IEA INTERNATIONAL ENERGY AGENCY

Power System Operation and Augmentation Planning with PV Integration:

Outcome of the IEA-PVPS Task 14's Subtask 3 – High Penetration PV in Power System

PVPS

PHOTOVOLTAIC
POWER SYSTEMS
PROGRAMME

Report IEA PVPS T14-04:2014
ISBN: 978-3-906042-26-8

Photo credits cover page

Kowa Company, Ltd.

INTERNATIONAL ENERGY AGENCY
PHOTOVOLTAIC POWER SYSTEMS PROGRAMME

Power system operation planning with PV integration

IEA PVPS Task 14, Subtask 3
Report IEA-PVPS T14-04: 2014
Nov 2014

Author:

Kazuhiko Ogimoto
University of Tokyo, Institute of Industrial Science,
Tokyo, Japan

Acknowledgement

This report is supported by
New Energy and Industrial Technology Development Organization

Contact:
New Energy and Industrial Technology Development Organization
Mr. Toshihiko Takai
18F Muza Kawasaki Building, 1310, Omiya-cho, Saiwaiku,
Kawasaki City Kanagawa 212-8554, Japan
Tel.: -81-44-520-5274
E-mail: takaitsh@nedo.go.jp

List of Contributor to IEA Task 14 Subtask 3

AUSTRALIA（chapter 4.1） Ben Noone,[1] Anna Bruce,[1] and Iain MacGill[1] [1]Centre for Energy and Environmental Markets (CEEM), School of Electrical Engineering and Telecommunications, University of New South Wales, Sydney, Australia
CHINA（chapter 4.2） Cao Rui [2] and Wang Yibo [2] [2]Chinese Academy of Science, Institute of Electrical Engineering, Beijing, China
GERMANY（chapter 2.4， chapter 4.3） Rafael Fritz[3] [3]Fraunhofer Institute for Wind Energy and Energy System Technology (IWES), Kassel, Germany
GREECE（chapter 4.4） Stathis Tselepis[4] [4]Center for Renewable Energy Resources and Saving (CRES), Photovoltaic Systems and Distributed Generation Department, Athens, Greece
DENMARK（chapter 4.5） Kenn H.B. frederiksen[5] [5]EnergiMidt , Silkeborg, Denmark
SWITZERLAND（chapter 4.6） Jan Remund[6], [6] Meteotest , Bern, Switzerland
JAPAN（chapter 1， chapter 2.1， chapter 2.3， chapter 4.7） Kazuhiko Ogimoto,[7] Yuzuru Ueda,[8] Izumi Kaizuka,[9] and Koji Washihara[10]

[7]University of Tokyo, Institute of Industrial Science, Tokyo, Japan

[8]Tokyo Institute of Technology, Department of Physical Electronics, Graduate School of Science and Engineering, Tokyo, Japan

[9]RTS Corporation, Tokyo, Japan

[10]New Energy and Industrial Technology Development Organization (NEDO), Kanagawa, Japan

ITALY（chapter 3.1， chapter 4.8）

Adriano Iaria,[11] Antonio Gatti,[11] Diego Cirio[11] and Enrico Gaglioti [11]

[11]Ricerca sul Sistema Energetico (RSE SpA), Energy Systems Development, Milano, Italy

THAILAND (Observer) （chapter 4.9）

Roengchai Khongthong[12]

[12]Electricity Generating Authority of Thailand (EGAT), Nonthaburi, Thailand

UNITED STATES OF AMERICA（chapter 2.2， chapter 3.2， chapter 4.10）

Barry Mather,[13] Francisco Flores-Espino,[13] and Lori Bird,[13]

[13]National Renewable Energy Laboratory (NREL), Golden, Colorado, USA

EUROPE（chapter 4.11）

Manoel Rekinger,[14] Karel De Brabandere,[15] and Carlos Dierckxsens[15]

[14]European Photovoltaic Industries Association (EPIA), Brussels, Belgium

[15]3E, Brussels, Belgium

Table of Contents

Executive Summary

Background and the Scope of the Study (from "1. Introduction")

PV generation is one of the RE generation with variability and limited-predictability[1]. It differs from the traditional thermal and reservoir-type hydro power generation whose output is fully controllable (dispatchable). PV output varies periodically in a year and in a day, and irregularly due to weather condition. High penetrations of PV generation will cause the issues not only of voltage and power flow fluctuation in a local distribution system, but also of the demand-supply balance of a whole power system, which will result in the problems including frequency fluctuation and difficulty of demand-supply management.

Accordingly, in order to realize high PV penetration in a power system, it is crucial to evaluate the impact on its operation planning and augmentation planning, to envision the future power system. In the planning of operation and augmentation, it is necessary to identify gaps in current PV system technology and electric power systems, to analyze, how large numbers of PV installations can be successfully integrated to a total power system including the technology of smart grids.

The IEA TASK14 Subtask3 deals with the PV integration to power systems from the total power system view point, based on the PV generation forecasting, power system operation and power system augmentation

The current study has mainly focused on the system level aspects of demand and supply balancing of a power system assuming a strong transmission system, although limited amount of description about the aspect of issues of transmission congestion and the requirement of reinforcement and expansion of transmission network is found in this report.

The report begins in Section 2 with a discussion of impacts of PV penetration and new technologies, and then reviews the state-of-the-art technology for system operation planning and system augmentation planning (Section 3). Section 4 collects the case studies of system operation planning and augmentation planning including issues, solutions and R&D activities of the member countries.

Impacts of PV Penetration (from Section 2.1)

(Power System)

Electric power systems have a various scale ranging from a system of several hundreds GW class of developed country on a continent, a system of tens MW class on an island, to a system of several tens kW class in a rural area in a developing country. The mission of a power system is to deliver power to the customers in a cost effective, reliable manner to support quality of life, industrial production and social activities.

A commercial power system, alternating current system, transmits and distributes power to the demand utilizing various voltage levels depending on the distance and the capacity, using a transformer to interconnect subsystems of different AC voltages with power plants and demands. The main impacts of PV penetration on a power system come with the natural variability and limited predictability of the power output, and the reduction of the operational amount of dispatchable generators.

At the system level, integration of PV into a power system rises various challenges in a system operation and, accordingly, in a system augmentation. Among the challenges, the increased complexity

[1] RE source generation technologies are divided into two categories: one is dispatchable generation, such as geothermal, hydro with a reservoir, and CSP (concentrated solar power) with thermal energy storage, and non-dispatchable generation, such as PV, CSP without thermal energy storage, wind, and run-of-river hydro.

of matching between demand and supply is the most typical impact when PV or a variable renewable generation penetrates into a power system to have a substantial share in the market.

(Balancing Operation and generation dispatch)

The total power demand, which reflects all the changes of all individual demands, varies during a day, a week, and a year. In current power systems, where dispatchable thermal and hydro generation have a substantial share, the balance of demand and supply is ensured by controlling the generation of the dispatchable generators in a demand-and-supply balancing area. When the balance is lost or insufficient, the power system frequency (nominally 50Hz or 60Hz) or the system voltage of a power system will fluctuate and the quality of supply is reduced. In the worst case, a blackout occurs because many devices in a power system including power plants, which are designed to operate within a specified range of frequency deviation, are disconnected from the power system.

In order to keep the power balance in a system, it is necessary to schedule the generation of each dispatchable generation unit. In a power system, the balancing between demand and supply is realized through sophisticated generation schedule to make the best use of the features of each generation unit and system: the hourly balancing through generation unit start and stop scheduling, the balancing in minutes through centralized automatic generation control specifying the production of each unit, the balancing in seconds through independent governor control of each unit, and the remaining mismatch is transformed into a fluctuation of the system frequency. Because the balancing requirements vary by time, by day, by season, reflecting the variation of the demand and supply structure including the share of variable renewable generation such as PV changes, the key concept to accommodate large amount of variable PV generation is the flexibility of a power system to cope with the balancing. (The flexibility will be discussed in Sections 2.2 and 2.3.)

(Power System Operation Planning)

Under a set of operational conditions such as composition of generators, generator characteristics, automatic generation control and economic load dispatch, an operator[2] plans a generation schedule typically for the next day. In the schedule, start and stop timing and generation level of each generator are decided to fit the predicted demand of various levels during the day. The operation plan of a power system, called as unit commitment, is a result of large-scale optimization planning considering economy, stability and security of the power system operation. The economy is mainly dependent on the operational cost of each power plant including fuel cost and generation efficiency of a thermal unit. The operational stability is mainly related to the total capability of all generators to change its output. The security is ensured through the reserved generation units which may work in a sudden increase of demand or in a sudden loss of generation due to a generation failure. If there is not enough balancing capability in a power system, it may be necessary to curtail the variable PV generation to secure the stability of the system operation, even if it reduces the economy of the system.

In the context of operation planning, the natural variation of PV generation increases the requirement demand-and-supply balancing capability of a power system which results in partial operation of some power plants. The uncertainty of PV generation requires additional operation of generation units with lower economy in preparation for the event of reduced PV generation. These changes bring about the reduced economy of the existing generators and the increase of stresses of the generators.

[2] System operators typically operate within the bounds of a regulatory or market framework. The real time operation is done by TSO or ISO, and a utility operator, in a deregulated market and traditional utility market, respectively.

There are many countries where electricity is traded in a power market. The trades are made for various, short or long time frames. In the competitive circumstances, the plan of unit commitment is decided partially in the market.

In the unit commitment including the power market operation, PV forecast plays a crucial role to decide the performance of a power system operation.

In the power system operation planning, in order to keep the viability of the analysis, we need to include the parameters such as maintenance schedule of power system elements.

(Power System Augmentation Planning)

In years, demand and generation mix changes in a power system. In order to reduce CO_2 emission in the energy sector, it is widely recognized that energy demand will increase as economy grows in general, the existing power demand will reduce through energy efficiency, much of energy demand will be electrified, and more energy will be supplied by variable renewable generation, which leads to a larger power demand and supply structure with a higher share of variable renewable generation including PV.

In the current practices of power system augmentation planning, a planner, following criteria such as economy, reliability, environmental, stability and security, optimize the future power system. When a power system augmentation is planned including RE such as PV, it is usually aimed to find the optimum path to integrate RE into a power system.

In order to develop such a future power system, the power system augmentation planning must have the new functionalities so as to accommodate substantial variable renewable generation, while satisfying the existing planning criteria and constraints. The impacts of PV penetration on the power system come with the variation and limited predictability of PV generation, and the reduction of the operational amount of dispatchable generators. Possible countermeasures include improvement of load following capability and reduction of minimum operation of existing and new thermal and hydro generators, improvement of PV forecast, demand activation (see Section 2.3) and utilization of energy storage including a pumped storage power plant and batteries.

In the augmentation planning, there should be a set of indicators to evaluate a status of a power system in a specific time resolution (for example, a year) and over a certain period (for example from now to 2030). Indicators can be decided and based on the objectives of the augmentation planning such as energy security economic efficiency and environmental compatibility which supports the ultimate objective, sustainability. These indicators will be further discussed in Section 3.

In the power system augmentation planning, the parameters which are used in the operation planning are necessary to estimate the operational performance of each augmentation scenarios.

In the augmentation planning, the time horizon is the most important parameter. A major thermal generation needs several years of legal procedures and construction period. The distributed generators also need long time for being properly disseminated. The augmentation planning usually has 10 to 20 years of study period.

Countermeasures (from Section 2.2)

The variability and uncertainty introduced by wind and solar generation technologies calls for a higher level of system flexibility. The amount of flexibility needed to accommodate the introduction of new wind and solar facilities depends on the amount of variable renewable energy capacity and the existing flexibility in the system’s infrastructure and operation. The most appropriate mitigation methods depend on economics and the characteristics of the specific system, including the generation sources, infrastructure, and operational practices. This section describes a few of the methods that are generally recognized as efficient integration mechanisms, grouped in four categories: 1) System Operations, 2) Forecasting, 3) Market Design and 4) Planning.

(Flexible resources)

Increasing the flexibility of generation sources is one mechanism for addressing generation variability and ensuring the balance of demand and supply. It can be important to consider the flexibility of new generating capacity additions. It is also possible to enhance the flexibility of existing conventional generators to allow for quicker responses to changes in variable output. The flexible operation of conventional generators often results in increased fuel, maintenance and capital costs that will have to be balanced against the benefits of increased levels of renewable energy in the system.

Aside from flexible conventional generation sources, resources that enhance the flexibility of the system, such as storage systems and demand response, can help operators balance steep ramps. Fly-wheels, pumped-hydro storage and compressed air energy storage are examples of storage systems that are able to respond to dispatch requests at quicker rates. Demand response can reduce the costs of maintaining additional spinning reserves, particularly during extreme events of over- or under-supply of variable renewable energy power.

(Geographical diversity)

Geographical dispersion of supply can be helpful in smoothing the variability of renewable energy sources. Figure ES1 shown below was produced by simulating the output of over 25 solar PV power plants located throughout a large geographical area (roughly half the size of Italy)[3]. The variability caused by cloud cover was reduced as the outputs of a higher number of solar plants were combined. The resulting output profile (shown in a solid, blue line), is not only more predictable and steady through the day, it also matches day-ahead forecasts more closely.

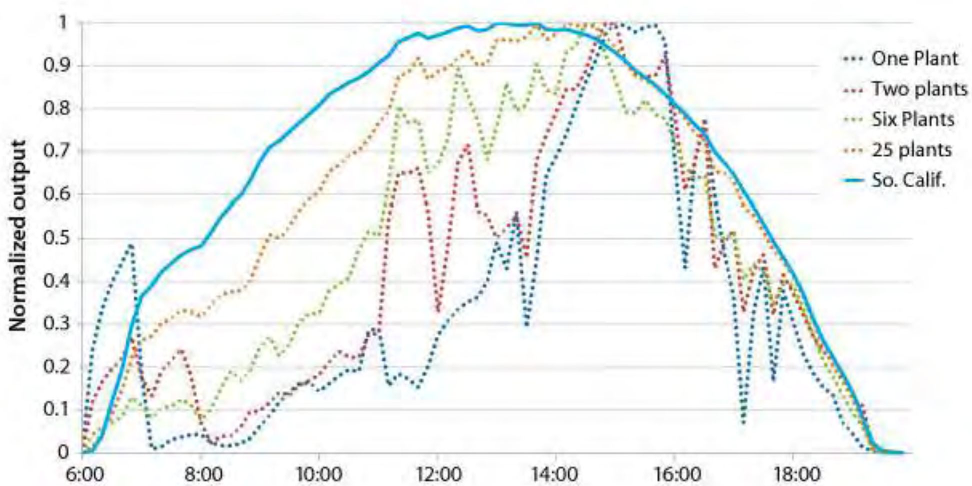


Figure ES1: The smoothing effects of aggregating PV plant output over various geographic areas.

Similarly, larger balancing areas, with a larger pool of available generation and demand, will generally be more capable of integrating larger amounts of variable renewable energy sources. Variability in load and in generation can be smoothed out when balancing occurs over a larger area. Furthermore, large balancing areas can provide access to additional flexible generators that may not be available in smaller areas. Combining adjacent balancing areas within the same synchronous area can be employed as a

[3] The source of this simulation was the Western Wind and Solar Integration Study Phase II that the U.S. National Renewable Energy Laboratory conducted in 2013. The actual geographical area was Southern California.

mitigation strategy to increase resilience and promote the integration of variable renewable energy sources in existing grids. Alternatively, cooperation across existing balancing authorities can achieve the same purpose through the optimized share of balancing activities between areas.

(Forecasting)

Forecasting can reduce the uncertainty associated with variable renewable energy generation technologies. This allows generators or grid operators to plan generation service or balancing services ahead of variations in the output of solar and wind generators and reduce the level of operating reserves needed, thus lowering the cost of balancing the system. Short-term forecasts assist in the dispatch of quick-start generators, demand response mechanisms, or other methods to quickly balance demand and supply.

Forecasts are more widely used to predict wind power generation variability, but solar forecasting is emerging. Cloud movements are the primary cause for solar variability, besides diurnal cycles. Sky imagers can be used to produce short-term forecasts, whereas satellite images can be used to predict changes in solar power production over a span of a few hours.

(Market design)

As challenges arise in several power markets where variable renewable generation has a substantial share, there are many on-going studies and discussions about the improvement of the power market design.

In our report, TASK14 experts approached the subject of sub-hourly scheduling and capacity markets. However, There are many other discussions about the relationship between optimum power system operation and the market design.

Sub-hourly scheduling: Markets operating with an hourly schedule or using a fixed hourly energy delivery scheme are not as efficient at integrating larger levels of variable renewable energy sources, because they don’t have enough flexibility to accommodate for wind and solar generation variability. Markets operating at 5- or 15-minutes intervals are more efficient at handling both load and generation variability, and minimize reserve requirements. Additionally, some markets have adopted new ancillary ramping products to encourage generators to perform in a flexible manner and ensure sufficient system-wide ramping capability.

Capacity markets: Because solar and wind have very low marginal costs, they can bid at a very low price in wholesale markets and exert a downward pressure on electricity prices. In some markets, this can raise longer term concerns about the integration of large amounts of renewable energy because owners of other types of generators may not earn enough revenues and lose their ability to operate. Additionally, lower wholesale prices may reduce the incentives to build additional generation plants and consequently increase the risk of capacity shortfalls. Ideally, energy-only wholesale electricity markets should provide enough incentives (in the form of higher wholesale prices) for generators when demand outpaces supply. However, in markets where this is not the case or where regulators have capped wholesale prices to contain volatility, capacity and availability can be rewarded through a separate mechanism designed to incentivize the necessary level of installed capacity for the future. Capacity markets have emerged as a complement to energy-only electricity markets to compensate owners of dispatchable resources for guaranteed deliverability. Critics argue that capacity markets increase electricity costs over energy-only markets and commit future incentives to existing technologies, thereby limiting investments in alternative and innovative generation technologies.

(Planning: Comprehensive Approaches)

Comprehensive planning approaches that integrate transmission, distribution, generation and system performance goals, from distribution to bulk power system across an entire network, greatly facilitate and reduce the implementation costs of variable renewable energy integration. The coordination and integration of planning processes helps regulators prepare for the potential impacts that variable generation may have on the system and evaluate the available options to optimize generation and transmission costs.

Planning processes that integrate multiple jurisdictions facilitate transmission expansions and the geographic distribution of renewable energy sources. Integrating local and regional planning efforts helps promote the cooperation or enlargement of balancing authorities, diversifies demand and supply and eases the integration of higher levels of variable renewable energy generation.

Resource planning takes many different forms around the world. However, the experience in different countries shows that there are a few practices that can be applied in many different regulatory contexts. Three key principles that have been identified include:

1. Integrating the planning of generation, transmission, and system performance
2. Ensuring institutions and markets are designed to enable access to physical capacity
3. Building from local and regional planning to better integrate and coordinate information across jurisdictions (Cochran, et al. 2012).

Planning processes that optimize generation, transmission and other resources across an entire network greatly reduce the need and cost of variability mitigation mechanisms.

Demand Activation (from Section 2.3)

(Demand Activation and Distributed Energy Management)

As discussed in Section 2.2, there is a need to secure flexible resources to cope with the variability of renewable generation, and the traditional generation is the first and largest flexibility resource. However, when the share of variable renewable increases, the share of thermal and hydro power plants which currently provide flexibility to a power system, necessarily decreases. For the future, it is necessary to identify new flexibility resources.

Demand has been used for demand and supply balancing since the 1990's, being called as demand side management (DSM). DSM has two areas of energy efficiency, reduction of energy, and load levelling, reduction of peak load. The load levelling is often called demand response, which means that a demand responses to a signal of cost, incentive or a control. However, as far as it is a human who make a response to the signal, its acceptability and reproducibility are low and the effectiveness of DSM is limited. US DOE states about the Demand Response as "Demand response is a tariff or program established to motivate changes in electric use by end-use customers in response to changes in the price of electricity over time, or to give incentive payments designed to induce lower electricity use at times of high market prices or when grid reliability is jeopardized. ".

The demand response has been introduced in the field of industries with resources of large DRs and also in the field of households and small businesses where is with the dissemination of smart meters. Recently, in line with the development of information and telecommunication technology, new devices are becoming available including, innovative distributed energy management systems such as HEMS[4] and BEMS[5]. With these devices which can control appliances and equipment, it is expected that demands in houses, commercial buildings and factories can be "activated" automatically, for example, in response to a price signal.

Figure ES2 depicts the concept to activate demand. A centralized energy management, which prepares unit commitment schedule for the next day, decides the hourly or time-dependent power prices for the next day using PV and wind generation forecast. The centralized energy management sends the power prices to a decentralized energy management such as HEMS in a house. The distributed energy

[4] (Home Energy Management System)
[5] (Building Energy Management System)

management system optimizes the power use of the house for the next day by minimizing cost without reducing service level by scheduling the period of EV charging and water heating. In an urgent situation, air conditioner might be controlled to reduce the peak load. A battery in a building will be a good resource to provide additional flexibility at the demand side.

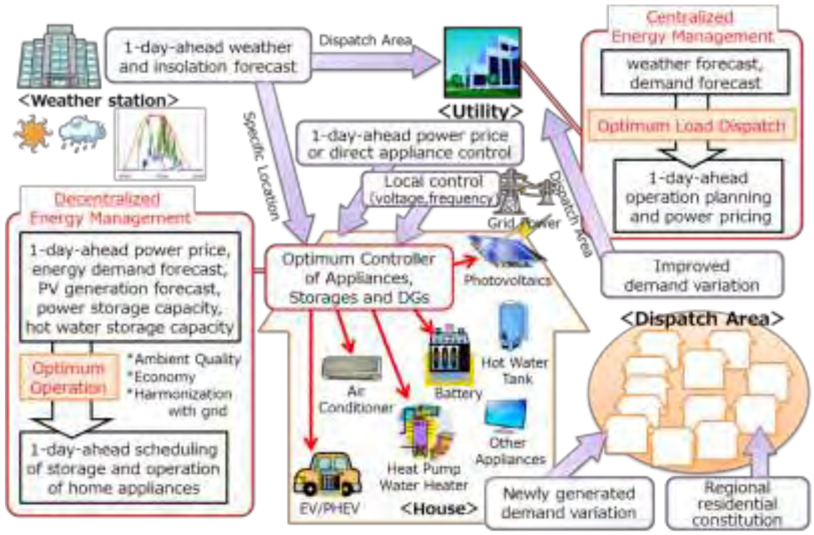


Figure ES2 : The concept of Demand Activation Source: Ogimoto, K., Iwafune, Y., Kataoka, K., Ikegami, T., & Yagita, Y... (2011a). Cooperation Model of Centralized and Decentralized Energy Management for the Supply-Demand Adjustment in a Power System, Proceeding of Power and Energy Society Conference of Institute of Electrical Engineers of Japan, 8-16 (in Japanese)

Electric vehicles, which are becoming popular these days, are emerging large power demands. The charging of EV which will tend to occur after each trip of individual cars will be one of the focuses of demand activation, because there is a certain allowance for charging period with each EV without reducing the service level.

There will be many other demands which have a potential to be activated. Demand activation will be an innovative and dominating countermeasure for the flexibility of a future power system. Its wide deployment will require large investment and various changes of technology, infrastructure, institution, economy, people's acceptance and security. For the substantial deployment of variable renewable generation such as PV, the activated demand is expected to increase the flexibility which is necessary to balance the additional variation with limited predictability of PV generation. In order to follow the change of PV generation due to time and weather, one-day-ahead and real time pricing and responsive distributed energy management systems will be applicable.

(Beyond Energy and Integration of PV)

Under the emerging impacts of variable renewable generation on some power systems, there are beginning many discussions going on by various stakeholders such as regulators, operators, utilities, manufacturers, customers to optimize flexibility resources including demand activation (auto-demand response) in a power system operation and augmentation.

In Japan after the East Japan Earthquake of March, 2011, and in the United States during the attack of Hurricane Sandy in October 2012, many people experienced the blackout of substantial days. These days, there are emerging critical natural disasters of climate change which have more serious impacts on people's life and business continuity. Under the situation, there is increasing concern about the stable supply of energy and power. Considering the nature of PV resources which is more evenly available at and near the living and business spaces, PV is expected to have a more important role as an energy/power source with a demand in case of shortage of power supply. And the distributed energy management is expected to have another value for the people’s life and business continuity as an energy management system.

For a demand, the decentralized energy management traditionally has a value of keeping appropriate environment, economy, and security for a demand such as a house, a business building, and an EV. For example, at a house, a home energy management system is supposed to keep comfortable living space while saving cost, reducing environmental impacts, and keeping security.

Although with the above-mentioned values for a power system and energy use, it is not likely that so many people or business entities will deploy the decentralized energy management system which needs initial and operational cost, and conveys limited amount of the financial benefit of demand response to an owner under constraints of energy use.

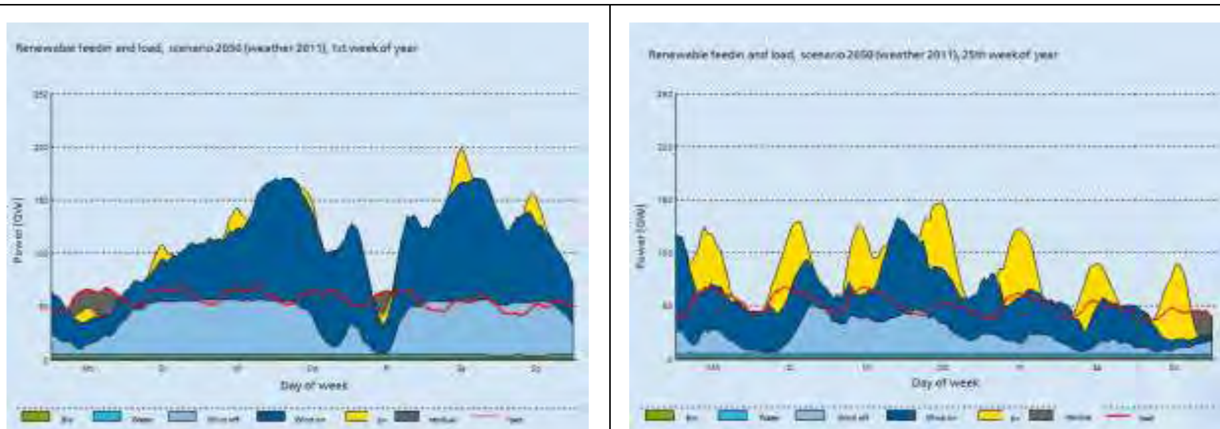
The distributed energy management is expected to contribute to the evolution of a power system to accommodate high penetration of variable renewable generation including PV. The distributed energy management is also expected to contribute to the evolution of a life and business through optimization and security of energy use optimization and offering additional value to peoples’ life and business. The house or a business where the new values are realized will evolve to be a smart house and a smart community, and PV will be more integrated into buildings and communities with enhanced value.

Impacts of Other Variable Renewable Energy (from Section 2.4)

Wind energy is similarly to PV a temporally and spatially fluctuating electricity resource. Unlike PV wind power is also available during the night and is – in the Northern hemisphere – usually more abundant in winter than in summer.

Also, wind energy from offshore-wind farms usually generates more energy per installed capacity due to better wind conditions and thus can be regarded as an additional renewable energy option with unique characteristics.

In the future, the impact of supply characteristics of fluctuating renewables will dominantly determine how the energy sector will look like in respect to storage, load management requirements, back-up capacity and load factors of conventional power plants. Two weeks – illustrating a “normal” situation of supply and demand variations in a very advanced future energy scenario dominated by fluctuating RE is shown in Figure ES3 a) and b) (left: week in winter / right: week in summer).



Figures ES3 a) and b): Exemplary weeks in a) winter and b) summer, based on a scenario for the year 2050, calculated with the meteorological year 2011. With the load (red curve) fluctuating around 50GW the need of conventional power production can be reduced to only a few hours per week by increasing the installed capacities of mainly wind offshore (light blue), wind onshore (dark blue) and PV(yellow).Source: Fraunhofer IWES, 2013

All three fluctuating renewable energy sources are important if impact on the energy system should be optimized. For Germany an analysis has shown that the residual load of the electricity sector is smoothest when different energy fluctuating renewable energy sources are combined. With residual load, the instantaneous electricity demand less the energy production from PV, wind energy on- and offshore is meant.

Integration of technologies and institutions (From Section 2.5)

In order to realize high penetration of PV and other variable renewable, as discussed in the prior sections, it is essentially necessary to overcome the variability which affects the demand supply balancing of a power system. Essentially, there is two approaches: the one is to reduce the variability and the other is to enhance the flexibility of a power system.

Variability can be reduced, as discussed in 2.2.1, through smoothing effects of geographical diversity of each of PV and other variable generation technologies, and that of technological diversity of various renewable energy generation technologies. This means that, in order to realize high penetration of variable renewable generation including PV, it is essential to allocate appropriate amount and technology to appropriate locations.

Flexibility can be enhanced, as discussed in 2.1 and 2.2, through utilization of the various resources of a power system: utilization of the traditional resources of supply side such as thermal power, hydro power and pumped-hydro power is the most economical option. Secondly, the generation of variable renewable can be curtailed or modified so as to reduce the variation or even to enhance stability of operation to some extent. Thirdly, as discussed in 2.3, the resources at the demand side are and will be available for the flexibility.

With reliable transmission system and generation forecast technology, a power system or interconnected power systems can enhance the power system operation or optimize the utilization of the whole resources of flexibility against the smoothed variability to realize the stable operation under the high penetration of variable renewable generation under the physical laws and operational and market rules. (Figure 2.5-1).

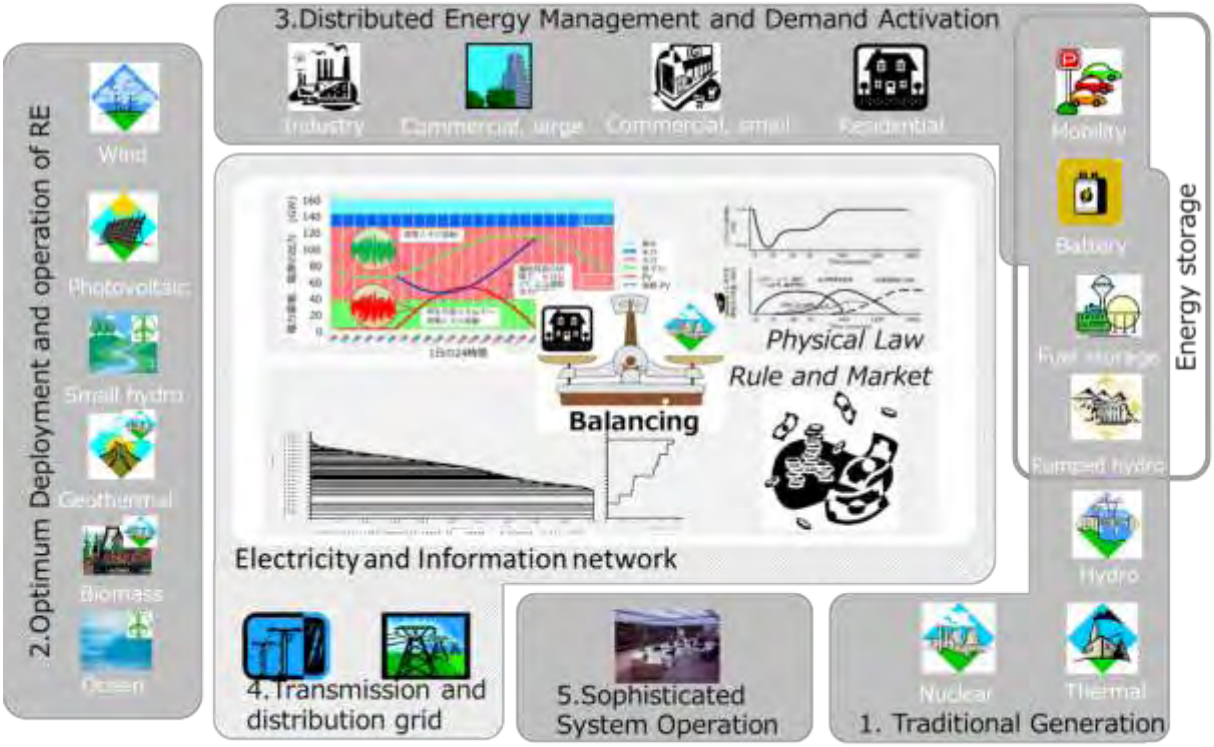


Figure 2.5-1: The enhanced power system operation by optimized utilization of the whole resources of flexibility against the smoothed variability
Source: Ogimoto, Laboratory.

Methodology: State of the art (From Section 3)

(Operation Planning)

Under the increased variability and uncertainty due to PV and wind generation penetration, in order to preserve reliability in an economic way, it is crucial to improve the predictability and flexibility in the operation of a power system.

To take into account the above uncertainties, a methodology was developed by the research centre RSE[6] on request of the Italian operator for renewables development (GSE[7]).

Given the unit-commitment and dispatching of the conventional generators assessed in the sale/purchase session of the energy market and given the forecast of load and renewables PV and WIND, the steps of the assessment of the balancing reserve are:

- the uncertainty evaluation[8] based on the load demand, the wind and solar power generation and the forced outage risk of thermal units;
- the probabilistic combination of the above mentioned uncertainties and the consequential evaluation on the needed balancing reserve to match the demand for a given confidence level.

Figure ES4 depicts the basic flow scheme of the adopted methodology aiming at the balancing reserve calculation for one day ahead.

[6] Ricerca sul Sistema Energetico – RSE SpA. Milan, Italy.
[7] Gestore Servizi Energetici.
[8] Hydro power plants are considered highly reliable in compliance with the Italian practice. No uncertainty is therefore associated with this kind of generation.

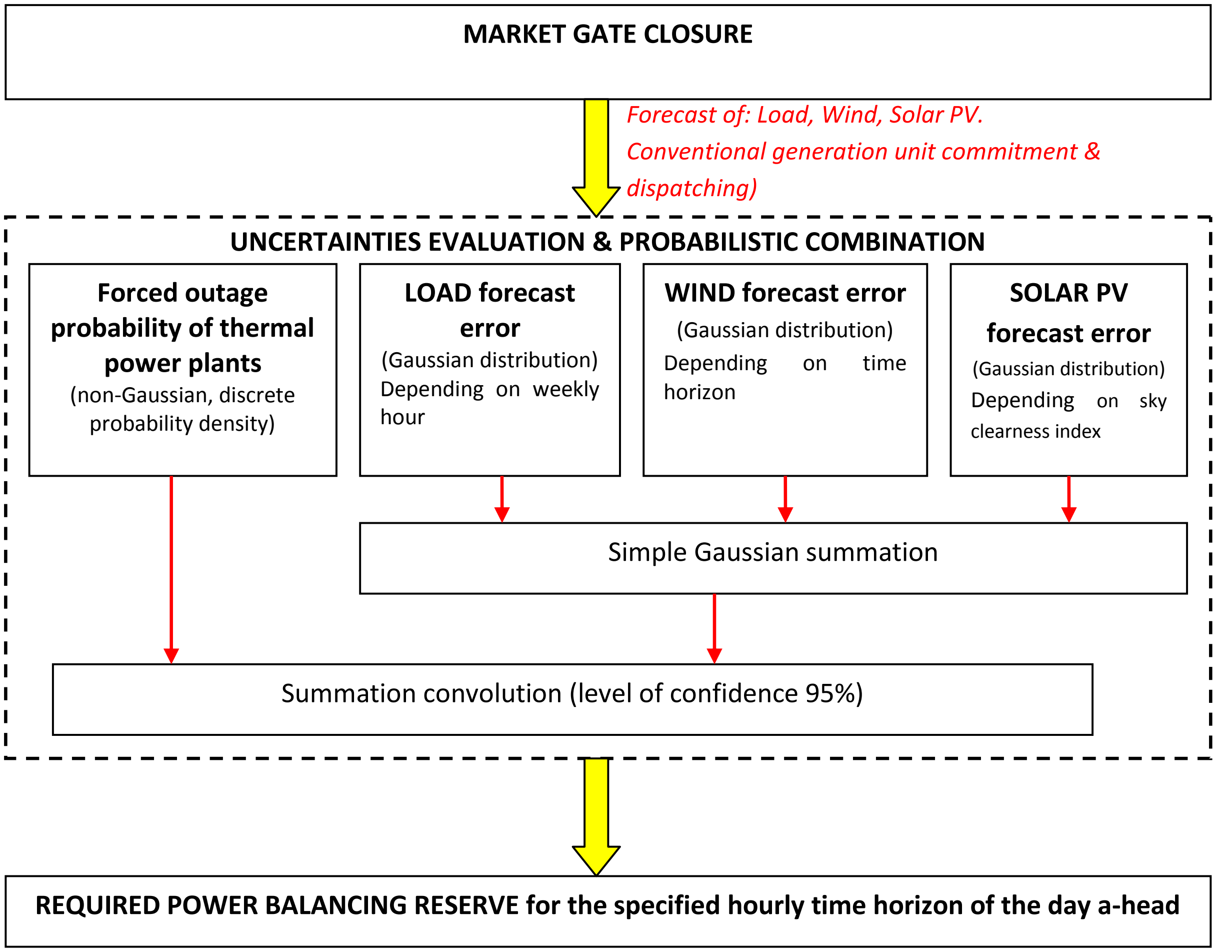


Figure ES4: Flow scheme of the methodology for the evaluation of the hourly balancing reserve

Under the high variability and unpredictability, in a power system operation, it is crucial to assure reserve margin at a least cost and maximum reliability including the technical and regulatory measures discussed before.

(Augmentation Planning)

In the last few decades, the increasing penetration of variable generation technologies – most notably wind and solar – has required changes in the way the electricity grid is operated. The daily and seasonal variability patterns observed in wind and solar technologies present a challenge to their efficient integration into existing electrical grids. Given the complexity of modern grids, it is necessary to employ computational simulation models to fully understand the effects of introducing increasing variable generation levels, devise effective mechanisms that facilitate their integration, and optimize costs.

The design and complexity of the optimal variable generation integration model will depend on the goals of each study, as well as the levels of added solar PV capacity. Some of the study components presented in this section may be omitted for studies looking at shorter time horizons, or relatively low levels of increased solar PV penetration, for example. Before designing a solar PV integration study it's important to consider its main goals. Examples include:

- Evaluating the costs of integrating variable renewable energy source into the system
- Identifying variable renewable energy integration impacts on grid operation

- Measuring the amount of variable renewable energy the existing system can absorb before changes in operation or physical configuration are needed

To address the complexity, the model structure can be divided in elements corresponding to relatively independent tasks as depicted in Figure ES5. Modularity also helps to scale down the model complexity to match actual needs. Most solar PV integration studies will follow an iterative process where a few of the steps are repeated, using outputs from certain modules to modify previous assumptions, or as inputs for other modules.

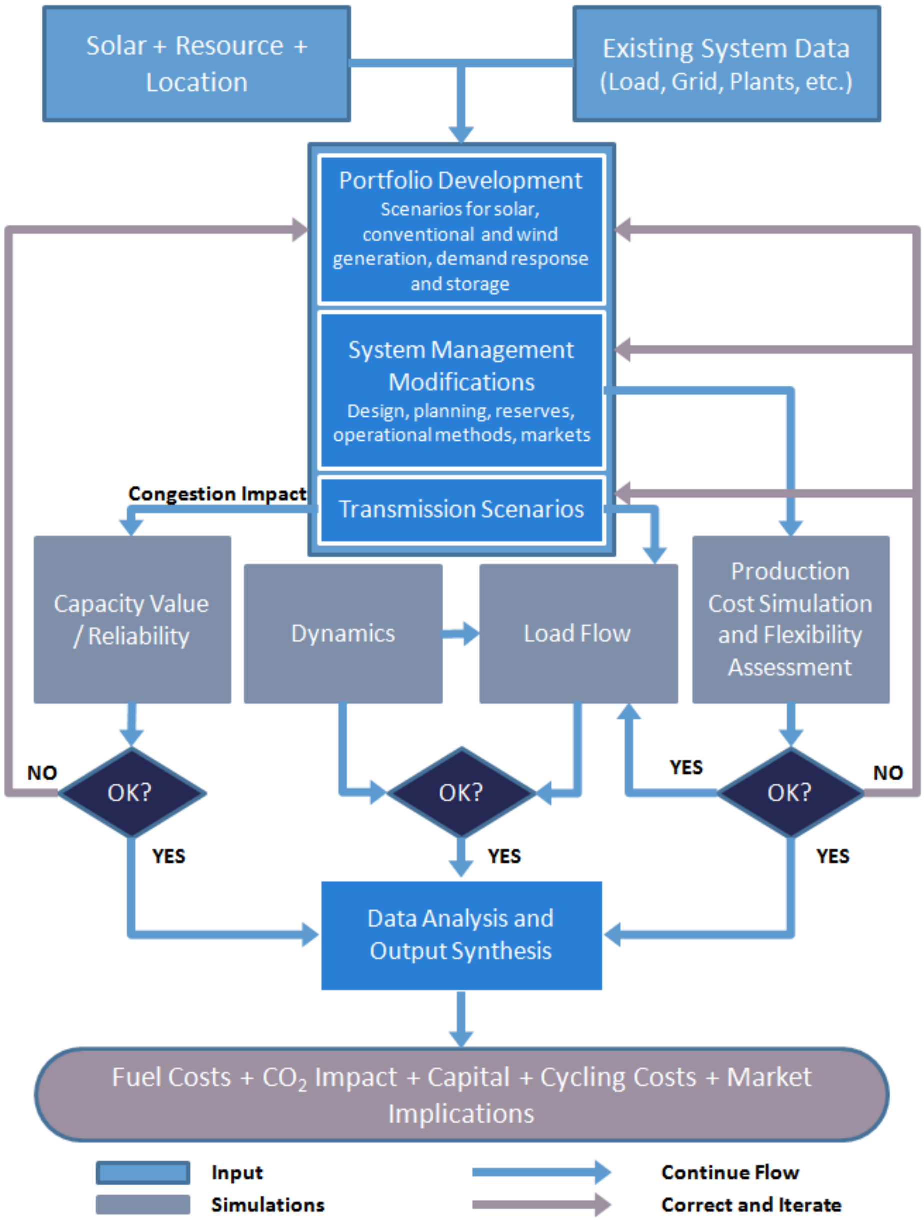


Figure ES5: Wind integration study recommended practices diagram.
Source: Holttinen et al 2013.

Key Messages

Through the study conducted by the TASK14, it has been revealed that the major issues of increasing PV penetration at transmission level is the demand supply balancing due to the increased variability of PV and other variable renewable generation and due to decreased flexibility of the traditional generation fleet. Countermeasures are the additional flexible resources such as flexible generation, demand activation and geographical smoothing of PV generation by stronger transmission system including interconnections.

In order to optimize the utilization of the flexible resources in terms of economy and stable operation, generation forecast technologies have also a crucial role to play. To realize the best use of the power system technologies, power markets have been continuously improved including closer to real time gate closure time for bidding and shorter (sub-hourly) trade intervals. Capacity markets concepts, a market for generating capacities, emerge also as a compliment to the energy-only market in order to address remuneration issues.

The methodologies of power system operation and augmentation have been adapted to accommodate the flexible resources, geographical diversity, generation and demand forecast uncertainty and improved market designs.

From the case studies TASK14 member countries have shown the wide range of efforts for PV penetration including following aspects:

- PV integration studies with various aggressive penetration targets under a variety of power system conditions, from a continent-wide system to an island or an area,
- Evaluation and optimization of new flexible resources based on the analysis of detailed operational impacts
- Research and Development of new flexible resources and system operation including generation forecast
- Optimization of a total power system operation and market design improvement
- Participation of many stakeholders such as regulators, TSOs (ISOs), utility, generators, manufacturers, research Institutes, consultancy companies and Renewables associations

For PV to become a major electricity source, power systems have to be transformed stepwise to facilitate the increased need for flexibility. The required flexibility at each PV penetration level will be mitigated through the geographical and technological smoothing effect of the weather dependent PV variability. And there are a large numbers of existing and potential flexible resources including traditional generation fleetness, control of variable renewable generation, demand activation, innovative storage technologies, transmission lines and interconnection, innovative centralized and decentralized energy management, power markets evolutions, etc…

The case studies have shown that all stakeholders, including regulators, operators, manufacturers, researchers, power customers have been practicing their efforts to realize high penetration of PV through technological but also regulatory innovation. There are enough technological potential to accommodate the transition to a high PV penetration. But increased efforts will be required in the area of regulations including whole sale and retail market and centralized and decentralized operations so as to realize the optimum evolution of a power system.

Future Work

PV generation varies cyclically in a year and in a day, and irregularly due to climate. The large penetration of PV generation are causing the issues not only of voltage and power flow fluctuation in a local distribution system but also issues of the demand-supply balance of the power systems where the high PV penetration is realized. The demand and supply balance issues are resulting in the difficulties in the operation of the power systems in the aspects of frequency regulation, load following, load-dispatching and the market operation.

In order to realize high PV penetration to a power system, it is crucial to evaluate the impacts, identify the countermeasures and envision the future power system. From grid interaction and penetration related aspects, it is needed to identify gaps in current PV system technology and electric power systems and analyze, how large numbers of PV installations can be successfully integrated total power system including the technology of smart grids.

Accordingly, as future work of the Subtask 3, it is recommendable to survey the resources for flexible transmission system operation, surveys and case studies of innovative transmission system operation with generation forecast in two steps, and surveys and case studies of asset optimization for high PV penetration in the following structure:

- Identification of existing and future flexibility resources for flexible transmission system operation
- Evaluation of capability of innovative power system operation of the transmission level with generation forecast
- Evaluation of transmission stability of a power system with flexibility resources
- Recommendation of Asset optimization for high PV penetration

Foreword

The International Energy Agency (IEA), founded in November 1974, is an autonomous body within the framework of the Organization for Economic Co-operation and Development (OECD) that carries out a comprehensive program of energy cooperation among its 23 member countries. The European Commission (EC) also participates in the work of the Agency.

The IEA Photovoltaic Power Systems Programme (IEA-PVPS) is one of the collaborative research and development (R&D) agreements established within the IEA, and since 1993, its participants have been conducting a variety of joint projects in the applications of photovoltaic conversion of solar energy into electricity.

The mission of the IEA PVPS program is to enhance the international collaboration efforts to accelerate the development and deployment of solar PV energy as a significant and sustainable renewable energy option toward the following goals:

1. To stimulate activities that will lead to a cost reduction of PV power system applications
2. To increase the awareness of PV power systems' potential and value and thereby provide advice to decision makers from government, utilities, and international organizations
3. To foster the removal of technical and non-technical barriers of PV power systems for emerging applications in OECD countries
4. To enhance cooperation with non-OECD countries and address both technical and non-technical issues of PV applications in those countries.

The overall program is headed by an Executive Committee composed of one representative from each participating country, while the management of individual research projects (Tasks) is the responsibility of Operating Agents. By mid-2012, fourteen Tasks were established within the PVPS program.

The overall goal of Task 14 "High Penetration of PV Systems in Electricity Grids" is to promote the use of grid-connected PV in electric power systems at the higher penetration levels that may require additional efforts to integrate dispersed generators. The aim of these efforts is to reduce the technical barriers to achieving high penetration levels of distributed renewable systems.

Member countries of the IEA PVPS Task 14 are: Australia, Belgium, Canada, Switzerland, China, Germany, Denmark, Spain, Israel, Italy, Japan, Portugal, Sweden, and the United States of America.

This report describes the study results of "Activity 3.2: Power system operation planning with PV integration" and "Activity 3.3: Power system augmentation planning with PV integration" of the "Task 14 Subtask 3: High penetration solutions for central PV generation scenarios."

The study results of "Activity 3.1: System-wide PV generation analysis and forecast" have been separately published as the report IEA PVPS T14-01:2012: "Photovoltaic and Solar Forecasting: the State of the Art."

The report expresses, as completely as possible, the international consensus of opinion of the Task 14 experts on the subject at hand. Further information on the activities and results of the Task can be found at: http://www.iea-pvps.org.

1.Introduction

PV generation is one of the forms of renewable energy generation with variability and limited predictability[9]. It differs from traditional thermal and hydropower generation, as its generation output is not fully controllable (dispatchable). PV output varies periodically in a year and in a day, and is irregular due to weather condition. High penetrations of PV generation will cause issues not only of voltage and power flow fluctuation in a local distribution system but also of demand-supply balance of the power system, which will result in problems including frequency fluctuation and difficulty in demand-supply management.

Accordingly, in order to realize high PV penetration in a power system, it is crucial to evaluate its impact on the operation and augmentation planning in order to envision the future power system. In operation and augmentation planning, it is necessary to identify gaps in current PV system technology and electric power systems to analyze how large numbers of PV installations can be successfully integrated into a total power system, including the technology of smart grids.

The IEA TASK14 Subtask3 deals with PV integration into power systems from the total power system viewpoint, based on PV generation forecasting, power system operation, and power system augmentation.

The current study has mainly focused on the system-level aspects of demand and supply balancing of a power system assuming a strong transmission system, although limited description of the aspect of the reinforcement and expansion of the transmission network is found in this report.

The report begins in Section 2 with a discussion of the impacts of PV penetration and new technologies, and then reviews the state-of-art technology for system operation planning and system augmentation planning in Section 3. Section 4 collects case studies of system operation planning and augmentation planning, including issues, solutions, and R&D activities of the member countries.

[9] Renewable source generation technologies are divided into two categories: dispatchable, such as geothermal, hydro with a reservoir, and concentrating solar power (CSP) with energy storage; and non-dispatchable, such as PV, CSP without energy storage, wind, and run-of-river-type hydro.

2.Impacts of PV Penetration and New Technology

2.1. Impacts of PV Penetration

2.1.1. Power system

Electric power systems have various scale ranging from a system of several hundred GW of developed land on a continent to a system of tens of MW on an island to a system of several tens of kW in a rural area in a developing country. The mission of a power system is to deliver power to the customers in a cost-effective, reliable manner to support quality of life, industrial production, and social activities.

