will be described.

1.4.1 Binary set

This is, by far, the most used scheme. Without doubt, this is because it is the cheapest one. The most common configuration uses a single-stage pump turbine coupled to a synchronous electrical machine directly connected to the grid. This set rotates in one direction when supplying energy to the grid and in the opposite direction when consuming energy from the grid.

Single stage pump turbines can be used with heads from 10 m up to 700 m (Alstom, 2010) (Figure 1.11). For larger heads multistage pump turbines should be used (Figure 1.11). Multistage pump turbines can be used with heads from 700 m up to 1200 m (Alstom, 2010).

However, this increase in head range comes at a price: multistage pump turbines do not usually have wicket gates (Cuesta and Vallarino, 2000), therefore, are unable to contribute to load frequency control. In the 1980's, a partial solution to this drawback was proposed and tested: double stage pump turbines with two adjustable sets of wicket gates, one for each runner (Alstom, 2010). It is a more complicated hydro mechanical equipment but it could contribute to power frequency control. In this sense, it is worthy to mention the regulated double stage reversible pump turbine recently supplied by Alstom for the Yang Yang PSHP (Alstom, 2010).



Figure 1.11 Scheme of a single stage pump-turbine (left) and of a multi-stage pump-turbine (right) (Alstom, 2010) Inertia contribution depends on unit inertia. Short-circuit power contribution is around 5 per unit (typical value for synchronous machines). Load frequency control contribution depends on the pump-turbine response.

Unit operation in generating mode is similar to conventional Francis units operation. It must be taken into account, that in general it is not possible to reduce water hammer overpressures slowing wicket gates closing since flow variation due to pump turbine speed variation is larger than the one due to wicket gates opening variation. This is of particular importance in case of an emergency shutdown of the units. Therefore, valves and pipes should be designed to resist frequent water hammer overpressures.

Unit operation in pumping mode is similar to conventional pumps operation, which means no load frequency control capability. Notwithstanding, in order to reduce the starting torque in pumping mode, the runner should rotate in air until rated speed is met. For this purpose, prior to unit starting, a dewatering of the pump runner should be carried out by using compressed air. Thus, compressed air needs are higher than in conventional hydropower plants.

Cycle efficiency, η_{cycle} , can be obtained from:

$$P_b = \frac{\gamma Q_n' \left(H_0 + H_r' \right)}{\eta_b \eta_g} \tag{1.1}$$

$$P_t = \gamma \eta_t \eta_g Q_n (H_0 - H_r) \tag{1.2}$$

$$\eta_{cycle} = \frac{P_t / Q_n}{P_b / Q'_n} = \eta_t \eta_b \eta_g^2 \frac{H_0 - H_r}{H_0 + H'_r}$$
(1.3)

where Y is the water specific weight; Q_n and Q'_n are, respectively, the rated flow in generating and pumping modes; H_0 is gross head; H'_r and H_r are the friction head losses between upper and lower reservoirs with Q'_n and Q_n , respectively; η average efficiency of turbine, pump or electrical machine depending on subindex: t, b, and g respectively.

There are many examples of this type of PSHPs; La Muela II PSHP (Navarro an Elipe, 2012) is a recent one.

1.4.2 Ternary set

It is composed of a turbine, an electrical motor/generator and a pump coupled altogether on the same shaft. Both, turbine and pump, rotate in the same direction in both operating modes. The electrical motor/generator is, usually, a synchronous machine. Differently from binary set in which the pump-turbine design is the result of compromises between targets of the two operating modes, in ternary set both turbine and pump designs are optimized.

Prior to 1960's, this was the preferred scheme with a horizontal shaft and a Francis turbine. Nowadays, this configuration is used only when single stage pump-turbines are not appropriate (i.e. for too large heads) and, therefore, the turbine is a Pelton turbine. Although both, horizontal and vertical shaft configurations could be theoretically used in these cases, vertical ones allow installing the pumps below water level in the lower reservoir and the Pelton turbines above the water level. In order to reduce shaft length, the Pelton turbine can operate inside a compressed air chamber that provides atmospheric conditions in the Pelton runner outlet. An example of this configuration is the Austrian hydro power plant of Kops II (Figure 1.12) (Voralberger Illwerke).

Inertia contribution depends on unit inertia. Short-circuit power contribution is around 5 per unit (typical value for synchronous machines). Load frequency control contribution depends on the Pelton turbine response.

Figure 1.13 shows efficiency versus flow rate for a Pelton turbine with two and one water jets (blue and red lines, respectively). As it can be seen, minimum flow of a Pelton turbines ranges from 10 to 20 % of maximum flow rate, which corresponds roughly to a power range of 10 to 20 % of rated power.



Figure 1.13 Efficiency variation versus percentage of maximum flow rate for a Pelton turbine (Renewables First). Unit operation in generating mode is similar to conventional Pelton units operation if the pump is decoupled (through the clutch) from the turbine-generator set. It must be taken into account that as these turbines could use deflectors in the water jets, water hammer overpressures can be properly controlled. This is of particular importance in case of an emergency shut-down of the units because deflectors allow eliminating torque in the turbine while nozzles are closed as slowly as needed.

In order to operate these units as pumps, it is necessary to couple the pump (through the clutch) to the turbine-generator set. Pump start up is carried out with the help of the turbine; once that the motor is connected and synchronized to the grid, the nozzles are closed.

In general, times are shorter than in binary units because pump start-up is carried out with the help of the turbine on the same shaft and because changing the shaft rotation direction is not necessary to go from pumping to turbine operation.

Cycle efficiency can be derived from eqs. (1.1)-(1.3).

1.4.3 Quaternary set

Quaternary configurations have two different powerhouses; one for pump units and the other one for turbine units; therefore, pumps and turbines are not mechanically coupled. Operation in generating mode is similar to that of the ternary set configuration, without the need of compressed air in the turbine chamber. Cycle efficiency and grid support capabilities are also similar to that of the ternary set configuration.

Pump start-up can be carried out "*back to back*" with a turbine or with the help of a frequency converter. Both possibilities imply an increase in the cost since proper electrical connections or an electronic converter are needed.

An example of this configuration can be found in *Gorona del viento* wind-hydro power plant (Merino et al., 2012). The hydraulic circuit consists of two water reservoirs connected by two different penstocks, one for generating and the other one for pumping. Because of the high net head (655 m), and in order to maximize the load-frequency control capability, the plant is composed of four 2.83 MW Pelton turbines. In addition, it comprises two groups of pumps. Each group will consist of one 1600 kW variable-speed pump and three 600 kW fixed speed pumps. The pumping station has a double purpose: to store the surplus wind power in the upper reservoir, to contribute to balancing the generation and demand of the island. Power absorbed by pumps will be variable depending on the system needs. The system will also have two electrical substations, one for the wind farm and the other one for the hydraulic power plant. Additionally the scheme will include a desalination plant.

1.4.4 Solutions for load-frequency control in consumption mode

In outline, load-frequency control can be provided in consumption mode¹ by means of:

1) Hydraulic short-circuit operation.

¹ The term "consumption mode" is intentionally used to include those cases where both turbines and pumps are running and the plant net power supply (generation minus consumption) is negative.

2) Variable-speed operation.

1.4.4.1 Hydraulic short-circuit operation

The so-called hydraulic short circuit operation allows providing load-frequency control by simultaneously pumping at rated power and controlling turbine power generation. To authors' knowledge, it has been only implemented in a ternary set PSHP (Kops II) (Mittereger and Penniger, 2008).

Nevertheless, theoretically it can be also implemented in binary set configurations with two or more reversible units, as well as in quaternary set configurations with at least one pump and one turbine.

The power regulation range in consumption mode depends on the power regulation range of the turbines in operation. In Figure 1.14 an example of this operating mode is shown.



Figure 1.14 Kops II hydraulic short-circuit operation (Voralberger Illvwerke).

The "excess" water that reaches the upper reservoir during load-frequency control operation can be used later for power generation. The cycle efficiency corresponding to said excess water depends on the operating point of the turbine during load-frequency control operation, and is therefore variable. Let *F* be the fraction of pump rated flow diverted for load-frequency control purposes (in per unit values) to either other unit (binary set configuration) or to the turbine coupled to the pump within the same ternary unit, the cycle efficiency corresponding to the water that reaches the upper reservoir during load-frequency control operation mode, η^{LFC} , can be derived from:

$$P_{b} = \frac{\gamma Q_{n}' (H_{0} + H_{r}')}{\eta_{b} \eta_{g}} - \gamma \eta_{t} \eta_{g} (F Q_{n}') \cdot (H_{0} + H_{r}')$$

$$(1.4)$$

$$P_t = \gamma \eta_t \eta_g Q_n (H_0 - H_r)$$
(1.5)

$$\eta^{LFC} = \frac{P_t / Q_n}{P_b / ((1 - F)Q'_n)} = \eta_t \eta_b \eta_g^2 \frac{H_0 - H_r}{H_0 + H'_r} \frac{(1 - F)}{1 - F \eta_t \eta_b \eta_g^2}$$
(1.6)

where H'_r and H_r are the friction head losses between upper and lower reservoirs with $(1-F)Q'_n$ and Q_n , respectively; see eqs. (1.1)-(1.3) for the rest of notation.

The overall cycle efficiency of the plant will therefore depend on:

- The time during which the plant provides load-frequency control both in generation and consumption modes.
- The turbine operating point during load-frequency control operation.
- The time during which the plant operates in a "classical" way.

A new ternary set PSHP, specifically designed for hydraulic short-circuit operation, is currently under construction in Switzerland (Lippold and Hellstern, 2012).

1.4.4.2 Variable speed operation

The most common solution for providing load-frequency control in pumping mode is the use of variable speed drives (Henry et al., 2012; Ciocan et al., 2012).

Figure 1.15 reports a comparison of operating ranges in terms of head and discharge variation between a fixed and a variable-speed pump-turbine with reference to the pumping mode. It is clear that the possibility of varying the speed significantly increases the operating range of the machine, which was limited, on the one hand, by cavitation problems (broken line on the right) and on the other by an instability operating area (broken line on the left), a typical behaviour of the pump-turbine at part load that should be avoided during the plant operation since it may lead to self-excited vibrations of the hydraulic system (Chapter 2).

From an electrical point of view (Chapter 3), the possibility of speed variation is obtained by means of a power converter employing power electronic to decouple motor/generator from the grid in terms of reactive power, voltage and frequency, that are properly set independently on the different sides (power-grid and motor/generator).



Figure 1.15 Comparison of operating domains between fixed (a) and variable-speed (b) pump-turbines (pumping mode) (Ardizzon et al., 2014)

The power regulation range of a variable speed pump strongly depends on the following aspects (Kopf and Brausewetter, 2005):

- The stable operation range of the pump.
- The minimum power necessary to provide at least the static head.
- The rated head and head variation.

The cycle efficiency of a variable speed PSHP can be calculated from eqs. (1.1)-(1.3). The overall cycle efficiency of the plant will depend on:

- The time during which the plant provides load-frequency control in both generating and pumping modes.
- The turbine operating point during load-frequency control operation in generating mode.
- The pump operating point during load-frequency control operation in pumping mode.
- The time during which the plant operates in a "classical" way.

1.4.5 Start-up and shut-down times

The new generation of PHES is characterized by good connection properties, depending on the power plant configuration.

Updated values of start-up and shut-down times have been recently presented by Voith Hydro in 2013 (Geise, 2013; Koutnik, 2013), considering four operating conditions:

- Standstill with the runner filled with water (ST)
- Pump Mode full load (PU)
- Turbine Mode full load (TU)
- Synchronous Condenser (SU)

Figure 1.16 and Figure 1.17 report comparisons of start-up and shut-down times between binary (reversible pump-turbine) and ternary sets typical values, considering different technological solution, as for example variable-speed and hydraulic short circuit operations.

	Pump Turbine			ti	me	sec	ond	s]
Т	Mode change		Α	В	С	D	Е	
1	Standstill		TU-Mode	90	75	90	90	65
2	Standstill		PU-Mode	340	160	230	85	80
5	SC-Mode	\longrightarrow	TU-Mode	70	20	60	40	20
6	SC-Mode		PU-Mode	70	50	70	30	25
8	TU-Mode		PU-Mode	420		470	45	25
9	PU-Mode	\longrightarrow	TU-Mode	190	90	280	60	25

Reversible PT

- A advanced conventional
- B extra fast response conventional
- C VarSpeed,

Ternary set

- D with hydraulic torque converter + hydr. short circuit, horiz, with Francis Turbine
- E same as E but vertical with Pelton Turbine



Figure 1.16 Start-up and shut-down times in different power plant configurations (Koutnik, 2013)

A - Reversible PT

	MODE CHANGE	Α	В
1	Standstill \rightarrow TU – Mode	90	60
2	Standstill \rightarrow PU – Mode	340	120
3	Standstill \rightarrow SC – Mode	120	60
4	$TU-Mode\ \rightarrow\ SC-Mode$	80	20
5	$\text{SC}-\text{Mode}\ \rightarrow\ \text{TU}-\text{Mode}$	70	20
6	$\text{SC}-\text{Mode}\ \rightarrow\ \text{PU}-\text{Mode}$	70	30
7	$PU-Mode\ \rightarrow\ SC-Mode$	140	30
8	$TU-Mode\ \rightarrow\ PU-Mode$	420	30
9	$PU-Mode\ \rightarrow\ TU-Mode$	190	30
10	$TU-Mode\ \rightarrow\ Standstill$	200	110
11	$PU-Mode \ \rightarrow \ Standstill$	160	50
12	$\text{SC}-\text{Mode} \rightarrow \text{Standstill}$	200	100

B - Ternary set (HTC + Pelton Turbine)

Figure 1.17 Comparison of start-up and shut-down times between a reversible pump-turbine and a ternary set (Geise, 2013)

2 MECHANICAL EQUIPMENT

The most common mechanical equipment adopted in the new generation of pumped-hydro energy storage is represented by pump-turbines, generally preferred to other technical arrangements, such as the combination Francis turbine/pump or Pelton turbine/pump, due to their cost-effectiveness.

Although pumped storage may solve several problems in the grid, fast and frequent changes between pumping and generating modes are required to pump-turbine, extending the operation of the machine at off-design conditions. However, the design of a pump turbine is the results of compromises between contradicting targets, as pump and turbine performance, regulation capacity, efficiency and cavitation behavior. Moreover, in the design of reversible pump-turbines a great attention is generally paid to the behavior in pumping mode, due to greater sensibility of the decelerated flow field to boundary layer detachments and flow separation, which causes recirculation and hydraulic losses. This design approach causes the onset of unstable behavior at offdesign conditions, that is not acceptable and may lead to self-excited vibrations of the hydraulic system.

