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| 11-IEP-1G | |
| DATE | APR 22 2011 |
| RECD. | APR 22 2011 |

To: IEPR Committee (Chair Weisenmiller and Commissioner Douglas)

Date: April 22, 2011

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Subject: Distributed Generation in Europe - Network Planning and Operational Impacts – Memorandum #2

KEMA is pleased to submit the attached memo on distributed generation in Europe with a specific focus on network planning and operational impacts. This memo is an interim deliverable for the European Distributed Generation Infrastructure Study.

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# INTRODUCTION

This memo identifies the analytical and simulation methods used for network planning and operation in Germany and Spain and specifies technical requirements for the interconnection of distributed generation and technical integration issues. It frames the network operation aspects for the distribution network and the transmission system and describes the connections between the behavior of the generating units and the network operation, along with the control performance standards and measures used.

The findings implicitly address the following issues and questions:

- What definition of distributed generation can be specified, and is distributed generation limited to the size of electricity generators?
- Which analytical methods and simulation software are available to help network operators plan the integration of distributed generation?
- How can grid operators monitor and control their network or system and improve the integration of distributed generation into the electric network?
- Summarize new analytical and simulation models available to help distributed generation (DG) operators plan the integration of photovoltaic (PV) planning and operational software.
- Summarize how Germany and Spain conduct the operational planning and dispatch coordination of their electric distribution systems as well as how they monitor and control their systems. Examine how much variability these countries experience (ramp, load following, and regulation) and their forecasting accuracy.
- Do these countries have a large amount of conventional electricity generation that can easily be turned on to manage the variability? Identify the type of the conventional electricity generation and the relative quantities of each type to gain a better understanding of how these countries use their fleet of electric generators to manage variability.
- Describe the dispatcher training that is provided to improve the integration of renewable DG into the electric distribution systems.
- Describe how curtailment is done in the context of operational planning and dispatch coordination.
- Compare the North American Electric Reliability Corporation (NERC) control performance requirements to the control performance requirements for the German and Spanish systems.

This memo is organized as follows:

- Section 1: Network Planning and Operational Impacts of DG in Germany
- Section 2: Network Planning and Operational Impacts of DG in Spain
- Section 3: European Standards on Frequency Control and Balancing Services
- Section 4: Comparison to the Situation in California
- Section 5: Summary of Key Lessons Learned.

# SECTION I:
# Network Planning and Operation Impacts of DG in Germany

This section provides an overview of the network planning and operation impacts of DG in Germany. The existing technical guidelines regarding the connection of distributed generation in Germany[1, 2] can be used to evaluate the point of common coupling. These guidelines, including their methods, are described further below.

In general, the rated power of distributed generation is not limited (e.g., not capped at 5 MW, etc). The local grid has to be able to transmit the output from distributed generation. Hence, all components of the individual grid must be considered. Because of the different components in the grid, the point of common coupling has to be evaluated.

**Definition of Distributed Generation in Germany**

DG in Germany is a generic term, but is generally comprised of generation connected to low-voltage and medium-voltage distribution grids close to energy consumers, and generation used by energy consumers for self supply. It is mostly based on renewable energy sources. The rated capacity of distributed generation is not limited to any specific size. Distributed generation comprises all generation plants that are connected to low- and medium-voltage distribution grids. Each plant is comprised of one or more generating units. Thus, DG plants include wind farms consisting of multiple wind turbines, or solar power plants consisting of many photovoltaic modules and a converter station.

## Network Connection and Planning Tools in Germany

Generally, assessing the technical feasibility of the point of common coupling is at the sole discretion of the responsible grid operator. In this context, the following effects should be addressed according to German codes:[3]

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1 Erzeugungsanlagen am Mittelspannungsnetz – Richtlinie für den Anschluss und Parallelbetrieb von Erzeugungsanlagen am Mittelspannungsnetz; VWEW Energieverlag GmbH; Juni 2008 [German Technical Guideline - Generating Plants Connected to the Medium-Voltage Network, June 2008]

2 Eigenerzeugungsanlagen am Niederspannungsnetz – Richtlinie für den Anschluss und Parallelbetrieb von Eigenerzeugungsanlagen am Niederspannungsnetz; VWEW Energieverlag GmbH; September 2005 [German Technical Guideline - Generating Plants Connected to the Low-Voltage Network, September 2005]

3 German Norm 50160 - Voltage Characteristics of Electricity Supplied by Public Distribution Networks, April 2008, and German Technical Guideline - Generating Plants Connected to the Medium-Voltage Network, June 2008.

- Loading capability of the existing grid components
- Voltage increase
- Voltage deviation caused by switching
- Flicker
- Harmonics
- Commutation notches
- Impacts on audio frequency ripple control
- Asymmetrical currents.

Technical investigation of the grid loading and voltage effects is usually performed by the grid operator using network calculation software able to carry out steady-state load-flow calculations and simulation of distributed generation properties at the point of common coupling. Many comparable software tools are available in the industry. Some of the more popular tools used in Germany and Spain include Siemen's PSS/E software, Dig Silent's Power Factory software, and KEMA's Elektra software (the PSS/E software is also used by many utilities in California, along with GE's PSLF software). Such network calculations model the existing grid components and their technical properties (i.e., rated current, etc.) as well as the technical data of the conventional and distributed generation plants.

- Simplified calculation methods are also available for performance factors that do not require the use of full load-flow models, as indicated in the discussion below.

## Transmission Capability of the Existing Components

All components in the medium- and low-voltage grids have to be able to transmit the output of distributed generation. That means grid overloads should not occur. In this context, the rated current and consequently the transmission capability of all existing components must not be exceeded if all distributed generating units are feeding into the grid. It is essential that:

$$S_r > \frac{\sum P_{DG}}{\cos \varphi_{DG}} \qquad (1)$$

| | |
|---|---|
| $S_r$ | Rated Apparent Power (Transmission Capability) [kVA] |
| $P_{DG}$ | Peak power output from Distributed Generation [kW] |
| $\cos \varphi$ | Value is a function of the power factor of the DG output (typically 0.95 or higher) |

This capability should be checked by doing a load-flow calculation or in a simplified network through comparison of the installed transmission capacity versus the connected power of distributed generation, adjusted for any coincident customer demand at the DG site.

## Voltage Increase

Voltage increases are caused by the injected power of generating units. The power transmission over the network impedance causes a voltage drop from the point of common connection to the network supply point. The magnitude of the voltage deviation relates to the size of the impedance. Existing standards define the maximum voltage deviation difference of the connection point voltages with and without the DG. Again, use of load-flow software is required for an accurate calculation. In German codes, a relative limit of 2 percent has been defined for the steady-state voltage increase. However, at this time a new technical guideline that would increase the steady-state voltage limit to 3 percent for low-voltage grids is being discussed.[4] Hence, it is essential that:

$$\Delta u \leq 2...3\% \qquad (2)$$

$\Delta u$ Steady-state voltage increase [%]

The steady-state voltage increase should be checked by doing a load-flow calculation considering all distributed generating units that are connected to the same grid. If no software is available, a rough estimation can be done using the following formula:[5]

$$50 \leq \frac{S_{SC}}{\sum P_{DG} \cdot \cos \varphi_{DG}} \qquad (3)$$

SSC Short-circuit duty at the point of common coupling [kVA]
PDG Peak power output from distributed generation [kW]

The short-circuit duty at a point of common coupling acts as a measure for the network impedance. High short-circuit duty relates to low network impedance and vice versa. Short-circuit duty is usually calculated using the same network calculation tools mentioned above.

### Voltage Deviation Caused by Switching

The switch-on and switch-off process of distributed generating units causes transient voltage deviations as well. To avoid a negative impact on other customers connected to the grid, applicable limits should not be exceeded. The permissible relative voltage deviation in Germany depends on the switching frequency. With respect to German guidelines the voltage deviation caused by switching should be within the following range:

$$\Delta u_s \leq 2...6\% \qquad (4)$$

$\Delta us$ Transient voltage deviation caused by switching [%]

4 Draft: German Technical Guideline - Generating Plants Connected to the Low-Voltage Network, July 2010.

5 German Norm 50160 - Voltage Characteristics of Electricity Supplied by Public Distribution Networks, April 2008, and German Technical Guideline - Generating Plants Connected to the Medium-Voltage Network, June 2008.

Voltage deviation can be simulated by dynamic network calculations using a typical transient stability model. In this context, a more detailed model of the distributed generating units is necessary. Again, the previously mentioned network calculation software tools have such modeling capability. However, if detailed data of the distributed generating unit are not available, a rough calculation can be made according to German guidelines as follows:[6]

$$\Delta u_s = k \cdot \frac{S_{SC}}{P_{DG} \cdot \cos\varphi_{DG}} \qquad (5)$$

| | |
|---|---|
| Δus | Transient voltage deviation caused by switching [%] |
| k | Switching current factor |
| SSC | Short-circuit power at the point of common coupling [kVA] |
| PDG | Peak power output from distributed generation [kW] |

The formula includes a switching current factor (k). This factor is the ratio of peak current and rated current of the distributed generating unit. For a rough calculation, the following values can be assumed:[7]

| | |
|---|---|
| k=1.2 | Synchronous machine |
| k=1.5 | Inverter-fed asynchronous machine |
| k=4.0 | Asynchronous machine |

## Flicker

Flicker is category of voltage deviation that causes visible fluctuations in illumination. To check this voltage deviation, the flicker coefficient of the individual distributed generating unit must be known. According to German guidelines it is essential that:

$$0.46 \geq c \cdot \frac{P_{DG} \cdot \cos\varphi_{DG}}{S_{SC}} \qquad (6)$$

| | |
|---|---|
| c | Flicker coefficient [from manufacturer's test report] |
| SSC | Short-circuit power at the point of common coupling [kVA] |
| PDG | Peak power output from distributed generation [kW] |

6 *German Norm 50160 - Voltage Characteristics of Electricity Supplied by Public Distribution Networks*, April 2008, and *German Technical Guideline - Generating Plants Connected to the Medium-Voltage Network*, June 2008.

7 *German Technical Guideline–Generating Plants Connected to the Medium-Voltage Network,* June 2008.

## Harmonics

Distributed generating units can cause harmonics that can influence other customers connected to the grid. In this context, German guidelines define limits of harmonic currents that may be generated by the individual generating unit. The permissible harmonic currents are related to the network short-circuit duty at the point of common coupling. It is essential that:

$$I_p = i_p \cdot S_{SC} \tag{7}$$

| | |
|---|---|
| $I_p$ | Permissible harmonic current [A] |
| $i_p$ | Permissible related harmonic current [A/MVA] |
| $S_{SC}$ | Short-circuit duty at the point of common coupling [MVA] |

The permissible related harmonic current depends on the voltage level. In this context, the German guidelines define the following parameters.[8]

8 *German Technical Guideline–Generating Plants Connected to the Low-Voltage Network*, September 2005, and Draft: *German Technical Guideline - Generating Plants Connected to the Low-Voltage Network*, July 2010.

**Table 1: Permissible Related Harmonic Currents**

| Harmonic ν | $i_p$ Permissible Related Harmonic Current [A/MVA] | | | |
|---|---|---|---|---|
| | 0.4kV Grid | 10kV Grid | 20kV Grid | 30kV Grid |
| 3 | 3.0 | - | - | - |
| 5 | 1.5 | 0.058 | 0.029 | 0.019 |
| 7 | 1.0 | 0.082 | 0.041 | 0.027 |
| 9 | 0.7 | - | - | - |
| 11 | 0.5 | 0.052 | 0.026 | 0.017 |
| 13 | 0.4 | 0.038 | 0.019 | 0.013 |
| 17 | 0.3 | 0.022 | 0.011 | 0.07 |
| 19 | 0.25 | 0.018 | 0.009 | 0.006 |
| 23 | 0.2 | 0.012 | 0.006 | 0.004 |
| 25 | 0.15 | 0.010 | 0.005 | 0.003 |
| **Uneven-numbered** | | | | |
| 25 – 40 | 0.15 x 25/ν | 0.01 x 25/ν | 0.005 x 25/ν | 0.003 x 25/ν |
| ν > 40 | 4.5/ν | 0.18/ν | 0.09/ν | 0.06/ν |
| **Even-numbered** | | | | |
| ν < 40 | 1.5/ν | 0.06/ν | 0.03/ν | 0.02/ν |
| ν > 40 | 4.5/ν | 0.18/ν | 0.09/ν | 0.06/ν |

Source - Eigenerzeugungsanlagen am Niederspannungsnetz – Richtlinie für den Anschluss und Parallelbetrieb von Eigenerzeugungsanlagen am Niederspannungsnetz; VWEW Energieverlag GmbH; September 2005 *[German Technical Guideline - Generating Plants Connected to the Low-Voltage Network, September 2005];* and ENTWURF: Erzeugungsanlagen am Niederspannungsnetz – Technische Mindestanforderungen für Anschluss und Parallelbetrieb von Erzeugungsanlagen am Niederspannungsnetz; VDE; Juli 2010 *[Draft: German Technical Guideline - Generating Plants Connected to the Low-Voltage Network, July 2010]*

## Commutation Notches

Commutation notches occur with inverter-fed generating units. With respect to German guidelines commutation notches should be within the following range:

$$\Delta c \leq 2.5...5\% \qquad (8)$$

$\Delta c$ Commutation notch [%]

To check commutation notches, detailed data from the individual distributed generating unit are necessary.

