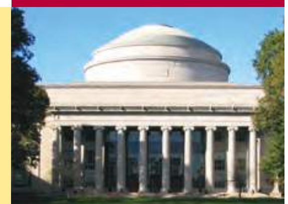
Managing Large-Scale Penetration of Intermittent Renewables



MITei

MIT Energy Initiative

An MIT Energy Initiative Symposium

April 20, 2011

Massachusetts Institute of Technology

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ABOUT THE REPORT

Summary for Policy Makers

On April 20, 2011, the MIT Energy Initiative (MITEI) sponsored a symposium on *Managing Large-Scale Penetration of Intermittent Renewables* that brought together experts in electricity generation, transmission system management, and regulation to discuss the impacts of large-scale penetration of intermittent renewables on electrical power systems. *Intermittency* refers to the limited control of electrical output from variable and partially predictable generating technologies, such as wind and solar. The grid can accommodate small amounts of intermittent electricity generation, but large-scale penetration requires rebalancing the different elements of the electricity system: generation, transmission, storage, demand management, and regulation. The symposium focused on three different aspects of intermittency: (1) prospects for more flexible operation of thermal power plants — coal, nuclear, and natural gas-fired — to compensate for intermittent sources through cycling and ramping, and the economic significance of this added flexibility; (2) impact of intermittent generation on the transmission grid and system operation; and (3) intermittent renewable generation policies and regulation. The symposium did not address the question as to the desired level of wind and solar, just the issues of managing their large-scale deployment. Prepared and contributed papers informed panel discussions; these documents are available at www.mit.edu/mitei.

Symposium participants came from different backgrounds and expressed a wide range of views. Here we summarize for policy makers the key points from the lively discussions. **The summary reflects our observations, and it is not offered as a consensus view of the symposium participants.**

- **Framing the issue.** Twenty-nine states, the European Union (EU), and countries around the world have adopted policies and incentives to encourage deployment of low-emission renewable electricity generating technologies. This has led to a rapid increase in wind and solar generation, both of which are intermittent non-dispatchable electricity sources. While their deployment remains small today in aggregate, some regions of the US and some countries have substantial amounts of wind power. This operational experience informs the challenges facing technology, policy, and regulation in managing widespread large-scale deployment.

  The characteristics of intermittent sources require system operators to adopt different, and more costly, measures to balance load and generation and maintain system reliability. Intermittency also will influence planning and design of future systems, electricity markets, and regulation. The technical and policy issues will not be resolved quickly because new arrangements will involve winners and losers compared to conventional grid operations.

  1. **Flexible operation of thermal power plants.** In 2010, thermal generation plants — coal, natural gas, and nuclear — provided 88% of US electricity generation. In the absence of pervasive utility-scale and economic storage systems, these units will be required to provide flexibility in a power system where large-scale penetration of intermittent renewables is mandated in the absence of large-scale storage. Providing generation flexibility entails fast ramping times, short startup times, and efficient partial load operation. Coal plants and current nuclear plants were not designed specifically for this flexible operation, but were instead intended to provide steady baseload generation. Natural gas plants, on the other hand, have been built, in part, with flexibility in mind in order to respond to the daily variations in load. However, the economics of baseload plants are affected significantly if they are called upon to operate in load-following mode. This is most clear for nuclear power. The very high capital costs require very high capacity factors for cost recovery.

Expanding the ability of coal, natural gas, and nuclear plants physically to ramp and cycle to varying degrees will negatively impact their operations, maintenance schedules, and expected operational lifetimes. Retrofits, advanced control systems, and newer plant designs can improve flexible operations and provide better monitoring of physical wear, but these upgrades are technically demanding and costly. In addition, when thermal generation plants are operated at partial load, fuel efficiencies will decrease, emissions will increase, and total system costs will be raised, thus diminishing the benefits of renewable generation. Accordingly, it will be crucial to assess continuously the balance between the benefits of greater renewable penetration with the cost of adapting conventional baseload systems to meet new operating requirements.

Increased flexibility of baseload generation will require new regulatory practices to allocate the recovery of the additional capital cost incurred by more flexible thermal generation capability among intermittent generation units, to adapt economic dispatch rules that take into account the differences in variable cost, and to offer incentives and compensate for sufficient capacity for balancing supply and demand in the face of uncertainty in both.

The costs to thermal plant operators of dealing with increased ramping and cycling requirements at different timescales remain to be understood in detail. Today, the optimal dispatch of thermal and intermittent sources cannot be implemented. The underlying point is that increased cycling of thermal power plants because of large-scale deployment of intermittent sources will require incorporation of both spatial and temporal considerations that have not been employed in economic dispatch algorithms.

2. **Managing intermittent generation on system operations.** Transmission, distribution, and storage technology improvements can aid the integration of intermittent renewables. These improvements include geographic aggregation, which smoothes the variability of the intermittency of wind and solar energy over large distances; increasing network interconnections to facilitate balancing through electricity imports and exports; and utilization of advanced sensors, control systems, and dispatch algorithms that can monitor and respond to power system changes in real time. Progress is slow because of inadequate mechanisms for exchanging data and setting interface standards, and because system operators understandably tend to be risk-averse and place a higher premium on reliability than on innovation. **Improved analytical and modeling tools are needed to optimize operation and regulation of the transmission and distribution system with significant deployment of intermittent generation.**

3. **Intermittent renewable generation policies and regulation.** Policies have been adopted around the world to promote deployment of renewable generation. These policies have been successful in increasing the capacity of wind and solar generation in various national systems, but the cost and operating implications of these policies are not fully appreciated. It is clear that policies that regulate investment, operations, and rates will undergo significant change. It is becoming clear that the total costs and consequences of these policies were not fully understood. In order to ensure the goals of reliability and economic efficiency while simultaneously lowering carbon emissions, substantial regulatory changes are needed. This is further complicated by the location of renewable resources, which is often remote from major load centers, which means transmission may cross multiple jurisdictions, greatly complicating siting options and opportunities.

In the US, power sector regulation is complex and involves three distinct levels of regulation with the Federal Energy Regulatory Commission (FERC) and the North American Electricity Reliability Corporation (NERC) at the federal level, a range of Regional Transmission Operators (RTO) and Independent System Operators (ISO) at the regional level (but only for part of the country), and Public Utility Commissions (PUC) at the state level. Since these agencies have overlapping jurisdictions, harmonization is needed to resolve questions regarding reliability criteria, capacity markets, and cost allocation for transmission and generation investments. For example, in the US, RTOs, vertically integrated markets, and regulated utilities have no coordinated agreements on how to curtail wind in the event of oversupply or threats to reliability. In some instances, regulations prohibit such curtailments. This lack of coordination between the various agencies is a barrier to introducing more efficient technologies and practices for integrating renewable generation into existing electricity systems.

Importantly, the policies to encourage deployment of intermittent renewable generating technologies are not aligned with cap-and-trade or emission taxes, which theoretically are economically more efficient ways to accomplish the reduction of greenhouse gas (GHG) emissions.

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MITEI Associates Program/Symposium Series

The MITEI Associates Program/Symposium Series is designed to bring together groups of energy experts to examine, analyze, and report on critical and timely energy policy/technology issues with implications for near-term actions. The centerpiece of the program is a one-day symposium in which invited experts, under Chatham house rule, discuss the selected topic. Topical white papers, which are sent to the participants in advance, are commissioned to focus and inform the discussion. The information from these white papers is supplemented by work from graduate students, who generate data and provide background information.

Potential symposium topics are solicited from MITEI members and are provided to the Steering Committee for consideration. Four MITEI Associate members – Cummins, Entergy, Exelon, and Hess – support the program with a two-year commitment and serve on the Steering Committee.

After each symposium a report is prepared and published, detailing the proceedings to include a range of findings and a list of recommendations. Two students are assigned to each session. They serve as rapporteurs for the symposium and focus their master's theses on topics identified from the symposium. MITEI also develops and implements an outreach rollout event to inform policy makers and the media of the results.

This report is the fourth in the series, following Retrofitting of Coal-Fired Power Plants for CO_2 Emissions Reductions, Electrification of the Transportation System, and the Role of Enhanced Oil Recovery in Accelerating the Deployment of Carbon Capture and Sequestration.

These reports are available electronically on the MITEI web site at http://web.mit.edu/mitei/research/energy-studies.html. If you would like to receive a hard copy of one or more of the reports, please send an email with your requested titles and quantities and your mailing address to askmitei@mit.edu.

MITEI extends its appreciation to these sponsors of the Symposium Series.

CONTENTS

The MIT Energy Initiative's Symposium on Managing Large-Scale Penetration of Intermittent Renewables

SECTION 1 FINDINGS IN BRIEF

The 2011 MIT Energy Initiative Associate Member Symposium brought together experts in the areas of coal/natural gas/nuclear power generation, transmission systems, and electricity regulation to discuss the impacts of large-scale penetration of intermittent renewables on power system operations and the capabilities of these technologies to accommodate the impacts of intermittent generation. Although many power systems are currently accommodating the intermittency effects of renewables, there is limited system-wide analysis of how the deployment of large-scale renewables physically affects conventional thermal plants, the limits of their capabilities for such accommodation, and the degree to which the integration of renewables is changing the physical and economic operations of power systems.

Throughout the symposium, participants used several terms of art in their discussions. For clarity in reading this report, the following are key terms and their definitions:

- **Predictability** refers to the ability to determine ahead of time the availability of a generation resource. Solar generation is more predictable than wind generation because the primary factors that affect solar generation — cloud coverage and night — are more predictable than the availability of wind.

- **Variability** refers to the variation over time of the availability of generation resources and the quantity of electricity demand. Wind generation has high variability because it will vary from 0%–100% over the course of a day.

- **Intermittency** refers to the limited-controllable variability and partial predictability of a generation resource.[1] For example, solar generation is intermittent because it both varies throughout the day and is not perfectly predictable.

- **Thermal generation** refers to fuel technologies that generate electricity using steam and combustion turbines. Coal, natural gas, and nuclear plants are all thermal generation units.

- **Intermittent renewables** refer to the generation of electricity from wind and solar resources.

- **Ramping** refers to changes in the output of a thermal generation unit, often done to balance the electricity supply with the electricity demand.

- **Cycling** refers to the startup and shutdown of thermal generation units, often done during low load periods such as overnight and on the weekends.

This report presents the symposium's main discussions and conclusions and is organized as follows:

- Section 2 provides an overview of how power systems and markets work in the US and an explanation of how intermittent renewables change traditional operations;
- Section 3 discusses the capabilities of power plants to respond to these operational changes;
- Section 4 discusses economic impacts of ramping and cycling;
- Section 5 discusses the impacts of renewables integration on global transmission systems, distributed generation networks, dispatch algorithms, and storage technologies; and,
- Section 6 gives details on renewable policies at the state, federal, and international level and the changes that these mandates are effecting in power systems.

Sections 2–6 provide the basis for the findings summarized in this overview.

Issues Summary: Framing the Issues

Twenty-nine states, the EU, and countries around the world have adopted policy mandates and subsidies to incentivize investment in low emissions renewable electricity generation. As renewable capacity has increased, the intermittent nature of wind and solar generation, that is, both variable and unpredictable, has led to operational difficulties and unintended consequences for emissions and economic efficiency.

The characteristics of intermittent generation combined with the need to maintain a constant balance between load and generation create challenges for system operators, who will require greater flexibility in the system to ensure reliability and meet policy goals. In the absence of economically viable large-scale storage, the burden of maintaining system reliability will fall mostly on the flexible operation of thermal generation units, such as coal, natural gas, and nuclear (hydropower is available in some regions). However, the ability of these plants to operate flexibly is limited by both physical plant constraints and economic profitability considerations.

This new mode of operation is also expected to have impacts at all levels of electric power system regulation, from economic dispatch in the short term to generation capacity investments in the long term. Ensuring the adequacy of the regulatory structure is an extremely complicated undertaking. In the US, the regulatory landscape for market rules and renewables policies is fractured and complex; planning and policy making for electric power systems occur at the state, regional, and national level.

Framing of the Issues: Key topics

- **Emissions:** While renewables can generate emissions-free electricity, the limited ability to store electricity, forecast renewable generation, and control the availability of intermittent renewables forces the rest of the electric power system to adapt with less efficient ramping and cycling operations. These operations potentially reduce the emissions benefits of renewables.

- **Unintended consequences:** Many power systems operate under mandated renewable portfolio standards that change existing market structures. The combination of mandates, markets, and physical system requirements present technological, economic, and policy-related integration challenges with unintended consequences to system planners and market participants. For example, mandates requiring renewable dispatch may increase the total system cost of generating electricity.

- **Future generation mix:** What does a well-adapted generation mix look like? How many gas peaking units and baseload plants does this mix require? What types of regulatory support are needed for units that contribute to reliability, but would likely have low-utilization rates? How will this generation be compensated? What regulatory structures are required to ensure adequate compensation? Spot prices may decline in the short term due to the fuel cost of renewables, but will this lead to an economically efficient generation mix in the long term?

- **Electricity markets:** The electricity market generally dispatches generation on a least-cost basis. Should the market treat renewables as any other generator, subject to scheduling penalties? For example, currently, renewable generators self-schedule their generation by declaring how much electricity they expect to generate in the next hour. The system operator takes these self-schedules into account when deciding which other plants to dispatch. If wind generators schedule themselves for 100 megawatts per hour (MWh) of electricity generation in the next hour, but are only able to generate 80 MWh, should the operator require that they purchase the remaining 20 MWh in the open market? Or, should the operator allow wind generators to exist independent from all, or a subset, of economic signals? Is priority dispatch justified?

- **Regulation:** Traditional regulations of transmission, business models, cost allocations, and planning criteria may not properly address the needs of renewables. The current regulatory system encourages cost reduction and reliability, not innovation. This may be inadequate to incentivize the development of the new transmission and generation technologies required to fully enable large-scale renewable generation.

Issues Summary: Flexible Operation of Thermal Power Plants

Thermal generation plants — coal, natural gas, and nuclear — accounted for 88% of electricity generation in the US in 2010. In the absence of large-scale storage, these units will be required to provide flexibility in a power system where large-scale penetration of intermittent renewables is mandated.

Providing generation flexibility entails fast ramping times, short startup times, and efficient partial load operation. Coal plants and current nuclear plants were not designed specifically for this flexible operation, but were instead intended to provide steady baseload generation. Natural gas plants, on the other hand, have been built, in part, with flexibility in mind in order to respond to the daily variations in load.

Although coal, natural gas, and nuclear plants physically are able to ramp and cycle to varying degrees, doing so will negatively impact their operations, maintenance schedules, and expected operational lifetimes. Retrofits, advanced control systems, and newer plant designs can improve flexible operations and provide better monitoring of physical wear, but these upgrades are not trivial and they are expensive.

In addition, fuel efficiencies will decrease when thermal generation plants are operated at partial load. Lower fuel efficiencies increase emissions rates and total costs, potentially diminishing the benefits of renewable generation. Continuously altering plant output also increases the need for operation outside of normal, steady-state procedures and the likelihood of operator error.

Flexible Operation of Thermal Power Plants: Key Findings

1. The most important requirements for the flexible operation of thermal generators are partial load efficiency, fast ramping capacity, and short startup times.

2. Coal plants can generally ramp their output at 1.5%–3.0% per minute. As ramp rates increase, expected maintenance costs also increase.

3. Current coal plants were not designed for flexible operation and will have mechanical, maintenance, and operational issues when pushed to operate flexibly. Generally, operators tend to run older coal plants flexibly because they are smaller capacity units (i.e., easier to ramp) and their capital costs have been fully recovered.

4. The role of coal-fired power plants is changing already due to lower natural gas prices and lower electricity demand. This trend towards lower capacity factor usage is expected to continue as higher levels of intermittent renewable generation resources are added to the electric power system.

5. It is technically possible to design coal-fired power plants for flexible generation, but it would require a substantial change in the overall design basis.

6. Natural gas-fired power plants provide the greatest generation flexibility to mitigate large-scale penetration of intermittent renewables with ramp rates of 8% per minute. New natural gas combined-cycle (NGCC) plants continue to improve their capabilities for responding to the intermittency of renewable generation.

7. The time required to start up an NGCC plant largely depends on the amount of time that the plant has been shut down. As the number of startups increases, the time between maintenance periods decreases, keeping units off-line for longer periods of time and increasing maintenance costs.

8. Relatively new nuclear reactors ramp asymmetrically: plants can down-ramp 20% of their total output within an hour, but they require six to eight hours to ramp up to full load.

9. Nuclear plant ramping operations are not fully automated. Operating a nuclear plant in a transient state requires manual manipulations that create additional opportunities for operator error.

Issues Summary: Economic Impacts of Flexible Generation

The economic impacts of flexible operation will also place constraints on thermal generation plants in systems with large-scale intermittent renewable penetration. Ramping, cycling, and partial load operations will reduce the amount of electricity generated in a year relative to baseload operation while increasing the operational costs; this impacts overall plant profitability. Under current market structures and dispatch rules, this will make it more difficult for thermal plant owners to recover costs because there will be fewer megawatt-hours across which to amortize their capital costs. Technologies that have high capital costs and low fuel costs — in particular, nuclear plants — will likely experience the greatest economic impacts from flexible operation.

Additionally, plant managers may not fully understand the costs associated with the physical wear from flexible operation and this will limit their ability to recover those costs. In the long term, these price signals may discourage future investment in flexible generation technologies that will be necessary as older plants retire, electricity demand grows, and intermittent renewable capacity expands.

Economic Impacts of Flexible Generation: Key Findings

1. The ability to operate a coal plant flexibly will require a detailed understanding of the component-level impacts on operation and maintenance costs, improved operating procedures, and updated control systems. Plant owners will likely operate existing units with minimal upgrades for economic reasons, instead of undergoing major equipment retrofits to improve plant flexibility.

2. Although NGCC plants provide the most flexible thermal generation option among baseload technologies, the historically high variable operating costs of NGCC plants limit their ability to be dispatched as often as less flexible nuclear and coal plants.

3. The traditionally higher variable costs of NGCC plants make cost recovery more difficult for plant owners (compared to baseload units) because they have to amortize capital costs across fewer generation hours. However, assuming similar capacity factors across all technologies, NGCC plants are cost competitive.

4. Absent the availability of utility-scale electricity storage technologies, incentives will likely be necessary to encourage investment in flexible generation.

5. Flexible operation of nuclear power plants dramatically impacts their profitability. Nuclear plants need to run as baseload units at high output levels to recover their high capital costs.

Issues Summary: The Transmission Grid and System Operations

Technology improvements at the transmission and distribution levels can aid the integration of intermittent renewables. For example, geographic aggregation — smoothing the intermittency of wind and solar energy over large distances — requires transmission technologies that can span longer distances and minimize power losses. Other innovations, such as increasing network interconnections to facilitate balancing through electricity imports and exports, would also benefit from new transmission technologies. Most proven transmission technologies have practical maximum lengths of only hundreds of kilometers (km), but pilot projects to test significantly longer transmission lines are underway.

Other improvements that can aid the integration of intermittent renewables include the utilization of new sensors and dispatch algorithms that can monitor and respond to power system changes in real time. Both academia and industry are working to advance the state of the art for these tools, but collaborations are limited, in part because of the inadequacy of data sharing. In addition, system operators tend to be risk-averse and place a higher premium on reliability than on innovation; this could hinder the deployment of new technologies to help manage and accommodate intermittent generation.

The Transmission Grid and System Operations: Key Findings

1. Connections to remote renewables will likely utilize high-voltage direct current (HVDC) lines. HVDC advances and innovations can contribute to the adoption of these technologies, as well as the creation of wide-scale "super-grids."

2. Intermittent renewables will likely contribute to power systems at both the transmission and distribution levels. The distribution system will have to significantly change to accommodate the back-feed problem, as well as to allow for more advanced control of generation resources.

3. Intermittent renewables present integration challenges at all timescales for the power system. As renewable penetration increases, system stability on the timescales of fractions of a second will increasingly matter as much as backup capacity at the minutes to hours scales.

4. Current algorithms to manage intermittent renewables do not accommodate the uncertainties involved in forecasting wind, load, and other probabilities. New algorithms and tools need to be developed to conduct geographic and temporal analyses and simulations that are of sufficient scale for power systems. Acquiring useful data from industry for these types of research projects is difficult.

5. Industry resists change and pilot projects on its grids, out of an abundance of caution for the reliability of its operations.

6. Storage can help integrate renewables on all timescales, for frequency regulation and backup capacity. With the exception of pumped hydro, however, many storage technologies face major economic and technological challenges.

Issues Summary: Intermittent Renewable Generation Policies and Regulations

Policies around the world to promote investment in renewable generation have been successful in increasing the capacity of wind and solar generation in various national systems. It is becoming clear, however, that the total costs and consequences of these policies were not fully understood. In order to ensure the core goals of reliability and economic efficiency while simultaneously lowering carbon emissions, substantial regulatory changes are needed. Appropriate allocation of the costs and benefits of achieving these policy goals will also require major regulatory changes and new regulatory structures. This is further complicated by the location of the best renewable resources, which tends to be remote from major load centers. This means that transmission to bring low-carbon electricity to consumers will have to cross multiple jurisdictions, including state lines and regional boundaries, greatly complicating siting options and opportunities.

In general, power sector regulation is complex and fractured across three distinct levels of regulation with FERC and NERC at the federal level, a range of RTOs and ISOs at the regional level, and PUCs at the state level. These agencies have overlapping jurisdictions; together, they will have to resolve questions that arise from current renewable policies regarding reliability criteria, capacity markets, and cost allocation.

Intermittent Renewable Generation Policies and Regulations: Key Findings

1. Proper policy and regulation are rooted in understanding and fairly allocating system costs, including existing asset costs, integration costs, and system infrastructure costs.

2. Policy challenges exist in both short-term operations and long-term planning in order to maintain a reliable, economically efficient power system.

3. Renewable technologies are highly scrutinized because their use is mandated in 29 US states, the EU, and other countries.

4. The major areas being considered for policy/regulatory changes are reliability criteria, capacity markets, and cost allocation.

5. There is a clear need for a statement on national goals for the electricity sector to streamline the US regulatory structure, which currently is complex and fragmented.

6. The regulatory landscape is rapidly evolving with progress being made at the federal, state, and regional levels.

7. Policy solutions will need to be regionally focused because of vast geographic differences in resources, demands, and markets. Each region will need to undergo extensive research to produce thoughtful and careful regulation that meets the needs of stakeholders and ensures overall system efficiency and reliability. There is a strong preference toward expanding regional decision making within the regulatory structure.

8. Too much electricity generation from intermittent renewables is as much of a problem as too little generation. Frequently, wind integration problems involve having too much wind during low demand periods; many renewables mandates require the dispatch of wind energy, regardless of demand.

9. Within the US, RTOs, vertically integrated markets, and regulated utilities have no coordinated agreements to curtail wind in the event of oversupply or threats to reliability. In some instances, state statutes also prohibit such curtailments. Lack of coordination between the various agencies involved leads to ramping and other inefficient plant operations as the main solution to accommodate excess generation.

10. An important lesson learned from the EU 20:20:20 goals is that renewable mandates are not aligned with a cap-and-trade system, which is theoretically the most economically efficient regulatory tool for the reduction of GHGs.

SECTION 2 INTRODUCTION

In an effort to decarbonize electric power systems, policy makers have promoted renewables with policies such as state-level renewable portfolio standards and federal-level production tax credits. As the quantity of generation capacity from wind and solar resources increases, the intermittent nature of these renewable resources will pose significant operational and economic challenges. Today, several sources of flexible capacity exist to help mitigate this intermittency: for example, storage and demand response. However, given the current laws, regulations, and practices that govern renewables dispatch and the high cost of large-scale storage, a large fraction of the operational and financial responsibilities for managing the intermittency of renewables will likely fall on owners of conventional power generation and transmission assets. To ensure the continuous operation of reliable and economically efficient power systems, system operators, policy makers, and regulators will need to fully understand the impacts of intermittent renewables on power systems and design new regulations and market structures that take these details into consideration.

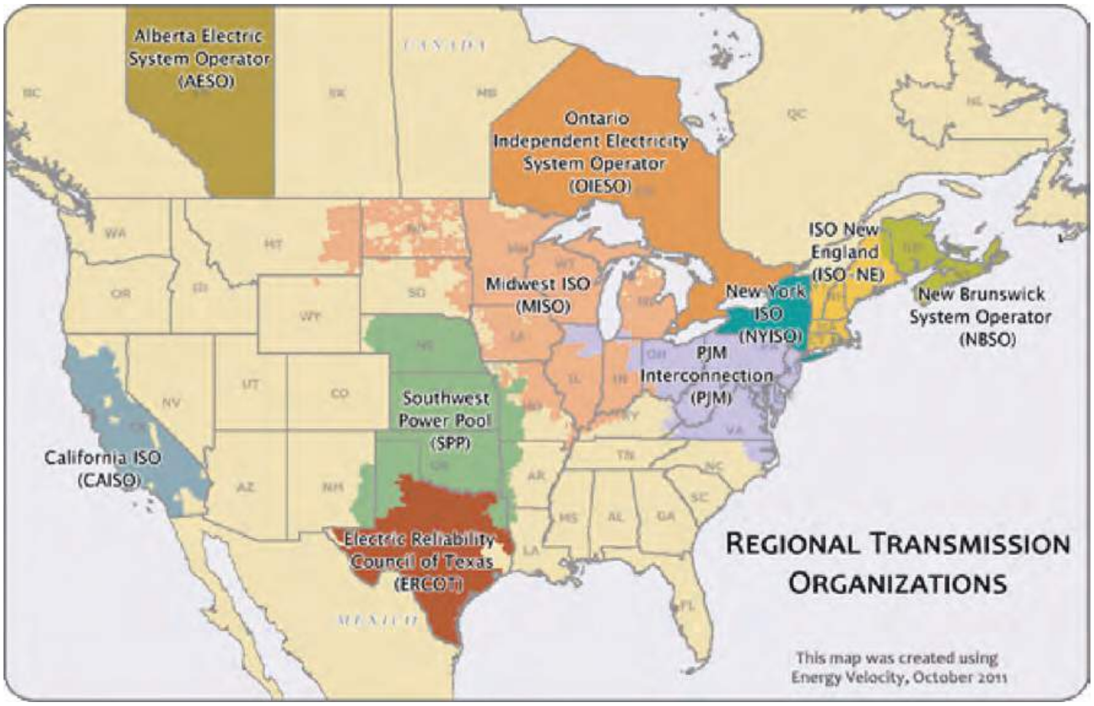
The current challenges posed by intermittent renewable resources stem from the unique characteristics of electricity. Electricity is not a primary fuel, and currently, it lacks economically competitive options for long-term, large-scale storage. Because electricity storage is limited, proper operation of power systems requires a constant balance between generation and load. More specifically, maintaining this balance requires accurate forecasts of demand, sufficient generation and transmission resources to meet demand, and flexibility in real time to adjust for imbalances. Traditional power systems operate based on a complex body of regulations and market structures that have been designed to maximize reliability and economic efficiency.

Electricity travels through a collection of high- and low-voltage transmission networks. Generation plants inject electricity into the transmission grid at high voltage to minimize power losses over long transport distances. At distribution centers located near consumers such as homes and small businesses, the high-voltage power is converted into medium and low voltages for end use. Distribution networks typically allow electricity to flow in only one direction: from generator to consumer. The symposium primarily focused on the issues that occur over high-voltage transmission networks as different types of generating stations respond to intermittent generation from renewable resources.

The US has several distinct power networks. An ISO or RTO has the responsibility to run each network so that generation is balanced with demand. There are subtle differences between ISOs and RTOs; for purposes of this discussion, they are treated as the same entity.

Figure 1 shows a map of the current ISOs. ISOs can span multiple states, and each ISO can import and export electricity to and from other ISOs. The amount of electricity that ISOs can import and export depends on the transmission capacity between them. Some ISOs, such as the Electric Reliability Council of Texas (ERCOT), are relatively isolated from the rest of the country and have limited import/export capacity. Others, such as the PJM Interconnection LLC (PJM) and Midwest Independent Transmission System Operator (MISO), have significant interconnections and cooperate extensively with each other to manage electricity supply and demand.

Figure 1 – Regional Transmission Operators in the US and Canada[2]



Source: FERC

ISOs in the US run electricity markets to minimize total system cost. Generators submit electricity bids and cost information for the operation of their plants, such as the cost of starting up, shutting down, and ramping. Based on these bids, the system operator ranks generators by total cost; this ranking is called the *merit order*. The system operator dispatches plants by merit order, from least to most expensive, to meet demand. In each hour, the most expensive plant that the system operator dispatches sets the marginal price for electricity, and all generators receive that marginal price for the electricity that they generate.

When awarding bids and making dispatch decisions, ISOs seek to make the most economically efficient decisions while achieving their top priority of maintaining system reliability. Both planned outages, such as plant maintenance and refueling activities, and unplanned disturbances, such as unexpected plant failures or sudden changes in weather, constrain the availability of thermal plants during normal power system operations.

These availability constraints require power systems to have enough spare capacity to ensure that at any given time enough generation capacity exists to meet demand. Small adjustments in plant outputs are typically referred to as *regulation capacity*. Larger adjustments, such as the startup of an additional plant, are typically referred to as *reserve capacity*. Collectively, these reliability products are examples of *ancillary services*. Plant owners, in addition to submitting generation bids, also submit ancillary services bids. In turn, when deciding which bids to award, system operators take both generation and ancillary service bids into consideration. When plant shutdowns occur, system operators plan simultaneously to replace that plant's electricity generation so as to not affect the power system as a whole. Except in the most unforeseen circumstances (one participant mentioned the recent nuclear incident in Fukushima as an example of an extreme, unforeseen circumstance), power systems with mostly thermal units in their generation mixes have well-adapted regulatory and market structures that can capably handle planned and unplanned outages.

Operating Roles of Thermal Generators

Thermal generation units do not all play the same role in meeting the electricity demand and reliability requirements of an electric power system. Generally, generators are classified as baseload, load-following, or peaking units based on the number of hours that they operate throughout the year and their capacity factor. 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.

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

- **Load-following** units will change their output based on demand fluctuations. These units may shut down on a daily or weekly basis, as the load changes. Additionally, these units shut down for maintenance after operating for a fixed number of hours or a fixed number of startups. NGCC plants and older coal plants can act as load-following units. In this role, their capacity factors range typically from 30%–50%.

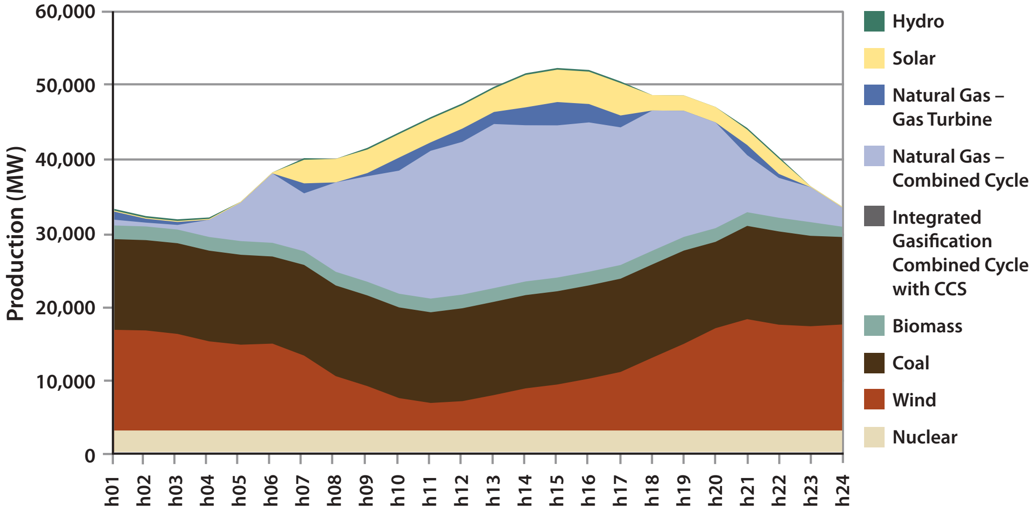
- **Peaking** units operate for a few hours each year, when electricity demand hits its annual peak. Simple cycle gas turbines and older oil-driven turbines generally act as peaking units; in these roles, their capacity factors are typically small.

Effects of Intermittent Renewables on System Reliability

The introduction of intermittent renewables, such as photovoltaic solar and wind generation,[3] complicates the traditional operation of power systems. A sudden change of wind generation requires system operators to make significant adjustments to balance generation and load by issuing instructions for 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 because they consume more fuel per unit of electricity generated. 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."

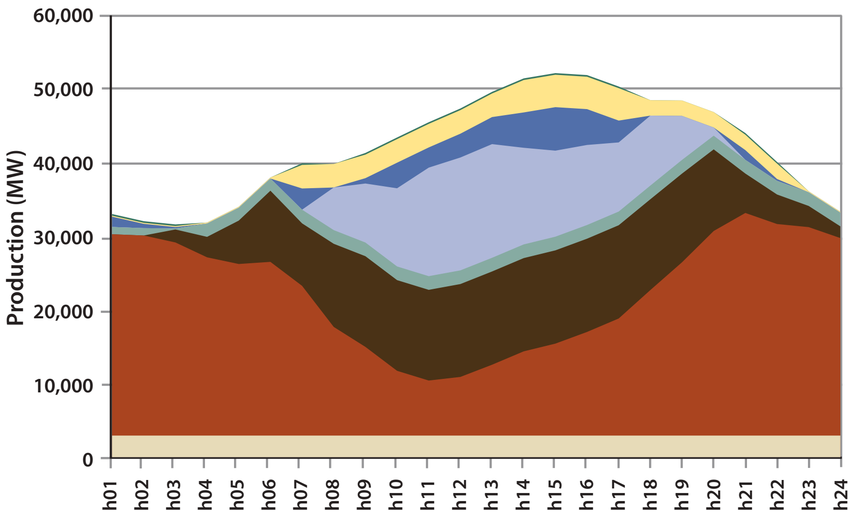
Net load is the amount of electricity that thermal generation plants must produce after the amount of generation from intermittent resources has been subtracted from the total demand. Figure 2 illustrates changes in net load due to varying amounts of wind generation. This figure shows a projected 24-hour dispatch scenario for Texas in 2030 with significant wind penetration. The net load is the amount of electricity generated by dispatchable plants above the wind output, marked in red. In Figure 3, the electricity demand remains the same, but wind generation doubles. This scenario could occur with a large introduction of wind in a short period of time. The system as a whole requires less generation from thermal generation resources (except for nuclear) with limited thermal generation in overnight hours. In particular for this stylized example, the combination of both low demand and high wind shuts down coal generation in the early and late hours and calls for more generation from gas turbines.

Figure 2 – Base Scenario: A Typical 24-Hour Electricity Dispatch[4]



Source: MIT Analysis

Figure 3 – Double Wind Scenario: An Example of the Impact of Excess Wind on Electricity Dispatch[5]



Source: MIT Analysis

Power system operators can plan for generation variability if it is predictable. For example, although photovoltaic solar is variable, its variability is easier to predict than wind. Additionally, concentrated solar power systems exhibit less variability than photovoltaic systems because they have thermal inertia.

Unlike solar technologies, wind is highly variable and difficult to predict. Additionally, peak onshore wind does not usually coincide with peak electricity demand. Symposium participants focused on the intermittent effects of wind because of its high variability, lack of predictability, and higher share of the generation mix. In 2009, wind accounted for 74 gigawatt hour (GWh) (1.9%) of electricity generation in the US.[6]

As wind penetration increases in a power system, changes in the wind will have a larger effect on the net load. To account for this increasing uncertainty, the percentage of wind's capacity that a system operator considers firm generally decreases as wind's share of the generation mix increases.

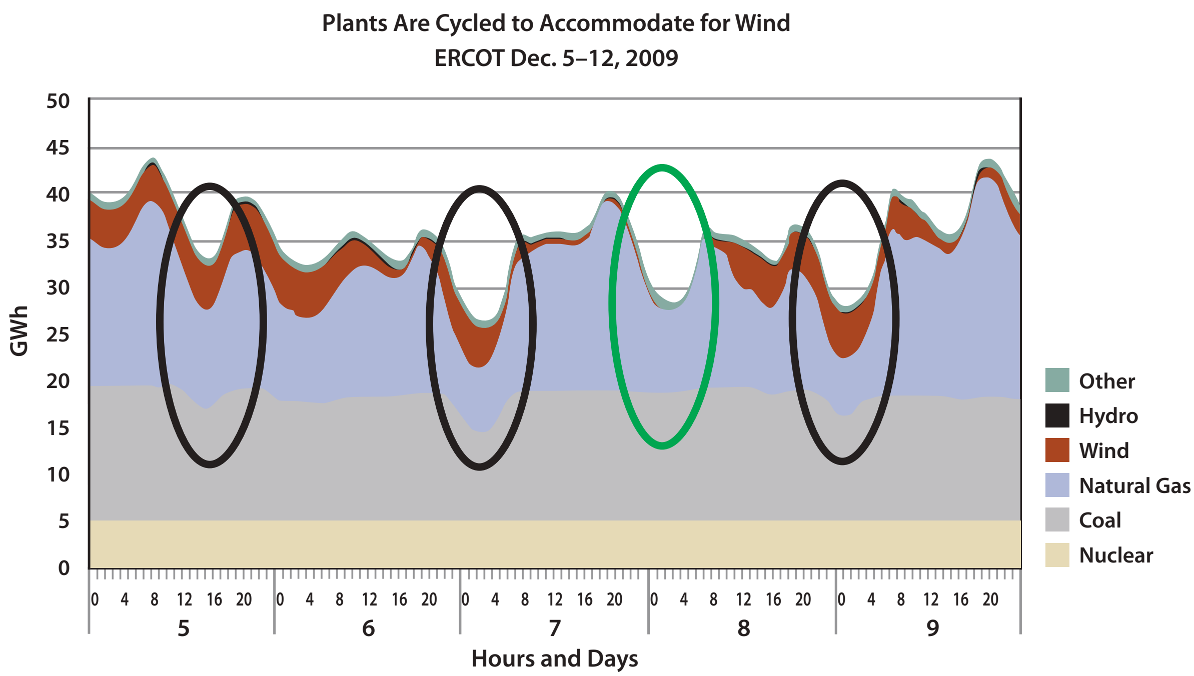
Intermittent Renewables with Limited Flexible Generation

Renewable resources are considered a clean source of electricity because of their low emissions profiles. Inefficient thermal plant ramping and cycling operations, non-coincident peaks between wind generation and demand, and regional differences in generation mixes can potentially reduce the emissions benefits of renewables.

The importance of these regional power system characteristics was described for symposium participants using a case study on the impact of wind generation on air emissions in various regions of the US, starting with ERCOT.[7] In December 2009, ERCOT experienced a combination of low demand and excess wind that forced system operators to ramp some coal plants because of inadequate ramping capacity in its mid-range gas units and the requirement to use all available wind. Figure 4 shows an example of a dispatch and demand profile that forced ERCOT to ramp its coal plants. The case study also presented generation and emissions results from December 2009 for ERCOT, during which emissions for sulfur dioxide (SO_2), nitrogen oxide (NO_X), and carbon dioxide (CO_2) increased as the thermal plants ramped down. This counter-intuitive response was the result of the ramping of thermal plants that occurred to comply with a requirement to use all available wind. The case study illustrates the unintended consequences on system operations from an inflexible renewables mandate.

Case studies for MISO, California ISO (CAISO), and Bonneville Power Administration (BPA) (Pacific Northwest) were reviewed as well. These case studies highlight the importance of local differences between regions and their power systems and generation mixes. As wind generation came on-line, emissions savings were highly dependent on the mix and availability of generation. With the exception of CO_2 emissions in MISO, no regional emissions savings actually met commonly accepted emissions reduction benchmarks for wind.[8]

Figure 4 – Electricity Dispatch for ERCOT Illustrating Coal Ramping Due to All Natural Gas Plants Running at Their Technical Minimums[9]



Source: Bentek Energy

Similarly, the costs associated with using wind to reduce NO_X, SO_2, and CO_2 emissions vary by region and generation mix. For example, regions with more gas and hydroelectric capacity start from lower emissions baselines than regions with abundant coal. Regions with relatively clean generation mixes might need more wind generation to save one ton of CO_2, compared to those regions with more carbon-intensive generation mixes, depending on the units dispatched at the margin.

Nationally, the abatement of one ton of CO_2 requires between 1 and 12 MWh of wind generation depending on the power system and its generation mix. MISO, because of its coal-heavy generation mix, can save one ton of CO_2 by replacing approximately one megawatt (MW) of its generation with wind. BPA, because of its gas- and hydro-heavy generation mix, however, needs to replace slightly more than 12 MW of its generation to save one ton of CO_2. The current production tax credit for wind in the US is $22/MWh, and the pretax value of this subsidy is $34/MWh.[10] Using a "first order" estimation based on the pretax subsidy value, the per ton mitigation costs of CO_2 are $33 in MISO and $420 in BPA. The nation's average abatement cost for one ton of CO_2 is $56.[11]

Some participants disagreed with the conclusions from this case study and raised concerns about the methodology used. The emissions and cost analysis for these case studies used statistical regression analysis, which takes data after events have happened and looks backward to reconstruct relevant details. Some participants disagreed with the case study's conclusions about wind, noting that gaining a full understanding of emissions requires an understanding of the power system's unit commitment[12] for each scenario. Understanding a power system at the unit commitment level requires knowing at all times details such as which plants are operating, which plants are ramping, and what each plant's output level and emissions rate are.

Statistical regression does not necessarily provide a complete emissions picture or properly attribute CO_2 savings to wind generation. For example, future dispatch algorithms will likely take into consideration the relative inflexibility of coal plants relative to gas plants as wind penetration increases. The resulting reduction in coal dispatch — perhaps coal plants will stay shut down for multiple days or weeks — would increase CO_2 savings. Participants also argued that relatively "clean" regions, such as CAISO, actually import some of their electricity from carbon-intensive regions, and a statistical regression analysis comparing regions does not take imports and exports into account.

Although these case studies closely examined wind, their results are generally applicable to solar generation as well. Ultimately, the level of emissions reductions achieved from renewables generation is highly dependent on both the amount of generation from each technology as well as the secondary effects that each generation technology forces onto the power system. Understanding these effects and their consequences will lead to a more precise understanding of the degree to which renewables technologies contribute to policy goals and requirements such as emissions reduction.

The Need for Flexibility

The need for increased generation flexibility is central to the challenges posed by intermittent renewables. Thermal power plants can help accommodate intermittent electricity sources with reduced startup times, increased ramping rates, and reduced minimum load levels. Each generation technology, however, faces separate challenges and presents different profiles for providing flexible capacity. The amount of flexible capacity needed to make a system reliable is typically referred to as the *firming capacity*.

There are two different ways to view firming capacity:

- A *resource-level* view requires each new renewable generation plant to have a certain amount of capacity available that can directly respond to fluctuations in its output. An example of this is a proposed solar thermal plant in Florida that is co-located with an NGCC plant to provide a consistent amount of power between the two generators.[13]

- A *system-level* view requires that the intermittent resources be viewed within the context of the entire electricity power system (e.g., at the RTO level). The aggregation of wind resources across a region could, for example, diminish the variability and reduce the need for the installation of additional backup capacity to firm up the intermittent resource.

Concerns about the reliability and firmness of wind prompted discussions about the "capacity value of wind," the "backup capacity" of wind, and the "backup cost of capacity."[14] Some participants noted that the discussion of wind generation in the policy arena is biased due to wind generation's relative immaturity. Although thermal generation technologies can also fail, they do not have explicitly specified "backup capacity." Some suggested that, instead of firming an individual resource, the correct integration approach should focus on firming the system as a whole.

Participants discussed and disagreed about creating a "rule of thumb" for the amount of capacity that would be necessary to provide backup generation from intermittent resources. Several participants noted that a Carnegie Mellon University (CMU) study[15] provides the only numbers available for planning future systems with large amounts of wind generation. Taking a *resource-level* view, the CMU study assumes that 3 MW of NGCC will be required for every 4 MW of wind.

There was strong resistance from some participants to the use of the CMU numbers. Taking a *system-level* view, these participants noted that there are many different variables that can affect the amount of firming capacity necessary, such as the existing resource mix, the size of the balancing area, and the scale of the renewable plant, and that it is not possible to create a single "rule of thumb" for firming capacity.

Participants generally agreed with the idea that natural gas plants currently provide the best technology-specific thermal generation option for managing the intermittency. Other technologies, such as coal and nuclear plants, operate less efficiently in load-following environments because they were designed for baseload generation. However, all of these conventional thermal plants will have to cycle and ramp more frequently in a future with larger penetration of variable sources, raising these overarching operational and economic questions:

- For all technologies, how often and how many times can a thermal plant cycle? How much capacity does a thermal plant have to ramp up or down? What effects do these operations have on costs?

- Can thermal plants operate profitably in this new environment of fewer hours of generation and lower output levels?

- Is must-run/priority dispatch justified for wind and renewables?

- Who is financially responsible for securing the reserves needed to handle deviations from scheduled obligations?

- Since technologies that receive subsidies could theoretically bid negative prices and still make a profit, what are the best ways to handle negative bids and the related competitiveness issues?[16]

Major Challenges to System Operation and Regulation

Given this background information about power systems and intermittent renewables, presenters and participants raised the following central themes and questions in the symposium.

- **Emissions:** While renewables can generate emissions-free electricity, the limited ability to store electricity, forecast renewable generation, and control the availability of intermittent renewables forces the rest of the electric power system to adapt with less-efficient ramping and cycling operations. These operations potentially reduce the emissions benefits of renewables.

- **Unintended consequences:** Many power systems operate under mandated renewable portfolio standards that change existing market structures. The combination of mandates, markets, and physical system requirements presents technological, economic, and policy-related integration challenges with unintended consequences to system planners and market participants. For example, mandates requiring renewable dispatch may increase the total system cost of generating electricity.

- **Future generation mix:** What does a well-adapted generation mix look like? How many gas peaking units and baseload plants does this mix require? What types of regulatory support are needed for units that contribute to reliability, but would likely have low-utilization rates? How will this generation be compensated? What regulatory structures are required to ensure adequate compensation? Spot prices may decline in the short term due to the fuel cost of renewables, but will this lead to an economically efficient generation mix in the long term?

- **Electricity markets:** The electricity market generally dispatches generation on a least-cost basis. Should the market treat renewables as any other generator, subject to scheduling penalties? For example, currently, renewable generators self-schedule their generation by declaring how much electricity they expect to generate in the next hour. The system operator takes these self-schedules into account when deciding which other plants to dispatch. If wind generators schedule themselves for 100 MWh of electricity generation in the next hour, but are only able to generate 80 MWh, should the operator require that they purchase the remaining 20 MWh in the open market? Or, should the operator allow wind generators to exist independent from all, or a subset, of economic signals? Is priority dispatch justified?

- **Regulation:** Traditional regulation of transmission, business models, cost allocations, and planning criteria may not properly address the needs of renewables. The current regulatory system encourages cost reduction and reliability, not innovation. This may be inadequate to incentivize the development of the new transmission and generation technologies required to fully enable large-scale renewable generation.

SECTION 3 FLEXIBLE OPERATION OF THERMAL POWER PLANTS

This section summarizes the ramping, cycling, and partial load capabilities of coal, natural gas, and nuclear plants. These plants accounted for 88% of the country's electricity generation in 2010.[17] As the penetration of intermittent renewables increases, these technologies will initially provide the main sources of flexibility for most power systems.

Coal-Fired Power Plants

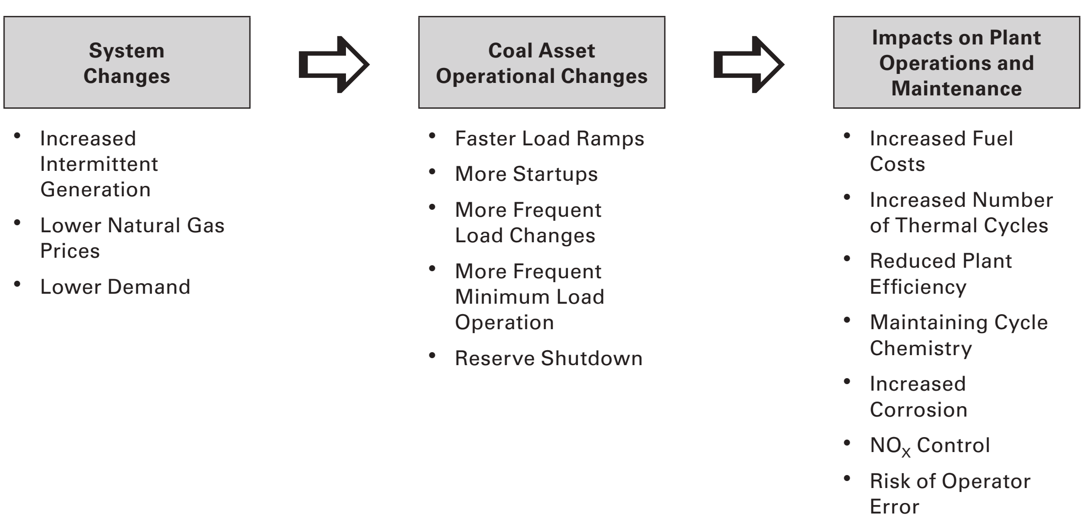
Coal-fired power plants produced 44% of the electricity generated in 2010.[18] Although historically coal plants have been primarily designed and operated as baseload units, the role of coal plants is already changing due to recent trends of lower electricity demand and lower natural gas prices that affect the dispatch order of power plants. Coal plants, especially older ones, are shifting from steadily operated baseload units to flexibly operated cycling units.

These operational changes will likely increase as the mandated levels of intermittent renewable generation are added to the grid. As the coal plants are forced to ramp and cycle more frequently, the plants will likely have increased mechanical issues, environmental and steam system control issues, and feed system issues,[19] as shown in Figure 5.

Despite these operational limitations with the currently installed coal fleet, participants agreed that it is technically possible to design coal-fired power plants to cycle. One analogy used throughout the discussion to compare coal plant designs was between an F-150 and a BMW. The current fleet of coal plants in the US has been designed to be steady work horses constantly pumping out power and not flashy sports cars with additional functionality built into their design.

The ramping rates of coal plants were generally discussed to be in the range of 1.5% to 3% per hour. Plant-level decisions will determine exactly how fast to change output based on economic considerations of the trade-off between providing flexibility versus increasing maintenance costs. Thermal expansion effects were also noted as limitations to ramping with 200°F/hour changes being a safe range to operate; ramping at 400°F/hour, while possible, would lead to higher damage rates.

Figure 5 – Impacts of Intermittent Renewables on Coal-Fired Power Plants[20]



Source: Hesler, Steve. *Impacts of Intermittent Renewable Generation on Coal Assets*. Presentation, April 20, 2011.

Beyond these generalizations, the capability of an individual coal-fired power plant to provide flexible operations depends on its size, age, and operating pressure. Participants saw data on the decadal differences in the subcritical coal plant capacity installed over the past 60 years,[21] as shown in Figure 6. Since the 1950s, the data show that plant capacity has greatly increased in size from an average of 137 MW to 512 MW.

Today, older and smaller plants are operated differently from the newer, larger plants as can be seen by the lower net capacity factor and the higher equivalent forced outage rate based on demand (EFORd).[22] A lower capacity factor indicates that these units are used less frequently, but provide flexibility by starting up more often and operating at minimum load. It is believed that both age and size contribute to greater flexibility. Older, fully depreciated units with relatively short remaining lifespans are frequently run under harsher conditions. As these older units are retired, it is unknown whether the next generation of plants will be able to provide the same type of flexibility. Small units are also able to ramp and start up faster as they will have less mass to bring up to operating temperature.

Figure 6 – Subcritical Coal Units in the US in 2009[23]

Commission Date	Number of Units	Average Net Rating (MW)	Net Capacity Factor
1950–1959	265	137	46.7
1960–1969	148	228	56.9
1970–1979	117	430	69.5
1980–1989	99	569	73.7
1990–1999	10	512	74.8

Source: Hesler, Steve. *Impacts of Intermittent Renewable Generation on Coal Assets*. Presentation, April 20, 2011.

Participants discussed the differences between subcritical and supercritical coal plants for operational flexibility.[24] To increase unit efficiency, supercritical units operate at higher temperatures and pressures, requiring thicker pipes and vessel walls that limit the rate of temperature changes. The supercritical units also have lower thermal inertia since they are designed for once-through flow of boiler water without a steam drum. Because of this, supercritical units are better able than subcritical units to provide load regulation services and small adjustments to output to maintain system frequency.

Subcritical units are, however, better than supercritical units for more frequent unit startups and shutdowns due to simpler startup procedures and overall ease of operation. For load ramping capabilities in which output is changed by a pre-determined amount, advantages are not seen for either design as both are governed by allowable component metal temperature changes.

Other factors will play an important role in determining the flexibility of a coal-fired power plant (e.g., size, fuel type, and control systems installed). As mentioned above, smaller units will be better able to respond to intermittent generation. High heating value fuels will also make it easier to operate flexibly since it will require less equipment to operate. Finally, advanced control systems around the burners and turbines will allow for increased flexibility.

Impacts of Cycling on Coal Plants

There is a range of impacts on coal plants associated with cycling and ramping. This range includes:[25]

- **Mechanical issues:** Cycling operations will lead to increased wear and tear on components through creep-fatigue interactions, repeated thermal expansion, thermal fatigue in the firebox, and rotor bore cracking of the turbine. The main areas of concern here are the steam headers, boiler tubes, and pipe hanger systems.

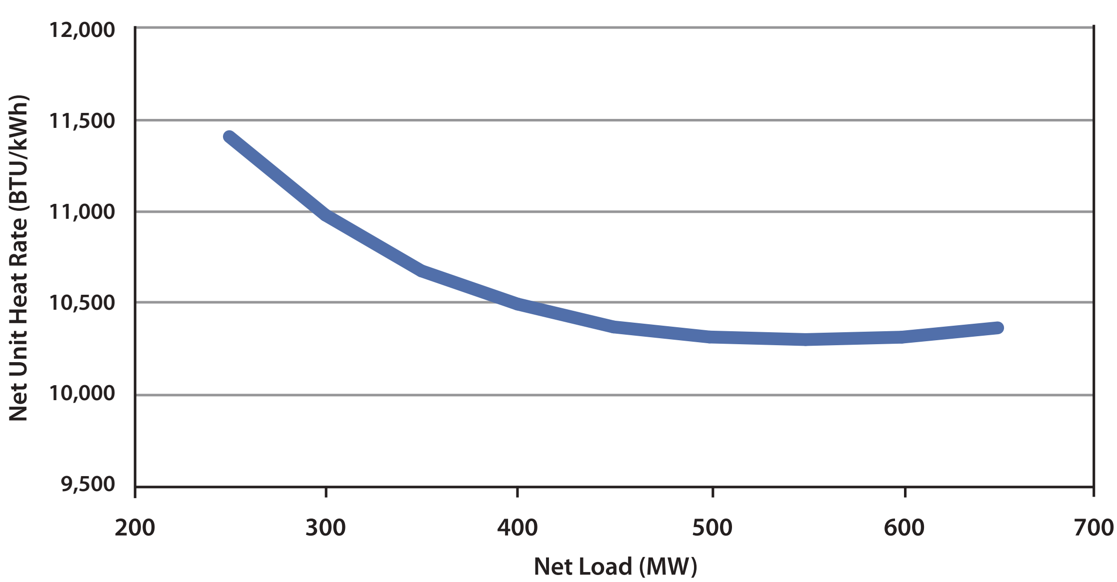
- **Water/steam chemistry:** Issues with maintaining water and steam chemistry will lead to increased corrosion throughout the steam cycle. The main areas of concern are the condensers where oxygen ingress can occur and low-pressure turbines where steam condensation leads to a buildup of corrosive material.

- **Environmental control equipment:** Performance and reliability of the flue gas desulfurization (FGD) system to remove SO_2 and selective catalyst reduction (SCR) system to remove NO_X can be affected by cycling. The FGD requires lengthy startup times and loses efficiency at turndown rates. When operated at low flue gas temperatures, the SCR can lose effectiveness from a buildup of ammonia bisulfate on the catalyst.

- **Loss of efficiency and extra startups:** Fuel usage per kilowatt hour (kWh) of electricity produced will increase as more frequent startups require more fuel to bring units up to full load and as less efficient turndown operations are used more often.[26] This will lead to increased emissions of criteria air pollutants and CO_2 on an energy basis as well. The heat rate curve for a typical coal plant, shown in Figure 7, illustrates the loss of efficiency.

- **Feed system and burn zone issues:** Operating at lower output will affect the solid transport systems used to move coal into the burning zone and will require redesign of the pneumatic system. Operating at the optimal mix of air and coal in the burn zone will face similar issues due to changes in gas flow through the feed system.

Figure 7 – Coal Plant Heat Rate Curve[27]



Source: Hesler, Steve. *Impacts of Intermittent Renewable Generation on Coal Assets*. Presentation, April 20, 2011.

- **Operator error:** Running coal plants outside of normal procedures requires operating the plant more frequently under transient conditions. Variable operations will create increased opportunities for operator errors.

With the operating environment for coal plants changing, participants noted that many of these issues are being considered in the design basis for new units. It was suggested that there should be a clean sheet look at how to build a plant so that future coal plants will be better able to provide flexible capacity to the electric power system.

There were also several suggestions from the participants for continued research and development that could be pursued to improve flexible operation of a coal-fired power plant. Materials research to alleviate the mechanical impacts of flexible generation was discussed, especially the use of Inconel 740, that would allow for thinner vessel walls in supercritical units. For operations, the suggestions included looking closely at control systems, adding strain gauges, and new transient operational strategies. The need for an industry-wide database of costs was discussed to better understand the impacts of cycling operations on the plants and the component costs that might arise.

Natural Gas-Fired Power Plants

Natural gas-fired power plants, which generated 25% of all electricity in 2010,[28] will also experience greater cycling and ramping operations as intermittent renewable penetration increases.[29] Natural gas plants include NGCC plants and simple cycle gas turbines (SCGT).[30]

The role of natural gas-fired power plants in the current system has generally been load-following for NGCC plants and peaking operations for SCGTs; both technologies are designed for higher levels of flexibility and responsiveness than baseload technologies.[31] These design characteristics include faster starts, quicker ramping, and limited heat rate penalty at minimum load, making these units well suited to meet the challenges posed by intermittent renewable generation. The amount of flexible gas generation required to balance intermittent renewables depends on the type of the renewable resource and the system in which the plant will operate.

Natural Gas-Fired Technologies

Electricity is generated from two types of natural gas-fired technologies:

- **SCGTs**, like jet engines, use the expansion of gases resulting from the combustion of natural gas and oxygen to drive a turbine that generates electricity. SCGTs are typically built to provide power during peak hours and designed to produce 100–200 MW of power with new units operating at 30%–40% efficiency.

- **NGCC** plants utilize one or more SCGTs to produce approximately 60% of the power and a heat recovery steam generator (HRSG) system to produce approximately 40% of the power from a steam-driven turbine. The HRSG system significantly increases efficiency by recovering waste heat in the gas turbine exhaust stream. NGCC plants are normally built to provide baseload or load-following power and are designed to produce 200–500 MW of power at 50%–60% efficiency.

Natural gas-fired plants are able to start up and produce power quickly because, unlike conventional coal units, steam systems are not required for initial operation of the turbines. NGCC units, however, take longer than SCGTs to reach maximum loads because bringing the HRSG system on-line takes additional time.

There was consensus that NGCC and SCGT plants can provide the electric power system with sufficient flexibility to respond to intermittent renewable power generation. They do so with a combination of the following capabilities:[32]

- **Part Load Efficiency:** NGCC plants can reduce their output to 80% capacity with minimal heat rate penalty with increasing efficiency losses at lower outputs.

- **Ramping Capacity:** The ramping rate of NGCC and SCGT plants is generally accepted to be ~8%/min, as compared to 1.5%–3.0%/min for coal-fired power plants.[33]

- **Startup Time:** Current designs of SCGTs in operation are able to ramp to 100–150 MW in 10 minutes and NGCC plants today can do so in 60–80 minutes. New NGCC designs with an increased focus on the ability to operate in a system with a large capacity of intermittent renewables are expected to produce 150 MW in 10 minutes and to ramp to full load in 30 minutes.

Startup times are highly dependent on whether the unit is turned on in a hot, warm, or cold condition, based on how much time has elapsed since its last shutdown.[34] Additional starts and stops directly affect the maintenance costs of plants, by shortening the time interval between planned maintenance. Although natural gas-fired plants are able to operate at lower output with limited loss of efficiency, there is a design trade-off in baseload mode between flexibility versus efficiency similar to that of coal-fired plants.

Nuclear Power Plants

The discussion of the impacts of intermittent renewables on nuclear generation centered on UK and US energy policies, investment opportunities, and plant operations, beginning with an overview of how nuclear generation fits into today's economic and political environment.

In 2010, nuclear power plants provided 20% of the country's electricity.[35] Nuclear power is emissions free, and the cost of fuel over the lifetime of the plant is small relative to the initial investment cost of the plant. Nuclear units are capable of limited ramping, but normally do not do so for economic reasons. Older units have ramped up for refueling and newer units can explicitly load-follow. The following list provides a brief overview of common nuclear power plant designs and their ramping capabilities:[36]

1. **Magnox** plants are gas-cooled[37] and use natural (unenriched) uranium fuel. These plants do not ramp or cycle. The US does not have any Magnox plants. The UK is expected to shut down its two remaining Magnox plants by 2012.

2. **Advanced Gas-Cooled Reactors (AGR)** use enriched uranium fuel. AGRs run at higher temperatures than Magnox plants, allowing greater thermal efficiency and less frequent refueling periods. AGRs were originally designed for full load refueling to maximize power plant availability, but operators have refueled AGRs when they were not running at full load.

3. **Pressurized Water Reactors (PWR)** are water-cooled, use enriched uranium, and require refueling every 18 to 24 months. PWRs maintain a high-pressure environment to keep water from boiling inside their cooling units. Heat from this water drives a separate steam process for electricity generation. PWRs can ramp, and have done so in the past explicitly to accommodate wind.[38]

4. **Boiling Water Reactors (BWR)** are similar to PWRs and can ramp. The main difference between BWRs and PWRs is that the water that circulates as coolant also turns to steam. The steam directly drives electricity generation and then condenses for recirculation.

The US has a total of 104 nuclear reactors. Of these 104 reactors, 69 are PWRs and 35 are BWRs; Figure 8 shows the location of these plants.[39] Although operators of BWRs have successfully run their nuclear plants in load-following configurations, participants stressed that the operation is uneconomic; one participant also noted that in the PJM/MISO area, excess wind is increasingly leading to more frequent and longer duration nuclear plant manipulations.

Operators use the phrase "manual manipulation" to describe ramping operations for nuclear plants because these operations are not entirely machine automated; each adjustment requires human intervention. Several participants stressed that the risk of human error should not be underestimated. Learning how to properly operate a nuclear plant at full load took the nuclear industry a great amount of time, and learning how to ramp these plants safely and efficiently to meet wide load variations not contemplated in the original design faces a similar learning curve.

Newer nuclear plants can ramp down fairly quickly: a reduction of 20% of total output in an hour is feasible. However, units need six to eight hours to return to full load. In short, nuclear plants in general cannot quickly load-follow to accommodate intermittent generation dispatch; plants that ramp down at night, for example, cannot ramp up fast enough to serve the morning load.[40]

Figure 8 – Map of Nuclear Power Plants in the US[41]

Source: "Nuclear Power in the USA." http://world-nuclear.org/info/inf41.html, June 2011.

Flexible Operations of Thermal Power Plants: Key Findings

1. The most important requirements for the flexible operation of thermal generators are partial load efficiency, fast ramping capacity, and short startup times.

2. Coal plants can generally ramp their output at 1.5%–3.0% per minute. As ramp rates increase, expected maintenance costs also increase.

3. Current coal plants were not designed for flexible operation and will have mechanical, maintenance, and operational issues when pushed to operate flexibly. Generally, operators tend to run older coal plants flexibly because they are smaller capacity units (i.e., easier to ramp) and their capital costs have been fully recovered.

4. The role of coal-fired power plants is changing already due to lower natural gas prices and lower electricity demand. This trend towards lower capacity factor usage is expected to continue as higher levels of intermittent renewable generation resources are added to the electric power system.

5. It is technically possible to design coal-fired power plants for flexible generation, but it would require a substantial change in the overall design basis.

6. Natural gas-fired power plants provide the greatest generation flexibility to mitigate large-scale penetration of intermittent renewables with ramp rates of 8% per minute. New NGCC plants continue to improve their capabilities for responding to the intermittency of renewable generation.

7. The time required to start up an NGCC plant largely depends on the amount of time that the plant has been shut down. As the number of startups increases, the time between maintenance periods decreases, keeping units off-line for longer periods of time and increasing maintenance costs.

8. Relatively new nuclear reactors ramp asymmetrically: plants can down-ramp 20% of their total output within an hour, but they require six to eight hours to ramp up to full load.

9. Nuclear plant ramping operations are not fully automated. Operating a nuclear plant in a transient state requires manual manipulations that create additional opportunities for operator error.

Throughout the symposium, as participants discussed the physical capabilities of thermal generation plants to operate in power systems with large penetrations of intermittent renewables, they also considered the economic implications of these operating conditions. This section reviews the primary economic impacts and concerns that arose.

Economic Impacts on Coal Plants

Participants discussed the need to better understand the costs of operation, maintenance, and shutdown of coal-fired power plants due to flexible operations, in order to know how long current plants will be able to operate and to plan for future generation capacity needs.

If coal-fired power plants are required[42] to operate more flexibly, plant managers will have to decide how often to ramp, cycle, and operate at reduced output to meet the new operational requirements without increasing maintenance costs so much that operation becomes uneconomical. To limit these effects, a detailed understanding of component life-limiting aspects of a plant is required along with changes to operations procedures and improved control systems.

There was a general consensus that the most likely and lowest-cost solution for coal-fired plants will be to improve operations by fully analyzing operational adjustments and control system changes as opposed to retrofitting existing units to enhance flexibility. Coal plants in the UK were suggested as examples of how operational adjustments can be implemented to allow for the plants to be cycled on a daily basis. There are, however, retrofit options that could be pursued, including the addition of steam bypass systems, the re-mixing of economizer inlet flows, and the re-circulation of flue gas for coal feed systems. The quoted costs for making plants more "adaptive" were in the range of $100–150/kW.

The ability of plant operators to project the additional costs of operating a plant more flexibly is crucial to submitting proper bids into the wholesale market and maintaining plant profitability. Not properly incorporating these variable operation and maintenance (O&M) costs into market bids, either because the costs are not fully understood or because current market rules do not allow these additional costs, will impact the profitability of plant operators and produce incorrect price signals for future investment.

New unit designs might also have to accommodate operations with added carbon capture and sequestration (CCS) units. The participants discussed a concept in which CCS may supply ancillary services to the system; CCS units consume a large "house load" that could quickly be diverted to power generation. The cost of venting CO_2 would be the primary driver in decision making, for which the high price of installing a CCS system must be weighed against the cost of venting CO_2. The upside could be the potential for recovering 40% of the costs through ancillary service payments.[43]

Economic Impacts on Natural Gas Plants

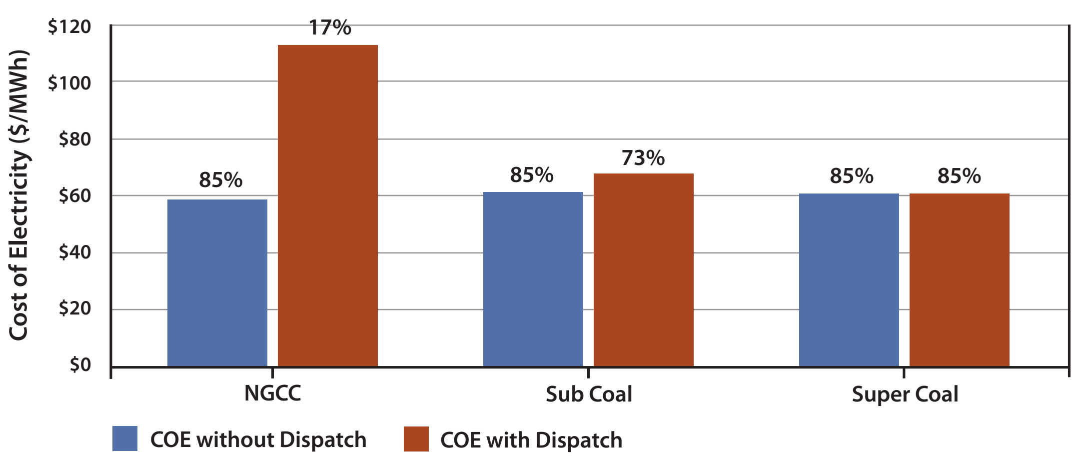
The economics of a load-following NGCC power plant and a peaking SCGT power plant differ from those of baseload coal or nuclear plants. Baseload plants generally operate throughout the year, logging a high number of operating hours. The capacity factor for baseload plants, which is the percentage of time each year that a power plant is operating, is commonly 80%–85% for coal plants and 90%–95% for nuclear plants.

Power systems dispatch load-following units last because the marginal cost of their generation tends to be the highest of all generator types. When demand declines, such as in the middle of the night, load-following plants shut down before other plants. These types of dispatch decisions reduce the total operating hours of load-following plants. Because of this operating cycle, the capacity factor of NGCC plants can vary greatly from region to region in actual operations. For example, the average capacity factor for NGCC plants in CAISO was 47%; in PJM, it was 22%.[44] In 2009, the national average was 41%.[45]

Because of today's low NGCC capacity factors, NGCC plants appear to be more expensive. Different generation technologies are often compared based on their levelized cost of electricity (LCOE). LCOE is expressed as a price per unit of electricity generated ($/MWh), taking into account both the initial capital and variable operating costs of a technology. LCOE comparisons, however, frequently rely on the assumption that different generation technologies will operate at specific capacity factors and do not consider operational issues, such as cycling and ramping capabilities. These assumptions lead to higher LCOEs for technologies that have lower assumed capacity factors. Figure 9 shows the LCOE for NGCC, subcritical coal plants, and supercritical coal plants with and without dispatch considerations. At equal capacity factors of 85%, the LCOEs are essentially the same for all three technologies. However, when the expected dispatch considerations are included, the cost of NGCC plants increases significantly compared to the coal technologies. Figure 9 provides an extreme result by choosing a very low NGCC capacity factor for illustration, in addition to using high natural gas and low coal prices relative to today's prices.

Planning for future power systems will require modeling based on the assets in place today and a realistic understanding of actual dispatch considerations and practices. Several participants urged that economic dispatch be included in the future as an essential feature of any system modeling in order to ensure more accurate results. System-wide modeling using a unit commitment dispatch model was also highlighted as important for accurate and useful data and information for decision making.

Figure 9 – Effect of Dispatch on Cost of Electricity (COE)[46]



Source: NETL

Investment in new NGCC plants to provide the system flexibility needed to accommodate renewables is especially challenging. Currently, the US has an excess of generation capacity because of previous overinvestment. At the same time, there is limited capacity to respond to the new challenges posed by intermittent renewables. System variability has already increased and will continue to do so with large-scale penetration of intermittent renewables, which creates a need for additional ramping capacity. Also, peak demand is rising faster than overall demand. This situation creates a need for regulatory structures that encourage investment in both peaking and ramping capacity in an environment where overall capacity requirements are already being met. The importance of this issue was highlighted by an example of how one major utility has had to ramp its coal plants due to a lack of NGCC capacity in its system. To accommodate additional mandated intermittent renewables, this same utility will likely be required to ramp its nuclear plants as well.

New NGCC generation capacity costs were discussed at roughly $1,000/kilowatt (kW) compared to $1,800/kW for wind, which has recently dropped from $2,200/kW. Some participants felt strongly that because the costs for all generation sources will be higher in the future, cost comparisons should focus on the future costs of each generation source, not on today's costs.

