The Role of Hydroelectric Generation in Electric Power Systems with Large Scale Wind Generation

by

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Submitted to the Engineering Systems Division
in partial fulfillment of the requirements for the degree of

Master of Science in Technology and Policy

at the

MASSACHUSETTS INSTITUTE OF TECHNOLOGY

June 2012

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ABSTRACT

An increasing awareness of the operational challenges created by intermittent generation of electricity from policy-mandated renewable resources, such as wind and solar, has led to increased scrutiny of the public policies that promote their growth and the regulatory system that maintains operation of a reliable and economically efficient power system. Anecdotal evidence has suggested that hydroelectric generation can provide significant benefits in power systems that have already significantly increased their power generation from intermittent renewable resources.

A heuristic-based algorithm for optimizing the scheduling of hydroelectric power generation facilities was developed and integrated into the Low-Emissions Electricity Market Analysis (LEEMA) model to analyze the interaction of generation capacity from wind, thermal, and hydro resources in the economic dispatch of individual generation plants. The algorithm identifies the most costly periods of thermal production, considering fuel, startup and operation and maintenance costs, to determine the optimal schedule of hydro generation within its capacity constraints.

The hydrothermal LEEMA model is run on the current Spanish electric power system to identify the impact of introducing hydro generation to a system, varying levels of flexibility in hydro generation, and increasing levels of wind generation. The analysis concludes that hydro generation can significantly reduce the impact of intermittent renewable generation, that the level of flexibility of hydro generation must be understood to determine how beneficial the hydro generation can be, and that hydro generation will delay the most significant impacts of increasing levels of wind generation.

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ACKNOWLEDGEMENTS

There are several people that I would like to thank for their help in completing this thesis project as well as my degree in the Technology and Policy Program at MIT.

It has been a pleasure to work with Dr. Carlos Batlle and his team of researchers at Universidad Pontificia Comillas on this project, especially Ms. Andrea Veiga. I would like to thank Dr. Ignacio Perez-Arriaga as well for being such a great resource over the past two years for learning about electric power systems and the complex world of power systems regulation.

I am very thankful to Dr. Ernest Moniz and Mrs. Melanie Kenderdine at the MIT Energy Initiative for providing me the opportunity to do research at MITei and to work on the Symposium series. I would also like to acknowledge the sponsors of the MITei Symposium series, especially Exelon that has provided the funding for my research over the past two years. A special thank you to Melanie for spending many late nights over the past several weeks helping me improve the quality of this paper and providing invaluable feedback on the content.

My time at MIT has been greatly enhanced by my peers in the Technology and Policy Program who have been an incredible group of people to spend time with over the past two years. I have truly enjoyed getting you to know you all and discussing our many diverse interests. Special thanks to Tommy Leung, Sarah Fletcher, Robert Brasington, Anna Delgado, Sarah Wood, Tanvir Madan, Devin Helfrich and Megan Lickley. I wish the best of luck to all of you in the future and hope the past two years are just a beginning for all that we wish to accomplish in the future. Stay in touch.

I would like to give my biggest thank you to my family who have strongly supported me from my initial interest in MIT through my final weeks finishing my degree. Especially, I would like to thank my fiancé Ellen for providing me the inspiration and encouragement on a daily basis that has made everything that I do worthwhile.

Thank you all.

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LIST OF ACRONYMS

ARRA	American Recovery and Reinvestment Act of 2009
AWEA	American Wind Energy Association
CCGT	Combined cycle gas turbine
DOE	United States Department of Energy
EECP	Emergency Electric Curtailment Plan
EIA	Energy Information Administration
ERCOT	Electricity Reliability Commission of Texas
FERC	Federal Energy Regulatory Commission
GW	Gigawatt
GWh	Gigawatt-hour
IEA	International Energy Agency
ISO	Independent System Operator
IRE	Irish pricing mechanism
LCOE	Levelized cost of electricity
LEEMA	Low Emissions Electricity Market Analysis model
LTSA	Long-term service agreement
MW	Megawatt
MWh	Megawatt-hour
NETL	National Energy Technology Laboratory
NREL	National Renewable Energy Laboratory
O&M	Operations and maintenance
OEM	Original equipment manufacturer
RoR	Run-of-the-river hydro generation plants
RPS	Renewable Portfolio Standard
RTO	Regional Transmission Organization
SCGT	Simple cycle gas turbine
SU	Startup
TWh	Terawatt-hour
VER	Variable energy resources

1 RESEARCH MOTIVATION

1.1 RENEWABLE POWER GENERATION

Renewable energy from wind and solar resources has long been pursued as a clean and sustainable source of energy. In recent years, the installed capacity of these low-carbon sources of electricity has seen significant growth in the United States with wind capacity growing at an average rate of 29% over the past ten years and solar capacity growing at 20% over the past five years, as shown in Figure 1 (EIA 2011a). These impressive growth rates have been seen as well in Europe, with the current installed capacities for the US and European Union (EU) and several power systems within them shown in Table 1-1. In Spain, for example, generation from non-hydroelectric renewable resources accounted for 22% of all electricity generated in 2011 (Red Eléctrica de España 2012).

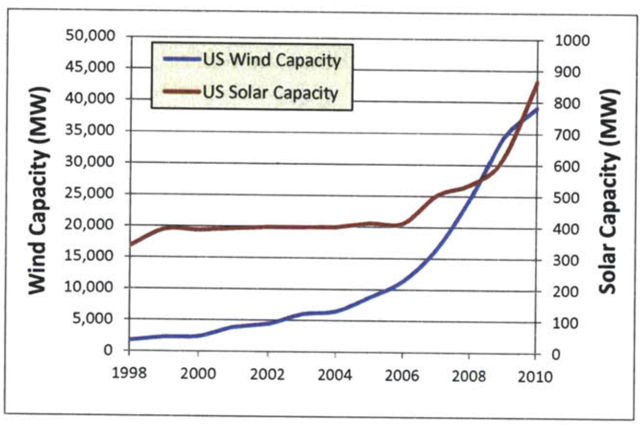

Figure 1-1 - Growth of wind and solar capacity in the US (EIA 2011a)

Wind Installations	Capacity (GW)
United States	**48.6**
Texas	10.6
Iowa	4.4
California	4.3
European Union	**94.0**
Germany	29.1
Spain	21.7
France	6.8

Table 1-1 - Installed capacity of wind in US and EU[1].

Generally large wind turbines can produce 1 – 3 MW of electricity with an average capacity of 1.77 MW for wind turbines installed in 2010 (AWEA 2012). Wind turbines are constructed into wind farms that can span vast areas of land and range in their total capacity. The largest single onshore wind installation, the Roscoe Wind Complex in Roscoe, TX, has a rated capacity of 781.5 MW and includes 627 wind turbines (E.ON 2012). In contrast, the largest offshore wind farms are currently being developed in the UK with 300 – 400 MW of capacity, while the Cape Wind project in Massachusetts is planned to be 450 MW.

[1] The most recent values for wind capacity have been gathered from the US and European wind associations. US data is from the American Wind Energy Association (AWEA) website (AWEA 2011) and the EU data is from the European Wind Energy Association (EWEA) annual publication (EWEA 2012).

The deployment of renewable generation has largely been supported by public policies put in place to provide sustainable energy, to reduce emissions of carbon dioxide and air pollutants, and to promote economic growth.

In the United States, production and investment tax credits have been the major incentives for renewable investment at the federal level while Renewable Portfolio Standards (RPS) have become the main driver at the state level. Currently 29 states have established a renewable portfolio standard and 8 states have set renewable portfolio goals ranging from 12.5% by 2021 in North Carolina to 33% in California by 2020 (DOE 2012). The American Recovery and Reinvestment Act of 2009 (ARRA) provided new opportunities for investment in renewable generation through loan guarantees and cash grants in lieu of production tax credits. The expected expenditures for promoting the development of renewable generation capacity is projected to be $25.3 billion from 2010 to 2014 with the ARRA funding leading to a projected 12,500 MW of renewable generation capacity, mostly through the cash grant program (Aldy 2012). While there has been some discussion of an RPS at the federal level, the most discussed technology mandate based system has been the Clean Energy Standard that would either require a certain percentage of electricity bought by utilities to be from "clean" sources or set a carbon dioxide emissions standard for generators to achieve (Aldy 2011).

In Europe, the primary tool for promoting the installation of renewable generation capacity has been the feed-in tariff. Meeting the European Union goal of near complete de-carbonization of the electric power sector by 2050 will require nearly continuous growth in power generation from renewable resources (European Commission 2011).

As generation from renewable resources has reached a significant quantity in the generation mix in many states, countries, and regions of the world, this level of penetration makes it essential that we understand in greater detail the impacts that these new sources of generation are expected to have on the operation and planning of the large, complex, and technically advanced electric power system.

Many of the initial concerns of renewable generation growth, especially from wind resources, were related to system reliability and the adequacy of the transmission network for integration of these new generation resources, which tend to be geographically constrained. The U.S. Department of Energy's National Renewable Energy Laboratory (NREL) has completed system-wide studies for the transmission networks of the Eastern US and Western US[2] focused on the necessary expansion of the transmission network to accommodate increased wind capacity. NREL's Eastern Wind Integration

[2] In the United States, three largely independent transmission systems, known as "interconnections", exist. The eastern and western interconnections exist on either side of the Rocky Mountains and a third interconnection exists solely in the state of Texas, known as the Electricity Reliability Commission of Texas, or ERCOT.

Transmission Study (EWITS) found that high penetration of wind generation (in the range of 20 – 30% of total electricity generation) is technically feasible with expansion of the transmission network, that wind integration costs are manageable, and that transmission networks can help reduce the variability of wind generation (EnerNex 2011). Forecasting the production from wind generation has also been a major challenge, as short term changes in output can provide many issues for system operators. The main focus of these integration studies was maintaining system reliability, which is the primary goal of transmission system operators.

An additional concern for renewable generation is the intermittent nature of wind and solar resources. As defined in Perez-Arriaga & Batlle (2012), "intermittency comprises two separate elements: non-controllable variability and partial unpredictability." Wind generation, for example, varies as the wind blows and it is often difficult to forecast precisely when wind farms will generate electricity. In addition, renewable generation cannot necessarily be dispatched to generate when it is most economically beneficial. In many locations, especially onshore, output from wind farms is highest at night when the demand for electricity is the lowest. The impacts of intermittency, which will be described in detail later in this section, include system reliability concerns, negative wholesale electricity prices, and increases in emissions of thermal generation plants.

Intermittency of renewable generation and its impacts on the operation of the electric power system, though touched upon in the integration studies, has led to a new effort to understand how renewable generation impacts operation and regulation of the electric power system across all sub-sectors – generation, transmission, distribution and retail – and timescales (Perez-Arriaga & Batlle 2012). In the long term, the future mix of generation technologies will need to be able to operate in scheduling regime marked by more cycling (the shutting down and starting up of a power plant) and ramping (changing the output from 100% down to 40% and back). In the medium term, the annual scheduling of generation maintenance periods will have to compensate for the seasonal changes in wind generation. And in the short term, reserve requirements and the economic dispatch of generation will have to adjust to the operational issues posed by wind generation.

This paper focuses on understanding the impacts of incorporating intermittent renewable generation resources into the medium to short term operational scheduling of thermal and hydroelectric generation plants. The goal of system operators in this timeframe is to schedule generation units in an economically efficient way while maintaining the overall system reliability. The non-dispatchable and variable aspects of intermittent renewable generation make the scheduling of thermal plants - nuclear, coal and natural gas – more difficult and may cause them to be operated in new and different ways not considered in their design. On the other hand, in systems where it is available, hydroelectric power generation (hereafter, to be referred to simply as "hydro") can provide flexibility to balance changes in both generation and load, and has been considered crucial to the large scale deployment of wind generation in northern Europe, especially Norway and Denmark. The complications associated with integrating intermittent renewables into a power system will change the dispatch order of thermal units as well as electricity prices in wholesale electricity markets, where generators sell electricity and load serving entities (such as your local utility) buy electricity.

The objective of this thesis is to provide greater understanding and insight into the likely impacts of increased wind generation on wholesale electricity prices. More specifically, this paper will examine the role of hydro generation in the dispatch of thermal generation and its impacts on wholesale electricity prices in systems that must also accommodate large scale penetration of wind generation.

In the remainder of this section, the factors that influence the operation for the electric power system and the setting of market prices will be described, starting from the everyday retail electricity prices seen by consumers and the structure of the electric power sector, followed by an explanation of the impacts of renewable generation on costs and market prices.

1.2 OPERATION OF THE ELECTRIC POWER SYSTEM

The structure of the electric power system

To better understand electricity prices, let's start with the electricity we use on a daily basis. For example, at my one bedroom apartment in Cambridge, Massachusetts, I receive a reliable supply of electricity for my daily needs. The refrigerator keeps my food cold; the stove provides heat to make dinner; and, the hallway light leads the way late at night. To pay for this service, I receive at the end of each month my electricity bill from NSTAR, the local utility in Cambridge, which details for me how much electricity I have consumed and how much I must pay for it.

For the month of February 2012, my bill for 158 kWh of electricity looked like this[3]:

Service	Rate	Amount
Generation	158 kWh x $.07928	$12.53
Transmission	158 kWh x $.01762	$2.78
Distribution	158 kWh x $.04467	$7.06
Retail Charge		$6.87
Total		$29.24

Table 1-2 - Electricity bill

Overall my electricity bill came to 18.5₵/kWh in February, which is higher than the average retail price of electricity in Massachusetts (15.4₵/kWh) and much higher than the national average

[3] In case the numbers look a little low, I live in a relatively small one bedroom apartment without cable or internet (which I borrow with my neighbor) and my landlord pays for heat and hot water.

(11.5₵/kWh)[4]. Of the total, 43% pays for the electricity generated while the remaining 57% is split between paying for high-voltage transmission lines, low-voltage distribution wires, and the costs of providing retail service to my apartment.

These services provide a good basis for understanding how the electric power system operates as the power system can be divided into the four components listed on the bill and shown below in Figure 1-2. Electricity is first generated at power plants where the energy stored in fuel or available in nature is converted to electrical power. Next, the electrical power is transmitted from the power plants to my neighborhood across a regional or national system of interconnected high voltage. Locally, substations step down the voltage for distribution of the electricity to the end-use customers through a radial system of power lines that eventually end up going down my street and being connected to the meter outside my apartment. Finally, the electricity is sold to the consumer through the retail company, generally the local utility, at the rates similar to what is shown above.

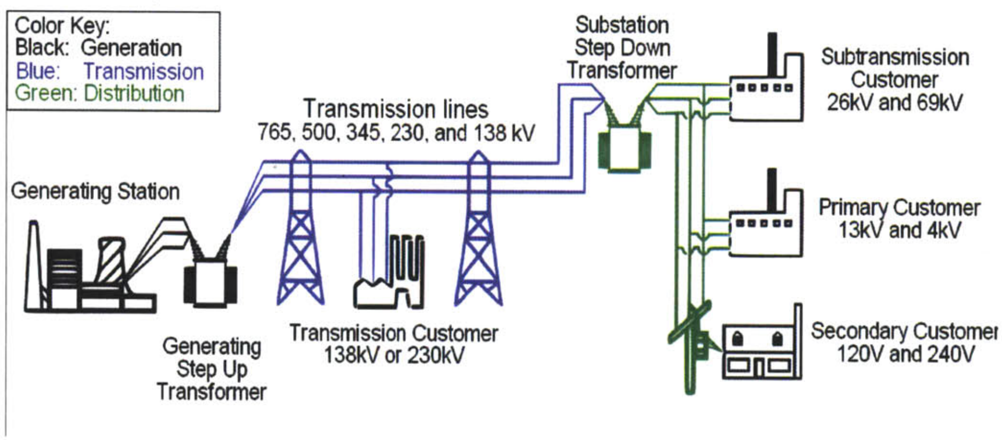

Figure 1-2 - Overview of electric power system

The introduction of renewable generation is likely to have impacts across the entire electric power system. As detailed in the EWITS report, wind generation will require a substantial upgrade of transmission networks to move electricity from the regions of the country with the best wind resources, largely found in the interior regions of the US (see Figure 1-3), to the load centers concentrated on the coasts. At the distribution level, the radial networks that are designed to move power from substations to consumers may have to be reconfigured for reverse flow from increased residential and commercial solar photovoltaic generation and will require additional maintenance. Finally, the regulated retail rates shown on my electric bill and set by the state public utility commission are expected to change as renewables enter the system.

[4] The higher rate is probably due to the impact of the flat retail charge on my relatively small electricity bill. Without taking that charge into account, the cost of electricity would be 14.2₵/kWh.

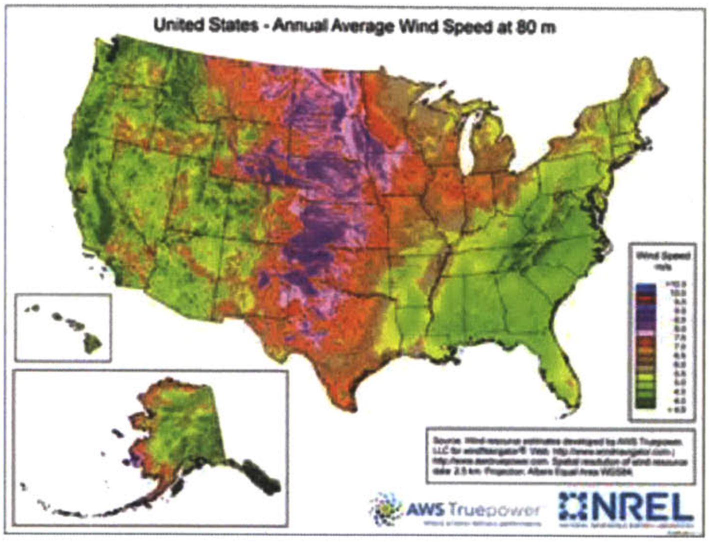

Figure 1-3 – US wind resources (DOE 2012)

This paper will focus specifically on the generation sub-sector where wind generation impacts the coordination of generation from hydro and thermal resources and the resulting wholesale electricity market prices.

Wholesale electricity markets

Across the US, there are several wholesale electricity markets that are loosely connected, as shown in Figure 3, and operated by either a Regional Transmission Operators (RTO) or an Independent System Operators (ISO). For the purposes of this paper, these entities can be considered to provide the same function and, for simplicity, will jointly be referred to as ISOs. These markets historically grew out of municipal networks that expanded first to state then to regional markets over time (Peskoe 2012). Wholesale markets are the venue for the sale and purchase of high-voltage and large volumes of electricity on the transmission network. The ISOs provide an open market for collecting offers from power plants to generate electricity and then determine the scheduling plan, or dispatch, for when each plant will operate. It is the role of the ISOs to forecast the level of demand that is anticipated and dispatch the generation plants to meet that demand while minimizing the total costs of production.

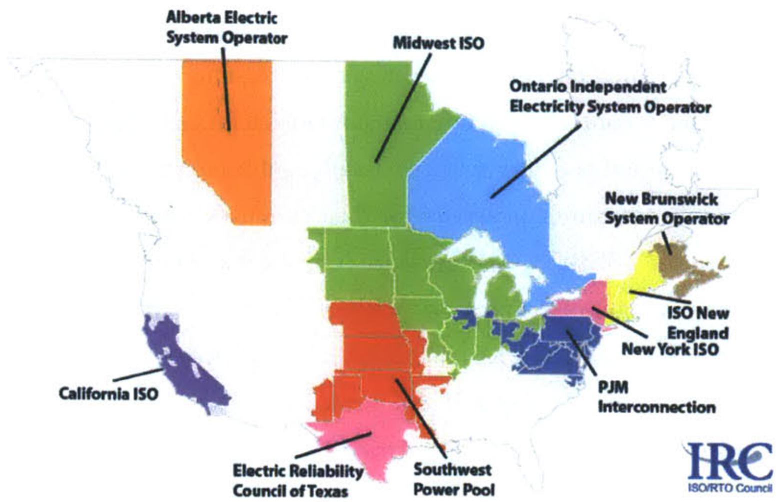

Figure 1-4 - The location of independent systems operators in the US (ISO/RTO Council 2012)

Areas in the map where there are no ISOs shown remain as regulated markets that are centrally planned by vertically integrated utilities. These areas will not have a wholesale market but will instead coordinate directly among generation plants to minimize the cost of production from thermal generation plants.

The presence of wholesale electricity markets is a relatively recent phenomenon as electric utilities were only deregulated in the past twenty years. Prior to this restructuring, vertically integrated utilities were provided a regulated territory in which they had monopoly right to operate generation, transmission, distribution, and retail services. Revenues for these monopolies were determined on a cost-of-service basis, in which the variable operational costs for providing electricity were passed through to the consumer and fixed capital costs of the system were based on a "fair" rate of return. This regulatory structure and pricing scheme lends itself to potential moral hazard problems where there is no incentive for managerial effort to reduce costs, either variable or capital.

The impetus for change occurred in the late 1980s when several other highly regulated industries were deregulated, including airlines and telecommunications. A groundbreaking book by Paul Joskow and Richard Schmalensee of MIT, *Markets for Power*, laid the groundwork for deregulation of the electric power sector. The goals of deregulation have been summarized as cost reduction, enhancing reliability, and improving environmental performance. There goals are, however, difficult to achieve without market forces to provide signals for decision making in the short term – for economic dispatch of generation and efficient use of the transmission network – and in the long term -- for generation and transmission expansion.

In the United States, the Federal Energy Regulatory Commission (FERC) promulgated Order No. 888 in 1996 which made fundamental changes to power systems regulation by requiring that "all public utilities that own, operate, or control interstate transmission facilities to offer network and point to point transmission services (and ancillary services) to all eligible buyers and sellers in wholesale bulk power markets, and to take transmission service for their own uses under the same rates, terms and conditions offered to others." (FERC 1997) The core components of Order No. 888 were open access to the transmission system and non-discriminatory pricing. The ruling required all transmission owners to file open access transmission tariffs (OATT) that unbundle the price of wholesale generation and wholesale transmission, and required vertically integrated utilities to divest their generation assets to allow for a competitive market for generating electricity to be formed. The goal of the order was to shift the incentives for pricing generation from cost-of-service to a more competitive marginal pricing scheme.

For competitive wholesale markets to operate, open access and non-discriminatory pricing were imperative as they allowed any market participant to generate power for sale into the wholesale market based on their marginal costs. Through Order No. 888, FERC was able to "remove impediments to competition in the wholesale bulk power marketplace and to bring more efficient, lower cost power to the Nation's electricity consumers." (FERC 1996)

The importance of the wholesale electricity market extends beyond the medium to short term operation of the electric power system. Decisions on transmission and generation expansion in a completely regulated market were made largely by regulators, who along with utilities, lacked incentives to make efficient choices. Marginal cost pricing enabled by Order No. 888 provided the marketplace with clear price signals to inform decision making on long term operation and planning of the transmission network and generation capacity.

Electric power system operation

The operation of the electric power system in the context of wholesale electricity markets brings many challenges that are largely driven by the requirements to maintain a tight balance between generation and demand. This tight balance is necessary due to the current lack of economically viable, large-scale storage options for electricity. A system becomes unbalanced when, for example, a thermal power plant suddenly trips or the load unexpectedly increases which will cause the system frequency (60 Hz in the US) to deviate from its target range for reliable operations. Depending on the severity of the event, system operators can respond with several measures, including usage of reserve capacity and reduction of demand from major consumers, to avoid further issues or, in the worst case, a blackout.

Maintaining this balance requires accurate forecasts of demand, sufficient generation and transmission resources, and flexibility in real-time to adjust for imbalances. The operation of the power system to achieve these goals reliably and efficiently in deregulated markets is overseen by the ISO. As the potential economic costs of black outs are quite high, the primary role of the ISO is to maintain system reliability. The second priority is operating the system in an economically efficient manner. When situations bring a system close to its reliability limitation, the ISO will, in the short term, provide instructions to generators and operate the transmission network accordingly and, in the long term, provide integrated resource plans for an expansion of generation or transmission deemed necessary to meet future supply and demand requirements.

Deregulation of wholesale electric power markets has given independent generators the opportunity to compete with utility owned generators. Independent players in the marketplace created the need for central coordination of generators to balance generation and load, which is done by the ISO. Based on generator-submitted bids for producing electricity, the ISOs provide detailed instructions to generation plants on when they can inject power into the wholesale market. Market to market, the details of the bids will be different, with some bids including just the variable costs of production while others more fully representing actual opportunity costs. Based on these bids, the ISO provides the detailed schedule of operations for the next day to meet the load demanded.

The amount of electricity demand changes throughout the day. The load is often lowest in the overnight hours and highest in the evening, as shown in Figure 1-5 in black. The green line indicates net load – the amount of electricity that thermal generation plants must produce after the generation from intermittent renewable resources, such as wind generation, has been subtracted from the total demand. With the addition of wind generation, the system as a whole requires less generation from thermal generation resources (with the exception of nuclear) and there will be limited need for thermal generation in overnight hours when the wind often blows the strongest.

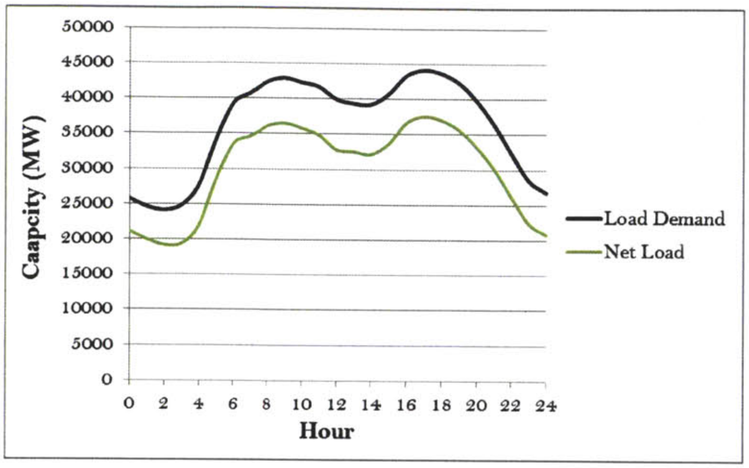

Figure 1-5 - Example load demand and net load for a 24-hour period

Generators must be scheduled at the different times throughout the day to produce the overall quantities of electricity demanded. For this example, the economic dispatch to cover the net load for the 24 hour period shown in Figure 1-5 may look something like Figure 1-6.

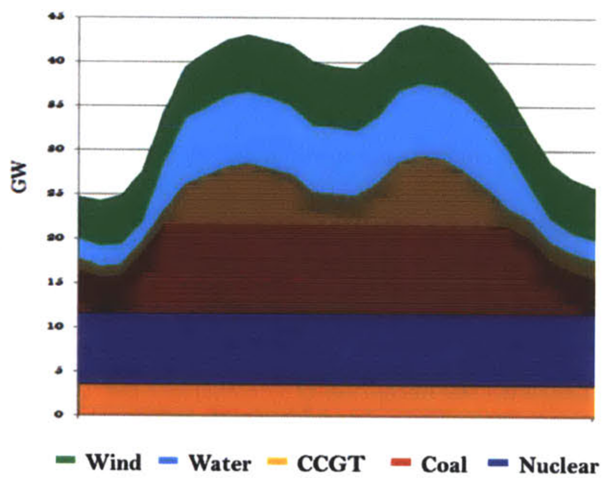

Figure 1-6 - A possible 24-hour dispatch of generation resources to meet the load

Some plants will operate throughout the day to produce baseload power. Other plants will need to be added to the system as the load begins to increase in the morning and then adjust their output as the load changes through the afternoon and evening. Eventually, most of the plants that started up in the morning hours will need to shut down as the demand falls off in the later hours of the evening. This scheduling of when plants are allowed to begin operating and must shutdown is referred to as the economic dispatch. The objective of the ISO is to coordinate which plants can provide the necessary capacity at the lowest cost to the consumers.

As Figure 1-6 demonstrates, thermal generation units do not all play the same role in meeting the electricity demand and reliability requirements of an electric power system. The thermal generation technologies most commonly in use today are nuclear, coal, combined cycle gas turbines (CCGT) and simple cycle gas turbines (SCGT). Each of these technologies has its own operational strategy based on the inherent physical constraints and economics of operating the plant. Generally, generators are classified as either baseload, load-following, or peaking units depending on the amount of electricity these units produce throughout the year, which is commonly known as their capacity factor[5]. Below are the common characteristics of each type of generation:

- **Baseload** units operate continuously throughout the year. They generally do not shut down often, except for planned maintenance. Nuclear, coal, and CCGT plants, with potential capacity factors between 70-95%, can all act as baseload plants.

- **Load-following** units change their output based on demand fluctuations. These units may shut down on a daily or weekly basis, as the load changes. CCGT and older coal plants can act as load-following units. In this role, their capacity factors range typically from 30-50%.

- **Peaking** units operate for a limited number of hours each year, when electricity demand hits its annual peak. SCGT and older oil-driven turbines generally act as peaking units; in these roles, their capacity factors are typically very low.

The introduction of intermittent renewables, such as photovoltaic solar and wind generation, complicates the traditional operation of power systems. A sudden change of wind generation requires system operators to make adjustments to balance generation and load by dispatching thermal generation plants to modify their output (*ramping*) or to start up/shut down (*cycling*). When thermal plants ramp or cycle, they incur physical wear and their heat rates suffer. In addition, plants that operate at *reduced outputs* generate electricity less efficiently. As the penetration of intermittent renewables increases, thermal plants will likely need to ramp, cycle, and operate at reduced output more frequently to accommodate the additional variability and unpredictability of the "net load."

[5] The capacity factor of a generating unit is the ratio between the amount of energy that a plant actually produces and the maximum amount of energy that it could produce for the same period of time based on its nameplate capacity. The capacity factor is normally calculated on an annual basis.

1.3 IMPACTS OF INTERMITTENT RENEWABLE GENERATION

Power system operators can plan for variability in generation if it is predictable. While generation is variable from both solar and wind resources, wind generation can be more difficult to accurately forecast for planning purposes. Additionally, peak onshore wind does not usually coincide with peak electricity demand. As wind generation continues to increase -- in 2011 wind accounted for 119 GWh (2.9%) of electricity generation in the United States (EIA 2012a) – understanding in greater detail how its output affects the operation of the power system is becoming more important.

An example of how wind generation impacts the cycling of thermal generation plants is shown in Figure 1-7 for the Spanish power system from November 8 – 15, 2010. Despite the considerable amount of hydro flexibility available in this system, the large amount of wind generation leads to significant challenges in the economic dispatch of thermal generation. The net load covered by thermal generation on a Tuesday can be similar or even lower than on a Sunday despite much higher total load. For example, total CCGT output must change on Wednesday from a low of 2 GW at 4:00 AM to a high of 11 GW at 19:00. Similarly, CCGT production swings on Sunday from 0.9 GW at 5:00 to more than 6 GW at 21:00. This will force many CCGT plants to be started up daily when wind production is high at night.

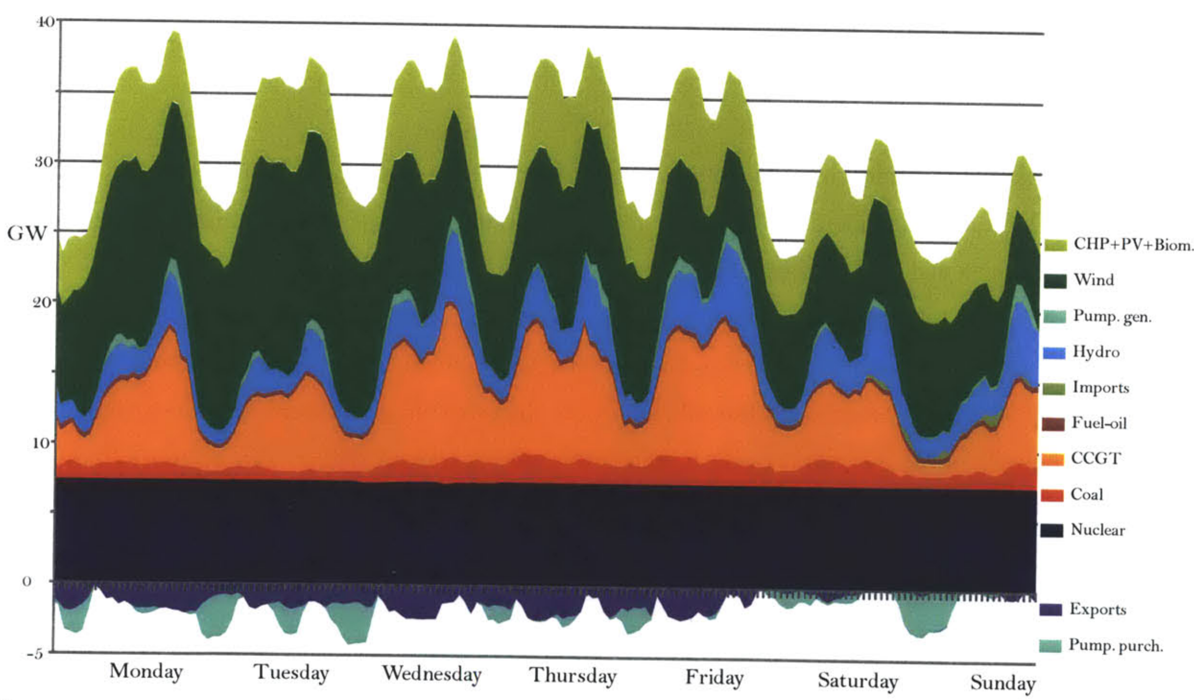

Figure 1-7 - Electricity supply in the Spanish system from Nov. 8th to 14th, 2010 (Red Eléctrica de España 2012b)

There have been several operational and market impacts already seen in electric power systems with high penetration of intermittent renewables that create concern about the current rate of deployment of these resources, especially wind generation. The three reports discussed next illustrate real world examples of the impact that wind generation can have on maintaining system reliability, electricity prices, and operation of thermal generators.

Reliability Impacts

On February 26, 2008, the Electricity Reliability Commission of Texas (ERCOT) triggered an Emergency Electric Curtailment Plan (EECP) due to an imbalance in generation and load in their system. The EECP was reviewed by NREL to better understand the events that led up to the emergency actions taken place, which had gained attention due to the role of wind generation (Ela 2008). In this case, the wind generation decreased by 1640 MW over a 3.5 hour timeframe, or approximately 8 MW/min. The loss of wind generation, which was predicted to occur several hours later than it did, played a role in the emergency event but was not the only cause for the EECP. According to the report, there were two additional factors that also contributed to the event: a sudden loss of a conventional generation unit and a faster than expected load increase during the evening hours. Due to the imbalance, the frequency of the power system started to decrease which caused ERCOT to take actions according their EECP prodcutions to bring the system back in balance by requiring the reduction of load for several major industrial consumers.

The report suggests several potential changes that could be made by ERCOT, including improvements in the ability of ERCOT to predict such events from the wind forecasting it receives and better integration of those forecasts into the planning models used for dispatching generation plants. It was also noted that there are important differences between these wind events and major contingency events, such as sudden loss of the largest conventional generation facility, which will require different tools to ensure system operators are prepared for these events.

Price Impacts

The second example of the impacts of wind generation on electric power system operations is the occurrence of negative electricity prices. Initially, negative prices may seem counterintuitive but generation plants in certain situations are willing to pay, instead of being paid, for generating electricity. Nuclear plants, for example, are capital intensive power plants that must run continuously to ensure revenue streams sufficient to pay for their high capital costs. In addition, adjusting the output of nuclear plants based on the load can be difficult and costly, and often the shutdown and startup of a nuclear plant can be even more costly[6].

For overnight hours when the load is at its lowest level and wind generation is often at its highest output, the physical and economic characteristics of nuclear plants can lead to an economically efficient decision for these plants to pay to remain operating, instead of reducing their output or shutting down. An evaluation of negative prices in the German electric system from October 2008 to December 2009 in Nicolosi (2010) details 86 hours of negative prices with 19 hours of prices less than -100 €/MWh. In fact, the most extreme price during that period reached -500 €/MWh at 3 am on October 4, 2009. The study finds that the main factors in producing negative prices were high wind generation, low load and inflexible baseload plants, such as nuclear and lignite coal plants. In addition, the report concludes that negative prices could become more extreme if the load had been lower and the amount of inflexible generation units had been larger, as they historically have been in similar circumstances.

Plant Emissions Impacts

The final impact of intermittent renewable generation highlighted here is the effect wind generation has on the operation of individual power plants. In the previous example it was shown that nuclear plants will resist changing the output of their plants in the presence of increased wind generation and pay a penalty to maintain operation. Other plant operators will be unwilling to pay such a high price for continued operation and must respond quickly to changes in output from renewables. As discussed, natural gas combined cycle plants are inherently flexible and have been designed to respond to changes in load by both cycling and ramping their plants. Coal plants are less flexible and must adjust their operations in ways not contemplated in their design to provide the flexibility the system requires.

