Trends and challenges in the operation of pumped-storage hydropower plants (PSHP)

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1.1 Context of the work

- The work presented here summarizes some of the discussions included in:

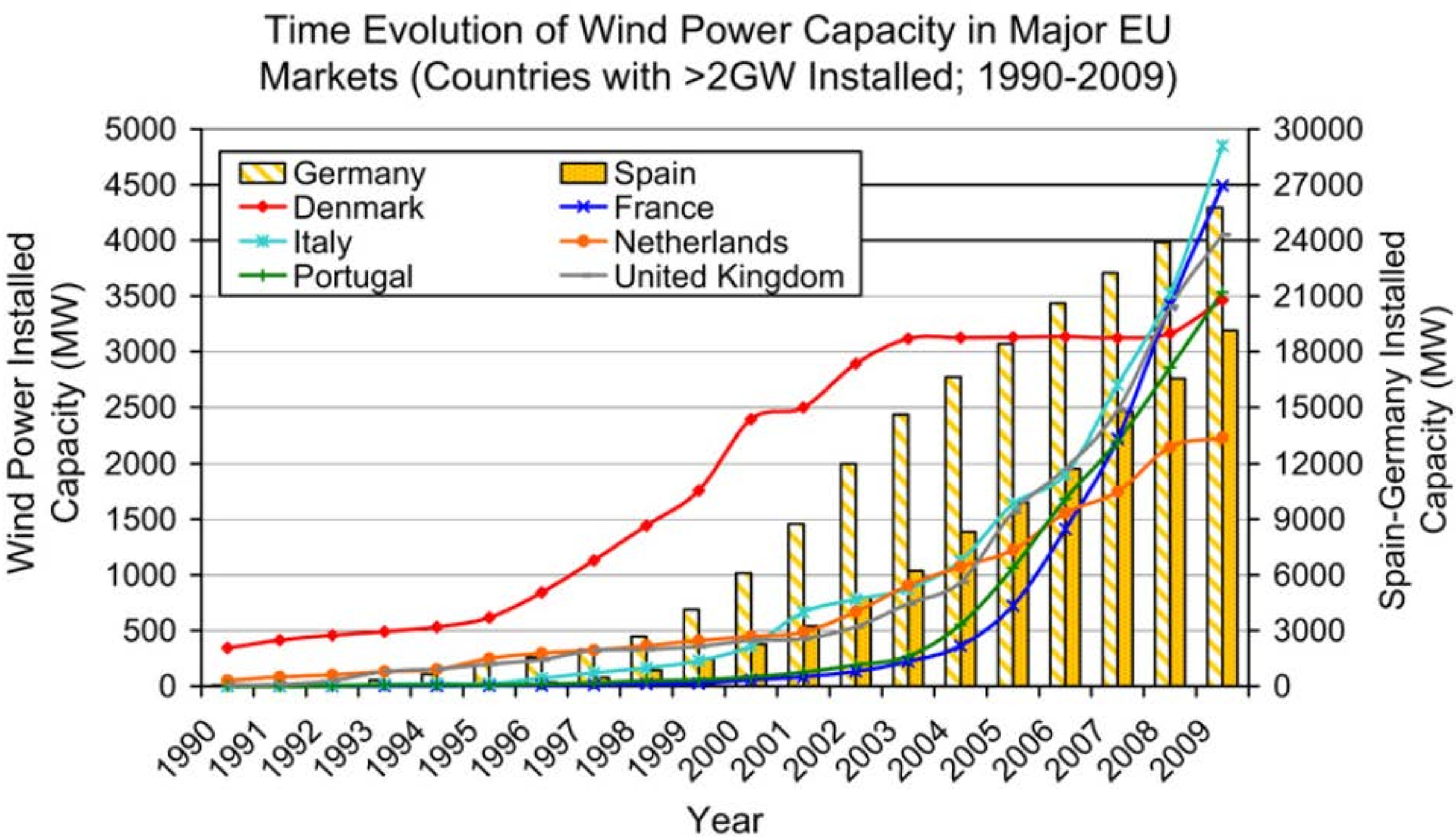
  Pérez-Díaz, J.I., Chazarra, M., García-González, J., Cavazzini, G. and Stoppato, Trends and challenges in the operation of pumped-storage hydropower plants, Renewable and Sustainable Energy Reviews, vol. 44, pp. 767-784, 2015.

- The work presented in the paper was partially funded by the **Spanish Ministry of Economy and Competitiveness** under the **research project ENE2012-32207 ("*Operation and control of pumped-storage hydropower plants*")**. The coordination tasks were carried out by the corresponding author during a research stay in the University of Padova, under the framework of the **Mechanical Storage Subprogram of the EERA Joint Programme on Energy Storage**

1.2 Why pumped-hydro energy storage (PHES)?

- There is a big amount of potential energy that can be stored in hydro reservoirs (Arántegui et al., 2012).
- High cycle efficiency (~ 80 %) (Teller, 2012).
- Reasonable cost per power unit (1000 – 2000 €/kW) (MWH, 2009)
- Flexibility (EURELECTRIC, 2011).
- It currently represents 99 % of the grid-connected electricity storage (IEA, 2012).