Economic Impacts on Nuclear Plants

Although nuclear power plants can technically ramp, such operations have dramatic impacts on profitability. As previously noted, upfront capital costs constitute the vast majority of the cost of nuclear generation, and investors face numerous front-loaded risks, such as cost overruns in the construction phase; possible changes in safety and environmental regulation; and various degrees of opposition from the public, politicians, and interest groups.[47]

In contrast, the operational costs and decommissioning risks associated with nuclear plants are relatively low. Since operational costs (including fuel) for a nuclear plant running at partial load versus full load do not significantly differ, there is no incentive to run a plant at less than full load. Additionally, the business model of a nuclear plant relies on high-capacity factors to recoup the initial investment costs and to establish reasonable rates of return; nuclear plants serve baseload demand for *economic* reasons.[48] In effect, because capital costs dominate the LCOE for nuclear power, the LCOE is nearly inversely proportional to capacity factor.

Given these risks and the high upfront costs for nuclear technology in today's economic environment, there was general consensus among participants that investors today prefer natural gas-fired power plants. Unlike nuclear, the operational costs for natural gas plants mostly involve fuel costs, and investors can pass fuel price volatility on to consumers. In liberalized power systems where gas-fueled mid-range and peaking units frequently set the marginal price for electricity, prices for natural gas and electricity are highly correlated. Simulations presented in the Nuttall white paper show that under scenarios with tightly correlated gas and electricity prices, the net present value of a combined cycle gas turbine (CCGT) matches the net present value of a nuclear plant. In these cases, nuclear's primary value is its ability to serve as a hedge against gas prices (in addition to providing emissions-free electricity).

Participants noted that natural gas prices and technologies currently set the benchmark for investment. Discoveries of new sources of natural gas are likely to keep gas prices relatively low for the near future, and most participants felt that over the next decade, investors are unlikely to take on new nuclear projects in the US (beyond those investors that have benefited from substantial "first mover" federal subsidies).

Economic Impacts of Flexible Generation: Key Findings

1. The ability to operate a coal plant flexibly will require a detailed understanding of the component-level impacts on operation and maintenance costs, improved operating procedures, and updated control systems. Plant owners will likely operate existing units with minimal upgrades for economic reasons, instead of undergoing major equipment retrofits to improve plant flexibility.

2. Although NGCC plants provide the most flexible thermal generation option among baseload technologies, the historically high variable operating costs of NGCC plants limit their ability to be dispatched as often as less flexible nuclear and coal plants.

3. The traditionally higher variable costs of NGCC plants make cost recovery more difficult for plant owners (compared to baseload units) because they have to amortize capital costs across fewer generation hours. However, assuming similar capacity factors across all technologies, NGCC plants are cost competitive.

4. Absent the availability of utility-scale electricity storage technologies, incentives will likely be necessary to encourage investment in flexible generation.

5. Flexible operation of nuclear power plants dramatically impacts their profitability. Nuclear plants need to run as baseload units at high output levels to recover their high capital costs.

SECTION 5 THE TRANSMISSION GRID AND SYSTEM OPERATIONS

Throughout the symposium, participants highlighted other important integration challenges and issues associated with the operational impacts of renewable electricity generation. This section summarizes these discussions about global transmission systems, distributed renewable generation, dispatch algorithms, and storage.

Global Transmission Systems

National transmission grids around the world have unique characteristics that reflect the priorities of their planning/regulatory entities.[49] As countries around the world increasingly rely on remote renewable resources, the need for siting longer and higher-capacity transmission lines must be addressed. For example, the North Sea is likely an abundant source of offshore wind, but is remote relative to European load centers. In the US, the midwest wind corridor poses a similar distance challenge (though the US also has substantial coastal wind resources).

Most large-scale renewable installations will likely require longer transmission lines. As a benchmark example, hydroelectric generation systems around the world can have transmission lines that are up to 3,000 km long.[50] These hydroelectric systems connect to transmission grids using HVDC lines because high-voltage alternating current (HVAC) lines lose significantly more energy over long distances.[51] Future installations of offshore wind, other non-distributed generation technologies, and "super-grids" connecting large geographic regions across entire continents will likely utilize HVDC systems.

Advances in HVAC and HVDC technologies will help enable large-scale grid integration of remote renewable sources. For example, China is piloting an ultra-HVAC project to bring onshore renewable resources to its grid. The pilot project, installed since 2009, connects Shanghai to Yibin, runs at 1,000 kilovolts (kV), and spans thousands of kms.[52] Modern innovations in HVDC technologies have also widened the operating range for direct current (DC) transmission systems, allowing voltages as high as 800 kV and transmission capacities typically between 1,000 and 3,000 MW (with a successful project at 6,400 MW).[53] Additionally, HVDC lines are increasingly competing with HVAC lines on an economic level at smaller scale, on the order of a few hundred Kms and tens of MWs of capacity. These innovations will enable the large-scale grid integration of renewables from both "large and lumpy" installations to local, distributed sources.

Distributed Renewable Generation

Participants discussed some distributed renewable generation systems in operation today that allow end users to generate electricity and supply surplus electricity back to the distribution grid. Countries like Denmark and Germany are pushing the boundaries of what can be achieved with distributed generation. Most power systems, however, do not have protection and control schemes to handle power flowing backward at the distribution level.

Significant opportunities exist to implement advanced controls for distributed renewable generation; these will raise compensation and ownership challenges. For example, during time periods of excess wind and solar power relative to demand, can the system operator curtail local renewable generation? If a local utility pays for the infrastructure to allow an end user to inject power back into the grid, does the end user simply pay for net electricity usage, or would there be separate meters for consumption and generation?

Utilities typically allocate shared costs to all of their customers based on how much electricity they consume. Paying only for net usage potentially forces other consumers to pay a disproportionate share of infrastructure costs. Take, for example, the case in which an end user generates exactly as much electricity at night as he uses during the day. The end user would pay nothing, because his net consumption is zero. Essentially, he has stored electricity on the grid for free and forced other consumers to pay for his fair share of this benefit. Resolution of these ownership and compensation issues will dictate the types of controls to use at the distribution level.

Intermittent Renewables and Power System Instability

In addition to focusing on mitigating problems associated with integration that occur on an operational timescale of minutes and hours, participants also discussed immediate power system impacts. As renewable penetration increases, power systems will have less inertia for dealing with sudden changes. For example, in 2008, the rapid loss of 1.4 gigawatts (GW) of generation in Texas nearly took down ERCOT's grid and forced rolling blackouts to avoid further problems.

The timescale for stability problems and control technologies (on the order of seconds and minutes) is much shorter than for ramping and cycling operations. Industry and academia continue to research new grid control technologies to enable real-time monitoring of power system dynamics across entire power systems. China, for example, is piloting a Wide-Area-Control program to provide automatic system control and real-time monitoring of frequency- and voltage-related information throughout its power network to help prevent future stability problems.[54] Despite the growing importance of this category of issues associated with integrating renewables into the grid, cautious transmission operators have tended to shy away from testing new monitoring and control technologies.[55]

Modeling Intermittent Generation

Power system operators currently run unit commitment strategies assuming fixed information. They treat wind as negative load and then dispatch thermal plants until electricity demand and supply are balanced. New strategies are required to effectively deal with the uncertainty of both load and supply associated with intermittent renewables.

In reality, the probabilistic nature of intermittent renewables significantly complicates dispatch decisions. Actual values for load and renewable generation fall within a range of probabilities. New algorithms are needed to reflect these probabilities and to inform dispatch decisions to help ensure system reliability and minimize cost. Also, in distributed generation environments with many small electricity producers, such models could help coordinate the actions of multiple agents.

Hardware already exists to provide better information at the grid level, but few operators utilize this level of detailed information in their control and dispatch operations. One participant challenged academia to shift away from its historically analytical role toward a role of development to help integrate new control technologies, such as real-time synchronized phasor measurement devices to monitor power system dynamics.[56] The participant noted, however, that this was a "rather tall order," given the industry's culture of resistance to new and experimental projects.

Others suggested that current academic studies of power systems lack the complexity necessary to thoroughly understand operations at critical physical and temporal scales. For example, during a discussion on geographically aggregating wind as an option for managing intermittency, one participant noted that academic research frequently utilizes hourly data, even though geographic aggregation occurs on the timescale of minutes and seconds. Averaged hourly data can make wind conditions appear meaningfully correlated across vast geographies. Assume, for example, that at wind farms A and B (physically far away from each other), the wind blows at 50 miles per hour (mph) for the first half hour and not at all for the second half hour. On an hourly basis, wind farms A and B look like they have the same wind speed. However, wind farm A clearly cannot generate electricity in the second half hour to make up for wind farm B and vice versa.

This example illustrates the need for more granular geographic and temporal data to accurately characterize wind generation and some of the effects of intermittent renewables. Participants noted that academic analyses and studies have been hampered by lack of access to key industry tools and data, but generally felt academia plays an essential role in such studies. They noted the need for new modeling tools and access to more data at the physical and temporal scales.

Storage

There is a range of storage technologies, such as batteries, pumped hydro, and flywheels, that can help mitigate the intermittency of renewables.[57] Storage technologies can also provide stability support and backup energy during long periods of low generation.

One participant focused specifically on compressed air storage. Compressed air storage uses electricity to compress air into an airtight space when electricity is available (and generally, when it is not expensive). Then, as needed, air is released to generate electricity.[58] There are currently several compressed air storage pilot projects underway in the US. Some participants felt strongly that compressed air storage is economically viable for bulk storage, but acknowledged that there are geologic risks associated with storing pressurized air in geologic formations such as old salt mines.

The Transmission Grid and System Operations: Key Findings

1. Connections to remote renewables will likely utilize HVDC lines. HVDC advances and innovations can contribute to the adoption of these technologies, as well as the creation of wide-scale “super-grids.”

2. Intermittent renewables will likely contribute to power systems at both the transmission and distribution levels. The distribution system will have to significantly change to accommodate the back-feed problem, as well as to allow for more advanced control of generation resources.

3. Intermittent renewables present integration challenges at all timescales for the power system. As renewable penetration increases, system stability on the timescale of fractions of a second will increasingly matter as much as backup capacity at the minutes and hours scales.

4. Current algorithms to manage intermittent renewables do not accommodate the uncertainties involved in forecasting wind, load, and other probabilities. New algorithms and tools need to be developed to conduct geographic and temporal analyses and simulations that are of sufficient scale for power systems. Acquiring useful data from industry for these types of research projects is difficult.

5. Industry resists change and pilot projects on its grids, out of an abundance of caution for the reliability of its operations.

6. Storage can help integrate renewables on all timescales, for frequency regulation and backup capacity. With the exception of pumped hydro, however, many storage technologies face major economic and technological challenges.

SECTION 6 INTERMITTENT RENEWABLE GENERATION POLICIES AND REGULATIONS

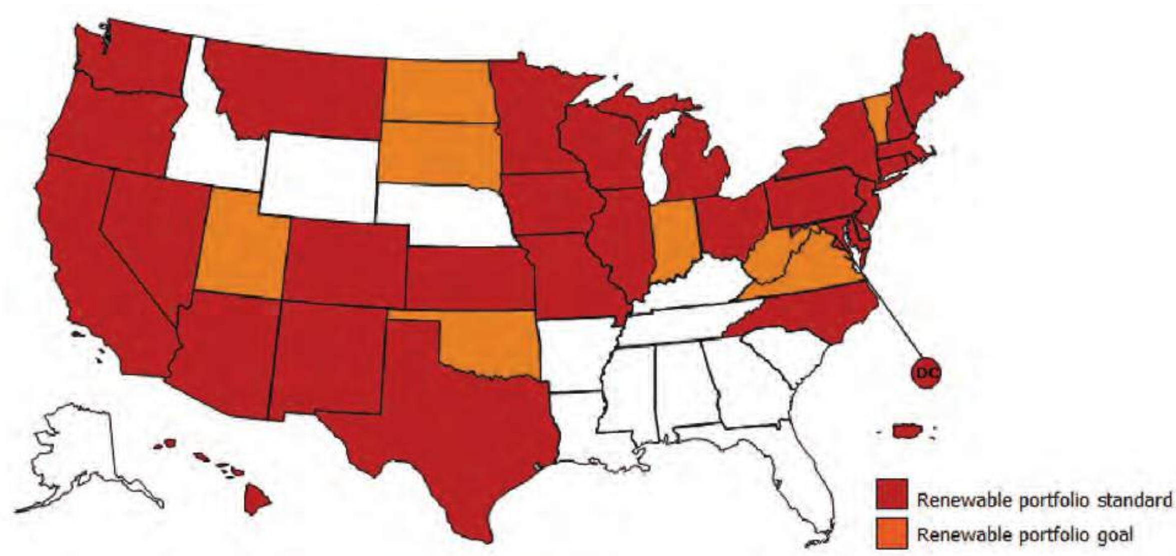
Many new requirements for thermal plants to load-follow and the physical, emissions, and economic impacts of such operations stem directly from policies that change the market rules for generator dispatch. This section reviews white paper contributions and participant discussions about renewable policies and the role of regulation at the state, federal, and international levels.

Domestic Policies

The addition of large-scale renewable resources creates new challenges for the electric power sector. Developing the optimum set of regulations to address these challenges will require considerable analysis and planning to adequately, efficiently, and affordably manage the reliability issues associated with intermittent renewables. Any regulatory and/or statutory changes to accommodate these challenges will be further complicated by the current complex regulatory framework and set of stakeholders that includes the FERC and the NERC at the federal level, a range of RTOs and ISOs at the regional level, and PUCs at the state level.

The main drivers of renewable generation investment are state-level Renewable Portfolio Standards (RPS) and federal-level tax credits that are intended to meet policy objectives to both reduce CO_2 emissions from the power sector, as well as promote job growth in the green energy sector. Currently, 29 states have some form of RPS. Most state RPS mandates have 15%–25% renewable generation by 2015–2025.[59] When combined, these state mandates would require the installation of 60,000 MW of renewable energy by 2025.[60] Texas has the largest installed capacity of wind generation with over 10 GW installed, and Iowa has the highest percentage of renewables in its system at 25% of installed capacity.[61]

Figure 10 – States with Renewable Portfolio Standards or Goals



Source: RPS Policies, www.dsireusa.org, August 2011.

The federal tax credits for renewable generation include both Production Tax Credits (PTC) and Investment Tax Credits (ITC). The PTC provides a 2.2¢/kWh tax credit for electricity produced from wind and 1.1¢/kWh tax credit for electricity produced from solar for the first ten years the plants are in service. The PTC for wind will expire in December 2012, and the PTC for solar will expire in December 2013. The ITC allows solar and small wind projects to receive a tax credit equal to 30% of investment costs. The American Recovery and Reinvestment Act (ARRA) of 2009 provides taxpayers who are eligible for the PTC and ITC with a one-time cash grant in lieu of the tax credits. In total, it is projected that the cost of these credits is $5.1 billion per year.[62]

Policy Challenges of Intermittent Renewables

Policy challenges posed by large-scale penetration of intermittent renewables for conventional generation fall into two categories: short-term operations and long-term planning.[63]

For short-term operations, the centralized control of balancing load and generation will require new protocols for unit commitment, economic dispatch, and frequency control. Traditionally, system operators take variations in demand into account when scheduling and dispatching generators for production and for reserve capacity. Renewable resources will add variability on the supply side that is difficult to predict; to meet this variability, system operators will have to use dispatchable generators to balance the “net load”[64] (although some participants thought system-wide load balancing was undervalued as an option). This net load will be less, on average, than the traditional load with more frequent cycling and greater changes over shorter periods of time.

Discussions about issues with wind capacity frequently focus on not having enough power during periods of peak load. However, often the largest operational challenge associated with intermittent renewables is having *too much* generation. For example, on a typical spring night with high wind and low electricity demand, wind generation dispatched to comply with a mandate may unintentionally force baseload technologies (such as nuclear and coal) to ramp down. “Must-run” requirements associated with mandates do not correlate with peak wind generation (normally overnight) and peak electricity demand (normally during the day and early evening hours). As noted earlier, this translates into increased fuel requirements and higher O&M costs and emissions.

Mandated renewable generation during low-load hours could also lead to “over generation” and negative electricity prices. In some situations, it may make economic sense for a thermal generation plant to pay to keep operating, to avoid the significant costs of shutting down and starting up at a later time. These situations result in negative electricity prices because generators, instead of receiving compensation for their electricity, are paying for the right to continue generating.

For long-term planning, the need for new flexible power plants in the generation mix and additional transmission capacity on the grid must be reflected in utility and ISO planning criteria to maintain electric power system reliability and policy goals. Regulatory structures to incentivize the construction and use of fast ramping, flexible resources will be required to accommodate intermittent renewables and maintain system reliability. Participants noted that the impending retirement of many older power plants due to new Environmental Protection Agency (EPA) regulations will increase both the need and opportunity for new flexible generation capacity.

Costs of Intermittent Renewable Integration

The costs of wind integration have been studied by NERC, CAISO, New England ISO (ISO-NE), ERCOT, New York ISO (NYISO) and the states of Minnesota, Colorado, and Idaho. Although these discrete studies vary in scope and methodology, in general, they find that intermittent renewable generation will increase the need for regulation, load-following capacity, and ancillary services with a cost to the system ranging from $5–$20/MWh.

Determining the full cost of integrating intermittent resources into the current system is complicated and represents a set of major policy and regulatory challenges. The costs of integration include the impacts on existing generation assets, the integration of the renewable resources, and the addition of system and operations infrastructure.[65]

- **Existing asset costs:** The costs of integration are first imposed on *existing assets*. The need to cycle plants and to operate at lower output will increase the costs of thermal plant operations and directly reduce plant profits. It will be necessary to take these costs into account and to allocate them properly to enhance the equity of RPS policies and to reduce the likelihood of opposition from current generators. This cost recovery is a major regulatory consideration and similarities with past "stranded cost" issues during deregulation might provide a blueprint for how such costs should be handled. For example, after electricity markets were deregulated in the mid-1990s, many utilities were left with long-term contracts that were no longer economically viable. These "stranded costs" were allowed to be recouped since the losses were due to a change in regulation, not inefficient operations.[66]

- **Direct integration costs:** These include transmission interconnection/upgrade costs and increased regulatory services. Traditionally, costs of this nature have been directly allocated to responsible entities; in this instance, they would be the renewable generators. FERC is adapting its rules to better accommodate the costs of integrating intermittent renewables as seen in the ruling on Westar generation regulation costs. In that case, FERC approved a tariff that would allocate charges for regulation and frequency response services to intermittent generators at higher rates than thermal generators based on the cost causation principle demonstrated by Westar's portfolio-wide analysis.

- **System infrastructure costs:** The final class of costs are those required for upgrading *system infrastructure* to maintain market operations and system reliability in the face of requirements for large-scale renewables generation. These costs include RTO adoption of new, more complex scheduling frameworks and capabilities for forecasting the system net load. Generally, these costs have been allocated widely as all participants rely on adequate system operations.

The focus on costs raises the question of value: what value do we place on bringing renewable resources into our power generation mix? Presumably, when renewable resources have been mandated as a matter of policy, costs and benefits were taken into account. Mandates are not necessarily the most efficient or least cost way to achieve policy goals; there are unintended consequences that are not trivial, such as those mentioned above. Once a mandate is in place, the obligation is to ensure that the least cost, least impact implementation of the mandate is pursued and that follow-on policy measures and regulatory structures are developed to ensure these outcomes. In this context, some participants expressed concern that the costs of wind and its impacts on thermal generation are more highly scrutinized because, as one participant put it, wind is the "new kid on the block."

Emerging Policy Questions

Three emerging policy questions for integrating renewables and allocating costs will need to be considered to ensure the reliable and efficient operation of the power sector in both the short and long term.[67]

- **Reliability criteria:** Maintaining system reliability requires second-to-second balancing of load with generation that is provided by regulation services such as spinning and non-spinning reserves.[68] The *net load* will be more variable and will require greater changes in output as intermittent renewable penetration increases, making it more difficult to meet the reliability criteria set by NERC. It is likely that the demand for such regulation services will increase. Contingency plans for major changes in generation output will also need to be examined as the sudden loss of a nuclear plant compared to a large wind farm represents different challenges and requirements for maintaining system reliability. Advances in forecasting of wind generation output will play a significant role in determining the appropriate levels of regulation services required to maintain system reliability.

- **Capacity markets:** Capacity markets are utilized in some regions to ensure that installed capacity is available for use at times of peak load demand. Determining capacity credit for renewable generation resources is more difficult than for thermal generation resources due to the lack of historical experience with wind and solar generation. The impacts on the existing generation assets described earlier must be accommodated in capacity market design. Without a clear understanding of these impacts in capacity market design, there could be an over- or under-investment in thermal generation resources.

- **Identifying beneficiaries:** Allocating the costs of intermittent renewables discussed previously requires identifying the transmission customers who will benefit from system upgrades and additional regulation services. Cost allocation has proved difficult because benefits can be measured both in prices and reliability. Only price benefits are easy to quantify. Identifying beneficiaries is essential, as a lack of clarity and accuracy could constrain transmission investment.

Regulatory Structures

In the context of these emerging issues, participants discussed the adequacy of the current electric power sector regulatory structure. Regulation currently is divided between FERC and state PUCs with many decisions on market design initially proposed by regional RTO/ISOs.

In general, FERC sets rules for participation in wholesale electric power markets that operate on the interstate transmission network. State PUCs traditionally oversee the power sector assets within their jurisdiction and give approval for the planning and siting of new generation and transmission capacity. With the restructuring of electricity markets over the last decade, RTO/ISOs are playing a larger role in regional decision making. Participants noted that an unintended consequence of FERC's establishment of RTOs has been a third level of regulation.

Participants, having acknowledged this new regulatory structure, generally supported the need for higher-level decision making because of growing regional interests and needs. There was, however, resistance to suggestions that these decisions might solely become federal responsibilities. While there was disagreement over federal versus regional versus state-level regulation in the face of the new requirements posed by intermittent renewables, the balance of opinion favored regional decision making as the most appropriate venue for the tasks at hand.

Apart from the structure of regulation, a participant suggested that a detailed statement from federal policy makers about long-term national electricity policy — over a 30-year time horizon — was an essential ingredient for encouraging the investments required to re-shape our generation and transmission systems to accommodate intermittent renewables.

The Evolving Regulatory Landscape

The following summarizes some of the major regulatory activities relevant to the integration of intermittent renewables that were underway at the time of the symposium:

- **FERC** has issued two Notices of Proposed Rulemaking (NOPR):

  – On November 18, 2010, a NOPR to reform the open access transmission tariff (OATT) was issued (Docket No. RM10-11-000) that would introduce intra-hourly transmission scheduling; require variable resources to provide meteorological and operational data to transmission providers; and create a new ancillary service rate schedule to offer regulation service to transmission customers. These changes are designed to ease the integration of high levels of renewable generation.[69]

  – On February 17, 2011, a second NOPR was issued to modify the compensation structure for regulation services (Docket No. RM11-7-00). The NOPR envisions a two-part structure that would create a uniform price for regulation capacity based on an hourly regulation auction and add a performance payment to reflect the accuracy of performance. The goal of the NOPR is to help ensure that payments are made for the most responsive resources and services to reduce the amount of regulation resources required.[70]

  – Since the Symposium, FERC issued Order No. 1000 on transmission planning and cost allocation requirements. For planning, the order requires participation in RTOs according to Order No. 890, consideration of public policy requirements as defined by statute or regulation, and increased communication with neighboring transmission planning regions. For cost allocation, the order establishes six principles[71] that must be satisfied within an established cost allocation method for both regional and interregional transmission projects. Overall, the order is meant to increase regional and interregional communication and planning and to ensure that costs are allocated across regions in a just and reasonable manner.

- **NERC** has been reviewing possible changes to standards to accommodate intermittent renewables in the North American power grids. NERC has specifically looked at regulatory requirements, but had implemented no changes at the time of the symposium. NERC's focus going forward will be on studying the frequency of ramping events to determine whether these events are compatible with current contingency reserve planning. For example, NERC has found that wind ramping events are slower than conventional system contingency events, such as contingency events that have been traditionally designated to meet sudden, quickly occurring events, such as unanticipated loss of a generator or transmission line."[72] This analysis will inform NERC about the possible need to alter conventional contingencies for reserve deployments and restoration rates.

- **State PUCs** with regulated utilities take a different view on the costs of integration since the costs can be bundled into a single tariff to the customers under their Integrated Resource Plans; only regulated utilities can aggregate the total costs of renewable integration into a single charge. Xcel Energy in Colorado is explicitly adding expected system costs associated with adding wind resources to the overall costs of electricity. PacifiCorp found in its study of wind integration that the likely range of integration costs is $8.85–$9.70/MWh. Westar has received approval from FERC for a transmission tariff that allows the utility to charge new generators for frequency and regulation response services to generators in Westar's balancing area when that output is delivered outside the balancing area.[73]

- **RTO/ISOs** have completed their own regional studies focusing on unique regional challenges as well as challenges that are generic to all regions working on integrating intermittent renewables. The main focus of these activities has been primarily on the impacts of high levels of wind generation.

  – NYISO already requires wind resources to operate under the same rules as other generators. NYISO has received FERC approval to integrate a wind forecasting system into its scheduling and to require that wind generators participate in supervisory and data acquisition processes, meet low voltage ride through standards, and conduct tests to determine the effect of the plant on the voltage profile at the interconnection. In addition, FERC has approved curtailment of wind in New York allowing NYISO to decrease the output from wind plants if necessary for reliability purposes.[74]

  – ERCOT is taking a similar approach, consolidating wind forecasting under a central system-wide control center and setting ramping limitations on wind generators. In addition, ERCOT has implemented an Emerging Technologies Integration Plan to further analyze the impacts of wind generation on market participants and stakeholders.[75]

  – CAISO is putting additional emphasis on solar generation as well as wind generation, investigating how to add operational flexibility to wind and solar resources, and how to improve day-ahead and real-time forecasting for operational needs.[76]

  – PJM, which covers 13 states from the mid-Atlantic to the Midwest, is studying the implications of renewable generation on its system, analyzing both solar and wind resources. PJM, like ISO-NE, must analyze and accommodate multi-state RPS policies in its region. PJM is pushing wind generators to comply with standard interconnection regulations regarding key electricity characteristics, such as input voltage. It is also considering a central wind power forecasting service similar to NYISO and ERCOT.[77]

Participants expressed some optimism about the pace of regulatory changes to accommodate intermittent renewables, noting that there has been considerable progress at all levels of regulation; this has created a rapidly evolving regulatory landscape. Concern was expressed about the lack of a single grand theory for allocation of costs associated with intermittent renewables. It was acknowledged that this is difficult given the inherent differences among regions, including regulatory institutions, legacy generation capacity, and indigenous resource availability. Without a single uniform solution, each region will need to undergo extensive research to produce thoughtful and careful regulation that meets the needs of stakeholders and ensures overall system efficiency and reliability.

European Energy Policy

Participants discussed the energy policies of the EU and their possible application to evolving US electricity markets. The EU has three overarching energy goals for the year 2020:

- a 20% reduction in GHG emissions from 1990 levels;
- a 20% utilization of renewable energy as a fraction of total energy use; and
- a 20% reduction in primary energy use.

Policy makers in the EU consider the first two goals to be binding targets, and the third goal as nominally binding. They have promoted the benefits of the 20-20-20 policies to the public under the theory that the first two goals are both binding and interrelated — they clearly assume renewable energy consumption will reduce GHGs associated with energy production.

The EU generally supports generation technologies that can help decarbonize its electricity sector. Crafting policies, however, to reach the most economically efficient solution — while also supporting security and reliability goals — presents complex policy problems. The EU's Emissions Trading System (ETS) encourages the development of the most economically efficient technologies. Theoretically, through the ETS, increases in the price of carbon should encourage investment in all emissions-free technologies, including nuclear.

As currently implemented, however, the GHG and RPS policies in the EU both overlap. Under the current 20-20-20 policy, a change in the market price for GHGs does not move the RPS target for total energy use. Regardless of how many nuclear plants the EU builds to help reduce GHG emissions, it will still have to build renewable generation facilities to meet the RPS goal.

In addition, in the EU, the public has been told that the renewables policy will reduce GHGs. In reality, because the GHG emissions level is set independently from the level of renewables deployment, newly installed wind turbines do not directly lower the emissions cap for GHGs. Consider the fictional case of the EU securing 100% of its electricity from wind generation. If, in this scenario, the EU does nothing with the GHG cap, then other sectors (such as transportation) can emit more GHGs to take advantage of the electricity sector's savings.[78]

Acting independently of the GHG requirement, the RPS target places downward pressure on carbon prices, depressing the development of non-renewable low-carbon and carbon-free technologies. Low carbon prices, however, do little to discourage coal and gas generation. Technology mandates appear to be in conflict in a decision environment driven by economic efficiency.

Compounding the economic conflicts, the electricity sector will pay proportionally more than other sectors for these policies. In order to help the EU reach its 20% renewables goal by 2020, the UK, for example, has committed to acquiring 15% of its total energy from renewable resources. For the electricity sector, the RPS target binds more tightly than the GHG goal because renewables cost less to implement in the electricity sector than in the transport sector. To meet the total renewables target of 20%, countries like the UK will need to lean heavily on their electricity sectors. Current estimates suggest that the UK's electricity sector will need to acquire at least 30% of its electricity generation by 2020 from renewables to meet the RPS goal.[79]

The 20-20-20 policy is an overarching policy of the EU, but is not prescriptive in its implementation. Its 27 member nations each have their own approaches to meeting these policy objectives and many of them conflict with each other. For example, the Irish and Austrians ban nuclear power, but the French have made nuclear expertise a source of national pride. Overall, participants expressed uncertainty about the likelihood that the EU will achieve its 20-20-20 goals on schedule.

Electricity market reform in the UK was offered as a case study on issues associated with meeting the EU 20-20-20 targets. The proposed legislation would make the following changes to the UK's energy markets:[80]

- Establish a carbon floor price, with the goal of providing greater long-term certainty on the costs associated with running generating units that emit carbon; and long-term, feed-in tariffs to support low-carbon generation sources, based on a contract-for-difference or a premium (a contract-for-difference is a contract between two parties where one party pays the other when the price of a good deviates from the agreed-upon benchmark; a premium is a fee that a seller receives, in addition to receiving the market price for the good);

- Develop a capacity-based market for flexible generation and demand reduction, to ensure reliability for a generation mix with an increasing amount of intermittent generation; and

- Set an emissions performance standard to limit carbon-intensive technologies.

In the long term, sufficiently stringent emissions standards will push carbon-intensive technologies out of the market, and high carbon prices will pressure *all* carbon technologies. As the carbon standard increases and prices rise, these market rules will provide support for investment in the most economically efficient decarbonized technologies, with complete neutrality to the decarbonized fuel sources. Participants agree that in this environment, the investment scenarios for nuclear significantly improve.

Intermittent Renewables Generation Policies and Regulations: Key Findings

1. Proper policy and regulation are rooted in understanding and fairly allocating system costs, including existing asset costs, integration costs, and system infrastructure costs.

2. Policy challenges exist in both short-term operations and long-term planning in order to maintain a reliable, economically efficient power system.

3. Renewable technologies are highly scrutinized because their use is mandated in 29 US States, the EU, and other countries.

4. The major areas being considered for policy/regulatory changes are reliability criteria, capacity markets, and cost allocation.

5. There is a clear need for a statement on national goals for the electricity sector to streamline the US regulatory structure, which currently is complex and fragmented.

6. The regulatory landscape is rapidly evolving with progress being made at the federal, state, and regional levels.

7. Policy solutions will need to be regionally focused because of vast geographic differences in resources, demands, and markets. Each region will need to undergo extensive research to produce thoughtful and careful regulation that meets the needs of stakeholders and ensures overall system efficiency and reliability. There is a strong preference toward expanding regional decision making within the regulatory structure.

8. Too much electricity generation from intermittent renewables is as much of a problem as too little generation. Frequently, wind integration problems involve having too much wind during low-demand periods; many renewables mandates require the dispatch of wind energy, regardless of demand.

9. Within the US, RTOs, vertically integrated markets, and regulated utilities have no coordinated agreements to curtail wind in the event of oversupply or threats to reliability. In some instances, state statutes also prohibit such curtailments. Lack of coordination between the various agencies involved leads to ramping and other inefficient plant operations as the main solution to accommodate excess generation.

10. An important lesson learned from the EU 20:20:20 goals is that renewable mandates are not aligned with a cap-and-trade system, which is theoretically the most economically efficient regulatory tool for the reduction of GHGs.

ENDNOTES

1 Perez-Arriaga, Ignacio. *Managing Large Scale Penetration of Intermittent Renewables*. Provided to the MITEI Symposium on Intermittent Renewables, April 20, 2011. Page 10.

2 "FERC: Industries – RTO/ISO." http://www.ferc.gov/industries/electric/indus-act/rto.asp. Last updated: October 26, 2011.

3 Thermal solar technologies are more resilient to abrupt changes in sunshine. Thermal solar systems build up heat and inertia, and this inertia takes time to dissipate when sunlight decreases.

4 MIT Energy Initiative. *The Future of Natural Gas: An Interdisciplinary MIT Study*. June 2011. Page 88.

5 Id.

6 "Energy Power Annual: Summary Statistics for the United States." http://www.eia.gov/cneaf/electricity/epa/epates.html. Last updated: November 23, 2010. Solar PV and thermal generation accounted for 891 GWh of electricity. Total electricity generation in 2009 was 3,950 TWh.

7 Bennett, Porter. *The Wind Energy Paradox*. Presented to the MITEI Symposium on Intermittent Renewables, April 20, 2011.

8 Id. at 10.

9 Id. at 8.

10 Id. at 13.

11 Id. at 13.

12 Unit commitment refers to the process that system operators use to decide which plants to dispatch in the most economically efficient manner while still respecting physical and reliability constraints.

13 Todd, Douglas. *Managing Large-Scale Penetration of Intermittent Renewables*. Provided to MITEI Symposium on Intermittent Renewables, April 20, 2011. Page 11.

14 Generally, the backup cost of capacity of wind refers to the additional capacity required, in addition to a unit of wind capacity, to sum to one unit of *firm* capacity.

15 Newcomer, A., Apt, J. "Near-Term Implications of a Ban on New Coal-Fired Power Plants in the United States." *Environ. Sci. Technol.*, April 27, 2009.

16 In negative bids, producers *pay* to generate electricity. If a producer receives a subsidy for generating, it can still make a profit if it pays some of the subsidy for the right to generate, crowding out other more economic technologies.

17 U.S. Energy Information Administration, *Electric Power Monthly*, Table 1.1 (March 2011).

18 Id.

19 Hesler, Steve. *Impacts of Intermittent Renewable Generation on Coal Assets*. Presentation provided to MITEI Symposium on Intermittent Renewables, April 20, 2011.

20 Id.

21 Id.

22 The metric equivalent forced outage rate based on demand (EFORd) is defined as the unit reliability when called upon. It was noted that lower numbers are better and that they correlate well with net capacity factors.

23 Hesler, *supra* note 19.

24 Subcritical and supercritical coal plants operate their steam cycles at different temperatures and pressures. The critical point of steam is 206.2 psia (221.2 bar) and a corresponding saturation temperature 705.4 oF (374.15 oC), above which the vapor and liquid are indistinguishable. Subcritical units operate below these conditions and supercritical units run above them.

25 Hesler, *supra* note 19.

26 Operation of the environmental control equipment and loss of efficiency are the operating issues that were highlighted in the previous section case study on effects of wind generation on emissions.

27 Hesler, *supra* note 19.

28 U.S. Energy Information Administration, *supra* note 16.

29 Spain currently has 20 GW of wind, 25 GWs of CCGT, and a 1.5 GW interconnection with France (new investments are expected to double the interconnection capacity over the next several years). Because of this relatively small interconnection, Spain and the Iberian electrical system is essentially isolated from the rest of Europe. CCGTs provide Spain with the majority of its flexible generation; additionally, Spain annually curtails about 2% of its wind generation to manage excess wind via its national Control Center for Renewable Energies.

30 Integrated gasification combined cycle plants (IGCC), which run on synthetic gas produced from coal gasification, were mentioned briefly in this section due to their similarities in power generation and operating capabilities to NGCC plants. Because few IGCC units are in operation today, symposium participants focused on natural gas-fired technologies. For more information on IGCC plants see: Todd, Douglas. *Managing Large-Scale Penetration of Intermittent Renewables*. Provided to MITEI Symposium on Intermittent Renewables, April 20, 2011.

31 NGCC plants are capable of operating as baseload plants. Historically, however, they have not served as baseload plants because of their higher variable costs of operation.

32 Todd, *supra* note 13.

33 GE announced soon after the symposium a new NGCC design, the FlexEfficiency 50, capable of 10%/min ramp rates: http://www.ge-energy.com/products_and_services/products/gas_turbines_heavy_duty/flexefficiency_50_combined_cycle_power_plant.jsp.

34 Todd, *supra* note 13.

35 U.S. Energy Information Administration, *supra* note 16.

36 "Nuclear Power Reactors." http://world-nuclear.org/info/inf32.html. Last updated: March 2011.

37 Gas-cooled reactors use a gas, like carbon dioxide or helium, as the coolant instead of water. Gas-cooled reactors are more thermally efficient (more electricity generated per unit of heat) than water-cooled reactors because the gas coolant allows those reactors to run at higher temperatures.

38 Nuttall, William. *Nuclear Power and Large-Scale Renewables in Liberalized Power Markets: A British and European Perspective*. Provided to MITEI Symposium on Intermittent Renewables, April 20, 2011. Page 10.

39 "Nuclear Power in the USA." http://world-nuclear.org/info/inf41.html. Last updated: June 2011.

40 Areva's EPR is a pressurized water reactor design first deployed in France. The EPR can operate at 25% of its full load and ramp up at a rate of 2.5% of its rated full output up to 60%, and then 5% of its rated output per minute up to full power. This allows ramping from 25% to 100% within 30 minutes, but at the cost of additional wear and tear. "Advanced Nuclear Power Reactors." http://www.world-nuclear.org/info/inf08.html. Last updated: October 2011.

41 Id. at 39.

42 Generally, it was noted that coal plants will only be required to ramp more often when ramping capacity in natural gas plants have been exhausted. The same is true for nuclear plants which will only ramp when natural gas and coal ramping capabilities have been maxed out.

43 Hesler, *supra* note 21, at 8.

44 Todd, *supra* note 27. Capacity factor values in paper by way of WorleyParsons.

45 MIT Energy Initiative, *supra* note 4, at 73.

46 National Energy Technology Laboratory. *Cost and Performance Baseline for Fossil Energy Plants – Volume 1: Bituminous Coal and Natural Gas to Electricity*. Revision 2, November 2010. DOE/NETL-2010/1397. 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 NGCC 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.

47 Nuttall, *supra* note 31, at 10.

48 Id.

49 Scholtz, Ernst. *Grid Integration of Renewables*. Provided to MITEI Symposium on Intermittent Renewables, April 20, 2011. Page 13.

50 Id. at 12.

51 Id. at 28.

52 "China Moves Ahead with Economical Ultra-high Voltage Transmission Lines." China Development Gateway. http://en.chinagate.cn/economics/industry/2009-02/08/content_17243018.htm. February 7, 2009.

53 Scholtz, *supra* note 42, at 30.

54 Id. at 42.

55 Id. at 42.

56 Id. at 42.

57 Id. at 52.

58 http://www.seco.cpa.state.tx.us/re_wind-reserve.htm.

59 U.S. Department of Energy. DSIRE: Database of State Incentives for Renewables & Efficiency. http://www.dsireusa.org.

60 Chang, Judy, et al. *Policy Challenges Associated with Renewable Energy Integration*. Provided to MITEI Symposium on Intermittent Renewables, April 20, 2011. Page 2.

61 U.S. Department of Energy. *U.S. Wind Installed Capacity*. http://www.windpoweringamerica.gov/wind_installed_capacity.asp.

62 U.S. Congressional Research Service. *Energy Tax Policy: Issues in the 112th Congress* (R41769; April 14, 2011), by Molly F. Sherlock and Margot L. Crandall-Hollick.

63 Chang, *supra* note 60.

64 See page 17 for definition of net load.

65 Chang, *supra* note 60.

66 U.S. Congressional Budget Office. *Electric Utilities: Deregulation and Stranded Costs*. October 1998.

67 Chang, *supra* note 60.

68 The generators that provide regulation services, such as spinning and non-spinning reserves, are able to start or adjust their output within a 5-, 10- or 15-minute time frame.

69 Chang, *supra* note 53, at 10.

70 Id. at 11.

71 The six principles are: 1) costs allocated in a way that is roughly commensurate with benefits; 2) no involuntary allocation of costs to non-beneficiaries; 3) benefit to cost threshold ratio; 4) allocation to be solely within transmission planning region(s) unless those outside voluntarily assume costs; 5) transparent method for determining benefits and identifying beneficiaries; and 6) different methods for different types of facilities.

72 Chang, *supra* note 53, at 14.

73 Id. at 15.

74 Id. at 12.

75 Id. at 13.

76 Id. at 12.

77 Id. at 13.

78 Nuttall, *supra* note 31, at 2.

79 Id. at 4.

80 http://www.decc.gov.uk/assets/decc/consultations/emr/1041-electricity-market-reform-condoc.pdf.

INDEX OF FIGURES

ABBREVIATIONS / ACRONYMS

AGR	Advanced Gas-Cooled Reactor
ARRA	American Recovery and Reinvestment Act
BPA	Bonneville Power Administration
BTU	British Thermal Unit
BWR	Boiling Water Reactor
CAISO	California ISO
CCGT	Combined-Cycle Gas Turbine
CCS	Carbon Capture and Sequestration
CMU	Carnegie Mellon University
CO_2	Carbon Dioxide
COE	Cost of Electricity
DC	Direct Current
EFORd	Equivalent Forced Outage Rate
EPA	Environmental Protection Agency
EPRI	Electric Power Research Institute
ERCOT	Electric Reliability Council of Texas
ETS	Emissions Trading System
EU	European Union
FERC	Federal Energy Regulation Commission
FGD	Flue Gas Desulfurization
GHG	Greenhouse Gas
GW	Gigawatt
GWh	Gigawatt Hour
HRSG	Heat Recovery Steam Generator
HVAC	High-Voltage Alternative Current
HVDC	High-Voltage Direct Current
IGCC	Integrated Gasification Combined Cycle
ISO	Independent System Operator
ISO-NE	New England ISO
ITC	Investment Tax Credit
km	Kilometer
kV	Kilovolt
kW	Kilowatt
kWh	Kilowatt Hour
LCOE	Levelized Cost of Electricity
mph	Miles per Hour
MW	Megawatt
MWh	Megawatts per Hour
MISO	Midwest Independent Transmission System Operator
MITEI	MIT Energy Initiative
NERC	North American Electricity Reliability Corporation
NGCC	Natural Gas Combined Cycle
NOPR	Notices of Proposed Rulemaking
NO_X	Nitrogen Oxide
NYISO	New York ISO
OATT	Open Access Transmission Tariff
O&M	Operations and Maintenance
PJM	PJM Interconnection LLC
PTC	Production Tax Credit
PUC	Public Utility Commission
PWR	Pressurized Water Reactor
RPS	Renewable Portfolio Standard
RTO	Regional Transmission Operators
SCGT	Single Cycle Gas Turbine
SCR	Selective Catalyst Reduction
SO_2	Sulfur Dioxide

APPENDICES

A. Symposium Agenda

B. List of Participants

C. White Paper, Ignacio J. Pérez-Arriaga, Comillas University, Madrid and MIT Center for Energy and Environmental Policy Research, *Managing Large Scale Penetration of Intermittent Renewables*

D. White Paper, Porter Bennett and Brannin McBee, Bentek Energy, *The Wind Power Paradox: An Empirical Study of Emission Reductions*

E. White Paper, Steve Hesler, Electric Power Research Institute (EPRI), *Impact of Cycling on Coal-Fired Power Generating Assets*

F. White Paper, Douglas M. Todd, Process Power Plants, *Managing Large-Scale Penetration of Intermittent Renewables (Gas Turbine Power Plants including SCGT, NGCC, IGCC)*

G. White Paper, William J. Nuttall, Judge Business School and the Engineering Department, University of Cambridge, *Nuclear Power and Large-Scale Renewables in Liberalized Power Markets – A British and European Perspective*

H. White Paper, Ernst Scholtz, ABB Corporate Research, *Grid Integration of Renewables: Challenges and Technologies*

I. White Paper, Judy Chang, Kamen Madjarov, Peter Fox-Penner, and Philip Q Hanser, The Brattle Group, *Policy Challenges Associated with Renewable Energy Integration*

SYMPOSIUM AGENDA

Managing Large-Scale Penetration of Intermittent Renewables

Massachusetts Institute of Technology
April 20, 2011

8:30–9:00	**Breakfast**		
9:00–10:30	**Experience with Wind Penetration from Spain to Colorado**		
Framing	Speakers:	Ignacio Perez-Arriaga – Visiting Professor, MIT	
		Porter Bennett – CEO, Bentek Energy LLC	
	Respondents:	Rob Gramlich – Sr. VP, American Wind Energy Association	
		Susan Tomasky – President, AEP Transmission	
10:30–10:45	**Morning Break**		
10:45–12:45	**Current Power Systems – Coal and Natural Gas**		
Coal	Speaker:	Stephen Hesler – Program Manager, EPRI	
	Respondents:	Janos Beer – Professor, MIT	
		Donald Langley – CTO, Babcock & Wilcox	
NGCC/IGCC	Speaker:	Douglas Todd – CEO, Process Power Plants	
	Respondents:	Andrew Marsh – System Planning and Operations, Entergy	
		Brandon Owens – Global Strategy & Planning, GE Energy	
		Steven Messerschmidt – Strategy & Development, Siemens	
12:45–1:15	**Lunch Break**		
1:15–2:45	**Current Power Systems – Nuclear and Electric Grid**		
Nuclear	Speaker:	William Nuttall – University Sr. Lecturer, University of Cambridge	
	Respondent:	Joseph Dominguez – Sr. VP, Federal Regulatory Affairs, Exelon	
Grid	Speaker:	Ernst Scholtz – Global Research Program Manager, ABB	
	Respondents:	Agustín Díaz – Network Studies, Red Eléctrica	
		Paul Denholm – Senior Analyst, NREL	
		Adam Schlosser – Principal Research Scientist, MIT	
2:45–4:00	**Regulating Increased Intermittent Power Generation**		
Policy	Speaker:	Peter Fox-Penner – Principal, The Brattle Group	
	Respondents:	Samir Succar – Energy Analyst, NRDC	
		Philip Giudice – Undersecretary, MA Department of Energy Resources	
4:00–4:15	**Afternoon Break**		
4:15–5:00	**Conclusions and Recommendations**		
Closing	Lead by:	Ernest Moniz – Director, MIT Energy Initiative	
		John Deutch – Institute Professor, MIT	

LIST OF PARTICIPANTS

Managing Large-Scale Penetration of Intermittent Renewables

Massachusetts Institute of Technology
April 20, 2011

Armstrong, Robert	MIT	
Bailey, Vicky	Anderson Stratton Enterprises, LLC	
Banunarayanan, Venkat	ICF International	
Batlle, Carlos	CEEPR	
Beer, Janos	MIT	Respondent
Behr, Peter	ClimateWire	
Bennett, Porter	Bentek Energy LLC	Speaker
Blair, Peter	National Academy of Sciences	
Brasington, Robert	MIT	
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Davies, Colin	Hess Corporation	
De Blasio, Nicola	MIT	
Denholm, Paul	NREL	Respondent
Deutch, John	MIT	Respondent
Díaz, Agustín	Red Eléctrica	Respondent
Dominguez, Joseph	Exelon	Respondent
Dykes, Katherine	MIT ESD	
Eckhart, Michael	Citigroup	
Farid, Amro	Masdar Institute	
Ferrao, Paulo	IST – MIT-Portugal Program	
Fowler, Mike	Clean Air Task Froce	
Fox-Penner, Peter	The Brattle Group	Speaker
Giudice, Phil	MA Department of Energy Resources	Respondent
Goggin, Michael	American Wind Energy Association	
Goodell, Tim	Hess Corporation	
Gramilch, Rob	American Wind Energy Association	Respondent
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Heidel, Tim	MIT	
Herzog, Howard	MIT	
Hesler, Stephen	EPRI	Speaker
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Madjarov, Kamen	The Brattle Group	
Marean, James	Gas Technology Institute	
Marsh, Andrew	Entergy	Respondent
McBee, Brannin	Bentek Energy LLC	
Messerschmidt, Steven	Siemens	Respondent
Mohr, Martin	Shell	
Moniz, Ernest	MIT Energy Initiative	Speaker
Muthiah, Shanthi	ICF International	
Nuttall, William	University of Cambridge	Speaker
Owens, Brandon	GE Energy	Respondent
Perez-Arriaga, Ignacio	MIT	Speaker
Riggs, Jack	The Aspen Institute	
Ritter, Jon	DOER	
Rodriguez, Jesse	Exelon	
Rosenfield, Jamey	IHS CERA	
Sadoway, Donald	MIT	
Schlosser, Adam	MIT	Respondent
Scholtz, Ernst	ABB	Speaker
Simon, Bob	US Senate Committee on Energy and Natural Resources	
Succar, Samir	NRDC	Speaker
Tapia-Ahumada, Karen	MIT	
Tinnium, Kannan	GE Global Research	
Todd, Douglas	Process Power Plants	Speaker
Tomasky, Susan	AEP Transmission	Respondent
Wall, John	Cummins	
Wallerstein, Mike	Massachusetts Department of Energy Resources	
White, William	Energy Future Coalition	
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Zhang, Richard	MIT	

2011 MITEI SYMPOSIUM

Framework paper

Managing large scale penetration of intermittent renewables

Ignacio J. Pérez-Arriaga[1]

Abstract

All power generation technologies leave their particular imprint on the power system that they belong to. Wind and solar power have only recently reached significant levels of penetration in some countries, but they are expected to grow much during the next few decades, and contribute substantially to meeting future electricity demand. Wind, photovoltaic (PV) solar and concentrated solar power (CSP) with no storage have limited-controllable variability, partial unpredictability and locational dependency. These attributes make an analysis of their impacts on power system operation and design particularly interesting.

This paper examines how a strong presence of intermittent renewable generation will change how future power systems are planned, operated and controlled. The change is already noticeable in countries that currently have a large penetration of wind and solar production. The mix of generation technologies, and potentially market rules, will have to adapt to accommodate this presence. Regulatory adjustments might be needed to attract investment in "well adapted" technologies. Distribution and transmission networks will be also profoundly influenced. This paper identifies open issues that deserve further analysis from a technical, economic and regulatory perspective.

[1] Professor and Director of the BP Chair on Sustainable Development at Comillas University, Madrid, Spain. Visiting professor at MIT, Center for Energy and Environmental Policy Research (CEEPR), Boston, US. Director of Energy Training at the Florence School of Regulation, European University Institute. Independent Member of the Single Electricity Market Committee of Ireland. Member of the Spanish Royal Academy of Engineering.

Table of Contents

1. Introduction

Several factors –climate change and other environmental considerations, energy security, anticipated limits in the availability of fossil fuels and a greater emphasis on the utilization of local resources– indicate a shift toward a much stronger presence of renewable sources in the mix of technologies for electricity production, both in the United States and elsewhere. While estimates vary widely amongst competent organizations that have analyzed this topic, published results from these groups all suggest that renewables will play an increasingly significant role in the future[2].

At the end of 2009, wind and solar power accounted for slightly less than 2% of total electricity production in the US, and about 2% (0.02% solar) worldwide. However, the penetration of these technologies could increase significantly in the next decades. World wind production has doubled in the last three years. In the US, almost 10 GW of new wind capacity came online in 2009, making the US the world leader in absolute terms[3]. As shown in Table 1, the level of wind power penetration is already significant in countries like Denmark, Spain and Portugal, Germany and the Republic of Ireland. In the case of solar, countries like Germany, Spain and Japan are taking the lead in the installation of new PV capacity.

Country	Wind capacity (MW)	% demand	PV capacity (MW)
Denmark	3,480	19.3%	4
Portugal	3,616	15.0%	102
Spain	19,149	14.4%	3,523
Ireland	1,264	10.5%	NA
Germany	25,777	6.5%	9,845
Italy	4,850	2.1%	1,181
US	35,086	1.9%	1,641
Japan	2,056	0.4%	2,627

Table 1: Worldwide installed capacity of renewable intermittent generation by 2009. Sources: (IEA Wind, 2010) & (IEA-PVPS, 2010).

Recent studies have examined penetration levels as large as 20% by 2030 in the US. Meanwhile, the European Union has set a 20% target for primary energy consumption to come from renewable resources. This level of penetration is projected to represent about 35% of the total European electricity supply, where wind will play a major role and contribute more than one third to the total renewable electricity supply (IEA Wind, 2010). The IEA estimates that nearly 50% of global electricity supplies will have to come from renewable energy sources in order to achieve a 50% reduction of global CO_2 emissions by 2050 (this is the CO_2 target discussed by G8 leaders in Heiligendamm, and endorsed at the recent Hokkaido Summit).

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[2] For an international perspective, see IEA 2010 World Energy Outlook. In the US, the Department of Energy, NERC and other organizations, motivated by existing or anticipated policy measures, have also commissioned several reports exploring the potential impacts of high levels of renewable penetration in the electricity generation mix.

[3] At the national scale, the US has had far less development when compared to other countries. However, on a regional scale, wind development has been important in California, Texas (about 10GW), and some Midwestern states, like Iowa (about 3.6GW).

Wind, and to a lesser scale solar –both photovoltaic (PV) and concentrated solar power (CSP)– will likely play a significant role for electricity production within the next two decades. Those countries with substantial volumes of wind or solar penetration are already experiencing noticeable impacts on the operation and economics of their power systems. It is within this context that this paper will evaluate the potential effects of large volumes of wind and solar generation on the utilization of natural gas for electricity.

Large scale penetration of intermittent renewables is expected to have profound implications on many aspects of power systems planning, operation and control, as well as on the corresponding regulation. These issues have been examined from different perspectives and there is already a significant amount of literature on this topic. Most of it is about the statement of the challenges and the enumeration of open issues, but also on the description of a diversity of experiences in dealing with intermittent generation, and some detailed analyses on specific issues. A sample of relevant documents includes (Holttinen H. , et al., 2009), (EWEA, 2005), (EWEA, 2009), (EURELECTRIC, 2010), (TradeWind, 2009), (IEA Wind, 2010), (IEA-PVPS, 2010), (ESB International, 2008), (DOE EERE , 2008), (NERC, 2009), (Charles River Associates, 2010), (EnerNex, 2010), (GE Energy, 2010), (GE Energy, EnerNex, AWS Truepower, 2010), (NYISO, 2010), (Xcel Energy, 2008), and (GE Energy, 2010). The final report (Holttinen H. , et al., 2009) of the International Energy Agency Task 25 on "Design and operation of power systems with large amounts of wind power" contains a summary of selected, recently concluded studies of wind integration impacts from participating countries.

This paper will refer frequently to the existing literature, but it is not meant to be a review paper in the strict sense. The objective of the paper is to present the major open issues that have been identified along with the major power system functions, and to classify them in a logic fashion to facilitate an orderly discussion. Some new ideas –or at least some new perspectives on well-known topics– will be introduced. The emphasis will be more on the regulatory than on the technical side.

This paper will not question the basic premise that a large penetration of intermittent renewable sources of electricity generation will take place in existing power systems over the next two decades and further. The drivers for this change could be varied, but they will not be disputed here[4]. Instead, the paper will examine the implications on capacity expansion, operation and control of power systems and the technical and (mostly) regulatory measures that will be needed to successfully integrate these new technologies in an efficient and secure manner.

When talking about "intermittent"[5] renewable generation, the paper will mean "wind" much more often that "solar," and more specifically, solar PV or concentrated solar power (CSP) with no storage. This is a consequence of the much higher present level of knowledge on wind, because of its much higher level of deployment.

The paper starts with section 2 that describes intermittency characteristics for both wind and solar. It also provides a general overview of the expected effects of penetration of intermittent generation on power systems. Section 3 specifically reviews the most relevant issues on the

[4] However, we shall discuss whether the claimed environmental benefits do materialize when detailed implementation is examined in a variety of contexts.

[5] Intermittent is admittedly an inadequate term, since the outputs of wind and solar generators do not oscillate between on and off states. Because of lack of a better name, "intermittent" is used here to comprise both non-controllable variability and partial unpredictability.

operation of power systems and the needed requirements to accommodate a large volume of intermittent renewable generation in a relatively short period of time. Section 4 explores the impacts on a longer timescale where, depending on the regulatory framework, a high penetration of intermittent generation will impact the future generation technology mix. Section 5 examines the implications on transmission network expansion and bulk power system operation. Similarly, Section 6 reviews the impacts on distribution network expansion and distribution system operation. Finally, Section 7 finishes with a list of open issues that require further consideration and research regarding how to best manage the penetration of intermittent generation in future power systems at large scale.

2. Overview of expected impacts of intermittent generation

This section examines in detail what intermittency means for both wind and solar PV generators. Next, a classification is presented of the different power system functions that are substantially impacted by high levels of intermittent generation.

2.1. Intermittency characteristics of wind and solar electricity generation

Wind and solar generation are both intermittent. Intermittency comprises two separate elements: limited-controllable variability and partial unpredictability. Note that the output of a plant could conceptually exhibit much variability, while being 100% predictable. Conversely, it could also be very steady, but unpredictable. Although the output of any actual power plant is variable and unpredictable to a certain point, wind and solar generation have these characteristics in a degree that justifies the qualification of "intermittent". Without storage, limited-controllable variability implies a likelihood that an individual plant could be unavailable when needed that is significantly higher than in conventional plants. This adverse feature is reduced when multiple plants are considered over a widespread region with sufficient transmission interconnection. Solar power has the obvious advantage of being mostly coincidental with the periods of high electricity demand, while wind production may happen at any time and, as reported in some systems, predominantly at night, when demand is lowest. Both wind and solar generation have virtually no variable operating costs.

Variability and uncertainty are familiar to the electric power industry. Demand levels, hydro inflows and failures of generation units and network facilities are uncertain. System operators have developed approaches to cope with prediction errors such as these, while still meeting the load reliably. Intermittent generation also adds new challenges to system operation and capacity expansion of power systems (these issues are discussed later in the paper).

Wind generation is variable over time, due to the fluctuations of wind speed. However, the output variability of a single wind plant is different from the variability of many wind plants dispersed over a geographic area. As noted in (Holttinen H. , et al., 2009) and (NERC, 2009), the variability of wind decreases as the number of turbines and wind power plants distributed over the area increase. Figure 1 shows an example of the variability of wind for a single wind turbine, several wind turbines and all wind turbines in a country. The variability of wind generation also decreases with spatial aggregation[6]. Wind energy output over larger geographic areas has less variability than the output of a single wind power plant.

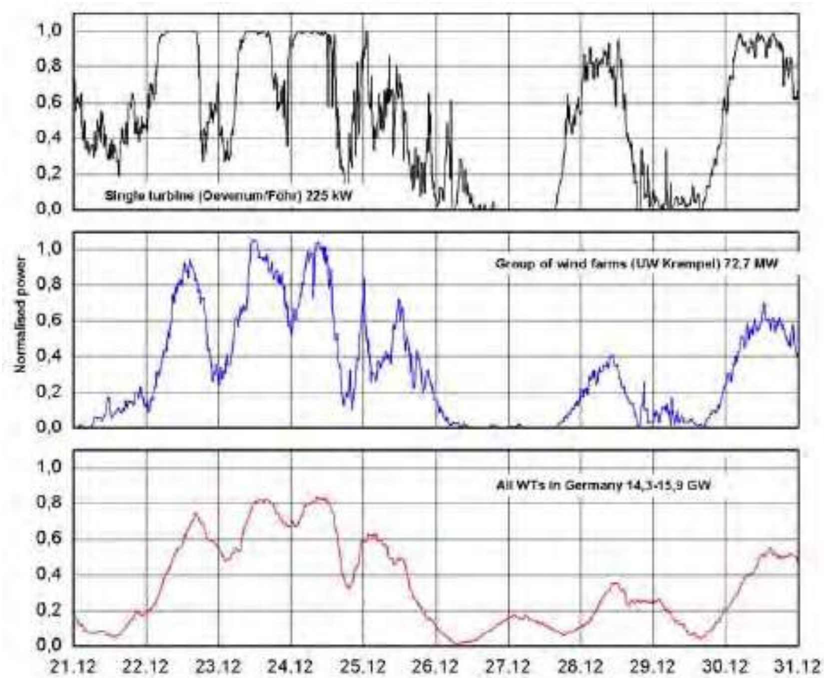

Figure 1: Sample of wind power output for a single wind turbine, and for a group of wind plants in Germany. Source: (Holttinen H. , et al., 2009).

Some illustrative statistics can be found in (EURELECTRIC, 2010): on average, only 4% (2.5% in Spain, 5.5% in Germany) of the total wind installed capacity has a probability of 95% of being present at all times, which is a similar level of availability in conventional power plants. On average, the expected working rate of wind capacity has a 90% probability of oscillating between 4% and 55%, with an average load factor (again in Germany and Spain) of 22%. These figures are very much system dependent.

In addition to wind's highly variable output, predicting this output is difficult—much more so than predicting the output of conventional generators or load. Experience shows that deviations in predictions of wind output decrease with proximity to real time and spatial aggregation. Load predictions made 24-36 hours ahead are fairly accurate. This is not true for wind predictions. Generally, only very near-term wind predictions are highly accurate (Xie, et al., 2011). In particular, the error for 1- to 2-hour ahead single plant forecasts can be about 5-7%; for day-ahead forecasts, the error increases up to 20% (Milligan, et al., 2009). This trend can be seen in Figure 2 (from REE, the Spanish transmission system operator), where clearly wind forecast error decreases as predictions approach to real time (EURELECTRIC, 2010). The picture also shows the improvement of forecast techniques over the years.

[6] This effect is explained because normally, the correlation between wind speeds at two different locations decreases with their distance. As wind speeds with varied correlations feed wind farms, their overall wind output generation will have much less variability. Thus, the geographical dispersion of wind farms has a beneficial smoothing effect on wind power variations.

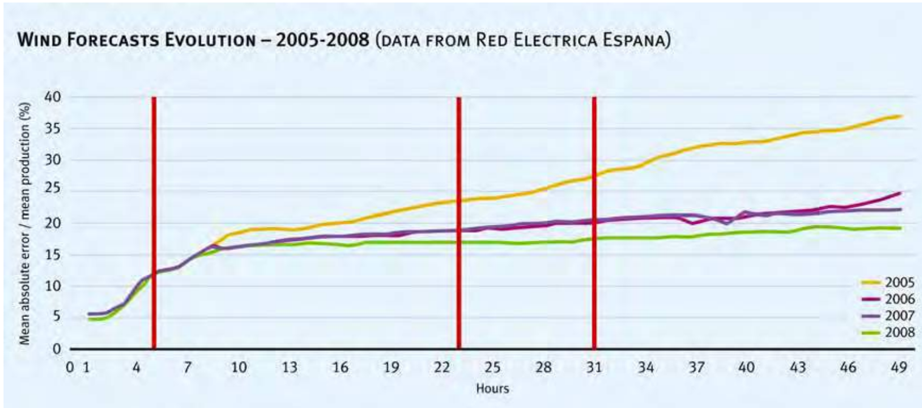

Figure 2: Evolution of the wind forecast error, as a percentage of wind production, as a function to the distance to real time. Source: (EURELECTRIC, 2010).

Similar to variability, spatial aggregation greatly reduces forecast errors. As seen in Figure 3, the level of accuracy improves when considering predictions for larger geographic areas. The aggregation over a 750-km region reduces forecasting error by about 50% (Holttinen H. , et al., 2009).

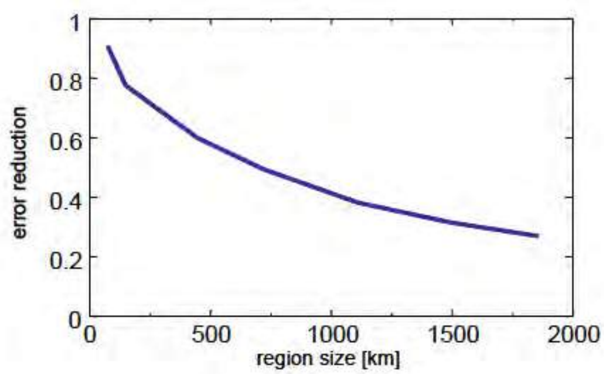

Figure 3: Decrease of the wind forecast error for aggregated wind power production due to spatial smoothing effects. Error reduction = ratio between rmse (root-mean-square error) of regional prediction and rmse of single site, based on results of measured power production of 40 wind farms in Germany. Source: (Holttinen H. , et al., 2009).

The intermittency of wind generation demands a flexible response of the power system, including making use of operating reserves, the use of advanced wind forecasting techniques and some changes in market rules to shorten the scheduling times (NERC, 2009). These issues will be discussed in detail in the following sections.

In general, solar power is characterized by a diurnal and seasonal pattern, where peak output usually occurs in the middle of the day and in the summer. This particular pattern makes solar power well correlated with the peak demand of many electric power systems (Mills, et al., 2009). Despite this beneficial characteristic, solar energy output –like wind– is still characterized as variable and uncertain. On one hand, the sun position impacts the output of PV plants due to its changing behavior throughout the day and seasons. On the other hand, clouds can rapidly change the PV power outputs.

Due to the lack of thermal or mechanical inertia in PV systems, rapid changes have been observed in the output of PV plants. For example, the output of multi-MW PV plants in the Southwest U.S.

(Nevada and Arizona) was reported to have variations of +/- 50% in a 30-to-90 second timeframe and +/- 70% in a timeframe of 5-to-10 minutes on partly-cloudy days (NERC, 2009). Figure 4 shows the output variability of PV plants located in Nevada on a sunny and partly-cloudy day, respectively.

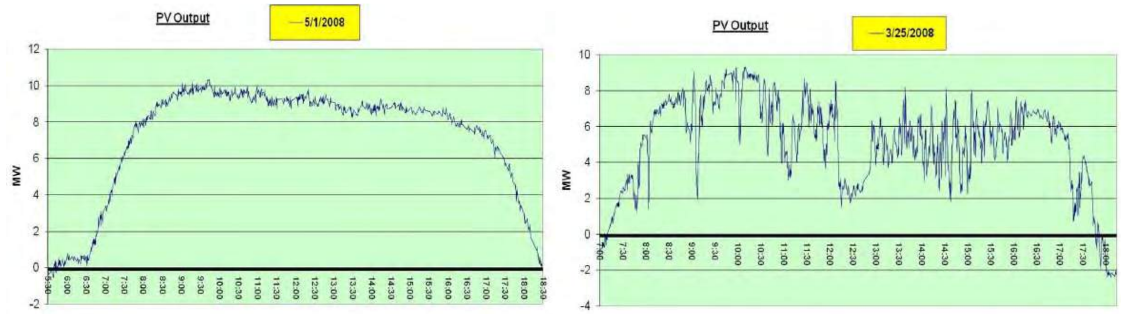

Figure 4: PV plant output located in Nevada on a sunny day (left) and on a partly-cloudy day (right) - Sampling time 10 seconds. Source: (NERC, 2009).

Although the ramping characteristics are fast for PV plants, the time it takes for a passing cloud to shade an entire PV system depends on factors such as the PV system size, cloud speed, and cloud height, among others. Therefore, for large PV systems with a rated capacity of 100 MW, the time it takes to shade the entire system will be on the order of minutes, not seconds. (Mills, et al., 2009).

Spatial diversity, as with wind, can mitigate some of this variability by significantly reducing the magnitude of extreme changes in aggregated PV output, as well as the resources and costs required to accommodate the variability. Either the aggregation of the output of separate PV panels within a plant, or the aggregation of the output of several separate PV plants at different locations helps to smooth the variability of the overall solar energy output (see Figure 5 for an illustration of this effect).

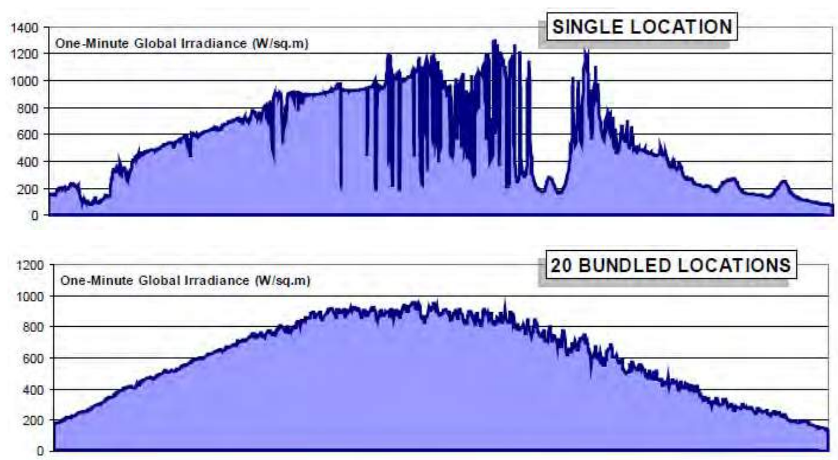

Figure 5: One-minute irradiance and variability at one single location in the network & from 20 bundled stations. Source: (Hoff, Perez, Ross, & Taylor, 2008)

Clearly, clouds are the main factor in solar forecast. Short-term PV forecasts are supported by satellite images that can predict the impact of clouds on PV output. Compared to wind energy, PV solar output is generally more predictable due to low forecast errors on clear days, and the ability to use satellite data to monitor the direction and speed of approaching clouds. For longer time scales, numerical weather models should be used to predict solar insolation out to multiple days (Mills, et al., 2009).

The system-wide smoothing effect for both wind and solar is contingent upon having enough transmission capacity in the system to pool wind and solar resources across varied geographic areas. A large body of experience with, and analysis of, wind energy demonstrates that this geographic smoothing over short time scales results in only a modest increase in the operating reserves required to manage the short-term variability of wind energy.

Finally, we need to stress the importance of accuracy in wind and solar forecast for the efficient and reliable operation of power systems. As indicated in (GE Energy, 2010), large forecast errors may compromise reliability, increase operating costs, and require greater ancillary service procurement. In particular, large wind over-forecasts can lead to under-commitment of flexible generation units resulting in contingency reserve shortfalls, while severe under-forecasts can result in wind curtailment.

2.2. Taxonomy of impacts

In a vertically integrated electric power industry, the complete decision making process is organized in a hierarchical fashion with multiple couplings. Longer-term decisions –such as capacity expansion of generation or transmission– "trickle down", providing targets and information to shorter-term decisions, see Figure 6. In power systems open to competition, as it is the case in most of the US and many countries of the world, most of these decisions are made by multiple agents in a decentralized fashion, therefore replacing centrally coordinated plans of capacity expansion or operation by the individual decisions of multiple agents driven by market forces. In general the generation activity can be open to competition, while the networks remain a regulated monopoly.

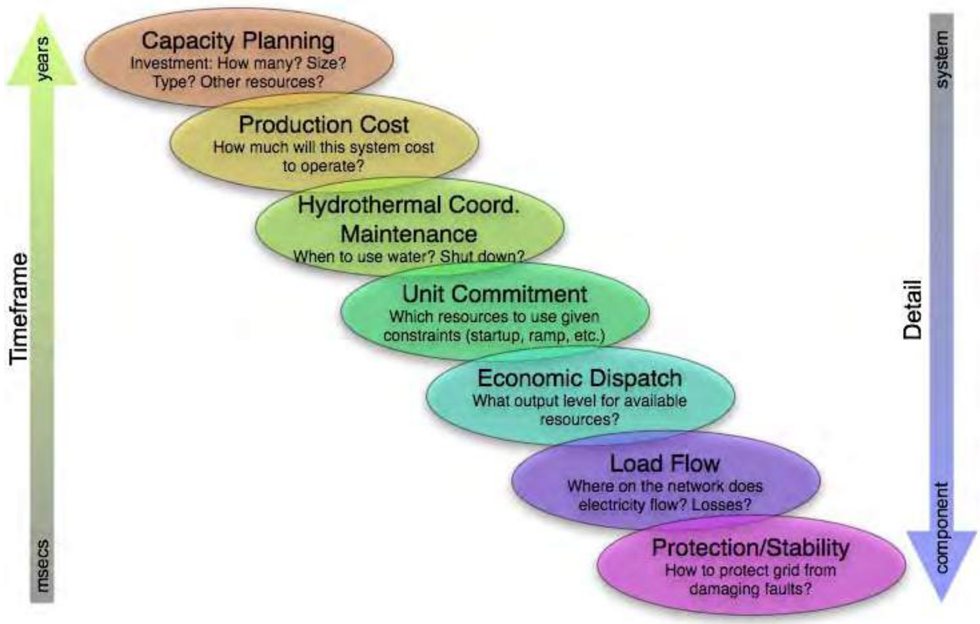

Figure 6: Hierarchical decision-making process in power systems. Source: Bryan Palmintier MIT's doctoral thesis (in preparation).