A study of the coal generation units around Denver, Colorado in 2008 found that periods of high wind generation resulted in the cycling of coal plants and increased emissions of regulated air pollutants (Bentek Energy 2010). This outcome is caused by the impact of ramping on the backend emissions reduction systems of coal units that are used to remove sulfur dioxide and nitrogen oxides. It can take several hours to bring these systems back to stable operation after being adjusted along with the rest of the coal plant for lower levels of output. In addition, coal plants generate electricity less efficiently when they are forced to reduce their output which increases carbon dioxide emissions for each unit of electricity produced during these times.

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[6] Standard nuclear plants are able to quickly reduce their generation (nuclear plants are generally cited as being able to reduce their output by 20% within an hour), but may require six to eight hours for the plants to return to 100% output with the potential to miss operating during high price periods the next day (MIT 2012).

These examples have been included to illustrate the impact that intermittent renewables can have on the operation of the electric power system and the need to understand the short term operational impacts when studying the long term issues that will affect future power systems. With current technologies, significant increases in cycling-related cost associated with the penetration of wind and solar generation is unavoidable and the flexibility of both thermal and hydro plants is an essential component of such a system. The cost impact of a large introduction of wind and solar generation will depend on the amount and type of existing flexible dispatchable generation available in the generation mix.

The recent IEA study titled *Harnessing Variable Renewables: A Guide to the Balancing Challenge* defines power system flexibility in the following way:

> Flexibility expresses the extent to which a power system can modify electricity production or consumption in response to variability, expected or otherwise. In other words, it expresses the capability of a power system to maintain reliable supply in the face of rapid and large imbalances, whatever the cause. It is measured in terms of megawatts (MW) available for ramping up and down, over time. For example, a given combined-cycle gas turbine (CCGT) plant may be able to ramp output up or down at 10 MW per minute (IEA 2011a).

The ability of thermal generation technologies – coal, natural gas, and nuclear – to provide flexibility in power systems where there is large scale intermittent renewable penetration was the focus of discussion at the 2011 MIT Energy Initiative Symposium. The symposium findings established that thermal generation units have both technical and economic limitations when operating flexibly to accommodate intermittent renewables. These limitations create new challenges, especially for nuclear and coal units, traditionally designed to operate as baseload generators. It also creates opportunities and a larger role in balancing the output from intermittent renewables for plants designed for load following, such as combined cycle natural gas units. In addition, findings from the symposium suggested that market rules and regulations must adapt to ensure an efficient, reliable and profitable electric power system in the future. (MIT 2012) An example of the potential changes in operation coal plants must undergo and their expected impacts is shown in Figure 1-8.

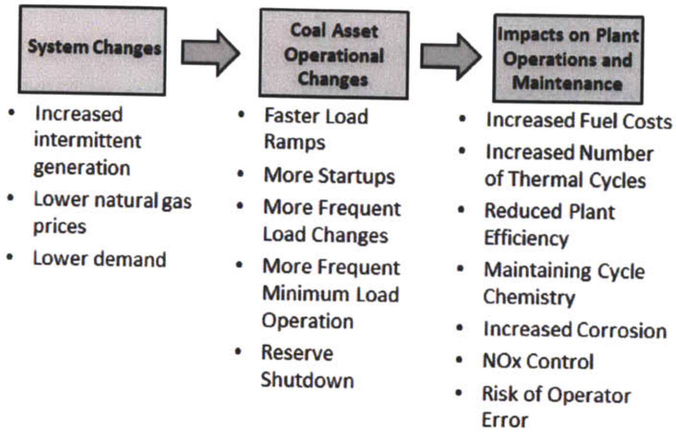


Figure 1-8 – Expected changes in coal plant operations (MIT 2012)

This paper focuses in particular on the role of hydro generation in providing flexibility to power systems with large scale installed capacities of intermittent renewables. Hydro plants, similar to the peaking thermal plants discussed above, can start quite quickly and respond easily to changes in the system. The role that hydro plays in flexibility can be seen in Figure 1-9 which compares the response times of different technologies over several time scales (IEA 2011a). The favorable characteristics of hydro are evident in its ability to provide 100% of its capacity in its short term (15 minute) as well as in the long term (36 hours).

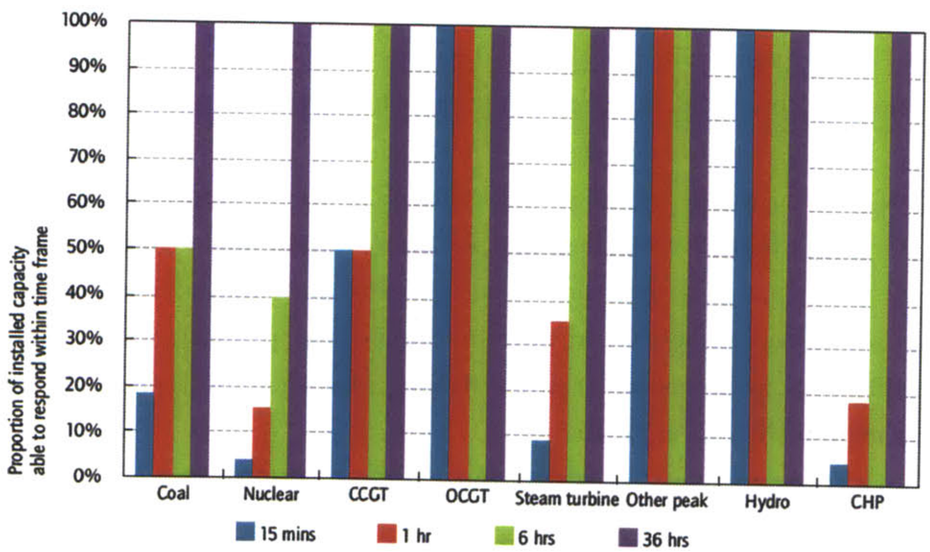


Figure 1-9 - Percentage of installed capacity that has flexibility to respond over certain timeframes (IEA 2011a)

The IEA study provides a high level review of dispatchable flexibility and notes in particular the role of hydro generation in enabling significant wind generation in the Nordic electricity market that encompasses the Scandinavian countries and Denmark.

Hydro generating facilities, however, will have their own constraints, including the physical shape and size of their reservoirs and flow limitations placed on plants to maintain the river quality desired by the local community. These issues for hydro generation will be further elaborated later in the chapter describing the Hydro Dispatch Module.

While electricity prices, the focus of this paper, are an important aspect of a well-functioning electric power system, additional work is being undertaken to understand the impact of increased intermittent renewable generation on system reliability (Leung 2012), system capacity expansion (Palmintier 2011), and investment in new CCGT plants (de Sisternes 2011).

1.4 ELECTRICITY PRODUCTION COSTS AND MARKET PRICES

With an understanding of how intermittent renewables affect the operations of generation units in the system, we now will turn to what the impact of this new operation regime could be on prices.

The costs of building and operating electricity power plants differ widely among the generation technologies discussed above. Because each type of generation plant has different cost structures (capital versus variable costs) and each plant will have different operation regimes (baseload versus peaking), it can be difficult to compare the costs of electricity generation from each source.

In the *2011 Annual Energy Outlook*, the U.S. Energy Information Administration (EIA) provided updated values for these different costs, which are summarized in Table 1-3 (EIA 2011b). In addition, the estimated fuel costs have been included based on EIA fuel price projections and have been calculated based on the heat rate values shown below. These costs can be generally split into fixed (capital and O&M) and variable (fuel and O&M) costs. Nuclear plants have the highest fixed costs but lowest variable costs, and natural gas combustion turbines (CT) have the lowest fixed costs and the highest variable costs, which are important considerations for the dispatch order and the impacts of intermittent renewables on the economics of the units.

Fuel Source	Technology	Nominal Capacity	Heat Rate	Overnight Capital Costs	Fixed O&M Costs	Variable O&M Costs	Estimated Fuel Costs
		MW	BTU/kWh	$/kW	$/kW	$/MWh	$/MWh
Uranium	Dual Unit Nuclear	2236	N/A	5,335	88.75	2.04	9.00
Coal	Single Unit Advanced PC	650	8,800	3,167	35.97	4.25	19.54
Natural Gas	Conventional NGCC	540	7,050	978	14.39	3.43	55.06
Natural Gas	Conventional CT	85	10,850	974	6.98	14.70	84.74

Table 1-3 - Characteristics and production costs for several generation technologies

Levelized Cost of Electricity

The most widely used metric for comparison of the cost of electricity generation across technologies is the levelized cost of electricity (LCOE). LCOE provides a first-order approximation of the costs of generating electricity, taking fixed and variable costs into account, and is expressed in dollars per unit of electricity generated ($/MWh). The annualized capital cost and fixed O&M cost are "variablilized" by spreading the fixed costs over the expected total quantity of electricity generated per year. To determine the amount of electricity generated, LCOE comparisons rely on the assumption that generation technologies will operate at certain capacity factors based on their standard mode of operation and design basis.

These assumptions lead to higher LCOEs for technologies, such as CCGT, which may have a lower capacity factor due to their position in the merit order. For example, Figure 1-10 shows the LCOE for an CCGT plant, a subcritical coal plant and a supercritical coal plant with and without dispatch considerations. At equal capacity factors of 85%, the LCOEs are essentially the same for all three technologies. When the expected dispatch considerations are included though, the cost of CCGT plants increases significantly compared to the coal technologies.[8]

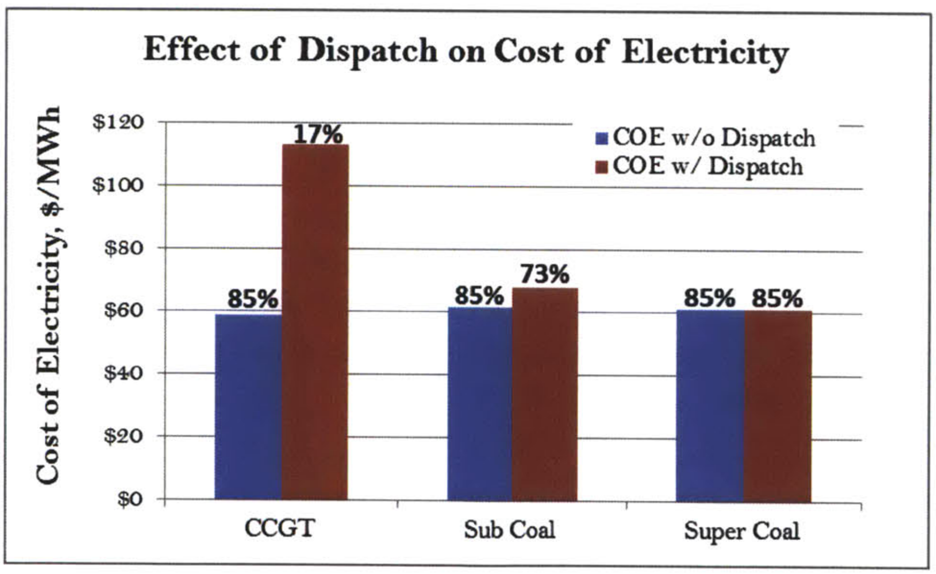


Figure 1-10 - The effect of dispatch on the levelized cost of electricity (NETL 2010)

[8] Figure 1-10 provides an extreme result by choosing a very low CCGT capacity factor for illustration, in addition to using high natural gas and low coal prices relative to today's prices. (NETL 2010) NETL used a coal price of $1.64/mmbtu and a natural gas price of $6.55/mmbtu based on projections in the EIA Annual Energy Outlook 2008. Using the heat rates assumed by NETL, current prices (natural gas - $5.16/mmbtu, coal - $2.88/mmbtu) will reduce the LCOE for CCGT plants by $10/MWh and increase the LCOE for coal plants by $10/MWh. Furthermore, if the average capacity factor of 41% were used, the dispatch effect on LCOE would be much smaller.

Determining the LCOE of intermittent renewables will depend on the predicted quality of the renewable resource being harnessed. The U.S. Department of Energy created a supply curve of onshore and offshore wind resources in the United States using LCOE to demonstrate the potential costs of production on a common basis as thermal generation (NREL 2008). As seen in Figure 1-11, the cost of wind generation ranges from \$60/MWh to \$140/MWh for the first 1,000 GW of wind capacity with 200 GW in the lower \$60-80/MWh range.

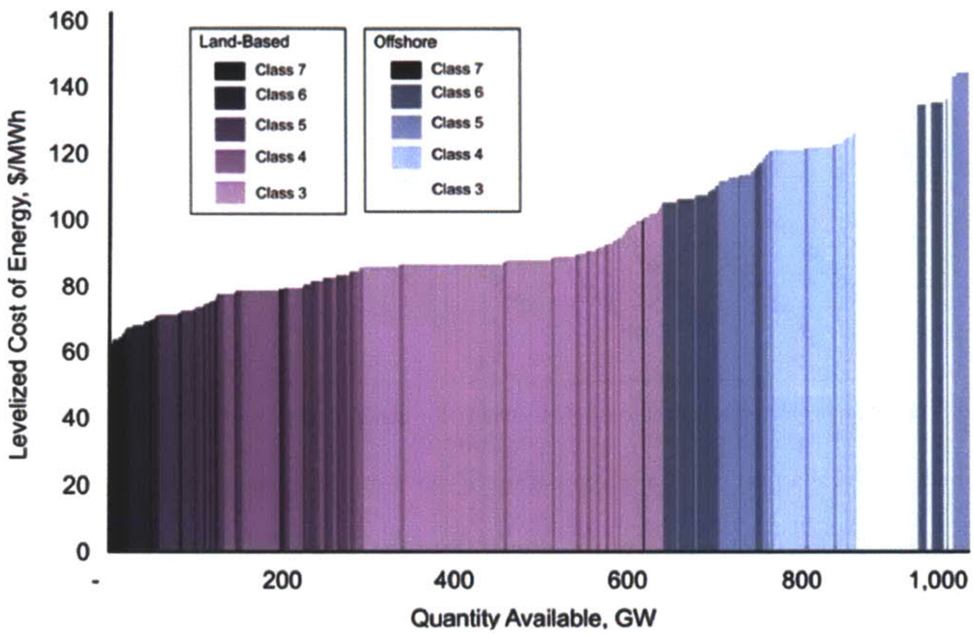


Figure 1-11 - Levelized cost of electricity for onshore and offshore wind resources in the US (NREL 2008)

Looking forward, Figure 1-12 compares the projected LCOE of both thermal and renewable technologies in the year 2016 with the assumed capacity factors included for each technology.

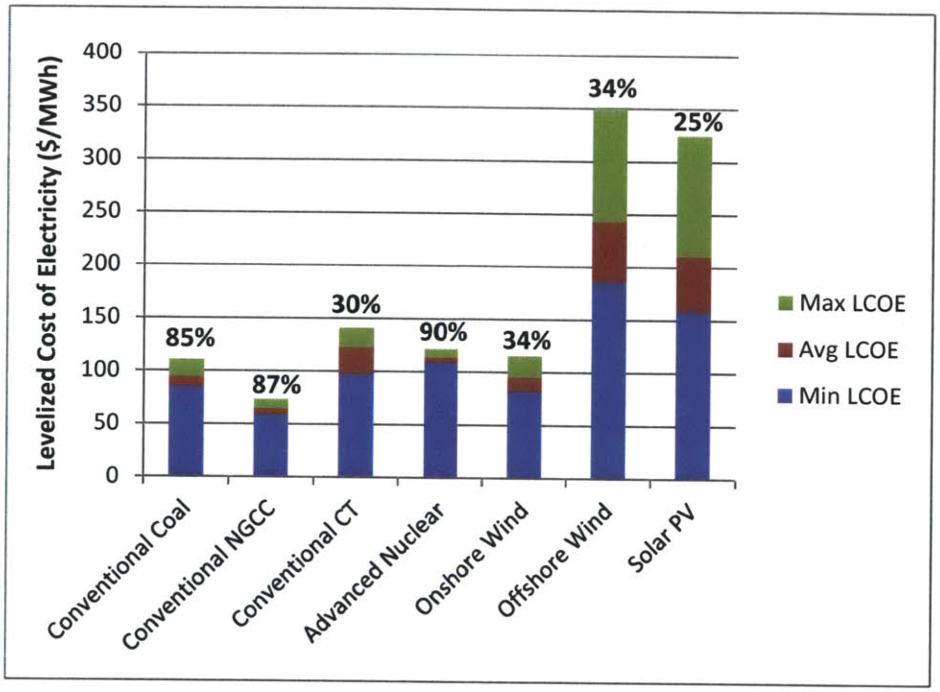


Figure 1-12 - The projected levelized cost of electricity for generation technologies in 2016. (EIA 2011b)

As mentioned, LCOE is a first order approximation of the cost of operating different generation technologies. However, it can often over simplify the value of technologies in a wholesale market. The EIA notes that LCOE values for the dispatchable thermal generators and non-dispatchable VER are not directly comparable (EIA 2011b). Although LCOE analysis may have been appropriate for comparisons of technologies in a cost-of-service regulatory regime, the value of renewable generation resources compared to thermal generation in a wholesale market should be determined by the hourly prices set by the market. Taking these factors into account, intermittent generation from wind resources, which generates the majority of its electricity at night, may have just a quarter of the value of a dispatchable generation plant with a comparable LCOE in a wholesale market (Joskow 2011).

Merit Order Effect

While the Joskow analysis expands on LCOE to find the market value for renewable generation, it does not take into account the effect intermittent generation will have on the operation of other generation technologies and on electricity prices.

Analyzing how this new form of generation will impact prices requires understanding how electricity prices are set. After the deregulation of vertically integrated utilities, it became necessary for pricing mechanisms to be developed that reflect the price of electricity on an hourly basis that changed throughout the day based on the fluctuations in load and the production costs of the generation technologies required to meet the load.

The key concept introduced for these pricing mechanisms is marginal cost pricing. As discussed earlier, generation technologies are dispatched by market operators based on their variable costs of production with the goal of meeting load with the lowest cost generation available. Marginal cost pricing sets the price of electricity based on the cost of production of the marginal generator, or the last generator to be economically dispatched to meet the load. The marginal generator is the price-maker, ensuring that pricing of all other generation is higher than its variable costs.

A merit order effect analysis is often used for understanding the impact of renewables on electricity prices in a marginal cost pricing regime. The merit order is based on the generation supply curve for a particular market and will define the elasticity of supply as the demand for electricity changes throughout the day. An example supply curve for the New England wholesale electricity market is shown in Figure 1-13.

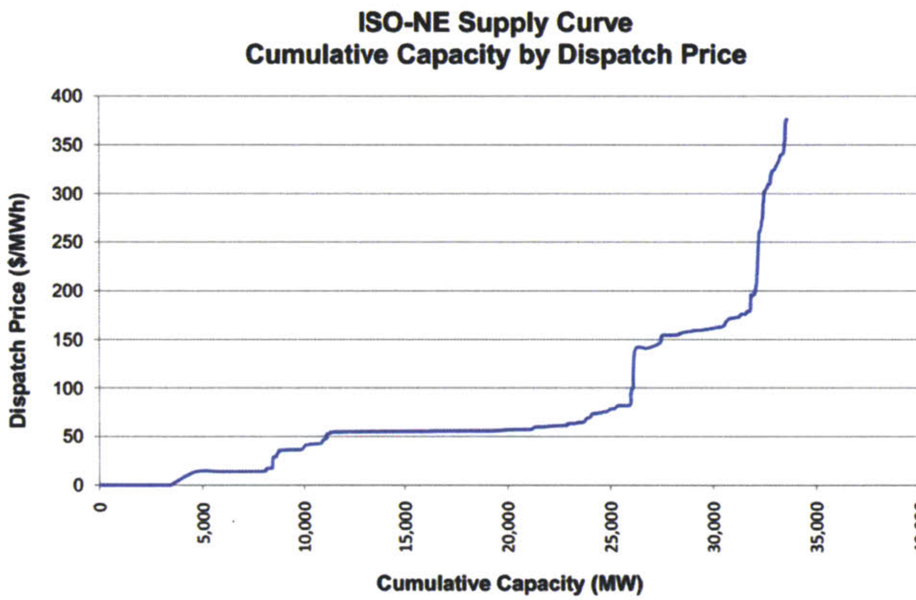


Figure 1-13 - Supply curve for generation capacity in ISO-NE (Lin 2011)

Since the variable costs of wind generation are essentially nil, the introduction of wind will shift the supply curve to the right and decrease the price of electricity, as shown in Figure 1-14 for high and low wind cases during the night, day and peak hours.

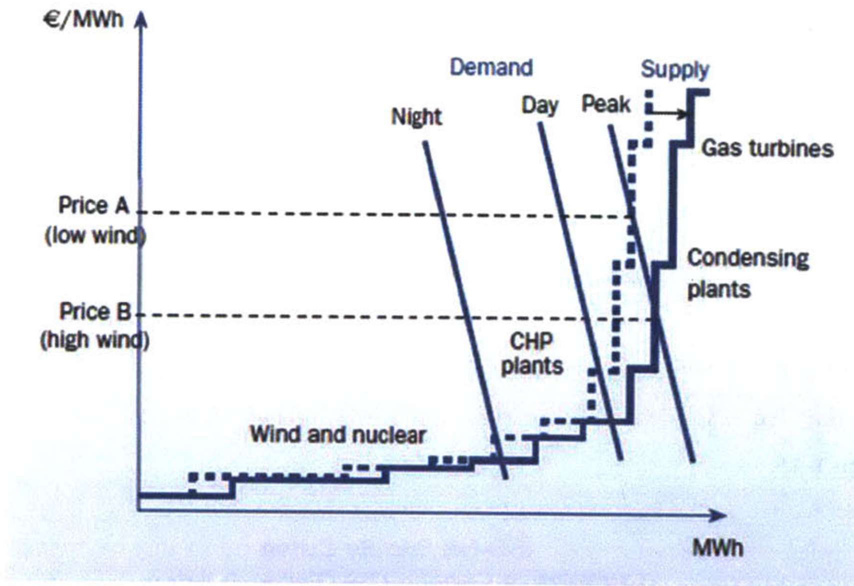


Figure 1-14 - Demonstration of merit order effect of wind generation (Poyry 2010)

While the merit order effect shown in Figure 1-14 shows a drastic change in prices with the introduction of wind, the price effect in actual wholesale market may be less pronounced. The scale of the merit order effect will depend on whether the intermittent renewable generation changes the technology that sets the marginal price in most hours of the year.

The potentially different outcomes of merit order effect analysis are shown in Figure 1-15 and Figure 1-16 below. The first set of charts show a supply function inspired by the Spanish system in 2000 and the probability distribution of the annual demand for thermal generation for cases with and without wind[9]. The resulting price distributions are plotted along the y-axis. Comparing the average prices marked by the dashed line on the right and left, there is a significant decrease in the annual average price with the addition of wind generation to the system.

[9] The load met by thermal generators in systems with significant wind penetration is referred to as the net load. The net load is found by chronologically subtracting from the demand the wind production.

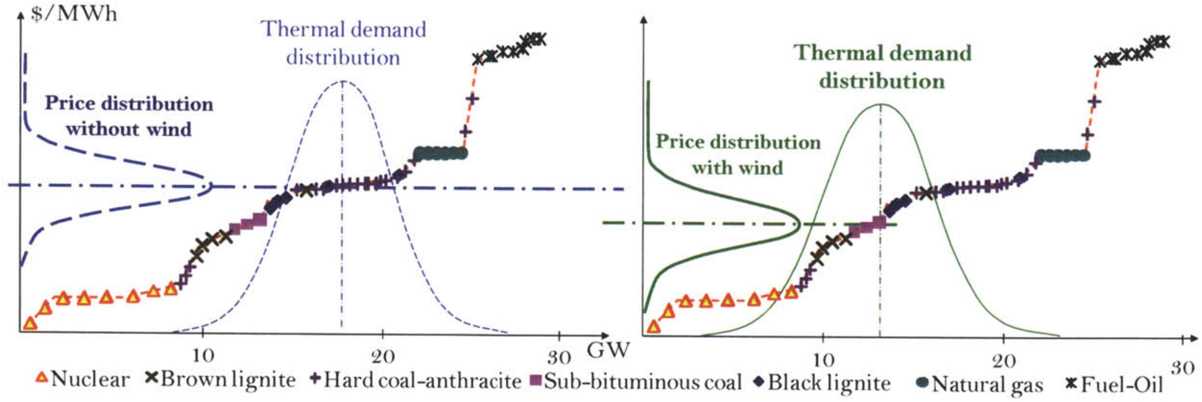


Figure 1-15 - Probability distributions of the marginal energy price without and with wind (year 2004)

On the other hand, Figure 15 reflects a typical European supply function in 2010 that has a large number of CCGT plants and a rather flat supply curve in the range in which marginal prices are set most of the time. The average price gap between the with and without wind scenarios in this case is significantly smaller, if different at all.

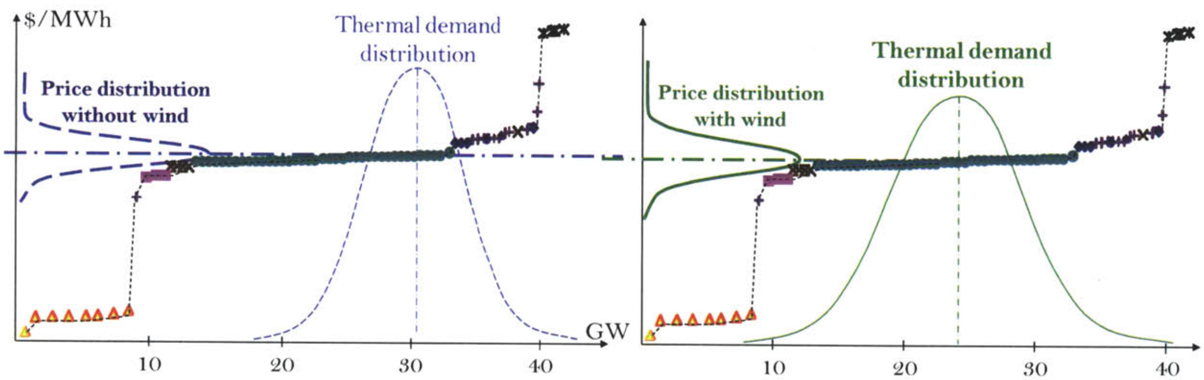


Figure 1-16 - Probability distributions of the marginal energy price without and with wind (year 2010)

Quantification of the merit order effect of wind generation has been completed by several studies. For the German power system, Sensfuss (2007) finds that the merit order effect of wind generation reduces electricity by 2.50 €/MWh in 2004 and 7.83 €/MWh in 2006. O'Mahoney (2011) finds for the Irish electric system that for 2009 the wind generation leads to savings of €141 million and reduces electricity prices by approximately 12%.

In a similar manner, the supply curve elasticity is often used to analyze market prices. Fischer (2010) uses the elasticity of supply for both the electricity and natural gas markets to determine the potential outcome of state-level RPS. First, evaluating renewable subsidies and fossil fuel taxes, Fischer finds that the subsidies would be expected to decrease prices while the taxes would increase prices. The portfolio standard combines elements of these policies and thus provides an indeterminate outcome of renewables on electricity prices. The price outcomes would depend on whether "the supply curve for natural gas generation is sufficiently steep relative to that of renewables."

These analyses provide additional information on the effects of renewable generation on prices but still do not tell the full story. They, for example, assume that prices are solely based on the linear variable costs of generation and that the introduction of intermittent renewables has no effect on the operation of the remaining generators.

Those assumptions will be investigated in this paper by analyzing the full set of production costs that are relevant in the operation of generation plants, including the costs of increased cycling and ramping that occur when dispatching generation plants efficiently with high levels of intermittent generation. This will be accomplished by investigating the chronological changes in demand and dispatch of generation facilities that provide a more accurate representation of how electric power systems are coordinated, how power plants are operated, and how market prices are determined.

1.5 THE NEED FOR NEW MODELING TOOLS

For environmental and political reasons, the penetration of intermittent renewable resources (hereafter referred to as Variable Energy Resources, or simply VER) in the electric power systems is expected to dramatically increase in the next decades. This fact will change the operation of thermal generation plants, forcing them to produce with more scheduled cycling that will push them to their technical operational limits.

There are a range of expected impacts of VER over several timescales that are pertinent to the operational and planning of the electric power systems[10]:

- From the very long term (decades) to long term (years), the expected outcome is an increase in the sustainability of power systems and a minimization of future energy supply costs. The implementation of VER technologies will be needed in the future as an alternative to conventional fossil-fuelled technologies, which use finite resources and emit greenhouse gases.
- From the long term to the medium term (months), the large scale penetration of VER will require adaptation of the thermal generation technology mix. Rapid VER deployment in the medium term will decrease the capacity factors of currently installed thermal generation units.

[10] There are many other impacts on the global economy and in particular in electric power systems (namely in the networks) that are not explicitly mentioned here, the scope of our analysis is limited to the electric power generation systems.

Increases in VER over a longer time horizon will allow the thermal generation capacity mix to adapt and include towards less capital-intensive thermal generating units, such as CCGT

- From the medium term to short term (days), VER use zero- or low- variable cost energy resources that will significantly change the scheduling regime of the rest of the generating facilities. The impacts of VER on operations in this time frame, as discussed, are significant and due to their non-dispatchable production that is uncorrelated with the demand. This is expected to have an effect on operational costs, which will tend to decrease due to a reduction of variable costs (i.e. fuel costs), but also tend to increase due to the additional costs introduced by thermal unit constraints.

- From the short term to the very short term (minutes), the unpredictability of VER generation leads to a larger need of provision of operation reserves and more sophisticated power system stability procedures. There has been a positive evolution in the forecast error of wind generation in the last few years[11] and in the technical design of VER facilities that allow them to participate in maintaining system reliability.

The model developed for this paper excludes the very long term sustainability effects and very short term reliability effects of VER penetration. The analysis will focus instead on the assessment of the effect of a large penetration of VER on the rest of the relevant timescales. From this view, the variable and unpredictable wind generation is less significant than the uncorrelated output of wind generation with load demand.

The extent to which the physical constraints of thermal generation plants may affect their scheduling in the future is becoming an active research topic at the present moment. There is a growing number of modeling analyses that deal with the impact this new regime will have in the short to medium term, see for example Delarue et al. (2009), Lannoye et al. (2010), Goransson and Johnsson (2009), with some analyses also including the potential for changes in market prices, e.g. Poyry (2010). However, there are still few studies that assess how VER can change the optimal capacity mix in the long term, and on the top of that, how market prices can also be affected by the new investment and operating trends, e.g. Traber and Kemfert (2011). Doing so requires introducing the short-term technical constraints intensified by VER into the long-term expansion models.

The traditional modeling tool utilized for long term capacity planning is the screening curve method. This basic approach, which will be explained later in more detail, derives the optimal generation mix from simplified representations of both the generation cost structure (capital and simplified variable

[11] For example, in the Spanish system, beyond five hours ahead, this error is around 15% (Imaz, 2011).

costs) and dispatch scheduling criteria (load duration curves). However, thermal unit operating constraints are not represented and limited energy plants, such as hydro plants, are excluded. Although it does not satisfy all of the properties usually required for system optimization studies, it has traditionally been considered an extremely useful approach to initially illustrate major trends in capacity expansion analysis.

The conventional screening curve methodology has recently been used by Nicolosi and Fürsch (2009) to illustrate how increasing wind production leads in the long term to a higher peak load capacity share in the conventional power market and a lower average utilization of the generating capacities. Green and Vasilakos (2011) used a similar method to assess the long-term impact of the introduction of large amounts of intermittent renewables in Great Britain on electricity prices and generating capacity[12].

The conventional screening curves approach, similar to the merit order effect, neglects the costs related to the chronological operating constraints to which thermal plants are subject. These constraints become much more relevant when a significant amount of VER is installed in the system, especially in the absence of sufficient storage capacity, and will be the focus of the new method of analysis developed in the next section.

[12] The authors conclude that, although the expected capacity mix changes (a shift towards power stations with higher variable costs but lower fixed costs), the changes to the pattern of prices, once capacity has adjusted, are relatively small. In this paper, on the basis of a more sophisticated modeling approach, we argue that the pattern of prices we expect in this new scenario with a large proportion of VER is significantly different.

2 THE LOW EMISSIONS ELECTRICITY MARKET ANALYSIS MODEL

Although neglecting cycling and ramping related costs has been considered a reasonable simplification to date, the new massive penetration of VER makes it necessary to revisit this previous assumption.

In order to face the analysis of the impact of VER penetration, a novel electric power system model has been developed named the Low-Emissions Electricity Market Analysis (LEEMA) model (Batlle & Rodilla 2011). The LEEMA methodology expands on the traditional screening curve methodology by combining the long-term conventional screening curves model with a short-term heuristic optimization scheduling algorithm (including startups, minimum loads, operation reserves, etc.). LEEMA considers and characterizes the main sources of production costs related to the new dispatch schedules of conventional thermal plants in a power system with large scale penetration of VER. Hydroelectric generation is introduced as well to capture the impact that the storable and limited resource will have on the dispatch of thermal generation. The resulting dispatch is used in a price computation model that represents two different pricing rules for determining the effect of VER on wholesale electricity prices.

LEEMA model has its own limitations, however, that include assumptions that all thermal generation units will have similar operational characteristics, such as minimum stable load levels, that thermal generation plants will always be available to operate, and that the same thermal generation units will always operate at the same level in the merit order. Also, the load and wind generation are deterministic and do not take the stochastic nature of their values into account.

A full description of the model can be found in Batlle & Rodilla (2011). The following description of the LEEMA model will focus on the areas that are essential for understanding the dispatch of hydro resources within the context of the LEEMA model. The description of the hydro dispatch in LEEMA will be fully described in the next chapter.

2.1 THE COSTS OF FLEXIBLE OPERATION

In LEEMA, the following three components of the overall thermal production costs are developed:

- Energy production costs: the fuel costs of producing electricity as a function of the incremental heat rate curve, which includes efficiency losses from suboptimal operation at reduced load.
- Fuel start-up costs: the fuel costs of raising the boiler to its minimum operating temperature as a function of the hours the unit has been shut down.

- Operation and maintenance (O&M) costs: the costs of operating and maintaining generation plants modelled as a function of the operating regime, as defined by operating hours and startups.

These factors cover a significant proportion of the overall costs incurred by flexible generation. Fuel and startup costs properly quantify operation costs in the short term and our extended approach to representing O&M costs include a good proportion of the long-term costs related to the wear and tear of the machinery.

How each of these thermal production cost factors are handled in LEEMA is described next to provide a better understanding of the fundamentals that lead to new market outcomes with large scale VER.

Energy production costs

In addition to normal operating hours when generation plants operate at their most efficient and typically maximum output, generation plants can choose to produce at their minimum output to avoid the additional costs of shutting down and starting up a plant. However, thermal plants are subject to a lower threshold on their output to maintain boiler stability, called the minimum stable load. This threshold depends on the technology but it is never negligible. Commonly in the case of fossil fuel plants, the minimum stable load is around 40 % of nameplate capacity of the plant.

Energy production costs from fuel consumption are higher per unit of electricity generated during low load operation than at full capacity as the production efficiency decreases. The efficiency loss at minimum stable load can be assumed to be in the range of 10-15% depending on the particular technology and plant. Figure 2-1, taken from Wood & Wollenberg (1996), illustrates this efficiency loss for the case of a standard 400 MW CCGT.

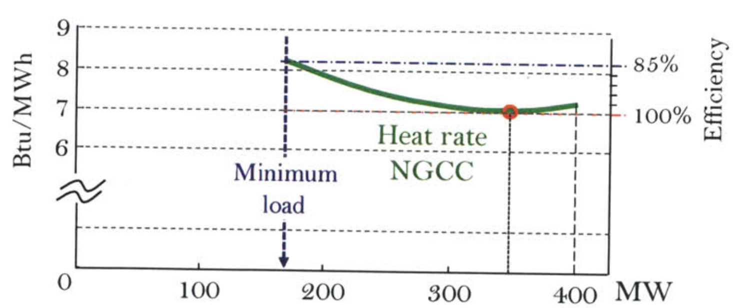


Figure 2-1 - Unit heat rate as a function of the output level

The energy production costs are thus a function of the output of the generation plant. Higher VER penetration is expected to require additional ramping of thermal units between full capacity and minimum stable load. The presence of hydro generation potentially could limit this impact of VER.

When plants reduce capacity to avoid additional startup costs, this relationship between output and production costs must be considered.