Figure 2.1 reports the evolution of the discharge factor $Q_{11} = Q \left(\frac{D_{11}}{D}\right)^2 \sqrt{\frac{H}{H_{11}}}$ [l/s] versus the speed factor $n_{11} = n \frac{D}{D_{11}} \sqrt{\frac{H_{11}}{H}}$ [rpm] (where H₁₁ and D₁₁ are equal to 1 m) for three different guide vanes openings in the so-called four quadrants characteristics (Houdeline et al, 2012), where H is the head, Q is the flow rate and D is the runner diameter.

Two main features of unstable behavior of pump turbines are identifiable in Figure 2.1:

- one occurring in generating mode at low load off-design operation close to runaway conditions (S-shape of the turbine characteristic)
- the other one occurring in pumping mode at part load (saddle-type pump instability of head curve – "hump" zone)

In pumping mode, the unstable behavior is associated with a positive slope of the head-flow curve $\frac{dH}{dQ} > 0$ (Figure 2.2) and is associated to unsteady flow patterns developing inside the machine, accompanied by pressure fluctuations that may lead to self-excited vibrations of the hydraulic system with severe consequences for the PSHP.



Figure 2.1 Typical four quadrant characteristics of a high head reversible pump-turbine (Houdeline et al., 2012)



Figure 2.2 Hump zone in pumping mode (Gentner et al. 2012)

If the hump zone is located below the highest operating head, start-up of the machine at higher heads becomes impossible due to the head drop and hence it is necessary that the saddle-type head drop has sufficient margin against the highest regular operating head.
On the other side, in turbine mode, the criterion for instability is expressed by a negative slope of the head-flow curve $\frac{dH}{dQ} < 0$ or by a positive slope of the dimensionless flow-speed curve $\frac{dQ_{ED}}{dn_{ED}} > 0$ (Figure 2.3), where $n_{ED} = \frac{nD}{\sqrt{gh}}$ and $Q_{ED} = \frac{Q}{D^2\sqrt{gh}}$ (Olimstad et al., 2012) (Figure 2.3).



This instability, associated with fluctuations of head and discharge flow rate in the system, is highly unwanted during startup and synchronization, since faster startup and switch-over times are extremely important nowadays. To overcome the unstable interaction of machine and hydraulic system, additional efforts are required during the pump-turbine start-up, as the misalignment of a few wicket gates, but these techniques have not reduced the unstable behavior of pump-turbines.

So, even thought the possibility of varying the speed has significantly increased the operating range of pump-turbines, unstable operating conditions still represents a limit for the exploitation of the full-working range of pump-turbines. For these reasons, in the recent years, several studies have been carried out on these topic and a summary is presented in the two following sections.

2.1 Instability in turbine mode: S-Shaped region

In turbine mode, the unstable behavior of the machine is strictly connected with the positive slope of the dimensionless flow-speed curve $\frac{dQ_{ED}}{dn_{ED}} > 0$ (fig.3), where $n_{ED} = \frac{nD}{\sqrt{gh}}$ and $Q_{ED} = \frac{Q}{D^2\sqrt{gh}}$

(Figure 2.3) (Olimstad et al., 2012).

This instability is associated with fluctuations of speed, torque, head and flow rate that negatively affect the startup and synchronization of the pump-turbine with the grid as well as the turbine brake.

At the startup, the machine operates at the no-load condition in which the energy input (the hydraulic energy) of the turbine is completely dissipated by the energy losses. Due to the severe torque fluctuations caused by the instability development, in this operating area (red broken line in Figure 2.4) the pump-turbine could be affected by sudden changes in working mode (from turbine to pump and viceversa) as well as by significant fluctuations of the head and flow rate with possible self-excited vibrations (Zhou et al., 2011) or water hammers stressing not only the mechanical equipment but the whole power plant (Pejovic et al., 2011).



Figure 2.4 Example of a dimensionless flow-speed curve with an unstable behavior (Seidel et al., 2012)

It was demonstrated by Olimstad et al. (2012) that the main reason of the S-Shape instability operating zone is the design criterion of the pump-turbine, much more focused on the behavior in pumping mode, due to greater sensitivity of the decelerated flow field to boundary layer detachments and flow separation. For this reason, pump-turbines present some geometry differences with Francis turbines, such as an inlet blade angle much smaller than that adopted in Francis turbine. These geometry differences affect the stable behavior of pump-turbines in turbine mode, determining the appearance of S-Shape region in the pump-turbine characteristic (Figure 2.5).

To improve the pump-turbine stability, Olimstad et al. (2012) tested different geometrical configurations, characterized by geometry changes small enough not to influence the machine

performance at the design operating condition, and identified four geometrical changes positively affecting the pump-turbine behavior at part load: the increase of the inlet blade angle, the increase of the radius of the curvature on the pressure side of the leading edge in turbine mode (to reduce the incidence condition and the corresponding detachment at off-design conditions), the decrease of the inlet radius and the increase of the blade length.



Figure 2.5 Pump-turbine versus Francis characteristics for different wicket gate angles (Olimstad et al., 2012)

In another study, presented by Hasmatuchi et al. (2011a and 2011b), the flow field inside a pumpturbine was analysed at different operating conditions from the best efficiency point through the runaway condition to the turbine brake area (Figure 2.4). At this critical operating conditions, the analysis allowed to identify a stall cell, developing in the gap between runner and wicket gates and rotating with a frequency equal to 70% of the runner rotation frequency. This stall cell resulted to be related to the blockage of some runner blade channels as a consequence of a strong detachment of the boundary layer on the runner blades. At critical conditions, the stall cell induced reverse flows and vortexes also in the wicket gates, as visualized by means of high-speed cameras (Figure 2.6). This flow field analysis, combined with the acquisition of pressure signals inside the wicket gates and the draft, highlighted unstable pressure peaks 25 times greater than those at the best efficiency point (Hasmatuchi et al., 2009).

To study more in-depth the S-Shape of the turbine characteristic, some other studies have been recently carried out by means of CFD.



Figure 2.6 Visualization by air bubble injection of the flow field in the wicket gates: best efficiency point (BEP), runaway condition, low discharge (turbine brake area) (Hasmatuchi et al., 2011 and 2011b)

Barrio et al. (2012) numerically analysed the pump-turbine performance at different flow rates, obtaining a quite good agreement with the experimentally acquired pump-turbine characteristic (maximum error of 3.5%). Reverse flows inside the runner were identified both at high and part loads.

Steady and unsteady numerical simulations were carried out on the entire model of a pump-turbine by Seidel et al. (2012), bringing the machine from a stable operating condition to runaway and turbine brake conditions. The analysis revealed the onset of flow instabilities inside the runner blade channels at the runaway condition (Figure 2.7 - left). These instabilities resulted to be amplified in the S-Shape region, characterized by stall cells totally blocking some runner blade channels. Even in this case, the stall was demonstrated to rotate with a frequency equal to 70% of the runner rotating frequency (Figure 2.7 – right).



Figure 2.7 Predicted streamlines at runaway condition (on the left) and at low discharge condition (on the right) (Seidel et al., 2012)

At lower discharge conditions, the rotating stall resulted to be so intense that the large recirculation areas significantly affected not only the runner but also the rotor-stator gap and the flow channels of stay vanes and wicket gates.

This rotating stall, blocking the flow rate passage in some runner channels, determines an increase of the head, causing the change of the pump-turbine characteristic in turbine mode (Figure 2.3). The reverse flow developing in some runner channels could also favour a change of pump-turbine working mode: from turbine to reverse pump mode (Figure 2.4).

The progressive blockage action of the runner flow channels due to the development of an intense rotating stall was also confirmed by Wang et al. (2011) and by Sun et al. (2012) (Figure 2.8). They studied the effects of the misaligned guide vanes technique on the stability of pump-turbine. Although this technique succeeded in reducing the blockage action of the rotating stall (Figure 2.9)

and in eliminating the S-Shaped characteristic, it resulted to increase pressure fluctuations and unbalanced radial forces on the runner, leading to an unstable behavior at no-load condition.

Further interesting results were obtained by Gentner et al. (2012a and 2012b) that simulated the time-varying flow field evolution during the turbine brake of a pump-turbine by progressive flow rate reduction in an unsteady simulation. Differently from the studies above mentioned, in this case the development of vortexes blocking the flow inside the runner channels resulted not to be related to a rotating stall, also captured at stable operating conditions.



Figure 2.8 Streamlines inside the runner at different operating conditions in the S-Shape region (Sun et al., 2012)



Figure 2.9 Influence of the misaligned guide vanes on the flow field in the runner (Sun et al., 2012)

In particular, the vortex structure resulted to be composed by a primary vortex developing in the rotor-stator gap combined with a secondary vortex developing in the runner channels (Figure 2.10).

The primary vortex was mainly due to the cross flow on the pressure side from hub to shroud at the blade leading edge and was demonstrated to be affected by the shape of the blade leading edge.

Even in this case, the intense blocking action, caused by the vortex structure fully-developed over the inlet area of the different runner channels, determined the increase of head of the pump-turbine (S-Shape).

Widmer et al. (2012) similarly analysed the flow field evolution in the S-Shape region by means of two different numerical simulations:

- progressive reduction of the flow rate starting from the runaway condition at different fixed wicket gate angles (turbine brake).
- progressive increase of the flow rate and of the wicket gate angle starting from an operating condition in the S-Shape region.



Figure 2.10 Flow structure driving the vortex formation in the vaneless space (Staubli et al., 2010)

The first simulation allowed to identify the development of vortexes and their evolution into a rotating stall extending from the runner channels to the wicket gates. This unstable behavior, characterizing the flow field at large wicket gate angles, was not confirmed at smaller ones due to the increased clearance of the vaneless gap between runner blades and wicket gates. In this case, the analyses highlighted the development of vortexes circumferentially distributed around the whole runner entrance.

Houdeline et al. (2012) investigated the flow field development in the S-Shape area of high-head pump-turbines, identifying the development of an intense reverse flow in the runner channels. They analysed the influence of different geometries on this reverse flow and succeeded in developing a

dedicated design significantly reducing the unstable behaviour at no-load condition. They also quantified the gain in time deriving from this dedicated design during the start-up sequence by dynamic simulation of the entire plant, highlighting a significant reduction in comparison with a typical pump-turbine design.



Figure 2.11 Turbine frequency evolution versus time during start-up sequence: Comparison between a typical and the dedicated high head designs for a low head coupling condition (Houdeline et al., 2012)

2.2 Instability in pump mode: the saddle zone

The saddle-type pump instability is undoubtedly the most challenging problem to face in order to significantly increase the operating range of pump-turbines in pumping mode, even in case of variable speed pump-turbine (Henry et al., 2012).

This unstable pump operating zone is characterized by a head drop associated with an increase of the hydraulic losses in the runner, in the stator parts or in both. At off design conditions, the diffuser and the draft tube do not work properly and give awkward boundary conditions to the runner, together with a strong fluid-dynamical interaction between runner and stator parts. Flow features, such as flow separations and recirculations, severely occur in an unsteady manner and guide vanes may experience strong vibrations. For this reason, the unstable behavior does not simply determine a head drop due to the increased hydraulic losses but also it is accompanied by high cycle fatigue stress that may result in the cracks propagation and in the failure of shear pin or guide vanes stem. The damage root causes can range from the misalignment during shear pins assembly on the guide

vane activation mechanism, which causes anomalous loading, to the strong excitation due to the Rotor-Stator Interaction (RSI).

It is certain that the complexity of the pump-turbine structures favors the RSI, that is a fluiddynamical interaction between the rotating element of the pump-turbine (runner) and the stator parts of the pump-turbine (stator vanes, return channel, draft tube, adduction).

Among the phenomena developing inside the machine, the onset of a fluid-dynamical instability as a consequence of the rotor-stator interaction still represents a crucial point in the research field and authors are still debating on the reasons of its onset and development. Several experimental and numerical analyses have been carried out on this interaction to identify a possible connection of unsteady flows and pressure fluctuations developing inside centrifugal pumps with runner/diffuser geometries and operating conditions.

In 2002, Gonzales et al. studies the dynamic and unsteady flow effects inside a centrifugal pump due to the runner-volute interaction. The results of both experimental and numerical analyses highlighted the existence of a spatial fluctuation pattern concentrated close to the runner exit, whose fluctuations levels increases at off-design conditions.

In 2002, Sano et al. highlighted the significant influence of the gap between runner and diffuser on the development of flow instabilities in the vaned diffuser, such as the rotating stall, alternate blade stall and asymmetric stall. In particular the study demonstrated the development of a runner/diffuser coupled rotating stall in case of a small gap and the switching between reverse flow and jet flows in the diffuser channel during the rotating stall development (Figure 2.12).

Alternate stalled and unstalled runner passages at part loads were observed by Pedersen et al. (2003), whose study presents one of the first experimental analysis capturing instantaneous flow fields inside the runner (Figure 2.13).

To better understand the effects of the diffuser blockage on the runner fluid-dynamics, Hong and Kang (2004) carried an experimental analysis to measure the flow field at the runner exit with and without a fence with sinusoidal width variation installed at the vaneless diffuser exit. The mean flow parameters, such as static pressure, total pressure and flow angles, resulted to be strongly dependent on the circumferential position.

The circumferential distortion of the pressure distribution at the runner outlet due to the rotorstator interaction was confirmed by Majidi (2005). Its study highlighted the existence of pressure fluctuations, strong at the runner outlet but spread to the runner inlet, affecting the mass flow rate through the runner blade passages and the runner blade loading. In particular, the flow unsteadiness was demonstrated to significantly amplify the blade loading fluctuations at off-design conditions, giving rise to important dynamic effects.



Figure 2.12 Instantaneous images of a reverse flow at the diffuser outlet (left) and of a jet flow in the channel (right) (Sano et al., 2012)



Figure 2.13 Instantaneous vector field experimentally acquired in the runner (Perdesen et al., 2004)

Due to the importance of the onset of dangerous dynamic effects, a significant interest in the spectral characterization of the unsteady pressure fluctuations due to the rotor-stator interaction started to growth. Guo and Maruta (2005) investigated the onset of resonance phenomena as a consequence of the circumferential unevenness of the pressure fluctuations, whereas Rodriguez et al. (2008) presented an interesting theoretical method to predict and explain the possible harmonics that could appear in a pump-turbine as a consequence of the interaction between moving and stationary blades.