1.2 Why pumped-hydro energy storage (PHES)?



Wind power capacity in major EU markets; taken from (Kaldellis et al., 2011)

1.2 Why pumped-hydro energy storage (PHES)?

- A substantial increase in the PHES installed capacity is expected, according to several international reports

	Eurostat [27]			Eurelectric [40]		
	2005	2009	2010	2007	2010[a]	2020[a]
Installed capacity (GW)	36.7	40.8	34.5	36.9	31.0	42.6
Electricity generation (TWh)	34.5	31.7	31.5	37.7	35.2	43.2

	NREAP [19]			HYDI	
	2005	2010[a]	2020[a]	2010	2020[a]
Installed capacity (GW)	23.4	28.2	39.5	42.1(19.5)[b]	60.7(24.1)[b]
Electricity generation (TWh)	23.8	23.6	32.6	39.1(12.4)[b]	56.4(15.3)[b]

[a] Forecast.
[b] Numbers in the brackets indicate mixed PSPs capacity and their renewable electricity generation, respectively.

Current and projected PHES installed capacity in EU; taken from (Punys et al., 2013)

2. Trends in the operation of PSHPs

- During the nineties, most power systems experienced a process deregulation (England, Wales, etc.).
- A wide number of electricity market schemes have appeared all over the world.
- Most of the liberalized electricity markets are organized around a short-term wholesale market, with 1-day *time horizon*, and hourly *programming periods* → **spot market.**
- Several successive markets are celebrated every day in order for the agents to correct power deviations → **intraday markets.**
- Certain services which contribute to guaranteeing the quality, reliability and security of supply are negotiated in other markets → **ancillary services markets.**

2. Trends in the operation of PSHPs

- Before the deregulation, PSHPs were scheduled by the Transmission System Operator (TSO) according to (Wood and Wollenberg, 1996):

$$\eta_{cycle} \geq \frac{F_p}{F_g}$$

- PSHPs played an important role in the so-called **load-shifting**, i.e. consume electricity during low-demand periods and thus help base-load power plants to operate more efficiently, and generate electricity during high-demand periods and thus reduce generation from more expensive and less efficient power plants.
- **(Deb et al., 2000)** is to the authors knowledge the first paper where the importance of the share of profits that a PSHP could obtain in the **reserve markets** is emphasized
- **Peak-shaving and heuristics** are used respectively for bidding only for energy and for energy and reserves

- Some conclusions drawn in (Deb et al., 2000) are:
  - ✓ A PSHP may almost **double its daily income by simultaneously bidding in the spot and reserve markets**
  - ✓ *Using* ***the peak-shaving algorithm*** *severely* ***underestimates the income*** *of the storage and pumped units*
- In 2004, Lu et al. derived an **analytical condition** that should be fulfilled for a PSHP to make profit from the spot and reserve markets

$$\frac{B_g}{B_p} = \frac{1}{\eta} + \frac{B_{\mathrm{rs}}}{\eta B_p} - \frac{B_{\mathrm{rn}} P_g}{\eta B_p P_p} + \frac{B_{\mathrm{rn}}}{B_p}$$

- The condition derived in (Lu et al., 2004) depends on the spot market prices (B_p, B_g), and the **spinning and non-spinning reserve prices** (B_{rs}, B_{rn})

2. Trends in the operation of PSHPs

- The previous condition was extended in (Kanasakapathy et al., 2010) to consider the **operating cost of the unit**, C_0 (including start-up and shut-down cost)

$$B_g = \frac{1}{\eta_p}\left[B_p + B_{rn}\left(\eta_p + \frac{P_g}{P_p}\right) - B_{rs} + C_o\left(\frac{1}{P_p} + \frac{\eta_p}{P_g}\right)\right]$$

- In addition, the algorithm proposed in (Kanasakapathy et al., 2010), considered the **dependency of the unit power limits and efficiency with the head**.
- **The algorithm proposed in (Kanasakapathy et al., 2010) yielded 4 % and 6 % higher profits than those presented in (Deb, 2000) and (Lu et al., 2004)**, in the framework of the New York Independent System Operator (NYISO)

2. Trends in the operation of PSHPs

- In (Connolly et al., 2011), several **price arbitrage strategies** are compared to each other in a series of (energy-only) **spot markets**.
  - ✓ A PSHP is a **risky investment** in most electricity markets (even assuming perfect forecast of the spot market prices)
  - ✓ Expected profit **differ considerably from one electricity market to another**
  - ✓ There exist **big yearly variations** in the PSHP profit within the same electricity market
- In (Pinto et al., 2011), a **deterministic MILP based** scheduling model is used for joint energy and reserve scheduling of a PSHP in the Portuguese electricity market
  - ✓ In all analyzed cases the optimal generation and consumption schedule leads to **negative revenue in the spot market**