## Impacts on Audio Frequency Ripple Control

Generally, the grid operator's audio frequency (audio-tone) protection and control systems that rely on a modulated signal superimposed on the normal 50 Hertz waveform should not be influenced by distributed generation. The frequency of such communication signals depends on the responsible grid operator. With respect to the German guidelines the level of the audio frequency must not be reduced by more than 5 percent.

### Asymmetrical Currents

According to technical guidelines in Germany, small units up to 5 $kW_{peak}$ can be served by a single-phase connection to the low-voltage grid without a detailed study. Larger DG units require a three-phase connection, and may require more detailed study.

## Network Operation Impacts of DG in Germany

In general, in Germany the following networks can be differentiated according to their operational functions:

- Distribution networks
- Transmission systems

The respective functions of these networks are legally stated in the German EnWG (law on the energy industry).[9]

### Distribution Networks

Distribution network operators (DNOs) should operate a secure, reliable, and efficient energy supply network. Therefore, DNOs have the responsibility to receive generated power – in the distribution network or from the transmission system – and to distribute it to the customers. DNOs must also connect generating units to their networks without discrimination. Consequently, distributed generating units must be accepted onto the medium- and low-voltage grid if they fulfill the respective technical network connection requirements.

Generating units must fulfill the corresponding valid network connection guidelines. However, they must also fulfill specific grid operational requirements to support a secure operation of the distribution networks in Germany. Generating units should particularly contribute to the operational services of the distribution networks. The relationship between the behavior of the generating units and the operation of medium- and low-voltage networks is described later in this section.

### Transmission Systems

In addition to the responsibilities of the DNOs, transmission system operators (TSOs) are responsible for the system of electrical energy supply as a whole. Therefore, a TSO is responsible for the wide-area network and system security. The TSO is responsible for maintaining the frequency, which is related to the active power balance in the network, as well

9 *Second German Law on the Energy Industry*, July 2005.

as maintaining the voltage, which is related to the reactive power balance in the network, among other duties. The frequency control performance standards are defined in the German Transmission Grid Code.[10]

As a result of the combined operation of all distributed generating units in subordinate distribution networks, system conditions can occur in a transmission system that threaten secure operation. In the case of such events, for the protection of system security, the responsible TSO is responsible to act according to § 13 EnWG[11] and take certain operational measures. These measures can also affect the network operation of the subordinate DNOs. The applicable measures, as well as the effects on DNO network operation, are described in the following section.

## Operation of Distribution Networks and Distributed Generation

As of April 2001, revised rules were implemented that require all new generating units that connect to the medium- and low-voltage networks to contribute to specific network ancillary services, including:

- Steady state voltage control (i.e., reactive power production)
- Dynamic grid support
- Active power reduction

These requirements and their intended benefits to system operation and reliability are discussed below.

### *Steady-state Voltage Control*

Generating units will need to contribute to the steady-state voltage control of the grid. Therefore, they must be capable of injecting reactive power into the medium- or low-voltage grid. The technical guidelines for Germany contain the requirements for the reactive power supply for distributed generating units and require that generating units can be operated at every operation point within the following power factor (cos φ) range:

$$\cos \varphi_{DG} = 0{,}95_{over-excited} \ldots 0{,}95_{under-excited} \qquad (9)$$

Within this range, a set point value can be predetermined by the DNO and transmitted by means of a remote control system. The following operating standards can be invoked for the reactive power supply from distributed generating units in Germany:

- Operate at a fixed cos ϕ – value

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10 *Transmission Code 2007, Network and System Rules of the German Transmission System Operators*, August 2007.

11 *Second German Law on the Energy Industry*, July 2005.

- Operate with a variable cos ϕ – value depending on the active power
- Operate with a fixed reactive power value
- Operate with voltage-dependent reactive power output according to a defined characteristic curve

In order to transmit these control settings and options in real time, a corresponding remote control system and associated communications must exist. According to EnWG, all generating units larger than 100 kW in Germany must be equipped with a remote control system and communications.

### *Dynamic Grid Support*

Dynamic grid support refers to stable behavior of a generation plant in case of voltage depressions caused by grid faults (i.e., fault ride-through capability.) This is necessary to avoid the sudden disconnection of generating units in medium- and low-voltage networks during normal clearing of faults on the network. Distributed generation must therefore fulfill the following requirements in the newest technical guidelines in Germany:

- During faults, distributed generating units should not disconnect from the grid.
- During faults, reactive power for grid voltage stability must be supplied by the distributed generating units.

These performance criteria should be met during all fault types (i.e., three-phase faults, line to ground faults, etc.). In addition, the operation of the DG unit must continue for a specified fault duration. An example of fault ride-through time requirement for a synchronous machine is depicted in Figure 1.[12]

12 *German Technical Guideline - Generating Plants Connected to the Medium-Voltage Network,* June 2008.

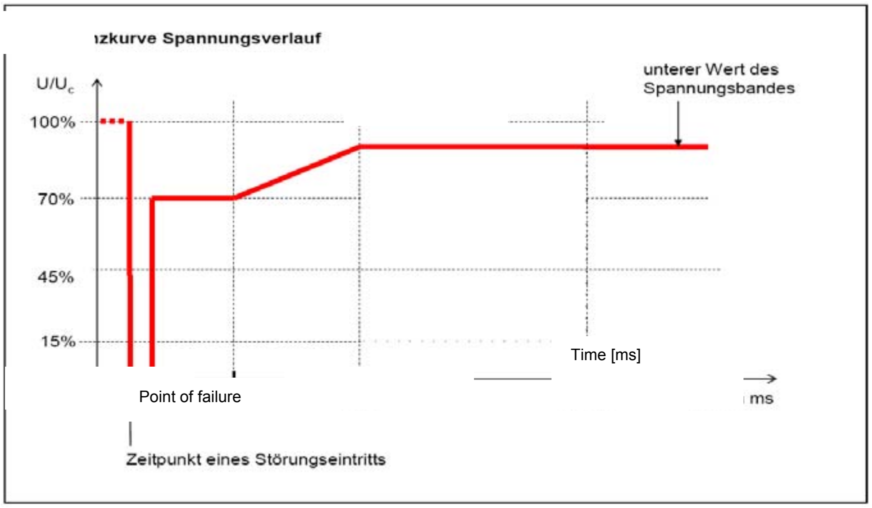


**Figure 1: Fault ride-through Characteristic for a Synchronous Machine Following Fault Initiation (Point of Failure)**

The ratio $U/U_c$ equals the instantaneous connection point voltage divided by the nominal connection point voltage. The technical guidelines stipulate similar requirements for other types of distributed generating units.

### *Active Power Dispatch Reduction*

Distributed generating units should be able to reduce their output. This can be necessary to avoid critical overloads in the network or other unacceptable grid conditions. The assessment of critical system conditions is carried out by the responsible TSO. Determination of the set points for DG active power dispatch reductions are also made by the TSO and are issued to DGs via remote control (telecommunications). According to the technical guidelines in Germany, the following power level steps have been established as a minimum requirement:[13]

- 100 percent rated power
- 60 percent rated power
- 30 percent rated power
- 0 percent rated power

Under the guideline, the active power reduction must take place through the action of a remote control system within one minute (e.g., cannot depend on action by the DG plant operators). DNOs also have authority to curtail DGs for emergency conditions, but DNO curtailment authority is less clearly defined than TSO authority. Therefore, DNOs may request the TSO to initiate the action.

13 *German Technical Guideline - Generating Plants Connected to the Medium-Voltage Network*, June 2008.

## Operation of Transmission Systems and Distributed Generation

Unbalanced system conditions can occur in transmission systems due to the operation of distributed generating units in subordinate distribution networks that can present a threat to a secure operation, including disturbances in the system load and supply balance. The following fundamental criteria are defined for assessment of the operating status of the transmission system:

- Active power balance and frequency stability
- Reactive power balance and voltage stability
- Angular stability of the generators

The German EnWG[14] obliges the TSO to assume responsibility for system security and stability. During a threat to the system security, the responsible TSO must take measures that ensure a secure network operation. These measures can occur at two levels:

- Network-related measures
- Market-related measures

At the first level, the network-related measures are intended to eliminate threats through switching processes in the transmission system. If a threat is not eliminated by means of network-related measures, market-related measures are to be used at a second level. Market-related measures can include the use of operating reserve, load shedding, and the reduction of active power generation (dispatch curtailment). Therefore, DG dispatch and DNO network operation can be directly influenced by the TSO.

A precondition for the early recognition and rapid mitigation of conditions that threaten the system is a remote control connection to the distributed generating units. According to EnWG, all generating units larger than 100 kW in Germany must be equipped with a remote control system. Over the remote-control connection, the status of the distributed generating units can be determined and necessary operating predictions can be made by the TSO. In addition to the distributed generating units, the DNOs must also convey certain real-time information to the TSOs regarding operating status of the distribution networks.

Intermittent renewable energy sources such as wind and solar can disrupt the system load and resource balance due to rapid ramping or tripping, including fluctuations in the output from groups of distributed generating units. A significant imbalance between grid loads and

14 Second German Law on the Energy Industry, July 2005.

resources can be a critical risk to network frequency and stability. DG impacts on these operating issues are discussed in the following paragraphs.

### Active Power Balance and Frequency Stability

Maintaining the active power balance of the system and the related frequency stability require quantitative measurement of the system status. If measurement and forecast values of supply and demand are fairly accurate, the system balance can be appraised in real time, or projected for the future. This information can also be used to identify potential network congestion. The active power balance can be controlled by the use of operating reserve from conventional power plants as well as the active power reduction from other generating units. In Germany, distributed generating units with active power greater than 100 kW must be able to be reduce their output in a stepwise fashion when needed. The determination of the required active power reductions are carried out by the TSO.

### Reactive Power Balance and Static Voltage Stability

The steady state voltage stability and the reactive power balance on the grid also impact the energy supply system. On long transmission routes that are heavily loaded, the impedance increase that occurs through the failure of any of the parallel transmission system elements can lead to critical grid voltage conditions. Using measurement technology, steady-state voltage stability can be assessed and reactive power reserves can be dispatched to counteract critical voltage conditions. Distributed generating units can be used for such network support if they are capable of supplying reactive power into the network. Therefore, the TSO and DNO can determine appropriate set-point values regarding voltage or reactive power that are transmitted by means of a remote control system to distributed generators on the MV and LV networks.

## Training and Forecasting for Renewable Impacts

Trends and forecast data in network operation, including renewable production, should be included at the earliest possible recognition of critical system conditions. Real-time measurement, assessment, and operator alarms for critical system conditions are necessary. These can be accomplished through algorithmic models that are integrated into the control system(s) of a TSO to provide computer-aided decision support for control center operational personnel. The specific requirements for such models and tools have been the subject of extensive discussions in Germany and are under development at this time.

Over the past decade, German TSOs have been confronted with an increasing portfolio of intermittent generation: first from wind power and more recently from solar power plants. Already at an early stage, this development triggered intensive cooperation between individual TSOs and various public and private meteorological and other research organizations. All four German TSOs currently use wind-power forecasting services from a public research institute known as IWES.[15] The wind forecasting methodology of IWES, which is widely regarded as one of the leading and most advanced in Europe, uses a variety of wind and weather forecasts from meteorological services, as well as a large number of online wind measurements from all over Germany to derive wind forecasts for increments from 15 minutes to 48 hours in advance. Apart from the German TSOs, these models are used today by various other European TSOs and provide the basis for the forecasting tools that are used by several commercial service providers.

As illustrated by Figure 2, the forecast accuracy of IWES' model has significantly increased over the past decade and is now in excess of 95 percent. While the root mean square error (RMSE)[16] for individual control-area day-ahead forecasts used to be approximately 10 percent, it has dropped to below 5 percent nationally in Germany in recent years. In 2007, the corresponding values for one- and two-hour forecasting horizons were 1.61 percent and 2.59 percent, respectively. Based on the recent DENA Grid Study II,[17] IWES expects that it will be possible to nearly double the forecast accuracy of the combined onshore and offshore production by 2020.