Fuel start-up costs

Fuel costs are incurred when starting up and shutting down a thermal generation unit. The cost of the fuel burned to heat the boiler differs depending on the number of hours the unit has been shut down prior to the re-start. A *hot start* can generally be considered when the unit has been shut down for less than 10 hours; a *warm start* occurs when the unit has been down for more than ten but less than 50 hours; and finally, a *cold start* is done for any shutdown time greater than 50 hours. Traditionally, this distinction has had a clear relationship with weekly demand cycles: 10 hours is the limit that represents the maximum number of hours a unit has to stop during the night hours between two working days, while 50 hours is related to the duration of stops during weekends.

For this reason, the fuel start-up costs are a function of the number of hours the unit has been out of operation before starting. The longer the unit has been off, the larger the fuel expenses will be to bring the unit back to operation. The penetration of VER increases the number of starts but at the same time reduces the costs of each one of these starts (Troy 2011).

Operation and maintenance costs

Operation of thermal power plants outside the expected scheduling regime will incur additional O&M costs due to the wear and tear on the units of thermal cycling. O&M costs come in different forms and can generally be divided into fixed and variable cost components. The fixed cost reflects the expense the plant owner expects to incur each year regardless of how much the generating unit actually operates and usually includes minor periodic maintenances, wages, property taxes, facility fees, insurances and overheads. The variable costs are a function of the operation of the plant and can change depending on the number of firing hours, starts, trips, etc. and usually include major maintenance inspections that are triggered after certain accumulated operation conditions are met (e.g. a number of operating hours or a number of starts). The focus here will be on the variable O&M costs as they are more likely to be impacted by the large scale introduction of VER and reduced by the introduction of hydro generation.

With every firing hour or startup, there is an indirect cost associated with maintenance inspections and thus a reduction of the total plant availability. As maintenance events will become more frequent with increased ramping and cycling, the weight of the variable O&M component in the overall production costs will increase.

Generating units require a program of planned inspections with repair or replacement of damaged components (Boyce, 2006) that range from daily checks to major maintenance events. These requirements are commonly defined for the owner of the generation facility by the original equipment manufacturers (OEM) through long-term service agreements (LTSA)[13] on a relatively fixed price basis. LTSAs are priced in various ways (including per fired hour, per start, per planned maintenance event and per calendar year) and specify when inspections have to be scheduled depending on several factors (including the startup cycles, the power level, the type of fuel, and the amount of steam or water injected).

Baseline conditions are set in LTSA for determining the maximum inspection intervals of a typical heavy-duty gas turbine. The baseline conditions, shown in , can vary in nature and can be categorized based on separate criteria limits for the number of starts and hours of operation (Option A), a single criteria limit with additional starts converted linearly to an equivalent number of operating hours (Option B), a non-linear function to combine operating hours and starts (Option C).

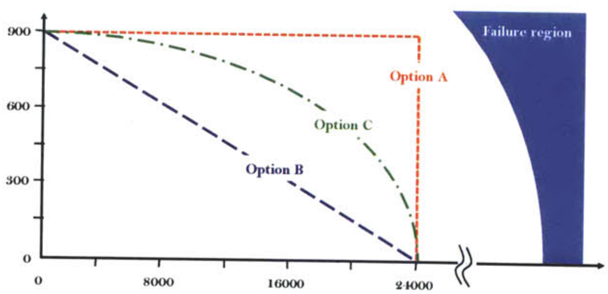


Figure 2-2 - Baseline functions for maintenance interval

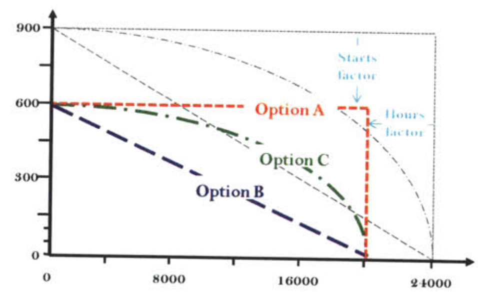


Figure 2-3 - Modified baseline functions for maintenance interval

As operating conditions will differ from the baseline conditions, the cyclic life of the generation plant components and the maintenance interval will be reduced (Balevic et al., 2010), as shown in . Increasing the cycling regime of a thermal plant due to large scale penetration of VER will translate into plant operators spending more time and money on maintenance activities.

In summary, in light of these operational impacts of VER on thermal production costs, it is evident that any sound electricity market analysis in the presence of a large penetration of VER must account for the operations factors just introduced both in the costs and prices in the short to medium term and on the capacity expansion in the long run.

In the next section, the LEEMA modeling methodology will be described to achieve this objective.

[13] LTSAs offer power plant owners a mechanism for controlling maintenance costs and maximizing turbine reliability while minimizing the need for internal resources to manage and perform turbine maintenance.

2.2 LEEMA MODEL OVERVIEW

The LEEMA model is broken into three separate modules for thermal systems, as shown in Figure 2-4, to perform the analysis of the short term operational constraints and then apply them to the economic dispatch before finally determining the electricity market prices[14].

- First, the Thermal Scheduling module performs a heuristic optimization that calculates at each level of the merit order the operation schedule required for thermal plant to chronologically cover the net load. This module does not presuppose any particular generation technology but instead simply estimates the cycling regime at each merit order position, known heretofore as a loading point, based on general operating constraints and economic criteria for thermal generators. The output of this module is a set of chronological hourly production profiles for each loading point throughout the time scope of the analysis.
- Second, taking into consideration the production profiles at each loading point, the Economic Dispatch module derives the production cost functions that would result if such production profiles were supplied by each one of the conventional thermal technologies (such as nuclear, coal and CCGT) being considered. This allows the model to derive the technology for each position in the merit order which is most cost-efficient at producing such profiles, thus allowing us to obtain the optimal generation mix. Additionally, if no capital costs are considered (i.e. if we just include operational costs), the model allows for the evaluation of the resulting production costs for an existing generation mix. Once the generation technologies are established, the total production costs of operating at those load levels to meet the system load are determined for each generator on an hourly basis.
- Finally, the market prices module takes as a starting point the costs of production of the generation technologies assigned to each loading point and computes the resulting wholesale market prices. The model allows considering those markets with discriminatory pricing rules (e.g. PJM) and those market designs with non-discriminatory (e.g. the Irish market).

[14] An additional module is added for the hydro dispatch in hydrothermal systems and requires a re-ordering of the modules, which is fully described later in the paper.

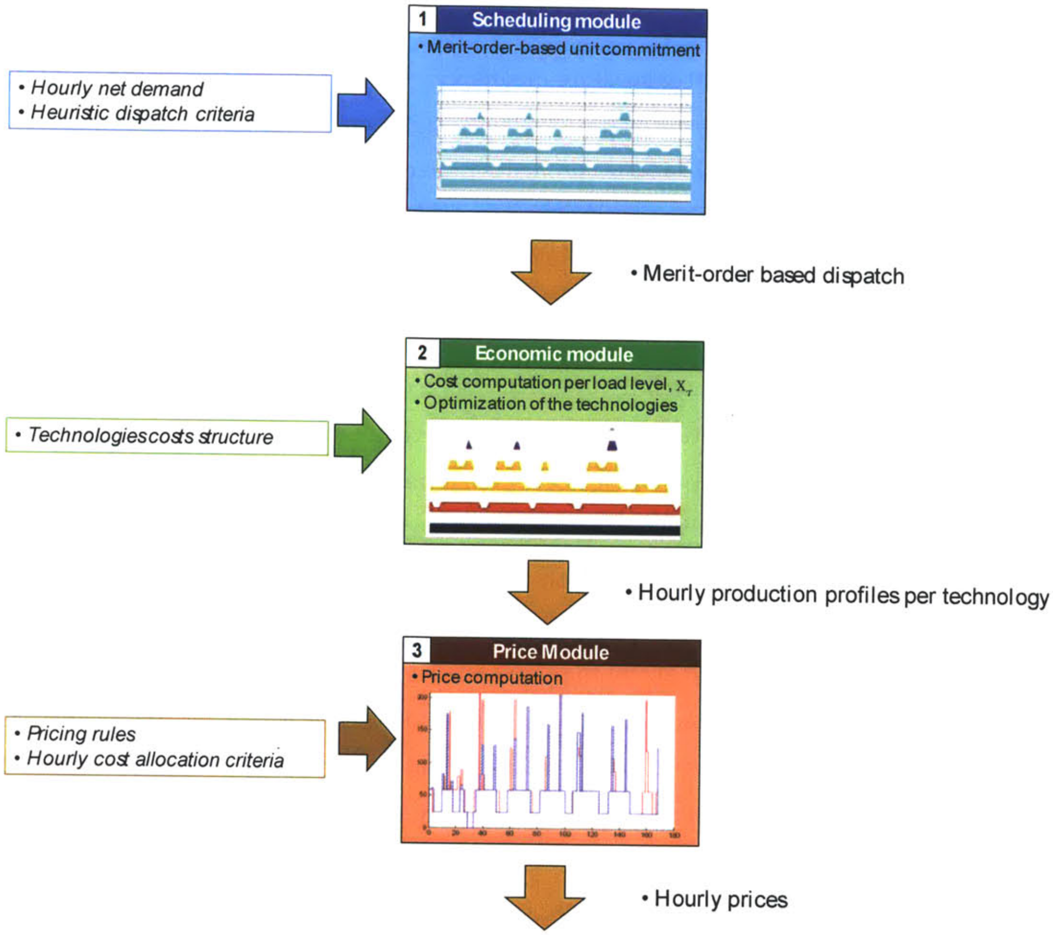


Figure 2-4 - LEEMA model structure

2.3 THERMAL SCHEDULING MODULE

The first LEEMA module performs the heuristic optimization of thermal plant production scheduling at each loading point. With the net load as an input, the scheduling is computed on the basis of a merit order-based dispatch where the scheduling of a thermal plant depends on its position in the merit order, or loading point[15]. It expands on the conventional screening curve methodology by introducing both physical constraints of thermal generation and the flexibility for generation units to avoid additional starts.

[15] The major consequence of these hypotheses is that the production profiles are computed per loading point as if they were independent from the technologies actually producing. The objective is that, in the same manner the conventional approach proposes, the technology will be latter optimized based on this schedules.

The Conventional Approach

The scheduling of thermal generators in LEEMA starts with the simplified premise of the conventional screening curve approach to generation dispatch, as shown in Figure 2-5. By this methodology, the optimal unit commitment of installed generation plants is determined by loading thermal units based solely on their variable costs. In this example, the resulting production profile of a 1MW capacity thermal plant at the loading point 19.8 GW is shown and can be represented equally well on either the chronological net load curve (CNLC) or on the net load duration curve (NLDC). This example is used to show the lack of consideration for chronological limitations or physical constraints of dispatching thermal generation plants by the conventional methodology.

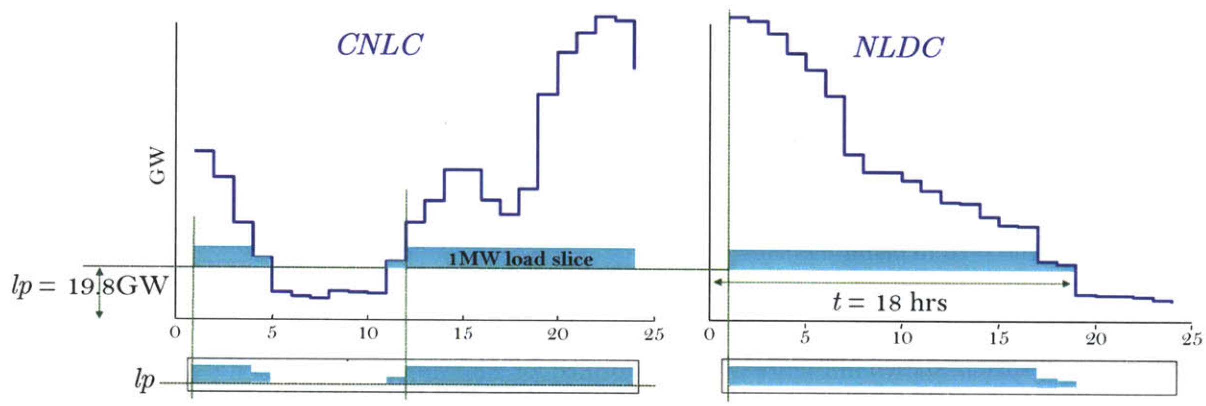


Figure 2-5 - The 1 MW production profile in chronological (CNLC) and net (NLDC) load duration curves

In reality, given the costs incurred by stopping the unit in this example at hour 5 and re-starting it at hour 11, thermal generation plants may choose instead to operate at their minimum possible output to avoid the additional start-up and the start-up costs that go along with it.

The LEEMA Approach

The heuristic optimization of production profiles utilized in LEEMA expands on the conventional approach by considering the production and chronological constraints discussed in the previous section. The objective in this new scheduling approach is to define a production profile, including the starts and output level, for each loading point that will reduce the total costs of production by limiting the number of unit startups while respecting the physical constraints of thermal generation units.

To perform this algorithm, three parameters must be established to determine the optimal scheduling of thermal generation plants to meet the load demanded.

- The minimum stable load ratio (m) is the ratio between the maximum capacity and the minimum stable load of the thermal units.

- The hours operating at minimum stable load ($\overline{t}_{ml}$) is the maximum number of consecutive hours a unit would be willing to keep the unit producing at a different level than the maximum load to avoid an additional start.
- The inflexible generation capacity (I_g) is the amount of capacity, normally a combination of nuclear and reserve[16] capacity, that will be unable to reduce its output for purposes of avoiding additional startups by plants higher in the merit order.

For the purposes of scheduling in this module, it is assumed that the production profiles at each loading point are technology independent. This is necessary so that the profiles represent all potential generating technologies and will require that values be assumed for these parameters across all technologies[17]. Generally, m is considered to be 40% (i.e. the minimum load limit for a 400 MW plant would be 160 MW), $\overline{t}_{ml}$ has been determined to be 12 hours by comparing the additional costs of minimum load to the additional costs of cycling the plant, and I_g will depend on nuclear and reserve capacities in the system being modeled[18].

To derive the optimal production profiles of thermal generation units in LEEMA, a preliminary thermal scheduling dispatch, shown in Figure 2-6, is performed for a loading point based on the conventional approach explained above. The preliminary dispatch is used to identify the initial number of starts, $N(p)$, and off-line periods, $\overline{t}_{off}(lp, n)$, that a generating plant at that loading plant would have to undergo if no flexibility is considered.

---

[16] Reserves have a non-negligible impact in terms of system overall costs and particularly in a system with large scale penetration of VER. The LEEMA model explicitly calculates the need for additional reserves due to the unpredictability of VER generation in the short term as well as calculates the contribution of reserves to the inflexible generation in the system. See Batlle & Rodilla (2011) for a full description of how reserves are determined in LEEMA.

[17] As we later discuss, the suitability of this hypothesis is tested in the next module of the algorithm so as to refine the results if needed.

[18] These values have been determined based on relevant information for the Spanish case. Spain currently has 8 GW of installed nuclear generation capacity.

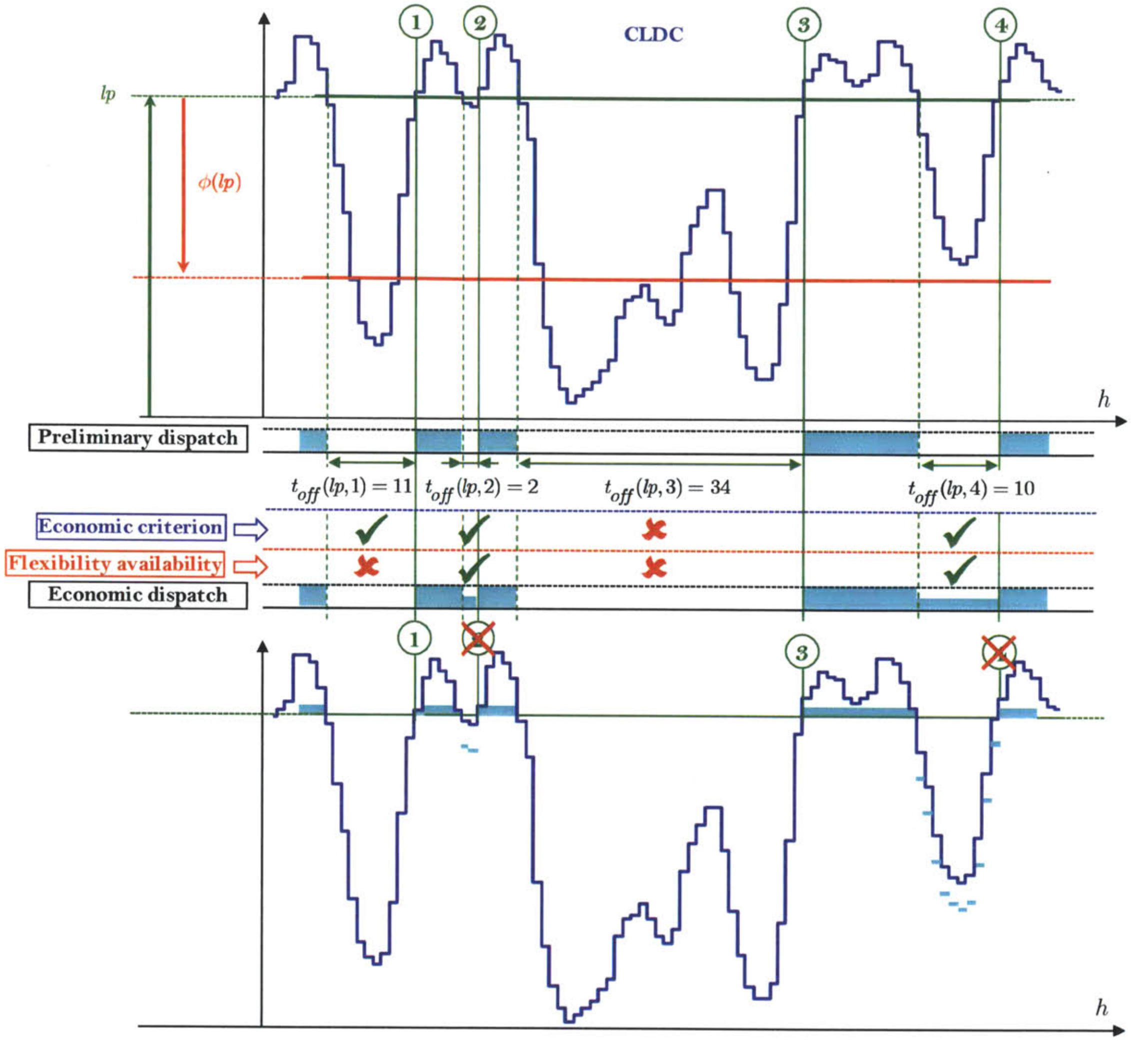


Figure 2-6 - Economic dispatch considering system flexibility

With this information, the four startups in the production profile can be evaluated to determine whether the off-line period prior to the startup could be avoided by instead operating at minimum load for those hours.

To do so, there has to be both an economic justification to do so and flexibility available in the system. The economic justification is found by comparing $\overline{t}_{off}(lp,n)$ for each startup with $\overline{t}_{ml}$. If the hours offline, $\overline{t}_{off}(lp,n)$, are less than the cut-off point for avoiding a startup, $\overline{t}_{ml}$, then the economic justification is there. The flexibility available will be based on the generating units operating at lower loading points and the inflexible generation in the system. If generation units at lower loading points will also be able to reduce their output to get past the valley hours, then the flexibility is available for avoiding the shutdown.

Considering these two criteria in the case shown, starts 2 and 4 can be avoided and the production profile is modified to reflect the new economic dispatch.

This methodology is applied at each loading point over the period of analysis of the model, with a representative week for an example system shown in Figure 2-7. The resulting economic dispatch for all loading points required to meet the system net load can be seen along with the detailed production profile for six plants shown below in blue.

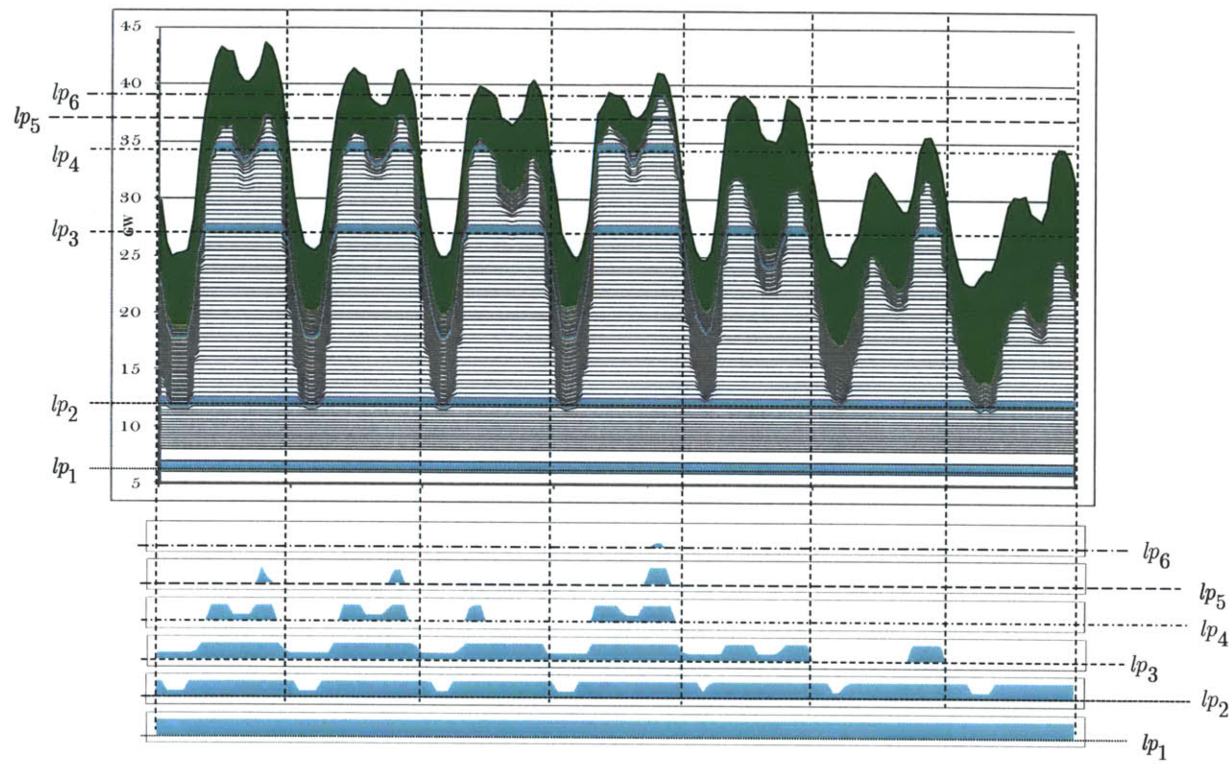


Figure 2-7 - Production profiles per loading point

Each of these production profiles include important pieces of information (the number of starts, the hours between starts and the output production levels) for understanding how thermal generation plants operate in systems with large scale VER and will be used in the following technology optimizing module, as shown in Figure 2-8.

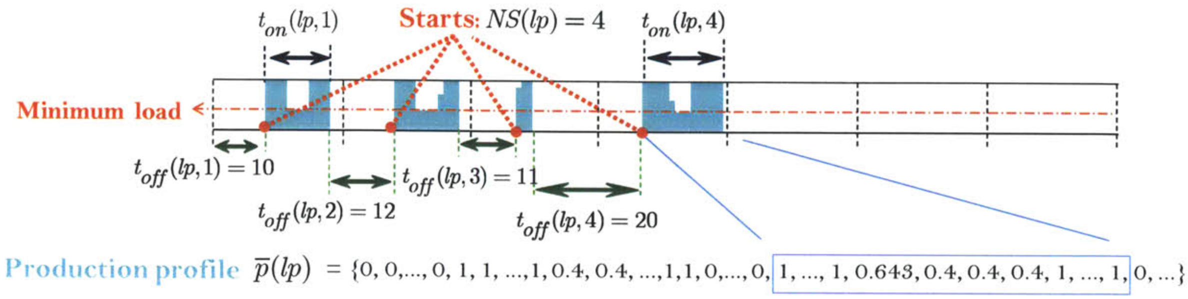


Figure 2-8 - Variables defining a production profile

2.4 ECONOMIC DISPATCH MODULE

Once the thermal scheduling module has determined the production profiles for each loading point, the next step is to determine the technologies that are able to supply those profiles at the lowest cost.

Conventional Approach

To again start with the conventional screening curve methodology, the total annual cost (TC) of producing a certain profile with technology generation unit (τ) is computed as the sum of the annualized capital costs, CC_{τ} , the annual energy fuel production costs, EFC_{τ}, and the annual operation and maintenance costs, OMC_{τ}, as shown in equation (1).

$$TC_{\tau} = CC_{\tau} + EFC_{\tau} + OMC_{\tau} \tag{1}$$

Capital costs are inherently fixed costs. The other terms in the annual total cost equation (1) though can be separated into their fixed and variable components, as shown in equation (2) for energy fuel production costs and equation (3) for operation and maintenance costs.

$$EFC_{\tau} = efc \cdot t \tag{2}$$

$$OMC_{\tau} = FOMC_{\tau} + eomc_{\tau} \cdot t \tag{3}$$

Energy fuel production costs are computed as the energy fuel cost (efc , expressed in $\$ / h$) times the number of the hours (t) it produces on a yearly basis. O&M costs are separated into the annual fixed operation and maintenance costs ($FOMC_{\tau}$) and the annual energy variable operation and maintenance costs, which are computed as the variable (energy-related) operation and maintenance cost ($eomc_{\tau}$, expressed in $\$ / MWh$) times the hours of operation (t).

Rearranging the fixed and variable terms in equations (2) and (3), a new equation for the total costs of production is obtained in equation (4), where the total annual production cost curve per installed MW ($TC_{\tau}(t)$), can be expressed for one particular technology, τ, as a function of the hours (t) it produces on a yearly basis.

$$TC_{\tau}(t) = FC_{\tau} + ec_{\tau} \cdot t; \qquad \begin{cases} FC_{\tau} = CC_{\tau} + FOMC_{\tau} \\ ec_{\tau} = efc_{\tau} + eomc_{\tau} \end{cases} \tag{4}$$

FC_{τ} represents the total annual fixed costs, i.e. the annualized capital cost (ACC_{τ}) plus the fixed operation and maintenance costs ($FOMC_{\tau}$) of technology τ [$/MWyr.] and ec_{τ} is the (variable) energy cost of technology τ [$/MWh], obtained as the addition of the variable energy production fuel costs (efc), i.e. the value resulting from multiplying the power plant heat rate times the fuel price plus the CO_2 emissions rate times the price of the ton of CO_2, if available and the variable (energy-related) operation and maintenance cost ($eomc_{\tau}$).

For a certain technology τ, the cost of supplying each of the 1 MW slices can be computed by combining both the total cost function, $TC_{\tau}(t)$, and the load duration curve, $LDC(t)$, as shown in Figure 2-9.

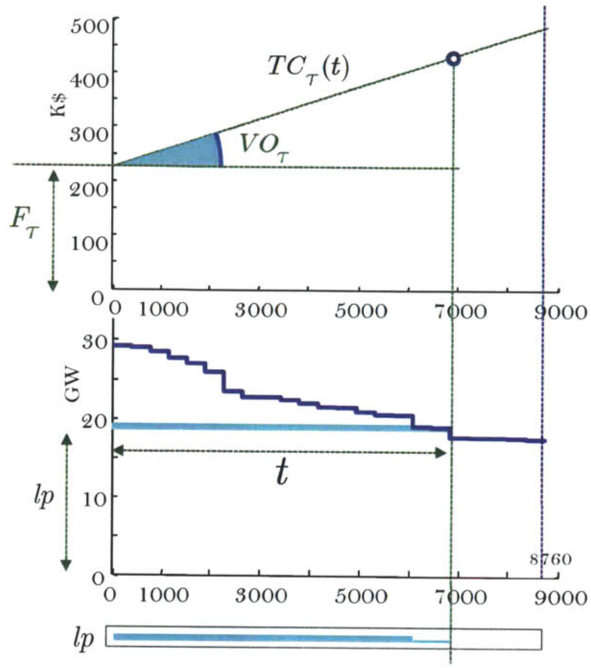
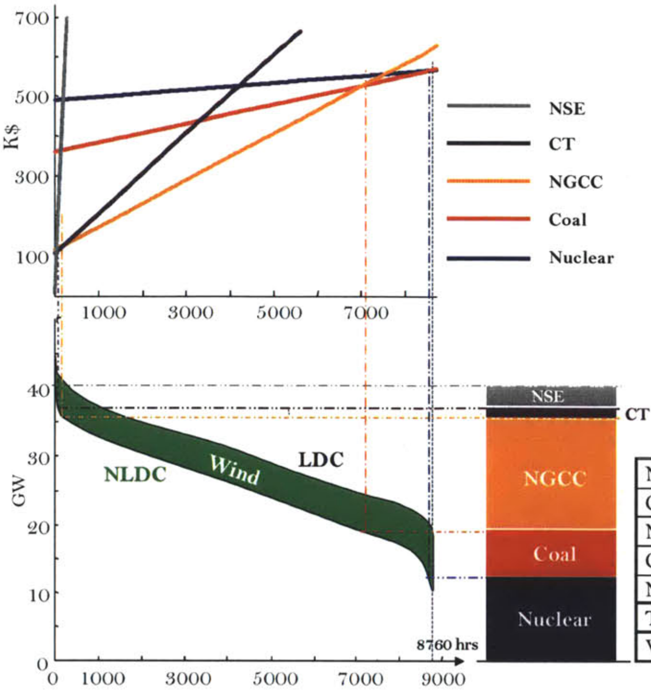


Figure 2-9 - The cost of supplying a 1MW load tranche with technology τ

Computing the optimal generation mix from this conventional method entails calculating which technology can provide at the lowest cost each of the 1 MW slices making up the load duration curve. This is achieved by representing the total production cost functions per installed megawatt of capacity for all the technologies across the operation hours in the period considered, as shown in Figure 2-10. The optimal capacities of each generation technology is then determined for each slice by identifying the technology that can provide that amount of electricity at the lowest cost (i.e. the lower envelope curve, made up of piecewise-linear segments).



	Installed capacity [MW]
NSE	2677
CT	2046
NGCC	16677
Coal	6248
Nuclear	12935
Total	**40583**
Wind	20000

Figure 2-10 - Optimal generation mix with VER resources

Once the cost minimization is solved, the chronological economic dispatch is obtained by applying these results to the simplified hypothesis of the traditional screening curves, as previously demonstrated in Figure 2-5.

LEEMA Approach

An alternative formulation of the traditional screening curve will be used in LEEMA that expresses the total production costs as a function of the loading point *lp* (MW) instead of the annual production hours. The screening curves will now be expressed as a function of the hours of operation at each loading point, i.e. $t(lp)$ with the cost function taking the form:

$$TC_{_T}(t) = FC_{_T} + ec_{_T} \cdot t(lp) \tag{5}$$

If we recalculate the cost functions from the previous example using this new formulation, we obtain the curves represented in Figure 2-11. To maintain the resemblance of the conventional representation of the screening curves, the x-axis has been inverted so that the x-values closest to the origin correspond to peak demand. It is demonstrated with the newly represented cost functions that the determination of the optimal technology for each loading point is perfectly analogous to the method used in Figure 2-10.

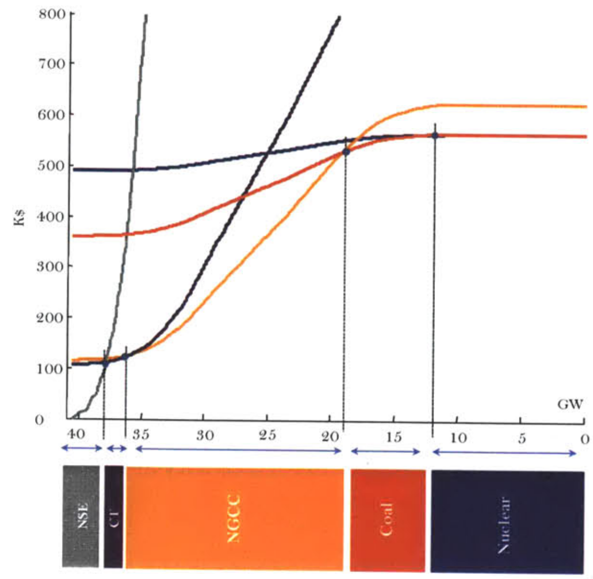


Figure 2-11 - Conventional screening curves method in the equivalent formulation

The objective of LEEMA is to extend this screening curve methodology to include the operational costs that become more influential as VER enter the system. The information obtained from the Thermal Scheduling module will now be used to determine costs for each possible generating technology to supply the production profile at each loading point.

The productions costs to be considered now include capital costs, energy fuel production costs, fuel start-up costs, and operation and maintenance costs (both fixed and variable). For modeling of the currently installed system, as done in this paper, the fixed costs are not considered.

For 1 MW installed of technology, τ, we expand equation (5), the total annual energy production cost curve, as follows:

$$TC_{\tau}(t) = CC_{\tau} + EFC_{\tau}(\overline{p}(lp)) + SFC_{\tau}(\overline{p}(lp)) + OMC_{\tau}(\overline{p}(lp)) \tag{6}$$

Where

$\overline{p}(lp)$ is the annual production profile vector that corresponds to charging the unit at loading point, lp

CC_{τ} is the annualized capital costs for 1MW of technology τ,

$EFC_{\tau}(\overline{p}(lp))$ is the total annual variable operating fuel cost of 1MW of technology, τ, operating at loading point lp,

$SFC_\tau(\overline{p}(lp))$ is the total annual start fuel costs for 1MW of technology, τ, operating at loading point lp

$OMC_\tau(\overline{p}(lp))$ is the annual value of operation & maintenance cost for 1MW of technology, τ, operating at loading point lp

The importance of the alternative formulation of the screening curves is seen here since the three last terms of the total costs expression (EFC, SFC and OMC) are computed as a function of the production profile, $\overline{p}(lp)$, instead of by the number of hours of operation. Each of these costs, explained previously in Section 2.2, will now be applied to the production profiles of the loading points for each technology to determine which is able to supply that electricity at the lowest cost.

Production Fuel Cost

The total annual variable operating fuel cost of technology τ is computed as:

$$EFC_\tau(\overline{p}(lp)) = \sum_{h=1}^{h} efc_\tau(p(lp,h)) \cdot p(lp,h) \tag{7}$$

The energy production fuel cost efc_τ (expressed in \$/MWh) is a function of the level of production $\overline{p}$ for each hour which takes the lower efficiency of minimum load operation into account.

Startup Fuel cost

The fuel cost of each start is a function of the number of hours the unit has been shut down before restarting (e.g. hot start for less than 10 hours, warm start for more than ten but less than 50 hours and cold start for more than 50 hours). Therefore, the startup fuel costs for each loading point take the form:

$$SFC_\tau(t) = \sum_{ns=1}^{NS(lp)} sfc_\tau(t_{off}(lp,ns)) \tag{8}$$

Variable O&M cost

The variable O&M costs require additional work due to the complexity of variablizing the terms of a LTSA, as explained previously. The cost of major inspections under the LTSA and the threshold conditions triggering them are determined at the moment the LTSA is signed. However, the points in time in which these major inspections have to be scheduled and thus the frequency of these inspections (which directly impact the annual O&M costs) depends on variables included in the production profiles, such as the annual number of starts and the annual firing hours.

Depending on the requirements in the LTSA, a variable can be defined for each loading point for the number of equivalent firing hours that triggers a maintenance event, FH^{*}_{om}. If $FH(lp)$ is the number of firing hours per year at a certain loading point, the frequency of the major maintenance inspections, $F_{om}(lp)$, can be computed as:

$$F_{om}(lp) = \frac{FH(lp)}{FH^{*}_{om}} \tag{9}$$

The annual variable O&M costs are simply expressed as the product of this frequency and the cost of an O&M cycle, $OMCC$ (for instance 50 M$):

$$OMC(lp) = F_{om}(lp) \cdot OMCC \tag{10}$$

In the model, a production/start ratio limit is introduced as well as a maximum number of annual starts for each one of the technologies considered. For example, it has been assumed that coal plants can neither start more than 50 times per year nor exceed one daily start. In the case of nuclear, the starts threshold is assumed to be 1 start per year. Beyond this number of startups, it is considered inconceivable at this time for that technology to provide the required operations scheduled.

Total Production Costs

In total, we can compute the cost of producing the profiles associated with each loading point as the sum of the four cost components:

$$TC_{T}(lp) = CC_{T} + EFC_{T}(\overline{p}(lp)) + SFC_{T}(\overline{p}(lp)) + OMC_{T}(\overline{p}(lp)) \tag{11}$$

In Figure 2-12, these cost functions are shown graphically for each technology across all loading points in a similar manner to the equivalent formulation to the screening curve above shown above.