The effects of penetration of intermittent generation will affect decisions made at all timescales and across geographic regions differently. Figure 7, adapted from IEA Wind Task 25 (Holttinen H. , et al., 2009), tries to capture both of these dimensions and highlights the anticipated major areas of impact.

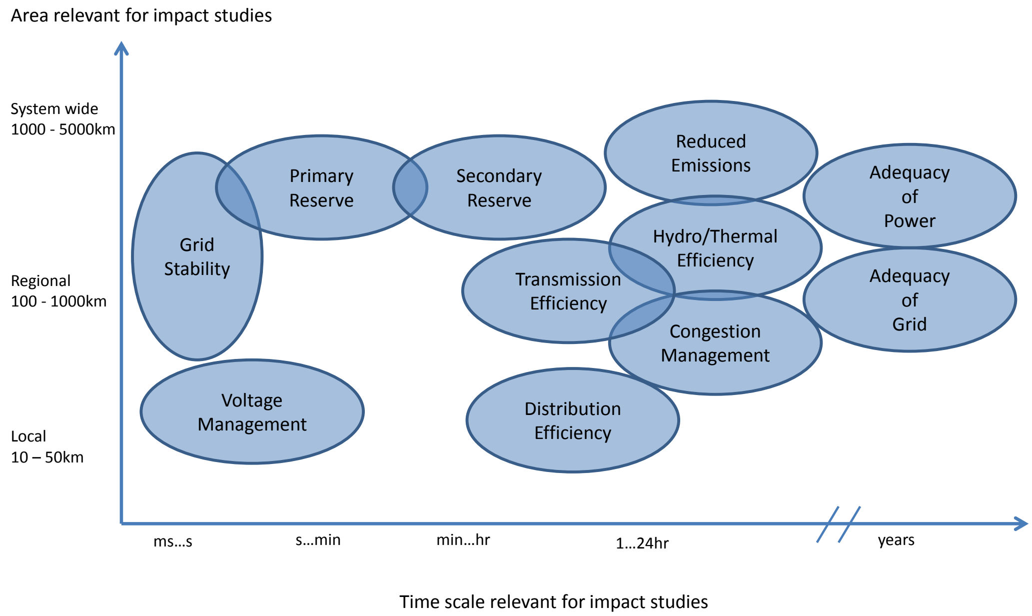

Figure 7: Impacts of wind power on power systems, divided into different time scales and size of area relevant for impact studies. Source: Adapted from (Holttinen H. , et al., 2009).

From a reliability perspective, see (NERC, 2009), different timeframes should also be considered when looking at the impacts of large-scale penetration of intermittent renewable generation on the planning and operation of power systems. From the seconds-to-minutes timeframe, system reliability is mostly controlled by automatic equipment and control systems. From the minutes through one-week timeframe, operators and operational planners need to commit and dispatch generators to maintain reliability through normal conditions, as well as contingencies and disturbances. For longer timeframes, system planners must ensure that existing transmission and generation facilities are adequate to keep a reliable operation of the system.

The addition of intermittent renewable generation will bring about a variable and only partly predictable source of power generation, with zero variable costs, to a power system that has to balance generation and varying demand at all times. At high levels of penetration, the characteristics of the bulk power system can be significantly altered. These changes need to be considered and accommodated into the current planning and operation processes, which were not designed to incorporate large volumes of intermittent generation. Multiple new issues must be addressed, ranging from increasing power system flexibility by a better utilization of transmission capacity with neighboring areas, to demand side management and optimal use of storage (e.g. pumping hydro or thermal), or changes in market rules to schedule the plants closer to real time. The future mix of generation technologies will have to accommodate the strong presence of intermittent generation and be able to cope with more cycling, fewer hours of operation and different patterns of electricity prices.

Inexpensive storage, at scale, represents the most straightforward way to deal with these issues. However, storage at the low cost and large scale needed will take some time. In the interim – which will likely be at the decadal scale– other sources of flexibility will be needed.

The review of topics in this paper is organized into three major blocks. We shall start examining the impact on operation of the generation plants, leaving the network aside for the moment, since this will allow understanding better the basic trade-offs that central system planners (under traditional regulation) or private investors of generation assets (under competitive market conditions) will have to deal with. Still under operation we have to distinguish the more technical security analysis of the power system –those that simulate stressful conditions for the power system, in terms of possible loss of stability, exceed voltage or transmission stability limits–, from the mostly economic functions –although limited by security constraints– that allow to make efficient utilization of the generation units to meet demand. Then we shall look into generation capacity expansion and also network issues.

Intermittent renewable generation and power system models

Suitable power system models are needed to capture the specifics of intermittent generation and evaluate its impact on planning and operation of the power system. From the generation perspective, these models should be able to represent: a) the economic merit order of the different technologies; b) how the diversity of their fixed and variable costs makes them more suitable to cover different levels and durations of demand; c) a prescribed margin of installed firm generation capacity over estimated peak demand (the investment adequacy requirement), including the contribution –the so called capacity credit– of intermittent generation; d) a specified quantity of operating reserves that will somehow depend on the volume and characteristics of intermittent generation, again including the stochastic nature of intermittent generation and any spatial and temporal correlations of production and demand; e) the chronological aspects and inter-temporal links in a realistic scheduling of the generating plants, including wind or solar curtailments and cycling –including shut downs and start-ups– of thermal plants and their associated costs and emissions. Network models are very much needed for transmission planning and to evaluate the remuneration of distribution networks with embedded distributed generation, see sections 5 and 6 of the paper.

Sound computer models that can provide a comprehensive appraisal of the economic, environmental and reliability implications of different levels of significant penetration of intermittent generation in power systems –such as the estimation of future electricity prices, levels of fuel consumption or reliability measures– should be a central piece in the design of energy policies that contemplate mandating large amounts of solar or wind generation. Dedicated efforts to expand or develop the sophisticated computation models that are needed for this task appear to be well justified.

Two relevant subjects that are transversal to all the topics covered in this paper will be mentioned next: power system models and the impact of the format of the adopted regulatory instrument to economically support intermittent renewable generation.

The influence of the adopted regulatory instrument to support renewable generation

Numerous regulatory issues are raised by the massive introduction of intermittent renewable generation in electric power systems. Foremost among them is the specific support scheme that is adopted to make wind or solar generation financially viable. Most of the discussion on the support schemes has been on their performance regarding the volume and the cost of the achieved investments in renewable generation: Some regulatory authorities prefer price mechanisms (i.e. feed-in tariffs, feed-in premiums, or tax incentives) while other consider that quantity mechanisms (i.e. renewable portfolio standards or tradable green certificates) are a better choice. However, these support instruments have also often profound implications on the behavior of the renewable plants in the operation of the power system and the electricity markets.

One example may suffice to illustrate this point. Feed-in premiums, FiPs, are paid to renewable producers as a fixed amount in $/MWh in addition to the electricity market price. FiPs are currently seen as beneficial for the efficiency of the system operation, since the premium plus market signals create incentives for the wind or solar plants to adjust their production according to the market conditions, and to improve the prediction of their output and the management of the maintenance activities. Experience has shown that exposing renewable producers to the cost of imbalances improves significantly their ability to predict their output in the short-term, leading to a significant decrease of the cost of imbalances for the entire system. But, at the same time, FiPs also create the incentive to integrate renewable generation with conventional thermal generation in the large portfolios of the incumbent utilities. They can exploit their own flexibility to solve internally any imbalances, reducing liquidity in the balancing market and thus setting an entry barrier for potential competitors in the intermittent renewable business. Wind and solar become additional inframarginal capacity within these large portfolios, thus increasing any market power that they might have. This example shows that the implications of the renewable support mechanisms have to be examined along the complete chain of capacity expansion, operation and control.

3. Impacts on power system operation

As shown in Figure 7, system operation encompasses a diversity of time spans. Common to all system operation functions is that the installed capacity is given and the decisions to be made only include how to operate the generation plants. This section focuses on several salient issues: the need for more operational flexibility in the generation resources; negative impacts on the operation of conventional thermal power plants; the need for additional operation reserves; the need for integration of balancing areas and enhancement of balancing markets; the need for support from and interaction with demand response, storage technologies and electric vehicles; the effect on operation cost and market prices; the impact of application of priority rules and the potential influence of the presence of wind and solar PV plants on power system stability.

3.1. The need for flexibility in system operation

Both the variability and uncertainty of intermittent renewable generation sources ask for more flexibility of the generation portfolio and in the operation of the power system, including the design and utilization of transmission and distribution networks.

System operators need to have generation, demand resources, or any other form of flexibility in the power system ready to respond whenever ramping and dispatchable capabilities are needed; for example, during morning demand pickup or evening demand drop-off time periods (NERC, 2009).

The power system needs more flexibility to handle the short-term effects of increasing levels of wind. The amount of flexibility will depend on how much wind power capacity is currently installed, and also on how much flexibility already exists in the considered bulk power system

(Parsons & Ela, 2008). Even with perfect forecasting, wind generation will remain variable, for instance from one hour to the next, and for this reason additional flexibility is required.

The impact of wind and solar generation on the operation of a power system can be better understood, in a first approximation and for the hourly to daily time range, by examining the changes in production levels of all technologies that take place when the output of these two intermittent technologies is modified with respect to some reference case. In principle, more wind and solar production at zero variable cost will result in less generation from other technologies. However, the share of reduction for each technology will not be the same. More wind or solar production means less production with the plants that are at the margin. Except for those non-frequent hours when peaking units are needed –typically open cycle gas turbines, OCGT– the plants at the margin for high levels of demand will be combined cycle gas turbines, CCGT, or less efficient coal plants, depending on the technology mix in the considered system, the respective prices of coal and gas and the future price of CO_2, in those systems that apply it. Obviously the impacts of wind and solar on the technologies at the margin will be different, because of the different temporal patterns of each one, within the day and also seasonally.

As an example, Figure 8 and Figure 9 show the impact of different levels of penetration of wind and solar generation (concentrated solar power, CSP, with no storage) in a 2030 projected generation portfolio. See (MIT, 2010) for details on modeling and assumptions. The three illustrations in Figure 8 give the results for varying levels of wind generation: the reference case, which is a *hypothetical representative day for ERCOT in 2030*, and other two cases with half and twice the amount of wind generation as in the reference case. Note that, in the base case, the night-time load (roughly hours 01-04) is met by nuclear and coal base load plus wind generation. There is no appreciable output from gas between hours 01-04 because it has higher variable costs than nuclear and coal, so gas gets dispatched last. Natural gas also has the flexibility to cycle. In hours 05 through 23, when overall demand increases during the early morning and decreases in the late evening, NGCC generation adjusts to match the differences in demand. In the picture, when less wind is dispatched, the natural gas combined cycle capacity is more fully employed to meet the demand, and the cycling of these plants is significantly reduced. The base load plants continue to generate at full capacity. In the case with twice as much wind as the base case, natural gas generation is reduced significantly and the gas capacity actually used is forced to cycle completely. Base load coal plants are also forced to cycle because of the relatively low night-time demand.

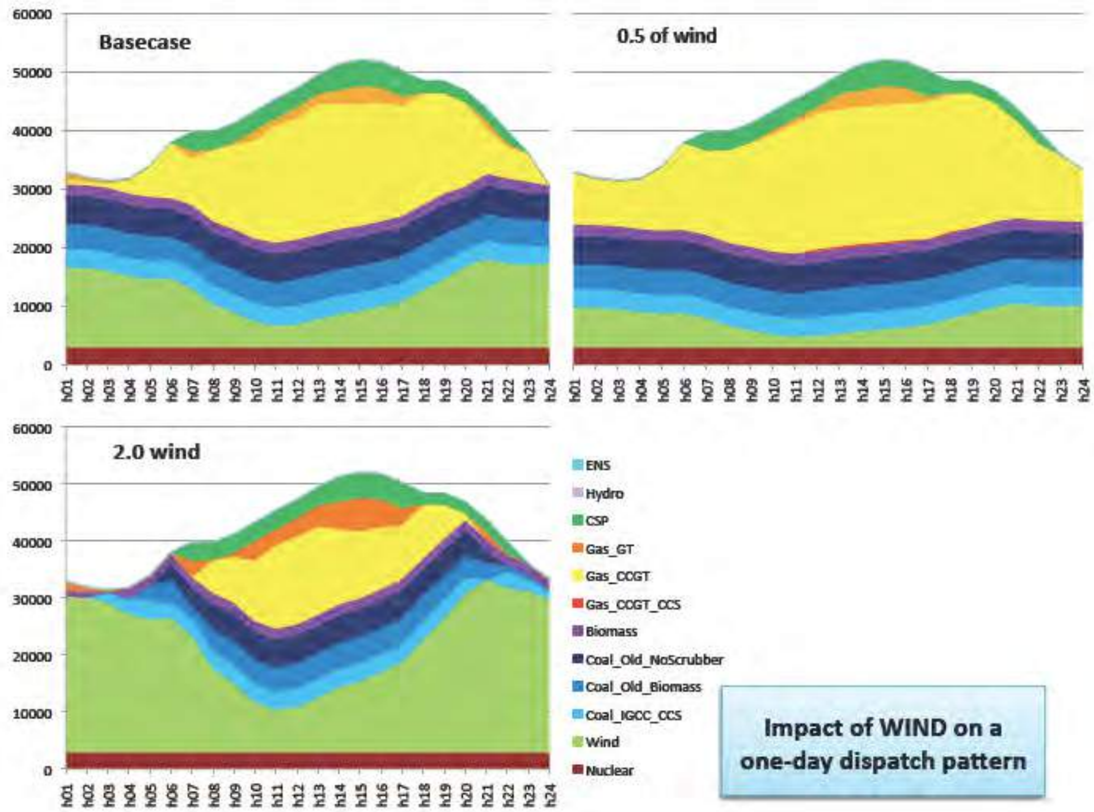

Figure 8: Impact of wind production on one-day hypothetical dispatch pattern for ERCOT in 2030. Source: (MIT, 2010).

The three cases for solar CSP with no storage in Figure 9 follow a similar pattern to Figure 8: a reference case, a case with half as much solar production, and a case with twice the level of solar production. However, there are some differences in the results. Solar generation output basically coincides with the period of high demand, roughly between hours 06 and 22, where the CCGT plants are also dispatched. The natural gas plants are used more when solar output is less. Conversely, when solar is used more, less gas is dispatched. The base load plants are largely unaffected and cycling is not a problem for them, since there is no intermittent solar-based generation during the low-demand night hours.

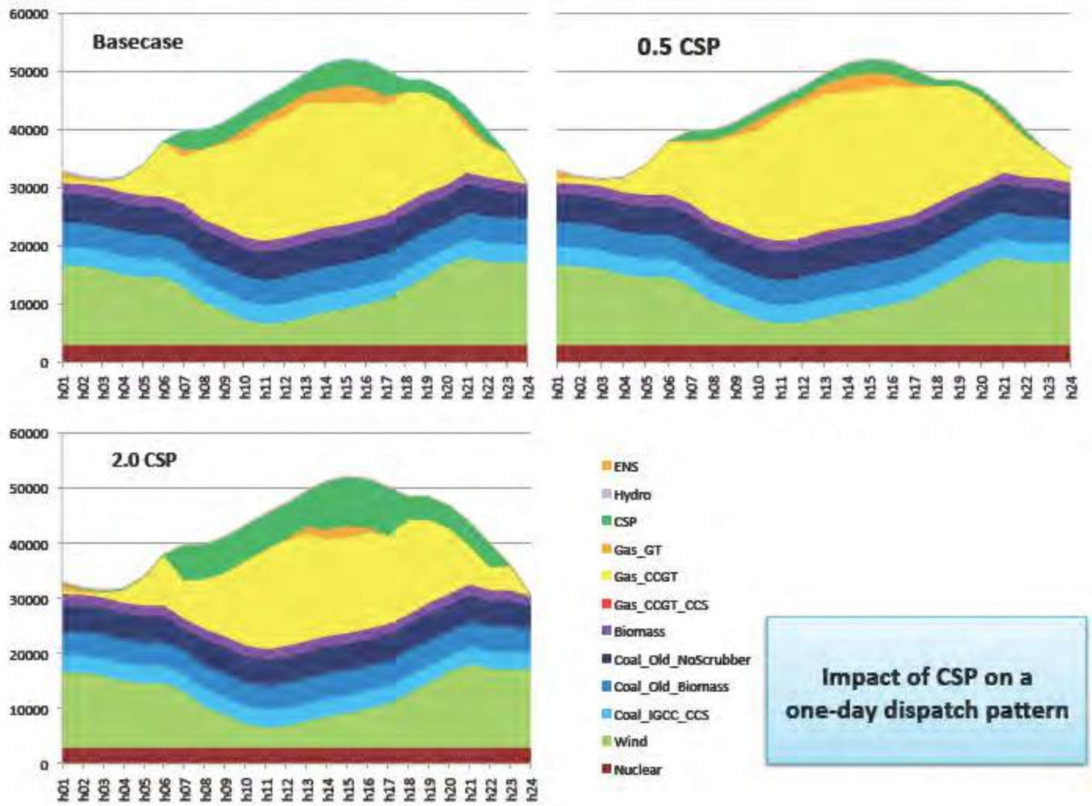

Figure 9: Impact of production of concentrated solar power (CSP) without storage on one-day hypothetical dispatch pattern for ERCOT in 2030. Source: (MIT, 2010).

There are several dimensions in achieving flexibility: a) better use of the flexibility that the existing system has or may have, for instance by changing market rules or by integrating current small balancing areas into larger ones; b) adding new flexible plants to the existing portfolio; c) utilizing flexibility contributions of the intermittent units.

There are different flexibility capabilities that are needed from all the power plants in a system with a strong presence of intermittent generation, corresponding to the different functions in power system operation, and ranging from fast response to frequency disturbances to the capability of shutting down and starting up again frequently. According to (NERC, 2009) these capabilities include: a) ramping of the variable generation (modern wind plants can limit up- and down-ramps), 2) regulating and contingency reserves, 3) reactive power reserves, 4) quick start capability, 5) low minimum generating levels and 6) the ability to frequently cycle the resources' output. Additional sources of system flexibility include the operation of structured markets, shorter market scheduling intervals, demand-side management, reservoir hydro systems and energy storage. System planners and electricity market regulators must ensure that suitable system flexibility is included in future bulk power system designs, as this system flexibility is needed to deal with intermittency on all time scales. It therefore can be said that, as penetration of intermittent resources increase, system planners need to ensure that the added capacity has adequate flexibility to meet the total new flexibility requirements of the system. This is a new design requirement for future systems, and it can be met with local generation, interconnections with other systems or demand resources.

Note that the lack of flexibility of some base-load technologies also imposes a cost to the power system and a burden on the remaining plants, since they are left with the entire responsibility of meeting the always changing demand. For instance, adding more inflexible nuclear capacity in Figures 8 and 9 would also result in increased cycling of coal and CCGT plants.

3.2. Negative unintended consequences

Wind and, especially, solar PV plants can be installed much faster than other generation technologies. When a quick deployment of intermittent generation takes place in an existing system without enough time for the technology mix to adapt to the new situation –power systems require massive capital investments and take decades to adjust to the new technologies and economic conditions– existing plants that were not designed for this amount of cycling and steeper ramps will have to function under quite different operating conditions. This will result in increments in start-ups, operation at sub-optimal levels with losses of efficiency in electricity production, increased ramping duty, additional maintenance costs and a premature deterioration of components of the power plants, shortening their lifetimes and, in general, increasing environmental impact and cost per unit of output. These findings are supported by multiple studies; see, for instance, (Troy, Denny, & O'Malley, 2010) and (Milligan, et al., 2009).

In particular, the operation of base-load CCGT units could be severely impacted. (Troy, Denny, & O'Malley, 2010) shows that wind displaces CCGT units into mid-merit operation, resulting in a much lower capacity factor and more start-ups (see Figure 10). In the case of coal units, it is noted that higher levels of wind also increase start-ups. However, this increment is not as drastic as for CCGTs, because coal plants are higher in the merit order, as the discussion for Figure 8 noted. Similar results are found for the Ireland's electric system under penetration scenarios ranging from 5% up to 30% of total energy requirements (ESB National Grid, 2004) and also in Spain (Alonso, de la Torre, Prieto, Martínez, & Rodríguez, 2008).

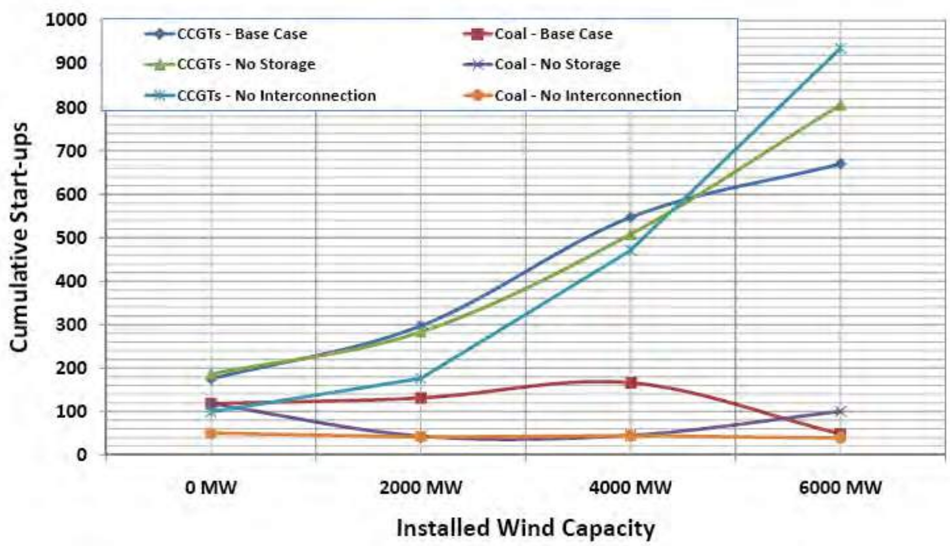

Figure 10: Impact of wind penetration on base-load and mid-range start-ups. Source: (Troy, Denny, & O'Malley, 2010).

A particularly interesting case has been reported in (Bentek Energy, 2010) for the power system of the US state of Colorado, involving also the impact of wind penetration on the emissions of SO_2 and NO_x produced by the conventional plants that are subject to cycling. The study contemplates four years of Public Service Company of Colorado (PSCO) operational history. A simulation analysis has been done for the ERCOT system, with similar results. The study shows that the installed capacity of flexible gas fuelled plants is insufficient to offset all of the amount of wind energy produced in PSCO and, therefore, coal units must be cycled to counterbalance the amount of wind that cannot be offset by natural gas. Since coal plants were not built for cycling, they operate less efficiently, substantially increasing emissions. All coal power plants show more emissions of SO_2 and NO_x, and some also of CO_2. However, this does not necessarily translate into more CO_2 emissions from an overall system perspective, since the amount of energy, and fossil fuel, displaced by wind is quite important, offsetting the increments of fuel because of efficiency loss and additional operating reserves (ESB National Grid, 2004). The study rightly indicates that these undesirable effects should be eliminated by the introduction of more gas capacity, a reduction in coal capacity or a combination of the two, which involves replacing less expensive coal generation by cleaner and more flexible gas production from spare gas capacity in the region. As indicated above, these problems should be minimized once the mix of generation technologies has had time to adapt to the new conditions with a high level of wind penetration. However, this indicates that there is a compelling need to better understand the implications of regulatory measures on the existing power systems, so that undesirable consequences can be avoided.

Reading this report also brings the question of what unintended impacts might result from adding more new base-loaded power plants to the portfolio of PSCO; for instance, a new nuclear plant or an efficient coal unit. These hypothetical new plants would augment the cycling of the less efficient coal units, with the corresponding loss of efficiency and rise of emissions.

3.3. Additional requirements of operating reserves

A critical issue in power system operation with a large volume of intermittent production is the amount of operating reserves that will be needed to keep the power system functioning securely and efficiently. The practical implications are: a) more expensive operation, as a number of plants have to be maintained in a state of readiness and kept from being used normally to generate electricity, regardless of the regulatory framework; b) a long-term impact on the generation mix, as appropriate investments have to be done to have these plants installed and ready when the level of penetration of intermittent generation makes these quick response plants necessary. A comprehensive review of the new requirements that intermittent generation may impose on power systems can be found in (Holttinen H. , et al., 2011).

Following (Milligan, et al., 2010), operating reserves are defined as the real power capability that can be given or taken in the operating timeframe to assist in generation and load balance, and frequency control. There is also need for reactive power reserve, but it will not be discussed here. The types of operating reserves can be differentiated by: a) the type of event they respond to, such as contingencies, like the sudden loss of a generator or a line, or longer timescale events such as net load ramps and forecast errors that develop over a longer time span; b) the timescale of the response; c) the type of required response, such as readiness to start quickly a plant or fast response to instantaneous frequency deviations; d) the direction (upward or downward) of the response.

Based on the characteristics listed above, a thorough international review (Milligan, et al., 2010) classifies all types of reserves used anywhere into five categories, in decreasing order of quickness of reaction: i) *frequency response reserve* (to provide initial frequency response to major disturbances; also called primary control or governor response, acting in seconds); ii) *regulating reserve* (to maintain area control error within limits in response to random movements in a timeframe faster than energy markets can clear; also termed frequency control or secondary reserve, acting in seconds); iii) *ramping reserve* (to respond to failures and events that occur over long timeframes, such as wind forecast errors or ramps; also termed deviation reserve, balancing reserve or forecast error reserve, acting in minutes to hours); iv) *load following reserve* (to maintain within limits area control error and frequency due to non-random movements on a slower time scale than regulating reserves; also named tertiary reserve, acting in several minutes); and v) *supplemental reserve* (to replace faster reserve to restore pre-event level reserve; also called tertiary reserve and replacement reserve, acting from minutes to hours). Regulating and load following reserves are used during normal system operation. Frequency response and supplemental reserves are used during contingencies. A mix of spinning and non-spinning reserves can be used for the slower reserves (ramping, load following and supplemental) while the faster reserves (frequency and regulating reserves) require strictly spinning reserves.

A review of the numerous studies that have been made on the subject of the impact of intermittent generation on the need for additional reserves appears to lead to the following findings, which have to be adapted to the diverse characteristics of each individual power system:

- Observations and analysis of actual wind plant operating data have shown that wind does not change its output fast enough to be considered as a contingency event. Therefore the largest contingency to be considered in the determination of reserves is not affected by wind penetration.
- Both the uncertainty and the variability of wind generation may affect the required amount of regulating (secondary) reserves, but not significantly in most cases. Fast response reserves – frequency response and regulating reserves– should be ready to respond to quick fluctuations in solar or wind production. However, since power systems already need these kinds of reserves to cope with load fluctuations and unexpected emergencies, the practical relevance on production levels or costs of the presence of intermittent generation on the demand for these reserves is not deemed to be of much relevance.
- More important is the impact of errors in the prediction of the output of wind and solar on the day-ahead schedule of plants, since this requires having ready a significant capacity of flexible generating plants with relatively short start-up times and/or fast ramping capabilities, such as OCGT and CCGTs plants, to provide load following and supplemental (tertiary) reserves. These reserves are typically established in the day-ahead timeframe, where the error in wind forecast is large. In a well-designed power system, a sufficient volume of these flexible peaking units must exist to cope with the not infrequent case of sustained very low output of wind and solar plants. Note, however, that the requirement for operating reserves does not necessarily mean that these flexible plants will be actually used for production. The need is more for readiness than actual production.
- These additional requirements imply an increasing amount of mandatory dispatching of thermal units. It reduces the capability of generators to manage their portfolio (trading with these units is limited), and consequently reduces the offers on the commodity market and may increase market prices.
- Results from several worldwide case studies show that reserve requirements increase with higher penetrations of wind, see (Parsons & Ela, 2008), (Holttinen H. , et al., 2011) or (EURELECTRIC, 2010). Figure 11 shows some results for Ireland: the impact of wind penetration on the requirement of reserves is strongly related to the growth of the error in the wind forecast with the distance to the real time. A sample of international experiences is displayed in Figure 12.

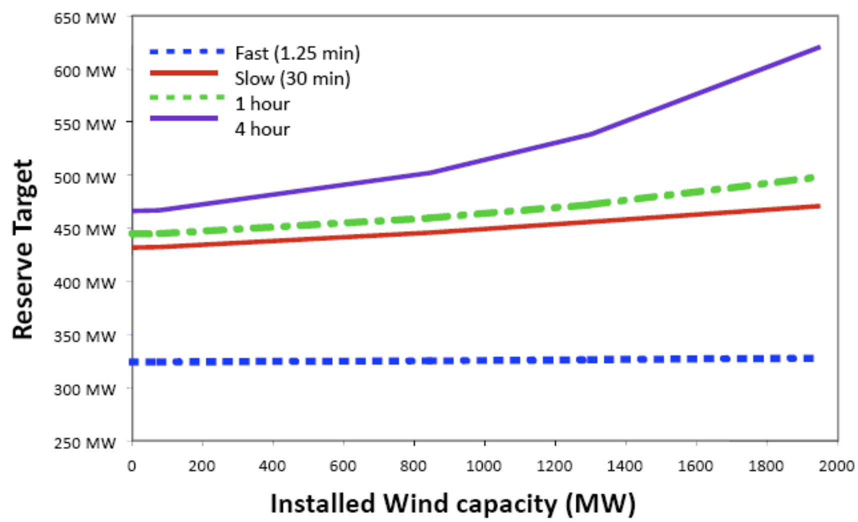

Figure 11: Operating reserve requirements as a function of wind power penetration. Source: MIT 2011 Wind Week. Presentation by Mark O'Malley. Available at http://web.mit.edu/windenergy/windweek/Workshop2011.html.

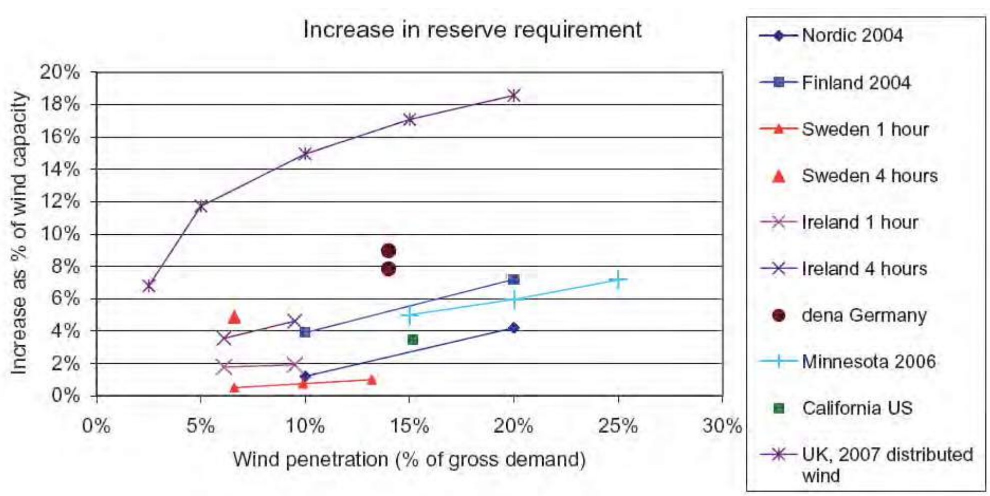

Figure 12: Results for the increase in reserve requirement due to wind power. Source: (Holttinen H. , et al., 2011).

As pointed out in (Holttinen H. , et al., 2011), an 'increase in reserve requirements' does not necessarily mean a need for new investments, as countries already with much wind power have learned from experience. Note that most wind-caused reserves are needed when wind output is highest and, therefore, the conventional power plants must have more spare capacity to provide reserves. Critical issues appear to be the capability to follow steep long ramps if the wind forecast errors are large enough that the slow units cannot follow.

It seems that careful attention must be given to the relationship between flexibility and reserves. It has to be realized that the need for flexibility is not the same as the need for reserves, which is smaller since a part of the variation of the net load –i.e. the original load minus intermittent generation output– can be forecasted. As it has been shown before, reserves mainly depend on forecast errors and the overall flexibility in scheduling deals also with the changes in output level for several hours and a day ahead; see ((Holttinen H. , et al., 2011), p. 182). This points out the open question of how to precisely define the flexibility requirements of a power system and how to incentivize the investment in the right kind of power plants and the provision of flexibility services.

3.4. Improving large scale integration of intermittent renewable generation: Coordination of balancing areas and reduced scheduling intervals

Large volumes of intermittent generation would be integrated much more easily in existing power systems if some institutional and organization problems could be properly addressed; see (EURELECTRIC, 2010), (Holttinen H. , et al., 2011), (NERC, 2009) and (ACER, 2011). Two approaches will be commented on here: a) geographical extension of the areas that are responsible for offsetting the variability and uncertainty of wind and solar production will smooth out the impacts and pool existing resources more efficiently and reliably; b) a proper treatment of intermittent generation requires a market organization that gets much closer to real time than the classical day ahead market, in order to reduce the negative impact of uncertainty in the operation of the system. Both approaches should be coordinated and addressed simultaneously. Other methods will be commented in the next section (3.5).

Integration and coordination of balancing areas

As described in (NERC, 2009), ancillary services are a vital part of balancing supply and demand and maintaining bulk power system reliability. Since each balancing area must compensate for the variability of its own demand and generation, larger balancing areas with sufficient transmission proportionally require relatively less system balancing through operation reserves than smaller balancing areas; see, for instance, (Parsons & Ela, 2008). With sufficient bulk power transmission, larger balancing areas or wide-area arrangements can offer reliability and economic benefits when integrating large amounts of variable generation. In addition, they can lead to increased diversity of variable generation resources and provide greater access to other generation resources, increasing the power systems ability to accommodate larger amounts of intermittent generation without the addition of new sources of system flexibility. Various kinds of coordination among different jurisdictions have taken place everywhere in the world for a long time. Now, the opportunities resulting from consolidation or participation in wider-area arrangements –either physically or virtually– have to be evaluated. Figure 13 shows a hypothetical future aggregation scenario of the current balancing areas in the US Eastern Interconnection.

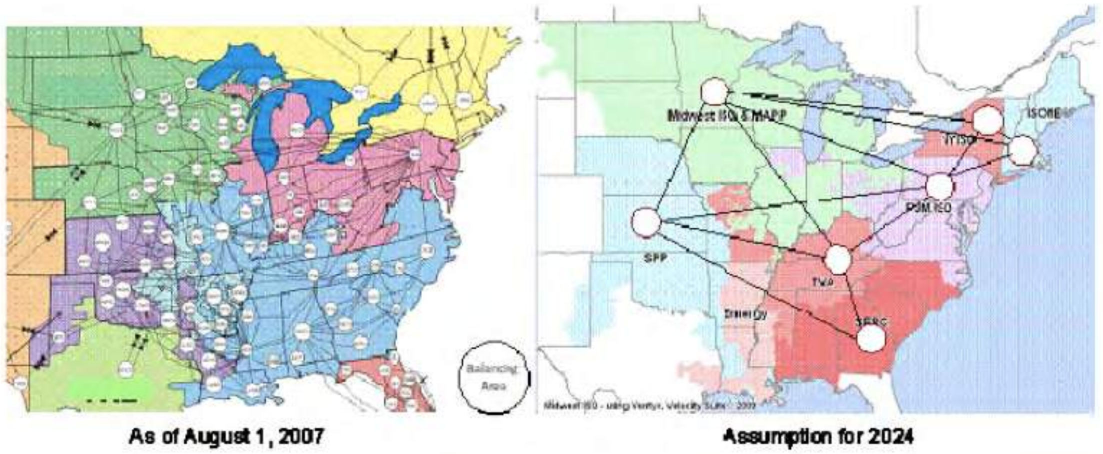

Figure 13: Assumed operational structure for the Eastern Interconnection in 2024 (the white circles represent the balancing authorities). Source: Presentation by Michael Milligan, NREL, at the MIT 2011 Wind Week.

Reduced scheduling intervals

Arrangements for the provision of the different kinds of ancillary services –and in particular operating reserves– widely depend on the individual power systems. In some cases the commitments for energy and some operating reserves are made at the day-ahead time range. In many cases, balancing energy transactions are scheduled on an hourly basis. More frequent and shorter scheduling intervals for energy transactions may assist in the large-scale integration of intermittent generation. If the scheduling intervals are reduced (for example, from one hour to 10 minutes, or providing intraday markets or even continuous trading to adjust previous positions in day-ahead markets), this will help to reduce the forecast errors of wind or solar power that affect operating reserves.

Given the strong level of presence of wind or solar generation in some power systems, there should be a level playing field for balancing responsibility, which applies to all producers, including wind and solar generator –although perhaps with some less stringent requirements– in order to stimulate all market participants to carry out thorough and proper scheduling and forecasting and thus limit system costs.

In summary, the virtuous combination of adequate available transmission capacity, larger balancing areas and more frequent scheduling –within and between areas– may significantly reduce variability of generation and demand, increase predictability and therefore reduce the need for additional flexible resources in power systems with large penetration of intermittent renewable generation. Consequently, the need for ancillary services would be less, and the costs of running the power system would be lower. As an example that this can be accomplished, a draft of mandatory Framework Guidelines has been recently issued for consultation in the European Union that contains all the necessary components: A pan-European intra-day platform to enable market participants to trade energy as close to real-time as possible to rebalance their positions, with the participation of the system operators to facilitate an efficient and reliable use of the transmission network capacity in a coordinated way, see (ACER, 2011). A similar approach is proposed in (NERC, 2009).

3.5. Other resources to improve the integration of large scale intermittent renewable generation

Some technical resources may help operators to properly respond to the patterns of intermittent generation. One should include here the additional flexibility of generation plants, energy storage, reservoir hydro systems, demand response, electric vehicles and improved wind forecast techniques.

The contribution of most power plants to the flexibility of the operation of a power system is –up to a certain point– a function of the existing economic incentives. Technical minima, ramping capabilities, start-up times and hydro reservoir management can be modified given the adequate economic conditions. It is a regulatory challenge to define these conditions and a technical challenge to respond to them. See, for instance, the debate on the regulating capabilities of nuclear generation units in (Pouret, Buttery, & Nuttall, 2009).

Wind and solar plants should also be considered in this respect. The share of wind power in relation to the strength of electricity grids and other power plants is reaching levels such that they can no longer be considered as neutral system components that do not contribute to balancing supply and demand. Now they must operate as other power plants and contribute to the needs of flexibility of the system; see next section 3.6 for details.

Storage, if available, can provide different types of reserves and also operate as a flexible plant. Inexpensive storage, at scale, represents the most straightforward way to deal with integration of intermittent generation. The benefits from this technology are more valuable when operated as a system-wide resource (rather than locally) able to provide regulation, demand following, capacity, and balancing capability (NERC, 2009), (DOE EERE , 2008). The value of storage depends on the mix of generation resources in the system, and it increases as more wind is added to the system. However, in a system with less base load units and more flexible generation, its value is not very sensitive to the penetration of wind, even at high levels (Milligan, et al., 2009). Moreover, it has been found that storage resources do not need to be developed to balance large volumes of wind (up to 20% wind energy), if enough transmission exists to allow the pooling of resources across the electric system (Ummels, Pelgrum, Kling, & Droog, 2008), (DOE EERE , 2008), (Milligan, et al., 2009) and (Denholm, Ela, Kirby, & Milligan, 2010).

Power systems with a very large percentage of hydro production, like those of Brazil or Norway, have no integration difficulties. Pumped-storage hydro plants, wherever possible, can provide an economically viable support to intermittent generation. Sites for new hydro plants are very difficult to find in industrialized countries, at least. Compressed-air in caverns, flywheels and batteries are already showing promising results. Solar thermal systems intrinsically offer some degree of storage, and direct solar-to-fuels conversion could eventually be the game-changing solution. However, technologies that could contribute very large additional amounts to what already exists do not appear to be available in competitive economic terms in the short-term, (Eyer & Corey, 2010). The same applies to electric vehicles, for the time being.

Demand response is another potential source of flexibility; see (NERC, 2009). Demand responsiveness by means of time-variant retail electricity rates, such as real-time pricing (RTP) or interruptible load agreements, could potentially reduce wind integration and forecast error costs. Through a price signal in the form of RTP, consumer demand could be made to follow the supply of wind generation, where if wind generation is high, for example, electricity demand will increase as a result of low electricity prices. Conversely, if wind generation is low, electricity demand will decrease as a result of high electricity prices (Sioshansi, 2010). Actual deployment of demand response schemes and an evaluation of its potential in the US can be found in (FERC, 2011).

The largest impact of intermittent generation on system operation costs appears to be in the unit-commitment time frame (Holttinen H. , et al., 2011), and it is caused by the potential error in the forecast of wind output. Therefore, improvements in day-ahead wind plant output forecasting offer a significant opportunity to reduce the cost and risk associated with this uncertainty. Current forecasting technology is far from perfect but nonetheless highly cost effective. Wind forecasting is very challenging. It depends on small pressure gradients operating over large distances, on turbulent & chaotic processes and also on the local topography. The dependence of wind plant output on wind velocity is very nonlinear and therefore errors in wind prediction may be substantially amplified. Improvements in prediction require better models and more observational data. The benefits of wind output aggregation at power system control level and the need for large investments in observational networks favor centralization of the wind forecasting activities.

3.6. Impacts on power system stability

Power systems must be able to maintain their integrity while responding to different kinds of contingencies that take place in very short time scales: short circuits in lines, sudden loss of load or generation, or special system conditions that gradually become unstable. Power system stability is the ability of an electric power system, for a given initial operating condition, to regain a state of operating equilibrium after being subjected to a physical disturbance, with most system variables bounded so that practically the entire system remains intact (Kundur et al., 2004).

There are several forms of instability that a power system may undergo. Transient stability refers to the capacity of the generators to maintain the synchronism in the presence of transmission line faults. Spontaneous low frequency oscillations must be damped quickly. Frequency excursions due to abrupt imbalances between generation and demand should be contained and the frequency brought swiftly to its nominal value. Voltages have to be maintained within safe boundaries at all times. The allowed response time to these contingencies typically ranges from some milliseconds to a few seconds or even minutes, therefore with some overlap with the activity of fast operation reserves. The most crucial factors for the stability of a power system are its mechanical inertia –provided by the rotating masses of all the turbines and the electricity generators– and its capability to damp any perturbation (Rouco, Zamora, Egido, & Fernandez, 2008).

The physical characteristics of wind and solar PV plants are substantially different from those of thermal plants –including concentrated solar power units– which consist of a boiler producing high-pressure steam that drives a turbine rotating in the same shaft with a synchronous generator. The ability to regulate frequency and arrest any sudden rise and decline of system frequency is primarily provided through the speed droop governors in conventional generators.

In principle, most wind turbine generators are often isolated from the grid by power electronic converters, and their inertial response to the overall power system is almost negligible. Solar PV plants have no contribution to the inertia of the power system. Therefore, an increased penetration of wind turbines and solar PV plants may result in significant changes in the dynamic performance and operational characteristics of a power system so far dominated by synchronous machines. In systems with a high penetration ratio of wind farms, the effective inertia of the system may be reduced and the system response to large disturbances could be significantly affected. As the system inertia decreases, the electric power systems are more sensitive to generation-load imbalances. This situation is more likely to happen for system conditions with a strong wind output and light demand. In particular, small standalone or weakly interconnected systems, as for example the Irish or the Hawaiian power systems, are more vulnerable to contingencies like the sudden loss of generation (Xie, et al., 2011).

An additional consideration is that long transmission lines are required by power plants that are located far from the main load centers –typically hydro, nuclear and, more recently, large wind or solar plants–. The synchronizing power capability of these lines is significantly reduced when they are heavily loaded (Gautam, Vittal, & Harbour, 2009).

Most wind generators that were deployed more than a few years ago were equipped with minimum voltage protections that can trip the unit, with the purpose of protecting both the machine and the power system. As noted in (Rouco, Fernández-Bernal, Zamora, & García-González, 2006), a large amount of wind power generation can be tripped if the voltage dip affects a large fraction of the power system with much installed wind capacity, leading to a potential system collapse. Depending on the technology being used, the dynamic response of wind power generators to voltage dips may be different. A sudden significant loss of wind production may also occur when wind velocity in a region happens to exceed the safety specifications of the plants, which then have to shut down immediately.

All these factors, plus the knowledge that large levels of penetration of wind and also solar PV are anticipated to take place in many countries, lead to two major conclusions. First, the operation of power systems with a strong presence of intermittent generation has to be profoundly reconsidered and grid codes have to be adapted to this new situation (Tsili, Patsiouras, & Papathanassiou, 2008). Second, wind and solar PV plants can no longer be regarded as passive units, shutting down when system faults occur and with local control of regulation. In this new context, they must behave as much as possible as ordinary power plants, which are able to provide reactive power, remain connected during system faults and increase the amount of control effort required to stabilize system frequency (Xie, et al., 2011). These features are considered essential for the future integration of high wind penetration in electric power systems.

The good news is that wind generation is technically able to actively participate in maintaining system reliability along with conventional generation. According to (NERC, 2009) modern wind turbine generators can meet equivalent technical performance requirements provided by conventional generation technologies with proper control strategies, system design, and implementation. In combination with advanced forecasting techniques, it is now possible to design variable generators with a full range of performance capability that is comparable, and in some cases superior, to that in conventional synchronous generators. This includes voltage and VAR control and regulation, voltage ride-through, power curtailment and ramping, primary frequency regulation and inertial response.

Regarding power management and frequency control, many modern wind turbines are capable of pitch control, which allows their output to be modified in real-time by adjusting the pitch of the turbine blades. This capability can be used to limit ramp rates and/or power output of a wind generator and it can also contribute to power system frequency control. A similar effect can be realized by shutting down some of the turbines in a wind farm. Unlike a typical thermal power plant whose output ramps downward rather slowly, wind plants can react quickly to a dispatch instruction taking seconds, rather than minutes. Operators need to understand this characteristic when requesting reductions of output. Examples of implementation of these techniques to provide frequency control can be found in (Martinez de Alegria, Villate, Andreu, Gabiola, & IBAÑEZ, 2004) or (Gautam, Vittal, & Harbour, 2009). Detailed simulations of a large penetration of wind generators equipped with doubly fed induction generators in the New York (assuming 10% wind) and WECC (assuming 20% wind) regions, have shown that wind plants can actually contribute to system stability by providing low voltage ride through capability and dynamic VAR support to reduce voltage excursions and dampen swings (GE ENERGY, 2005). From the WECC system frequency response study, results have shown benefits provided by special wind plant controls specifically contributing to system frequency performance during the first 10 seconds of a grid event by providing some form of inertia. These cases show that wind generation does not necessarily result in degraded frequency performance (Miller, N.; Clark, K.; Shao, M., 2010).

Large PV solar plants can potentially change output by +/- 70% in a time frame of two to ten minutes, many times per day. Therefore, these plants should consider incorporating the ability to manage ramp rates and/or curtail power output. It is probable that these large impacts could be smoothed out by geographical dispersion and the size of the solar plants. The use of inverters in solar PV plants makes them able to provide real-time control of voltage, supporting both real and reactive power output.

Concentrating solar thermal plants that use steam turbines typically make use of a “working fluid” such as water or oil; molten salt may be used for energy storage. The mass of working fluid in concentrating solar thermal plants results in these types of plants having stored energy and thermal inertia. Due to their energy storage capability, the electrical output ramps of a solar thermal plant can be less severe and more predictable than solar PV and wind power plants.

Voltage control can also be implemented in wind power plants, which, as well as PV plants, can control reactive power. As variable resources, such as wind power facilities, constitute a larger proportion of the total generation on a system, these resources may provide voltage regulation and reactive power control capabilities comparable to that of conventional generation. Further, wind plants may provide dynamic and static reactive power support, as well as voltage control in order to contribute to power system reliability. The most demanding requisite for wind farms, especially those equipped with doubly fed induction generators (DFIG) is the fault ride through capability. The effect of such a voltage dip in the wind turbine is different for different wind turbine system technologies. Voltage ride-through can be achieved with all modern wind turbine generators, mainly through modifications of the turbine generator controls. Older types of wind turbine-generators at weak short-circuit nodes in the transmission system must be disconnected from the grid unless additional protection systems are provided, or there may be a need for additional transmission equipment.

For the system to take advantage of the capabilities of wind and solar power plants, the operator of each balancing area must have real-time knowledge of the state of each plant regarding operating conditions, output and availability and must be also able to communicate timely instructions to the plants, regarding frequency control, voltage control or curtailment orders. Figure 14 shows the national control center and one of the 14 satellite control centers that exclusively monitor and control renewable generation in Spain.

Figure 14: National control center for renewable energies in Red Eléctrica, the Spanish system operator (left) and Iberdrola's wind control center (right), one of the 14 satellite control centers for wind in Spain.

In summary, in the near future is expected that intermittent renewable generation will actively participate in maintaining system stability through varied control capabilities such as: primary frequency regulation, power curtailment and ramping, voltage/VAR control/regulation, voltage ride-through, and inertial response. As the wind penetration increases, these features on power wind facilities will be essential for the operation of the system, in particular during post-contingency system restoration, peak generation during low demand periods, and unexpected ramp-up generation at times when demand drops (NERC, 2009) (Holttinen H. , et al., 2011).

3.7. Effect on operation cost and market prices

Much has been written about the integration costs of wind and solar generation, and also on the expected impact on electricity prices, see (Holttinen H. , et al., 2011) and (EURELECTRIC, 2010) as recent references for this topic. This interest stems from the fact that in most cases the deployment of wind and solar plants is the result of a policy decision in pursuit of some broader goal than the mere minimization of electric power supply costs in the existing system. This broader objective may include the reduction of carbon emissions, the utilization of indigenous resources, the creation of a more level playing for all generation technologies, support for the long-term technical improvement and cost reduction of these sustainable technologies or the creation of jobs and promotion of rural development[7]. As a result, some kind of regulatory support –under the format of a feed-in tariff, renewable portfolio standard or any other, see (Batlle et al., 2011)– makes economically viable the installation of these plants. It seems therefore justified to evaluate the implications of a specific energy policy favoring renewables –and wind and solar generation in particular– on costs, prices and reliability of the power system.

[7] In the preface of the European Directive 2009/28/EC it is stated that "the control of European energy consumption and the increased use of energy from renewable sources, together with energy savings and increased energy efficiency, constitute important parts of the package of measures needed to reduce greenhouse gas emissions (...). Those factors also have an important part to play in promoting the security of energy supply, promoting technological development and innovation and providing opportunities for employment and regional development, especially in rural and isolated areas".

Except for this fact –wind and solar penetration being a consequence of a regulatory decision– we might be asking the same question about other generation technologies: what for instance is the cost of integration of more base load plants –such as coal or nuclear plants– in a given power system? We would easily discover that more penetration of inflexible base load plants would result in more start-ups and cycling of other plants that are lower in the economic merit order, also with some undesirable consequences as the ones described in section 3.2 of this paper. And we cannot ignore that other technologies are also frequently supported by regulatory instruments, either at the investment or operation levels (for instance, in most electric power markets, due to alleged security concerns, nuclear plants have more priority of dispatch than renewable installations). It is also often claimed that the penetration of renewables increases the need for short-term reserves, but again, large base load plants also create a significant need for these reserves, a fact that is not usually mentioned[8].

The impact on power system costs is discussed first, and the effects on market prices will be examined later. The implications of the regulatory framework will be indicated. In power systems with a competitive wholesale market price consumers will have to pay some sort of pass-through of the wholesale market prices, in addition to some additional charge to cover the costs of subsidizing the investment in renewable energy sources. In vertically integrated power systems, under some form of traditional cost-of-service regulation, consumers typically pay average production costs instead of marginal prices, with regulated charges including an extra component to cover the higher costs of renewables.

The impact on operation costs

In the operation time frame, wind and solar are generation technologies characterized by a variable cost of production that is basically zero. Therefore, at least in a first approximation, the expected global impact on the power system should be a reduction in total production cost, since other more expensive generation technology or technologies have been displaced by the wind or solar production. However, it remains the complex task of evaluating the several side effects. These include: increase of reserve requirements and corresponding changes in the unit commitment costs, impact on the efficiency of conventional power plants, and any potential impact on the future demand and price of primary fuel for the remaining conventional plants, in particular for gas-fired based plants.

As explained earlier, until new sources of flexibility could be developed and deployed in large volumes, the additional flexibility required by the system to deal with the intermittency of wind or solar will translate into flexible generation plants operating in a frequent cycling mode, with more start-ups and fewer operating hours during the year than is presently the case (EURELECTRIC, 2010). Also, until the current technology mix has time to adapt to the new situation, mid-range and some base-load plants may have to operate at suboptimal (and hence less efficient) production levels. These effects should result in an increase of the power system operation costs.

[8] For instance, in the Spanish system, with a total of about 25 GW of installed wind and solar capacity, the System Operator asks for 600 MW of wind and solar-related regulating reserves, while the amount of regulating reserves that are needed for the event of an unexpected thermal plant failure (following the so-called n-1 criterion) is 1000 MW, the size of the largest nuclear plant in the system. In addition, 1000 MW of the very scarce interconnection capacity with France has to be left unused to allow for the sudden incoming surge of about 1000 MW into the Spanish grid in case one of the largest nuclear units trips.

The results from several studies on balancing costs –both estimated and actual numbers– for different countries and regions in Europe and the US are reported in (Holttinen H. , et al., 2011). These results normally account for the impact on operating reserves and on the efficiency of conventional power plants for day-ahead operation. The evaluation of the impacts is made by comparing the operation costs without wind and adding different amounts of wind with different historical wind patterns. The authors mention several factors that influence the estimated costs in the studies, such as the region size relevant for balancing, initial load variations, geographic distribution of wind power, and the frequency used in updating load and wind forecasts.

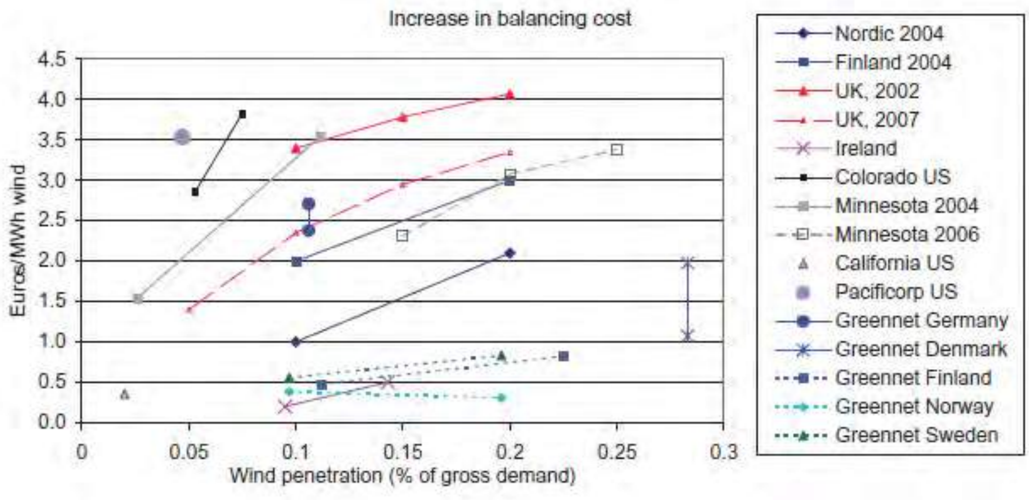

Figure 15: Results from estimates for the increase in balancing and operating costs due to wind power. The currency conversion used here is 1 € = 0.7 £ and 1 € = 1.3 US$. For the "UK, 2007" study only the average cost is presented here; note that the range in the last point for 20% penetration level is from 2.6 to 4.7 €/MWh.

Source: (Holttinen H. , et al., 2011).

From the estimated results of these studies (Figure 15), it is noted that at wind penetrations of up to 20% of gross demand the increase in system operating costs is about 1-4 €/MWh of wind power produced –equivalent to about 10% or less of the wholesale value of the wind energy–. In addition to costs estimates, (Holttinen H. , et al., 2009) also mentions actual balancing costs due to existing wind power in countries like Denmark. For West Denmark, the balancing cost from the Nordic day-ahead market has been reported to be 1.4-2.6 €/MWh for a 24% wind penetration of gross demand.

In addition, several factors have been identified to reduce operating costs due to wind power, such as the aggregation of wind plant output over large geographical regions, larger balancing areas, and utilizing gate closure times closer to real-time. The use of interconnection capacity for balancing purposes plays a major role in the estimation of costs. The studies reported lower balancing costs in those cases where the interconnection capacity was allowed to be used (Holttinen H. , et al., 2011).

It should be mentioned that distribution grids have to incur into additional costs to accommodate significant volumes of distributed generation, either intermittent renewable or not. Transmission grid reinforcements may be needed to handle larger power flows and maintaining a stable voltage, and are commonly needed if new generation is installed in weak grids far from load centers. These issues are discussed in sections 5 and 6.

The impact on marginal electricity prices

Now we focus on the impact of wind or solar PV generation on marginal –rather than average– electricity prices[9]. In principle a reduction in marginal prices should be expected, as the "residual demand" –i.e. the demand that remains after the intermittent generation output has been subtracted– is now lower and, therefore, the most expensive plants that otherwise would be needed to meet the total original demand can be avoided. Again, things are more complex that they first appear to be.

Electricity wholesale markets follow complex rules, and particularly so in the formation of market prices. These rules are noticeably different in the multiple existing markets: uniform versus locational marginal prices, simple (just quantities and prices) versus complex bids (that also include start-up costs, non-uniform heat rates, technical minima, minimum up or down times, or ramping limits), algorithms to compute the matching of supply and demand, the rules of determination of the marginal prices and, if this is the case, of make-whole payments to generators who do not recover their nonlinear operation costs with marginal prices.

Several authors have recently tried to assess the impact of intermittent generation on electricity market prices. See, for instance, (Troy, Denny, & O'Malley, 2010), (Morales, Conejo, & Perez-Ruiz, 2010), (EWEA, 2009), (Mac Cormack, Hollis, Zareipour, & Rosehart, 2010), and (Nicolosi & Fürsch, 2009). Many of these studies come to the conclusion that marginal electricity prices will be reduced, because of the reasons already mentioned. For instance, in (Mac Cormack, Hollis, Zareipour, & Rosehart, 2010) simulations show that as wind generation penetration increases, average electricity prices decrease in the short to medium term as more supply is added to the system and prices are more frequently set by the marginal cost of intermediate and base load generator units. However, as (Batlle & Rodilla, 2011) shows, for the most part these papers miss the fact that in many electricity markets, now and increasingly in the future, the system marginal price is mostly set by the same technology (CCGTs) so the supply bidding function is, and it will probably be, rather flat, so the actual market price reduction might be much less significant than what these publications expect.

Additionally, many authors have indicated that the deployment of intermittent generation will necessarily result in a larger need for operation reserves, with an upward pressure on the energy supply costs, see for instance (Holttinen H. , et al., 2009) or (Nicholson et al., 2010).

Also, until rather recently, many of these papers have missed or poorly considered the detailed impact of the operation complexities of actual power plants in the market price formation and also the long-term effects of the short-term prices on future generation investment. Some authors who claim to have taken into consideration this issue in one way or another and get to varied conclusions are (Delarue et al., 2006), (De Carolis & Keith, 2006), (Rosen et al., 2007), (Milligan & Smith, 2007), (Milligan, et al., 2009), (Poyry Energy, 2009) and (Traber & Kemfert, 2011). A rather rigorous, but merely qualitative discussion of just the expected short-term impacts is given in (EURELECTRIC, 2010), and anticipated in (Batlle & Rodilla, 2009). More recently, (Batlle & Rodilla, 2011) provide a broader assessment of the impact of wind generation on a power system with a satisfactory realistic representation of the operation of thermal plants and also the varied bidding

[9] The analysis is similar for the impact on marginal costs in power systems with no competitive wholesale markets, where marginal costs can be used as a component of real time pricing.

and pricing mechanisms currently in force in different electricity markets, as well as a discussion on the long-term implications on investment.

(Rodilla, Cerisola, & Batlle, 2011) examine in detail the effect that the modification in the operation pattern of mid-range plants like CCGTs, because of a strong presence of wind, has on the bidding behavior of these plants, as well as on the formation of prices according to actual pricing rules in different market designs. The paper distinguishes those markets with complex bids (e.g. PJM) from those with simple bids (e.g. the Iberian Market). When designing simple bids, mid-range units facing frequent cycling, with short functioning periods of uncertain duration, will have to internalize those costs in their bids in short functioning periods, resulting in higher bids and, consequently, higher marginal prices for consumers. This has been also indicated by (Troy, Denny, & O'Malley, 2010). The results that are obtained indicate that, contrary to what has been generally announced to date, a large penetration of wind does not necessarily lead to a reduction of marginal prices in wholesale electricity markets.

Short-term electricity market prices have also implications on the long-term behavior of the market agents. This effect has been analyzed in several studies for a variety of power systems, see for instance (EIRGRID, 2010) (Poyry Energy, 2009), (Mac Cormack, Hollis, Zareipour, & Rosehart, 2010), (EURELECTRIC, 2010), (Traber & Kemfert, 2011) and (Batlle & Rodilla, 2011). Here, the key point is that the future technology mix of generation will depend on the anticipated short-term marginal prices of electricity and the operating conditions that the investors expect to encounter in the market in the future. In the presence of a large wind or solar PV penetration, marginal market prices are expected to be more volatile, with larger differences between peak and off-peak values, and more uncertain. More important, the expected average level of electricity market prices will also depend much on intermittent generation penetration via the competing factors that we have just described: reduction in the net demand (price reduction) and impact on the cycling activity of mid-range plants (price increase, via internalization in bids or price formation mechanisms). In particular, (Batlle & Rodilla, 2011) highlight how, in the presence of a large volume of intermittent generation, the adopted pricing mechanism plays a key role, since it significantly affects the expectation of income in generation capacity investments. Some pricing schemes include any incurred nonlinear generation costs in the marginal price (e.g., Ireland) while others just make whole the individual generators that have incurred into these costs (e.g., PJM). The former scheme is more favorable for base loaded technologies and the latter for peaking ones. This second impact on future investment will be discussed in more detail in section 4.

Priority of dispatch, negative prices and normality of market rules

The presence of intermittent generation in power systems has frequently motivated the creation of ad hoc market rules to deal with the new patterns of behavior that have been encountered. A prominent case is the so-called "priority of dispatch" rule included in the EU legislation –the Renewables Directive 2001/776– to promote the development of renewables. This requires that "Member States shall ensure that when dispatching electricity generating installations, system operators shall give priority to generating installations using renewable energy sources in so far as the secure operation of the national electricity system permits and based on transparent and non-discriminatory criteria". The practical effect of this rule is that production with renewables can only be limited because of security reasons. Therefore, whenever the market price equals zero, even if the optimal solution of the unit commitment algorithm indicates that the most economic option is to curtail wind rather than to stop some conventional thermal plant for a short period of time, renewable production will be scheduled and receive the feed-in tariff or premium, if this is the case.

Several reasons have been given to support this drastic rule. In the first place, the rule helps meet the committed renewable production targets, as well as any carbon reduction targets, by minimizing curtailments of renewable production. The rule may also incentivize a more flexible operation –to avoid being driven out of the market– of conventional plants that, otherwise, might not try to make an effort to accommodate increasing volumes of intermittent generation.

The down side of this rule is that it may be the cause of inefficient dispatches of generation, as described above, as the rule may constrain what otherwise would be the optimal unit commitment, whether based on generators operating costs or bids. The arguments from both sides in this trade-off have value, and it seems that a reasonable compromise should be reached, attending to the specific circumstances of each case.

Note that conventional generators may be willing to bid negative prices to avoid being shut down. Wind or solar generation would be also willing to bid a negative price to retain the income from any financial support scheme that is linked to production. The link between negative prices and renewable support mechanisms has to be carefully examined. Note, however, that negative prices may already occur in the absence of intermittent generation since, at times with low demand, conventional generating plants may be forced to regulate downwards up to their technical minima or even to shut down and, in an effort to avoid incurring in the additional operational costs and tear and wear of the machines, these generators prefer to bid negative prices with the purpose of keeping their plants running (EURELECTRIC, 2010). This is normal rational economic behavior of the agents in a competitive market and should not be interfered with. The occurrence of negative prices becomes more frequent in the presence of high wind output during times of low demand. What may not be considered reasonable is that renewable generators that receive some kind of financial support linked to production –such as a feed-in tariff– can outbid the conventional power plants with negative prices up to the value of the feed-in tariff. And the higher the subsidy –e.g. solar PV would have a higher subsidy than wind– the more “competitive” a technology would be bidding negative prices while still capturing some rent. The conclusions of a careful analysis on this topic may lead to revisions of market rules, with the purpose of eliminating any undesirable market behavior or distortion.

“Normal” market rules should be used as much as possible with intermittent generation (EURELECTRIC, 2010). Making wind generators subject to the same balancing and scheduling obligations as conventional power plants does not jeopardize the development of this technology, as the experience of several European countries already shows. On the contrary, this seems to be the best way to stimulate improvements in forecasting methods, operation of reserves and frequency control by wind generators: as a result of it, system balancing requirements can be reduced and costs will be fairly allocated. Priority of dispatch and guaranteed network access for renewable generation should not exempt these generators from their scheduling and balancing obligations. This will speed full integration of wind generation in the power systems.

On the other hand, as it has been already indicated in section 3.4, market rules should facilitate this integration as much as possible by increasing trading possibilities closer to the moment of physical delivery and by augmenting the geographical scope of the balancing areas.

Allocation of the costs of support to renewables

Finally, it is worth mentioning one related issue that has received little attention to date from an academic perspective. Currently, the economic burden of supporting renewables is passed to electricity consumers in most countries, with the production tax credits in the US being one of the few exceptions to the general rule. This allocation criterion results in an inefficient energy consumption behavior. The targets of a broad renewable energy policy concern all energy supplies (explicitly in the EU case, implicitly in other instances). Therefore, charging electricity consumers only, sends the wrong signal to switch to other less efficient sources of energy, thus increasing the need for more electricity generation with renewables to offset the increment in consumption of other types of final energy (EURELECTRIC, 2010). (Batlle, 2011) reviews these efficiency incentives linked to tariff design and proposes a methodology to allocate the costs of renewable support whereby these costs are charged to final energy consumers, in proportion to their total energy consumption, regardless of the type (liquid fuels, gas, electricity or coal).

4. Impacts on the future electricity generation mix

The operation of a system with a substantial presence of intermittent generation will be very different from today's operation. The future well-adapted mix of generation technologies will also change, probably reducing the weight of less flexible base-loaded units and increasing the percentage of more flexible generation plants, always depending on the level of penetration of intermittent generation.

The impact analysis will be different depending on the existing regulatory framework in the power system under consideration, either market oriented or centrally planned. In those power systems under competitive market regulation, the generation mix will be dictated by the expected profit margin that the investors in the several technologies expect to obtain in a market with these characteristics. Note that, under competitive market conditions, a shift in the technology mix will happen in a natural way, as the investors react to the new economic opportunities to capture profit margins in systems that have a strong presence of intermittent renewable generation. The mix of generation technologies will be the outcome of a complex process, where each decision of operation and investment has a justification. If some socially acceptable system of market signals and incentives results in a technology mix with a strong percentage of intermittent generation and also with flexible plants that take advantage of the increasingly frequent situations of high market price spikes, then this is the first best mix under the circumstances, freely chosen by the investors. This also includes the response of investors to any economic incentives (such as, for instance, a capacity payment mechanism) or command-and-control mandates that have been established by the regulatory authorities.

On the other hand, in those systems with traditional cost-of-service regulation and centralized capacity expansion planning, the critical issue is how much investment is necessary and of which technology, in order to meet the expected demand at minimum cost while meeting some prescribed reliability constraints and environmental targets. The key point here is that a strong presence of intermittent generation will significantly change the existing procedures and evaluation techniques.

The assessment of the impacts on the future electricity generation mix is presented next for both regulatory approaches.

4.1. Centralized capacity expansion planning and resource adequacy

Each generation technology has different technical and economic characteristics and the challenge of capacity expansion planning is to combine them properly. Intermittent generation technologies presently have high investment costs, provide energy at basically zero variable cost, but are subject to high variability and uncertainty, and generally contribute much less to the firm capacity of the power system than conventional technologies[10], (Batlle & Barroso, 2011).

From a reliability perspective, according to (NERC, 2009), the system planner has to maintain some percentage reserve margin of capacity above its demand requirements to maintain reliability following unexpected system conditions. Reserve margins are determined by calculating the firm capacity of supply resources; this requires that some fraction of the rated capacity be discounted to reflect the potential unavailability of the resource at times when the system is in high-risk of not being able to meet all the demand.

If a large portion of the total supply resource portfolio is comprised of intermittent generation, the reliability evaluation becomes more complex. However, this does not fundamentally change existing resource adequacy planning processes in that the process must still be driven by a reliability-based set of metrics. The analytical processes used by resource planners range from relatively simple calculations of planning reserve margins to rigorous reliability simulations that calculate probabilistic measures of loss of some demand.

The capacity credit of wind

Much has been written about the “capacity credit” or “firm capacity” of intermittent generation, i.e. a measure of the contribution of wind to the reliability of the power system, see (Milligan & Porter, 2008). The capacity credit of wind or solar PV per unit of installed capacity is significantly inferior to that of conventional generation technologies, although the importance of this factor is very dependent on specific system characteristics, such as interconnection or hydro storage capacity.

The capacity contribution of conventional generating units to reserve margins is mostly based on the unit performance rating, forced outage rate, fuel availability and maintenance schedules. However, the capacity contribution of intermittent generation is not straightforward, as it will depend on its variability and uncertainty, as well as on the correlation of the availability of wind with electricity demand. It has been noted in (NERC, 2009) that current approaches based on the “Effective Load Carrying Capability (ELCC)” may need to adapt to properly include intermittent generation, see also (IEA, 2011). Thus, for ELCC, the weather-driven correlation between variable generation and demand is critical, where a large amount of time-synchronized hourly wind generation and demand data is required in order to estimate the capacity contribution of variable generation. Approximations should be avoided and more detailed approaches, such as ELCC with abundant historical data should be employed.

It has been stated that the capacity value of wind decreases as its level of penetration increases, indicating a diminishing incremental contribution to reliability with output, see (NERC, 2009) or (ESB National Grid, 2004). The results of several studies are summarized in Figure 16. According to

[10] This statement is correct for most, but not all, power systems. In Brazil wind generation is a strong contributor to the reliability of electricity supply, and not only because of the dominance of hydro production in the Brazilian power sector, see (Batlle & Barroso, 2011).

some of these sources, the contribution can be up to 40% of installed wind power capacity in situations with low penetration and high capacity factor at peak load times, and down to 5% under higher penetration, or if regional wind power output profiles correlate negatively with the system load profile. It remains to be well understood the logic behind this result, which is probably the effect of a "common cause of failure": a quasi-simultaneous absence of the wind resource throughout the entire system. The larger the presence of wind in a system, the stronger this negative impact is on the system reliability performance.

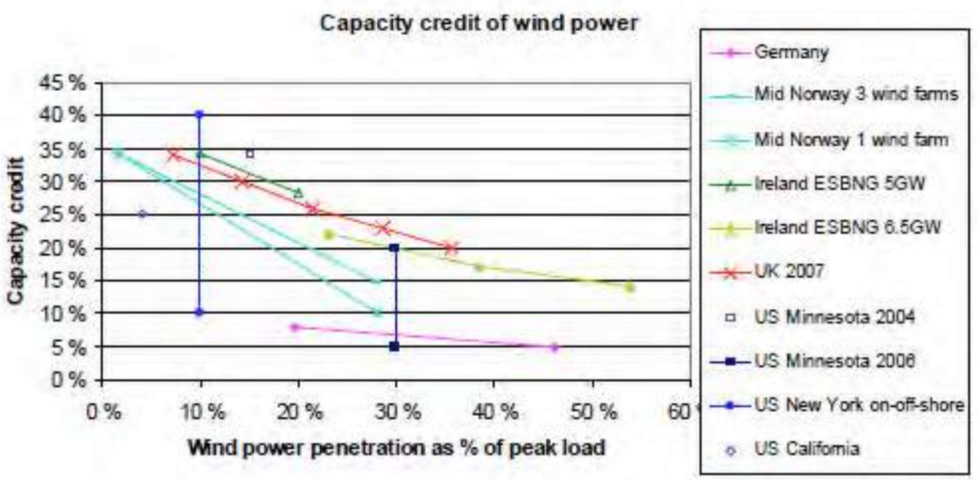

Figure 16: Capacity credit of wind power, results from eight studies. The Ireland estimates were made for two power system configurations, with 5 GW and 6.5 GW peak load. Source: (Holttinen H. , et al., 2009).