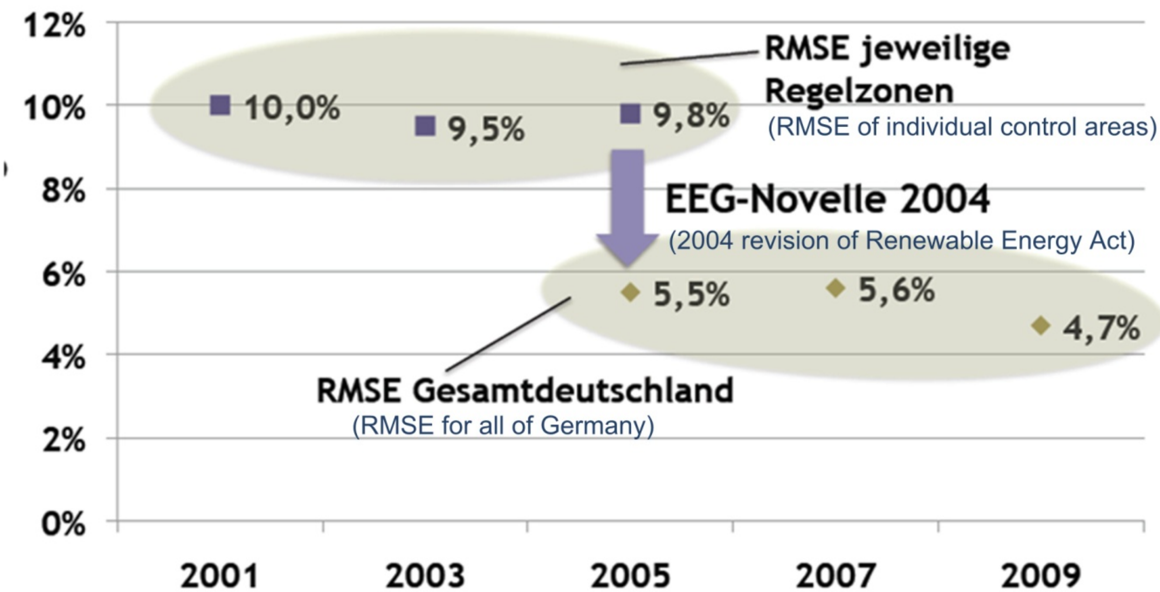


**Figure 2: Error Levels for Day-ahead Wind Power Forecasts in Germany between 2001 and 2009**

Source: Neubarth, Jürgen. Integration Erneuerbarer Energien unter besonderer Berücksichtigung der Regelenergie. Presentation at E-world 2010. Essen. February 9, 2010, p. 11

15 Fraunhofer-Institut für Windenergie und Energiesystemtechnik, which is based in the towns of Kassel and Bremerhaven.

16 Root mean square error, related to total installed (wind) capacity.

17 Deutsche Energie-Agentur Network Study II – Planning of the Grid Integration of Wind Energy in German Onshore and Offshore up to the Year 2020 ("DENA Grid Study II"), 2010.

In recent years, similar efforts have been made on developing corresponding tools and methodologies for solar power forecasting. Today, the German TSOs use the forecasts of several service providers, including IWES as well as two privately owned companies (meteocontrol and Suncast). Similar to the approach for wind power forecasts described above, these tools use different combinations of weather forecasts, satellite data on global radiation, statistical methods, and quarter-hour on-line data for hundreds of PV installations to create 15-minute to 4-day forecasts in advance. Besides global and regional forecasts, for instance EnBW from Southwestern Germany is engaging into additional research into the development of detailed locational solar-power forecasts[18] to detect potential congestion.

In general, the forecast accuracy for solar power production is similar to wind power. For example, Suncast reports an RMSE accuracy at approximately 4.5 percent for day-ahead and less than 4 percent for intra-day forecasts. For forecasting horizons for a very few hours ahead, other sources report an RMSE of approximately 1 percent (excluding night hours).

Forecasts for wind and solar power are mainly used by the German TSOs today, whereas DNOs have not made regular use of such tools so far. A recent position paper by the federal regulator,[19] however, explicitly called on DNOs to implement adequate forecast methodologies by April 1, 2011. This new requirement stems from the increase of forecast errors for solar power in 2010, resulting in the need of activate 100 percent of all contracted operating reserves for several hours on September 6, 2010. However, it is important to note that the corresponding provisions of the position paper are not immediately binding for DNOs. It remains to be seen how German network operators will implement them in practice.

To deal with the operational impacts of intermittent generation, German network operators are increasing related training measures for operational personnel, including simulator-based training for dispatchers. However, it is important to note that the corresponding activities are related only partially to the challenges of integrating large amounts of renewable energies in the power system. Another major driver for expanded dispatcher training is the uncertainty due to increasing international energy transactions, the separation of generation, transmission and distribution system operation, and trading functions (*unbundling*) in the electricity market.

Over the past decade, German TSOs as well as several DNOs[20] have made use of a dispatch simulator, DUtrain,[21] a dedicated training facility based in Duisburg. The simulator, which was

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18 Schierenbeck, S. et al. Ein distanzbasierter Hochrechnungsverfahren für die Einspeisung aus Photovoltaik. Energiewirtschaftliche Tagesfragen. 60. Jg. (2010), Heft 12, pp. 60 - 64

19 Bundesnetzagentur. Positionspapier zur verbesserten Prognose und Bilanzierung von Solarstromeinspeisungen. November 2010

20 In addition, many other European TSOs, as well as virtually all Dutch and some other DSOs, have been using the simulator, often on a regular basis. Amongst others, all Dutch dispatchers havehave to undergo a regular training at DUtrain.DUtrain.

21 DUtrain is 60 percent owned by KEMA

originally developed by the University of Duisburg, offers the real-time simulation of a power system, comprised of one or more transmission control areas, distribution networks, and generators. In contrast to typical simulation packages used with SCADA systems, the DUtrain system has been developed for training related to the interactions between different actors in a liberalized power market, such as TSOs, DNOs, and producers. In contrast, the recent deployment of a dispatch simulator at the Technical University of Cottbus was directly triggered by the massive expansion of renewable energy sources in Germany. In addition to increasing international energy trading, the Eastern German TSO grid has been exposed to other operational challenges caused by local oversupply and legal restrictions on the curtailment of renewable energy.

As a result, an entity known as *50Hertz Transmission* has built a simulator and training center, in cooperation with the Technical University of Cottbus, the SCADA-system provider BTC, and KEMA. The goals of this training center are to:

- Properly qualify operating personnel from the German network and power plant operators
- Practice the interactions of the TSO, DNOs ,and power plant operators, particularly in those situations that demand coordinated measures to assure secure operation
- Alert the operational stuff for critical system states, including network restoration after disturbances
- Practice behavior and procedures for operational situations that endanger system security

As illustrated by **Error! Reference source not found.**, the training simulator in Cottbus has been designed to simulate all voltage levels, from 380 kV down to 0.4 kV.

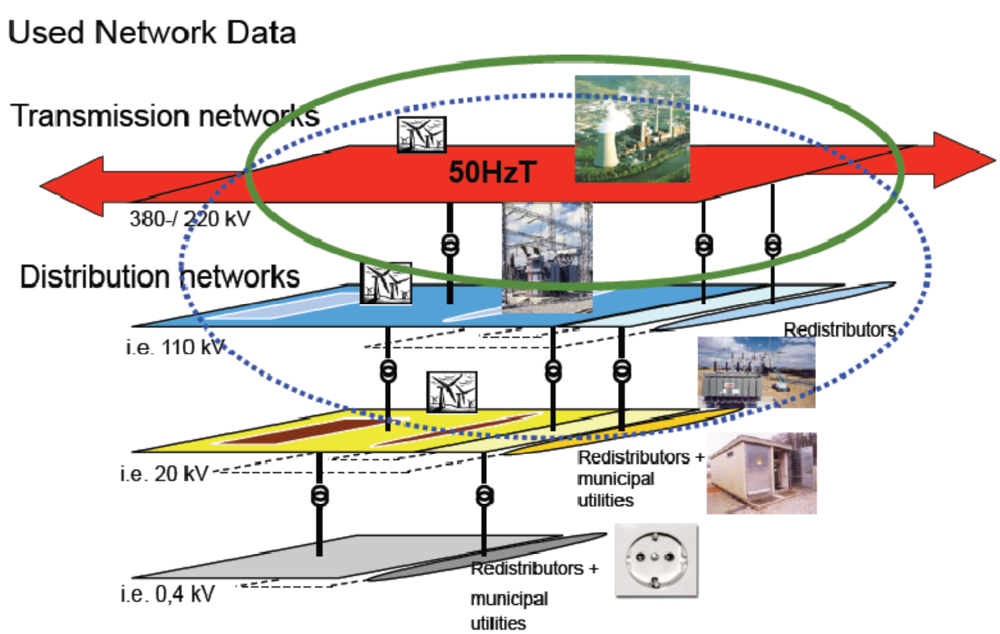


**Figure 3: Network Levels Represented by the Dispatcher Training Simulator in Cottbus**

Source: 50Hertz Transmission

# SECTION 2: Network Planning and Operation Impacts of DG in Spain

In Spain, the focus of renewable DG interconnection technical rules is on the fault ride-through (FRT) requirements of the units, as discussed below.

## Existing Fault Ride-through (FRT) Requirements

The FRT requirements for conventional generators connected to the transmission system states that the generation plants will not disconnect from the grid in the event of voltage sags associated to short-circuits that are correctly interrupted.

To reach that standard, the necessary design and control actions will be taken in the generation plants (all their components) for them to withstand three-phase, phase-phase (with and without ground), and phase-ground short circuits without disconnection. The voltage sags (independent of the short circuit type) at the connection point will not result in disconnection as long as the sag is located within the grey area of Figure 4.

The curve is valid for all generators sizes and all voltage levels. Although FRT requirement is independent of the network condition, the steady state voltage and reactive power supply requirements are dependent on network conditions.

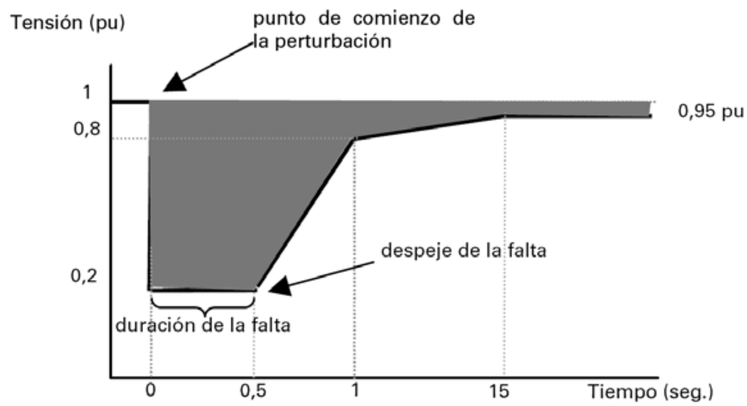


**Figure 4: General FRT Requirement for Generators Connected to the Spanish Transmission System**

| Legend/Translation | |
|---|---|
| Tensión (p.u.) | Voltage (p.u.) |
| Tiempo (seg.) | Time (sec.) |
| Punto de comienzo… | Fault initiation… |
| Duración de falta | Fault duration |
| Despeje de falta | Fault clearing |

Customized FRT requirements that have been developed specifically for wind generation, which are slightly different from those developed for conventional generation:

- The same curve as for conventional generation (Figure 4) applies to the voltage sags associated to three phase, phase-phase with ground, and phase-ground short circuits. For the voltage sags associated to phase-phase without ground short circuit, the same curve applies with the lower limit is fixed at 0.6 per unit (p.u.) instead of 0.2 p.u.

There are also requirements for reactive current support from wind generators during faults. These are illustrated in Figure 5.

- In general, for three-phase faults, both during the fault and at the recovery period (after fault elimination), the wind farm should not consume reactive power. Without contradiction to the previous general requirements, wind farms are allowed to momentarily consume reactive power for a period of 150 ms after fault initiation and 150 ms immediately after fault elimination, as long as the following conditions are simultaneously respected:
    - During a period of 150 ms after the fault initiation, the net reactive power consumption will never be more than 60 percent of the registered rated power in every cycle (20 ms).
    - For 150 ms after fault elimination, the net reactive power energy consumption will not be more than the equivalent reactive energy corresponding to the wind turbine

operating at 60 percent of the wind farm's registered, rated power during that period.

- The net consumption of reactive current in each cycle (20 ms) will not exceed 1.5 times the current corresponding to rated power.

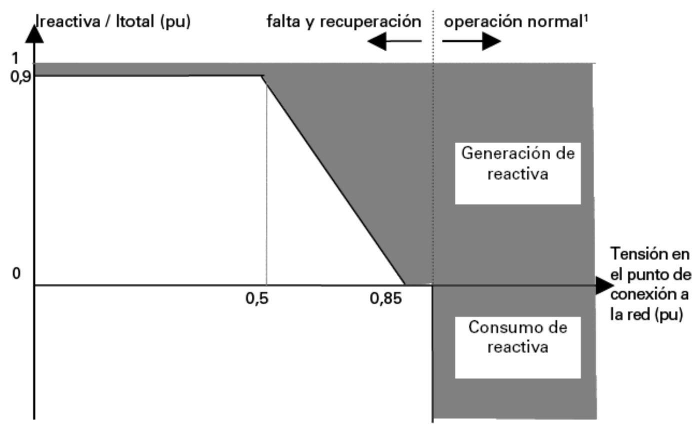


**Figure 5: Reactive Current Injection during Fault Requirements for Wind Turbines**

Source: REE: P.O 12.3

Legend/Translation

| | |
|---|---|
| Ireactiva/Itotal (p.u.) | Reactive current/total current (p.u.) |
| Falta y recuperación | Fault and recovery |
| Operación normal | Normal operation |
| Generación de reactiva | Reactive power generation |
| Consumo de reactiva | Reactive power consumption |
| Tensión en el punto de conexión a la red (p.u.) | Voltage at interconnection point (p.u) |

There shall be no active power consumption at the PCC (point of common coupling) during the period of fault duration and after fault clearing. Similarly to the previous case, the wind farm is allowed under the technical rules to have momentary active power consumption during 150 ms after fault initiation and after fault elimination. Active power consumption is also allowed during the remaining periods of the fault as long as it is not greater than 10 percent of the rated power of the wind farm.