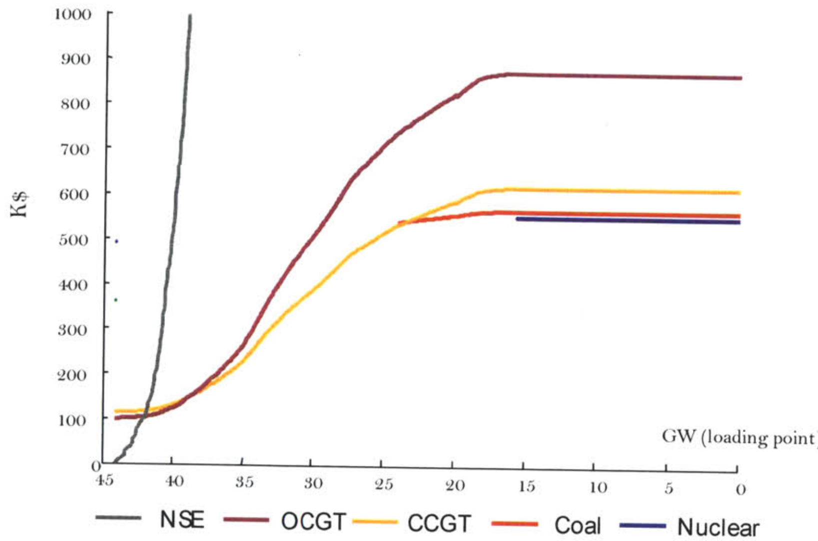


Figure 2-12 – Production costs by loading point and technology

Coal and nuclear cost functions are just represented for the range of loading points not violating the startup limits. Beyond these limits, the cost of these technologies is assumed to be infinite.

Resulting economic dispatch

To illustrate the scheduling results provided by the model, Figure 2-13 shows the dispatch of the thermal generation units for a representative week.

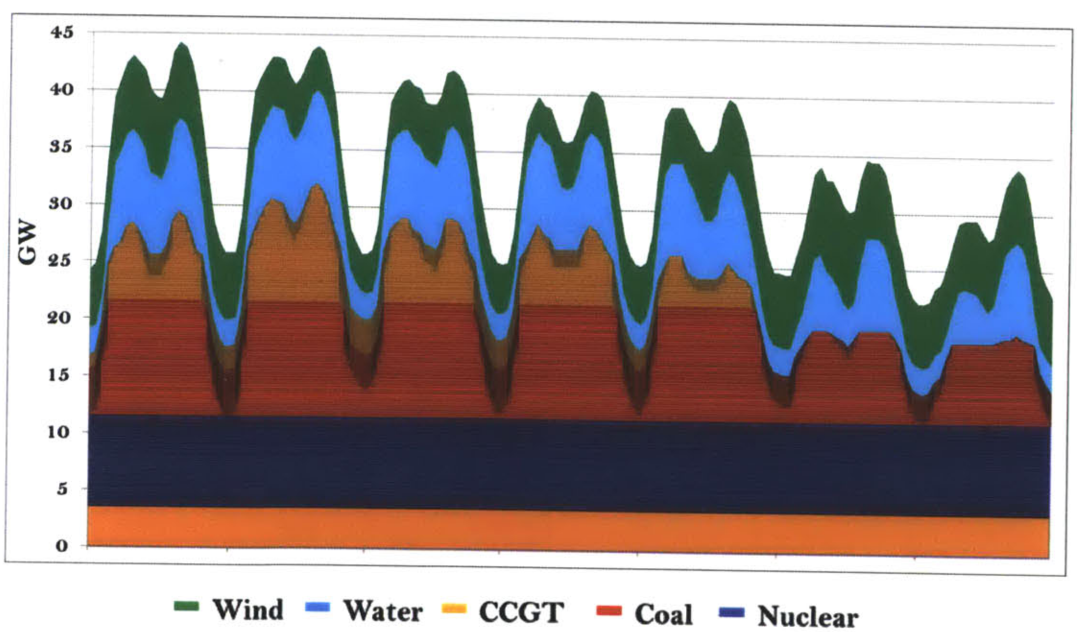


Figure 2-13 - Hourly scheduling of generation units.

2.5 PRICE COMPUTATION MODULE

The final step for understanding how VER affect the operation of power systems is to determine the electricity market prices. In this section the algorithms for computing hourly market prices are described. The objective is to allow for a proper assessment of the effect that changes in system operation patterns and thus in the production costs caused by VER have on market prices.

Short-term, hourly market prices, usually determined in the day-ahead market, serve as the signals around which operation, management, planning and capacity expansion revolve. The particular design of the short-term market (format of the bids, market clearing algorithm and pricing and remuneration rule) significantly affects these market results.

Roughly speaking, in organized short-term wholesale electricity markets the day-ahead market price is determined hourly by matching generators offers and consumers bids to develop a classic supply and demand equilibrium price. Since electricity is a complex commodity, and its production is subject both to inter-temporal constraints and to the existence of a number of non-convex costs, the format of the generators offers can range from simple bids (a series of quantity-price pairs per time interval) to a grayscale of more complex alternative bids, in which inter-temporal constraints and/or multidimensional cost structures can be declared. As these constraints and cost structures provide sufficient uncertainty in determining adequate simple bid strategies, simple bids will not be covered here. Instead, the main alternatives for complex auction will be described.

A complex auction occurs in the following steps:

- First, generation participants submit offers, representing the costs and physical limitations which best define the characteristics of their generating unit. At the same time, the demand participants (in most cases utility companies) submit bids representing their willingness to pay for the electricity consumption.

- Second, the market operator clears the market using an optimization-based algorithm. The algorithm seeks the maximization of the net social welfare, resulting in the market-based economic dispatch. In the particular case in which electric demand is inelastic, the maximization of the net social benefit problem turns to the minimization of the overall generation cost.

- Third, market prices for each one of the time periods (e.g. hours) are obtained from the optimization-based algorithm.

- Last, due to the existence of non-convex costs, the price calculated might not be sufficient to ensure cost recovery for all units. In this case, the market operator determines a remuneration rule to guarantee that all committed generating units at least fully recover their operating costs (including linear, e.g. fuel costs and non-linear ones, e.g. start-up costs).

Although there are a wide variety of auction designs generally they can be summarized in two large reference groups:

- Discriminatory-pricing schemes, commonly implemented in US ISO markets, set the hourly price based on marginal cost pricing and pay additional, differentiated side-payments to each unit to remunerate unrecovered costs. The payments are considered non-linear since payments are not determined solely on the quantity of electricity produced.

- Non-discriminatory pricing schemes, commonly implemented in EU markets, pay all generators a single hourly price based on the opportunity cost of the marginal generator. The component of the price in excess of the marginal cost price required for cost recovery is referred to as the "uplift" price. The payments in this case are linear since generators will receive revenue proportional to their production.

These two pricing schemes can produce different payments for consumers and different revenue streams for generating units. For this reason, two pricing mechanisms have been developed in LEEMA. The discriminatory pricing scheme is based roughly on the system used by PJM in the United States and the non-discriminatory one based on the Irish pricing scheme (which will be denoted in this paper as IRE).

The earlier modules in LEEMA have generated the scheduling and cost production data necessary for calculating market prices in both cases, including for each loading point, lp , the corresponding production profile, $\overline{p}(lp)$, the technology generating that production profile, and the total production costs incurred each time the unit operates.

In the remainder of this section, the pricing schemes developed in LEEMA will be demonstrated. First, the total annual costs of production determined in the Economic Dispatch module will be allocated to each hour of operation. Next, prices will be determined first based on the concept of marginal cost pricing and then by the two remuneration mechanisms, IRE and PJM, that ensure cost recovery for all generating units.

Allocating total production costs to the hourly production periods

In the previous section, it was shown how the lowest cost generation technologies are determined for each loading point based on the total costs of production. Once the lowest cost technology has been determined, the costs need to be allocated to each hour of operation for determining the market prices with each component allocated differently.

Energy fuel production costs

The energy fuel production costs are those associated with the units' production in each hour using the variable fuel cost function so that no additional allocation is necessary.

Start fuel costs

The startup fuel cost associated to each start is distributed among the hours in which the unit is in operation before shutting down.

Variable operational and maintenance costs

Allocating the costs associated to the variable operational and maintenance costs requires additional analysis since the operation of the unit throughout the year will affect the O&M cost component in each hour. In Batlle & Rodilla (2011), it is fully discussed how to allocate or "variabilize" these costs along the production hours, and particularly, how to allocate them in terms of firing hours and startups. A summary is provided here.

As major maintenance events are commonly triggered by a generation unit reaching a pre-determined number of firing hours, the variable O&M cost is initially set as the cost of the maintenance per megawatt-hour of production expected. However, as O&M costs will be highly dependent on the actual operation of the plant, the additional costs of each startup needs to be priced into each operating hour. Let us in the following denote by $fhomc$ and $suomc$ the separate O&M cost components per-firing hour and per-start (expressed in \$/fh and \$/start respectively) that must be added as the unit is operated.

A constant per-firing-hour component is defined which only depends on the function defining the threshold for triggering a major maintenance and the cost involved in the major maintenance cycle, $OMCC$. The per-firing hour cost component does not depend on the operation regime of the unit.

$$fhomc = OMCC \,/\, FH_{MAX} \tag{12}$$

An operation-dependent startup component which serves to impute all costs the previous component fails to allocate is next defined. This non-allocated cost is equal to $(FH_{MAX} - FH_{om}) \cdot eomc$. The additional O&M costs caused by starts will be calculated based on the number of starts calculated in the previous section. This way, each start is attributed with a cost due to the major maintenance equal to:

$$suomc = (FH_{MAX} - FH_{om}) \cdot eomc \,/\, NS_{om}(lp) \tag{13}$$

Once these two terms are calculated, they can be summed up to determine the allocation of variable O&M costs in each hour.

LEEMA pricing mechanisms

With this information, prices can now be simulated in each of the two contexts, PJM and IRE. Regardless of the pricing mechanism, the computation of market prices on an hourly basis requires two steps. First, marginal cost pricing is utilized to set prices to the marginal costs of production. Second, the additional payments necessary for full recovery of production costs for each generator are determined and allocated to market prices by a set of rules unique to the pricing mechanism. In this way, market prices are a combination of the variable costs of production of the marginal generator and additional payments required for full cost recovery.

For purposes of demonstration, the price computation algorithm for determining marginal cost prices will be displayed for one particular day contained in the yearly simulation, with the hourly production of each of the units of that day represented in Figure 2-14.

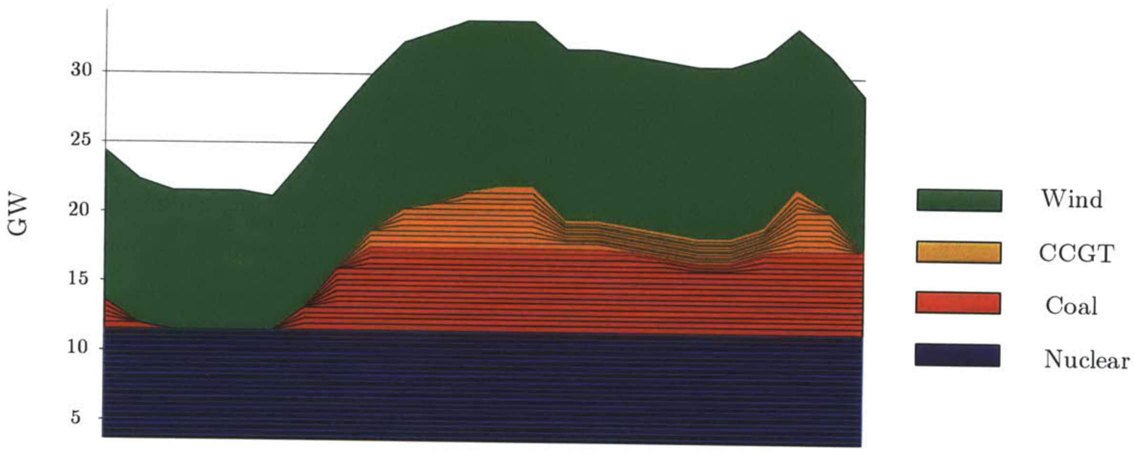


Figure 2-14 - The reference day production

Marginal cost pricing

In the first step, prices are set in each hour to the marginal costs, defined as the variable costs of production of the marginal generation unit. The marginal unit generally is the last, highest variable cost unit dispatched but two considerations need to be made for properly determining the marginal costs:

- Units producing at their minimum technical output are never considered as marginal. In these hours, the unit adopts the behaviour of a price-taking unit. Thus, the price of the price-quantity pair offer is set to 0 $/MWh.

- When the last accepted unit is a must-run type of unit, system marginal production costs are set to zero. The marginal cost is zero since in these situations there is wind energy spillage so that the cost of supplying an additional MWh of consumption would be null.

In the particular day shown above, the hourly marginal prices correspond to the variable costs of coal ($22/MWh), the variable cost of CCGT ($55/MWh) and the variable cost of curtailed wind ($0/MWh), as shown in Figure 2-15. Following the rules above, the price in some hours corresponds to the marginal cost of coal when CCGT are producing at the minimum technical output and prices are zero in the hours when wind has been curtailed to prevent nuclear plants from having to reduce their load.

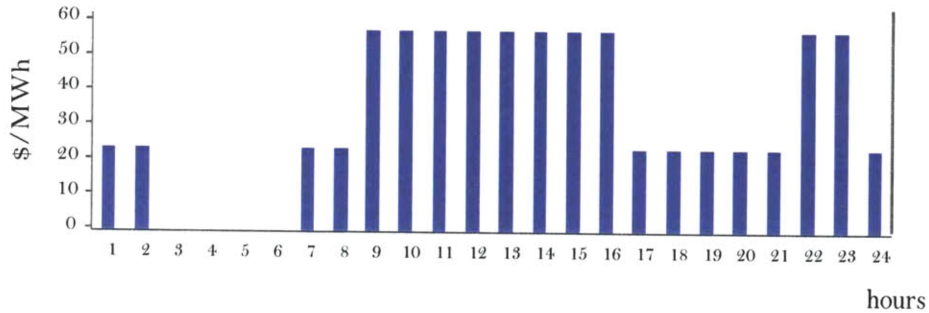


Figure 2-15 - Hourly marginal costs in the reference day

As mentioned, equating prices to the marginal costs is not enough for determining wholesale electricity prices since there are several additional costs associated with additional startups that need to be accounted for to provide full cost recovery to all generating units. The methods for determining these additional payments for the two pricing mechanisms previously mentioned are described below.[19]

Discriminatory pricing mechanism

In the discriminatory schemes, two types of payments are made to generators. Hourly marginal prices are computed, as shown above, that will be paid to all generators based on the system marginal costs. Once these marginal prices have been determined, the next step requires computing side-payments that are paid on a unit-by-unit basis so as to ensure total operation cost recovery of each generation plant. This method leads to paying generators at different rates for the same hour of production, which is referred to as discriminatory pricing. This settlement is carried out on a daily basis.

The following are the components of the total production costs that will not be covered by marginal prices along with calculation of the total costs of production for each component on a daily basis:

- Production at minimum load: The majority of fuel production costs is covered by marginal prices but will not account for hours operating at minimum load when generation is less efficient and the unit becomes a price-taker.

[19] In Batlle & Rodilla (2011), a complete description of the algorithms is provided along with a thorough analysis of the remuneration received under each pricing rule for different units in the merit order.

- Startup costs: Startup costs are by nature non-linear and will not be covered in the marginal prices.
- Startup O&M costs: As described earlier, O&M costs will depend on the nature of the LTSA and generally are assumed to be determined on a firing hour basis with startups in some cases reducing the number of firing hours before a major maintenance is triggered. The increased O&M costs caused by startups will not be recovered by marginal cost pricing.

The total production costs are calculated in equation (14) from the components described in the previous section. The total income received through the marginal prices over the same time period is calculated in equation (15).

$$TC_i = EFC_i + FSC_i + OMC_i \tag{14}$$

$$I_i = \sum_{t=1}^{24} price_{marginal} \cdot p_i(lp, h) \tag{15}$$

The unrecovered costs for each unit are calculated in equation (16). If the value is positive, unrecovered costs will be compensated directly to the individual generation units on a daily basis through side payments. No payments will be made if the units already receive enough income to cover their costs.

$$SP_i = TC_i - I_i \tag{16}$$

Unlike generators, all the load serving entities in a discriminatory auction market will pay the same price on an hourly basis. The single price is determined by adding together the marginal cost component and side payment component. The side payment component is determined by calculating the total side payments paid to all generators on a daily basis and dividing it evenly across the total load produced for the day, in units of \$/MWh. This value will augment the marginal price determined above to set the market prices for load serving entities to purchase electricity in the wholesale market. In equation (17), the determination of the additional price component paid by load serving entities is shown:

$$Price_{SP} = \frac{\sum_{i=1}^{I} SP_i}{\sum_{t=1}^{24} load} = \$ / MWh \tag{17}$$

Non-discriminatory pricing mechanism

In the non-discriminatory pricing scheme, no side-payments exist so that hourly market prices must, at a minimum, provide full cost recovery of all production costs to each generation unit. This is the approach that has been implemented in Ireland. The Irish market operator, on the basis of complex bids (start-up costs, no-load costs, etc.), first calculates the unit commitment that minimizes the cost of dispatch. Then, since these prices do not guarantee total cost recovery for all the units in the system, an ex-post linear optimization is used to obtain the uplifts to be added on top of the previously calculated prices to correct the result. This second optimization aims to provide full operating cost recovery while at the same time ensuring payments are minimized.

The non-discriminatory IRE pricing mechanism in LEEMA computes the hourly bids of the marginal generator, which will set the market prices for all generators in that hour, based on the following set of bidding rules:

1. In the hours in which the unit is marginal, the objective of the unit is to set a price that ensures the recovery of all its operation costs. This price has to be computed taking into account all daily production costs (TC_i) and the income received in the hours in which the unit is a price-taker (I_i). There are two type of hours in which the unit is price-taker.

    a. Hours in which the unit produces at the minimum technical output. Prices will in this case be the marginal cost prices determined previously.

    b. Hours in which the unit produces above the minimum technical output and the marginal unit corresponds to a unit loaded at a higher loading point. In this case, the unit will compute the period income taking into account the prices bid by the marginal unit.

2. Once the income received in these previous price-taker periods is determined, the left-to-be-recovered costs are spread uniformly along the hours in which that plant is marginal (H_i) to set the bids (B_i) for those hours, as shown in equation (18):

$$B_i = \frac{TC_i - I_i}{H_i} \tag{18}$$

The algorithm takes into account these criteria on a daily basis, starting at the generating units located at the highest loading point and then moving downwards until all hourly prices have been fixed.

3 HYDRO DISPATCH MODULE

As noted, large scale penetration of VER requires flexible operation from other generation technologies to maintain power system reliability and efficiency. In systems today where there is both hydroelectric generation and VER, the hydro generation plays a key role in providing that flexibility (IEA 2011a). The physical and economic characteristics of hydro generation plants make them both uniquely capable of responding to changes in output from VER and difficult to optimally dispatch.

The following section describes the introduction of hydroelectric generation into the LEEMA model in the following way. First, a summary of hydro generation characteristics and modeling challenges for economic dispatch will be reviewed. Next, the approach taken for bringing hydro dispatch into the context of the larger LEEMA model will be explained followed by a detailed description of the method used to dispatch hydroelectric generation in LEEMA. Finally, the hydro dispatch and its impacts on the dispatch of thermal generation and market prices will be demonstrated.

3.1 INTRODUCTION TO HYDRO SYSTEMS

Hydro plants characterization

The source of energy used in hydroelectric generation stations is water, with its potential for generating electricity expressed in terms of flow rate and reservoir height, or "head". A key advantage of hydro generation, in addition to the low cost of the fuel and lack of pollution, is its operational flexibility, making hydro generation highly suitable for adjusting production to the needs of the system[20]. Nonetheless, hydroelectric plants are capital intensive installations that normally require flooding vast areas to ensure a steady supply of water and are typically operationally contingent upon the highly random occurrence of rainfall in the area where they are sited.

The countries with the largest hydroelectric generation, e.g. Norway and Brazil, produce the majority of their power from hydro resources at 96% and 84%, respectively (IEA 2011b). Hydro facilities in these countries rely on significant reservoir storage to respond to the fluctuations of intermittent generation. Other countries produce hydro power at a scale that is roughly equivalent to thermal generation, such as Spain and Romania which produce 18% and 28% (EURELECTRIC 2011) of their power from hydro.

The Spanish and Romanian systems differ however in their reservoir capacity to manage hydro resources throughout the year. Spain has significant reservoir capacity, enhancing the ability of hydropower to provide flexibility to the system. The hydro in Romania, while significant in scale, is

[20] As we will explain later, not all the hydroelectric stations can be used as regulating stations. Here, we refer to those with storage capacity.

largely generated by continuously operating run-of-the-river (RoR) generation capacity that cannot be stored at sufficient volumes to provide the flexibility associated with dispatchable generation.

The United States, which is made up of many relatively independent power systems, produces 7.1% (IEA 2011b) of its power overall from hydro resources with state-level hydro electricity generation ranging from 66% of generation in Washington to very little or no generation in several states (EIA 2012b).

The planning and operation of the hydro resources is highly dependent on the scale of its resource relative to the system load. In systems, such as Norway, where hydro generation provides close to all of its electricity, the focus of operating the hydro resources is on matching generation with the daily, weekly, and annual changes in demand within the hydraulic constraints of the generation plants. Systems where hydro generation provides most of the generation capacity, such as Brazil or Washington, attempt to manage water resources across several seasons, or even years, to minimize the cost of thermal production, which covers the remaining load. In other systems, where the hydro generation is roughly equivalent to thermal generation, such as in Spain, the hydro resources will be co-optimized with thermal plants to minimize thermal generation production costs.

Regardless of the capacity of the hydro generation resources, hydro generation plants and systems present challenges to the economic dispatch of any power system. The challenges center on the physical constraints of hydro plant operations and the economics of operating hydro plants to maximize the value of the water resources. These constraints on hydro systems are dynamic, nonlinear and large in scale, including limitations on both the reservoirs, such as flood control capacity, evaporation rates, and acceptable levels for recreation purposes, and on the flows, such as downstream water quality, river navigability and interstate agreements (Labadie 2004). In addition, there are constraints caused by the coordination between connected hydro systems as well as the physical constraints of the water turbine generators themselves, which vary widely based on the shape of the reservoir and the changes in efficiency associated with the hydraulic head[21] of the reservoir. The objective function of any single hydro generation facility or system will depend on many of these additional factors beyond maximizing the value of its electricity production potential and will require weighing the value of different options over long time scales. As noted repeatedly by Wood and Wollenberg (1996), "no two hydro generation facilities are the same."

As previously noted, hydro generation plants are capable of responding to changes in output from VER, which is non-dispatchable, unpredictable and intermittent. However, not all the systems with a large

[21] The hydraulic head of a generation plant is the pressure of the water as it enters the water turbine which is defined by the height of the surface of the reservoir upstream of the dam.

hydro capacity installed are equally flexible. The grade of flexibility in the hydro generation depends on the relationship between its dispatchable and non-dispatchable capacity.

There are generally three types of hydroelectric generation stations:

- Conventional hydroelectric stations have storage capacity that allows the generation capacity to be dispatched during periods when the water is most valued. The long-term as well as the short-term operation decisions of the plant are strongly conditioned by the size of the reservoir. These plants can regulate their production from zero to maximum capacity in very short timeframes with their maximum capacity a function of the reservoir level. These hydro plants are the most common.

- Run-of-the-river (RoR) plants have no storage capacity and consequently have to use their water resources as they become available. For this reason, they cannot be used as regulating stations but instead can be expected to operate more like a baseload power plant.

- Pumping power stations have a raised reservoir to which they can pump water uphill when electric power is cheaper, and then release it downhill to generate electricity when it is cost-effective to do so. Pumped storage can be regarded as an efficient means of storing energy, with roundtrip efficiency of approximately 70%.

The hydro dispatch in the model described here will consider hydro plants with characteristics of both conventional and RoR plants.

Planning and operation modeling

Due to the physical characteristics of water and hydro generation plants, the management and operation of water reservoirs is complex and is typically divided into several sub-problems.

Operation planning

In the long-term, planning for hydro generation plants must consider both the limited and cost-free nature of the water in the reservoir. For this reason, hydroelectric plants commonly are categorized as "limited energy plants". Even though the water is cost-free, the opportunity costs of hydro generation are determined by the future value the generation could provide to the system by displacing costly thermal production at a later time. Therefore, its use must be scheduled in the most beneficial manner based on projections of future system conditions. In this model, hydro generation plants is dispatched in a centrally planned context where the maximum value of the hydro resources is in the ability to replace the most costly thermal production.

Determining the optimal schedule for dispatching water stored in reservoirs is a key decision made by generation managers. Depending on the size and generation characteristics of the reservoir, such decisions may cover timeframes ranging anywhere from a single day to several weeks, months or even years for the largest reservoirs. Since the logical aim of such planning is replacing the most expensive thermal production with dispatchable hydro, this type of planning is usually termed hydro-thermal coordination. Therefore, while the water is available "free of charge", the limited and storable nature of dispatchable hydro has a significant opportunity cost.

Run-of-the-river stations require no planning as the plants are restricted by constraints previously mentioned. These plants act similar to baseload generation, generating a fairly steady and continuous amount of electricity.

Modeling tools for hydro planning

In medium and long term planning of hydro resources, uncertainty plays a crucial role. Besides the stochastic nature of water inflows, market participants in deregulated systems also face price uncertainty. The widespread methodology to solve the optimal hydrothermal coordination problem is through stochastic programming models (Wallace & Fleten, 2003). Independent of the technique used, the output from these models will provide data to inform the short-term dispatch of the hydro resources, which normally includes the water values curves (describing the marginal value of water in the reservoir) and either the final level of the reservoir or the energy available to produce in each period. The length of the periods considered in these models will depend on the system and the hydro generation plant which is being planned.

Unit commitment and economic dispatch

Short-term decision-making typically refers to a weekly time horizon at most and involves determining the production plan for hydroelectric power stations on an hourly basis for each day within its physical constraints. The optimal scheduling of hydroelectric production takes a number of considerations into account: higher-level decisions on the amount of water resources to be used in the day or week, the most cost-effective hourly distribution (weekly or monthly hydro-thermal coordination), system reserve capacity requirements, and technical constraints on steam plant units.

Hydroelectric generation and its use of water in reservoirs must likewise comply with restrictions imposed by water management for other purposes, including irrigation, the needs of fauna, and minimum reservoir and river flow levels, as well as other conditioning factors typical of water works and their configuration: canals, pipelines, reservoir limits and reservoirs operated in tandem. At this level, system details are extremely important, with all aspects of the wider power system considered, such as steam plant generating unit start-up and shut-down processes and costs, wind and solar forecasts, hydrological constraints in river basins, stations in tandem arrangement, demand chronology profiles (which call for accurate production monitoring) and generating capacity to be held in reserve to respond immediately to fortuitous equipment failure.

Usually weekly planning is considered a multi-stage problem involving mixed-integer decisions and subject to uncertainty (inflows and market prices). One approach for solving such problem is the stochastic Lagrangian relaxation of coupling constraints (Redondo and Conejo 1999).

Reserve and regulation markets

In addition to the ability to economically dispatch hydro resources to meet the total system load, hydro plants also are capable of providing fast response times to variable and uncertain generation from renewables. Hydroelectric stations are much more flexible than thermal power plants with practically zero lead time, no significant start-up costs and few real limits on modulating generating capacity.

Although these characteristics of hydro generation are significant for dispatch in the reserve and regulation markets, these characteristics of hydro generation in the very-short term are outside the scope of our model.

3.2 HYDRO MANAGEMENT IN LEEMA

As mentioned, the problem of planning and operation of hydro reservoirs is usually decomposed into smaller problems. The LEEMA model addresses these problems at two levels:

- First, the quantity of available hydroelectric energy in each period (either weeks or months) is determined. In our case, these values are obtained from a higher decision level model and entered as input data. In the case example we provide in this paper, we take the actual values of the energy produced per month in the Spanish system in a year considered to be average[22].
- Second, a stylized heuristic optimization of the hydrothermal unit commitment is completed for each period. The objective is to minimize the supply cost of satisfying the net load demand (demand after subtracting the wind) with the hydro and thermal plants in the system. We aim at replicating the optimal economic dispatch that would result from the implementation of a mixed integer programming unit commitment optimization while at the same time solving the problem considering hourly granularity in reduced computation times.

[22] In the case example we have used the data corresponding to 2009 (in 2010 hydro production in Spain was high, significantly different from the average).

Next, we describe the way each of the hydro units in the system are characterized in the model, and then we describe the algorithm implemented to represent the hydrothermal weekly unit commitment.

Characterization of hydro generation

In this section, the characterization of the hydro units in the LEEMA model is explained based on the following two assumptions:

- First, a group of hydro plants set in the same river basin and operated by the same firm are synthesized into a unique plant[23]. We will refer to these composite representations as hydro plants.
- Second, the constraints for each hydro generation plant considered within LEEMA have been reduced to the total water (energy) available in each period, the maximum generation capacity and the minimum continuous RoR generation requirements. Figure 3-1 illustrates the capacity constraints.

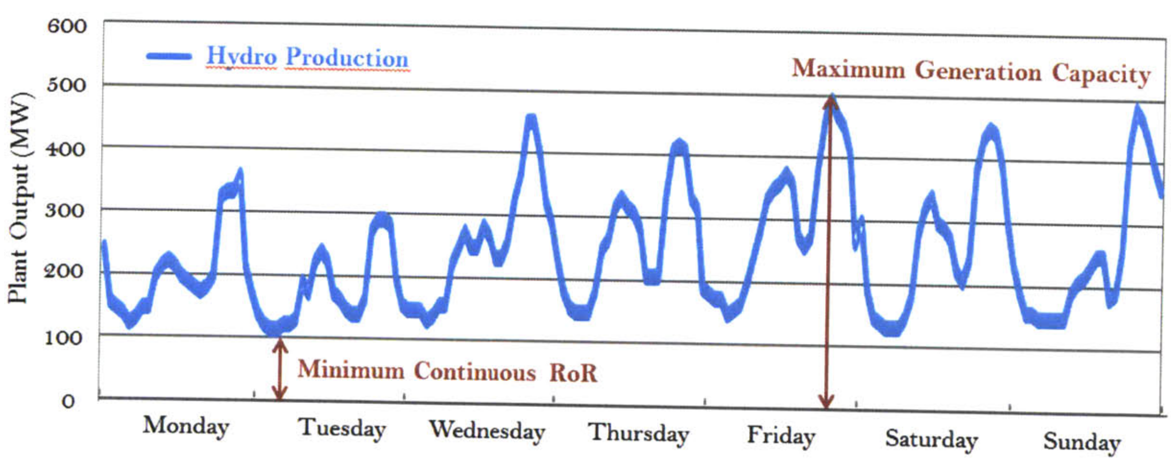


Figure 3-1 – Hydro generation capacity constraints

While the operating constraints of the thermal plants can be considered to be constant throughout the time scope of analysis, the three parameters that define the generation capabilities of each hydro plant are greatly time-dependent. In the model, the maximum and the minimum capacities are calculated as a function of the energy to be produced in each period. The rationale for this relationship between capacity and energy produced is based on actual generation data gathered in Spain. For one particular hydro plant shown, in Figure 3-2, the relationship between the maximum capacity, the minimum capacity and the energy produced per week is demonstrated.

[23] Indeed, in the case example we consider the hydro plants aggregations considered in the Spanish day-ahead market.

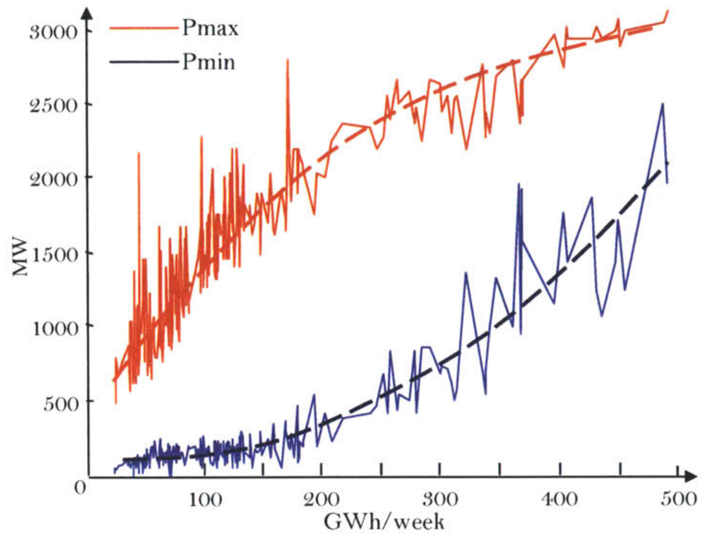


Figure 3-2 – Hydro plant capacity constraints as a function of energy availability

As previously explained, we use a higher decision level model to determine the hydroelectric energy to be produced in each period. Using this information and a regression model that takes into account the abovementioned relationship, the maximum and minimum output of each one of the hydro plants in each period considered can be calculated.

Hydrothermal economic dispatch

Since the LEEMA model aims to properly characterize the impact that intermittency can have on the overall system economic dispatch, the hydro dispatch algorithm has been designed to be able to cope with the granularity at the hour-by-hour chronological level while allowing a sound representation of maximum capacity and energy availability constraints of the hydro plants in the system. A stylized optimization algorithm of hydrothermal economic dispatch in LEEMA has been developed to chronologically dispatch a known quantity of water with the goal of minimizing the total cost of thermal production.

Generally, the algorithm can be summarized by two broad stages. First, the unit commitment is solved considering just the thermal generation portfolio, as described in the previous chapter. This first run provides the information of the cost of scheduling each of the thermal units in the system which we then use in the second stage as an input to allocate the water in an optimal way while respecting the hydro plants operational constraints previously mentioned.

In more detail, this co-optimization of the hydro and thermal generation within LEEMA, as shown in Figure 3-3, occurs in four sequential steps:

- Step 1 – Run-of-River Hydro: The RoR hydro generation is deducted from the net load profile. Similar to wind generation, the RoR generation is treated as a negative load and is subtracted from the total load required to be covered by the thermal generation resources on an hourly basis.

- Step 2 – Initial Thermal Dispatch: The thermal sections of the LEEMA model is used to generate production and cost profiles for thermal generation to meet the net load, assuming no hydro generation in the system. As earlier described, the Thermal Scheduling optimization module first calculates the production profiles of each loading point, and then the Economic Dispatch module computes the particular generating units operating at each loading point and provides the related cost of those schedules.

- Step 3 – Hydro Dispatch: From this information and taking into account the characteristics of the hydro plants defined for each period (energy, maximum output and minimum output), the hydro plants are dispatched on an hourly basis utilizing the detailed chronological data acquired from the previous step with the objective of minimizing the cost of the fully thermal unit commitment. As will be shown later, the hydro resources are used to replace the most costly thermal production in the period being analysed. The result of the Hydro Dispatch module is a cumulative hourly hydro operation profile of all hydro plants modelled which is used to modify the net load profile.

- Step 4 – Final Thermal Dispatch: The thermal optimization model is run again taking into account the net load profile obtained in the third step (i.e. demand net wind and hydro generation). In this case, the scheduling and economic modules of the LEEMA model are used to determine the final thermal production profiles and the wholesale electricity market prices.