Spot market	- 1.95 k€
Reserve market	8.58 k€

2. Trends in the operation of PSHPs

- The papers discussed so far follow a **deterministic approach** → the conclusions could be deemed as **not reliable enough**
- In (Swider et al., 2007), a **stochastic NLP-based model** is used for bidding in the European Energy Exchange (EEX) spot market and the RWE Net Ag and E.ON Netz GmbH tertiary reserve markets
- The influence of the reserve bids on the reserve prices is considered in the paper (**price-maker approach**)

Power plant capacities (thermal and pumped-hydro)	75-150 MW
Total reserve requirement in E.ON Netz	≈ 1100 MW
Total reserve requirement in RWE Net	≈ 1000 MW

✓ The expected **profit is "dominated by the reserve market products"**

- In (Ugedo and Lobato, 2010) a **multi-stage stochastic MILP based** model is used for bidding in the spot market, the secondary reserve market and the first intraday market in the Spanish power system
- The influence of the producer bids on the prices of the above-mentioned markets are considered through a set of scenarios of **Residual "Demand" Curves** (RDC); the reserve requirement in the Spanish power system ranges from 500 to 900 MW

Perfect forecast	1.49 M€
Expected revenue	1.28 M€
Real revenue	0.71 M€

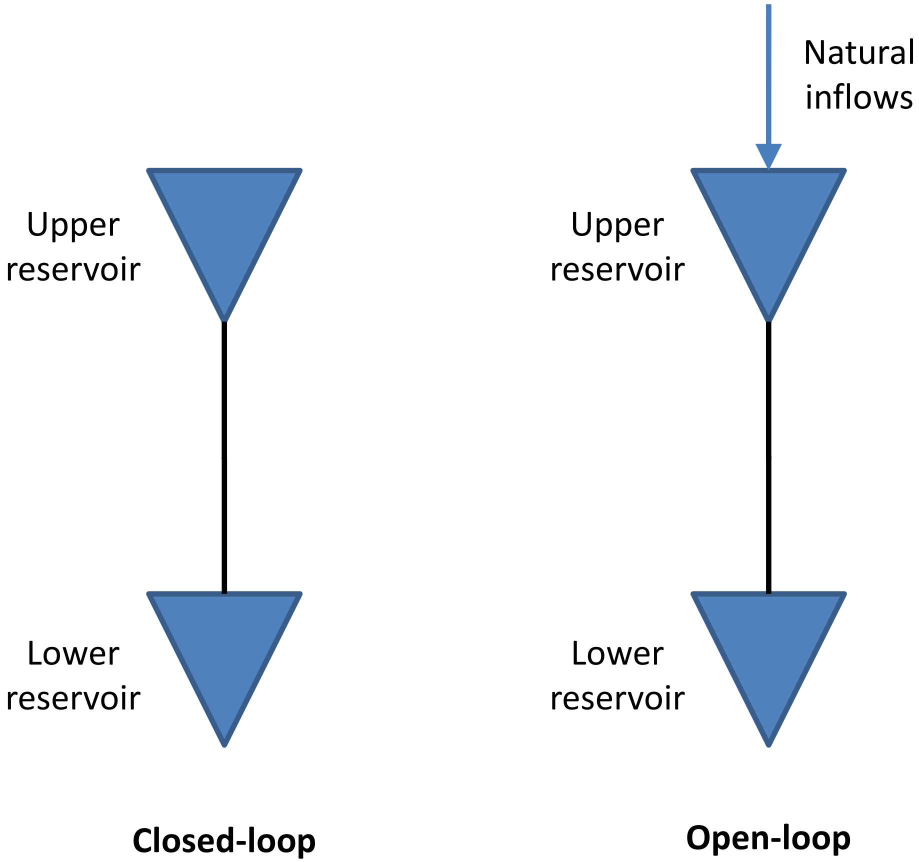
- ✓ The **value of perfect information is significant**
- ✓ The **intraday market might be relevant** for solving possible infeasibilities
- ✓ **5 % increase in the revenue** is obtained when **considering the reserve market** in the perfect forecast case

2. Trends in the operation of PSHPs

- In a significant number of reserve markets (Rebours et al., 2007), reserve is remunerated for two different concepts: **reserve availability and delivery**
- **Reserve delivery is requested in real-time** by the TSO depending on real-time power and load fluctuations
- To the authors' knowledge, the first attempt to consider the uncertainty in the real time use of the reserve (RTUR) was done in (Kazempour et al., 2009a), where a **stochastic MILP based** model was used for the scheduling of a PSHP in the spot, spinning reserve and regulation markets in the Spanish power system
- The **uncertainty in the RTUR** was **considered through a suitable probability parameter**, explicitly **included in the water balance equation** of the PSHP upper reservoir (↔ expected percentage of use)