- The wind farm should provide the electrical power system at the PCC (point of common coupling) with the maximum possible current during the fault and during voltage recovery according with the curve presented in Figure 5
- The wind farm should comply with the curve 150 ms after fault initiation or after fault elimination. Therefore, for voltages below 0.85 p.u. at the PCC (point of common coupling), the wind farm should generate reactive current and for voltages values between 0.85 p.u. and the minimum voltage allowed in normal operation, the wind farm cannot consume

reactive power. Above the minimum voltage allowed in normal operation, the wind farm should be compliant with the requirements for normal operation existing in the document "P.O. 1.4 Condiciones de entrega de la energia en los puntos frontera de la red gestionada por el operador del sistema." [Translation: "Operational Procedure 1.4 (Conditions for power delivery in the interconnection points to grid management by the independent system operator."]

- In general, for unsymmetrical faults (single phase and phase-to-phase) the wind farm cannot absorb reactive power at the PCC during the fault and during voltage recovery. Still, it can momentarily consume reactive power for 150 ms immediately after the fault initiation and for 150 ms after fault elimination. Furthermore, it can consume transient reactive power during the remaining periods of the fault as long as:
  - The reactive energy consumption (at the three phases) is not more than the equivalent reactive energy of 40 percent of the nominal power registered during a period of 100 ms
  - The reactive power consumption of the wind farm in each 20 ms cycle is not more than 40 percent of the nominal power registered
- During the remaining periods of the fault, it can consume active power as long as:
  - Active energy consumption (at the three phases) is not more than the equivalent active energy of 40 percent of the nominal power registered during a period of 100 ms
  - Active power consumption in each 20 ms cycle cannot be more than 30 percent of the nominal power registered.
- Furthermore, it can draw transient reactive power during the remaining periods of the fault as long as: the reactive energy consumption (at the three phases) is not more than the equivalent reactive energy of 40 percent of the nominal power registered during a period of 100 ms, and the reactive power consumption of the wind farm in each 20 ms cycle is not more than 40 percent of the nominal power registered. During the remaining periods of the fault, it can draw active power as long as: the active energy consumption (at the three phases) is not more than the equivalent active energy of 40 percent of the nominal power registered during a period of 100 ms, and the active power consumption in each 20 ms cycle cannot be more than 30 percent of the nominal power registered.

The existing wind farms at the time of the grid-code approval did not have to fulfill the requirements related with active and reactive power consumption during unsymmetrical faults unless the wind farm is significantly reinforced or improved.

The documents that specify these requirements are:

- Conventional generation - P.O. 12.2 of REE - "Instalaciones conectadas a la red de transporte: requisitos mínimos de diseño, equipamiento, funcionamiento y seguridad y puesta en servicio". [Translation: Operating Procedure 12.2 of REE – "Installations Connected to the Delivery Grid: Minimum Requirements for Design, Equipment, Functionality, Reliability and Energization"] Approved February o11, 2005, by Resolution 3419 of the General Secretariat of Energy.

- Renewable generation- P.O. 12.3 of REE - "Requisitos de respuesta frente a huecos de tensión de las instalaciones eólicas". [Translation: Operating Procedure 12.3 of REE – "Time Domain Voltage Response Requirements of Wind (Power) Installations"] Approved October 4, 2006, by Resolution 18485 of the General Secretariat of Energy.

## Evolution of Fault Ride-through (FRT) Requirements

The first Spanish grid code requirement regarding generators FRT capability was released in the P.O. 12.2 on November 2, 2005. Due to the increasing wind power integration in the peninsular system characterized by limited interconnection capacities with neighboring countries and the features of the existing wind power plants (without FRT), it was necessary to review the wind energy penetration that is technically permissible in the Spanish power system in peak and off-peak periods. The P.O. 12.3 released in April 10, 2006 contains the wind farm requirements necessary to secure a high wind power penetration in the Iberian system, guaranteeing security and quality of supply. These requirements are related with FRT capability and injection of reactive power during faults to support network voltage.

The appendix on technical requirements of the P.O. 12.2 is under revision. This revision is oriented to wind, solar power plants and every technology not based on a synchronous generator directly connected to the grid. The following main modifications are proposed:

- The plant must withstand 0 percent residual voltage dips without disconnecting during 150 ms.
- The plant should be able to stand a voltage swell up to 130 percent at the connection point.
- The plant shall be able to generate/consume reactive current within the voltage margin defined by the set-points sent by the TSO in less than 20 seconds. During transient grid voltage events the control will switch to an automatic voltage controller using the previous unaltered voltage set point as current set-point. The control can be implemented as a voltage, reactive power, or power factor controller and will maintain the reactive current injection/consumption within the limits of saturation. The controller will remain active for at least 30 seconds after voltage recovery returning then to the operational mode previous to the perturbation. Figure 6 illustrates this requirement.
- The plant shall include the required equipment to perform power-frequency control, equivalent to a proportional controller with adjustable dead band.

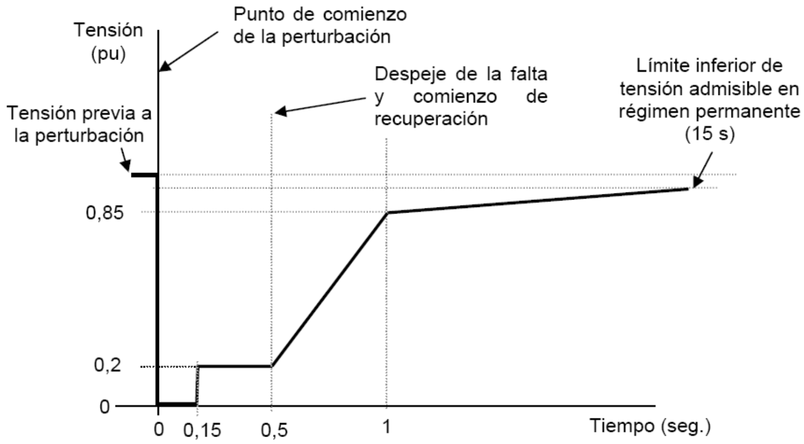


**Figure 6: Proposal of FRT Requirement for Renewable Generation**

Legend/Translation

| | |
|---|---|
| Tension (p.u.)/Tiempo (seg.) | Voltage (p.u.)/Time (sec.) |
| Despeje de la falta comienzo de recuperación | Fault clearing and start of grid recovery |
| Limite inferior de tension admissible en regimen permanente | Lowest voltage level that the generator is required to operate indefinitely |
| Tensión previa a la perturbación | Voltage prior to the grid disturbance |
| Punto de comienzo de la perturbación | Beginning of the grid disturbance |

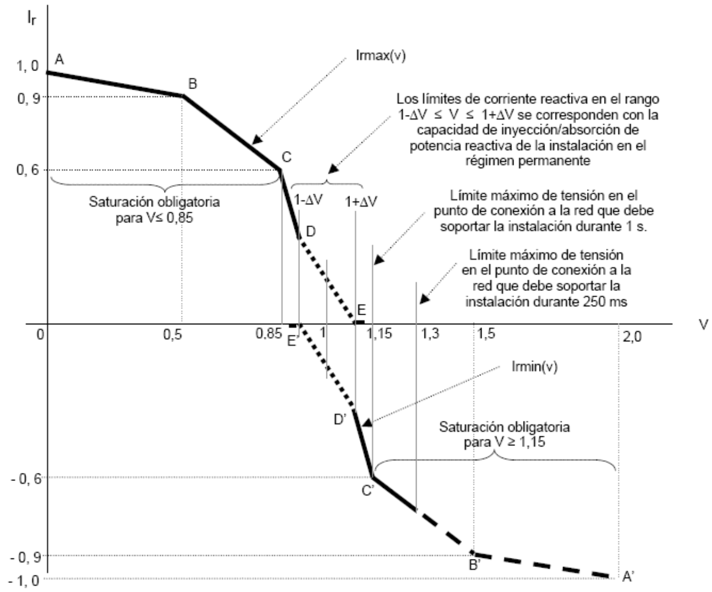


**Figure 7: Proposed Reactive Current Injection during Fault Requirement for Renewable Generation**

Legend/Translation

| | |
|---|---|
| $I_{r\,\&}\,I_{rmax}$ (p.u.) | Reactive current & Max. Reactive current (p.u.) |
| V | Voltage (p.u.) |
| Saturación obligatoria para V> 1,15 | Reactive current required for Voltages > 1.15 (p.u.) |
| Saturación obligatoria para V< 0,85 | Reactive current required for Voltages < 0.85 (p.u.) |
| Consumo de reactiva | Reactive power consumption |
| Limite maximo de tensión en el punto de conexión a la red que debe soportar la instalacion durante 250 ms | Voltage limit at interconnection point with grid that the generator must be able to support for up to 250 msec. |
| Limite maximo de tensión en el punto de conexión a la red que debe soportar la instalacion 1 s | Voltage limit at interconnection point with grid that the generator must be able to support for up to 1 sec. |
| Los limites de corriente reactive el el rango… | Limits of reactive current in the range of 0.90 < V < 1.00 (p.u.) that the generator must be able to inject or absorb (from the grid) on a continual basis |

## Control Center for Renewables

One of the hallmarks of Spain's leadership in integration of renewable generation is the creation of the Control Center for Renewable Energy (CECRE). CECRE was established by REE (TSO) and is now integrated in its control room. It enables control and supervision of all of Spain's renewable power production. It presently focuses on wind farms, but there are plans to include solar, biomass, small-scale hydro, cogeneration, and municipal solid waste incineration plants. All renewables over 10 MW are required to be connected via telemetry to a renewable energy source control center, which in turn is linked to the CECRE. Specifically, the goal of CECRE is to maximize the production of renewable energy while maintaining system reliability.

A critical part of CECRE is a wind generation forecasting system. This forecasting system is composed of three components: a database on the wind farms, a prediction algorithm based on a self-adaptive time series, and a forecast combination module. It uses as input real-time wind power and probabilistic wind forecasting and combines them into a multi-model forecast.

CECRE has a solid communication link with generation control centers for monitoring and control. Presently, it can issue wind generation curtailment orders when demand falls below what is provided by must-run units. It also continuously runs real-time simulations of faults and analyses the response of independent generators to these voltage sags. If an unsafe system situation is detected (mainly dependent on overloads on the tielines connecting to France), the renewable generators (for now only wind) will receive new operational set points to reduce their output, and conventional generation may receive more operational set points.

Although only about 40 percent of the wind power is connected to distribution, most of the curtailment orders issued by CECRE are due to requests from distribution companies that have trouble running their infrastructure due to lack of coincidence between load (demand) and wind generation. The rules in Spain do not allow a DNO to order such curtailments directly, so curtailments must be done through CECRE acting on behalf of the DNO. This also allows CECRE to consider if there are any better options to mitigate the operating condition of concern before ordering DG curtailment.

### Dispatch Priority for Renewables

In Spain all generating units have to send their offers to the market operator, OMEL, which makes an economical match between bids and offers and establishes a market price. OMEL pays each generating unit that has offered its production below the market price the hourly market price for their production. However, the economically based generation selection made by OMEL may not be physically deliverable. Therefore, the TSO analyzes the deliverability of the program made by OMEL and generates a new dispatch program for all generating units in the list from OMEL. Those units that are decreased compared to the initial economical selection have to pay the TSO back for the decreased production at the market price. Those units that get increased production get paid for the increased production at the price they had offered, which can be more or less than the market price.

All conventional generating plants have the same priority order in the re-dispatch. However, renewable resources have priority over conventional in the re-dispatch. Within renewable resource group, the renewable energy sources without storage capability have the highest dispatch priority according to Royal Decree 661/2007 published in June 2007. For example, this means that if there is a restriction related to the level of generation dispatch at a grid node where conventional power plants, hydropower plants with storage capabilities and wind farms are all connected, then the conventional plants will decrease their production first. If that re-dispatch is not enough to mitigate the grid constraint then the hydropower plants with storage capabilities will be directed to decrease production. Lastly, the wind farms will only be required to decrease their production after all other generating units have been curtailed.

### Operational Planning Related to DG/Renewables

Currently there are 4.9 GW of pumped hydro storage. Apart from that there are no other storage technologies deployed in the field. Alternatives such as demand side management are also not currently applied. To compensate for the variability of DG, particularly wind power, Spain either modulates hydro generation or cycles thermal generation, using mainly its natural gas fired combined-cycle units. Spain has 16.7 GW of hydro generation (includes pumped-hydro) and 25 GW of gas-fired combined-cycle plants.

On a typical operating day combined-cycle power plants have pronounced cycling behavior to offset non-dispatchable wind production. As an example, on January 12,2011 at the minimum load time (about 4 a.m.) there were 2.2 GW generated by combined cycle plants, while at the peak hour (9 p.m.), more than 9 GW of output was dispatched on combined cycle plants. The wind in Spain is highly variable. On the same day at the minimum load time wind farms generated 8.3 GW, but at 10 a.m., they produced only 5.9 GW, almost a 2.5 GW reduction in three hours. At peak system demand that day only 4 GW of wind power was available and thus required conventional generating resources to ramp for both the loss of wind as well as the increase in demand. Again, combined-cycle power plants take the main role in providing this ramp up capacity.