The smoothing effect due to geographical distribution of wind power has a positive impact on the wind capacity value at high penetration, subject to having enough capacity in the grid (Parsons & Ela, 2008).

Note also that a sudden loss of all wind power on a system simultaneously due to a loss of wind is not a credible event. It might happen because of automatic disconnection in case of excessive wind velocity, but this can be mitigated by adequate control measures. A sudden loss of large amounts of wind power, due to voltage dips in the grid, can also be prevented by requiring fault-ride-through from the turbines.

The worst credible scenario for wind under a reliability viewpoint consists of an extended period of time –maybe as long as a few days– with very low output, during a high demand season. It is very important to characterize the probability of occurrence and the depth and duration of these events, since the power system has to be ready to cope with them. More on this issue on section 4.4.

4.2. Competitive electricity markets and the incentives to invest

In power systems under competitive market conditions generation capacity expansion is left to the decentralized decisions of private investors[11], who will evaluate the convenience of building plants

[11] In most electricity markets the regulatory authorities have implemented some kind of mechanism to ensure generation security of supply, see (Batlle & Rodilla, 2011) for a review of this topic.

in a particular power system depending on the expected price levels and operating conditions during the lifetime of the potential facility, among other considerations.

Several studies for a diversity of power systems –see for instance (MIT, 2010), (DOE EERE , 2008), (GE Energy, 2010), (Charles River Associates, 2010), (Poyry Energy, 2009)– have analyzed, in detail, plausible future scenarios with a large presence of wind and solar generation, and shown that this also leads to an increased presence of flexible mid-range generation capacity with high cycling capability and low capital cost. The function of some of these plants –typically open cycle gas turbines, OCGT– is almost exclusively to provide reserve capacity margins. Other plants are subject to heavy cycling regimes with relatively low capacity factors (e.g., 2000 to 3000 hours per year), typically combined cycle gas turbines, CCGT. These results are obtained under the assumption of centralized planning. Ideally the same mix should also be the outcome of a competitive electricity market.

However, in deregulated wholesale markets with substantial penetration of renewables, the volatility of marginal prices is expected to increase. Also, mid-range technologies, of which CCGT is the most likely candidate, will see their output reduced, as indicated above. The uncertainty regarding the adequate technology mix, the penetration of renewables, and the economics of such a mix under the anticipated future prices and operating conditions raise concerns about attracting sufficient investment in these flexible plants under a competitive market regime.

This issue is presently being addressed by several European countries with significant penetration of wind generation, where the patterns of production of combined and single cycle gas turbines, and also of some base load technologies, have already been substantially affected, see (EURELECTRIC, 2010), (Poyry Energy, 2009) and (Batlle & Rodilla, 2011). Similar situations are already developing in some parts of the U.S. Presently there is no consensus on a suitable regulatory response to this situation, which could include enhancements of any capacity mechanisms such as those already in place in most U.S. wholesale markets, new categories of remunerated ancillary services or other instruments. This issue must be analyzed in the context of the market price implications that were discussed in section 3.7 and, if justified, appropriate regulatory measures should be developed to facilitate adequate levels of investment in flexible generation plants to ensure system reliability and efficiency.

4.3. The “back-up cost” of wind

It is frequently stated that intermittent generation needs back-up power, implying that the installation of wind capacity is necessarily associated with additional capacity of some other technology, therefore increasing the actual investment cost of the wind generation technology.

As it has been already discussed here, the meaning and implications of this statement depend on the regulatory context and the specific technology mix of the system in which wind generation is deployed.

Regarding the technology mix, it has to be realized that there is no single technology that is fully suitable, both technically and economically, to meet all the electricity demand, with its daily, weekly and seasonal patterns and associated uncertainty. Each technology presents some advantages and also shortcomings. One could ask what “the flexible back-up cost” is for inflexible base-loaded technologies, like coal or nuclear. Or the cost of reserve capacity, and spare interconnection capacity, that has to be permanently available in case the largest unit in the system –a nuclear generator, typically– suddenly trips. Or, the “economic back-up cost” of peaking plants, with high variable operating costs. An optimal generation mix with a strong presence of wind will be very different depending whether the specific power system has good storage resources (presently only hydro reservoirs, either the regular kind or pumped hydro, provide substantial capability), strong interconnection capacity and significant demand response (for instance with interruptible supply contracts with large consumers). Many systems have abundant flexible spare capacity, typically because of recent overinvestment in CCGT plants –less flexible than OCGT plants, but much more than coal or nuclear generators–, and they can accept large amounts of intermittent generation before additional flexible capacity is needed.

When the "back-up cost of wind" is mentioned, what appears to be loosely meant is the cost of the amount of firm capacity of the least expensive conventional technology that is needed to go together with 1 MW of wind capacity so that the combination has a firm capacity of 1 MW. But this does not make much sense, because the investment in wind is not meant to be a substitute of a base-load technology. More investment in wind does not require additional investment in back-up capacity. Quite the opposite, more investment in wind reduces the utilization of conventional fuels and modestly contributes to the total firm capacity of the system, therefore reducing the need of investment in conventional generation technologies.

The question about the impact of the presence of wind is very dependent on the reason why the investment in wind generation has taken place. If the amount of installed capacity of wind generation is the result of a regulatory decision, and the installed capacity of the remaining technologies is well adapted to the demand with the amount of wind, then it is a valid question to ask how much the total cost of electricity supply would be, should the installed wind capacity increase (ignoring any cost of externalities, which normally would decrease with more wind generation). The correct question would be: how much is the additional total cost for the system of the mandated level of wind production?[12] Answering this question is not a trivial exercise, since it requires including both investment and operation costs and the comparison with a counterfactual: what should have done had the wind not been installed[13].

Note, however, that if the installation of wind obeys to purely economic reasons and the existing amount of wind happens to be well adapted to the demand and the other technologies because wind happens to be competitive, the presence of wind naturally follows from the logic of the market. In this case the presence of wind is necessary to achieve the lowest cost of supply for the system and, therefore, the question of "how much is the back-up cost of wind" or how much is the cost that the presence of wind is causing to the system becomes meaningless and cannot be answered. This is, of course, an issue open to debate.

4.4. Other sources of flexibility

A power system can respond with flexibility to the variability and uncertainty of wind and solar PV generation with more resources than new investments in flexible power plants. To start with, as indicated in the previous section, a very important source of flexibility is the spare capacity of

[12] A parallel question to this one is how many CO2 emissions are avoided by increasing wind or solar production. And, piecing all the pieces together, what is the abatement cost of CO2 that is achieved by increasing the production with renewables. Of course, this comparison does not take into account other side benefits (and also costs) that can be achieved by a higher production of renewables.

[13] If a capacity expansión optimization model is used, then the required information is provided by the dual variable of the constraint that imposes the mandated amount of wind generation.

already existing flexible power plants. For instance, the New England Wind Integration Study (NEWIS) has revealed that the ISO-NE system presently has adequate resources to accommodate up to 24% of annual energy penetration of wind generation by 2020, see (GE Energy, EnerNex, AWS Truepower, 2010).

But in a power system there are more sources of flexibility besides generation plants, see (EURELECTRIC, 2010) for instance. Reinforcement and optimal use of interconnections and integration of balancing areas is essential to accommodate large amounts of intermittent generation resources, as discussed in section 3.4. Market rules that reduce the scheduling intervals in electricity markets help wind and solar PV mitigate the uncertainty impact.

Contribution from the intermittent generators themselves will also be needed. Note that costs of operating reserves are socialized in most markets through the system tariffs, which means that presently in many systems there is no price signal to the intermittent generators to contribute to the higher flexibility requirements in the power system.

Storage other than hydro still is in need of development; however, existing regulations do not provide the right signals or the incentives needed for storage systems to mature adequately. Increased penetration of intermittent generation should result in large price differentials, providing appropriate economic signals that should not be limited by caps or floors. Storage, in sufficient amount, should allow renewable energy sources to be captured and stored for later use, reducing the waste of resources; and it can also be a valuable instrument to provide the needed flexibility.

Demand response holds a huge potential that still has to be demonstrated; see (FERC, 2011). This includes applications that have been used for a long time, such as interruptibility contracts with large industrial consumers, as well as others that still are in its infancy, like tapping the response of smart domestic appliances or of large aggregates of medium size consumers, as the company ENERNOC has already achieved. More futuristic measures, such as massive vehicle to grid coordinated control, could be commensurate with potential very large penetrations of wind and solar generation, as anticipated at least in some European countries. Creative solutions, perhaps revising the classical concept of power system reliability metrics, will have to be adopted in this case, especially when confronting the worst case scenario that was described in section 4.1.

5. Impacts on transmission network expansion and bulk power system operation

TO BE COMPLETED

6. Impacts on distribution network expansion and distribution system operation

TO BE COMPLETED

7. Some open issues

A large number of relevant issues have been identified during the review of the power system functions that can be affected by a large penetration of intermittent renewable sources of electricity production. We are left with many open questions regarding how to best manage each one of these areas of concern. A list of topics for discussion follows.

On how to facilitate the integration of large volumes of intermittent generation in electric power systems, either to mitigate any negative impacts or to make possible an even larger penetration level:

- What should be done to minimize any negative impact (or to maximize any positive impact) of wind or solar PV generation on power system stability?
- What should be done to reduce the uncertainty and the variability of intermittent resources
  - as an input to the unit commitment function?
  - in the determination of the volume and cost of operating reserves?
  - in balancing supply and demand close to real time?
- What should be done to reduce undesirable effects (frequent cycling of conventional plants with limited operational flexibility, resulting in loss of efficiency of these plants) of the strong presence of intermittent renewable generation in the dispatch of generation in existing power systems? In the short-term? In the longer-term?
- What should the regulation be for intermittent renewable generators as participants in a competitive electricity market?

  Case A) If they receive some regulated financial support to be economically viable:

  - As any other generator, subject to spot market electricity prices, cost of deviations from schedules and acquisition of operation reserves, and remuneration for contribution to firm system capacity.
  - Completely independent on market prices and other economic signals.
  - Not subject to spot market electricity prices or capacity payments, but receiving other operation-related economic signals regarding to deviations and utilization / contribution to system reserves.

  Case B) If they do not receive any financial support:

  - (Same as above)

On the short-term and the long-term consequences of a strong presence of intermittent generation on the power system *costs and environmental impacts*.

- Identification of types of costs and environmental impacts that could be modified.
- The effect of reduction of net demand.
- Other consequences of the presence of intermittent generation. Evaluation of other costs and / or benefits.
- Why evaluate the costs of integration of intermittent renewable generation only, as opposed to doing this for all technologies?
- What is really meant by “the back-up cost” of wind or solar generation? Is it related to the fact that wind and solar generation are presently given some kind of financial support, or the subject of mandated targets?

On the short-term and the long-term consequences of a strong presence of intermittent generation on *electricity prices*. The effect of the reduction of net demand. The effect of the nonlinear characteristics of power plant operation (costs of start-ups, ramping limits, technical minima, etc.) in the computation of the electricity market prices.

- Evaluation of the impact on final electricity prices for end consumers.
- Evaluation of the impact on remuneration of the existing generators. Should any "stranded costs" be allowed if some "unexpected" large penetration of wind or solar generation takes place in a short amount of time with regulatory support?
- Long-term impact of the price signals on future generation investments.
- Should negative electricity spot market prices be allowed? Should intermittent generation plants be allowed to bid negative prices?

On the future "well adapted" generation technology mix with a strong presence of intermittent renewable generation.

- What does a well-adapted technology mix look like?
- Does this mix need of any regulatory support? What kind of support (e.g. capacity remuneration mechanisms, some new type of ancillary service)? Implications on the design of electricity market rules.

On the need for additional flexibility in the response of power systems with a strong presence of intermittent generation.

- Is all the existing flexibility capability of the current power system being fully used already? Of the conventional power plants? Of the interconnectors? Of the intermittent generation itself? Are the market rules properly designed so that all the existing flexibility capability can be used?

On the possible existence of barriers to the deployment of intermittent renewable generation because of the distribution or transmission networks.

- How is the remuneration of the distribution activity linked to the level of penetration of wind or solar generation?
- Is the present regulation of transmission (planning criteria, responsible institutions for planning, cost allocation procedures, business models, siting processes) adequate to support a large deployment of intermittent renewable generation?

On the influence of the regulatory mechanisms to support the deployment of wind and solar production.

- Could they have an impact on the functioning of electricity markets? Could this be a matter of concern when the penetration of intermittent renewables reaches a substantial level?
- Could a "priority of dispatch" regulation be justified?
- Who should pay the direct extra costs of promoting renewables?

On computer models to evaluate the impact of large volumes of intermittent generation.

- Are existing computer models able to properly simulate the potential impacts of a large penetration of intermittent generation on power system stability, unit commitment, utilization of operating reserves, electricity costs and prices and the future generation technology mix? What improvements are needed?

On plausible characteristics and management approaches to electricity markets with very large penetration levels (e.g., larger than 50%) of intermittent generation.

- What happens when intermittent generation becomes the dominant production technology? What are the new challenges and opportunities? How could power systems cope with a "worst case" scenario?

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The Wind Power Paradox: An Empirical Study of Emission Reductions

Authors: Porter Bennett & Brannin McBee

Wind power presents a paradox. Wind power is inherently a relatively clean technology, and that reality has placed wind power at the center of state and federal renewable energy programs. But while wind is clean, it is also intermittent. When wind blows, other power-generation facilities must generally be ramped down to accommodate wind power. When the wind dies, the same facilities must be ramped up. This interaction with other generation facilities makes the non-wind plants less efficient from the standpoints of generation and environmental impact.

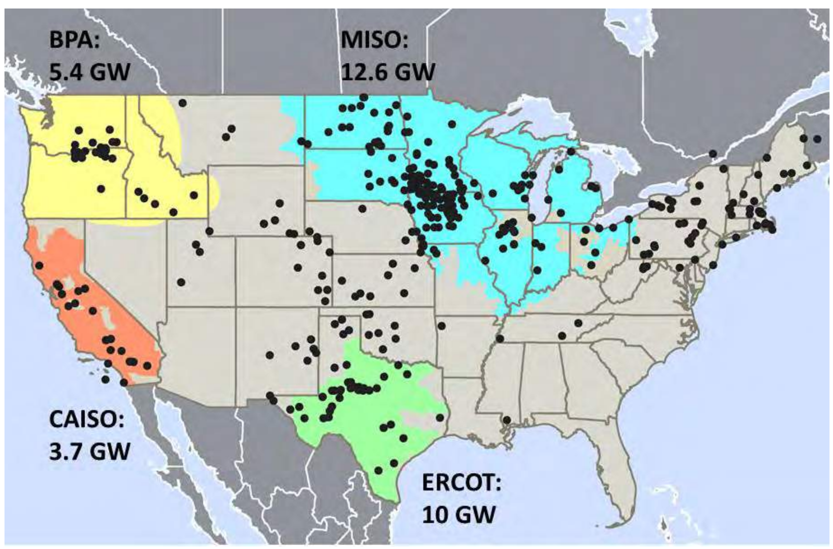
The objective of this paper is to assess the systemwide impact that introducing wind power to a utility grid has on air emissions. Over the past 10 years more than $12 billion in federal tax credits have been provided to wind power developers as incentives to build large-scale wind plants. The primary objectives motivate issuance of the credits: a) to reduce our dependence on hydrocarbon fuels; and b) to thereby reduce our emissions of CO_2, SO_2 NO_X and other pollutants such as mercury. The question underlying this paper is whether the performance of wind power as an emission control technology over the past three years justifies these expenditures.

This paper summarizes work performed by BENTEK Energy as part of its ongoing Wind Energy Project. MITEI requested a summary of the research be presented at its symposium on Managing Large-Scale Penetration of Intermittent Renewables. The ongoing effort by BENTEK is aimed at providing a current empirical data test of the emissions benefits associated with using wind power in large-scale electric utility systems. This paper analyzes the SO_2, NO_X and CO_2 savings from wind generation that have been achieved in the ERCOT, Bonneville Power Administration (BPA), California Independent System Operator (CAISO) and the Midwest Independent System Operator (MISO). BENTEK, in conjunction with Dr. Daniel Kaffine from the Colorado School of Mines (CSM), developed an econometric model of the interaction between wind, coal and natural gas-fired generation within each region and the resulting change in SO_2, NO_X and CO_2 emissions that occurred as wind energy generation increased. The analysis is based on hourly generation data for the years 2007, 2008 and 2009 provided by the Independent System Operators (ISO) in each of the four areas and actual hourly emissions data reported by utilities to the U.S. Environmental Protection Agency (EPA) through the Continual Emissions Monitory System (CEMS).

Background

Since 2000 wind power has made significant inroads as a generation source in the U.S. power market. In 2000, wind power generated less than 6,000 GWh of power, 0.2% of total U.S. electricity generated during the year. In 2010, wind power accounted for more than 2% of total generation and was the dominant form of non-hydro renewable energy. Today there is more than 36,000 MW of installed wind turbine capacity, with another 6,000 MW in development.

Figure 1
Study Areas and Installed Wind Capacity

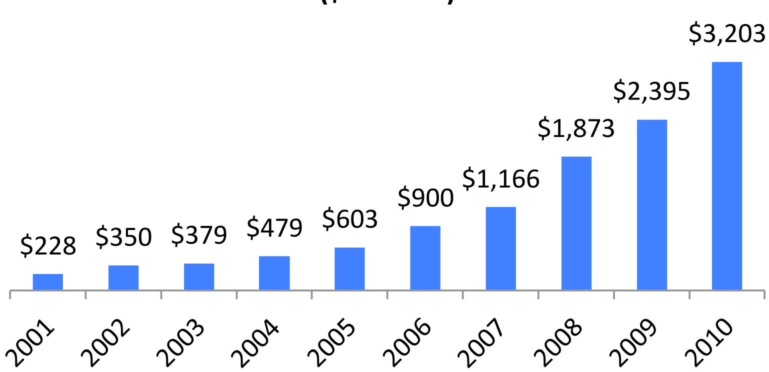


Wind farms are generally sited where wind energy can actually be captured at economically viable rates. The importance of the Central region in the U.S. (the Great Plains along with Oklahoma and Texas) is shown in Figure 1, which depicts the location of wind generation facilities across the U.S. as of 2010. Wind facilities are also relatively numerous in California and along the Columbia River (i.e. Bonneville Power Administration). The number in each region indicates the aggregate wind power capacity in each region as of 2010.

Wind power development surged beginning in the mid-2000s due in large part to state and federal policy actions. Renewable Portfolio Standard (RPS) is the primary policy action taken at the state level to promote wind energy development and 33 states have RPS obligations as of December 2010. Typical RPS mandate utilities operating in the state obtain some percentage of their energy sales requirements from renewable energy. In some cases the mandates specify renewable energy types, but mostly utilities are free to choose from whatever renewable source they want to meet the standard.

At the federal level, the Renewable Electricity Federal Production Tax Credit (PTC) is the primary means used to encourage wind and other renewable power development. Enacted in 1992, this tax credit offers renewable operators tax credits for the amount of electricity generated. Wind, geothermal and closed-loop biomass generation facilities receive 2.2 cents per kWh generated ($22/MWh) in the form of a tax credit. Other eligible technologies receive 1.1 cents per kWh and this credit applies to both commercial and industrial sectors. In order to be eligible for the tax credit, operators must have begun construction of the facility before Dec. 31, 2013. Operators are compensated through this credit for the first 10 years after the date the facility goes into service.[1] Since January 2001, wind generation operators have received a total of more than $12 billion in federally subsidized compensation. In the early stages of the program, monthly costs to the government were typically below $20 million and on an average basis ranged from $13 million to $22 million. By 2010, however, the program became more costly with a total annual expenditure of $3.2 billion. It is important to recognize that these costs build upon themselves because the subsidy extends for 10 years from the date the plant becomes operational. Figure 2 shows the value of annual PTC payments since 2001.

Figure 2
Annual Cost Of Federal Production Tax Credits for Wind Generation
($Millions)



[1] DSIRE. (2010, 5 4). *Renewable Electricity Production Tax Credit*. Retrieved 11/3/2010,from Database of State Incentives for Renewables & Efficiency: http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=US13F&re=1&ee=1

The Environmental Impacts Of Wind Generation

Wind power intermittency reduces the utility of wind power as an emission control strategy. On the one hand wind power is inherently a relatively clean means to generate electricity. Particularly when compared to hydrocarbon-based generation, wind power by itself produces virtually no air emissions such as CO_2, NO_X and SO_2. The paradox results because large-scale wind projects must operate as part of an integrated utility or grid system. The intermittency of wind imposes operational inefficiencies on the utility grid into which the wind is integrated such that CO_2, NO_X and SO_2 are not offset proportional to the degree to which the displaced fuel is replaced by wind. As a result of this paradox, wind power is often far less effective as an emission control strategy than is intuitively assumed.

Cycling

When wind produces power, unless demand grows commensurately, the grid operator must reduce power received from other power plants on the grid in order to accommodate the power from wind. When the wind ceases to blow and power production stops, the power that was being purchased from the wind facility must immediately be replaced by power from another source or total demand is not met (assuming total demand remains flat). Aptech, an engineering consultant used by Xcel Energy, describes the process as follows.

> *"Integrating intermittent, volatile electricity into the grid can cause a surge or a sag that can lead to brownouts or blackouts. So grid operators, like Xcel Energy, must balance the wind-generated electricity with electricity online, ready and available to the system. In order to do that, plants that are already operating and connected to the grid must suddenly and rapidly increase or decrease their output to maintain balance. In some cases, this means that plants that are offline must be brought online quickly. The rapid starts and stops or increases and decreases in output are called 'cycling'."*[2] *- Aptech*

Cycling power plants has an impact on fuel, and thereby emissions and efficiency rates. This impact can be likened to operating a vehicle. Operating a car at a steady pace uses less fuel than operating a vehicle in stop-and-go traffic, or at continually varying speeds. Figure 3 captures the typical effects of cycling a power plant.

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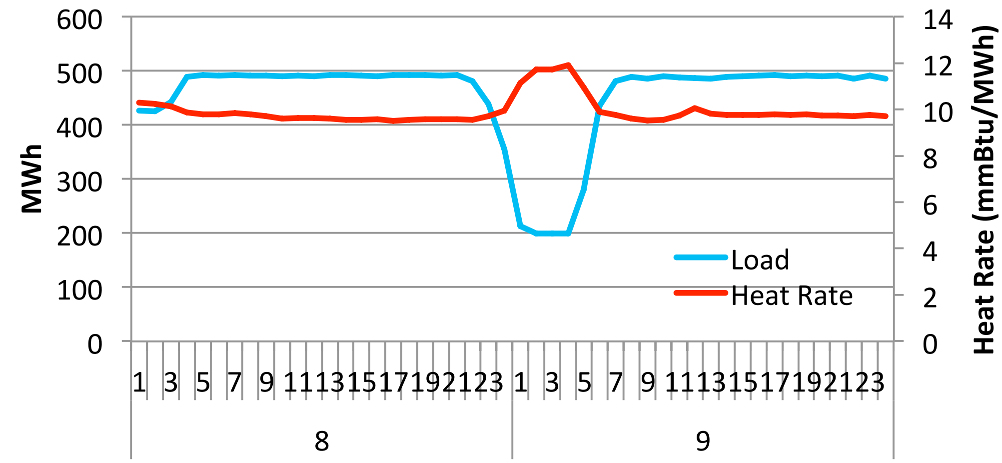
[2] Aptech. (n.d.). *Integrating Wind: Cost of Cycling Analysis for Harrington Station Unit 3 Phase 1: Top-Down Analysis.* Retrieved 10/26/2010, from http://www.blankslatecommunications.com/Images/Aptech-HarringtonStation.pdf

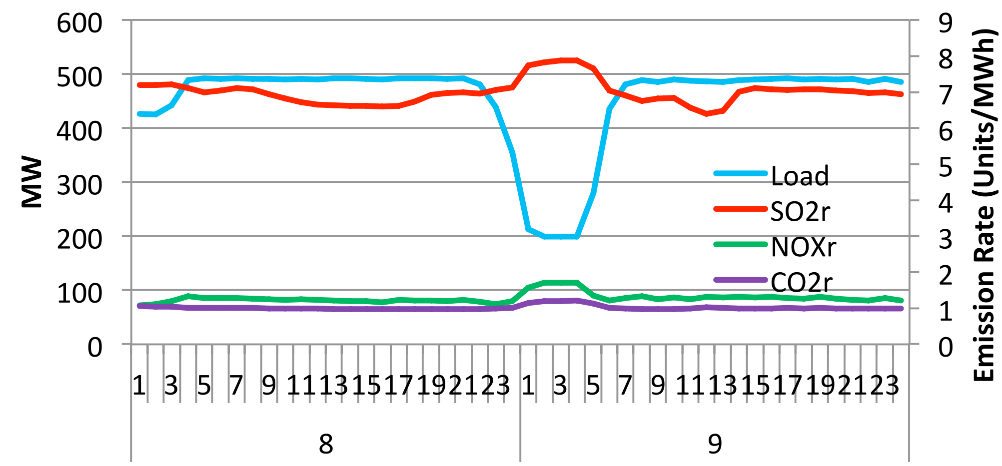
Figure 3
Gibbons Creek Steam Electric Coal Station
(January 2009)



The blue line captures generation output for the Gibbons Creek Steam Electric Station during June 8-9, 2009. The red line indicates heat rate; the amount of fuel consumed per MWh of generation. As the facility deviates outside of normal operations (~500 MWh), the unit uses more fuel per unit of electricity generation.

Emissions are a direct output based on fuel combusted. If more fuel is combusted to generate one unit of electricity, then more emissions will be released for that one unit of electricity. This relationship is captured in Figure 4.

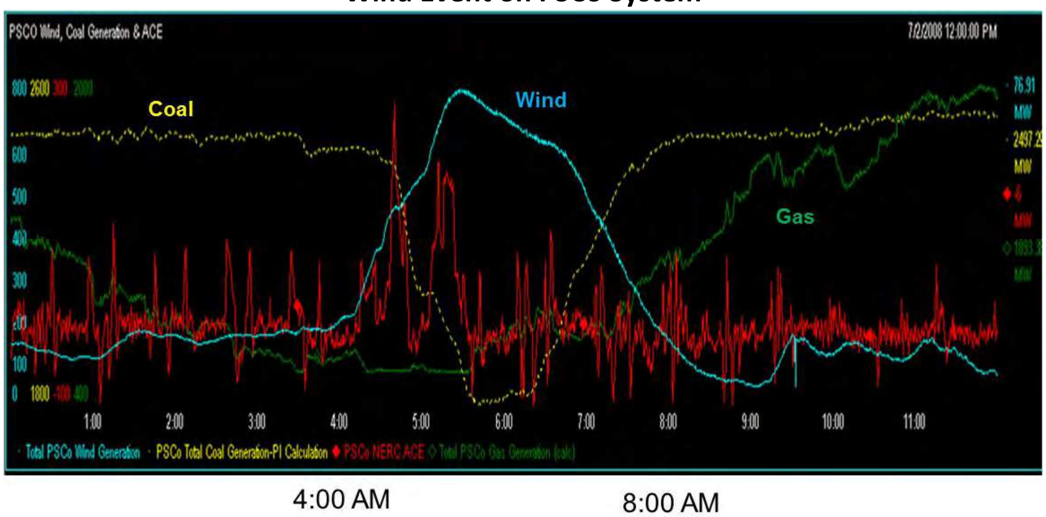
Figure 4
Gibbons Creek Steam Electric Coal Station
(January 2009)



As fuel consumption increased during the cycling event, the rate of emissions output increased across the board.

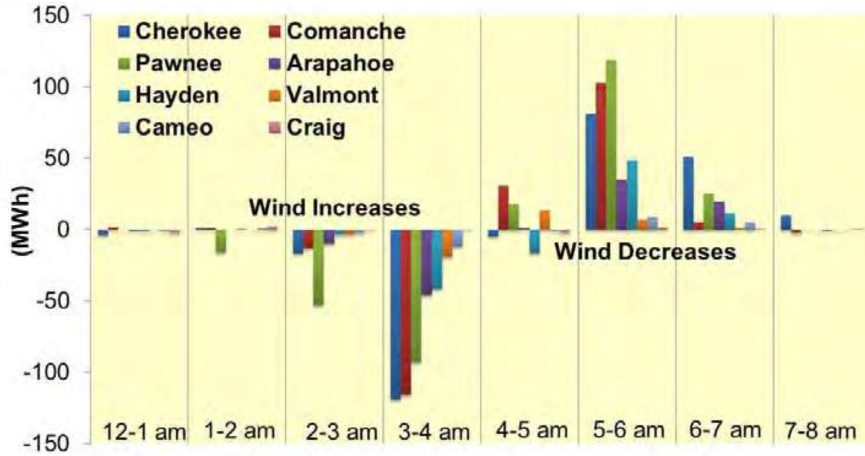
Cycling of plants causes other operational inefficiencies. A specific example of a cycling event and the inefficiency that it causes is illustrated in the following graphics. On July 2, 2008 during the morning hours, wind generation ramped up from 150 MWh of output to 800 MWh of output in less than two hours (Figure 5). Typically, operators dispatch units based on cost of operation; more expensive units are dispatched down before less-expensive units. However, gas generation on Public Service Company's (PSCo) system was already at such a low level that it could not be further reduced without sacrificing reliability. Accordingly the coal plants were cycled as shown with the yellow line.

Figure 5
Wind Event on PSCo System



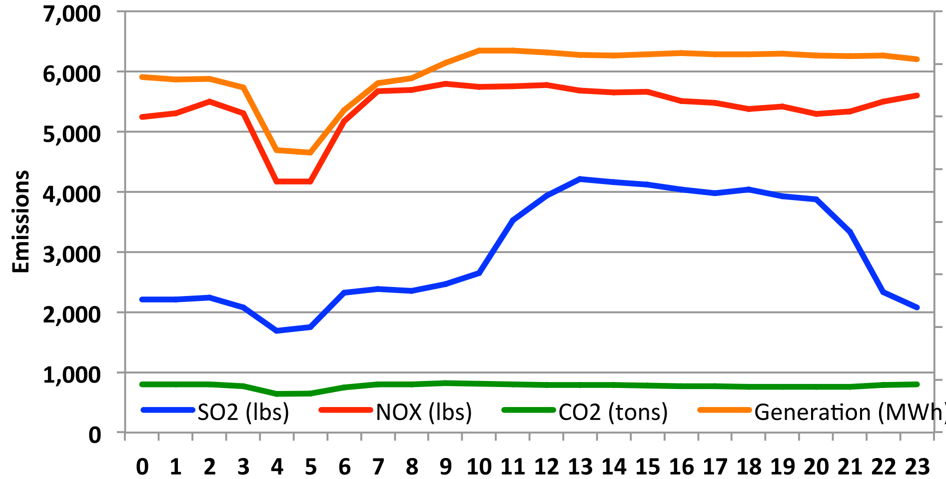
PSCo was forced to reduce coal generation from 2,500 MWh to 1,800 MWh in a very short timeframe. As wind generation dropped to roughly 150 MWh by 8 a.m., coal generation was ramped back up to 2,500 MWh to meet increasing load levels on PSCo's system. Generation at several coal plants was reduced in order to accommodate wind generation on the system. The hour-to-hour change of generation output at the facilities operated by PSCo on July 2, 2008, is shown in
Figure 6. The Cherokee, Comanche and Pawnee coal facilities provided the most operational flexibility for PSCo on July 2, 2008, as they were cycled the most dramatically.

Figure 6
Hour-to-Hour Change in Generation
At PSCo's Coal-fired Plants



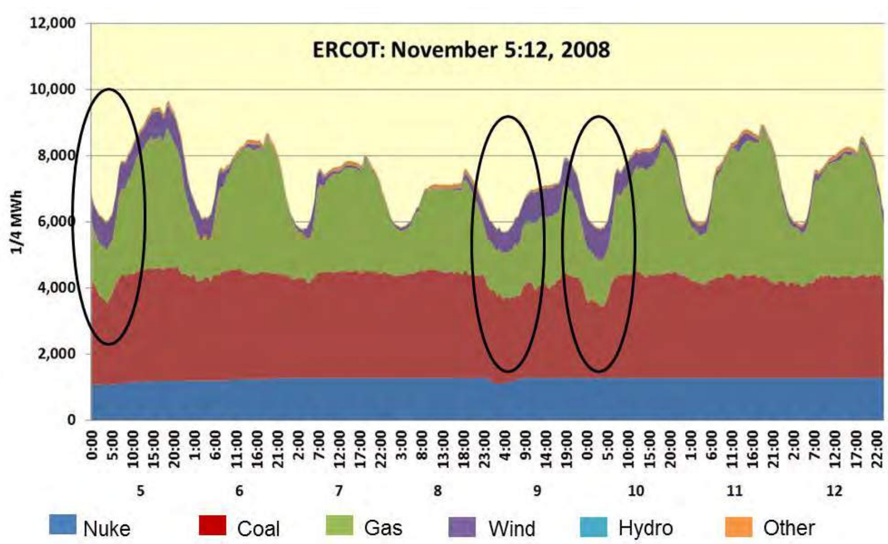
The impact that cycling can have on environmental controls is illustrated in Figure 7. CO_2 emissions are depicted in green, SO_2 is shown in blue, NO_X is shown in red and generation in orange. All are shown on an hourly basis. Between the hours of 2 a.m. and 7 a.m. generation output at Cherokee fell as it was offset by wind generation. There are associated fuel and emission savings with the lower level of generation throughout this timeframe, as indicated by the dips in NO_X, SO_2 and CO_2. However, complications at the facility for hours after the cycling event partly negate any SO_2 and NO_X emission savings. In fact, SO_2 and NO_X emissions ended up higher for the day because of the difficulties that PSCo incurred when it cycled the coal unit. By about 10 a.m. generation levels at Cherokee settled at roughly 720 MWh, 7% above output before the cycling event. However, NO_X levels increased 10% after the cycling event and SO_2 levels increased 90%. CO_2 emissions remained steady after the cycling event. While this example is extreme, it is by no means unique. These types of events must be accounted for when quantifying emission reductions due to wind generation. Complications arose at Cherokee on July 2. Efforts to balance the boilers using natural gas ended up plugging SO_2 reduction units, eliminating their effectiveness. Repairs were made to the units but took most of the day to complete, and emissions spiked during the interim period.

Figure 7
Emissions and Generation Output at Cherokee One



This impact of wind intermittency is visible in all areas of the country studied in this project. Figure 8 depicts the interaction of wind, coal, natural gas and other power sources in ERCOT. Periods of time are circled where wind is injected into the system, because that generally causes coal and natural gas units to be cycled. This happens virtually every time wind power generates electricity because wind tends to blow during the night or in the early morning hours when demand is typically lowest; thus, to accommodate the wind power, something else must be displaced.

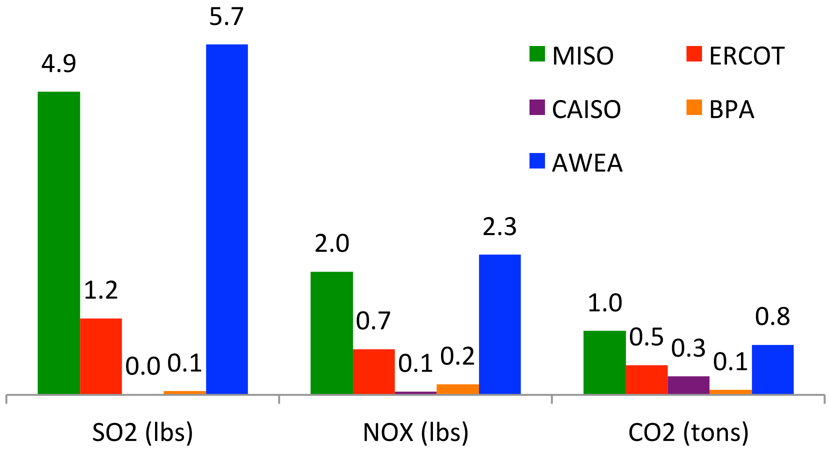
Figure 8
Thermal Plant Cycling in Response to Wind Generation (ERCOT)



Emission Impacts of Wind Power

BENTEK estimated the emission savings that resulted from introducing one MWh of wind power to the ERCOT, BPA, CAISO and MISO systems between 2008 and 2010. The results are shown in Figure 9. The average savings of SO_2, NO_X and CO_2 for MISO are presented in green, ERCOT in red, CAISO in purple and BPA in orange. Emission savings in each region are compared to the estimated savings reported by the American Wind Energy Association.

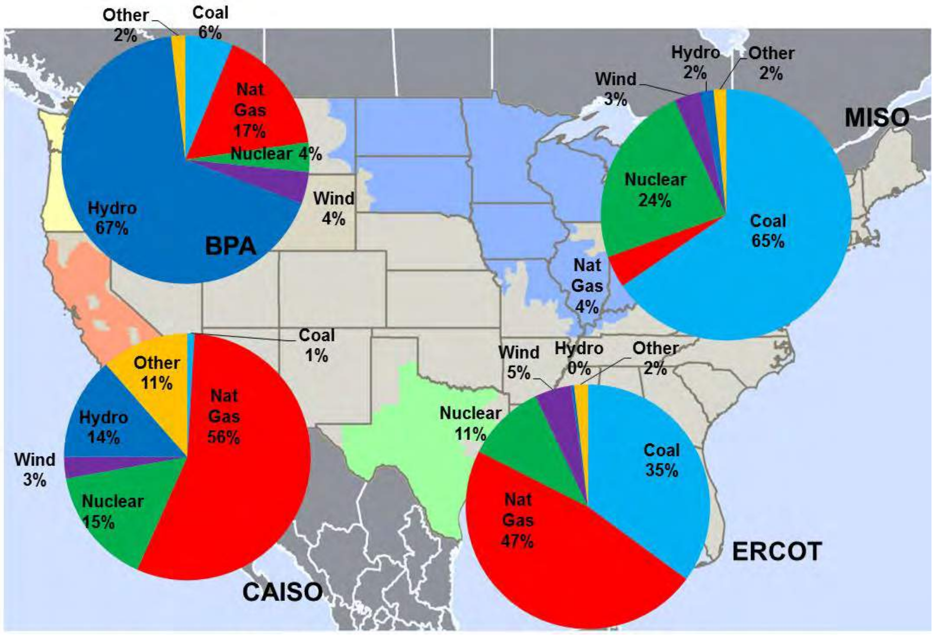
Figure 9
Wind Generation Emission Savings per MWh by Territory



Wind generation-driven CO_2 emission savings vary from 0.081 tons per MWh in BPA to 1.025 tons per MWh in MISO. NO_X emission savings are between 0.17 pounds per MWh to 1.995 pounds per MWh. Emission savings for SO_2 range from 0.008 pounds per MWh to 4.89 pounds per MWh. Compared to estimations provided by AWEA, actual emission savings are less than expected with the single exception of the MISO where CO_2 emissions due to wind are slightly higher than projected by AWEA.

The results lead to several conclusions. First, the levels of emissions savings that result from adding an incremental MWh of wind depend on the composition of the grid. The average annual fuel share of the electricity market for 2010 is captured in Figure 10. Savings are highest in the MISO area where coal constitutes a very large portion of the generation stack (approximately 65%). Accordingly, when wind blows, coal is the principle generation source that is cycled. Since coal is higher in CO_2, SO_2 and NO_X content than the other fuel sources, emission savings in this region are relatively high. In sharp contrast are the BPA and CAISO regions. In both of these areas coal plays a relatively small generation role (coal constitutes 6% and 1% percent, respectively, of total generation on average in these areas). In BPA particularly, wind tends to force hydropower plants to cycle. Since there are no emissions from hydropower, wind forces no air emissions savings. ERCOT is between these two extremes as it has significant coal and natural gas generation, which when offset by wind yields emissions savings.

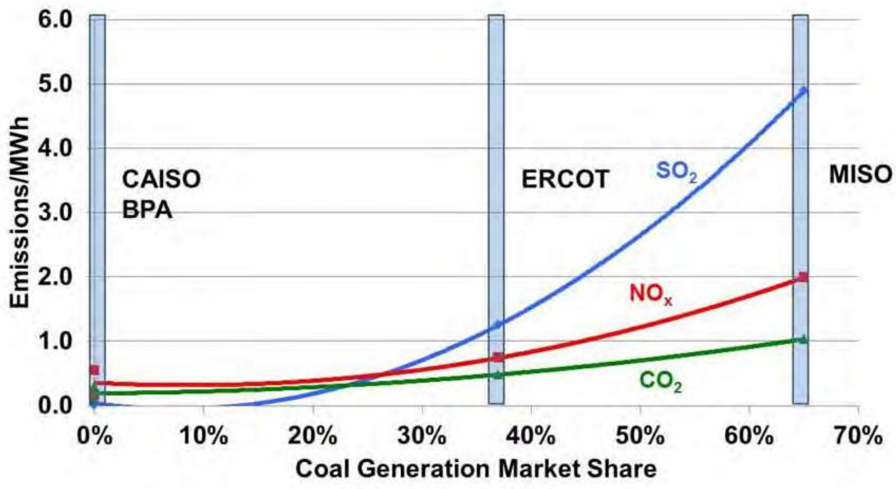
Figure 10
Composition of Generation Stack By Fuel Type
(2010)



The second major conclusion is that actual emissions savings are significantly less than has been assumed by policymakers and advertised by AWEA. Again, the disparity is less pronounced in areas such as MISO where coal provides a higher proportion of the generation base, but even in MISO, SO_2 savings are 23% less than estimated by the AWEA approach and NO_X savings are nearly 15% below AWEA's estimates. Remember, the AWEA estimates are based on dispatch models developed by AWEA and others. These models predict total emissions and emissions associated with specific units based on a variety of inputs including assumed emission savings. The significance of this finding is that the actual performance of wind power facilities does not match their projected performance levels. Cycling due to the intermittency of wind causes enough inefficiency in these systems to significantly diminish the utility of wind power as an emission control strategy. This reality compounds a second: if the generation base is already relatively low-emission (i.e., a hydro-based generation stack such as BPA's), substituting wind power for existing generation is not going to achieve large environmental gains. This is particularly pronounced relative to SO_2 and NO_X but is also true for CO_2.

What do these findings say about the potential of wind energy to reduce air emissions around the country? Insight into this question is provided by Figure 11, which shows a curve for the emission savings in each of the four study regions versus the percent of coal-fired generation. As described above, the higher the percentage of coal in the generation stack, the higher the emission savings value for wind.

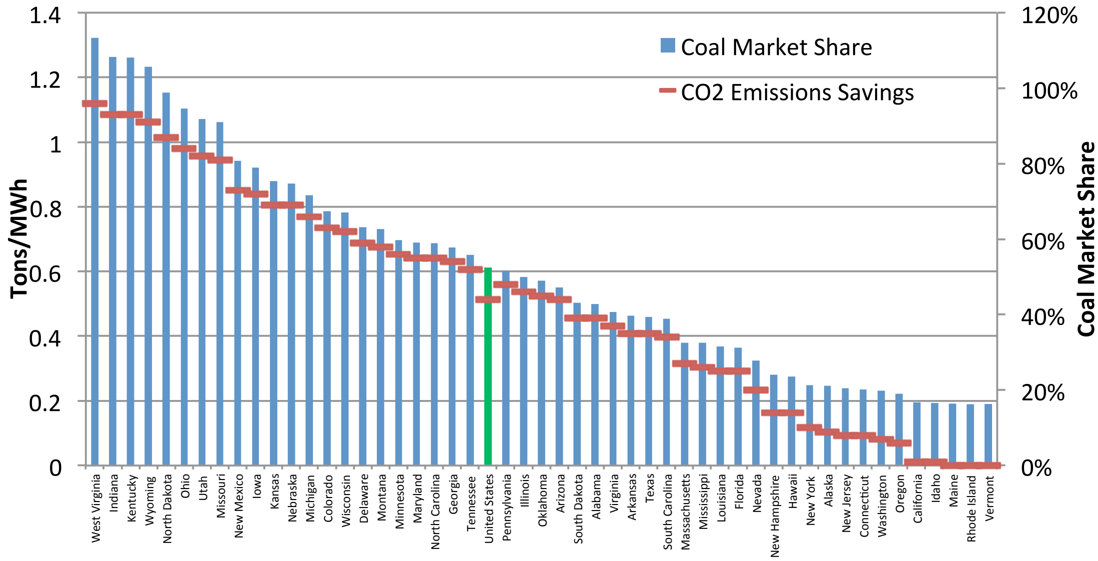
Figure 11
Wind Generation Emission Savings vs. Coal Generation Market Share



Coal-fired generation assets in the MISO operating area represent 65% of total generation. In comparison, there is little to no coal-fired generation in the CAISO or BPA operating areas as natural gas and hydro generation units are used to accommodate wind generation. Due to the low emission rates of these units (no emissions in the case of hydro), there is very little emission savings in BPA or CAISO. ERCOT has a relatively balanced mix of natural gas and coal generation assets, which explains why emission savings in this region fall between those in BPA/CAISO and MISO.

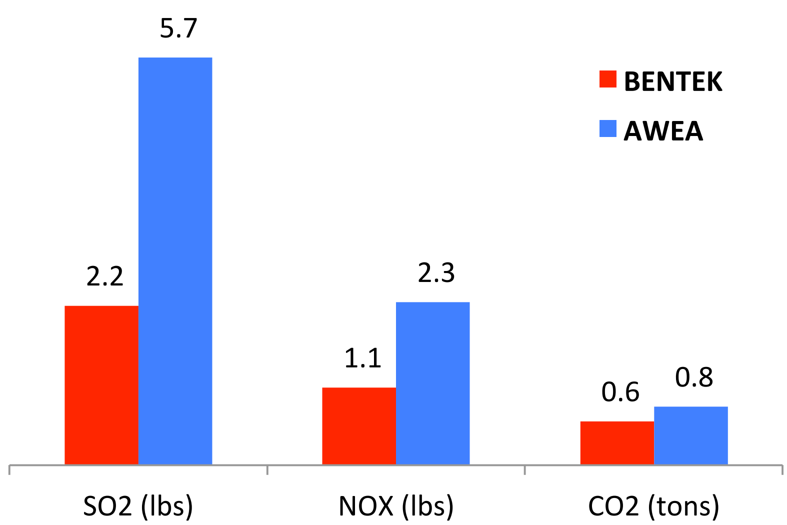
Extrapolating the wind emissions savings from the data behind Figure 11 enables estimation of the potential for wind power as an air emission reduction strategy around the U.S. Emission savings per MWh are estimated for each state using the relationship developed based on the percent of coal in the generation stack.

Figure 12
Estimated CO2 Emission Savings Rate by State



The average CO_2 savings associated with wind energy in 2009 is calculated by summing avoided CO_2 emissions from Figure 12 and dividing the sum by total wind generation across the U.S. A similar calculation can be used to estimate average national SO_2 and NO_X savings. Figure 13 shows the results.

Figure 13
Average U.S. Emission Savings per MWh of Wind Generation (2009)



These results indicate that on a national basis actual CO_2, SO_2 and NO_X emission savings that result from utilizing wind power are significantly below the projections of AWEA and those used by various policymakers. The emissions savings potential touted by AWEA are more than twice as high as actual performance for SO_2 and NO_X and roughly 33% higher for CO_2.

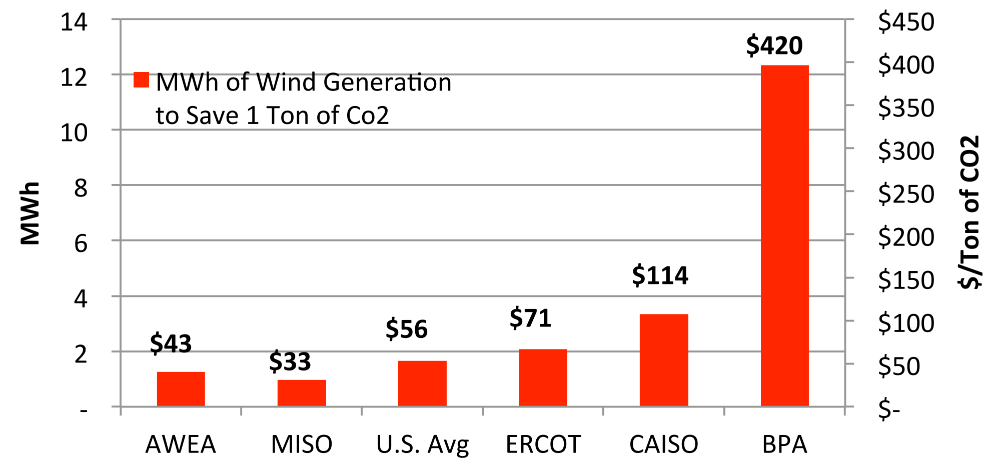
Economic Considerations

Estimating the costs associated with integrating wind power into specific utility and generation grids is complex. Numerous factors should be considered including the wear and tear on existing coal and gas-fired equipment that is cycled, the cost associated with recalibrating emissions controls when units are frequently cycled, the costs of building and maintaining adequate backup capacity, and the costs associated with building and maintaining incremental transmission infrastructure needed to move wind power to markets and other factors. A thorough analysis of costs should assess each of these factors.

As a first step in this process, BENTEK analyzed the costs of saving SO_2, NO_X and CO_2 using wind power in each of the study regions based solely on the cost of the federal production tax credit provided to wind generators. Currently, the PTC offers \$22 per MWh of tax credits to wind generation operators. Because this is a tax credit, the true cost of the subsidy should be evaluated as pre-tax, which carries a value of approximately \$34 per MWh. Therefore, each ton of CO_2 saved by wind generation costs \$34.

Figure 14 illustrates the estimated cost of saving an incremental ton of CO_2 in each region and for the U.S. on average using the above methodology. The cost to reduce one ton of CO_2 emissions in BPA is \$420, for CAISO \$114, for ERCOT \$70 and in MISO it drops to \$33. Across the U.S. the average cost of offsetting CO_2 through the production tax credit is \$56 per ton. With the exception of MISO these costs far exceed the per-ton CO_2 costs discussed in recent debates about a national carbon tax or cap-and-trade program. It is important to note, however, that while wind is currently a marginally viable CO_2 reduction technology in MISO, to the degree that new EPA rules cause MISO utilities to replace marginal coal units with natural-gas fired units, the marginal value of wind power as a CO_2 mitigation strategy shrinks and the per ton cost increases.

Figure 14
Value of the Production Tax Credits Needed
To Offset 1 Ton Of CO2 Using Wind Power



Conclusion

This study compares the actual performance of wind power as an air emission mitigation strategy in BPA, CAISO, ERCOT and MISO over a three-year period from 2007 through 2009 to the expected emissions savings as projected by AWEA. The results suggest that wind energy presents a significant paradox: wind power, per se, yields no emissions. However, integration of wind power into complex utility systems has led to little or no emissions reductions on those systems, while significantly increasing costs to power producers, grid operators and electricity consumers.

Several specific conclusions can be drawn from this research.

1. RPS programs force utilities to cycle coal and natural gas-fired generation capacity in order to accommodate intermittent wind generation. Cycling significantly decreases efficiency at the facilities, thereby increasing the emissions rates.

2. Wind power yields slim emission savings. The emissions savings that can be obtained in any region are heavily dependent on what type of fuel is being offset by the wind power. In the case of BPA, hydro generation is offset by wind generation. As there are no associated emissions with hydro, very little emissions are saved through wind generation in this area. An operating area

where coal fuels a higher proportion of its generation base, such as MISO, achieves higher emissions savings benefits by using more wind.

3. Policymakers should be skeptical of the emission benefit claims made by AWEA and other wind power advocates. The results of this study clearly shows that actual performance of wind power over a three-year period in multiple regions of the country does not meet the savings rates projected by wind power advocates.

4. If a ton of carbon is valued at between $10 and $25, none of the regions observed in this study saved enough CO_2 through the use of wind power to make wind power economically viable as a CO_2 mitigation strategy.

5. The convergence of low, stable natural gas prices, increasing coal costs and impending EPA environmental legislation that will tighten SO_2, NO_X, mercury and other emissions will increase the market share of natural gas-fired generation across the U.S. As this happens, total power generation-related emissions rates will decline. As the generation share associated with gas increases, the CO_2 savings associated with an incremental MWh of wind will decline and the cost of using wind to achieve the savings will increase. Wind will become an increasingly expensive method to reduce emissions.

6. Emission savings are already occurring naturally due to the competition between coal and natural gas-fired generation. The suppression of natural gas prices due to the domestic supply boom has created a pricing environment where natural gas is consistently offsetting coal-fired generation. This process is saving more emissions per MWh than wind generation achieves across the U.S., without legislative intervention or subsidies.

Appendix
Model Methodology

The explanation below is adopted from Kaffine, McBee, Lieskovsky (2011):

The model presented below captures the relationship between total emissions $Eirt$ of pollutant *i* in territory *r* at hour *t* against the total hourly wind generation Wrt (in MWh), average hourly temperature Trt and its square T^2rt, and a vector of other control variables Xt:

$$E_{irt} = \alpha_{ir} + \beta_{ir} W_{rt} + \gamma_{1ir} T_{rt} + \gamma_{2ir} T_{rt}^2 + \delta_{ir} X_t + \epsilon_{irt}.$$

Bir, the coefficient of interest, captures the marginal change in emissions in each territory due to wind generation. This coefficient captures the amount of emissions reduces in pounds/pounds/tons for SO2, NOX and CO2 for each MWh of wind generation in a given territory.

Other control variables need to be introduced in order to account for ongoing trends throughout the study period which, if left unaccounted, would result in an erroneous interpretation of Bir. Temperature is a strong representative of total load, which can impact the amount of wind generation allowed onto a system. Additionally, day of week and monthly fixed effects are introduced to account for changes of which temperature may represent total load. Hourly fixed effects are included to represent both differences of load during a given day (at a given temperature) and to account of the diurnal wind variation over the course of the day. On average, wind generation is strongest in the early morning hours when electricity demand and emissions are lowest. Month-year fixed effects are included to account for changes in wind generation capacity throughout the study timeframe.

Impact of Cycling on Coal-Fired Power Generating Assets

April 20, 2011

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Abstract

Large-scale integration of renewable power generation assets over the next two decades will have a significant effect on operation of the coal-fired units that will contribute to system load balancing. This white paper discusses a range of impacts on coal plants that result from the expected future need for greater flexible operation. Increased cycling of coal plants is already evident today due to factors such as the decreased overall demand, lower natural gas prices, and deployment of intermittent generation sources in some regions of North America and Europe. The operational experiences to date provide some insight into specific reliability issues and successful mitigating strategies. This foundation can be the basis for proactive measures that ensure coal's reliable contribution to the bulk electric system following large-scale renewable deployment.

Introduction

The fleet of coal-fired power generating units in North America is changing roles from baseload duty to various modes of cycling operation. Reduced overall demand caused by the U.S. recession, coupled with low gas prices have resulted in lower overall coal unit capacity factors. In addition, the plans for large scale deployment of intermittent renewable generation such as wind and solar will further impact the operation of conventional coal units. Large-scale deployment of intermittent generation will have five primary operational impacts on coal generating units used to balance system load:

- Increased load-following operation
- Higher unit turndown during low demand
- Frequent unit starts (hot, warm, and cold)
- Increased load and thermal ramp rates
- Frequent reserve shutdown

One or more of the above operational impacts will affect many coal units in various regions of North America. Intermittent generation on the system can be a contributor in each of the above operational impacts. Seasonal variation in wind and solar production can lead to higher turndown and/or reserve shutdown of balancing assets. Hourly variations in the output of these intermittent sources within a typical day can be rapid, and lead to load-following of coal units, frequent unit starts, and most importantly, increased frequency and rates of load ramping. The problem of peak hourly wind generation being out of phase with hourly trends in demand forces more coal units to run at minimum loads during the night, and ramp up and down to balance load. In addition to the anti-correlation between wind output and system demand seen on an hourly basis for each day, there is a similar trend observed on a monthly basis throughout a typical year. These two factors can combine to result is a wide range of coal balancing load required between the extremes of renewable generation levels.

Analysis of NERC-GADS data reported by coal units in the 2005-2009 timeframe indicates an increase in reserve shutdown hours in 2009. This is observed across a range of unit sizes, in both supercritical and subcritical designs. This had produced a reduction in reported net capacity factor, particularly for older subcritical units which are experiencing high turn-down. These impacts may be primarily driven by an overall demand reduction (four percent from 2008 to 2009 according to EIA) and a shift in dispatch to gas-fired assets (gas-fired combined-cycle production net capacity factor increased by five percent from 2008 to 2009). However, displacement of coal by intermittent generation is already a factor in certain regions, with a growth in overall renewable generation of 18 percent from 2005 to 2009 reported by EIA. A study conducted by NREL on wind and solar integration in the western states predicts a wide range in the level of coal-fired balancing load required during the time period of 2017 assuming a 35 percent renewable asset portfolio [1]. These balancing units would experience frequent starts, high turndown, ramping, and reserve shutdown hours.

Coal Plant Design Basis

The rapid build of coal generating capacity during the 1960s and 1970s included primarily base-load units designed to meet expected trends in demand growth. Over 60 percent of the total North American subcritical coal-fired generation in 2009 was produced by these units commissioned prior to 1980. Since 1980, power producers have opted to build fewer numbers of large capacity, more efficient units with supercritical steam conditions. These units were also designed for base-load operation. The existing coal fleet therefore includes few units designed specifically for flexible operation.

An analysis of NERC-GADS data for subcritical coal-fired generation in 2009 suggests that the bulk of the coal-fired load balancing needs are being met by units commissioned prior to 1970. The average net capacity factor reported for these units is close to 50 percent.

Categories of Cycling Influences on Coal Generation

The five *operational* impacts of cycling listed above result in significantly increased occurrences of thermal transients in the material of critical high-temperature boiler and turbine components. These transients, and other operational factors associated with cycling, have the following influences on coal-fired generating assets:

1. increased rate of high temperature component life-consumption
2. increased wear and tear on balance of plant components
3. decreased thermal efficiency at low load (high turndown)
4. increased fuel costs due to more frequent unit starts
5. difficulties in maintaining optimum steam chemistry
6. potential for catalyst fouling in NOx control equipment
7. increased risk of human error in plant operations

The additional wear on plant components requires increased spending on preventive and corrective maintenance. This is often challenging to plants that are placed lower on the dispatch stack and therefore receive less revenue and operating budget. The human error risk in the above list is due primarily to the increased amount of transient operation, producing more opportunities for error. Major plant events caused by human error can result in costly equipment damage and related safety challenges.

Key Material Damage Mechanisms Associated with Cycling

A few important material damage mechanisms are responsible for the majority of the financial impact of flexible operation of coal-fired plants. The severity of the impact of these mechanisms can be mitigated to a certain extent through improved plant operation and process controls, but it is not possible to completely eliminate the reduction in major component life experienced in cycling operation. Table 1 below summarizes these key material damage mechanisms. Note that fatigue (either mechanical or thermal) can combine with other primary damage mechanisms, such as creep (Figure 1) and corrosion, to significantly enhance their impact.

Table 1 - Summary of Material Damage Mechanisms Associated with Cycling Operation

Failure Mechanism	Description
Creep	Material damage mechanism caused by long-term exposure to combination of static stress and elevated temperature. Result is a gradual reduction of materials strength measured in terms of rupture strength. In the later, more observable phase of creep, appearance of voids at grain boundaries and macroscopic deformation of component is evident.
Fatigue	The cumulative damage to material microstructure due to repeated cycles of applied mechanical and/or thermal strain. Crack initiation occurs when damage reaches the endurance limit of the material. Crack propagation follows.
Creep-Fatigue	The interaction of creep and fatigue has a synergistic effect on the rate of damage, greatly reducing the operating life (see Figure 1 below). This is an ongoing area of research. Reducing the impact of creep-fatigue in non-baseload units has been the motivation for increased usage of creep-strength enhanced ferritic steels such as alloy P91.
Corrosion	The dissolution of metal in the presence of inorganic acids created by impurities in the steam. Most prevalent are chlorides, sulfates, nitrates, and fluorides. Oxygen, which can be introduced to the water-steam circuit during cycling operation, can accelerate the rate of corrosion.
Corrosion-Fatigue	The interaction of corrosion with fatigue significantly reduces the material endurance strength. The mechanism of surface micro-pitting due to corrosion can lead to fatigue crack initiation at much lower levels of applied stress than simple fatigue in a clean environment.
Stress Corrosion Cracking	This mechanism primarily affects low-alloy materials subjected to high operating stresses, such as turbine rotors. Corrosion pits are initiation sites for intergranular attack when combined with applied *static* stress and chlorides
Quenching	The rapid reduction in surface temperature of hot components as a consequence of contact with liquid phase process flow. This liquid phase is often the result of condensation and ineffective drainage, or poorly operating attemperating sprays.

Creep Fatigue Interaction, ASME Case N-47
Effect of Introducing Two-Cycling

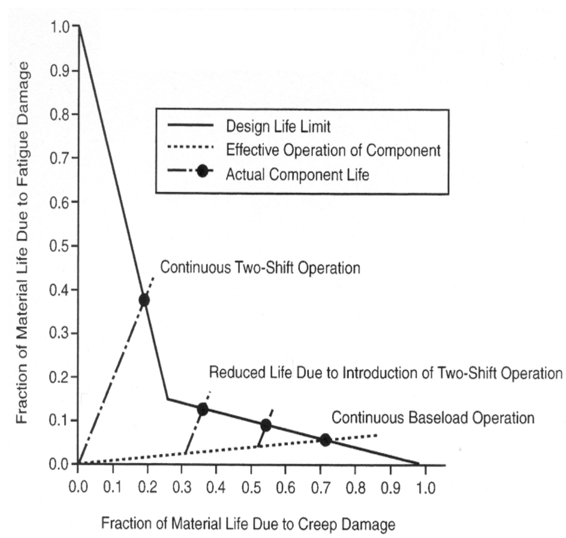

Figure 1 - Interaction of Creep and Fatigue

Details of Equipment Damage Caused by Variable Operation

The paragraphs below briefly summarize some major examples of damage to coal plants caused by operational impacts likely to arise from renewable integration [2]. The information is arranged by type of damage, followed by components affected.

Fatigue and Creep-Fatigue Interaction

This can produce cracking in thick-walled components, especially castings such as turbine valves, steam chests, and turbine casings. Also affected are boiler superheater and reheater headers, where ligment cracking is commonly seen between between tube stubs. These headers are expensive, thick-walled vessels operating under high steam pressure, making this damage of particular concern to plant owners. Header cracking is caused by frequent large temperature swings associated with cycling, and in some cases by thermal quenching produced either by condensate formed during idle stand-by or poorly controlled attemperator sprays (again associated with transient operation). Economizer headers are likewise damaged by cycling operation since during startups relatively cold feedwater is introduced to the heat exchanger tubes. The third type of boiler header impacted by cycling are waterwall headers. Thermal cycling of the massive waterwall structures creates large differential expansions across a wall section sharing a common header. This differential expansion induces high stress in the upper and lower headers.

Thermal Expansion

There are several systems in a coal plant which are comprised of components which undergo high thermal growth relative to surrounding components. Plants are designed to accommodate this growth and minimize the stress associated with inadvertent growth constraint. The most important example of this is the large movement of boiler structures relative to the cooler support framework. This includes waterwall sections, gas ductwork, and the ties used to support superheat and reheat tubing. These support ties are designed to accommodate growth, but are subject to accelerated life consumption if the frequency of thermal cycling increases. Significantly greater attention must be paid to these components in the form of inspection and preventive maintenance for plants not operating at base load. Plant high-energy piping systems deliver steam between the boiler and turbine. These are massive piping systems that must be carefully supported to allow for not only its own thermal growth, but movement of the boiler and turbine endpoints as well. The inevitable deterioration in performance of the pipe hanger systems over time, relative to design, becomes problematic in cycling plants as the resulting increase in piping stress can lead to creep and creep-fatigue. Locations of dissimilar metal welds are an area of particular concern in piping life consumption. In the case of rotating equipment such as steam turbines, the thermal growth issue is one of preventing contact between the high-speed rotor and stationary components in close proximity. This can occur if thermal ramp rates are not controlled to within the limit of the designer specifications. Supervisory instrumentation is critical to monitoring rotor relative growth during fast ramping to avoid rotor damage. Another important example of the impact of thermal growth is seen in the main generator windings, as well as the windings of large motors. In this situation, small relative motion of the insulated windings within their support structure of either the rotor slots or core eventually weakens the insulation and increases the risk of partial discharge. The end result of this damage mechanism is more frequent, expensive, rewinds.

Corrosion-Related Issues

Two-shifting, or any other operation that challenges the ability of the plant to maintain water chemistry, can lead to increased corrosion and accelerated component failure. Increased levels of dissolved oxygen in feedwater can be the result of condenser leaks, aggravated by more frequent shutdowns. Other factors impacting chemistry include increased need for make-up water and the interruption in operation of the condensate polishers and deaerators. These water/steam chemistry issues can combine with thermal transients that damage the protective magnetite layer and expose the metal to corrosion processes. Proper protection of the entire steam circuit (boiler, piping, feedwater, and turbine) is critical during periods of reserve shutdown. Methods such as wet layup, nitrogen blanketing, and dry layup using active dehumidification are necessary to minimize upsets in water chemistry and ensure a prompt return to service of the unit [3]. One key area of concern with regards to corrosion is the low-pressure steam turbine. The phase-transition zone of the low-pressure turbine is the location of steam condensation as well an area of concentration of many damaging corrosive species. During periods of very low load operation, this phase transition zone shifts upstream in the turbine steam path due to changing thermodynamic conditions (for example, reduced reheat temperature). This shift, in turn, exposes more of the turbine rotor to chlorides, which can lead to pitting in presence of moist oxygenated environments associated with unit shutdowns.

Fireside Corrosion and Thermal Fatigue
Load cycling and relatively quick ramp rates under staged conditions will have a negative impact on both fireside corrosion and circumferential cracking. This impact can be understood by considering the following:

- Flame length, and consequentially, boiler tube fireside temperatures, is proportional to load. As thermal fatigue is a first order root cause of circumferential cracking, rapid changes in temperature will exacerbate this issue.
- During load transients, fuel-to-combustion air ratios are in flux. Deviations in fuel-to-combustion air ratios will impact not only flame length, but particle burnout and trajectories as well. As deposition of reducing ash particles (such as FeS and chlorides) are a first order cause of fireside corrosion, these issues will be exacerbated.
- During forced wall cleaning and natural slag shedding, load transients exacerbate thermal impact thus increasing thermal fatigue and deposition leading to circumferential cracking. Natural and forced wall cleaning will remove iron oxide (FeO) protective layer thus allowing for new formation of both FeO and reducing ash particles (FeS and Chlorides) to form on boiler wall. This cycle of removal and formation of deposited species combined with thermal fatigue impacts will lead to crack initiation and propagation.

Rotor Bore Cracking
The high-pressure and intermediate-pressure steam turbine rotors, when subjected to transients in the temperature of the admitted steam, can suffer thermo-mechanical stress excursions resulting in low-cycling fatigue damage. The damage can result either from introducing hot steam to a relatively cold rotor exterior, or the opposite. In both scenarios, the problem arises from the massive rotor forging and the resulting time required for the metal temperature difference between the rotor exterior surface and the inner (bore) region to equilibrate. During the transient period, large circumferential ("hoop") tensile stresses are built up at either the rotor exterior or bore region. These tensile stresses, if allowed to "cycle" by repeated thermal transients, will initiate or propagate radial-axial cracks from the inner bore surface or rotor periphery. These cracks often initiate at inclusions or voids in the original forging. The toughness of the rotor material then becomes extremely critical to ensuring that the propagating crack front does not severely compromise the rotor integrity. Exceeding the material stress intensity, due to a large crack and/or brittle material, can result in rotor destruction at high-speed. This event would have severe safety and financial consequences for the plant operator. A significant improvement in quality of rotor forgings and material toughness over the past 30 years has reduced the risk of rotor burst. However, many rotors in the 40+ year age span still operate with older forgings. These are the units that are increasing dispatched to balance the system load and are thus experiencing an increase in load ramping and thermal transients.

Impact of Cycling on Environmental Control Equipment
Flue gas desulfurization (FGD) equipment and selective catalytic reduction (SCR) systems are being deployed increasingly on high-capacity factor coal units to meet emissions mandates. The impact of load following, high turn-down, ramp rates, and reserve shutdown on the reliability and performance of these systems should be considered when assessing impact of large scale renewable penetration.

The chemical processes carried out in FGD and SCR systems require precise control of the reaction conditions which are influenced by reagent flow, water flow, and flue gas temperature. Startups of FGD systems should be minimized because of need to purge system to avoid slurry solidification, impact of fuel oil residues on linings, and the lengthy warm-up time. Low load operation of FGD systems may be difficult to optimally control if the reagent flow is at a fixed rate. High ramp rates also challenge the FGD control systems due to time delays in the process flows. In the SCR systems, the main operational concern related to cycling is the impact of lowered flue gas temperature at part-load on catalyst plugging. Ammonium bisulfate (ABS) forms in the pores of the catalyst due to condensation at low flue gas temperatures. This removes effective surface area of the catalyst and reduces the SCR performance. Recent EPRI research is investigating specific factors influencing ABS formation, low-load operation, SCR response to load changes, and options for maintaining minimum operating temperature [4].

Assessment of Costs Associated with Cycling Coal Assets

Tangible costs associated with cycling of coal units include additional fuel costs due to more frequent unit starts and low-load operation at higher unit heat rates. Higher operations and maintenance costs are the result of increased water chemistry needs, make-up water, and increased inspections as well as preventive and corrective maintenance activities. Intangible costs include the accelerated life consumption of major boiler, piping, and large rotating equipment components. Life consumption costs are not realized immediately following the onset of cycling operation, and are thus difficult to correlate to damaging operating modes. The most common approach to estimating the costs associated with various types of unit cycling is to collect historical plant data for fuel costs and preventive/corrective maintenance costs. This aggregate cost data is then compared to historical operational data that can quantify the various cycling operating characteristics. Correlating these two datasets across a sample of plants provides at least a first-order estimate of costs associated with cycling. The simplest approach is to focus on unit starts as the key operational parameter. This approach ignores load-following, low-load operation and any load ramping not associated with starts or shutdowns. Unit starts are often divided into *Hot Starts*, *Warm Starts*, and *Cold Starts* which are in increasing order of overall damage to the unit. EPRI has compiled some data on total cost per coal unit startup that draws from a number of researchers [5]. The reported data on costs per **cold** start for small, medium, and large coal units respectively is $21K, $46K, and $70K (referenced to 2000 year dollars). It must be emphasized that cycling cost information is very approximate and is best assessed at the unit level rather than average fleet level. Continued research is recommended to improve the accuracy of cycling costs, particularly in regards to the intangible O&M and capital replacement costs due to wear and tear on equipment.

An alternative to the use of historical data on O&M and capital costs to quantify cycling impact would be the use of component modeling using remaining life assessment software. For example, creep-fatigue analysis of headers could be undertaken on a parametric basis using a range of component geometry and thermal transient inputs. The incremental damage (life consumption) per cycling “event” can be calculated and the results expressed as curve families used later to calculate cost over a range of operating time. This analysis process has not been deployed on a widespread basis yet, however the analysis tools exist [6,7]. The parametric approach described would require a broad collaborative effort across the industry to be cost-effective.

Strategies to Mitigate Impacts of Cycling Damage

A range of strategies will need to be employed to mitigate damage to coal units cause by flexible operation [2]. These should be generally assessed in terms of benefit-to-cost ratio when selecting action plans for specific units. Significant capital investment in improved-design boiler components may be warranted in cases of new, efficient units with control technology installed. In older plants, the most cost-effective strategy from a life-cycle cost perspective may be to focus on improved operator performance and selected plant controls upgrades. This approach could also include installation of additional process sensors (typically temperature) strategically located to guide operators through transients without damaging over-temperature events. Increased attention to location, operation, and capacity of drains is another cost-effective O&M strategy.