A commercial power system, alternating current (AC) system, transmits and distributes power to the demand utilizing various voltage levels depending on the distance and the capacity, using a transformer to interconnect subsystems of different AC voltages with power plants and demands. The main impacts of PV penetration on a power system are affected by the natural variability and limited predictability of the power output, and the reduction of the operational amount of dispatchable generators.

At the system level, integration of PV into a power system rises various challenges in system operation and, accordingly, in system augmentation. Among these challenges, the increased complexity of matching between demand and supply is the most typical concern when PV or other variable renewable generation penetrates into a power system to have substantial market share.

2.1.2. Balancing operation and generation dispatch

The total power demand, which reflects all the changes in all individual demands, varies over the course of a day, a week, and a year. In current power systems, where dispatchable thermal and hydro generation have a substantial share, demand and supply are balanced by controlling the generation of the dispatchable generators. When the balance is lost or insufficient, the commercial frequency (usually 50 Hz or 60 Hz) or system voltage of a power system fluctuates, and the quality of supply is reduced. In the worst case, a blackout occurs because many devices in a power system, including power plants, which are designed to operate within a specified range of frequency deviation, are cut off from the power system.

In order to maintain power balance in a system, it is necessary to schedule the generation of each dispatchable generation unit. In a power system, balancing of demand and supply is realized through a sophisticated generation schedule to make the best use of the features of each generation unit and system: hourly balancing through generation unit start and stop scheduling, balancing in minutes through centralized automatic generation control specifying the production of each unit, and balancing in seconds through independent governor control of each unit. The remaining mismatch is transformed into a fluctuation of the system frequency. Because the balancing requirements vary by time, by day, and by season, reflecting the variation of the supply and demand structure including the share of variable renewable generation changes, the key concept to accommodate a large amount of variable PV generation is the flexibility of a power system to cope with the balancing. (This flexibility will be discussed in Sections 2.2 and 2.3.)

2.1.3. Power system operation planning

Under a set of operational conditions such as composition of generators, generator characteristics, automatic generation control, and economic load dispatch, an operator plans a generation schedule, typically for the next day. In the schedule, start and stop timing and the generation level of each generator are decided to meet the predicted demand of various levels during the day. The operation plan of a power system, called unit commitment, is the result of large-scale optimization planning considering the economy, stability, and security of the power system operation. The economy is mainly dependent on the operational cost of each power plant, including fuel cost and the generation efficiency of a thermal unit. The operational stability is mainly related to the total capability of all generators to change their output. The security is ensured through reserved generation units, which may work in a sudden increase of demand or in a sudden loss of generation due to a generation failure. If there is not enough balancing capability in a power system, it may be necessary to curtail the variable PV generation to secure the stability of the system operation, even if it reduces the economy of the system.

In the context of operation planning, the natural variability of PV generation increases the required supply-demand balancing capability of a power system, which results in partial operation of some power plants. The uncertainty of PV generation requires additional operation of generation units with lower economy in preparation for the event of reduced PV generation. These changes bring about reduced economy for the existing generators and an increase of stresses on the generators.

There are many countries where electricity is traded in a power market. The trades are made for various short- or long-term timeframes. In these competitive circumstances, the unit commitment plan is decided partially in the market.

In a unit commitment including the power market operation, the PV forecast plays a crucial role in determining the performance of the power system.

In power system operation planning, in order to maintain the viability of the analysis, we need to include such parameters as the maintenance schedule of power system elements.

2.1.4. Power system augmentation planning

Over the years, the demand and generation mix will change in a power system. In order to reduce CO_2 emissions in the energy sector, it is widely recognized that: energy demand will increase as the economy grows in general; the existing power demand will decrease through increased energy efficiency; much of the energy demand will be electrified; and more energy will be supplied by variable renewable generation, which leads to a larger power demand and supply structure with a higher share of variable renewable generation share, including PV.

In current practices for power system augmentation planning, a planner optimizes the future power system following criteria such as economy, reliability, environmental, stability and security. When a power system augmentation is planned to include renewables such as PV, the planner typically aims to find the optimum path to integrate renewables into the power system.

In order to support such a future power system, the power system augmentation planning must have the functionalities to accommodate substantial variable renewable generation, while satisfying the existing planning criteria and constraints. The impacts of PV penetration on the power system are a result of the variation and limited predictability of PV generation, and the reduction of the operational amount of dispatchable generators. Possible countermeasures include: improvement of load-following capability and reduction of minimum operation of existing and new thermal and hydro generators; improvement of PV forecasts; demand activation (see Section 2.3); and utilization of energy storage, including pumped storage power plants and batteries.

Augmentation planning should include a set of indicators to evaluate the status of a power system in a specific time resolution (for example, a year) and over a certain periods (for example, from now to 2030). Indicators can be decided and based on the objectives of the augmentation planning, such as energy security, economic efficiency, and environmental compatibility, which supports the ultimate objective of sustainability. These indicators will be further discussed in Section 4.

In the power system augmentation planning, the parameters that are used in the operation planning are necessary to estimate the operational performance of each augmentation scenario.

In the augmentation planning, the time horizon is the most important parameter. A major thermal generation station requires several years of legal procedures and construction. Distributed generators also need time for being properly disseminated. The augmentation planning usually has a 10- to 20-year study period.

2.2. Countermeasures

The daily and seasonal variability of wind and solar generation present a challenge to their efficient integration into existing electrical grids. However, studies have shown that integrating high levels of variable renewable energy is achievable without compromising reliability with operational and institutional changes. In general, the variability and uncertainty introduced by wind and solar generation technologies calls for a higher level of system flexibility. The amount of flexibility needed to accommodate the introduction of new wind and solar facilities depends on the amount of variable renewable energy capacity and the existing flexibility in the system's infrastructure and operation. The most appropriate mitigation methods depend on economics and the characteristics of the specific system, including the generation sources, infrastructure, and operational practices. This section describes a few of the methods that are generally recognized as efficient integration mechanisms, grouped in four categories: 1) System Operations, 2) Forecasting, 3) Market Design and 4) Planning.

2.2.1. System Operations

(1) Flexible resources

Increasing the flexibility of generation sources is one mechanism for addressing generation variability and ensuring the balance of demand and supply. It can be important to consider the flexibility of new generating capacity additions. It is also possible to enhance the flexibility of existing conventional generators to allow for quicker responses to changes in variable output. The flexible operation of conventional generators often results in increased fuel, maintenance and capital costs that will have to be balanced against the benefits of increased levels of renewable energy in the system.

Aside from flexible conventional generation sources, resources that enhance the flexibility of the system, such as storage systems and demand response, can help operators balance steep ramps. Fly-wheels, pumped-hydro storage and compressed air energy storage are examples of storage systems that are able to respond to dispatch requests at quicker rates. Demand response can reduce the costs of maintaining additional spinning reserves, particularly during extreme events of over- or under-supply of variable renewable energy power.

(2) Geographical diversity

Geographical dispersion of supply can be helpful in smoothing the variability of renewable energy sources. Figure 2.2.1-1 shown below was produced by simulating the output of more than 25 solar PV power plants located throughout a large geographical area (roughly half the size of Italy)[10]. The variability caused by cloud cover was reduced as the outputs of a higher number of solar plants were combined. The resulting output profile (shown in a solid blue line) is not only more predictable and steady through the day, it also matches day-ahead forecasts more closely.

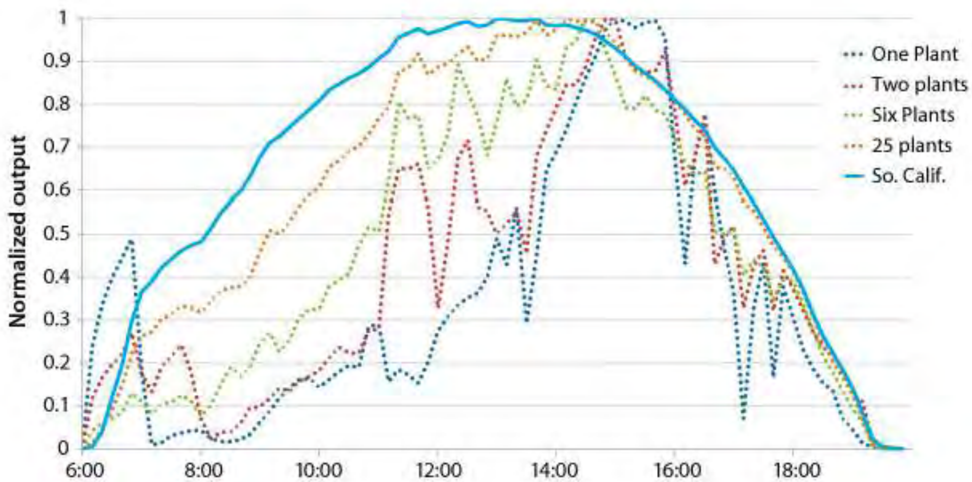


Figure 2.2.1-1: The smoothing effects of aggregating PV plant output over various geographic areas.

Similarly, larger balancing areas, with a larger pool of available generation and demand, will generally be more capable of integrating larger amounts of variable renewable energy sources. Variability in load and in generation can be smoothed out when balancing occurs over a larger area. Furthermore, large balancing areas can provide access to additional flexible generators that may not be available in smaller areas. Combining adjacent balancing areas within the same synchronous area can be employed as a mitigation strategy to increase resilience and promote the integration of variable renewable energy sources in existing grids. Alternatively, cooperation across existing balancing authorities can achieve the same purpose.

2.2.2. Forecasting

Forecasting can reduce the uncertainty associated with variable renewable energy generation technologies. This allows generators or grid operators to plan ahead of variations in the output of solar and wind generators and reduce the level of operating reserves needed, thus lowering the cost of balancing the system. Short-term forecasts assist in the decision to dispatch quick-start generators, demand response mechanisms, or other methods to quickly balance demand and supply.

Forecasts are more widely used to predict wind power generation variability, but solar forecasting is emerging. Cloud movements are the primary cause of solar variability,

---

[10] The source of this simulation was the Western Wind and Solar Integration Study Phase II that the U.S. National Renewable Energy Laboratory conducted in 2013. The actual geographical area was Southern California.

besides diurnal cycles. Sky imagers can be used to produce short-term forecasts, whereas satellite images can be used to predict changes in solar power production over a span of a few hours.

The state-of-the-art of generation forecasting is discussed in a separate publication 'Photovoltaic and Solar Forecasting: State of the Art' as the deliverable of IEA PVPS Task 14, Subtask 3.1 (IEA-PVPS T14-01: 2013).

2.2.3. Market Design

(1) Sub-hourly scheduling

Markets operating with an hourly schedule or using a fixed hourly energy delivery scheme are not as efficient at integrating larger levels of variable renewable energy sources, because they don't have enough flexibility to accommodate for wind and solar generation variability.

Markets operating at 5- or 15- minute intervals minimize reserve requirements and are more efficient at handling both load and generation variability. Additionally, some markets have adopted new ancillary ramping products to encourage generators to perform in a flexible manner and ensure sufficient system-wide ramping capability.

(2) Capacity markets

Because solar and wind have very low marginal costs, they can bid at a very low price in wholesale markets and exert a downward pressure on electricity prices. In some markets, this can raise longer term concerns about the integration of large amounts of renewable energy because owners of other types of generators may not earn enough revenues and lose their ability to operate. Additionally, lower wholesale prices may reduce the incentives to build additional generation plants and consequently increase the risk of capacity shortfalls. Ideally, energy-only wholesale electricity markets should provide enough incentives (in the form of higher wholesale prices) for generators when demand outpaces supply. However, in markets where this is not the case or where regulators have capped wholesale prices to contain volatility, capacity and availability can be rewarded through a separate mechanism designed to incentivize the necessary level of installed capacity for the future. Capacity markets have emerged as a complement to energy-only electricity markets to compensate owners of dispatchable resources for guaranteed deliverability. Critics argue that capacity markets increase electricity costs over energy-only markets and commit future incentives to existing technologies, thereby limiting investments in alternative and innovative generation technologies.

2.2.4. Planning

(1) Transmission

Utility-scale wind and solar power plants need to be located where the resource is rich, which is often far away from consumption centers and existing transmission lines. The distance between generation and consumption, the granularity of renewable energy sources,[11] and the need for geographic dispersion to smooth out generation variability mean that significant transmission additions will be required to accommodate high levels of variable renewable energy integration.

The need for timely construction of transmission lines and their rising construction costs are emerging as important challenges for the integration of higher levels of renewable energy. New planning, regulatory, and cost-recovery approaches are necessary to facilitate transmission network expansions cost-effectively. Reactively responding to transmission expansion requests from individual projects lead to more expensive solutions, and may tax the available planning processes and resources. Proactively designing transmission solutions for projects in the same area, on the other hand, can improve the efficiency of the planning process and influence generation siting decisions that lead to the lowest overall generation and transmission costs (Madrigal and Stoft 2012).

Planning and constructing new transmission lines can be a protracted process, given the number of stakeholders involved and the complexity of the numerous processes required in many jurisdictions. Public engagement in a process where the information flows freely from and to the public can minimize the potential friction in siting, permitting and building new transmission lines.

(2) Comprehensive approaches

Comprehensive planning approaches that integrate transmission, distribution, generation and system performance goals, from distribution to the bulk power system across an entire network, greatly facilitate and reduce the implementation costs of variable renewable energy integration. The coordination and integration of planning processes helps regulators prepare for the potential impacts of variable generation on the system and evaluate the available options to optimize generation and transmission costs.

Planning processes that integrate multiple jurisdictions facilitate transmission expansions and the geographic distribution of renewable energy sources. Integrating local and regional planning efforts helps promote the cooperation or enlargement of balancing authorities, diversifies demand and supply, and eases the integration of higher levels of variable renewable energy generation.

Resource planning takes many different forms around the world. However, the experience in different countries shows that there are a few practices that can be applied in many different regulatory contexts. Three key principles that have been identified include:

1. Integrating the planning of generation, transmission, and system performance

[11] In the U.S., the average size of wind projects constructed in 2012 was 71 MW according to the American Wind Energy Association, compared to the average operational coal plant size of 550 MW.

2. Ensuring institutions and markets are designed to enable access to physical capacity
3. Building from local and regional planning to better integrate and coordinate information across jurisdictions (Cochran, et al. 2012).

Planning processes that optimize generation, transmission, and other resources across an entire network greatly reduce the need and cost of variability mitigation mechanisms.

2.2.5. References

[1] Bird, L., M. Milligan, and D. Lew. 2013. "Integrating Variable Renewable Energy: Challenges and Solutions." NREL/TP-6A20-60451. National Renewable Energy Laboratory (NREL), Golden, CO. http://www.osti.gov/scitech/biblio/1097911.

[2] North American Electric Reliability Corporation (NERC). 2009. "Accommodating High Levels of Variable Generation." Princeton, NJ. http://www.nerc.com/files/ivgtf_report_041609.pdf.

[3] Cochran, J., L. Bird, J. Heeter, and D. A. Arent. 2012. "Integrating Variable Renewable Energy in Electric Power Markets: Best Practices from International Experience." NREL/TP-6A20-53732. National Renewable Energy Laboratory (NREL), Golden, CO. http://www.osti.gov/scitech/biblio/1041369.

[4] Western Governors' Association (WGA). 2012. "Meeting Renewable Energy Targets in the West at Least Cost: The Integration Challenge." http://www.westgov.org/reports/doc_download/1602-meeting-renewable-energy-targets-in-the-west-at-least-cost-the-integration-challege.

[5] M. Miller, L. Bird, J. Cochran, M. Milligan, M. Bazilian, E. Denny, J. Dillon, J. Bialek, M. O'Malley, and K. Neuhoff. 2013. "RES-E-NEXT, Next Generation of RES-E Policy Instruments." http://iea-retd.org/wp-content/uploads/2013/07/RES-E-NEXT_IEA-RETD_2013.pdf.

[6] Madrigal, Marcelino, and Steven Stoft. 2012. *Transmission Expansion for Renewable Energy Scale-up Emerging Lessons and Recommendations*. Washington D.C.: World Bank.

2.3. Demand Activation (Auto-DR)

In this section, demand activation (auto-demand response), including decentralized energy storage, is discussed as the most innovative flexible resource for the future, driving energy-smart consumers and communities.

2.3.1. Demand Activation

As discussed in Section 2.2, flexible resources must be secured in order to cope with the variability of renewable generation, and traditional generation is the first and largest flexible resource. However, when the share of variable renewable resources increases, the share of thermal and hydro power plants, which currently provide flexibility to a power system, necessarily decreases. For the future, we are identifying new flexible resources.

Demand-side management (DSM) has been used for demand and supply balancing since the 1990s. DSM has two areas: energy efficiency, which is reduction of energy, and load leveling, which is reduction of peak load. Load leveling is often called demand response, which means that a demand responds to a signal of cost, incentive, or a control. However, as far as it is a human who responds to the signal, DSM's acceptability and reproducibility are low, and its effectiveness is limited. The U.S. Department of Energy (DOE) states that: “Demand response is a tariff or program established to motivate changes in electric use by end-use customers in response to changes in the price of electricity over time, or to give incentive payments designed to induce lower electricity use at times of high market prices or when grid reliability is jeopardized.”[1]

Demand response has been introduced to in the field of industries with resources of large distributed resources and also to households and small businesses with the dissemination of smart meters. Recently, in line with the development of information and telecommunication technology, new devices are becoming available, including distributed energy management such as home energy management systems (HEMS) and building energy management systems (BEMS). With these devices, which can control appliances and equipment, it is expected that demand in houses, commercial buildings, and factories can be “activated” automatically, for example, in response to a price signal.

Figure 2.3.1-1 compares current and future balancing with batteries and demand activation. The power supply and demand balance is currently regulated by a centralized EMS using major generators. When renewables penetrate into a power system, a large number of new devices might be required to balance the variability. However, demand activation by distributed EMS will take a part of the required flexibility at the demand side. It is expected that optimum deployment of flexible resources including demand activation will enable high penetration of PV and other variable renewable generation economically without reducing stability.

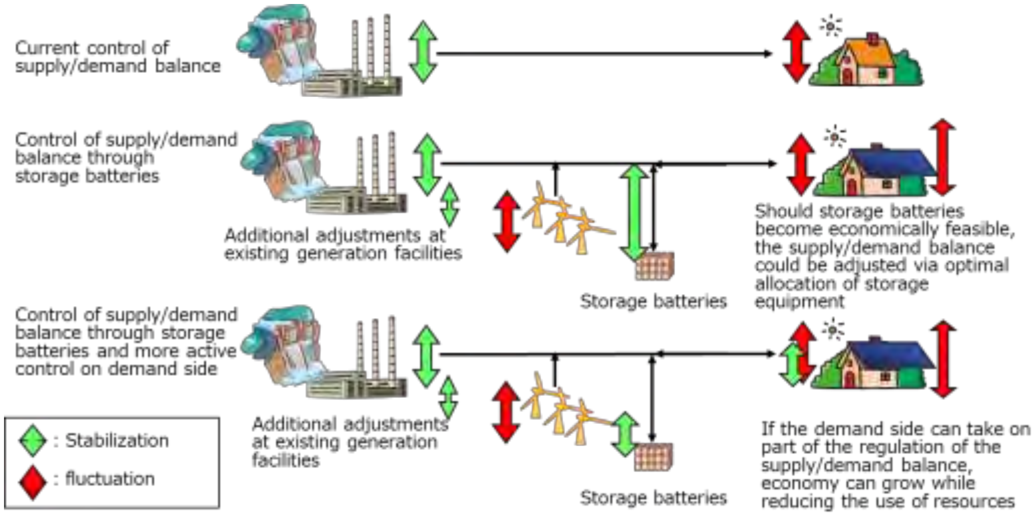


Figure 2.3.1-1: Demand Activation by Distributed EMS
Source: K.Ogimoto, the University of Tokyo

Figure 2.3.1-2 depicts the concept of demand activation. Centralized energy management, which prepares the unit commitment schedule for the next day, decides the hourly or time-dependent power prices for the next day using PV and wind generation forecasts. The centralized EMS sends the power prices to a decentralized energy management such as an HEM in a house. The distributed energy management system optimizes the power use of the house for the next day by minimizing cost without reducing service level by scheduling the period of electric vehicle (EV) charging and water heating. In an urgent situation, an air conditioner might be controlled to reduce the peak load. A battery in a building will be a good resource to provide additional flexibility on the demand side.

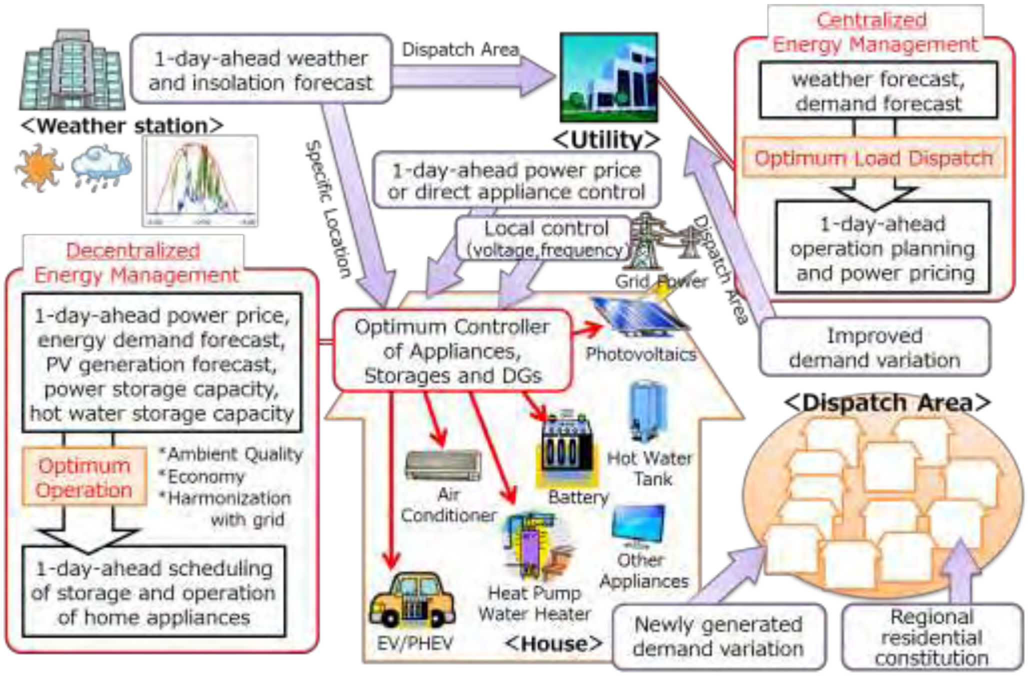


Figure.2.3.1-2 : The concept of demand activation.[2]
Source: Ogimoto, K., Iwafune, Y., Kataoka, K., Ikegami, T., & Yagita, Y. (2011a). Cooperation Model of Centralized and Decentralized Energy Management for the Supply-Demand Adjustment in a Power System, Proceeding of Power and Energy Society Conference of Institute of Electrical Engineers of Japan, 8-16 (in Japanese)

EVs, which are growing in popularity, are emerging large power demands. EV charging will tend to occur after each individual trip and will be one of the focuses of demand activation, because there is a certain allowance for charging period with each EV without reducing the service level.

There will be many other demands that have a potential to be activated. Demand activation will be an innovative and dominant countermeasure for the flexibility of a future power system. Its wide deployment will require a large investment and various changes in technology, infrastructure, institution, economy, public acceptance and security. For the substantial deployment of variable renewable generation such as PV, the activated demand is expected to increase the flexibility that is necessary to balance the additional variation that comes with the limited predictability of PV generation. In order to follow changes in PV generation due to time and weather, one-day-ahead and real-time pricing will be applicable.

The recent IEA publication “The Power of Transformation” [3] discusses the viability of demand activation as follows: "While there is some degree of uncertainty around the ultimate capabilities of DSI (demand side integration), it is more than likely that benefits will, by far, outweigh initial costs." DSI may be the flexible option where clear policy action could produce the largest benefit. Policy intervention may indeed help overcome initial barriers, such as the cost of putting infrastructure in place for smart DSI applications beyond large-scale consumers. In addition, clear policy measures may actually trigger investment in demand monitoring and control devices that would otherwise remain dormant for a long period. This would facilitate economies of scale and cost reduction. Detailed information and discussions on technology, value of renewable integration, economic analysis, policy, and market considerations for DSI are available in the publication.

Considering the emerging impacts of variable renewable generation to some power systems, various stakeholders such as regulators, operators, utilities, manufacturers, and customers are beginning to discuss ways to optimize flexible resources including demand activation (auto-demand response) in power system operation and augmentation [3,4,5].

2.3.2. "Smart" Homes and Businesses

In the previous section, demand activation is discussed as an emerging measure to contribute to the stable operation of a power system. As discussed, the decentralized EMS should have an important role in realizing the wide deployment of demand activation for various appliances or facilities in homes or buildings, including EVs.

In Japan after the East Japan Earthquake of March 2011, and in the United States during Hurricane Sandy in October 2012, many people experienced substantial blackouts of several days. Currently, there are emerging critical natural disasters due to climate change, which have serious impacts on society. In this situation, there is increasing concern about the stable supply of energy and power. Considering the nature of PV resources that are more evenly available at and near living and business spaces, PV is expected to have a more important role as an energy/power source in case of a shortage of power supply. Distributed energy management is also expected to bring value to society as an EMS.

For a demand decentralized energy management traditionally has the value of maintaining the appropriate environment, economy, and security for a demand such as a house, commercial building, or EV. For example, at a house, a home EMS (HEMS) maintains a comfortable living space while saving cost, reducing environmental impacts, and maintaining security.

Although the abovementioned values for a power system and energy use, it is not likely that many consumers or business entities will deploy a decentralized EMS because of its initial and operational costs, and because it conveys a limited amount of the financial benefit of demand response to an owner under energy use constraints.

Figure 2.3.2-1 depicts the future HEMS, which has two axes of value (contribution to a power system and energy use) and one additional axis (quality of life). HEMS, which monitors and communicates with appliances and collects information from outside the house, has a potential to contribute additional value to enhance quality of life through offering new services for home security, health, and entertainment.

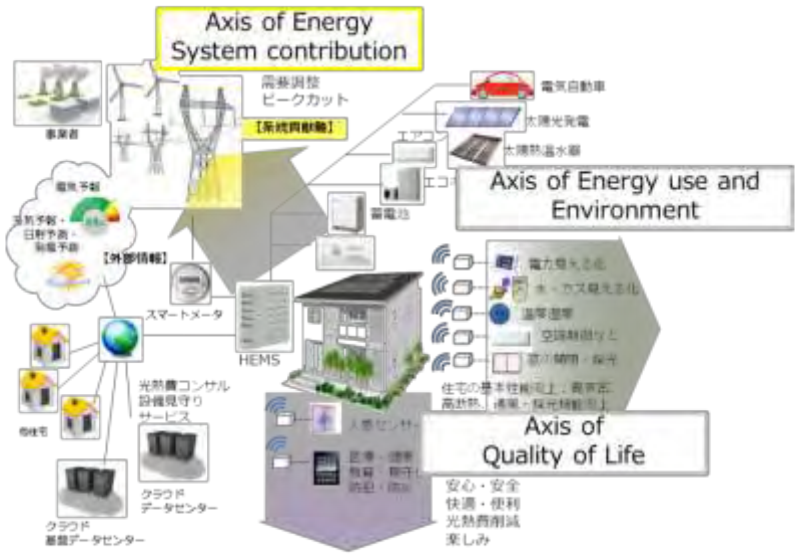


Figure 2.3.2-1 : Three axes of the home energy management system. [5]
Source: Ogimoto, K., University of Tokyo

Distributed energy management is expected to contribute to the evolution of a power system to accommodate high penetration of variable renewable generation, including PV. Distributed energy management is also expected to contribute to the evolution of a life and business through energy optimization and security, offering additional value to peoples' life and business. The affected homes or businesses will evolve to become "smart" homes and communities, and more PV will be integrated into buildings and communities with enhanced value.

2.3.3. References

[1] DOE 2005. “Benefits of Demand Response in Electricity Markets and Recommendations for Achieving them - A Report to the United Congress Pursant to Section 1252 of the Energy Policy Act of 2005” http://energy.gov/sites/prod/files/oeprod/DocumentsandMedia/DOE_Benefits_of_Demand_Response_in_Electricity_Markets_and_Recommendations_for_Achieving_Them_Report_to_Congress.pdf.

[2] Ogimoto, K., Iwafune, Y., Kataoka, K., Ikegami, T., & Yagita, Y. (2011a). Cooperation Model of Centralized and Decentralized Energy Management for the Supply-Demand Adjustment in a Power System, Proceeding of Power and Energy Society Conference of Institute of Electrical Engineers of Japan, 8-16 (in Japanese).

[3] ACER (Agency for the Cooperation of Energy Regulators). 2013. “Pre-consultation on 'Energy Regulation: A bridge to 2025'" set of papers. http://www.acer.europa.eu/Official_documents/Public_consultations/Pages/PC_2013_E_05.aspx.

[4] CEER (Council of European Energy Regulators). 2013. “Regulatory and Market Aspects of Demand-Side Flexibility.”

[5] FERC (Federal Energy Regulatory Commission). 2013. “Technical Conference on Centralized Capacity Markets in RTOs/ISOs (AD13-7-000).”

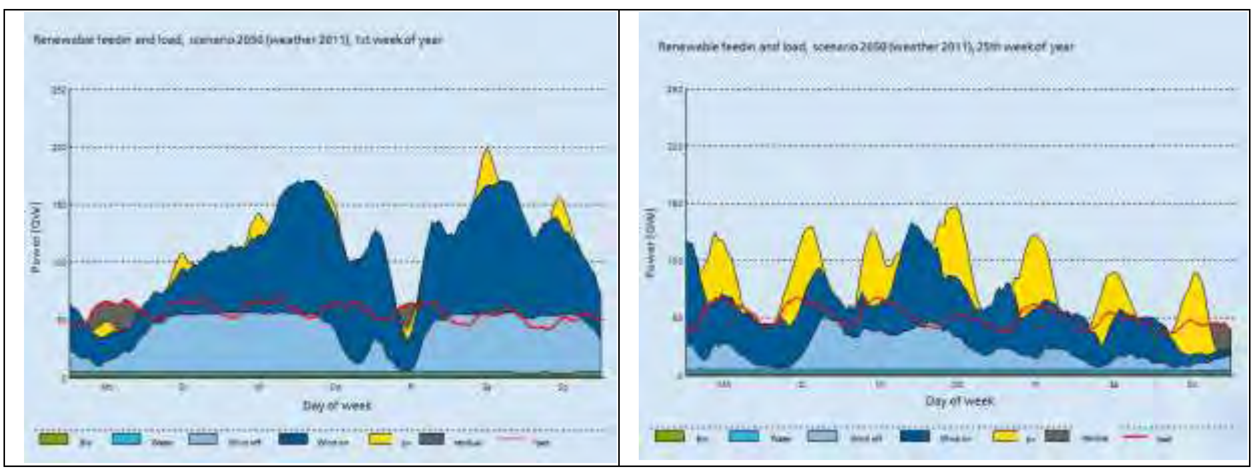
2.4. *Impacts of Other Variable Renewable Energy*

2.4.1. General Impact and Characteristics of Wind Energy Supply Patterns for the Energy System

Wind energy is, like PV, a temporally and spatially fluctuating electricity resource. Unlike PV, wind power is also available during the night and is—in the Northern Hemisphere—usually more abundant in winter than in summer.

Also, wind energy from offshore wind farms usually generates more energy per installed capacity due to better wind conditions and can thus be regarded as an additional renewable energy option with unique characteristics.

In the future, the impact of the supply characteristics of fluctuating renewables will predominantly determine how the energy sector will look with respect to storage, load management requirements, back-up capacity, and load factors of conventional power plants. Two weeks illustrating a "normal" situation of supply and demand variations in a very advanced future energy scenario dominated by fluctuating renewables are shown in Figure 2.4.1- a) and b) (left: week in winter; right: week in summer).



Figures 2.4.1-a) and b): Exemplary weeks in a) winter and b) summer, based on a scenario for 2050, calculated with the meteorological year 2011. With the load (red curve) fluctuating around 50 GW, the need for conventional power production can be reduced to only a few hours per week by increasing the installed capacities of mainly offshore wind (light blue), onshore wind (dark blue), and PV (yellow).Source: Fraunhofer IWES, 2013.

2.4.2. Dynamic behavior of wind power production

A closer look at the power production pattern of wind energy is provided in Figure 2.4.2-1. The graph shows the number of occurrences of sudden power drops or increases (from timestep t to t+1, hourly resolution). It shows that (in seldom cases within a year) power changes between two hours may reach up to 30% of installed capacity. More frequently, the rate of change of power production is much lower. However, the fluctuating behavior of wind power needs to be absorbed by the electricity system.

Markov-Matrix for a Wind Energy Feed-In Time Series - 80% Renewable Energy Scenario for Germany
(normalized for total installed wind energy capacity, 160 GW in 2050)
[number of events in hours of a year]

feed-in in % of nominal installed wind-capacity in t = t+1	0% - 10%	10% - 20%	20% - 30%	30% - 40%	40% - 50%	50% - 60%	60% - 70%	70% - 80%	80% - 90%	90% - 100%
90% - 100%	0	0	0	0	0	0	0	0	0	0
80% - 90%	0	0	0	0	0	0	0	27	301	0
70% - 80%	0	0	0	0	0	1	63	479	27	0
60% - 70%	0	0	0	1	1	85	472	64	0	0
50% - 60%	0	0	0	4	89	455	88	0	0	0
40% - 50%	0	1	4	110	617	94	0	0	0	0
30% - 40%	0	4	124	640	120	0	0	0	0	0
20% - 30%	0	148	1005	132	0	0	0	0	0	0
10% - 20%	117	1405	152	1	0	0	0	0	0	0
0% - 10%	1811	117	0	0	0	0	0	0	0	0

very high rate of power change (up to 30% of installed capacity)
medium rate of power change (up to 20% of installed capacity)
moderate rate of power change (up to 10% of installed capacity)

Figure 2.4.2-1: feed-in in % of nominal installed wind-capacity in t = 1
Source: Fraunhofer IWES, 2013

2.4.3. Smoothing effects by combining different fluctuating renewable energy sources

All three fluctuating renewable energy sources are important in optimizing the impact on the energy system. For Germany an analysis has shown that the residual load of the electricity sector is smoothest when different fluctuating renewable energy sources are combined. With residual load, the instantaneous electricity demand less the energy production from PV, and onshore and offshore wind energy is meant.

To illustrate this point, Figure 2.4.3-1 shows the standard deviation of the residual load for all theoretically possible renewable energy mixes in Germany (colored area). The y-axis defines the percentage of wind energy in percent of total supply from fluctuating renewable energy sources (thus, remaining supply is provided by PV). The x-axis defines the percentage of offshore wind energy in percent of total wind energy supply (thus, remaining wind supply is provided by onshore plants. The lowest standard deviation (blue-colored area) can be reached if all these fluctuating renewable sources provide a substantial amount of electricity.

The analysis was done for a future scenario with 80% renewable share in all energy sectors (transportation, electricity, and heat) in 2050. Very strong energy-efficiency measures, coupling of all energy sectors, new infrastructure (storages, transmission networks), and a large renewable energy production (800 TWh) were assumed as cornerstones of the scenario.

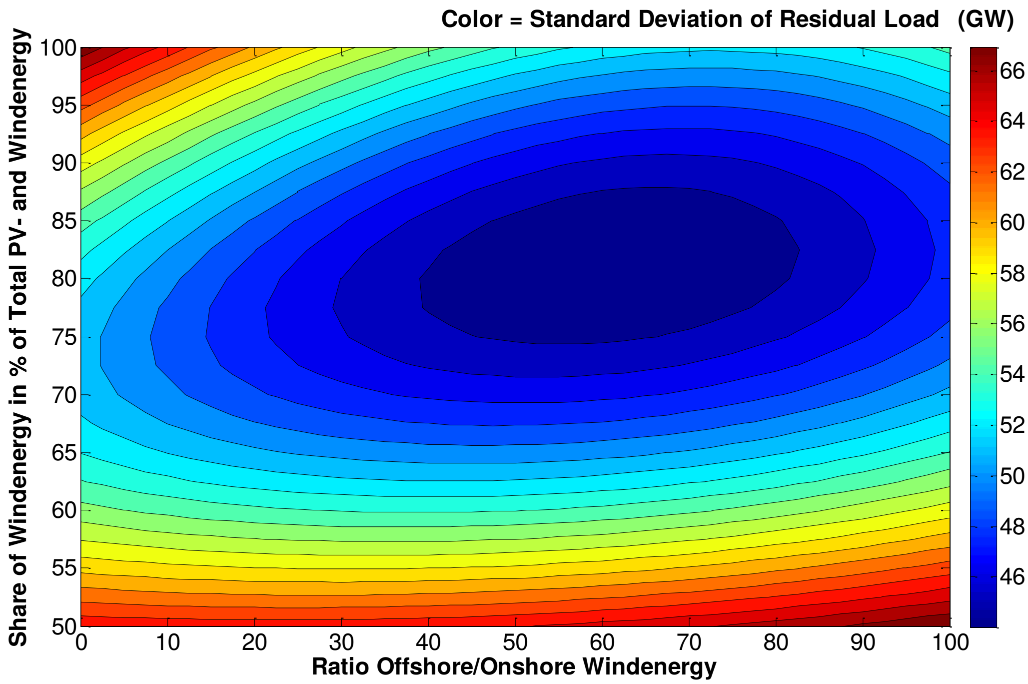


Figure 2.4.3-1: Standard deviation of residual load depending on different mixtures of installed renewable energy capacity in a future German electricity system.
Source: Fraunhofer IWES, 2013.

2.5. Integration of technologies and institutions

In order to realize high penetration of PV and other variable renewable, as discussed in the prior sections, it is essentially necessary to overcome the variability which affects the demand supply balancing of a power system. Essentially, there is two approaches: the one is to reduce the variability and the other is to enhance the flexibility of a power system.

Variability can be reduced, as discussed in 2.2.1, through smoothing effects of geographical diversity of each of PV and other variable generation technologies, and that of technological diversity of various renewable energy generation technologies. This means that, in order to realize high penetration of variable renewable generation including PV, it is essential to allocate appropriate amount and technology to appropriate locations.

Flexibility can be enhanced, as discussed in 2.1 and 2.2, through utilization of the various resources of a power system: utilization of the traditional resources of supply side such as thermal power, hydro power and pumped-hydro power is the most economical option.

Secondly, the generation of variable renewable can be curtailed or modified so as to reduce the variation or even to enhance stability of operation to some extent. Thirdly, as discussed in 2.3, the resources at the demand side are and will be available for the flexibility.

With reliable transmission system and generation forecast technology, a power system or interconnected power systems can enhance the power system operation or optimize the utilization of the whole resources of flexibility against the smoothed variability to realize the stable operation under the high penetration of variable renewable generation under the physical laws and operational and market rules. (Figure 2.5-1).

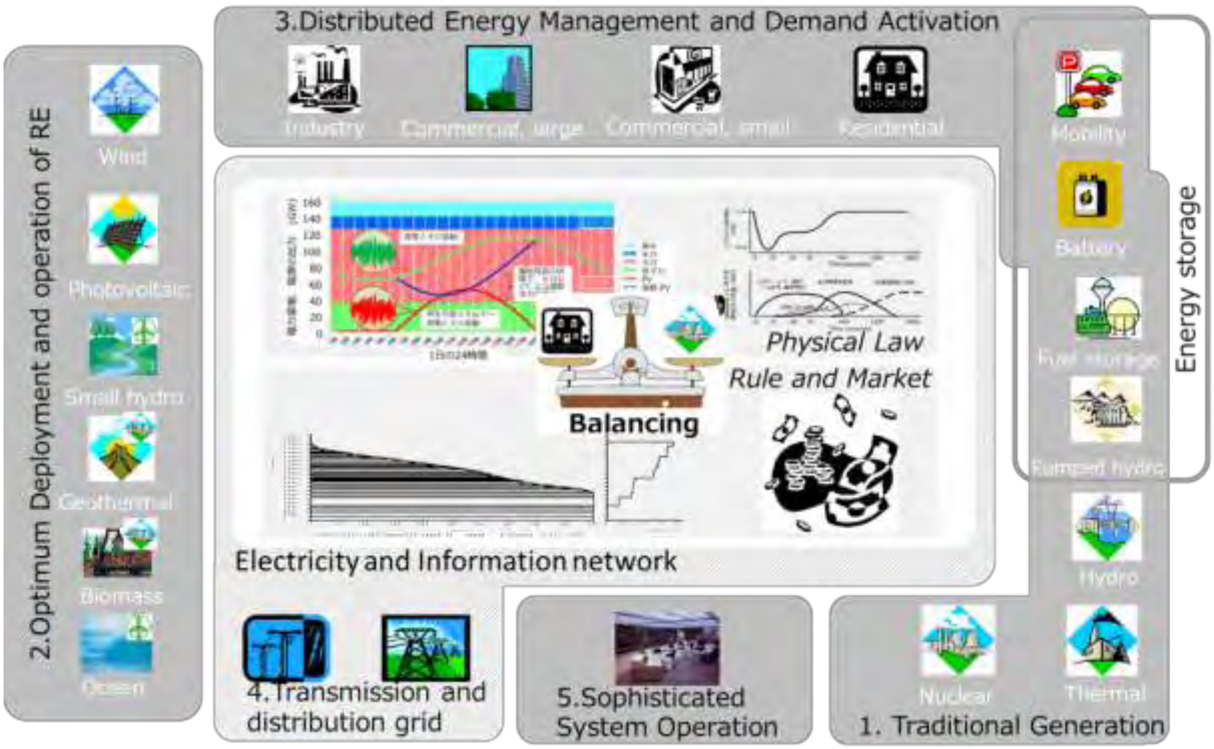


Figure 2.5-1: The enhanced power system operation by optimized utilization of the whole resources of flexibility against the smoothed variability
Source: K. Ogimoto, the University of Tokyo.

3. Methodology: State of the Art

3.1. Description of Power System Operation Planning

This chapter shows a simplified approach for the evaluation of balancing reserve in the market- regulated Italian power system.

3.1.1. Methodology Workflow

Given the unit-commitment and dispatching of the conventional generators assessed in the sale/purchase session of the energy market, and given the forecast of load and renewable PV and wind power, assessment of the balancing reserve involves:

- Uncertainty evaluation based on the load demand, the wind and solar power generation and the generation supplied by thermal units;
- Probabilistic combination of the abovementioned uncertainties and consequential evaluation of the needed balancing reserve to match the demand for a given confidence level of 95%.

Regarding the confidence level of 95%, this value was considered taking into account other international experiences ([1]); in any case, this parameter can be changed maintaining the same methodological approach proposed here.

Figure 3.1.1-1 depicts the basic flow scheme of the adopted methodology for the balancing reserve calculation for one day ahead.

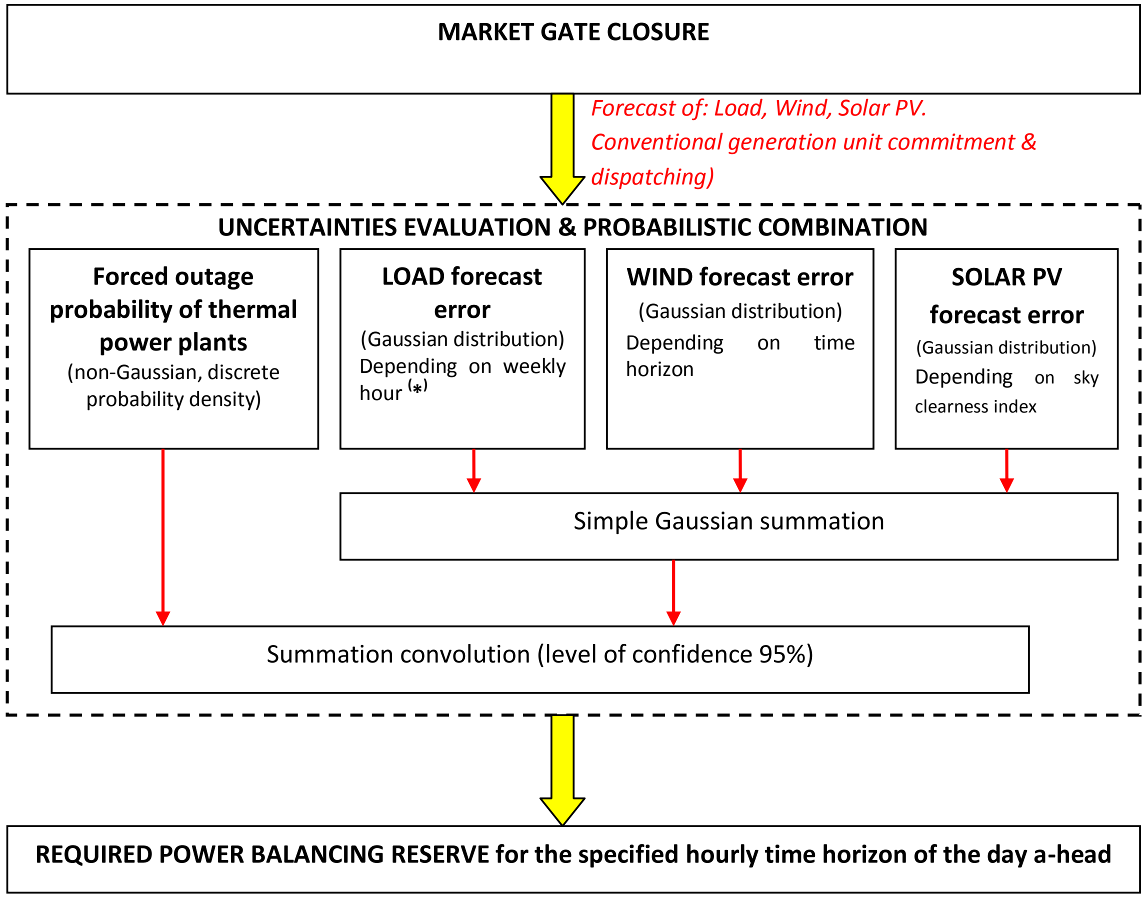


Figure 3.1.1-1: Flow scheme of the methodology for the evaluation of the hourly balancing reserve.

*The analysis of the load forecast error historical data showed that the load error depends on daily hours (morning, afternoon, weekend, etc.) but does not substantially depend on time horizon (4–16 hours ahead).

Framework of the Italian electricity market

While load and solar PV forecast errors will be assumed not sensitive to the time horizon, uncertainties concerning wind generation and the probability of thermal plants outages are evaluated within a given look-ahead horizon. This time horizon is calculated starting from the end time of the market sessions for the electric energy trading.

The Electricity Market consists of the:

- Day-Ahead Market – MGP (energy market);
- Intra-Day Market - MI (energy market);
- Ancillary Services Market - MSD.

The Day-Ahead Market (MGP) hosts most of the electricity sale and purchase transactions.

The Intra-Day Market (MI) allows market participants to modify the schedules defined in the MGP by submitting additional supply offers or demand bids. The MI takes place in four sessions: MI1, MI2, MI3, and MI4.

The Ancillary Services Market (MSD) is used by the Italian TSO TERNA in order to get the needed resources for managing, operating, and controlling the power system (relief of intra-zonal congestions, construction of energy reserve, real-time balancing). In the MSD, TERNA acts as a central counterparty and accepted bids/offers are valued at the offered price (pay-as-bid). The MSD consists of three scheduling sessions (MSD1, MSD2, and MSD3) covering the following timeframes: 1–24 hours (MSD1); 13–24 hours (MSD2); 17–24 hours (MSD3).

Events occurring until half an hour before the time of communication of the MSD results (last column of the following Table 3.1.1-1) are considered deterministic.

Table 3.1.1-1: Summary of MSD market and adopted hypotheses for time of data acquisition

MSD Session	Covered timeframe of the day "D"	Time of results communication	Hypotheses on the scheduled time for data acquisition
MSD1	1-24	21.00 D-1	20.30 D-1
MSD2	13-24	10.00 D	09.30 D
MSD3	17-24	14.00 D	13.30 D

"D" delivery day ahead; "D-1" one day before

It is hypothesized that data concerning wind/solar generation and forced outages of thermal power plants are available by the abovementioned scheduled times for each MSD session, and thirty minutes is considered sufficient for the elaboration of final results. For every MSD session, events are considered as probabilistic in the corresponding covered timeframe.

As shown in the following Figure 3.1.1-2:

- Forecasts are available for MSD1 by 20.30 of day "D-1" and are considered as probabilistic in the period 0.00–12.59 of delivery day-ahead "D";
- In the MSD2 session, forecasts are available by 09.30 of "D" and the probabilistic analysis covers the timeframe 13.00–16.59;
- In the MSD3 session, forecasts are available by 13.30 of "D" and the probabilistic analysis covers the interval 17.00–23.59.

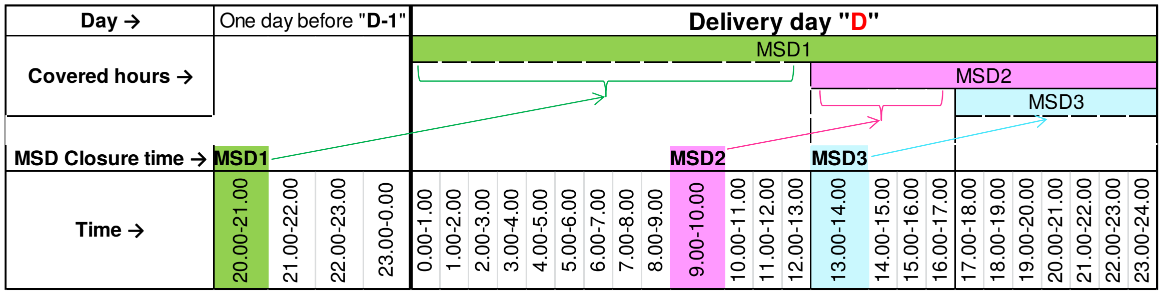


Figure 3.1.1-2: MSD market sessions and covered periods.

