Dispatch modelling: Quantifying long term benefits via high resolution analysis

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White paper
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1 Introduction

From Boston to Bangalore, power systems are facing a daunting list of challenges. Security of supply, affordability of electricity, environmental considerations, electrification, and industrialization are all driving change at a pace that is, to say the least, unusual for the slow-moving power sector. Emerging, modern technologies and their requirements clash with the old way of running things. Hundreds of power plants are being mothballed because the operating environment for which they were built, no longer exists. For many system operators dispatching, the act of continuously optimising the power system, is becoming a daily nightmare.

The changes underway in power systems around the world are affecting all aspects and objectives of dispatching, and are giving rise to a set of short-term challenges with long-term costs. Increasing variability imposes a more cyclic operating profile on dispatchable power generation, with considerable cost implications. This issue is compounded by the shortened forecasting horizon, itself a direct result of increased variability. The increased variability and shortened forecasting horizon, in turn, lead to unit commitment issues and increased costs due to unnecessary start-ups. All these issues combined make the already demanding task of minimising costs and emissions extremely intractable.

Most tools used for long-term analysis and resource planning in the context of power systems, fail to acknowledge these short-term challenges listed above. To gain a realistic view, what is needed is a tool that is capable of taking into account short-term phenomena and expanding those into a long-term view. PLEXOS® is a power market modelling and simulation software that can do just that.

With PLEXOS®, one can model an entire power system and use it to observe and analyse the potential challenges facing many power systems in the coming years. In Chapter 4, findings from one such study are presented.

Based on the studies undertaken thus far, it is safe to say that, if current plans for increases in renewable power generation are to be met, system operators and owners of power plants will face some tough decisions in the coming decade. Moreover, flexibility in dispatchable power generation will be at a premium.

2 Dispatching

2.1 What is dispatching?

Dispatching could be concisely described as the act of continuously optimising the operation of the power system from one minute to the next. In the context of a developed and complex power system, the responsibility for dispatching usually resides with the system operator. To be able to optimise the power system, the system operator is continuously engaged in three activities that define dispatching: forecasting, planning, and controlling.

2.1.1 Forecasting

Forecasting is the task of finding out the expected load demand and what generating assets are available to meet that demand. Depending on the assets present in the power system, forecasting can be for different time horizons. For traditional longer-term forecasting, considerations include seasonal variations in load demand, macro-level weather patterns affecting demand, as well as planned maintenance outages of large generating units. Shorter term forecasting involves mainly daily load variations and, which is of increasing importance in many systems, the output of intermittent renewable power generation. The result of forecasting is a net load curve, that is, the forecasted load demand less the forecasted output from intermittent power generation. This is the part of demand that needs to be met with dispatchable power generation, i.e., generating units that can be started and stopped as and when needed.

2.1.2 Planning

Based on the forecast, the system operator can plan which generating units will be used to meet the expected net load demand at each point of the coming day. One approach is to rank the units in the system in ascending order of their marginal cost of generation[1], known as a merit order. Renewable sources come first, as they have no fuel costs. Traditionally, this means hydro power – especially in the case of run-of-river hydro plants, as they are non-dispatchable[2]. Some systems have considerable amounts of dispatchable renewable sources, such as geothermal in Indonesia and Iceland, which would also be placed first in the merit order.

Renewable sources are followed by nuclear and coal plants, which typically have very low marginal operating costs, notwithstanding the emission costs imposed on coal plants in some countries. Next come combined cycle gas turbine (CCGT), combustion engine, and open cycle gas turbine (OCGT) plants running on gas, while possible oil-fired units come last, as their fuel costs are the highest.

Having planned which generating need to be running and at which times, the system operator makes allowances for start times and ramp up rates to see when each generating unit needs to be started up in order to be running at the required level when it is needed. In the case that a generating unit has to be started up twice during the same day, the minimum uptime[3] and minimum downtime[4] also have to be taken into consideration.

Finally, contingencies, such as a malfunction in a large generating unit, or a forecasting error, also have to be accounted for. Some generating units are needed to be at the ready in case of an unexpected shift, positive or negative, in net load demand. Reserve requirements are system-specific, and can be met with a combination of spinning and non-spinning generating units.

1 The cost incurred by producing one additional kilowatt-hour.
2 The output of a run-of-river hydro plant cannot be postponed: it either has to be put to use, or lost.
3 The minimum time a plant, after being started, has to run until a shutdown sequence can be invoked.
4 The minimum time a plant, after being shut down, has to remain so until a start-up sequence can be invoked.

In some systems, dispatchable hydro facilities, i.e., pumped storage and reservoir hydro plants, are used strategically rather than as base load. As hydro plants are typically very quick in changing operating modes[5], they are sometimes left in reserve. This is especially common in systems where the amount of hydro power is small compared to total demand, in other words, where hydro couldn't fill a substantial part of the demand in base load operation and thus becomes more valuable as a reserve.

In many countries, the planning phase takes place on the market. Owners of generating units bid their production onto the market, whereby a merit order is established according to the bid prices. The system operator then dispatches generating units according to net demand and based on the merit order.

2.1.3 Operating

In parallel with the forecasting and planning, continuous controlling is needed to keep frequency stable throughout the grid, and to maintain stable voltage locally. Routine control chiefly revolves around the dispatch plan based on forecasts and the merit order. If the actual demand deviates from the forecast too much or too quickly, for whatever reason, reserves will be called upon to regulate generation as needed.