The focus on improved operator performance should include a thorough investigation and optimization of transient procedures to optimize based on reduced damage. This should be followed by rigorous training, coaching, and observation to ensure that improved procedures are consistently applied. When transient unit operation becomes common, more attention should be paid to operations fundamentals such as DCS display characteristics, procedures, and alarm management. Introducing additional automation in startup logic can be considered to reduce chances for human error and improve consistency.

Future Coal Plant Designs: Dispatch Considerations

Supercritical and ultrasupercritical coal plants are inherently less flexible than subcritical steam plants under thermal transients due to the higher steam temperatures and heavier wall thickness on pressure components. Nonetheless, the advantage these plants offer in terms of higher thermal efficiency will make them attractive in future new builds. If the next generation of efficient plants is fitted with carbon capture and storage (CCS), there would be new opportunities for creating significant flexibility in the net plant output through changes in operation of the CCS systems [8]. Because the CCS systems consume 20-30 percent of the gross plant output, an operational decision to bypass the CCS and vent CO_2 into the atmosphere would result in very rapid ramp-up capability of the plant. The same would apply to ramp-down capability. Analyses have been performed by EPRI of the net present value of this ancillary service against the capital costs of CCS retrofit. The results show that approximately 40 percent of the costs could be recovered in the ancillary market. It is assumed in this scenario that regulations would permit CO_2 venting when system load demand requires it.

Research and Development Needs

Continued research, development, and technology demonstration in several key areas is needed to address the current industry needs, as well as future needs with large-scale renewable integration. A few of the most important research areas are listed below:

1. Improvements in properties of creep strength enhanced ferritic steels
2. Approval of advanced nickel alloys such as Inconel 740 for use in supercritical boiler and turbine designs, which would allow reduced wall thickness and improved thermal transient response
3. Reliable high-temperature strain gages that can be inexpensively integrated into the Plant Information (PI) systems
4. Identification of gaps in current control systems that result in temperature excursions in boiler components
5. Cost-effective operational strategies that reduce operator-induced damage to high-temperature components during transients
6. An industry-wide database to support cost-of-cycling estimations, including a mix of historical cost data as well as information from component-specific damage analyses
7. Industry database of observed plant equipment reliability issues to be shared with plants seeking to develop a proactive strategy to managing cycling

In addition to the above research aimed at existing coal units, it is recommended that an industry effort be initiated to define the design characteristics of the future coal cycling unit. This information would be used in future procurement specifications in situations where the prime need for the asset is its ability to operate flexibly. Starting the design process with a “clean sheet of paper” would be expected to yield significant improvements in unit flexibility. This research effort should start soon in order to be available for potential new builds in the next decade.

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Managing Large-Scale Penetration of Intermittent Renewables

(Gas Turbine Power Plants including SCGT, NGCC, IGCC)

April 20, 2011

Douglas M. Todd

Introduction

Maintaining power system stability while accommodating intermittent renewable power sources will become more difficult for grid operators as the penetration of such renewable energy increases. Renewable generation, particularly wind and solar power can be highly variable requiring other types of power sources to respond to load changes quickly to maintain system stability. We are already seeing issues even at current low levels of deployment. Up to some yet unknown level of penetration, Gas Turbine Power Plants can provide the necessary flexibility. This paper discusses the various current capabilities for Simple Cycle Gas Turbines (SCGT), Natural Gas Combined Cycles (NGCC) and coal fired Integrated Gasification Combined Cycles (IGCC) along with some thoughts about potential technical improvements that could be made to decrease response time allowing increased renewable penetration.

First, it is important to understand power generation economics of dispatched systems including cost of electricity (COE) and capacity factors (CF) of various types of plants with and without Carbon Capture and Storage (CCS). We will then discuss the capabilities to support fast load changes to maintain system stability. This will include necessary part load operation advantages/penalties along with load change ramp rates. At some point in the renewable penetration other plants will not only have to ramp up and down but will have to be started and stopped causing even higher O&M costs and additional air emissions. The paper provides an insight to all of these effects and concludes with some discussion of System Stability Modeling Study results.

GT/CC Fit with Existing Sources and/or planned Intermittent Renewables

To maintain overall power system stability using electric power sources that are subject to non-planned load changes such as from intermittent wind and solar there needs to be back-up power sources capable of matching the up and down intermittency. The matching back-up equipment will need to be capable of quick load ramping while load following and later rapid starts and stops as intermittent sources penetrate to higher capacity levels. System planners will need to know the frequency and speed of response required to determine the correct type of back up. Two examples from PG&E are shown in Figure 1 showing the wide variations in output that need to be accommodated. PG&E is already at 17.7% renewables.

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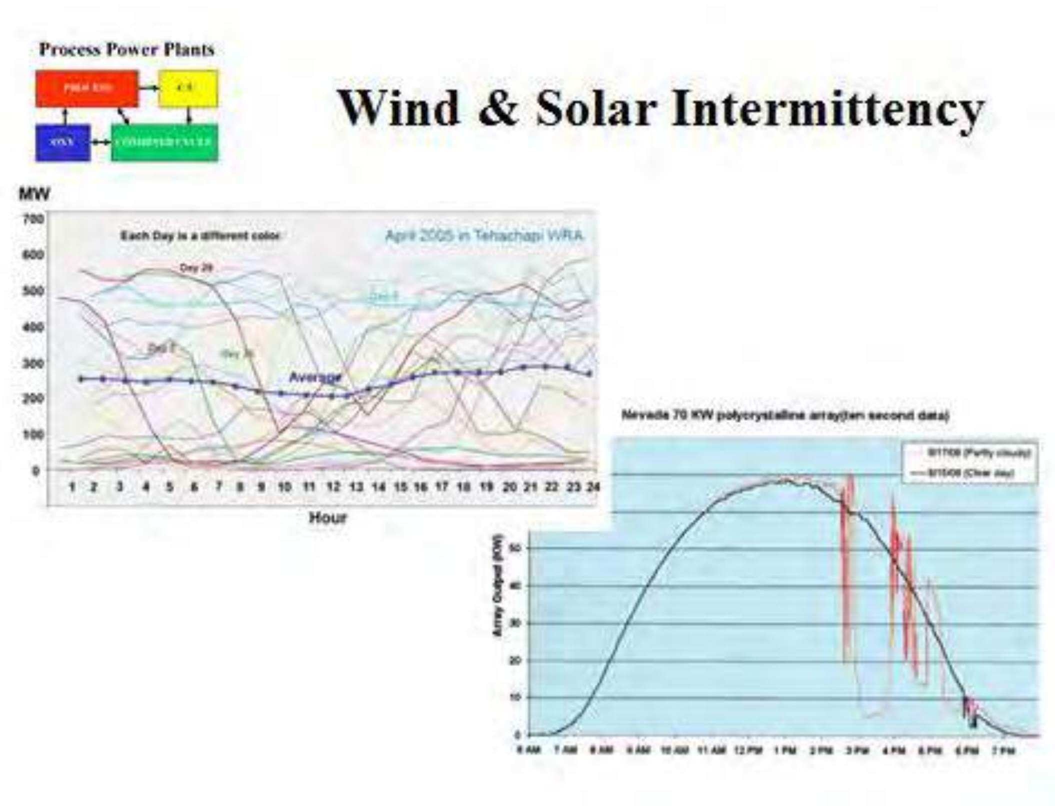

Source: PG&E [1]

Figure 1 - Examples of Wind and Solar Intermittency[1]

In these two examples you can see some slow and some fast response ramp rates would be required. It takes a probability analysis to determine how much back-up is required.

Before defining the quantitative capabilities of Gas Turbine Power Plants in cycling duty, it may be helpful to discuss the economic relationships with other various existing types of power sources. For this, we can use some US DOE/ NETL comparison results. The first is a Cost of Electricity (COE) comparison of NGCC with Coal PC and IGCC based on a specified capacity factor for each technology (Figure 2). While you see this comparison frequently, it is not how plants are actually dispatched so we have two other examples explaining the economic relationships for dispatched systems pointing out the reversal of the most economic technology choices (Figures 3 and 4). This is followed by an example of a DOE Life Cycle Analysis COE comparison including Global Warming Potential (GWP) for the same technologies but including Wind with and without back-up (Figure 5). The importance of these comparisons is not the specific numbers as they can be very different depending on the base assumptions but to understand the issues of dispatch, capacity factor and economics with regard to how to accommodate intermittency.

[1] Pacific Gas & Electric, http://www.energy.ca.gov/2011_energypolicy/documents/2010-11-16_workshop/presentations/09_Schainker_PGE_Applying_Large_Scale_Energy_Storage.pdf

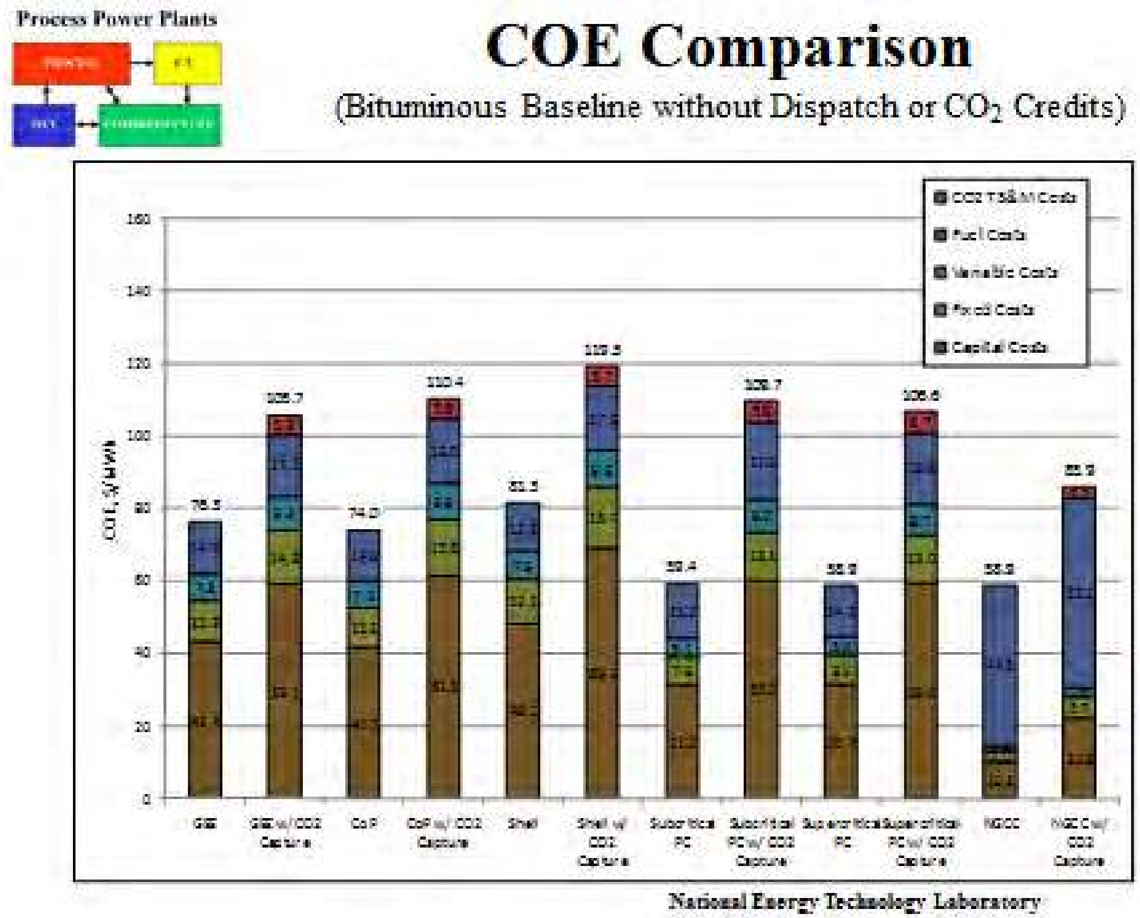

Figure 2 - Cost of Electricity Comparison NGCC, PC IGCC[2]

This first year cost of electricity (FYCOE) comparison is made with and without Carbon Capture and Storage (CCS) costs but without taking into account the way plants are normally dispatched nor the value of carbon capture. In this specific study NGCC has the lowest COE because it is operated at 85% capacity factor as are the pulverized Coal (PC) plants. Even though IGCC w CCS is penalized at 80 % capacity factor in this study it can be slightly lower COE than PC especially with CCS. We see this type of analysis frequently and it is a help in comparing plants with the same fuel but can be somewhat confusing when adding plants with significantly different fuel costs such as NGCC. For that we need to consider dispatch economics.

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[2] "Cost and Performance Baseline for Fossil Energy Plants - Volume 1: Bituminous Coal and Natural Gas to Electricity" (http://www.netl.doe.gov/energy-analyses/pubs/BitBase_FinRep_Rev2.pdf), Exhibit ES-7.

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Capacity Factor by ISO

(Without CO_2 Credits)

	Fuel	MW	HHV Heat Rate Btu/kWh	Fuel Cost	Variable O&M	Production Cost	CAISO Cf	PJM Cf
Simple Cycle	NG	48.8	10,609	6.368	2.407	69.963	35%	20%
Combined Cycle	NG	565	7,477	6.368	2.407	50.023	47%	22%
PC Supercritical without CCS	Bit	550	9,555	1.319	3.233	15.836	66%	63%
IGCC without CCS	Bit	622	9,631	1.319	4.720	17.423	61%	56%
IGCC with CCS	Bit	487	11,503	1.319	6.013	21.186	60%	35%

Courtesy of WorleyParsons

Figure 3 - Capacity Factor by Independent System Operator

Once a plant has been purchased and is constructed it can be economically dispatched based on the relationship of production costs to other units on the system. This data chart is used here only as an example to explain the use of production cost to determine capacity factors (Cf) and to show the wide variation in different areas of the country. The production cost is generally calculated by including fuel and variable operation and maintenance costs. Figure 3 is an example of a simulation made by WorleyParsons to show the differences between how various types of power plant might be dispatched in the California system (CAISO) and the Eastern system (PJM). This comparison predicts the capacity factors by using a systems dispatch model. NGCC varies between 47% and 22% capacity factor. In this specific case IGCC without CCS happens to have a higher heat rate and maintenance cost forcing it to operate at lower a capacity factor than we normally see. Adding the value of carbon capture to the production cost would significantly alter the results. We should note the predicted capacity factors for NGCC at 47% and 22% is nowhere near the 85% NETL used in the previous comparison. Again the specific numbers are not as important as the understanding of how various plants need to operate for the best economics.

DOE/NETL also recognized the dispatch economics and has provided a similar study on that basis (figure 4).

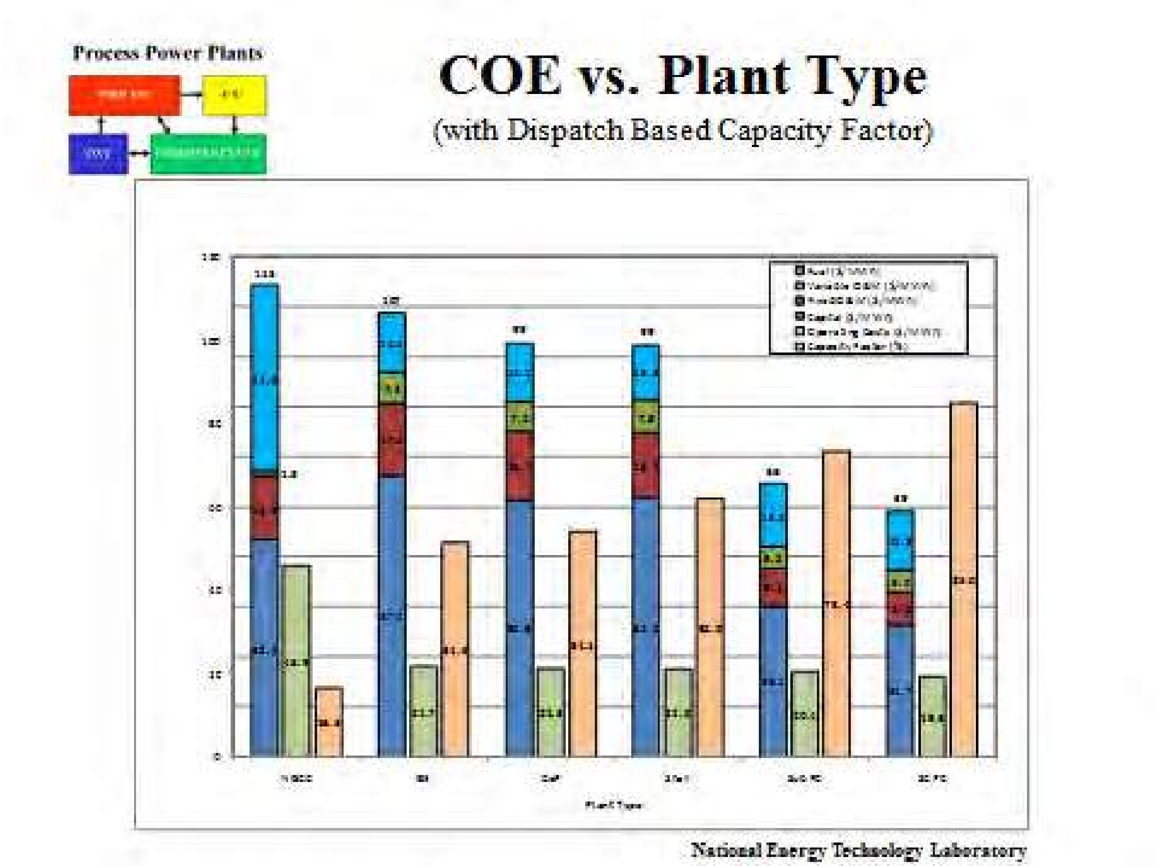

Figure 4 – Dispatched Based Capacity Factor COE vs. Plant Type[3]

This NETL chart is a similar comparison example on a dispatched model basis predicting capacity factors. This study has somewhat different inputs than the WorleyParsons example so the numbers are different. It does not include CCS for any of the technologies. At some point in time, depending on regulations, the value of CO_2 capture with regard to dispatch will need to be taken into account.

Here we see that the technology choice is reversed with NGCC at the highest COE based on the derived 16.5 % CF for the specific region compared to 85% in Figure 2 and the 47% and 22 % CFs in Figure 3. Economic dispatch will be different depending on the specific combinations of existing plant types. It is possible that NGCC plants may be forced into non- economic operations to accommodate intermittency, if the back-up requires more operating hours. IGCC even with lower fuel costs has lower CFs than PCs due the specific variable O&M costs chosen. If CCS had been included IGCC with CCS would have fared better.

It can also be very interesting to consider Global Warming Potential (GWP) using life cycle costs for CO_2. NETL has also included GWP and Renewables in a different study (figure 5).

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[3] Cost and Performance Baseline for Fossil Energy Plants - Volume 1: Bituminous Coal and Natural Gas to Electricity" (http://www.netl.doe.gov/energy-analyses/pubs/BitBase_FinRep_Rev2.pdf), Exhibit 6-12 the specific chart is not in the report.

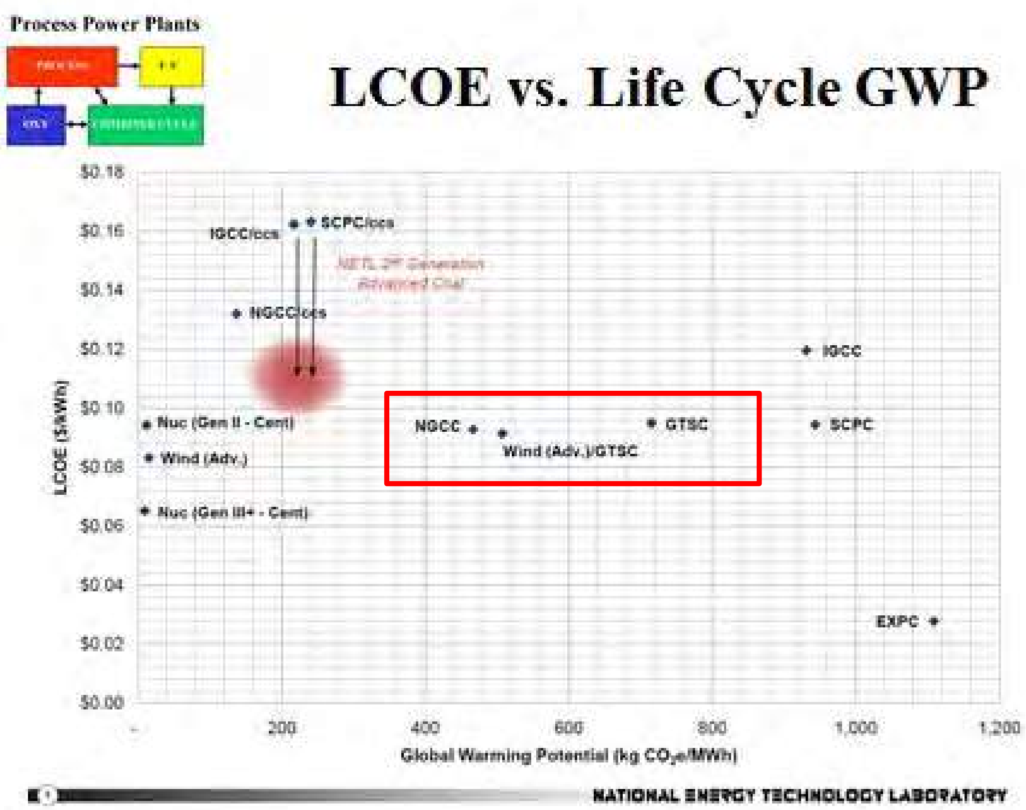

Figure 5 - Levelized COE - Life Cycle Analysis - Global Warming Potential (GPW) [4]

To complete our understanding of system needs to be met by Gas Turbine plants we can use this DOE/NETL plot of LCOE vs. GWP[1]. It also includes the LCOE for wind with and without a back-up SCGT. The GWP is based on a compilation of the inputs, outputs and the potential environmental impacts of a power plant throughout its life cycle from raw material acquisition to the final disposal as well as the energy conversion facility. This includes upstream emissions (material acquisition and transport) as well as downstream emissions (product transport and end use). Greenhouse gases such as CO_2, CH_4, N_20 and SF_6 were converted to Global Warming Potential using IPCC 2007 100-year CO_2 equivalents.

For the Wind point shown with GT back-up NETL uses an SCGT back-up at 30 % capacity factor and shows a similar COE to wind without back-up and NGCC. We do not know the relative MW sizes but a recent Carnegie Mellon Study calculated that a 300 MW NGCC would be needed to ramp up and down to maintain firm power to back-up wind capacity of 400 MW size in order to maintain system stability at larger penetration rates. That study did not include wind above 20% penetration.

The NGCC-CCS point is calculated with 85% capacity factor. With a more realistic dispatch level of 40% the COE would have been higher than the IGCC-CCS point. DOE has added advanced coal IGCC to this chart due to the progress of their development programs. Again, the numbers are not as important to this discussion as the relationships provided the assumptions are correct.

[4] http://www.netl.doe.gov/energy-analyses/

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Cycling Duty Performance, Options and Costs for Gas Turbine Plants

Current Gas Turbine plants have good potential to support increased penetration of intermittent renewables and can be modified for even greater capabilities. We need to study several different operational issues for perspective, each one with an economic impact caused by the added cycling duty:

- As penetration of intermittents grows the GT plants will probably have to run at part loads in order to ramp up or down to maintain system stability
  - Part Load Operation has a penalty of fuel efficiency (Heat Rate)
  - Load Change Ramp Rates have effects on Operation & Maintenance (O&M) costs
- With higher penetration rates, GT plants will have more starts and stops
  - GTs have many different start options each with an effect on fuel use and O&M costs
- Emissions will be affected
  - Start and stop emissions may increase or decrease
  - Part load emission rates for CO_2 will increase

For the first issue of part load operation to handle cycling, most combined cycles are arranged with two Gas Turbines each with its own Heat Recovery Steam Generator (HRSG) and one Steam Turbine. They can be operated at partial load as shown in Figure 6.

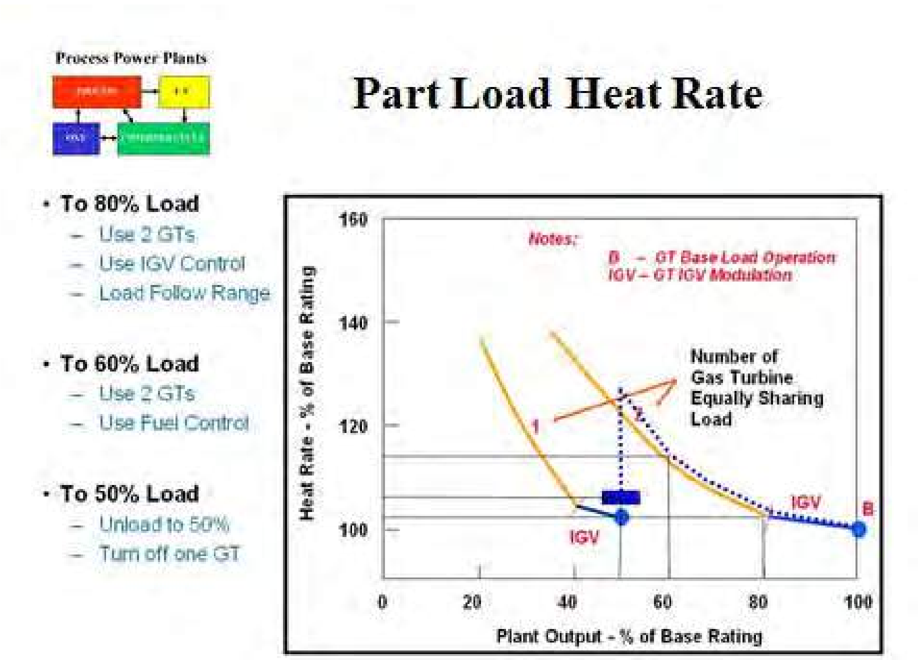

Figure 6 - Part Load Heat Rate

The plot of Heat Rate vs. % load shows a general approximation of the fuel penalty for operating at part load. The yellow lines are for Natural Gas and the blue dotted lines are for IGCC. In either case the operator may lower the output to about 80% load with little penalty as the firing temperature is held constant and the load reduction comes from lowering air flow by adjusting Inlet Guide Vanes (IGV). If operated at 80 % the plant could ramp up to 100% or down to 60% to accommodate intermittents. From 80% down to 50% the curve becomes steep as firing temperature is reduced and the penalty is significant. Emissions are generally within compliance down to 50% load. At 50% it is possible to turn off one GT and HRSG with the resulting improvement in heat rate. IGCC performance follows the same pattern but with larger penalties from the gasification system. To calculate the economic penalty one must determine the amount of load cycling needed for each individual unit and that of course can only be done by the system operator. We can have some perspective however by assuming a case where the plant would operate at 80 % load and cycle from there. A 50 % load point is also included. Figure 7 is based on those assumptions assuming that the SCGT and NGCC use 6 $/ MM Btu natural gas and the IGCC-CSS uses 2 $/MM Btu coal.

Process Power Plants

PROCESS → CU
OXY ↔ COMBINED CYCLE

Part Load Heat Rate Penalty

SCGT

80% Load - 9000 Btu/KWhr x 15% x 565MW x 5000 hrs/yr x 6$/MMBtu = 22.9MM $/yr

50% Load - 9000 Btu/KWhr x 34% x 565MW x 5000 hrs/yr x 6$/MMBtu = 51.9MM $/yr

Note – a GT can run at full speed no load but it needs 1/3 of the full load fuel

NGCC

80% Load -7000 Btu/KWhr x 2% x 565 MW x 5000 hrs/yr x 6$/MMBtu = 2.4MM $/yr

50% Load - 7000 Btu/KWhr x 22% x 565MW x 5000 hrs/yr x 6$/MMBtu = 26 MM $/yr

IGCC w CCS

80% Load - 11000 Btu/KWhr x 3% x 565MW x 5000 hrs/yr x 2$/MMBtu = 1.9 MM $/yr

50% Load - 11000 Btu/KWhr x 27% x 565MW x 5000 hrs/yr x 2$/MMBtu = 17 MM $/yr

Significant Penalty to operate at Part Load
- Additional Fuel Rate
- Additional CO_2 Rate in lbs/MWhr

Figure 7 - Part Load Heat Rate Penalties

Using the above curve and round numbers for full load heat rates (HHV) we can see the variation in extra yearly cost for a 565 MW size plant to be operated for 5000 hours/year at part loads for a SCGT, NGCC and IGCC. The IGCC is lower due to fuel costs. The 5000 hours was chosen simply as a discussion point and could probably be lower in the early years with low penetration rates. It is the lower fuel cost that gives IGCC its smaller penalty.

One example of a NGCC that has provided load following capability for many years is Tepco's first CC located at Futtsu, Japan shown in Figure 8.

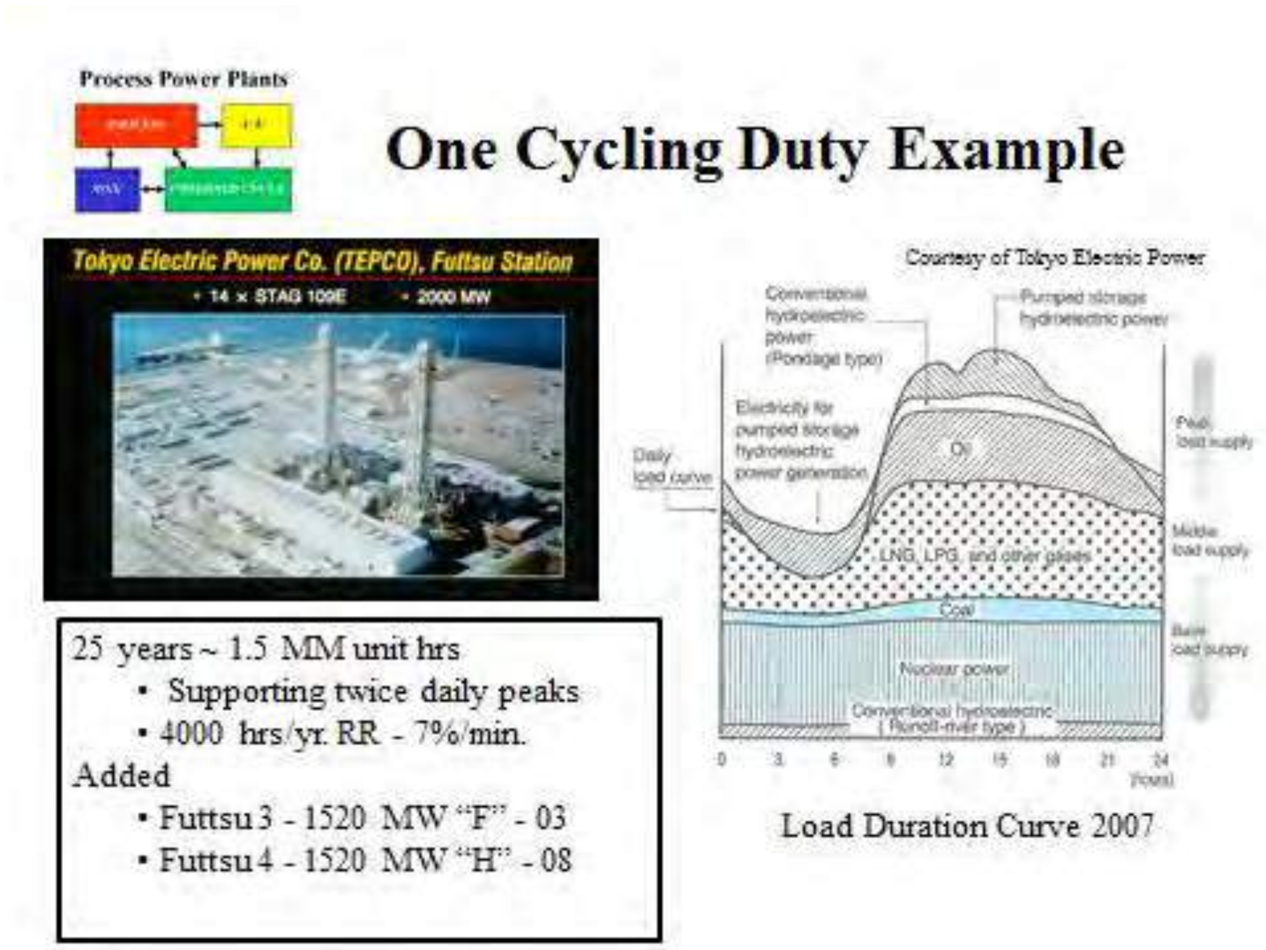

Figure 8 – TEPCO Futtsu 1 & 2 - 2000 MW NGCC

The original Futtsu plant of 14 units started in December 1985 and was required to follow the daily double peak load demand of Tokyo. At that time there was a significant peak in the morning and another later in the day. By 2007 the peaks had been trimmed to a less severe situation but you can still see the double peak by following the daily load curve in figure 8. The NGCC performance on that duty was good enough for TEPCO to add a more modern 4 unit 1500 MW plant in 2003 and an even more modern 3 unit 1500 MW in 2008. Lately (before the Tsunami), the original plant was running about 4000 hours/year. That means many starts and stops as well as ramping hours. Assuming that lower level of operation for 25 years provides about 1.5 million unit hours of experience. I have been told recently that the ramp rates for the plant are about 7%/ minute.

Looking at this load duration curve for NG plants, we need to speculate about how a cycling NGCC can also be used as backup without dedicated units.

That 7% ramp rate is reasonable however we should assume the cycling duty may have some extra maintenance costs. That is discussed on Figure 9.

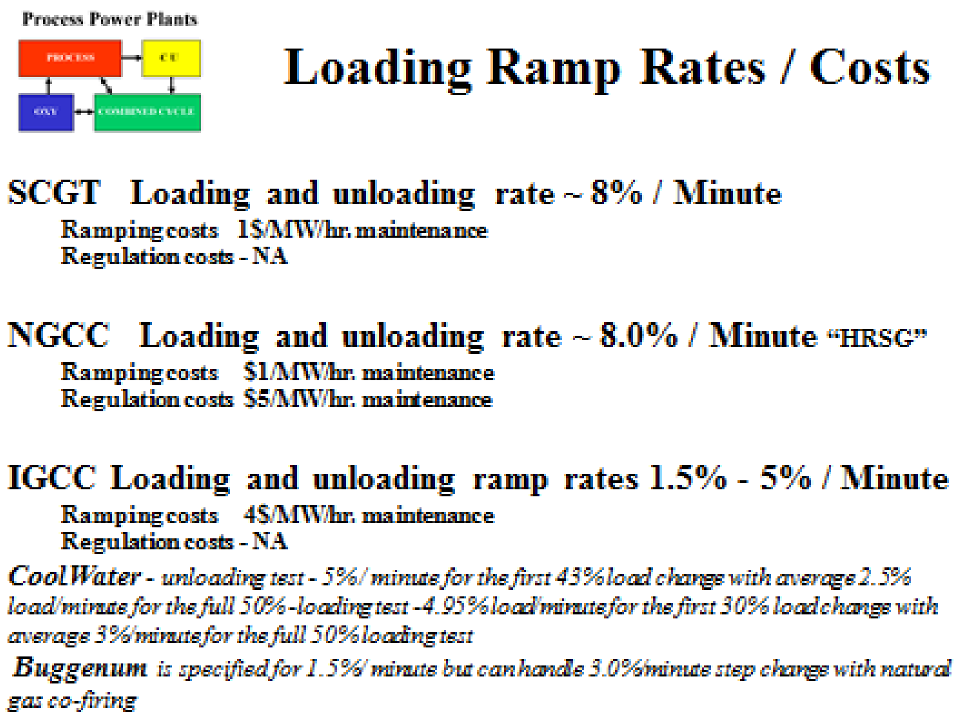

Figure 9 - GT Plant Loading Ramp Rates and Costs

Loading ramp rates are set from stress and strain calculations to maintain a planned maintenance cost. Gas Turbine ramp rates have improved over the years from 4 % of full load MW/minute to 8 % and there are special cases up to 22.5 %. Combined cycles have improved from 2.5 % to 8 % / minute providing the HRSG is designed for higher stress levels. IGCCs have ranged between 1.5% and 5% / minute. The wide variation in IGCC ramp rates is probably because not much thought has yet been given to ramping an IGCC which would normally be dispatched a full load.

We have also included some generalized, indicative costs used in some system stability studies for Regulation (instantaneous load change) and Ramping. System dispatch studies are covered later in the paper.

There is one unique example of a base load plant now in operation accommodating intermittent solar systems that is worth discussing. Florida Power and Light announced on March 5, 2011 start-up of a 75 MW Hybrid Solar plant at their Martin Station completely integrated with a 1150 MW NGCC (figure 10).

Figure 10 - FP&L Hybrid Solar/NGCC – Martin Station

The FP&L Martin Station is a unique and very interesting solution for accommodating intermittent solar. It includes several combined cycles and a 75 MW Hybrid Solar system. On the left of the photo are the older NGCC Units 3 & 4 totaling 1000 MWs and on the right front is Unit 8 with a 4+1, 1150 MW NGCC. Unit 8 has supplementary fired HRSGs and a single 470 MW Steam Turbine. The Hybrid Solar plant has mirrors that focus on tubes heating a fluid which is sent to steam generators in the Unit 8 steam cycle. The steam fluctuation from intermittency can be accommodated by varying the HRSG natural gas supplementary firing thereby eliminating ramping of the gas turbines. This unique feature with only one generator involved is a very good solution for both grid stability and distribution system issues. It is however only available for steam making renewables. Also it requires at least some part of the combined cycle to be operating during all daylight hours.

At some future point of continued penetration of intermittent renewables it will be necessary to shut down either the renewable or some other operating plants. Gas Turbine plants are particularly applicable to start and stop service. Each type has different start times and costs (figure 11).

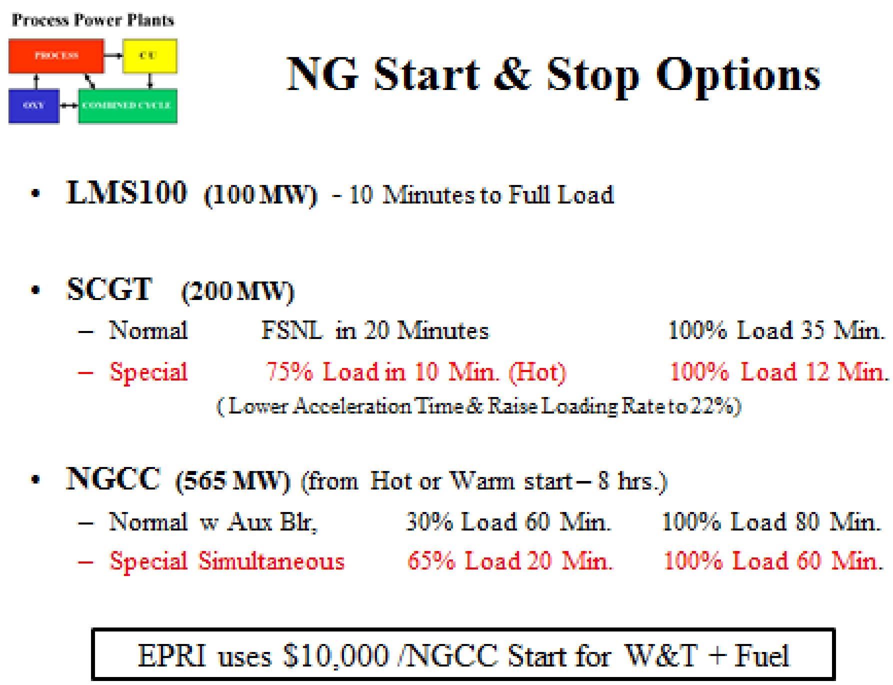

Figure 11- GT Plant Start and Stop Options

Aircraft derivative gas turbines such as the LMS100 are especially suitable for fast start and that specific machine can reach full load of 100 MWs in 10 minutes after the start button is pushed. For the heavy duty, larger size turbines normally used by utilities two kinds of starts (Normal and Special) are shown. OEMs have their own names for so-called Fast Starts or “Special” as listed here.

A turbine starts by using a motor or it’s generator to raise the speed followed by ignition which then provides the power to accelerate the unit to Full Speed No Load (FSNL). At that point the turbine is using approximately one third of its full load fuel. That is a lot of fuel with no output so spinning reserve for a gas turbine is costly as you can see from the previous part load heat rate curves. Starting times are limited by stress and strain calculations and depend on the length of time the unit has been shut down. Hot starts are generally thought of as occurring after a shutdown of no more than 8 hours. For the heavy duty units the Special Starts would require a hot start to maintain reasonable maintenance costs. Warm starts are maybe over a weekend.

NGCC starts usually require some steam to be available from an auxiliary boiler. Also the NGCC Special Starts would require:

- Two gas turbines to start simultaneously meaning each would have its own starting device
- An HRSG designed for higher stress levels
- A hot start

The special starts are being developed to accommodate renewable intermittency issues and appear to be quite a good step forward.

System planners use different formulas for start-up costs and we have simply shown the figures normally used in system studies by EPRI for wear and tear (W&T) plus fuel for an NGCC.

IGCC start-up times and costs are somewhat different due to the Gasification System and Air Separation Unit. Figure 12 is based on data from the postponed Tampa Electric Polk 6 IGCC Permit application with normal starts. We can consider it as good data since it was based on 12 years of operating experience with the Polk 1 IGCC.

Process Power Plants

IGCC Start & Stop Options

Polk 6 Plan	Controlled Starts Cold	Controlled Starts Hot	Controlled Shutdowns
Year 1	21	5	21
Year 4+	8	8	8
Train 1	18 hrs.	2 hrs.	2.5 hrs.
Train 2	2 hrs.	2 hrs.	2.5 hrs.

We could apply Special Start Option to IGCC (as it starts on NG)

EPRI Uses $15,000 / IGCC Start for W&T + Fuel

Figure 12 – Tampa Electric Polk 6 IGCC Start-up Plan

This plan, from the permit application is based on normal starts with no consideration for accommodating intermittent renewables. You can see the extra starts needed in the early years and that Train 1 is providing the capability for Train 2 to start in 2 hours. It is a relatively conservative plan as needed to make sure the permit does not conflict with potential early operating difficulties of a first of a kind plant. Since an IGCC starts up on natural gas fuel for safety reasons, it would be possible to build in some of the Special Start capabilities developed for NGCC.

Again we have shown nominal figures for starting costs for O&M plus fuel.

The fourth subject to be discussed concerning accommodating intermittency is added O&M costs. Like additional fuel costs for the back-up plants, these need to be planned and possibly assigned to the renewable technology. The industry sometimes uses OEM Long Term Maintenance Contracts that build in guarantees based on specific operational plans. OEM's are able to predict the added O&M costs for cycling duty well due to their large fleet experience. Figure 13 covers some of the philosophy and costs based on normal starts.

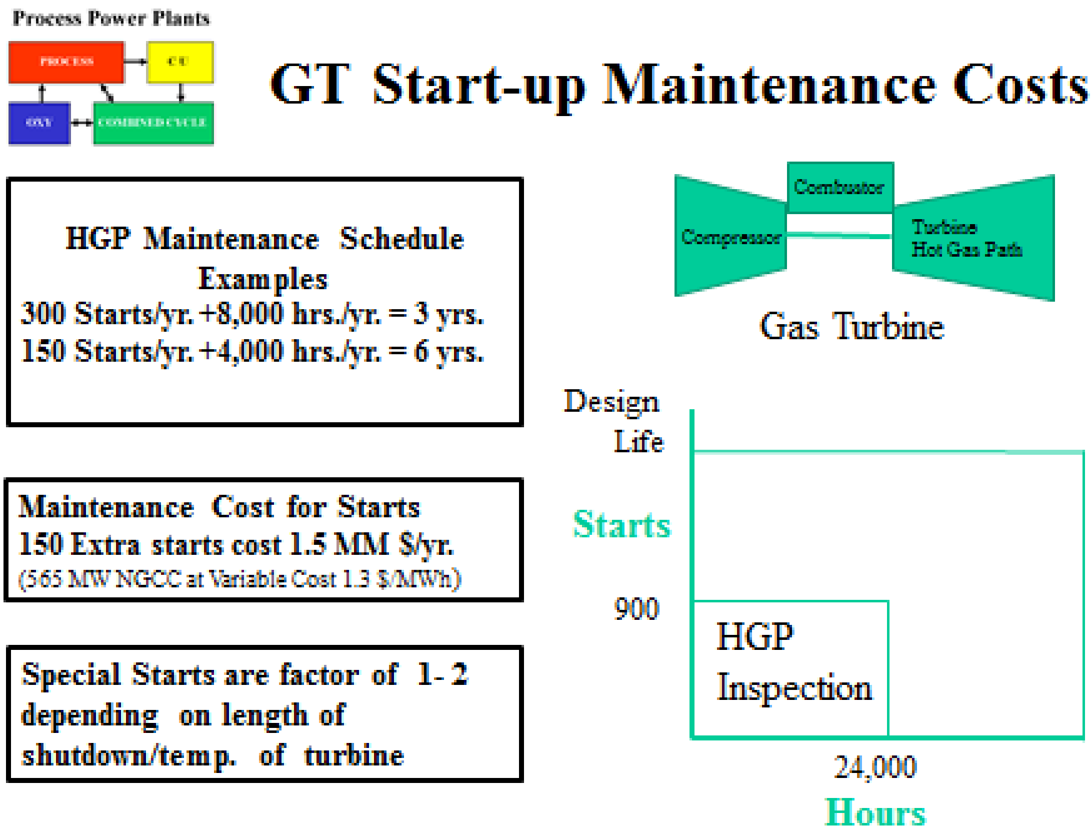

Figure 13 - GT Cycling Duty Maintenance Costs

Extra Start-ups and hours of operation have a maintenance cost that can be estimated from historical data. The Industry philosophy differs but in general, maintenance plans use independent counts of hours and/or starts to define the time when major maintenance procedures should take place. Starts criteria has dropped from 1200 to 900 but hours criteria have stayed at 24,000 hours, even as firing temperatures have increased to obtain better output and efficiency. Example 1 is based on 300 starts / year while example 2 is based on 150 starts / year. Both cases meet the maximum requirements for a Hot Gas Path inspection based on current starts limitations for modern machines of 900 starts. For our example 565 MW plant using typical variable costs for NGCC plants we have 8.8 MM $ differential in the 6 years or 1.5 MM $/ yr. for normal starts. The Special Starts factor can be <1 for hot starts or up to 2 for longer than 4-8 hours shutdown.

The next subject concerning cycling duty that needs discussion is the effect on emissions from the back-up power plants (figure 14).

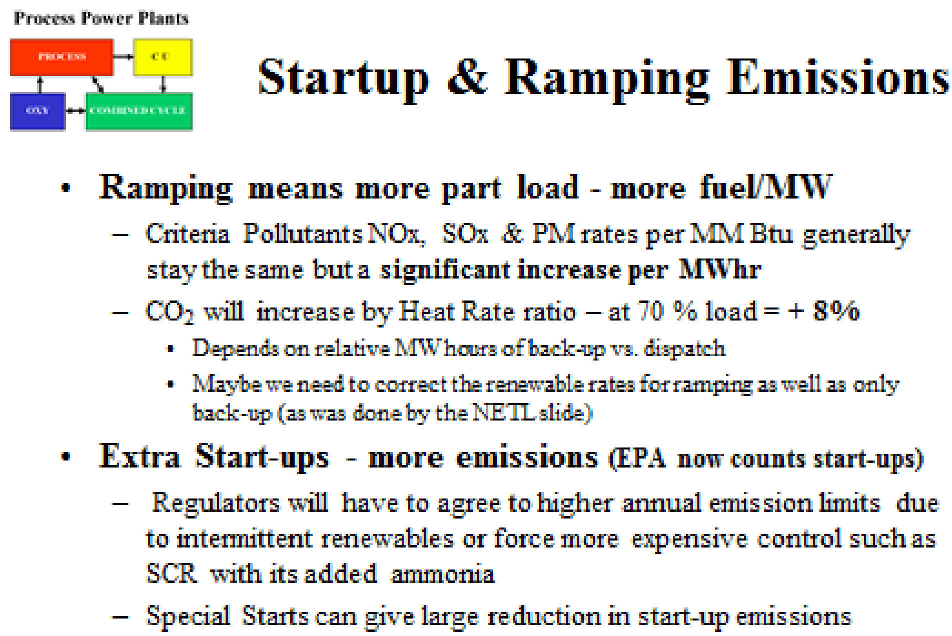

Figure 14 – Start-up and Ramping Emissions

Overall emissions levels from the system will change due to balance of positive effects from the non-emitting renewables and the negative effects of accommodating intermittency with GT plants. That balance depends totally on the MWhrs of backup service as compared with a normally dispatched plant.

For ramping service in general the emissions of criteria pollutants will stay the same on a per MM Btu basis but with a significant increase on a per MW hr. basis due to the poorer part load heat rates. If an NGCC plant was operated at 70 % load the effect would be ~ 8% more CO_2 / MW hr.

For start and stop service there could be more emissions on an annual basis causing potential extra costs to meet annual limits.

One interesting point is that if Special Starts are needed they are fast enough to more than compensate for normal start up emissions but of course that depends on the relative duties.

System Stability Modeling

To put the subject of Managing Large Scale Penetrations of Intermittent Renewables into perspective with regard to the balance of positive and negative effects we need detailed studies from System Stability Models. The studies must compare the complete system with and without the intermittent renewables covering all the economic factors including fuel, O&M and emissions (figure 15).

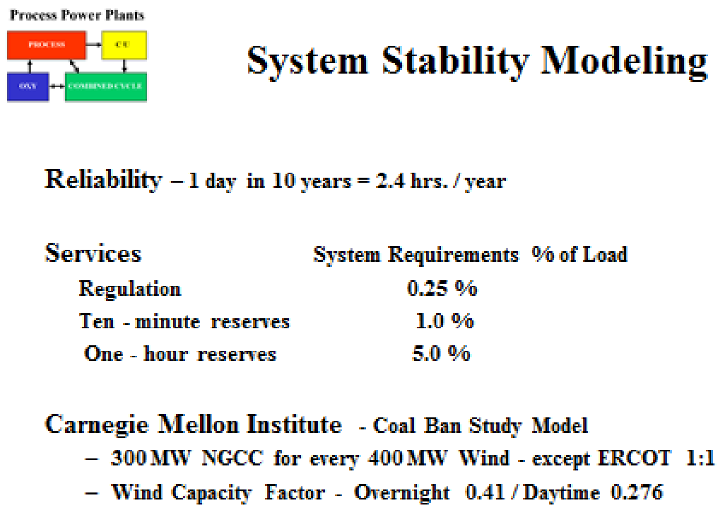

Figure 15 – System Stability Modeling

In the USA we use reliability criteria of 1 day in 10 years which equates to 2.4 hours per year of allowed outage. That drives the various pools to have 0.25 % of total system capacity available for regulation (instantaneous MWs) and about 1 % available for 10 minute reserves along with 5% available for 1 hour reserves. With higher penetrations of intermittent sources these figures may need to be increased.

One study by Carnegie Mellon University[5] uses an economic dispatch model to simulate load growth, resource planning, and economic dispatch of the Midwest Independent Transmission System Operator, Electric Reliability Council of Texas (ERCOT) and PJM under a ban on new coal generation. It uses the economic dispatch model to calculate the resulting changes in dispatch order, CO_2 emissions, and fuel use until 2030. The wind scenario reflects a future where there is a large push toward renewables and wind turbines. Because of the output power variability and low capacity factors (25-45%) of wind, the wind scenario pairs wind with NGCC to create firm power. The model installs 300MW of NGCC for every 400 MW of wind, even though lulls in the wind in regions such as ERCOT may require 1:1. The model dispatches wind resources with an overnight capacity factor of 0.41 and a daytime (4am-4 pm) capacity factor of 0.276, reflecting actual generation; gas is dispatched appropriately to maintain firm power. The model allows up to 20% wind penetration, but that maximum is not reached by 2030 because it is not required by demand growth in the three regions.

In addition to systems studies, there are other pieces of the puzzle that will need discussion. GE is proposing that a smart grid demo in Hawaii will free up the grid to theoretically receive additional renewable energy from wind turbines and solar. Siemens expects the current worldwide 4% penetration to rise to 13-17 % by 2030 and that one half of the growth will come from wind power and one third from solar. For NGCC, this kind of growth will also raise a question of whether USA gas pipelines can handle the intermittency.

[5] Near-Term Implications of a Ban on New Coal-Fired Power Plants in the United States, Adam Newcomer, Jay Apt, *Environ. Sci. Technol.*, Article ASAP • DOI: 10.1021/es801729r • Publication Date (Web): 27 April 2009, http://pubs.acs.org

Nuclear Power and Large-Scale Renewables in Liberalized Power Markets

A British and European Perspective

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White Paper prepared for Managing Large-Scale Penetration of Intermittent Renewables
MIT, Cambridge Mass. USA April 2011

In this paper I do not attempt to provide a review of the academic literature linking nuclear energy with the growth of large-scale intermittent renewables in liberalized European power markets. Rather, I simply seek to refer to work relating to such matters in which I have participated personally as a result of various collaborations with Cambridge University students and colleagues. However before I report on our various results, I should like briefly to describe some of the relevant contextual policy issues.

1.0 The European Union Policy Context

At the heart of current European energy policy lies a set of policy targets launched in early 2007 during the rotating German Presidency of the Council of the EU. These targets establish goals for energy sector greenhouse gas emissions reductions, the contribution of renewable sources of energy and for improvements in energy efficiency. These targets are known as the EU 20:20:20 by 2020 targets.

1.1 EU 20:20:20 by 2020

There are three combined targets for the EU and they are all having profound impacts for the European electricity sector. The targets may be summarized (Europa):

- 20% of <u>total energy</u> consumed to be supplied from renewables by 2020
- 20% reduction in greenhouse gas emissions by 2020
- 20% reduction in primary use of energy – i.e. efficiency improvement

These emissions target is defined against a 1990 baseline and the efficiency target is defined with respect to business as usual growth. The first two targets are nominally binding. In the

Cambridge University Electricity Policy Research Group there has been much discussion of '*how binding is binding?'* The answer appears to be *'not very and certainly not quickly'* (and for this perspective I am grateful to Angus Johnston, now based at University College, Oxford). Despite the nominally binding nature of the first two targets, it seems increasingly probable that the renewable target will not be met by several key countries. The non-binding efficiency target will be especially difficult to achieve. Despite such difficulties the successful attainment of the targets, remains axiomatic within official EU energy policy circles and it is very difficult to plan for arguably more probable realities. These constraints of axiomatic optimism are causing difficulties for sensible policy making and for nuclear energy planning in particular.

Clearly civil nuclear power has much to contribute to greenhouse gas emissions reductions, but of the three EU 20:20:20 by 2020 targets, it is the renewables target that seems likely to be having the greatest impacts on nuclear energy policy in the 27 EU member states.

The renewables target matters most because it is a policy target to be achieved at any cost. As such, it does not sit well alongside the GHG emissions reductions target; the policy measures for which are primarily economics-based. For instance, the EU Emissions Trading Scheme (EU-ETS) is market-based. The resulting dissonance between the two binding EU 20:20:20 targets has technology and policy consequences.

1.2 EU 20:20:20 Policy Consequences

The EU-ETS policy is a quantity-based cap and trade system. That is, an emissions quantity is set by policy and a price emerges in the EU carbon market. Meanwhile the policy pressure to deploy renewables is entirely unabated by changes to that price. Furthermore the renewable target is set sufficiently high that it bites even harder than the GHG target within the electricity sector. Importantly the renewable target is set for total energy and not just for electricity. Given that the deployment of renewables in electricity is more cost-efficient than in transport, and to a lesser extent heating, the consequence of a total energy renewable target is a yet higher goal for renewable in the electricity sector. For instance, for the United Kingdom the renewables target emerging from the EU 'burden sharing' was for 15% of total energy to be supplied from renewables by 2020, up from roughly 3% today. Realistically this implies an electricity sector at more than 30% renewables by the same date (up from approximately 6% today). For the UK short-term large scale renewables mean wind energy, and given UK planning processes and poor public acceptance of onshore wind power projects, this increasingly means offshore wind power. As mentioned earlier this pressure is completely independent of the EU-ETS price and GHG policy. The consequence of such a situation across Europe is to depress the EU-ETS price which might otherwise have been expected to be a rational economic tool for efficient decarbonisation. My EPRG colleague Michael Pollitt points out that, in the short term at least, the consequence is that every wind turbine erected in Britain does nothing to reduce Greenhouse Gas Emissions, as that is fixed by the separate GHG cap. That cap, 16% for the UK, is a fixed number unchanged by the level of wind energy deployments. Pollitt further posits that a political problem looms in

Europe, as the public have been led to believe that the renewables policy adds to GHG reduction rather than sitting within what will be done anyway.

1.3 EU 20:20:20 Technology Consequences

Many of the technology problems are also being felt even before the 2020 target date. As mentioned earlier, the success of these two separate policies is regarded as axiomatic by EU officials and many member state governments. As such it is not easy to advance technology options based on assumptions of arguably more probable futures.

Let us briefly imagine a Europe in 2020 with 20% of total energy from renewables and close to 30% of electricity generated from renewables. In northern Europe we would have a large-scale deployment of offshore wind power connected to the land via a super-grid able to trade power surpluses and reduce the impacts of intermittency in generation. In southern Europe there would be a widespread adoption of solar power including power imports from North Africa (although in EU policy terms such dedicated power imports would be regarded as 'European'); again super-grids will be important. Across Europe there will have been a major push for smart metering and for the slightly less well understood notion of 'smart grids'; all this done largely independent of costs and economic efficiency. Much of the costs would (in order not to wreck liberalized energy markets) be placed upon the natural monopoly aspects of transmission.

These changes to electricity infrastructures will be profound, arguably eliminating the role of baseload power. Furthermore they will very expensive. Such efforts risk crowding out other investments, risk exhausting political capital and risk dominating engineering capacity deployment.

Even before the thinking of a major push to a new electricity infrastructure, the costs and effort required to update and replace aging existing infrastructures in electricity generation, transmission and distribution were daunting enough. As a large centralized source of baseload electricity nuclear power is well suited to the existing structure of the electricity industry.

1.4 EU Energy Policy is not 'European'

It is important to point out that despite the fact that energy security is dominated by considerations outside Europe and that climate change is a global threat, energy technology policy in Europe remains a matter for the member states. The electricity generation mix remains a sovereign matter for each member state and the differences are clearest in connection with nuclear energy. Some European countries are strong supporters of nuclear power (e.g. France) while others (e.g. Austria) remain staunchly opposed. Many aspects of nuclear energy policy in Europe continue to be shaped by a separate and special treaty dating from the earliest days of the European project, the Euratom Treaty (Nuttall, 2009 and 2010).

1.5 EU Emissions Trading System

For more than six years key components of the EU energy sector have faced a price for carbon via the EU-ETS trading system. This market is illustrated in figure 1. While it might be said that it is impressive that the EU-ETS market exists at all, it must be pointed out that the market has been characterized by high levels of volatility, lower than expected price levels and even price collapses. Many lessons relating to market design and, in particular, permit allocation have been learned. Despite the problems arising from the EU 20:20:20 targets and the resulting downward pressure on EU-ETS prices, the carbon market still represents an important cornerstone of EU policy relating to electricity policy. It is the key EU-wide instrument favoring new nuclear build. Generally in much of European energy policy measures are restricted for the assistance of renewables, hence excluding nuclear power. Recently, however, the UK has started to make a move to more technology neutral approaches in the Electricity Market Reform proposals. Notwithstanding the continuing power of EU 2020 renewables target, the new UK ideas would shift from a 'renewables' support agenda towards the domain of 'low carbon' policies.

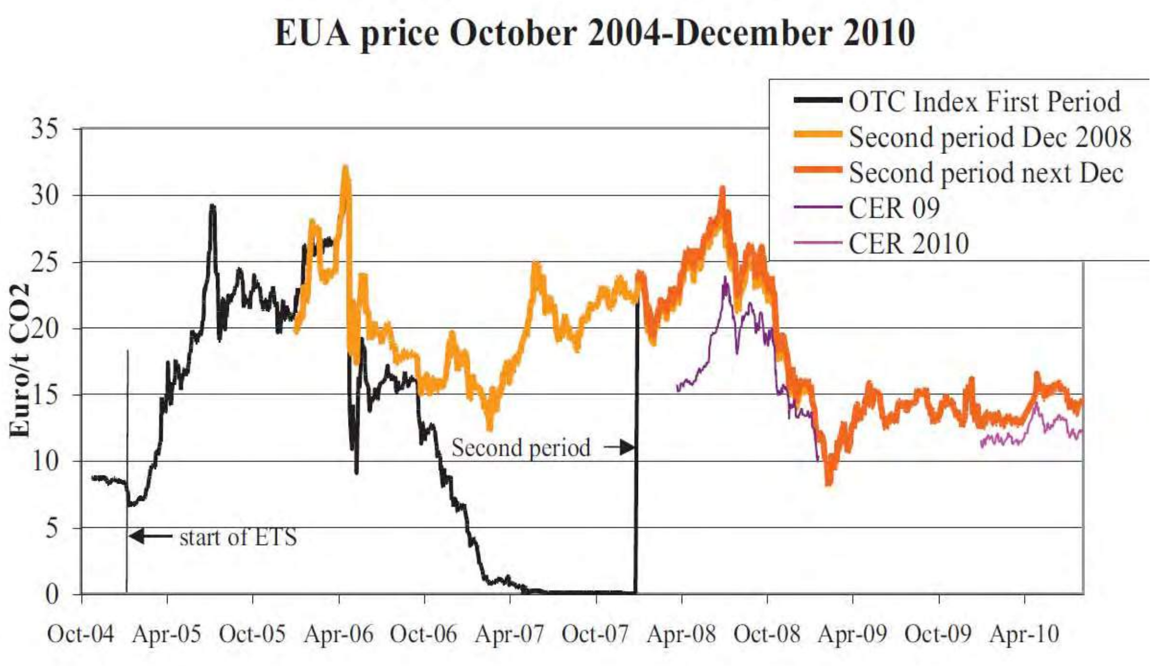

Figure 1. EU Carbon Price History, Source: David Newbery, Evidence to House of Commons Energy and Climate Change Select Committee, 12 January 2011.

2.0 UK Climate Policy

2.1 The Climate Change Act 2008

UK Climate Policy is further reinforced by a statutory framework shaping progress towards a low carbon society. Despite the reality that according to the British Constitution ‘Parliament is sovereign’, implying that no Parliament can constrain the powers of a future parliament, the statutory framework, the Climate Change Act, would be politically very embarrassing for any future Parliament to repeal. The Climate Change Act requires an annual government carbon budget and formal reporting of progress towards future targets.

My EPRG colleague Michael Pollitt has summarised the components of the Climate Change Act:

- 80% GHG emissions reduction by 2050 (-34% by 2020)
- Creation of a high-level ‘Climate Change Committee’
- Five Year Carbon budgeting
- The Climate Change Committee’s first report recommended the complete decarbonisation of electricity by 2030

2.2 Electricity Market Reform 2011

During 2010 it became increasingly clear that in the liberalized electricity market of the United Kingdom the risks and costs of new nuclear build were simply too high for new nuclear power investments to be an attractive proposition for even the most diversified and largest European energy companies. In December 2010 the UK Government issued a consultation paper proposing four important market changes, one objective of which appears to have been to make new nuclear build possible. The measures proposed are:

1. Establish a stable and significant floor to the carbon price
2. New ‘Contract for Difference’ Feed in Tariffs for low carbon electricity generation investments. Note the technology neutrality of this measure. It is a low carbon policy, not a renewables policy.
3. Establish ‘Capacity Payments’ moving the UK market away from an energy-only market
4. Introduce an ‘Emissions Performance Standard’ which would block new unabated coal generators

These are arguably the most radical proposals in UK energy policy for more than 20 years. The Emissions Performance Standard is perhaps the most interesting measure, as in a market with a low-carbon feed in tariff and a rising and substantial carbon price presumably no investor would want to invest in a new unabated coal-fired power plant. Hence there would appear to be no reason for the Emissions Performance Standard. Perhaps, however, the Emissions Performance Standard is a form of 'Trojan Horse', which in later years could be used to render other fossil-fuel-based generation projects illegal. This may be a route to later block on new natural gas combustion for power, without generating the major negative consequences for domestic heating (where much UK natural gas is used) that might arise from solely price-based measures.

3.0 Nuclear Energy in the UK

The United Kingdom was one of the first countries involved in civil nuclear energy. In 1956 the UK commissioned the world's first commercial-scale grid-connected power station at Calder Hall in the Northwest of England. Britain's first two generations of nuclear power plants were carbon dioxide gas-cooled and graphite-moderated. The first generation of stations was known as the 'Magnox' plants and the second generation is known as the 'Advanced Gas-Cooled Reactors' (AGR). All these power plants were twin units with two reactors per station. In the 1990s the UK commissioned it first light water reactor (LWR) a modified Westinghouse SNUPPS (Standardized Nuclear Unit Power Plant System) pressurized water reactor (PWR). In recent years several Magnox plants have closed and only Oldbury and Wylfa remain operational.

Reactors	Type	Net capacity	First power	Expected shutdown
Oldbury 1 & 2	Magnox	2 x 217 MWe	1967-1968	Mid 2011
Wylfa 1 & 2	Magnox	2 x 490 MWe	1971	End 2012
Dungeness B 1 & 2	AGR	2 x 545 MWe	1983 and 1985	2018
Hartlepool 1 & 2	AGR	2 x 595 MWe	1983 and 1984	2014 possibly 2019
Heysham I 1 & 2	AGR	2 x 580 MWe	1983 and 1984	2014 possibly 2019
Heysham II 1 & 2	AGR	2 x 615 MWe	1988	2023
Hinkley Point B 1 & 2	AGR	2 x 610 MWe*	1976	2016
Hunterston B 1 & 2	AGR	2 x 610 MWe*	1976 and 1977	2016
Torness 1 & 2	AGR	2 x 625 MWe	1988 and 1989	2023
Sizewell B	PWR	1188 MWe	1995	2035
Total (19)		10,962 MWe		

Table 1: Nuclear power Plants operating in the UK. [* Operating at 70% power (420 – 430MWe)] Source: WNA Country Report UK October 2010

The previous British Labour Government and the Coalition Government elected in 2010 have both advocated the construction of a fleet of new nuclear power plants. Two designs, the Westinghouse AP1000 and the Areva EPR, are currently going through safety and environmental design approval.

The UK has led the liberalization of electricity markets in Europe and it is an axiom of UK energy policy that the government does not build power stations. The initiative for new nuclear build must therefore come from the private sector and current plans are summarized in Table 2.

Proponent	Site	Type	MWe	Start up
EdF	Hinkley Point, Somerset	EPR x 2	3340	End 2017 and mid 2019
EdF	Sizewell, Suffolk	EPR x 2	3340	2020 and 2022
Horizon	Oldbury Gloucestershire	EPR x 2 or AP1000 x 3	3340-3750	2022
Horizon	Wylfa, Wales	EPR x 3 or AP1000 x 4	Approx 5000	2020
Nugeneration Ltd	Sellafield, Cumbria	Not known	3600 max	2023

Table 2, New build nuclear power plans for the UK. Possible new build total: up to 19,000 MWe. Sources: WNA Country Report UK December 2010 and NuGeneration Ltd announcement 29 November 2010

Despite the declared interest of several companies and consortia, the economic basis for nuclear new build has been on a knife-edge for some time, hence the proposed Electricity Market Reform (EMR) discussed earlier. There are two separate, but related, economic issues: project cost and project risk. As concerns project cost: for many years it has been an axiom of UK energy policy that there should be *'no subsidy for nuclear power'*, although in the autumn of 2010 the Secretary of State for Energy and Climate Change Chris Huhne MP clarified the policy by explaining that in essence it really meant no special subsidy for nuclear power. I.e. nuclear power would be eligible for subsidies and support available to other energy technologies, measures later visible in the EMR proposals. In a future where higher carbon prices are likely to reduce the cost competitiveness of fossil-fuel based power plants it is the issue of economic risk that becomes pivotal for the success of a nuclear renaissance.

Historically the UK liberalized electricity market has suited investors interested in investing in low-risk natural-gas fuelled combined cycle gas turbines (CCGT). This is because such plants are relatively quickly permitted and constructed and the principal economic risk relates to fuel price volatility. Investors can take substantial comfort from the UK's relatively stable 'spark spread' and know that in a natural gas supply crisis any risks could readily be passed through to electricity consumers. In essence, when natural gas prices rise UK electricity prices rise almost in lock-step. The economic risks of a nuclear power project are very different. In the case of the natural gas-fuelled CCGT roughly 70% of the lifetime levelized costs relate to fuel, but for a nuclear power plant (as shown in figure 2) 2/3rds of total lifetime levelized costs relate to the construction of the plant itself. Investors are unable to pass such risk onto end user consumers, or perhaps even any other third parties. All potential investors know full well that a 95% complete nuclear power plant is not yet an asset. In the event that the nuclear project encounters difficulty there is no-one who will protect the interests of the investors and hence it is not surprising that many potential investors are deterred from new nuclear power projects. Nuclear New Build in the UK is being led by large multinational energy companies with diversified portfolios of assets and interests. Even they have been finding the risks daunting.

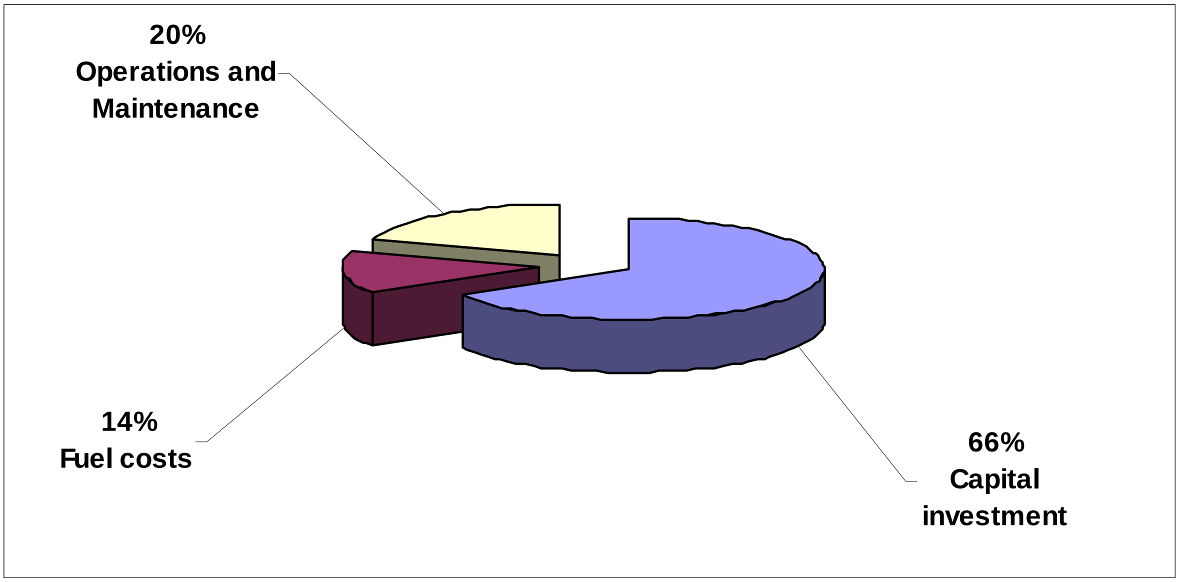

Figure 2, Breakdown of lifetime costs of a nuclear power plant. **Capital investment is the most significant factor in the economics of nuclear power**. Source: DTI *Energy Review – A Report,* chart A1, page 175, cm6887, (July 2006). Available at: http://www.berr.gov.uk/files/file39525.pdf Discount Rate assumption 10% real post tax

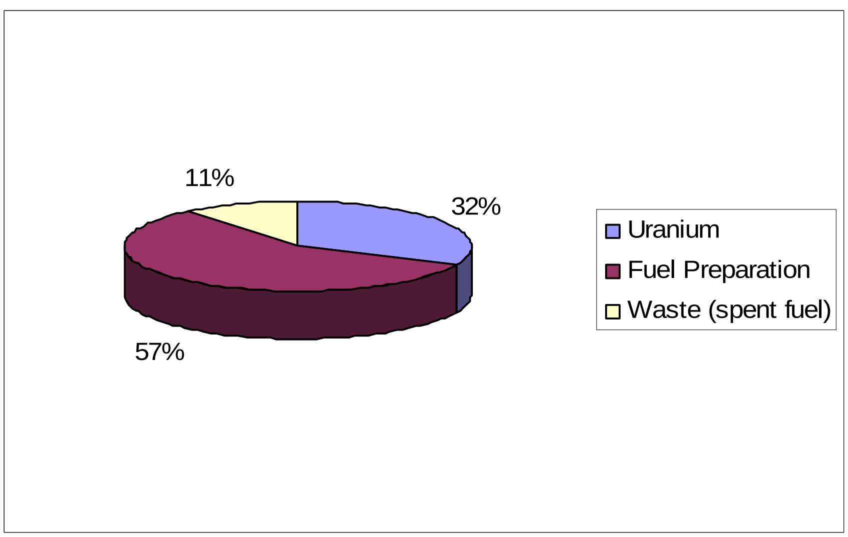

Figure 3, Nuclear fuel costs (relating to previous figure) Typically decommissioning costs are less than 1% of ongoing operating costs (10% discount rate assumed). Ref: *Nuclear Power in the OECD*, IEA (2001) Raw uranium costs are only a minor part (about 5%) of the total costs this is in contrast to fossil fuel power generation where equivalent fuel costs are approximately 70%.