3.1.2. Forecast Error

(1) Load

Due to the highly repetitive nature of the daily load profile, load forecast error is not sensitive to the time horizon and can be effectively assessed on the basis of historical data. Therefore historical data of hourly national demand are considered; this data includes the error between forecast and actual load (data published by TERNA [2]). Load forecast error can be modelled as Gaussian stochastic variable with a zero mean value and a standard deviation $\sigma_L\%$ given by:

Eq. 1 $$\sigma_L\% = \sqrt{\frac{\sum_{i=1}^{N_{samples}} e_i\%^2}{N_{samples}}}$$

Where:

- $N_{samples}$ is the number of samples of the load forecast error;
- $e_i\% = \dfrac{Actual_{load} - Forecast_{load}}{Forecast_{load}} * 100$ is the hourly percent error of the load forecast.

The analyzed historical series cover the time period from November 29, 2010 to November 28, 2011. Holidays, August, and hours with high anomalous load values are excluded from the statistics in compliance with the procedure adopted by TERNA (enclosure A30[12] of [3]).

Data analysis for every hour of the weekday showed that:

- Midweek days from Tuesday to Friday are characterized by very similar values of $\sigma\%$ and therefore can be represented with the same values;
- Monday has higher values of σ_L until 16.00, while after 16.00 can be considered the same as the other midweek days;

[12] Available only in Italian at the Italian TSO TERNA website: http://www.terna.it/LinkClick.aspx?fileticket=wlZHX3fTGFo%3D&tabid=106&mid=468.

- Saturday and Sunday are very different and cannot be assimilated to the midweek days.

The following Figure 3.1.2-1 outlines, for the whole week, the adopted values for the standard deviation of the load forecast error; as these values are obtained from samples concerning the whole year (aside from August and holidays), they are applied independently of the analyzed season or month in which the analyzed week is included.

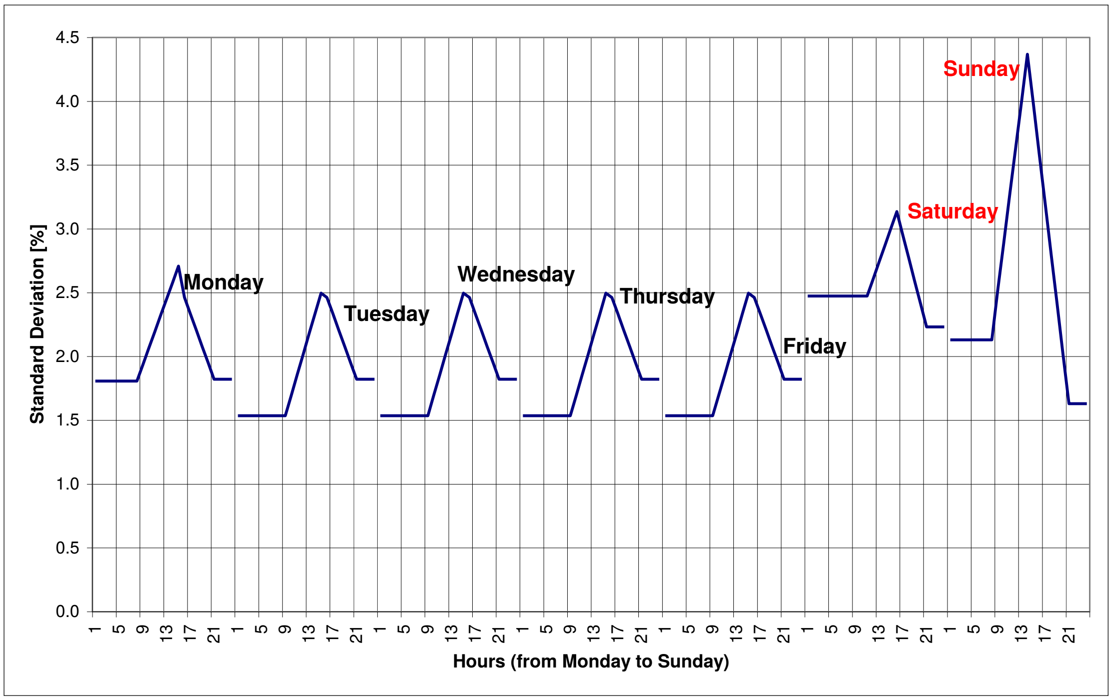


Figure 3.1.2-1: Standard deviation [%] of load forecast error for the whole week.

(2) Wind generation

Like load forecast errors, the wind forecast error can be modeled as a Gaussian stochastic variable with a mean of zero and a standard deviation $\sigma_W\%$. On the other hand, unlike the load, the wind forecast errors generally increase as the forecast horizon increases. Moreover, it is generally necessary to consider several wind farms in order to exploit the spatial smoothing effects on the wind prediction error; for this purpose, the hypothesized standard deviation here is based on results presented in scientific literature and, in particular, on the results of an analysis performed on 30 wind farms monitored in Germany [4]. These results outline the values of the standard deviation normalized to the installed power P_{INST_WIND}; in particular $\sigma_W = 12\% P_{INST\_WIND}$ for a prediction time of 6 hours and $\sigma_W = 14.5\% P_{INST\_WIND}$ for 18 hours ahead. Starting from these two values, a linear relationship between $\sigma_W\%$ and the time horizon was defined for the present methodology. Figure 3.1.2-2 depicts this relationship for the 24 hours of the day ahead; note that no significant differences were found in the considered time range.

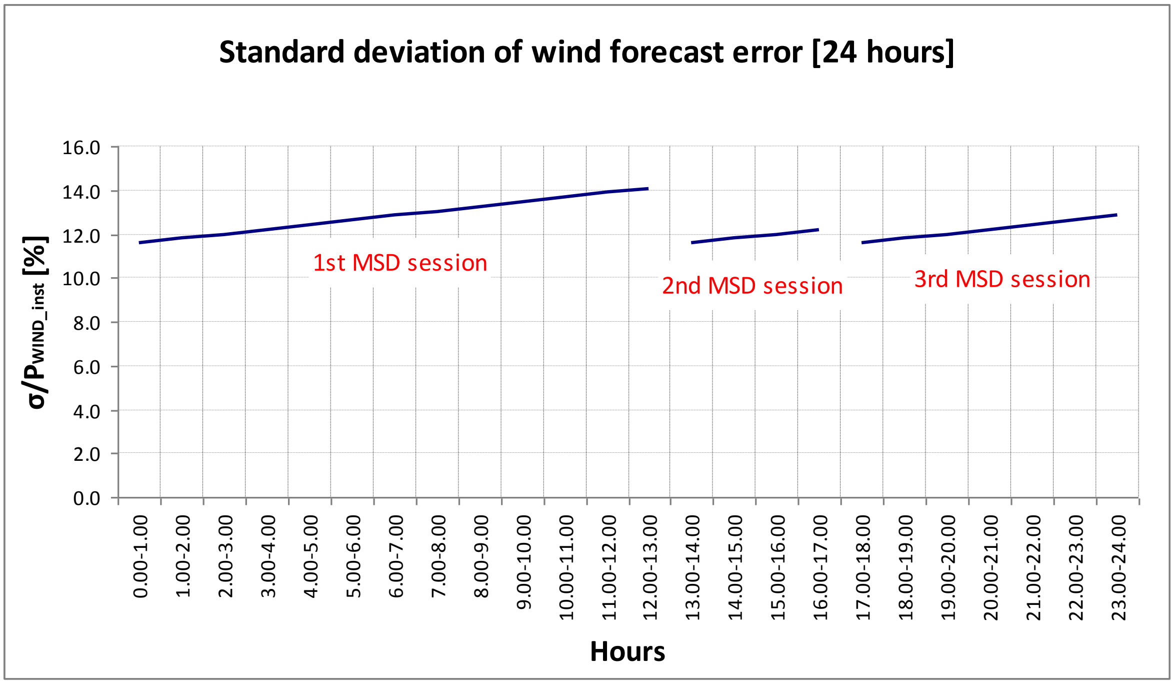


Figure 3.1.2-2: Standard deviations of the wind forecast error in the 24 hours of the day ahead.

The discontinuity of the curve is due to the MSD2 and MDS3 market sessions within the delivery day "D" involving closer time horizons and consequently lower uncertainty values because it has reasonably hypothesized the update of the wind provisions.

It's worth emphasizing that adopted standard deviation values are comparable with ones published by TERNA [5] for 195 MW of installed wind farms in the Sardinia market zone.

(3) Solar PV generation

Like load and wind forecast errors, the solar PV forecast error can be modeled by means of a Gaussian curve with a mean of zero and a standard deviation $\sigma_{PV}\%$. Given a certain forecasted sky clearness condition, $\sigma_{PV}\%$ is considered as percentage of the maximum generable power depending on the installed PV in operation and on the maximum solar radiation.

Latitude, longitude, and day/period of the year characterize the maximum solar radiation and consequently the maximum generable PV power $P_{MAX\_GEN\_PV}$ in the case of a perfectly clear sky without fog and panel shadowing. The maximum generation may be achieved in the case of panels lying on a horizontal plane defined by terrestrial surface and vertical radiation supplied by the sun in the zenith location (90° directly overhead). The sun is in the Zenith location at the equator on the equinox days and along the tropics on the solstice days. The sun cannot reach the Zenith location outside the tropical latitudes; in the northern hemisphere (reference for the Italian area), the longest day of the year is the 21st of June with a sun angular deviation $\delta = 23.45°$ with respect to the equinox days; in the southern hemisphere the longest day is December 21st with $\delta = -23.45°$ (see Figure 3.1.2-3).

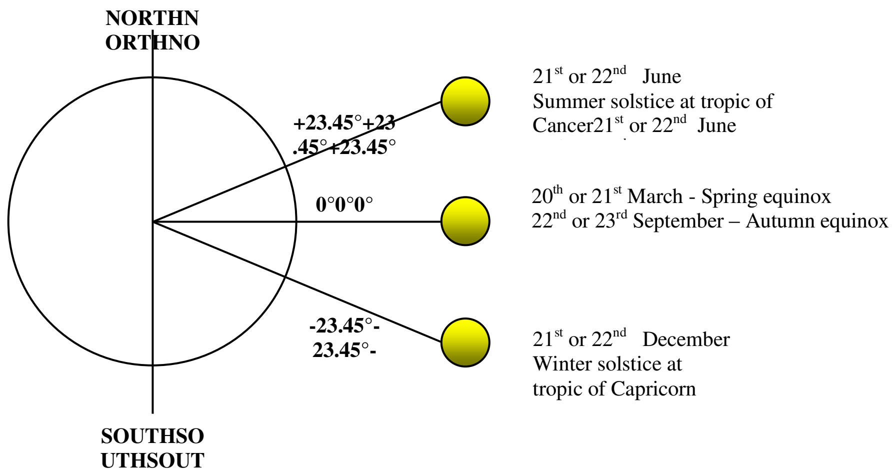


Figure 3.1.2-3: Sun deviation from Equator-Zenith in various periods of the year.

The maximum hourly generable power, with a fully clear sky, is finally given by:

$$P_{MAX\_GEN\_PV\_hour} = \sin\alpha \cdot P_{INST\_PV}$$

where α represents the solar height angle, which is the complementary to the one between Zenith and the solar position. In other words, $\sin\alpha$ is the vertical position of the sun depending on latitude, longitude, hour, and day of the year.

The actual generated power depends on the meteorological sky conditions: the absence of clouds and fog makes the solar output very predictable, while cloud and fog impacts are less predictable and act quickly; moreover, in case of a thick cloud cover, only a little variation is appreciated in solar output. Consequently, the forecast error will depend on the sky clearness as well, being minimal for fully sunny or cloudy days. Therefore a sky clearness index (CI) can be taken into account in order to define the error standard deviation σ_{PV} as function of the clearness ([6],[7]): basically, limited values of σ_{PV} correspond to very sunny days (CI_{MAX}=1) and heavily cloudy days (CI→0), whereas higher σ_{PV} values are related to intermediate situations (see Figure 3.1.2-4). A dependence of the forecast errors on time horizon also exists; however, it has been neglected in this methodology because not only it is smaller than the dependence on CI, but historical data were not available to assess it.

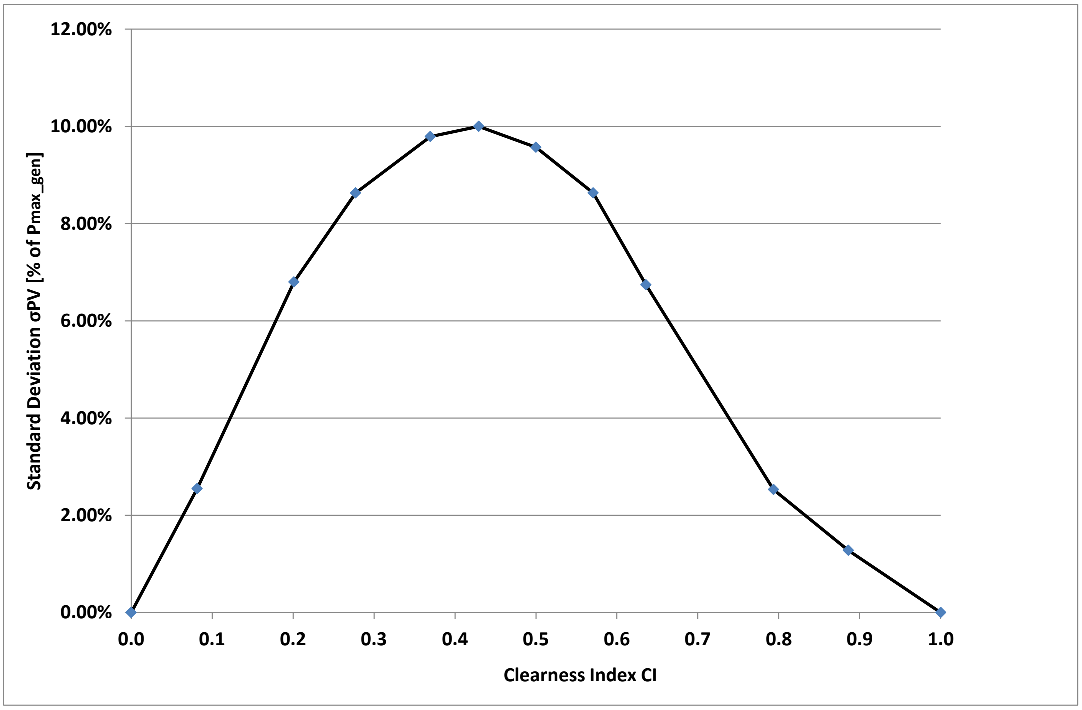


Figure 3.1.2-4: Standard deviation as a function of the clearness index (CI).

It is hypothesized that a unitary value of CI (very sunny days) corresponds to the maximum generable power $P_{MAX\_GEN\_PV}$. By analogy with the CI, the standard deviation $\sigma_{PV}\%$ can be assumed as function of forecasted P_{GEN_PV} (normalized to the maximum generable power $P_{MAX\_GEN\_PV}$). Therefore $\sigma_{PV}\%$ is:

- Null during the night when the generated power forecast is null ($P_{GEN\_PV} = 0\%$);
- Null during the very sunny days ($CI_{MAX} = 1$) when the maximum generable power is foreseen ($P_{GEN\_PV} = P_{MAX\_GEN\_PV}$);
- Maximum during intermediate situations represented by partly cloudy days when the generation forecast is about 40% of the maximum generable power (accordingly with the previous Figure3.1.2-4 showing the maximum standard deviation σ_{MAX} in the case of $CI \approx 0.4$).

The day with maximum clearness index $CI_{MAX} = 1$ is the one characterized by the historical maximum ratio between the actual generated and maximum generable PV power. The CI is considered constant within the analyzed day, and its value is based on the ratio “forecast / maximum generable” normalized to its historical maximum.

The maximum hypothesized value of $\sigma_{PV}\%$ is 10% $P_{MAX\_GEN\_PV}$ (according to [7]). Finally, the hourly standard deviation of PV forecast error in MW is given by:

$$\sigma_{PV\_hour}[MW] = \sigma_{PV\_day}[pu] \cdot P_{MAX\_GEN\_PV\_hour}[MW]$$

3.1.3. Forced Outage Model of Traditional Generation

The power supplied by predictable traditional generation can be affected by uncertainties due to different factors; unforeseen forced outages of thermal power plants are considered in this methodology. Hydro power plants are instead considered fully reliable (null probability of forced outage) in compliance with assumptions of the Italian Transmission Grid Code (enclosure A30[13] of [3]).

(1) Unavailability parameters of traditional generation

The adopted parameters for the assessment of the uncertainty concerning the power supplied by thermal power plants are shown in this subsection.

Remember that forced outages are here considered deterministic events until half an hour before the market gate closure. Because three MSD market sessions are present in the Electricity Italian Market (see Table), three different closure times are considered: "20.30 D-1" for day-before MSD1; "9.30 D" for intra-day MSD2; and "13.30 D" for intra-day MSD3. After these three closure times, it's necessary to consider the forced outages as probabilistic in the corresponding timeframes covered by MSD sessions.

Forced full outage probabilities are differentiated on the basis of two main different categories of thermal power plants: conventional steam turbines and natural gas combined-cycle power plants. The hourly outage probability $p_{FS}\%$ is adopted on the basis of some historical data ([8], [9]) and is shown in the following Table 3.1.3-1.

Table 3.1.3-1: Hourly probability of full forced outage per generation unit

	Combined cycle	**Conventional thermal**
Number of events/(plant · year)	16.44	12.24
$p_{FS}\%/(plant \cdot hour)$	$0.19 = \frac{16.44}{8760} \cdot 100$	$0.14 = \frac{12.24}{8760} \cdot 100$

(2) Probabilistic distribution of lost generation in case of full forced outages

Starting from the abovementioned forced outage probabilities for every market zone, the probability density functions concerning the outage of one or more thermal generation units can be calculated. This calculation is carried out for every hour in the horizon timeframe; needed inputs for the calculation of the density probability function are:

[13] Available only in Italian at the Italian TSO TERNA website: http://www.terna.it/LinkClick.aspx?fileticket=wlZHX3fTGFo%3D&tabid=106&mid=468.

- Total number of thermal generation units[14] in service N_{TOT} ;
- Total committed power generation of the thermal units $P_{GEN\_TOT}\ [MW]$;
- Outage probability p_{FS} (p.u.[15]) rate of the thermal power plants in the 24 hours of the day ahead.

The probability p_{NFS} concerning the simultaneous outage of N_{FS} units can be described as the binomial distribution:

Eq. 2 $$p_{NFS} = \binom{N_{TOT}}{N_{FS}} \cdot p_{FS}^{\ N_{FS}} \cdot (1 - p_{FS})^{(N_{TOT} - N_{FS})}$$

In order to simplify the calculation, it's reasonably hypothesized that generated power is homogeneously shared among all the units in service. The active power committed for every thermal generator is therefore:

$P_{unit}\ [MW] = P_{GEN\_TOT} / N_{TOT}$

and the total lost generation, in case of N_{FS} units out of service, is $(N_{FS} \cdot P_{unit})$.

3.1.4. Calculation of the Balancing Reserve

(1) Gaussian summation

Load, wind, and solar PV forecast errors are assumed as uncorrelated Gaussian stochastic variables; therefore, the resultant total forecast error can be considered Gaussian with a standard deviation σ_{L-W-PV} given by:

$\sigma_{L-W-PV} = \sqrt{\sigma_L^2 + \sigma_W^2 + \sigma_{PV}^2}$

With: $\sigma_L(\,LOAD\,), \sigma_W(\,WIND\,), \sigma_{PV}(\,SOLAR\ PV\,)$.

Because the forced outage probability of thermal power plants cannot be treated as a Gaussian variable, the combination with the abovementioned $"L - W - PV"$ forecast error must be carried out by means of a discrete "summation convolution." This allows assessment of the probability concerning a given imbalance between load and generation; the cumulative distribution function of this probability gives a needed balancing reserve associated with a reliability probabilistic level that is here assumed to be 95% (5% probability of mismatch between balancing requirements and calculated reserve), as shown in the example of a two-dimensional probability density function depicted in the following Figure 3.1.4-1.

---

[14] For the sake of simplicity, a whole generation plant is here considered a generation unit unless it includes different conventional and combined-cycle or gas turbine sections. In any case, the same calculation can be performed for every generator without heavy increase of time computation.

[15] p.u.: per unit.

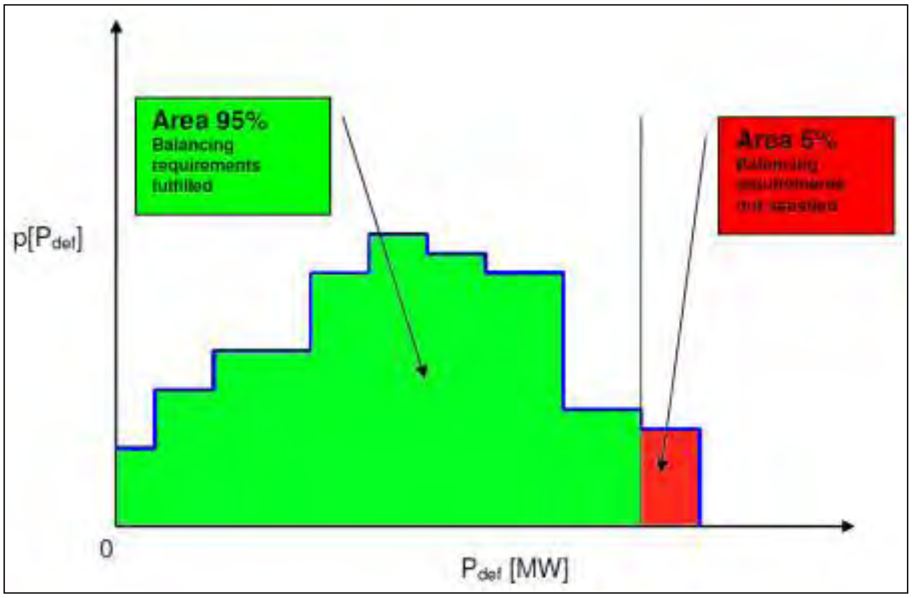


Figure 3.1.4-1: Example probability density function of the power deficit P_{def}.

(2) Convolutional summation

The final aim is not to assess the whole probabilistic density function of balancing but rather to calculate the maximum realistic level of power imbalance corresponding to the reasonable needed reserve. Therefore, the probabilistic level of 95% is reasonably chosen, but more conservative and higher coverage levels can also be considered with this methodology.

The presented methodology has been applied for the analysis of the week of July 25 to 31, 2011[16]. The following Figure 3.1.4-2 depicts the results as a summation of the six market zones: the left vertical axis of ordinates concerns the balancing reserve and the wind/solar generation, whereas the one on the right concerns the load demand. It has been hypothesized that the load demand is fully covered by thermal, wind, and solar PV power generation (conservative hypothesis with no highly reliable hydro power plants in operation).

[16] Data for load demand, wind, and solar PV generation are published on the website: http://www.terna.it/ .

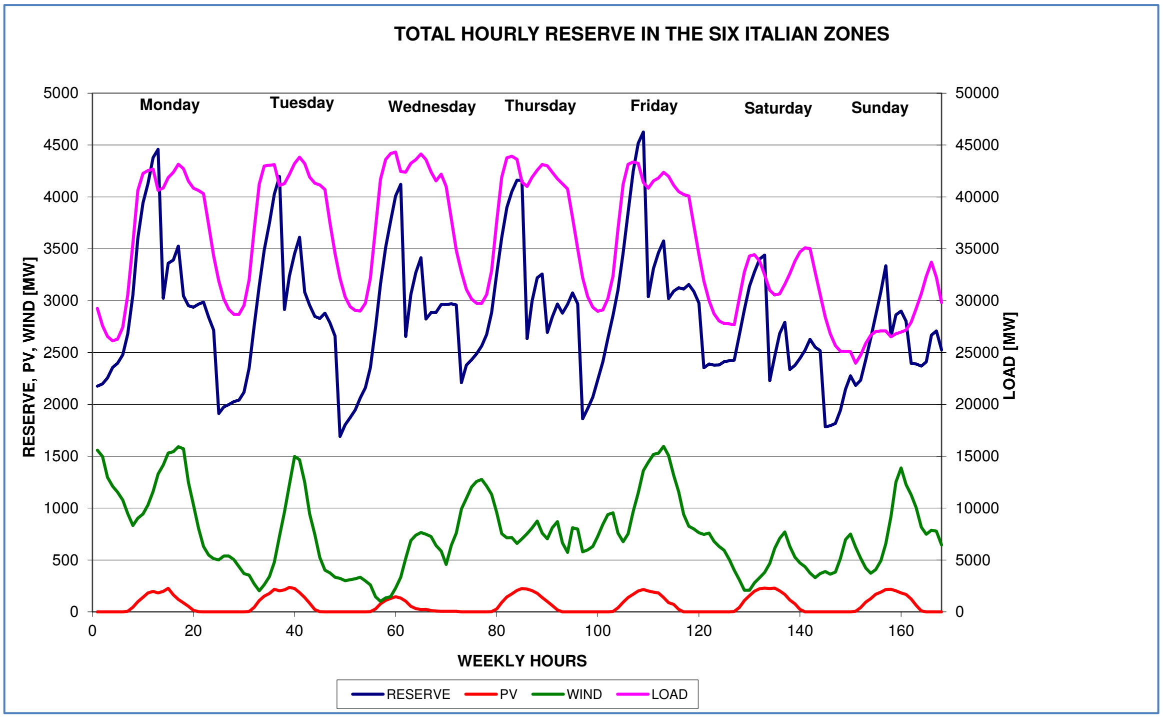


Figure 3.1.4-2: Total calculated needed balancing reserve in the six Italian market zones (July 25 to 31, 2011).

The comparison in Figure 3.1.4-3 between calculation and actual allocation shows an average calculated reserve of 2,865 MW against an average actual allocation of 3,455 MW. Despite higher and more conservative reserve calculated values in the midday hours, the reduction of the weekly average hourly reserve by means of the present methodology is 590 MW in the 168 weekly hours.

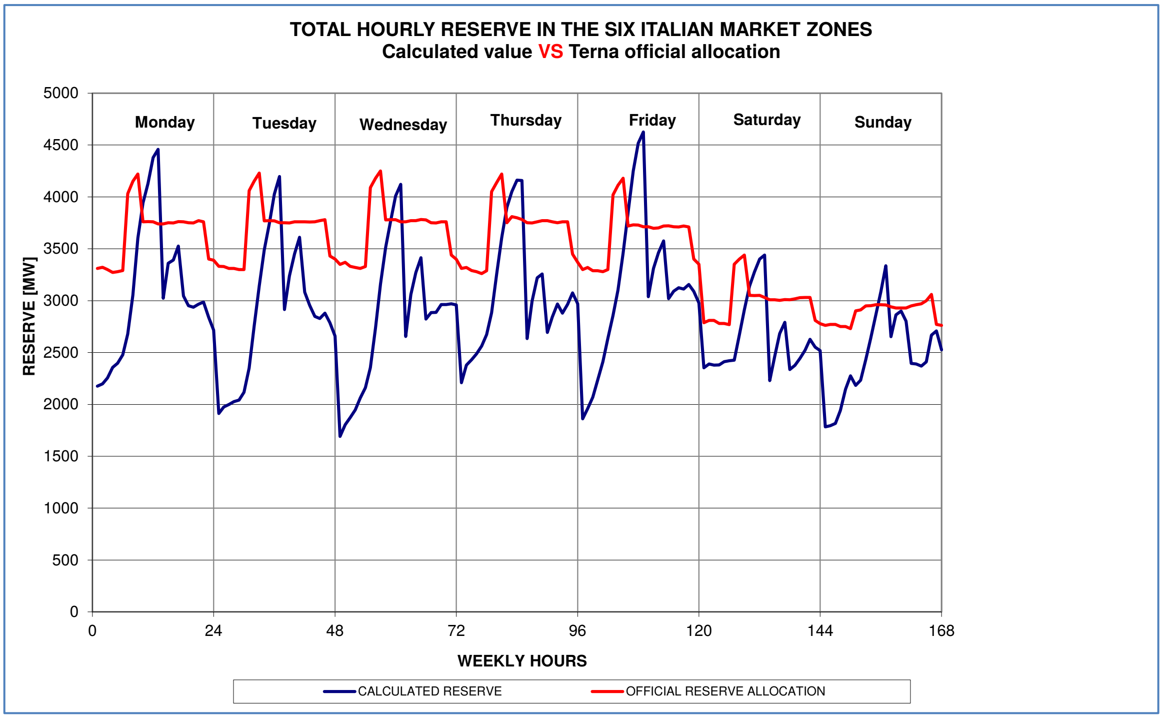


Figure 3.1.4-3: Comparison: calculated reserve vs. official allocation (Italy, July 25 to 31, 2011).

(3) Operation in a broader area

In order to reduce the impact of the variation of the renewable energy generation, it is effective to share power balancing capability in a broader area. The following Figure 3.1.4-4 shows the reduced required balancing reserve in the hypothetical scenario with unlimited transmission capacity between the six Italian market zones. It can be seen how a balancing average reduction by 25% can be reached hypothesizing the Italian area as a broader hosting market zone without internal congestions.

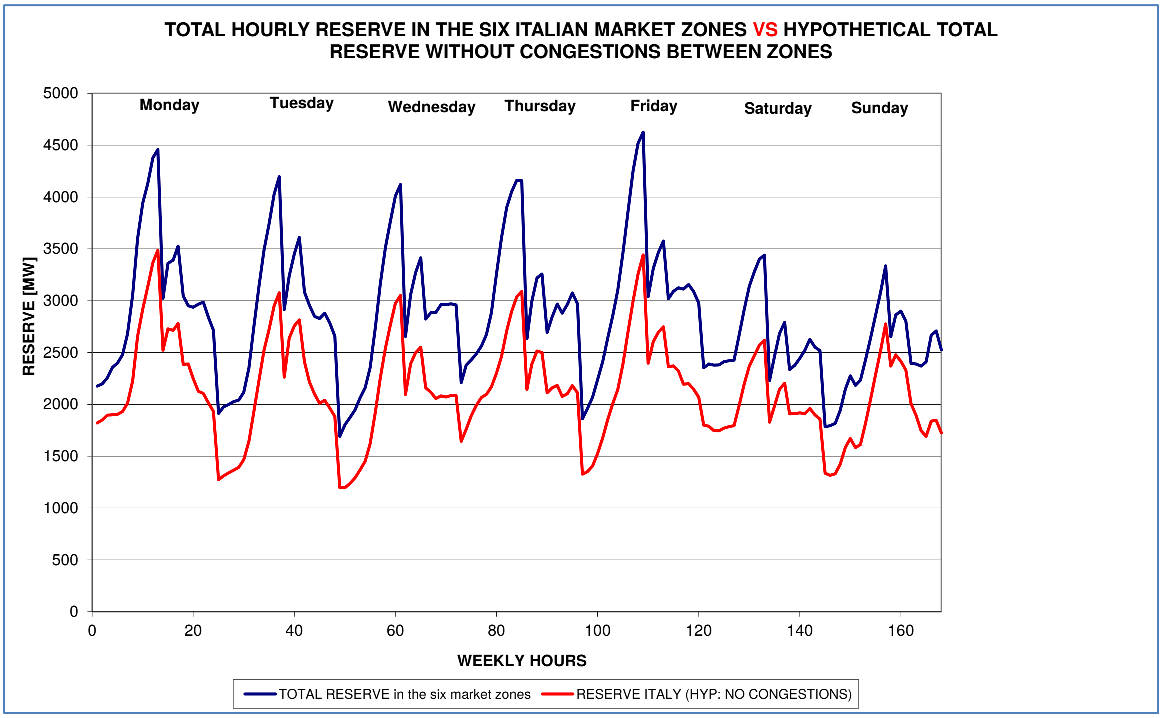


Figure 3.1.4-4: Calculated needed balancing reserve in the Italian system without internal congestions (July 25 to 31, 2011).

Finally, it's worth noting that the 90% of the PV installations are on medium/low voltage distribution levels; therefore, the PV power generation shown in Figure 3.1.4-2 is mainly included in the net load profile seen from the point of view of the high voltage transmission level. Recent data published by the Italian TSO TERNA shows a ratio of about 15 between total estimated and measured PV generation; further analyses with the larger estimated amount of PV generation need to be performed in order to clarify the influence of PV in the balancing reserve calculation, especially taking into account the large number of installations in Italy.

3.1.5. Background of the New Methodology

(1) Penetration of variable generation

In order to reduce the impacts of the variation of renewable energy generation, it is effective to share balancing capability in a broader area, in a single power system to cover a broader area, or in multiple interconnected power systems. In the case of interconnected power systems, for operation of interconnections, which are often highly sophisticated, a system operation tool has to have enough functionality to analyze their operation. Such an interconnection operation includes scheduled power flow, sharing short-term demand and supply balancing capability, and procedures in case of a failure of transmission or generation system.

With the increasing capacities of intermittent solar PV and wind power generation, the provision of an adequate level of system balancing reserve is becoming more and more crucial in many electricity systems around the word. The Italian system is characterized by an installed power of 16.6 GW of solar PV and 8 GW of wind by the end of 2012 (see Figure 3.1.5-1); 18.3 TWh and 13.1 TWh of energy were respectively supplied by PV and wind [10]. The level of renewable energy penetration is high, taking into account that in 2012 the maximum Italian load was 54 GW on July 27, the minimum load was 21 GW on January 26, and the total energy demand was about 325 TWh ([10]).

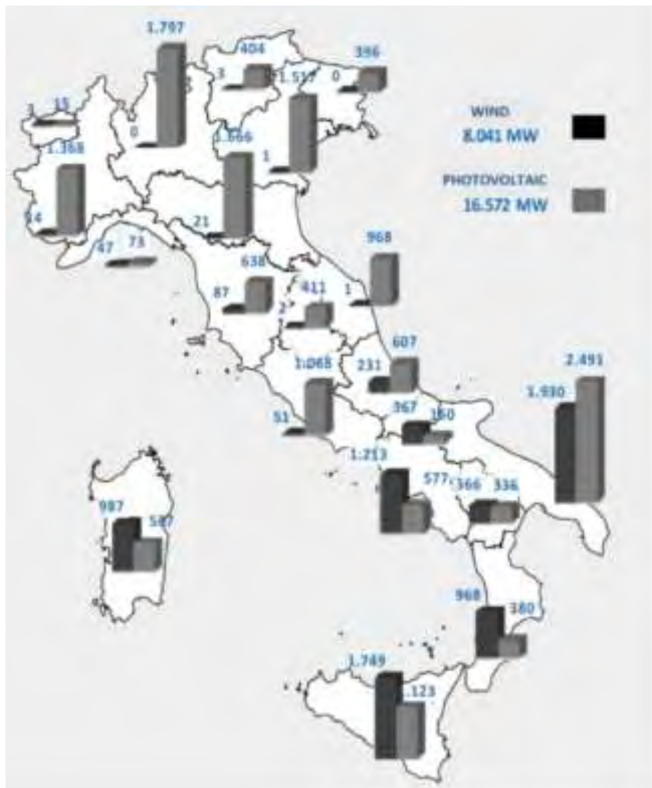


Figure 3.1.5-1: Cumulative installed wind and solar PV power in Italy (source: TERNA [11]).

(2) Italian power system market and operation

The Italian power system ([3]) is operated first in order to match the security constraints; then it is regulated by the national energy market. In particular, the Italian TSO TERNA acquires, in the Dispatching Services Market (MSD), its supply of resources for the dispatching services aimed to keep the power balance between power injection and absorption. Acquiring the abovementioned services is necessary for ensuring operation security; e.g., frequency must be maintained within the proper grid standards within strict limits around the set-point value of 50 Hz. Offers for the dispatching services are submitted on the MSD, which include one-day-ahead “D-1” and two intra-day “D” sessions. TERNA carries out the selection of the balancing quantity in both planning “D-1” and intra-day “D” phases. The acquired balancing quantity can be used in real time by TSO dispatching commands, which, in order to guarantee the power balancing, changes the working points of the participating generators whose dispatching services were offered in the MSD.

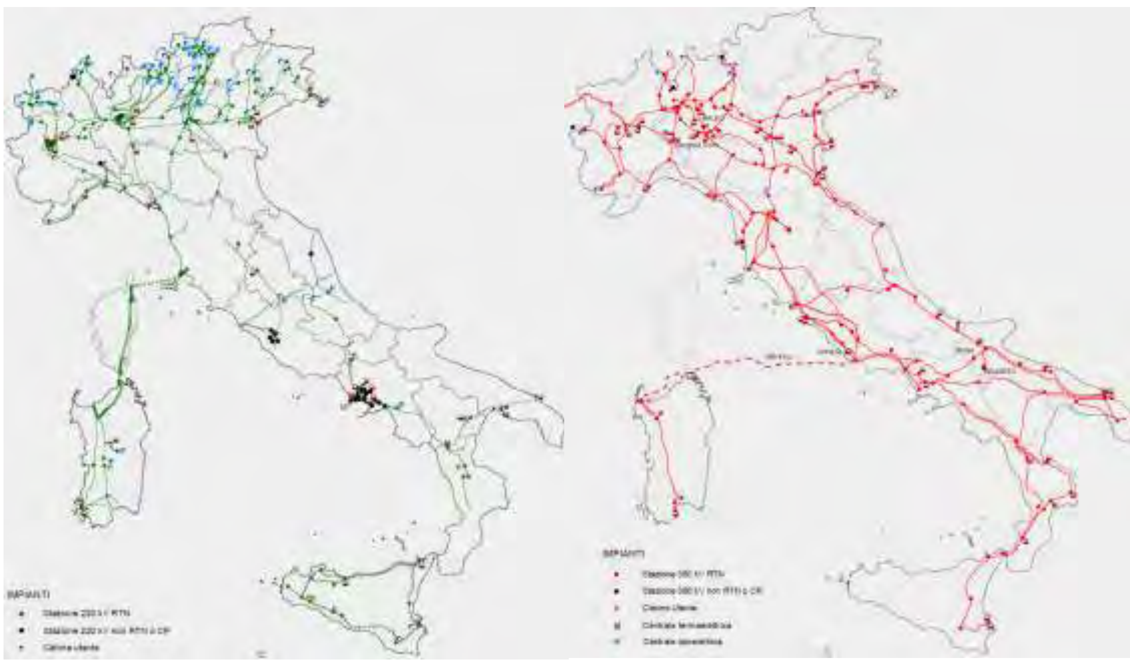
(3) Requirement of new operation methodology

An accurate approach is needed for an efficient balancing reserve assessment aimed to simultaneously: i) cover renewable energy variability, together with other uncertainty factors, for secure operation planning; and ii) limit costs for reserve allocation, avoiding excessive overestimations. It is clear that a statistical approach is needed in order to match these two requirements. The methodology proposed here was carried out in order to overcome the limits of traditional deterministic approaches that are not able to manage stochastic variables like the intermittent injections by renewable PV and wind sources. The methodology allows the calculation, with a time interval varying from four to 16 hours ahead, of a suitable power reserve margin aimed to ensure the fulfillment of load demand in case of deviations from the expected values of demand itself, wind generation, and solar PV generation, and in the case of unexpected unavailability of thermal generation due to forced outages; hydro power plants are considered highly reliable in compliance with the approach proposed by the Italian TSO[17] TERNA (*Code for transmission, dispatching, development and security of the grid*, 2012). The balancing reserve is considered adequate when, in each market zone of Italian power system (Figure 3.1.5-2), the allowable generation resources can cover the load demand for a given confidence level.

Figure 3.1.5-2: Market zones of the Italian power system.

[17] Transmission System Operator.

The identification of the market zones is carried out by the TSO stating the “critical interfaces” between areas according to the N-1 criterion[18] for different grid scenarios and different seasonal periods of the year. The subdivision in six market zones is necessary since the Italian power system is peripheral in the Synchronous Continental European Power System and it is has a quite long structure which involves limited transmission capacities especially in the central southern area, while Sicily and Sardinia islands are weakly connected with the mainland. In Figure 3.1.5-3 below, the 400-220 kV Italian transmission system is presented; the red lines represent the 380 kV level while the green ones depict the 220 kV level. Moreover, 150-132–120 kV levels are present as the sub-transmission part of the grid.



(a) 220 kV level **(b) 380 kV level**

Figure 3.1.5-3: Italian Transmission Grid (Source: TERNA).

3.1.6. Resources for Operation Planning

(1) Italy

A share of the tertiary control reserve[19] is used in order to restore an adequate margin aimed to maintain the power balance in case of sudden variation of load and of not

[18] The N-1 criterion is a rule, adopted in the Continental European Synchronous Area, according to which elements remaining in operation after failure of a single network element (transmission line, transformer, generating unit, or in certain instances a busbar) must be capable of accommodating the change of flows in the network caused by that single failure.

[19] Tertiary control reserve is any automatic or manual change in the working points of generators aimed to restore an adequate secondary control reserve used for stable system operation at nominal frequency.

programmable renewable generation, as well as in case of unexpected unavailability of thermal generation lasting more than one hour [3]. The balancing quantity, acquired by TERNA in the Italian ancillary services MSD, can be used in real time by means of dispatching commands on the working points of the participating generation plants. Main requirements [3] for these plants are:

- Connection to the transmission grid;
- Feeding by programmable energy sources;
- Regulating response delay of no more than 5 minutes after the dispatching command (power increase/decrease);
- Regulating response (power increase/decrease) of at least 10 MW within 15 minutes after the dispatching command;
- In the case of hydro power plants, a minimum ratio of 4 hours between the daily available energy and the plant maximum power.

A large amount of PV generation involves a higher net[20] load gap between the minimum value in the daylight hours and the maximum one in the evening. A share of the tertiary control is devoted to cover the fast daily net load ramps; in this case, regulating plants are asked to ensure a response gradient of at least 50 MW/min.

Looking at the above requirements, the power balancing is mainly supplied by thermal and hydro power plants; the latter are mainly located in the northern area of the national system. The increasing amount of renewable generation like PV and wind is resulting in a progressive decrease of the committed programmable units with the consequent reduction of the balancing reserve of the system. While the competitiveness of hydro power plants is indisputable, many thermal power plants are switching off. For example, on the island of Sicily (Figure 3.1.5-2), which is characterized by few operating hydro power plants, the high penetration of wind and PV makes the balancing issue very relevant: a large thermal power plant is currently kept in operation because of the need for an adequate tertiary control margin ([12]). Sicily is connected to the mainland by means of only one submarine cable, and the balancing problem is present in the hours of islanding operation due to the scheduled maintenance of this cable; in order to overcome this situation, two new submarine cables are commissioned by 2015 [11]. Moreover, a "pilot" project ([13]) was already approved by the Italian Ministry of Economic Development (MiSE) and consists of the installation in the Sicilian system of 20 MW innovative "power intensive" battery storage systems; installation of another 20 MW is already approved by MiSE for Sardinia.

In order to improve operation planning, several solutions may be implemented in the Italian system; any of them are:

- An increasingly accurate evaluation of the needed balancing reserve in order to avoid overestimation of reserve margin; the methodology presented above is devoted to this aim;

[20] Gross load minus distributed generation.

- Grid reinforcements in order to share power balancing capability in a broader area; the grid development plant of TERNA ([11]) includes projects aimed to reduce grid bottlenecks;
- Smart grid operation by means of the exploitation of new technologies able to allow energy storage/supply; the abovementioned “pilot” project ([13]) consisting of the installation of innovative battery storage systems is aimed to improve operation security in the systems of the two main Italian islands.

3.1.7. References

[1] YV Makarov, RT Guttromson, Z Huang, K Subbarao, PV Etingov, BB Chakrabarti, J Ma: "*Incorporating Wind Generation and Load Forecast Uncertainties into Power Grid Operations,*" U.S. Department of Energy, January 2010. Available at: http://www.pnl.gov/main/publications/external/technical_reports/PNNL-19189.pdf

[2] Italian Transmission System Operator TERNA: "Historical record of load forecast." Available (only in Italian) at: http://www.terna.it/default/Home/SISTEMA_ELETTRICO/dispacciamento/dati_esercizio/dati_giornalieri.aspx.

[3] Italian Transmission System Operator TERNA: *"Code for transmission, dispatching, development and security of the grid,"* 22 February 2012. Available at: http://www.terna.it/default/home_en/electric_system/grid_code.aspx.

[4] U. Focken, M. Lange, K. Mönnich, H.P. Waldl, H.G. Beyer, A. Luig: "A statistical analysis of the reduction of the wind power prediction error by spatial smoothing effects," Preprint submitted to Elsevier Science, 10 July 2001. Available at: http://www.energy-meteorology.de/35171.html#WindConferences.

[5] T.B. Scirocco, V. Biscaglia, C. Sabelli, E. Gaglioti, A. Iaria: "Integration of large wind generation in the Italian power system: security enhancement and prediction system development," CIGRÈ Session 2008.

[6] YV Makarov, R Diao, PV Etingov, S Malhara, N Zhou, RT Guttromson, J Ma P Du, NA. Samaan, C Sastry (Pacific Northwest National Laboratory): "Analysis Methodology for Balancing Authority Cooperation in High Penetration of Variable Generation," February 2010. Final report available at: http://www.pnl.gov/main/publications/external/technical_reports/PNNL-19229.pdf.

[7] Nader Samaan, Pacific Northwest National Laboratory: "Benefits of Balancing Authorities Cooperation Across the Western Interconnection," WECC VGS Subcommittee Meeting Salt Lake City, Utah, June 9, 2011. Available at: http://www.wecc.biz/committees/StandingCommittees/JGC/VGS/06082011/Lists/Presentations/.

[8] G.A. Zanetta, "Reliability analysis of combined cycle plants and concerning diagnostic techniques," RdS report no. 07005640, CESI RICERCA, Milan, October 2007. Available only in Italian language (Analisi dell'affidabilità dei cicli combinati e delle relative tecniche diagnostiche) at: http://www.ricercadisistema.it:8080/site/binaries/content/assets/rse-sola-lettura/pregresso/2007/Flessibilit__e_affidabilit__degli_impianti_a_ciclo_combinato/5a6f20b9-4f0f-4ec2-a0d7-d00feebc4fa6_07005640.pdf.

[9] Documentation of the University of Pisa Italy: "Reliability of the electric systems." Available only in Italian language at: http://webm.dsea.unipi.it/poli/materiale_didattico/Affidabilit%e0%20dei%20sistemi%20elettrici/Lezioni/Lez6%20SQDC.PDF.

[10] Italian Transmission System Operator TERNA: "*Provisional operation data of Italian Transmission System 2012.*" Available only in Italian at: http://www.terna.it/default.aspx?tabid=380.

[11] Italian Transmission System Operator TERNA: "*The National Electricity Transmission Grid Development Plan.*" Summary available at: http://www.terna.it/default/home_en/electric_system/grid_development_plan.aspx (full version only in Italian language).

[12] Italian Transmission System Operator TERNA (2012): *"Elenco degli impianti di produzione essenziali per la sicurezza del sistema elettrico – Anno 2013."* Enclosure A.27 of the Italian Grid Code available at: http://www.terna.it/LinkClick.aspx?fileticket=105540.

[13] TERNA plus: "STORAGE SYSTEMS - TERNA'S INVESTMENTS." Info available at: http://www.ternaplus.it/StorageSystem.htm.

3.2. Description of Power System Augmentation Planning Solar PV Integration Study Guide – Bulk System

3.2.1. Introduction

In the last few decades, the increasing penetration of variable generation technologies – most notably wind and solar – has required changes in the way the electricity grid is operated. The daily and seasonal variability patterns observed in wind and solar technologies present a challenge to their efficient integration into existing electrical grids. Given the complexity of modern grids, it is necessary to employ computational simulation models to fully understand the effects of introducing increasing variable generation levels, devise effective mechanisms that facilitate their integration, and optimize costs.

The design and complexity of the optimal variable generation integration model will depend on the goals of each study, as well as the levels of added solar PV capacity. Some of the study components presented in this section may be omitted for studies looking at shorter time horizons, or relatively low levels of increased solar PV penetration, for example. Before designing a solar PV integration study it's important to consider its main goals. Examples include:

- Evaluating the costs of integrating variable renewable energy source into the system
- Identifying variable renewable energy integration impacts on grid operation
- Measuring the amount of variable renewable energy the existing system can absorb before changes in operation or physical configuration are needed

This section presents a basic introduction to the principles behind designing and implementing a solar integration study based on simulation models. Task 25 of the IEA Wind Implementing Agreement[21] published in 2013 a comprehensive guide[22] to provide interested stakeholders with the best available information on how to perform a wind integration study. Although the document was created by wind experts and focuses on wind integration studies, the steps described apply also to other variable renewables, such as solar PV.

3.2.2. Study Elements

A solar integration study can be a complex process, with multiple steps and variables. Integration studies should include a description of the study methodology and its objectives. A complete description of the methodology employed is essential to

[21] Design and Operation of Power Systems with Large Amounts of Wind Power: http://www.ieawind.org/task_25.html

[22] Holttinen, H. et al. 2013. Wind Integration Studies, Expert Group Report on Recommended Practices. International Energy Agency Wind Task 25. http://www.ieawind.org/Task_25/PDF/HomePagePDF's/RP%2016%20Wind%20Integration%20Studies_Approved%20091213.pdf

correctly interpret the results. It is also important to describe other parameters and assumptions used in the study, as well, such as CO_2 caps and allowance prices, fuel prices, and incentives. Developing and following internationally standardized best practices helps improve the quality and reliability of the results, and facilitates the comparison amongst different studies.

To address the complexity, the model structure can be divided in elements corresponding to relatively independent tasks as depicted in Figure 3.2.2-1. Modularity also helps to scale down the model complexity to match actual needs. Most solar PV integration studies will follow an iterative process where a few of the steps are repeated, using outputs from certain modules to modify previous assumptions, or as inputs for other modules. The following sections describe the key study elements: 3.2.3. Input Data, 3.2.4. Scenario Development, 3.2.5. Simulations, and 3.2.6. Reporting Results.