Combined-cycle power plants that routinely operate under such a cycling regime require costly maintenance. To compensate, new combined-cycle plants in Spain are compensated on their availability and capacity (capacity credit concept). Thus there is still an incentive for combined-cycle plants to be built, though renewable energy tends to dominate new generation technologies.

CECRE (the renewables control centre) is responsible for wind generation forecasting. This system provides forecast of wind power up to 48 hours in advance and was developed using Matlab by The Spanish Meteorological Agency and Meteologica, a Spanish company specializing in forecasting and mathematical modeling services for wind power generation. In total, some 94 percent of the wind farms in Spain report to CECRE and production data is updated every 20 minutes.

The errors of the wind forecast depend on the forecast horizon. Over a 48-hour horizon the maximum error in 2009 was just over 15 percent, while for a four hour forecast the error was about 12 percent. REE uses probabilistic wind forecasts to buy reserves for on a day-ahead basis. The forecast error has been decreasing over the years and therefore, helping REE to reduce the amount of acquired reserves while still operating the system in a reliable manner.

# SECTION 3:
# European Standards on Frequency Control and Balancing Services

Frequency control and balancing services usually require all services to maintain and/or restore system frequency to within acceptable levels as well as to restore the energy balance of the system. Within the interconnected power system of continental Europe, which was formerly known as UCTE,[22] the following three main types of services are defined in the relevant guidelines and procedures:

- ***Primary frequency control*** is the automated, decentralized response of the governor controls on individual generators to any frequency excursion on the grid to counteract deviations of system frequency.
- ***Secondary frequency control*** [23] is based on the centralized control of particular generating units and helps to restore system frequency by restoring the area control error (ACE) of a given system to zero.
- ***Manually instructed reserves*** involves tertiary services with an advance notice time for activation (normally no less than 15 minutes), as well as any other spinning or non-spinning reserves that may be activated by a specific instruction from the system operator and which serve to restore the energy balance of the entire system.

The characteristics of these three services in the EU grid are further elaborated in Table 2.

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22 Union for the Coordination of the Transport of Electricity (UTCE) was an association of TSOs that jointly operated the interconnected power system of continental Europe. It was set up to coordinate transmission system operation across control areas. As of 2005 the TSOs agreed upon the mandatory introduction of UCTE standards. From mid-2009 the newly founded European Network of Transmission System Operators for Electricity (ENTSO-E) absorbed the tasks of existing TSO associations, including UCTE.

23 This service is also known as power-frequency control, regulation or automatic generation control (AGC) in other jurisdictions.

**Table 2: Characteristics of the Three Frequency Control Reserve Levels in UCTE**

| | Primary Control | Secondary Control | Tertiary Control |
|---|---|---|---|
| Why is the control used? | To stabilize the frequency in case of imbalance | To bring back the frequency and the interchange programs to their target | To restore the secondary control reserve, to manage eventual congestions, and to bring back the frequency and interchange programs to their target if the secondary control reserve is not sufficient. |
| How is control achieved? | Automatically | | Manually |
| Where is this control performed? | Locally | Centrally (TSO) | |
| Who sends the control signal to the source of reserve? | Local sensor | TSO | TSO or generators and consumers (after receiving instructions from the TSO) |
| When is the control activated? | Immediately | Immediately (seconds) | Decided by dispatcher |
| How long is the service provided? | Continuous | | Based on instruction<br>(Often scheduled) |
| What sources of reserves can be used? | Partially loaded units | | Partially loaded units, loads fast/slow starting units, changes in exchange programs |
| Minimum reserve capacity | 3,000 MW, shared by all the different control areas in EU | Secondary control reserve *<br>$\sqrt{10\, L_{\max zone} + 150^2} - 150 \; in\, MW$ | Sufficient to cover at least the largest loss of power or to replace secondary control reserves |
| Timing**<br>Start<br>Full availability<br>End | Immediate<br>≤ 30s<br>≥ 15min | ≤ 30s<br>≤ 15min<br>As long as required | No recommendation<br>Short time: often 15min<br>No recommendation |
| Activation | Fully activated at frequency deviation of<br>+/-200 MHz | Country-specific | - |

* L max zone is the expected peak load in the zone for the considered period (e.g. one hour).

**It is recommended that secondary control is replaced by tertiary control as soon as possible.

Sources: EU Directorate General for Competition Report on Energy Sector Inquiry 10 January 2007; and Rebours / Kirschen: *A Survey of Definitions and Specifications of Reserve Services*, 2005

In most continental European countries, the technical specifications of these services roughly correspond to UCTE requirements. However, it is important to note that the requirements of UCTE apply to system operators, while the respective national rules (e.g., grid codes) typically specify the minimum requirements for generating units or other potential service providers, which may be different.

That the provisions on the total reserve capacity in Table 2 represent minimum requirements, whereas each TSO decides on the level of reserves it holds in practice. The requirement for 3,000 MW of primary control has been mutually agreed upon by all TSOs, and the provision of each TSO's share of the total is a binding obligation. The formula for secondary control reserves has recently been declared by ENTSO-E to be a minimum requirement as well. In practice, many European TSOs apply the formula, while others procure more reserves. For instance, the German TSOs apply a probabilistic method, which results in a significantly greater need for secondary control reserves than suggested by the formula listed above.

**Primary Reserve** covers a loss of generation or load up to 3,000 MW in the UCTE synchronous area. As soon as the reserve is required, it shall be activated according to the function shown in Figure 7. The figure distinguishes two different scenarios and minimum requirements for deployment. First, 1,500 MW of primary control reserve have to be fully activated within the first 15 seconds after a disturbance (loss of generation or load) . Secondly, if the disturbance is between 1,500 MW and 3,000 MW, full activation is required within the first 30 seconds after the start of the event.

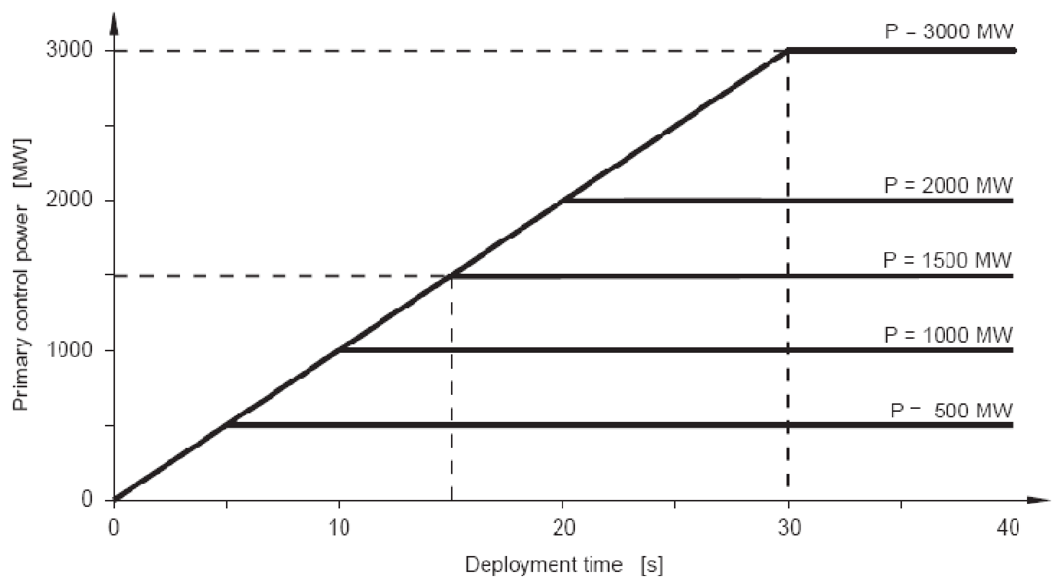



**Figure 8: Minimum Deployment of Primary Control Reserve as a Function of Time and Disturbance Magnitude**

Source: UCTE. *Operational Handbook, A1 – Appendix 1: Load-Frequency Control and Performance* [E], A1-9.

As the control is provided from all control areas interconnected in the UCTE synchronous area, the timely harmonized deployment of reserves is as important as the compliance with reaction time requirements stated above.

## Control Measurement

UCTE has not defined detailed control performance requirements for each of these services. For primary control, the Operations Handbook requires that the quasi-steady-state frequency deviation must not exceed ±180 mHz, while the maximum instantaneous frequency deviation must not exceed ±800 mHz. In contrast there are no firm measures for secondary and tertiary reserves. However, UCTE does produce a confidential monthly report with performance statistics on the operation of primary and secondary control in each control area, which is largely based on a statistical analysis of frequency deviations and ACE.

### Primary Control Reserve

The measurement of primary control reserve quality aims at evaluating the performance of control deployment and indicating operational reliability of the UCTE synchronous area. Quality control measurement is based on system frequency analysis after major disturbances. It relies on frequency measurements of both the entire synchronous area and each control area, using the following two indicators:

- Ratio of the power variation causing the disturbance and the quasi-steady-state frequency deviation in response to the disturbance
- Ratio of the variation in power generated in a control area in response to a disturbance and the quasi-steady-state frequency deviation in response to the disturbance, whereby cross-border exchanges and power deficits and surpluses at the interconnections between control areas have to be taken into account.

Both measurements have to be carried out simultaneously. Moreover, it is assumed that the major part of primary control reserve is activated within 20 seconds after the start of the event, and that the contribution of secondary control reserve is negligible.

TSOs must constantly record and analyze the quality of their primary control reserve as well as major disturbances from production or consumption outages. Such anomalies are considered significant if they exceed 1,000 MW. TSOs must interchange information on the location, time, type, and magnitude (amount of production/ consumption lost) of significant disturbances.

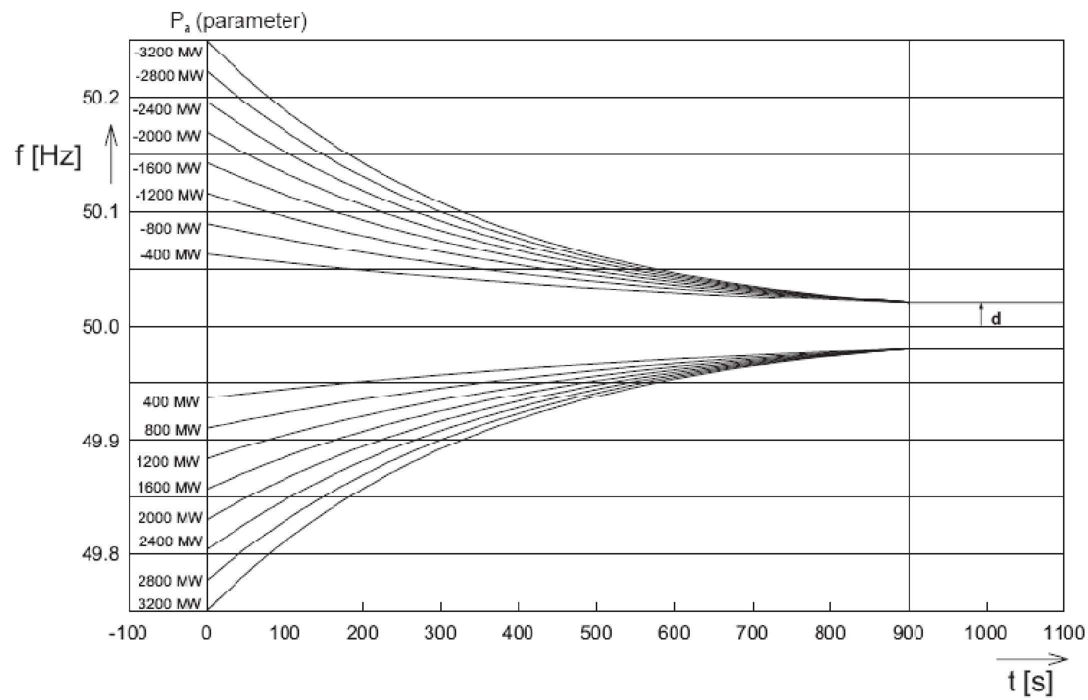
### Secondary Control Reserve

The cases of normal operation and abnormal operation are distinguished for the purpose of measuring secondary control reserve quality. The former includes small disturbances and frequency deviations, while the latter embraces large deviations beyond 1,000 MW.

Under normal, continuous operation, the following indicators are used for quality control:

- Standard deviation of the average frequency deviations over each 15-minute interval in a month
- Number and duration of frequency corrections
- Proportion of time during which frequency deviations are greater than or equal to 50 mHz

For large frequency deviations, the ability of secondary control reserve to bring the system frequency back to the standard value after a significant disturbance is checked based on the so-called trumpet method. Depending on the absolute frequency deviation assumed, a trumpet-shaped curve is plotted (see Figure 9), which serves to indicate how the secondary control Reserve reacts and how default frequency is established. The aim is to maintain system frequency above the lower trumpet function in case of frequency decline or below the upper trumpet function in case of frequency excess during control reserve deployment (see figures below). The aim is to restore the default frequency value within 15 minutes after an incident with an accuracy accepting a final deviation of +/-20mHz.