The fundamental economic risks of a new nuclear power project are:

- High costs of capital (high discount rates and rates of return)*
- Overrun of construction phase (lost time is lost money)*
- Future electricity prices (as for any power technology)
- Changes of safety or environmental regulation during planning and construction*
- Political risk and public acceptance problems*
- Risk of a low carbon price
- Poor plant reliability in operational phase (low load factor)

* The risks marked with an asterisk occur before a single unit of electricity has been sold. This aspect amplifies the importance of the risk for potential investors, conscious that until a nuclear power plant is commissioned and operational it is not any easy item to sell.

For nuclear power the following factors are, however, relatively minor:

- Decommissioning costs (40-60 years in the future and hence much attenuated by discounting)
- Fuel costs (raw U_30_8 is only a few % of total costs)
- Geopolitical risks (fuel is easily stored and is typically regarded as “domestic” for energy security)

4.0 Baseload Power

4.1 Future for Baseload?

As discussed earlier in section 1.3 the EU binding commitment to achieve 20% of total energy from renewables by 2020, while perhaps unlikely to be achieved, can have the effect of forcing developments which are sub-optimal in terms of the twin goals of cost minimization and GHG emissions reduction. In-extremis super and smart grid measures introduced to smooth the intermittency of large-scale renewables (wind and solar) and to link to despatchable renewables such as large scale hydroelectricity raise the prospect that the twentieth century concept of busload power might become an anachronism. Nuclear energy has historically been the most baseload of baseload options.

4.2 Why is Nuclear power Baseload?

This question was tackled by my former student Laurent Pouret in collaboration with Nigel Buttery of EDF Energy (Pouret, 2009). The main message of our paper is that modern nuclear power plants, such as the Sizewell B PWR in the UK, are capable of output power adjustments, as shown in figure 4.

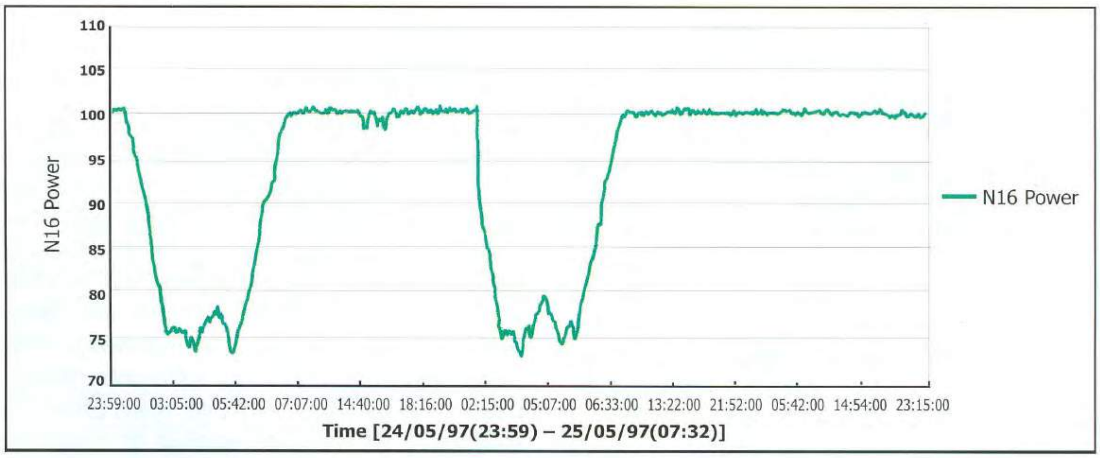

Figure 4 Power variations during two periods of Automatic Frequency Responsive Operation at Sizewell B Nuclear Power Plant in England in 1997. Power Variations of up to 30MW were achieved. Source: (Pouret et al., 2009)

Indeed as shown in figure 5 German nuclear power plants have adjusted their output in order to facilitate the grid acceptance of intermittent wind energy.

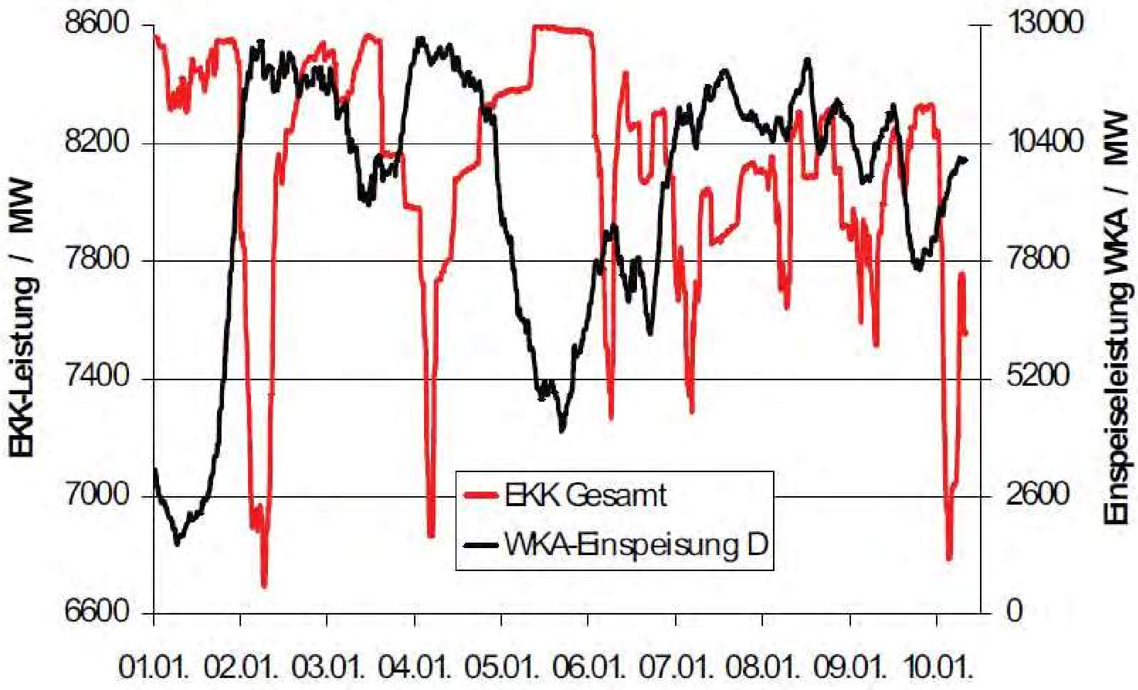

Figure 5, E.On operational experience in Germany with the integration of stochastic wind power feed-in. The red line labeled 'EKK' represents E.ON nuclear power output the black line labeled 'WKA' illustrates wind energy output. Source: M. Micklinghoff and as published (Pouret, 2009)

Given that nuclear energy is technically capable of output power variation, the reason for its baseload status must lie elsewhere. The source of the baseload nature of nuclear power, for modern plants at least, lies in the economics of nuclear power generation. The costs structure of nuclear power, described earlier in section 3, is such that the marginal cost of generation is very small. In essence it costs as much to run a station in low power mode than in high power mode. Given the nature of actual planned LWR nuclear power plant shutdowns (typically for refueling over a few weeks every 18 months alternating between spring and autumn) costs for a shutdown nuclear power plant can be higher than for an operating plant, albeit for somewhat special reasons.

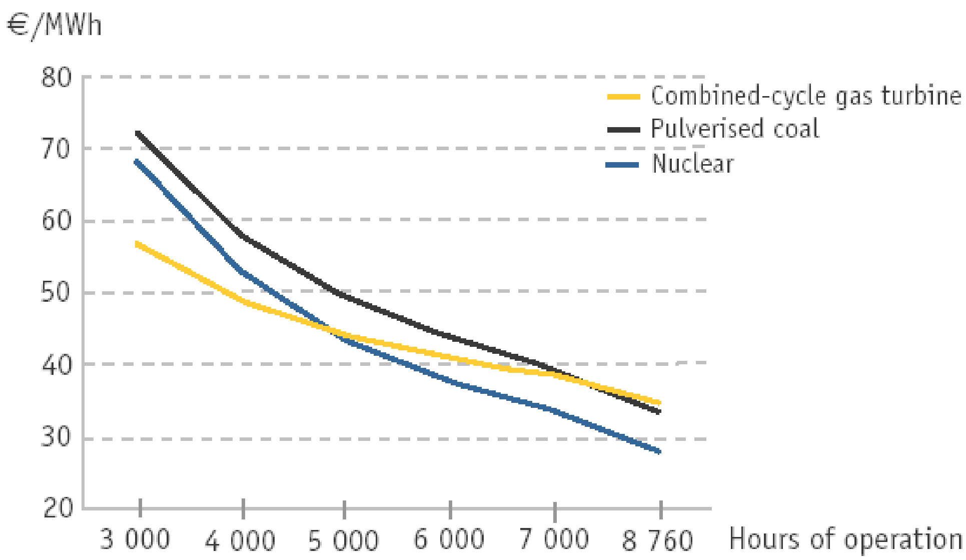

Figure 6, Competitiveness of centralised power production plants in 2015 including tax, but excluding externalities. Source: (DGEMP, 2004) and as reproduced (Pouret, 2009)

Figure 6 illustrates how the relative economic competitiveness of coal, natural gas and nuclear based electricity evolve with rising hours of operation per year. The nuclear option only becomes attractive at high levels of power output, i.e. for baseload operation.

5.0 Nuclear Power and Business Risk

In section 4.2 we considered the availability of nuclear power and its importance for the economic viability of the technology. In that section our attention focused on planned operations, but of course nuclear power suffers economically if reliability is poor and there are a large number of unplanned outages. Some British AGR reactors (e.g. Dungeness B) have suffered in such terms. While modern LWRs tend to be highly reliable, future innovative nuclear power systems might, initially at least, suffer from poor reliability performance. This is widely perceived to be a particular risk for one advanced nuclear energy concept the Accelerator-Driven Subcritical Reactor (ADSR). A former post-doctoral research colleague Steven Steer led our work on such matters. While the insights were developed with the ADSR concept in mind, the results are almost entirely generalizable to any 600MWe power station with reliability problems.

5.1 Reliability

In their paper of 2009 Steer et al consider the failure of a generator to supply contracted power in the UK liberalized electricity market. In such a situation the generator is said to be short and in the very short term at least will need to cover their contract to sell by purchasing electricity at the system buy price (SBP). Steer et al report:

> **"***The UK National Grid balancing service is provided by ELEXON. Publicly available records are kept for three prices relevant to the cost of electricity supply imbalances. There are the Market Index Price (MIP), which is the wholesale price of electricity; the System Buy Price (SBP); and the System Sell Price (SSP). Regardless of whether the system is long or short, the SBP is the price paid by an operator for the contracted electricity sales that it is short of and the SSP is the price paid to an operator for their contracted sales in excess of their contracts (i.e. for being long). The SBP and SSP are non-negotiable prices: they are formulaically fixed by the current state of the market. The electricity supplier agrees liability to pay the SBP and to be paid the SSP when entering into the British Electricity Trading and Transmission Agreements (BETTA). The formulas that dictate the SBP and SSP give rise to one of the four scenarios described in [Table 3]. The actual values of the SBP and SSP at any point in time are predominantly determined by the magnitude of imbalance and the MIP.***"** (Steer, 2011)

	System is Long	**System is Short**
Operator is Long	The operator is paid the SSP for the excess electricity it has generated. The SSP is low as the electricity is not needed.	The operator is paid the SSP for the excess electricity generated. The SSP is high as the excess electricity has helped bring the system back into balance.
Operator is Short	The operator has to pay the SBP for not generating as much electricity as contracted to. The SBP is low as the shortfall has helped bring the system back into balance.	The operator has to pay the SBP for not generating as much electricity as contracted to. The SBP is high as the grid operator has to use its ancillary services to balance the grid.

Table 3, Electricity grid and operator imbalance scenarios. An instantaneous unplanned shutdown of a generator will make an operator short, (Source Steer et al 2009)

Generally in considering the operation of a poor reliability nuclear power plant the issues are more likely to relate to the operator being short than being long. As such the System Buy Price would be of key concern. Figure 7 shows the high level of volatility in the System Buy Price in the real UK electricity market.

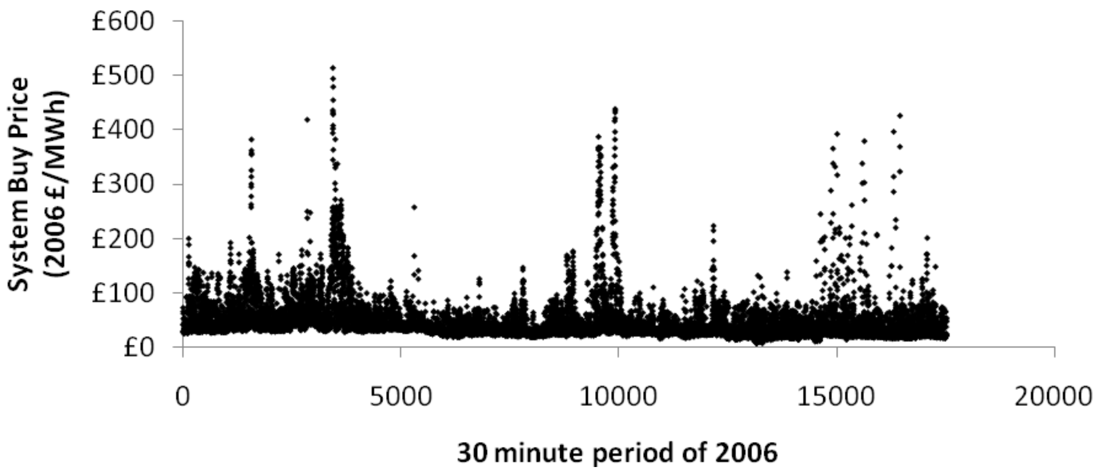

Figure 7, The historical SBP in the UK electricity market (1st March 2005 to 28th February 2006, inclusive) in 2009 money (Source: Steer, 2011)

One issue given significant attention by Steer and coworkers is whether the loss of a nuclear power station might actually drive up the System Buy Price. That is the operator must buy power from the system, but has itself forced up the price it must pay because of the power shortage it has introduced into the system. For a 600MW plant at least that concern turns out to be minor as illustrated in Figure 8.

Steer et al observe (2009):

> *"[Figure 8] shows the SBP (in nominal money) for 48 periods following the commencement of a failure averaged over all of the unplanned shutdowns. Also shown for each of the 48 periods is the average SBP for the corresponding period of the day, each day, for ±2 weeks averaged over all of the shutdowns. The data show that the change in the SBP due to a sudden loss of 600MWe from the grid supply is small compared to the absolute SBP. It is concluded that any correlation between unplanned shutdowns and the SBP is not significant."*

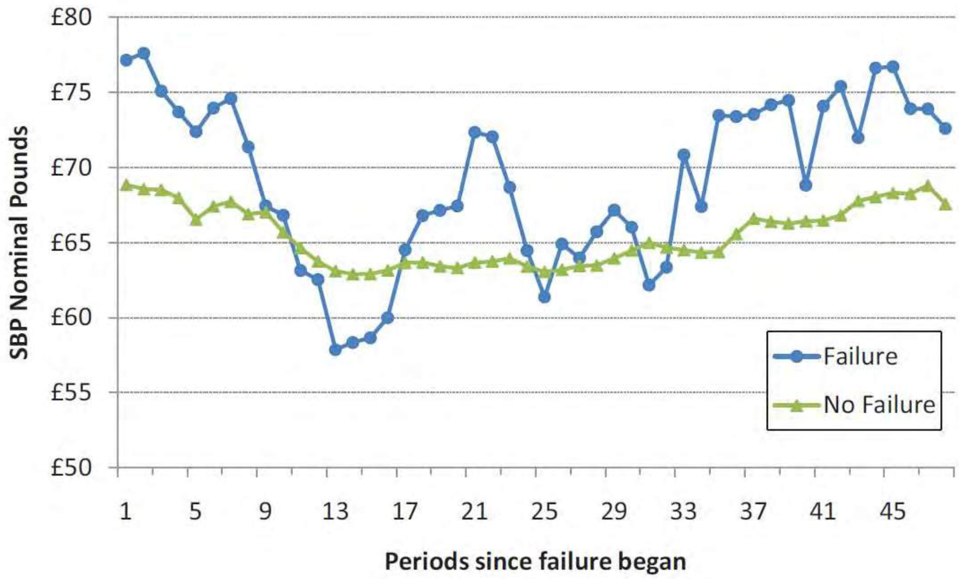

Figure 8, The average SBP following the commencement of unplanned shutdowns of 400 – 800 MWe power generators (blue circles) and the average SBP for the same unit of the day for ± 2 weeks before/after the shutdowns (green triangles). Source (Steer, 2011)

In the event of an extended unplanned outage the operator's electricity traders will have a busy time. Initially and automatically power will be purchased at the SBP, but looking ahead the traders will increasingly be able to buy power at typically lower prices from the commercial market at the Market Index Price (MIP). Over the duration of an unplanned shutdown the power purchases needed to cover pre-existing contracts will shift from being dominated by the SBP to being dominated by the MIP. These issues are summarized in Figure 9.

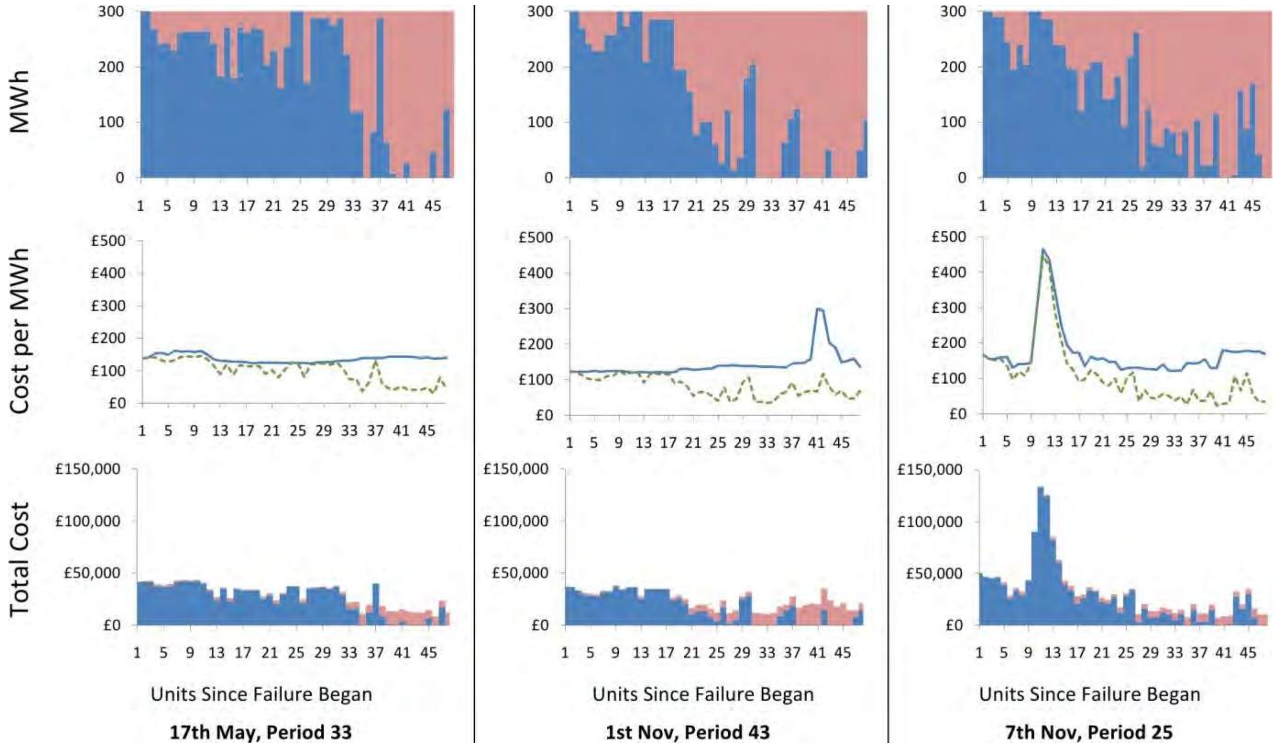

Figure 9, Three iterations from simulating the cost of a 24 hour failure to generate 600MWe. The quoted dates and periods refer to the sampled historical 2006 data for the SBP and MIP. Each iteration has three vertically aligned spectra associated with it. Top: is the distribution of private contracts (light red) and electricity purchased from the system (dark blue). Middle: is the modified SBP (solid blue) and the average price paid per MWh of electricity (dashed green). Bottom: is the total cost buying electricity for each period, the cost of system and privately purchased electricity are shown in dark blue and light red, respectively. All x-axes are in 30 minute periods following failure. Money is quoted in 2006 pounds. Source: (Steer, 2009)

5.2 Hedging and Portfolios

My former doctoral student Fabien Roques led work considering the role that nuclear power might play for a power generating company as part of its business risk management strategy. First he considered the relative merits of an investment in a new combined cycle gas turbine (CCGT) or a nuclear power plant, noting the differing cost structures of the two propositions (as discussed earlier in this paper) and the volatile nature of real UK electricity prices, fuel prices (gas) and carbon dioxide emissions in the early part of the last decade. Performing a Monte-Carlo simulation over these assumed to be independent variables it was possible to calculate discounted (10%) net present values for a single merchant project of one power plant and for a small utility already owning gas-fired assets. As shown in figure 10 in both cases the distributions of net present value (NPV) are such that a nuclear power investment appears to be the best option.

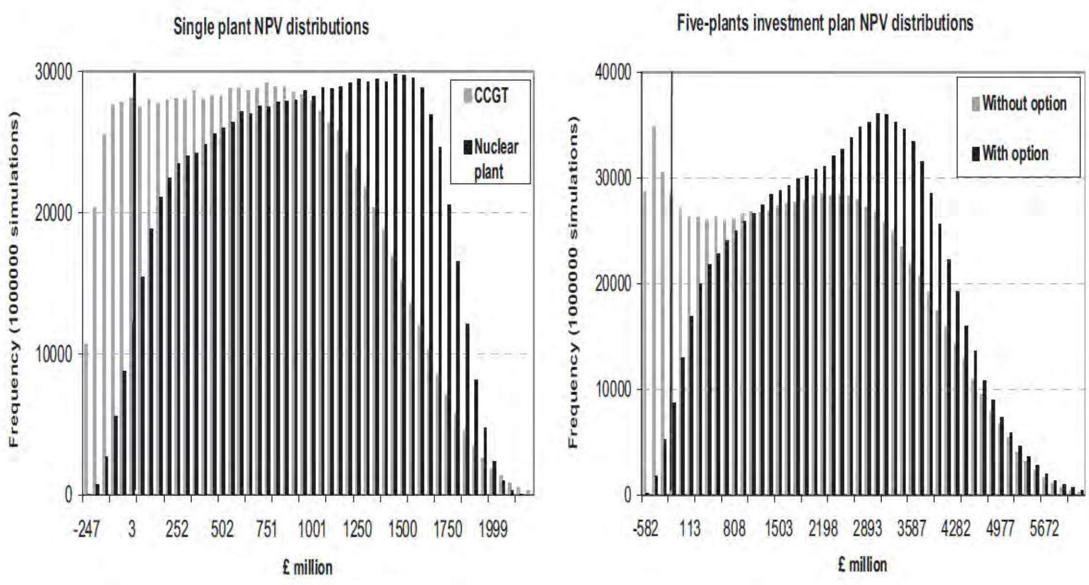

Figure 10, NPV distributions for single CCGT and Nuclear plants and for the 5-plant investment plan with and without the optional addition of a nuclear power plant (10% discount rate), zero correlation between electricity, gas, and carbon prices (£million), Source: (Roques, 2006)

Roques then extended his analysis to include realistic correlations between natural gas, carbon dioxide emission permit and electricity prices. As discussed earlier, the UK electricity market has a relatively high correlation between natural gas and electricity prices. Incorporating such correlations into the analysis dramatically increased the attractiveness of the natural gas proposition for the investors. Any relative advantage of a nuclear power investment was effectively lost. The only remaining difference between the CCGT and nuclear options was that in the single plant case the CCGT option had a tighter distribution of possible outcomes, as shown in Figure 11. Figure 11 also shows that in the case of the five-plant utility even that small remaining difference is largely lost.

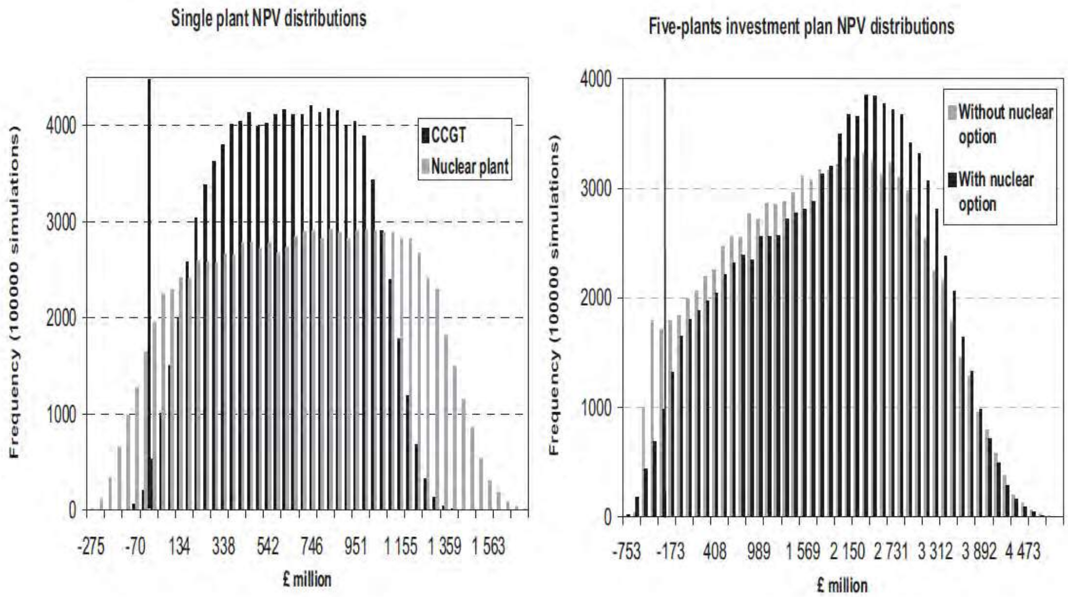

Figure 11, NPV distributions of single CCGT and Nuclear plants and for the 5-plant investment plan with and w/o nuclear option (10% discount rate), 70% correlation between electricity, gas, and carbon prices (£million) – c.f. previous figure Source: (Roques, 2006)

In their paper Roques et al. (2006) remark:

> *"The correlation between the main cost (gas and carbon prices) and revenue (electricity price) drivers of the CCGT investment reduces its intrinsic riskiness to a lower level than a nuclear plant, which is only subject to revenue (electricity price) risk. The more correlated the costs and revenues of the CCGT plant, the narrower is its NPV distribution, while the NPV distribution of the nuclear plant remains unchanged. This implies that a greater degree of correlation between electricity, gas and carbon prices reduces the potential intrinsic risk reduction value for the company, and thereby significantly reduces the nuclear option value."*

Roques et al. (2006) conclude their paper with the observation:

> *"These results imply that there is little private value to merchant generating companies in retaining the nuclear option in risky European electricity markets with the consequent high discount rates, given the strong correlations between electricity, gas and carbon prices. Our modelling does not conclude that fuel diversity from nuclear power is of no value in liberalized markets. We simply conclude that there is little or no value for merchant generators in preserving such an option. The U.K. government clearly accepts that there is a social or consumer value in 'keeping the nuclear option open' as this has formed a part of U.K. government policy since the Energy White Paper of 2003."*

The work by Roques and coworkers revealed a possible policy problem for the UK. In such a liberalized market, where the power to initiate a project rests with private investors and where the government does not build power stations, investors will make choices to maximize their private interests and these choices may not represent the wider societal interest. This is because investors have an incentive to make investment choices which pass risks through to final end-user consumers. For the investor it is better to build a CCGT where it is clear that because of price correlations the fuel price risk can be passed through; rather than to build a nuclear power plant where a greater proportion of project risks rest with the project developers. This point has been considered earlier in this paper.

I would add that it is my anecdotal sense that the British public when considering their attitude to nuclear energy tends to consider themselves as the potential victims of a nuclear accident or incident. Far more rarely do they consider their relationship to nuclear energy as being an issue of their electricity bills. Some might have the, arguably valid, sense that nuclear power can be expensive, but I venture that, in the early part of the century almost no consumers considered the possibility that nuclear energy expansion might represent a hedge against the greater economic risks of a gas supply crisis. If consumers had no awareness that nuclear energy expansion might protect them from economic risk they are not in a position to pressure their electricity suppliers to make choices to protect consumers against such risks. Noting that UK electricity suppliers are essentially the same community as the generators, there is little consumer pressure on the generators to stop the generators making choices that pass key economic risks to consumers. Government has increasingly understood these realities over the last ten years and has increasingly acted to incentivize private sector generation investments that protect societal interests. The recent Electricity Market Reform proposals are a key step in that process.

Fabien Roques followed the work reported above with a three-technology portfolio analysis considering technology mixes for private generators. His work yielded expected net present values (ENPV) for technology portfolios in various market circumstances. The resulting diagrams (Figures 12 and 13) represent with distorted triangles the perimeters of three-technology portfolios. The three vertices represent portfolios comprising only one technology. The lines represent regions with only two technologies and inside the triangles three technologies occur in varying proportions. The X-axis denotes the width of the probability distribution of expected net present values (ENPV) while the Y-axis is scaled in ENPV and shows the most profitable (as probabilistically estimated) portfolio as highest up the chart. At a 10% discount rate entirely CCGT-based portfolios are preferred (Figure 12) whereas at a 5% discount rate wholly nuclear portfolios perform best. The grey/black lines show the situation with fixed electricity tariffs and the colored lines denote the situation with variable market prices (and with correlations as discussed earlier).

The pricing structure greatly affects the range of ENPV outcomes, but does not alter the conclusion that low discount rates favor nuclear dominated portfolios and high discount rates favor gas dominated portfolios. In the UK there are many reasons that through the transition twenty years ago from a state owned monopoly electricity company (the Central Electricity Generating Board) to a liberalized market there was a strategic move away from nuclear power and towards a 'dash for gas.' The CEGB was able to raise capital at low rates close to sovereign guarantee rates, whereas private players in a liberalized market must raise capital at commercial rates. Such realities, and Fabien Roques' analysis, indicate that such changes in costs of capital are consistent with the portfolio changes that occurred.

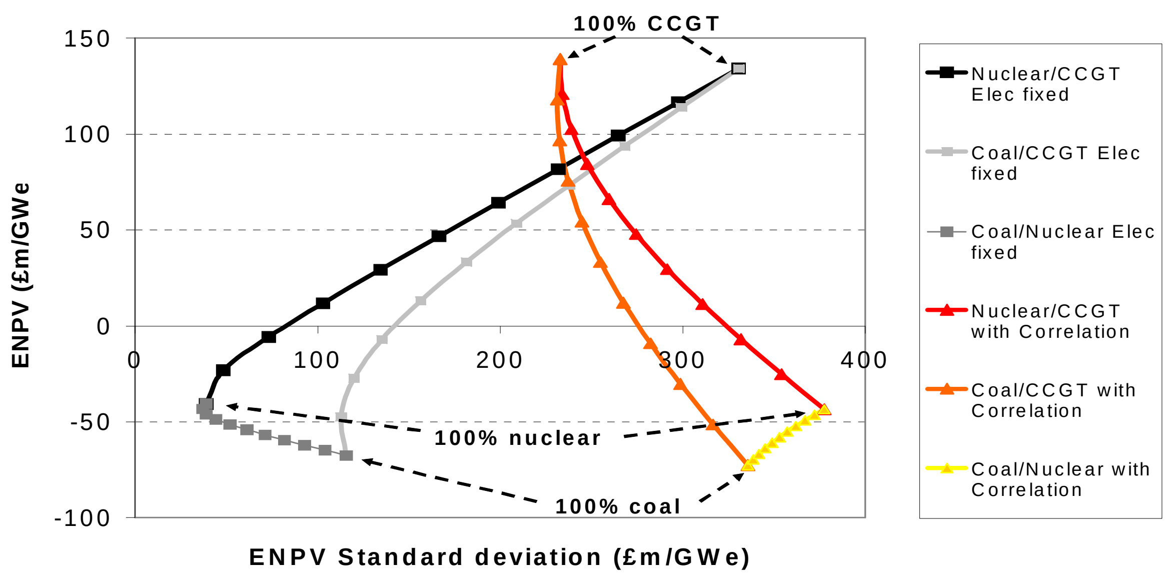

Figure 12, Portfolios of Nuclear, Coal and CCGT plants with fixed and uncertain electricity prices 10% discount rate, Source F. Roques (private communication), but see (Roques, 2008) for related analysis

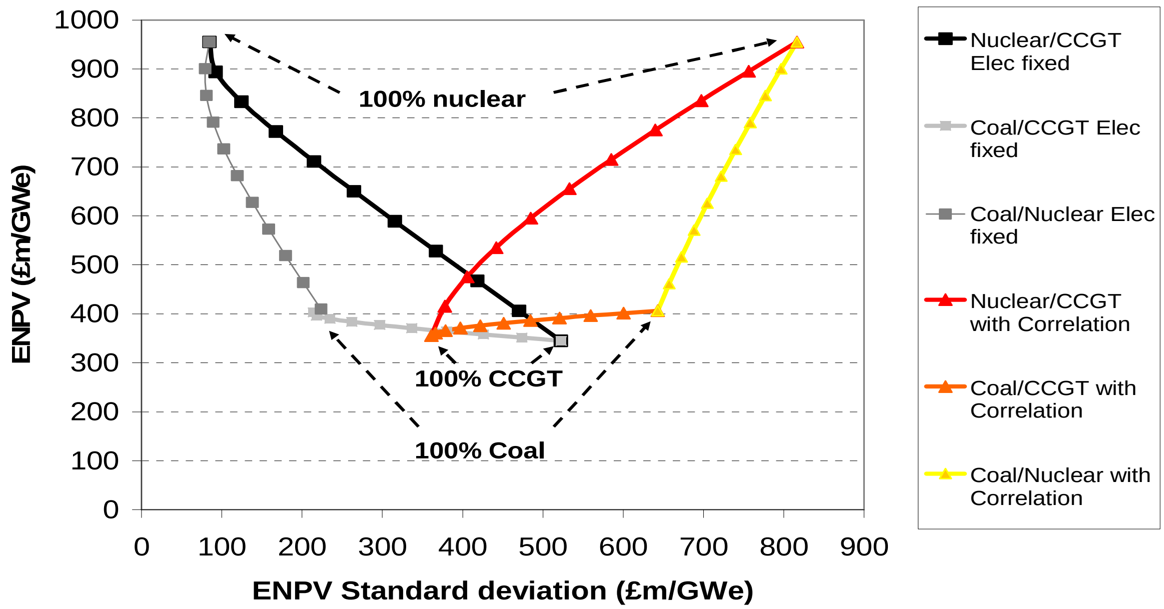

Figure 13, Portfolios of Nuclear, Coal and CCGT plants with fixed and uncertain electricity prices 5% discount rate, Source F. Roques (private communication), but see (Roques, 2008) for related analysis

It is my impression that the strongest drivers for what gets built in the UK electricity system are economic. Public acceptance, politics and technological hubris matter somewhat, but far less than in other European countries. Government can shape the market to promote its perception of the public interest, but key decision making rests with private investors. For twenty years those investors have faced an evolving four way choice between coal, gas, nuclear and renewables. While renewables have grown significantly, and policy says they must grow even more significantly, it is my impression that in the UK the greatest choice has long been between CCGT gas-fired power and new nuclear build. This is a choice between a moderately low emission technology (CCGT) and a very low emission technology (nuclear power). My sense is that fundamental gas-nuclear choice remains.

6.0 Conclusions

As discussed earlier while nuclear power is technically a variable source of electricity that is not an economically sensible path. CCGT power, on the other hand, is much better suited to variable output and hence is better suited to sitting alongside large-scale intermittent renewables.

I note the shale gas innovations and the greatly improved UK and European gas security arising from the growth of liquefied natural gas (LNG) supply. I note the UK EMR, if adopted, would incentivize the building of new nuclear power plants, but it will also hold open the prospect of building new CCGT plants. I expect the next 20 years to be characterized by the deployment at scale of renewables, CCGT (in a second dash for gas) and some new nuclear build. In the years approaching 2030 we shall be able to see the carbon intensity of the UK electricity system and of the UK energy system as a whole. At that point we may need to tighten the Emissions Performance Standard and push for deeper decarbonisation. As such, while I expect the nuclear option to remain open for decades to come, I suspect that the CCGT option might be somewhat time-limited. Hence I would not be surprised if the coming years are remembered more for a second wave of expansion in gas fired-generation than they will be remembered for an expansion in nuclear energy and renewables. The current nuclear renaissance in the UK will be a substantial undertaking, but I do not expect it to be much more than '*replace nuclear with nuclear'*. My sense is that we must now prepare the ground for what could be much more dramatic shifts in the national power portfolio in the years after 2030, as I suspect that by then moderate improvements in GHG emissions reduction will no longer have been regarded as sufficient. These issues were considered in a paper I co-authored with Robin Grimes in the summer of 2010 (Grimes, 2010).

6.1 Consequences of Fukushima Accidents

Many countries around the world, including the UK, have initiated safety reviews of existing nuclear power plants and future plans. In many cases this is likely to lead to a delay in nuclear new build. Already it has been announced that the UK Generic Design Assessments for new build are delayed by some months. Across Europe the impacts of Fukushima have been felt. Perhaps not unsurprisingly the greatest political impacts have been seen in Germany with a big electoral boost to the anti-nuclear Green Party in provincial elections.

In the UK my sense is that the independent safety reviews will indeed be truly independent and will be insulated from political or economic constraints. Accident design basis threats will be reassessed as will possibilities for common-mode failure. There is a risk that expert assessment will reveal that current plans are not 'safe enough' and this may prompt requirements for redesign. Some such changes could increase project capital costs and cause delay. Given that the economics of nuclear new build was already on a knife-edge in Britain, and given a relatively urgent need for new generation capacity such factors could derail the nuclear renaissance in favor of a stronger second dash for gas. The drivers of such effects in the UK would be economic and largely independent of political and public acceptance factors.

However, for those countries that hold their nerve and which maintain pre-existing plans and timelines there may be advantages. If the safety reviews conclude that the new build designs are indeed already safe enough, then the UK might find itself in this situation. Some component prices may fall as other countries turn away from nuclear energy. Supply chains might become less congested and vendors and project developers could become more engaged and enthusiastic for the continuing projects. In the longer term one might even expect that pressure on uranium supply may be eased by a more widespread turning away from nuclear power. This can be expected to delay uranium fuel price rises and concomitantly reduce the need for nuclear fuel reprocessing or advanced nuclear power plant concepts. Such speculation is however premature. At the time of writing the Fukushima-Daichi incident cannot be said to be over. It will take many months before proper reflection will be possible.

Acknowledgements

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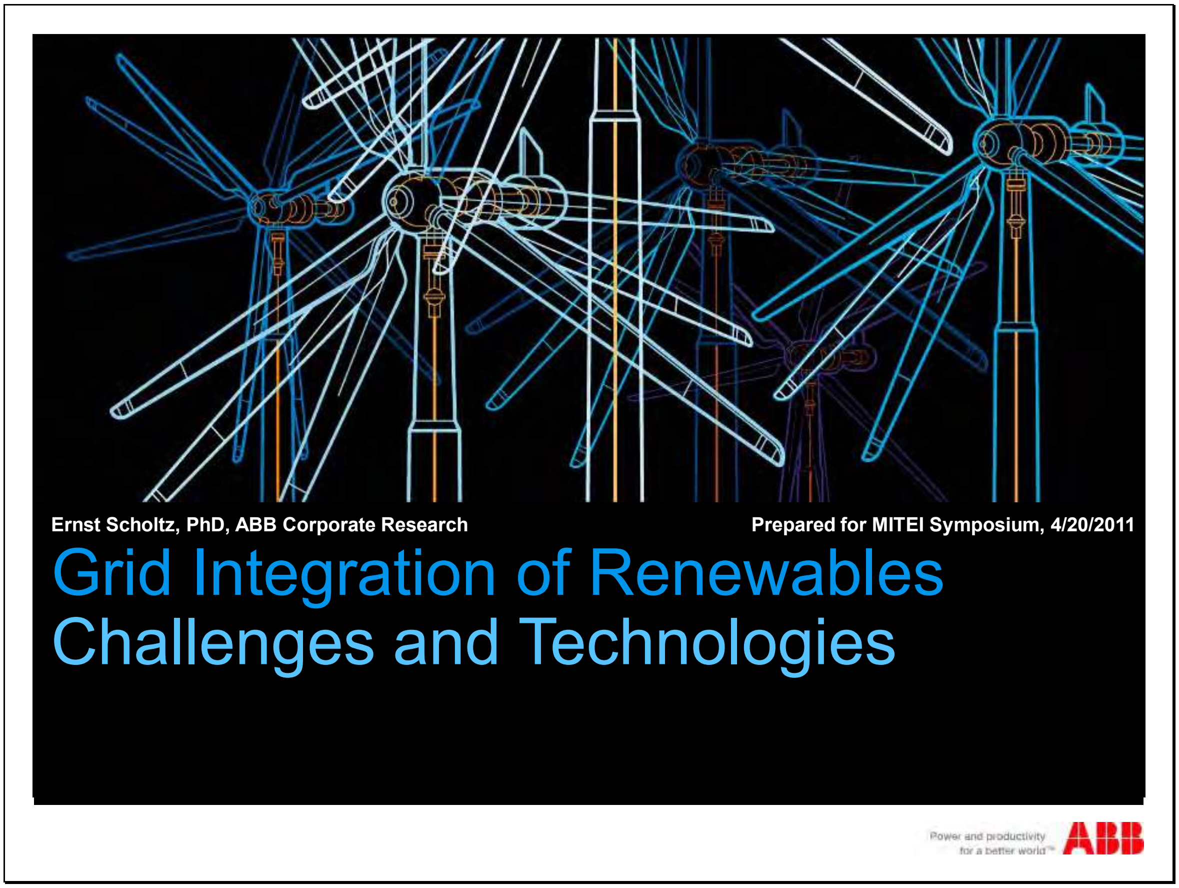

This document consists of a set of slides with notes inserted to aid the reader with processing of information conveyed in the slides. References are listed on each slide where appropriate.

Document was prepared as input to the MITEI Symposium on “Managing Large Scale Penetration of Intermittent Renewables” held 4/20/2011 in Cambridge, MA, and updated afterwards.

Grid Integration of Renewables
Outline

- Why Renewables?
- Types of Renewables and Regional Differences
- Challenges of Renewables
- Technologies for Grid Integration of Renewables
  - Transmission Systems
  - Distribution Systems
  - Energy Storage
- Conclusions and Open Challenges

Grid Integration of Renewables
Nomenclature

BANANA	Build Absolutely Nothing Anywhere Near Anyone (or) Anything
BESS	Battery Energy Storage System
CAES	Compressed Air Energy Storage
CAGR	Compound Annual Growth Rate
CCGT	Combined Cycle Gas Turbine
CIGRE	International Council on Large Electric Systems
CSC	Current Source Converter
CSP	Concentrating Solar Power
DER	Distribution Energy Resources
DMS	Distribution Management System
DR	Demand Response
EMS	Energy Management System
ENBW	Energie Baden-Württemberg
EPIA	European Photovoltaic Industry Association
ERC	Energy Research Center
ESS	Energy Storage System
EWEA	European Wind Energy Association
FACTS	Flexible AC Transmission Systems
GHG	Green House Gas
GIS	Gas Insulated Switchgear
GW	Giga Watt
HV	High Voltage
IEA	International Energy Agency
ISO	Independent System Operator
kV	Kilo Volt
MEF	Major Economics Forum
MV	Medium Voltage
MW	Mega Watt
NG	National Grid
NIMBY	Not in my backyard
OECD	Organisation for Economic Co-operation and Development
OLTC	On-line Tap Changing
PMU	Phasor Measurement Units
RPS	Renewable Portfolio Standard
SCADA	Supervisory Control and Data Acquisition
SGCC	State Grid Corporation China
T&D	Transmission and Distribution Power Systems
UCD	University College Dublin
UCTE	Union for the Co-ordination of Electricity Transmission
UHVAC	Ultra High Voltage AC
VAR	Voltage Ampere Reactive
VSC	Voltage Source Converter
VVO	Voltage VAR Optimization

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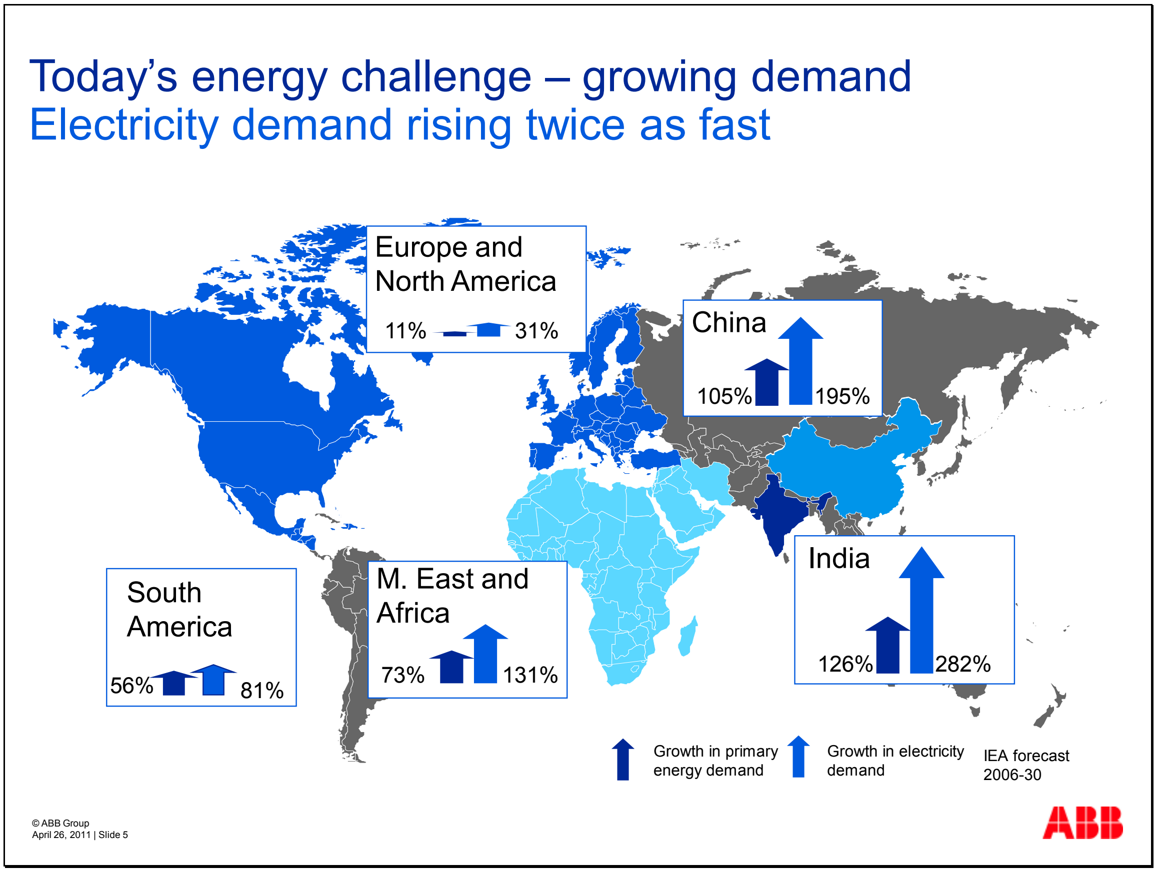
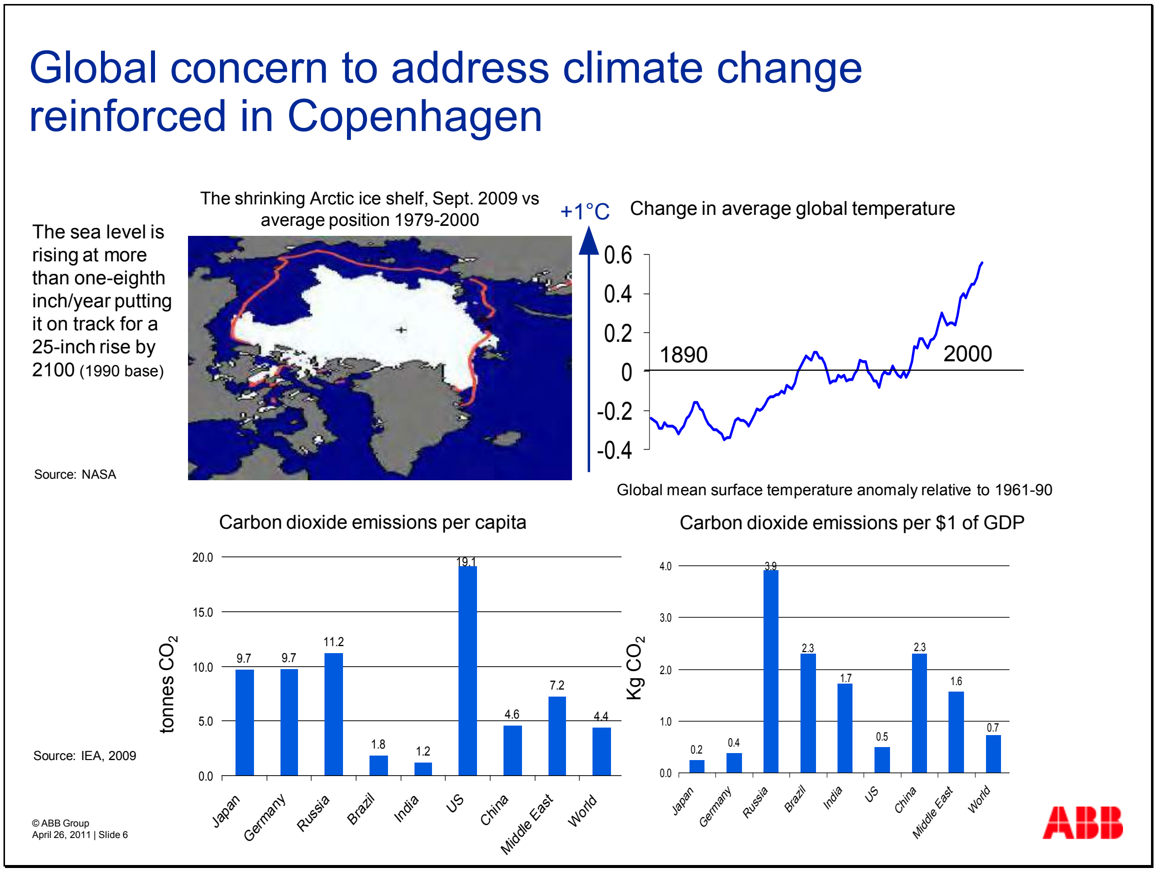
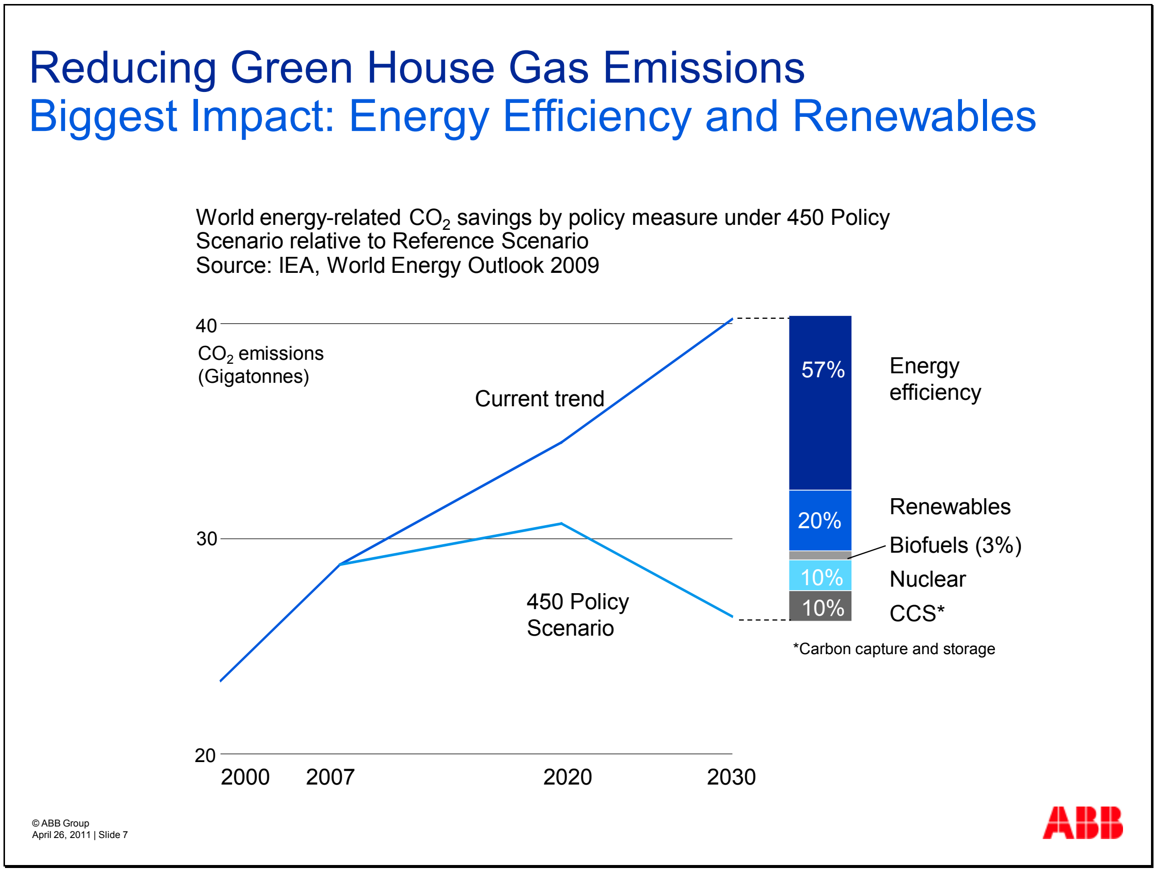
In order to set the stage for a deeper discussion regarding challenges associated with the integration of Renewables into Power Grids; it is helpful to understand the drivers for why this topic is of interest. In the following few slides high level summaries of the drivers are conveyed.



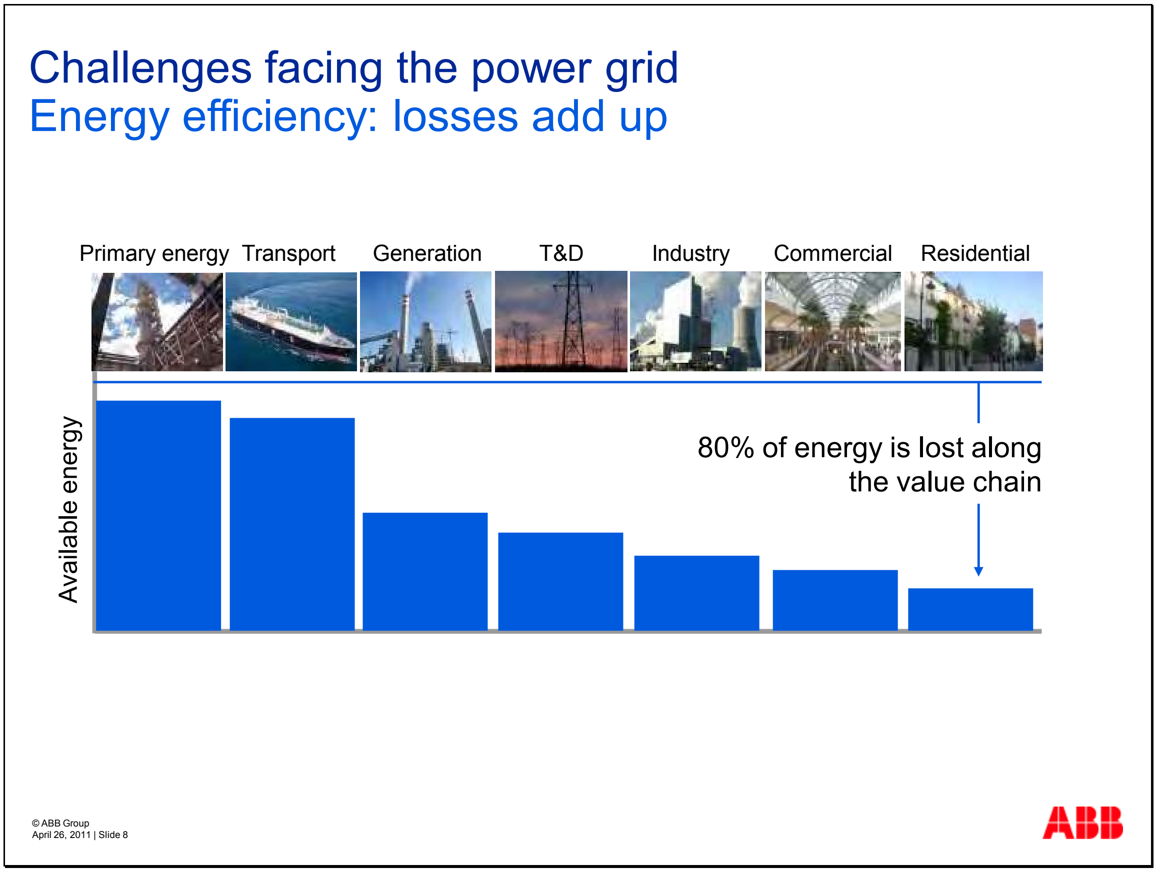
The demand for energy has risen steadily in the past decade. What is more astounding is that electricity consumption is rising even faster, and it is predicted to increase about 80 percent between 2006 and 2030 (IEA estimate). Electricity demand in China alone is expected to triple. It will likely rise almost fourfold in India, where the government is driving a campaign to provide electricity to all by 2012.



Even in the presence of rising electricity demands there is growing concern about the climate. This underlines the challenge that we need to meet the energy and electricity demand without compromising the environment.



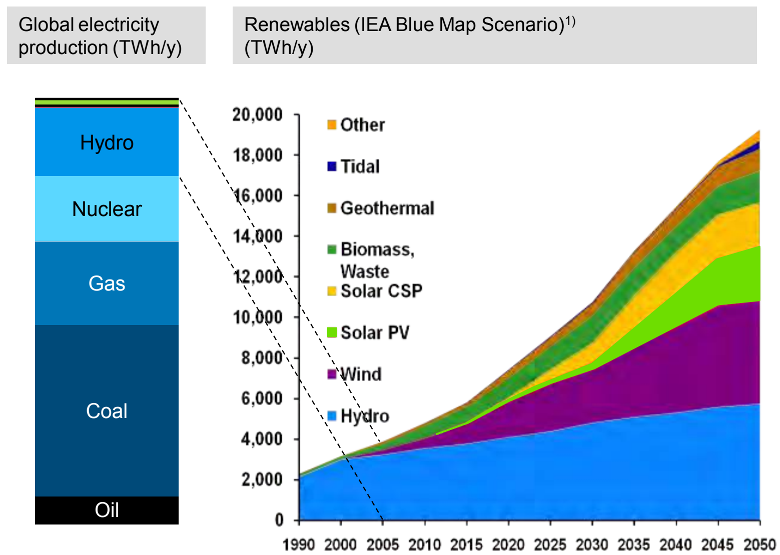
This slide highlights the sizable CO_2 emissions reductions potential from energy efficiency improvements and the use of renewable sources of energy. Energy efficiency improvements across the energy supply chain also enjoys significant industry focus and is considered by some as low hanging fruit from a technology point of view. In the scenario modeled by the International Energy Agency, renewable sources of energy are likely to account for about one-fifth of the emissions abatement, as you can see in the bar on the right. Biofuels, nuclear energy and carbon capture and storage, together represent potential savings relative to the current trend of about 23 percent.



In this slide we highlight that along the energy value chain substantial losses occur, and the potential gain of energy efficiency improvement is evident. In all of these segments there are ongoing efforts to reduce the amount of energy lost along the way.

Renewable Energy Sources
Types and Regional Differences

Global Growth of Renewable Energy



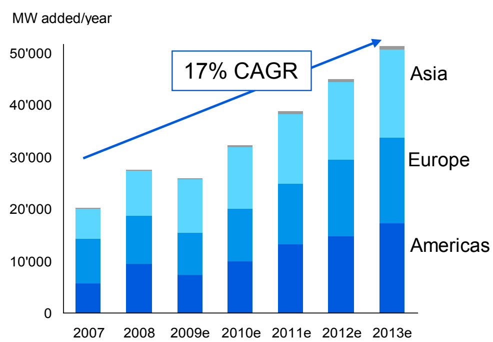
Source: IEA

[1] Blue Map Scenario is a combination of high efficiency, biofuels, electric vehicles and hydrogen fuel cells; the result is that CO_2 emissions in 2050 will be half of 2005

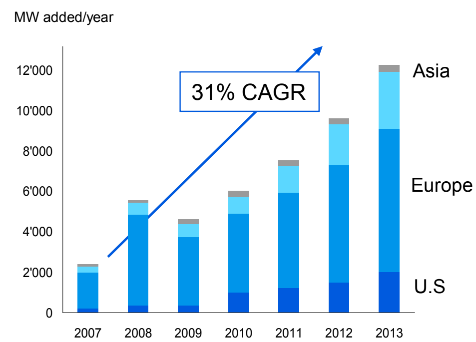
IEA projects that there will be substantial growth in Renewable Energy in the coming years.

Renewables
A Fast-growing Market for both Wind and Solar

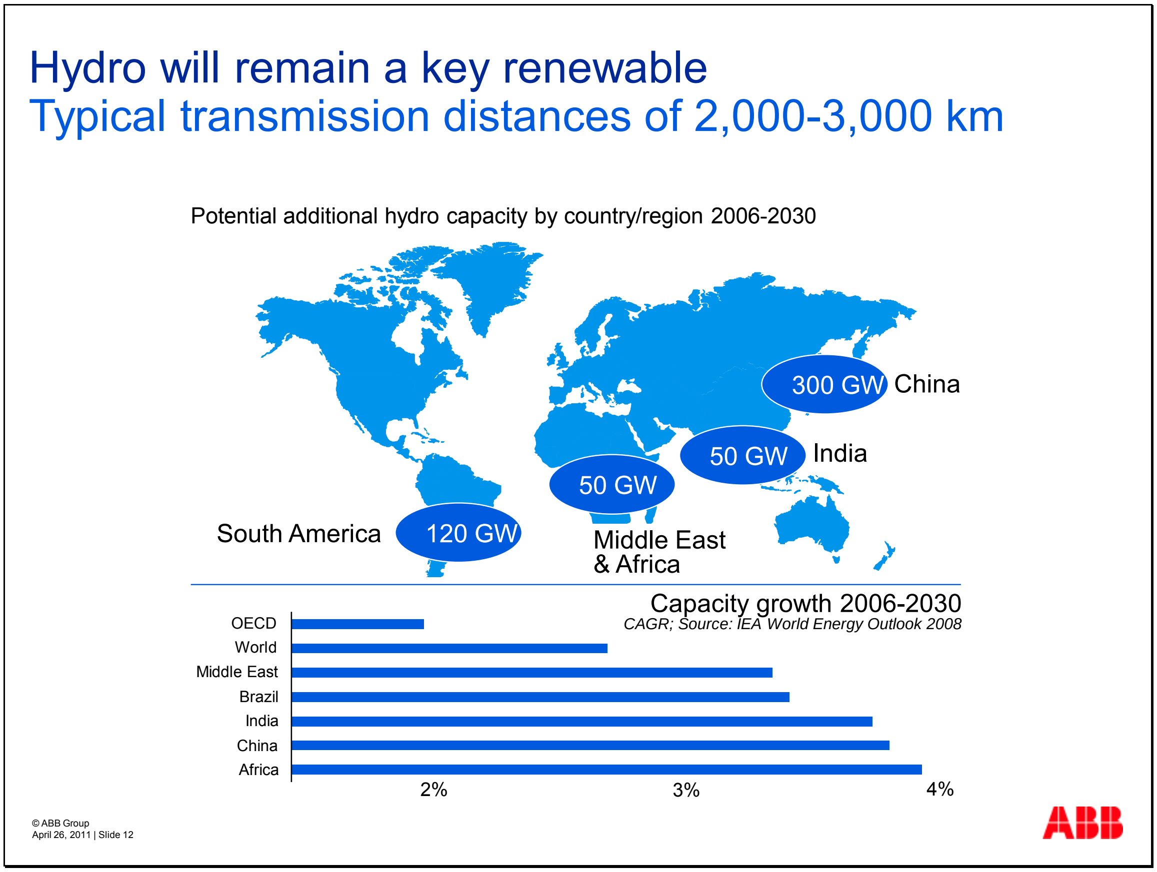
Global wind power market 2007-13
Source: MAKE Consulting March 2009



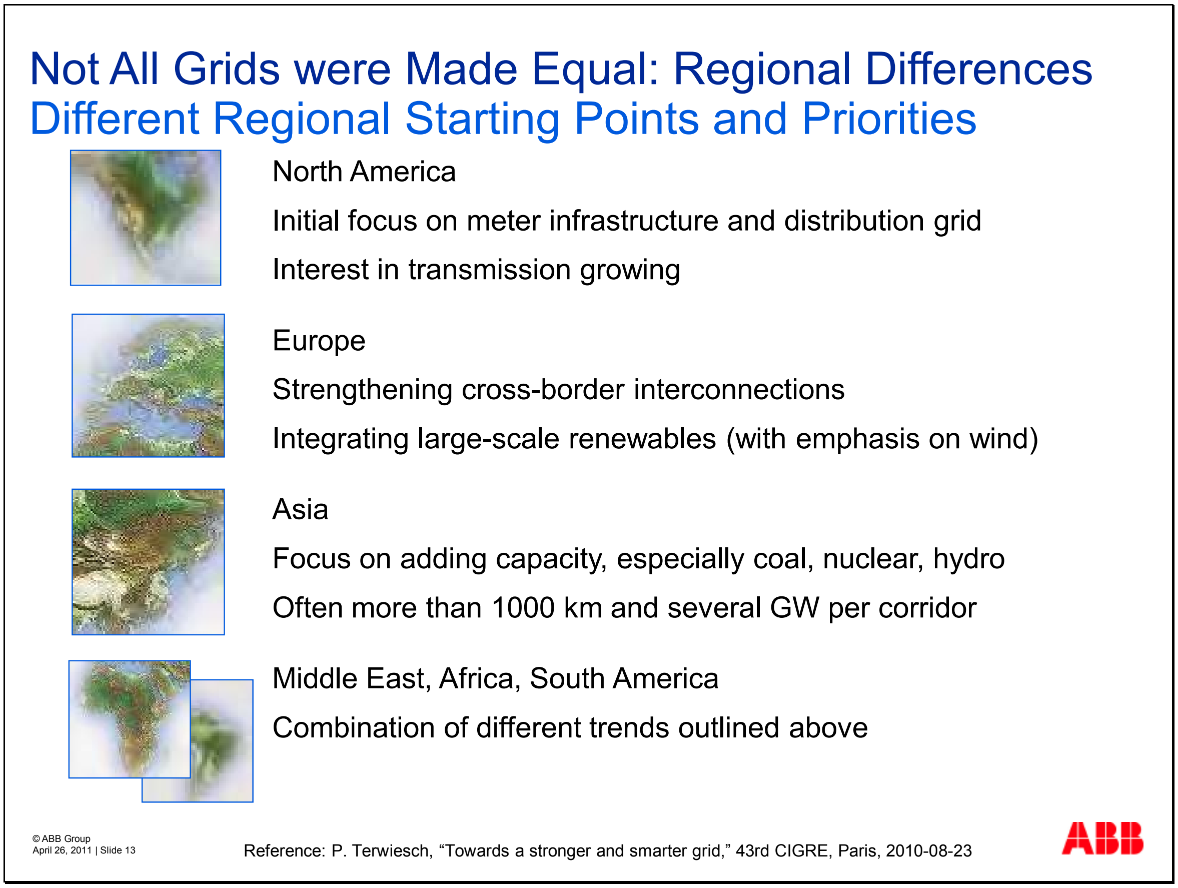
Global photovoltaic market 2007-13
Source: EPIA 2009



What can be observed is that the already attractive markets for Wind and Solar are poised for growth.



In the discussions around Renewables, growth in the Hydro market is often overlooked. Hydro is one of the preferred renewable energy sources, due to the added benefit of having some inherent storage capability making this source flexible. However Hydro installations are geographically limited and in certain cases adding additional hydro is not an option. From the growth projections it is expected that Hydro will be more of relevance in non-OECD countries, whereas in OECD countries the growth is more in renewables such as Wind and Solar.

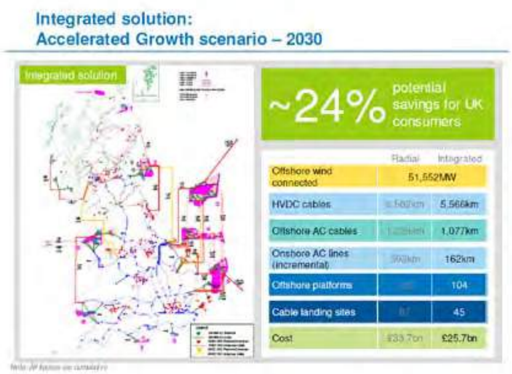


There is a relationship between Grid Integration of Renewables and Smart Grids. The focus of this note is not on Smart Grids, but in the industry it is recognized that integration of renewables - in order to make the electricity energy supply sustainable - is a key aim of Smart Grids. In order to understand different initiatives across the globe it is interesting to look at the current state of Grids across the globe and then also on what their priorities are when it comes to charting the evolution of their respective grids.

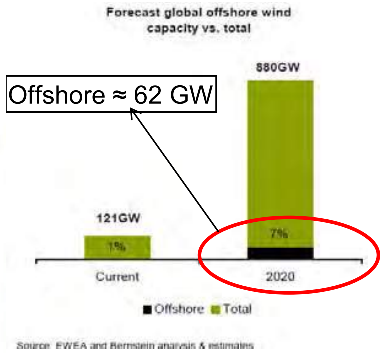
Offshore Wind
Significant focus in EU

References:
[1] CIGRE, „Offshore Workshop, Jan 2011, http://www.cigre-uk.org/Technicalactivities_files/Cigre%20Workshop%20on%20Offshore%20Networks%20Jan%202011%20-%20Presenations.pdf
[2] National Grid, RenewableUK, http://www.nationalgrid.com/NR/rdonlyres/14BFDA91-01E7-49A2-82CB-A7151155D12F/43325/2010ODIS_Chapters_Final.pdf
[3] EWEA, „Oceans of Opportunity ,“ http://www.ewea.org/fileadmin/ewea_documents/documents/publications/reports/Offshore_Report_2009.pdf

- The EWEA expects annual offshore shipments to grow to 7.7GW by 2020, which represents 7% (62 GW) of total cumulative installed wind capacity



	Radial	Integrated
Offshore wind connected	51,552MW	
HVDC cables	[illegible]	5,566km
Offshore AC cables	[illegible]	1,077km
Onshore AC lines (incremental)	[illegible]	162km
Offshore platforms	[illegible]	104
Cable landing sites	[illegible]	45
Cost	[illegible]	£25.7bn



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There are significant efforts under way in Europe focusing on tapping Offshore Wind potential. This effort requires a range of integration technologies both primary and secondary systems which is already subject of R&D focus in the industry.