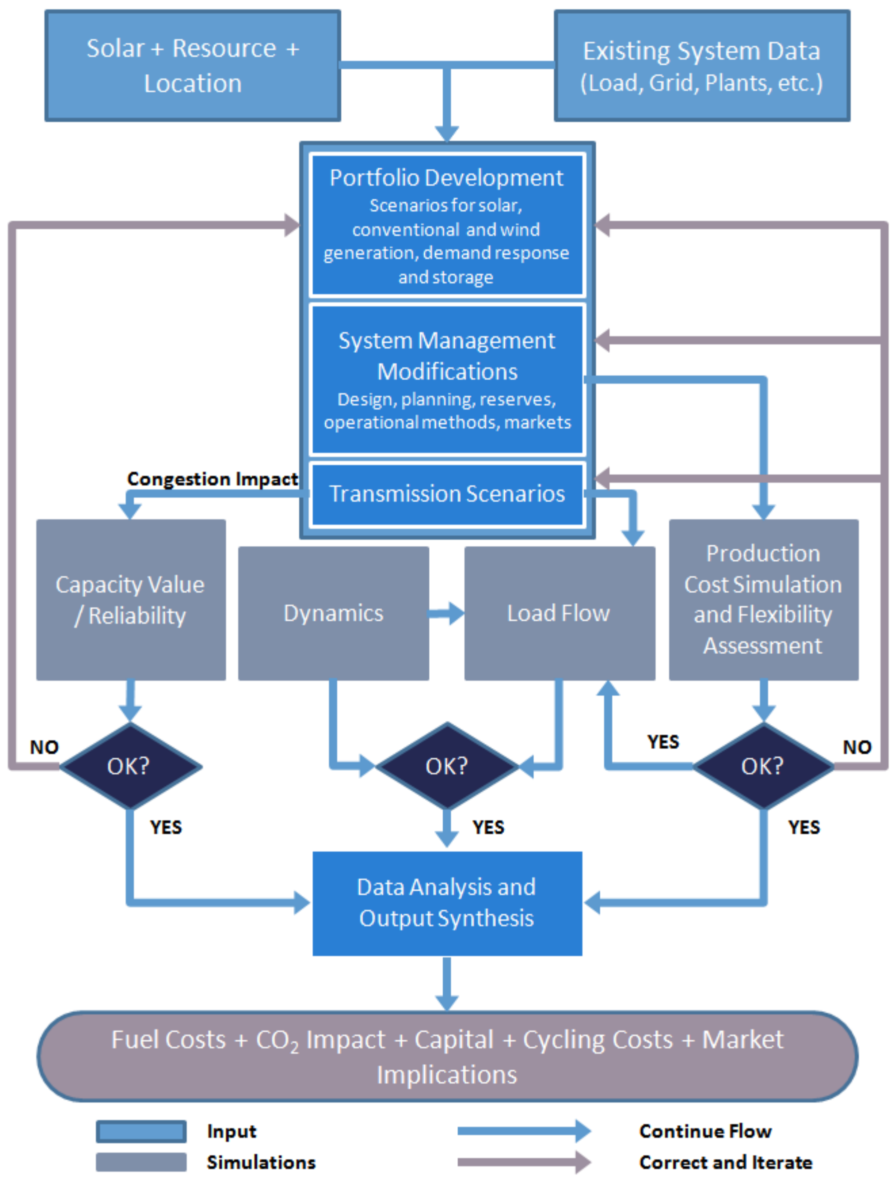


Figure 3.2.2-1: Wind integration study recommended practices diagram.

Source: Holttinen et al 2013.

3.2.3. Input Data

The quality of the model outputs will heavily depend on the quality and reliability of the inputs used, particularly for high levels of solar penetration. Initial data is needed to characterize solar PV power generation potential and location, existing and projected load, the transmission network, and the rest of the generation fleet, including non-conventional resources such as energy storage and demand response. Both load and generation data need sub-hourly granularity and must be synchronized to estimate reserve requirements and solar PV generation capacity value, and simulate unit commitment and economic dispatch.

Solar PV data can be historical, generated or a combination of the two. Regardless of the source, sub-hourly granularity (15 minutes and under) is especially important for solar data, given the fast changes in solar power output that result from cloud cover. The geographical component of the generation data is indispensable to simulate potential network congestions and the smoothing effects of spatial distribution.

Besides rated capacity, characteristics needed to accurately simulate conventional generators include outage rates, ramp rates, start-up time, and efficiency curves. Fuel costs and emission rates are necessary to account for economic and environmental impacts.

3.2.4. Scenario Development

Initial inputs are aggregated in scenarios that describe the physical and operational characteristics of the system at different time intervals. Operational practices, such as market design and reserve operations, are essential inputs in this step in addition to the transmission, generation and load input data. Results from initial iterations can be used to inform future scenarios, particularly for high levels of solar penetration.

(1) Generation portfolio and transmission scenarios

The first round of current and future scenarios is modeled using input data. The scenarios considered may be altered in subsequent iterations as more information about the system is gathered through the model outputs. Generation portfolios in future scenarios will be influenced by projected levels of new variable generation, retirements from the current fleet, changes in operational practices, etc.

During the scenario building phase, initial decisions will need to be made about how additional solar PV capacity is added to the system and what types of generators it may replace. New variable generation capacity can be added to the existing fleet, it can replace existing generation, or both, depending on the goals of the study and the level of variable capacity added. Similarly, new solar generation can be added to the system in proportion to load growth.

Load data must be synchronized with generation data, particularly variable generation. Load data is easier to generate than other synchronous data because of its seasonal and diurnal patterns.

The level of input data to model transmission will vary according to the goals of the simulation. For resource adequacy and loss-of-load calculations, the transmission grid does not need to be taken into account. Modeling only interconnections between different areas (assuming perfect transmission within each area) may be appropriate for other calculations. In regions where locational marginal prices are used, a more detailed nodal transmission model is frequently used.

(2) Operational methods

Current operational methods are usually adequate for current scenarios or simulations of low levels of solar PV penetration. For higher levels, different operational practices should be incorporated into the model to find reliable, cost-efficient alternatives. Sub-hourly scheduling, shorter notification periods, and faster and more frequent ramping of baseload generators are examples of alternative operational methods that could be evaluated with a solar PV integration model. Assessing the potential cost reductions associated with better forecasting systems can be used to limit spending on such technologies.

(3) Reserve allocations

Synchronized, sub-hourly load and generation data is needed to calculate reserve requirements. One method to calculate reserve requirements involves calculating or choosing a level of risk based on current conditions, then increasing reserves to reach the same level of risk under increased levels of solar PV penetration.

3.2.5. Simulations

After collecting input data and building the system scenarios, simulations are designed and run. Simulations show the static and dynamic relationships between different components of the system, and calculate the system's response to different operating conditions.

Modeling renewable energy penetration is an iterative process as shown in the flow diagram in Figure 3.2.2-1. Changes in one part of the system will affect the rest of the components. System simulations will reveal relationships that may not have been expected, particularly for complex systems. Analysis results can be used as a feedback for previous simulations, including the initial assumptions, especially when the results yield, for example, an unstable system, or when the impacts of solar PV integration prove costly or difficult to manage.

Optimizing integration costs is difficult because of the large number of components that are part of an electric system. Additionally, integration studies examine the system under numerous conditions that change over time. Some conditions change independently of grid operation (like technology costs), while other change as a result of grid modifications, multiplying the number of possible scenarios.

Simulations are grouped in three categories: 1) Capacity value and reliability, 2) Production cost simulation and flexibility assessment, and 3) Load flow and system dynamics.

(1) Capacity value and reliability

Capacity value is the amount of additional load a newly added generator can serve. Geographical distribution data from variable generation sources is important, since capacity values for solar PV increase with spatial diversity. Both reliability-based and approximation methods can be used to calculate capacity value of solar PV. Standard reliability-based methods include the effective load-carrying capability (ELCC), equivalent conventional power (ECP), and equivalent firm power (EFP) methods. While these methods are accurate, they require detailed system data and can be computationally burdensome and time-consuming. Approximation techniques – such as Garver's ELCC approximation, the Z method and other capacity-based methods – can be chosen as simpler alternatives (Madaeni, Sioshansi, and Denholm 2013).

(2) Production cost simulation and flexibility assessment

Production cost simulations are used to estimate the impacts of solar PV's penetration on system flexibility, operating costs and total emissions. Unit commitment and dispatch is done at this stage to test the ability of the system to meet projected demand at different time frames. To fully capture the impacts of solar PV variability, time intervals of 15 minutes and under must be considered. This will help assess the adequacy and flexibility of the system to respond to quick changes in solar output.

Usually, several iterations of the same scenario are performed to test different assumptions and constraints. Multiple operational and technological strategies can be evaluated to ease and lower the cost of adding solar PV capacity to the system. Examples of operational strategies include higher-resolution commitment and dispatch schedules, enlarging balancing areas, market rules oriented to optimize the integration of solar PV, and solar PV ramping limits. Technology strategies include improved forecast methods, solar PV output curtailment, conventional generation fleet increased flexibility, additions to the transmission network, and increased storage capacity.

(3) Load flow and system dynamics

The system dynamics and load flow simulations are performed once the production cost simulations have indicated that each scenario has adequate resources to safely integrate the chosen levels of solar generation. In load flow simulations, the impacts of solar PV penetration on the transmission grid are assessed by studying network contingency situations. This involves steady-state load flow analyses, system reliability analyses through probabilistic methods, and dynamic system stability analyses.

Load analyses should be performed to assess the system's ability to control the voltage profile, and to identify bottlenecks in the transmission system under high and low solar PV generation, as well as during shoulder periods in which new transmission loading patterns that stress the transmission network may be created. It is also important to assess the capability of the system to recover after a failure, including the largest possible failure.

Dynamic stability analyses test the ability to maintain frequency, voltage profile and synchronism when the system is subjected to small and severe transient disturbances, or major imbalances between generation and load.

3.2.6. Reporting Results

Presenting the results, goals and limitations of the study is an important part of the process. Assumptions, methods and data sources must be included to ensure that the results presented can be correctly interpreted and compared to other analyses. It is recommended to also report the levels of solar PV penetration considered, the size of the system in terms of capacity and peak load, a description of how solar PV capacity is added, the assumptions used regarding flexibility, interconnection and operational practices, as well as other considerations used such as CO_2 allowance prices, incentives, etc.

3.2.7. Differences between wind and solar variability

Solar PV variability is generally faster than wind. Large changes in wind power output typically occur during the course of hours, while solar PV changes due to cloud cover can even be measured in seconds (Bird et al. 2013). The significant, rapid ramps in the output of each PV module caused by cloud cover are mitigated by spatial diversity. Solar PV integration studies require high spatial and temporal data granularity and accuracy to assess the impacts of high frequency solar power ramps on the system.

Specific temporal resolution requirements vary depending on the study purpose. Production cost operation simulations, for example, require solar output data with a > 5-minute resolution in order to accurately calculate reserve requirements. A 5- to 60-minute resolution would be adequate to optimize unit commitment and economic dispatch (Hummon et al. 2013; Lave et al. 2013). Lave et al. (2013) summarize the effect of solar variability in different timescales:

a) *In the seconds-to-minutes timescale, variability can cause voltage regulation or power quality issues locally on distribution circuits, and can cause additional tap or switching operations on transformers or capacitors.*
b) *In the minutes-to-hours timescale, variability can increase the amount of regulating and ramping reserves required to balance the system.*
c) *In the hours-to-days timescale, variability and uncertainty can increase production cost by reducing the efficiency of generation unit commitment and dispatch.*

In the Western Wind and Solar Integration Study Phase 2, Lew et al. compared the impacts of wind and solar penetration, using sub-hourly data to account for solar generation variability. They found that even though wind and solar affect the grid in different ways (both mostly displace gas combined-cycle generation, although winds tends to displace more coal), their impacts on system-wide costs are remarkably similar (Lew et al. 2013).

3.2.8. References

[1] Holttinen, H. et al. 2013. Wind Integration Studies, Expert Group Report on Recommended Practices. International Energy Agency Wind Task 25. http://www.ieawind.org/Task_25/PDF/HomePagePDF's/RP%2016%20Wind%20Integration%20Studies_Approved%20091213.pdf

[2] Madaeni, S.H., R. Sioshansi, and P. Denholm. 2013. "Comparing Capacity Value Estimation Techniques for Photovoltaic Solar Power." *IEEE Journal of Photovoltaics* 3 (1): 407–415. doi:10.1109/JPHOTOV.2012.2217114.

[3] Bird, L., M. Milligan, and D. Lew. 2013. "Integrating Variable Renewable Energy: Challenges and Solutions". NREL/TP-6A20-60451. National Renewable Energy Laboratory (NREL), Golden, CO. http://www.osti.gov/scitech/biblio/1097911.

[4] Lave, Matthew, Abraham Ellis, and Joshua S. Stein. 2013. "Simulating Solar Power Plant Variability: A Review of Current Methods." SAND2013-4757. Sandia National Laboratories, Albuquerque, NM; Sandia National Laboratories (SNL-CA), Livermore, CA (United States). http://www.osti.gov/scitech/biblio/1089977.

[5] Hummon, M., A. Weekley, K. Searight, and K. Clark. 2013. "Downscaling Solar Power Output to 4-Seconds for Use in Integration Studies: Preprint". NREL/CP-6A20-60335. National Renewable Energy Laboratory (NREL), Golden, CO. http://www.osti.gov/scitech/biblio/1107457.

[6] Lew, D., G. Brinkman, E. Ibanez, B. M. Hodge, M. Hummon, A. Florita, and M. Heaney. 2013. "The Western Wind and Solar Integration Study Phase 2". NREL/TP-5500-55588. National Renewable Energy Laboratory (NREL), Golden, CO. http://www.osti.gov/scitech/biblio/1095399.

4. Case Studies

4.1. Australia

4.1.1. Power System

Around 90% of Australian electricity demand is in the Eastern States which now form an interconnected National Electricity Market (NEM) with over 50GW generation and peak demand of around 35GW. The NEM is one of the largest geographically connected networks in the world as can be seen in Figure 4.1.1-1. There are two much smaller interconnected systems, the South West Interconnected System (SWIS) in Western Australia and the Darwin-Katherine Interconnected System. The generation mix is predominantly coal-fired in the three larger Australian States of NSW, Queensland and Victoria. South Australia, Western Australia and the Northern Territory have predominantly gas-fired generation while Tasmania is mostly hydro generation (AER, 2012), as shown in Figure 4.1.1-2. Remote communities off the grid are predominantly located in the larger States of Western Australia and South Australia, and the Northern Territory. These communities are generally powered by stand-alone mini-grid systems running on oil or, where available, gas.

The NEM itself serves over 10 million customers with an average demand of around 24GW and non-coincident peak demand of over 40GW. All States except Tasmania are now summer peaking (AER, 2012).

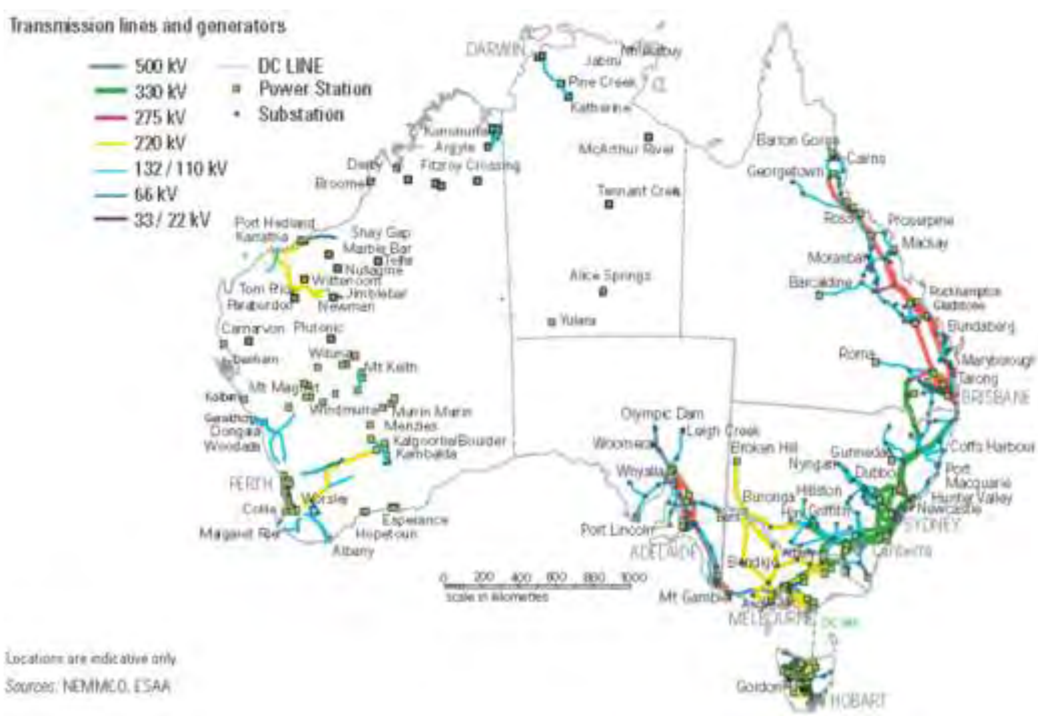


Figure 4.1.1-1: Australian Transmission systems and major generation, and larger isolated stand-alone grids (Australian Government, 2012).

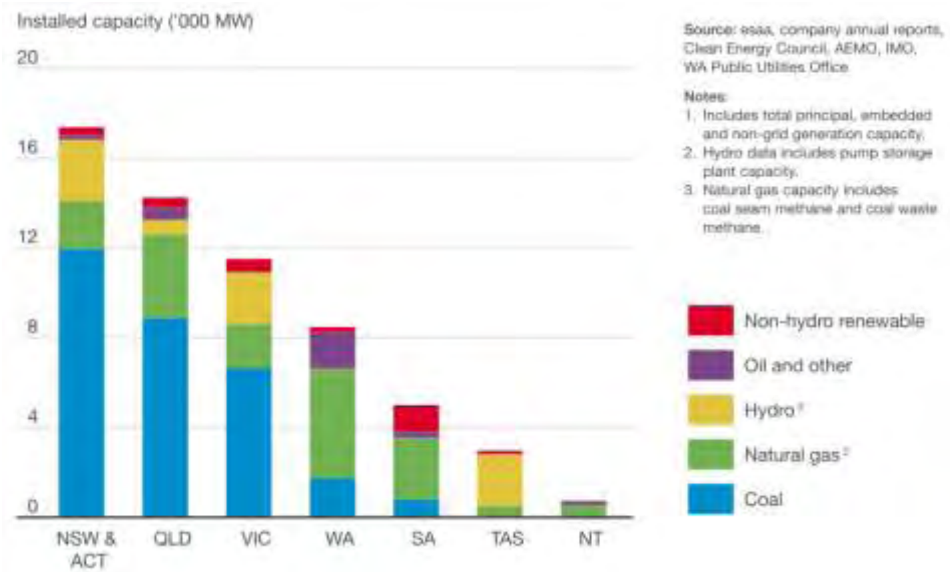


Figure 4.1.1-2: Installed major generation capacity in each State of Australia. Note that non-hydro renewables is dominated by wind in every State except Queensland which has significant biomass generation (ESAA, 2013).

4.1.2. Penetration PV and Other generation Situation

PV capacity in Australia has grown markedly over the past few years and is now an estimated 2.9GW, almost entirely due to over 1 million household rooftop systems. The current penetration of PV is shown in Table 4.1.1-1 and the remarkable growth in deployment, and the change in average system size is shown in Figure 4.1.2-1.

Table 4.1.2-1: Summary of Australian statistics for solar PV, electricity generation and demand

Statistic	Value	Year
Installed PV capacity	**2.9 GW**	**2013 [1]**
Peak load – National Electricity Market (NEM)	**31.1 GW**	**2011-12 [2]**
Peak load – South-West Interconnected System (SWIS)	**3.9 GW**	**2011-12 [3]**
Total generation capacity – NEM	**48.3 GW**	**2012 [2]**
Total generation capacity – SWIS	**6 GW**	**2012-13 [3]**
Estimated total energy generated by PV	**3400 GWh**	**2013 [1]**
Share of PV on total electricity consumption	**1.9 %**	**2013 [1, 3-5]**
Average size of PV System	**2.6 kW**	**2013 [1]**

1. Clean Energy Regulator, 2013. 2. AER, 2012. 3. WA IMO, 2012.
4. AEMO, 2013. 5. NT Utilities Commission, 2013.

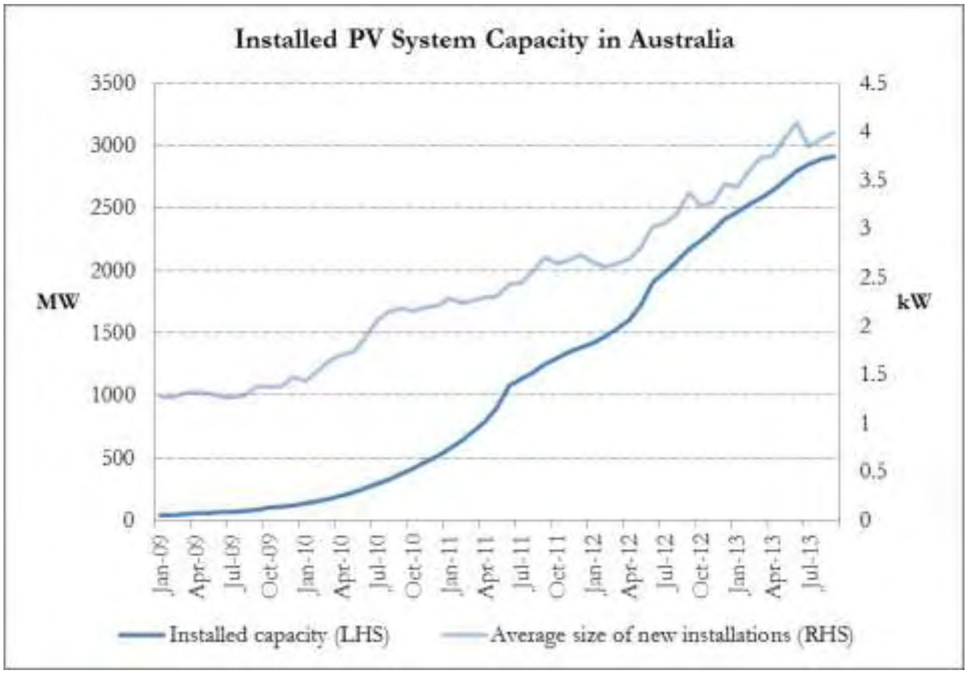


Figure 4.1.2-1: Installed PV capacity and average system size in Australia over 2009-2013.(CER, 2013).

At times of peak PV generation, instantaneous penetrations of the approximately 2.9 GW of PV installed in the Australian NEM may be of the order of 5-10%. Significantly higher PV energy and peak penetrations are seen in a number of isolated grid systems in the country.

Although total and per-capita PV capacity are not large by comparison with a number of other countries, the near complete deployment of PV as residential rooftop systems means that a significant proportion of electricity customers now have a PV system, as shown in Figure 4.1.2-2. Differing levels of PV deployment across the States has resulted from considerable variations in solar resource quality and hence system performance, but also, critically, different levels of State Government policy support including a range of PV Feed-in-Tariffs. For example, PV systems have now been deployed by around one in five electricity customers in the State of South Australia, and its contribution to energy consumption is now approaching 4% (AEMO, 2013b). A 10MW utility-scale PV project in Western Australia is currently the largest PV project in Australia, however, a number of utility scale projects totalling more than 200MW of capacity are now under development in the NEM (CEC, 2013).

Other utility generation investment in the NEM over the past five years has been predominantly for gas-fired generation (particularly Open Cycle Gas Turbines) and wind generation. Wind generation capacity is similar to that for PV and consists almost entirely of utility-scale wind farm projects. It has been largely driven by the Federal Government’s Renewable Energy Target (RET) which mandates that at least 20% of Australian electricity supply come from renewable resources by 2020. Gas generation has been largely driven by peak demand associated with the growing use of reverse cycle air-conditioning, as well as growing climate change policy efforts including the introduction of a fixed carbon price for the electricity industry in mid-2012 (AER, 2012).

The future prospects for PV deployment in Australia are unclear at present given a rapidly changing and uncertain policy context. At present, small PV systems receive some financial deployment support through the Australian Renewable Energy Target. There is also the Solar Flagships program which is intended to deliver two major utility scale PV projects within the next three years. However, previously significant State Government support for PV has almost all been withdrawn while there are a number of regulatory initiatives which might even reduce underlying deployment. However, continued significant growth in capacity is forecast by a number of industry experts (APVA/CEEM, 2013).

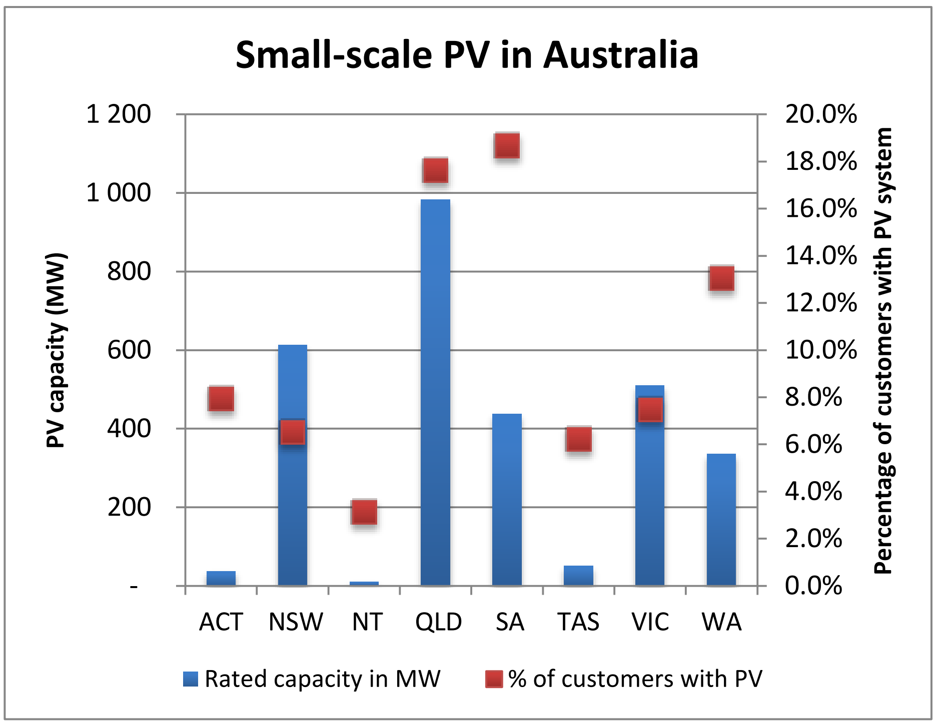


Figure 4.1.2-2: Estimated PV capacity (November 2013) and proportion of electricity customers with a PV system in each State and Territory of Australia (APVA/CEEM, 2013).

4.1.3. System operation/augmentation planning

The NEM features a wholesale energy only gross regional pool electricity spot market with linked Frequency Control Ancillary Services for regulation and contingency management. A range of derivative markets provide hedging against volatile spot prices, and long term prices to support investment.

The Australian Energy Market Operator (AEMO) has the roles of both the Independent System Operator and Market Operator. Its primary obligation is to ensure on-going system security and reliability. It therefore undertakes on-going security constrained 5/30 minute wholesale spot market dispatch, while also providing market participants with forward looking information through a range of Projected Assessments of System Adequacy looking from one week to 2 years ahead.

Generation investment within the NEM is undertaken within a competitive commercial context. AEMO does provide some guidance through an annual Electricity Statement of Opportunities with projections of supply/demand balance out 10 years ahead (AEMO, 2012). AEMO is also the National Transmission Planner. In this role it undertakes an annual National Transmission Network Development Plan which presents longer term scenarios of possible electricity demand and generation portfolios in order to guide transmission planning (AEMO, 2012b). Note, however, that this process only directs transmission investments. Such investments are taken by economically regulated monopoly network service providers within a revenue or price cap framework under the oversight of the Australian Energy Regulator Generation investment, by comparison, is meant to be undertaken by commercially focussed, private market participants in response to changing market conditions and expectations, including broader energy and climate policy directions set by State and Territory governments (AER, 2012).

Western Australia features its own industry and market arrangements including a vertically integrated utility, Horizon Power, for remote grid operation and planning. The Northern Territory electricity industry has the vertically integrated Power and Water Corporation which undertakes both DKIS and remote grid operation and planning.

A range of other stakeholders including the Federal Government, CSIRO, industry players and their associated consultants, and a number of universities have also undertaken longer-term modelling of possible future Australian electricity industry scenarios. The Federal Government has undertaken an Australian Energy Technology Assessment (AETA) of the expected future costs of a range of low-carbon generation technologies to support such modelling efforts (BREE, 2012). Government modelling has most recently been undertaken by the Climate Change Authority (CCA, 2013) in support of national emission target setting and progress reporting.

Planning arrangements have come under increasingly scrutiny in recent years given some electricity market developments that were not well forecast by market participants. Of particular importance, overall electricity demand has fallen considerably over the past five years in marked contrast to on-going forecasts of demand growth (AEMO, 2013c). Furthermore, there has been considerable investment in networks over recent years that has considerably increased retail electricity prices (AER, 2012). As discussed in the following Section, PV has been one of the drivers of these planning challenges.

4.1.4. Issues and Solution for PV penetration

As noted above, virtually all PV capacity in Australia to date is in the form of small residential systems. As such, its deployment has not fallen within the standard monitoring, operational, regulatory and planning frameworks of the NEM which are focussed on utility scale generation within the wholesale electricity market, and the associated transmission network. AEMO is now paying increasing attention to growing PV penetrations within the NEM. They now assess domestic PV as contributing significantly to the apparent fall in demand (measured as load met by large scheduled generators) in the NEM over recent years. Recent initiatives include commissioning work on potential solar PV market growth over the coming decade (AEMO, 2013c) and exploring possible extensions to their existing Australian Wind Energy Forecasting System (AWEFS) to include solar forecasting. They have also estimated the likely PV capacity generating at times of peak demand in particular regions of the NEM such as South Australia (AEMO, 2013b).

Future large utility scale PV systems will be required to participate in the NEM as semi-scheduled generation as currently seen for larger (greater than 30MW) wind farms. However, there is less clarity on how domestic PV systems (currently representing virtually all PV capacity in Australia) might be bought more formally into industry operation.

In terms of planning, the AEMO NTNDP does consider scenarios with significant deployment of PV in the longer term. However the central view 'planning' scenario which is of greatest importance to network investment decision making still includes only very modest PV deployment in the short to medium term.

Of greatest relevance to PV has been recent work by AEMO estimating the least cost 100% renewable generation portfolio for Australia 2030 and 2050. PV features very prominently in some of these scenarios, contributing from 15% to approaching 30% of total electricity supply, as shown in Figure 4.1.4-1. This study included an assessment of operational issues that suggests that 100% renewable supply of the NEM was technically feasible, although further studies would be required to confirm this finding, and distribution network issues were not considered (AEMO, 2013d).

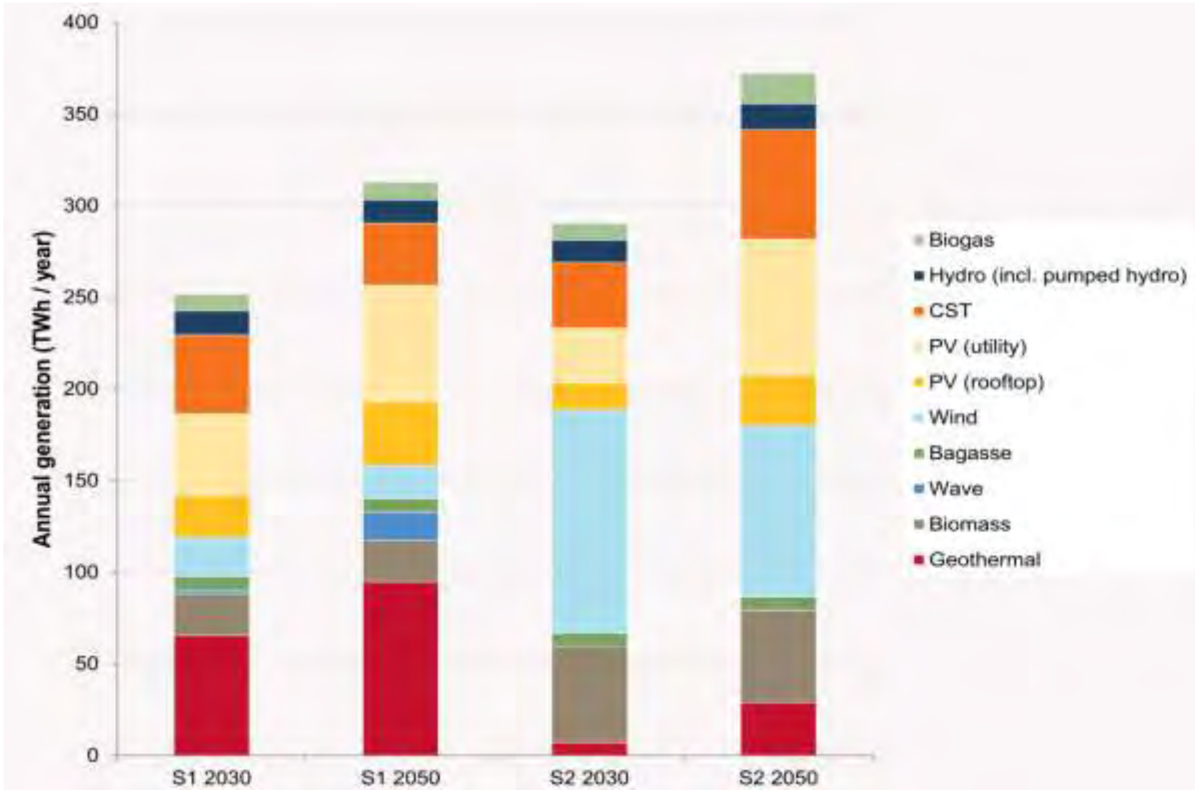


Figure 4.1.4-1: Estimated annual generation of different renewable energy technologies for a 100% renewable sourced NEM in 2030 and 2050 under two different scenarios of future economic growth and technology development progress (AEMO, 2013d).

Another least-cost 100% renewable energy study by Elliston and colleagues (2012) for the NEM provided broadly similar findings including a significant (approximately 20% contribution by energy) role for PV in the key scenarios. This study involved only hourly simulations and did not consider shorter-term operational issues.

On some remote grids in Australia, existing PV penetrations are considerably greater than seen on the main networks and have already posed some system-level operational issues as highlighted in two case studies undertaken for the power systems of Alice Springs and Carnarvon (APVA/CEEM, 2011; APVA/CEEM, 2012).

Operational issues have included incidents where frequency deviations on the grid triggered significant distributed PV shutdowns. Questions of spinning reserve strategies given significant PV penetrations have also emerged as shown Table 4.1.4-1 and Table 4.1.4-2.

Strategies have included exploring forecasting options for PV – requirements here are likely to be relatively shorter-term given the high flexibility of small gas and diesel gensets although the PV also has particularly high value given high fuel costs.

Table 4.1.4-1: Summary of Key PV System-level Experiences/Issues on the Alice Springs Network (APVA/CEEM, 2011)

PV Penetration Experience/Issue	Comment/Status
Significant tripping of PV systems during system frequency drop events.	**Previously experienced during certain system low frequency events. Steps have been taken by P&W to address this by changing inverter low-frequency trip requirements (i.e. reduced to 46Hz). This issue has been resolved for connection of future PV systems but not yet fully resolved for existing PV systems on the network. There has been no significant impact on network operation. Raises a related issue concerning the ability or otherwise of utilities to confirm and change settings for existing inverters.**
Small PV fluctuations on system net load profile due to clouds.	**Recently observed (order of close to 1MW over period of minutes). No material impact on network operation as yet. To be monitored by P&W.**

Table 4.1.4-2: Summary of key PV system-level experiences/issues on the Carnarvon stand-alone network, and current/proposed management strategies (APVA/CEEM, 2012).

PV Penetration Experience	Summary of the experience	Current/Proposed Management Strategies
PV systems impact on network stability due to inverter anti islanding protection detecting significant frequency deviations	There has been one recorded instance of multiple PV systems disconnecting due to a system wide frequency disturbance, resulting in additional load for the central generator to cover rapidly. A lack of standardisation amongst inverter anti islanding protection settings within AS4777 is also a concern.	Current: • Operating the network with sufficient spinning reserve to maintain the network if PV systems disconnect Trial: • Dispatchable load trial to increase system capability to respond to such disturbances Proposed: • Review of and PV inverter protection settings • Community solar farms with feed in management
PV system impacts on network stability due to cloud fluctuations	There have been no recorded system-wide fluctuations in load due to PV output variability. However significant	Current: • Operating the network with sufficient spinning reserve to maintain network stability with PV system

	fluctuations have been observed on a localised level. It is possible that with increased PV penetration this effect will be more evident on the supply network.	fluctuations Trials: • Cloud sensor technology Proposed: • Further monitoring of system loads and PV generation
PV system impact on planning strategies	The variability of PV system output makes it difficult to plan for system peak loads as seen by the dispatchable generation. There is also a push for more commercial sized systems to connect to the network.	Current: • Work is being undertaken on forecasting the impact of PV systems on the network load levels Trial: • Horizon Power is trialling a feed in management system for a 300kW system installed Feb 2012.
Reduction in generator fuel use	The current PV system generation in the network is resulting in a generator fuel saving which is equivalent to approximately 830 tonnes CO_2 per annum.	Benefit: • There is potentially significant value in such fuel savings depending on gas/diesel prices. The value of climate change abatement with PV is also potentially significant. By managing the spinning reserve strategy effectively and increasing the amount of PV in the system these benefits can be maximised.
Offsetting of peak summer loads with PV generation	PV generation generally corresponds well with the peak system loads implying possible deferral of network upgrades, and benefits can be further maximised by adjusting customer loads.	Benefit: • Analysis is currently being undertaken to estimate the amount that the PV systems can contribute to peak demand reduction in order to fully realise this benefit in terms of system planning

In conclusion, PV deployment in Australia to date is relatively modest at the system-level within the NEM and other interconnected systems. Nevertheless, uptake has been rapid in recent years and PV now represents around 5% of total generation capacity while PV generation is approaching 2% of overall electricity demand. In one region of the NEM, PV's energy contribution is approaching 4% and it represents above 20% of total in-State generation during some daylight periods. Australia also has a number of stand-alone grids with considerably higher PV penetrations.

Planning processes to date are still coming to terms with the particular characteristics of PV deployment and generation – notably in the Australian context, its highly distributed deployment as predominantly small (<5kW) systems over more than a million households. PV is only now being formally integrated into the electricity industry's operational and planning processes. Utility scale PV should be reasonably well managed by existing semi-scheduled arrangements that have been put in place to facilitate wind energy integration. However, the challenge for appropriately integrating small-scale systems into electricity industry processes remains considerable. Work exploring possible low-carbon electricty industry futures for Australia have highlighted the potentially major role that PV might play, highlighting the importance of further developing industry operational and planning frameworks to better facilitate effective and efficient PV integration.

4.1.5. R&D for Transmission Level Challenges

A growing range of R&D activities is underway in Australia to better understand and plan for possible future high PV penetrations. Key contributors are the Australian Commonwealth Science and Industry Research Organisation (CSIRO) which has an 'Energy Transformed' flagship, and numerous Australian universities that also have major energy research activities.

Solar forecasting*:* A number of forecasting projects are underway through Universities and the Australian CSIRO with funding support from the Australian Renewable Energy Agency (ARENA). The intent is to deliver a solar forecasting system for AEMO that provides useful PV forecasts from time-periods ranging from five minutes to two years ahead. Techniques under investigation include statistical methods, cloud vector analysis and the use of Numerical Weather Prediction models (ARENA, 2014a).

NEM operation: Work is underway to better understand how well current NEM arrangements might manage high PV and other variable renewable generation penetrations. Projects include a CSIRO Cluster project involving four Australian Universities that seeks to better understand the technical, economic, market and policy implications of a future low-carbon Australian grid (Futuregrid, 2014). Projects include modelling tools development for assessing NEM security under high RE penetrations, and another on robust policy frameworks for the future grid that is exploring how well current short-term ancillary service mechanisms are likely to fare as penetrations increase (Riesz et al, 2013a).

NEM planning*:* The CSIRO Future Grid cluster project is also investigating longer-term challenges and opportunities with PV and other variable renewables including grid planning and co-optimisation of electricity and gas networks, led by University of Newcastle, the economics of alternative network development paths and estimates of total cost and price impacts and policy measures and regulatory changes to facilitate a smooth transition to a decarbonised future grid. Other relevant work includes a joint University project funded by ARENA looking at least-cost cabon abatement for the Australian electricity industry (ARENA, 2014b).

4.1.6. References

[1] AER (2012) *State of the energy market 2012*.

[2] AEMO (2012) *Electricity Statement of Opportunities - 2012*.

[3] AEMO (2012b) *National Transmission Network Development Plan*.

[4] AEMO (2012c) Rooftop PV Information Paper.

[5] AEMO (2013) *Electricity Statement of Opportunities - Update*.

[6] AEMO (2013b) *South Australian Electricity Report*.

[7] AEMO (2013c) *National Electricity Forecasting Report*.

[8] AEMO (2013d) *100% Renewable Energy Study.*

[9] APVA/CEEM (2011) *Alice Springs PV Penetration Case Study*, available at www.ceem.unsw.edu.au

[10] APVA/CEEM (2012) *Carnarvon PV Penetration Case Study*, available at www.ceem.unsw.edu.au

[11] APVA/CEEM (2013) *PV integration on Australian Distribution Networks,* APVA/CEEM *Discussion paper and Literature Review*, available at www.ceem.unsw.edu.au.

[12] Australian Government (2012) *Australian Energy White Paper.*

[13] Australian Renewable Energy Agency (2014a) *Australian Solar Energy Forecasting Project*, http://arena.gov.au/project/australian-solar-energy-forecasting-system-asefs-phase-1/

[14] Australian Renewable Energy Agency (2014b) *Least-cost carbon abatement modelling*, http://arena.gov.au/project/least-cost-carbon-abatement-modelling/

[15] Bureau of Resource and Energy Economics BREE (2012) *Australian Energy Technology Asssessment.*

[16] Clean Energy Council CEC (2013) Large Scale PV Deployments, available at www.cleanenergycouncil.org.au.

[17] Clean Energy Regulator CER (2013) *RET postcode data October 2013*.

[18] Climate Change Authority (2013) *Targets and Progress Review Draft Report*

[19] Elliston B., I.F. MacGill and M. Diesendorf (2013) "Least cost 100% renewable electricity scenarios in the Australian National Electricity Market," in press for *Energy Policy*

[20] ESAA (2013) *Electricity and Gas Australia 2013*.

[21] Futuregrid (2014) *The futuregrid research program*, http://www.futuregrid.org.au/p/home.html

[22] NT Utilities Commission (2013) *Power System Review 2011-12*.

[23] Riesz J and I. MacGill (2013a) "Frequency Control Ancillary Services – Is Australia a Model Market for Renewable Integration?" in the International Wind Integration Workshop 2013, London, 22-24 October, available at www.ceem.unsw.edu.au.

[24] WA IMO (2012) *Statement of Opportunities Report 2012*.

4.2. China

featured by hydro/PV hybrid system with HP PV, Yushu project in qinghai, China

4.2.1. Power System

In China, there are 45,000 small hydropower plants that supply a rural population of millions. In the dry season (from October to March), these hydropower plants slow or stop production because of low water levels in the rivers. However, there is usually abundant solar irradiance in the same area, so a hydro/photovoltaic (PV) hybrid power system would guarantee a reliable power supply throughout the year. Hydro/PV hybrid power systems are mainly used in remote areas and islands, such as Qinghai Province and theTibet autonomous region in China.

In Qinghai Province, China, there is an isolated power grid in Yushu County, located far from the Qinghai power grid. The power supply relies on local small hydropower plants, and the power supply capacity is weak. Most power plants run independently; the power grid structure has not yet been formed. In 2010, the grid was powered by two hydropower plants with total capacity of 12.8 MW, but the available power in the dry season was reducedby 50%.

4.2.2. Penetration PV and Other generation

The hydro/PV hybrid power system in Yushu consists of hydropower plants, PV systems, and energy storage systems. The hydropower capacity is 12.8 MW, composed of two hydropower plants. The capacity of the PV power system is 2MW, and the total battery capacity is 15.2 MWh. The PV station connects to a 35 kV transmission line. Hydropower plants meet the load requirement during the daytime, and the 2 MW PV systems mainly used to meet the peak load electricity demand in the evening.

4.2.3. Case Study

In 2011, a 2 MWp PV power station was established in Yushu, located far from the main power grid and supplied by 12.8 MW of hydropower plants. The station connects to a 35 kV transmission line.

For the planning of the hydro/PV hybrid power system, we have considered the following aspects.

(1) Research the local power grid architecture

The Yushu power grid is standalone and located far from the Qinghai power grid. Currently, the power supply of this prefecture relies on local small hydropower stations, and the power supply capacity is weak. Among the 13 small hydropower stations, most of them have been operated for many years and their equipmentis worn out. The voltage levels of the Yushu power grid are 35 kV, 10 kV and 0.4 kV. Most power stations run independently; the power grid structure has not yet been formed.

(2) Evaluate the solar resource

In Yushu, the solar resource is very abundant; annual sunshine amounts to approximately 2,467.7–2,789.1 hours. The total annual solar radiation in Jiegu is 6.2–6.3 GJ/m^2, and the average daily solar radiation is 17–17.3 MJ/m^2. That means horizontal PV modules can fully generate electricity 1,722–1,750 hours of the year, with an average daily generation of 4.72–4.8 hours. Jiegu belongs to a solar resource rich area, which means solar energy is abundant and the area is suitable for the construction of a large PV power station.

(3) Analyze the geography of the target area

The PV power system location is in Yushu breeding stock farm. The farm is located in Batang Beach, which has an altitude of 3,860 meters and is 28 km from Jiegu in southeast Yushu. The farm is located west of Xiongqin River. The station site terrain is flat and high-lying southwest, low-lying northeast; its elevation is between 3,983 m and 3,989 m. The PV power station occupies 70,370 m^2.

(4) Research the local load situation

The Yushu power grid is divided into four areas, of which the Yushu Chengduo power grid supply ability is strongest and load is heaviest. According to the statistical data in 2007, summer peak load reached 16,500 kW, and winter peak load reached 18,000 kW. The power supply ability is 13,000 kW in summer, and 10,200 kW in winter; shortage of electricity is a very serious issue.

The hydro/PV hybrid power system structure is shown in Figure 4.2.3-1. The PV station is composed of 20 branches of 100 kWp PV systems. The total capacity of the PV module is 2 MWp. In each branch, there is a 760 kWh battery bank integrated into a DC bus, and the total capacity of the battery is 15.2 MWh. The PV station consists of three PV units, including a power controllable unit, two dual-mode PV units, and a self-synchronous PV unit.

In normal operation, hydropower plants support the power grid, and the PV power system outputs active power and reactive power in accordance with the requirement of the scheduling institute. When the grid is down, the two dual-mode PV units support the grid alone. Figure 4.2.3-2 shows aphoto of the 2 MW PV station.

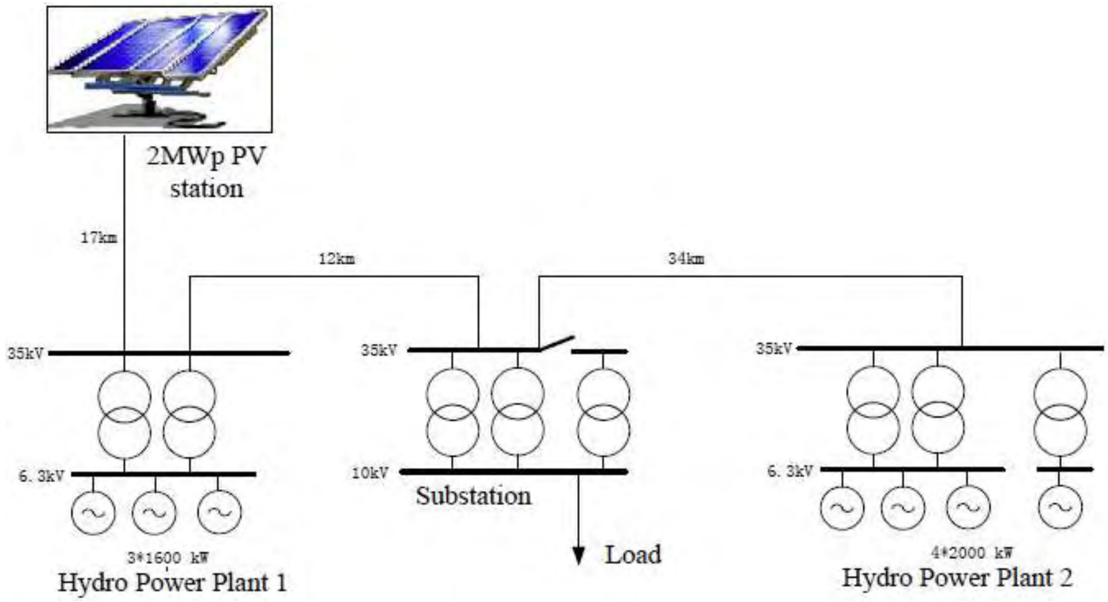


Figure 4.2.3-1: Hydro/photovoltaic hybrid power system in Yushu County [1]

Figure 4.2.3-2 : Photo of 2 MW PV station with battery in Yushu County

The initial investment cost of the Qinghai hydro/PV hybrid power system is about RMB 100 million. The annual generating capacity of this power system is nearly 3 million kWh; its lifetime generating capacity is nearly 70 million kWh. Compared with traditional power plants, the hydro/PV hybrid power system can save about 24.5 thousand tons standard coal, which saves 64 thousand tons of CO_2, 588 tons of SO_2, and 172 tons of nitrogen oxide emissions; the beneficial effect of reducing carbon emissions is obvious.

4.2.4. Issues and Solution for PV penetration

The PV penetration of the hydro/PV hybrid power system in Yushu is about 17%. The control strategy of the hybrid power system as follows: In daytime, the hydropower plants support the power grid operation;the electricity generated by the PV power station will be stored in the battery. In the peak load time in the evening, both the hydropower plants and the PV power station supply power to the grid as instructed. When power is insufficient, the load is reduced. Thus, through energy storage, the impact of PV fluctuationis decreased.