Contingency power and frequency and voltage control create costs in the form of lower total system efficiency, thus creating also increased fuel costs and emissions. An analysis of those effects, however, is beyond the scope of this paper.

2.2 Objectives of dispatching

The goal of dispatching is two-fold. The first objective is to ensure security of supply. In the short term, this is achieved mainly by successful controlling the system. In the longer term, forecasting accuracy needs to be maintained, and reserves capable of meeting both the scale and speed of unexpected variations are required. The second objective of dispatching is to minimise total system costs. The merit order approach is an important tool here. Quite a lot also depends on the accuracy of forecasting – both long term and short – as unneeded start-ups will inevitably manifest themselves in the form of higher operational and maintenance costs.

Most steam power plants – nuclear, coal, CCGT – have been designed and optimised for steady-state base load operation. They have not been designed with frequent starts and stops in mind. Consequently, the various components of a steam plant always go through varying levels of thermal stress during a start-up procedure. Over time, those stresses add up and can surface in a number of ways, including reduced equipment lifetime, increased maintenance expenditure, increased forced outages, decreased efficiency, etc. Thus, for a large steam plant, the long term implied cost for a single start-up can run to hundreds of thousands of dollars[6].

Due to the implied cost of start-ups, one objective of dispatching is to minimise the number of start-ups required during the day, especially for steam plants. If some steam plants still have to be started up or shut down during the day, CCGTs will be the first in line, for two main reasons. Firstly, the implied cost of a start-up is directly proportional to the scale (in terms of megawatts) of the steam cycle, and the steam cycle of a CCGT plant is typically considerably smaller than that of a nuclear or coal plant.

Secondly, the start-up time, shutdown time, and minimum downtime of a CCGT plant are superior compared to those of other steam plants. Whereas a modern

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5 For a hydro plant, the start-up time from standstill to full output can be less than 15 seconds, compared to about 60 minutes for a CCGT plant.

6 See Power Magazine, August 2011, pp. 58-67: Make Your Plant Ready for Cycling Operations, by Steven A. Lefton and Douglas Hilleman, PE

CCGT plant can be up to full load in 60 minutes from start-up, a large coal plant will take as long as 72 hours to ramp up to full load and stabilise all processes, and nuclear plants will take even longer. Thus, shutting down coal or nuclear plants is seen as something of a last resort, and starting one up for anything less than several months of operation on full load is not usually an option.

2.3 Emerging challenges in dispatching

Today, many system operators face challenges due to the growing variability in both demand and generation in their systems. While well established and robust, the traditional methods of dispatching are ill equipped to cope with these demands. While several purported solutions have already been presented to the public, there remains something to be gained by improving the general understanding of the challenges themselves.

2.3.1 Challenge #1: Variability on the generation side

Most power systems have traditionally consisted only of dispatchable power generation. Consequently, traditional methods of dispatching have not been developed with an eye on variability in generation, at least not on today's scale.

In systems with both wind and solar power plants, the challenge is even greater due to the fact that output from these two sources don't correlate. Consequently, while the fluctuations of wind and solar can often even out, sometimes they can also create difficult situations. Intermittent generation has a magnifying effect on load changes for dispatchable generation (Figure 1); the smooth curves of aggregate load demand become violent shifts in the net load demand. These rapid shifts entail more cyclic operation – that is, start-ups, shutdowns, ramps – as well as part-load operation for dispatchable units, with obvious cost implications.

The implied long-term costs of start-ups are becoming increasingly and more widely understood in the industry. Less acknowledged is the fact that ramps, whether up or down, carry with them implied long-term costs not unlike start-ups[7]. These costs are relative to the steepness and depth of the ramp, which is why operating profiles, such as that depicted in Figure 1, are worrying.

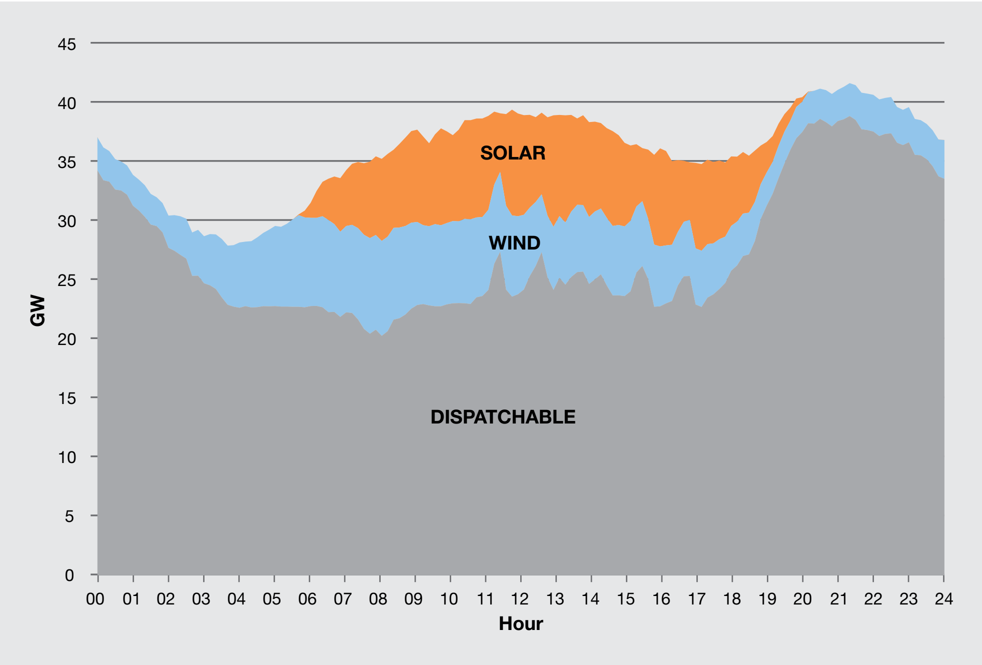

Figure 1. A Spanish net load curve, actual data. Notice the difference between the smooth curves of aggregate demand and the output of dispatchable power generation.