Renewables in USA
Renewable Portfolio Standard (RPS)

References:
http://apps1.eere.energy.gov/states/maps/renewable_portfolio_states.cfm#chart

- Synonym: Renewable Electricity Standard (RES)
- Similar efforts in other countries, e.g. Renewables Obligation in the UK

- In US the target averaged across all states:
  - ~ 20% by 2020
  - Some states are more aggressive (CA, ME)

- Eligible ‘Renewable’ Technologies
  - List differs on a state-to-state basis
  - Frequently cited technologies: Wind, Solar
  - Following also potentially counts:
    - Energy efficiency improvements
    - Import of Green Energy
    - Nuclear power

- Large as well as small and distributed installations count towards Renewable Energy targets
- ‘Energy’ includes scenarios where renewable energy is consumed without first converting to electricity (e.g., solar thermal for residential water heater)

Renewable energy implies energy that is derived from a renewable source and which is consumed without necessarily being converted into electricity. Renewable electricity on the other hand is where the renewable energy is converted to electricity and transported on electricity networks from source to sink.

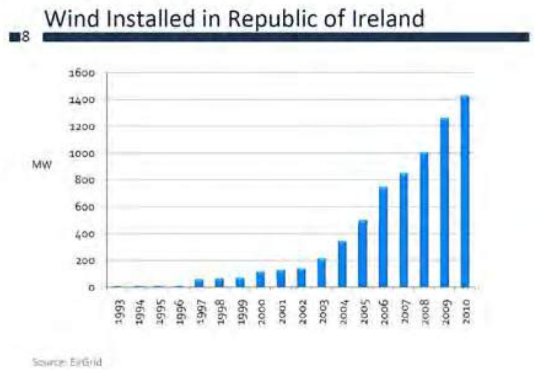
Wind In Ireland
Example case

Reference:
M. O'Malley, "Integrating Wind in Ireland: Experience and Studies," Jan 2011, Boston, MIT, http://web.mit.edu/windenergy/windweek/Presentations/OMalley%20-%20Final%20MIT%20Jan%2019th%202011-Update.pdf

- Ireland is an interesting example because it has a unique renewable resource & technical environment
- ERC at University College Dublin is conducting broad range of Renewable Grid Integration research, and some of their work will be discussed in this document

System Facts

- 9.7 GW Installed
- 1.8 GW Wind (> 10 % energy)
- 450 HVDC to GB
- Max load: 6.5 GW
- Min load: 2.4 GW
- High reliance on imported fossil fuel
  - Gas ~ 66%
  - Wind ~ 10%
  - Hydro ~ 2%
  - Coal ~ 13%
  - Peat ~ 8%



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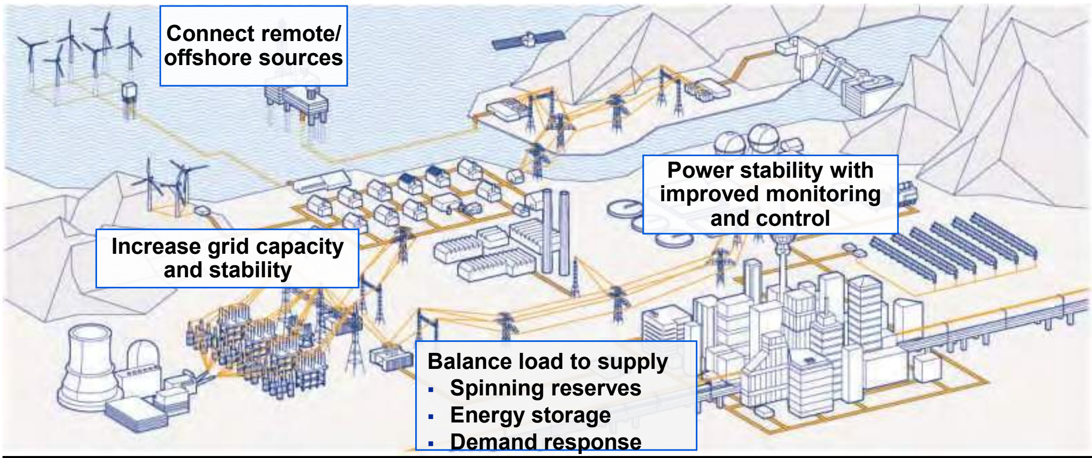
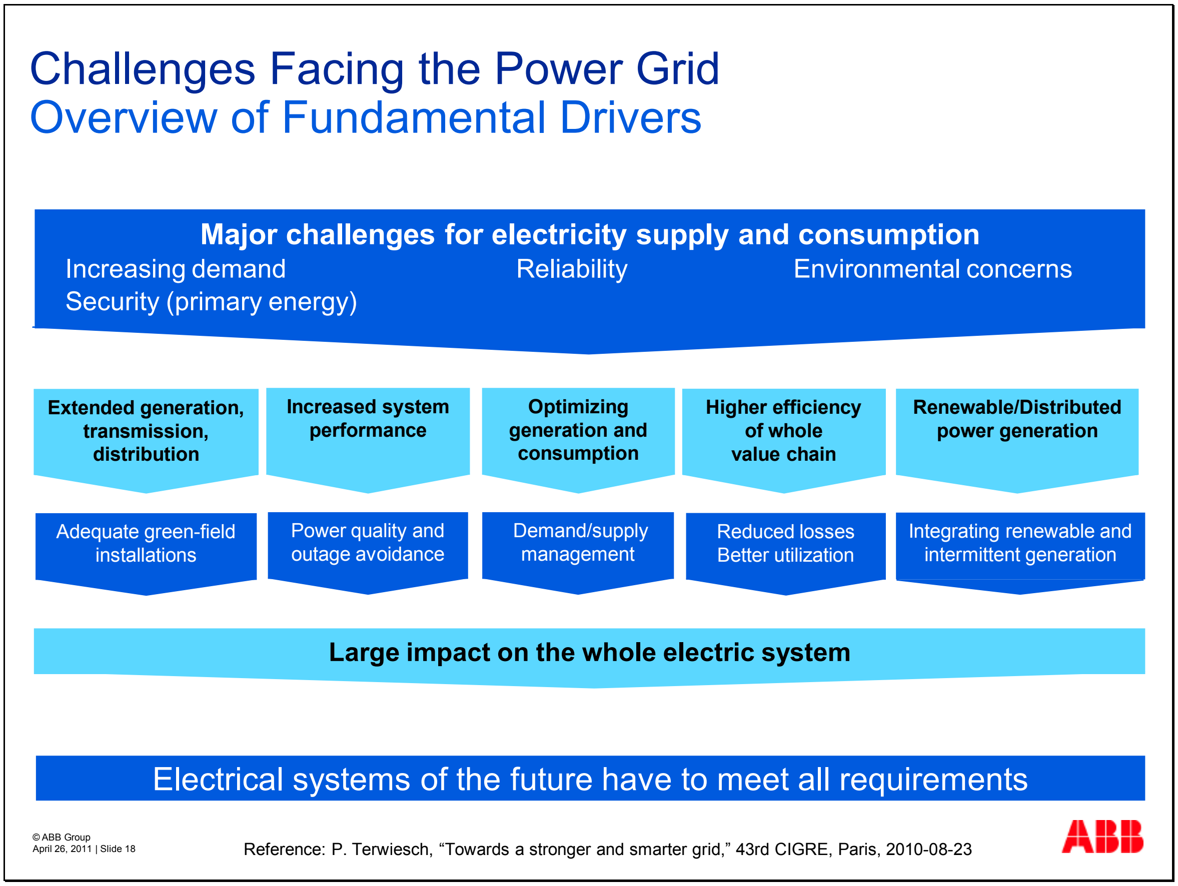
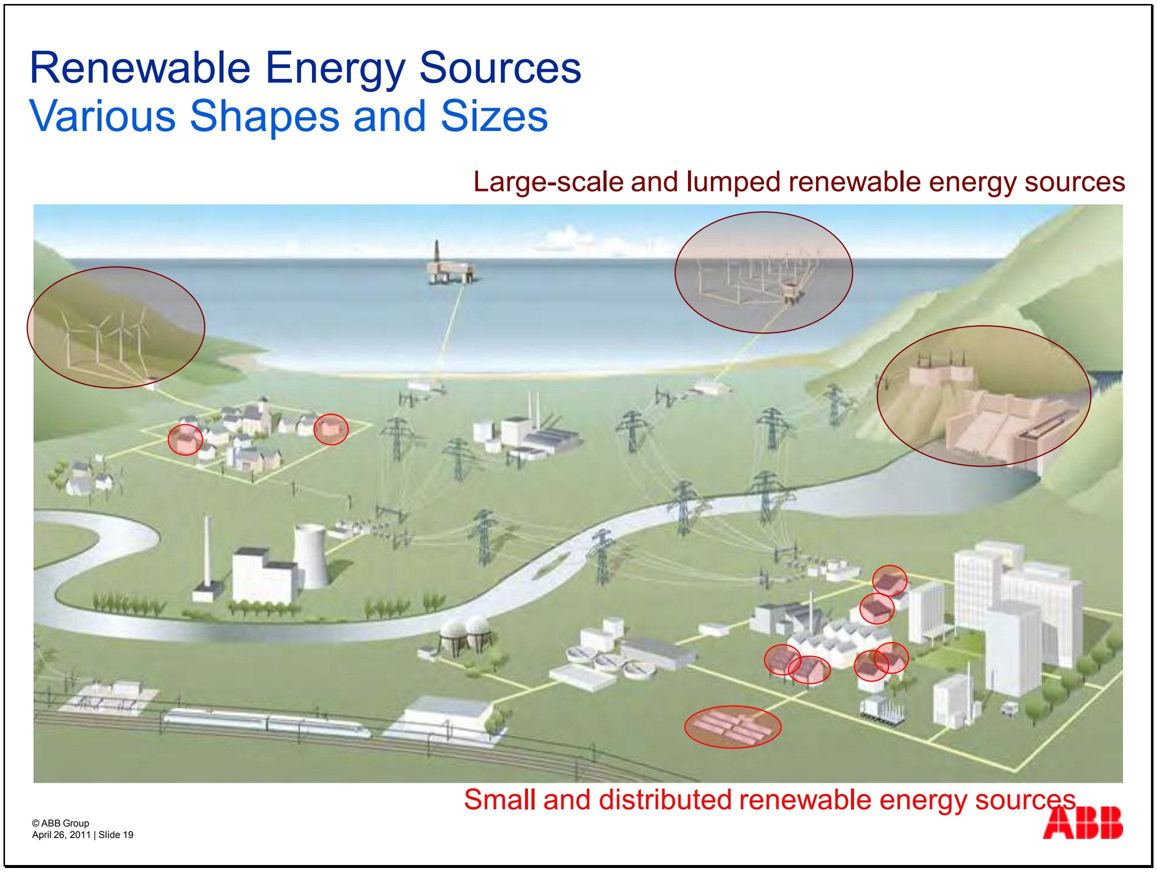


Grid Integration of Renewables
Challenges

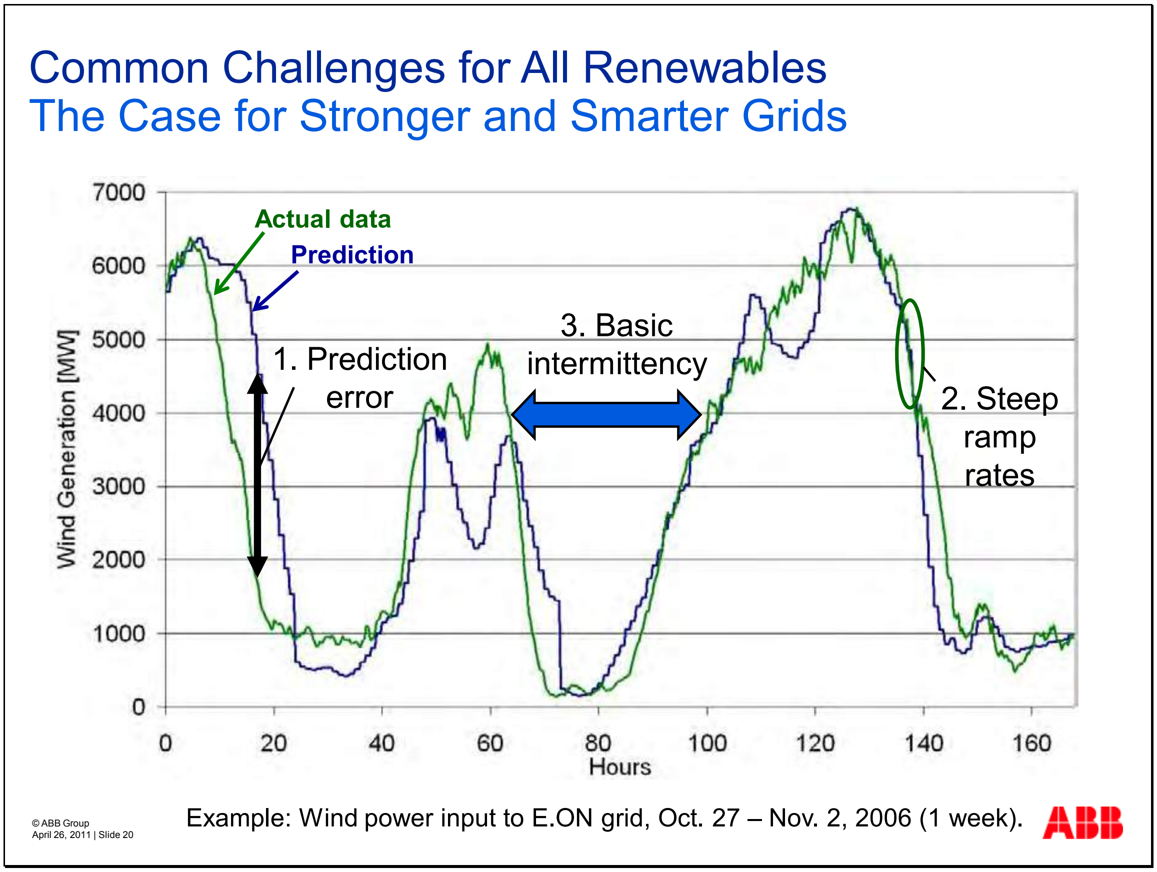


In this note not all of the challenges will be discussed in details. This slide provides a good summary of the challenges evolving power grids are facing. Only the subset pertaining to challenges around renewables will be discussed in more detail.



Renewable Energy Sources come in various shape and sizes. For the Gird Integration discussion we distinguish between large and lumped installations (e.g., wind-parks on-shore or off-shore connected to the transmission grid) or smaller – but plentiful – distributed installations (e.g., residential solar panels).

In the following few slides we will highlight common problems to renewable energy sources and elaborate on the differences between the lumped and distributed forms of renewable sources.



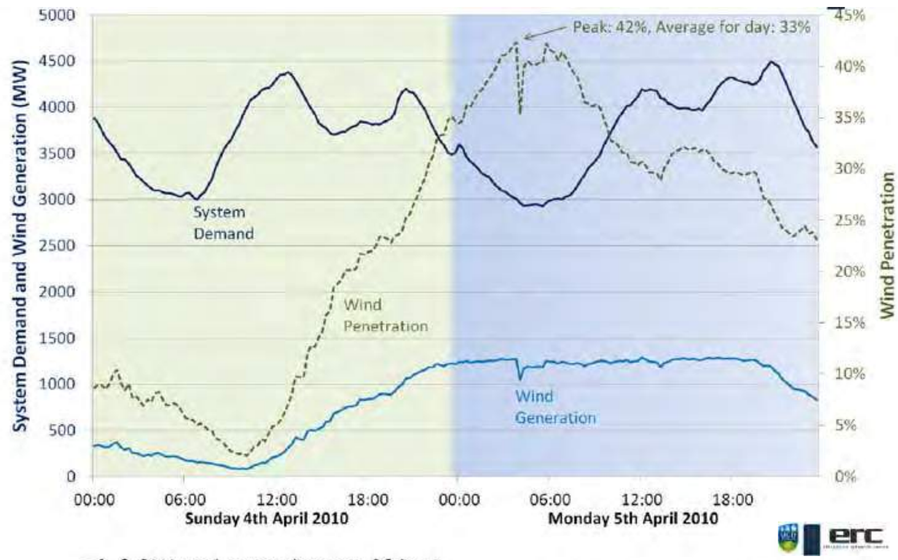
Common to renewable energy is the three problems highligted in this figure. For some sources and type of installations the problems are pronounced or not delibitating. The problems are:

- One can aim to predict the anticipated output from a renewable energy plant, but there are limits to prediction methods and some uncertainty regarding output power can be observed
- The primary source of energy can also exhibit sudden changes (e.g., drop of wind) which would require other types of power sources to counter balance
- The issue on basic intermittency address the problem that the output from a renewable source does not necessarily correspond with when the energy is needed (i.e., what is the correlation between peak power output and peak demand)

Problems 1 and 2 can be solved by smarter prediction technology to limit the uncertainty bounds and short term generation management. Problem 3 requires other power generation (local, or remote through increased tranmission capacity), energy storage solutions or more interconnection.

Large Penetration of Renewables
Wind in Ireland April 2010

Reference:
M. O'Malley, "Integrating Wind in Ireland: Experience and Studies," Jan 2011, Boston, MIT, http://web.mit.edu/windenergy/windweek/Presentations/OMalley%20-%20Final%20MIT%20Jan%2019th%202011-Update.pdf

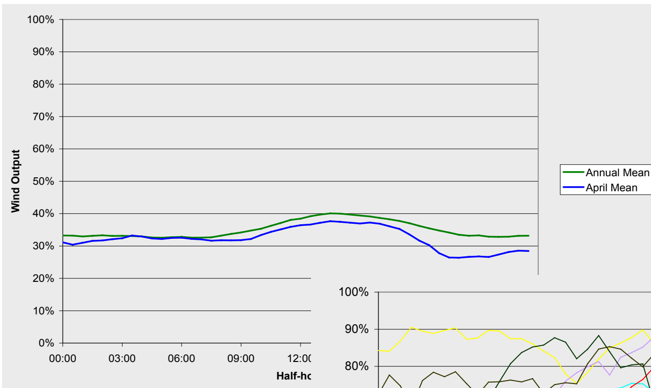


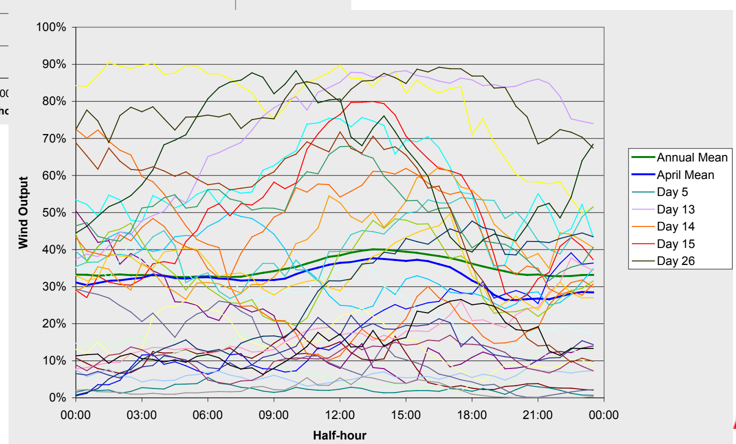
~1 .2 GW wind power change in 18 hours
(2 % to 42 % penetration)

All island data from EirGrid & SONI

In Ireland the grid operator is already facing situations where wind power becomes a significant portion of the daily generation. The University College Dublin has a strong research group focusing on Integration of Renewables in reponse due to this reality of large wind penetration into a relatively weak power system. In most other parts of the world the penetration levels are lower, with Spain being an obvious exception.

Renewable Power Output Prediction
Average versus Daily Variations in Ireland





Reference:
M. O'Malley, "Integrating Wind in Ireland: Experience and Studies," Jan 2011, Boston, MIT, http://web.mit.edu/windenergy/windweek/Presentations/OMalley%20-%20Final%20MIT%20Jan%2019th%202011-Update.pdf

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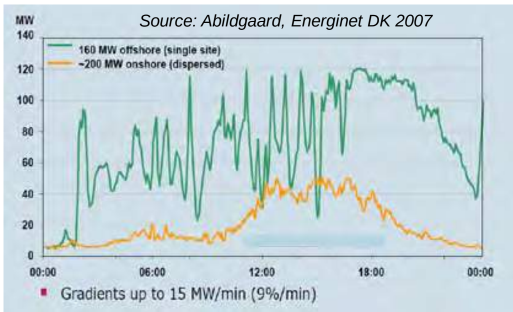
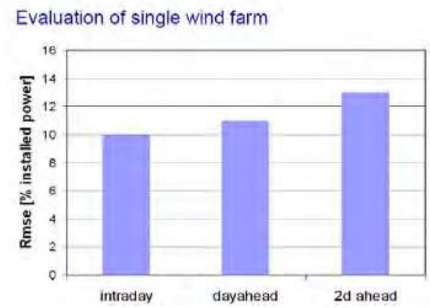
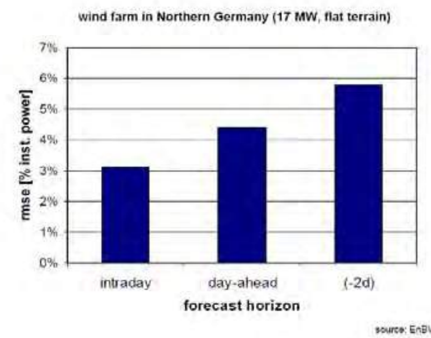
Forecasting of Power Outputs of Renewables
Local versus Global







- In the *aggregate* dispersed generation appears *less volatile* and *easier to predict*
- However local prediction is more challenging and associated errors can lead to local grid issues (such as overloading of circuits)

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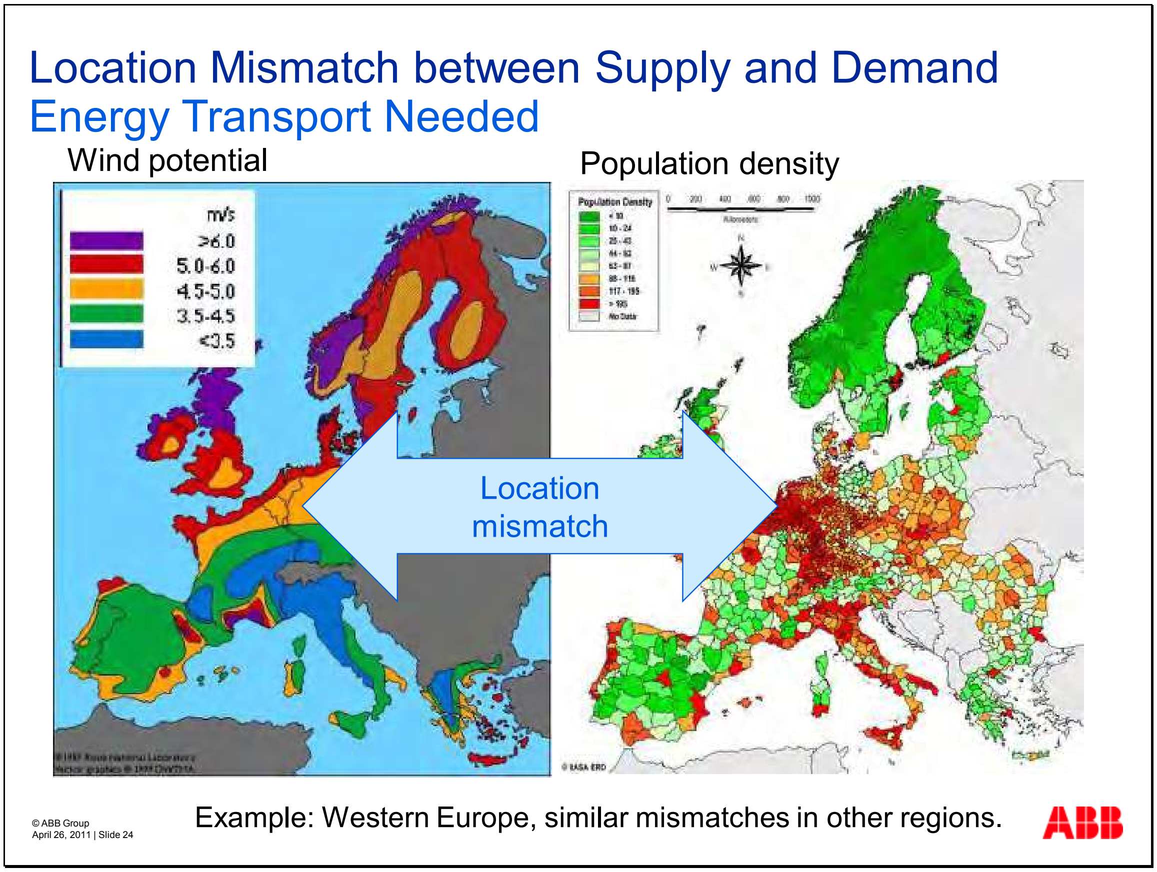
An often cited observation is that when comparing the variability of large-scale renewable plants versus small and distributed installations (such as solar panels on one's roof), then the intermittency of the sum of the distributed sources appear less volatile and hence should be easier to predict. This is true as shown in the top left figure; however such a comparison ignores possible grid issues such as overloading of a local circuit (i.e., network constraints).

Focusing on the local versus the global it can be observed that local output prediction for a small unit has larger uncertainty than for a larger installation, as is illustrated by data assembled by EnBW.

The main point on this slide is to emphasize that the grid (and its associated capacity) should be considered in the discussions around integration of renewables.

Local versus Global:
- A wind power forecast can be generated for each wind unit
- Deviation of the overall/global wind power from its forecast value is smaller
- However, the location of the wind power generation units matters as it is relevant for the network constraints



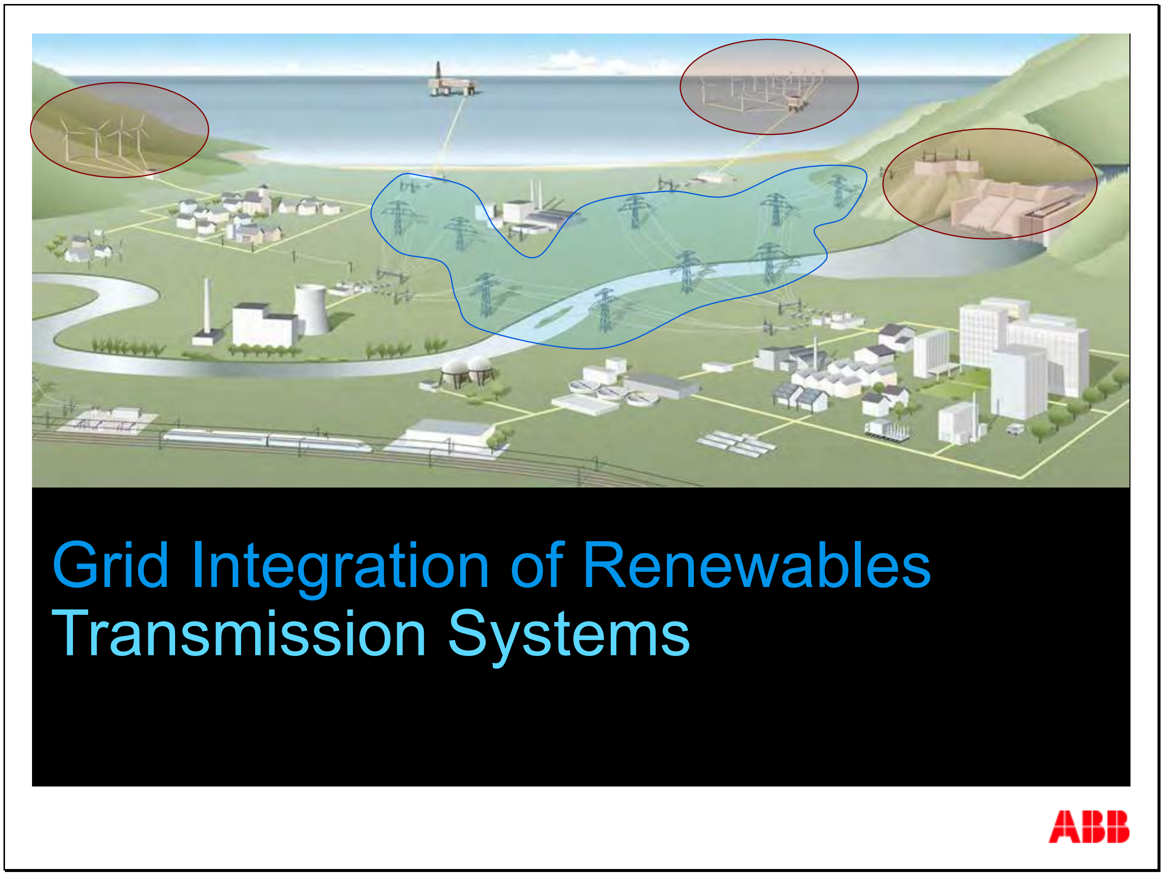
Besides the previously mentioned issues another challenge is that there is a location mismatch between where the potential of renewable energy generation does not correlate well with where the energy will be ultimately consumed. This location mismatch between generation and loads is not a new problem, and in order to cope with said challenge electricity networks (i.e., transmission and distribution grids) are required.

(Slide 25 has been removed.)

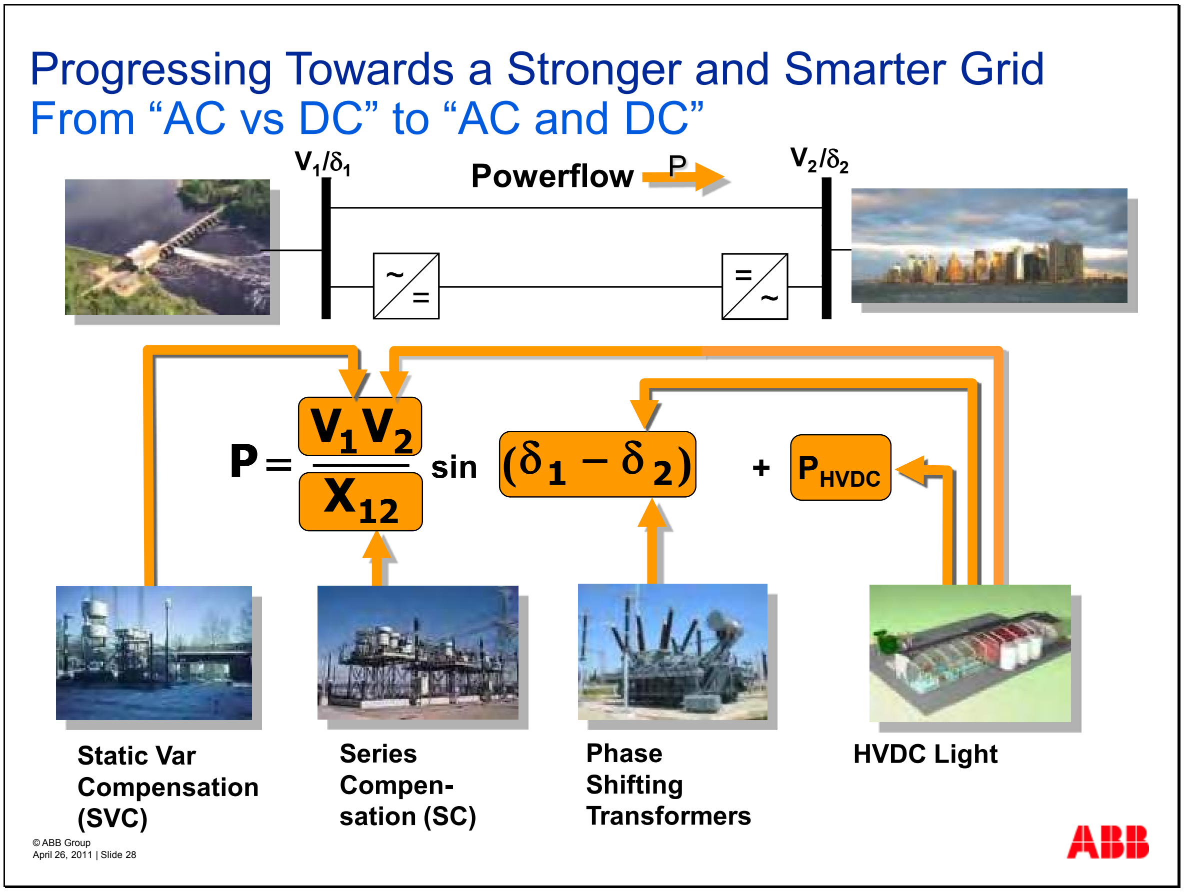
The Case for a Stronger and Smarter Grid
Approval Processes and Public Perception

- Public acceptance and siting/approval processes for new power infrastructure have become increasingly challenging (“NIMBY” and “BANANA”)
- Technology and intelligence
  - To maximize utilization of existing infrastructure and existing rights of way
  - To minimize environmental, visual, and other impacts of necessary new infrastructure

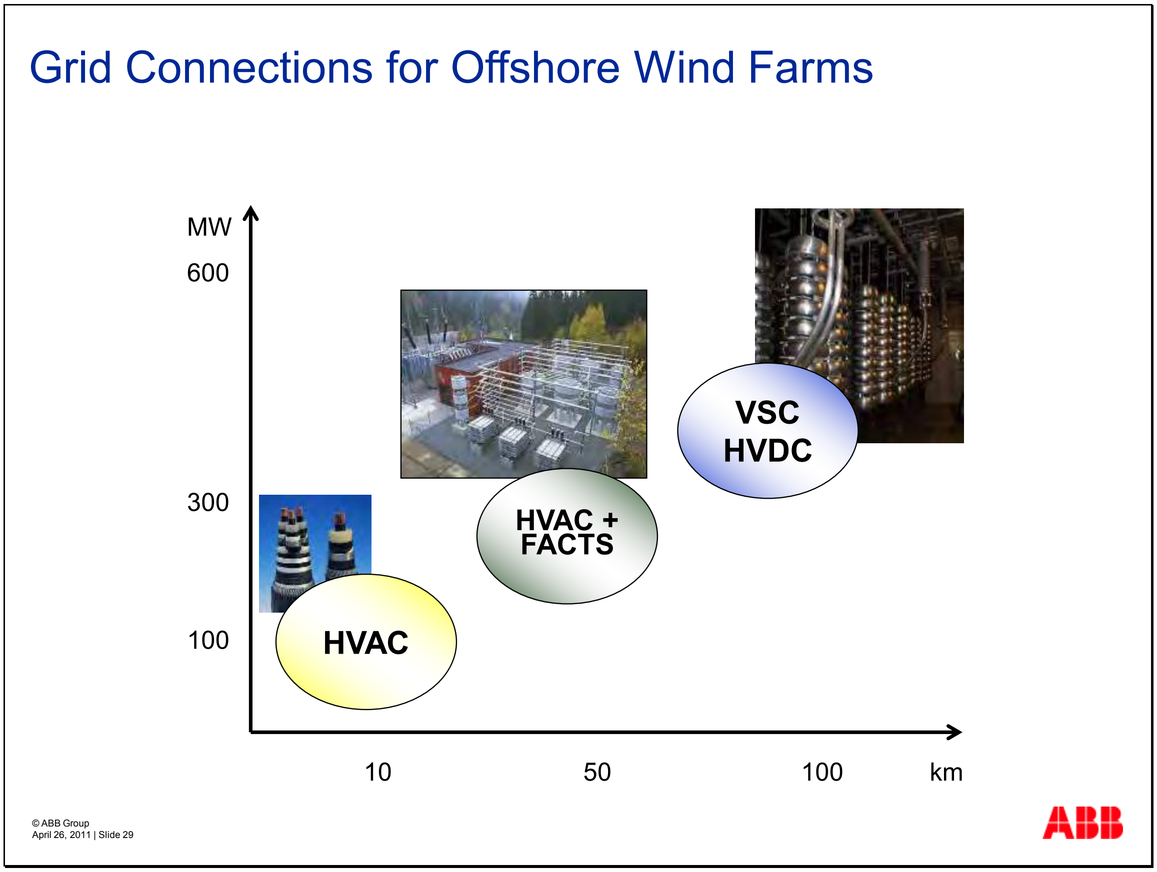
As mentioned earlier a need for more routing of power will be faced, implying new lines. Once new lines are mentioned one has to consider approval processes and public perception. In this talk we will not cover these issues, but merely mention it here to say that strengthening of the grid is needed, but increasing grid capacity can run into public resistance and new technology (moving towards a stronger and smarter grid) can alleviate some of this pressure.



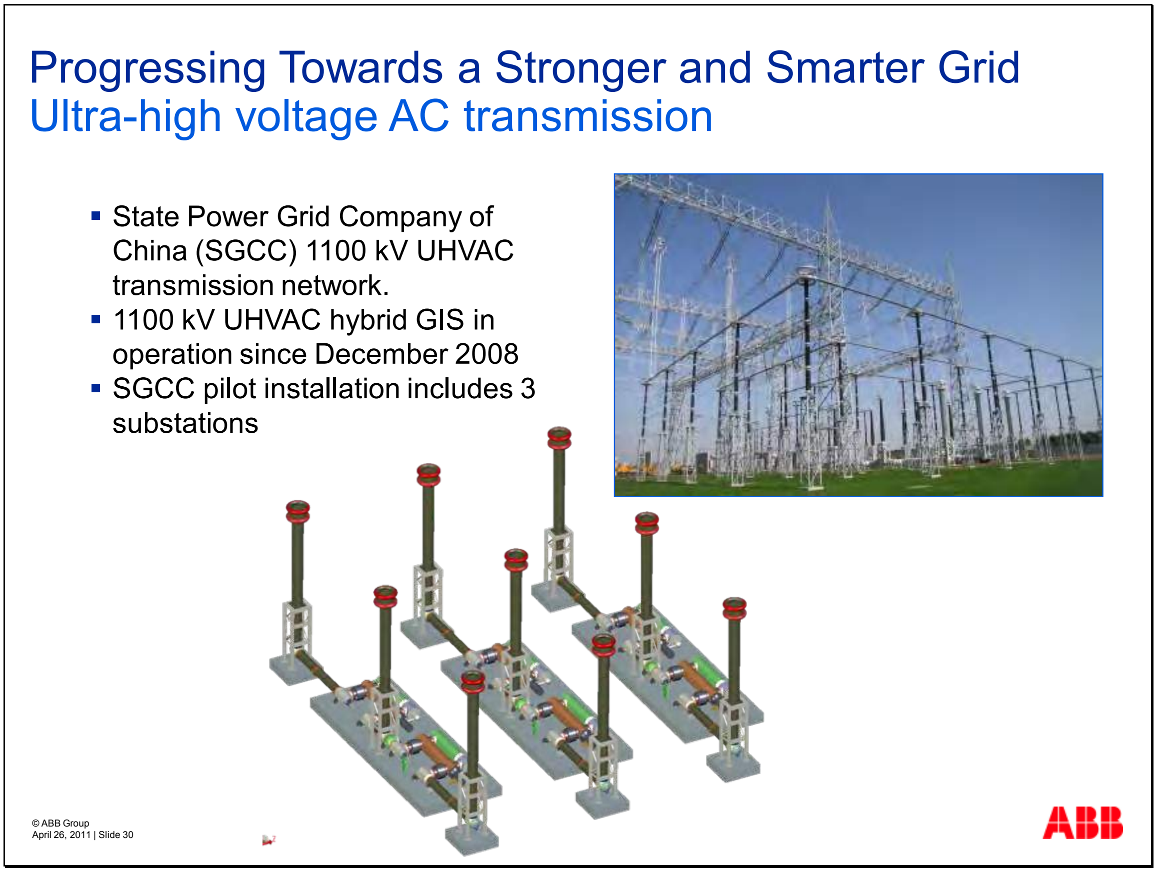
In the following few slides we highlight some existing technologies that can be used for the integration of Renewables into T&D Grids. It is worthwhile to point out that to fully integrate renewables, both hardware and software technologies are needed to overcome the previous introduced challenges.



As illustrated in previous slides there is a need to route power from one location (e.g. renewable source) to another (e.g. load center) in a controllable fashion. Different technologies (AC and DC) are available that can facilitate the routing of power from one location to another in a controllable fashion, but for connection of remote renewables HVDC technology is especially suited due to low losses and high controllability when compared to AC.

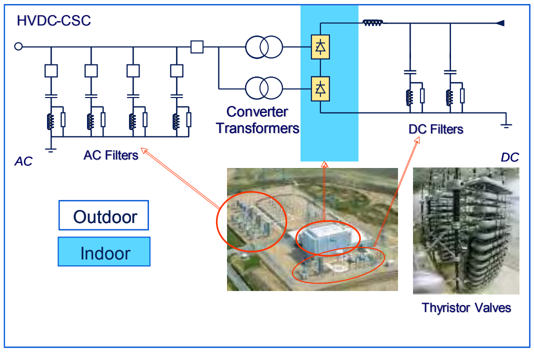


In order to help decide when to use a specific technology the following diagram for Offshore Wind Farms is used with great effect. It is clear that for short distances and relative low power HVAC technology suffice. When the power as well as distance to increases, HVAC should be augmented with FACTS devices in order to compensate for HVAC losses, and to provide stability support. In order to connect remote located renewables to a grid, HVDC technology is preferred.



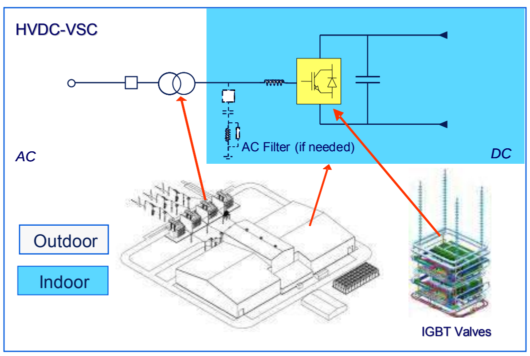
In order to present you with a full picture it is worthwhile to point out that there are still R&D focused on AC technologies. In China, State Grid is pushing for the advancement of AC technology through the demonstration of 1100 kV Ultra High Voltage AC system. This UHVAC systems are suited mainly for transport of electricity from on-shore renewable sources due to Overhead Lines.

Core HVDC Technologies from ABB



HVDC Classic

- Current source converters (current stiff)
- Line-commutated thyristor valves
- Experience since 1954
- Requires additional “Q” control (AC filters)
- Requires min short circuit capacity for connection
- Over 100 projects around the world, many in 1000-3000MW, max power is 6400MW
- ±500kV, ±800kV
- Other manufacturers: Siemens, Alstom



HVDC Light

- Voltage source converters (VSC)
- Self-commutated IGBT valves
- Experience since 1997
- PWM accommodates the “Q” control (i.e., four quadrant control)
- Virtual generator at receiving end: P,Q
- Suitable for weak system, and black start
- Compact footprint, low losses (~ 1% per converter)
- Dozen projects around the word, growing number in the 300-400MW range
- ±150kV, ±320kV
- Other manufacturers: Siemens

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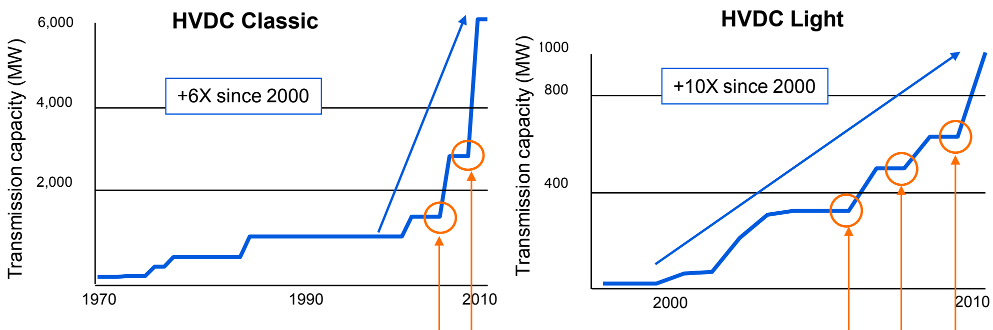
HVDC Tutorial at ABB:
http://www.abb.com/cawp/GAD02181/C1256D71001E0037C1256D08002E7282.aspx

Progressing Towards a Stronger and Smarter Grid
Advances of HVDC Technology



Significant innovation steps

- More power, lower losses
- Reduced cost/MW
- Power electronics/power semiconductors and cables are key contributors

→Longer transmission distances

→Key enabler for integration of remote renewables

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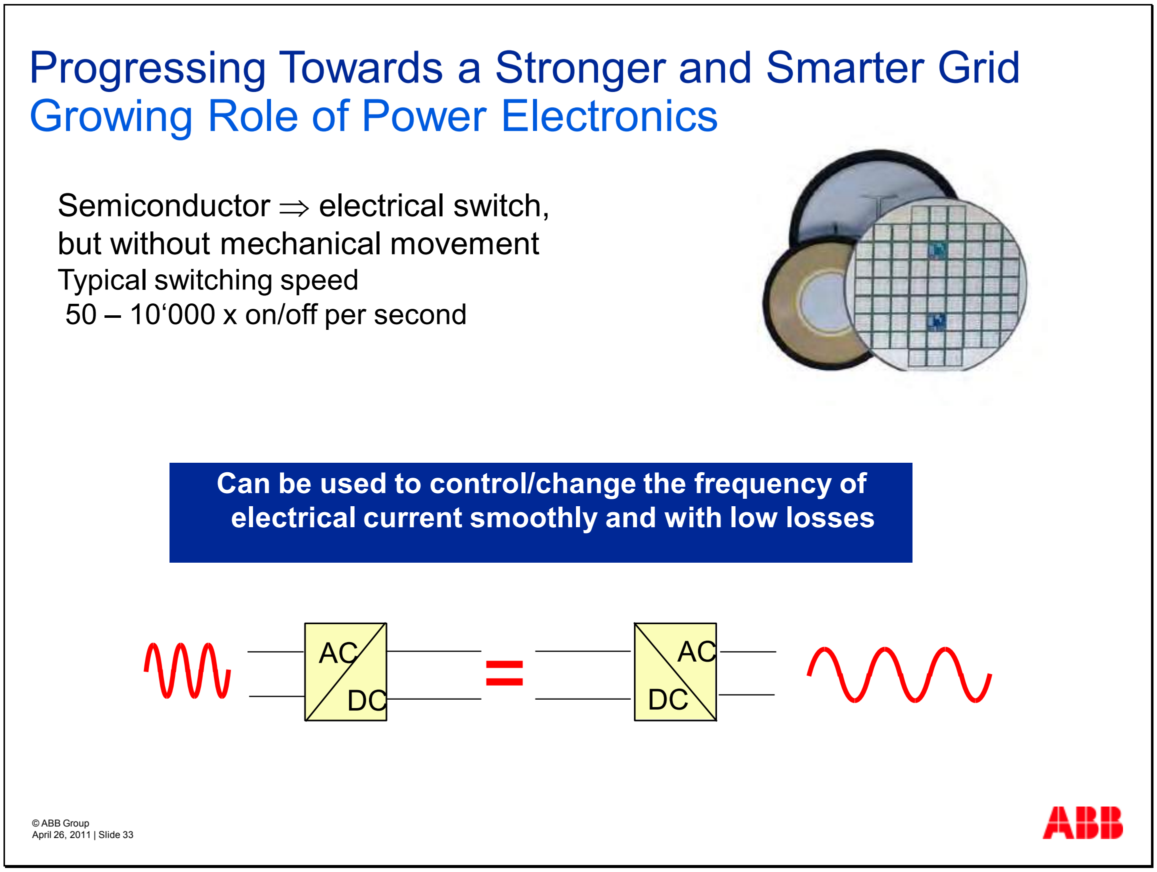

At the heart of advances of controllable transmission-grid hardware is power electronics. Proliferation of power-electronic enhanced devices in distribution grids is also on the rise in the form of grid-interfacing converters for renewables.

Progressing Towards a Stronger and Smarter Grid
Advances in Cable Technology

- Cable technology advances
- Higher voltages
  → lower losses, longer distances
- Oil-free insulation systems
- Dynamic cables enable connection of floating structures
  → floating oil & gas production
  → floating wind power generation

StatoilHydro's Gjøa platform
will be powered from shore using dynamic cable, avoiding 230'000 tons of CO_2/year

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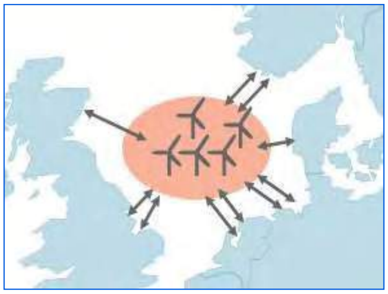
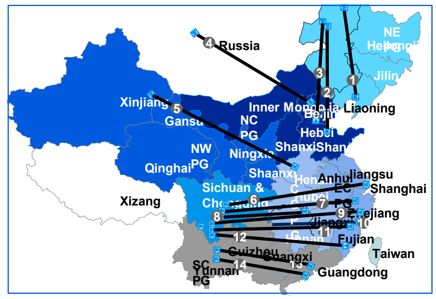
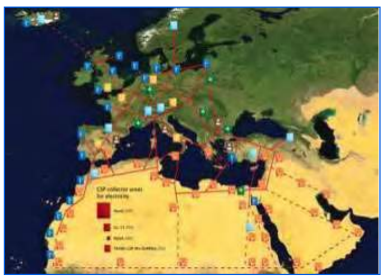
ABB

Another interesting aspect is that advances in the carrying mechanism is also required. For instance if we want to transfer large quantities of power from remote locations a low loss medium would be required. Research into basic science associated with cable technologies is a continuing effort, but in order to realize a stronger and smarter grid technology advances are also necessary on the carrier medium.

Progressing Towards a Stronger and Smarter Grid
More HVDC Power and Lower Cost Drive New Visions







Sources: Stattnet, energienet.dk, Svenska Kraftnet, Vattenfall, Airtricity, SGCC, desertec, US DoE

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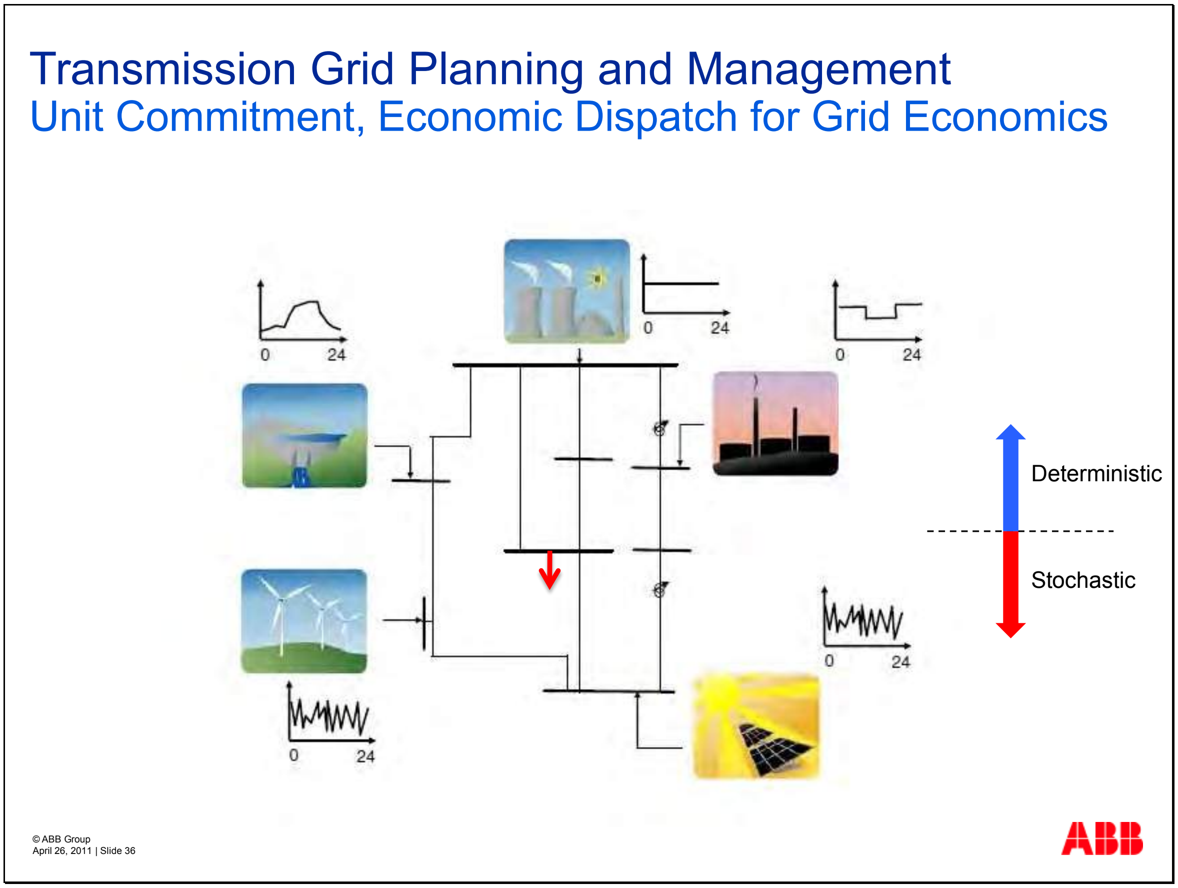


One of the primary concerns of transmission system operators is to have enough generating and/or grid capacity to meet demand (current and projected) over varied time scales (e.g. long-term planning focusing on grid expansion and new generation, as well as shorter day-ahead and real-time operation using the existing generation stack and grid infrastructure). The unit commitment problem refers to the task of finding an optimal schedule, and a production level, for each generating unit in a power system, where limitations on the grid infrastructure (existing grid when evaluated on the short-term time-scale or a modified grid when conducting planning studies) is also accounted for, over a given scheduling horizon. This decision process is translated into a multistage optimization problem with both continuous and integer variables.

The addition of renewable sources, with its varying output, present a challenge to the existing predominantly deterministic optimization framework used in the industry. Research on the improved ways to deal with this variability is a continuing effort.

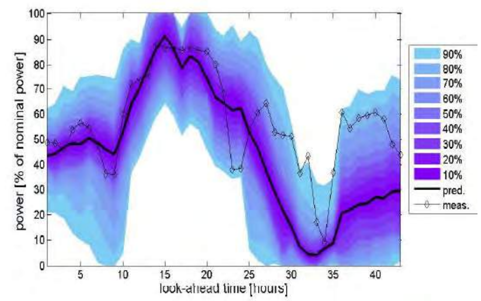
Stochastic Unit Commitment
Initial Indications

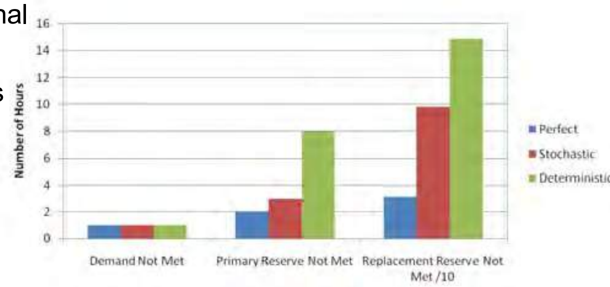
References:
[1] M. O'Malley, "Integrating Wind in Ireland: Experience and Studies," Jan 2011, Boston, MIT, http://web.mit.edu/windenergy/windweek/Presentations/OMalley%20-%20Final%20MIT%20Jan%2019th%202011-Update.pdf
[2] P. Meibom et.al, "Stochastic optimisation model to study the operational impacts of high wind penetrations in Ireland", *IEEE Transactions Power Systems, in press,* 2011.
[3] A. Tuohy et al., "Unit commitment for Systems with Significant Installed Wind Penetration", *IEEE Transactions on Power Systems , Vol, 24, pp. 592 – 601, 2009.*

- Uncertainty bounds on renewable power outputs (and loads) factored into stochastic unit commitment framework
- Tighter bounds (due to improved forecasting) on predicted power outputs can alleviate computational burden, because output can be consider deterministic
- Need for using computational intensive Stochastic Unit Commitment in Real-Time Power System Operation is dependent on the Penetration Level and Location of Renewables

→ Not widely adopted yet

Wilmar (Risø DTU)





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The wind power forecast is provided as a mean together with an upper/lower bound on its variation. Associated with the upper/lower bound is a confidence value, which describes the amount of real measurements, expected to be within the related interval. The unit commitment problem assumes a given confidence value related to the risk the utility is comfortable to assume.

Through observations at technical conferences (i.e., no single reference) it has been concluded that conservative ISOs take about 25% of the forecast wind power as trustworthy. The remaining 75 % reserves are allocated via conventional power plants, limiting the benefits of integrating wind power. In order to capitalize more on Renewable energy one can:

- Improve the forecasting tools in order to reduce the uncertainty bounds and in doing so make it closer to being deterministic
- Or adopt more widely a stochastic* unit commitment framework, where one can integrate trust factors and formulate the amount of necessary reserves accordingly

Both approaches require more computational effort (especially #2). Relative low levels of Renewable penetration and existing conservative operating paradigm can explain why the power industry have not fully embraced stochastic unit commitment (bearing in mind that unit commitment for existing systems following a predominantly deterministic approach is already a taxing problem to solve).

*Stochastic Unit Commitment: Deterministic unit commitment has historically been one of the most analyzed application-based optimization problems and a number of classical formulation and solution approaches exist. The availability of renewable energy sources with uncertain power output variations due to changing meteorological conditions. The probabilistic nature of the problem can be accounted for by considering a set of possible alternative future scenarios, and the objective function to be minimized is effectively expressed as the expected value of the cost conditioned on the probability of occurrence of each scenario. In following this approach the stochastic unit commitment problem can be solved by solving unit commitment problem for each identified scenario using well adopted techniques (such as Benders' decomposition and Lagrangian relaxation) and then assembling all of the outcomes as described earlier. The greater the uncertainty in the system the larger will be the number of possible outcomes leading to increased problem dimension.

Cycling of Base Load
Research by ERC at University College Dublin

References:
[1] N. Troy, “Wind, Cycling and the Impact on Base-load Plant”, Aug 2009, http://www.seai.ie/Renewables/Renewable_Energy_Policy/Policy_Initiatives/Electricity_Storage_Event/niamh_troy.pdf
[2] N. Troy, “The Relationship Between Base-load Units, Start-up Costs and Generation Cycling”, Sept 2008, http://www.ier.uni-stuttgart.de/abteilungen/eam/school08/pdf_dateien/D3_03_Troy.pdf
[3] N. Troy, “Base-load Cycling and the Impact of Wind on Thermal Plant,” Dec 1, 2009, http://erc.ucd.ie/files/presentations/2009%2001%2012%20-%20ERC%20Seminar/Niamh_Troy.pdf

- Cycling is the operation of electricity generating units at varying load levels, low load levels or in a start/stop manner
- Effects:
  - Creep & Fatigue,
  - Stresses & Strains,
  - Chemical Corrosion

- ERC conducted a sensitivity analysis of cycling when varying parameters such as:
  - penetration of wind,
  - pumped storage [yes/no] or interconnection to other grids,
  - varying start-up costs of base units
- Used the stochastic unit commitment tool Wilmar (solved at 1hr resolution) on the 2020 Irish Network Model

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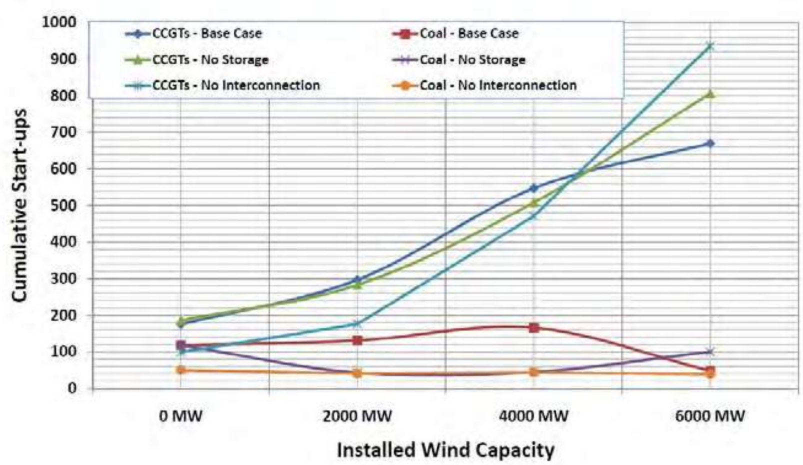
In the following two slides a study by ERC at UCD focused on studying questions around cycling of base load in the presence of significant level of Renewable penetration. As was previously remarked, Ireland has a very unique situation to address these research questions. Some of these reasons are: 1) Already significant penetration can reach up to 40% of the generation at any given time, 2) A strong research group with large industry (Irish as well as global) and government support, 3) A good test bed to pilot some innovative approaches.

Cycling of Base Load
Results from Sensitivity Analysis

References:
[1] M. O'Malley, "Integrating Wind in Ireland: Experience and Studies," Jan 2011, Boston, MIT, http://web.mit.edu/windenergy/windweek/Presentations/OMalley%20-%20Final%20MIT%20Jan%2019th%202011-Update.pdf
[2] Troy, N., Denny, E. and O'Malley, M.J. "Base load cycling on a system with significant wind penetration", *IEEE Trans. Power Syst.,Vol. 25, pp. 1088 - 1097, 2010.*
[3] N. Troy, "Wind, Cycling and the Impact on Base-load Plant", Aug 2009, http://www.seai.ie/Renewables/Renewable_Energy_Policy/Policy_Initiatives/Electricity_Storage_Event/niamh_troy.pdf



Troy, N., Denny, E. and O'Malley, M.J. "Base load cycling on a system with significant wind penetration", *IEEE Trans. Power Syst.*,Vol. 25, pp. 1088 - 1097, 2010.

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"No Storage" implies the available pump storage in the 2020 Irish-Grid Planning Case is not available for use. "No Interconnection" implies that foreseen interconnection to other grids are not enabled. Base Case refers to being able to use pumped storage or interconnection to diversify the energy mix.

Conclusions as discussed in detail in [2] and summarized in [3]. Some take away points for this Irish Study Case are:
• For increased penetration level of Wind CCGT units are cycled the most (because they are more flexible) and coal units are less affected (because they are less flexible).
• From low to high levels of wind pumped storage displaces the need for thermal plant to be online to provide spinning reserve. Therefore base-load units spend less hours online on a system with storage.
• Interconnection undercuts local/domestic plant generation which are forced down the merit order. Therefore more base-load cycling with interconnection.

An interesting observation is that for very high levels of wind penetration there is a crossover where a system with storage/interconnection is better equipped to deal with large amounts of fluctuating wind.

The impact of modifying the penalties associated with start-up cost will either make the base units cycle more (due to low penalties/costs) or cycle less (due to high penalties/costs). For more detailed discussions please see [2, 3].

SCADA/Energy-Management Syst for Renewables
Wind Energy

References:
[1] A. Timbus et al., "Extension of Contingency Analysis to Wind Power," 9th International Workshop on Large Scale Integration of Wind Power in Power Systems, Quebec City, Canada, 18-19 October, 2010
[2] A. Timbus et al., "Integration of Wind Power in Reserve Calculation and Monitoring," 9th International Workshop on Large Scale Wind Power Integration in Power System, Quebec City, Canada, 18-19 October, 2010

- Enhancements SCADA/EMS:
  - model wind power components in SCADA database
  - enhance EMS applications (e.g. Security Analysis) to cover wind power variations and outages
  - Fetch from 3rd party, aggregate and provide wind power forecasts to different EMS applications
  - account for the stochastic nature of the wind plant outputs in Energy Market Systems (i.e., unit commitment and economic dispatch)

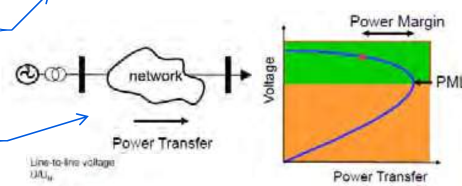
Besides the technologies used for increasing the grid capacity through installation of primary hardware, grid management software also needs to be modified to allow for the integration of Renewables. In this slide we highlight modifications needed to widely used transmission grid management software, SCADA/EMS.

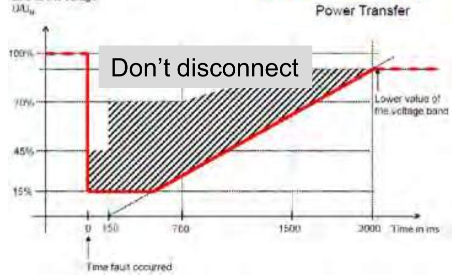
Integration of Renewables
Power System Stability

References:
[1] P. Sauer, M. A. Pai, "Power System Dynamics and Stability"
[2] L. Söder, Explaining Power System operation to non-engineers
[3] M. O'Malley, "Integrating Wind in Ireland: Experience and Studies," Jan 2011, Boston, MIT, http://web.mit.edu/windenergy/windweek/Presentations/OMalley%20-%20Final%20MIT%20Jan%2019th%202011-Update.pdf

- Stability issues [1] arise after an unplanned event (e.g. faulted line)
  - will the dynamics settle to a new equilibrium?
  - if not, how to guide them to reach one?
- Stability phenomena in power systems
  - Transient (or angle)
  - Frequency: oscillations (local and global) of interconnected electromechanical system. Inertia in system is important.
  - Voltage stability: Depressed voltage and high load demand (> max power transfer capability) . Starts locally, but spread due to complex network interactions
- Renewables should contribute to system control
  - Ride-through capability
  - Voltage control
  - Output power control
- Lack of energy storage /inertia of Renewables make existing systems more prone to dynamic stability issues, problem not well studied yet

[2]





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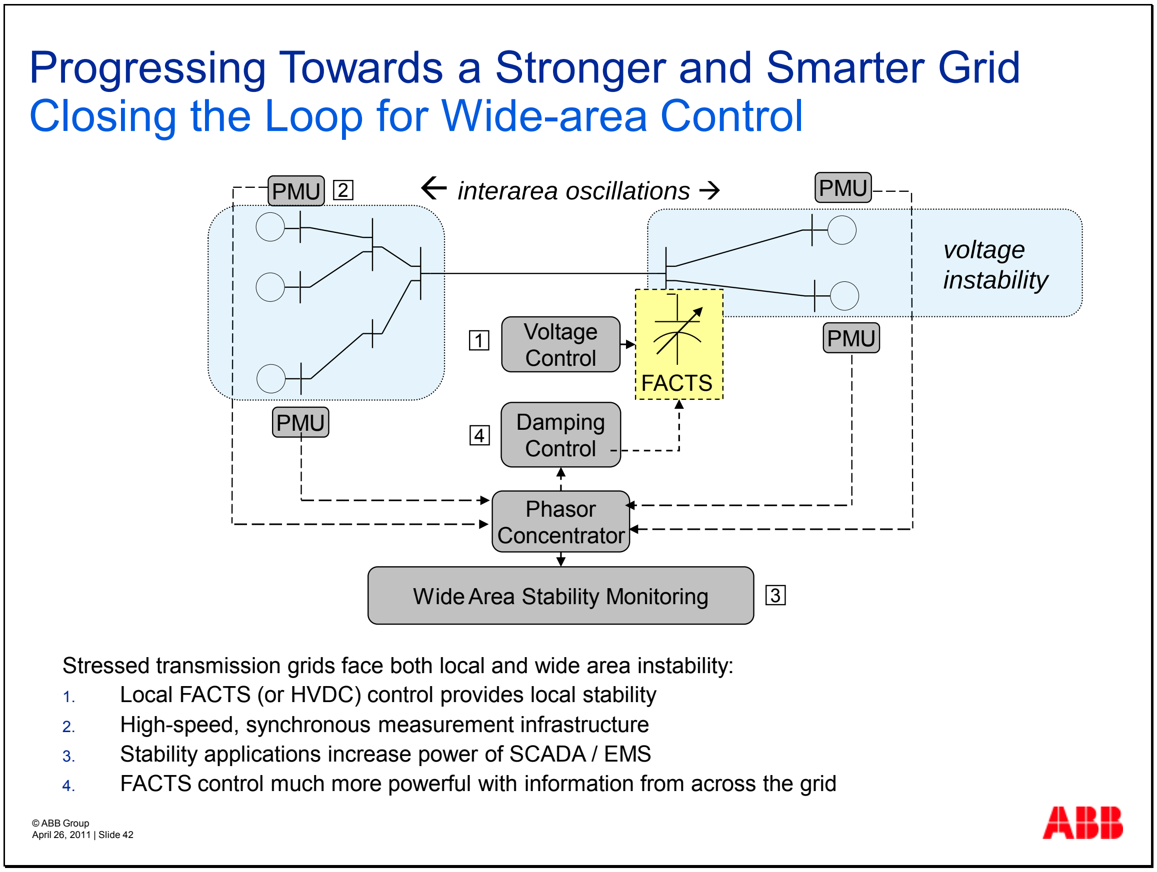
Incorporating more Renewables into the Generation stack, stability situations can arise when all of a sudden a large amount of generation disappears (or are disconnected due to reasons such a depressed voltage) placing the interconnected system under stress. Two such examples are:

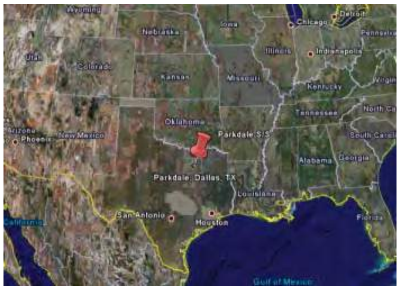
- The near blackout in Texas on 26 Feb 2008 when the Wind generation dropped from 1.7GW to 0.3GW (see http://saveourseashore.org/?p=829)
- Spain, Feb 26 2004: 600 MW loss of wind power due to one grid fault



There are technologies available to help stabilize the system. One in particular is Wide-area Control (WAC), which is a good example of how intelligence is coupled with controllable hardware such as FACTS. At the heart of these schemes are synchronized phasor measurements (PMUs) that allow an operator the ability to view power system dynamics in real-time at a central location (which is not currently achievable with a SCADA/EMS system that provides the operator with only a single-time snapshot view of the system). Advanced *system-wide* control can then be deployed to use the measurements from these PMUs to force controlled changes in the grid through grid actuators such as FACTS devices. WAC has been a research focus in academia and industry for at least the past decade, but this technology has been largely untested (a few pilot cases across the world, with China being the current trendsetter) in the field due to conservative nature of Transmission System Operators that prefer that a human operator be in the control loop.

It should be noted that local (as opposed to system-wide) fast acting control using controllable hardware (such as FACTS) might be more amply deployed, but this type of control can only affect local phenomena and the system will remain prone to global stability problems.