The frequency content of the pressure fluctuations was analysed both in frequency and in the timefrequency domains by Pavesi et al. (2008), whose study presented a spectral analysis of the unsteady phenomena developing in a pump-turbine. Their analysis highlighted the existence of a rotating structure of pressure pulsations at the runner exit appearing and disappearing in time, having greater intensity at part loads (Figure 2.14).



Figure 2.14 Evolution in the time-frequency domain the structure of pressure pulsations (wavelet analysis) (Pavesi et al., 2008)

This strong RSI, experienced by several authors at off-design conditions, resulted to be further emphasized in multi-stage pump-turbines in which a 'full-load-instability' (FLI) develops in the range from 60 to 90% of the design flow rate (Gülich, 2010).

Even though the experimental analyses allowed to identify and characterize the development of unsteady pressure pulsations in the hump zone of the pump-turbine operating range, a significant boost to the understanding of this instability was provided by CFD, whose ability and capability of modeling the flow through the entire machine in a single CFD simulation was significantly increased in the last years.

Numerical analyses on different configurations of pump-turbines allowed to improve the understanding of these unsteady phenomena, highlighting on one side the existence of reverse flows inside the runner channels rotating with a frequency not related to the blade passage frequency, the so called "unforced" unsteadiness (Fernandez Oro et al., 2009), on the other the existence in the

stator parts of related recirculating phenomena partially or totally blocking the flow in channels/regions downstream or upstream the runner.

An example of a simulation carried out at an unstable operating point on a multi-stage pumpturbine is reported in Figure 2.15, in which it is possible to identify the pulsating onset of reserve flow cells in the runner moving along the blade length and from one channel to another (Cavazzini et al., 2011). This unsteady behavior in the runner resulted to be associated with a perturbation of the diffuser flow field, characterized by an unsteady flow rate migration between passages and by unsteady flow jets (Figure 2.15).



Figure 2.15 Flow field in the runner and diffuser at mid-span (Q/Q_{des}= 50%) at four time instants (Δt =47°) (Cavazzini et al., 2011)

This flow rate migration in its turn was caused by vortexes developing in the first part of the return channel and partially or totally blocking the flow coming out from the diffuser (Figure 2.16). This strong rotor-stator interaction resulted not only in an asymmetrical distribution of the flow coming

out from the runner but also in the development of rotating pressure pulsations, causing severe vibrations and an unstable pump-turbine behavior in terms of fluctuating head and flow rate.



Figure 2.16 Flow jets developing in meridional sections of the first part of the return channel for $Q/Q_{des}=50\%$ (Cavazzini et al., 2011)

Unsteady numerical analysis carried out by Gentner et al. (2012) in pump-turbine highlighted the dependence of the flow behaviour in the head drop from the specific speed of the pump-turbine. For high values of the pump-turbine, the unstable operating conditions resulted to be related to the onset of a fully-developed pre-rotation at the runner inlet shroud which extends beyond the pump leading edge. At a lower specific speed, the head drop resulted to be due to a strong interaction between the runner pre-rotation (previously identified) and a stall developing in the stator (Figure 2.17).

2.3 Future Challenges

Even though CFD has allowed to obtain interesting information on the unstable behavior of pumpturbines, to reduce the instability problems and to significantly enlarge the working range of pumpturbine, much more details about the influence of the pump-turbine geometry on the flow patterns and on the dissipation mechanisms are needed.

As regards the S-Shape region, it is quite clear that the unstable behavior is due to the increased in head at part loads (negative slope in the head-flow curve) and that this increase is related to the blocking action of vortexes developing in the channels.



Figure 2.17 Stall cells in the stator for an unstable operating point in the hump zone (Gentner et al., 2012).

However, several aspects regarding this unstable behaviour should be further investigated: the reasons of the onset and development of the vortexes in the runner channels as well as the reasons of their further enlargement and stabilization with the consequent blocking action of the flow; the existence of further flow mechanisms that negatively affect the pump-turbine stability; the geometrical parameters affecting the flow mechanisms developing in S-Shape regions.

As regards the hump zone at part load in pump mode, the strong fluid-dynamical interaction between runner and stator parts was demonstrated to be strictly related to the onset of different types of rotating structures of pressure pulsations. However, even in this case, the characteristics and flow mechanisms of the development of these unsteady phenomena in the hump zone and the effects of the geometry on their onset and stabilization still represent a challenging point for the research.

CFD has certainly improved the understanding of these unsteady phenomena. However, in spite of the significant advances of the last years, the investigation of the unstable behavior of pump-turbine is still extremely time-consuming and it requires a huge amount of computational efforts. Gentner et al. (2012) demonstrated that steady calculations, even if carried out with a fine mesh, failed in correctly predicting the head drop (Figure 2.18).

So, to favour an in-depth knowledge of the unstable behavior of pump-turbine, further improvements in CFD are also necessary in order to model turbulent flow and performance at a wider range of discharge rates more accurately and faster.



Figure 2.18 Head flow curves from measurement, unsteady and steady state calculation (Gentner et al., 2012)

3 ELECTRIC MACHINERY

3.1 Introduction

Most part of electric energy is produced by rotating electrical generators² that are driven by prime movers, called turbines. Different primary energy sources can be used in the prime mover, resulting into different power plant technologies, with different economic and technical characteristics. Depending on the type of prime mover, the most common power plants can be classified in (Knapen et al., 2013):

- Steam turbine thermal plants (nuclear, coal, oil, gas, biomass, solar, geothermal)
- Combustion thermal plants (gas, Diesel, combined cycle)
- Hydraulic turbine plants (reservoir, run-of-the-river, tidal)
- Wind turbine plants

The prime mover supplies rotational mechanical energy to the generator, which in turn converts it into electrical energy that is injected into the grid (Figure 3.1). These machines generate alternating current (AC) with constant frequency and voltage.



Figure 3.1 Turbine and electric generator (USGS, 2014)

Conventional power plants are located far away from the populated areas; therefore it is necessary to transport this energy to the consumers using overhead transmission lines and underground cables. Voltage generated at the power plants is stepped up to higher voltage using power transformers,

² There are also direct electric energy production methods that avoid the coupling of the prime mover to the generator, for example photovoltaic systems.

before being connected to the transmission network. These High Voltage transmission lines end in the transmission substations, where voltage is stepped down and the energy is distributed in Medium Voltage (industrial consumers) or Low Voltage (domestic consumers) as shown in Figure 3.2.

For PSHPs different types of electrical machines can be used depending on the desired application. For fixed speed applications and large units, conventional synchronous machines (SYM) are commonly used. For variable speed applications and small units (less than 60 MW), the SYM is linked to the grid by a static frequency converter. For larger variable speed units, this solution is not justified economically and double fed induction machines (DFIM) is the chosen solution. In some micro hydro power plants, other configurations based on induction generators can also be used.



Figure 3.2 Electric power system (USCPSOTF, 2004)

3.2 Conventional synchronous machine

The bulk of electric energy is produced by three-phase synchronous generators. SYMs with power ratings of several hundred MVA are common; the biggest machines have a rating up to 1500 MVA.

Synchronous generators are characterized by a uniformly slotted stator laminated core that house a three-phase alternating current (AC) winding and a direct current (DC) excited rotor (Fraile Mora, 2008; Fitzgerald et al., 2003; Boldea, 2006).

SYMs used in hydro power plants are built with salient-pole concentrated-excitation rotors (Figure 3.3).

DC excitation power on the rotor can be transmitted by:

- Copper slip-rings and brushes.
- Brushless excitation systems.

The controlled rectifier, with a nominal power around 3% of generator rated power controls the DC excitation currents according to the needs of generator voltage and frequency stability.

3.2.1 Operating principle

A DC current is applied to the rotor winding, which produces a rotor magnetic field. The rotor is then driven by the prime mover (i.e. water) producing a rotating magnetic field. This rotating magnetic field induces a three-phase set of voltages within the stator windings of the generator (Figure 3.4).



Figure 3.3 Synchronous machine with salient pole DC concentrated excitation (USACE, 2014).



Figure 3.4 Synchronous machine scheme (Fraile Mora, 2008)

These machines are synchronous in the sense that the electrical frequency produced is *synchronized* with the mechanical speed of the generator by Equation (3.1):

$$n = \frac{60f_1}{p} \tag{3.1}$$

Where *n* is the mechanical speed, f_1 is grid frequency and *p* the number of poles pair.

For small power applications, it is also possible to use permanent magnet synchronous machines, PMSYM. This type of synchronous machines uses permanent magnets in the rotor instead of using a winding fed by a DC source to produce the rotor magnetic field (Figure 3.5).



Permanent magnets

Figure 3.5 Permanent magnet synchronous machine scheme (VENSYS, 2014)

These machines are simpler and cheaper than the conventional synchronous machines but they have some limitations: in PMSYMs, the output voltage is directly proportional to the speed and since the air gap flux is not controllable by adjusting the DC voltage, its terminal voltage cannot be easily regulated without using power electronics devices.

3.2.2 Conventional synchronous generation regulation

In order to connect a synchronous generator to the electric grid, four voltage conditions must be satisfied:

- Voltage must have the same phase sequence as the grid voltages.
- Voltage must have the same frequency as the grid.
- Voltage must have the same amplitude at its terminals as the one of the grid voltage.
- Voltage must be in phase with the grid voltage.

The procedure to adjust the generator voltage to the grid voltage conditions is called *synchronization*.

When the generator is connected to a large grid, its output voltage and frequency (and rotational speed) are locked to the system values. It is said that the generator is connected to an infinite bus representing an ideal voltage source with a fixed voltage amplitude and frequency (Figure 3.6).

The equivalent circuit of the SYM connected to an infinite bus (Fraile Mora, 2008) is represented by an internal electromotive force (EMF), E_o , and a series reactance X_s . This reactance X_s is called **synchronous reactance** and is constant during normal steady-state conditions. The resistance of the stator coil is neglected in this simplified equivalent circuit.





Immediately after synchronization and coupling to the grid, the machine is neither feeding power to nor absorbing power from the grid. The water going through the turbine is the same as before the coupling action and it is just enough to drive the rotor and compensate for the losses of the turbine and the generator.

If more water is fed into the turbines, the internal EMF, E_0 , leads the terminal voltage. The amplitude of the machine internal EMF, E_0 , is a function of the DC field current and is controlled by the operator. In Figure 3.6, the internal EMF, E_0 , leads the system voltage U by an angle δ , which is known as the **power angle**. As a consequence, current and active power is fed into the grid.

The expression for the current is given by:

$$\mathbf{I} = \frac{\mathbf{E}_0 - \mathbf{U}}{jX_s} \tag{3.2}$$

Where I is the current phasor, E_0 is the machine internal EMF phasor, U is the system voltage phasor (also called terminal voltage) and X_s is the machine reactance.

The three-phase complex power supplied to the power system equals:

$$\mathbf{S} = 3\mathbf{U}\mathbf{I}^* = P + jQ \tag{3.3}$$

Expression for the active and reactive power is found by substituting I from Equation (4.2) in Equation (4.3):

$$\mathbf{I} = \frac{\left(E_0 \cos \delta - U\right) + jE_0 sen\delta}{jX_s} \tag{3.4}$$

$$\mathbf{I}^* = \frac{(E_0 \cos \delta - U) - jE_0 sen\delta}{-jX_s}$$
(3.5)

$$\mathbf{S} = 3V \frac{(E_o \cos \delta - U) - jE_o sen\delta}{-jX_s}$$
(3.6)

$$\mathbf{S} = \frac{3UE_o}{X_s} sen\delta + j3 \frac{UE_0 \cos \delta - U^2}{X_s}$$
(3.7)

$$P = \frac{3E_o U}{X_s} sen\delta = P_{\max} sen\delta$$
(3.8)

$$Q = 3 \frac{E_o U \cos \delta - U^2}{X_s}$$
(3.9)

A closer look at the active power equation (Equation (3.8)) shows that the sign of the active power is determined only by the power angle.

- $\delta > 0 \rightarrow P > 0$, the machine is working as generator supplying active power to the grid.
- $\delta=0 \rightarrow P=0$, the machine has no active power exchange with the grid.
- $\delta < 0 \rightarrow P < 0$, the machine is working as motor absorbing active power from the grid.

A similar approach can be obtained by analyzing the reactive power equation (Equation (3.9)). The sign of reactive power is determined by the following relations:

- $|E|\cos(\delta)>|U| \rightarrow Q>0$, the machine supplies reactive power to the grid and is overexcited.
- $|E|\cos(\delta)=|Y| \rightarrow Q=0$, the machine has no reactive power exchange with the grid.
- $|E|\cos(\delta) < |U| \rightarrow Q < 0$, the machine absorbs reactive power from the grid and is underexcited.

3.2.3 Variable speed operation using synchronous machines

Some of the first applications of variable speed operation of pump-turbines using SYMs were considering full-scale converters based on the configuration shown in Figure 3.7.



Figure 3.7 Full-scale thyristor based current source converter driving a synchronous machine (Fitzgerald et al., 2003)

Although this configuration is simple and based on using a conventional SYM, the use of a full-scale converter has been considered a main drawback. In this case, the converter losses would closely offset the gain in turbine efficiency, leaving little net improvement of efficiency. There would be a gain in capacity at low heads and speeds, but not sufficient to offset the substantial cost of the power electronics converters (Gish et al., 1981). Therefore, only a few PSHPs with high demands on power regulation in pumping mode have used this topology for continuous variable speed operation until now. However, thryistor converters with reduced rating have become a common solution for the start-up of pumps and pump-turbines running at constant speed; for example (Chiang et al., 1997) present an applications for six 300 MVA synchronous machines using a static starter at the Mingtan PSHP (Taiwan). Converters with reduced ratings have also been proposed for improved transition between different operating conditions of PSHPs with constant speed (Magsaysay et al. 1995).

3.3 Induction machines

3.3.1 Operating principle

The induction machine (IM) is the most commonly used industrial motor. It is simple and relatively inexpensive, and the absence of sliding contacts in the squirrel-cage machine reduces maintenance to a minimum. There are two general types of IMs: the **squirrel-cage** type and the **wound-rotor** machine. Both machines have a stator structure similar to that of the SYM, consisting of a hollow cylinder of laminated sheet steel in which are punched longitudinal slots. A symmetrical 3-phase winding is laid in these slots which, when connected to a suitable voltage source, produces a travelling magnetomotive force (MMF) wave in the air gap, rotating at synchronous speed equal to Equation (3.1).