7 See Power Magazine, August 2011, pp. 58-67: Make Your Plant Ready for Cycling Operations, by Steven A. Lefton and Douglas Hilleman, PE

2.3.2 Challenge #2: Increased variations in load

The daily load variation, and specifically the difference between the daily peak load and the load during the night, is growing rapidly in many power systems. The prime example of this development is Japan, where the daily peak load that usually occurs in the evening is twice as much as the lowest demand point in the middle of the night.

This is problematic for two reasons. Firstly, the large discrepancy between electricity consumption during the day and the night mean that more and more generating units are subject to an operating profile whereby they start and stop daily. Such an operating profile carries considerable long-term cost implications.

Secondly, the low night-time load demand constitutes a limiting factor for the exploitation of renewable power. This is because baseload plants, typically coal and nuclear, are not suited for cyclic operation. However, with sufficient amounts of wind power in a system, even coal and nuclear plants will need to be ramped down or even shut down altogether during windy nights. Alternatively, the output of wind farms can be curtailed to avoid ramping down coal and nuclear plants. Either solution leads to additional costs and increased emissions.

2.3.3 Challenge #3: Forecasting resolution and errors

Typically, forecasts and models used for analysing and optimising power systems are based on an hourly resolution, i.e., load demand and the corresponding generation is considered 24 times during a day. This approach does not reflect the stresses imposed on the system by intermittent generation. Indeed, when comparing the result of a dispatch model with an hourly resolution to actual grid data on a ten minute resolution, the discrepancies can be striking (Figure 2).

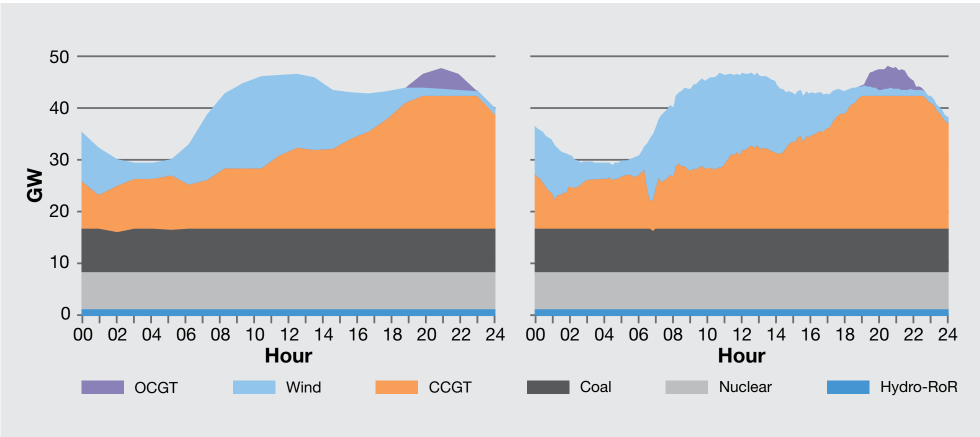

Figure 2. The generation curves on the left are the result of one hour resolution, whereas the actual generation data on the right shows generation on a ten minute interval basis. The surge in wind output and subsequent rampdown of CCGT output between 6 and 7 am is almost invisible in the one hour resolution forecast.

The forecasting challenge is compounded by the fact that, due to basic mathematics, increasing errors in forecasting are an inevitable by-product of the increasing variability in generation. Thus, either decisions have to be made based on forecasts less reliable than previously, or decisions are made with the same level of reliability but with less time for implementation.

2.3.4 Challenge #4: Unit commitment issues

The interplay of shortened forecasting horizons and rapid shifts in net load demand, combined with the relative inflexibility of traditional dispatchable power generation, leads to unit commitment issues. Starting up a plant is costly, especially if the wind picks up again and the start-up turns out to have been unnecessary. Similarly, shutting down a plant is risky since, due to its minimum downtime, the plant will not be able to help for some time should the net load demand suddenly increase. Due to inadequate flexibility, in many systems the response to this issue has been an increase in partial loading.

2.3.5 Challenge #5: Minimising long term costs

Considering these challenges, it is not surprising that system operators are having problems with minimising long term costs. Increased variability in net load demand means that dispatchable generating units have to ramp considerably more steeply and deeper than traditionally, thus increasing wear and tear to components. Increases in daily load variation have led to more and more generating units starting up every morning and shutting down every night, leading to higher operational and maintenance costs. Forecasting difficulties increase the amount of unnecessary start-ups and shutdowns, and also aggravate the ramping requirements, with obvious cost implications. Finally, the increasing use of partial loading is degrading the system level efficiency and, subsequently, increasing fuel costs per unit of electricity generated.