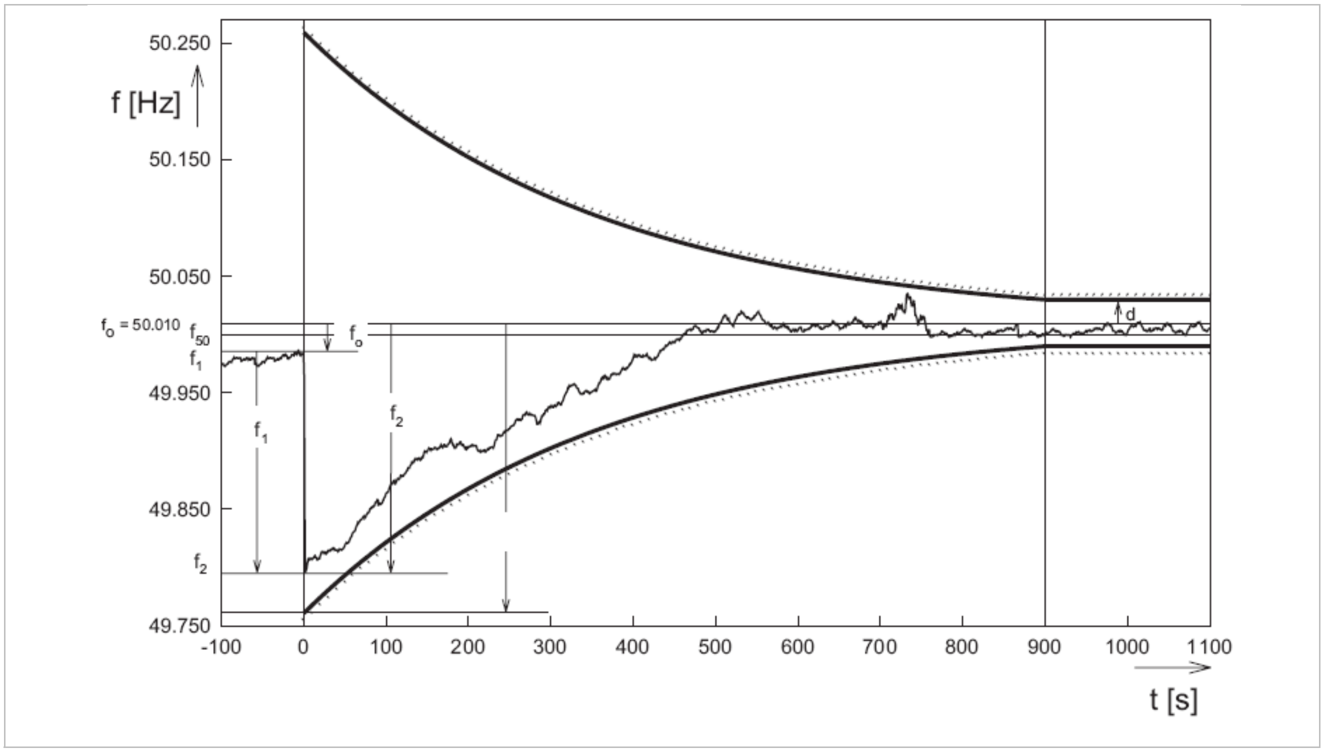



**Figure 9 and Figure 10: Trumpet Curve(s) for Secondary Control Reserve**

Source: *UCTE Operational Handbook, A1 – Appendix 1: Load-Frequency Control and Performance [E*], A1-20- A1-21.

## Procurement of Frequency Control Reserves

Besides the minimum technical requirements, there also exist major differences in the methods applied for the procurement of these services by TSOs. In Germany, reserves and balancing services are offered by generators (and consumers) on a voluntary basis, while many other countries rely on compulsory offers. In the former case, all services are procured by separate tendering mechanisms on a regular basis, which are jointly carried out by the four German TSOs. Besides primary, secondary and tertiary reserves, the German TSOs have been procuring two other types of related services:

- Wind reserves, which have been used to compensate for unexpected fluctuations in the production by wind power plants and that may consist of several products, such as additional 15-minute reserves and hourly reserves[24]
- Re-dispatch services, which are used to resolve network constraints outside the balancing mechanism, which is thus, limited to simple energy balancing.

24 Please note that the German TSOs also utilize secondary reserves for managing the real-time variability of wind power generation across the four control areas.

As of 2011, TSOs in Germany are no longer allowed to procure wind reserves for mitigating renewables variability. It was only allowed as an interim basis and as a limited measure to help cover situations when the power exchange would not provide sufficient liquidity to buy and sell renewable power volumes that result from updated forecasts. However, in prior years two of the leading TSOs procured the following volumes of wind reserve regulation service.

**Table 3: Levels of Wind Reserve Service Procured**

| Categories and Years | TSO1 | TSO2 |
|---|---|---|
| **Upward Regulation (MW)** | | |
| 2007 | 300 | n/a |
| 2010 | 100-150 | 30 |
| **Downward Regulation (MW)** | | |
| 2007 | 300 | n/a |
| 2010 | 200 | 200-240 |

One of the main parameters for the required amount of frequency control reserves is electricity from intermittent renewable sources and the inaccuracy inherent to the short-term forecast of output from such sources, especially wind power. Most of the wind power forecast models used so far apply a global approach, i.e. providing a forecast for any weather conditions. A European study[25] compared the forecast quality of various models for a specific set of wind power installations and delivers some valuable results both on current and future forecast quality. According to the study, the forecast error depends on the model used, the wind power installation the model is applied to, and the complexity of the surroundings of the installation. For onshore wind power in plain areas (least complex) the average forecast error among all models considered is about 10 percent, but increases to up to 21 percent for highly complex surroundings. The offshore wind forecast error is around 12 percent and, thus, comparable to installations in less complex onshore areas. Moreover, models tailored to specific wind power installations, their surroundings and local climate conditions may perform up to 20 percent to 40 percent better than more generic models. For solar power the forecast error was estimated at 10 percent for the year 2005. For both wind power and solar power scientific literature rates the potential for quality improvements at 40 percent.

If one takes into account the potential improvement in forecast quality, this may decrease the need for control power reserves or at least partially compensate for the increase of variability form increasing scales of renewable electricity in Germany. Two studies published in 2010 contribute to this issue and estimate the scales of control power reserves required in 2020. The results are shown in Table 4, but are not directly comparable as will be explained below.

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25 ANEMOS project (Kariniotakis et al., 2006), found in Dena Netzstudie II (see below)

**Table 4: Size of Control Power Reserves**

| Control Power Reserve Type | 2010 Actuals | 2020 Forecast | |
|---|---|---|---|
| | | Dena Grid Study II | Consentec Study |
| Secondary and tertiary reserves for upward regulation | ~ 4,600 MW | 3,867 – 4,180 MW | 6,500 |
| Secondary and tertiary reserves for downward regulation | ~ 4,600 MW | 3,145 – 3,317 MW | 7,500 MW |
| Primary reserve | +/- 600-700 MW | - | |

The first study[26] estimates that current forecast models may be improved so that a total performance (average absolute error) increase by 40 percent to 50 percent may be achieved. This would result in a stable need for total reserves required in 2020 compared to the volumes currently procured by German TSOs. This is despite the strong growth of renewables that is anticipated to occur by 2020. The study assumes that the reserves are determined including a one-hour wind power forecast and different security margins (confidence intervals), and subject to the assumption that energy deviations up to one hour before the fact are balanced by same-day trading at the power exchange.

The second study[27] concludes that the need for control power reserves would increase only slightly, while the share of renewable electricity will increase to 30 percent by 2020. It includes a forecast quality performance increase of 20 percent until 2015 and another 10 percent until 2020. The difference may be explained by the fact that, here, the estimated absolute values subsume all reserve capacity services currently procured by German TSOs including, wind reserve power (see above) and other balancing mechanisms. Moreover, the authors note that the current volumes procured by the TSOs are significantly below the model-based estimations. The study concludes that the reserve requirement would increase by 50 percent (upward regulation) and 30 percent (downward regulation), compared to the above scenario, if the renewables forecast performance does not occur to the extent mentioned above. And the authors assume that the more intermittent renewable sources are connected to the network (beyond the value of 30 percent assumed), the lesser the forecast quality improvement will compensate for the former.

26 Dena Netzstudie II, 2010, p.382ff. (engl. Dena Grid Study II – *Integration of Renewable Energy Sources in the German Power Supply System from 2015 – 2020 with an Outlook to 2025*).

27 Consentec /r2b: „Voraussetzungen einer optimalen Integration erneuerbarer Energien in das Stromversorgungssystem, 2010 (engl. Conditions for optimal integration of renewable sources into the electricity system)

# SECTION 4:
# Comparison to Situation in California

## Comparison DG Interconnection Rules in California

The rules in California governing distributed generation interconnection are very different from Germany. First, the California Independent System Operator (California ISO) only has jurisdiction over generating resources that would interconnect to the California ISO-controlled transmission grid, and these resources are typically 1 MW or larger facilities.

California's ISO is now using a cluster-study process to expedite processing for new generation interconnection studies. Separate from California ISO's interconnection procedures are metering and telemetry requirements for projects that sign a participating generator agreement (PGA) with California ISO. All participating generators 1 MW or greater must have California ISO metering. Telemetry is required for intermittent generators 1 MW or greater and for all other participating generators 10 MW or greater.

Generation that will interconnect to the utility controlled, lower-voltage portions of the California grid are subject to the respective utility's interconnection process, such as Southern California Edison Company's (SCE) Wholesale Distribution Access Tariff (WDAT) rules. On March 1, 2011, SCE filed an amendment with FERC to request approval for a modified WDAT process, which will allow SCE to group generators in their interconnection queue into *clusters* for interconnection study purposes. This is similar to the cluster study approach already being used by the California ISO.

Distributed generation resources that are 1 MW or less are subject to the local utility's interconnection rules that are approved by the applicable regulator, i.e., FERC or the California Public Utility Commission (CPUC) for the investor-owned utilities or by the appropriate municipal utility board or irrigation district board. In addition, the CPUC has established Rule 21 as the standard for the interconnection of DG facilities to the distribution system. The DG units typically do not contribute

**Rule 21 Certification Codes and Standards**

IEEE1547 Standard for Interconnecting Distributed Resources with Electric Power Systems (including use of IEEE 1547.1 testing protocols to establish conformity)

UL 1741 Inverters, Converters, and Controllers for Use in Independent Power Systems

IEEE Std 929-2000 IEEE Recommended Practice for Utility Interface of Photovoltaic (PV) Systems NFPA 70 (2002), National Electrical Code

IEEE Std C37.90.1-1989 (R1994), IEEE Standard Surge Withstand Capability (SWC) Tests for Protective Relays and Relay Systems

IEEE Std C37.90.2 (1995), IEEE Standard Withstand Capability of Relay Systems to Radiated Electromagnetic Interference from Transceivers

IEEE Std C37.108-1989 (R2002), IEEE Guide for the Protection of Network Transformers IEEE Std C57.12.44-2000, IEEE Standard Requirements for Secondary Network Protectors

IEEE Std C62.41.2-2002, IEEE Recommended Practice on Characterization of Surges in Low Voltage (1000V and Less) AC Power Circuits

IEEE Std C62.45-1992 (R2002), IEEE Recommended Practice on Surge Testing for Equipment Connected to Low-Voltage (1000V and Less) AC Power Circuits

ANSI C84.1-1995 Electric Power Systems and Equipment – Voltage Ratings (60 Hertz)

IEEE Std 100-2000, IEEE Standard Dictionary of Electrical and Electronic Terms NEMA MG 1-1998, Motors and Small Resources, Revision 3

IEEE Std 519-1992, IEEE Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems

NEMA MG 1-2003 (Rev 2004), Motors and Generators, Revision 1 reactive power for voltage support. They also are expected to disconnect from the distribution system in the event of a short circuit or system outage and not contribute to the ride through or recovery of the system from a disturbance.

Rule 21 specifies the applicable standards and codes the generator must meet. Generators no larger than 5 MW (up to 3 MW for a 21kV interconnection, and up to 2 MW on a 12k V interconnection) will be evaluated under a fast-track process. Generators that are larger than 5 MW require a more detailed interconnection study by both the local utility and the California ISO.

Unlike Germany, the California ISO has no visibility of the energy production of DG resources connected to the distribution system and cannot send dispatch commands to these DG Resources. This is especially true for DG Resources that are connected behind the meter at a customer site and the DG output is netted with the customer load. By virtue of its balancing area authority status, the ISO must be prepared to cover the total load at the customer site in the event that the DG unit shuts down, but the amount of load being offset by DG output is typically unknown to the ISO. This has not posed a serious problem to date since the amount of DG in California is been relatively limited. However, with the amount of DG—especially solar PV—projected to grow to 3,000 MW or more in the next 10 years, the potential impact from an unexpected shut down of these resources could represent a future reliability problem for the California ISO—and for California.

The California ISO previously had a set of tariff rules for the interconnection of Small Generation resources rated between 1 MW and 20 MW. However, their Small Generator Interconnection Procedure (SGIP) and their Large Generator Interconnection Procedure (LGIP) were merged into one Generator Interconnection Procedure (GIP) in December 2010. The ISO Tariff – Appendix Y now covers interconnection process for all generators. It includes a section for small generator certification that reads as follows:

> "Small Generating Facility equipment proposed for use separately or packaged with other equipment in an interconnection system shall be considered certified for interconnected operation if (1) it has been tested in accordance with industry standards for continuous utility interactive operation in compliance with the appropriate codes and standards referenced below by any Nationally Recognized Testing Laboratory (NRTL) recognized by the United States Occupational Safety and Health Administration to test and certify interconnection equipment pursuant to the relevant codes and standards listed in GIP Appendix 9, (2) it has been labeled and is publicly listed by such NRTL at the time of the interconnection application, and (3) such NRTL makes readily available for verification all test standards and procedures it utilized in performing such equipment certification, and, with consumer approval, the test data itself. The NRTL may make such information available on its website and by encouraging such information to be included in the manufacturer's literature accompanying the equipment."