The squirrel-cage type of rotor (Figure 3.8) is made up of sheet steel laminas keyed to the shaft and having slots punched in the periphery. The rotor conductors in most machines are made of aluminum alloy either molded or extruded in place in the slots.



Figure 3.8 Squirrel-cage rotor of an induction machine (Fraile Mora, 2008)

The wound-rotor IM (Figure 3.9) has a three-phase insulated winding. This winding is usually wyeconnected with the terminals brought out to three slip rings on the shaft. Graphite brushes connected to the slip rings provide external access to the rotor winding.



Figure 3.9 Wound Rotor of an induction machine (Fraile Mora, 2008)

Applying a three-phase set of currents, each of equal magnitude and differing in phase by 120° flowing in the three-phase stator windings, will produce a rotating magnetic field of constant magnitude in the uniform air gap. This field links the short-circuited rotor windings and the relative motion induces short-circuit currents in them, which move about the rotor in exact synchronism with the rotating magnetic field. It is well known that any induced current will react in opposition to the flux linkages producing it, resulting herein a torque on the rotor in the direction of the rotating field (Fraile Mora, 2008; Fitzgerald et al., 2003). This torque causes the rotor to revolve so as to reduce the rate of change of flux linkages reducing the magnitude of the induced current and the rotor frequency. If the rotor were to revolve at exactly synchronous speed, there would be no changing flux linkages about the rotor coils and no torque would be produced. However, the practical induction motor has friction losses requiring some electromagnetic torque, even at no-load, and the system will stabilize with the rotor revolving at slightly less than synchronous speed. A mechanical shaft load will cause the rotor to decelerate, but this increases the rotor current, automatically increasing the torque produced and stabilizing the system at a slightly reduced speed.

The difference in speed between rotor and the rotating magnetic field is termed *slip* which is equal to:

$$s = \frac{n_1 - n}{n_1}$$
(3.10)

Where n_i is the rotating magnetic field speed (also called synchronous speed and given by Equation (3.1)) and n is the rotational rotor speed.

An IM operates as generator when its stator is connected to the electric grid with fixed frequency and voltage, f, U (as shown in Figure 3.10a), and it is driven by a prime mover above the synchronous speed given by:

$$n > \frac{60f}{p} \tag{3.11}$$

The electric grid provides reactive power to magnetize the machine and increasing the rotational speed n (above 60f/p) will increase the active power delivered from the machine to the power grid.



Figure 3.10 Cage-rotor IM (a) connected to the electric grid. (b) Stand-alone applications (Boldea, 2006)

There are many existing variable speed machines using this cage-rotor configuration for example in early wind turbine generators. In this case, the blade pitch angle is adjusted according to the wind speed and power delivery requirements. The main drawback of this configuration is its stiffness, as

these machines are stable only until *n* reaches the value:

$$n_{\max} > \frac{60f}{p} \left(1 + \left| S_k \right| \right) \tag{3.12}$$

Where S_k is the critical slip, which decreases with power and is below 8% for induction generators in the hundreds of kilowatts range (Boldea, 2006).

Alternatively, the reactive power may be provided by parallel (plus series) capacitors (Figure 3.10b) to operate in stand-alone. The main drawback of this configuration is that, even if the speed is kept constant through prime mover speed control, the output voltage and frequency vary with the load.

3.4 Doubly fed induction machines

For most applications of PSHPs, only a limited controllable speed range is needed during normal operation. This allows for obtaining variable speed operation by utilizing the concept of a **doubly fed induction machine** (DFIM) and a power electronic converter with reduced converter rating compared to the total machine rating. This topology has been preferred in most large scale implementations to limit the converter ratings. With this concept, the industry has been able to build units with total ratings in the range of several hundred of MVAs (Lung et al., 2007; Merino and López, 1997; Kuwabara et al., 1996). In addition to the reduced converter rating compared to the full scale current source converter, this configuration has as another advantage that the reactive power exchange with the grid can be easily controlled. This can be used for voltage control in the grid and contribute to improving the stability and the operating conditions in the rest of the power system.

When the first commercial, large scale, implementations of variable speed on PSHPs were investigated, the power electronic converters had to be based on thyristor to achieve sufficient ratings. Since the required frequency for the rotor circuit in the DFIG is given by the deviation from synchronous speed, it is usually limited to a few Hz. Therefore configuration with **cycloconverters**, as shown in Figure 3.11, has been considered suitable solutions that can be made with rugged designed for high capacity and low losses (Kuwabara et al., 1996). Japan was one of the first countries to apply cycloconverters to PSHPs: 85 MVA in Yagisawa PSHP, 360 MVA in Shiobara PSHP, 400 MW in Ohkawachi PSHP.



Figure 3.11 Configuration of DFIM using cycloconverters (Fitzgerald et al., 2003)

As the voltage and current ratings of gate-controlled switches like GTOs, IGBTs, etc. have increased, topologies based on **back-to-back voltage source converters** have become relevant for feeding the rotor windings of the DFIMs. This configuration, shown in Figure 3.12, with a two-level or three-level neutral-point-clamped voltage source converter is considered as the preferred converter topology. The voltage source converter topology is gaining even more relevance as the development of high power voltage source converters for other drive applications is continuing, and is being used in some of the most recent pumped-storage implementations (Hodder et al., 2004; Hämmerli and Odergard, 2008); for example, 300 MW Okukiyotsu hydro power plant (Japan).



Figure 3.12 Configuration of DFIG using back-to-back voltage source converter and capacitive DC-Link (Fitzgerald et al., 2003)

4 POWER ELECTRONICS EQUIPMENT

4.1 Introduction

In the last years due to social and environmental concerns, it is predicted that there will be increased use of photovoltaic power generation, wind power, and other renewable energy sources. These power generation systems, which are small-scale decentralized power generation plants, have a strong power variation due to environmental changes such as weather and are therefore unstable power supplies. Hence, the increasing use of small-scale renewable power sources raises concerns in regard to power supply stability.

In this new scenario, variable speed PSHPs can play an important role in stabilizing the electric power supply (Mitsubishi Heavy Industries, 2011), due to:

- Quick response to electric power demand
- Input power adjustment during pump operations

Most PSHPs have only one electrical machine operating in generator or motor modes (Zea Cuadros, 2012). These systems have been presented in the previous chapter, showing the need for an electronic converter to connect the electrical machine to the grid. There are two options: synchronous machine or slip rings induction machine.

While the synchronous machine (SYM) connects to the grid through a full power converter, the induction machine has a double connection: the stator is directly connected to the grid and the rotor is connected through a low power electronic converter (Doubly-Fed Induction Machine (DFIM)). Thus the power available in the electronic converter determines the use of one technology or another. Although some manufacturers provide new developments in power converters of 100 MVA (Schlunegger and Thöni, 2013), most of them are located around 60 MVA.

<u>Synchronous Machine (SYM)</u> is used when the generation unit does not exceed 60 MVA. It presents two main advantages:

- It is a conventional and economical machine
- The full converter allows starting the pump in fully controlled mode, avoiding electrical transients.

Its use is particularly interesting in islanded electrical systems, where at the same time the PSHP can be controlled to take part in the frequency control of the system and also to control grid voltage or reactive power flow. It can reduce the dependency on power generation based on fossil fuels (Suul et al., 2008).

Doubly-Fed Induction Machine (DFIM) is the solution when the generation unit exceeds 60 MVA. As explained in the previous chapter, the electronic converter active power is proportional to the rotor slip, which is less than 0.25 in conventional DFIM. Although the converter must be oversized by the need of DFIM consuming reactive power, high power units can be developed with converters around 60 MVA. Thus, due to hydraulic power units generally do not need a control range over ± 10% of synchronous speed, with converters around 60 MVA could be used DFIM up to 400 MVA (Mitsubishi Electric Corporation, 2008).

DFIM is the choice made by all manufacturers for high-power plants. ALSTOM has developed units of 130-306 MW (Lavigne et al., 2010; Houdeline et al., 2009); MITSUBISHI presents units between 30 and 400 MW (Mitsubishi Electric Corporation, 2008); VOITH installed this technology in units of 30 to 400 MW, at speeds between 300 and 600 rpm (Geise, 2013).

Although with this concept, the industry has been able to build units with total ratings in the range of several hundred of MVAs, these rates are not standard for DFIM. Its high price will lead to lose interest with the increase in power of new electronic converters topologies in the future.

In pumping mode the electrical machine can be started as explained in the previous chapter. However the changes in the winding connections during starting process make this system more complex than the one with full converter.

In any case, there is the need for a bidirectional converter in all variable speed PSHPs. Power generation companies currently located in a band around 60 MVA the limit for selecting one technology or another, SYM or DFIM. This limit strongly depends on the cost of the power converter and consequently it will go up with the development of new high power converters. Nowadays there are available two types:

- Cyclo-converter (Direct converter) for high power devices but with reactive power consumption on the grid side.
- DC-link converter for reduced power but with separate active and reactive power control possibility.

4.2 Cyclo-converter

The cyclo-converter is a frequency converter which is based on the three phase - full-wave controlled rectifier. It is the topology that allows higher power developments. It has been used in Japanese

PSHPs, pioneers in these applications (Nagura et al., 2010). These units have been developed with DFIM and the power supplied in the cyclo-converters can be seen in Figure 4.1 and Figure 4.2.

Considering the powers of DFIM units (about 400 MW maximum) power converters to be used should not exceed 80 MVA.



Figure 4.1 Cyclo-converter power depending on the year of construction (Mitsubishi Electric Corporation, 2008)



Pumped-storage power plants with cyclo-converter and DFIM



The cyclo-converter is constituted by an association of three rectifiers, as detailed below (Figure 4.3). This type of converter is the only one in which there is a direct conversion from AC to AC power; for this reason, it is also called direct converter.

The output frequency (f2) is lower than the input frequency (f1), so it does not require high-speed semiconductor; thyristors are used instead. Its field of application is in high power and low speed

drives, which need low frequency power supply. The voltage amplitude and frequency output can be adjusted, from a fix voltage and frequency input (Merino Azcárraga, 1997).



Figure 4.3 Cyclo-converter detailed power diagram

The usual topology of a cyclo-converter is based on three double Graetz bridges opposition to operate in all four quadrants. With a control strategy, which is detailed below, each single rectifier gives a single-phase alternating voltage. With the three rectifiers, a three phase voltage is obtained.

The ideal voltage provided by a controlled rectifier is given by the following expression:

$$U_{DC\alpha} = U_{DC0} \cos \alpha$$

The cyclo-converter control system is based on the appropriate variation of the thyristor firing angle α . If the angle is varied in accordance with a law that provides a DC variable from zero to its maximum value, it can form a half-wave of the desired AC frequency. Table 4.1 gives the values of the control angle as a function of the cycle time of the wave frequency to be obtained. These values correspond to one of the two Graetz bridges that form the opposition for each phase.

Т	A	U _{DCα}
0	90°	0
t ₂ /4	45°	0.707·U _{DCo}
t ₂ /2	o°	U _{DCo}
3 t ₂ /4	45°	0.707·U _{DCo}
t ₂	90°	0

Table 4.1 Control parameters for a cyclo-converter to obtain the positive half wave

With a symmetric control in the other half bridge rectifier, the negative half-wave is generated. In Table 4.2, the firing angles for the negative half wave cycle are shown. It can be observed an alternative wave of t2 period.

Τ	A	$U_{DC\alpha}$
t2	90°	0
5 t ₂ /4	135°	-0.707·U _{DCo}
3 t ₂ /2	180°	-U _{DCo}
7 t ₂ /4	135°	-0.707 · U _{DCo}
2 t ₂	90°	0

Table 4.2 Control parameters for a cyclo-converter to obtain the negative half wave

It should be noted that in order to obtain the output frequency, there is a limitation in time t2, because the thyristors can be controlled no more than once for each wave cycle phase. For this reason from a 50 Hz grid, the maximum output frequency of a cyclo-converter is around 20 Hz.

This feature makes impossible using cyclo-converters in PSHPs with SYM. Nevertheless, it is not a limitation for the DFIM machines where the frequencies to be supplied are lower than 20 Hz.

Finally, Figure 4.4 shows a voltage ripple on the fundamental wave, which results in a high harmonic content.

As shown in Figure 4.3, the cyclo-converter is composed of three double Graetz bridges, so at least 36 thyristors must be used in cases in which only one thyristor is needed to carry the rated current. High current cyclo-converters can be made with several thyristors parallel connected; hence the total number of thyristors is multiple of 36.

The simplified diagram in Figure 4.5 represents a general cyclo-converter configuration.

In conclusion it can be noted that this is an electronic converter using thyristors and it does not need a DC link. Since thyristors are line commutated, the control system is relatively simple but the output frequency is higher than 0.4 times the grid frequency.

It is therefore a simple, robust and cheap technology but it cannot be used in units with SYM.



Figure 4.4 Output voltage of a cyclo-converter. Output frequency 16 2/3 from the 50 Hz grid



Figure 4.5 Cyclo-converter simplified power diagram

However, the main disadvantages are:

• Reactive power consumption on grid side.

Reactive consumption by thyristors and the absence of DC link, causes the reactive consumption required for operating DFIM.

• High harmonic currents on grid side.

The inability to force the turn off of the thyristor results in a large ripple in the current exchanged with the grid.

• More space requirement.

In order to avoid the transmission of harmonics to the grid, high power harmonic filters must be installed, for which more space must be provided.

• Malfunction of the converter at grid faults.

There is a risk for loss of commutation of the thyristors when a grid fault appears. It can produce the DFIM shut down.

4.3 DC-link converter.

It consists of a rectifier stage (AC / DC), a DC-Link, and an inverter stage (DC / AC) and it allows operation of the electrical machine with a better efficiency at voltages and frequencies different from the grid rated ones.

The DC-Link is a decoupling between the frequency and amplitude of the grid voltage and the applied AC machine. The most common is that the DC-link is achieved through a certain capacity C, with capacitors. Most condensers used nowadays are made of polypropylene, which has a higher efficiency than the conventional electrolytic. Additionally, they are more robust and operating conditions outside their margins only cause degradation of the element (reduced capacity) and not an explosion of the device. The capacitance value is chosen to minimize voltage ripple produced by electronic converters and switches.

The simplified diagram in Figure 4.6 represents a general configuration of a Voltage Source Converter (VSC).