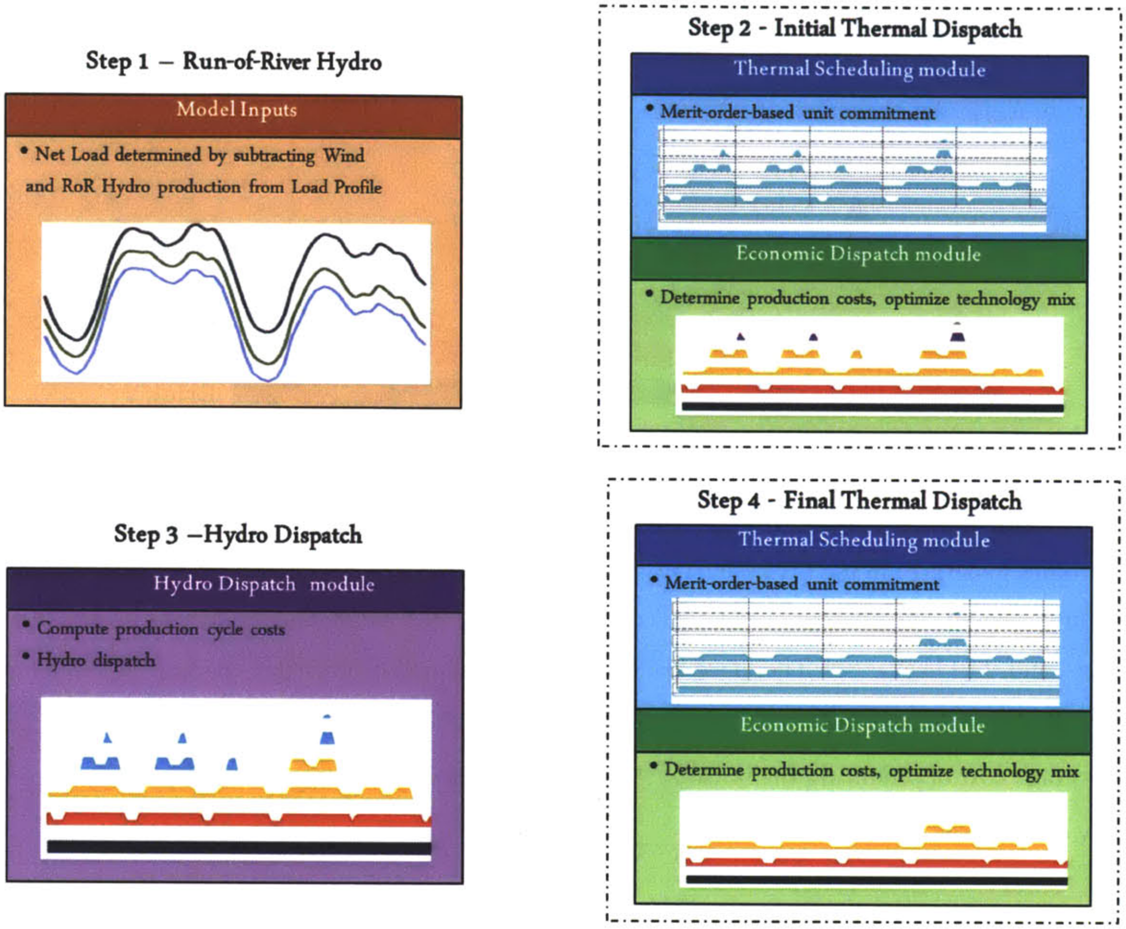


Figure 3-3 - The position of the hydro dispatch module in LEEMA

3.3 HYDRO DISPATCH ALGORITHM

As previously mentioned, the RoR hydro generation cannot be optimized and is instead dispatched during the initial calculation of the net load in Step 1. How the LEEMA model optimizes the dispatchable portion of hydro generation in Step 3 is discussed in this section.

The optimal dispatch of hydro generation in LEEMA is completed by identifying the highest cost blocks of generation and replacing the thermal production in those periods with zero-cost hydro generation within the capacity constraints of the plants.

The thermal production blocks, which we will denote as "bricks", are determined from the production profiles generated in the Thermal Scheduling module. Each of these production blocks from startup to shutdown is handled as a separate brick that could potentially be replaced by hydro generation. The productions profiles are analyzed to identify for each brick the hour of startup, $h_{su,b}$, and the hour of shutdown, $h_{sd,b}$. An example is shown in Figure 3-4, where seven bricks are identified.

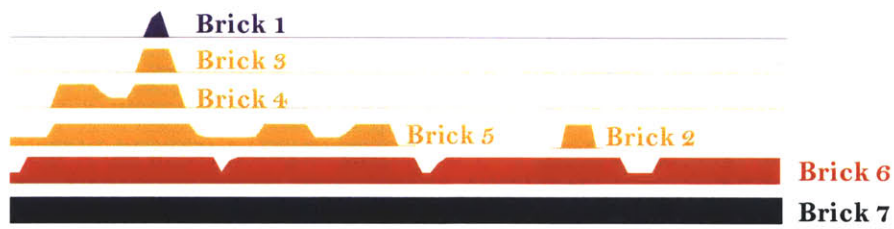


Figure 3-4 - Example production profiles with seven "bricks"

Once the bricks have been identified, the average cost of production of each brick is calculated from the cost profiles generated in the Economic Dispatch module. In the calculation of the total cost, we have taken into account the different production cost components, such as the fuel production costs, the start-up costs, and the O&M costs. Therefore, the total cost of the brick b located in the loading point lp and produced by the technology τ is the sum of each one of the production costs for the brick analyzed. The average cost of producing the brick b, AC_b, is determined by dividing the total costs by the energy of the brick:

$$AC_b = \frac{EFC_{\tau,b} + SFC_{\tau,b} + OMC_{\tau,b}}{\sum_{h=h_{su,b}}^{h_{sd,b}} p(lp,h)} \tag{19}$$

Where

$p(lp,h)$ is the production that corresponds to the loading point lp in hour h

$EFC_{\tau,b}$ is the energy fuel cost for the brick b

$SFC_{\tau,b}$ is the startup fuel cost for the brick b located in the loading point lp.

$OMC_{\tau,b}$ is the operation & maintenance cost corresponding to the brick b of technology τ, operating at loading point lp

Next we analyze in detail the formulation of each component of the production costs in terms of the model variables.

Energy fuel costs

The energy fuel costs depend on the level of production as there are efficiency losses in the hours when the generation unit operates at minimum load. The expression to calculate the energy fuel cost is:

$$EFC_{T,b} = \sum_{h=h_{su,b}}^{h_{sd,b}} efc_T(p(lp,h)) \cdot p(lp,h) \tag{20}$$

Where $h_{su,b}$ and $h_{sd,b}$ are the first and last hour of the brick b and efc_T (expressed in \$/MWh) is the energy production fuel cost which is a function of the level of production $p(lp,h)$ for each hour.

Start-up fuel costs

The fuel cost of each startup is a function of the number of hours the unit has been out of operation before starting up again (e.g. hot start for less than 10 hours, warm start for more than ten but less than 50 hours and cold start for more than 50 hours). The start-up fuel cost associated to the brick b is:

$$SFC_{T,b} = sfc_T(t_{off}(lp,n_b)) \tag{21}$$

$t_{off}(lp,n_b)$ represents the number of hours offline prior to proceeding with start number n_b in the loading point lp that defines the first hour of the brick b.

Variable operation and maintenance costs

The variable O&M costs have been shown to depend on the plant operation at each loading point and can be represented by the two terms, $fhomc$ and $suomc$. The constant per-firing-hour component $fhomc$ is determined by the threshold of firing hours for triggering a major maintenance and the cost involved in the major maintenance cycle, $OMCC$. The operation-dependent startup component $suomc$ serves to impute all costs the previous component fails to allocate.

With these values previously determined, the computation of the variable operation and maintenance cost associated to the brick b is:

$$OMC_{T,b} = fhomc \cdot FH(lp,ns) + suomc \tag{22}$$

Once the average cost of all bricks has been evaluated, they are sorted by their average cost of production in decreasing order so that the most costly generation bricks can be replaced first. Using the same example from above, the results of the four highest cost bricks are shown in Table 3-1.

Brick	Firing hours	Energy [MWh]	Costs [$]	Average cost [$/MWh]
1	2	200	18000	90.00
2	3	300	22500	75.00
3	4	400	24500	58.75
4	12	1020	65250	53.75

Table 3-1 - Calculation of brick costs and merit order

To demonstrate how hydro plants are dispatched, we consider one hydro generation plant with a limited quantity of water to be used for generation in the time period shown in Figure 3-4. To simplify, only the energy constraint is considered in this example to illustrate the methodology used to replace the most costly thermal generation bricks with hydro generation. The thermal generation bricks were enumerated from the most expensive (Brick 1) to the cheapest (Brick 7).

In this simple case, if only enough water is available to replace the first three bricks (and the maximum and minimum output are not taken into account), the most costly bricks are identified and replaced by hydro generation, as shown in Figure 3-5 below.

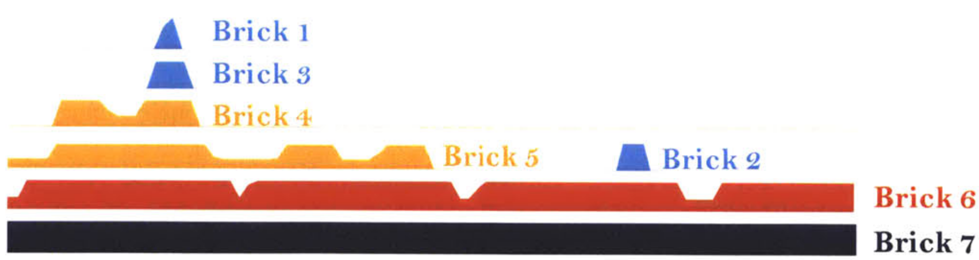


Figure 3-5 – Example of how brick shaving targets the most costly bricks

Operational constraints

The limitations on hydro generation by the water availability and the maximum and minimum output constraints will now be added to the hydro dispatch algorithm.

As previously described, the most expensive bricks are replaced first by the hydro production. Before replacing a brick, we must determine if there is enough water (energy) to replace the whole brick and if the capacity constraint has been reached in any of the hours of operation for the brick. The hydro dispatch algorithm has been designed as follows:

- If there is enough water available and the capacity constraint is not reached, the whole brick is removed.
- If there is not enough water to remove the whole brick, the water will be distributed evenly across the brick to reduce its energy and the brick will remain available for the next hydro plant to displace the remaining energy. The dispatch of hydro in the case when there is limited water availability is shown in Figure 3-6.

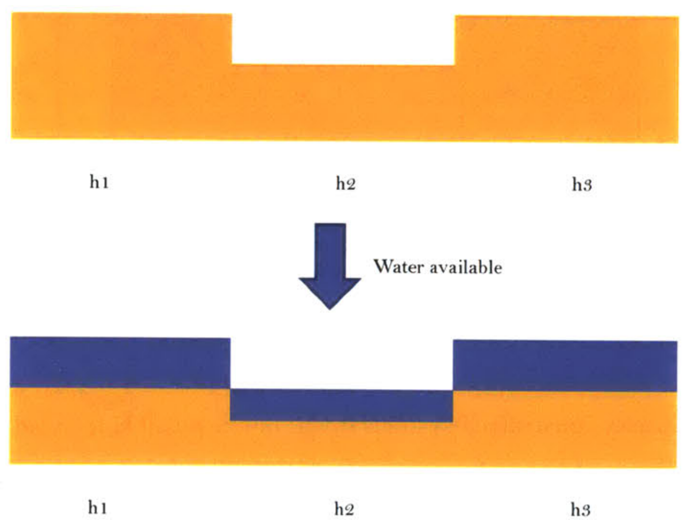


Figure 3-6 - Hydro dispatch when there is limited water availability

- In the case where a capacity constraint is reached, the hydro capacity in the constrained hour will be dispatched up to its limitation. In the unconstrained hours, the full capacity will still be dispatched as before to remove those sections of the brick. Figure 3-7 demonstrates the dispatch of a hydro plant for removing Bricks 1 and 2. Brick 1 is fully removed as it is within the maximum capacity output. For Brick 2, there is limited capacity remaining for hour 2 but full capacity for hours 1 and 3. In this case, the hydro plant is dispatched up to its limitation in hour 2 and for the whole capacity of the brick in hours 1 and 3.

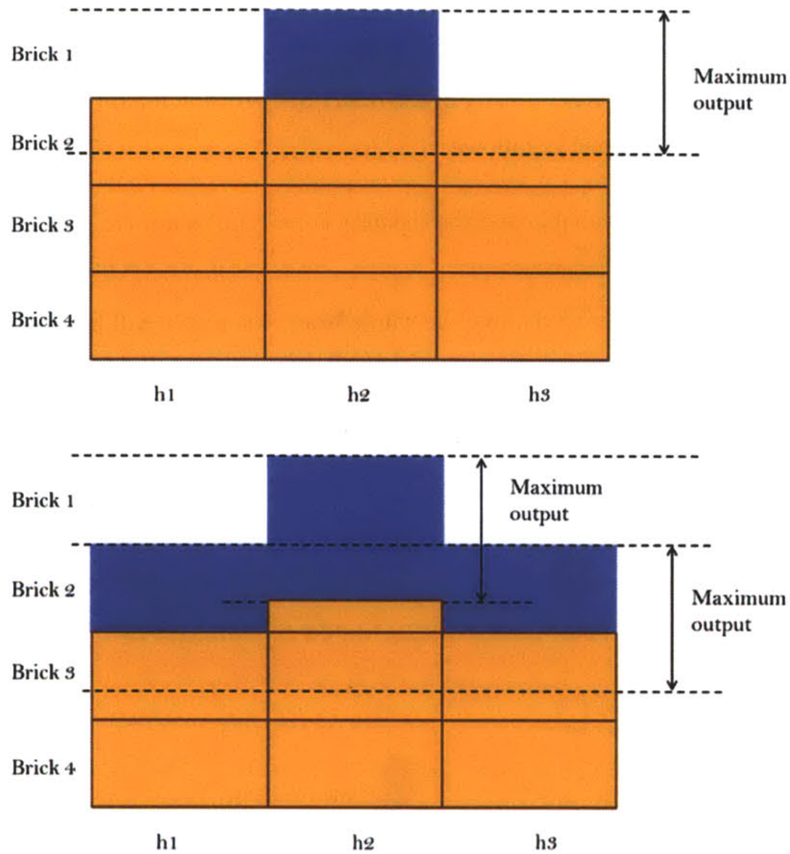


Figure 3-7 - Hydro dispatch when a capacity constraint is reached

For this reason, in capacity constrained systems it will not be possible to avoid all short term peaks. The result will be minimization of thermal production costs but not necessarily electricity prices in every hour, as will be later demonstrated.

Figure 3-8 shows that the dispatch of the hydro capacity tends to fully eliminate the most expensive bricks which are usually those bricks in the peaks. However, in some hours the maximum output limit is reached. In these cases, the full bricks will not be able to be removed.

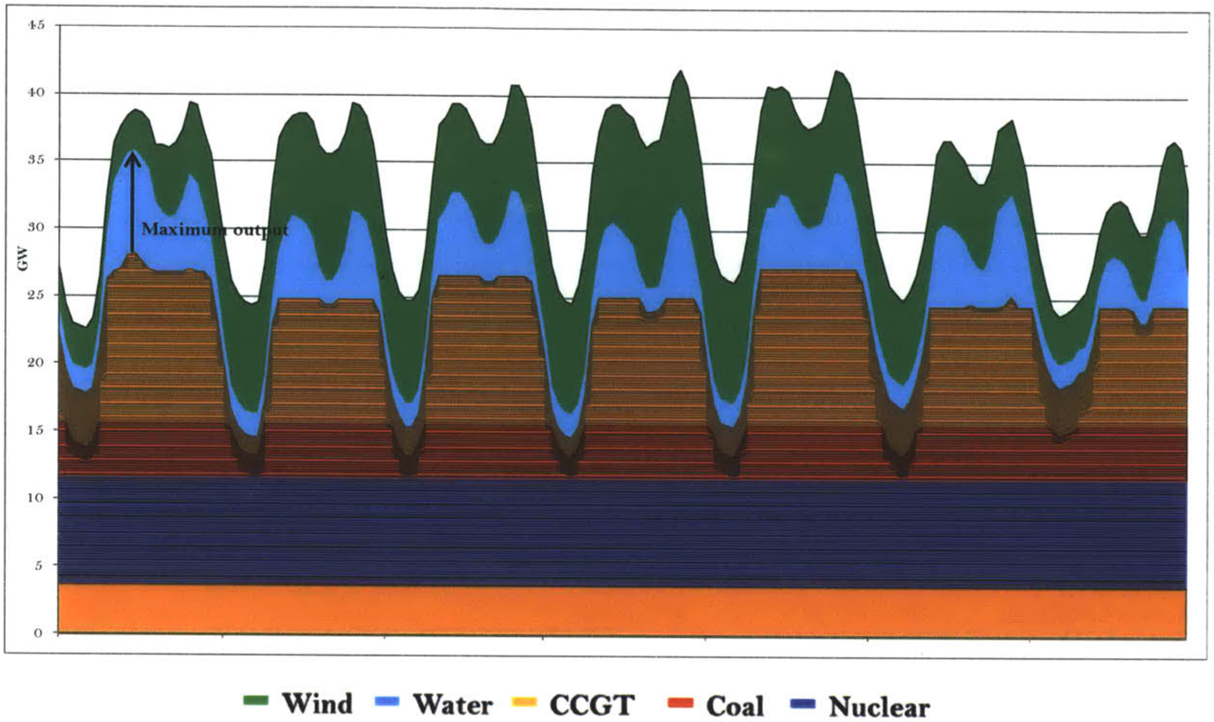


Figure 3-8 - Dispatch of hydro generation with capacity constraints and thermal generation plants.

Valley hours

The hydro dispatch algorithm makes an important consideration for the portions of bricks that operate at less than 100% of capacity. Thermal plants produce at less than 100% during short term dips in load ("valley hours") to maintain operation, as previously discussed. If hydro plants were dispatched during these hours, they would increase the depth of the valley and make it more, not less, difficult for operating thermal plants to avoid additional costly startups. For this reason, the algorithm limits hydro generation during valley hours.

Figure 3-9 – Avoiding hydro production in valley hours

To demonstrate this concept, take the example of the short time period shown in Figure 3-9. It can be seen on the left side that there are hours between the two load peaks when Brick 3 and Brick 4 are reduced to minimum load to avoid an additional startup. Although there may be enough hydro resources to completely replace the top three bricks, the algorithm will avoid doing so to limit hydro production in valley hours. Instead, only the portion of Brick 3 operating at 100% will be replaced by hydro production as can be seen on the right where Brick 3 has now been split into two hydro dispatch periods (Brick 3' and 4'). The remaining production of Brick 3 in the valley hours is transferred to the brick at a lower loading point, instead of being replaced by hydro. This can be seen in the difference between Brick 4 and Brick 5'. During the valley hours, the algorithm checks whether there is available capacity at a lower loading point to take on this generation instead of replacing it with water.

In this way, hydro generation in the valleys hours is avoided by distributing the thermal generation to a generation plant at a lower loading point that has available capacity to increase production. If the brick operating in the valley has no alternative thermal unit below it with capacity available to take on the production, the hydro is dispatched as it would have been originally. The transfer of energy to lower loading points preserves the limited hydro energy capacity for reducing total system costs at the next most costly brick.

Dispatch of hydro generation plants

The hydro plants used in this model are described based on their maximum capacity, minimum capacity and energy availability in Appendix A. The plants are ranked in decreasing order for dispatch according to the total number of hours that they can produce at full capacity. This is done so that the most flexible hydro plants can be dispatched first to remove the bricks with the highest average cost of production, which tend to be the bricks at the top of the daily peaks in net load. Later bricks that operate over longer hours will be displaced by similarly operating hydro plants. The plants are dispatched in this way, separately and sequentially, with capacity and energy constraints respected for each plant starting with the most expensive brick remaining.

The result of the brick shaving hydro dispatch is that the highest cost thermal production bricks are replaced by hydro production regardless of where they lie in the load profile. Once a hydro plant has consumed all of the water available, the production of that plant is added to a single hydro production profile. The total hydro production profile is then subtracted off the previous net load profile, which defines the level of generation that must be met by thermal generators in each hour.

3.4 DEMONSTRATION OF HYDRO DISPATCH

The results of the stylized optimization algorithm for hydrothermal economic dispatch described here will be demonstrated with two cases that will emphasize the merits of the algorithm and show how hydro generation impacts the system production costs and resulting market prices.

First, we will demonstrate the algorithm through a staged introduction of water available to the hydro plants that isolates the RoR dispatch, the energy limited dispatch, and the capacity constrained dispatch.

Second, the results obtained from dispatching the hydro capacity by the "brick shaving" algorithm will be compared to the results if a simple peak shaving algorithm had been used instead.

For demonstration purposes, the current Spanish power system which has a peak load of 44 GW is modeled. The full details of the test case can be found in Appendix B.

Hydro dispatch with increasing water availability

The utilization of hydro generation plants is largely dependent on the balance in the system between the storage capacity, the generation capacity, and the water availability. The system storage capacity determines the flexibility to dispatch hydro when it is most beneficial. When storage capacity is limited, hydro plants must operate continuously as RoR hydro plants do, such as in Romania which was noted earlier to be an example of a system that is largely constrained to RoR production. At the other extreme are systems that are "energy limited" since they have sufficiently large storage reservoirs and generation capacity to dispatch the water whenever it is determined to be optimal, such as in the Brazilian system. These systems will provide maximum flexibility to the hydrothermal economic dispatch. In other systems that are "capacity constrained", the capacity available in any hour may be limited by geography or flow constraints and decrease the ability to optimally utilize the water resources, as it is in the Spanish system shown here.

The hydro dispatch algorithm is demonstrated by implementing the water resources in stages, shown in Figure 3-10, based on the three types of hydro dispatch — RoR dispatch, energy limited dispatch, and capacity constrained dispatch – by adding increasing amounts of water available to the hydro plants in the system. These three stages of water availability show the impact that the relationship between the energy available, which varies greatly from year to year, and the maximum output of the hydro plants, which is fairly consistent, can have on the net load, the costs of the system, and the market prices.

In these cases, the wind production remains constant and the water in the reservoir increases in each stage. Figure 3-10 shows the hydro-thermal dispatch in each one of the following stages:

- In the first stage, solely RoR hydro has been added. The resulting dispatch of hydro can be seen to be operating at a constant rate throughout the week. The introduction of run-of-river hydro tends not alter the thermal plants scheduling.
- In the second stage, dispatchable energy has been added but not enough to activate any capacity constraints, which is considered the "energy limited" case. Hydro production when not

constrained by capacity can be used most effectively to flatten the most costly peaks in the thermal load.

- In the third stage, the energy available now exceeds the capacity available during certain hours. In this "capacity constrained" case new peaks appear in the net load. This economic dispatch minimizes the thermal production costs, but could have a significant impact on the resulting market prices.

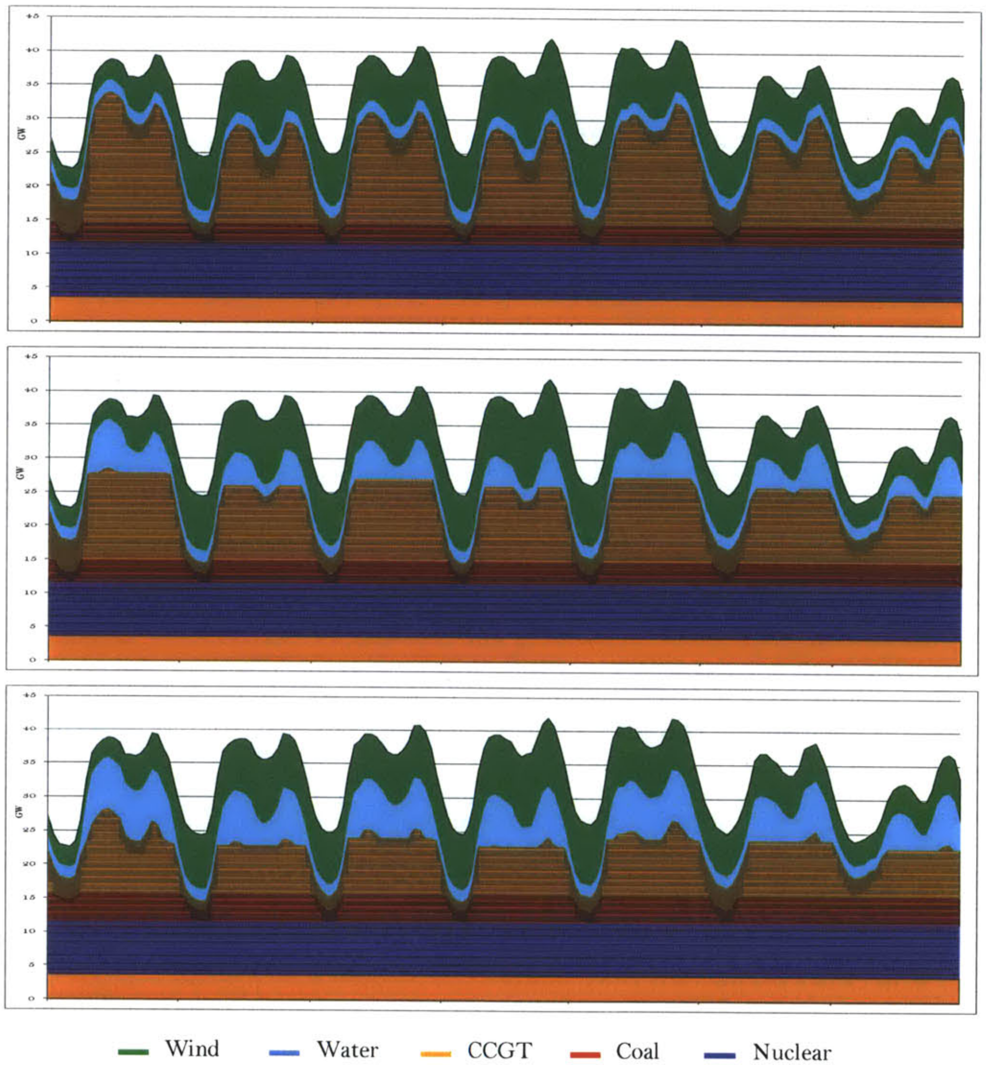


Figure 3-10 - The dispatch of hydro in LEEMA in three stages.

Once the hydro dispatch has been completed, the modified net load profile, which now takes the wind and hydro generation into consideration, is passed on to the previously described thermal dispatch modules for the final dispatch of the thermal generation and determination of wholesale electricity prices.

Next, based on these three cases we illustrate how the production costs and market prices change as the increased water availability leads to different outcomes.

As the goal of the hydro dispatch is to minimize the costs of thermal production, the most important result of the hydro dispatch algorithm developed here is the change in the the total cost of thermal production. Figure 3-11 shows the total costs for each day and each stage of water availability described above. It can be seen that the introduction of increasing amounts of hydro generation reduces total thermal production costs due to the reduction of the thermal generation and the cost-free nature of water.

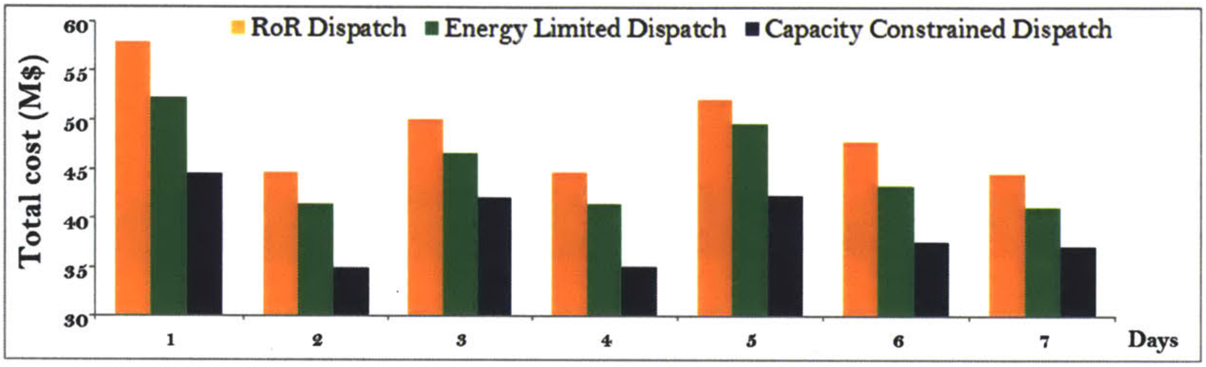


Figure 3-11 - Total costs of thermal production for the three stages of water availability

Figure 3-12 shows the hourly electricity prices that result from the three stages of dispatch for the hydro generation plants over the seven day period above. The pricing mechanism based on non-discriminatory pricing (IRE) was used for determining the electricity prices. The following results are observed from this staged implementation of hydro:

- The RoR dispatch has limited impact on the thermal scheduling of generation.
- The energy limited dispatch decreases the number of price spikes dramatically from the RoR dispatch . As seen above, the hydro production is used to flatten the peaks in the thermal load and the prices reflect this cheaper and less "peaky" thermal dispatch.
- The capacity constrained dispatch increases the price spikes. When the amount of water in the reservoir increases, the capacity constraint can be reached and new peaks can appear in the net load, which lead to price spikes.

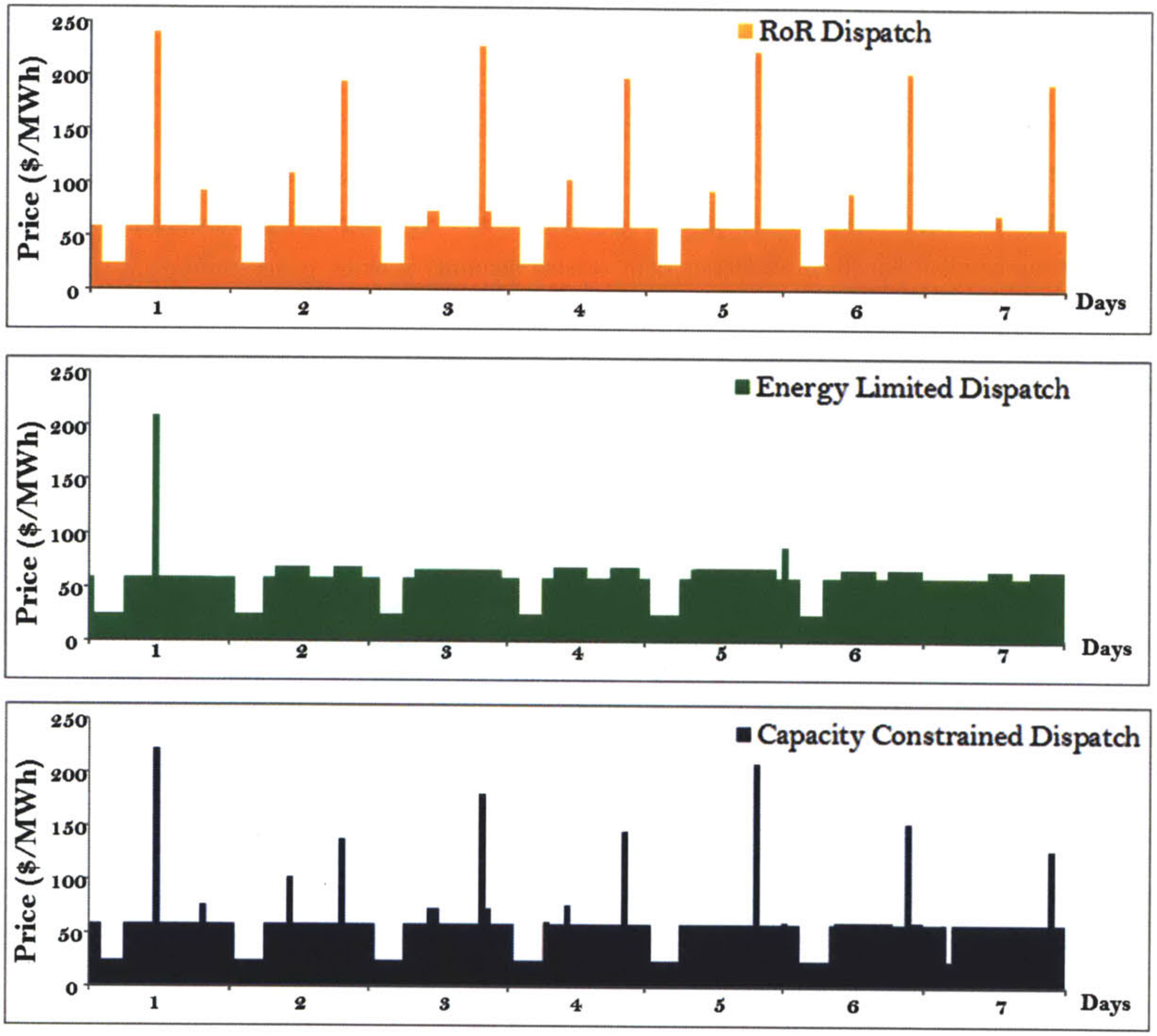


Figure 3-12 - Hourly electricity prices for three stages of water availability

The resulting load-weighted average price of electricity for each day and case are shown in Figure 3-13. It can be seen that the energy limited dispatch always reduces prices from the RoR dispatch, as would be expected from the results above. The additional dispatch of hydro energy in the capacity constrained case produces lower prices than the intial RoR dispatch across all cases but varying results relative to the energy limited dispatch.

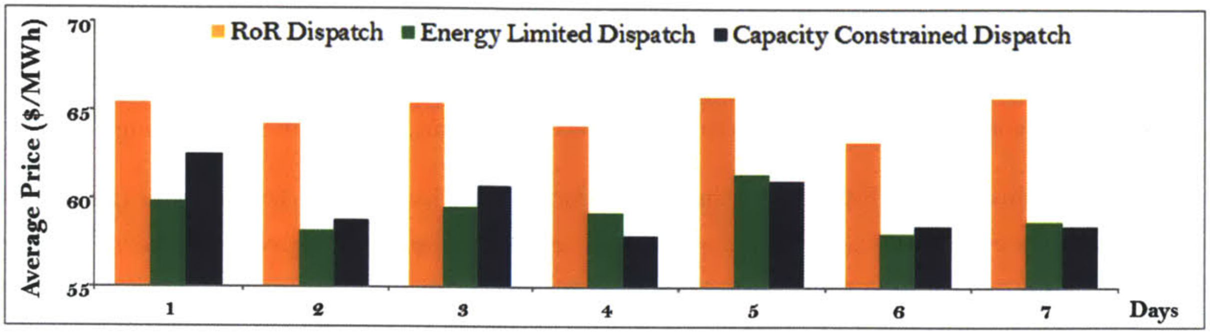


Figure 3-13 - Load weighted average electricity prices for three stages of water availability

The varying results of the capacity constrained dispatch are based on the tradeoff between two factors, which effect prices in different directions. First, the additional dispatch will change the marginal generator to a lower cost technology in some hours, such as CCGT to coal,. Second, additional non-linear payments may be necessary as startup costs will be spread over fewer hours, potentially increasing prices in some hours.

This can be seen in Day 2 of Figure 3-12 above by comparing the energy limited dispatch and the capacity constrained dispatch. In the energy limited case, prices rise twice to a moderately higher price for several hours. For the capacity constrained case, the prices remain consistent except for two hours when prices spike dramatically higher then return to lower prices. Whether the increased price in one hour is greater than the decreased prices in the other hours will determine whether prices are higher or lower for the day when the capacity constrained hydro is implemented.

Comparing brick shaving and peak shaving

When facing medium to long term analyses of hydrothermal electric power systems (for example when using a screening curves framework), the traditional rough heuristic-based method for dispatching a known quantity of hydro capacity is to operate hydro plants when the demand is at its highest points to avoid the use of relatively expensive peaking plants. This procedure, traditionally referred to as "peak shaving", is expected to result in a good approximation of the optimal economic dispatch, in such a way that supply costs are minimized. Peak shaving assumes that there is a direct correlation between demand levels and dispatch costs.

But this simplified methodology is becoming less valid for current hydrothermal systems. First, demand "peakiness" has been steadily growing due mainly to the increase of household consumption (industrial consumption tends always to be much flatter). Also, the addition of VER production also is expected to increase the peakiness of the net load to be supplied by thermal plants.

These two factors make it possible for supply costs and prices to be higher during the weekend than in a working day, even if the net load peak might be significantly higher in the latter. In this case, the right methodology to model the hydro scheduling should be "cost shaving" instead of "peak shaving".

This issue is illustrated in Figure 3-14 that shows the load, net load and market prices in the Spanish day-ahead market in a week in November 2010. The highest prices in a given time period do not necessarily occur during the hours with the highest (net) load. Electricity prices often are just as high during the weekend as during the weekdays, since in both cases, an additional plant is required to start to meet the peak. In Figure 3-14, the maximum loads and maximum prices do not necessarily align. Peak shaving would miss these high cost/high price hours at lower load levels and would not properly represent the economic dispatch, which is based on the marginal value of water, i.e. its opportunity costs.