4.2.5. R&D

Some of the innovations of the hydro/PV hybrid power station are as follows:

1) With a new PV/battery system structure based on an AC/DC hybrid bus, we isolated PV shock and the power grid [2].

2) Using the strategy of active power/frequency droop control and reactive power/voltage droop control, simulated synchronous generator output characteristics, we achieved parallel operation of multiple inverters and parallel operation of inverters with other generators.

3) Indirect current control technology replaced the traditional switching mode of current loop control/voltage loop control, and we realized a smooth transition between grid-connected and standalone operation, with a transition time less than 20 ms.

4)Through monitoring the remaining capacity of the storage battery with dynamic linear programming technology, we considered the efficiency of the inverter and the battery charge state, and achieved optimal power for 20 generation branches.

4.2.6. References

[1] Wang Yibo, Xu Honghua. Research and practice of designing hydro/photovoltaic hybrid power system in microgrid. IEEE PVSC39.

[2] Wu Chunsheng, Liao Hua, et al. Voltage and frequency control of inverters connected in parallel forming a micro-grid. International Conference on Power System Technology: Technological Innovations Making Power Grid Smarter, 2010.

[3] Yang Zilong, Wu Chunsheng, et al. Research on hydro/photovoltaic hybrid generating system. International Conference on Power System Technology: Technological Innovations Making Power GridSmarter, 2010.

4.3. Germany

Since 2000 the amount of yearly new installed PV capacity increased almost exponentially and reached its historical maximum of around 7.5 GWp per year in 2010, 2011 and 2012. By the end of 2012 there were 32.4 GWp installed PV power in Germany, at that time almost one third of the total capacity installed worldwide.

Nationwide distributed, one finds highest density of PV capacity not only in the southern and northwestern part of the country, but also in many areas in east and north. Seeing PV plants on rooftops as well as larger installations on fields have become a normal part of the landscape everywhere.

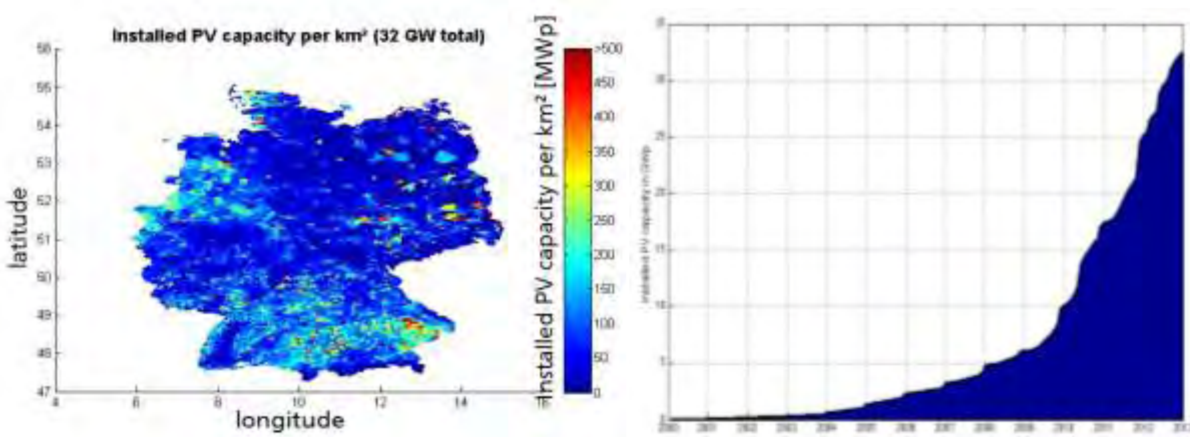


Figure 4.3.0-1: Distribution of installed PV capacity over Germany in the beginning of year 2013 and historical development of the total capacity since the year 2000.
Source: Fraunhofer IWES, 2013, data from EEG-KWK 2013.

Renewable energy feed-in tariffs above the conventional electricity price level, guaranteed for 20 years starting at the day of installation by the Renewable Energy Sources Act *Erneuerbare-Energien-Gesetz (EEG)*, encouraged investments not only from ecologically interested private households but more and more from an economical point of view. Periodic decrease in the height of feed-in tariffs for new installations manifests in peaks of augmentation before the due date as can be seen in the plot of installed capacity over time. The higher the announced reduction is, the higher the pressure to finish the installation before.

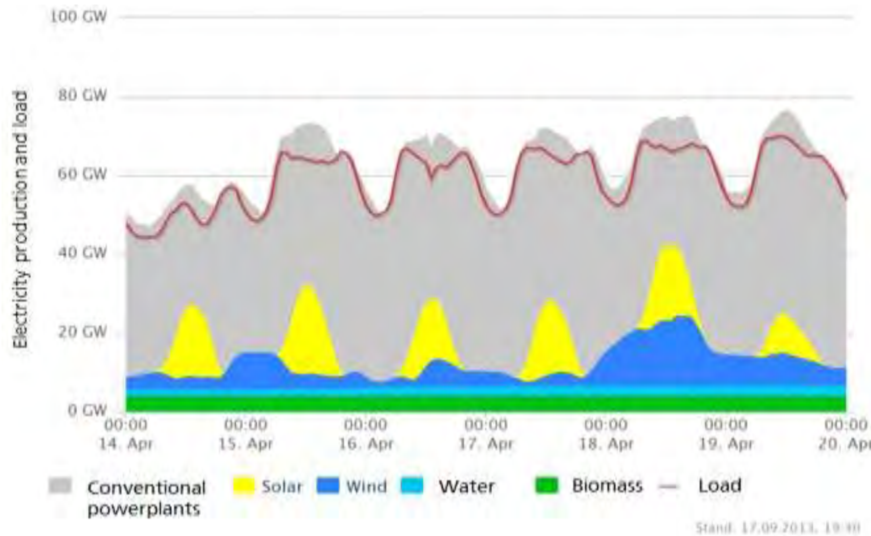


Figure 4.3.0-2: Electricity load (red) and production between April, 14th and 20th 2013 in Germany. PV (yellow) and wind (dark blue) on top of energy from running water (light blue) and biomass (green) contribute to over 50% of the peak load on April 18th.Source: Agora 2013. (Legends are translated into English)

Even before the summertime with far higher irradiation, the high available capacity of PV and wind power plants made it possible to reach a breakthrough on April 18th 2013: For the first time the peak power from PV and wind energy exceeded that produced by conventional power plants, see Figure 4.3.0-2.

4.3.1. Power System

(1) Power Industry and Market

With around 550 TWh electrical power consumption per year and a total generation capacity of around 125 GW, the German electricity market is the largest in Europe. Control energy is provided by four transmission system operators (TSOs) to secure the grid operation and its very high reliability. Very high voltage grid systems (alternating current) of 380 kV, 220kV and 110 kV deliver the electricity which is then further distributed through lower level grids. Although the distribution grid was originally built to bring the electricity from the higher grid levels to the consumers it is nowadays connected to over 70% of the installed PV capacity which stresses transformer stations and grid connections.

(2) Demand and Supply Mix

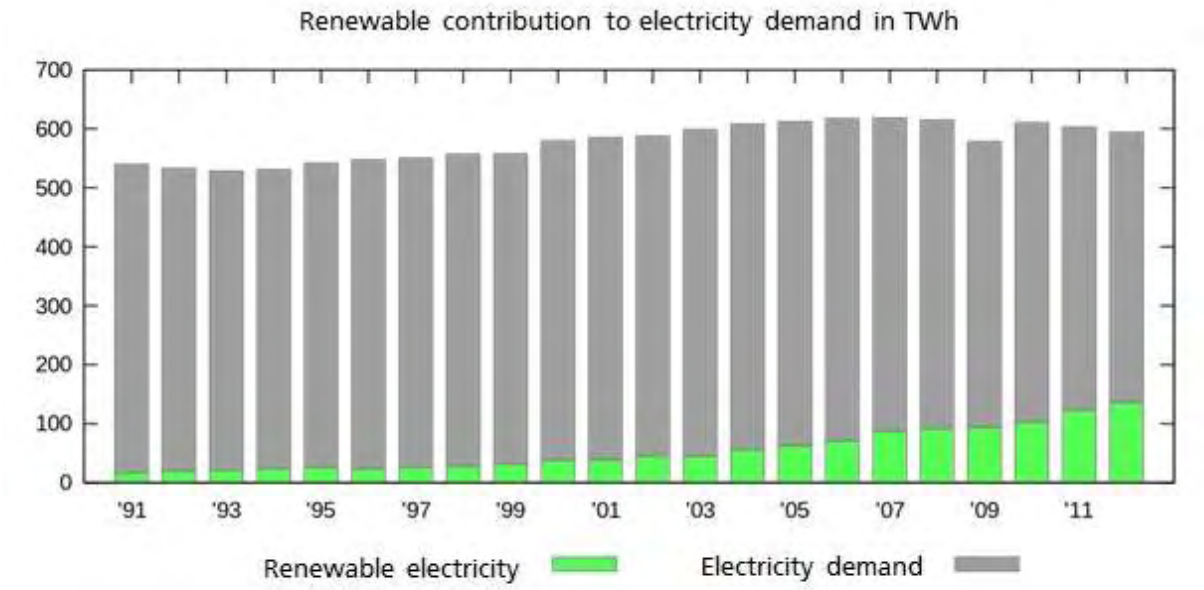


Figure 4.3.1-1: Development of German electricity supply from 1991 to 2012. Source of data: BMU 2012, image: wikipedia.de

Around half of Germanys electricity supply is still based on lignite and hard coal while especially nuclear power continuously decreases and is decided to phase out completely in the year 2022. Compared to the year 1990, where renewable energy sources shared already 3.1% of the German electricity supply mix, the development of both wind energy and PV capacity allowed to increase that portion to 16.8% in 2010 and recently to a total share of 22.9% in 2012. This portion of circa 136 TWh consists to equally parts of 1/3 biomass, wind energy and PV & hydropower.

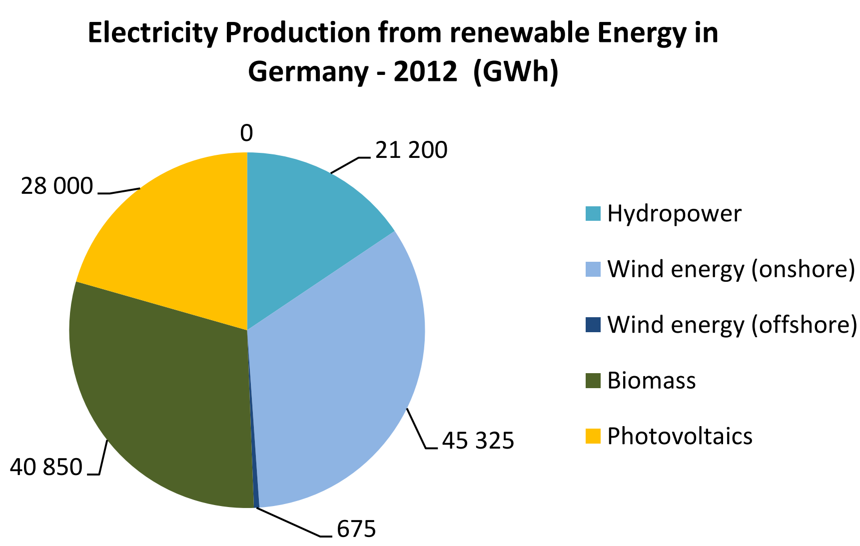


Figure 4.3.1-2: German renewable electricity production in year 2012 [GWh], Source: BMU 2013.

4.3.2. Penetration by PV and Other Generation

Together with over 30 GWp of installed wind power capacity Germany is on its way to continuously change to a higher share of electricity generated by renewables which is to reach at least 35% by the year 2020 and 80% by 2050. While the Federal Government aims in the current EEG for a total of 52 GWp photovoltaic installations, several studies discuss the available renewable energy potential and possible scenarios of augmentation to reach the political and scientific goals for the coming decades.

4.3.3. Case Study

Due to the rapid development of renewable energies in Germany there has been high interest in studies modeling future energy supply systems. Numerous studies have been conducted to predict future requirements and identify necessary adaptations to increasing shares of fluctuating feed-in from renewable energies. Amongst the most comprehensive ones are the “Long-term scenarios and strategies for the deployment of renewable energies in Germany in view of European and global developments” (BMU, 2012). Following, the major assumptions and findings of this study will be presented.

The long-term scenarios picture the development towards an energy system predominantly based on renewable energies. Until the year 2050 85% of electricity supply will be provided from renewable resources. The scenario is compliant with the German Federal governments ‘Energy Concept’ (Energiekonzept, 2010) and the subsequent energy laws of summer 2011. Both these political decisions are publically subsumed under the term ‘Energiewende’, meaning a transformation of the energy system towards renewable sources accompanied by a substantial increase in energy efficiency.

By the year 2050 the greenhouse gas emissions in Germany have to be reduced by 80% to 95% from the 1990 level. Furthermore, the Energy Concept includes a target of a 25% reduction in electricity consumption by 2050 (from 2008 final energy consumption) while a phase-out of nuclear power plants by the end of 2022 was decided in the wake of the nuclear disaster of Fukushima in 2011.

Table 4.3.3-1 shows the installed generating capacity of renewable energies according to the scenario A of the long-term scenarios. This scenario is considered the middle variant of the three main scenarios of this study. Here, the share of mileage of fully electric and plug-in-hybrid vehicles reaches 50% in 2050. Furthermore, hydrogen is applied as a chemical storage for electricity.

While the total installed capacity of renewable energies was around 55 GW in 2010 this value is expected to increase to 148 GW in 2030 and reaches 179 GW in 2050.

The installed capacity of hydroelectric will only slightly increase and also geothermal power plant will only have a small share of installed generation capacity. The use of biomass for energy applications is considered to be restricted due to competition with food and the environmental effects of the cultivation of fuel plants. Therefore, most development is predicted for the technologies photovoltaics and wind power.

Table 4.3.3-1: Installed generating capacity from renewable sources in Scenario 2011 A (capacities at end of each year). Source: BMU, 2012

in GW *)	2000	2005	2010	2015	2020	2025	2030	2040	2050
Hydroelectric	**4.24**	**4.33**	**4.40**	**4.51**	**4.70**	**4.80**	**4.92**	**5.09**	**5.20**
Wind power	**6.1**	**18.4**	**27.2**	**36.9**	**49.0**	**58.1**	**67.2**	**77.5**	**82.8**
- on-shore	6.1	18.4	27.1	33.9	39.0	41.4	43.7	48.0	50.8
- off-shore	-	-	0.09	2.94	10.0	16.7	23.5	29.5	32.0
Photovoltaic **)	**0.076**	**1.98**	**17.3**	**38.5**	**53.5**	**57.3**	**61.0**	**63.3**	**67.2**
Biomass	**1.17**	**3.12**	**6.34**	**8.08**	**8.96**	**9.48**	**10.00**	**10.38**	**10.38**
- Biogas, sewage gas, etc.	0.39	0.70	2.96	3.63	3.72	3.90	4.16	4.45	4.45
- solid biomass	0.19	1.21	2.03	2.83	3.54	3.88	4.14	4.23	4.23
- biogenic waste	0.59	1.21	1.35	1.62	1.70	1.70	1.70	1.70	1.70
Geothermal	-	-	**0.01**	**0.08**	**0.30**	**0.65**	**1.00**	**1.94**	**2.95**
EU power grid	-	-	-	-	**0.35**	**1.98**	**3.60**	**8.15**	**10.45**
- solar-thermal plants	-	-	-	-	-	-	1.20	5.15	6.55
- wind & other renew.	-	-	-	-	0.35	1.98	2.40	3.00	3.90
Total renew.power	**11.57**	**27.85**	**55.27**	**88.1**	**116.8**	**132.3**	**147.8**	**166.3**	**179.0**

*) Data until 2010 from [AGEE-Stat 2011], as of July 2011 **) for 2015 and 2020 cf. footnote 1

The resulting development of gross electricity production over time is shown in Figure 4.3.3-1. With a certain share of renewable electricity import from renewable sources abroad an overall share of electricity from renewable resources of 85% is achieved by 2050. The remaining fossil fueled power plants are highly efficient combined heat and power plants (CHP) and few flexible gas turbines.

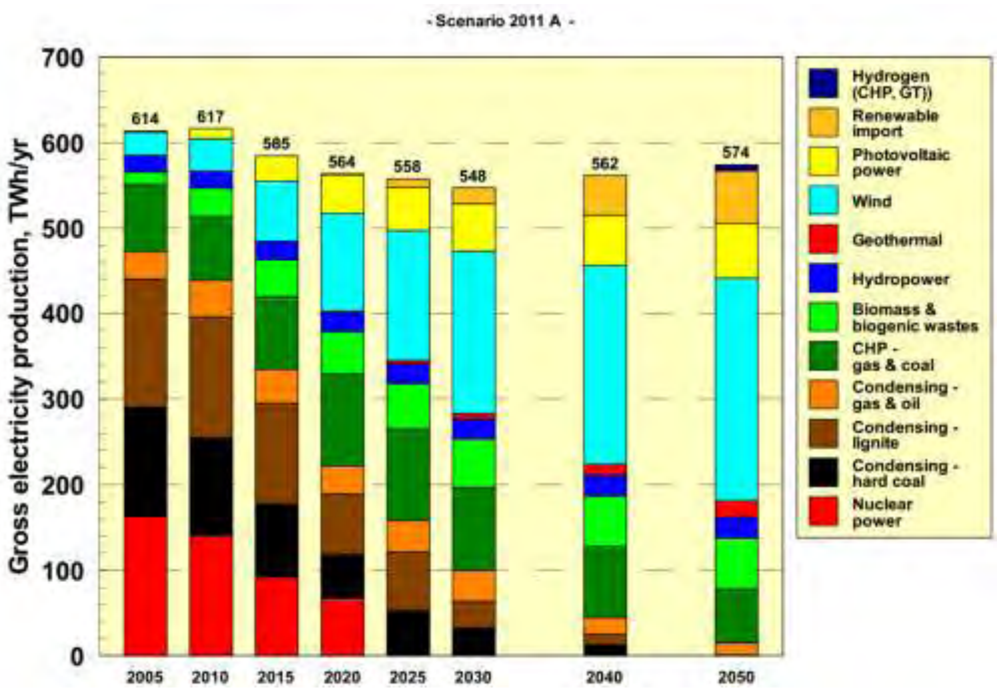


Figure 4.3.3-1: Structure of gross electricity generation in Scenario 2011 A. Source: BMU, 2012

Load balancing measures in electricity supply

The share of electricity production from the fluctuating renewable energies wind and PV was only 8% in 2010 but is expected to increase to 44% by 2030 and finally 55% by 2050.

By 2020, with an installed capacity of renewables at 117 GW, generating power from renewables will exceed electricity demand resulting in increasing need for balancing and storage options. Furthermore, a large potential for load balancing by transporting electricity through a reinforced European transmission network was identified. While this balancing option is considered to be the economically most feasible one, its realization might only be possible to a limited extent due to problems of public acceptance.

To take into account interaction between sectors and resulting flexibility options, the study does not exclusively look at the electricity sector. Under the assumption of an increased use of electric power in the sectors heating/cooling and transportation via efficiency technologies such as electric heat pumps and e-mobility these new consumers can be integrated into the power system while providing additional flexibility. In Addition, electricity production from biomass and CHP plants have to be flexibilized to avoid power feed-in from those sources at times when feed-in from wind and solar is high. Furthermore, excess energy which cannot be stored or transported to consumers via a reinforced transmission network is in this 2030 scenario predominantly used to charge pumped hydro storages.

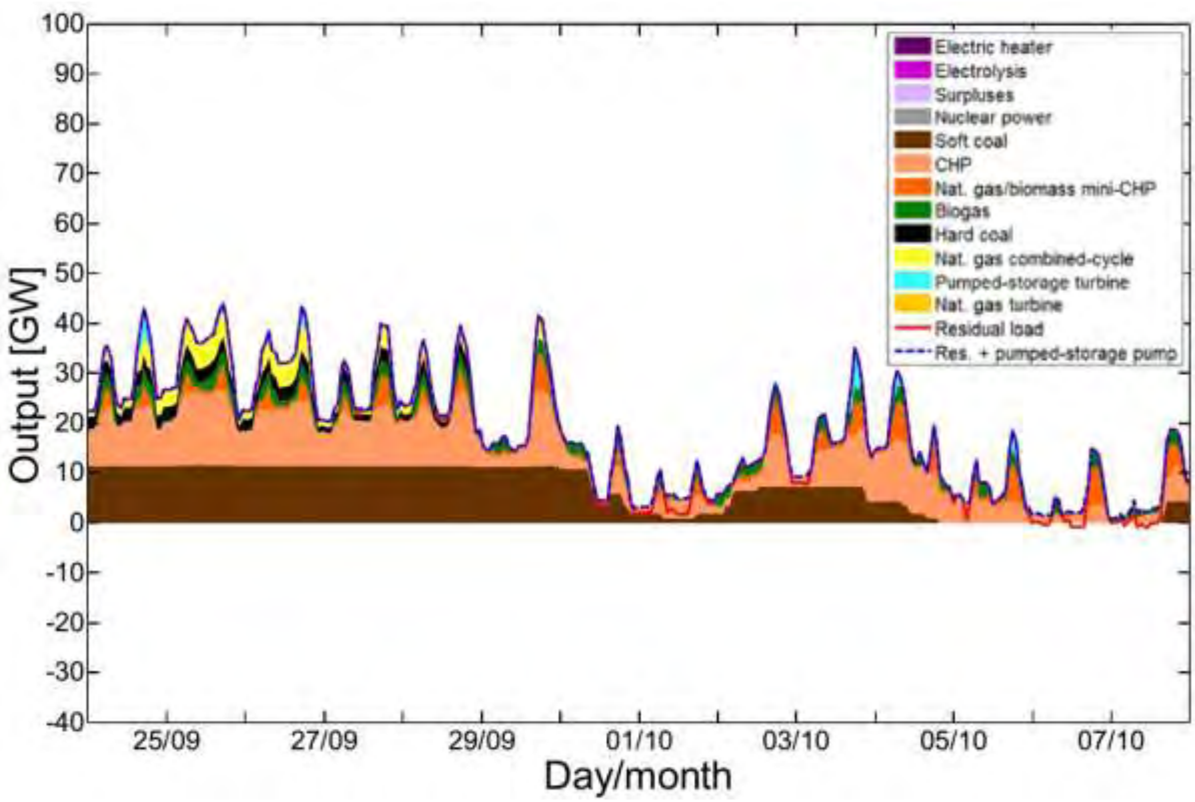


Figure 4.3.3-2: Typical course of the residual load and generation scheduling over two weeks in 2030. Source: BMU, 2012

Figure 4.3.3-2 shows the course of the residual load and resulting generation scheduling in a 2030 scenario over a period of two weeks. Due to volatile feed-in from RES the residual load curve during this period is relatively noisy with a remaining electricity demand ranging between < 5 GW and > 40 GW. However, the residual load shows an overall range between -19 GW and +53 GW in 2030 as shown in the load duration curve in Figure 4.3.3-3 (left). In 2030 a strong power grid including strong interconnection with neighboring countries, demand-side-management, flexible biomass and the foreseeable capacity of pumped hydro storage is sufficient to integrate almost all renewable generation. During the very few hours when surplus power exceeds these flexibility options the energy is used in electric heaters which are characterized by low specific investment costs. However, in 2050 excess power is expected during more than 4,000 hours, as shown in Figure 4.3.3-3 (right). To integrate this high amount of electric energy chemical storages are applied via the electrolysis of water. The hydrogen that is being generated in this way can be stored directly or after conversion to methane by chemical reaction with CO_2. The hydrogen and the methane can furthermore link between sectors and provide high temperature heat or provide fuel for long distance mobility.

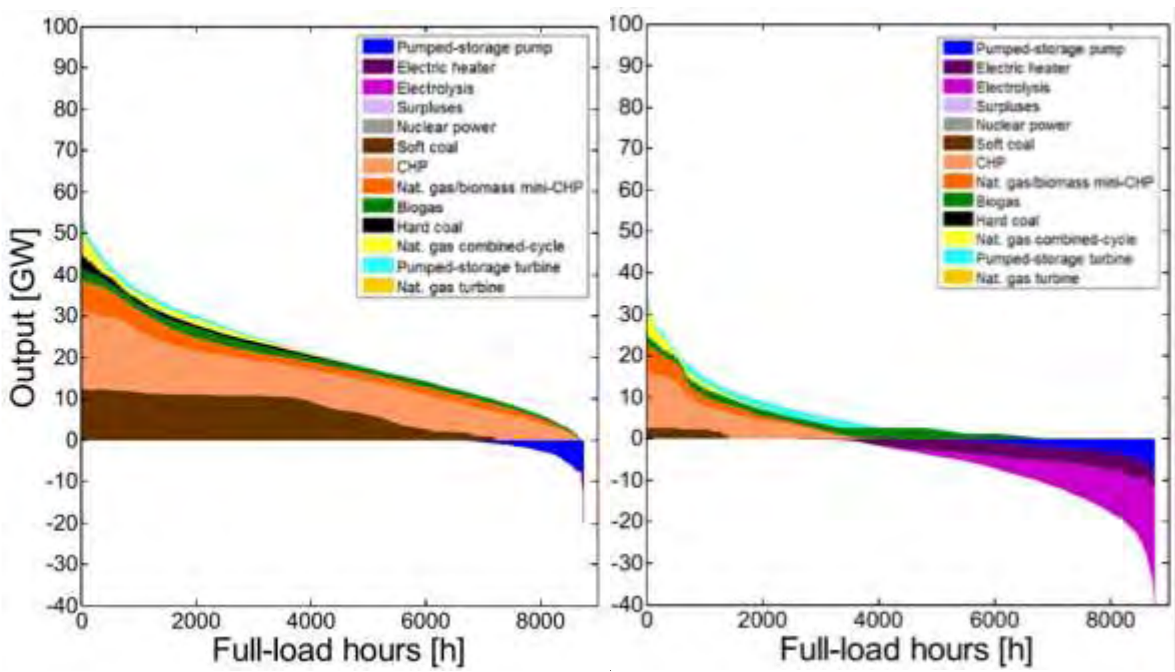


Figure 4.3.3-3: Load duration curve resulting from scenario A by 2030 (left) and 2050 (right). Source: BMU, 2012

4.3.4. Issues and Solution for PV Penetration

(1) 50.2 Hertz issue

Considering the ideal frequency of 50 Hz in the European power grid, in 2005 there was the demand to regulate the behaviour of PV-plants in the situation of large frequency deviations. As a result, all later installations would automatically switch off when a frequency of 50.2 Hz would be reached, helping to stabilize the frequency. Since the increase of installed capacity in the following years accelerated much more than could be expected one had to face the 50.2 Hz-issue, namely significant capacities switching off in a second, much higher and faster than the available reserve energy. The solution was to start the use of inverters continuously decreasing the power by 40%/Hz when 50.2Hz-situations occur. Older PV systems, around 300.000 installations above 10 kWp, were still requiring a retrofit with every single installation then having its individual, randomly chosen frequency slightly above 50.2Hz. (see also: BSW 2013, VDE 2011)

(2) Storing the surplus of energy and avoid curtailment

Energy storage is seen to be a solution for several challenging aspects of a high penetration of photovoltaics and other fluctuating renewable energy sources. Since the different applications of energy storage differ hugely, so do the requirements concerning the dimension of total capacity and temporal availability.

A joint initiative to support research and development in the field of energy storage technologies is established by the Federal Ministries of Economics and Technology, of Education and Research and for the Environment, Nature Conservation and Nuclear Safety. A budget of EUR 200 million is available to research projects concerning the storage of electricity, heat and other forms of energy within the 6^{th} Energy Research Programme of the Federal Government. (see also BMWi 2011)

To reduce the need of conventional power plants, even in times of minor availability of solar irradiation and wind, our future energy system will have to make use of a high proportion of the potential photovoltaic and wind energy expansion. As a consequence already for 2020 a significant surplus of renewable energy is widely forecast. For the period 2025-2030 it is estimated to at least 3.5-8TWh and will increase to over 40TWh between 2040 and 2050.

To smooth out short-term fluctuations stressing the local electricity grid, the combination of battery storage with decentralized renewable energy systems is focused on in the field of “batteries in distribution grids”, one of the central energy storage initiative beacon projects.

The potentials of using pumped-storage hydroelectricity (PSH) power plants as well as compressed air energy storage are analysed and corresponding methods improved. With today 40GWh capacity and 7GW power the surface-bound potential in Germany is almost exhausted. Due to that geographical dependence of PSH new projects involve the use of underground reservoirs like numerous coal mines or opencast pits.

In the range of days or even weeks the storage of energy needs to cover much higher amounts in order to compensate nationwide low feed-in of solar and wind energy. Since there exists a huge system for transmission, distribution and storage of natural gas in Germany (capacity ~230TWh), a further key topic is "power-to-gas": generating hydrogen and methane from the surplus of renewable energy and feeding that to the available gas system may allow the storage of energy up to seasonal balancing almost without significant expansions.

(3) Capability of curtailment

The shut off during periods of potential instabilities in the electricity grid is seen to be an easy and "efficient" alternative to storage. The capability of curtailment was already required for PV installations with a nominal capacity of 100kW or larger, but that changed with the amendment of the renewable energy act EEG in mid 2012. Now all new PV systems need to be able to shut off, independent of the nominal peak power. The amendment specified that, for existing systems, generators would pay half the cost of enabling curtail ability, with the other half recovered from ratepayers. Generators are compensated for any energy that is curtailed, but they are paid at 95% of the feed-in tariff rate in order to create an incentive for generators to be sited in less congested areas. (see also PVGRID 2013)

4.3.5. R&D (for Transmission level Challenges)

On the level of the high voltage electricity transmission system the typical challenges of high PV penetrations and also other renewables, like high capacities of wind in northern Germany, include a commonly higher load to transmit the energy to the centers of high demand in western and southern Germany. The expansion of transmission grid is assumed to solve that. Moreover, the often locally very high density of renewable energy source capacities leads to a highly concentrated stress on a small scale, only bothering one or several grid nodes and network connections. To handle that issue and to improve trading aspects of renewable energy the transmission system operators need better forecasts. Another aspect is the amount of reserve energy needed to balance out mismatching demand and feed-in of energy.

(1) Expansion of transmission grid

Since 2012 the German Grid Agency (Bundesnetzagentur or briefly 'BNetzA') requires a yearly 'Grid Development Plan' of the transmission grid operators which should contain all necessary expansions to ensure todays reliability in operation for the next decades. It is based on the expected development of the electricity production capacities as well as the consumption, always accounting for the medium to long-term energy policy goals of the German Federal Government. In the scenario based on the 2012 plan the expected construction necessary to manage future penetrations of renewable energy sources sums up to 3,800km of high voltage grid connections, also containing several north-south connections via low-loss, highest voltage DC. (see also BNetzA 2013)

(2) EWeLiNE Project

The German energy system is going through a fundamental change. Based on the energy plans of the German federal government, the share of power production from renewables should increase to 35 percent by 2020. Increasing the average power production from renewables to 35 percent means that in the near future, renewable energies will provide Germany's entire power production at certain times. By the year 2050, 80 percent of the total power supply in Germany should be provided by renewables. Power production from renewables is dominated by weather-dependent components such as wind energy and photovoltaics (PV). Operating a power supply system with a large share of weather-dependent power sources in a secure way, requires global as well as regional weather forecasts. The most promising strategy to improve the existing wind power and PV forecasts, is to optimize the underlying weather forecasts and to enhance the collaboration between the meteorology and energy sector. Here the development and establishment of new forecast products in decision making processes, as well as the integration of information provided by the energy sector into the weather forecast models, are of particular importance.

Fraunhofer IWES and Deutscher Wetterdienst address these challenges within the research project EWeLiNE. The overarching goal of the project is to improve the wind and PV power forecasts by combining improved power forecast models and optimized weather forecasts. During the project, the weather forecasts by Deutscher Wetterdienst will be generally optimized towards improved wind power and PV forecasts. For instance, it will be investigated whether the assimilation of new types of data, e.g. power production data, can lead to improved weather forecasts. With regard to the probabilistic forecasts, the focus is on the generation of ensembles and ensemble calibration. One important aspect of the project is to integrate the probabilistic information into decision making processes by developing user-specified products. The product development will take place in a close collaboration with the end users. To define the requirements for existing and future power forecasts, the Transmission System Operators Amprion GmbH, TenneT TSO GmbH and 50 Hertz Transmission GmbH are taking part in the project. (see also Eweline 2013)

(3) Dynamic method for setting electricity system operating reserve

In cooperation with the transmission system operator TenneT TSO GmbH, scientists from the Fraunhofer IWES intend to develop a new method to set the operating reserve on a daily basis. The advantage of this new method is the possibility to include forecasts, e.g. for the power input for wind energy and photovoltaics. With this, setting the operating reserve becomes more reliable and efficient, particularly for those electricity systems with a great amount of renewable energies. The research project runs from March 2013 to February 2015 and is supported by the Federal Ministry for the Environment, Nature Conservation and Nuclear Safety.

The transmission system operators (TSO) are responsible for a secure and reliable network operation. This includes maintaining frequency stability which is done by minimizing the imbalances between production and consumption with the help of the operating reserve. The operating reserve is divided into primary reserve, secondary reserve and tertiary reserve and these differ, inter alia, in their activation time (30 seconds, 5 minutes and 15 minutes). The essential question is how to set the operating reserve.

The amount of primary reserve for Europe is set by the ENTSO-E[23]. The secondary reserve and tertiary reserve in Germany is set on a quarterly basis by the TSO and which is modified by the Graf-Haubrich-method. The idea behind the Graf-Haubrich-method is that any different forecast errors leading to an operating reserve are combined to a total reserve distribution. This distribution is used to set the operating reserve. A disadvantage of this method is that the fluctuating power feed-in of wind and solar power leading to different amounts of operating reserve is not considered.

Setting the operating reserve on a daily basis, taking the available forecasts for the next day into consideration, could lead to a substantially lower operating reserve. The costs of secondary and tertiary reserves were around €476 million throughout Germany, so there is a huge potential for savings. In addition, critical situations such as in early 2012, when low temperatures led to an increased operating reserve, can be avoided by recognizing them at an early stage and provide operating reserve at the appropriate time, thus improving grid stability.

Therefore the project consortium, consisting of Fraunhofer IWES and TenneT TSO GmbH, intends to develop a method for setting secondary and tertiary reserves on a daily basis. In order to determine the share of the secondary and tertiary reserves in the total reserve, an automated decision for calling up the tertiary reserve is developed. Furthermore, the forecast errors of different categories of balancing groups are analyzed. These have a crucial influence on the balancing energy and thus indirectly on the operating reserve. (see also DNB 2013)

[23] (European Network of Transmission System Operators for Electricity)

4.3.6. References

[1] Agora 2013: Agora Energiewende, think tank, Berlin, Germany, www.agora-energiewende.de

[2] BNetzA 2013: creating future proof networks, Bundesnetzagentur, http://www.netzausbau.de/cln_1911/EN/BundesweitePlaene/BundesweitePlaene-node.html

[3] BMU 2012: Long-term scenarios and strategies for the deployment of renewable energies in Germany in view of European and global developments. DLR; Fraunhofer IWES; IfnE. http://www.dlr.de/dlr/Portaldata/1/Resources/documents/2012_1/leitstudie2011_kurz_en_bf.pdf

[4] BMWi 2011: Federal Ministry of Economics and Technology, 6th Energy Research Programme http://www.bmwi.de/EN/Press/press-releases,did=428778.html

[5] BSW 2013: 50.2Hz problem, activities of *German* Solar Industry Association, Bundesverband Solarwirtschaft, http://www.solarwirtschaft.de/en/activities/502-hz.html

[6] DNB 2013: project by Fraunhofer IWES & Tennet TSO, press release.

[7] EEG-KWK 2013: http://www.eeg-kwk.net/de/Anlagenstammdaten.htm

[8] Energiekonzept, 2010: Energy concept for an Environmentally Sound, Reliable and Affordable Energy Supply. German Federal Ministry of Economics and Technology and the German Federal Ministry for the Environment, Nature Conservation and Nuclear Safety. http://www.bmu.de/fileadmin/bmu-import/files/english/pdf/application/pdf/energiekonzept_bundesregierung_en.pdf

[9] Eweline 2013: project by Fraunhofer IWES & DWD, 2012-2016, http://www.projekt-eweline.de/

[10] PVGRID 2013: curtailment and storage of grid connected pv, www.pvgrid.eu

[11] VDE 2011: the 50.2 Hz problem, http://www.vde.com/en/fnn/Pages/50-2-hz.aspx

4.4. Greece

AGIOS EFSTRATIOS ISLAND MICROGRID AUTONOMOUS POWER SYSTEM ELECTRIFIED BY SOLAR PHOTOVOLTAIC AND WIND POWER

Introduction

The study deals with the design. operational control, simulation and sensitivity analysis of an autonomous microgrid with central main components consisting of Wind turbines, Photovoltaic systems, bi-directional inverters, storage of electricity to follow the load demand of the non-interconnected island of Agios Efstratios, in the Aegean sea, Greece.

This work is initiated by the project “Green Island - Ai Stratis”, which is a research-demonstration project funded by the Greek state, where mature technologies in Renewable Energy Sources (RES), storage and control will be implemented aiming to cover a very high percentage of the annual energy consumption in the island, optimally 100%.

The innovation of the project is mainly in the integration and operational control of variable renewable energy generators and storage, the appropriate management of the resources and of certain non-critical loads aiming at 100% RES contribution and not less than 85% of the annual electricity demand. The proposed system will substitute local production of the existing thermal power plant where expensive and polluting diesel fuel is being used.

To achieve this objective, the power system should be able to operate continuously with full coverage by RES, the new power system, when and if needed, should allow the synchronization of the existing conventional diesel gensets of the island to the grid formed by inverters in order to cover the deficit of electrical energy.

The new power system will use the existing grid infrastructure incorporating RES and storage units and all the necessary monitoring, control and communication infrastructure in order to maintain power availability, quality, reliability and safety respecting the technical requirements of the Public Power Corporation and the Hellenic Distribution Network Administrator which are the owners and operators of the existing electric power system on the island. This study is an updated version of a former detailed study that was elaborated by NTUA National Technical University of Athens), CRES, PPC (Public Power Corporation) and PPC Renewables, and the Aegean University, submitted to the General Secretariat of Research and Technology (GSRT) in 2009 [1], covering all planned actions within the project. An international tender for offers was launched in November 2013. The evaluation of the offers will be performed in January 2014 and the project realization will start in the first half of 2014.

The new study is focusing only on the electrification island power system, mainly due to the large cost reduction of the photovoltaic systems (three times lower than in the previous study) and more accurate solar radiation data. The modeling and simulations in the new study, deal only with the electrification system and they were performed using the HOMER [2] software.

The innovation of the project is mainly in the integration and operational control of variable renewable energy generators and storage, the appropriate management of the resources and of certain non-critical loads aiming at 100% RES contribution and not less than 85% of the annual electricity demand. The proposed system will substitute local production of the existing thermal power plant where expensive and polluting diesel fuel is being used.

To achieve this objective, the power system should be able to operate continuously with full coverage by RES, the new power system, when and if needed, should allow the synchronization of the existing conventional diesel gensets of the island to the grid formed by inverters in order to cover the deficit of electrical energy.

The project “Green Island - Ai Stratis” besides the RES the electrification system, foresees the introduction of “green transportation” (electric vehicles), heating and cooling in public buildings using renewable energy technologies and energy saving measures in buildings with the main objective of reducing dependence on fossil fuels and establishing environmentally friendly technologies. All these measures, in the long term, are expected to reduce the peak demand and the total electric energy consumed after all the interventions are in place and operating. Currently, an international call for offers was launched in November 2013 for the electrification system of the island and the realization of the project will start in 2014.

In this study the existing power system and load profile and historic data are presented, then the potential of solar and wind energy resources and the selected sites on the island are presented. Afterwards the RES Electrification power system operation approach and modes of operations are suggested. Finally, modelling, simulation and sensitivity analysis regarding the capacity of the various components, i.e. PV system, wind turbines, battery storage and energy demand, follows using HOMER software. The simulation is performed with 1 hour time step for one year, considering suggested components for the proper operation of the island microgrid and subsequently technical and economic issues are discussed.

4.4.1. Power System

(1) Description of the existing power system

Agios Efstratios is a small island located between Lesvos and Limnos in the middle of the Aegean Sea. The island is currently powered by a conventional power station with 5 light diesel fuel gensets, two units of 90 kW nominal power, with a technical minimum power of 45 kW, and three units of 220 kW nominal power, with technical minimum power of 110 kW. The power station is managed by the Public Power Corporation which the main electricity utility in Greece. There is an aerial Medium Voltage (MV) grid (at 15 kV) for power distribution from the power station of the island which is located 200 meters south of the island village. The total length of the MV Cu wires (3X35 mm^2), used for the MV network is about 9 km, including all branches. The installed capacity of the 8 MV/LV (at 380 V) transformers is 825 kVA, the larger distribution transformer power being 250 kVA and the smaller 25 kVA. The MV network is not grounded. In Figure 4.4.1-1, a rough diagram of the Medium Voltage network is presented.

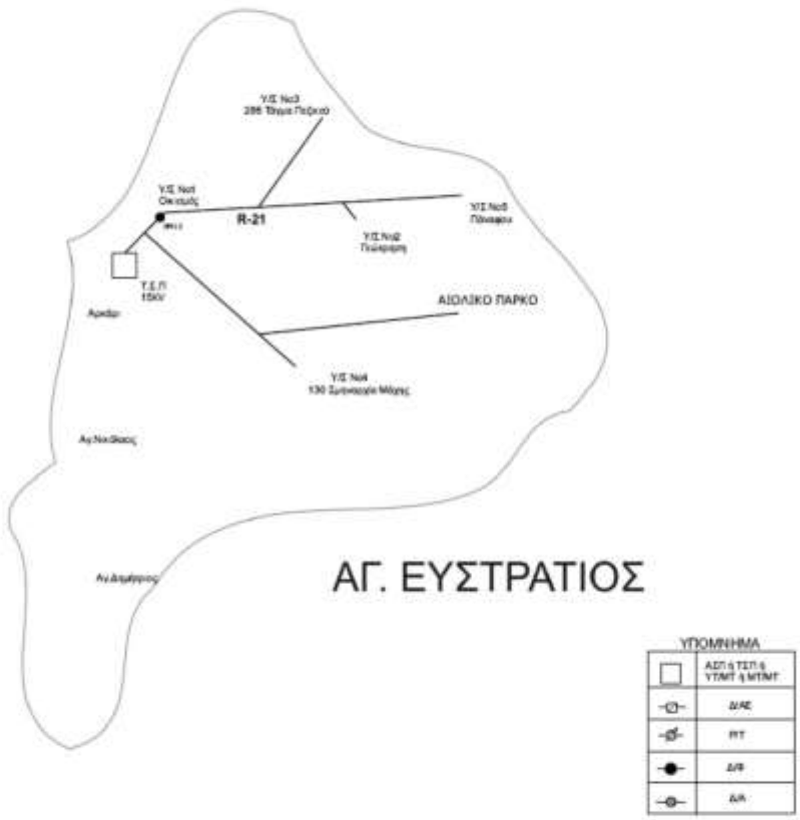


Figure4.4. 1-1: Rough diagram of Medium Voltage network of Agios Efstratios.

The permanent population of the island is 210 Inhabitants (December 2004 local census). The population of the island at least doubles for 1-2 months, during the summer months of July and August. Table 4.4.1-1 presents the historic data for peak hourly annual load and the annual energy consumption. The historic up to the year 2009 rate of peak power demand was increasing by about 4% and the historic capacity factor was 35-40%.

The peak power demand occurs on August. In the past 2 years the peak load and annual consumption is not developing as estimated before the economic crisis in Greece, therefore for 2011 and 2012 both the annual consumption and the peak load have decreased below the 2010 values. The variable cost for electricity production for Agios Efstratios in 2010 was 225 Euro/kWh [3] a year of lower international prices for diesel fuel compared to 2008 and 2012-3.

The fixed cost for electricity is expected to be reduced due to the automated operation and the dismantling of 2 diesel thermal units of the local power station which will give place to the hydrogen powered generators.

4.4.2. The Case Study

The project "Green Island - Ai Stratis", which is a research-demonstration project funded by the Greek state, where mature technologies in Renewable Energy Sources (RES), storage and control will be implemented aiming to cover a very high percentage of the annual energy consumption in the island, optimally 100%.

The innovation of the project is mainly in the integration and operational control of variable renewable energy generators and storage, the appropriate management of the resources and of certain non-critical loads aiming at 100% RES contribution and not less than 85% of the annual electricity demand. The proposed system will substitute local production of the existing thermal power plant where expensive and polluting diesel fuel is being used.

To achieve this objective, the power system should be able to operate continuously with full coverage by RES, the new power system, when and if needed, should allow the synchronization of the existing conventional diesel gensets of the island to the grid formed by inverters in order to cover the deficit of electrical energy.

As part of other activities of the project "Green Island - Ai Stratis", intending to reduce dependence on fossil fuels used, it is planned to introduce heating and cooling systems in the public buildings, using renewable energy technologies (solar thermal and ground heat geothermal) and energy saving measures. The introduction of such systems is expected to increase the annual electric energy demand and the peak load but in the long term the overall efficiency and emissions will be lower.

The new power system will use the existing grid infrastructure incorporating solar PV, wind energy and storage units and all the necessary monitoring, control and communication infrastructure in order to maintain power availability, quality, reliability and safety respecting the technical requirements of the Public Power Corporation and the Hellenic Distribution Network Administrator which are the owners and operators of the existing electric power system on the island.

(1) Sites and potential for wind turbines and solar PV systems

The sites for the installation of the wind turbines and photovoltaic system were selected according to the resource potential, the proximity to the existing MV network, the minimum possible aesthetic interference with the island natural environment and architecture and the possibility to lease the land at reasonable cost. The sites that fulfill all the above requirements are now selected and private contracts for use have been signed between the owners and the mayor of the island. The sites are presented in Figure 4.4.2-1, in white circles for wind turbines and in white polygones the land parcels for the PV system. The white arrow indicates a small wind turbine (20 kW) already installed by CRES, at geographical coordinates: 39 31' 12''N, 25 00' 36''E.

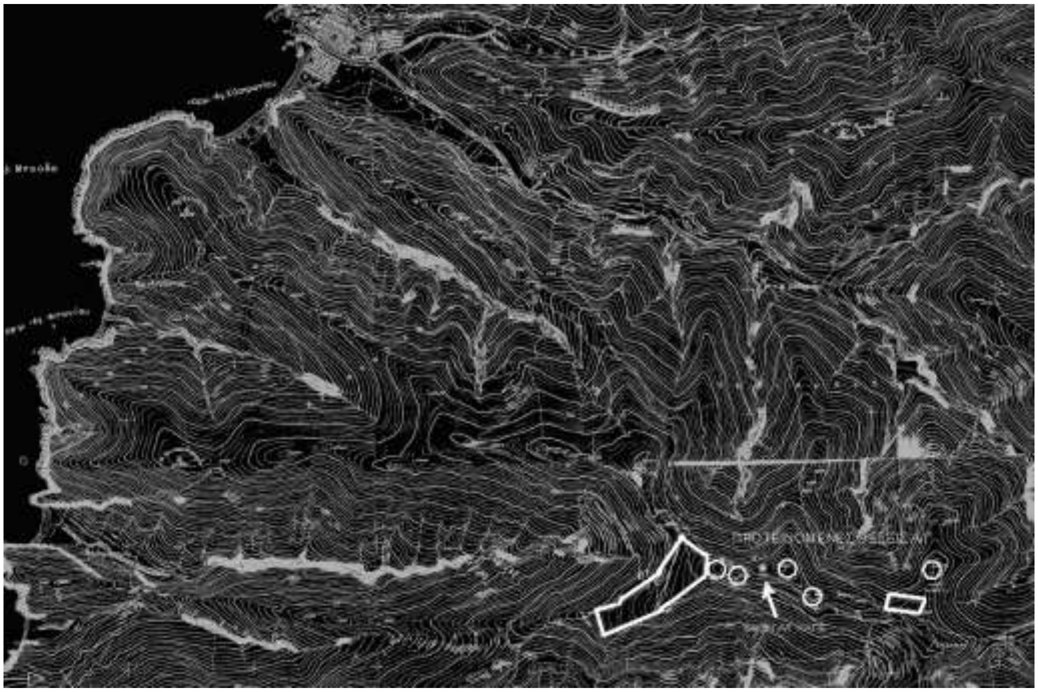


Figure 4.4.2-1: Possible sites for wind turbines in white circles and land parcels for PV system in white polygones. The white arrow indicates a small wind turbine (20 kW) already installed by CRES.

The electrical connection of the wind turbines and the PV system will be carried out on the existing MV network of the island (15kV/50Hz), through the nearby MV overhead line. The distance of the selected sites from the MV line ranges from 50m to 600m, approximately.

The selected position for the installation of the PV system is next to the sites of the installation of the wind turbines (see Figure 4.4.2-1). Each wind turbine will be connected at the 15kV grid through its own substation and switchgear. Possible connection of the wind turbines through a common substation may be considered if there is no reduction on the reliability and the performance of the installation. The same requirements are valid for the grid-connected PV system.

(2) Wind resource

The wind resource was measured for almost 2 years at the site of the already installed small wind turbine by the Wind department of CRES, at a height of 10 meters above the ground. The mean annual wind speed was calculated to be 9.1 m/s for the measurement period. All the measured and deduced wind parameters by the Wind Department of CRES are presented in Table 4.4.2-1 and in Figure 4.4.2-2, the main wind directions and probability of wind speeds per directions as well as the mean wind speed variation over the monitoring time period.

Table 4.4.2-1: Time period of wind measurements and deduced parameters for 2 years at the site of the already installed small wind turbine by CRES at a height of 10m (source: CRES Wind Department).