2. Trends in the operation of PSHPs

- The **RTUR** may not only affect the day-ahead revenue of the PSHP, but also the **fulfillment of the end of day or week target storage** (closed-loop PSHP) or the **final water value** (open-loop PSHP), and thus the **future revenue** of the PSHP

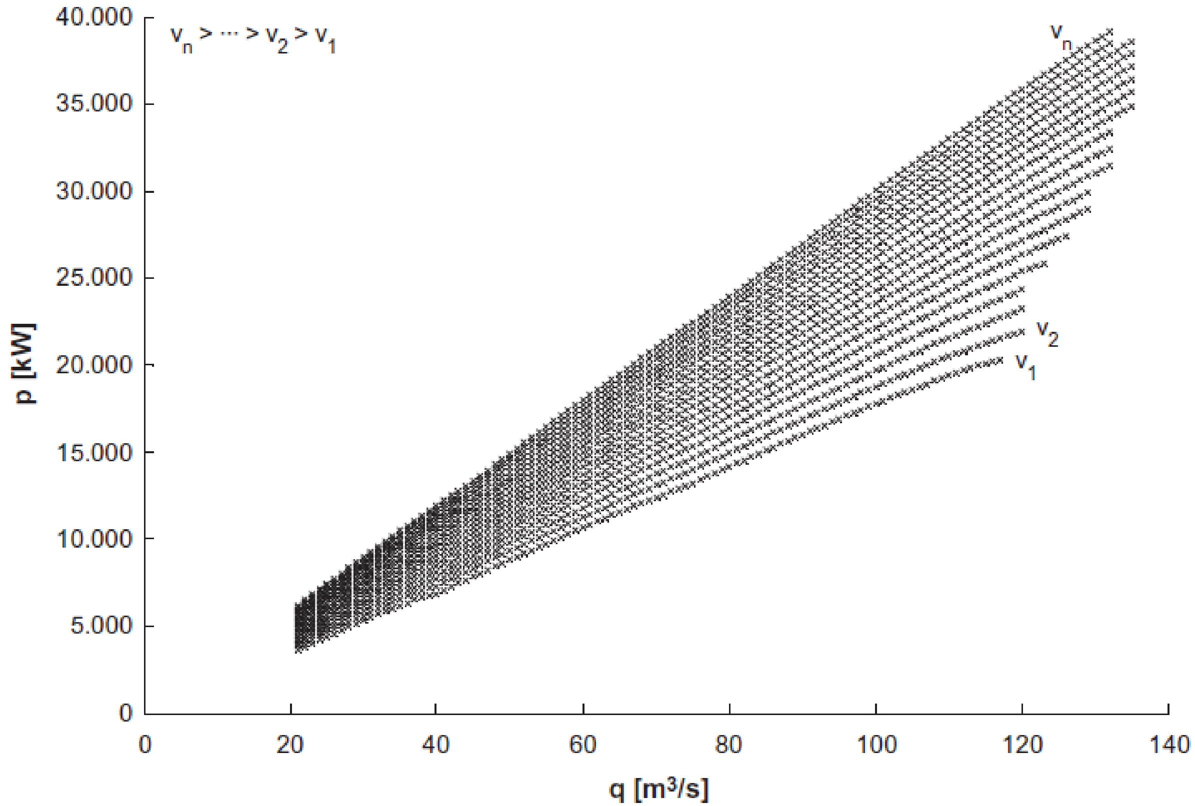


- The **uncertainty** in the spot, spinning reserve and regulation **market prices** is considered through the **variance of the forecast errors** (first proposed in (Conejo et al., 2004)) → several risk terms are included in the objective function, each weighted by a penalty term (↔ producer's degree of **risk aversion**)
  - ✓ The **risk penalty factor** corresponding to the **spinning reserve prices** turned out to have by far the most **significant impact on the expected profit**
- In outline, there are two different approaches to face the uncertainty:
  - ➢ **Risk neutral**: the decision maker tries to optimize the expected value
  - ➢ **Risk averse**: aims at quantifying and to limit the exposure to risk (*risk-constrained*)

- The use of the **variance as a risk measure** has been **criticized for its symmetry** with respect to the expected value of the revenue (Hongling et al., 2008)
- The **most widely adopted risk measure** in the power generation scheduling is the so-called ***Conditional Value at Risk* (CVaR)** (Dicorato et al., 2009)
- Other risk aversion approaches* used in the hydro scheduling literature are:
  - To impose a **target minimum profit** (García-González et al., 2007)
  - To minimize the ***downside risk*** (i.e. failure to meet a target minimum profit) (Wu et al., 2008)

* Power schedule and expected profit can be **very sensitive to the selected target**, even resulting in infeasible solutions.

- The model presented in (Kazempour et al., 2009a) is revised in (Kazempour et al., 2009b) in order to consider the so-called ***head-effects*** by means of a **MINLP based** formulation



Hydropower plant generation characteristic; taken from (Pérez-Díaz et al., 2010).