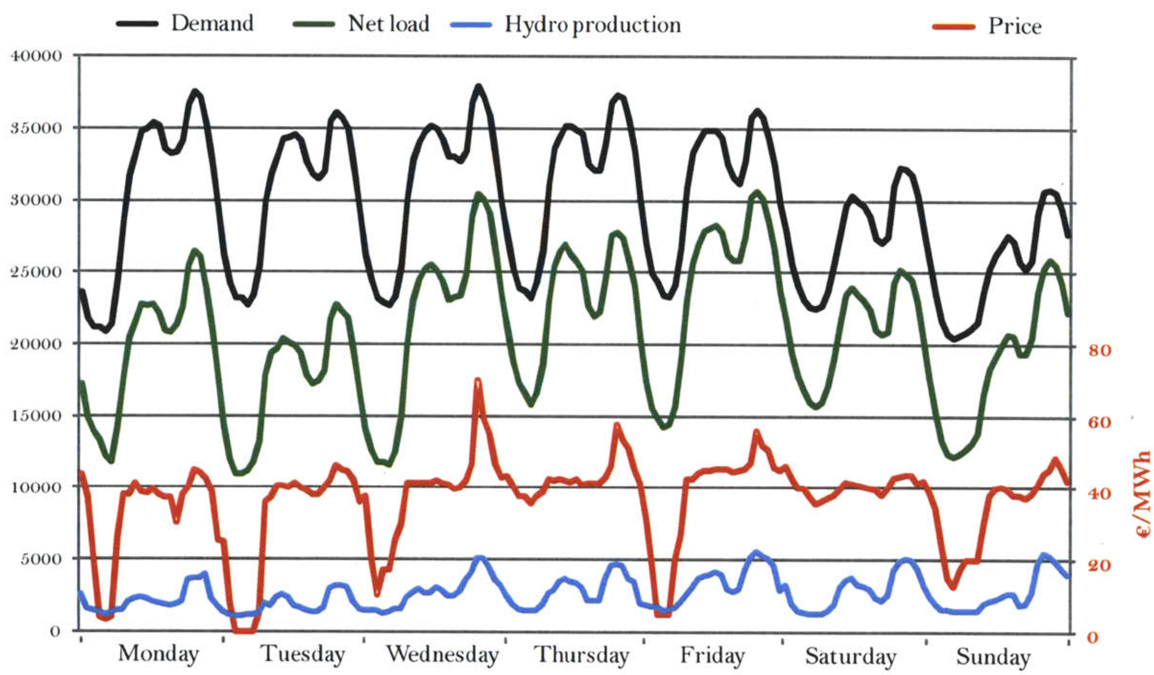


Figure 3-14 - Scheduling of the hydro resources in the Spanish case

This example demonstrates why we have not used the traditional "peak shaving" algorithm in our model and have opted instead for developing a new algorithm that replaces the most expensive thermal production with hydro generation.

The resulting dispatch of hydro and thermal resources is shown over a seven day period in Figure 3-15 for both the brick shaving (top) and the peak shaving (bottom) algorithms. The first five peaks in load in the figure represent week days and the last two peaks on the right are the weekend.

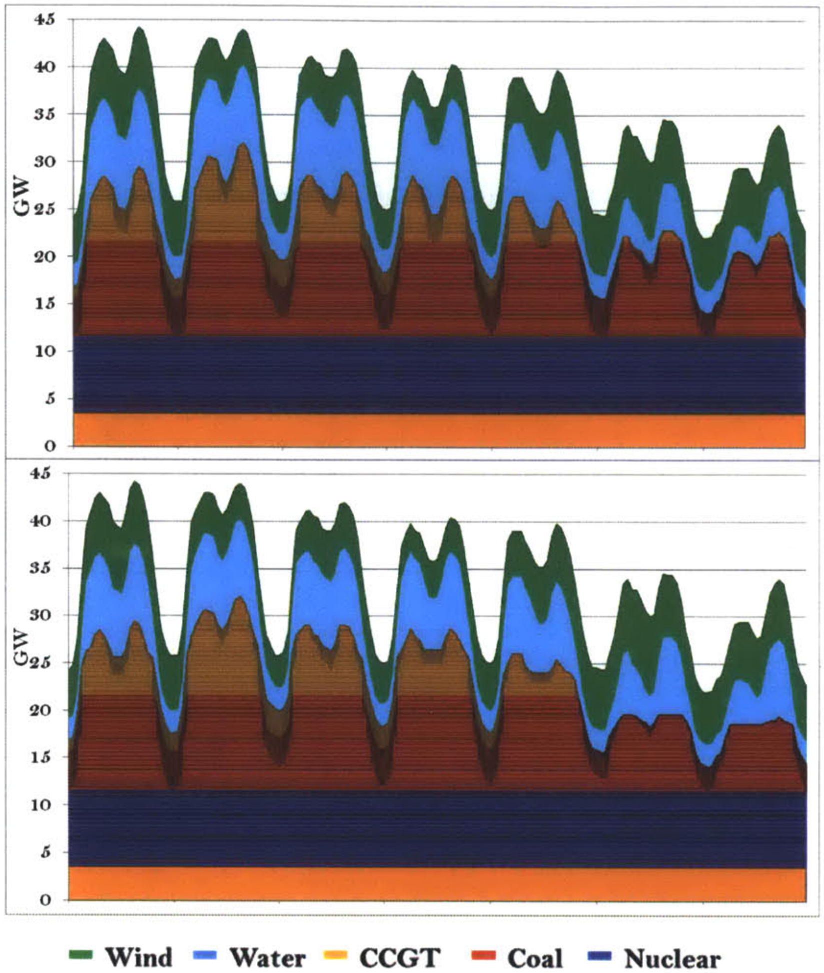


Figure 3-15 - Comparison of Peak Shaving (top) and Brick Shaving (bottom) hydro dispatch algorithms

The brick shaving method reduces the load during the highest cost production periods across the whole week. This can be seen, for example, during the weekend peak periods where the net load is substantially less than for brick shaving. Due to the activation of the capacity constraint, peak shaving will still dispatch the hydro on the weekends, as can be seen in the bottom part of the figure, but to a lesser extent than the brick shaving algorithm that seeks out the periods when the hydro generation can be most effective at reducing the total production costs of the thermal generation plants.

During the weekday peak periods, the two dispatch algorithms have similar dispatch schedules. The main difference between the algorithms for these days comes in the valley hours between the daily peaks in load. The impact of the brick shaving algorithm which avoids production in valley hours can be seen by comparing the dips in load between the peaks for the fourth and fifth days. In fact, during the dip in the fifth day it can be seen for peak shaving that coal plants at the top of their dispatch are forced to reduce load while for brick shaving only about half of the CCGT plants are required to do so. The impact of limiting the depth of the valley is seen in the ability of plants to operate across the valley and avoid an additional costly startup.

The cumulative benefits of dispatching the hydro resources by brick shaving over the course of a year are shown in Table 3-2 based on the total costs of thermal production, the total number of startups for thermal plants, and the average price of electricity. Brick shaving can be seen as a superior strategy for dispatching hydro with costs, startups and prices being reduced more by brick shaving than peak shaving.

Dispatch Method	Total Costs of Production (billion USD)	Number of Startups	Average Electricity Price ($/MWh)
No Hydro	7.52	15,058	59.19
Peak Shaving	6.03	10,257	57.79
Brick Cutting	5.99	9,234	56.00

Table 3-2 - Comparison of hydro dispatch algorithms

4 RESULTS

Having described the hydro dispatch algorithm in LEEMA and demonstrated the hydro dispatch by the brick shaving method, the goal in this section will be to show the impact that hydro generation has on the final thermal dispatch and the resulting market prices of systems with large scale VER capacity. The power system modeled here is based on the 2010 Spanish system. The details of the system are available in Appendix B along with the values used for modeling the thermal generation technologies.

The results will be broken into the following cases:

- First, hydro generation will be introduced into a single case of the current Spanish system with 20 GW of wind capacity installed and the impacts on thermal generation will be detailed throughout the implementation of the LEEMA model.
- Second, the different types of hydro generation and their contributions to systems with significant wind capacity will be examined. The flexibility of the hydro generation resources will be altered by shifting generation from inflexible run-of-the-river hydro to the fully flexible hydro production with no capacity constraints. In addition, the limitations posed by the capacity constraint on the current Spanish hydro generation will be evaluated by providing additional capacity to the system to see what effect the constraint has on market prices
- Third, the impact of hydro generation as large scale wind capacity enters the Spanish system will be modeled with wind capacity ranging from 0 GW to 40 GW. The impact of the hydro dispatch will be seen through the analysis of the thermal generation that is dispatched to meet the remaining load in the system.

Conclusions from the results presented here will be discussed in greater detail in the next section, including recommendations for policymakers and future work.

4.1 INTRODUCTION OF HYDRO GENERATION

The dispatch of the hydro generation capacity, as described in the previous section, is completed in LEEMA to maximize the value of the water resources available by targeting the most costly periods of thermal production required to meet the system demand. The purpose in this section is to isolate the impact of hydro generation for a single case to demonstrate its effect across the range of variables considered in LEEMA.

Hydro production profile

The electricity production from the hydro plants modelled in this paper can be seen in a representative dispatch over a seven day time period in Figure 4-1 from early January, 2010[24]. The hydro generation is the combined dispatch of all the hydro plants modelled in the system, including the run-of-the-river (RoR) hydro. The maximum capacity of the system can be seen during the hours in which hydro production levels off at its maximum production levels. The RoR capacity can also be seen at the minimum output which occurs several times throughout the week.

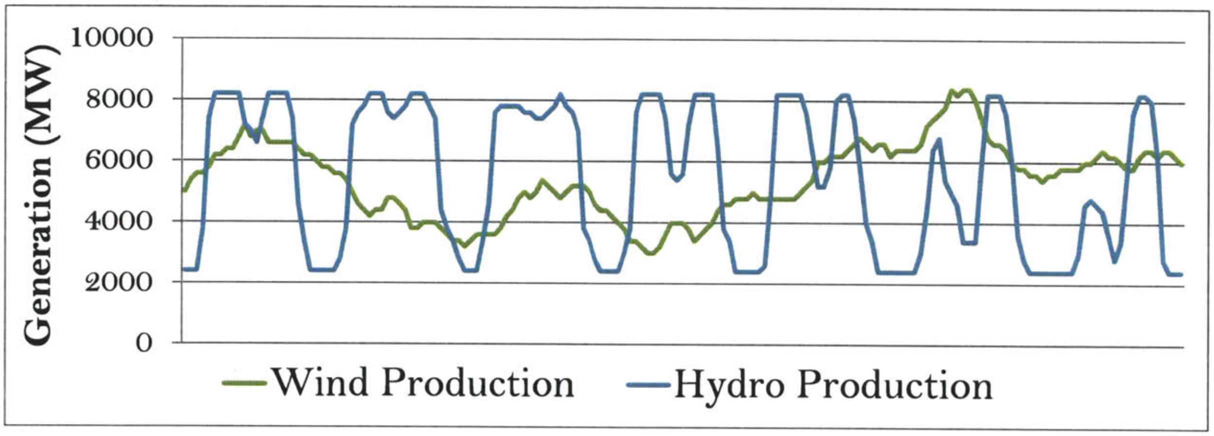


Figure 4-1 - Representative dispatch of hydro generation along with wind generation

The wind generation for the same period is included in Figure 4-1 to show the relative scale of hydro production and the difference in the daily output from these two generation resources over the course of the week. The daily load cycles can easily be seen based on the cycling of the hydro plants from minimum production during low load periods to maximum production during high load periods. It is clear that generation from wind resources does not correlate with changes in load. This relationship highlights the non-dispatchable nature of wind generation and why hydro, as a low cost and storage generation resource, is considered a valuable resource in systems that generate a significant amount of their electricity from intermittent resources.

The accumulated hydro production determined from the Hydro Dispatch Module across all plants and hours modifies the net load profile, which defines the amount of generation that is required from thermal power plants for each hour. As shown in Figure 4-2 for the same week shown above, the net load is determined by starting with the total demand, subtracting the wind generation and then the hydro generation. The area that remains below the net load represents the generation that will be

[24] This same week will be used throughout the results section to demonstrate the results of the model.

provided by the thermal generation plants that can most efficiently operate with the least total production cost as determined by LEEMA.

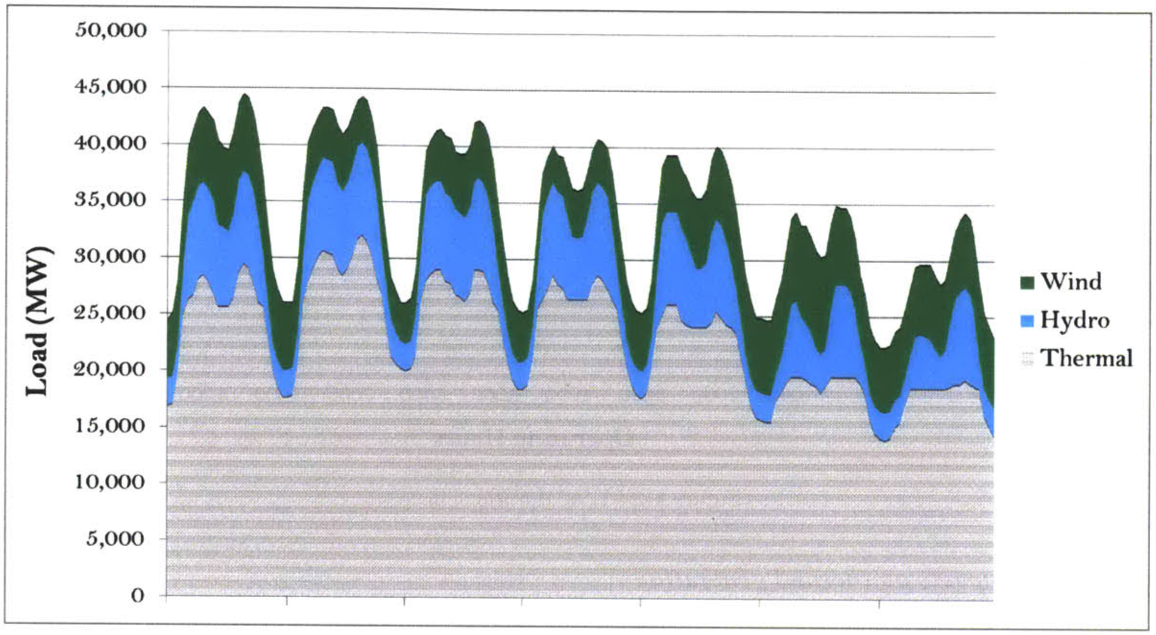


Figure 4-2 – The demand and net load for a representative week

The result of the hydro dispatch across the full time period being analysed, in this case a 52 week period, can be seen in the load duration curve in Figure 4-3.[25] The load duration curve is not used directly in the LEEMA since it does not provide the chronological granularity required for our analysis. But it does provide a visual representation of how hydro production is spread throughout the year. With the aim of reducing the most costly periods of thermal production, the hydro resources are generally dispatched more often during hours of peak load, as had been shown above, while the net load will be reduced across all time periods from the RoR production. In this case, the peak load has been reduced by 8000 MW, the maximum capacity of the hydro generation plants.

[25] The load duration curve describes the number of hours that the load demand is at or above each capacity level on the y-axis. For example, the minimum load for the system will be the point at which all hours of the year the load is greater than it and will thus be the load at hour 8760 on the load duration curve.

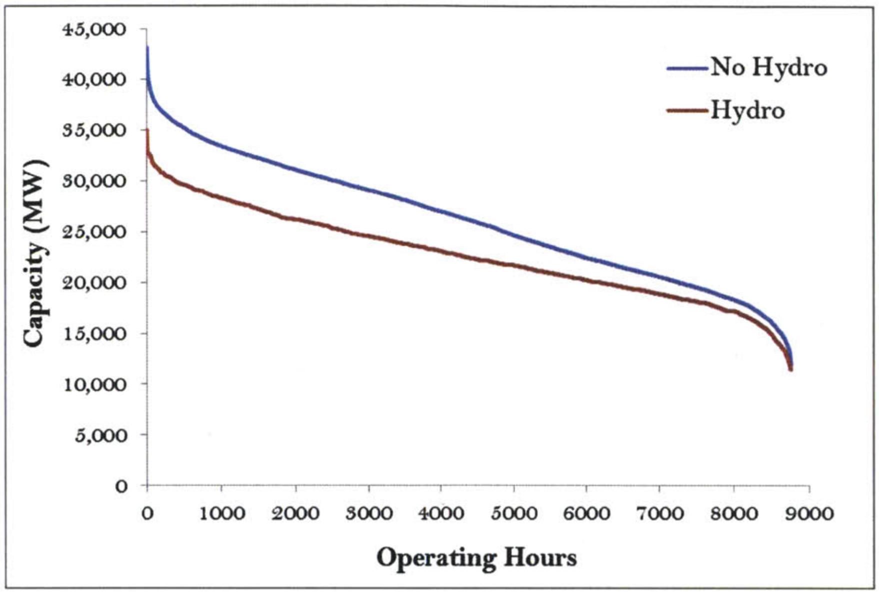
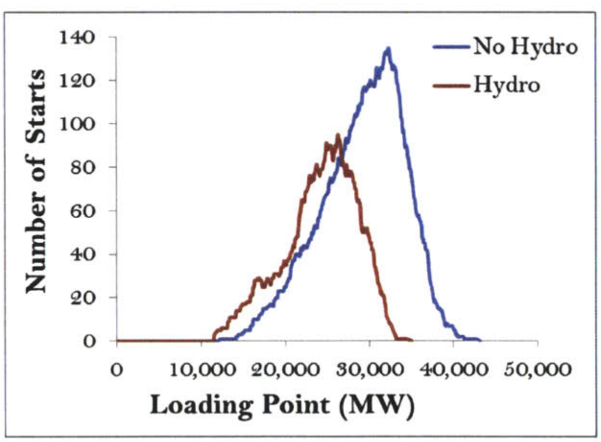


Figure 4-3 - Load duration curve

Operational impacts on thermal generation

With the modified net load profile now defined, LEEMA optimizes the dispatch of thermal generation units.

The first step is to define the production profiles at each loading point in the Thermal Scheduling module. Two of the key pieces of information generated from the production profiles for each loading point are the number of startups and the hours of operation at minimum load. These characteristics of operation are shown for each loading point in Figure 4-4 for the cases without hydro and with hydro.



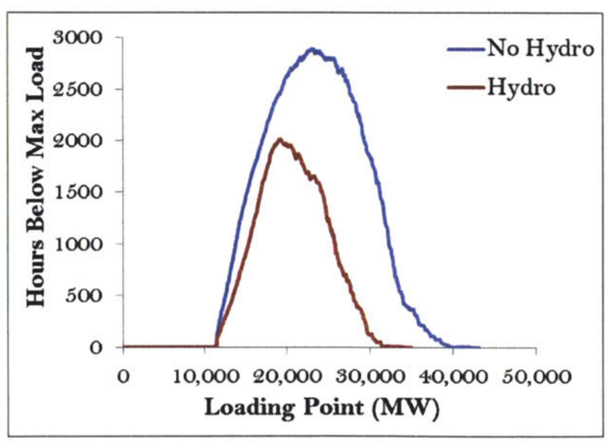


Figure 4-4 - Number of startups and the number of hours operating below max load

The advantages of the introduction of hydro generation are clear; the thermal plants are required to startup and operate at minimum load significantly less often across the load levels. Increased starts at lower loading points at the far left of the chart are due to a shift in production profiles caused by the presence of the continuous RoR production.

The total number of starts and hours operating at minimum load across all loading points for the two cases are shown in Table 4-1. Starts are reduced by approximately 40% and minimum hours by over 50% with the introduction of hydro generation.

	Number of Startups	Hours Operating at Minimum Load
No Hydro	15,054	450,133
Hydro	9,234	213,800
Difference	5,820	236,333

Table 4-1 - Total number of startups and hours operating at minimum load

Utilization of thermal generation capacity

Once the production profiles have been defined, LEEMA next determines the lowest cost technology to provide the required generation at each loading point. The costs for each technology considered are represented in the screening curves shown in [26].

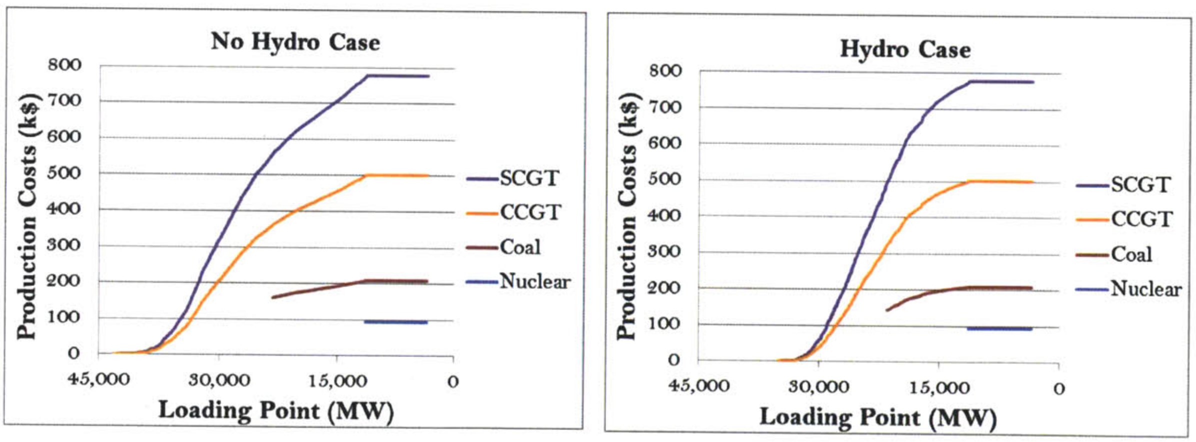


Figure 4-5 - Screening curves for cases without hydro (left) and with hydro (right)

As mentioned above, the current Spanish system is being considered in this paper with a previously installed capacity, so that the capital costs, which are considered sunk costs, are not included in the

[26] A full description of screening curves can be found in Section 2.4

economic analysis. Additional analysis is possible with LEEMA for projecting the optimal generation mix of technologies, unbound by the current installed generation, but that analysis is not within the scope of this paper.

The nuclear and coal curves do not extend across all loading points since LEEMA places operational constraints on them that limit their ability to operate at loading points that cycle more often than is currently practical for those plants. The limit for coal plants is fifty starts per year and for nuclear is one start per year. The loading point at which coal stops being practical can also be found in Figure 4-4 when the number of startups exceeds fifty.[27]

Simple cycle gas turbines (SCGT) are shown to be more costly than CCGT operation across all load levels shown and thus do not appear in the utilized capacity. Additional constraints could be placed within LEEMA to account for the limitation of operating CCGTs for only a few hours for each start but the justification is not seen in current power systems where improvements in the flexible operation of CCGTs enables economic generation during the few hours of daily peak load.

The screening curves identify which technologies can provide the lowest cost generation for each loading point. The resulting operating capacity and total amount of electricity generated for each technology are shown in Figure 4-6. The capacity factors of each technology are also shown.

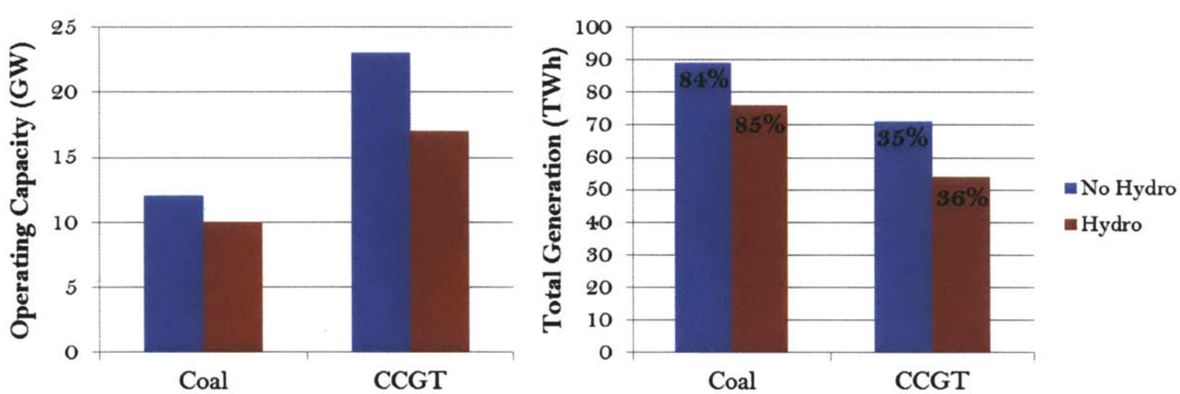


Figure 4-6 - Utilized thermal capacity and generation for coal and CCGT plants

The introduction of hydro generation reduces both coal and CCGT capacity in the system. The coal capacity is reduced due to start limitations at lower loading points. Although CCGT plants replace the reduced coal capacity, the overall CCGT capacity is reduced due to the use of hydro generation to cover

[27] This limitation is implemented by setting the costs of production to an infinite value for those loading points above the limit.

the highest load levels throughout the year. In fact, the introduction of hydro generation will have a larger impact on the capacity of CCGT plants then on coal plants, reducing CCGT capacity by 6400 MW compared to an 1800 MW reduction for coal.

The reduction of thermal capacity and generation due to the impact of hydro generation can be seen in the representation of the economic dispatch of generation technologies over a seven day time period, as shown in Figure 4-7.

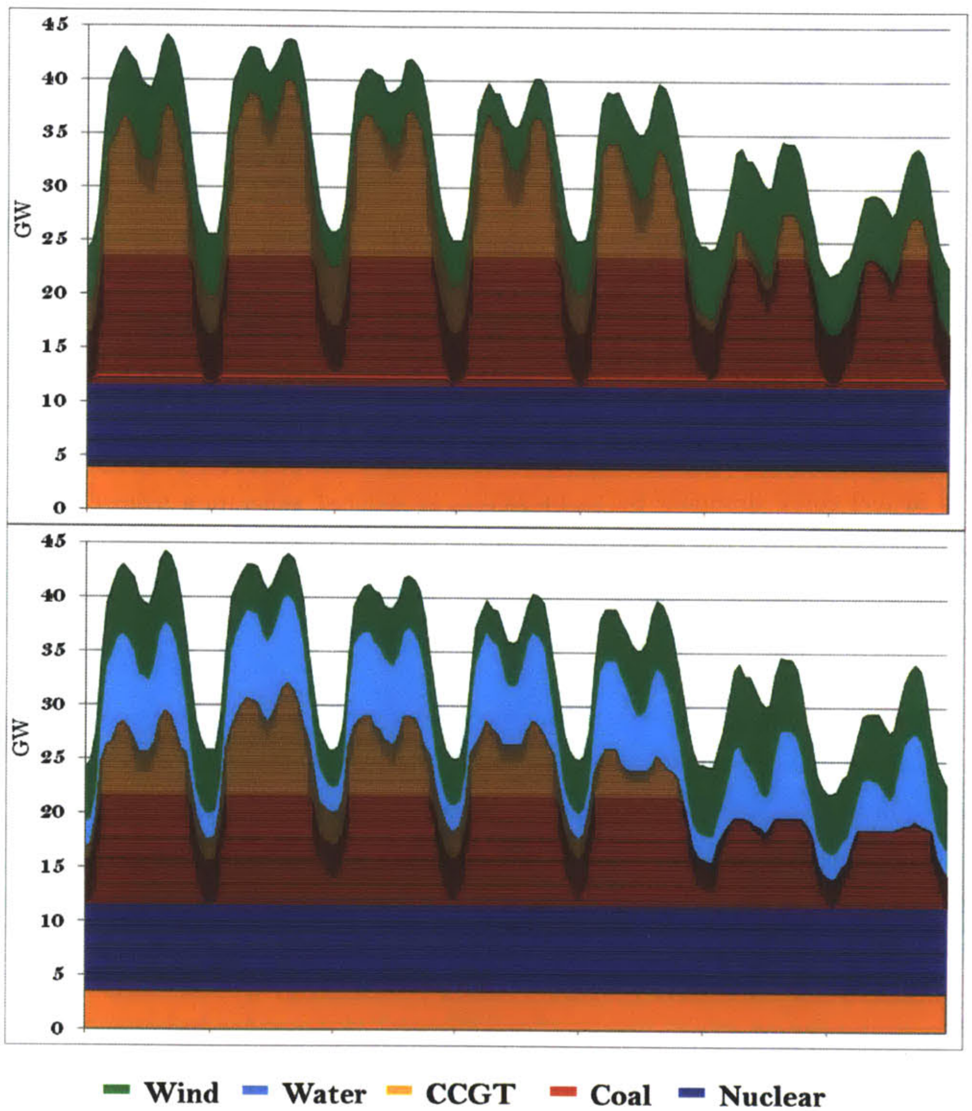


Figure 4-7 - Thermal dispatch for cases without hydro (top) and with hydro (bottom) of generation

Thermal generation production costs

The average cost of thermal production for the full year of operations is shown below in Figure 4-8 with the total cost broken out into each cost component - fuel, O&M and startup costs - analyzed in LEEMA. The O&M costs are also broken out into its components on the right.

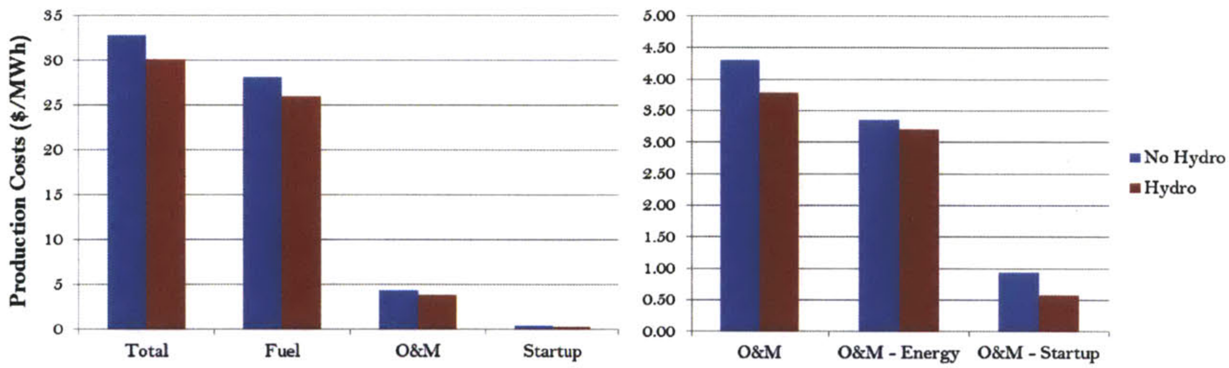


Figure 4-8 - The total and component production costs per megawatt-hour of thermal generation

The relative scale of each cost component can be seen with fuel costs as the dominant component. All costs are reduced with the introduction of hydro generation on an energy produced basis. The largest reduction is in fuel costs, dropping by $2.14/MWh, as reduced generation from CCGT and coal is weighed less heavily than the low cost generation from nuclear plants.[28]

Market prices

The average price of electricity decreases substantially when hydro is introduced into the system. In Table 4-2, the average price is shown for two pricing mechanisms without and with hydro in the system as well as the difference in prices between the two cases for both pricing mechanisms. Hydro generation has a larger impact on the non-discriminatory IRE-based prices, reducing the average price by $3.19/MWh or 5%, which tend to reflect the costs of additional non-linear costs, more than the discriminatory PJM-based prices, which decreased by $1.56/MWh or 3%[29].

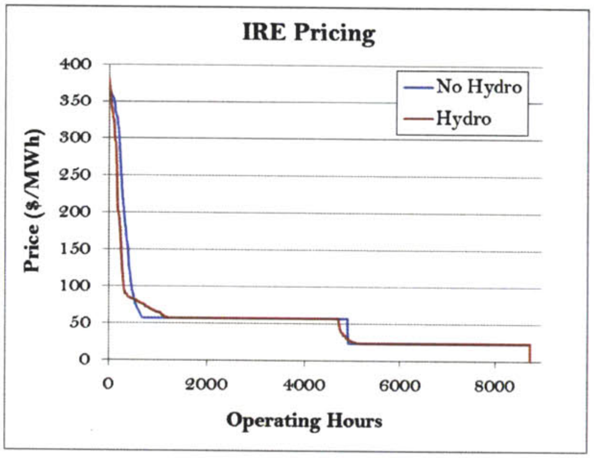
[28] These costs only include the production from thermal generation units.

[29] For a description of the pricing mechanisms used here, refer to Section 2.5.

	IRE Prices ($/MWh)	PJM Prices ($/MWh)
No Hydro	59.19	50.93
Hydro	56.00	49.37
Difference	3.19	1.56

Table 4-2 - The load weighted average price of electricity.

Price duration curves showing electricity prices across the full year are shown in Figure 4-9 for the two pricing mechanisms. The figures show the very different outcomes, especially during peak hours, between the pricing mechanisms with maximum prices for the non-discriminatory IRE scheme around $370/MWh and $67/MWh for the discriminatory pricing PJM scheme.



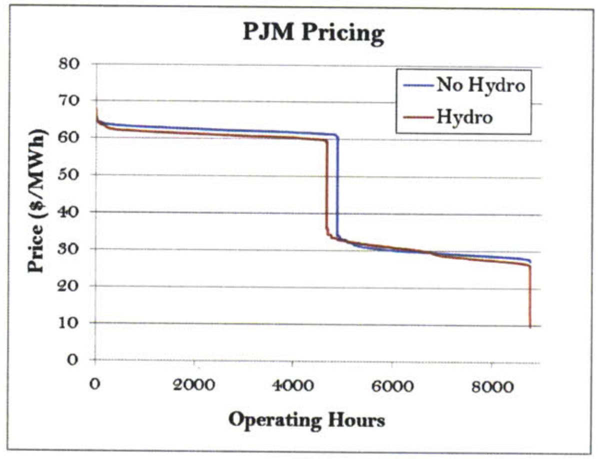


Figure 4-9 - Price duration curves

Electricity prices include two components: the linear component based on the marginal costs of production and the non-linear component added to ensure full cost recovery for generators each day they operate. The linear price component is determined by the variable cost of generation of the marginal generator, while the non-linear price component is determined from the additional payments that need to be made for the thermal generation plants to, at a minimum, fully recover their costs of operation each day.

These payments are made in different ways in the two pricing mechanisms shown. For non-discriminatory pricing, such as the mechanisms used in the Irish power system (IRE), every generator receives the same price per unit of electricity produced such that the additional non-linear uplift price is included in the hourly market prices. This tends to increase the prevalence of the non-linear components in the overall price of electricity.

For discriminatory pricing, such as the mechanism used in the PJM power system (PJM), every generator will receive the linear price component for each unit of electricity produced. Additional "make-whole" payments are then made solely to the generators that require them for full cost recovery. As each generator will be receiving a separate payment, the non-linear component of the PJM prices shown in this paper are calculated by totalling all side payments made in a day and dividing it across the load produced throughout the day. The PJM prices reported here are prices that the demand would have to pay for electricity in each hour.

These two components of prices for the current case are shown in Figure 4-10 for both pricing mechanisms and without and without hydro. The non-linear component is dependent on the additional costs that occur due to the varying operation of thermal units and have been considered throughout LEEMA, such as the startup costs, the increased fuel costs from operation at minimum load, and the O&M costs. Although these costs have been shown to have little impact on the utilized capacity, they do significantly influence prices.

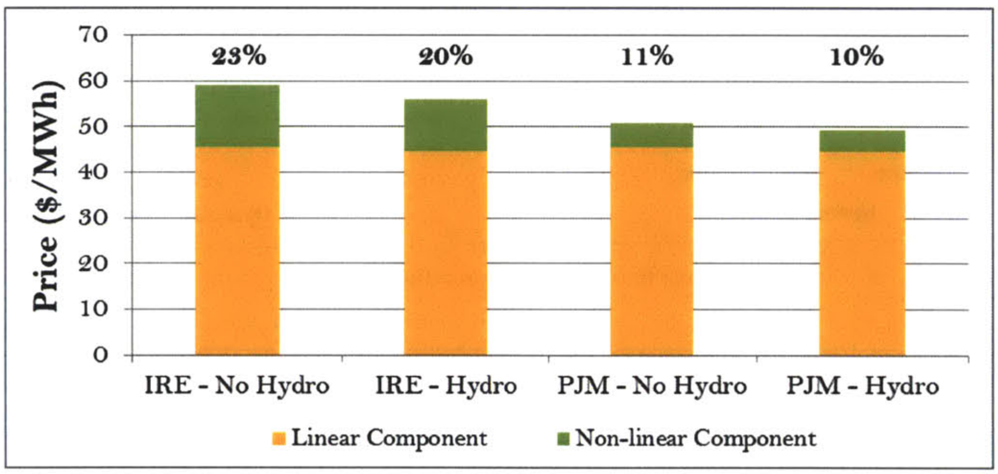


Figure 4-10 – The breakdown of prices to the linear and non-linear components along with the percentage of the costs from the non-linear component

The non-linear component can be seen to decrease with the introduction of hydro generation due to the reduction in starts and hours at minimum load previously shown with the IRE non-linear component dropping by $2.42/MWh and the PJM non-linear component by $0.78/MWh.

The relatively outsized influence of these non-linear costs on prices can be seen here with the non-linear component around 20% of the total price in the IRE scheme and 10% of the price in the PJM scheme. The non-linear component becomes a lower percentage of the overall price as it is reduced with the introduction of hydro generation more than the linear component.