Measurements Period : from 1/10/2011 to 31/10/2012		
		WindRose ver.4.08-6.06
Mean Wind Speed (at 10m height)	9.1 m/s	
Mean Turbulence Intensity (at 10m/s)	11.0 %	
Max. 10min Average Wind Speed	31.2 m/s	(6/1/2012 13:40)
Maximum Gust	43.6 m/s	(6/1/2012 17:00)
Uncertainty of Wind Speed measurement	0.2 m/s	
Mean Wind Power and Total Wind Energy	941.3 Watt/m²	7777.5 kWh/m²
Autocorrelation coefficients	0.940 (1-hour)	0.986 (10min)
Weibull Distribution constants		
shape factor (k)	1.76	
scale factor (C)	10.2 m/s	
Total number of valid data	49576	
Included number of calms (<2m/s)	2212 (4.5%)	
Missing data	7592 (13.3%)	
Best Sector in Energy contain	NNE 55.21 %	
2nd best Sector in Energy contain	NE 14.03 %	
Best Sector in Time distribution	NNE 30.51 %	
2nd best Sector in Time distribution	N 11.21 %	

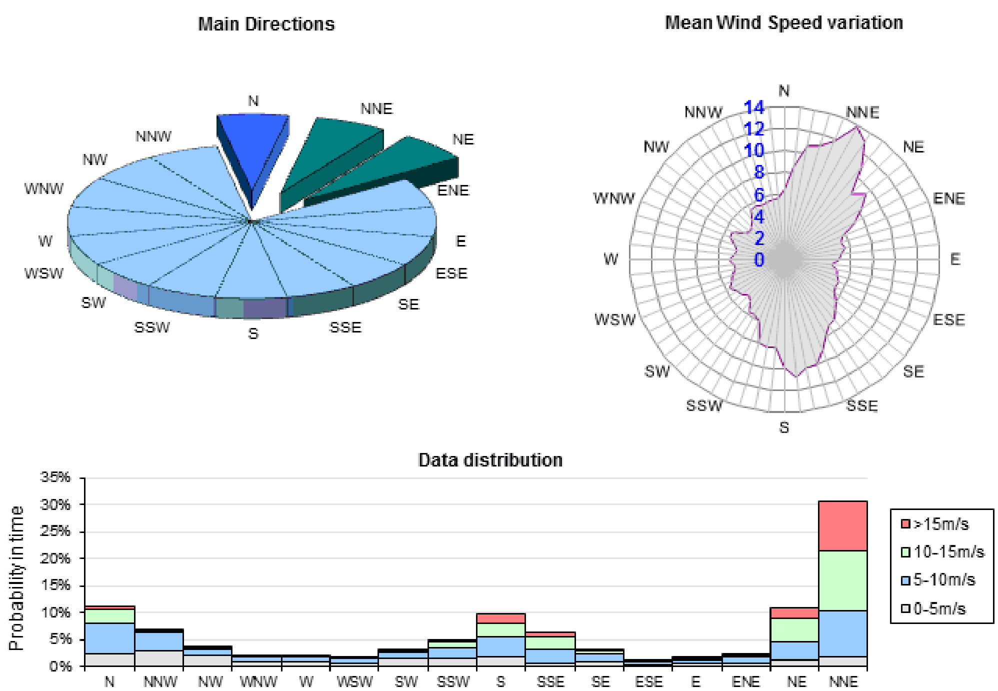


Figure 4.4.2-2: Main wind directions and probability of wind speeds per directions, mean wind speed variation over the time period of 2 years at the site of the already installed small wind turbine by CRES at a height of 10 m (source: CRES Wind Department).

(3) Solar Irradiation Resources

The main parameter for the estimation of the energy yield of a PV plant is the good estimation of the meteorological data of the installation site.

For the estimation of the solar irradiation of the selected site, the geographical coordinate was used as the main input in the database CM-SAF[24], available at the PVGIS website of European JRC[25], Institute for Energy and Transport. Through this web tool the mean monthly values of global horizontal irradiation can be derived for a given location. These mean values refer to a 12-year period, from 1998 to 2010. The estimation of solar radiation at ground level for the CM-SAF database is based on data from satellites. The database has been created through processing of images taken by satellites and measurement of reflected light from Earth, performed by CM-SAF. The CM-SAF dataset has been tested extensively against high-quality ground measurements (pyranometers), with the annual error claimed to be less than 5%. The spatial resolution of the database values is 1.5 arc-minutes (or about 3 by 3 km right below the satellite).

The meteorological data which were used concern the following coordinates:
Longitude: 39°30'51" North,
Latitude: 25°0'39" East,
Elevation: 204 m

The results from the processing by PVGIS are presented in Table 4.4.2-3 and in Figure 6. Hm is the average sum of global irradiation per square meter received by the modules of the given PV system (kWh/m^2).

---

24 (The Satellite Application Facility on Climate Monitoring)
25 http://re.jrc.ec.europa.eu/pvgis/apps4/pvest.php

Table 4.4.2-2: Monthly and Total Annual in-plane irradiation for fixed angle PV system, inclination=31 deg., orientation=0 deg., at the above selected site.

Month	**H_m** in kWh/m^2
Jan	85.7
Feb	106
Mar	163
Apr	188
May	223
Jun	228
Jul	242
Aug	237
Sep	197
Oct	155
Nov	105
Dec	82
Total Global Irradiation per year in kWh/m^2	**2010**

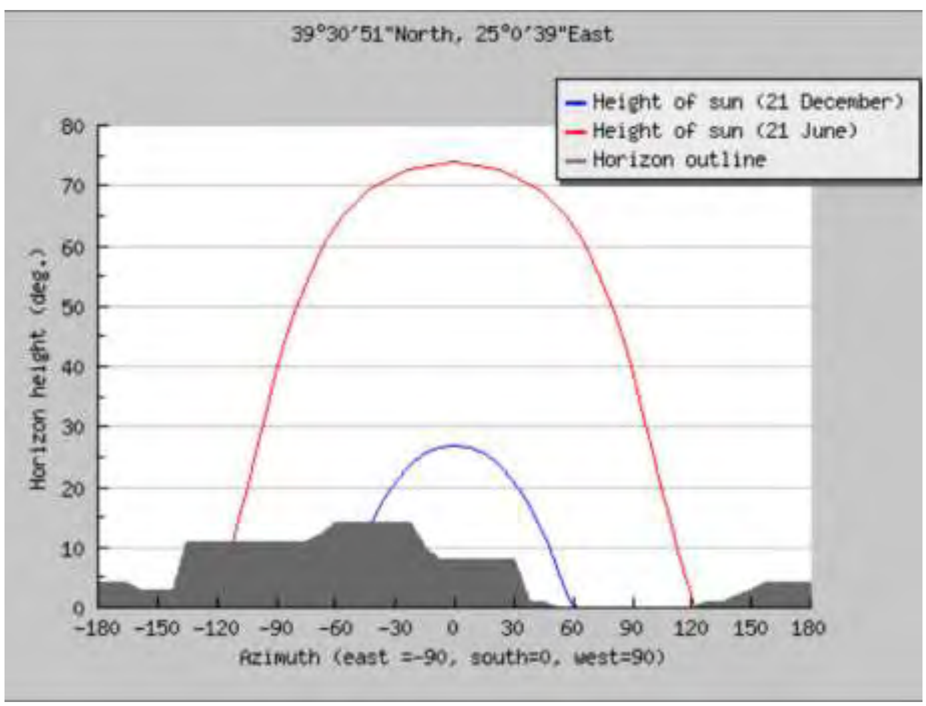


Figure4.4. 2-3: Outline of horizon with sun path for winter and summer solstice.

(4) Estimation of solar electricity generation

Using the PVGIS tool the solar electricity generation was estimated at the above selected site. The electricity generated annually and monthly is estimated by assuming a PV system performance ratio (typical value for systems with modules of mono- or polycrystalline silicon is 0.75, which may be considered conservative for professional systems), the losses are accounted as follows for a PV system with nominal DC power of 1.0 kWp (for crystalline silicon):

- Estimated losses due to temperature and low irradiance: 9.7% (using local ambient temperature)
- Estimated loss due to angular reflectance effects: 2.4%
- Other losses (cables, inverter etc.): 12.0%
- Combined PV system losses: 24.2%

Table 4.4.2-3: Monthly and Total Annual electricity production for fixed angle PV system, inclination=31 deg., orientation=0 degrees at the above selected site.

Month	E_m in kWh/kWp
Jan	69.1
Feb	84.9
Mar	129
Apr	144
May	167
Jun	166
Jul	175
Aug	172
Sep	147
Oct	118
Nov	82.8
Dec	65.3
Total Annual electricity production in kWh/kWp	**1520**

Em: Average monthly electricity production from the given 1 KWp PV system (kWh)

Therefore, it is estimated the AC power electricity production for a crystalline silicon PV system will be 1520 kWh/kWp with an estimated accuracy of ± 5%.

4.4.3. Issues and Solution for PV and other Generation

(1) RES Electrification island power system operation approach

In Figure 4.4.3-1, the basic block diagram of Agios Efstratios RES based Electrification system is presented as it is expected to operate in its final scheme including Hydrogen production, storage and electricity production associated with Hydrogen.

In a real application, the electrification system should be supported by a monitoring and a decision support system that will take into account forecasts for load, weather (solar, wind, etc.) and state of charge of batteries, hydrogen storage, etc. and provide an operation schedule and strategy for the following minutes and hours. Extensive work has been carried out in the island of Kythnos in the passed 30 years [4], [5]. Below a description of a possible realization of a decision scheme and its logic are presented.

The main components for the management of the overall power system and decision logic are a Data Acquisition system and a Central Supervisory Control. Additional systems, such as dynamic compensation components and adjusting devices for security necessary for the proper dynamic operation of the network are also considered.

The additional systems, depending on the architecture of the proposed power system may also include: flywheels, rotary capacitors and additional bi-directional converters with local storage.

Interventions may be also needed to the existing diesel generators of the power station such as: upgrade or replacement of the engine rpm regulators to comply with the dynamic support characteristics and communication of the existing SCADA[26] system of the power plant with the central monitoring, control and management system.

[26] (Supervisory Control and Data Acquisition)

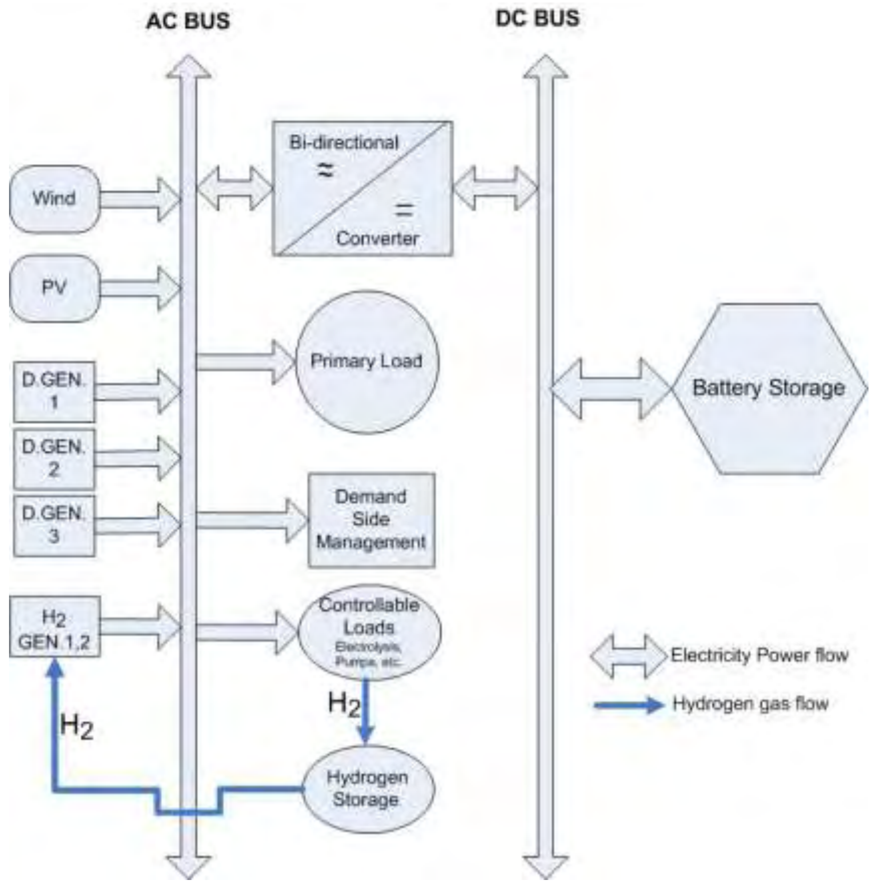


Figure 4.4.3-1: Basic block diagram of Agios Efstratios RES and Hydrogen based Electrification system.

In terms of the main components of the power system, such as the bi-directional converters, for reasons of reliability and security of load supply, it is desirable to have more than one bi-directional power converter able to supply the loads and integrating the battery storage to the grid. For this reason, it is recommended to have redundancy, that is to have at least two converters of roughly 300 kVA each, able to operate in parallel in a master-slave mode of operation or if needed, each one on its own separately, forming the grid. Furthermore, it would be advisable for reliability reasons and despite the economic initial cost and surcharge on the levelized cost of electricity, over the lifetime of the power system, to install two wind turbines. Regarding the central grid-connected photovoltaic system, the use of three-phase inverters in the range of 20 kW would also be beneficial for the system reliability, due to the remoteness of the island location, as in all the previously mentioned cases.

The additional measures of environmental and strategic energy character that are planned in the other part of the project "Green Island - Ai Stratis" are expected to add significant electrical loads, whose function will be largely controlled, such as heat pumps and circulators for heating and cooling of public buildings, hydrogen generation (through water electrolysis unit) and storage and use of components that add an experimental aspect to the electrification system for further optimization. The existence of such electric loads is desirable for feeding the available excess RES power and thus energy over time, which would otherwise be discarded. The energy stored in hydrogen may be used later when there is demand that cannot be met by the energy available from RES or satisfied by the available energy of the central electricity storage system.

Below the equation that balances the instantaneous load of the island is presented:

Island Instantaneous load = Primary load + Controllable large loads (Electrolysis, Pumps, etc) + Demand Side Management = P_{Wind} + P_{PV} ± $P_{Bi\text{-}directional\ Battery\ Converter}$ + $P_{Diesel\ Gensets}$ (1,2,3, P> technical limit) + $P_{H2\ Gen.}$ (1,2, P>tech. limit)

In the above equation, as **Primary load** all the usual pre-existing loads (power demand) in the island are considered. **Controllable large loads** are such loads as the electrolysis, water pumps, etc. **Demand Side Management** measures are considered those that would reduce primary load, by providing incentives to the consumers for electricity use during periods of high RES generation. By the term **P** and the associated following subscripts (wind, PV, Bi-directional Battery Converter, Diesel Gensets, H_2 Gen.) the instantaneous power output of those devices is denoted or in the case of the battery converter also the power absorption. The numbers in parentheses represent the number of available generators and the compliance with the limitation regarding the lower power technical limit of each generator.

For this purpose, the central management system given the forecasts for load and RES availability and the state of charge of the battery system should be able to make a prediction of short term RES production and island system demand, providing appropriate signals for the management of power production and of the controllable loads. In Figure 4.4.3-2, a logic block diagram for the forecast, state estimation and scheduling of the island electrification system components is presented.

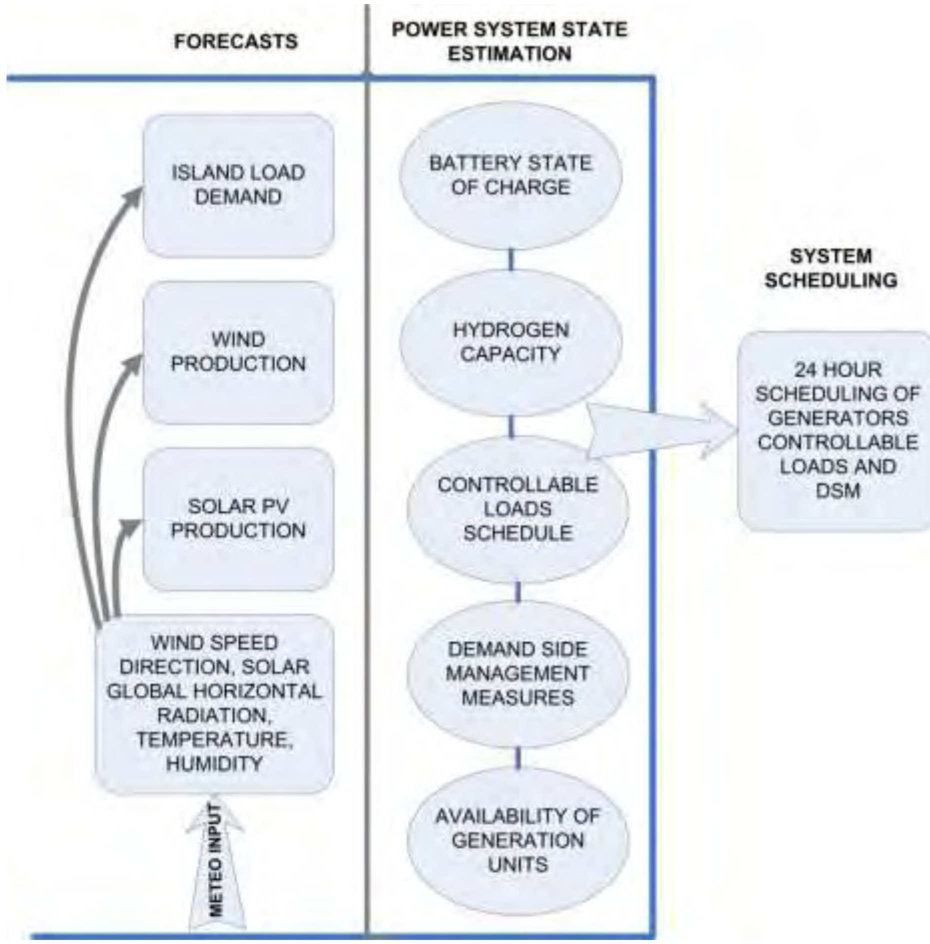


Figure 4.4.3-2: Block diagram for forecasts, state estimation and scheduling

As RES units are being generally characterized by variability in their production, the penetration of RES in the conventional power systems' generation mix is limited due to technical constraints introduced by the conventional units. With limited control capabilities, operators are obliged to follow conservative procedures, rejecting part of the available resources. To overcome this limitation, advanced management systems with effective control capabilities need to be implemented. The Hellenic island system operator plans to install an advanced Energy Management System (EMS) in the non interconnected islands with a semi-distributed architecture and new functions [3]. The EMS will have a semi-distributed architecture. It will include a central control center to be installed in Athens, together with several Local Control Centers (LCCs) installed on each island. The central control center will implement the day-ahead planning and monitoring functions, including electricity market functions, relying on load and generation forecasts or power/energy bids for all types of RES stations (wind farms, hybrid stations, CSP(Concentrated Solar Power) plants and PV systems). Another driving force for these changes is the new legal framework that requires the operation of an energy market.

In the case of the project "Green Island - Ai Stratis", it is important to be interoperable with the planned Energy Management System (EMS) approach for the Hellenic island system operator, which should also take into consideration island cases with very large penetration (>85%) of renewable energy sources.

(2) Operation Modes of the Power System

Regarding the anticipated modes of operation of the proposed new power system, they can be described briefly as follows:

1) The main operation mode

In the main operation mode, the bi-directional power converters should form the grid, that is, they will be responsible for providing and controlling the frequency and voltage as well as the maintaining the balance of active and reactive power, supported by the remaining generator components of the hybrid system.

This kind of operation can be realized either sending through a communication bus set points to the units or applying droop mode operation already studied in reference [6]. The implementation of a droop concept also facilitates the future expansion of the system without further complicated communication requirements.

At high RES availability that exceeds power demand, excess production of renewable energy is fed to the central storage system for use in periods of low RES production, while any additional excess production from renewables is directed to controllable loads of the island, such as the electrolysis for hydrogen production (in the order of 100 kW) and water pumping units and other loads. If the production of renewable energy exceeds the storage capacity and demand of controlled loads, then the rejection of excess active power is activated through appropriate commands (set points) for power curtailment of the RES units.

In situations where the availability of RES production is insufficient to meet the load demand, the deficit of power and energy is provided by the storage system through the bi-directional converter, when the state of charge is adequate, according to the battery technology and lifetime planning.

In case the renewable energy production for a certain period of time is forecasted insufficient to meet the demand and the battery state of charge is not adequate, then the two Hydrogen gensets (75 kW each) may be put into operation.

Furthermore, if the stored hydrogen is not enough to bridge the gap of energy then the appropriate diesel generator/s of the existing conventional power plant are started up and synchronized to the grid formed by the inverters, in order to support the demand and charge the battery system. This mode of operation, with the gensets in operation should normally cover a small percentage of time (usually less than 15%) within a year. Once the charging status of the central storage system becomes satisfactory in relation to the expected in the coming hours consumption and production from RES, then the power system should switch off the gensets of the conventional power system.

Therefore, in order to reach a high RES energy penetration the availability of reliable bi-directional converters is critical for the operation of such an electric power system. The operation of the power system with the diesel gensets switched off is considered to persist for most of the time.

The synchronization and disconnection of either or both the diesel and hydrogen fed generators to the grid formed by the battery inverter should be uninterruptable.

2) Emergency Operation mode

In case of non-availability of the bi-directional power converters, the island will be powered by the conventional power system, in the legacy mode of operation. This case concerns an emergency situation due to failure, maintenance of equipment or for any other reason. In such a case the conventional gensets will operate according to current conventional mode of the existing power plant, with the support of the central supervisory system, which should be able to control (e.g. to limit) the production of the grid connected renewable energy plants, to meet the minimum power technical requirements of conventional units.

The central supervisory control (CSC) monitors the RES production in all cases, the demand and weather forecasts, the state of charge of the storage systems and undertakes to implement the described operating mode of the system. The algorithm of the central supervisory control determines the operation mode, mandating the inclusion or shut down of the diesel generator sets, decides to integrate or disconnect controllable loads, and gives set points to limit the production of RES units when required.

Furthermore, there should be provision for the operation of the existing power station without the central supervisory control system.

To regulate RES production, the RES units should have the ability to limit power output, and provide reactive power (voltage support) based on external reference signals (from the central supervisory control system or local electrical parameters monitoring).

Switching between the different operation modes of the power system, the operations for start-stop and regulation of the production-consumption of the individual components should be made with fully automated manner, without the need for operator intervention. This applies also for the conventional power units of the power system. In the case the CSC system is not functioning then a complete manual mode should be available with detailed instructions for emergency operation.

(3) Island electrification system simulation using HOMER software

The new island electrification system is simulated over a year using the free HOMER software version 2.68 beta. The simulation is performed with one hour time steps for one year, using measured time series for load, wind resources and a synthetic time series for solar irradiation at the selected island sites, considering the following components for the needs of the electrification system model in the sensitivity analysis:

Wind Turbine Enercon E33 (of 330 kW nominal capacity) allowing the use of up to 3 wind turbines (0 to 990 kW) in the parametric analysis with an average annual wind speed of 9.04 m/sec using the power law for the variation of wind speed with height (power law exponent taken 0.06).

Photovoltaic systems of total capacity from 0 to 900 kWp, in steps of 100kWp in the parametric analysis

Electricity storage system, of nominal capacity in the range of 4 to 10 strings of 240VDC each string with 720 kWhs nominal capacity of lead acid battery 2V cell of the type OPzS, for a range of nominal capacity 2880 to 7200 kWh

Bi-directional power converters (at least 2 for reliability reasons) of total power capacity from 300 to 800 kVA, aiming to form the frequency and set the voltage level of the electric power grid and connecting the electricity storage system to the island grid,

Three existing diesel generators, two of 90 kVA and one of 220 kVA capacity, with lower technical limit 50% of their nominal capacity

The hourly island load profile of 2010 is considered as the primary load (1220 MWh) with a peak of 360 kW, a second case with an annual consumption of 1953 MWh with a 570 kW peak was also examined to take into account the introduction of heating and cooling systems in the public buildings using renewable energy technologies and the use of electric vehicles.

The minimum battery state of charge allowed is 40% of the nominal.

Assumptions:

The diesel fuel cost was taken as 1.4 Euro/l and the installed system cost for the PV system was 1.5 Euro/Wp, while the installed system cost per E33 wind turbine was taken 600.000 Euro. The fuel consumption of the diesel generators was taken from reference [1]. For example the specific consumption of the 90 KW generator, at 50% load, is 291.9 g/kWh, while that of the 220 kW generator is 250.7 g/kWh. At full load (100%) the specific consumption of the 90 KW generator, is 263.3 g/kWh and that of the 220 kW generator 242.8 g/kWh. The project lifetime considered is 25 years and the discount rate was assumed 6%. A charge for CO_2 emissions of 20 Euro/t is also considered.

The bi-directional converter cost is considered 0.5 Euro/VA of nominal capacity which includes also the central supervisory control (SCADA). The OPzS battery cost is assumed at 150 Euro per nominal kWh.

The HOMER software allows two dispatch strategies, the load following (LF) and cycle charging (CC). The optimal strategy depends on many factors, including the sizes of the generators and battery bank, the price of fuel, the O&M[27]cost of the generators, the amount of renewable power capacity in the system, and the characteristics of the renewable resources. Both models were chosen for simulation to be able to see which is one is optimal.

[27] (Operation and Maintenance)

Under the load following (LF) strategy, whenever a generator is needed it produces only enough power to meet the demand. Load following tends to be optimal in systems with a lot of renewable power, when the renewable power output sometimes exceeds the load.

Under the cycle charging (CC) strategy, whenever a generator has to operate, it operates at full capacity with surplus power going to charge the battery bank. Cycle charging tends to be optimal in systems with little or no renewable power.

The Hydrogen Electrolysis, storage and Hydrogen internal combustion engines are not considered in the simulation because their operation logic could not be simulated with the available options in HOMER software.

(4) Simulation results

In Table 4.4.3-1, the electrification systems that achieved the lowest cost of electricity production over a lifetime of 25 years for each primary load and average wind speed simulation case. As the PV system will have a modular design through the use of several grid connected inverters, in scenario 3, 4 and 7, 8 the lowest levelized cost of electricity using 2 wind turbines are presented for the low primary load (3.345 MWh/day) and higher primary load (5.352 MWh/day) cases respectively. It is noted, that the increase in the cost of electricity with 2 wind turbines, in the higher primary load case is much smaller than the lower load case.

Table 4.4.3-1: Selected HOMER simulation results according to the above assumptions and sensitivity analysis

Primary Load in MWh/day	Annual Average wind speed in m/sec	Scenario	PV (kW)	Number of Wind Turbines 330kW/each	Gen1 Max. Capacity (kW)	Gen2 Max. Capacity (kW)	Gen3 Max. Capacity (kW)	Number of 2V Cells of 6 kWh each	Converter (kW)	Dispatch strategy	Initial capital in Euro	Operating cost (Euro/yr)	Total Net Present Cost in Euro
3.345 (1220 MWh/year)	9	1	300	1	90	220	90	480	300	LF	1,632,000	116,237	3,117,895
		2	500	1	90	220	90	480	300	LF	1,932,000	96,680	3,167,897
		3	200	2	90	220	90	480	300	LF	2,082,000	123,409	3,659,587
		4	100	2	90	220	90	480	300	LF	1,932,000	135,650	3,666,059
5.352 (1953 MWh/year)	9	5	700	1	90	220	90	720	300	LF	2,448,000	195,845	4,951,560
		6	700	1	90	220	90	840	300	LF	2,556,000	187,378	4,951,325
		7	500	2	90	220	90	600	300	LF	2,640,000	183,159	4,981,385
		8	500	1	90	220	90	600	300	LF	2,040,000	253,704	5,283,186

Primary Load in MWh/day	Annual Average wind speed in m/sec	Scenario	Cost of Electricity in Euro/kWh	Renewable fraction	Excess Electricity kWh/yr	Unmet Load kWh/yr	Total Diesel Gen. prod in kWh/yr	Diesel used in Liters	Gen1 operation hrs	Gen2 operation hrs	Gen3 operation hrs	Battery Autonomy hr	Battery Through-put kWh/yr	Battery Life yr
3.345 (1220 MWh/year)	9	1	0.200	0.925	796,747	0	91,268	29,601	697	318	271	12	198,797	20
		2	0.203	0.959	1,041,996	0	50,368	16,199	346	186	135	12.4	215,699	20
		3	0.234	0.952	2,190,942	0	58,125	18,674	387	226	156	12.4	155,454	20
		4	0.235	0.932	2,067,169	0	83,025	26,711	555	321	233	12.4	162,425	20
5.352 (1953 MWh/year)	9	5	0.199	0.907	684,129	3,133	181,494	65,974	1,205	561	572	11.62	361,783	20
		6	0.199	0.915	662,900	3,133	165,875	60,211	1,099	510	516	13.56	378,910	20
		7	0.200	0.935	1,926,926	2,546	127,627	46,380	847	391	409	9.69	272,761	20
		8	0.212	0.857	516,040	3,600	280,118	102,007	1,781	901	910	9.69	291,030	20

LF: Load Following mode

CC: Cycle Charging mode

The optimum PV system capacity, for the lower primary load (3.345 MWh/day – scenario 1, 2, 3, 4) for the current electricity use, according to the simulation is in the range of 500 to 100 kWp, while all proposed systems have a high renewable fraction higher than 92% with a levelized cost of electricity production for 25 years in the range of 0.200 to 0.235 Euro/kWh.

The additional measures of environmental and strategic energy character to be introduced during the project are expected to add significant electrical loads, whose function will be largely controlled, such as heat pumps and circulators for heating and cooling of public buildings and Hydrogen generation (through water electrolysis unit) and associated storage. For this case a second case was simulated with a load 1.6 times higher (5.352 MWh/day– scenario 5, 6, 7, 8). In this case the optimum PV systems are in the range of 500 to 700 kWp, while all proposed systems have a high renewable fraction higher than 90%, except scenario 8, with a levelized cost of electricity production for 25 years around 0.200 Euro/kWh. Scenario 8 was chosen in a way to have almost the same component sizes as scenario 2, for the lower primary load case. In this case it is noted that the levelized cost of electricity is calculated to be 0.212 Euro/kWh and the Renewable Energy Fraction drops from 0.959 to 0.857, between the two primary load cases (scenario 2 and 8). It also noted

The battery autonomy in the scenario presented is about 9 to 13 hours assuming average daily consumption and storage medium capacity considered.

The optimal solution in all cases presented above always considers a Converter of 300 kW, but for reliability reasons in a real system two 300 kW should be considered. Given also the remoteness of the island location in the Aegean Sea, it is also recommended to install 2 wind turbines for reliability reasons. The nominal battery capacity most suited for the realistic cases in terms of wind energy production is 480 to 840, 2 Volt cells of 6 kWh capacity each, or 2880 to 5040 kWh nominal capacity. Also regarding storage capacity, higher capacities are desirable for higher safety margin in energy use and longer time for battery replacement (20 years).

The integration of the electrolysis unit for hydrogen production (in the order of 100 kW) and the two Hydrogen gensets (75 kW each) are not considered in this simulation but when introduced they will make use of the excess electricity and further reduce the use of diesel fuel and increase accordingly the renewable fraction, while the electrification system will be able to cope with even higher renewable energy generation if the energy consumption increases further in the future.

In Figure 4.4.3-3, the monthly average electric production according to all generator units for scenario 7, as in Table 4.4.3-1, are presented. This scenario is projected to be the one that represents the most probable case in energy load use, while fulfilling the requirements for high RES penetration and higher reliability in making use of RES with a competitive electricity production cost.

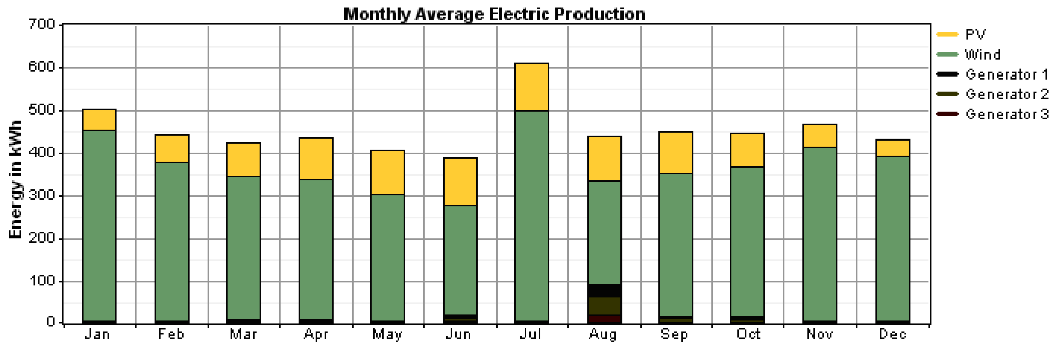


Figure 4.4.3-3: Scenario 7 of Table 5, Monthly average electricity production for all generating units.

In Figure 4.4.3-4a, b, the power output over the year of the wind turbines and the PV system are presented, in Figure 4.4. 3-4c the battery bank state of charge is presented.

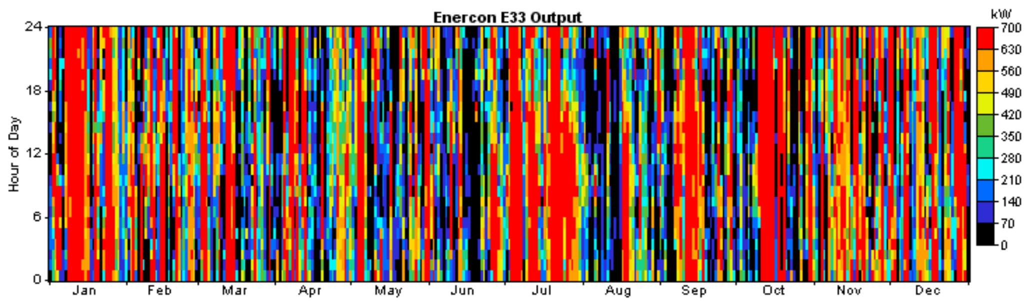


Figure 4.4.3-4a: The power output over the year of the wind for Scenario 7.

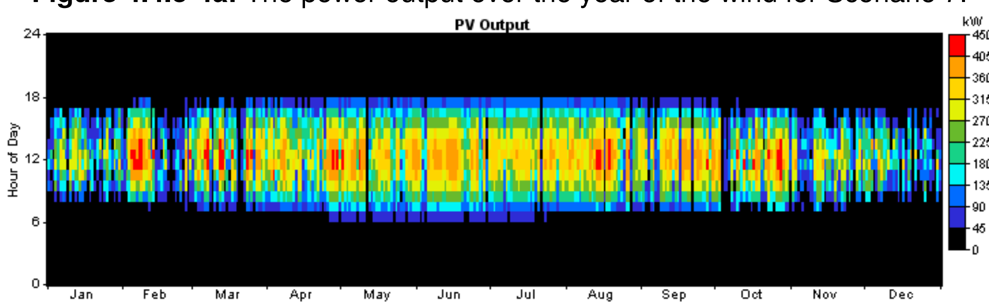


Figure 4.4.3-4b: The power output over the year of the PV system for Scenario 7.

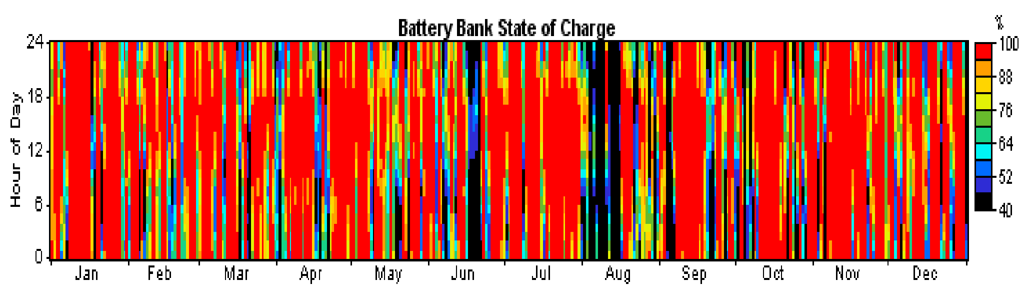


Figure 4.4.3-4c: The annual fluctuation of the battery bank state of charge for Scenario 7.

In Figure 4.4.3-5, the cash flow for the lifetime of 25 years for each system component is presented. Note that the various cash flow categories for the various system components. The largest cost component, during the lifetime of the system, is associated with the two wind turbines that will be replaced at 15 years, which is the estimated useful lifetime. In this figure also note the replacement cost contribution in the wind turbines and battery bank net present cost and the importance in the project cash flow during the considered system lifetime of 25 years.

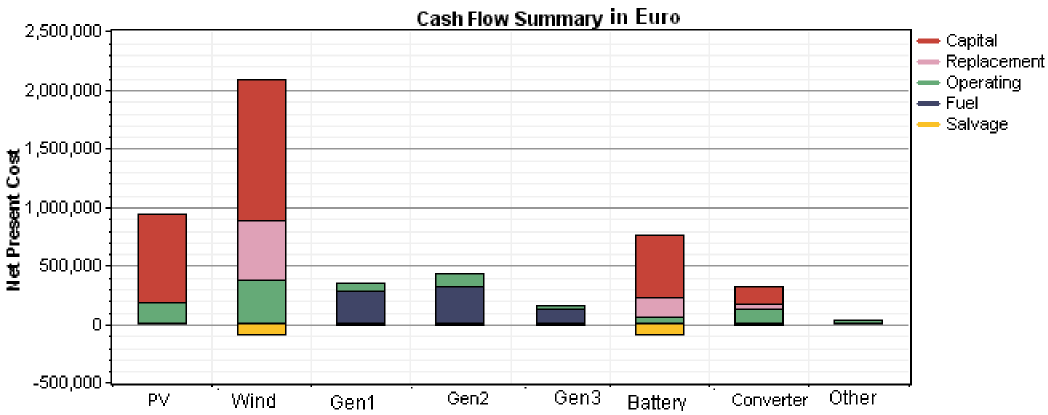


Figure 4.4.3-5: The lifetime cash flow for each system component for Scenario 7.

The production cost of each system includes variable and fixed operating costs. The variable cost of power stations includes the cost of fuel, cost of maintenance due to operating costs and the cost for manpower due to the operation. Fixed costs include costs for human resources, other maintenance costs and equipment depreciation cost. The renewable energy sources systems present a very small variable cost as the primary resource is for free (solar irradiation, wind, etc.). The electricity production of RES units has to be amortized over the years of their lifetime the initial investment, maintenance and operation costs. In Table 6, some historic data for the cost of production of the power station in Agios Efstratios are presented together with the earlier simulation results for some of the scenario presented. It is anticipated that the drastic reduction of the diesel gensets operation time and the automation of the new RES based power station will decrease significantly the fixed cost, as defined for conventional power stations. Regarding the RES based microgrid, in the HOMER software the calculation provides the total levelized electricity cost. The calculated electricity cost per year by HOMER (Table 4.4.3-1) does not allow the breakdown between variable and fixed cost. The fixed cost is the main component of the total cost for the RES based systems, because the variable cost represents the cost of the fuel used, which is not applicable to RES systems and their relatively lower maintenance and operation cost with respect to conventional generators.

Table4.4.3-2: Historic data for electricity production cost of the power station in Agios Efstratios compared to simulation results (sources: [1], [3] and PPC).

Year or Scenario	Variabale cost of electricity in €/MWh	Fixed cost of electricity in €/MWh	Total cost of electricity in €/MWh
2002	--	--	373.46
2008	312	331.65	643.65
2010	225	331*	556
Scenario 1 (3.345 MWh/day)	--	--	200
Scenario 3 (3.345 MWh/day)	--	--	234
Scenario 5 (5.352 MWh/day)	--	--	199
Scenario 7 (5.352 MWh/day)	--	--	200

***:** Assuming that the fixed cost did not change between 2008 and 2010

Comparing the historic values of electricity production cost of the conventional power station of the island with the simulation results there is a remarkable difference in favor of the RES based systems. The RES based island microgrid has a total electricity cost over a system lifetime of 25 years, of less than half of the conventional diesel fuel powered system. In fact the RES based microgrid has a total electricity cost less or comparable to the variable electricity cost of the diesel fueled power system.

4.4.4. Conclusions

The system analysis, simulation and comparison with historic electricity production data show that the implementation of a RES based power system for the island is cost effective, with a total electricity cost over a system lifetime of 25 years, of less than half of the conventional diesel fuel powered system.

The design of the new system has to take into account the reliability issues of the most important components in order to avoid lengthy disruption in the main mode of RES operation of the microgrid and avoid the use of diesel fuel.

The backbone for the operation of the microgrid is the Central Supervisory Control and Data Acquisition system for the overall automatic and uninterruptible switch between modes operation of the microgrid. It should be reliable in order to have an effective microgrid operation.

In this study, the integration of an electrolysis unit for hydrogen production and the two associated hydrogen gensets are not considered in the simulation but when introduced they will make use of the excess electricity and further reduce the use of diesel fuel and increase accordingly the renewable fraction, while the electrification system will be able to cope with even higher renewable energy generation if the energy consumption increases further in the future.

The model autonomous microgrid of Agios Efstratios could be an example and learning real life “laboratory” for high penetration of renewables with central main components in electricity grids. Furthermore, the microgrid should be designed and established in order to be transparent to the Hellenic island system operator who plans to install advanced Energy Management Systems (EMS) in the non interconnected islands.

4.4.5. References

[1] Report: "Green island - Agios Efstratios", issue A', "electrification system, energy storage and energy management", by NTUA, CRES, PPC and PPC Renewables, and the Aegean University, delivered to General Secretariat of Research and Technology in 2009.

[2] http://homerenergy.com/version_history.html

[3] Nikos Hatziargyriou, Stavros Papathanasiou , Isidoros Vitellas, Stavros Makrinikas, Aris Dimeas, Theodora Patsaka, Kostas Kaousias, Antiopi Gigantidou, Nikos Korres, Eleanna Hatzoplaki, Paper by PPC and NTUA titled: "Energy management in the Greek islands", CIGRE Study Committee C6-303, 2012.

[4] Thomas Degner, Philipp Taylor, Dave Rollinson, Aristomenis Neris, Stathis Tselepis, "Interconnection of solar powered mini-grids - a case study for Kythnos island", 19th European Photovoltaic Solar Energy Conference and Exhibition, Paris, 7.–11. June 2004.

[5] Stathis Tselepis, "Greek experience with microgrids, results from the Gaidouromantra site, Kythnos island", Oral presentation at the 6th International Symposium on Microgrids, Fairmont Pacific Rim, Vancouver, Canada, July 22nd 2010.

[6] Engler, A., Hardt, C. & Rothert, M. "Next generation of AC coupled hybrid systems- 3phase parallel operation of grid forming battery inverters". 2nd European PV-Hybrid and Mini-Grid Conference, Kassel, Germany, September 25-26 2003.

4.5. Denmark

4.5.1. Power system

High penetration of photovoltaics on the island of Bornholm

Bornholm is an island located in the very east end of Denmark in the Baltic Sea. The island of Bornholm is in everyday speech also called the rock island or the sunshine island. The area of the island is 588.5 km^2, and the longest distance from coast to coast is north to south, namely 40 km. Bornholm has app. 41,000 inhabitants, and the number is decreasing. [28]

The electricity supply on the island is supplied from the utility Østkraft who is a full utility dealing with both generation, distribution, sale of electricity and Demand Side Management (DSM). Connected to the grid are also private IPPs (Independent Power Producers) such as biomass plants, wind turbines and photovoltaic plants. Østkraft has a total of 28,000 customers on Bornholm. [29] The total electrical energy consumption went up by 20 % during the 1980s. Since 1991 it has been stable at approximately 250,000 GWh/yr. [30]

The key figures of the electrical grid on Bornholm are shown in the table below:

Table 4.5.1-1: Utility network data on Bornholm

Item	Numbers	60 kV (km)	10 kV (km)	0.4 kV (km)
60/10 kV transformer	15	-	-	-
10/0.4 kV transformer	953	-	-	-
Overhead line	-	73	79	405
Cable	-	58	862.5	1,367

Østkraft has a plan for replacing all the overhead lines with ground cables over the next decade, so in a few years all overhead lines will be removed from the island and provide a more stable grid operation.

The total installed production capacity on Bornholm is 145.2 MW. The production capacity is a mix of fossil fuel and renewable energy plants. The split between technologies can be seen in the table below. First priority plants are the renewable energy systems with the combined heat and power plants as second priority.

[28] (EcoGrid Bornholm, 2013)
[29] (Østkraft Hans Henrik Ipsen)
[30] (Miljø & Teknik, 2008)

Furthermore, the island has a 60 MW AC cable interconnected between Sweden and Bornholm for securing the balance of the system.

Table 4.5.1-2: Generating capacity on Bornholm

Production capacities (2012)	**MW**
Combined heat and power plant (steam)	76
Diesel generators	32
Biogas generators (RE)	2.1
Wind turbines (RE)	29.9
Photovoltaics (re)	5.2
Total	**145.2**

The maximum load on Bornholm is 55 MW, so the amount of installed production capacity is approximately a factor 3 above the load without taking the connection to Sweden into consideration. The amount of renewable energy systems is 37.2 MW corresponding to 68% of the maximum load. The minimum load on Bornholm is 15 MW at night and approximately 25 MW during the daytime. So during peak periods for the renewable energy systems, power needs to be exported to Sweden, or the renewable energy plants need to be periodically curtailed. The amount power from photovoltaic corresponds to approximately 10% of the maximum load and 20% of the minimum load during daytime.

The amount of renewable energy (wind and PV) will increase within the next years. Bornholm is a part of the EcoGrid EU. The key idea of the EcoGrid EU project, running for 4 years from May 2011 to May 2015, is to introduce market-based mechanisms close to the operation phase that will enable balancing capacity, particularly from flexible consumption. Of a total of 28.000 customers on Bornholm, approximately 2000 residential consumers will participate with flexible demand response to real-time price signals. The participants will be equipped with residential demand response devices/appliances using gateways and "smart" controllers.

Installation of the smart solutions will allow real-time prices to be presented to consumers and allow users to pre-program their automatic demand-response preferences, e.g. through different types of electricity pipe contracts. "Automation" and customer choice are ones of the key elements in the EcoGrid EU concept.

A real-time market concept (Figure 4.5.1-1) is under development to give small end-users of electricity and distributed renewable energy sources new options (and potential economic benefits) for offering TSO's additional balancing and ancillary services. To make the EcoGrid EU solutions more widely applicable, the market concept will be designed for existing power exchange(s). Because of the test site location on Bornholm, the real-time market concept will first be operational in the Nordic power market system.

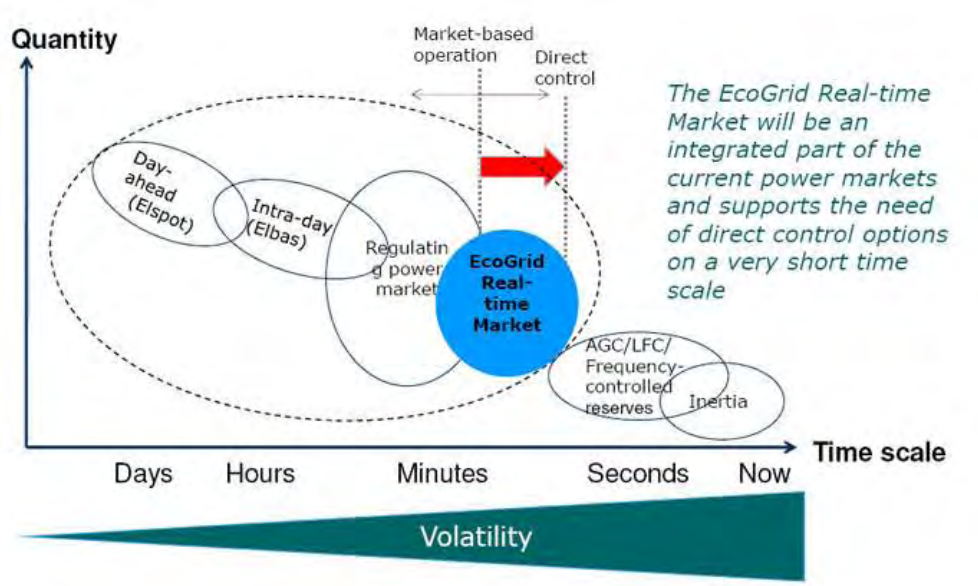


Figure 4.5.1-1: Representation of the EcoGrid Real-time market concept

Strong industrial participation and innovative experiences from related European and US Smart Grids RD&D projects will contribute to the development and implementation of robust ICT platforms and information architectures. This is crucial to allow all distributed energy resources to participate actively in the real-time power market.

Nordic partners cover a significant share of the consortium since the demonstration takes place on Bornholm and because the EcoGrid EU market concept will be an extension of the Nordic market model for electricity trading and regulating power.

European-wide relevance of project results is a key objective. This is endorsed through wide regional EU participation and allocation of a substantial part of project resources to the development, replication, deployment and dissemination of EcoGrid EU throughout Europe.

More information is available at: http://www.eu-ecogrid.net/

Besides the EcoGrid project, some parallel projects are in progress. One is the PVNET.dk project which studies how to facilitate large-scale grid integration of solar PV into the existing grid. This is done by examining different types of grid-voltage control, applying Smart Grid features and introducing novel ancillary services integrated into the inverters. The background for the PVNET. dk project is the already ongoing Photovoltaic Island Bornholm (PVIB I - III) projects, the EcoGrid EU project, and the Danish Cell Project. The first part of the PVNET.dk project will establish the theoretical framework for integrating large amounts of solar PV into the grid. The project will suggest, analyze and assess different solutions. In the second part, the proposed solutions are implemented into solar PV installations already deployed during the PVIB projects. Finally, the operation of the network without and with the developed solutions will be verified by a third part parallel with the first two phases. For more information about the PVNet project see http://www.pvnet.dk.

4.5.2. Installed photovoltaic plants on Bornholm

A summary indicates a total of 5.2 MW installed solar power capacity on Bornholm spread over 870 installations. The largest single installation is 320 kW at Almegard barracks. On the figure below the PV development on Bornholm is shown.