2. Trends in the operation of PSHPs

- **Head-effects are not usually considered for the scheduling of PSHPs** because:
  - In closed-loop PSHPs, the head is usually very large (for economic feasibility reasons)
  - In open-loop PSHPs (with typically large reservoirs), the head variation is usually neglected in the short-term
- In (Borghetti et al., 2008) a **MILP based** model is used for the short-term scheduling of an open-loop multiunit PSHP
- The formulation used to model the generation characteristic (GenCar) is similar to the one proposed in (Conejo et al., 2002) and takes into account the head-effects by using a reduced set of convex power-discharge curves

2. Trends in the operation of PSHPs

- **MINLP solvers are barely used** for power generation scheduling purposes, mainly due to numerical difficulties
- Recently, MINLP solvers have experienced a significant development (Lee and Leyffer, 2012)
- Some recent papers have used MINLP based models for short-term hydro scheduling purposes (with no PHES) in order to consider the head-effects:
  - (Díaz et al., 2011) used the **SBB solver** under GAMS
  - (Lima et al., 2013) developed a "tailor-made" DICOPT-based branch and cut algorithm and made a comparison with the BARON solver, both running under GAMS; the **tailor-made algorithm outperformed the BARON solver** in all analyzed cases

2. Trends in the operation of PSHPs

- The **influence of the RTUR** on the expected revenue of a PSHP is **preliminarily analyzed** in (Varkani et al., 2011)
- In that paper, a **stochastic MINLP based** model is used for the scheduling of a **wind power plant and a PSHP** in the spot, spinning reserve and regulation markets of the Spanish power system
- The hourly market prices are considered deterministic, whereas the **uncertainty in the wind power production** is considered through a **set of scenarios**
- Different probabilities of the RTUR are considered in the paper
  - ✓ A **significant increase in the revenue** can be obtained as a result of the **coordinated operation** (wind-PHES)
  - ✓ **The higher the probability of RTUR, the bigger the added value of the coordinated operation**

2. Trends in the operation of PSHPs

- Some other papers have dealt with the coordinated operation of wind and PHES, such as (Castruonovo et al., 2004) or (García-González et al., 2008)
  - ✓ The results obtained in all those papers indicate that a **significant added value can be expected from the coordinated operation of wind power and PHES**
- In (Reuter et al., 2012), authors assess the profitability of new wind-hydro schemes in the Norwegian and German power systems
  - ✓ Investing in a **wind-hydro** scheme **without public support is not profitable**
  - ✓ Very **high price premiums or subsidies would be necessary** for the investment to be profitable
- Recent works on wind-PHES coordination focus on modelling the **intrahour variations of wind power** (Ding et al., 2012; Abreu et al., 2012)

What about the long-term?

- As in the short-term, **electricity market considerations have been gradually introduced in the long-term hydro scheduling models** during past decades (Fosso et al., 1999)
- To the authors' knowledge the long-term hydro scheduling model presented in (Löhndorf et al., 2013) is the one where uncertainty in the hourly market prices is considered with a greater detail
- The model is based on **SDDP** and takes some ideas from **Approximate Dynamic Programming** (ADP)
- The model takes into account the bidding decisions in the **spot and intraday markets** of the European Power Exchange framework (EPEX SPOT), and the influence of the producer's bids on the intraday market prices (**price-maker**)
- **On/off status** of both turbines and pumps is also considered in the model (**stochastic MIQP one-step problem**)

2. Trends in the operation of PSHPs

- The **start-up costs** of the generating and pumping units is also considered in (Helseth et al., 2013), along with the **maximum capacities of the transmission power lines**
- **Wind power** is considered **as a stochastic variable** both in (Helseth et al., 2013) and (Löhndorf et al., 2013)
- The **head-effects** were first considered within a SDDP based long-term scheduling model in (Goor et al., 2011), where the hydropower GenCar is approximated by a suitable convex hull
- The head-effects are also considered in (Cerisola et al., 2012), where the hydropower GenCar is approximated by a set of McCormick envelopes and a binary variable (start-up costs)
- **Risk averse approaches** have been recently proposed for the long-term hydrothermal scheduling in (Philpott and de Matos, 2012) and (Shapiro et al., 2013), among others

SUMMARY OF TRENDS

1. **Price-arbitrage** strategies appear to be **no longer profitable**
2. **Reserve markets** emerges as **an important source of revenue** for PSHPs in liberalized market contexts
3. Big efforts are being done to model the **uncertainty in the spot, intraday and reserve markets**
4. **Price-maker approaches** are gaining importance to model the reserve and intraday market prices
5. Certain modelling details such as the **head-effects** and the units **start-up costs** are being given full consideration, whenever interesting
6. **MILP** (Li and Shahidehpour, 2005) **and SDDP** are the most widely used techniques for **short- and long-term** hydro scheduling respectively
7. **Risk-averse approaches** are proliferating