2.3.6 Challenge #6: Minimising emissions

Partial loading, besides increasing fuel costs, also increases the level of emissions per unit of electricity generated. Moreover, modern emissions reduction technologies don't operate at optimum levels in unstable conditions. In other words, during start-up, shutdown, and steep ramping, emissions are invariably higher than during stable operation at full load.

3 A tool for the job: PLEXOS®

PLEXOS® is a power market modelling and simulation software developed by Energy Exemplar, a software company based in Australia. It is a derivative of a simulation tool developed by Glenn Drayton, founder of Energy Exemplar, for his doctoral studies on electric power markets.

PLEXOS® can be scaled from a single generating unit or the plant portfolio of a given utility, all the way up to a group of interconnected power systems, such as Western Europe. In terms of time scale, available resolutions range from one minute to multi-annual timeframes. The wide range of functionalities mirrors the myriad of aspects that constitute a power system. Thus, PLEXOS® can model power generation and transmission, as well as support optimal expansion planning for either of the two. PLEXOS® covers hydro power modelling, ancillary services, and the restrictions of emission limits or the effects of emission prices. Through its capacity to model market clearing, PLEXOS® offers the possibility to model financial reporting for market participants, be they individual generators, regions, or companies. In other words, PLEXOS® can both optimise the profit of a single market participant under the prevailing market framework or, alternatively, optimise – that is, minimise – total system costs.

In little over a decade since its original launch, PLEXOS® has emerged as one of the leading simulation software for market modelling purposes. Today, the software is used by system operators, regulators, generation companies, transmission companies, consultants, and analysts around the world.

3.1 Main inputs for modelling

In order to build even a rudimentary model of a power system, immense amounts of data are required (Figure 3).

The list of requirements starts with a catalogue of all the generating units comprising the system, both dispatchable and non-dispatchable, along with their capacities. Regarding consumption, load demand data for the desired planning horizon on as tight a resolution as possible, is a good starting point (many Western system operators publish this data in real time on a ten or fifteen

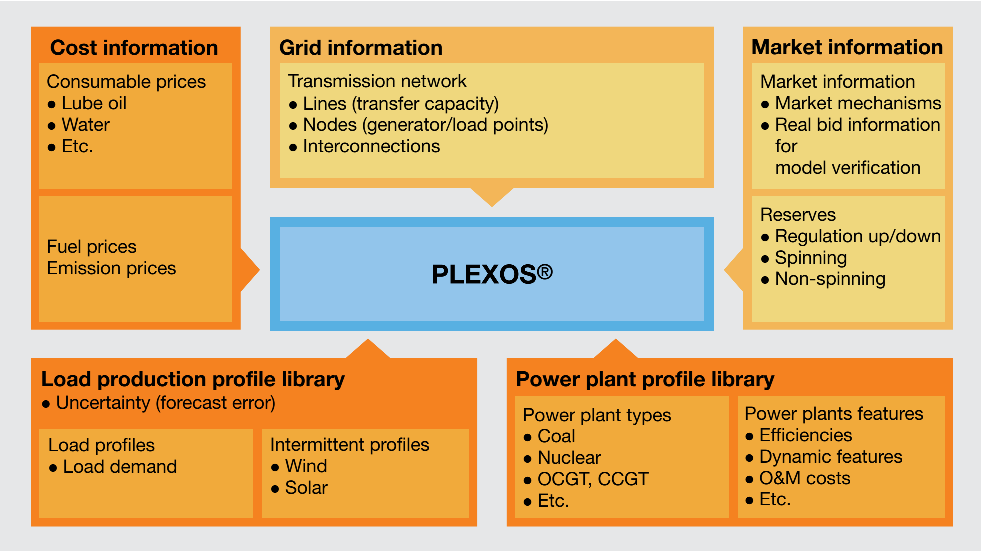

Figure 3. A PLEXOS® model requires vast amounts of quality data.

minute resolution). Finally, to get the net load demand, history data for intermittent renewable generation is required[8].

For modelling on ten minute resolution, further details are required regarding the operational properties of the technologies present in the system. Start-up and shutdown times, ramp rates, and minimum up and down times create the boundary conditions for knowing how within which dispatchable generation will react to short-term changes in net load demand. It should be noted that these operational properties are what makes the difference between a model based on ten minute resolution and one based on one hour resolution. On one hour resolution, the operational properties do not come into play, whereas on ten minute resolution – as well as in real life – they make all the difference.

To complete the physical infrastructure of the system, the transmission grid needs to be modelled as well. In effect, the transmission system is quantified according to its ability to shift generation between regions, or nodes as they are called in the model. If the power system consists of multiple nodes, dispatchable capacity, load demand and intermittent generation also needs to be configured on a node by node basis. To make the transmission system as realistic as possible, interconnections with neighbouring regions or countries can also be included.

Finally, in order for PLEXOS® to optimise system level costs, the variable costs of the system are needed. This means, firstly, the prices of consumables, e.g., fuel, water, and lube oil, for all generation technologies. Secondly, the prices for emission permits, if in use in the system, are needed. Thirdly, net efficiencies for all generating units[9] are required to calculate fuel consumption and emissions, thus finally yielding system level fuel and emission costs, respectively. Lastly, for accurate modelling, long-term cost implications, such as operation & maintenance costs and the aforementioned start-up cost, are projected into the short term[10].

Given the above data, PLEXOS® is able to model the operation of the system and minimise the total system costs by optimal dispatching. As mentioned previously, the model can be expanded to include the electricity market[11], as well. The full extent of market mechanisms, ranging from, for example, day-ahead clearing, to feed-in tariffs, to reserve requirements (regulation, spinning, non-spinning), can be fed to the model. Armed with this data, PLEXOS® can model and optimise the generating activities of individual market participants.