The California ISO tariff only applies to DG units rated over 1 MW that seeks to be interconnected to the ISO controlled grid. This includes DG interconnections to California IOU network facilities down to the 60 kV to 70 kV level in both the Pacific Gas and Electric Company (PG&E) and San Diego Gas and Electric Company (SDG&E) service areas, but only at 220 kV and above in the Southern California Edison Company (SCE) service area. The California ISO tariff does not apply to lower voltage DG interconnections or any DG facilities located in publicly owned utilities in California.

## Comparison of EU Control Performance Standards to California

NERC sets the control performance standards for all control area operators (balancing authorities) in United States, Canada, and Northern Mexico. Additional or more stringent standards have also been approved that apply to only the balancing authorities in the Western Electricity Coordinating Council area (WECC), which includes California. The current applicable NERC and WECC standards are summarized in the following table.

| | |
|---|---|
| BAL-001-0.1a | **Real Power Balancing Control Performance**<br>To maintain interconnection steady-state frequency within defined limits by balancing real power demand and supply in real-time. |
| BAL-002-WECC-1 | **Contingency Reserve (WECC)**<br>Contingency reserve is required for the reliable operation of the interconnected power system. Adequate generating capacity must be available at all times to maintain scheduled frequency, and avoid loss of firm load following transmission or generation contingencies. This generating capacity is necessary to replace generating capacity and energy lost due to forced outages of generation or transmission equipment. |
| BAL-003-0.1b | **Frequency Response and Bias**<br>This standard provides a consistent method for calculating the frequency bias component of area control error (ACE). |
| BAL-004-WECC-1 | **Automatic Time Error Correction (WECC)**<br>To maintain Interconnection frequency within a predefined frequency profile under all conditions (i.e., normal and abnormal), and to ensure that time error corrections are effectively conducted in a manner that does not adversely affect the reliability of the interconnection. |
| BAL-005-0.1b | **Automatic Generation Control**<br>This standard establishes requirements for balancing authority automatic generation Control (AGC) necessary to calculate area control error (ACE) and to routinely deploy the regulating reserve. The standard also ensures that all facilities and load electrically synchronized to the Interconnection are included within the metered boundary of a Balancing Area so that balancing of resources and demand can be achieved. |

| | |
|---|---|
| BAL-006-2 | **Inadvertent Interchange**<br><br>This standard defines a process for monitoring balancing authorities to ensure that, over the long term, Balancing authority areas do not excessively depend on other balancing authority areas in the Interconnection for meeting their demand or Interchange obligations. |
| BAL-502-RFC-02 | **Planned Resource Adequacy Assessment (RFC)**<br>To establish common criteria, based on “one day in ten year” loss of load expectation principles, for the analysis, assessment and documentation of resource adequacy for load in the Reliability First Corporation (RFC) region. |
| BAL-STD-002-0 | **Operating Reserves (WECC)**<br>Regional reliability standard to address the operating reserve requirements of the western interconnection. |

The NERC and WECC control performance standards are similar to the EU standards with one exception: there is no requirement for operators to hold reserves to replace energy from variable generating resources such as wind generation or solar. The WECC members cannot deploy contingency reserves, a subset of operating reserves, for replacement energy from variable generating resources.

The WECC members are testing a new control performance standard known as the Balancing Authority ACE Limit (BAAL) standard, which permits greater variance in frequency control and in the area control error (ACE) tolerance band. The new BAAL proposed standard is graphically represented in Figure 11, which shows the permitted system frequency variation with the balancing authority’s ACE.

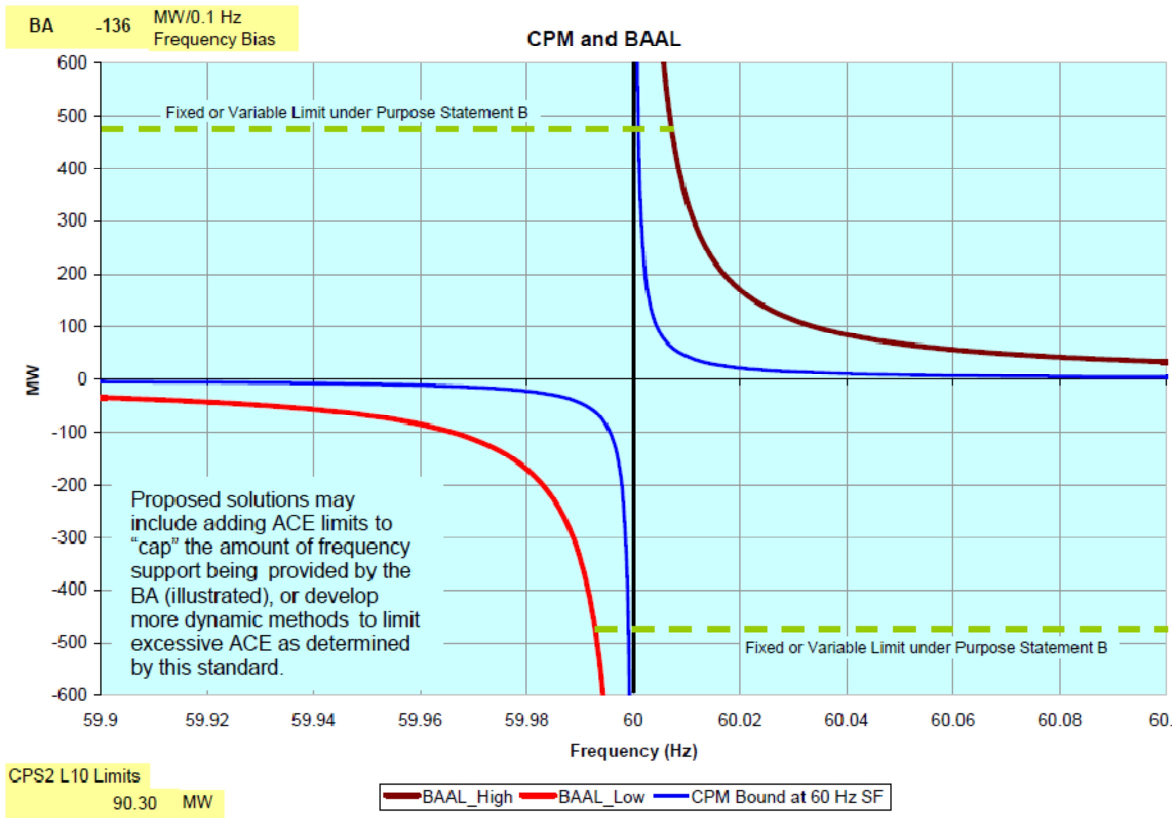


**Figure 11: Proposed BAAL Balancing Area ACE Standard**

Source: North American Reliability Corporation. *Reliability-based Control Standard Drafting Team's Proposed Metrics.* August 29, 2008
www.nerc.com/docs/standards/sar/Background_for_RBC_Metrics_Comment_Form.pdf - 2008-08-29

The WECC system has traditionally been operated to very tight frequency and interchange error-control standards. These standards have been lowered over the past 10 years due to criticism that the grid operators were required to *over control* for system frequency and ACE, which has resulted in excessive, and possibly unnecessary re-dispatching of generating units up and down throughout the day. The interconnection of large amounts of variable generation resources, such as wind and solar generation, further exacerbates such control problems if the system must continued to be operated to the same tight control performance standards. Therefore, the new proposed BAAL standard would allow for larger ACE deviations, as long as the system frequency remains within acceptable limits. The BAAL standard would help balancing authorities, such as the California ISO, Sacramento Municipal Utility District, and Los Angeles Department of Water and Power, to handle the minute-to-minute fluctuations of energy from variable generation resources. WECC members have been testing the BAAL standard for the past year to verify the interconnected system can still meet reliability levels expected by the public and by regulators. In the researchers' opinion, the BAAL control standard is closer to the control standards (as previously described) for EU grid operations.

However, it is unknown at this time if the proposed BAAL standard will be adopted in the WECC, or if it may be modified prior to adoption.

### California ISO Rules for Dispatch of Renewable DG Connected at the Transmission Level if Grid Congestion Occurs

The California ISO's preferred method for relieving transmission congestion in real-time operations is to use market rules for reducing output from generators on the supply side of a congestion bottleneck and increasing the output from generators on the receiving side of the bottleneck. If there are no market based resources to re-dispatch, then the ISO can go out of market and send dispatch notices to any generator that could relieve the congestion or overload. The operator has 30 minutes to relieve a thermally overloaded transmission line, but only 20 minutes to relieve a transient stability limited transmission line. If the ISO declares an emergency, the ISO dispatcher has the authority to send command and control instructions to any generator connected to the grid if changes are required for system reliability. The operator often has no real-time information about DG units that are 10 MW or less and probably does not have a telephone number to contact the owner/operator of the individual DG units. If there is a compelling need to contact the DG facility, the ISO would request the distribution system operator at the local utility to contact the DG operator and request the change.

### California ISO Forecasting for Balancing Area Demand and Renewable Production

Current California ISO load forecast errors typically run less than 2 percent for day-ahead forecasts of its balancing area demand. In comparison, the California ISO's day-ahead wind generation forecast error runs around below 15 percent, and the 1-hour-ahead wind generation forecast is typically less than 10 percent. When the amount of DG increases in the future, these numbers are expected to increase, unless the ISO is able to improve the available renewable data and forecasting models. The ISO is working to improve the accuracy of both the short-term forecasts and the day-ahead wind and solar generation forecasts for the integrated forward market. In fact, the ISO sent a representative to visit both the control centers at both Spain's and Germany's TSOs in 2010 and have used the knowledge gained in that trip to implement a Renewable Resource Coordinator position in grid operations at the California ISO on April 1, 2011.

The objective of this position is to provide forecast information to the generation dispatcher on what changes in energy production to anticipate from wind and solar generation for upcoming 15-minute minutes to 3- hour intervals ahead. This ensures that sufficient replacement energy is available from the real-time energy market in the event that some of the energy from variable renewables ramps down. Solar and wind generation can also ramp up in very short periods (less than 30 minutes), and it is important to forecast these events to ensure other generation can be rapidly ramped down to keep system frequency and ACE within standards. Because energy is scheduled on an hourly basis, the amount of deviation from schedule can be a very significant problem. The amount of deviation recently exceeded 800 MW in both the plus and minus direction on the same day.

The California ISO currently uses day-ahead and hour-ahead wind generation and solar generation forecasts that are provided by a professional forecasting service. The day-ahead forecast error for wind and solar generation is typically less than 15 percent range. A comparison of the current level of renewable production forecasting error levels for the California ISO, Spain and Germany is shown in Table 5 below:

**Table 5: Comparison of Forecast Error for Renewables**

| Renewables Forecast Error Category | Spain | Germany | California[28] |
|---|---|---|---|
| Day-Ahead | 15% | 5% | < 15% |
| 2-4 Hour-Ahead | 12% | 5% | <10%[29] |

The California ISO is also working to improve both the quality of data inputs available from all renewables in its balancing area and improve the tools available for use by its new renewable staff position in the ISO operating center. It is also important to use the renewable forecast data into the ISO's real-time *State Estimator Model* in order to accurately anticipate potential transmission operating constraints. The ISO is also working on implementing a voltage-stability analysis (VSA) tool to check for potential voltage collapse problems.

## California ISO Strategy for Operational Planning of Large-scale DG

Unlike Germany, the ISO has no visibility of the energy production of DG resources connected to the distribution system and cannot send dispatch commands to these DG resources. This is especially true for DG resources that are connected behind the meter at a customer site and the DG output is netted with the customer load. The ISO is expected to cover the total load at the customer site in the event that the DG unit shuts down, but the amount of load to be covered is often unknown. This has not been a serious problem to date since the amount of DG in California is been relatively limited. However, with the amount of DG, especially solar PV, projected to grow to 3,000 MW or more in the next 10 years, the potential impact from a sudden, unexpected ramp-down or shut down of these resources could represent a future reliability problem for the California ISO and California.

The California ISO describes its plans for addressing the impacts of large amounts of DG on their system in publication *IC-3 Non-dispatchable Distributed Energy Resources (DER) Changes, ISPO Forecast and Unit Commitment Decisions*. Large amounts of DG is a relative concept, but California's ISO system is a 50,000+ MW system, so 3,000 MW of DG is less than 6 percent of the California ISO's peak load. However, an aggregate of 3,000 MW of DG could be 10 percent or more of the total California ISO's generation dispatched during the Spring's or Fall's *shoulder*

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[28] Revised Analysis of June 2008 – June 2009 Forecast Service Provider RFB Performance, March 25 2010. CA ISO (http://www.caiso.com/2765/2765e6ad327c0.pdf).

[29] Note that this figure reflects the aggregate hour ahead forecast error reported by the CA ISO in the above referenced report.