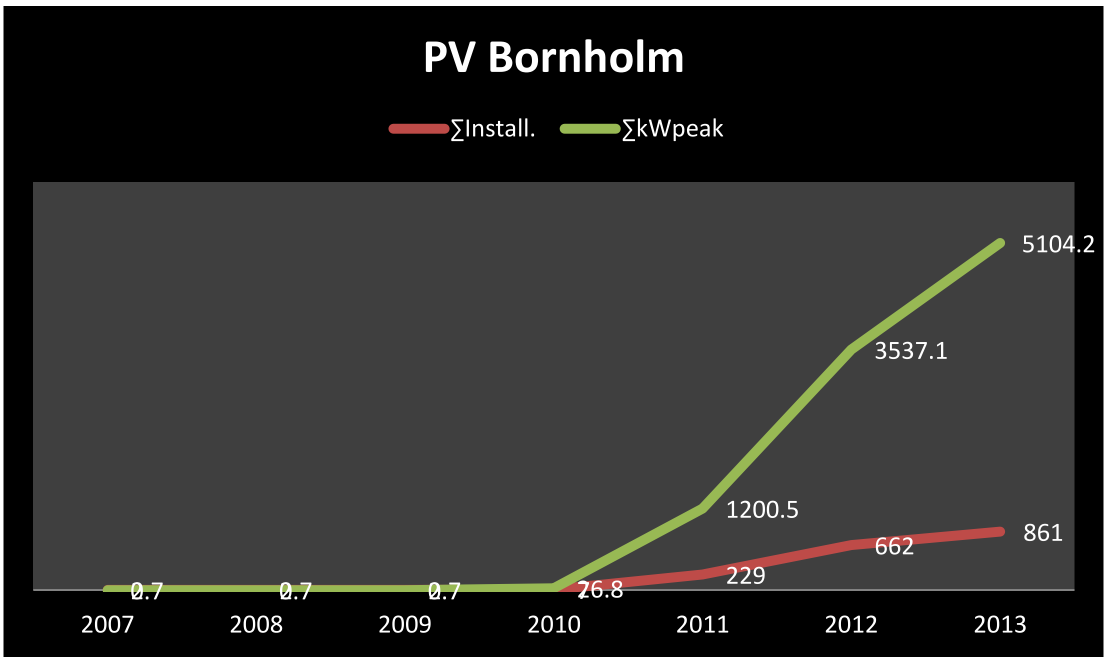


Figure 4.5.2-1: Installed photovoltaic capacity on Bornholm

The installation of PV units has increased rapidly from 2010 to 2013. Based on a subsidy scheme via the PVIP phases 1-3 and support schemes from the Danish government made to promote environmentally friendly energy sources, it became feasible to invest in small PV units. This subsidy scheme has been reduced, but it is still attractive for private consumers to install PV, so a further increase in installed capacity is expected.

The table below displays the 20 transformer stations with the most photovoltaic installed. It is calculated as the relation between transformer power and installed PV power. B/A [%].

Table 4.5.2-1: Transformer stations on Bornholm with highest PV generation

STATION NO. (TRANSFORMER)	A [$KVA_{TRANSFORMER}$]	B [ΣKW_{PEAK}]	B/A [%]	PV INSTALLATIONS
546	100	40.2	40.2	7
637	50	16	32	3
401	50	13.6	27.2	3
84	100	27.1	27.1	5
459	400	100	25	1
302	100	24.8	24.8	5
324	50	12	24	2
645	50	12	24	2
649	50	12	24	2
652	50	12	24	2
751	50	12	24	2
737	50	11	22	2
932	50	11	22	2
728	50	10.5	21	2
697	200	40.4	20.2	7
9	30	6	20	1
399	50	10	20	2
39	50	10	20	2
726	50	10	20	2
738	50	10	20	2

As shown in the table, station 546 is the transformer with the highest amount of PV installed. The power ratio is above 40%. The single PV plant in the top of Figure 4.5.2-1 has a 4.2 kWp plant installed. The rest all have 6 kWp plants installed.

Figure 4.5.2-2: PV systems on transformer 546

Despite the high numbers of PV installations on the Island, there has only been a few incidents where measures had to be taken into account at the electrical grid. Until now there have only been minor challenges by connecting and hosting the renewable energy systems in the grid. The only issues with PV systems have been a few overvoltage problems when consumers connect single phase inverters at a point in the grid where the grid impedance is relatively high. These problems have all been solved by connecting the inverters to another phase or using the tab changer in the transformer to lower the outlet voltage at the 10/0.4 kV transformer.   The next chapter describes a case where a PV plant caused problems.

4.5.3. High penetration of PV – CASE

At Dyndevej 20, 3751 Østermarie, a privately owned photovoltaic was installed in October 2012. The PV system consists of 14 panels oriented south with a tilt of 45 degrees. Peak output is 2.6 kW. The PV plant is connected to the low voltage grid with a single phase Danfoss ULX 3000 inverter.

During the spring of 2013, the PV owner observed that the inverter was disconnected during the daytime and a little bit later connected to the grid again. He could see in the menu of the inverter that the inverter disconnected due to overvoltage on the AC side.

In order to analyze the problem, data was collected from the system. In the two plots below from April 2013, it clearly shows the inverter disconnecting during the day, when the production is high, and the voltage rises above the recommended level. The inverter disconnects four times during the middle of the day on April 3rd as indicated by the dark green curve. The logged voltage inside the inverter reach a maximum at 250 Vac.

The same problem shows on April 4th. Other fluctuations are a result of clouds blocking the sun or other forms of shadowing of the PV panels. Inverter shutdown is indicated, when the graph touches the x-axis.

Figure 4.5.3-1: PV generation on 3rd of April

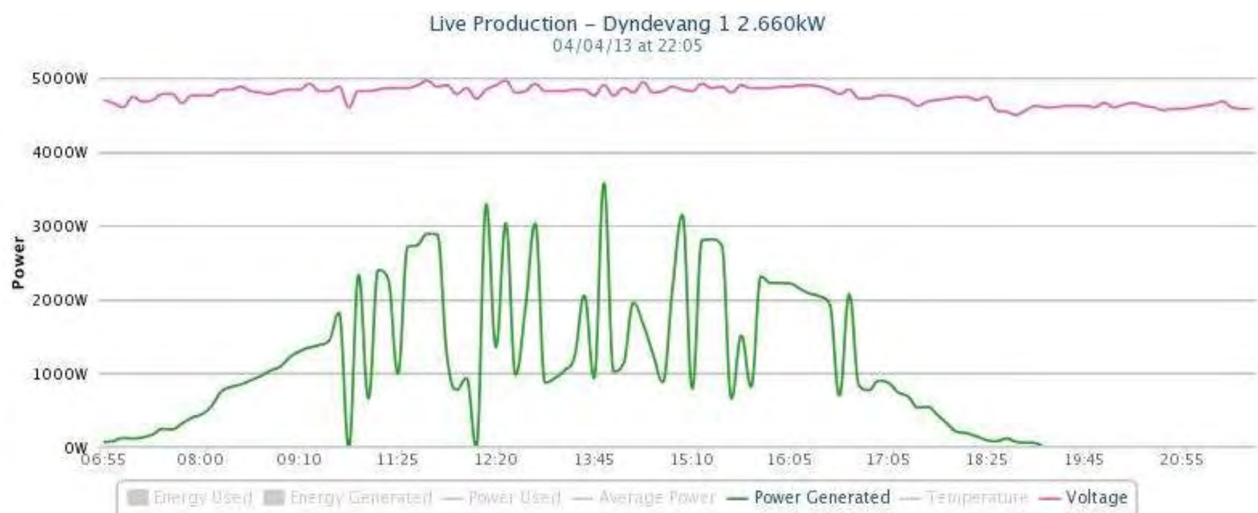


Figure 4.5.3-2: PV generation on 4th of April

The inverter is a single phase and probably by coincident, it was connected to a phase already coupled to some PV-power. This combined with a transformer adjusted to maintain a constant 230 V at the most distant point of the radial feeder line causes high voltage cut out. Feed-in at a radial will normally cause the voltage to increase. Depending on transformer presettings, this could result in the above mentioned situation. The nominal voltage cannot exceed the limit max U_n +/- 10 %.

Dyndevej 20 is connected to the low voltage grid via an AL-M PVIKS cable and transformer station 446. According to Østkraft, the grid is outlined as in 6. The total cable distance from transformer to consumer 5624 is 620 m.

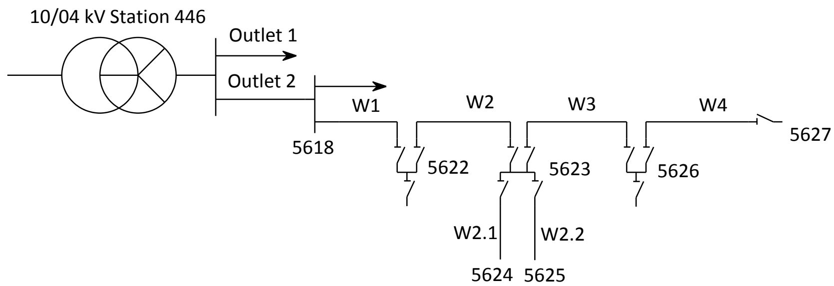


Figure 4.5.3-3: Station 446 diagram

Figure 4.5.3-3 is based on appendix one that shows the physical location of the transformer, cables and routing towards the customers. Junction 5624 represents Dyndevej 20 which has had problems concerning voltage control.

As a solution to the problem, the inverter was connected to another phase during June 2013. As the data logging in the figure below shows, the inverter only disconnects one time during the day, and the problem is partly solved.

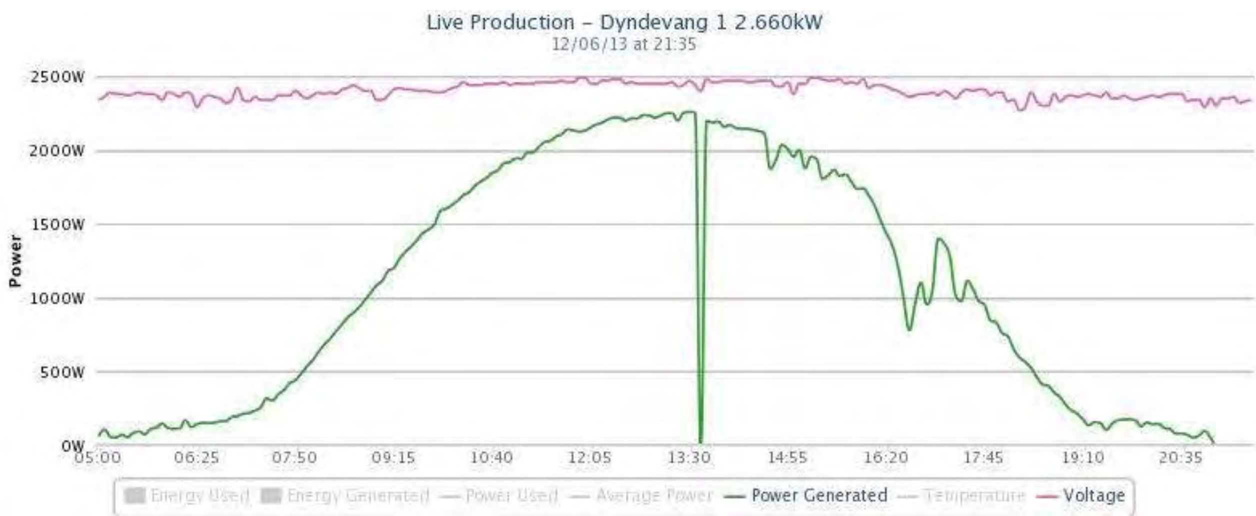


Figure 4.5.3-4: PV generation on 12th of June

To solve the problem 100%, other measures need to be taken into consideration to eliminate the disconnection due to over voltage in the system. It could be replacing the cable with new cable with less resistance, replacing the inverter with a 3-phase inverter or introducing a load management combined with smart grid control.

The case study is made in the PVNET.dk project which studies how to facilitate large-scale grid integration of solar PV into the existing grid. This is done by examining different types of grid-voltage control, applying Smart Grid functionalities and introducing novel ancillary services integrated into the inverters. The background for the PVNET.dk project is the already ongoing Photovoltaic Island Bornholm (PVIB I - III) projects, the EcoGrid EU project, and the Danish Cell Project. The first part of the PVNET.dk project will establish the theoretical framework for integrating large amounts of solar PV into the grid. The project will suggest, analyze and assess different solutions. In the second part, the proposed solutions are implemented into solar PV installations already deployed during the PVIB projects. Finally, the operation of the network without and with the developed solutions will be verified in a third part, which runs parallel to the first two.

The project consortium is formed by:

- Danfoss Solar Inverters, which is in charge of the project management and also providing the inverter platform and test facilities.
- Centre for Electric Technology at the Technical University of Denmark, which will develop the required algorithms and test them with a hardware-in-the-loop grid simulator, for making solar PV systems "Smart Grid enabled' and will also be the link to the EcoGrid EU project.
- EnergiMidt, a DNO which have been in the Danish PV-business for two decades and making the link to the PVIB projects and the IEA photovoltaic power system programme task 14.
- Østkraft, which is the local distribution network operator on the island of Bornholm. The PVNET.dk project is in part financed under the Electrical Energy Research Program (ForskEL, grant number 10698), administrated by Energinet.dk

4.5.4. Reference

[1] EcoGrid Bornholm. (2013). EcoGrid Bornholm. Retrieved Sep 17, 2013, from http://ecogridbornholm.dk/category/faq/

[2] Østkraft, Hans Henrik Ipsen

[3] Miljø og Teknik (2008). transplanproject.eu. Retrieved Sep 17, 2013, from http://www.transplanproject.eu/docs/ENERGYSTRATEGIES/Bornholms_Energistrategi_2025_-_Vejen_til_et_MERE_b_redygtigt_Bornholm.(mindre_fil).pdf

4.6. Switzerland

4.6.1. Power System

(1) Power industry and market

There are approximately 800 utilities in Switzerland. Most are very small and work on a local level. Three larger utilities deliver most of the energy production. Each of them produces in the range of 10–20 TWh. The utilities are owned mostly by public bodies (cantons and cities). Today approximately 60% of the electricity is produced by hydropower and 40% by nuclear power (approximately 25 TWh). Switzerland has one single control area. The transmission grid is owned by one company (Swissgrid).

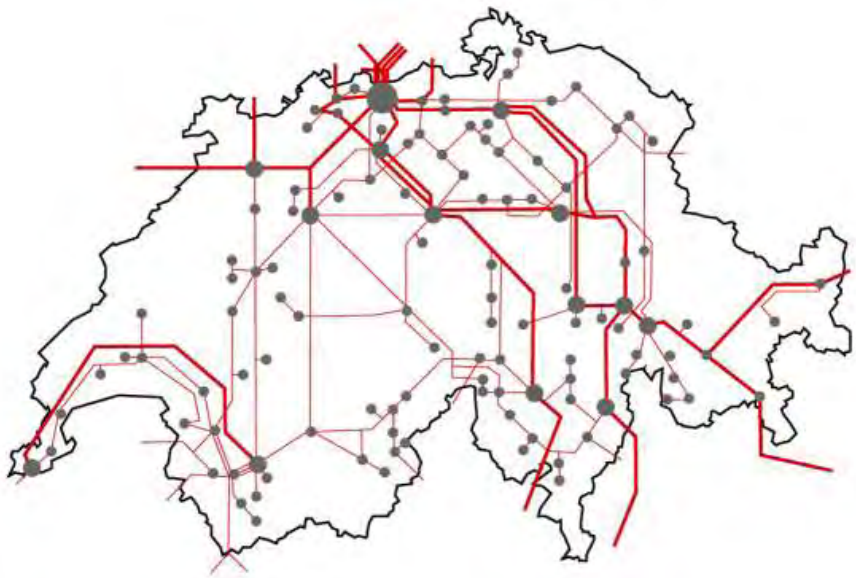


Figure 4.6.1-1: Transmission grid of Switzerland[31] (220 V / 380 V).

Switzerland has relatively strong grid connections with its neighboring countries and is integrated in the European Electricity Exchange (EEX) Leipzig. Today, about the same amount of electricity as Switzerland's internal consumption (60 TWh) is exchanged yearly with its neighbors. The market is only partly liberalized. Customers with a consumption of more than 100 MWh/year can choose the producer; smaller consumers cannot yet do so. A further liberalization is planned for the next years.

[31] http://www.swissgrid.ch/swissgrid/en/home.html

(2) Demand and Supply Mix

In the last decades, Switzerland exported electricity during summer months and imported it during winter months due to the seasonal variations of hydro power production and the base load of nuclear power (Figure4.6.1-2).

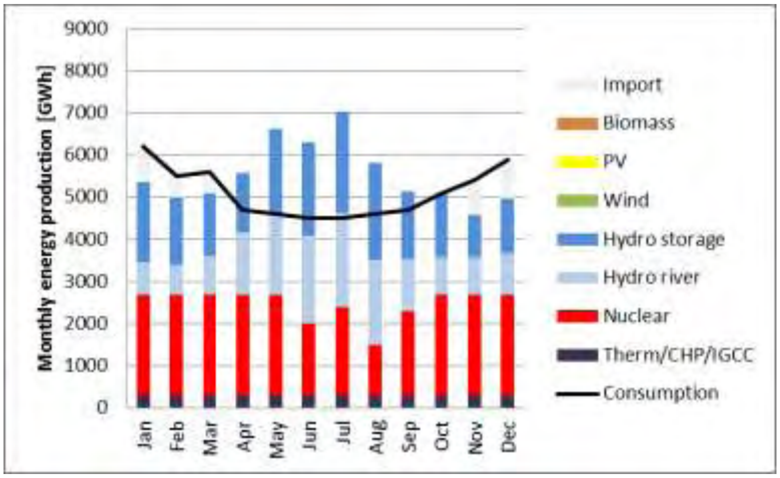


Figure 4.6.1-2: Monthly production and consumption in Switzerland in 2009; "Therm" means thermal production.

4.6.2. Penetration of PV and Other Generation

(1) The Swiss PV Market in 2013

The Swiss PV market grew strongly during the last three years. In 2013, 300 GW was installed, which adds up to 700 MW total (600 GWh production or 1% of the total consumption).

(2) The FIT Program

In 2008 a fed-in tariff (FIT) program started. This induced a growth of PV installations. However, due to the low cap of the FIT, till 2013 the growth has been strongly limited. At the moment more than 30,000 PV installations are on a waiting list. The current FIT is capped to 1.4 Rp/kWh.

(3) Future Prospects

The two houses of parliament voted for an increase of the FIT cap to 1.4 Rp/kWh in 2013. With this increase the installations could grow until 2020 to 2 – 3 GW (with a yearly installation of approximately 300 MW/year), if allocations of PV are not too low (the government intends to keep some allocations for PV). The feed in tariff for a 100 kWp plant for the year 2014 is 17.2 EUR cts/kWh.

4.6.3. Case Study

(1) Issues with heavy deployment of variable renewable energy

Energy storage is one of the key issues of variable renewable electricity production. This case study examines the electricity storage needs for four renewable energy scenarios with high penetrations of PV in Switzerland until 2050. The background of this report is the decision of the Swiss government and parliament in 2012 to phase out nuclear power stations in Switzerland and to exchange them until 2050 mainly with renewable energy.

Table 4.6.3-1 shows the four chosen scenarios. There are two different types of scenarios: first, there are two scenarios that are driven by the available natural resources and the aim to achieve almost 100% renewable electricity by 2050[32] (scenarios RS1 and RS2). Another aim is to fulfil the target to limit the worldwide climate change to 2°C, meaning that CO_2 emissions must be lowered by more than 80%. This implies that a large part of the mainly fossil-based energy system in Switzerland (75% is fossil-based today) must be transformed to electricity, which induces a rise in electricity consumption.

The other two scenarios are based on one of the official scenarios of the Swiss government "Neue Energiepolitik, Variante C&E"[33] (scenarios SG1 & SG2). The first scenario includes the official production targets. The second uses the same input but enhanced PV targets (13.6 instead of 10.2 TWh). The four scenarios include measures for efficiency of about 15%–30% (otherwise the consumption would increase even more).

[32] http://www.gruene.ch/web/dms/gruene/doc/positionen/umwelt/energie/energiepolitik/energiestrategie_bericht_ES_2050_def/Hintergrundsbericht%20Energiestrategie%202050.pdf

[33] www.energiestrategie2050.ch

Table 4.6.3-1: Energy production and consumption of the four scenarios (2050)

	100% scenario 1 RS1 [TWh]	**100% scenario 2 RS2 [TWh]**	**Government scenario 1 SG1 [TWh]**	**Government scenario 2 SG2 [TWh]**
CHP/IGCC	3.5	3.5	8.1	4.8
Wind	4.8	2.2	4.1	4.1
Biomass	3.5	3.3	3.5	3.5
New hydro	3.2	2.2	3.2	3.2
PV	17.8	13.8	10.2	13.6
Total new renewables	**29.3**	**21.5**	**21.0**	**24.4**
Hydro (existing)	37.2	37.2	37.2	37.2
Thermal (waste)	2.5	2.5	2.5	2.5
Import	8.3	1.0	0.0	0.0
Consumption (incl. losses)	**80.9**	**65.9**	**68.9**	**68.9**

All four scenarios show PV as the main new source of energy, which will deliver between 15% and 25% of the electricity. The second important new source is wind, although wind energy is limited in Switzerland due to high population density, complex terrain, and low wind speeds in more than 50% of the country.[34] All new sources are modeled with exponential growth functions, which have yearly and total limits (above those limits, the growth is lowered).

Electricity consumption is also modeled, but only on a yearly scale. Hourly load has been scaled but not shifted. With the 100% scenarios, nuclear is phased out in 2029 (45 years of lifetime for each of the nuclear reactors). In the two governmental scenarios, nuclear is phased out in 2034 (50 years lifetime). Generally the government scenarios include higher levels for methane (via CHP or IGCC), which results in higher CO_2 emissions. Those scenarios do not fulfil the 2°C target until 2050.

Whereas in the 100% scenarios a constant consumption in the next 15 years is modeled along with a slow increase after 2030 due to the transition from fossil to electrical consumption, the governmental scenarios include an increase until 2030 and a decrease after this date. Figure 4.6.3-1 shows one of the four different scenarios.

[34] www.wind-data.ch

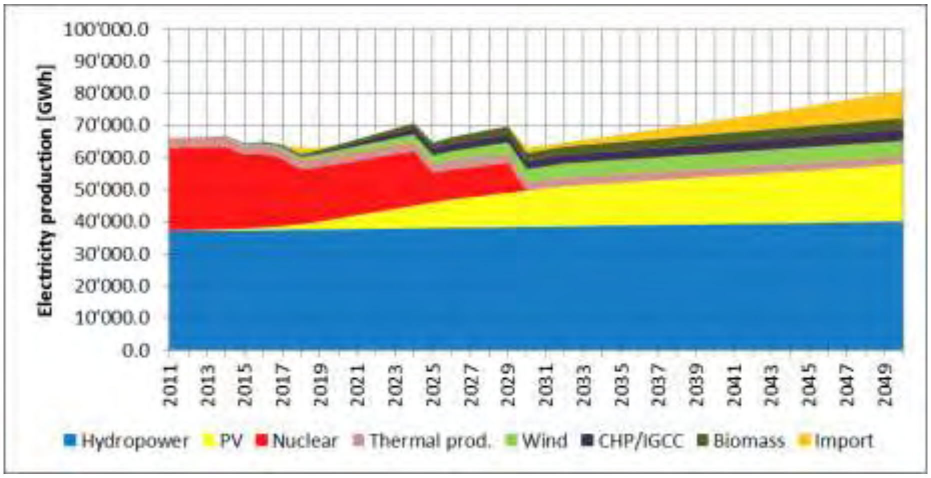


Figure 4.6.3-1: 100% scenario RS1 (nuclear phase-out: 2029).

An electricity system without import and export has not been modeled, as such a system would neither be economic nor ecological.

(2) Overview of demand-supply balancing capability analysis for a future power system

The current balancing capabilities are high due to a high portion of hydro power (especially of the storage type). At the moment, approximately 9.5 GW of dispatchable hydro power capacity exists (maximum load is approx. 10.2 GW). Currently, pumped hydro capacity has increased from 1.5 to 4 GW, plans exist for another 2.5 GW, and the potential is at least 10 GW. The increase started before the decision to phase out nuclear and has been based on economic reasons[35]. The cost of new pumped hydro power in Switzerland is in the range of €0.04–€0.12/kWh (or €0.8 million–€1.6 million/MW).

(3) Assumptions and model

Renewable energy technologies have been modeled based on hourly data of the MeteoSwiss network (Swissmetnet,[36] approximately 70 stations, 2009–2011) and monitored production data of the Swiss Federal Office of Energy, including weekly and monthly values.

PV is modeled with PVSAT[37] (Bayer et al, 2004) using a typical installation based on crystalline cells. Diffuse radiation has been modeled with the Borland-Ridley-Lauret model,[38] and radiation on inclined planes has been calculated with Hay's model[39].

[35] At the moment, the difference between peak and base load price at the EEX is too low for financing new pumped hydro. This is mainly due to the fact, that the current installation of PV (32 GW) in Germany just covers the peak load in Germany during most of the year. This will presumably change in the future.

[36] http://www.meteoschweiz.admin.ch/web/en/climate/observation_systems/surface/swissmetnet/smn-stations.html

[37] http://pvsat.de/papers.html

Wind energy has been modeled with help of a typical wind generator. Hydro power of rivers has been modeled based on precipitation and has been adapted to measured historical values. Hydro power production of the storage type has been modeled only on historical monthly values.[40]

Switzerland has a relatively dense meteorological network (70 stations with radiation measurements within 41,000 km^2), which allows use of ground network data for simulating total production. The selection of different subsets of stations for solar, wind, and hydro power is important in order to get representative mixes.

PV production has been varied with different levels of peak shaving (68%–75%) and different distributions of module orientations (higher shares of optimal tilts or more east/west and façade installations). The transmission grid has not been modeled, but is assumed to be a copper plate. Reverse flow from lower to higher grid levels is allowed. Figure 4.6.3-2 shows the storage model used.

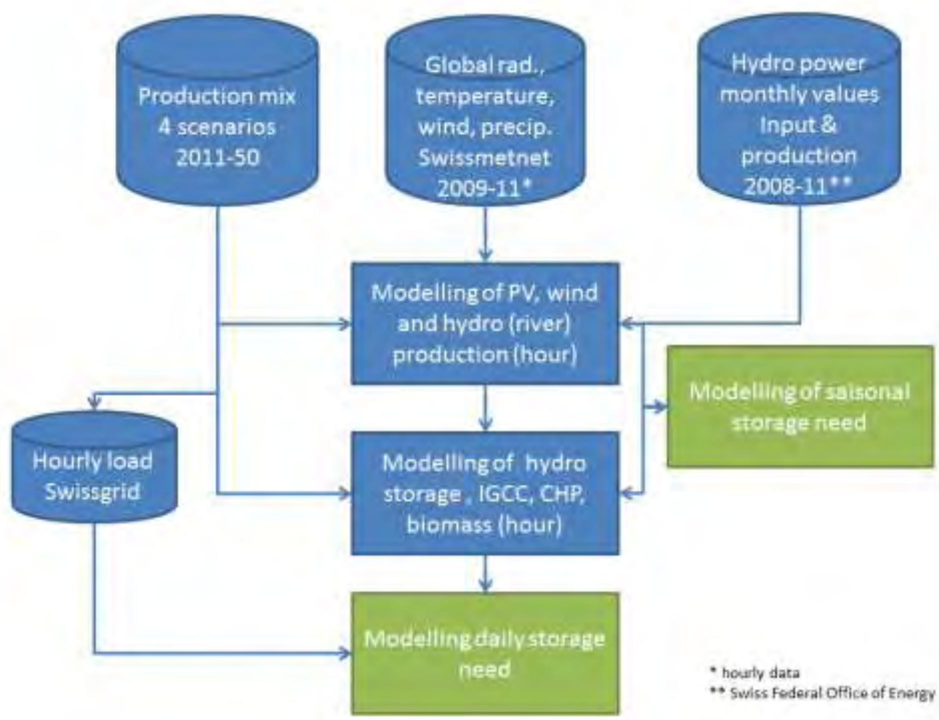


Figure 4.6.3-2: Storage model.

Several assumptions had to be made to reduce the complexity of the model. Gas (methane) based cogeneration systems, CHP systems, and integrated gasification combined cycle (IGCC) systems have been modeled as largely heat controlled. During

---

[38] B. Ridley, J. Boland, and P. Lauret. Modelling of solar fraction with multiple predictors. Renewable Energy, 35:478{483, 2010. doi: 10.1016/j.renene.2009.07.018.

[39] Hay JE (1979) Calculation of monthly mean solar radiation on horizontal and inclined surfaces. *Solar Energy*, Vol. 23, pp. 301-307.

[40] http://www.bfe.admin.ch/themen/00526/00541/00542/00630/index.html?lang=de&dossier_id=00769

times with higher combined values of PV, wind, and hydro power than the load, gas-based electricity is set to zero.

If the non-dispatchable energy production (wind, PV, and hydro river) is higher than the load, pumped hydro is used. After such events (at night), the pumped hydro storage is refilled within the following 14 hours (see Figure 4.6.3-4).

Hydro storage is modeled in order that the system is kept stable and the monthly import and export rates for the period of 2008–2011 remain unchanged. A description of the seasonal model (based on work of the Nordmann and Remund model) can be found at Swissolar.[41]

For seasonal storage, climate change has been partly taken into account based on current knowledge.[42] A temperature rise of 1°C is assumed till 2050. This shifts the seasonal production of hydro power towards spring (with earlier input to storage in the higher Alps due to earlier snow melt). A slightly changed precipitation pattern—higher precipitation in winter and lower in summer—is used for hydro power production of rivers.

(4) Results of the analysis

Figure 4.6.3-3 shows the monthly energy production for scenario RS1 (2050).

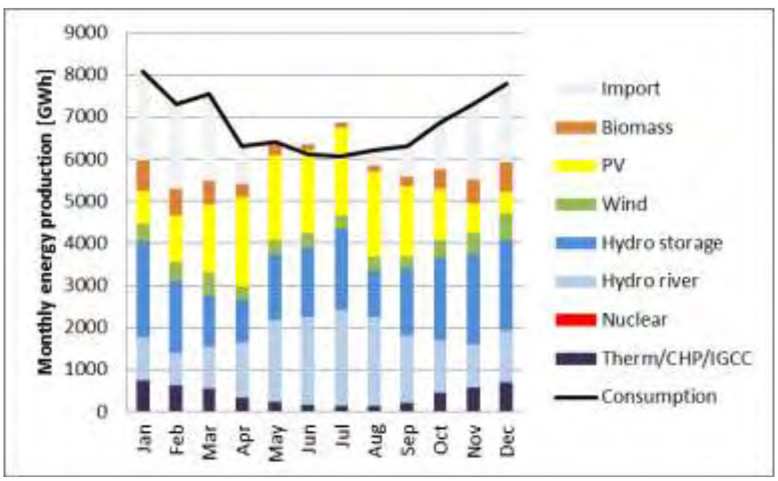


Figure 4.6.3-3: Monthly electricity production and consumption for scenario RS1 (2050).

Figure 4.6.3-4 shows as an example the electricity production of 10 days during summer 2050 for scenario RS1.

[41] http://www.swissolar.ch/fileadmin/files/swissolar_neu/medien/2012/Remund-Nordmann_PV_Speicherung.pdf

[42] http://www.wsl.ch/fe/gebirgshydrologie/wildbaeche/projekte/hydropower/index_EN

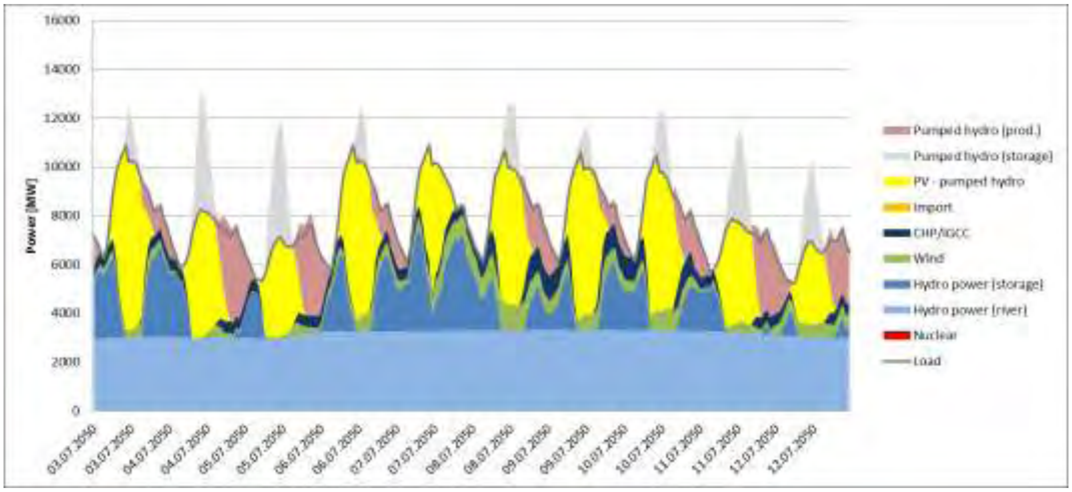


Figure 4.6.3-4: Electricity production during 10 days in July 2050 (based on weather of 2009) for scenario RS1.

The sum of non-dispatchable hydro power (river), wind, and PV will peak during 9 of the 10 days clearly over the load. This power (colored light grey in Figure 4.6.3-4) must be shifted to evenings. In Figures 4.6.3-3～4.6.3-5, this is done by pumped hydro power. However, this could also be done partly by batteries or by load shifting. The maximum PV load (summed over all of Switzerland) comes to approximately 70% of the installed capacity if no peak shaving is used. This is a result of spatial smoothing of solar radiation (and not merely due to peak shaving). Figure 4.6.3-5 shows the schematic electricity production model for scenario RS1 for 2050 according to the German 100% study from Fraunhofer ISE published in 2012.[43]

[43] http://www.ise.fraunhofer.de/de/veroeffentlichungen/veroeffentlichungen-pdf-dateien/studien-und-konzeptpapiere/studie-100-erneuerbare-energien-in-deutschland.pdf

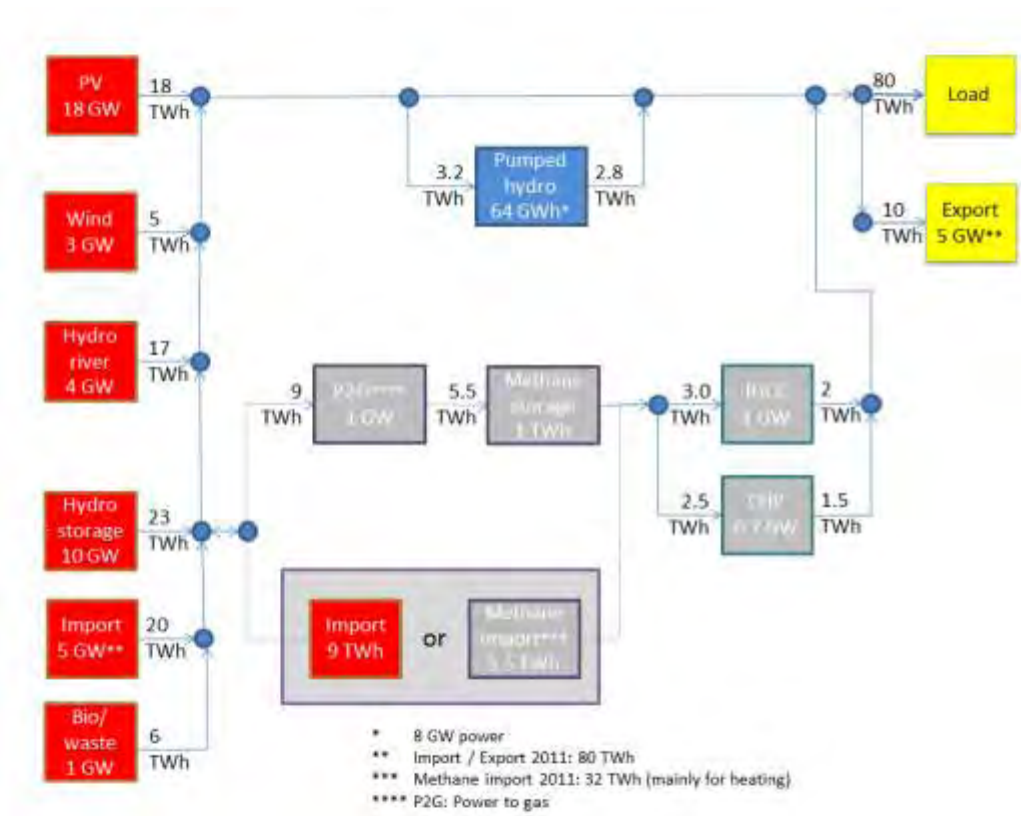


Figure 4.6.3-5: Storage model for scenario RS1 in 2050 (according 100% study of Fraunhofer ISE 2012). P2G: production of synthetic methane based on electricity.[44] Red = renewable electricity production; grey = fossil (methane) based energy; blue = storage; yellow = load and export.

The target of 100% renewable energy for scenario RS1 can only be reached if renewable electricity or methane (based, e.g., on power-to-gas technology) can be imported. The installation of a power-to-gas utility in Switzerland is possible, but not needed.

[44] http://www.solar-fuel.net/fileadmin/user_upload/Publikationen/Wind2SNG_ZSW_IWES_SolarFuel_FVEE.pdf

4.6.4. Issues and Solutions for PV Penetration

(1) Daily storage need

Figure 4.6.4-1 shows the changes of the daily power storage need until 2050 depending on the scenarios. For all four scenarios the needed daily power storage rises after 2020. Scenario RS1 has the highest need (up to 7.5 GW). The governmental scenario (SG1) has the lowest need (4 GW). The existing and planned pumped hydro power could provide the needed daily power storage needs. For the highest scenario, additional measures (e.g., DSM or batteries) could be needed.

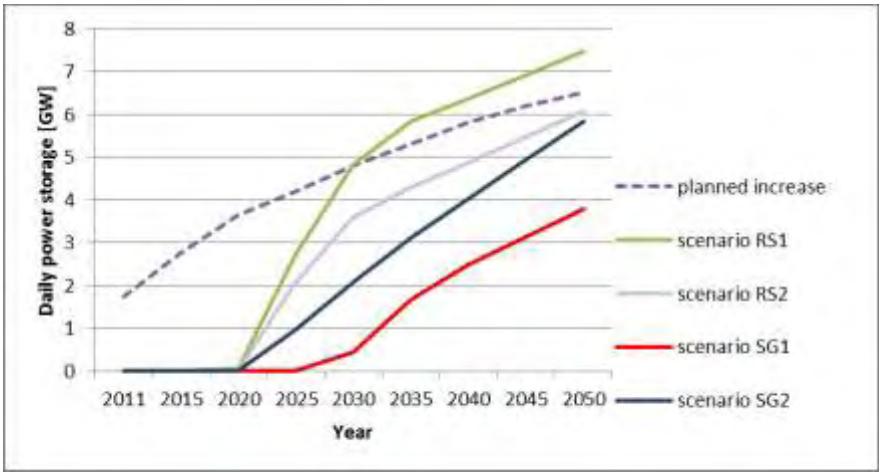


Figure 4.6.4-1: Change of needed daily power storage depending on the four scenarios.

(2) Yearly storage needs

Today, a seasonal storage capacity of hydro power of 8.8 TWh is available in Switzerland, and hydro storage power production is approximately 20 TWh. The potential of additional seasonal hydro power storage is according the Swiss association of hydro power.in the range of 2 TWh[45] The cost of new hydro storage power is in the range of €0.1/kWh. Figure 4.6.4-2 shows the changes of seasonal storage need depending on the scenario. Both renewable scenarios show an increased storage need of 1.5 TWh.

The two governmental scenarios SG1 and SG2 have only a small need for additional seasonal storage. The reason for this is the higher share of gas-based electricity production, which will be used in our model mainly in winter. However, the maximum need with scenario RS1 is clearly lower than the hydro power potential. If climate change is not taken into account, the storage need will rise for scenario RS1 to 3 TWh and for scenario SG1 to 0.4 TWh. Climate change will reduce the need for additional seasonal storage up to 50% and is therefore not negligible. The main reason for the decrease is the fact that the time when precipitation falls in form of snow will be shorter.

[45] http://www.swv.ch/Dokumente/Referate-SWV/Wasserkraftpotenzial-im-Alpenraum_Referat-SAB-Tagung_2012.pdf

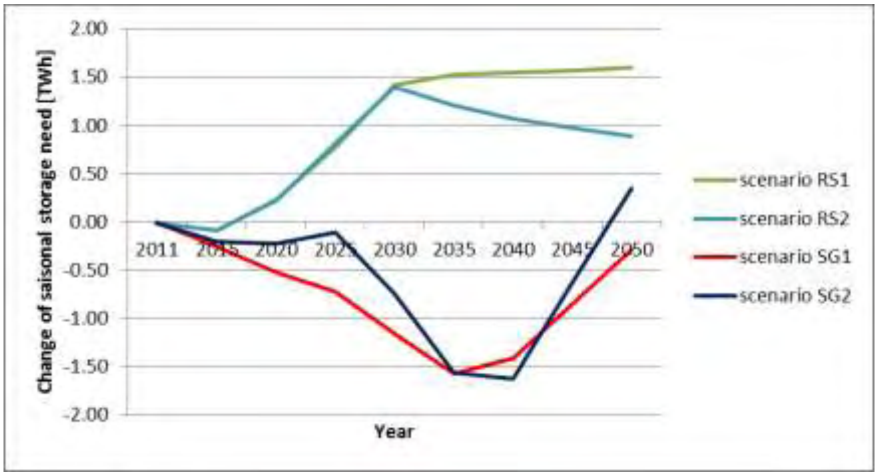


Figure 4.6.4-2: Changes of seasonal storage need for each of the four scenarios (including climate change effects). Today, 8.8 TWh of storage is available.

(3) Peak shaving and different module orientations

Figure 4.6.4-3 shows the relative changes of additional needed storage power and PV production depending on the amount of peak shaving. Peak shaving clearly reduces the needed storage power. Additionally, the losses of the production are by a factor of 2 smaller than the gained daily storage power.

Figure4.6.4-4 shows the relative changes of needed storage power and PV production depending on different distributions of the orientation of the PV modules.

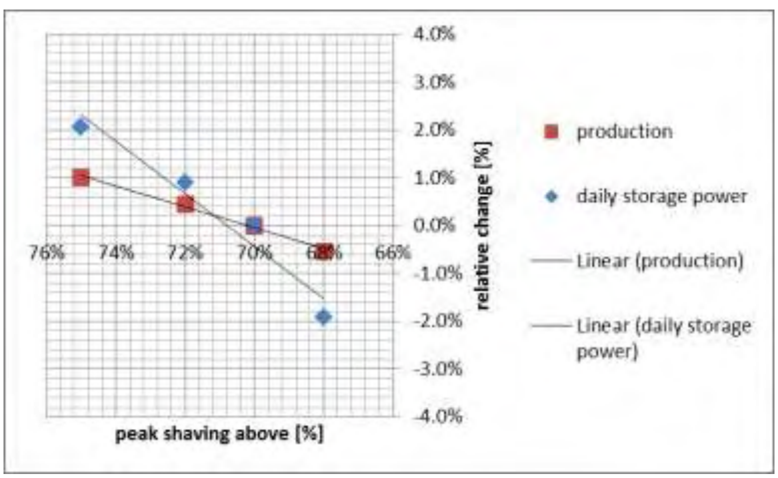


Figure 4.6.4-3: Relative changes of production and peak load depending on peak shaving (68%–75%).

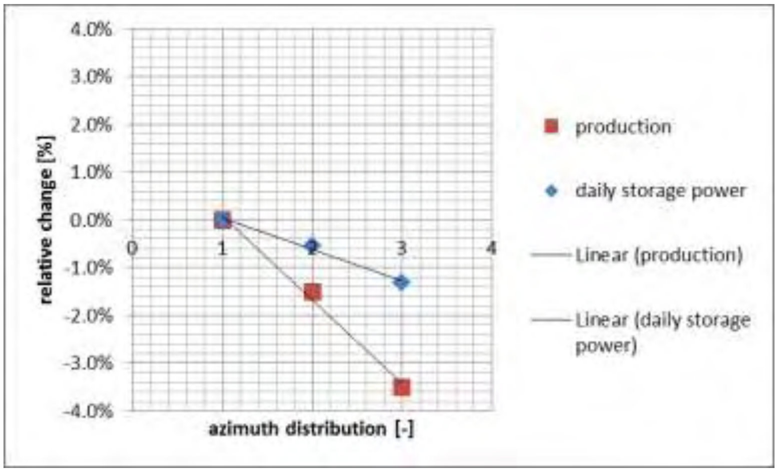


Figure 4.6.4-4: Relative changes of production and peak load depending on the distribution of the module orientation (1 = standard; 2 = east/west, 3 = east /west /facades).

More east- and west-facing modules (points 2 and 3) reduce the needed storage power. However, the energy production losses are much greater (by a factor of 3) than the gained storage power.

We therefore suggest introducing some measures for peak shaving, e.g., as in Germany. However, measures for a more distributed orientation of the modules seem not to be helpful (on a national level).

(4) Conclusions

This study shows that high penetrations of PV of up to 25% can be integrated in the Swiss electricity grid concerning the storage need. The need for daily and seasonal storage can be covered by relatively small extensions of the pumped and conventional hydro storage capacity and therefore with existing technologies with known and relatively low costs. As such, Switzerland is in a privileged situation concerning needs for further electricity storage.

The consideration of climate change is important and cannot be neglected. It changes the seasonal variations of the input to the hydro storage and reduces the additional seasonal storage need.

Peak shaving is shown to be useful to reduce daily storage power on a national level, whereas a forced installation on east- and west-facing roofs seems not to be a good strategy.

This report doesn't allow conclusions to be drawn concerning grid integration and the need for grid enhancements. However, it can be stated that peak shaving will also lower the need for grid enhancements on local and regional level.

4.6.5. R&D for Transmission-Level Challenges

(1) Plan

As stated in Section 4.6.1 (1) and shown in Figure 4.6.1-1, Switzerland has one control area, a relatively dense network, and relatively strong grid connections to its neighboring countries. Additionally, grid enhancements between the plateau (where most people live) and the hydro storage power stations in the Alps are planned[46].

The operator of the transmission grid (Swissgrid) uses forecasts of solar and wind energy to plan the operation. The production from all installations under the FIT program (which doesn't include all PV installations) is gathered and sold by one company, energiepool Schweiz AG (which is included in the balance group "renewables"). They also use weather forecasts for production planning . However due to the relatively small amount of wind energy (88 GWh in 2012 or 0.1% of the total production) and PV (350 GWh in 2012 or 0.5%), the influence of these new renewables is still minor. Generally direct model output based on MeteoSwiss' Cosmo model with 2.2 and 7 km grid resolution based on ECMWF(European Centre for Medium-Range Weather Forecasts) is used.

(2) Projects

An international project to assess the possibilities of dynamic thermal power line rating as well as the influence of atmospheric icing in Switzerland started in 2012 within the framework of the COST project ES 1002.[47] At given pilot power lines, meteorological measurements as well as measurements of conductor temperature will be carried out. The main goal is to better understand the correlation between meteorology and conductor performance and to set up short-term high-resolution forecasts of conductor temperature and atmospheric icing.

A study including transmission net simulation and calculating storage need for the government energy scenarios is currently being undertaken by KEMA[48] on behalf of the Swiss Federal Office of Energy.

Meteotest is developing together with the utility BKW-FMB AG and energiepool Schweiz AG a shortest-term solar forecast system (1–6 h) based on satellite data and wind vectors from numerical weather prediction models.[49] The aim is to lower the uncertainty of point and regional forecasts for the coming next hours.

[46] http://www.swissgrid.ch/dam/swissgrid/grid/development/PA200026_Netz%202015.pdf
[47] http://www.bfe.admin.ch/php/modules/enet/streamfile.php?file=000000010965.pdf&name=000000290730.pdf
[48] http://www.dnvkema.com
[49] http://www.societe-mont-soleil.ch/einspeisevorhersagen.html

4.6.6. References

[1] Swissgrid, TSO Switzerland. Available at: http://www.swissgrid.ch/swissgrid/en/home.html.

[2] Swissgrid, TSO Switzerland, planned grid extensions until 2015. Available at: http://www.swissgrid.ch/dam/swissgrid/grid/development/PA200026_Netz%202015.pdf.

[3] Energy Strategy 2050 of the Green Party of Switzerland, Report. Available at: http://www.gruene.ch/web/dms/gruene/doc/positionen/umwelt/energie/energiepolitik/energiestrategie_bericht_ES_2050_def/Hintergrundsbericht%20Energiestrategie%202050.pdf.

[4] Energy Strategy 2050 of the Swiss Federal Office of Energy (SFOE), available at: www.energiestrategie2050.ch.

[5] The Swiss Wind Power Data Website. Available at: www.wind-data.ch

[6] SwissMetNet: A monitoring network fit for the future. Federal Office of Meteorology and Climatology MeteoSwiss. Available at: http://www.meteoswiss.admin.ch/web/en/climate/observation_systems/surface/swissmetnet.html

[7] Lorenz, E., Betcke, J., Drews, A., Heinemann, D., Toggweiler, P., Stettler, S., van Sark, W.G.J.H.M., Heilscher, G., Schneider, M., Wiemken, E., Heydenreich, W., Beyer, H.G., 19th European Photovolatic Solar Energy Conference & Exhibition, Paris 7.6.-11.6.2004. PVSAT-2: Intelligent Performance Check of PV System Operation Based on Satellite Data. Available at: http://pvsat.de/papers.html.