8 Here, quantity creates quality. PLEXOS® can build a stochastic, i.e. probabilistic, model of intermittent generation. The representativeness of the model increases with the amount and accuracy of history data.
9 If actual data is not available, generic data will be substituted.
10 In other words, costs that are relative to the utilisation of the unit, yet may only materialise once or twice in the lifetime of a generating unit, are levelised and represented in terms of cost per unit generated ($/kWh).
11 If market structures are not included, PLEXOS® will optimise based on cost of generation alone

3.2 Main outputs of modelling

The amount of output available from PLEXOS® is even more impressive than the data required as input (Figure 4). For each individual generating unit, PLEXOS® reports the power generated, fuel consumed, the net efficiency of all generation, emissions, load factors, as well as costs for generation, emissions, operation and maintenance, start-ups, and so on.

Regarding the grid, data on power flows, possible overload situations, and the voltages and total losses per line, are available. For the power system as a whole, PLEXOS® reports total generation, load demand, and unserved and dumped energy[12], respectively. A non-zero reading of unserved energy means that the system wasn't able to fulfil load demand, whereas dumped energy reflects the amount of energy that is wasted due to inflexibilities in the system, e.g., a wind turbine being switched off due to an inability to accommodate its output by ramping down another generating unit.

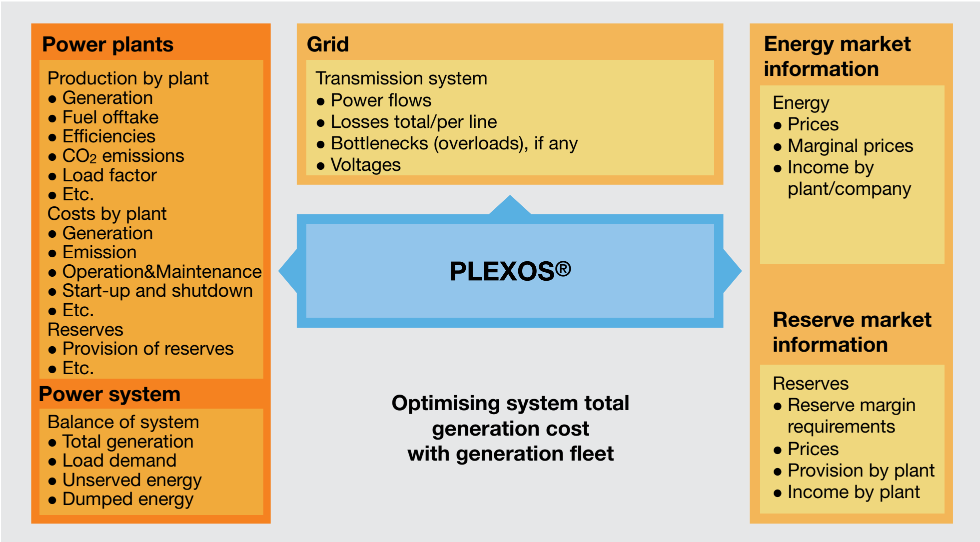

Figure 4. PLEXOS® gives a wide range of outputs.

If the market module is included in the model, the results will show energy prices, marginal prices, i.e., the price of the last kilowatt-hour generated, and income by plant or company. If a reserve market is in place, the results will also cover reserve margin requirements, clearance prices for reserve capacity, and reserve provision and income by plant, among other things.

It should be noted that while PLEXOS® can be used in the traditional way of optimising hourly energy balance and generating a dispatch plan, moving to ten minute resolution and applying the aforementioned operational properties of generating units allows for a much more profound and accurate analysis of the system (see Chapter 4).

For the purposes of this paper the key outputs available from PLEXOS® can be listed as follows:

(1) total system generation cost
(2) running profile of each generating unit
(3) generation and fuel off-take: the combination of these two gives the actual operational efficiency of each generating unit, as well as that of the system as a whole
(4) CO_2 emissions of each generating unit and the whole system
(5) potential problem situations in the system, i.e., overloads, unserved energy
(6) revenues for individual plants (if market structures included)

12 These variables are purely for modelling purposes. In real life, the power system always balances itself.

Through the above six outputs, it is possible to observe how changes in the fleet of generating units affect total system costs and emissions, and whether such changes have an effect on how other generating units in the system operate. The results of one such analysis are exhibited in the following case study.

4 Case study: Spain 2020

4.1 Setup

As of late 2011, Spain was already one of the leading countries in the world with respect to its installed capacity of wind and solar power. Nevertheless, the government has set an ambitious agenda to more than double renewable output by 2020. Thus, Spain makes for a good case study in observing how a system would cope with the challenges of intermittency.

For the purposes of compiling a representation of the Spanish power system as it could be in 2020, some assumptions have had to be made. Load demand was assumed to grow from 2010 to 2020 at an average annual rate of 2.1%. Spain would reach its emission targets, mostly by adding wind power. For lack of history data, it wasn't possible to build a probabilistic model of the outputs of wind and solar power, so output data from 2010 was scaled up in accordance with the assumed increase in capacity by 2020. Interconnections with neighbouring countries – France, Portugal, and Morocco – were assumed to remain unchanged in capacity from 2010.