*month* load periods. If the amount of DG increased to 6,000 MW, or even 12,000 MW, it would represent a very significant portion of the energy supply for the state. The risks associated with losing a portion of this energy resource would have to be studied to assess the impact on reliability and necessary changes to operating practices. Distributed generation would likely be very geographically dispersed, so the probability is low that large quantities of DG will be lost during a common event. A big concern is that if a major breakup of the transmission grid occurs and numerous islands are formed—in some cases with isolated loads islanded with comparable amounts of DG—it will be difficult for the grid operator to resynchronize such islands and reconnect them to the system. This scenario provides a rationale for having California ISO telecommunications and remote control capability to at least some clusters of DG in each area, which could help resynchronize and reconnect islanded areas with the main grid.

The California ISO states that it does not need to know the output of an individual DG facility that is less than 1 MW, but it does need to know the potential aggregate impact of the DG facilities that are installed in a load area. The concept is to collect daily net-load and weather information, probably with five-minute granularity, from substations that supply a distribution area. The goal is to create a predictive/forecasting model for each area that would reflect the amount of base load, temperature sensitive load, price sensitive load, solar energy production based on the amount of sunshine, and wind energy (if any) based on the amount of wind, and other known types of DG in the area. The ISO can use its weather forecast data and load forecast models to forecast the net load in an area for the next day and the potential amount of variability to expect. Based on these improved hourly and sub-hourly forecasts and aggregation of the area forecasts with diversity factors, they can then make more accurate predictions of the amount of energy, regulation, and operating reserves that will be required to ensure grid reliability for the next operating day. Based on these improvements in the forecast models, the ISO can then ensure the optimum amount of generating units are dispatched and scheduled for the next operating day.

So there are two issues to be initially addressed:

1. The commitment of generating units for the next operating day
2. The procurement of the optimum amount of regulation and operating reserves for the next operating day

The potential consequences of ignoring this requirement for improved forecasting models that reflect the amount of DG on the system include major over-commitment of thermal generating units on days/hours when they are not needed and this cost (potentially millions of dollars annually) is passed on to the rate payers. Another potential consequence is under-estimation of the amount of load to be served if the DG energy does not show up in the real-time operating day and there is insufficient quick start units available (reliability issue), or only peaker plants are available—at a very high additional cost for their energy.

So for the California ISO to have this information for important distribution load pockets they need to work collaboratively with the ,load serving entity (LSE) to insure the data collection systems are in place and the required data can be transmitted to the California ISO on a regular basis. The LSE may also want the same type of load forecasting model for their distribution planning purposes although they do have access to the data from all the smart meters installed at the customers in these areas.

Another question is: What size area that should be selected for this type of net-load data collection and what is the trigger for determining an area warrants special forecasting treatment? Does DG in the area have to reach some predetermined percentage of total load in the area? This is an issue to be discussed with the LSEs and criteria developed as the amount of load forecast error now exceeds 5 percent for a specific area.

A third issue is how to handle transmission constrained areas with significant DG resources. It is conceivable that the amount of DG in a given area may eventually reach the point that it equals or exceeds the total amount of load in an area. The extreme case might be when the net-load is driven to zero within an area, and then an event occurs that triggers the loss of major amounts of DG in the area, placing all load back onto the higher-voltage network and resulting in transmission overloads. However, this risk can be avoided if the network is always planned and operated so that it is not dependent on DG capacity for reliability. In fact, this is the approach currently used in Germany and Spain.

In summary, the California ISO should be able to handle much larger amounts of DG on the system in the future if the enhanced data collection system and improved forecasting models discussed above are successfully developed and implemented. It will require close cooperation and collaboration with the distribution companies to create the data collection systems and the new forecasting models.

# SECTION 5:
# Summary of Key Lessons Learned

The following key observations can be drawn from the scope of the investigation covered in this memo:

- In general, the definition of distributed generation DG in Germany and Spain is not capped at a specific power level (e.g., 5 MW, 10 MW, 20 MW, etc.). Rather, it tends to be applied to any generating project that is small enough to connect to the HV, medium-voltage (MV), or LV networks defined in Table 6 of Memorandum No. 1. Generation projects requiring connection at the EHV level are excluded from the DG category. Based on Table 1 of Memorandum No. 1, this would restrict use of the term DG to projects of 80 MW or less in Germany. As previously noted for Spain, projects with an installed capacity larger than 50 MW are excluded from the special regime; therefore, no individual renewables projects exist above this size in Spain and use of the term DG in Spain seems limited to projects under 50 MW.
- Software tools used by grid operators for DG interconnection planning in Germany and Spain are comparable to those used in California, and some of the same vendor's load-flow tools are employed. However, the German grid codes also provide simplified r*ule-of-thumb* formulas that estimate the technical performance levels of any proposed DG project and point of common coupling. Applying similar rule-of-thumb formulas may be useful in California.
- There are significant differences between the ways that grid operators monitor and control distributed/renewable generation in the respective electric networks in Germany, Spain and California. As noted in Memorandum No. 1, one significant difference is the excellent level of visibility and control that grid operators have over DG/renewable dispatch in Germany and Spain, which is vastly different from the current situation in California. In Spain, this is facilitated by CECRE, but in Germany it is handled directly at the TSO level. However, it is important to note that based on royal decree in Spain, renewable generation projects with no storage capability are the last tier of resources that can be curtailed to relieve grid constraints.
- Operational planning and forecasting tools and approaches related to DG/renewables are also different in the three countries. Only Spain has a centralized approach in this regard by virtue of CECRE, which resides on the control room floor at the national TSO. In Germany and California these functions are handled by the individual grid operators, which includes multiple TSOs in Germany and both the California ISO plus the various public power entities in California. CECRE employs a wind generation forecasting system composed of three components: a database on the wind farms, a prediction algorithm based on a self-adaptive time series, and a forecast module. In the future, CECRE plans to expand its capabilities to include other categories of renewables.
- The California ISO has recently added a renewables forecasting position on the control room floor to monitor and forecast renewable production. This position will play a key role in ensuring the California ISO can continue to meet grid performance standards and have the

optimum amount of dispatchable resources available under market protocols to handle the increased variability of renewable resources in its balancing area. In the future, the functions of this position at the ISO could expand into a scope closer to that of CECRE in Spain. However, this would require that the California ISO acquire additional authority for curtailing of renewables when needed for grid reliability. In addition, given the relatively high level of renewable forecasting error currently occurring in California (particularly in the day-ahead forecast), it appears that the ISO should continue to monitor the types of forecasting tools and processes used by grid operators in Europe as well as other balancing areas in the U.S. with large amounts of renewables to determine *best practices*(e.g., BPA, ERCOT, etc.) that can be incorporated into California ISO's renewable forecasts.

- The European Network of Transmission System Operators for Electricity (ENTSO-E) has a requirement for a minimum of 3,000 MW of primary frequency control and the provision of each TSO's share of the total is a binding obligation. This impacts the daily unit commitment of conventional generators (e.g., with governor response capability) by TSOs in the EU. Similar requirements exist for secondary control (i.e., AGC units). Some individual TSOs also invoke additional unit commitment and AGC requirements within their respective control area. For e*xample, the Ge*rman TSOs apply a probabilistic method, which results in a significantly greater need for secondary control reserves than required by ENTSO-E.
- The German electricity generation profile relies on a balanced mix from various sources of installed capacity. Renewable sources are ranked first due to a strong increase of power from wind, solar and biomass in recent years. In California, electricity from nuclear and conventional generating plants still contribute more to the net electricity portfolio than renewables as the former provide the bulk of base load power.
- A comparison of installed generation capacity (conventional, hydro and renewable) in Germany and Spain is shown in Table 6. While the level of installed renewables is similar in both countries, it is shown in Table 6 that the ratio of conventional/hydro generation capacity to installed renewable capacity is much greater in Germany (3.5 to 1) than in Spain (1.9 to 1). This indicates that there are significantly greater reserves of conventional/hydro resources available in Germany to commit for system control, if needed. However, even with a ratio as low as 1.9 to 1, Spain has apparently been able to meet its ENTSO-E control performance requirements.

**Table 6: Installed Generation Capacity**

| Country | Installed Conventional Capacity (GW)<br><br>*[Excludes Hydro]* | Installed Hydro Capacity (GW) | Installed Renewable Capacity (GW)<br><br>[Excludes Hydro] |
|---|---|---|---|
| Germany<br>(as of 12-31-09) | 109.2 | 10.6 | 34.6 |
| Spain<br>(as of 12-31-10) | 47.2 | 16.7 | 33.6 |

Based on Table 6, it appears that the combination of California's installed conventional/ hydro resource capacity is comparable to Spain and roughly half of the capacity in

Germany. However, this does not account for balancing resources that may be available over transmission ties with neighboring systems. For example, there is about 15 GW of tie capacity between the California ISO balancing area and neighboring systems. Therefore, it should be possible for market participants in other regions of the WECC to bid on and provide a significant component of the California ISO's ancillary service requirements. Similarly, Spain has a major interconnection with France, and the loss of this inter-tie is studied routinely by CECRE because this contingency significantly affects reliability of the Spanish grid. In fact, based on its operational studies of this contingency, CECRE invokes a limit on the amount of renewable dispatch allowed to run at certain times in order to ensure that the system will remain stable if the contingency occurs. Germany is also interconnected with the Scandinavian market via several major ties as follows:

- Kontek cable (Denmark): 600MW
- Baltic line (Sweden): 600MW
- Jutland: 1,500MW import capacity and 950MW export capacity

However, these interconnections are used for energy-trading purposes only. None of the capacity on these ties is reserved for transfer of regulating power between countries.

- German TSOs have been able to manage the renewable variability of generation by committing dispatchable generation assets combined with market-based ancillary services to meet system reliability requirements. Dispatch flexibility is provided by various generation technologies including nuclear power, hard coal, oil-fired installations, and gas-fired and large pump-storage hydro power plants. Moreover, as the scale of grid interconnections to neighboring countries increases, new electricity sources become available to supply ancillary services to the German power system. For instance, some Austrian power producers (predominately hydropower) also participate in the German frequency control reserve markets and provide fast-reacting power reserves to German TSOs.
- The largest impacts on ramping, load following and regulation in the German grid are from intermittent wind resources. In order to address these requirements, as noted in Section 3, the TSOs have monthly, seasonal, and annual auctions for bilateral contracts with conventional generators (usually hydro power or pumped hydro) for primary reserves that provide first level of re-dispatch related to wind. Contracts can also exist between TSOs for such reserves. Also, the TSOs have a monthly secondary reserve balancing market for energy and frequency regulation. Finally, the TSOs procure tertiary reserve on a daily basis for any ancillary services that can be handled/re-balanced through manual dispatch orders in a 15-minute timeframe (e.g., those services that do not require automatic response). In recent years German TSOs responsible for regions with high wind power penetration conduct annual and monthly solicitations for wind reserves to augment their other categories of regulation services, and execute bilateral contracts with the successful bidders to provide this supplemental service for up to 200 MW to 300 MW of bidirectional regulation. However, this option has been terminated in 2011 and TSOs must now rely on

secondary reserves and the power exchange to manage control performance impacts of intermittent generation.

- For practical purposes, renewables do not participate in today's power reserve markets in the Germany, as these suppliers cannot guarantee the provision of these reserves for a sufficient period of time, as required under the current procurement mechanism. However, it is assumed that wind and biomass power may contribute to frequency control in the future. A portfolio of dispersed wind power installations might provide significant amounts of downward regulation power, while biomass facilities may be able to provide control power for both downward and upward frequency regulation.
- New energy storage technologies (apart from pump-storage hydro power) and demand–side management in Germany, although not yet implemented, could be used to provide additional flexibility for mitigating generation and consumption variability in the future. Similar benefits to large scale renewable/DG integration can be realized from continued deployment of these same technologies in California.
- Deployment of large amounts of DG is going to challenge distribution planning engineers to perform rapid and comprehensive studies on the impact of each proposed DG facility on the distribution system. They will need to have the right tools for evaluating the voltage profile on the circuits for the following two extreme conditions: 1) Maximum DG output and low customer loads and 2) High customer loads and low or zero DG output. They will have to verify the circuit design that will keep voltages within acceptable limits, and keep flicker and harmonics are within standards.
- Key load area substations in California must have data acquisition and information storage and communications to enable the load and DG generation forecasters to be able to build new models that reflect the net load for the area. These models must include temperature, wind, and solar data for the area. When California moves to price sensitive loads, such as a lower nighttime price for charging plug-in electric and hybrid vehicles or other loads that would respond to price signals, then the forecasting models must be enhanced to predict the revised load for the area.
- The European experience shows that it is vital for the power system operator to be able to monitor the output of DG facilities as well as direct DG units to curtail dispatch when required for emergencies, such as grid reliability and safety.
- Findings on forecast error for renewables show that California is achieving a comparable forcasting accuracy as Spain at this time. Both countries are clearly not achieving the accuracy levels that are being achieved in Germany. However, this may not be an apples-to-apples comparison because of the amount of offshore and coastal wind in Germany, which has very consistent wind patterns. Regardless, we believe the CA ISO is well on track to continuously improve it's renewables forecasting methodology, particularly in light of it's new state-of-the-art renewables desk at the control center staffed by a dedicated Renewable Resource Coordinator.