CHALLENGES NOT YET FULLY ADDRESSED

A. Forecasting/Modelling the **uncertainty** associated with the **real-time use of the reserves**

B. Revising the approaches currently used to determine the **long-term guidelines**: end of day or week target storages and water values

C. Considering **recent technical developments** such as **variable-speed and hydraulic short-circuit operation** in the scheduling of PSHPs

D. Detail modelling of the **water time delay** between hydropower reservoirs

A. Uncertainty in the RTUR

- Attempts to forecast the market prices, other than the spot market ones are limited (Fleten and Pettersen, 2005; Olsson and Söder, 2008); to the authors' knowledge, there is **no documented attempt to forecast the RTUR**[*]
- In most of the papers where reserve scheduling is dealt with, either the RTUR is not considered, or a single constant value is used (100 %, historical average)
- In power systems with a high share of non-dispatchable renewable energy, the RTUR is expected to be higher; in 2010, the mean upward and downward RTUR for secondary load-frequency control in the Spanish power system were, respectively, 28.6% and 30%
- **Interhourly variations in forecast load and wind power** might be used as **explanatory variables** for a regression-based RTUR forecasting

[*] A preliminary work on the topic has been presented in the Workshop by Chazarra et al.

B. Long-term guidelines

Closed-loop PSHPs

- The traditional “empty at 0:00” target used for daily-cycle PSHPs prevents the PSHP from providing upward spinning reserve during off-peak hours
- The traditional “fill during the weekend” rule used for weekly-cycle PSHPs prevents PSHP from providing upward spinning reserve during the weekend
- **End of day or week targets** should be **revised considering a reserve-driven operation**
- Relaxing the end of day or week target and considering instead a **look-ahead period** (Deane et al., 2013) might be a solution

B. Long-term guidelines

Open-loop PSHPs

- **Marginal water value functions** should be determined **considering** the participation of the PSHP in the **reserve markets**
- The methodology presented in (Abgottspon and Andersson, 2012) may be a **good starting point** for this purpose
  - **SDP-MIP** based model with 1-year horizon and weekly steps
  - Several scenarios of hourly spot market prices and weekly reserve prices are considered each week
  - 1 - 2 % increase in the expected profit when considering the reserve market
- **SDDP** should be used for **large hydro systems**
- **Price-making** should be considered **in the reserve market** (Löhndorf et al., 2010)