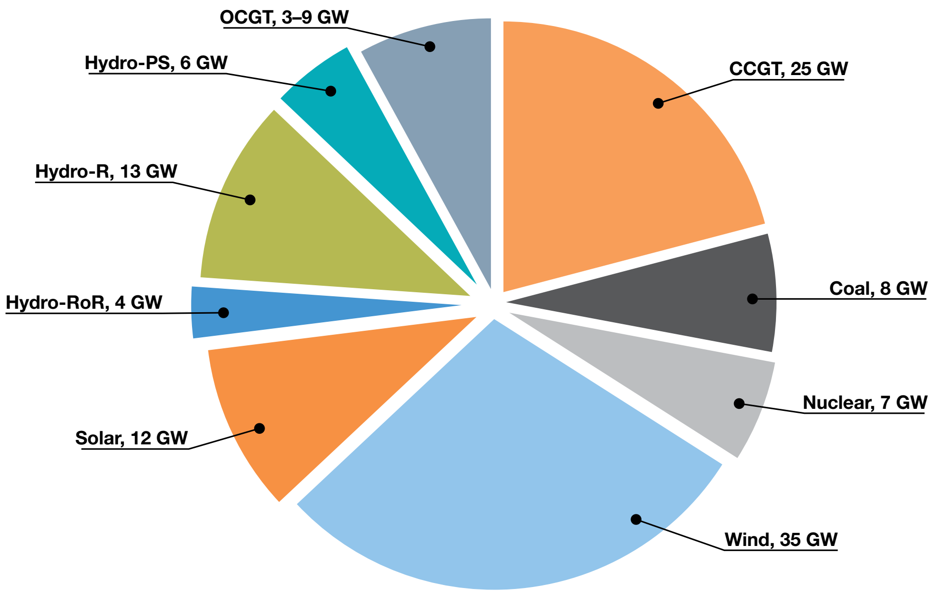

Figure 5. Base Case distribution of capacities in the Spanish power system model for 2020 (RoR = run-of-river, R = reservoir, PS = pumped storage).

As it is important to analyse how the system would cope with challenging conditions, the output from hydro reservoirs was modelled according to the year 2005, which was somewhat drier than average. Furthermore, modelling was focused on a week of the year that was identified as having higher than average variability in wind power output.

This week was then simulated using ten minute resolution for four separate cases. The first case constituted the Base Case. In the second case, three GW of Smart Power Generation[13] plants were added to the system. For the third and fourth cases, the amount of Smart Power Generation capacity in the system was increased to six and nine GW, respectively[14].

13 Smart Power Generation is a modern, dynamic power generation technology based on a multi-unit approach.
14 For brevity's sake, only cases 1 and 4 are discussed in detail.

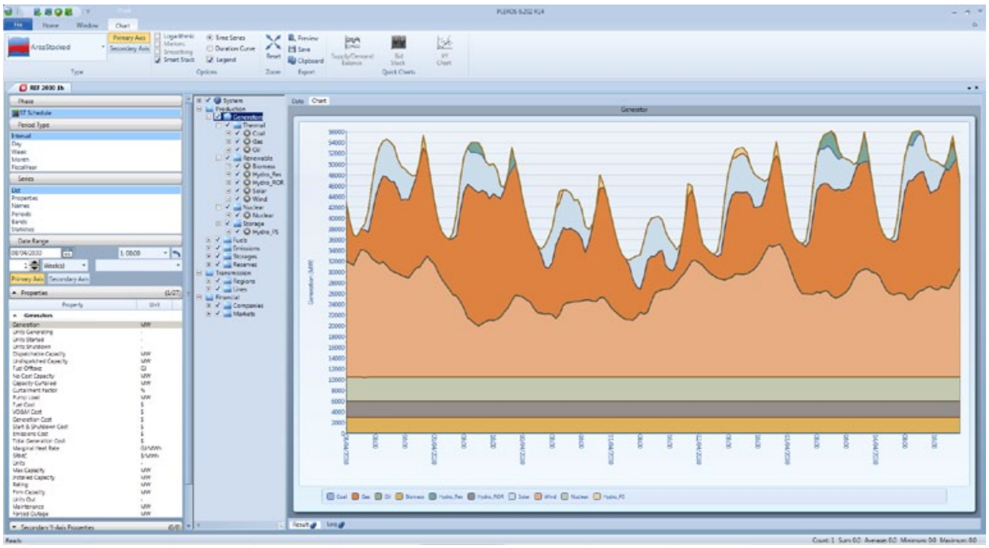

Figure 6. Spanish model in PLEXOS®. The user interface shows the respective running profiles of individual generating units.

It should be noted that the version of PLEXOS® used for this study did not account for the possibility of a forecasting error. In other words, the "system operator" knows exactly what the wind and solar conditions and net load demand will be, and will dispatch units accordingly. In reality, of course, this is not the case. Thus, the results presented below should be considered as "best case scenarios" with respect to how the large, less flexible steam plants in the system would operate.