Figure 4.6 Simplified scheme of a VSC

Both rectifier and inverter stages are developed with semiconductors whose shutdown can be forced; this is a more complex power electronics compared to direct converter. Regarding the cost, this is a

disadvantage but nevertheless it greatly improves the performance of the DC-link converter with respect to cyclo-converter:

- The DC-link converter can be used for both DFIM and SYM.
- The separation of the rectifier and the inverter via a DC link allows the controls of P and Q independently (Mohan et al., 1989).

Figure 4.7 shows an example of DFIM operation with DC-link converter, whereas Figure 4.8 shows an example of SYM operation with DC-link converter.



Figure 4.7 Active and reactive power flows in DFIM in pumping mode



Figure 4.8 Active and reactive power flows in SYM in generating mode
Previous figures only represent some examples of possible operating modes of DFIM and SYM. The connection to the grid through a DC-link converter allows operation in the four quadrants (P_{Grid} >o, Q_{Grid} >o), (P_{Grid} >o, Q_{Grid} <o); (P_{Grid} <o, Q_{Grid} >o); (P_{Grid} <o, Q_{Grid} <o). However, in most cases, reactive power control will be held in order to achieve cos ϕ = 1 on the grid side.

The use of VSC converter has a number of additional advantages:

• Low harmonic currents on the grid side.

The installation of expensive filters is not necessary. It produces a reduction in the cost and space requirements.

• Improvements in the ability to start-up and brake.

Machine start-up and braking are possible without a separate converter, by means of the short circuit connection of the machine stator windings.

DC-link converters have been made possible by the development of semiconductor devices with ability for shutdown control that cannot be achieved with thyristors. There are three semiconductors with these features:

- Gate Turn Off thyristor (GTO)
- Insulated Gate Bipolar Transistor (IGBT)
- Insulated Gate Commutated Thyristors (GCT)

The development of high-power converters and medium voltage (MV) drives started in the mid 1980's when 4500V GTO became commercially available (Rizzo and Salgari, 2004). The GTO was the standard for the MV drives until the advent of high-power IGBTs and GCTs in the late 1990s (Brunner et al., 1997; Steimer et al., 1997). These switching devices have rapidly progressed into the main areas of high-power electronics due to their superior switching characteristics, reduced power losses, easy of gate control and snubberless operation.

The MV drives cover power ratings from 0.4MW to 40MW at the medium voltage level of 2.3KV to 13.8KV. The power rating can be extended to 100MW, where synchronous motor drives with load commutated inverters are often used.

Table 4.3 summarizes the characteristics of these semiconductors.

In the following sub-sections the operating characteristics of the different semiconductors are briefly described.

	GTO	IBGT	IGCT
Switching	Low frequency	High frequency	High frequency
capacity			
		Integrated gate	Integrated gate driver
		driver	
Losses	Low conduction	Low switching	Low switching
		High conduction	Low conduction
Converter	Complex clamping	Suitable for series /	Suitable for series /
design	circuit	parallel connection	parallel connection at
		at high voltages	high voltages

Table 4.3 Comparison of different semiconductors used in DC link converters

4.3.1 GTO (Gate Turn Off thyristor)

They were first used in the early 1980's and for many years they have been the only available technology (Ohashi and Nakagawa, 1981; Matsuda et al., 1983). Nowadays they are still being used in high voltage and current applications.

This technology was used in the first generation of PSHPs installed in Japan, as shown in Figure 4.9 and Figure 4.10.



GTO DC-link converter power evolution

Figure 4.9 GTO DC link converter power depending on the year of construction (Mitsubishi Electric Corporation, 2008)



Pumped-storage power plants with GTO DC Link converter and DFIM

Unit generation power (MVA)

Figure 4.10 GTO DC link converter power vs. DFIM power (Mitsubishi Electric Corporation, 2008)

A GTO is a special type of thyristor, a high-power semiconductor device. GTOs, as opposed to normal thyristor, are fully controllable switches which can be turned on and off by their third lead, the Gate lead. Additionally, GTO thyristor can be fabricated with a reverse conducting diode in the same package. These are known as RC-GTO.

This property significantly simplifies the circuitry that is required for the blocking of the thyristors. Furthermore, GTOs have the property of shorter switching times which is feasible for application in modern converters, with waves of low harmonic content.

GTO has considerably improved the controllability of conventional thyristors and the reason lies in its internal structure (Figure 4.11).



Figure 4.11 GTO internal structure

GTOs are four-layer PNPN devices that act as switches, rectifiers, and voltage regulators. Like other thyristor, GTOs can be turned on by the application of a positive gate signal; however, unlike other more conventional devices that can be turned off only at a zero crossing of current, GTOs can be turned off at any time by the application of a gate signal equal to zero.

When a positive signal is applied, a GTO switches to conduction state like the ordinary thyristor. However in ordinary thyristor the current gains of NPN and PNP transistors are very high so that gate sensitivity for turn on is very high and on state voltage drop is low.

However in GTOs, the current gain of PNP transistor is low so that turn off is possible if significant current is drawn from the gate. When a negative gate signal is applied the excess carriers are drawn from the base region of NPN transistor and collector current of PNP is diverted to the gate. Thus the base drive of NPN transistor is removed and this in turn removes the base drive of PNP transistor and turnoff is achieved.

From the point of view of current and voltage operation, GTOs have not reached the performance of conventional thyristors but are every day more and more close. Nowadays GTO-based frequency converters are used within the range of a few tens of MW, but the need to inject high currents through the gate turn-off remains a disadvantage.

4.3.2 IGBT (Insulated Gate Bipolar Transistor)

In the case of high voltage and current value, power transistors do not offer enough switching frequency for any converters with output waveform close to sinusoidal. However, MOSFET devices have a high switching frequency but with reduced power.

IGBT began to be used at the mid-nineties and it is the semiconductor with the best technical compromise between switching speed and high power control (Khanna, 2003; Blaabjerg et al., 1995). The reason lies in its internal structure (Figure 4.12).

IGBT is basically a functional integration of Power MOSFET and Bipolar Transistor BJT devices in monolithic form. IGBT behavior can be summarized by the equivalent circuit represented in Figure 4.13.

In this device, the semiconductor shutdown is also done by the gate control, but in this case by voltage. The control principle is based on control of the gate-emitter voltage V_{GE} . When a positive voltage on the emitter E is applied, the MOSFET becomes saturated and BJT passes quickly to saturation state. Consequently, the IGBT begins to conduct. In order to block the IGBT it is only necessary to eliminate the gate voltage and, in many cases, it is a common practice to apply a negative voltage to ensure off.



Figure 4.12 IGBT internal structure



Figure 4.13 IGBT Equivalent circuit

The main advantages of IGBT over a Power MOSFET and a BJT are:

- It has a very low on-state voltage drop due to conductivity modulation and has superior onstate current density. So smaller chip size is possible and the cost can be reduced.
- Low driving power and a simple drive circuit due to the input MOS gate structure. It can be easily controlled as compared to current controlled devices (thyristor, BJT) in high voltage and high current applications.
- It has superior current conduction capability compared with the bipolar transistor. It also has excellent forward and reverse blocking capabilities.

The main drawback is the switching speed is inferior to that of a Power MOSFET and superior to that of a BJT. The collector current tailing due to the minority carrier causes the turn-off speed to be slow.

The current and voltage capability of the IGBT devices is continually growing. It can be paralleled quite well, so that two parallel IGBT support 1.5 to 1.6 times the rated current for one. IGBT

semiconductors have some interesting features in the switching speed. In the market there are IGBTs switching devices with frequencies between 20 and 50 kHz.

Figure 4.14 shows an IGBT device for a DFIM that can be used in a PSHP.



Figure 4.14 DFIM with and IGBT Voltage Source Converter (VSC).

4.3.3 IGCT (Integrated gate-commutated thyristor)

IGCTs began to be used in the last nineties (Steimer et al., 1997). It is composed of a 4-layer structure similar to the GTO. It is in principle a GTO with high dynamic parameters in turn-on and turn-off mode. Turn-off process speed is above all a factor by which GTO and IGCT devices differ from each other.

The IGCT device is composed of two elementary parts, a GCT thyristor structure which is placed in a disk case similarly to the GTO device and a gate unit to which the disk case is attached as tight as possible. The English name of this new sort of device stems from the fact that the gate unit is literally integrated with the GCT thyristor. It is so because the rate of rise of gate turn-off current must be extremely high for the due function of GCT and therefore self-inductance (spurious inductance) of gate unit including lead must be minimize. It makes the semiconductor block with a very low supply voltage typical value of about 20 V.

As result the IGCT device unites in itself the main advantages of thyristors (low on-state voltage drop, low on-state power losses) with the advantages of transistors or more precisely of IGBT devices (a convenient way of snubberless turn-off)

Both IGBT and IGCT are suitable for applications in high power an medium voltage MV, but IGCT is favorite for high-power applications where a lowest switching frequency is acceptable (static reactive compensators, static switches, ...). In contrast, IGBTs are more suitable for applications requiring

higher switching frequencies, and sophisticated control protections (e.g. motor drives, active filters, ...).

Nevertheless it seems that the IGBT extended its application domain from the low voltage LV drives market to the MV one. As show in Figure 4.15 and Figure 4.16, the IGCT technology has been used in the last PSHPs installed in Japan.





Figure 4.15 Comparison between GTO and GCT DC link converter power depending on the year of construction (Mitsubishi Electric Corporation, 2008).



Unit generation power (MVA)

Figure 4.16 Comparison between GTO and GCT DC link converter power vs. DFIM power (Mitsubishi Electric Corporation, 2008)

4.3.4 Some commercial developments

Figure 4.17 shows a general block diagram of the MV drive. Depending on the system requirements and the type of the converters employed, the line- and motor-side filters are optional. A phase

shifting transformer with multiple secondary windings is often used mainly for the reduction of line current distortion.



Figure 4.17 General block diagram of the MV drive (Wu, 2006a)

The rectifier converts the utility supply voltage to a dc voltage with a fixed or adjustable magnitude. The commonly used rectifier topologies include multipulse diode rectifiers, multipulse silicon controlled rectifiers (SCR), or pulse-width-modulated (PWM) rectifiers. The dc filter can simply be a capacitor that provides a stiff dc voltage in voltage source drives or an inductor that smoothes the dc current in current source drives.

The inverter can be generally classified into voltage source inverter (VSI) and current source inverter (CSI). The VSI converts the dc voltage to a three-phase ac voltage with adjustable magnitude and frequency whereas the CSI converts the dc current to an adjustable three-phase ac current.

Multipulse rectifiers are often employed in the MV drive to meet the line-side harmonic requirements. Figure 4.18 illustrates a block diagram of 12-, 18- and 24-pulse rectifiers. Each multipulse rectifier is essentially composed of a phase shifting transformer with multiple secondary windings feeding a set of identical six-pulse rectifiers.

Both diode and SCR devices can be used as switching devices. The multipulse diode rectifiers are suitable for VSI fed drives while the SCR rectifiers are normally used for CSI drives.

Depending on the inverter configuration, the outputs of the six-pulse rectifiers can be either connected in series to form a single dc supply or connected directly to a multilevel inverter that requires isolated dc supplies. In addition to the diode and SCR rectifiers, PWM rectifiers using IGBT or GCT devices can also be employed, where the rectifier usually has the same topology as the inverter.

To meet the motor-side challenges, a variety of inverter topologies can be adopted for the MV drive.



Figure 4.19 illustrates per-phase diagram of commonly used three-phase multilevel VSI topologies, which include a conventional two-level inverter, a three-level neutral point clamped (NPC) inverter, a seven-level cascaded H-bridge inverter and a four-level flying-capacitor inverter. Either IGBT or GCT can be employed in these inverters as a switching device.

A high number of MV drive products are available on the market today. These drives come with different designs using various power converter topologies and control schemes. Each design offers some unique features but also has some limitations. The diversified offer promotes the advancement in the drive technology and the market competition as well. A few examples of the MV industrial converters are reported in Table 4.4.



Inverter	Switching	Power Range (MVA)		Manufacturor	
Configuration	Device	2006	2013		
Two-Level Voltage Source Inverter	IGBT	7.2	-	Alstom (VDM 5000) [Alstom, 2001]	
Three-Level Neutral Point Clamped Inverter	GCT	27	36	ABB (ACS 6000) [ABB, 2010a]	
	GCT	20	-	General Electric (GE) (Innovation Series MV-SP) [Wu, 2006b]	
	IGBT	7.2	-	Siemens (SIMOVERT-MV) [SIEMENS, 2001]	
	IGBT	2.4	-	Toshiba-GE (Dura-Bilt5 MV) [GE-TAS, 2003]	
Multilevel Cascaded H- Bridge Inverter	IGBT	31	-	ASI Robicon (Perfect Harmony) [ASI Robicon, 2003]	
		6	-	Toshiba Mitsubishi-Electric –GE (TMdrive-MV) [TMEIC-GEAS, 2007]	
		7.5	-	GE (Innovation MV-GP Type H) [Wu, 2006b]	
NPC/H-bridge Inverter	IGBT	-	19.5	Toshiba Mitsubishi-Electric (TMdrive- MVG2) [TMEIC, 2012]	
Flying-Capacitor Inverter	IGBT	8	-	Alstom (VDM6000 Symphony) [Alstom, 2001]	
PWM Current Source Inverter	Symmetric al GCT	20	-	Rockwell Automation (PowerFlex 7000) [Wu, 2006b]	
Load	SCR	То 70		Siemens (SIMOVERT S) [SIEMENS, 2004]	
Inverter	(Thyristor)	To :	36 00	ABB (LCI) [ABB, 2010b] Alstom (ALSPA SD7000) [Alstom, 2001]	

Table 4.4 Commercial converters topologies

4.4 Control schemes.

There are many factors that have motivated the drive for variable speed operation of pump-turbines, regarding the operation of both the pump-turbine itself and the power system.

One important motivation for variable speed operation has been the possibility to improve the efficiency of the pump-turbine, since the speed corresponding to maximum efficiency is different for pumping and generating modes, and is also changing with the water head.

Even more important is the possibility for power control in pumping mode, since traditional pumpturbines with synchronous machines connected directly to the grid will operate at constant speed and therefore constant power in pumping mode. Variable speed operation has therefore been strongly motivated by the possibility to obtain similar power controllability in pumping mode as when operated as a generator.