	IRE Pricing	PJM Pricing
Linear Component	$0.77	$0.77
Non-linear Component	$2.42	$0.78
Total Reduction	$3.19	$1.55
Percentage Reduction	5%	3%

Table 4-3 - Reduction in prices with introduction of hydro generation

The linear component is the same regardless of the pricing mechanism but is influenced by the introduction of hydro generation. The calculation of the linear costs depends on the number of hours each generation technology is considered the marginal generator, with the results for the two cases shown in Table 4-4.

	Hours as Marginal Generator		
	CCGT	Coal	Nuclear
No Hydro	4880	3880	0
Hydro	4671	4083	6

Table 4-4 - Hours that each technology is marginal generator for the two cases.

Hydro generation shifts the marginal generators slightly, reducing the hours that the higher cost CCGT is marginal and increasing the hours that lower cost coal and nuclear are marginal. The shift towards lower cost generators results in a linear price component that is $0.77/MWh lower for the case with hydro generation.

4.2 FLEXIBILITY OF HYDRO GENERATION

The flexibility of hydro generation is different in every system and is dependent on several factors. The second analysis completed in this paper focuses on the range of flexibility hydro generation is able to offer to a power system and how it impacts production costs and market prices.

The first factor that will affect the flexibility of hydro systems is the amount of storage capacity that is available in reservoirs to store the potential energy for several days, weeks or months so that it can be dispatched at the times that provide the most value to the system. Systems that have little capacity for storage produce mostly RoR hydro which operates much like a baseload generation unit. These RoR plants provide little flexibility to the system for responding to changes in demand or VER production. Plants with substantial storage capacity and no capacity constraints however provide maximum flexibility. The impact of switching a similar quantity of water available from 100% RoR production to 100% dispatchable production is described below.

The second factor that will affect the flexibility of hydro systems is the maximum hydro generation capacity available in the system. As shown earlier, capacity constraints will limit the generation from hydro resources in the peak hours when it would otherwise provide the most value. Hydro generation is a complicated system with capacity dependent on the head of water in the reservoir and the flows that are required through the system for multiple reasons. This constraint is analysed below by increasing the maximum capacity of the Spanish hydro unit in stages to analyse how the relaxation of the capacity constraint will influence the thermal plant dispatch and the market prices.

Varying levels of hydro system flexibility

The balance between RoR and dispatchable generation is an essential distinction to understanding what role hydro generation is able to play in power system with large scale VER. This relationship is analyzed below and will demonstrate the difference among hydro generation between two extreme cases.

Several assumptions have been made for this analysis which is largely based on the hydro plant data in Appendix A. First, the maximum capacity has been assumed to be infinite and unconstrained. Second, the minimum capacity is modified for each case run to alter the amount of RoR hydro utilized. Each stage of the analysis is completed by changing the percentage of energy utilized in the RoR capacity, starting at 0% and increasing by 25%. While the capacities have been altered, the quantity of energy available has stayed consistent.

Three cases, 100%, 50% and 0% RoR, are shown below in Figure 4-11. The 100% RoR case operates at a constant, continuous rate similar to adding 2 GW of inflexible baseload generation. The 50% case has a balance between RoR and dispatchable hydro. And finally the last figure shows the 100% dispatchable case where the hydro is dispatched solely during the hours with the most costly production.

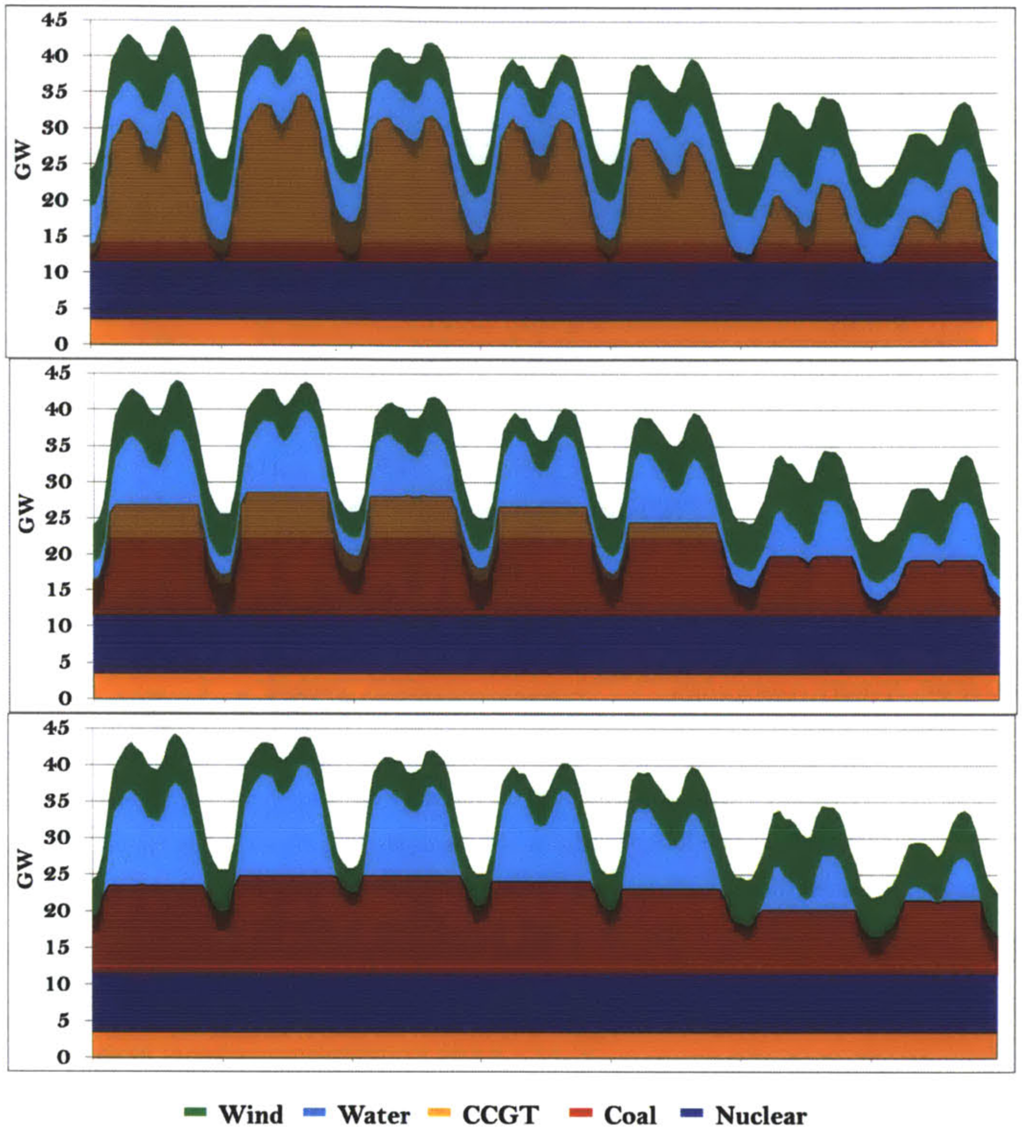


Figure 4-11 - Dispatch of hydro generation with varying hydro flexibility – 100% RoR (top), 50% RoR (middle), 0% RoR (bottom)

The switch from RoR to dispatchable hydro completely changes the thermal generation utilized from almost no coal plants in the RoR case to no CCGT plants in the dispatchable case. The impact of this balance between RoR and dispatchable hydro can be seen in the prices and costs shown in Figure 4-12. The 100% RoR case has 78% percent higher prices and 60% higher costs than the fully dispatchable case. While these are extreme cases, they do fully demonstrate the needs to understand the characteristics of a hydro system to determine its impact on thermal generation.

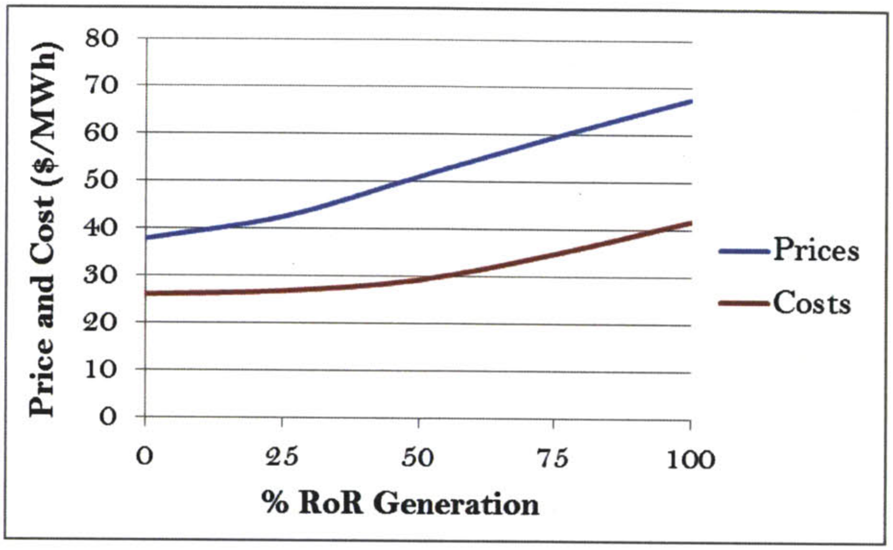


Figure 4-12 - Impact of RoR generation on the average production costs and market prices

The impact of capacity constraints

As every system will have some capacity constraints, the prevalence of those constraints will be analysed next. To show what impact capacity constraints have on the dispatch of thermal resources, again the hydro plants in described in Appendix A will be used. This time though they will be modified by making changes just to the maximum capacity of each plant. By increasing the maximum capacity, the impact of capacity constraints will be reduced.

The following dispatches are for cases with the following amount of additional capacity: the first dispatch has 50% additional capacity, the second dispatch has 10% additional capacity and the final dispatch has no additional capacity. The influence of the capacity constraint can be seen in the gradual change in net load from flat peaks, in the case with 50% higher capacity, to peaks that closely resemble the original load profile, when the capacity constraint is activated.

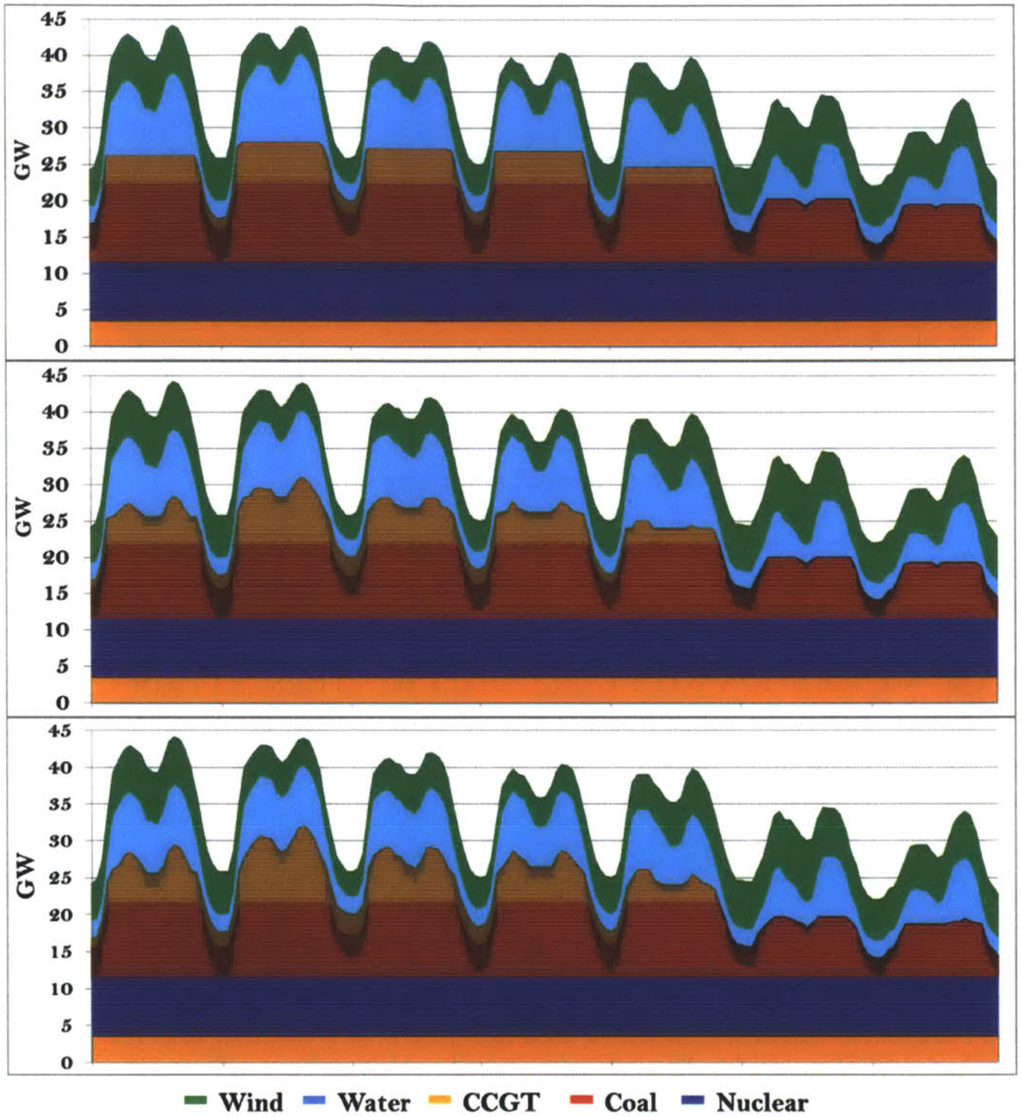


Figure 4-13 - Dispatch of hydro generation with varying levels of capacity – 50% additional capacity (top), 10% additional capacity (middle), no additional capacity (bottom)

Unlike the changes seen previously by adjusting the type of hydro generation, the changes shown here in the capacity constraint do not seem to have a major impact on the dispatch of different generation technologies but will greatly influence the operation of the units in the system. Unsurprisingly, capacity constraints increase the capacity of CCGT plants but have little effect on coal capacity.

Although the resulting impact on prices and costs is much less than the switch between RoR and dispatchable hydro, they are significant. Decreasing the capacity from an unlimited case to the standard case utilized in this paper, the prices increased by 12% and the costs increased by 5%. In this case, there are not many changes in the generation technologies but there is a substantial change in the number of startups.

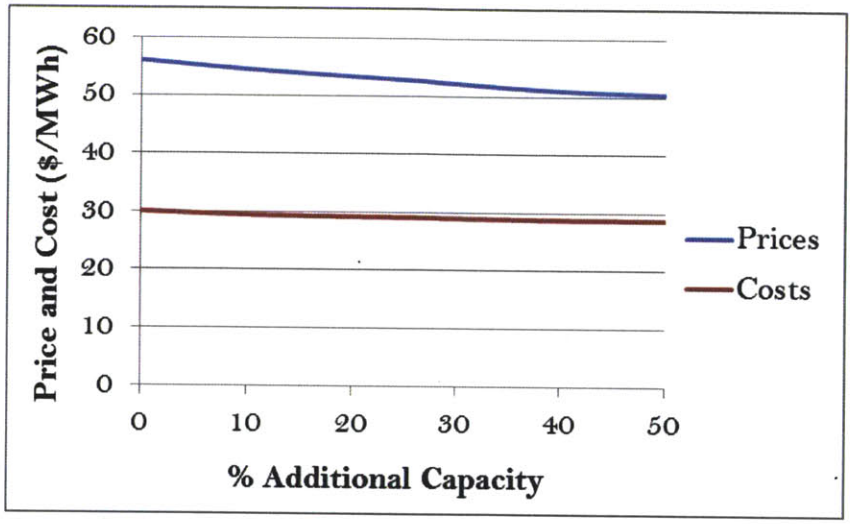


Figure 4-14 - Impact of additional capacity on production costs and market prices

4.3 HYDRO GENERATION WITH LARGE SCALE WIND GENERATION

The impact of hydro generation has been established for one case and will now be analysed for a system with increasing levels of VER capacity. Again the current Spanish case will be modelled with in this case varying levels of wind generation (current capacity is 20 GW)[30].

Figure 4-15 shows the dispatches of hydro and thermal generation for wind scenarios of 10, 20, 30 and 40 GW of installed capacity. With increasing wind generation, it is clear that there will be a shift in generation from coal to CCGT. It can also be seen that at 40 GW of wind capacity there is a substantial amount of wind and RoR hydro spillage as the limitations posed by the inflexible generation, nuclear and reserves, become more impactful with higher levels of wind generation.

[30] Although there is only 12 GW of coal capacity in the current Spanish system, we will allow this number to rise above 12 GW since it complicates the results and reduces the focus on the addition of hydro generation and different levels of wind capacity.

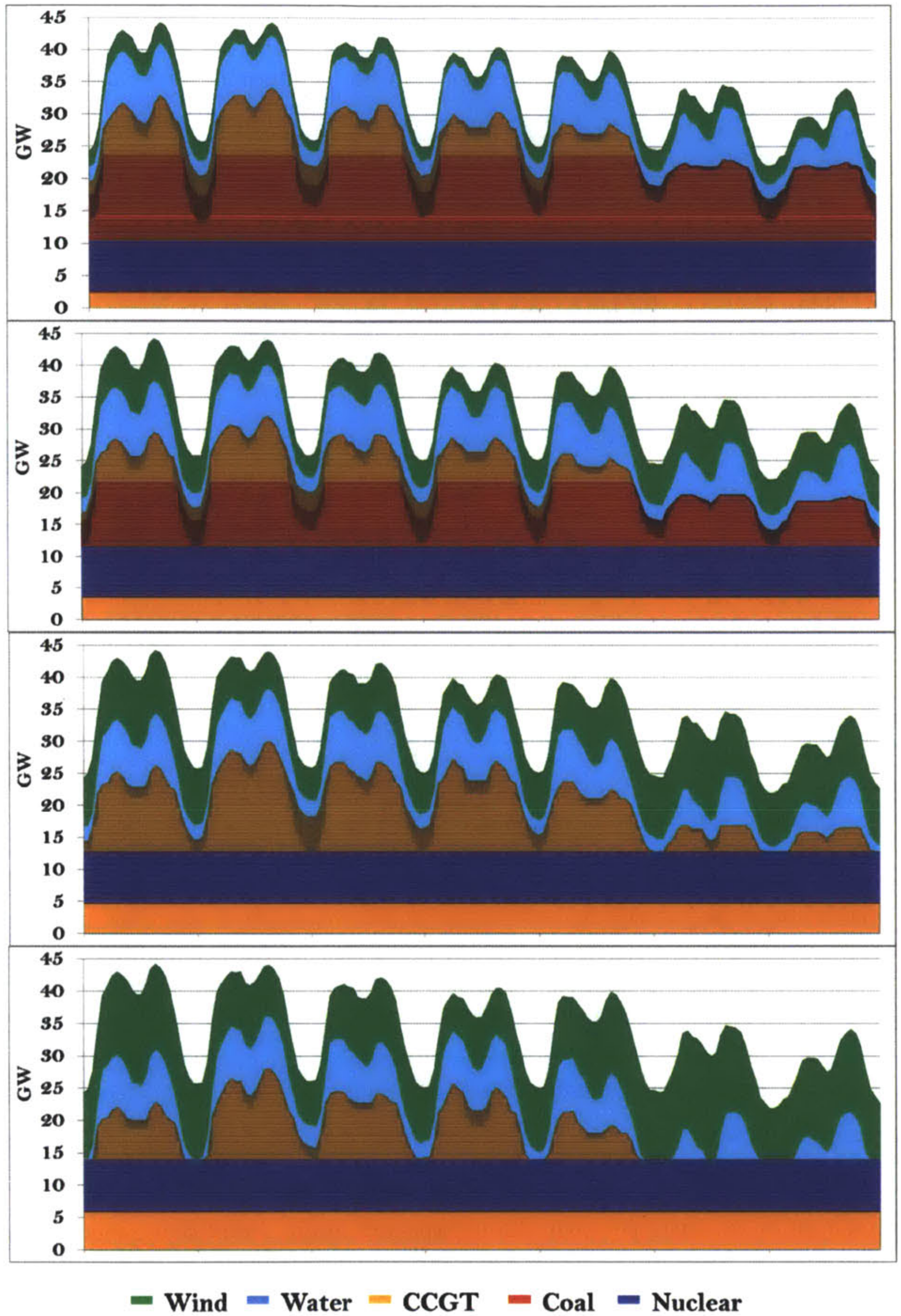
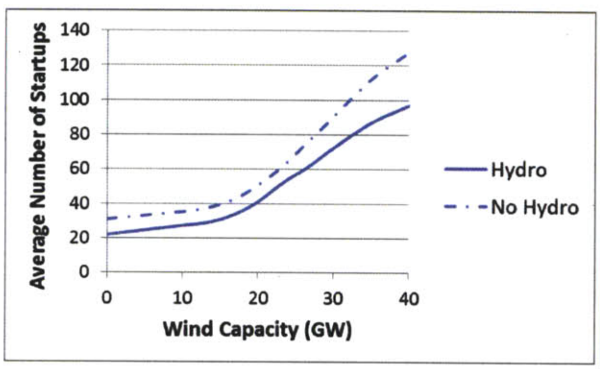


Figure 4-15 - Economic dispatch of hydro and thermal generators at different levels of wind capacity. From top to bottom: 10 GW wind, 20 GW wind, 30 GW wind, and 40 GW wind.

The remainder of this section will demonstrate the changes in operation, capacity and production costs that occur for hydrothermal systems with increasing levels of wind generation. The impact of hydro generation will be highlighted throughout by comparing the outcomes between the cases without and with hydro in the system.

The initial impact seen in LEEMA is on the cycling and ramping operation of thermal units as wind capacity increases. Figure 4-16 show the average number of thermal plant starts per year and the percentage of operating hours below 100% output for the flexible thermal generation. As would be expected, thermal generation units will have to cycle more often with increasing wind generation. Hydro generation is expected to reduce the number of starts at each level of wind capacity, and especially at high levels of wind capacity, by approximately 8 – 10 starts per year for the average flexible thermal plant. However, for both cases the average number of starts increases dramatically, with approximately four times as many starts at 40 GW as with no wind generation. The presence of hydro generation can greatly reduce these startups.

The impact on ramping can be seen to increase as wind generation rises but reaches a maximum before decreasing again. This result shows that increased wind generation cause plants to cycle more often but not necessarily ramp more often, depending on the capacity of wind installed.



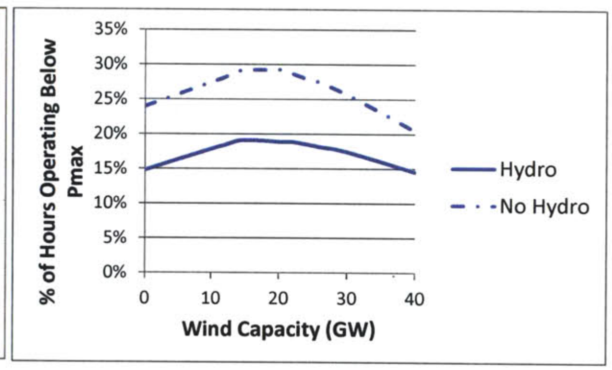


Figure 4-16 – Operational constraints on thermal generation cycling (left) and ramping (right)

The screening curves reflect these changing operating regimes. Figure 4-17 shows the progression of screening curves for increasing wind capacities with hydro generation across all cases. With the increased amount of cycling, coal is unable to operate at the same quantity of loading points due to the operational limitation of 50 starts per year. An unexpected result is that coal generation capacity does not decrease from being uncompetitive at costs (at least for currently installed generation that does not take capital costs into account and at the fuel costs assumed in this study) but instead coal will decrease do to the inability to cycle as often as will be necessary with increasing wind generation at the higher loading points.

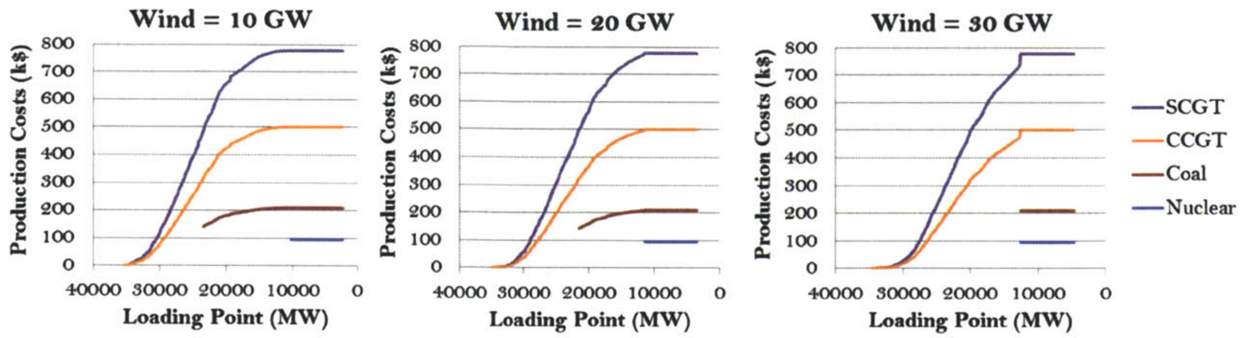


Figure 4-17 - Screening curves for hydrothermal system with increasing wind capacity

The quantity of utilized capacity that results from the screening curve analysis for coal and CCGT is shown in Figure 4-18 for the two cases. The presence of hydro affects the CCGT capacity more than the coal capacity across all wind capacities, as mentioned previously. However, the additional wind generation forces coal capacity out of the system around 30 GW of wind capacity due to the operational constrains shown above. The coal capacity starts decreasing faster in the case without hydro generation as the gap between the two cases comes close to disappearing around 22 GW of wind capacity. At this point the coal capacity in the hydro case seems to start decreasing more rapidly. The coal capacity is replaced by CCGT capacity, which doubles from low wind capacity to high wind capacity.

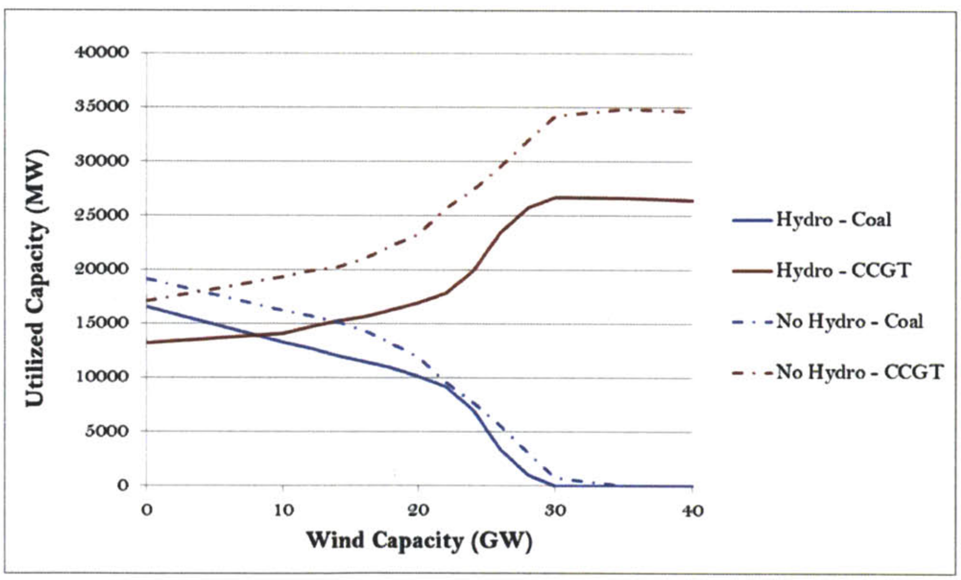


Figure 4-18 - Utilized capacity of thermal technologies with increasing wind capacity

The operational impacts of increased wind generation for each of these technologies are shown in Figure 4-19. The average number of starts for each technology (left) increase with wind capacity until coal hits its operational limit of 50 starts per year. The reason for the faster reduction in coal capacity with hydro in the system can be seen as starts actually rise faster with hydro in the system due to the baseload nature of RoR hydro. The percentage of hours that each technology spends reducing its load to avoid additional starts (right) shows that before the coal capacity starts reducing dramatically around 20 GW, it is forced to ramp about 50% more often than it would without wind generation. CCGTs on the other hand remain fairly consistent in their operating mode at low wind capacity but then start to ramp less as they displace coal at the lower loading point levels which require less ramping.

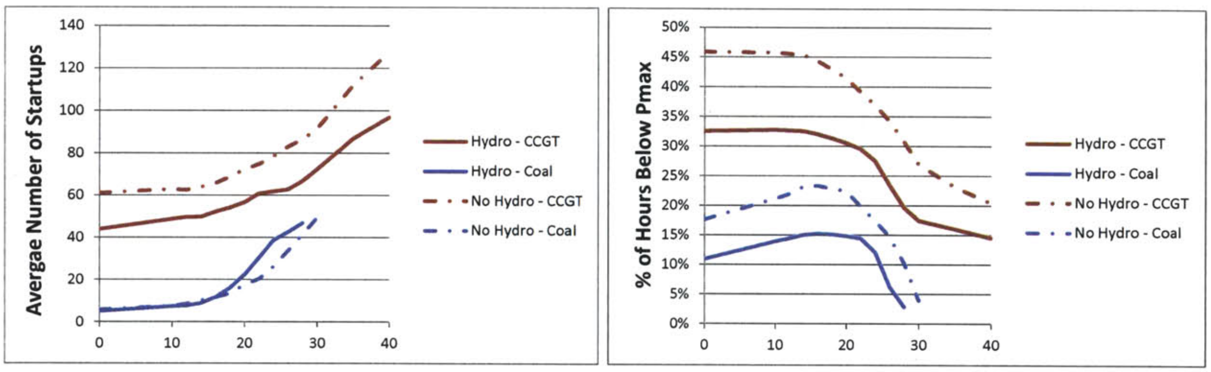


Figure 4-19 – The operational constraints on coal and CCGT plants with increasing wind capacity

Determining the average capacity factors for the coal and CCGT plants in the system with increasing wind generation presents a challenge. While the previous results have shown the expected operation and utilized capacity of flexible thermal plants it is reasonable for each level of wind generation to be a single snapshot in time. However, calculating the capacity factors requires an assumption about whether the plants in the system over time will remain operating and whether the capacity will be built as more is required in the case of CCGT or retired as less is required in the case of coal. The resulting capacity factor will vary based on what assumptions are made on the speed in which wind capacity is entered into the system and how quickly the rest of the generation mix is able to respond.

For this reason, the capacity factors for coal and CCGT generation are calculated for two cases. In the short term, wind capacity is added quickly with minimal time for the thermal generation to adjust capacity. This case assumes that the maximum capacity of each technology required at any level of wind generation exist in the system for all levels of wind (maximum coal capacity is 15,200 MW at 0 GW and maximum CCGT capacity is 26,700 MW at 30 GW) The long term case, on the other hand, assumes that additional plants are able to be built and idle plants retired so that at each load level only the utilized plants are considered in the calculation.[31]

[31] The case without hydro generation is not shown here since it does not lead to significantly different capacity factors, as mentioned previously.

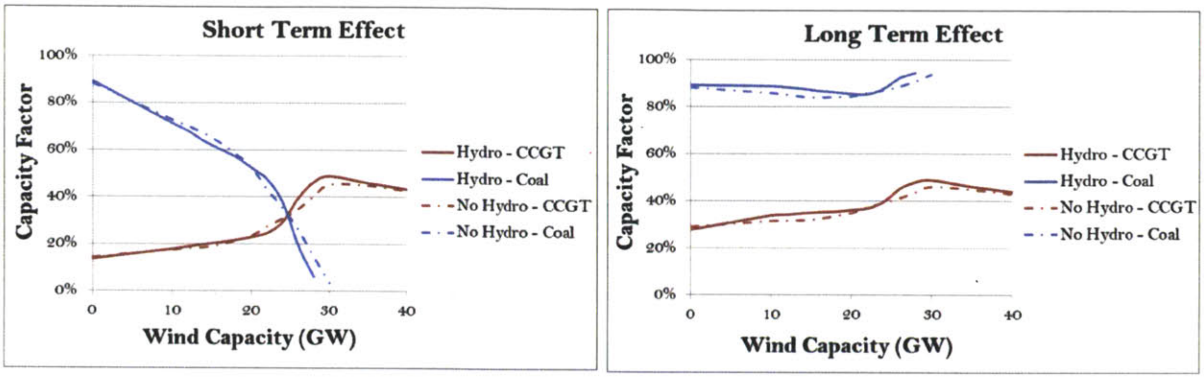


Figure 4-20 – Capacity factor of coal and CCGT plants in the short term and long term

The capacity factors for the short term and long term cases are shown in Figure 4-20. As shown in the previous section, the introduction of hydro generation has limited impacts on the capacity factors of the utilized thermal generation. The most dramatic effect of considering the temporal nature of changes in generation capacity can be seen in the capacity factor of coal plants. In the short term, the capacity factor drops precipitously due to the decreased utilization of the total capacity that was required at low levels of wind capacity. In the long term though, if the unused plants are retired so that operating capacity is equal to the utilized capacity, the remaining coal plants will continue to operate at consistently high capacity factors until they are no longer able to operate as required.

The capacity factor for CCGT plants in both the short term and long term cases is expected to rise to 40-50%. In the short term case, it is assumed that additional capacity is built into the system at low wind capacities so that there is enough CCGT capacity when in a short period of time additional wind generation requires more CCGT plants to operate. When CCGTs are able to be built as wind enters the market due to the operational dynamics shown above, the capacity factor remains higher across lower the levels of wind capacity.

The inflexible generation in the system also plays a significant role in determining the amount of thermal generation technologies utilized. The inflexible generation is considered in LEEMA to be the generating capacity from nuclear plants and reserve CCGT plants. Nuclear plants, though technically able to ramp, are assumed not to ramp for economic reasons. Reserves, by definition, are not able to ramp to follow load since their output is fixed at a level where in a short period of time they could either increase or decrease their output depending on perturbations in the balance between generation and load. The inflexible generation will increase as wind capacity is added since enough reserves are set aside to match 5% of wind capacity due to the short term changes in output from wind turbines.

The influence of inflexible generation is shown in Figure 4-21 which shows the total generation capacity required to meet the annual maximum load first in the case without hydro and second with hydro across different levels of wind capacity. Increased levels of inflexible generation will initially decrease the capacity of coal plants and, at high wind capacity, start reducing the amount of CCGTs operating to match the load.

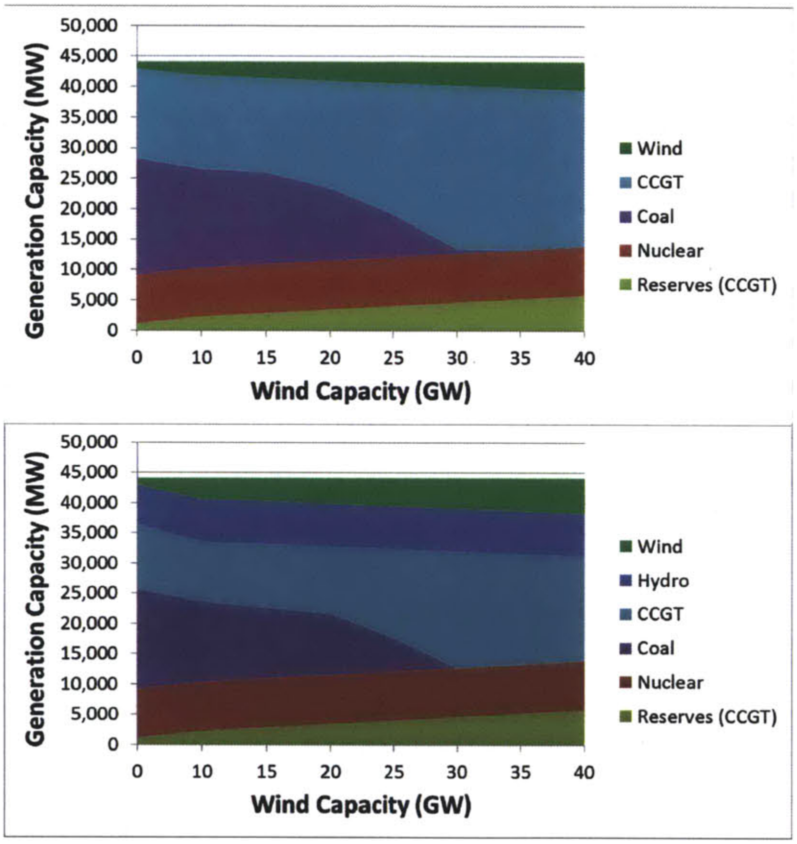


Figure 4-21 – The combined generation mix for cases without hydro (top) and with hydro (bottom).

It is important to understand how the operational dynamics of the system shift with wind capacity for applying the results of this one case in the current Spanish system to other systems and timeframes. Those dynamics can be clearly seen in the charts above where the interfaces between each technology can be defined by operational constraints in the system:

- The overall system maximum load defines the top of the chart;
- The maximum net load covered by thermal generation is at the interface of wind and CCGT in the top chart and hydro and CCGT in the bottom chart
- The capacity at which 50 starts is required for operating thermal plants is defined by the interface between CCGTs and coal

- The capacity of inflexible generation sets the interface first between nuclear and coal at low wind capacity and then nuclear and CCGTs at high wind capacity.