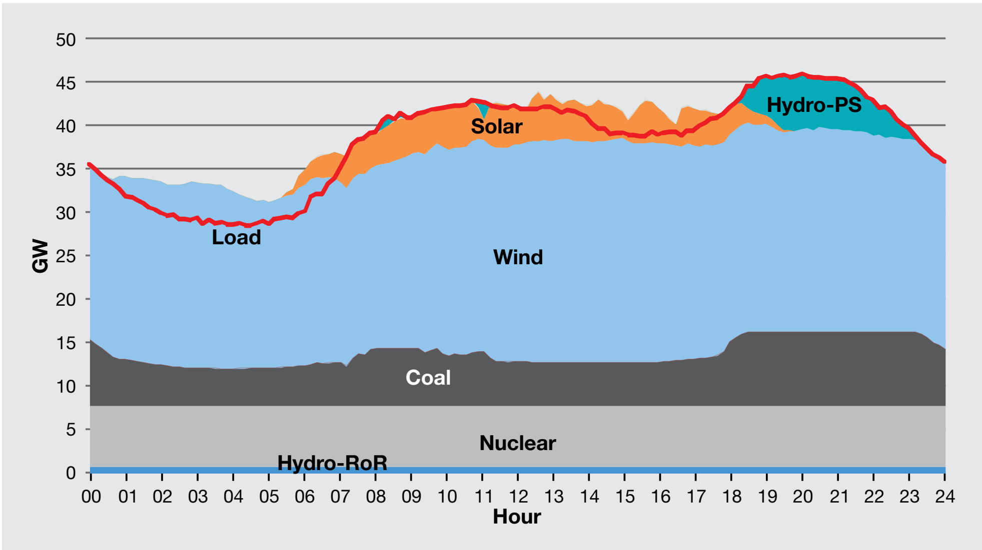

Figure 7. Operating profile for a windy day. Notice that all gas fired power plants are shut down, as are a majority of the coal fired power plants.

It should also be noted that the cases presented below only depict one aspect of the challenges facing the Spanish system in the future. While the week chosen for closer scrutiny, as mentioned previously, represents higher than average variability in wind conditions, the absolute level of wind output is quite low compared to the total capacity of wind power in the system. Indeed, according to the model, periods of strong wind conditions will present an entirely different challenge in 2020, namely, that of choosing which baseload plants to shut down to accommodate the wind (Figure 7).

4.2 Results

4.2.1 Case #1: Base Case

In the Base Case, the effects of the compound intermittency of wind and solar are clearly visible (Figure 8). After satisfying the previous evening's peak, CCGT plants quickly shut down for the night. As wind output increases in the early morning, and especially after solar output starts to grow around 6 am, the pumped storage load climbs to over 5 GW. Effectively, due to the prohibitive start-up costs, it is cheaper to run 5 GW of CCGTs on partial load and use the excess electricity to run pumped storage hydro plants in reverse, than it would be to shut them down.

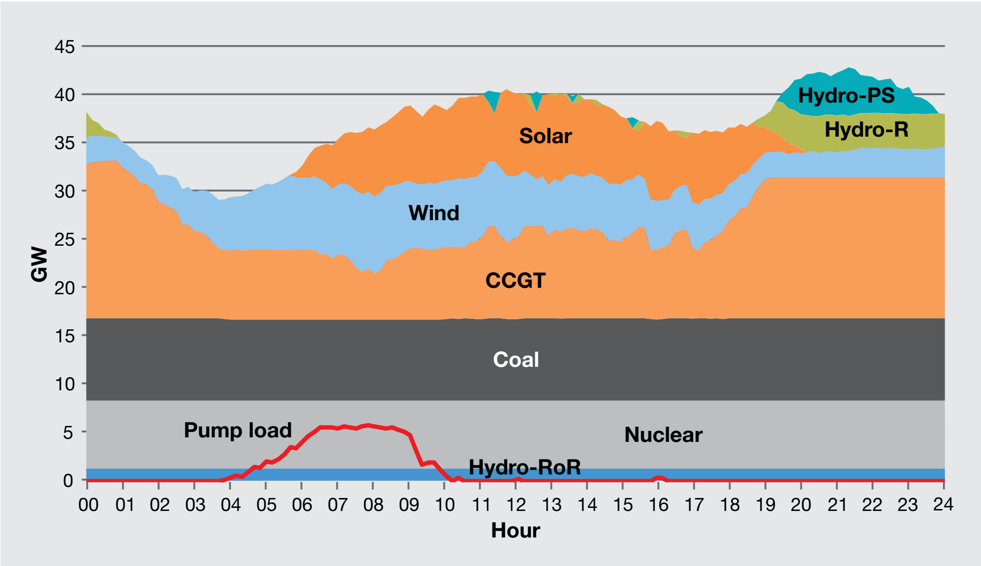

Figure 8. Base Case operating profile for a single day. Notice the sharp fluctuations in CCGT output and the heavy reliance on pumped storage hydro capacity.

This has a considerable impact on total system efficiency. The roundtrip efficiency for a typical pumped storage hydro plant is around 70%. Thus, running a CCGT on partial load, i.e., with poor efficiency, and then 'recycling' that electricity through a pumped storage facility, yields very poor overall efficiency.

Consumption catches up with the renewable output around 10 am, after which fluctuations in wind and solar output are met with a combination of CCGT and hydro power. Between 5 and 6 pm, an increasing number of CCGT plants are started up to compensate for the decreasing solar output, and then ramped up to meet the evening peak. Reservoir hydro and pumped storage hydro are also needed to meet demand between 7 pm and midnight.

It is worth pointing out that, due to their low efficiency as compared to CCGTs, the 9 GW of OCGT plants in the system remain completely unused throughout the day.