From the power system point of view, this possibility is also one of the most important benefits obtained by variable speed operation of PSHPs. The power electronic drive system can also be used to increase the response time for power control by utilizing the inertia of the pump-turbine and the electrical machine, both in generating and pumping mode. The fast response can allow for compensation of power fluctuations and damping of power oscillations, and by that improve the stability of the power system.

For large scale implementations of variable speed PSHPs, the need for reduced power converter makes the DFIM the optimal solution. At the first commercial plant in Japan, the power electronic cyclo-converters had based on thyristors to achieve sufficient ratings.

As the voltage and current ratings of gate-controlled switches like GTOs, IGCTs and IGBTs have increased, DC-link converters have become relevant for feeding the rotor windings of the DFIM. The voltage source converter topology is gaining even more relevance as the development of high power voltage source converters for other drive applications is continuing, and is being used in some of the most recent pumped-storage implementations. The main reason is that DC-link converters, unlike cyclo-converters, allow separately regulate the active and reactive power.

For low scale implementation, in small and isolated power systems, especially if energy storage is used to increase the utilization of renewable energies, pumped-storage units with a full-scale voltage source converter controlling the stator windings of the machine can be a possible configuration (Suul, 2009). It is preferred a configuration based on a normal SYM with field windings because it will be possible to bypass the converter and operate the machine directly connected to the grid. It

can allow for a kind of redundant operation of the system in case of problems with the converter, and can also be utilized to reduce the losses in generating mode.

4.4.1 P-Q control

The general scheme for the P-Q regulation of DFIM is shown in Figure 4.20.



Figure 4.20 General scheme for the P-Q regulation of DFIM

P* and Q* references are generated depending on the needs of frequency and voltage regulation, respectively. The power errors (active and reactive) are corrected in two regulators in order to obtain the references for the current injected to the grid, in d-q coordinates respectively. From them and the actual grid currents, the reference for the inverter output voltage is generated.

Figure 4.20 clearly shows that the system has the advantage of being able to separately regulate the active and reactive power.

PSHPs have the peculiarity that the optimum operating point is different in pumping and generation modes, so that the above arrangement leads to two different control schemes. Figure 4.21 and Figure 4.22 show the schemes in generating and pumping mode, respectively.

As noted above, in weak grids with a high percentage of renewable energy, the SYM option is preferred. It is possible to bypass the converter and operate the machine directly connected to the grid once the steady state has been reached. Figure 4.23 and Figure 4.24 show the control schemes in generating and pumping mode, respectively.



Figure 4.21 Scheme for the P-Q regulation of DFIM in generating mode



Figure 4.22 Scheme for the P-Q regulation of DFIM in pumping mode



Figure 4.23 Scheme for the P-Q regulation of SYM in generation mode



Figure 4.24 Scheme for the P-Q regulation of SYM in pumping mode

4.4.2 Doubly-Fed Induction Machine starting techniques.

The full power converters used with SYMs do not require any special modifications during starting process. In pumping mode, it is possible at low speed feeding the electrical machine through the converter. However, in the case of DFIM some modifications are required due to its reduced power converter.

The following solutions are proposed:

<u>Asynchronous starting at reduced voltage (autotransformer)</u>

The starting process is carried out with a resistance connected in the rotor and stator fed at reduced voltage through an autotransformer (Figure 4.25).



Figure 4.25 DFIM asynchronous starting at reduced voltage (autotransformer) layout

The starting process begins with S₁, S₂ and S₃ opened while S₄ and S₅ are closed. The resistance Rv is connected to the rotor at its maximum resistance position. S₁ is closed, and then the stator is fed with a reduced voltage through the autotransformer. During rotor acceleration Rv value is reduced up to about the 95% of rated speed. At this speed the breaker S₄ is opened, therefore the autotransformer neutral is open, so the autotransformer become a limiting reactance. The breaker S₅ is opened and the resistor Rv will be disconnected from the rotor. At this moment the rotor is fed from the converter by closing the switch S₂. By reducing the frequency of the rotor current to zero the rotor speed will increase up to rated speed. When synchronizing conditions are reached the breaker S₃ will be closed, so the stator is feed at rated voltage from the network. At the end of the starting process the status of the breakers is: S₁, S₂, S₃ closed and S₄, S₅ opened

Synchronous starting through an auxiliary converter.

The starting process is performed by the use of the main converter feeding the rotor and an auxiliary converter for the stator (Figure 4.26). The starting process begins with S1, S2 and S4 opened while S2 and S5 are closed. S1 and S4 are closed. The main converted feeds the rotor with a DC current while the auxiliary converter increase the frequency of the current in the stator up to the rated frequency. At rated speed the synchronization process is performed by closing S3. Next, the breakers S4 and S5 will be opened. At the end of the starting process the status of the breakers is: S1, S2, S3 closed and S4, S5 opened.



Figure 4.26 DFIM synchronous starting through an auxiliary converter layout

<u>Asynchronous start at reduced voltage (stator short-circuit).</u>

The starting process is performed with the main converter in the rotor and the stator with a three phase short-circuit (Figure 4.27). The starting process begins with S1, S2 and S4 opened while S2 and S5 are closed. S1 is closed; the rotor is fed by the main converter while the stator is short-circuited. The frequency of the rotor should be increased up to 25 Hz, at this state the rotor speed is half the rated speed. In this condition the voltage/current induced in the stator has a 50 Hz frequency. The breaker S5 is opened and the breaker S4 will be synchronized to the secondary side of the transformer converter. The frequency in the rotor will be reduced to zero and therefore the rated speed is reached. By reverse sequence injection it is possible to reach a speed over the synchronous speed; approximately at 103 % of the rated speed the breaker S4 is opened and S3 is closed when

synchronizing conditions are reached. At the end of the starting process the status of the breakers is: S1, S2, S3 closed and S4, S5 opened.



Figure 4.27 DFIM asynchronous starting at reduced voltage (stator short-circuit) layout

Asynchronous starting at reduced voltage (stator short-circuit) Alternative 2.

The starting process is performed with the main converter in the rotor and the stator with a three phase short-circuit (Figure 4.28). The starting process begins with S1, S2 and S4 opened while S4 is closed. S1 and S2 are closed; the main converter feeds the rotor while the stator is in short-circuited conditions.



Figure 4.28 DFIM asynchronous starting at reduced voltage (stator short-circuit alternative 2) layout

The rotor frequency is increased up to 50 Hz, consequently the rotor raises the rated speed. At this moment S4 will be open, and the stator is not in short-circuit, just after that the breaker S3 will be synchronize to the network. At the end of the starting process the status of the breakers is: S1, S2, S3 closed and S4 opened.

Reverse phase sequence to rotor and stator start.

The starting process is performed with the main converter feeding the rotor and the stator together but with different phase sequence (Figure 4.29). The starting process begins with S1 and S3 opened while S2 is closed. The starting process starts by closing the breaker S1. The main converter feeds the rotor and the stator with direct and reverse phase sequence respectively. This situation can be performed by exchange two phases between the main converter and the stator. The frequency of the converter is increased up to the rated speed. In this moment the breaker S2 should be open, hence the stator is in no-load condition. In this moment the breaker S3 is synchronized to the network.

At the end of the starting process the status of the breakers is: S1, and S3 closed and S2 opened.



Figure 4.29 DFIM reverse phase sequence to rotor and stator start layout.

4.5 Current trends and new developments.

The cyclo-converter has been the most used converter in the early development of PSHPs. For example, one of the world's largest adjustable speed pumped-storage unit (400 MW, Ohkawachi Power Station, in Japan), uses this technology (Kuwabara et al., 1996). It had a complicated architecture called 6-pulse cyclo-converter composed of 36 thyristors, but its main drawback was the high value of the Total Harmonic Distortion, (THD). In the rotor current it can reaches values of 15.69% (Abdalla and Han, 2013).

The second generation of PSHPs began to use DC-Link converters also called back to back converters. The most simple topology of back to back converters is the two levels voltage source converter (VSC) presented above in this document. They are composed of 12 IGBT or IGCT switching devices, with a free-wheeling diode in parallel with each one. By means of a Pulse Wide Modulation (PWM) or a Space Vector Modulation (SWM) a switching signal is generated. In this devices the THD factor in rotor current decreases down to 4.42 % (Abdalla and Han, 2013).

With a non-negligible complication of the back to back topology, it is possible to improve the THD factor. For example, with a 3 level diode clamped VSC composed of 24 IGBT or IGCT, the THD factor in rotor current decreases down to 4.19 % (Abdalla and Han, 2013). Industry has developed VSC converters of 5 and 7 levels but their designs are quite complicated.

Nowadays, the research of power electronics converters for variable-speed pumped storage is focused on the Multilevel Modular Converter (MMC). This topology is receiving a special attention for being used in transforming devices DC/AC and AC/DC as part of the links in High Voltage Direct Current (HVDC).

It is composed of a large number of modules in series. Each module, called H-bridge, is capable of providing positive, negative or zero voltage at its output terminals. Therefore each branch is capable of providing a (2n+1) voltage levels where n is the number of modules in a branch. The main advantages of this topology are:

- It requires fewer components than the diode-clamped and circuit for the same number of levels.
- Optimized circuit layout and packing is possible because each level has the same modular structure.
- Almost sinusoidal output voltage.
- Low THD in the current. It can be reduced to 1.07% (Abdalla and Han, 2013).

5 PUMPED STORAGE HYDROPOWER PLANTS OPERATION STRATEGIES

5.1 Introduction

Since the beginning of the nineties, electricity markets all over the world have gradually experienced a continuous process of deregulation. These new market schemes have served as a framework for the development of plenty of planning tools that assist the power generation companies to better utilize their energy resources.

As a result of the above-mentioned deregulation process, a wide number of electricity markets schemes have appeared all over the world. In spite of the differences existing among the distinct electricity markets, the activities of buying and selling electric power are in most cases organized around a short-term wholesale energy market. These markets are supervised by an independent agent usually referred to as the Market Operator, who is in charge of the market clearing process, from the selling and buying bids submitted respectively by the generation companies and consumers. As a result of the market clearing process, the Market Operator determines the energy prices as well as the energy to be delivered by every power generation company, power plant or group of power plants, at each programming period of the time horizon, usually one day.

In order to allow the agents correcting any error in their generation or consumption forecast due to, for example, unexpected unit unavailabilities or weather conditions, different successive markets, usually referred to as intraday markets (Weber, 2010), take place every day once that the spot market has been cleared.

Besides the day-ahead and intraday markets, there exist other markets wherein certain ancillary services that contribute to guaranteeing the quality, reliability and security of supply, are negotiated; frequency and voltage control are examples of said services (Rebours et al., 2007a; Rebours et al., 2007b). Mainly due to the increase in the penetration of non-dispatchable energies, such as solar or wind, in quite a few electric power systems, the amount of ancillary services and, consequently, the economic volume negotiated in the corresponding markets, have considerably increased (González et al., 2014).

5.2 Short-term operation strategies

In view of the complex structure of the deregulated electricity markets, it seems logical that the marginal approach and peak shaving method traditionally used to determine the short-term

operation schedule of a pumped-storage hydropower plant (PSHP) (Wood and Wollenberg, 1996; Deb, 2000) have been gradually replaced by more sophisticated scheduling tools or models.

Nevertheless, some authors have used a marginal approach to optimally schedule the energy and reserves for the corresponding markets. In (Lu et al., 2004), authors obtained an analytical condition depending on the energy and reserve prices, as well as on the unit cycle efficiency (generating-pumping), that should be fulfilled in order for the bids to be profitable. In (Kanakasabapathy and Shanti, 2010), the above-mentioned condition was revised in order to consider the unit start-up and shut-down costs.

Most of the scheduling models found in the technical literature have been developed to be used within a specific electricity market, which can considerably differ from others in terms of the time horizon, number and duration of programming periods, etc., and for a specific generation technology, or mix of these. Nevertheless, and fortunately, most of the approaches proposed in the literature can be easily applied to a wide range of electricity market schemes, as well as different power plants or systems. For this reason, authors trust that the reader will understand that some discussions on thermal and hydrothermal scheduling models have been included in the chapter, as a mean to introduce some important issues for defining or planning the operation strategy of a PSHP.

In this sense, it is important to highlight the work presented in (Baíllo et al., 2006), where different criteria are established to classify the power generation scheduling models presented in the literature. One of the criteria used in the paper was the consideration of the uncertainty associated to certain variables involved in the problem, such as the prices of both the energy and the ancillary services.

The consideration of uncertainty in energy prices in the short-term generation scheduling was a "hot topic" during last decade. Among the works presented at the beginning of the last decade, it is worthy to mention (Conejo et al., 2002b), where hourly market clearing prices for the next day were modeled by means of a Lognormal probability density function. Energy selling bids were obtained from the results of a deterministic mixed integer linear programming (MILP) based model and a simple rule based on the required level of confidence for the bids to be accepted.

Two years later, the same research team published (Conejo et al., 2004), where a mixed integer quadratic programming (MIQP) based model is used to calculate the optimal operation schedule of a thermal power producer for the next 24 hours. In this paper, the risk associated to the revenue that the producer expects to obtain in the energy market is measured from its variance, which is in turn calculated from the covariance matrix of the hourly energy prices. In order to obtain a trade-off

solution between maximum profit and minimum risk, a weighted penalty term is included in the objective function of the problem.

The use of the variance as a risk measure has been criticized for its symmetry with respect to the expected value of the revenue, what implies that certain revenues above the expected one are considered as risky values (Hongling et al., 2008); however, some authors have recently used it to consider the risk in pumped hydro scheduling problems (Kazempour et al., 2009a).

Other indicators, such as the value at risk (VaR) or the conditional value at risk (CVaR), are considered more efficient than the variance as a risk measure. In (Catalao et al., 2010), the CVaR is used as a risk measure within a day-ahead power scheduling problem of a hydropower system, which is formulated as a mixed integer nonlinear programming (MINLP) problem.

All the above-mentioned scheduling models were developed for a price taker producer. This is usually the case in electricity markets with a high degree of competition, where the size of every company is considerably small with respect to the size of the power system. In (Baíllo et al., 2004), a stochastic MILP based model is used to prepare the *portfolio bids* of a price maker producer for the day-ahead, intraday and secondary regulation reserve markets of the Spanish power system; the company is assumed to own thermal, hydro and pumped hydro generation assets. In order to consider the influence of the company supply bids on the market clearing price, a series of *residual demand curves* (RDC) were considered for each hour of the day. RDC are also called *price-quota curves* (Conejo et al., 2002a) and represent the market clearing prices for different production levels (quotas) of the company. Intraday and reserve markets' prices were considered deterministic.