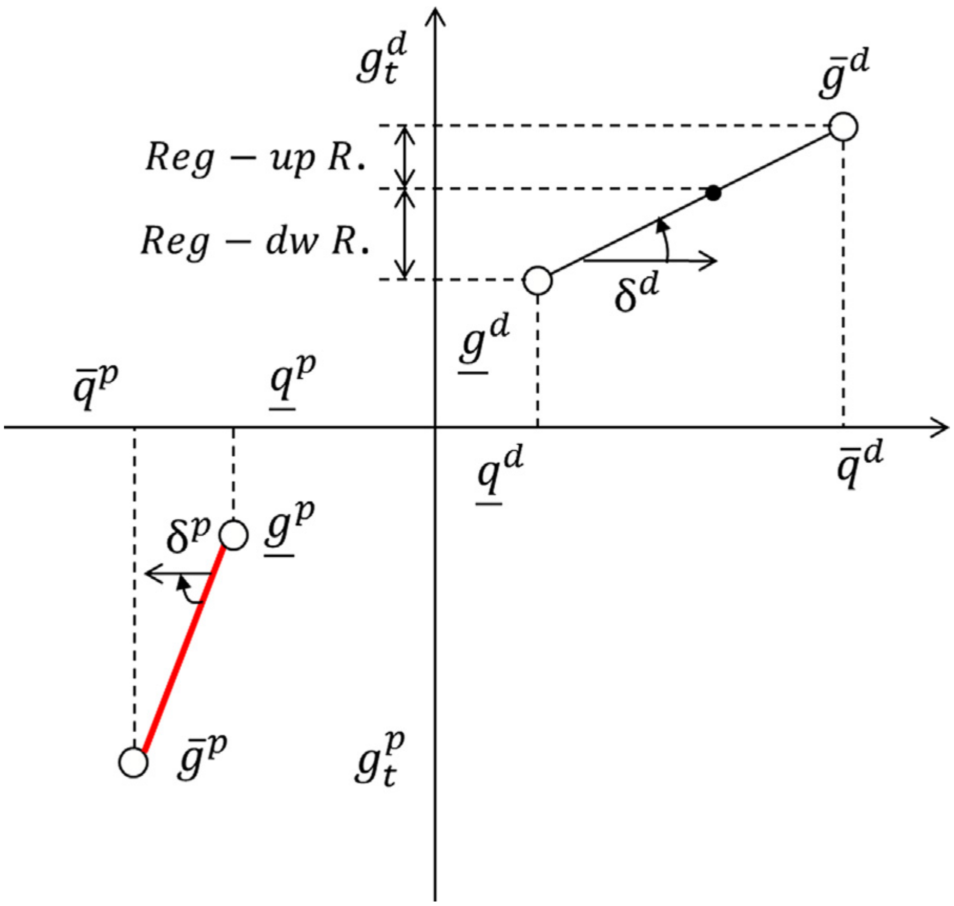
C. Technical developments

Variable speed operation

- Variable speed operation allows the PSHP to **regulate power** both in **generating and pumping modes**
- Additionally, it allows enlarging the operating range and increasing the efficiency in generating mode
- Even though there are **several PSHPs in operation equipped with variable speed drives** in Europe (Forbach, Goldisthal, Avce, Grimsel II), China (Panjiakou) and Japan (Narude, Yagisawa, Ohkawachi, Okukiyotsu), and quite a few under construction (Frades II, Venda Nova III, Nant de Drance, Linthal, Tehri, etc.), the **scheduling of variable-speed PHPs** in liberalized market contexts has received **little attention in the literature** (Aihara et al., 2011; Chazarra et al., 2014)

C. Technical developments

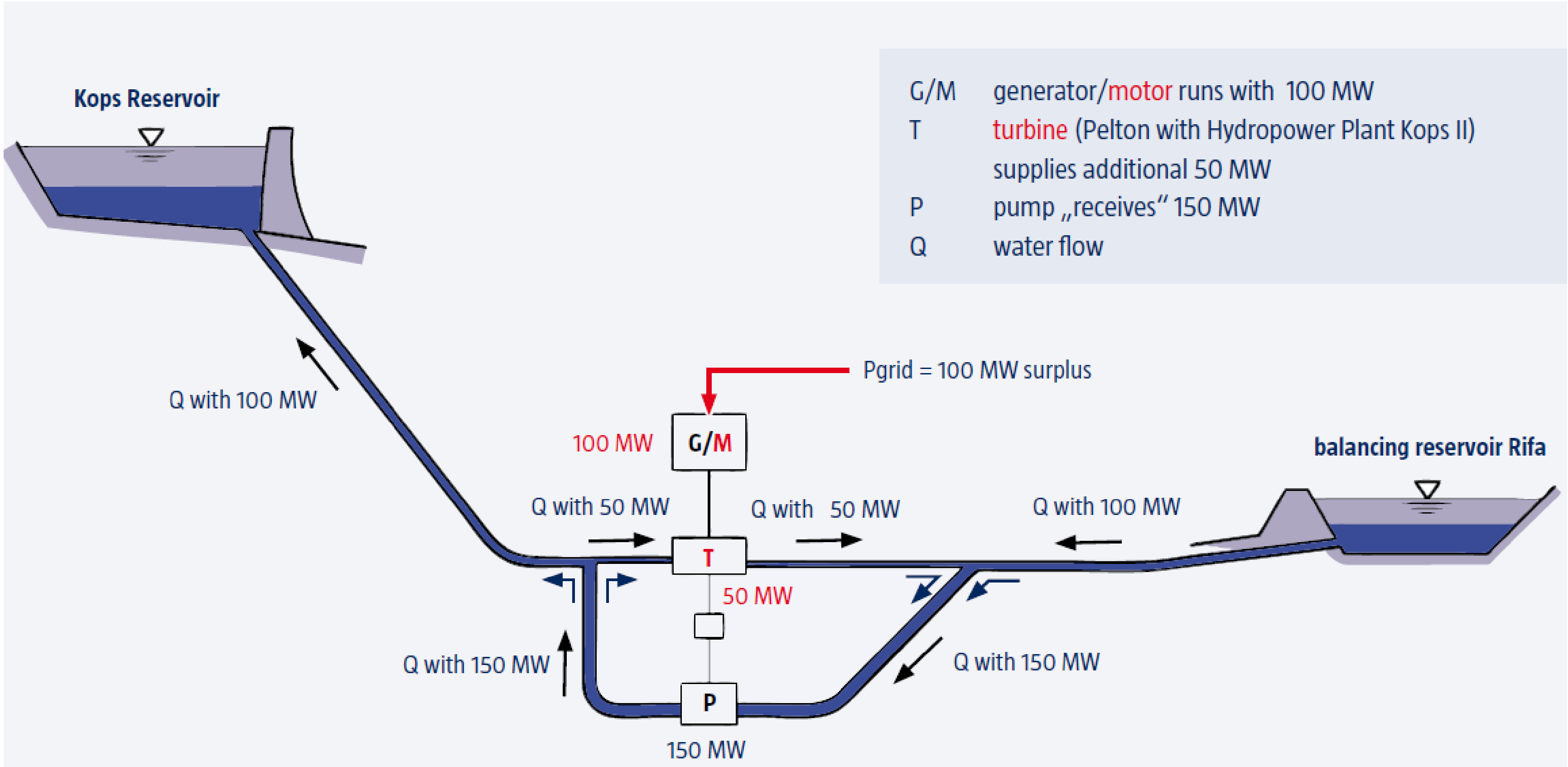
Variable speed operation



Power-discharge curve of a variable-speed pump turbine unit ; taken from (Pérez-Díaz et al., 2015)