4.2.2 Case #4

For the fourth case, the Smart Power Generation capacity was set at 9 GW. Although a relatively small addition in comparison to the total capacity in the system, this turned out to have a considerable impact (Figure 9). Immediately noticeable is the generation profile from 6 am to 10 am: CCGT production was decreased throughout the period. In the Base Case CCGT plants were kept running despite the impact on total system efficiency, as they were needed for the evening peak and it would have been too expensive to shut them down only to start them up again in the evening. At 9 GW, however, the Smart Power Generation capacity, together with hydro, is capable of covering the evening peak so that no additional CCGTs are needed. Consequently, CCGTs don't need to be kept on minimum stable load through the afternoon, and are shut down in the morning instead. The CCGT that remain in operation get to do what they do best, namely, run on full load throughout the evening.

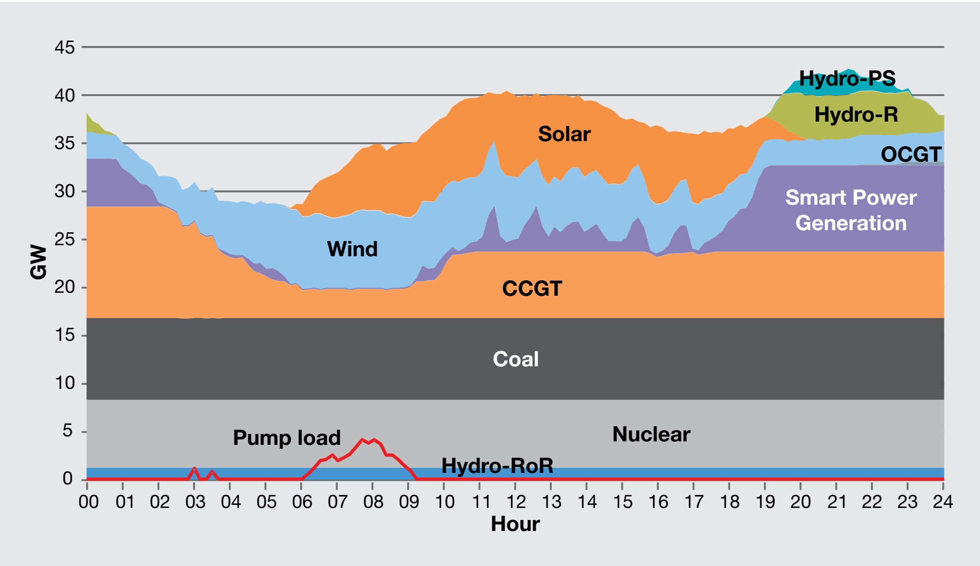

Figure 9. Case #4's operating profile for a single day. Notice the difference in the operating profiles of CCGTs and pumped storage hydro in the morning, as well as the flat profile of the CCGTs from noon onwards.

4.2.3 Comparison of cases

Comparing the results of the four cases allows for a quantification of the benefits of adding flexibility into a power system. The main observation is the profound impact on the CCGT running profiles achieved by adding flexible power generation. As could be deduced from the graphs above, Smart Power Generation took over from the CCGTs the role of balancing wind and solar output, and allowed for a considerably smoother running profile for the remaining CCGTs. This is also visible in the data (see Table 1). The addition of Smart Power Generation reduced the amount of electricity generated by CCGTs while simultaneously increasing the average load of those CCGTs that remained in operation. In other words, the addition of Smart Power Generation enabled a more optimal running profile for the other generating units in the system, in this case CCGTs. This effect was most pronounced in Case 3, where 6 GW of Smart Power Generation capacity led to an increase of 7.3% in average CCGT load.

	CCGT generation (GWh/d)	Change vs base case (%)	Average CCGT load (%)	Change vs base case (%)
Case 1 – Base case	244		87.5	
Case 2 – 3 GW of SPG	215	-12	91.0	+4.0
Case 3 – 6 GW of SPG	195	-20	93.9	+7.3
Case 4 – 9 GW of SPG	161	-34	90.6	+3.5

Table 1. Comparison of electricity generated by CCGTs and CCGT average load, respectively, across the four cases.

5 Summary and future steps

Over the coming decades, power systems around the world will experience great changes. These changes should not be left to chance. Rather, potential trajectories should be evaluated and compared. Moreover, the impact of emerging technologies on current systems needs to be assessed in detail and, to the extent that potential challenges are identified, counterbalancing actions planned. Thankfully, highly sophisticated tools, such as PLEXOS®, can provide immensely valuable guidance.

With respect to renewable power generation, the traditional methods of modelling and dispatching are not capable of responding to the foreseeable challenges in integrating a growing share of intermittent power generation into the power system. The impact of intermittency needs to be analysed on a much finer resolution than the traditional methods are capable of achieving.

One of the main benefits of PLEXOS® is the fact that it can combine short term analysis with long term decision making. By applying ten minute resolution to what is, effectively, long term analysis, it is possible to gain a deeper understanding of the challenges that must be overcome in order to reach the full potential of emerging technologies. It could be argued that, for power systems with considerable variability, any analysis that does not incorporate such a short term view is inherently flawed. This is especially true for traditional methods of feasibility analysis, that focus only on hourly energy balance, with little to no consideration for phenomena that only become visible with 15 or 10 minute resolution.

Wärtsilä is a global leader in complete lifecycle power solutions for the marine and energy markets. By emphasising technological innovation and total efficiency, Wärtsilä maximises the environmental and economic performance of the vessels and power plants of its customers. Wärtsilä is listed on the NASDAQ OMX Helsinki, Finland.

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