The charts above also provide some insight into the amount of wind capacity that could potentially be considered "firm capacity". Generally, firm capacity is the capacity that is available during the hours of maximum load each year. Figure 4-21 shows that an increase in wind capacity does not lead to a reduction of an equivalent capacity of thermal generation. In fact, the decline in overall thermal capacity in this specific case with known load levels and wind generation is on average about 100 MW of reduced thermal capacity for every additional 1 GW of wind capacity. This results in 10% of wind capacity being considered firm capacity

Thermal production costs

With the generation capacities determined for each level of wind capacity, the total costs of thermal generation for cases with and without hydro are shown in Figure 4-22 for overall costs and normalized costs based on the amount of electricity produced by thermal generators. By both measures, costs rise with a greater rise seen in normalized costs.

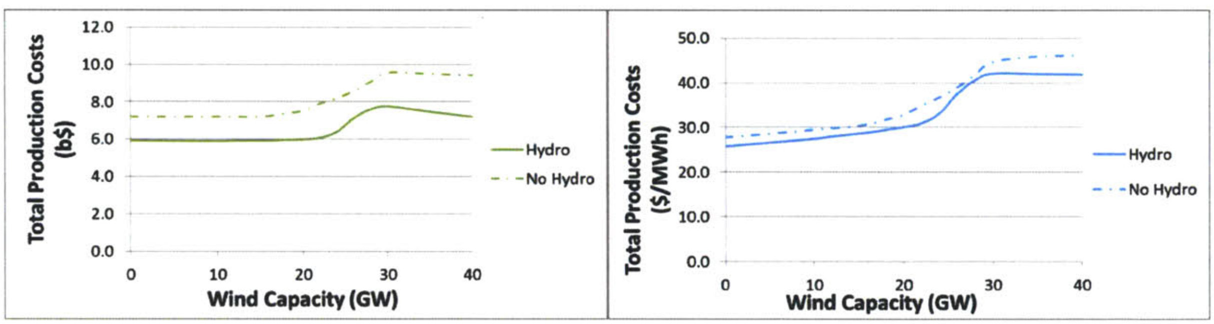


Figure 4-22 – Thermal production costs overall (left) and per megawatt-hour produced (right)

The cost components, fuel, O&M and startup costs, that are analyzed throughout LEEMA are shown in the following charts. The scale of the costs on the y-axis should be noted as it is an order of magnitude different on each chart.

Fuel costs, shown in Figure 4-23, rise with the displacement of coal generation by CCGT generation at higher wind capacities. Fuel costs also represent the majority of overall production costs, which closely mirror the rise seen here in fuel costs.

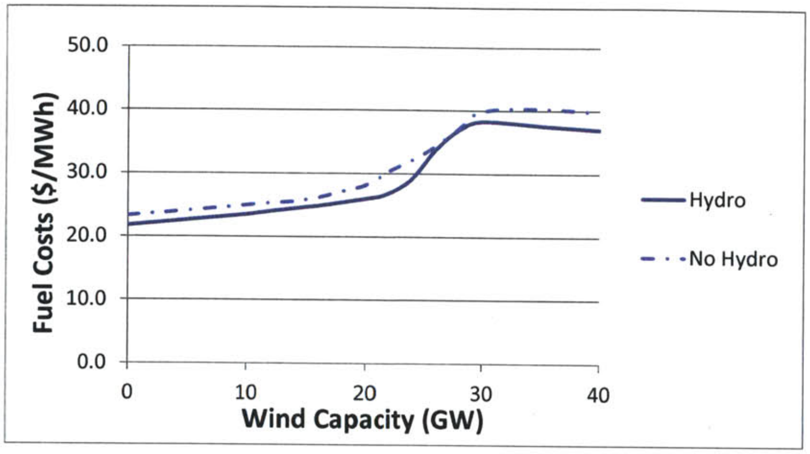


Figure 4-23 - Fuel costs per megawatt-hour produced

The second cost component, shown in Figure 4-24, is the operations and maintenance (O&M) costs. The total O&M costs is shown along with the contribution to the total O&M costs of additional hours of operation (O&M Energy) and additional startups (O&M SU). The overall O&M costs are shown to be lower with hydro generation and to rise with wind capacity. The contribution from the plant operating hours, O&M Energy, is shown to decrease with additional wind generation and to be only slight effected by the introduction of hydro generation. On the other hand, the contribution of the additional plant startups increases dramatically with the additional wind generation and is reduced with hydro generation. Although, the O&M SU costs increase by a factor of six, the overall contribution to O&M costs and the overall costs of production is limited since the relative scale of the costs is relatively small. For example, at 40 GW of wind capacity and with hydro generation in the system, O&M SU costs contribute just 5% of overall production costs.

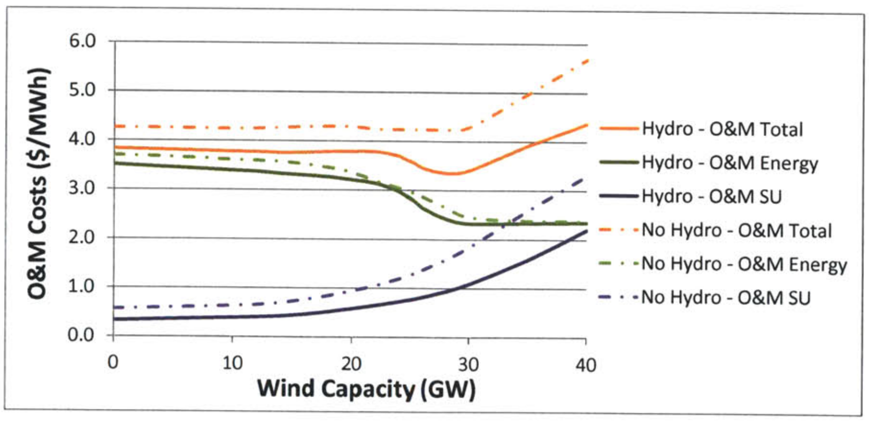


Figure 4-24 - Operation and maintenance costs per megawatt-hour produced

The final cost component is the actual costs of starting up thermal generation plants, which are shown in Figure 4-25. The scale of the costs again should be noted as it is an additional order of magnitude lower than the O&M costs. The additional startups that are required with higher levels of wind capacity increase the startup costs per unit of electricity produced but at a relatively low cost overall. The startup costs at 40 GW of wind generation and with hydro in the system represent just 1% of the total costs of production.

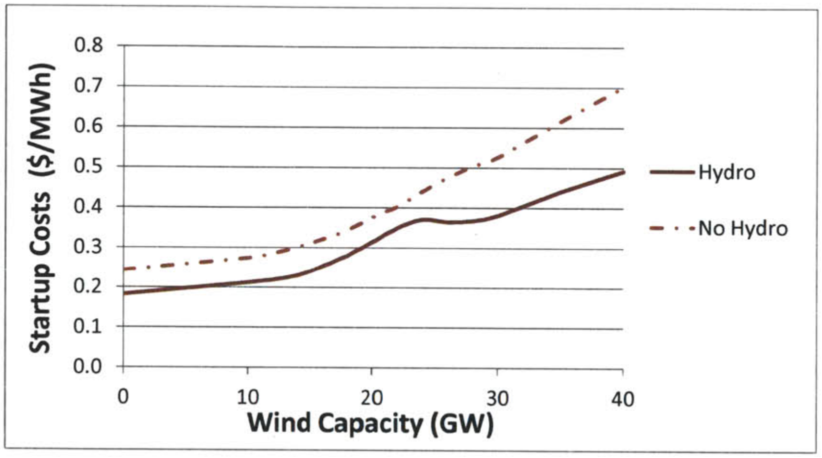


Figure 4-25 – Startup costs per megawatt-hour produced

It is clear from these results that, although there is an increase in several of the cost components with higher levels of wind capacity, the main driver of higher costs of thermal production is the fuel costs, which increase with the switch from coal generation to CCGT generation.

To better isolate the impact of each cost component on the total costs without the large swing in fuel costs and differences in the costs of O&M and startups for each technology, a case was run solely with CCGT plants available to cover the total system load. As shown in Figure 4-26 for the case with hydro generation, the higher costs (total and fuel costs) are on the left axis and the lower costs (O&M and startup costs) are on the right axis. This result highlights the level of importance of each cost component as the wind generation increases. Although there is a significant increase in the costs of startups and O&M, it is clear that the effect of these increases is quite small compared to the costs of fuel switching seen in the previous charts.

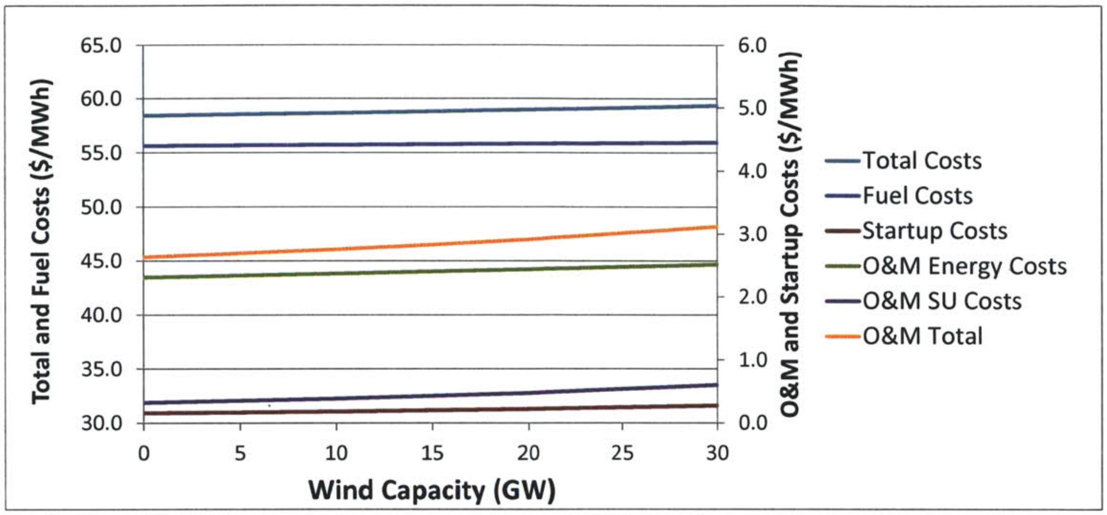


Figure 4-26 - Costs of production for case with only CCGT plants in operation

Market prices

The market prices for the IRE and PJM pricing mechanisms are shown in Figure 4-27 for cases with and without hydro generation. The prices have been averaged on a load-weighted basis across the entire time period of analysis[32].

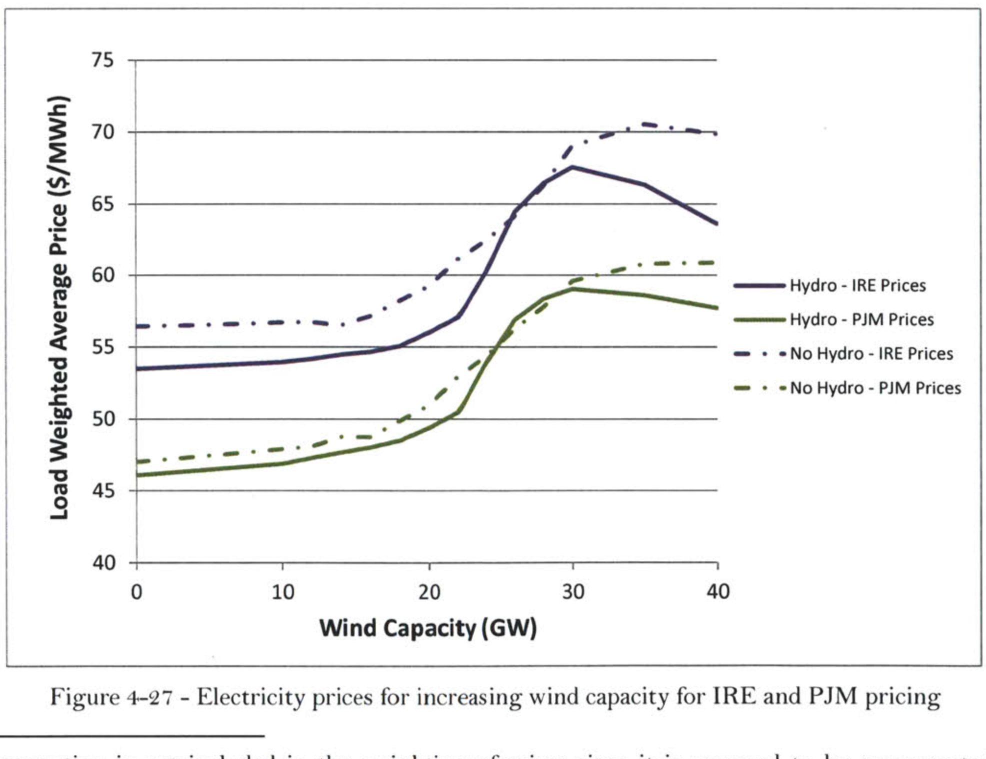
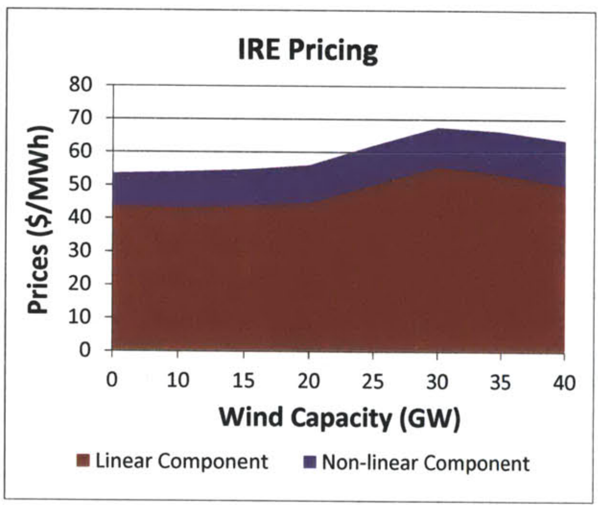


Figure 4-27 - Electricity prices for increasing wind capacity for IRE and PJM pricing

[32] Wind generation is not included in the weighting of prices since it is assumed to be remunerated by other means.

At low levels of wind generation, hydro generation will decrease prices by approximately 4% in the IRE case and 2% in the PJM case. Electricity prices rise however with increased wind generation, regardless of whether there is hydro generation in the system and which pricing mechanism is deployed. Without hydro generation, prices begin rising at a higher rate earlier, especially in the IRE case, with a significant increase in prices starting at 14 GW. The prices for the hydro case remain relatively flat until 22 GW of wind capacity and then increase faster than the case without hydro. Prices converge for both cases in the 26 – 30 GW range and then begin to separate again.

The underlying dynamics that cause higher prices with increased wind generation are a combination of the changes in the linear costs of production, which are dependent on the marginal generators in each hour, and the non-linear costs of production, which are dependent on the additional costs of cycling and ramping thermal generation units. The breakdown of the market prices into their linear and non-linear components is shown in Figure 4-28 for different levels of wind generation and the case with hydro generation.



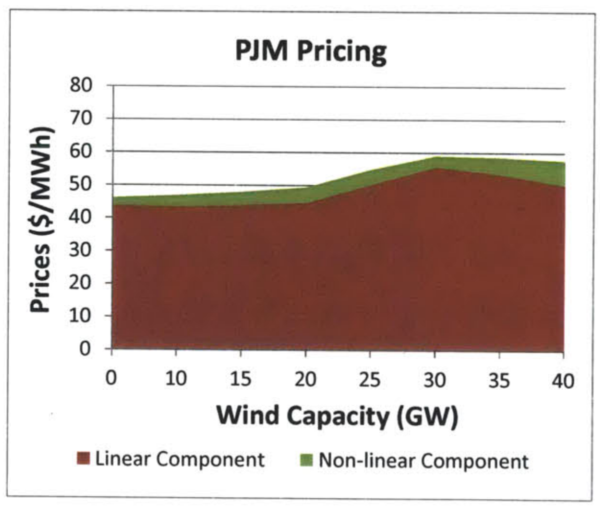


Figure 4-28 - Linear and non-linear pricing components for IRE and PJM pricing

Both the linear and non-linear components will increase with additional wind capacity. The non-linear prices increase in both pricing mechanisms due to the additional cycling and ramping costs shown to occur with increased wind generation. While it was seen above that the non-linear costs did not contribute substantially to the overall costs of production, these non-linear costs have an outsized effect on market prices with increasing wind capacity. For the IRE case, the non-linear price component increases by \$3.74/MWh across the range of wind capacity shown and the non-linear price component for the PJM case increases by \$5.21/MWh. Overall though, the contribution of the non-linear component to the overall price is expected to remain about 20% of average prices in IRE-type pricing systems and 8% of average prices in PJM-type systems.

The linear component depends on the number of hours that each technology is the marginal generator. Although there is a switch between coal and CCGT, that alone does not mean that prices change. But, as Figure 4-289 shows, the marginal generators change with wind capacity which causes prices to rise and then fall with wind capacity for both pricing mechanisms shown. The major change, as expected, is in the share of hours that CCGT and coal are marginal, which causes the prices to rise in the 15 GW to 30 GW range of wind capacity. Nuclear generation begins to be marginal at higher wind penetrations when wind generation must be curtailed to avoid the ramping or cycling of nuclear plants. This introduces hours when the marginal cost is zero since an additional 1 MW of generation would be free by increasing output from the curtailed wind generators, which decreases the linear component of the price of electricity. Although curtailed wind production is not considered desirable, at 40 GW of installed wind capacity the curtailment of wind generation amounts to just 4% of total possible production.

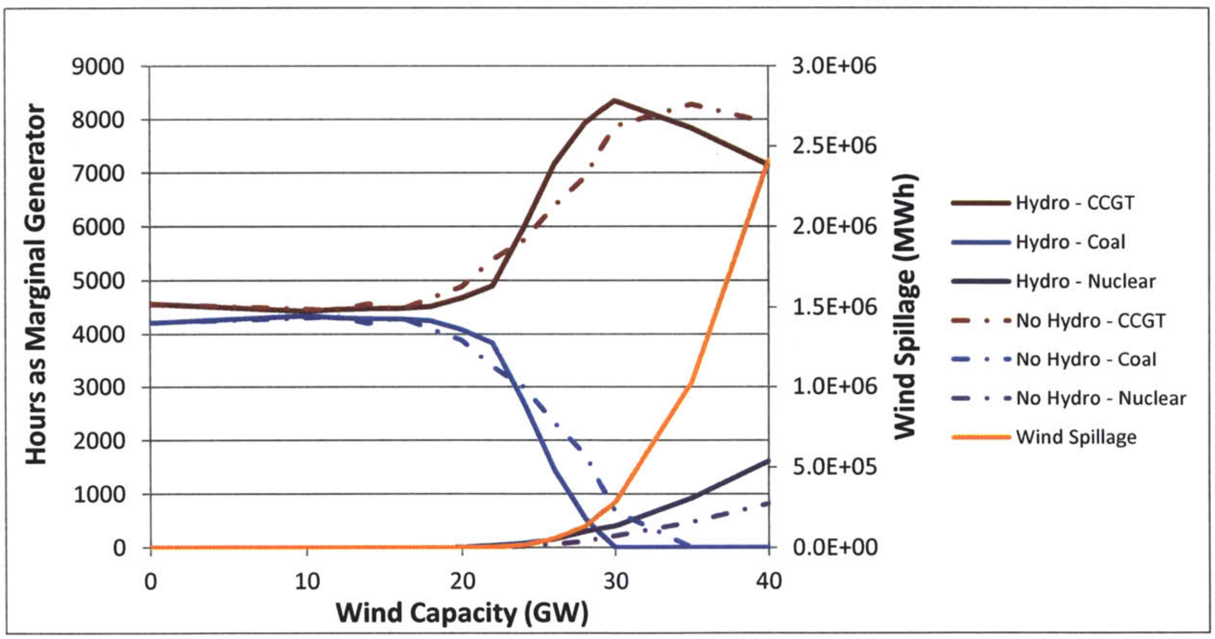


Figure 4-29 – Number of hours each technology is marginal with wind spillage shown.

5 CONCLUSIONS AND POLICY RECOMMENDATIONS

The growth of renewable power generation to significant levels in electric power systems has been promoted through a range of public policy incentives – from production tax credits to renewable portfolio mandates to loan guarantees. Wind generation, an intermittent and non-dispatchable generation resource, has however brought new challenges to the operation and regulation of the electric power system. The impacts of the intermittent generation from wind resources have already been seen at modest levels of penetration, including issues with system reliability, thermal power plant operations, and electricity prices.

Based on the hypothesis that electric power generation from hydro resources could significantly reduce these impacts, this study provides a comprehensive evaluation of the role a limited and storable generation resource, hydroelectric power generation, can play in the economic dispatch of generation resources in systems with large scale wind capacity and generation.

For this purpose, a hydro dispatch optimization algorithm was developed for the analysis of hydrothermal systems in the Low Emissions Electricity Market Analysis (LEEMA) model. The LEEMA model more specifically focuses on the chronological factors that influence the hourly scheduling of generation in an economic dispatch by considering the hour-to-hour decisions of thermal generation units and the annual production costs incurred due to the cycling and ramping of thermal plants.

The hydrothermal LEEMA model has been run on three cases based on the current electric power system in Spain, and analyzes:

- The introduction of hydro generation to the current generation mix;
- Varying levels of flexible capacity in the hydro generation facilities; and
- Increasing quantities of wind capacity and generation

The results presented here are based on a single, deterministic representation of the Spanish power system. Although there is uncertainty in many of the inputs to this deterministic model, there are several significant conclusions from the cases analyzed in this paper, as well as issues that require additional study and analysis. For this reason, the conclusions will largely be directional – focused on the trends observed in the results, as well as a qualitative description of the system dynamics most relevant for future electric power systems.

5.1 STUDY CONCLUSIONS

Hydro generation can play a significant role in reducing the impact of intermittent renewable generation on the operation of thermal generators and on electricity market prices. These positive contributions are driven by the ability of hydro generation to dispatch a portion of its limited water resources with the highest cost thermal production. Displacing thermal generation in these hours, which most commonly occur during the daily peak load, reduces the number of startups required for thermal generation plants and the percentage of operating hours that thermal plants are required to operate at less than full capacity. It will also displace the need for thermal generation capacity, with greater reductions for CCGT plants than coal plants. There is a modest reduction in market prices with the introduction of hydro generation, reflecting the lower production costs from cycling power plants, and an increase in the hours that lower variable cost coal generation is the marginal generator. Although fuel costs are generally the largest portion of market prices, the introduction of hydro has a larger impact on the amount of incremental payments to generators required for cost recovery, either through uplift or side payments.

A detailed understanding of the varied characteristics of hydro generation is required to determine the degree to which it can benefit the system. While the dispatchable portion of hydro generation provides benefits to system operation, the impacts of baseload-like run-of-the river hydro generation can make it more difficult for some generators as it reduces the net load across all hours, but most critically when net load is the lowest. Shifting hydro generation between 100% dispatchable generation and 100% non-dispatchable run-of-the-river generation leads to dramatically different outcomes for the generation mix and market prices. In addition, capacity constraints will limit the benefits of the dispatchable portion of the water resource during hours of maximum thermal production costs. These inherent characteristics of hydro generation system make it impossible to make a blanket statement about the benefits of hydro generation in systems with large scale wind generation. There are however some important observations that can be made about the role of hydro and increased penetration of intermittent renewables.

The most important factors for determining the flexibility of hydro generation systems are the minimum flow requirements and the ratio of energy available to maximum capacity output. Both factors provide insight into the limitations on hydro plants to efficiently dispatch the limited and cost-free water resources. Minimum flow requirements, which are set for many diverse purposes, limit the ability of hydro generation plants to utilize their limited resources in the most efficient way and can negatively influence the operation of lower merit order plants in periods of low demand. The balance between the energy available and the maximum generation capacity determines the number of hours in a given time period that a hydro generation plant must run to utilize the cost-free water resource. The more hours that hydro plants must run reduces their ability to optimally dispatch their cost-free resources at the times it is valued the most.

Hydro generation delays the impacts of increasing levels of intermittent wind generation on cycling and ramping of thermal plants, changes in the generation capacity mix, and higher wholesale electricity market prices. At higher levels of wind generation however, significant changes occur to the operation of the power system regardless of whether hydro generation is present. At low levels of wind generation, the advantage of hydro generation is clear as the average number of thermal unit startups is reduced by 20% and the electricity prices are lower by 2 - 4%. The number of startups and prices though will begin increasing dramatically as wind increases for both cases, with and without hydro generation, but the increase will begin at higher levels of wind generation for the hydro case. As the number of plant startups increase, it will have a direct effect on the generation mix – coal plants will begin to be forced out of the system due to the startup limitations -- and production costs will reflect those changes. A similar impact is seen in market prices. The introduction of hydro generation, in this case, delays the ramping of prices by 5 – 8 GW of wind capacity but, at higher levels of wind capacity, the prices actually merge so that there is no longer a benefit in electricity prices to hydro generation.

At higher levels of wind generation, the complexity inherent in electric power system for determining the market outcomes that result from dispatching a mix of wind, hydro and thermal generation resources makes it difficult to isolate the impact of hydro generation. The additional factors that will impact the results with rising wind generation include increased reserve requirements and wind spillage due to inflexible generation. This becomes especially true at higher wind generation levels where it becomes difficult to determine which factors are having the largest effect on plant operation and market prices. Additional analysis will be required to further explore the interactions between generation technologies that occur at high levels of wind generation. The analysis is however instructive for articulating and guiding additional inquiries into the role hydro power can play in power system efficiency, reliability and economics.

5.2 POLICY RECOMMENDATIONS

As the MIT Future of the Electric Grid study highlights, the National Academy of Engineering has called the modern US electric power grid the "supreme engineering achievement of the 20th century." As vast an achievement as the planning, construction and maintenance of the electric power system is, it is becoming clear, especially with the deployment of large scale intermittent renewable generation, that the efficient operation of these technically and economically complex systems will require further development and implementation of sophisticated policies and regulations, informed by better data and analysis.

The goal of this research has been to provide insight into the new challenges that are posed by intermittent renewable generation by highlighting the interactions among thermal and hydroelectric generation technologies. The hope is that regulators can improve on the many processes used for maintaining a reliable and efficient system and policymakers can make informed decisions on the most beneficial use of such systems for the public at large.

The results and conclusions shown above undoubtedly will be important for regulators as well as provide significant outcomes for policymakers. A few results will be further highlighted for policymakers especially as the introduction of renewable generation has largely been the result of their actions and decisions.

First, the results here have shown that electricity prices are likely to rise as renewable generation increases. This analysis provides context for the different mechanisms within the larger power system that will influence prices and shows the complexity of how different players in the system will influence each other and specifically, the role hydro power can play as systems seek to adjust to a range of policies that support increasing the role of intermittent renewables. The main factors to consider for understanding what changes should be expected include:

- the relative price of coal and natural gas generation;
- the prevalence of inflexible generation, such as nuclear and reserve requirements;
- the availability and nature of hydro resources;
- the correlation between wind generation and load; and
- the general shape, or "peakiness", of the load.

Second, the results show a substantial shift in generation capacity and natural resource utilization that will adversely affect coal-fired generation. Changes in profitability associated with policies promoting renewable generation may increase pressure on regulators and policymakers to compensate those that have been most negatively impacted by these policies. There is a suite of policies and market conditions that are impacting coal generation, including lower natural gas prices and lower overall demand as well as a range of environmental regulations outside the scope of this paper. The introduction of VER adds to these pressures on coal generation, which currently accounts for more than 40% of overall generation in the US.

Last, these initial results highlight the benefits that a flexible and storable source of electricity can have on the operation of the power system. The growth of hydro generation capacity in mature economies such as the US and EU, however, is expected to be limited. These results suggest the need for a continued push to bring electricity storage technologies to market that can reduce the burden of renewable generation on the overall power system. Many of the benefits of additional storage will however be incurred by other generators in the system, such that the investment in storage capacity, whether in the form of pumped hydro or electrochemical batteries, may be undervalued and the market alone may not provide sufficient investment incentives for development of utility scale storage resources.

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APPENDIX A: HYDROELECTRIC PLANT DATA

The hydroelectric generation plants that are modeled in this paper are a simplification of historical averages of the hydro plants in Spain using a model that was originally developed by Batlle (2002).

Overall, 17 plants are modeled in this paper with a total of 42.8 terawatt-hours of energy available throughout the year. The levels of water are allocated on a monthly basis as shown in Figure A-1.

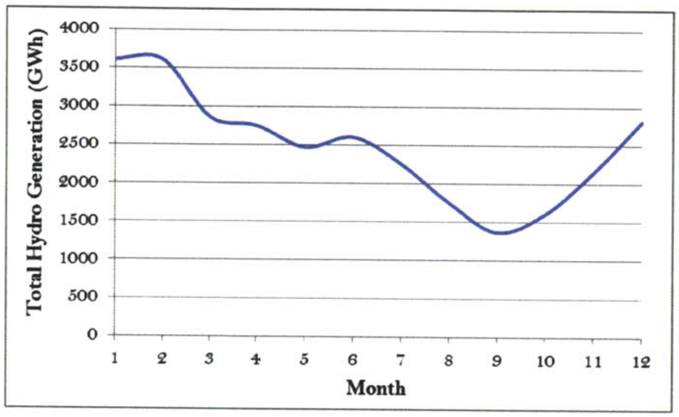

Figure A-1 – Hydro system monthly water availability.

Within the month, the water is distributed to each plant in the model based on historical averages. The amount of water available to each plant for four representative months is shown in Figure A-2.

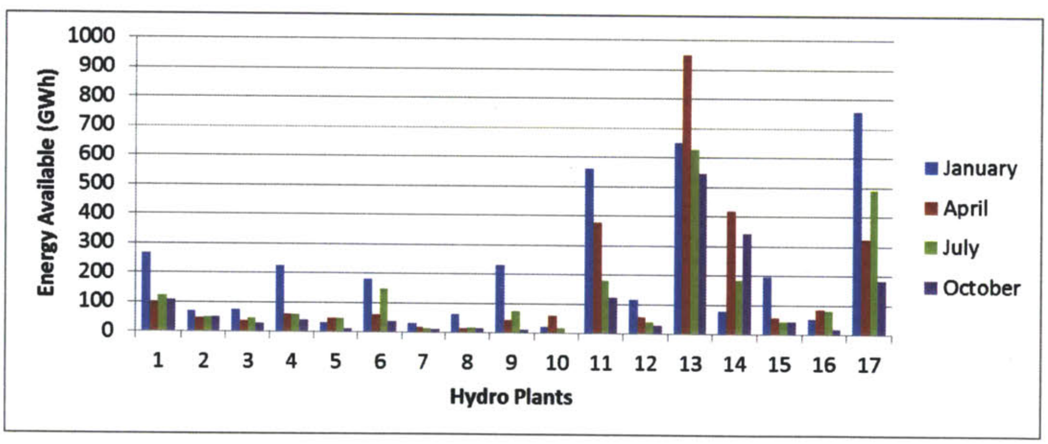

Figure A-2 – Allocation of monthly water availability to plants modeled

As discussed in Section 3.2, the many constraints placed on hydro plant operations have been simplified for each hydro generation plant based on their historical output to properly represent the maximum capacity, minimum capacity for run-of-the-river generation, and water availability. The relationship described in Figure 3-2 between the amount of water available in each month and the capacity constraints are represented in the definition of each plant. This relationship is shown in Figure A-3 for Plant 13 in the model.

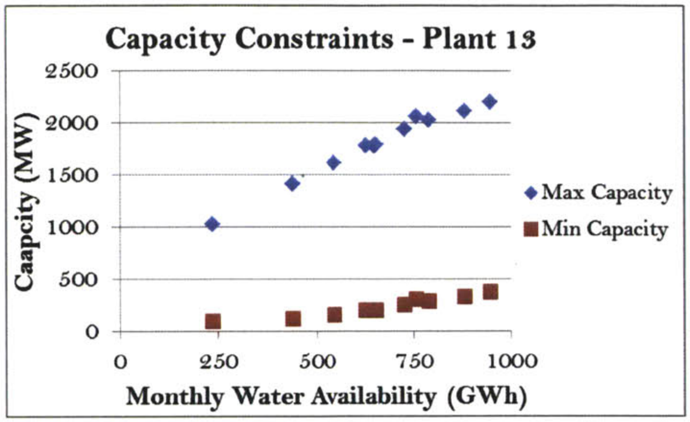

Figure A-3 – Example of hydro plant capacity constraints and water availability

On average, the maximum capacity of the hydro plants is 6900 MW and ranges each month from 5000 – 9200 MW. The average minimum capacity, or run-of-the-river (RoR) capacity, is 1200 MW with a range of 400 – 2300 MW. Across the year, 34% of generation in this case comes from RoR generation. The full details of the hydro plants are shown in Table A-1.

Plant Number	Average Maximum Capacity (MW)	Average Minimum Capacity (MW)	Average Energy Available (MWh)
1	523	14	172874
2	187	25	59287
3	132	10	43022
4	320	32	93351
5	111	23	38780
6	255	82	108073
7	69	2	20770
8	57	12	23158
9	155	73	80010
10	81	2	17996
11	688	226	306216
12	115	49	57722
13	1790	226	658303
14	927	1	227647
15	292	36	87674
16	189	23	55455
17	992	323	437492

Table A-1 – Hydro plant data

APPENDIX B: TEST CASE DATA

Implementation of the hydro dispatch within LEEMA has been completed for a test case that is modeled after the Spanish power system in 2010. The Spanish system is highly connected with the Portuguese system in the Iberian Electricity Market (MIBEL). The wholesale electricity market is operated by entities in both countries, with energy based day and intraday trading at OMEL in Madrid and derivatives trading at OMIP in Lisbon. Each country has a separate Transmission System Operator (TSO) with Red Eléctrica de España being the TSO in Spain.

The load profile used in the model is from January 1 – December 31, 2010 and is available via Red Eléctrica de España's website. The load profile is based on the Operating Hourly Program (P48) demand values with a maximum load of 44,122 MW, minimum load of 18,110 MW and total electricity demand of 260.1 TWh.

The wind profile is based on the Red Electrica de Espana Peninsular Wind Power Generation Forecast for January 1 – December 31, 2008 with maximum output of 9,865 MW, minimum output of 330 MW, and total wind production of 31.1 TWh. This data was chosen as it provided a clear representation of the role of hydro generation in the current case. The current case of the 2010 data led to results where the hydro generation impacted a complex set of interactions amongst generation technologies, as is shown in Section 4.3 of this paper, at the higher levels of wind generation.

The generation technologies studied in LEEMA are simplified representation of the conventional thermal generation mix, considering four different generating technologies: uranium (dual unit nuclear), coal (single advanced unit PC), conventional natural gas combined cycle (CCGT) and conventional combustion turbine (CT). The corresponding power plant capital and operating costs are from EIA (2010), see Table B-1.

Technology	Overnight capital cost [2010k$/MW-yr]	Fixed O&M cost [2010k$/MW-yr]	Heat Rate [kBtu/MWh]	Variable O&M cost [$/MWh]
Nuclear, τ_1	5335	88.75	N/A	2.04
Coal, τ_2	3167	35.97	8.80	4.25
CCGT, τ_3	978	14.39	7.05	3.43
CT, τ_4	974	6.98	10.85	14.70
Wind Onshore	2438	28.07	0	0

Table B-1 - Thermal generating technologies cost structures (EIA 2010)

The fuel costs were obtained from the EIA (2010) levelized cost of electricity calculations. The values are shown in Table B-2 along with the variable operating fuel costs based on the heat rates shown above.

	Nuclear	Coal	CCGT	CT
Fuel price [$/kBtu]	-	2.22	7.81	7.81
VOF [$/MWh]	6.62	23.61	55.06	84.74

Table B-2 - Fuel prices and variable operating costs

Table B-3 includes the start-up costs and heat rate efficiency losses when producing at minimum stable load (40% output) for each of the four technologies considered in the case example. The startup costs are dependent on the number of hours the plant has been shut down. Cold startups occur when the unit has been down for more than fifty hours; warm starts for when the unit has been shut down for more than eight hours; and hot starts for when the unit has been shut down for less than eight hours.

Technology	Cold start-up cost [$/MW]	Hot start-up cost [$/MW]	Heat Rate efficiency loss [%]
Nuclear, τ_1	1000	1000	N/A
Coal, τ_2	150	75	12%
CCGT, τ_3	75	30	12%
CT, τ_4	20	12	12%

Table B-3 - Conventional fossil fuel generating technologies cost structures