Progressing Towards a Stronger and Smarter Grid
Stability Improvement Example



Customer

- ONCOR – Texas' largest regulated electric utility, serving over 7.5 million consumers

Solution

- Parkdale : Two SVCs ; Renner : Two SVCs

Key objectives

- Address growing load in Dallas
- Facilitate retiring of old generation and integration of renewables (wind)
- Improve grid reliability

Benefits

- Mitigating the risk of blackouts and brownouts in the Dallas-Fort Worth area
- Quick solution : alleviating need for new capacity & lines - long lead time

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Grid Integration of Renewables
Distribution Systems

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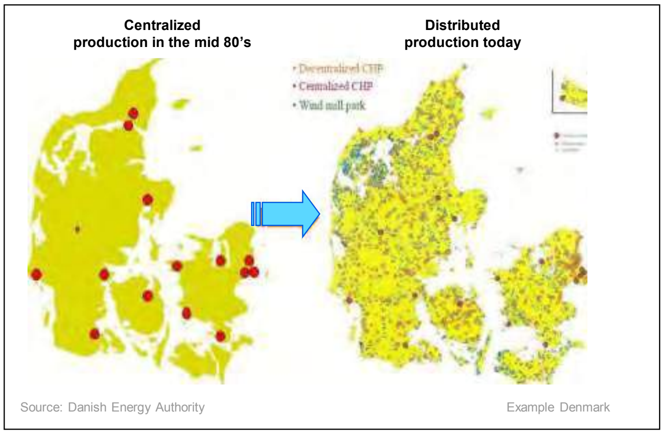
Distributed Energy Resources
Opportunities as well as Challenges



- Small scale generation growing fast, complementing central power
- Combined heat and power plants with high energy efficiency (~ 89 %)
- Small wind and residential solar with option of feeding into grid
- Today's individual consumers may also become distributed generators
- *Technical and regulatory challenges to stabilize voltage and frequency*

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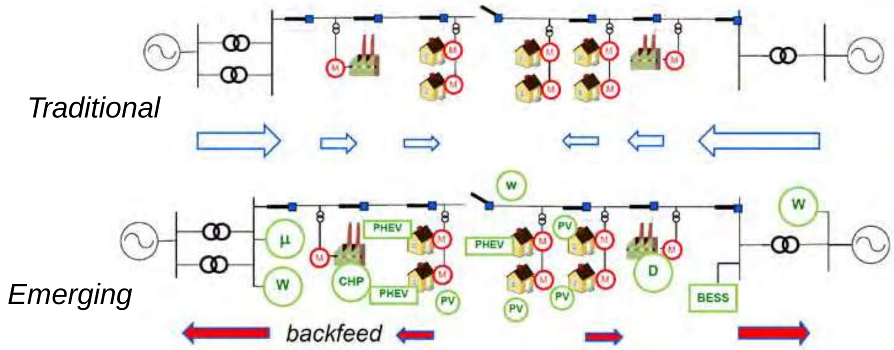
There are examples, such as the displayed Danish one, where the T&D power system morphed from predominantly centralized generation to a mix of few centralized and many more distributed generation sources. With such an evolution there are some opportunities as well as challenges as listed above.

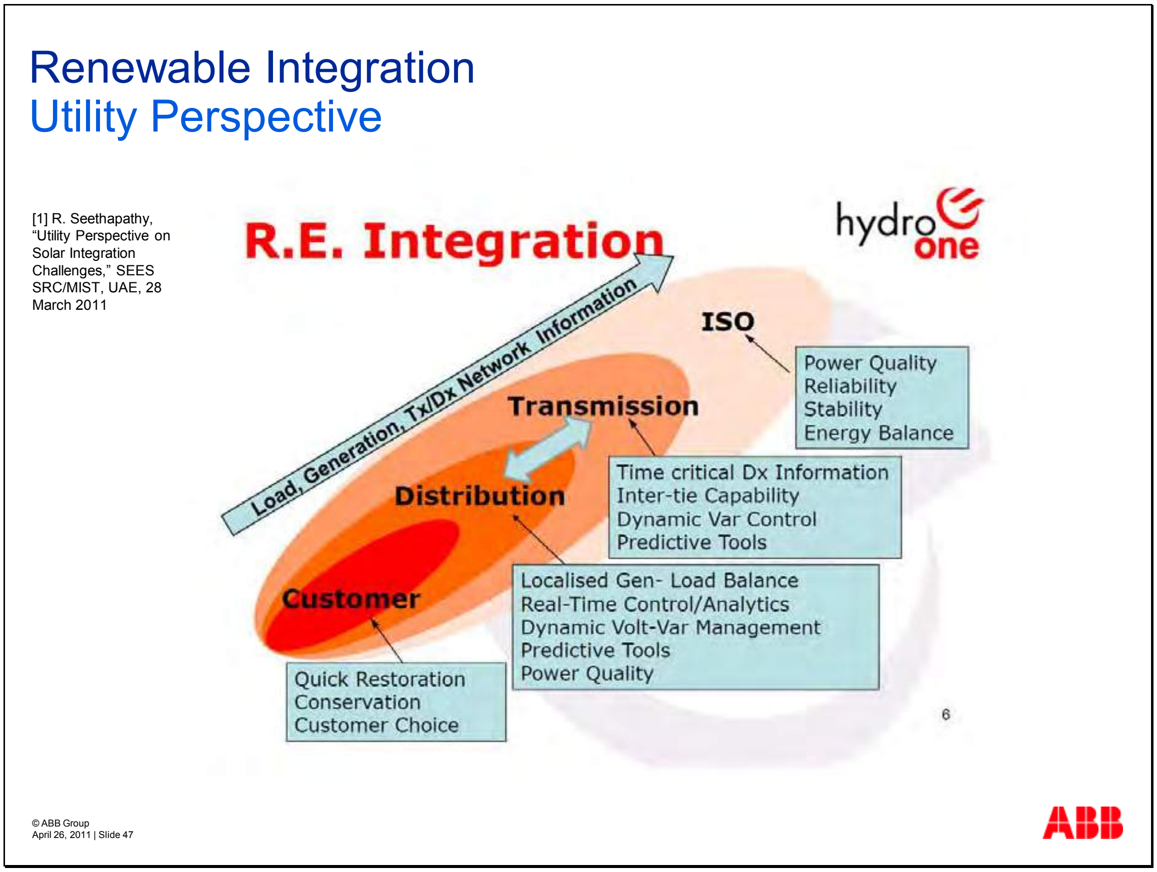
Distribution Grid with Renewables
Small and Plentiful Distributed Energy Resources



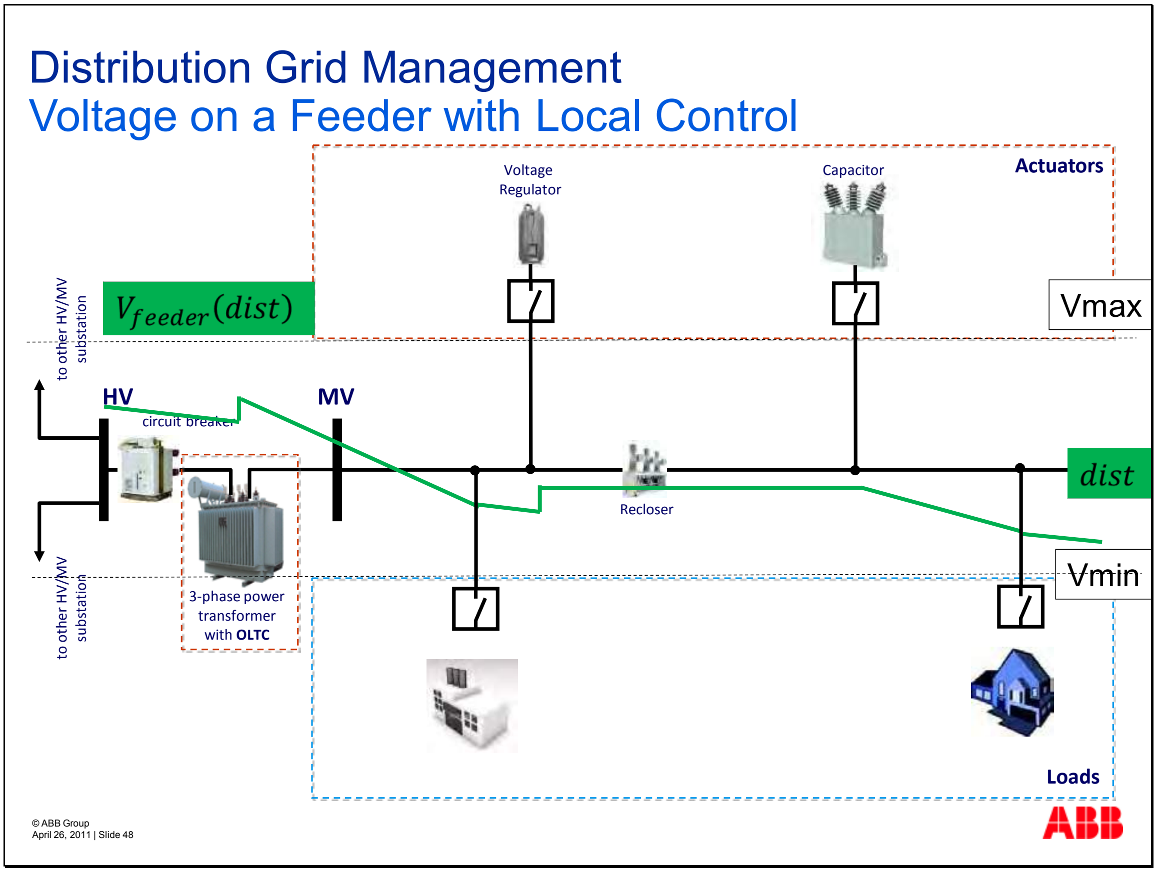
- Integration of DER introduces
  - Possible backfeed into the grid
  - Intermittency of renewables poses a challenge for grid operation
  - Many entities to control or interact
- Thus requires
  - Protection coordination needs to be revisited
  - Incorporation of forecasting for renewable sources
  - Demands new and efficient algorithms, such as coordinated control

In the 'traditional' grid, energy flows from the large central generation and enters the medium voltage network and flows 'downhill' to the load. Generation and storage of many technologies will continue to be distributed in the MV and LV networks. The electric power these sources now inject may 'swim upstream' (backfeed) creating problems for existing protection and control systems. Work is ongoing in industry to modify existing methodologies to handle these changes.

The existence of the new resources yields opportunities for e.g. energy dispatch and voltage control, but the random nature of sun and wind, as well as the question on who owns and control a resource, make for a challenging new operating environment.



In this slide Seethapathy highlights some of the issues Hydro One faces with the integration of Renewables into their grids (i.e., both Transmission and Distribution). The take away point from the slide is that the coupling between Transmission (Tx) and Distribution (Dx) is becoming stronger due to situations such as backfeed from distribution to transmission as well as active demand management in the residential, commercial and industrial segments. When it comes to significant backfeed from the distribution to transmission it is fair to say that most systems were not designed to handle this flow reversal and tighter interactions between the two systems emerge.



In this slide we illustrate what a typical voltage profile can look like as a function of distance along a distribution feeder. What we observe are:

- Voltage drop on the lines or cables
- Local, and potentially uncoordinated, control actions by actuators such as the On-line Tap Changing Transformer, Voltage Regulator, Capacitor provide some means to compensate for the above mentioned voltage drops.

This picture represents the status quo, but with Energy Efficiency Initiatives and penetration levels Renewables in Distribution Grids on the rise more sophisticated Grid Management approaches are needed. Next we will discuss one such example.

Voltage and VAR Optimization (VVO)
Improving Operation of Distribution Grid

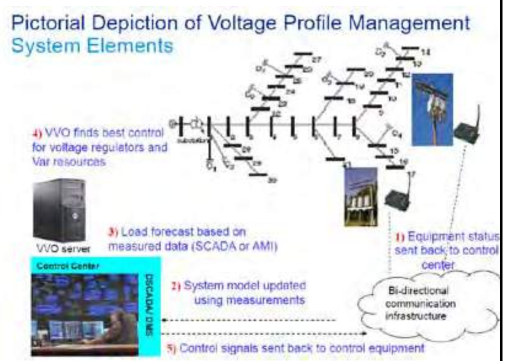
References:
[1] X. Feng et. al, "Volt/VAR Optimization Reduces Losses, Peak Demands," 2010, http://www.electricenergyonline.com/?page=show_article&mag=61&article=466
[2] X. Feng et. Al, "Smarter grids are more efficient," ABB Review, 2009Q3, http://search.abb.com/library/Download.aspx?DocumentID=9AKK104295D7437&LanguageCode=en&DocumentPartID=&Action=Launch

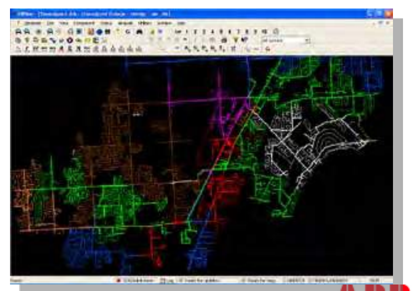
- Minimize (Grid losses + Peak Power Demand)

Subject to:

- Power flow equations
(unbalanced multi-phase system, meshed network)
- Voltage constraints
(phase to neutral and phase to phase)
- Current constraints
(cables, overhead lines, transformers, neutral, grounding resistance)
- Operational constraints of actuators
(tap changers, shunt capacitors, …)

→ Mixed Integer Nonlinear Programming Problem





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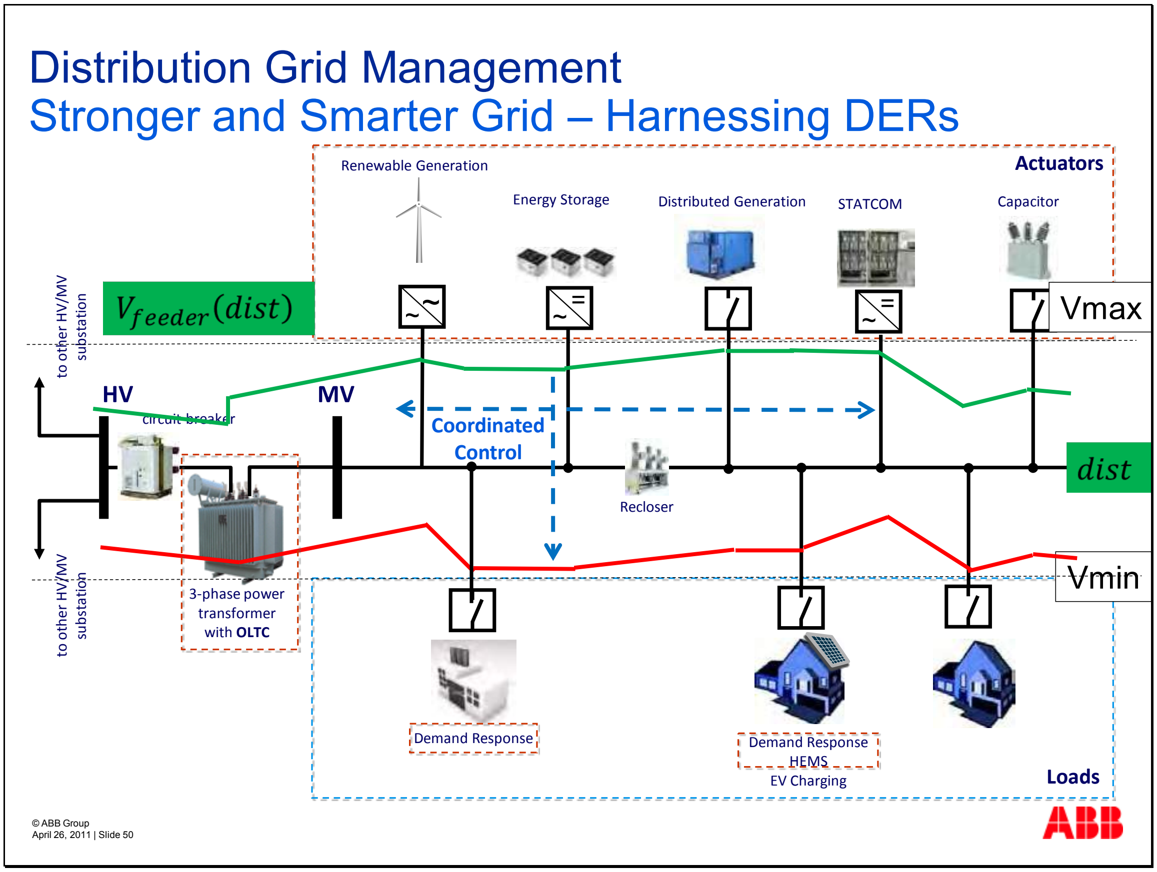
Improvement of Operation of Distribution Grids is a big focus of Smart Grids and in this slide we highlight some recent advances in operational tools available to Distribution Grid Operators. VVO can be thought of as the Distribution Grid version of Unit Commitment. Using this application one can improve the energy efficiency of the grid, and as was discussed earlier such improvements can be counted towards satisfying RPS targets.



In this slide we illustrate how the landscape is changing on the simple distribution feeder illustrated earlier. We notice more Distributed Energy Resources penetrating into the grid, and these sources can be considered as actuators that can be used by an advanced DMS Application such as VVO. A Utility can now operate its grid to increase its revenue (Vmax) or save energy (Vmin). VVO helps the utility to reduce its losses in the Grid and in doing so reduces the need for new peaking generation units to be installed in order to keep up with load growth. As was mentioned earlier some Regulators allow these savings to count towards CO_2 reduction targets.

Ownership and control of a distributed renewable source can present a challenge for using said resource/actuator in a coordinated control scheme as discussed here. This problem can't be solved by technology alone, and innovative business models might be required.

Grid Integration of Renewables
Energy Storage

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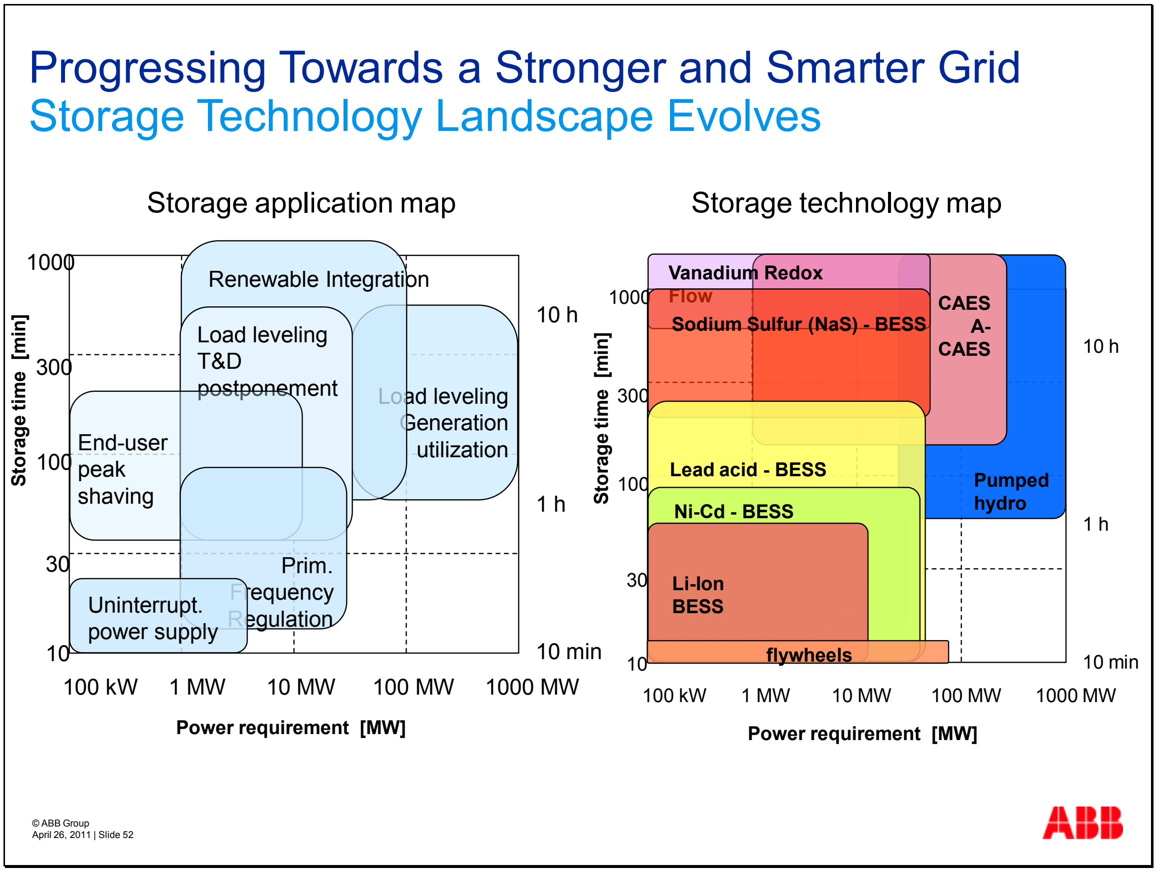

Recall the basic intermittency issue discussed earlier, this ultimately leads us to touch on storage. In this slide a mapping of grid applications that can benefit from storage is shown as a function of storage time and power requirement. In the right hand figure a similar mapping is made of the capabilities of known storage technologies. Most of these technologies are already available, but for some the cost-benefit ratio is still not at the right level to see a drastic deployment of storage into T&D grids. However as penetration of renewables increases the need for storage will also increase, and ongoing R&D to advance storage technologies is required.

Progressing Towards a Stronger and Smarter grid
New Combinations of FACTS with Storage

Example:
- Storage system based on series connection of Li-Ion battery modules
- Integrated safety, protection and control functions
- Technical data:
  - Rating up to ≈ ±100 MVA
  - Active power capability typically 5-50 MW for 5-60 minutes
- Benefit:
  - Short-term and emergency power
  - Enable integration of renewables into weak electrical networks by providing stability support

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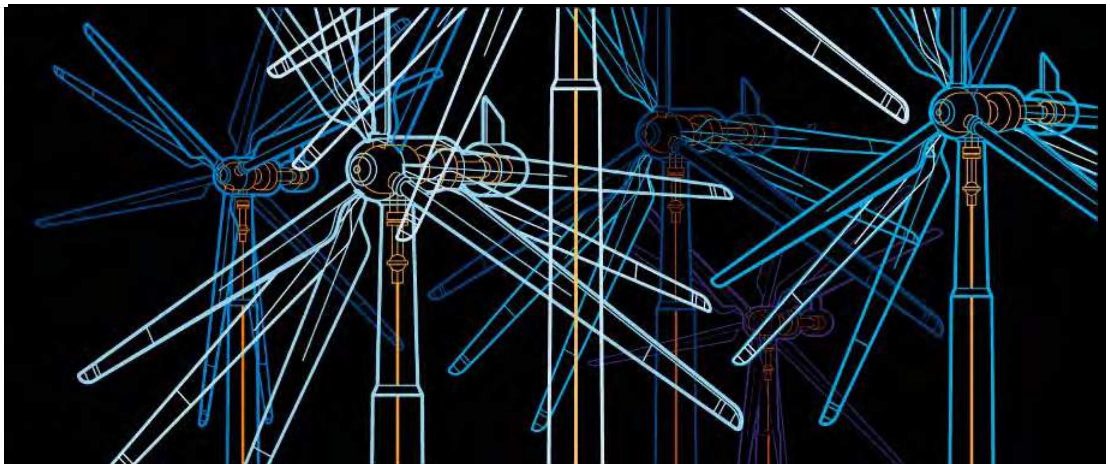
More information of DynaPeaQ can be found at:
http://www.abb.com/industries/db0003db004333/f4fe0de96f60d23ac1257674004dbcb5.aspx?productLanguage=us&country=US



Grid Integration of Renewables
Conclusions and Open Challenges

Power and productivity for a better world

Grid Integration of Renewables
Conclusions and Open Challenges

- Range of Technologies exist for Integration of Renewables
- Some technology gaps exist, and are subject to further investigations
- Intermittency
  - Improve forecasting and management algorithms – ongoing work
  - Use energy storage – improving cost competitiveness requires work
  - Cycling of traditional power plants – ongoing investigations to understand feasibility and impact
- Inclusion of Remote Renewables into Transmission Grid
  - Grid Hardware – good building blocks, but continuing R&D needed
  - Grid Management – dynamics and stability will become more prominent, hence better understanding and algorithms are required
- Distributed Renewables
  - Need for improved control algorithms leveraging new real-time information (aka Smart Grid) and power-electronic enabled actuators
  - A better understanding is needed of the emerging tighter coupling of Transmission and Distribution systems

Grid technology will continue to evolve, bringing about Stronger and Smarter Grids that will allow incorporation of even greater levels of Renewables

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Acknowledgement: Material contained in this note has been assembled by many individuals within ABB, and the author would like to recognize their effort in realizing this document.

The Brattle Group

Policy Challenges Associated with Renewable Energy Integration

April 2011

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Prepared for

2011 MITEI SYMPOSIUM:
Managing Large-Scale Penetration of Intermittent Renewables

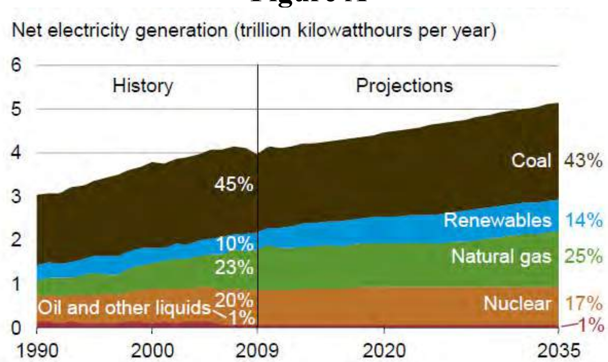
Please note: Opinions expressed in this report, as well as any errors or omissions, are the authors' alone and do not reflect those of *The Brattle Group* or its clients.

Table of Contents

I. INTRODUCTION

During the next 100 years, the world's electricity systems will almost certainly transition to a high degree of reliance on renewable energy generation resources. Over 29 states currently have renewable portfolio standards (RPSs), requiring utilities to purchase a total of approximately 60,000 MW of renewable energy by the year 2025. The Department of Energy's Energy Information Administration projects that an additional 54,000 MW of renewable generation will be added to the US grid by 2035.[1] As shown in Figure A, net energy generation from renewable energy is projected to rise from 10% to 14% of total U.S. supply by 2035.

Figure A



Source: U.S. EIA Annual Energy Outlook 2011 Early Release Overview

For the next several decades, these renewable resources will be added to a system that operates via centralized controls and price signals to balance regional generation and load continuously, but which has very little large-scale storage. In a system for which its safe operation historically has required that total supply be immediately adjustable to match load, the inability to control the output of variable renewable power sources introduces new technical and policy considerations. These considerations require new protocols to maintain reliability at required levels that apply in all three power system time frames: the planning horizon (one to ten years); the commitment and dispatching (operating) time frame (a few months to the current hour); and the reliability time frame of seconds to minutes following a reliability event.

In traditional power systems, the penetration of uncontrollable variable generation sources has historically been quite small. Accordingly, one can compare the difference in the overall costs of building and operating systems with higher and lower amounts of variable supplies and treat this difference as the costs that variability imposes on the system. Today, this is commonly called the costs of integrating variable resources.

While the notion of renewables integration costs is a useful construct today, two accompanying notions should be kept in mind. First, integration costs are not the same as total comparative system costs, as they do not factor in any benefits of renewable sources not captured in the system cost calculations. For example, from the customer standpoint, renewable sources provide

[1] U.S. Energy Information Administration "Annual Energy Outlook 2011" Reference Case, December 16, 2010. Can be found at: http://www.eia.gov/neic/speeches/newell_12162010.pdf

valuable fuel price hedges, but renewables are not credited for this value when measuring integration costs.[2]

The second point to keep in mind is that the underlying benchmark system against which variability's cost is measured is changing gradually over time. As storage becomes cheaper and more common, grid operators develop better monitoring and control algorithms, and dynamic prices self-modulate consumer demand, the costs imposed by variable renewable generation will diminish. Ultimately, we can foresee a much smaller variability premium as the system becomes designed around continuously varying distributed resources and loads.

For the near future, however, these costs are significant. They spread themselves across all three time frames. In this paper, we briefly survey the nature and size of these costs and the policies being adopted to measure and collect them. Although there is enormous overlap with similar issues in the European Union today,[3] we confine our examination to North America.

II. CURRENT OVERALL RESEARCH

Utilities and organizations responsible for grid reliability already have begun to examine the potential issues associated with a significant penetration of intermittent renewable energy. In anticipation of the operational and reliability impacts which renewable resources may have on the grid, the North American Electric Reliability Corporation (NERC) issued a report in 2008, titled Accommodating High Levels of Variable Generation.[4,5] There have also been numerous studies by utilities and independent system operators (ISOs), among them: the CAISO Integration of Renewable Resources studies (2007, 2010),[6,7] the New England Wind Integration Study (2010)[8], the Minnesota Wind Integration Study (2006),[9] the Wind Integration Study for Public Service Company of Colorado (2006, 2008),[10] Analysis of Wind Generation Impact on ERCOT Ancillary Services Requirements (2008),[11] Operational Impacts of Integrating Wind Generation into Idaho Power's Existing Resource Portfolio (2007),[12] and the NYISO 2010 Wind

2 See, Peter Fox-Penner, Smart Power (Island Press, 2010), pp. 56-65 for a discussion of the benefits of distributed generation.

3 For example, see "Integrating Intermittent Renewables Sources into the EU Electricity System by 2020: Challenges and Solutions," Eurelectric, 2010.

4 http://www.nerc.com/docs/pc/ivgtf/IVGTF_Outline_Report_040708.pdf

5 One of the seemingly mundane operational questions faced is simply creating a uniform approach to the reporting of renewable resource outages and deratings which is comparable to that for conventional generation. See http://collaborate.nist.gov/twiki-sggrid/pub/SmartGrid/PAP16Objective1/NERC_GADS_Wind_Turbine_Generation_DRI_100709_FINAL.pdf

6 http://www.caiso.com/1ca5/1ca5a7a026270.pdf

7 http://www.caiso.com/2804/2804d036401f0.pdf

8 http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/reports/2010/newis_es.pdf

9 http://www.state.mn.us/portal/mn/jsp/content.do?contentid=536904447&contenttype=EDITORIAL&hpage=true&agency=Commerce

10 http://www.nrel.gov/wind/systemsintegration/pdfs/colorado_public_service_windintegstudy.pdf
http://www.uwig.org/CRPWindIntegrationStudy.pdf

11 http://www.uwig.org/AttchB-ERCOT_A-S_Study_Final_Report.pdf

12 http://www.idahopower.com/AboutUs/PlanningForFuture/WindStudy/default.cfm

Generation Study[13]. These studies vary in scope and methodology, but in general, analyze the potential implications of high wind turbine generation and solar generation penetration on system reliability, scheduling, and planning, as well as the effect on markets and the rules that govern market transactions.

While the precise methods used in these renewable integration analyses vary, their conclusions are more or less consistent. For example, all of the above studies conclude that a high penetration of variable generation will increase the grid's need for regulation, load-following and other ancillary services needed to help compensate for the variability and uncertainties associated with their generation pattern. Estimates for the costs of these ancillary services are in the range of $5 to $20 (2011$) per MWh of wind energy accepted by the system.

III. OPERATION AND PLANNING CHANGES

While the existing power system has traditionally been designed to meet varying demand levels from one moment to the next, it has not been developed to respond to large unexpected variations in both generation output and in load. Although load exhibits significant variability, the overall seasonal, daily, and hourly patterns typically result in enough predictability to permit the month, week, and day-ahead scheduling of resources, both in magnitude and kind, *i.e.,* unit commitment. When the variability of generation resources is small relative to that of load, the system uses generation resources that can quickly match their output to the varying demand above "base load" levels. On the smallest time scale of second to second or minute to minute, certain generators are interconnected to the grid in such a way that they automatically respond to those varying demand levels by providing frequency control and regulation services. "*Primary frequency control* involves the autonomous, automatic, and rapid action (*i.e.,* within seconds) of a generator to change its output to compensate large changes in frequency. Primary frequency control actions are especially important during the period following the sudden loss of generation, because the actions required to prevent the interruption of electric service to customers must be initiated immediately (*i.e.,* within seconds).[14]" In addition to primary frequency control, the grid operator must have the capability to provide secondary frequency control. "*Secondary frequency control* involves slower, centrally (*i.e.,* externally) directed actions that affect frequency more slowly than primary control (*i.e.,* in tens of seconds to minutes). Secondary frequency control actions can be initiated automatically or in response to manual dispatch commands. *Automatic generation control* (AGC) is an automatic form of secondary frequency control that is used continuously to compensate small deviations in system frequency around the scheduled value."[15]

On the time scale of generation and transmission scheduling, blocks of energy may need to be dispatched up or down to supplement the wind and solar energy that are used on a must-take basis. Together, one can think of these compensations as "balancing services" needed to maintain system equilibrium and reliability. Balancing services can come from some of the existing generation fleet and demand-side resources. However, planning for the future requires a

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[13] http://www.nyiso.com/public/webdocs/newsroom/press_releases/2010/GROWING_WIND_-_Final_Report_of_the_NYISO_2010_Wind_Generation_Study.pdf

[14] Eto, Joseph H. *et al.,* Use of Frequency Response Metrics to Assess the Planning and Operating Requirements for Reliable Integration of Variable Renewable Generation, Lawrence Berkeley National Laboratory, LBNL-4121 at p. 9. (http://certs.lbl.gov/pdf/lbnl-4142e.pdf)

[15] Ibid at p. 9

fresh look at what that optimal mix would be for the coming decades as renewable generation becomes a significant and possibly dominant resource on our systems.

IV. TODAY'S OPERATIONAL CHALLENGES

Electric systems have always had to accommodate continuously changing customer loads and some variability in generator output, including planned and unplanned generator and line outages. A portion of renewable integration costs is simply the result of higher levels of variability in operating generator output than previously experienced. In the operating time frame, the main challenges can be summarized as follows:

First, wind and solar generation resources exhibit significant minute-to-minute variations in their output. Their variations alone may not be troublesome; however, the unpredictability of their variations creates new operational concerns. Recall that the grid operator must continuously keep the system in balance. Thus, the grid operator is faced with "guessing" what resources will be needed to compensate for the loss/gain in output from the intermittent renewable resources. Ultimately, the amount of compensating resources needed depends on how "wrong" the grid operator is at various time frames. For example, regulation services are used to compensate the second-by-second deviations from the 10-minute-ahead forecast that determines the generators' dispatch. As an example, if the operator expected 100 MW of wind for the next 15-minutes, but only 96 MWs (more or less) actually show up, regulation services will be used to compensate those second-to-second deviations from the 100 MW forecast. It is precisely those deviations that drive how much regulation service the system will need.

Given both the uncertainty and the variability of wind and solar generation, systems need more generation than in the past that can quickly ramp up and down, possibly with short start-up times and minimal cool-down times. Whether or not such new demand on cycling and peaking plants can be met by existing generation — which could experience low profitability due to low capacity factors — is an empirical question, and each system must evaluate the physical and economic drivers that its generation fleet faces or will face in the future.

Second, by displacing some of the marginal peaking and cycling generation, wind and solar generation also forces some traditional baseload plants to operate as cycling units, many of which are not designed to do so. This reduces their capacity factors and, revenues, and increases their heat rates. For many units not designed for cycling, the additional ramping can significantly increase going-forward operation and maintenance costs, further reducing their profitability. The combined effect of these first two situations is illustrated in Figure B below.[16]

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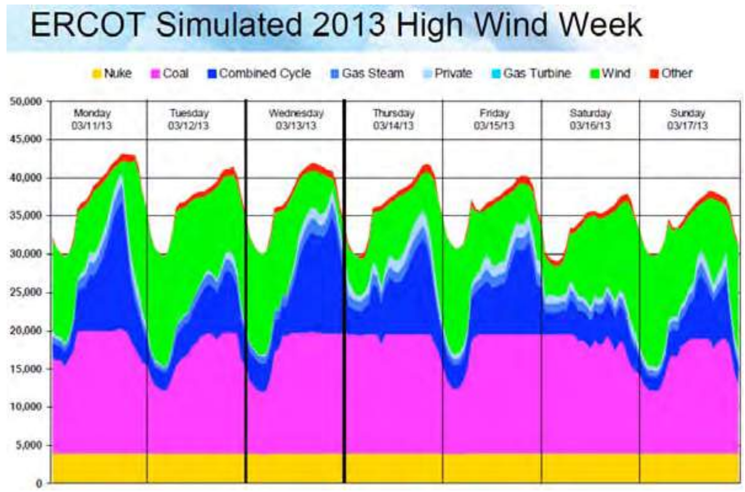
[16] Source: ERCOT Energy Seminar 2009, Chairman Barry T. Smitherman, Public Utility Commission of Texas, November 12, 2009.

http://www.puc.state.tx.us/about/commissioners/smitherman/present/pp/GDF_Suez_111209.pdf

Figure B



Source: ERCOT Energy Seminar 2009, Public Utility Commission of Texas, November 12, 2009

Third, because wind often tends to be stronger during off-peak periods such as during the night, the resulting higher wind generation output tends to exacerbate the existing system's "over-generation" condition. Over-generation occurs when load is lower than the amount of dispatched generation on a system. Most of these situations occur because baseload plants with relatively high minimum generation levels[17] and long start-up and shut-down time, cannot be turned off economically and reliably over-night when they have to be turned back on for the next day. Thus, during those hours in the middle of the night, neither the baseload generators' nor the wind plants' owners would want their generation curtailed. Each of those plant types would be willing to receive zero to slightly negative prices before they would agree to reduce their production levels.[18] This is particularly acute with high penetrations of wind generation because while wind generation output may increase at night, its output is greatly reduced during the day (particularly hot humid days when air-conditioning and other cooling loads are at their maxima) and conventional generation must be energized. Negative energy prices already are observable in Texas and the Midwest, as shown in Figure C for ERCOT[19] system in 2010 and Figure D for MISO[20] in 2009.

Finally, because most renewable resources are needed to satisfy the growing renewable portfolio standards, and they have near-zero marginal costs, they are typically operated as must-run

17 We have estimated that the coal plants in the Midwest-ISO market have a minimum generation level of about 60% relative to their peak generation capacity.

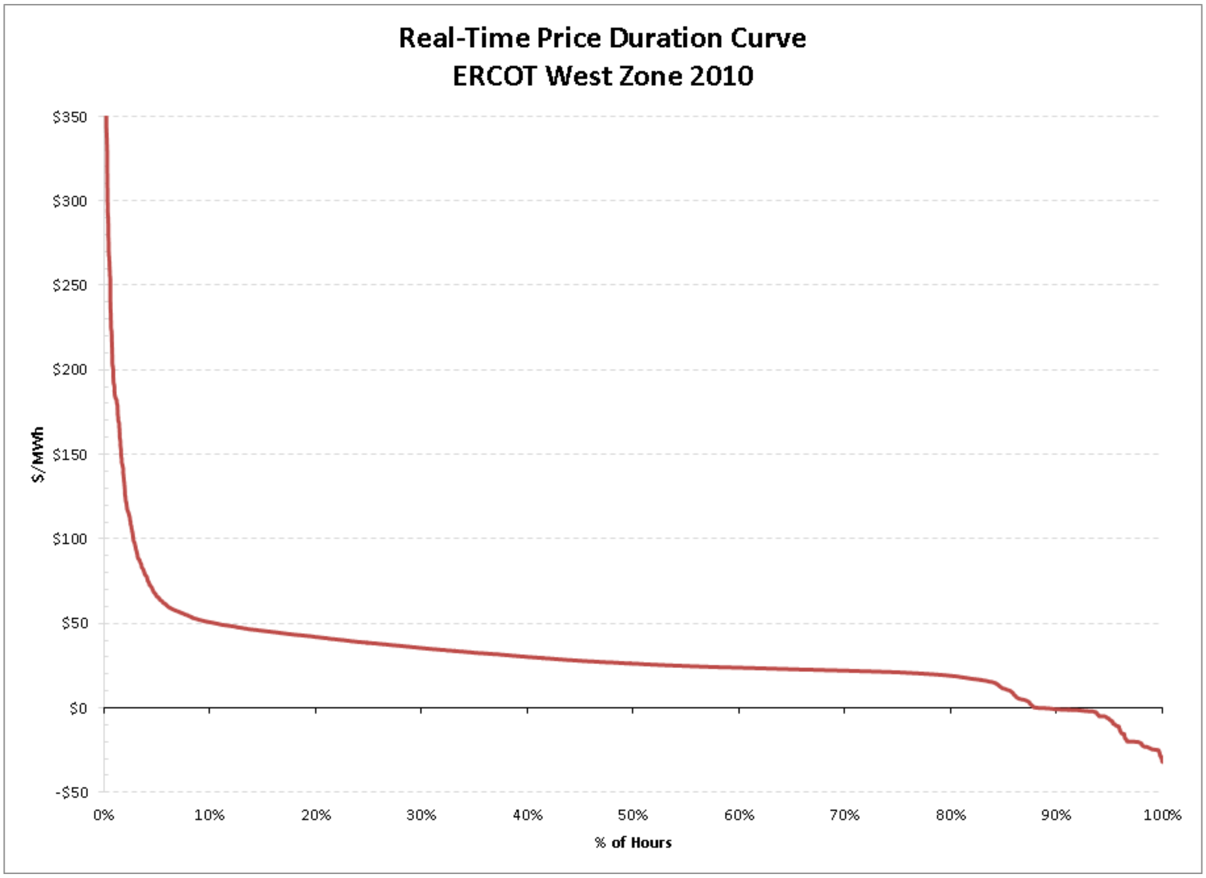
18 In many cases, wind plants that qualify for Renewable Energy Credits (RECs) and/or Production Tax Credits (PTC) are willing to receive negative market energy prices because their opportunity cost of not producing would be the foregone values of RECs and PTC, which in most cases are greater than \$20/MWh. In some cases, the generator is paid both for the implied value of RECs and PTCs through their long-term contracts with load-serving utilities even if the power is curtailed, in which case, the generators would curtail before receiving negative prices. However, under those circumstances, it's usually the rate-payers who ultimately pay for the renewable generation contracts are left paying twice, once for the environmental attributes that they never received due to the curtailment, and another time for the coal generation that could not be backed off.

19 Source: ERCOT market data from http://www.ercot.com

20 Source: 2009 State of the Market Report Midwest ISO

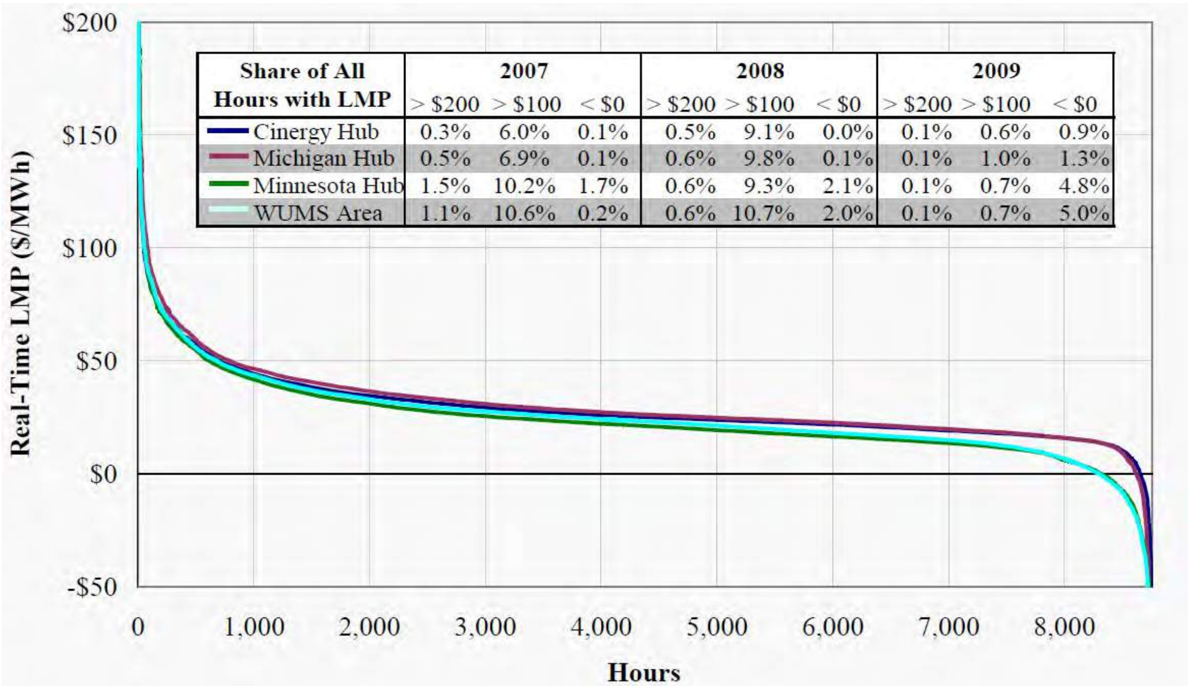
generation, that is, when they generate, the system operator must accept their output. Operated as must-run, they force the grid operator to reduce the output of existing marginal generation resources, triggering all of the adverse impacts noted above. In deregulated markets where generators may have no revenues sources beyond hourly energy sales. The consequent revenue reduction could force some plants to shut down, reducing cycling and peaking generation just when it may be needed.

Figure C



Source: ERCOT market data from http://www.ercot.com

Figure D
Real-Time Price Duration Curve
Midwest ISO Pricing Hubs
All Hours 2009



Share of All Hours with LMP	2007			2008			2009		
	> $200	> $100	< $0	> $200	> $100	< $0	> $200	> $100	< $0
Cinergy Hub	0.3%	6.0%	0.1%	0.5%	9.1%	0.0%	0.1%	0.6%	0.9%
Michigan Hub	0.5%	6.9%	0.1%	0.6%	9.8%	0.1%	0.1%	1.0%	1.3%
Minnesota Hub	1.5%	10.2%	1.7%	0.6%	9.3%	2.1%	0.1%	0.7%	4.8%
WUMS Area	1.1%	10.6%	0.2%	0.6%	10.7%	2.0%	0.1%	0.7%	5.0%

Source: 2009 State of the Market Report Midwest ISO

In addition to incurring an O&M and heat rate penalty from greater cycling, the latter negatively affects plant and system air emissions and therefore air emissions compliance costs. As noted above, the variability of wind and solar output requires that conventional units operate at lower levels to preserve their ability to be called on for immediate response. Those units are frequently combined cycle gas turbines. Combined cycle gas turbines (CCGT) typically have low NOx burners which reduce their nitrous oxides emissions by lowering the temperature of combustion. However, this type of control has significantly reduced effectiveness if the generator operates at less than sixty percent of its nominal rating, as will be the case when they are operating as a regulation services source for intermittent resources. This also occurs when intermittent generation, operating as 'must-take' units, forces reductions in CCGTs level of output or generation efficiency. In addition, baseload units that have been forced to cycle but are not designed to do so will, as noted above, suffer from increased heat rates, in which case they will be burning significantly greater amounts of fuel to produce the same level of electric output. Such increases in fuel use also result in increased emissions.

V. ISSUES IN THE PLANNING TIME FRAME

The above operational changes are starting to affect the criteria used for long-range system planning. Many renewable integration studies have already identified the need for fast ramping resources to help "balance" the intermittent generation. The ramping requirement is a multi-dimensional puzzle at various time scales, involving capacity, ramp rate (in MW/min) and ramp duration. For example, the CAISO renewable integration studies have estimated the ramping requirement associated with regulation and separately with load-following requirements. The 2010 CAISO study finds that the simulated maximum load-following down ramp rate could be as high as -845 MW/5min, which could pose a challenge to the system.[21] However, these estimated ramp requirements do not directly translate into a specific resource type or capacity size that would be needed to resolve the need.

Some researchers have argued that most of that additional need can be met with existing generation and demand-side resources.[22]. But how much of existing resource can be used to meet the new ramping needs is a non-trivial empirical question that requires detailed evaluation of each system, including inventorying the capability of existing fleet and demand response capabilities to determine if newer technologies would be needed.

In some jurisdictions, the increasing penetration of renewable energy is taking place at the same time that some baseload generation will likely retire due to pending EPA regulation. In addition, as discussed above, higher renewable penetration tends to decrease the wholesale price of energy which places downward pressure on the profitability of other market-priced generation, including some cycling plants that typically can be used to meet the ramping needs at various time scales.

More sophisticated tools for reliability calculations by ISOs and other grid operators may also be needed. Likely of more crucial importance in future planning is accounting for the time connectedness of the states of the system. Many of the planning tools have a kind of implicit time-independence in their calculation of the system's state of reliability, *i.e.,* the system's potential to fail to meet load requirements. That works when the energy source for generation lacks time dependency. The energy sources for intermittent resources, *i.e.,* wind and solar inputs, have a very strong correlation with time and this information needs to be brought to bear on the calculation of reliability. Even using existing models, the reliability criterion may need to be re-evaluated. For example, effective load carrying capability may be a better choice for assessing a generator's potential contribution to the system's reliability than simply its rated capacity and outage rates.[23]

VI. POLICY RESPONSES TO THESE CHALLENGES

A. Policies Proposed by FERC

Several of the challenges just discussed and others were the subject of a FERC Notice of Inquiry in January 2010 (Docket No. RM10-11-000). In that proceeding, dozens of industry stakeholders presented valuable comments and perspectives. Out of the several potential layers of issues, FERC decided to first focus on three primary topics in its subsequent Notice of

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21 "Integration of Renewable Resources: Operational Requirements and Generation Fleet Capability at 20% RPS," August 31, 2010, CAISO at p. viii.

22 Kirby & Milligan, "The Impact of Balancing Areas Size, Obligation Sharing, and Energy Markets on Mitigating Ramping Requirements in Systems with Wind Energy,"

www.consultkirby.com/files/milligan-kirby-wind-engineering-part2.doc

23 See L.L. Garver, "Effective Load Carrying Capability of Generating Units", IEEE Transactions on Power Apparatus and Systems, Vol. PAS-85, No. 8 (August, 1966) and L. Soder ad M. Amelin, "A review of different methodologies used for calculation of wind power capacity credit" (http://www.ee.kth.se/php/modules/publications/reports/2008/IR-EE-ES_2008_013.pdf). For an example applied to wind resources, Xcel Energy's An Effective Load Carrying Capability Study for Estimating the Capacity Value of Wind Generation Resources. (http://www.xcelenergy.com/SiteCollectionDocuments/docs/PSCoELCCFinalReport030107.pdf) Also, see the discussion in R. B. Billinton and R.A. Allan, Reliability Evaluation of Power Systems, 2d ed, (New York: Plenum, 1996) on Markovian reliability assessments.

Proposed Rulemaking (NOPR) in November 2010 (Docket No. RM10-11-000). In that NOPR, FERC proposed reforms to the pro forma Open Access Transmission Tariff (OATT) to help integrate the growing amount of variable energy resources. The proposed changes include:

1. Require public utility transmission providers to offer intra-hourly transmission scheduling. Specifically the NOPR proposes to require public utility transmission providers to offer all customers the option to schedule transmission service at 15-minute intervals instead of the current hourly scheduling procedure. The more frequent scheduling interval would provide for greater accuracy in scheduling and thereby reduce the amount of ancillary services that systems would need to provide and customers would need to purchase.

2. Incorporate provisions into the pro forma Large Generator Interconnection Agreement requiring interconnection customers whose generating facilities are variable energy resources to provide meteorological and operational data to public utility transmission providers for the purpose of improved power production forecasting.

3. Add a new ancillary service rate schedule through which public utility transmission providers will offer regulation service to transmission customers delivering energy from a generator located within the transmission provider's balancing authority area. This service would provide transmission providers an opportunity to recover costs associated with the integration of variable energy resources. FERC specified that it expects transmission providers to implement the intra-hour scheduling and power production forecasting as conditions to collect additional charges under the new ancillary service.

Of the many operational and planning issues and potential solutions FERC has chosen, likely the most relevant ones to deal with renewable resource integration and the transmission system appear in its January 2011 NOPR. First, requesting transmission service providers to set up procedures for intra-hour transmission scheduling is a move in the right direction. FERC's intention in requiring shorter scheduling time intervals is to help manage the systems' variability more effectively and efficiently with less reliance on ancillary services. From a conceptual level, increasing the frequency of scheduling could improve the efficiency of the system and allowing flexible resources to respond to changes of variable resources on the system.

However, based on the comments submitted by many industry participants, particularly transmission providers, how the intra-hour transmission scheduling would be implemented ultimately is currently not yet clear. One commenting party stated: "The Commission should clarify what processes a transmission provider will have to perform at 15-minute intervals. For example, will the transmission provider be required to review and approve E-tags at 15-minute intervals, settle generator imbalance on 15-minute intervals, and review and address Available Transfer Capability, reserve change issues or loop flow change issues at 15-minute intervals?"[24] A less important concern is how the scheduling will coincide with the RTO's calculation of LMPs. The fifteen minute transmission schedule is not problematic if the RTO calculates LMPs on a five minute basis, but may be if the interval is ten minutes, or any other even multiple of five.

Second, FERC would like variable generation resources to provide more forecasting data to grid operators to help them manage the system more effectively. In our view, the NOPR's proposed

[24] Comments by the Pacific Northwest Parties in FERC Docket No. RM10-11-000, March 2, 2011, page 17.

requirement along these lines is a move in the right direction. The proposed policy will increase the demand for wind and solar power production forecasting and over time, those forecasts should improve in their accuracy. Less clear is whether there will be any penalties for failing to forecast with a modicum of accuracy.

Finally, FERC is allowing transmission providers to add a new transmission service to pay for the regulation and frequency control service used to compensate variable generation. The FERC has in mind that such regulation reserve costs will be allocated to those that caused the costs. We believe that such a cost causation principle is appropriate; however the implementation of the cost allocation will not be simple. For instance, every grid operator would need to distinguish the incremental amount of regulation that variable generators impose onto a system. Such analysis would require an assignment and quantification of the amount of regulation used to serve load variability (and perhaps the variability of conventional generation) separately from the amount of regulation used to compensate for wind and solar variability and uncertainty. Further, as we have discussed above, there are other integration services needed and the costs associated with them may require further analyses.

In February of 2011, the FERC also issued a Notice of Proposed Rulemaking on the Frequency Regulation Compensation in the Organized Wholesale Power Markets.[25] In the NOPR, FERC proposes that RTOs and ISOs be required to implement a two-part compensation structure for the provision of regulation. First, a uniform price for regulation capacity will be paid to all resources that clear in an (hourly) regulation auction market. Secondly, an additional "performance payment," which reflect a "resource's accuracy of performance" would also be rendered. FERC argues that "taking advantage of the capabilities of faster-ramping resources can improve the operational and economic efficiency of the transmission system and has the potential to lower costs to consumers."[26] In essence, the NOPR attempts to investigate whether there is a substantial difference in regulation service quality as provided by conventional (often slower) resources vs. regulation provided by newer technology such as battery storage devices. The NOPR cites a recent study by the Pacific Northwest National Laboratory[27], which examined the extent to which faster-ramping resources can replace conventional generation resource, currently providing regulation. The authors found that, "compared to the current CAISO fleet mix providing frequency regulation, which includes fast-responding hydro units, 1 MW of a limited energy ideal resource could replace 1.17MW of the current generation mix."[28]

B. New Rules for Scheduling and Dispatching Renewable Generators

Virtually all RTOs and ISOs have completed wind integration studies and, with active input from stakeholders, are addressing renewables integration issues via specifically-dedicated working groups.

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25 Notice of Proposed Rulemaking. Frequency Regulation Compensation in the Organized Wholesale Power Markets. FERC Docket Nos. RM11-7-00 AD10-11-000.

http://www.ferc.gov/whats-new/comm-meet/2011/021711/E-4.pdf

26 Ibid. at p. 2.

27 Makarov, Y.V., Ma, J., Lu, S., and T.B. Nguyen, "Assessing the Value of Regulation Resources Based on Their Time Response Characteristics," Pacific Northwest National Laboratory, PNNL-17632, June 2008.

28 In the study, an "ideal resource" was defined as a resource that has a ramp rate equal to its entire capacity in one minute.

The California Independent System Operator (CAISO) published its first comprehensive wind integration study in 2007[29] and recently completed a second study focusing on the operational requirements and generation fleet capability at 20% RPS.[30] CAISO's present focus on meeting the challenges of renewables integration is defined by an updated 20% RPS resource mix, which includes 2,200 MW of solar resources and the intent to investigate the sub-hourly operational challenges presented by the mix of solar and wind resources on the California grid. The CAISO found that introducing solar generation to the renewable portfolio changes the initial 2007 findings relative to a wind-only case. Integrating solar generation is expected to increase the load-following down and regulation down requirements in mid-morning and the load-following up and regulation up requirements in early evening. On the other hand, the mix of wind and solar generation can reduce the operational strains in other hours due to output diversity. Finally, the CAISO concludes that there may be significant reductions in energy market revenues to thermal generation due to the displacement by wind and solar and the reduction in market clearing prices. The study recommends that market and operational mechanisms to improve utilization of existing generation fleet operation flexibility be evaluated. In addition, CAISO suggests investigating ways of obtaining additional operational flexibility form wind and solar resources and making improvements to the day-ahead and real-time forecasting of operational needs.

In 2010, NYISO completed its most recent Wind Generation Study.[31] The study was a follow-up to its 2004 study, which had concluded that the New York Power System can reliably accommodate up to a 10% penetration of wind generation (3,300 MW) with "only minor adjustments to and extensions of existing planning, operation, and reliability practices."[32] Given the presence of more than 3,300 MW of wind on the NYISO interconnection queue and the New York RPS standard of 30% by 2015, an updated examination of wind integration issues and challenges was needed.

In terms of reliability, the study finds that the addition of up to 8,000 MW of wind generation to the New York Power System "will have no adverse reliability impact."[33] However, the addition of wind generation will increase system variability as measured by net-load, with the increase varying over seasons, months, and time of day.

At present, NYISO has a FERC-approved (2008) centralized wind forecasting system for scheduling of wind resources and requires wind plants to provide meteorological data to the ISO for use in forecasting their generation levels.[34] In addition, the NYISO wind interconnection process requires wind plants to participate fully in the ISO's supervisory and data acquisition processes and, to meet low voltage ride-through standard, and to conduct tests to determine

29 "Integration of Renewable Resources," November 2007, CAISO.
http://www.caiso.com/1ca5/1ca5a7a026270.pdf

30 "Integration of Renewable Resources: Operational Requirements and Generation Fleet Capability at 20% RPS", August 31, 2010. CAISO
http://www.caiso.com/2804/2804d036401f0.pdf

31 "Growing Wind: Final Report of the NYISO 2010 Wind Generation Study." September 2010. NYISO
http://www.nyiso.com/public/webdocs/newsroom/press_releases/2010/GROWING_WIND_-_Final_Report_of_the_NYISO_2010_Wind_Generation_Study.pdf

32 Ibid. at p. i.

33 Ibid. at p. iv.

34 Ibid.

"whether the interconnection of wind plants will have an adverse impact on the system voltage profile at the point of interconnection."[35] Moreover, in 2009 FERC approved NYISO operational rules that allow system operators to dispatch wind plants down to a lower generating level—in case of failure to follow down instructions, wind generators are charged the market price for regulation down service. Wind generators are also fully integrated in the economic dispatch process via NYISO's "wind energy management initiative."[36]

ISO-NE also recently completed a wind integration study of its system.[37] The study found that "New England could potentially integrate wind resources to meet up to 24% of the region's total annual electric energy needs in 2020" conditional on system transmission upgrades, "availability of existing supply-side and demand-side resources as cleared through the second FCA," the "retention of the additional resources cleared in the second Forward Capacity Auction, and increases in regulation and operating reserves as recommended by the study."[38]

Following FERC Order 890, ISO-NE instituted a pilot program, the Alternative Technology Regulation (ATR) Pilot program. The aim of the program is "to allow ISO-NE to identify the impact on the New England system of alternative technologies with new and unique performance characteristics."[39] Among the resources participating in the program are flywheel technology, battery technology, and certain Demand Response resources.[40] ATR resources are compensated "based on AGC performance (*i.e.,* mileage payments) and availability to provide Regulation (*i.e.,* time-on regulation payments) at the Regulation Market's hourly Regulation clearing price."[41] In the context of increasing regulation and load-following service needs due to higher renewables penetration, such market policies are aimed at increasing efficiencies. In its February 2011 NOPR on Regulation, FERC notes that "both [NYISO and ISO-NE] have a relatively higher concentration of faster-ramping resources, easily meet NERC reliability standards, and yet procure less regulation capacity, as a percentage of peak load, than other RTOs and ISOs."[42]

ERCOT has also worked actively to address the challenges of integrating wind generation. In 2008, ERCOT completed its wind integration study, which identified operational challenges for the ERCOT system.[43] ERCOT procures regulation service by analyzing recent historical deployments and deployments from the same month from the prior year and utilizing a formula derived from the results of the 2008 study.[44] The formulaic procurement results in adding incremental MWs of regulation for each 1000 MWs of increased installed wind capacity. In December of 2010, ERCOT moved from a Zonal Balancing Energy Market, which executed

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35 Ibid.

36 Ibid.

37 "Final Report: New England Wind Integration Study." GE Energy, EnerNEx, AWS Truepower. December 2010

http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/reports/2010/newis_report.pdf

38 Ibid. at p. 14.

39 http://www.iso-ne.com/support/faq/atr/#faq1

40 Ibid.

41 Ibid.

42 FERC NOPR at p. 20.

43 GE Energy, *Analysis of Wind Generation Impact on ERCOT Ancillary Services Requirements*, March 28, 2008

44 http://www.ercot.com/content/meetings/etwg/keydocs/2010/1001/2010-2011_Ancillary_Services_Methodology_Presentation.pdf

every 15 minutes to a Nodal Balancing Energy Market, where the Security Constrained Economic Dispatch (SCED) executed every 5 minutes. One expected benefit of the transition is that more frequent execution of the real-time market should result in less required regulation.[45]

In November of 2010, ERCOT also published the Emerging Technologies Integration Plan (ETIP), which documented "recent ERCOT stakeholder efforts to integrate renewable and other emerging technologies," presented a list of recommendations and strategies and established a framework "to guide and track further integration activities."[46] Among the key issues that have already been addressed via changes to market rules and procedures are: finding a common understanding of the impact of wind generation on operations among market participants and stakeholders, replacing wind generation resources wind schedules with ERCOT wind forecast, and establishing ramp-rate limitations for wind generators.

PJM recently completed the bidding process for initiating a system-wide comprehensive renewable integration study. The study is expected to build upon PJM's present experience with wind and solar generation and establish the full dimension of challenges the system is expected to face as multi-state RPS scenarios are met across PJM's control area. PJM has already worked on establishing a range of market procedures that are directly related to renewable integration. These procedures require "new wind–powered generation to maintain a power factor of 0.95 leading to 0.95 lagging, measured at the point of interconnection; and that wind projects connected to lower voltage systems be designed to operate to a voltage schedule, reactive schedule or power factor schedules designed to meet local transmission owner criteria."[47] In addition, PJM implemented a centralized wind power forecasting service in April 2009 for use in PJM reliability assessments—this includes a day-ahead (mid-term wind power forecast) and a real-time (short-term wind power forecast).[48] PJM generating resources are also "able to submit negative price offers, enabling wind resources to submit flexible offers that better reflect the price at which they will reduce output."[49]

C. North American Electric Reliability Corporation's Activities Around the Integration of Renewable Generation

While NERC has been actively involved in analyzing the potential effects of integrating large volumes of variable generation resources on system reliability, almost no specific operating reliability requirements have been changed. In NERC's recent comments submitted in response to the FERC NOPR described above, NERC states that it has not identified any insurmountable hurdles that would prevent the industry from providing intra-hour scheduling flexibility. In addition, NERC has recognized that the wind ramping events are slower than the conventional system contingency events, such as contingency reserves that have been traditionally designated to meet sudden, quickly occurring events such as the unanticipated loss of a generator or transmission line. Such resources are not necessarily best suited to compensate for the burdens

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45 Ibid. at p. 5.

46 "Exhibit A: Emerging Technologies Integration Plan (ETIP)", ERCOT, November 2010 at p. 2.
http://www.ercot.com/content/meetings/etwg/keydocs/2011/0105/Item_06e_-_Emerging_Technologies_Integration_Plan.zip

47 http://www.usea.org/Programs/EUPP/globallowcarbonworkshop/Mar2/Ken_Schuyler_Integrating_Renewables_in_PJM_Interconnection.pdf

48 Ibid. at p. 19.

49 Ibid.

imposed by wind and solar generation on the transmission grid. In that regard, NERC has suggested that the frequency of ramp events would need to be studied to determine which part of wind and solar ramp events are compatible with contingency reserve use. NERC believes that the industry should consider developing rules governing reserve deployment and restoration, similar to those that currently address conventional contingencies.

D. POLICIES ADOPTED BY STATES AND/OR UTILITIES

Faced with a number of pressures acting to increase customer rates, state regulators in many jurisdictions have become conscious of the many issues described above. With ratepayer advocates questioning the costs associated with meeting renewable energy requirements, several utilities already have begun to evaluate the likely cost implications of integrating large amounts of wind onto their systems. The results of those studies have been used by regulated utilities in their Integrated Resource Plants. For example, Xcel Energy (both Northern State Power Company and Public Service Company of Colorado) has been analyzing the potential cost of integrating various levels of wind onto their systems. Xcel has added those costs to the cost of delivered wind in their long-term resource plans. In doing so, NSP and PS Colorado have explicitly accounted for the expected system costs associated with increasingly adding wind resources onto their systems.

Because NSP and PS Colorado are both vertically-integrated regulated utilities, these integration costs are subsumed into the overall costs paid for by their ratepayers. However, estimating the cost of integrating wind helps the utilities plan their systems while accounting for many of the challenges discussed above, in addition to the actual capital and operational costs of the wind generators. While state regulators have not explicitly required utilities to include such integration costs in their plans, it has become a useful way for utilities and regulators to evaluate some of the tradeoffs between building conventional generation and variable renewable generation. PacifiCorp represents another set of regulated utilities whose systems have significant wind penetration and expects to see more added in the future. In 2010, PacifiCorp initiated a wind integration analysis that estimated the cost of wind integration will likely be in the range of $8.85 to $9.70 per MWh integrated on its system.[50]

In addition to using integration cost estimates as part of resource planning, similar and consistent with an aspect of the proposed policy from FERC described above, some utilities have requested FERC to allow certain "home" utilities to pass a portion of those costs to "beneficiaries" of the wind resources located on their systems. For instance, in March 2010, FERC accepted Westar's proposed transmission tariff change to allow charging new generation regulation and frequency response service to generators located in Westar's balancing area whose output is delivered outside of Westar's balancing area.[51] In all likelihoods, given the pressures that state regulators face from rate payers, FERC's policies will ultimately allow those systems with significant amount of wind used by external utilities to charge those who "cause" the costs.

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[50] PacifiCorp 2010 Wind Integration Resource Study, September 1, 2010, can be found at http://www.pacificorp.com/es/irp/wind_integration.html

[51] FERC Docket No. ER09-1273-000, March 18, 2010.

E. EMERGING POLICY QUESTIONS

1. Reliability Criteria May Need to be Re-Examined

Today, the use of frequency control and regulation services help system operators match generation's second to second output to the load on the system. Such demand is anticipated to significantly increase with greater penetration of intermittent generation on the system. The amount of regulation service procured today by system operators is typically in the range of approximately one percent of load. For example, PJM's operational manual specifies that it procures 1% of its daily forecast peak load for all peak hours and 1% of its forecast valley load for all off-peak hours.[52]

Much of the current practice is based on rules-of-thumb from operators' past experience subject to their need to meet NERC reliability requirements or control standards.[53] Even if the fundamental NERC reliability requirements and standards do not have to change along with the high penetration of intermittent resources, historical rules-of-thumb around the procurement of regulation services will likely need to be adjusted.

Likewise, the magnitude of reserve requirements, such as spinning and non-spinning reserves, tends to be based on the largest potential failure or contingency on a system.[54] The largest single contingency on any system tends to be a high-voltage transmission line or a large baseload power plant. Some have contended that wind or solar are not likely to become the largest contingency on a system even when all of the wind/solar capacities on a system exceed that of the largest baseload generator or high-voltage transmission line. That is because wind and solar generators tend to be geographically spread out such that they are not likely to fail simultaneously.

However, even if large wind and solar plants are unlikely to experience drastic large failures simultaneously, the magnitude of reserves will need to increase to accommodate the un-anticipated variations in wind and solar output. Such additional reserve requirements will depend partly on the history of deviations of actual wind and solar output from the forecast used by system operators to schedule generators (and transmission). The better the schedule (based on forecast information) can match the actual output, the less reserves will be needed. Thus, the magnitude of the additional reserve requirement will not only depend on how good the forecasts are, but also on how frequent the forecasts can be updated and effectively used during scheduling.

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52 PJM Manual 11: Energy & Ancillary Services Market Operations, June 23, 2010, Section 3.2.4 Regulation Requirement Determination. The Manual also states that the requirement percentage may be adjusted by PJM to be consistent with NERC control standards.

53 For a general treatment, see: http://www.nerc.com/docs/oc/ps/tutorcps.pdf

54 PJM carries 150% of its largest contingency as Primary Reserves. New York ISO carries 50% of its largest contingency as 10-minute spinning; total 10-minute reserves equal to it largest contingency; and 30-minute reserves equal to 50% of its largest contingency. ISO-New England carries an amount of 10-minute reserves equal to its largest contingency (with the split between spin and non-spin that can vary), and the amount of 30-minute reserves is equal to 50% of its largest contingency.

2. The Capacity Credit for Renewable Generation and Its Implications for Resource Planning

In regions with centralized capacity markets, the capacity credit provided to wind and solar generation is usually a simple function of how much generation can be expected on the "super-peak" hours of the year. However, the severely limited amount of historical experience is a poor basis upon which to estimate the capacity contribution from intermittent resources. Some studies have shown that the capacity value of wind is highly sensitive to the load shape and wind profile used in the analysis.[55] Yet modeling multiple load shapes with a reasonable distribution of future wind profiles is almost impossible to achieve today. Such difficulty may result in over- or under- building conventional generation to meet the resources adequacy (and reliability needs).

3. Definition of the Customer for Cost Allocation Purposes

One institutional issue that may need attention is the definition of a transmission customer, or more abstractly, the geographic locus of benefits provision from a particular transmission service, capital improvement, or ancillary service. This issue recently arose forcefully when New England state regulators objected to the fact that the FERC allocated a portion of the cost of a new phase shifter installed to prevent loop flow around Lake Ontario to them despite the fact that they had no customer relationship with the transmission company in Michigan who installed the equipment.[56] The protest notes that the Federal Power Act does not allow FERC the authority to spread the costs of facilities that do not provide service under a tariff to entities who happen to be connected to the grid. This would appear to constrain significantly the ability to allocate certain types of grid integration costs.

VII. CONCLUSION

Research and experience are both demonstrating conclusively that high levels of variable renewable energy sources can be safely and reliably integrated into modern power systems. However, as power system technologies and institutions evolve, this integration clearly comes at a cost. These costs include a greater need for overall regulation and ramping resources (which someone must build and pay for), cost penalties on traditional incumbent generators, and enhanced (though perhaps more costly) forecasting (especially in short term) and more complex operating procedures for system operators.

The primary policy challenges associated with these integration needs arise around cost causation and allocation. When cost causation as well as associated benefits are relatively broad and highly interdependent with system configuration and conditions – as is often the case for renewables integration – the costs take on the nature of quasi-public goods and cost allocation to the "users" or "beneficiaries" becomes difficult. In this case, allocation inevitably involves issues of equity that must be resolved by policymakers, ideally without reducing efficiency incentives.

55 "Final Report: New England Wind Integration Study." GE Energy, EnerNEx, AWS Truepower. December 2010 at pp. 315-328.

56 Motion to Intervene and Protest, New England Conference of Public Utilities Commissioners, Docket No. ER11-1844-000, November 17, 2010. Similar comments were filed by the Sacramento Municipal Utility District in the FERC Cost Allocation NOPR, Docket No. RM10-23-000, September 29, 2010.

It is likely useful to distinguish between integration costs that reduce the value of existing assets from costs that require system operators to incur additional costs. The latter category can be further divided into costs that are more tracked to a causal agent or beneficiary and those that are more public in nature.

Broadly speaking, utility regulatory policies vary between these three types of costs. The reduction in existing asset values is akin to a stranded cost, which is recovered when regulators agree that constitutional and long-term market efficiency considerations call for it. When approved, these costs have been collected rather broadly from market participants, with appropriate protective conditions in place.

In the latter category, where costs can be allocated to customers or beneficiaries to a substantial degree this is usually both the fairest and most efficient solution. Most of the FERC's proposals aim in this direction, notably their approval of Westar's proposal to charge renewable integration costs to customers outside their retail footprint who were consuming locally-generated renewable energy. However, it is inevitable that some costs will be lumpy, indivisible, and not marginally assignable—for example, the costs of an RTO adopting a more complex scheduling framework. Regulatory bodies must inevitably allocate these costs on the basis of fairness and efficiency.

Fortunately, these difficulties are certainly not hindering the considerable progress being made by the RTOs and ISOs, the FERC, utilities, and state policymakers. We do not see any grand, unifying theory of cost allocation for the costs of renewable variability, nor do the institutional differences, legacy generation, or indigenous resources, across regions of the U.S. and other global power systems lend themselves to uniform solutions. Instead, the allocation of each element of integration costs will call for extensive research and thoughtful advocacy on the part of all stakeholders and great care on the part of regulators to balance economic efficiency, administrative burden, and fairness considerations. While the road ahead may be contentious and laborious, there seems to be no technical or economic reason why a well-functioning regulatory system cannot find its way to a sustainable, reliable, and economical destination.

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