In (Olsson and Söder, 2003), the uncertainty associated to the day-ahead energy market is not considered, whereas that associated to the reserve market (regulating market) is modeled by using a series of price scenarios. In the paper, the reserve bids for each hour are represented by a linear curve. This allows reducing considerably the dimension of the problem with respect to the approach used in (Baíllo et al., 2004).

The MILP based model presented in (Kazempour et al., 2009a) is aimed at maximizing the weekly profit of a price-taker PSHP in a multi-market framework. The uncertainty associated to the hourly prices of the energy, spinning reserve and regulation markets, is considered through the variance of the corresponding forecast errors. The uncertainty associated to the hourly power delivery request in the ancillary services markets (i.e. real time use of the committed power reserves) is modeled through a suitable probability parameter, which is explicitly included in the water balance equation of the upper reservoir. Even though this approach can be viewed as a rough approximation, this is to

authors' knowledge the first attempt to model the uncertainty associated to the effective use of water for load-frequency control purposes.

Particular characteristics of each market bids are not considered in the paper, but rather a single hourly value for each market is obtained as a result of the model, in a similar way to (Olsson and Söder, 2003). Several risk terms are included in the objective function of the problem, each weighted by a risk penalty factor. In a similar way to (Conejo et al., 2004), these factors are to be specified by the user according to his/her degree of risk aversion.

The influence of each risk penalty factor on the expected profit was analyzed separately. It is worth noting that the risk penalty factor corresponding to the spinning reserve prices turned out to have by far the most significant impact on the expected profit, mainly due to the high percentage of the profit that is expected to be obtained from the spinning reserve market.

The importance of building offer curves or bids is emphasized in (De Ladurantaye et al., 2007). In that paper, a multi-stage stochastic MILP based model is proposed to calculate the bids of a price-taker hydropower company for the day-ahead and reserve markets. Water effectively used for load-frequency control is neglected in the paper, since as stated by the authors "*the reserves that are asked for by the market are rarely consumed*". The results presented in the paper show that both the operation schedule of the hydro units and the expected revenue can vary substantially depending on whether or not the bid prices are considered as decision variables.

In (Ugedo et al., 2006) a multi-stage stochastic MILP based model is proposed to calculate the bids of a price-maker power company for the day-ahead, the secondary reserve and the first intraday markets. The power company is assumed to own thermal, hydro and pumped-storage units. The influence of the power company on the prices of the above-mentioned markets is considered through a set of scenarios of RDC. In contrast to (Baíllo et al., 2004), in (Ugedo et al., 2006) authors obtain the hourly offer curve of each generating unit, for each considered energy and reserve market. Particular characteristics of each market bids are fully considered in the paper, as suggested in (De Ladurantaye et al., 2007). Hourly power delivery request in the reserve market is not considered in the paper.

Pumped-hydro units are modeled in a somewhat simplified manner, by means of a single energy balance equation; no decisions on the operation mode (generating/pumping) or the on/off status of the units are considered. Previous formulation was improved in (Ugedo and Lobato, 2010), where binary variables were used to select the operation mode as well as the on/off status of the units.

It is worthy to mention that a significant change in the strategy of the pumped-hydro portfolio was observed in (Ugedo and Lobato, 2010), as a consequence of considering the intraday market when bidding in the day-ahead and secondary reserve markets. As shown in the paper, the intraday market might be relevant for solving possible infeasibilities that could appear after the clearing of the reserve market, whose consideration in a deterministic case yields a 5 % increase in the daily revenue, in agreement to some extent with the conclusion drawn in (Kazempour et al., 2009a).

(Deb, 2000) is to authors' knowledge the first paper where the importance of the share of profits that a PSHP could obtain in the ancillary service markets is emphasized. As it was emphasized in (Deb, 2000), and later in (Ugedo and Lobato, 2010), among others, the revenues that a PSHP can obtain from providing ancillary services are of a pretty considerable magnitude in comparison with those that can obtain from levelizing the power demand. It is worthy to mention in this sense the works presented in (Pinto et al. 2011) and (Connolly et al., 2011). In the former, a MILP based deterministic model is used to calculate the bids of a price-taker PSHP for the day-ahead and spinning reserve markets; bids consist in a single hourly value for each market. In an analogous way to (Kazempour et al., 2009a), authors consider a single value for the power delivery request in the spinning reserve market.

Even though the MILP based model presented in (Pinto et al., 2011) is somewhat simplified and that the design parameters of the PSHP used in the case study are rather odd, some results presented in the paper are worthy of mention. Such is the case of the fact that in the three analyzed cases, the optimal operation strategy leads to negative revenue in the day-ahead market. Considering only the so-called base case, in which the hourly prices of the day-ahead and reserve markets, as well as the power delivery requests in the latter, are historical, the revenue obtained in the day-ahead market is negative, whereas that obtained in the spinning reserve market is positive and more than order of magnitude bigger than the previous one, in absolute value. According to the results, the expected share of revenue obtained in the spinning reserve market could even increase with respect to the base case as the share of wind generation increases, under the assumptions used in the paper to predict the impact of such increase in the share of wind on the day-ahead and spinning reserve markets prices.

In (Connolly et al., 2011), authors compare different price arbitrage strategies in a series of electricity markets. No ancillary service market is considered in the paper. The strategies differ from each other essentially in the future time horizon for which the hourly energy prices are assumed to be known. The operation of a PSHP with a 6-h charge/discharge cycle, following each strategy, is simulated during a one-year period, using data from different electricity markets. The results of the simulations show that the expected profit of the PSHP differ considerably from one electricity market to another;

the maximum expected profit ranges from 60 to 70 M ϵ /year, whereas the minimum expected profit is roughly 3 M ϵ /year.

From the results of the above-mentioned simulations, authors determined the most profitable strategy and simulated the operation of the PSHP, in according with said strategy, during a five-year period, using data from different electricity markets. The obtained results show that even for the same electricity market, the expected profit may vary considerably from one year to another. In order to gain insight on the economic feasibility of the PSHP, the expected profits were compared to the annual repayments corresponding to different values of the interest rate and the initial investment cost. As stated in the conclusions of the paper, the results show that even with a low investment cost and a low interest rate, a PSHP is a risky investment in most electricity markets, provided that the operation strategy is based on the price arbitrage.

The results obtained in (Connolly et al., 2011) give full evidence that the operation strategies based on the traditional price arbitrage are far from being economically feasible for a PSHP in a liberalized market context, and provide a sound numerical support to the conclusions drawn in (Deb, 2000; Kazempour et al., 2009a; Ugedo and Lobato, 2010), regarding the importance of making a profit from the reserve markets. Nevertheless, as it can be deduced from the works previously discussed, in order to maximize the profits that a PSHP can obtain from the reserve markets, it is necessary to deal with the uncertainty associated to the effective power delivery request, what to authors' knowledge remains a challenging task.

As far as we know, (Varkani et al., 2011) is the only paper where the influence of the so-called power delivery request on the expected revenues of a PSHP is analyzed. In that paper, a mixed integer nonlinear (MINLP) based model is proposed to obtain the power offers of a wind power plant and a PSHP for the day-ahead, spinning and regulating reserve markets of the following day; bids consist of a single hourly value for each market. The hourly prices of the above-mentioned markets are considered in a deterministic way, whereas the uncertainty associated to the wind power production is modeled through a set of scenarios. Different probabilities of power delivery request are considered in the paper.

The results included in the paper show that a significant increase in revenues could be obtained as a result of the coordinated operation. As it is shown in the paper, the higher the probability of power delivery request in both the spinning and regulation reserve markets, the bigger the added value obtained as a result of the coordinated operation.

Similar conclusions regarding the benefits that could be obtained as a result of the coordination between wind and pumped-hydro assets were obtained in (García-González et al. 2008). In that

paper, a MILP based model is used to calculate the power bids of a wind farm and a PSPP for the day-ahead market considering the uncertainty associated to both the hourly prices and wind power, by means of a suitable scenario tree; in a similar way to (Varkani et al., 2011), bids consist of a single hourly power value. In addition to assessing the benefits that could be obtained as a result of the coordinated operation, authors analyze the evolution of said benefits as a function of the installed power of the PSHP. The results presented in the paper show that the benefits of the coordinated operation increase as the PSHP size increases; nevertheless, the rate of increase decreases as the PSHP size approaches that of the wind farm.

A similar study to the one presented in (García-González et al., 2008) can be found in (Abreu et al., 2012). In that paper, a MILP based model is used to calculate the power bids of a wind farm and a set of cascade hydropower plants for the day-ahead electricity market. The main contribution of (Abreu et al., 2012) is the consideration of the intrahour variations of wind speed. The results obtained in the paper show that the imbalance prices do have a strong influence on the benefits that the coordinated operation may yield.

The coordinated operation of wind and conventional or pumped hydro power in liberalized market contexts has been subject of study during, at least, the last ten years (Castruonovo and Peças Lopes, 2004). Special attention has received such operation strategy in island power systems, such as the Greek and Canary islands, where the fuel costs are usually higher than in most mainland power systems (Jensen, 1998), and where in most cases electricity market is organized in centralized way (STORIES, 2012). Some recent wind-hydro scheduling studies developed in centralized market contexts are described next.

In (Tuohy and O'Malley, 2011) the benefits of a pumped storage hydropower plant (PSHP) on the operation of the Irish electric power system are analyzed considering different levels of wind power penetration. For these purpose, authors use a stochastic MILP-based unit commitment model with hourly time resolution and 36-hours rolling planning horizon, updated every 3 hours as new wind and load forecasts become available; i.e. here-and-now decisions are made for the following three hours. Wind power uncertainty is considered by including multiple scenarios of future wind power production.

The objective function of the model is aimed at minimizing the costs for meeting the system demand and spinning and replacement reserves. Specific constraints are included in the model to prevent simultaneously pumping and generating, consistently with the use of reversible pump-turbines, as stated by the authors. No power regulation capability is considered in pumping mode. Nevertheless, the PSHP is assumed to be able to offer spinning reserve. The value of energy stored in the upper reservoir at the end of each is determined by the marginal cost of water storage at the end of the previous day.

The model is run sequentially for a one-year period, with and without a large PSHP (500 MW of installed capacity and 5 GWh of energy storage), and considering several cases of wind power installed capacity (6 GW, 7.5 GW, 9 GW, 10.5 GW and 12 GW). Maximum and minimum power demands considered in the study were 9.6 and 3.5 GW, respectively.

The results presented in the paper indicate that the investment in the proposed pumped storage hydropower plant could be justified for a wind installed capacity greater or equal than 8.5-9 GW (48-51% of energy from wind), assuming a PSHP lifetime of 40 years.

With respect to the PSHP operation, results show that for a wind installed capacity higher than 6 GW (34% of energy from wind), there would be more days in which the PHSP would pump at peak hours and generate at off-peak ones, as wind energy would be more frequently the marginal technology to meet the system demand. As it seems logical, results show that as wind penetration increases, Ireland would go from being a net energy importer to becoming a net energy exporter; nevertheless, energy exports would decrease with storage since the system could either benefit from the lower energy prices of Great Britain or store the excess wind power instead of exporting it.

Finally, it is worthy to highlight that as demonstrated in (Tuohy and O'Malley, 2011), it is important to analyze the impact of PSHP taking into account wind stochasticity since, otherwise, wind curtailments would be underestimated and, as stated by the authors, the more uncertain the wind energy is, the more beneficial is the flexibility of the PSHP.

In (Pezic and Moray Cedrés, 2013) a deterministic MILP based minimization-cost model is proposed to calculate the optimal short-term operation schedule of the world's first Megawatt-level renewable energy system in El Hierro Island (Spain). The system is composed by five wind turbines, each of 2.3 MW, and a PSHP comprising four Pelton turbines (2.83 MW each) and eight pumps (six fixed speed 0.5 MW pumps and two variable speed 1.5 MW pumps, which are able to regulate power consumption between 1 and 1.5 MW each). In addition, there are some thermal units to be used only in case of an emergency.

The objective function of the model consists in minimizing the sum of thermal generation costs (fuel and start-up costs) and six "artificial" cost terms related with the energy stored in the upper reservoir and wind power curtailments, among others. Cost coefficients of the artificial cost terms are defined by using a heuristic criterion based on the regulations in force at that time. Since the PSHP comprises two different pipes (one for pumping water flow and the other one for water discharged flow), the scheduling model considers the possibility of simultaneously using both pumps and turbines. Given the high wind penetration in the system (maximum historical power demand is 7.8 MW), both inertia and spinning reserve requirements become critical for power generation scheduling, and therefore, are considered as constraints in the scheduling model. It is important to highlight that to authors' knowledge, this is the first work where inertia requirements are explicitly considered within a power generation scheduling model, consistently with the special characteristics of the power system under study. In order to emphasize the importance of including the above-mentioned requirements on both spinning reserve and inertia, authors compare the power generation schedules obtained with and without considering such requirements for a specific scenario. As expected, the power generation schedules turned out to be pretty different from each other, the most noteworthy difference being the continuous simultaneous use of both pumps and turbines to minimize wind power curtailments and meet the inertia and reserve requirements.

As it can be observed from the technical literature, MILP has been widely used for power generation scheduling purposes during last fifteen years. Such a profuse use has been strongly favored by the increase in the processing capability of the commercial computers, but is also due to its flexibility for modeling. In (Li and Shahidehpour, 2005) a comparison between MILP and Lagrangian Relaxation (LR) abilities to solve a deterministic unit commitment (UC) problem of a power generation company is presented. The company is supposed to own a set of thermal, combined cycle, cascade-hydro and pumped-storage units. Market prices for energy and ancillary services (spinning and non-spinning reserves) are considered deterministic. Authors assume that spinning and non-spinning reserves scheduled are always requested.

In the MILP formulation, each operation mode of the pumped-storage units (generating, idle and pumping) is modeled as a *pseudo unit*. Transition costs among different operation modes as well as minimum on/off times for each mode are considered in the paper.

Upper bounds for the total energy and ancillary services supplied by the company are considered in the paper. In order to cope with such a *complicating constraint*, present both in the MILP and LR formulations, authors propose a three-step sequential solution procedure. At each step the problem is solved considering a different subset of power generation units (cascade-hydro, pumped-storage, and thermal and combined cycle). The above-mentioned upper bound is updated at the beginning of each step by subtracting the energy and ancillary services obtained in the previous step.