C. Technical developments

Hydraulic short-circuit operation



Hydraulic short-circuit operation in Kops II PSHP ; taken from (Voralberger Illwerke)

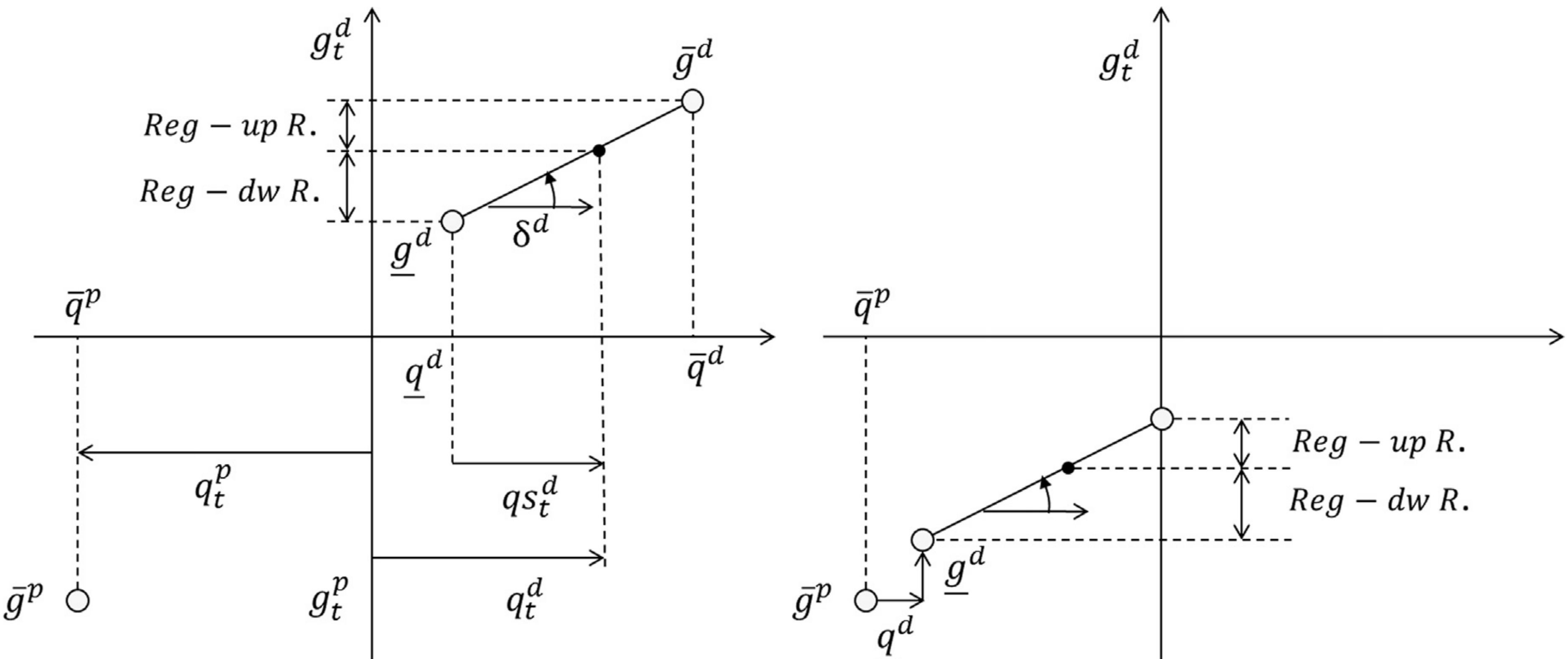
C. Technical developments

Hydraulic short-circuit operation

- Even though there are **several PSHPs in operation which can operate in hydraulic short-circuit mode** in Europe (Geesthacht, Häusling, Säckingen, Wehr, Roβhag, Malta, Luenersee, Kops II), and at least one under construction (Veytaux II), to the authors' knowledge, **this operation mode has not been considered in any scheduling model**

C. Technical developments

Hydraulic short-circuit operation



Power-discharge curves of a ternary pump turbine unit in generating and pumping modes (left), and in hydraulic short-circuit mode (right); taken from (Pérez-Díaz et al., 2015)

D. Water time delay

- To the authors' knowledge, the so-called ***participation factors*** (De Ladurantaye et al., 2007; Diniz and Sousa, 2014) constitute the **state-of-the-art** in water time delay modelling
- Participation factors are a set of parameters for each river reach which indicate the percentage of water volume released from the upstream reservoir, that arrives in the downstream reservoir with a specific delay
- Participation factors should **vary as a function of the "state" of the river reach** since the "wave" speed propagation depends on the volume of water travelling across the river reach at hand → **the consideration of such dependence may ruin the convexity of the problem**
- **Non-convex optimization** techniques should be applied to solve this problem → **Genetic algorithm + embedded river simulation?**

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Thank you very much for your attention

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