Three different cases depending on the considered type of units are studied in the paper: cascadehydro, pumped-storage and thermal and combined cycle. The expected profit obtained with the MILP based model is higher than the one obtained with the LR based one in the three cases. The operation schedules of the cascade-hydro and pumped-storage units obtained with the MILP and LR based models differ considerably from each other; the MILP based one turned out to be more responsive to market prices and made better use of limited water resources. The results of the third case (thermal and combined cycle) show that even though it takes longer for the MILP based model to find an initial feasible solution, this solution is much closer to the optimal one than that of the LR based model. The results of a fourth case, show that the computation times of both the MILP and LR based models increase almost linearly with the number of scheduling periods up to certain value beyond which that of the MILP based model increases abruptly whereas that of the LR based one still follows a linear trend.

The LR based method used to solve the unit commitment of the pumped-storage units in (Li and Shahidehpour, 2005) is described in (Guan et al., 1994). As stated in that paper, the basic idea of the model is to relax the pond level dynamics and constraints by using a set of Lagrange multipliers. In this way, the problem can be decomposed into a series of subproblems, each corresponding to a stage or scheduling period. Assuming additionally that the operating state is known a priori, each subproblem consists in optimizing a single variable function. Once that the optimal generation or pumping level is obtained for each operating state and scheduling period, dynamic programming (DP) is used to optimize the transitions between states across hours.

As it is well known, the dual solution obtained from LR is not guaranteed to be feasible. In order to obtain a feasible solution from the LR results, authors propose an interesting heuristic method that consists in checking sequentially the pond level constraints and consequently modifying the generation or pumping levels in a set of hours selected as a function of their marginal cost. A similar criterion is used in (Pérez-Díaz et al, 2010a) to guide the search within a branch and bound tree of a MINLP based short-term scheduling model of a hydropower plant.

MINLP solvers are barely used for power generation scheduling purposes, mainly due to numerical difficulties. Nevertheless, during last decade MINLP solvers have experienced a significant development (Lee and Leyffer, 2012) and as a consequence, some recent studies on power generation scheduling have used different MINLP solvers, such as the above-described work by (Varkani et al., 2011), or the work by (Kazempour et al, 2009b). In the latter, authors present a MINLP based model aimed at maximizing the weekly profit of a set of cascade hydro plants and one PSHP in a multi-market framework. Main features of the model are similar to those of the model presented in (Kazempour et al., 2009a). The model is formulated as a MINLP problem and solved using the SBB solver (Bussieck and Vigerske, 2012).

Other MINLP based short-term hydro scheduling models can be found in (Díaz et al., 2011) and (Lima et al. 2013). Both in (Kazempour et al., 2009b) and (Díaz et al., 2011), the use of a MINLP formulation is mainly aimed at accurately modelling the so-called head effects on the hydro generation characteristic. Since usually, the rated head of closed-loop³ PSHPs is considerably large, head effects are of minor importance for such type of PSHPs, and therefore, head is normally considered constant throughout the time horizon as in (Chang et al., 2001). This is not necessarily the case in open loop PSHPs, where the rated head is strongly influenced by other parameters different from the economic feasibility of the generating-pumping cycle. In this sense, it is worthy to mention (Borghetti et al., 2008), where a MILP based model is proposed to calculate the short-term operation schedule of an open-loop multiunit PSHP. The formulation proposed to model the hydropower generation characteristic is similar to the one proposed in (Conejo et al., 2002c), where three piecewise linear non-concave power-discharge curves were used to model the hydropower generation characteristic, each corresponding to a different reservoir level. A smart MILP formulation was proposed to select one of the curves as a function of the actual reservoir level; each curve was used to compute the plant power output within a specific interval of reservoir volumes. In (Borghetti et al., 2008), a reduced set of power-discharge curves is also used to model the hydropower generation characteristic. Nevertheless, the curves are convex, what contributes to reducing the number of binary variables and therefore the CPU time, and the power output is obtained by interpolating between the two "nearest" power-discharge curves, what yields a more accurate power estimation.

5.3 Long-term operation strategies

Except for one of the cases analyzed in (Conolly et al., 2011), all the above-discussed papers are focused on the short-term scheduling (i.e. the scheduling horizon ranged from one day to one week), and therefore either an end of day or week target stored energy (Kazempour et al., 2009a), or an end of day or week marginal *water value* function (Ugedo and Lobato, 2010) is assumed to be known in advance. The use of one or another approach is not an arbitrary decision, but rather it depends, among other things, on the characteristics of the PSHP under study. For closed-loop PSHPs, a target value is normally used. Traditionally, the target value is determined in such a way that the PSHP can make as much profit as possible from the price arbitrage. For daily-cycle PSHPs, this usually means to begin and end everyday (0:00 am) with the upper reservoir empty. For weekly-cycle PSHPs, the end of week target strongly depends on the difference between Sunday and Monday energy prices; nevertheless, a null storage is established as end of week target (Monday 0:00 am) in quite a few cases (Kanakasabapathy and Shanti, 2010).

³ Without natural inflows.

Noteworthy results were obtained in (Connolly et al., 2011) regarding the determination of the end of day targets of a closed-loop PSHP in a liberalized market context. In that paper, the profit obtained assuming a perfect forecast of the hourly energy prices over a one-year period is used as a basis for comparing different short-term price arbitrage strategies. It is interesting to note that, according to the results of the one-year period simulations, the most profitable strategy would allow a PSHP with a 6-h charge/discharge cycle (daily cycle) to obtain a 97 % of the profit obtained with perfect forecast; however, when considering a 24-h charge/discharge cycle (weekly-cycle), the most profitable strategy yields an 82 % of the maximum theoretical profit. Taking into account that the planning horizon of most profitable strategy is one day, these results demonstrate that a daily-cycle closed-loop PSHP does not need an accurate price forecast for a time horizon longer than one day and equally important, that the intraday price arbitrage strategy may be far from the optimum for a weekly-cycle closed-loop PSHP.

These results shall be understood in the context of a price arbitrage strategy, what according to other results presented in (Connolly et al., 2011) does not allow justifying the investment in a new PHSP. Considering the ongoing shift in the operation of PSHPs from the traditional price arbitrage to an operation more focused on the ancillary services markets, further studies on the determination of the end of day and week targets of closed-loop PSHPs are necessary.

Even though in a centralized market context, this topic has been recently analyzed in (Deane et al., 2013). The objective of that paper is to establish day-ahead and week-ahead reservoir targets for a PSHP with a large storage capacity in an electric power system with high wind power penetration, from the TSO point of view.

In order to fully exploit the PSHP storage capacity, authors propose a two-step optimization procedure. The first step consists in calculating the power generation scheduling of all generating units of the power system by means of a MILP based stochastic model. The time horizon of the model is one year, divided into 6-hours intervals. The objective function consists in minimizing the power supply costs. Weekly storage targets are derived from the reservoir weekly end levels obtained as a result of the model. The second step is aimed at deriving daily storage targets, even though it can be understood as a procedure for daily power generation scheduling. A MILP based model is used here with a time horizon of 1 week, divided into 2-hours periods. The model is run day by day; i.e. only the results corresponding to the first day of the week are considered as a firm operation schedule. For each run, a set of 7-days wind power forecasts is used.

The two-step procedure proposed in the paper is compared on an annual basis to a *weekly refill* method that consists in forcing the reservoir to be full at the end of each week. Additionally, a

perfect foresight case was used as a reference for comparison. The results show that the two-step procedure proposed in the paper provides a lower increase in cost, relative to the perfect foresight case, than the weekly refill method. Also, results show that the two-step procedure allows a greater flexibility in the PSHP operation, increases the PSHP capacity factor and reduces wind curtailments.

For open-loop PSHPs, both weekly storage targets and marginal water value functions have been recently used in the literature (Borghetti et al., 2008; Ugedo and Lobato, 2010). These targets or water value functions are usually obtained as a result of a long-term scheduling problem. The most widely used techniques for long term hydropower generation scheduling are stochastic dynamic programming (SDP) (Stedinger et al., 1984) and stochastic dual dynamic programming (SDDP) (Pereira and Pinto, 1985). The use of one or another technique depends mainly on the "size" of the hydro system under study. The former is subject to the so-called *curse of dimensionality* (Dreyfus and Law, 1977) and therefore, is limited to reduced size hydro systems with one or a few reservoirs (Labadie, 2004), unless aggregate or composite system representations are used (Arvanitidis and Rosing, 1970). The latter combines the ability of SDP to solve multi-stage stochastic programming problems, with the use of Benders cuts to approximate the marginal water value functions, and has been successfully used for long-term generation scheduling of large size hydro and hydrothermal systems during the past two decades (Gjelsvik et al., 2010).

As in the short-term range, electricity markets considerations have been gradually introduced in long-term hydro scheduling models during past decades (Fosso et al., 1999). Nevertheless, given the long time horizon of these models, and with that, their generally large computational requirements, the introduction of electricity markets considerations in the long-term range has occurred at a slower pace, and still today remains a challenging task.

To authors' knowledge, the long-term hydro scheduling model presented in (Lohndorf et al., 2013) is the one where uncertainty in hourly energy prices has been considered with a greater degree of detail. The model presented in that paper is based on SDDP and considers the bidding decisions in the day-ahead and intraday markets within the European Power Exchange (EPEX SPOT) framework. The time horizon of the model is one year, divided into daily steps, and these in turn into hourly stages, according to the programming periods of EPEX SPOT (Scharff and Amelin, 2011). The model was tested on a hydropower system located in the Austrian Alps, considering six different configurations were analyzed as a function of the number of reservoirs and maximum and minimum generation and pumping capacities.

Another noteworthy long-term generation scheduling model is the one presented in (Helseth et al., 2013). In that paper, a SDDP-based model is proposed for the long-term scheduling of a

hydrothermal system with pumped-storage and wind power. Even though the uncertainty in energy prices is not modelled with the same degree of detail as in (Lohndorf et al., 2013), in terms of both the number of markets considered and the time resolution, it is fair to highlight that as far as we know (Helseth et al., 2013) is the first work where the start-up costs of pumps and thermal generating units are considered within a long-term generation scheduling model.

As it has been already mentioned in this and other chapters of the present report, PSHPs are expected to have a central role in the integration of non-dispatchable energies, such as solar and wind, into the electric power system. Actually, as it has been soundly discussed in this chapter, quite a few firm numerical results support the idea that the traditional operation strategies based on price arbitrage or peak shaving must be replaced by ancillary services or balancing driven operation strategies, both in liberalized and centralized market contexts. In such a new operation paradigm, it seems rational to think that the above-mentioned targets or marginal water values used as a link between the long- and short-term operation scheduling of open-loop PSHPs, could vary substantially.

In this regard, it is worthy to mention and briefly describe the preliminary results presented in (Abgottspon and Andersson, 2012), where the participation of a large open-loop PSHP in the secondary load-frequency control market was considered within a long term scheduling model.

For this purpose, authors use a stochastic dynamic programming (SDP) based model, with a 1-year time horizon, divided into weekly stages. Water level or storage in the reservoir at the beginning of each week is used as state variable. Weekly water inflows are considered in a deterministic way. Several scenarios of hourly pool prices and weekly secondary control prices are considered within each week. The work is carried out within the framework of the Swiss electric power system, where weekly "capacity blocks" (in MW) are submitted to the TSO (Swissgrid) for secondary control purposes. For each water level and secondary control price, the expected weekly profit is calculated by means of a MILP-based weekly scheduling model. The expected future profit is then calculated by solving a simple recursive equation for each feasible state; water values are obtained from the derivative of the expected future profit values.

In order to analyze the importance of considering the secondary control market within the longterm scheduling, authors compare the expected profit at each feasible state with and without the possibility to offer secondary control. The differences observed in the comparison turned out to be of little importance; a 1-2 % increase in the expected profit might be attained when secondary control is considered. Additionally, authors compared the expected profit obtained without considering the secondary control market with the one obtained in a case where the hydropower plant was forced to offer secondary control every week. The latter proved to be around 15-25 % lower than the former, what seems to indicate that, as authors state, secondary control offers must be wisely calculated.

The methodology proposed in (Abgottspon and Andersson, 2012) seems to be sound enough to analyze the impact of short-term operation strategies, constraints, etc., in the long-term scheduling. The results obtained in the case study regarding the little sensitivity of the long-term scheduling to the secondary control offers should not be generalized to every PSHP or electricity market. On the contrary, they should encourage researchers to carry out similar analyses in other PSHP and electricity markets. The structure of the secondary control market in the Swiss power system might introduce certain degree of "rigidity" in the PSHP operation, which does not appear in other secondary reserve markets with hourly auctions.

5.4 Current trends and future challenges in pumped-storage hydropower plants operation strategies

Current trends in PSHPs operation strategies can be summarized as follows:

- Traditional operation strategies based on price arbitrage and/or peak shaving appear to be no longer economically feasible.

- Ancillary services markets, particularly those related to balancing generation and demand, emerge as the main source of revenue for PSHPs in liberalized market contexts. Analogously, support to the integration of non-dispatchable energies in the electric power system presents itself as the essential role of PSHPs in centralized market contexts, such as those currently in place in many island power systems.

- Consistently, special attention is being given to accurately modeling the uncertainty in energy and ancillary services prices, as well as in wind and/or solar power production, for the power generation scheduling of PSHPs in both liberalized and centralized market contexts.

Future challenges that, in authors' opinion, would be interesting to deal with in the next future can be summarized as follows:

- Modeling the uncertainty in the power delivery requested in real time for ancillary services purposes, in the short-term range, is still a pending task that, according to authors' experience, could contribute significantly to increasing the participation of PSHPs in said services, and thus the penetration of intermittent energies into the electric power system, and to improving the PSHPs economic feasibility.

- The determination of the long-term guidelines typically used as a link between the short- and longterm scheduling for open-loop PSHPs (storage targets and marginal water values), should be "revisited", considering the new ancillary services or balancing based operation paradigm. Analogously, the suitability of the end of day or week storage targets traditionally used for closedloop PSHPs operating in liberalized electricity markets should be reevaluated. Authors guess that either the use of different targets "updated" to the new operation strategies, or the replacement of such "targeted" operation strategy by a flexible one with a suitable look-ahead period (Deane et al., 2013), would yield better results in terms of both the PSHP profitability and participation in the ancillary services.

- Taking into account the ongoing PSHPs projects all over the world, studies on the operation strategy of more flexible PSHPs, such as those described in previous chapters of this report, become mandatory.
6 References

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