[8] Stettler, S., Toggweiler, P., 5. Nationale Photovolatik - Tagung, ETH Zuerich 25.03.-26.03. 2004. PVSAT-2 - satellitengestuetztes Monitoring von netzgekoppelten Solaranlagen. Available at: http://pvsat.de/papers.html.

[9] Beyer, H.G., Schondorf-Rother, M., Betcke, J., Drews, A., Hammer, A., Heinemann, D., Lorenz, E., 19. Symposium Photovoltaische Solarenergie, Staffelstein 11.3.-13.3. 2004. Ertragsberechnung fuer PV-Anlagen in Brasilien ueber das PVSAT Verfahren. Available at: http://pvsat.de/papers.html.

[10] B. Ridley, J. Boland, and P. Lauret. Modelling of solar fraction with multiple predictors. Renewable Energy, 35:478{483, 2010. doi: 10.1016/j.renene.2009.07.018.

[11] Hay JE (1979) Calculation of monthly mean solar radiation on horizontal and inclined surfaces. Solar Energy, Vol. 23, pp. 301-307.

[12] Electricity statistics, Swiss Federal Office of Energy SFOE. Available at: http://www.bfe.admin.ch/themen/00526/00541/00542/00630/index.html?lang=de&dossier_id=00769.

[13] Roger Nordmann, Nationalrat, Präsident Swissolar, Jan Remund, dipl. Natw. ETH, Meteotest, Entwicklung des Speicherbedarfs im Laufe des Ausstiegs aus der Kernenergie unter der Annahme, dass die Photovoltaik 70% des Atomstroms ersetzt. Available at: http://www.swissolar.ch/fileadmin/files/swissolar_neu/medien/2012/Remund-Nordmann_PV_Speicherung.pdf.

[14] Climate change and hydropower production, Swiss Federal Institute for Forest, Snow and Landscape Research WSL. Available at: http://www.wsl.ch/fe/gebirgshydrologie/wildbaeche/projekte/hydropower/index_EN.

[15] Hans-Martin Henning, Andreas Palzer, Fraunhofer-Institut für Solare Energiesysteme: ISE100% Erneuerbare Energien für Strom und Wärme in Deutschland. Available at: http://www.ise.fraunhofer.de/de/veroeffentlichungen/veroeffentlichungen-pdf-dateien/studien-und-konzeptpapiere/studie-100-erneuerbare-energien-in-deutschland.pdf.

[16] Dr. Specht et al., FVEE, AEE Topics 2009, Storing bioenergy and renewable electricity in the natural gas grid. Available at: http://www.solar-fuel.net/fileadmin/user_upload/Publikationen/Wind2SNG_ZSW_IWES_SolarFuel_FVEE.pdf.

[17] Roger Pfammatter, SWV. SAB-Tagung "Energiewende – Chancen für Berggebiete," Ausbaupotenzial Wasserkraft im Alpenraum. Available at: http://www.swv.ch/Dokumente/Referate-SWV/Wasserkraftpotenzial-im-Alpenraum_Referat-SAB-Tagung_2012.pdf.

4.7. Japan

(Featured by evenly distributed rooftop or other small- or medium- size deployment, Japanese 2030 renewable energy scenario)

4.7.1. Power System,[1]

(1) Power industry and market

In Japan, there are 10 privately owned electric power companies that are in charge of regional power supply services as general electricity utilities in 10 owner systems. Ten power companies are responsible for supplying electricity from power generation to distribution to the consumers in their respective service area.

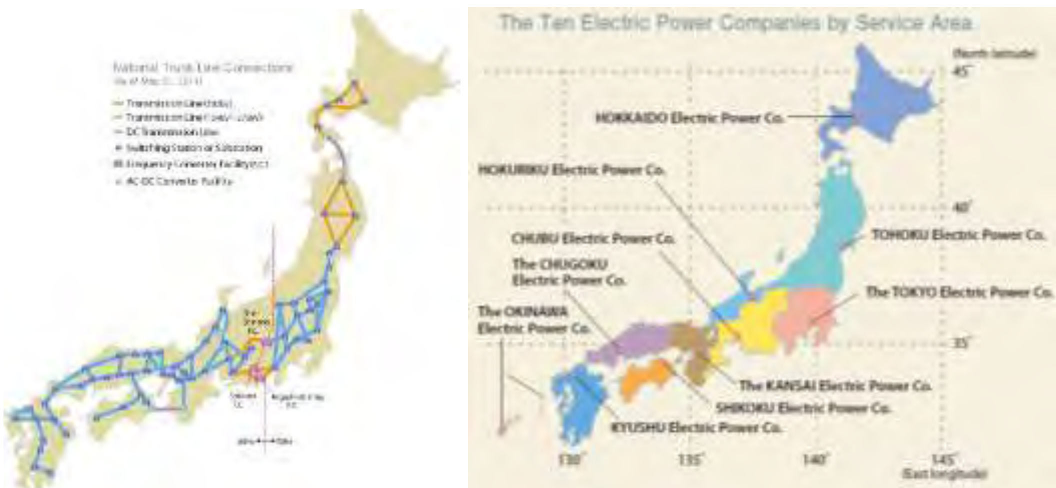
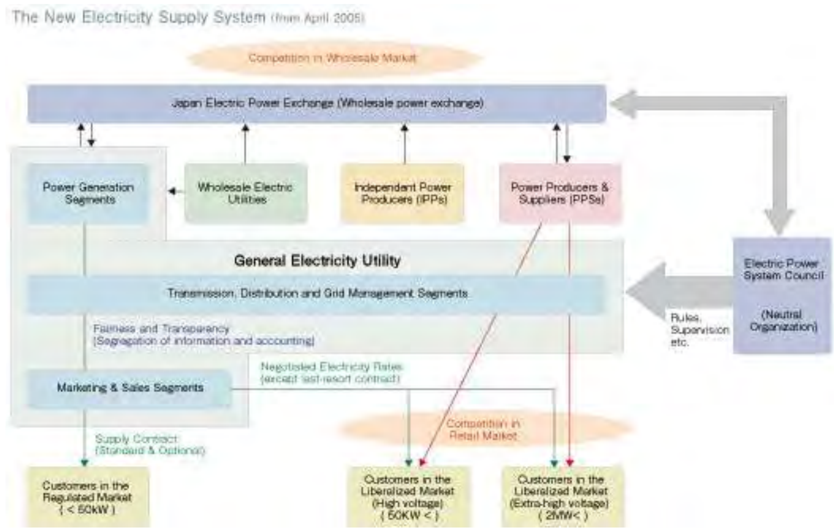


Figure 4.7.1-1 : Power system of Japan

The electric power market in Japan has been progressively liberalized to ensure competitive neutrality on the basis of a stable power supply by the existing 10 general electricity utilities that consistently handle all functions from power generation to distribution. In 1995, a law was revised to enable IPP(Independent Power Producer)s to participate in the electricity wholesale market in addition to the conventional wholesale electricity utilities. Then, in March 2000, use of the transmission/distribution network owned by the electric power companies was liberalized with the partial retail market liberalization of the customers of extra-high voltage and more than 2 MW. The scope of liberalization is now expanded to customers of more than 50 kW. The scope of liberalization covers approximately 60% of total electricity demand in Japan.

To maintain fair and transparent use of the electric power transmission and distribution system, the Electric Power System Council of Japan (ESCJ) was established as the sole private organization to make rules and supervise operations from a neutral position, and started full-scale operation on April 1, 2005. In addition, the Japan Electric Power Exchange (JEPX) was established in November 2003, with investments by the electric power companies, PPS(Power Producer and Supplier)s, self-generators, etc., and started business on April 1, 2005.



* In Okinawa, the scope of market liberalization is different.

Figure 4.7.1-2 : Power market of Japan

(2) Demand and supply mix

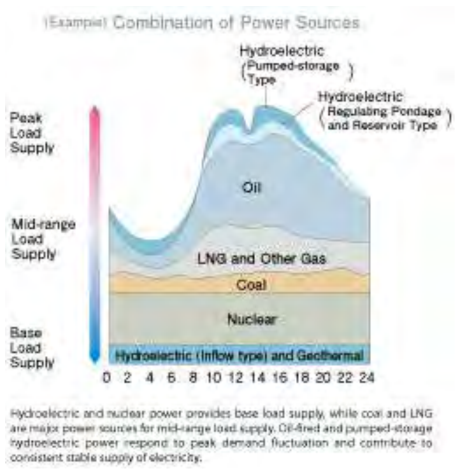


Figure 4.7.1-3 : Daily demand supply balance

Figure 4.7.1-4 : Location of major power plants of Japan

Electric power companies in resource-poor Japan are committed to developing an optimal combination of power sources that combines various energy sources such as hydro, thermal and nuclear power in order to provide electricity, which is essential for modern living, in a stable manner at the lowest prices.

As electricity is nearly impossible to store in large quantities, electric power companies generate electricity by combining various power sources, considering optimal operational and economic performance, to ensure that the fluctuating demand, such as during the daytime in the height of summer, can always be met.

4.7.2. Penetration of PV and Other Generation,[2][3][4][5][6][7]

(1) The Japanese PV market in 2013

In 2013, for the first time, the annual installed capacity of PV systems in Japan surpassed 5 GW, reaching 6.9 GW, which represents a 306% increase from the 1.7 GW of capacity in 2012 (see Figure 4.7.2-1). In 2010, the Japanese PV market was activated by a subsidy program for residential PV systems and a program to purchase surplus power, at a preferential price, from PV systems with a capacity of less than 500 kW. The cumulative installed capacity of PV systems in Japan in 2013 reached about 13.2 GW, as shown in Figure 4.7.2-1. The market share of each segment is depicted in Figure 4.7.2-2. There are no significant price differences in two types of FITs. However, the increase in commercial FIT is more notable as business operators are easily collecting funds compare to FIT for residential homes which only able to sell surplus energy of PV systems with below 10 kW capacity.

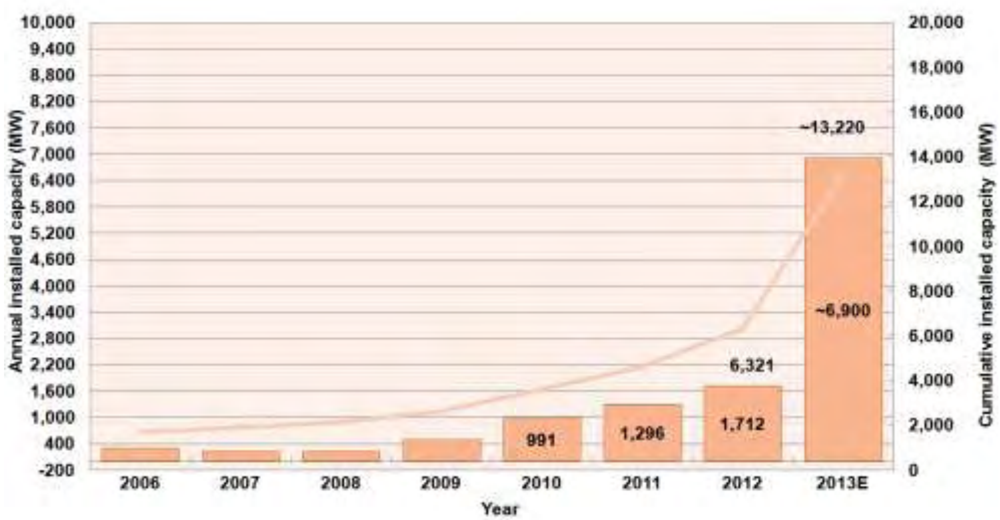


Figure 4.7.2-1 : Installed capacity of PV systems in Japan.
Source : IEA PVPS Task 1, NSR 2013 and SnapShot Report 2014

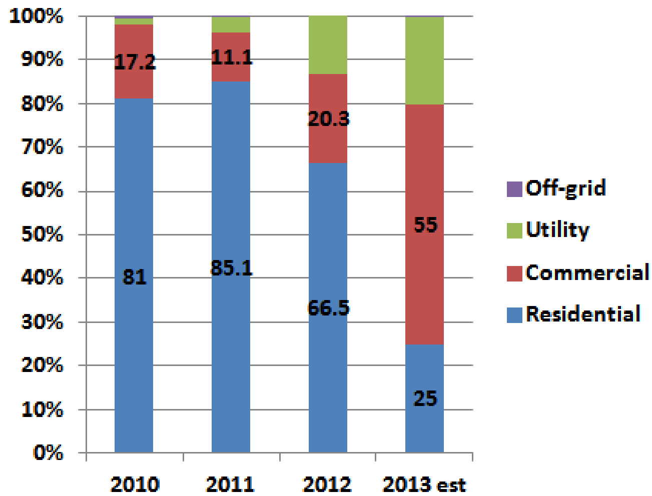


Figure 4.7.2-2 : Market segments of installed PV systems.
Source: RTS Corporation

Residential PV market

The major application in the market has been residential PV systems. The cumulative number of residential PV systems in Japan topped 1.5 million in January 2013. As shown in Figure 4.7.2-3, the annual installed capacity of residential PV systems in 2012 was 1.4 GW. In grid-connected applications, residential PV systems accounted for 66.5% of the total in 2012. The key drivers of this market are the national subsidy program, which provides 35,000 yen/kW (system price is more than 35,000 yen and not exceed 475,000 yen) or 30,000 yen/kW (system price is more than 475,000 yen and not exceed 550,000 yen)for a PV system with less than 10 kW of installed capacity (in FY 2012), and the Surplus PV Power Purchase Program, in which individual PV owners can sell surplus PV power at 42 yen/kWh. In addition to the national government, more than 800 local governments have been continuing subsidy programs, and individuals are able to apply to both programs at the same time.

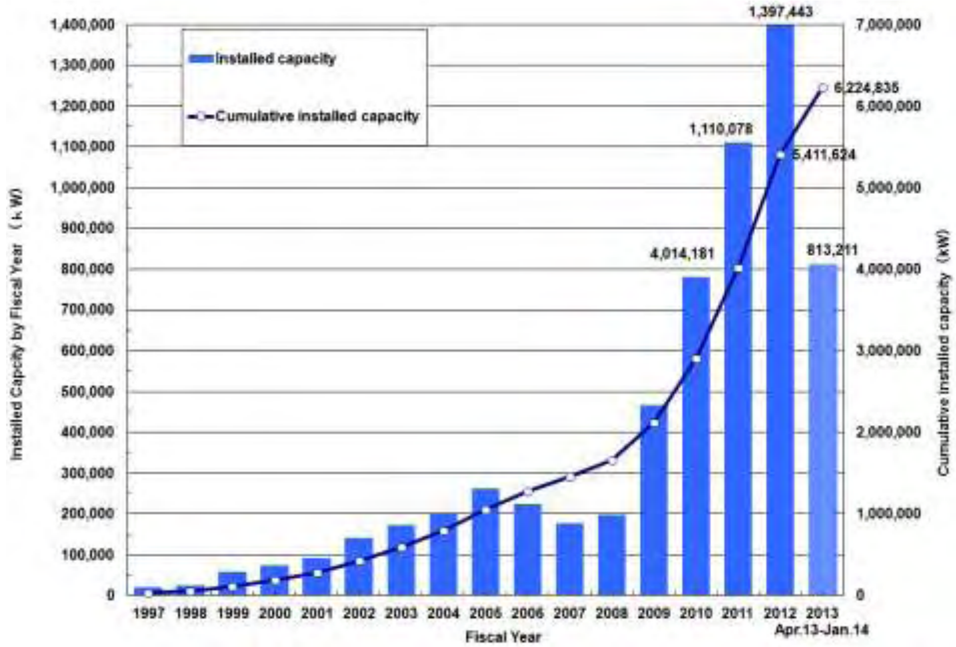


Figure 4.7.2-3 : Installed capacity of residential PV systems in Japan.

Source : JPEA, J-PEC, compiled by RTS Corporation

Commercial and industrial PV markets

As for medium-scale to large-scale PV systems for public and industrial facilities, installed capacity in 2011 was 139 MW, accounting for 10.7% of total grid-connected applications. There were increase of 20% (340 MW) in 2012, and 55% (3.8 GW)in 2013.

In 2011, there were no new projects awarded by the Project for Promoting the Local Introduction of New Energy and the Project Supporting New Energy Operators, which means there was no national support program in 2011 in this category. After experiencing the rolling blackouts that followed the earthquake and the subsequent power shortages in east Japan, however, local governments and municipalities installed PV systems in schools and other public facilities that could be used as evacuation sites in emergency situations.

Large-scale PV plant market

As of 2011, large-scale PV plants with a total capacity of 46 MW were installed for grid-connected, centralized applications, mainly by power utilities. The Federation of Electric Power Companies (FEPC) also announced a plan for 10 electric utilities to construct 32 PV power plants with a total capacity of 160 MW across the nation by 2020. Most of these projects were originally scheduled to be underway by 2012, but construction of MW-scale PV power plants proceeded ahead of schedule, and 25 such PV plants as shown in Table 4.7.2-1 will be in operation by the end of FY 2013. A small number of large-scale PV projects were deployed by entities other than power utilities in 2011. But after the new FIT program that started in July 2012, there are an increase in the number of projects conducted by utility companies and private companies due to an increase in unique subsidies provided by national and local government.

Table 4.7.2-1 : Large-Scale PV Projects of various power utilities
Source: Press releases of utility companies

Power Producer	Scale (MW)	Location	Start of Operation (planned)	Operation
Hokkaido Electric (HEPCO)	1	Date, Hokkaido	Jun. 2011	In operation
Hokuden Eco-Energy/ Hokkaido Electric (HEPCO)	1.5	Ikeda Town, Hokkaido	Dec. 2013	In operation
Hokuden Eco-Energy/ Hokkaido Electric (HEPCO)	1.5	Honbetsu Town, Hokkaido	Mar. 2014	In operation
Tohoku Electric	2	Shichigahama Town, Miyagi	May 2012	In operation
Tohoku Electric	1.5	Hachinohe, Aomori	Dec. 2011	In operation
Tohoku Electric	1	Minamisoma, Fukushima	Jan. 2015	SOC Mar. '14
Tohoku Solar Power/ Tohoku Electric	1.43	Kuji, Iwate	Sep. 2013	In operation
Tokyo Electric (TEPCO)	13	Kawasaki, Kanagawa	Dec. 2011	In operation
Tokyo Electric (TEPCO)	7	Kawasaki, Kanagawa	Aug. 2011	In operation
Tokyo Electric (TEPCO)	10	Kofu, Yamanashi	Jan. 2012	In operation
Chubu Electric	7.5	Taketoyo Town, Aichi	Oct. 2011	In operation
Chubu Electric	1	Iida, Nagano	Jan. 2011	In operation
Chubu Electric	8	Shizuoka, Shizuoka	Feb. 2015	Under construction
Hokuriku Electric	1	Toyama, Toyama	Apr. 2011	In operation
Hokuriku Electric	1	Suzu, Ishikawa	Nov. 2012	In operation
Hokuriku Electric	1	Sakai, Fukui	Sep. 2012	In operation
Hokuriku Electric	1	Shiga Town, Ishikawa	Mar. 2011	In operation
Kansai Electric (KEPCO)	18	Sakai, Osaka	Unknown	
Kansai Electric (KEPCO)	10	Sakai, Osaka	Sep. 2011	In operation
Kansai Electric (KEPCO)	0.5	Takahama Town, Fukui	Nov. 2014	
Kansai Electric (KEPCO)	0.5	Ohi Town, Fukui	FY 2013	In operation
Kansai Electric (KEPCO) / Kyoto Pref.	1.98	Seika Town, Kyoto	Dec. 2013	In operation
Kansai Electric (KEPCO)/TonenGeneral	30	Arida, Wakayama	FY 2014	SOC FY 2013
Chugoku Electric	3	Fukuyama, Hiroshima	Dec. 2011	In operation
Chugoku Electric	3	Ube, Yamaguchi	Dec. 2014	SOC Nov. '13
Chugoku Electric	–	Hatsukaichi, Hiroshima	TBD	
Shikoku Electric	4.3	Matsuyama, Ehime	2020	Partial operation
Kyushu Electric	13.5	Omura, Nagasaki	May 2013	In operation
Kyushu Electric	3	Omuta, Fukuoka	Nov. 2010	In operation
Kyushu Electric/ Kyuden Ecosol	10	Sasebo, Nagasaki	Mar. 2014	In operation
Okinawa Electric	4	Miyakojima, Okinawa	2010	In operation
Okinawa Electric	1	Nago, Okinawa	Mar. 2011	In operation

(2) The new FIT program

The FIT program is based on the Bill on Special Measures Concerning Procurement of Renewable Energy-Sourced Electricity by Electric Utilities (also known as the Renewable Energy Law), which was passed by the Japanese national legislature on August 26, 2011. The law requires utilities to purchase as much electricity from renewable sources as possible so as to intensively expand the use of renewable energy. In November 2009, before the new FIT program started, Japan’s Ministry of Economy, Trade, and Industry (METI) implemented the Purchase Program for Surplus PV Power (an FIT program for surplus PV power), based on the Law on the Promotion of the Use of Non-Fossil Energy Sources and Effective Use of Fossil Energy-Source Materials Energy Suppliers, which had been enacted in July 2009. Under this law, electric utilities were obligated to purchase surplus PV power. Under the new FIT program, the electricity from PV, wind, geothermal, biomass, and small-sized hydropower generation is eligible for FITs. In the case of PV, all the generated power can be sold if the installed capacity of the PV system is 10 kW or larger. While the former program limited the PV system capacity to systems less than 500 kW, the new FIT has not set a maximum output capacity. Figure 4.7.2-4 shows the difference between the former surplus PV power purchase program and the new FIT program.

Table 4.7.2-2: Purchase rate and period of PV system

Category	Electricity to be purchased	Purchase period	FY 2012	FY 2013 FITs	FY 2014 FITs
below 10 kW	Surplus power only	10 years	42 Yen/kWh	38 Yen/kWh	37 Yen/kWh
≥ 10kW	100%	20 years	40 Yen/kWh (tax excluded)	36 Yen/kWh (tax excluded)	32 Yen/kWh (tax excluded)

Source: Ministry of Economy, Trade and Industry (METI), arranged by RTS Corporation

Table 4.7.2-3: Purchase rate and period of PV system (included Basic of calculation)

Category		FY 2013	FY 2014
PV systems with a capacity of 10 kW or larger (non-residential)	FIT	36 Yen/kWh (tax excluded)	32 Yen/kWh (tax excluded)
	Period	20 years	20 years
	Basis of calculation	- System: 280,000 Yen/kW	- System: 275,000 Yen/kW
		- Land development: 1,500 Yen/kW	- Land development: 4,000 Yen/kW
		- Connection: 13,500 Yen/kW	- Connection: 13,500 Yen/kW
		- Land lease fee 150 Yen/m²/year	- Land lease fee 150 Yen/m²/year
		- Repair, labor & other costs: 9,000 Yen/kW/year	- Repair, labor & other costs: 8,000 Yen/kW/year
		- Expected IRR: 6 %	- Expected IRR: 6 %
		- Capacity factor: 12 %	- Capacity factor: 13 %
PV systems with a capacity below 10 kW (residential)	FIT	38 Yen/kWh	37 Yen/kWh
	Period	10 years	10 years
	Basis of calculation	- System: 427,000 Yen/kW	- System: 385,000 Yen/kW
		- Subsidy: National: 20,000 Yen/kW, local: 34,000 Yen/kW	- Subsidy: 0 Yen
		- O&M: 4,300 Yen/kW/year	- O&M: 3,600 Yen/kW/year
		(ca. 1 % of system cost)	(ca. 1 % of system cost)
		- Capacity factor: 12 %	- Capacity factor: 12 %
		- Expected IRR: 3.2 %	- Expected IRR: 3.2 %

Source: Ministry of Economy, Trade and Industry (METI), arranged by RTS Corporation

Purchase price and period

Following the passage of the Renewable Energy Law, the Purchase Price Calculation Committee of METI finalized the purchase price and the period for electricity generated by renewable energy sources, as stipulated by the law. The committee studied the costs and conditions of eligible renewable energy technologies, compiled a final proposal by April 27, 2012, and submitted it to METI. METI solicited public comments on tariffs and purchase periods. This was followed by discussions among: the minister of economy; the minister of the environment; the minister of land, infrastructure, transport, and tourism; and the minister of agriculture, forestry, and fisheries. Subsequently, and with reference to an opinion by the minister of state for consumer affairs, the minister of METI announced the tariff and purchase period.

As shown in Table 4.7.2-2, FITs and purchase periods for 100% of the electricity generated by PV systems with capacities of at least 10 kW were set at 40 yen/kWh, plus a consumption tax, for a period of 20 years. The consumption tax is excluded from the table because the consumption tax rate will probably change in the future. The purchase price is set so as to achieve a 6% internal rate of return (IRR) before tax. Table 4.7.2-2 shows a trends of purchase price , and Table 4.7.2-3 shows the parameters used in the calculation of the purchase price.

For PV systems with capacities less than 10 kW, surplus electricity will be purchased at 42 yen/kWh, including a consumption tax, for 10 years. Because residential consumers, who are the main owners of such PV systems, are not obliged to pay a consumption tax for the sold PV power, FITs are the same for both tax-included and tax-excluded tariffs.

For residential PV systems, the actual FIT is equivalent to 48 yen/kWh if the 2012 governmental subsidy of 35,000 yen/kW is taken into account. The assumed IRR is 3.2% before tax.

This scheme, which provides incentives for surplus PV power, was based on several factors. Owners of residential PV systems are motivated to conserve energy because the less power they consume, the more power they can sell to the utilities from their PV systems. Shifting to the gross FIT scheme (which provides incentive for the entire amount of generated energy) will increase the surcharge, which will be charged to all of the electricity users in accordance with their electricity usage to compensate for the cost of the FIT.

The PV market under the new FIT program

METI estimates that new installation of residential PV systems in the calendar year until the last quarter in FY 2012 will increase by 40% from entire FY 2011, and cumulative installation of non-residential PV systems will increase by about 500 MW by the end of FY 2012. The total additional capacity in calendar year 2012 is thus likely to reach the 2 GW level, compared with 1.3 GW added in 2011, as shown in Figure 4.7.2-1. In 2011, residential PV accounted for 85% of newly installed PV capacity in Japan, as shown in Figure 4.7.2-2. With the new FIT program, and non-residential applications including utility-scale PV power plants will increase significantly (see Figure 4.7.2-5) by making the use of vacant land.

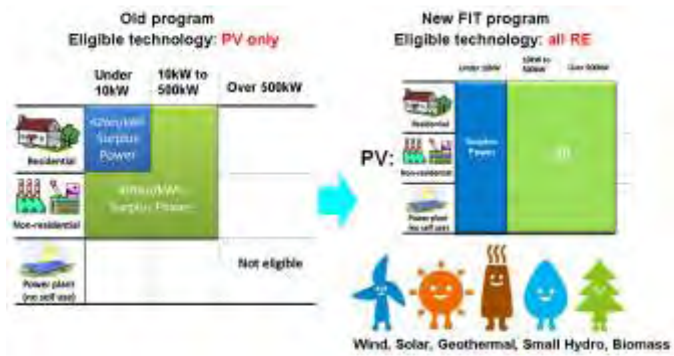
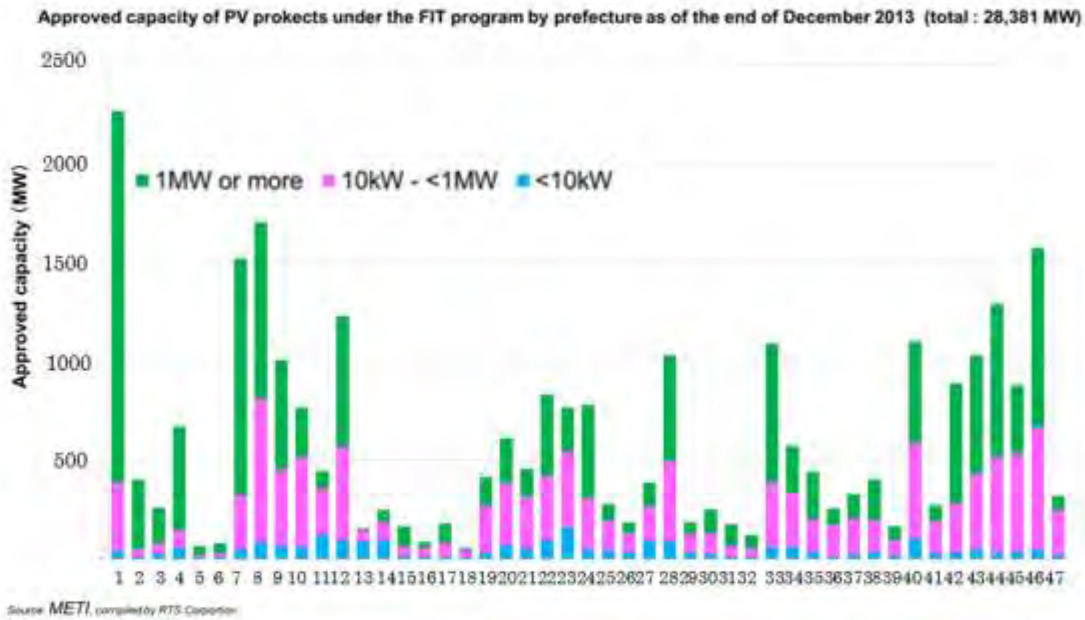


Figure 4.7.2-4 : Difference in eligible technologies between the former surplus PV power purchase program and the new FIT program.

The growth trend in non-residential installations was clear from the first METI report to list approved, FIT-eligible PV facilities, dated August 2012. There were 32,659 approved PV systems with capacities of less than 10 kW; these were mostly residential installations, with a total installed capacity of 144 MW. There were 946 PV systems with capacities of between 10 kW and 1 MW; these were mainly installed on the rooftops of public, commercial, and industrial facilities, and had a total installed capacity of 57.6 MW. And there were 81 so-called “mega-solar” PV systems with capacities of 1 MW or more, mainly large-scale PV power plants, with a total installed capacity of 243 MW.



1) Hokkaido
2) Aomori
3) Iwate
4) Miyagi
5) Akita
6) Yamagata
7) Fukushima
8) Ibaraki
9) Tochigi
10) Gunma
11) Saitama
12) Chiba
13) Tokyo
14) Kanagawa
15) Niigata
16) Toyama
17) Ishikawa
18) Fukui
19) Yamanashi
20) Nagano
21) Gifu
22) Shizuoka
23) Aichi
24) Mie
25) Shiga
26) Kyoto
27) Osaka
28) Hyogo
29) Nara
30) Wakayama
31) Tottori
32) Shimane
33) Okayama
34) Hiroshima
35) Yamaguchi
36) Tokushima
37) Kagawa
38) Ehime
39) Kochi
40) Fukuoka
41) Saga
42) Nagasaki
43) Kumamoto
44) Oita
45) Miyazaki
46) Kagoshima
47) Okinawa

Figure 4.7.2-5: Approved capacities of PV projects under the FIT program by the end of December 2013

The new FIT program has created PV business opportunities in Japan and, by involving local governments, is also providing a strong impetus to revitalize local economic activities. In developing large-scale PV power plants, owners and operators can effectively use spaces at industrial complexes that were developed by local governments and idle land owned by private companies. Companies from various industrial sectors are entering the business of PV generation.

Furthermore, some electric utilities have established subsidiaries specifically for the PV power generation business.

(3) Future prospects

The FIT program has brought about a significant change in the expansion of PV system installations in Japan. PV system deployment, originally led mostly by the supply side, is now mostly led by users. Japanese financial institutions are actively supporting the PV industry. Advances by PV system integrators, PV-utilizing industries, and users are enabling downstream sectors of the PV industry to flourish, broadening the scope of the PV business. Installations of PV systems for public, industrial, commercial, road and railroad, and agricultural applications, which have lagged behind residential applications, have become more easily achievable. These applications are establishing a new core market in addition to the residential PV market. Meanwhile, overseas manufacturers are increasingly entering the Japanese PV market by emphasizing the lower prices of their products.

In July 2008, the Japanese government set a national target for the introduction of PV systems with a cabinet decision on an action plan to create a low-carbon society. This plan specifies targets and measures regarding innovative technological development and the deployment of existing advanced technologies. Among other things, the plan establishes a framework for transforming the entire nation into a low-carbon society. The national targets are to increase PV power generation to 10 times its 2008 level, to 14 GW, by FY 2020 and to 40 times the 2008 level, or to an estimated 53 GW, by 2030. In April 2009, the government formulated an economic stimulus measure named the J-Recovery Plan.

This plan set a new 2020 PV power target: 20 times the cumulative installed capacity (as of 2009), to a level of 28 GW. Figure 4.7.2-6 shows the prospects for PV power installation as presented by the J-Recovery Plan. In this plan, the target for 2030 was kept at 53 GW.

Following the nuclear power plant failures in Fukushima after the March 2011 earthquake, the Japanese government began formulating a new energy strategy from scratch. It is called the Innovative Energy and Environment Strategy and was discussed in the cabinet on September 14, 2012. The strategy stipulates that all available efforts and resources are to be used to reduce the generation share of nuclear power, including maximum deployment of all types of renewable energy.

Before the announcement of the strategy, the National Policy Unit issued its outlook for the energy mix in 2030.

According to that document, the government expects renewable energy to supply 25%–35% of the nation’s total generation, and PV and wind, whose generation is variable, should supply 9%–18%, with the rest coming from hydropower and geothermal plants. In this scenario, the national 2030 PV target will be raised from the current 53

GW to about 60 GW or more. To achieve such a generation mix, the Japanese PV research institutes, industry, planners, project developers, end users, and customers need to successfully address all the challenges of regulation, institutional integration, costs, and reliability. The government has announced that its energy plan will be revised, based on the Innovative Energy and Environment Strategy, by the end of 2012. In parallel with PV deployment in Japan, the Japanese PV industry will also able to contribute to the deployment of PV in foreign countries.

Japan's PV industry must enhance its global competitiveness by continuing to shift its business structure, based on the technologies, engineering, and services that support the life cycle of PV systems.

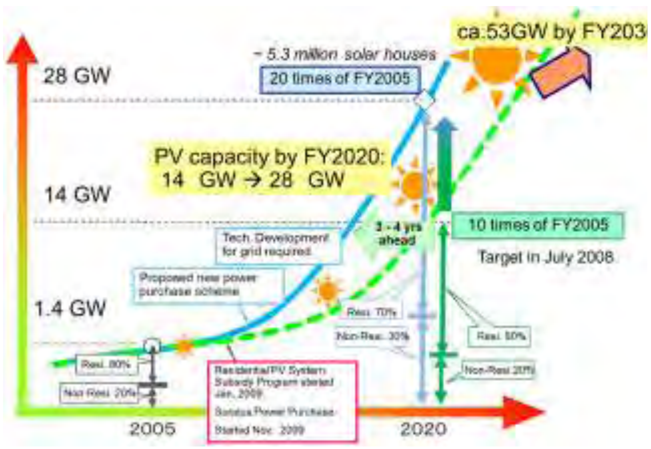


Figure 4.7.2-6 : Target PV capacity in Japan

(4) The Strategic Energy Plan of Japan

The fourth Strategic energy plan

On April 11th, 2014, the Cabinet of the Japan Government decided the third Strategic Energy Plan (The PLAN, herein after) in place for the third Strategic energy plan which was decided in 2010 before the East Japan Earth Quake and the failure of the Fukushima-daiichi Nuclear power Plant.

The PLAN begin with the issues related to the energy supply-demand structure in Japan (Chapter 1) which includes the structural issues faced by Japan and the issues that become apparent around the time of the Fukushima Nuclear Accident. In Chapter 2, the PLAN described the four viewpoints of the basic policy regarding measures concerning energy supply and demand; to first and foremost ensure stable supply ("Energy Security") , and realize low cost energy supply by enhancing its efficiency ("Economic Efficiency") on the premise of "Safety." It is also important to make maximum efforts to pursue environment suitability ("Environment").The PLN also describes the PLAN describes the position of each energy source and time frame (Chapter 3), the promotion of strategic technology development (Chapter 4) and the communication with all levels of the society and deepening of energy related understanding.

Basic energy policy

In "Section 2 Position of each energy source and policy time frame" Basic of Chapter 2, the PLAN states as follows for the total consideration:

To establish a stable energy supply-demand structure in Japan, it is important to identify the characteristics of the respective supply chains of individual energy sources, clarify the energy sources' position in the supply-demand structure and indicate policy directions so that their strengths can be exercised to complement each other's weakness.

Particularly, in terms of electricity supply, it is important to utilize each energy resource based on its character as electricity power source in order to realize energy supply structure where stable supply, low cost and environmental acceptability can be achieved in a proper balance; each energy source is positioned as an electricity power source as below.

1) Geothermal energy, ordinary hydropower (run of river type), nuclear energy and coal as "base-load power source", which can be operated stably and by low cost regardless of day and night.2) Natural Gas and so on as "intermediate power source", which can be produced by low cost next to base-load power source, whose power output can respond quickly and flexibly to the situation of electricity demand. 3) Oil and pumped-storage hydropower as "peaking power source", whose power output can respond quickly and flexibly to the situation of electricity demand in spite of high cost.

In the Section 2, the PLAN, define the position and the policy direction of renewable energy as follows:

Position: *Renewable energy has various challenges in terms of stable supply and cost at this moment, but it is a promising, multi-characteristic and important energy source which can contribute to energy security as it can be domestically produced free of greenhouse gas emissions.*

Policy direction: *GOJ (Government of Japan) has accelerated the introduction of renewable energy as far as possible for three years since 2013 followed by continuous active promotion. Therefore, GOJ steadily proceeds with the enhancement of power grids, rationalization of regulation, research and development for cost reduction, etc. Therefore, GOJ establishes "Related Ministers' Cabinet Meeting on Renewable energy" for policy coordination, and to promote cooperation among related ministries. By these measures, GOJ pursues the higher levels of introducing renewable energy than the levels which were indicated based on the former Strategic Energy Plans, and GOJ takes it into account when it considers energy mix.*

In the Section 2, the PLAN, among the other energy sources, states about solar energy as follows: *Small and medium-scale solar power can be generated in an area adjacent to end users including individuals. Therefore, small and medium-scale solar power reduces the burden on main grids and it can be used as an emergency power source. However, the power generation cost of solar power is high, and power output is unstable. Therefore, further technological innovation is necessary. In the mid- to long-term, cost* *reduction is expected to promote the introduction of solar power based on its position as an energy source which complements peaking demand in daytime hours in the distributed energy system and which contributes to the implementation of energy management involving the participation of consumers.*

Measures for Renewable energy

In Chapter 3 of eight sections of individual measures of energy supply and demand, after “Section 1 Promotion of comprehensive policy toward securing stable supply of resources” and “Section 2 Realization of an advanced energy-saving society and smart and flexible consumer activities”, the PLAN describes “Section 3 Accelerating the introduction of renewable energy: Toward achieving grid parity over the mid- to long-term”.

In Chapter 3, the PLAN states about the acceleration of the introduction of renewable energy as follows: *GOJ has accelerated the introduction of renewable energy as far as possible for three years since 2013 followed by continuous active promotion. Therefore, GOJ steadily proceeds with the enhancement of power grids, rationalization of regulation, research and development for cost reduction, etc. Therefore, GOJ establishes “Related Ministers’ Cabinet Meeting on Renewable energy” for policy coordination, and to promote cooperation among related ministries. By these measures, GOJ pursues the higher levels of introducing renewable energy than the levels which were indicated based on the former Strategic Energy Plans, and GOJ takes it into account when it considers energy mix.*

As concrete measures, appropriate management of the feed-in-tariff system and deregulation measures, such as reducing the period of the environmental assessment, will be promoted. At the same time, in order to resolve problems such as the high power generation cost, unstable power output and the limited availability of suitable locations, diligent efforts will be made to develop technologies for cost reduction and efficiency improvement and conduct development and demonstration projects for large storage batteries and build power grids

The PLAN, after the subsection of “Strengthening measures to accelerate the introduction of wind and geothermal power”, states about PV generation in the subsection of the “Promotion of use of renewable energy in distributed energy systems” for woody biomass, medium/small hydropower, soar power and renewable energy-driven heat, as follows: *Photovoltaic generation has the characteristics of easiness to introduce diversely in medium/small scale with small burden on main grids and of capability for usage as emergency power source. The popularization of photovoltaic generation proceeds in regions such as idle lands, roofs of schools and factories, and GOJ continues to support such measures.*

Feed-in-tariff

The feed-in-tariff program for renewable energy started in July 2012, one year after the East Japan Earthquake. The installed capacity of renewable energy power generation, excluding large-scale hydropower, has grown from 20.6 GW by 9.0 GW (almost PV) at the end of March 2013, indicating steady progress in the introduction of renewable energy.

The PLAN states about the feed-in-tariff in Section 3, as follows: *The objective of the feed-in-tariff program is to accelerate investments in renewable energy by providing predictability regarding the recovery of investments. For this reason, it is important to continue operating the program in a stable and appropriate manner so as to reduce risks involved in the program and enable businesses to concentrate on competition. Also, it is meaningful to consider systems taking vitalization of regions into account including small-scaled efforts.*

On the other hand, from the standpoint of the cost burden on the people, appropriate consideration must always be made; for example, the procurement cost must be reviewed so that it reflects the amount of cost reduction achieved in accordance with the legal provisions. Moreover, the systems for promoting the use of renewable energy sources, such as the feed-in-tariff program, must be comprehensively studied in light of such issues as a cost increase, reinforcement of power grids, in reference to the situations in other countries, and on the axis of developing policy combination which can balance both promotion of maximum use of renewable energy and mitigating people's burden, in accordance with the revision of the Strategic Energy Plan based on the law. Necessary steps will be taken based on the results of the study.

As a total, the PLAN's appears to be less enthusiasm for photovoltaic generation than that for wind and geothermal is partially because the huge amount of certified FIT application of photovoltaic generation (60GW as of March 2014).

4.7.3. Case Study

[A] Operation analysis for a future power system in Japan

(1) Issues with heavy deployment of variable renewable energy

Among renewable energy generation, PV and wind generation output is particularly dependent on weather conditions. When these variable renewable energies are heavily deployed in the existing power system, the deployment may affect the stability of the power supply in various situations, whether in the condition of "normal / an accident" or "specific / system-level."

Table 4.7.3-1 : Main system-level issues in a normal condition

	Normal condition	Accidental condition
Specific Issues	■ Distribution voltage increase due to PV deployment ■ Power flow fluctuation due to wind generation deployment	■ Islanding operation
System-level Issues	■ Insufficient frequency regulation capability ■ Surplus power	■ Simultaneous huge drop-out of variable renewable energy from the power system ■ Instable synchronous operation

In the power system, the frequency fluctuates when the balance of demand and supply crumbles. Therefore, the power system is operated to constantly maintain the balance of demand and supply.

When variable renewable energy is heavily deployed, it may cause difficulties in maintaining demand-supply balance due to insufficient control of a few to 20 minutes short-cycle fluctuation and turning-down of supply during the light-load period.

It is necessary to maintain demand-supply balance based on economic dispatch considering constraint of LFC(Load Frequency Control) regulation.

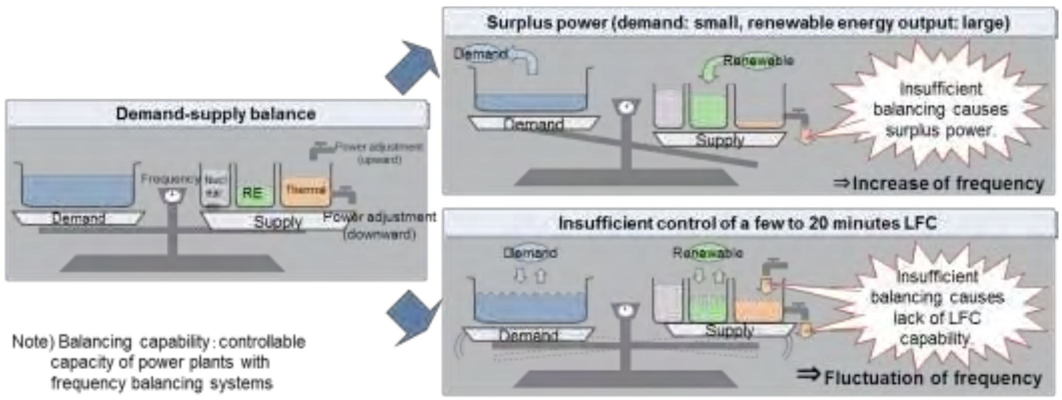


Figure 4.7.3-1: Balancing Capacity

(2) Overview of demand-supply balancing capability analysis for a future power system

The future prospect of 10 Japanese power systems with heavy deployment of variable renewable energy is examined in this analysis. Impediments to renewable energy deployment and the measurement scenario are assessed in a quantitative method as follows:

1) How much PV and wind power will be introduced without the need to take countermeasures against imbalance of the power system?
2) When control of the power system is required, how much can measurement costs be reduced?

The main features are as follows:

1) Assumption: both PV and wind power are heavily deployed.
2) In order to use maximum resources, interconnection is broadly operated if there are no constraints. Specifically, 10 grids in Japan are classified into five blocks for economic dispatch analysis.
3) The power system operation is modeled based on economic dispatch considering constraint of LFC regulation.
(The control of the power system, such as distribution voltage increase, power flow fluctuations, and instable synchronous operation, is out of the scope of this work.)
4) In cases where economic dispatch is not feasible, countermeasures are conducted in the order of demand activation, pumped-storage plant utilization, and generation curtailment.

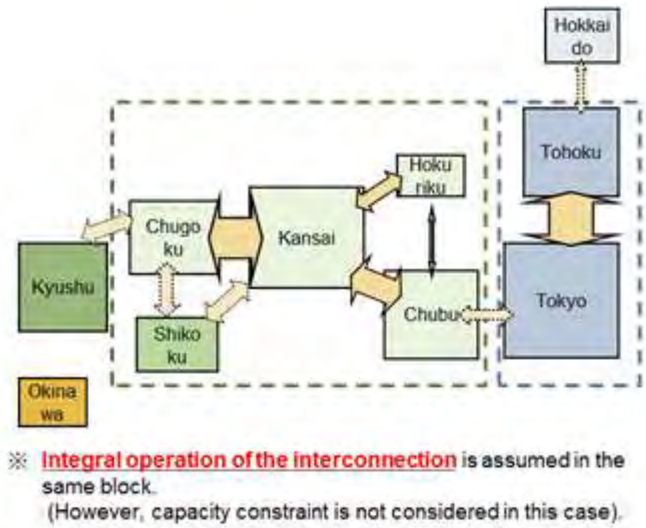


Figure 4.7.3-2: Five Blocks for Economic Dispatch Analysis

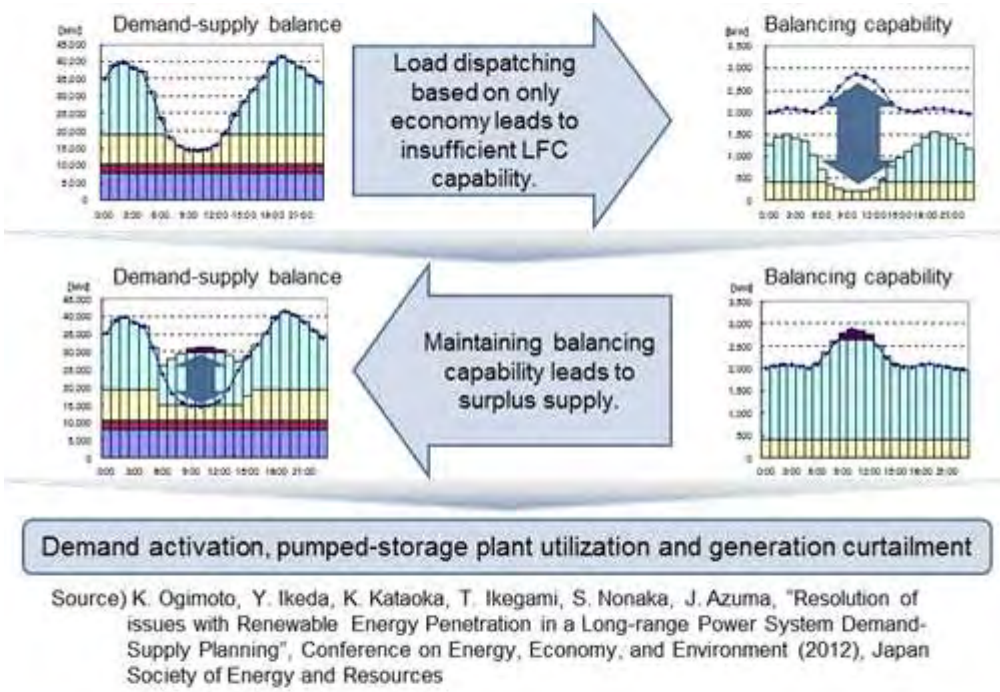


Figure 4.7.3-3: Dispatch Management (image)

(3) Assumptions and results of the analysis

The impact of heavy deployment of PV and wind power in the Japanese power system in 2030 is analyzed based on the following assumptions. The analyzed area is divided into five blocks (see the following table).

It is necessary that about 7% of output of variable renewable energy should be curtailed in the current operation, while less than 5% of generation curtailment would be necessary when demand activation (EV(Electric Vehicle)and HP(Heat Pump) utilization) is taken and pumped storage is actively used.

In Hokkaido, the required generation curtailment rate of variable renewable energy is about 10% even with demand activation and pumped-storage plant utilization. In east and central Japan, the required generation curtailment rate is estimated around 5% or less, and therefore more wind power could be deployed in these areas.

Table 4.7.3-3 : the required generation curtailment rate

Year of analysis, Number of blocks		■5 blocks in nationwide (at the year of 2030)
Demand	Demand of areas and time	■Current demand + additional capacity from activation equipments
	Activation equipments	■Heat pump water heater(14.3 million units), Electric vehicle(6 million cars) ■30% of the above is subject to activation
	Fluctuations regulated by LFC	■3% of demand at the assumed time
Renewable Resources	Deployment capacity	■PV: 100,600 MW（higher-order case） ■Wind power: 32,520 MW（higher-order case）
	Hourly generation of each block	■Estimated hourly generation in each block based on the assumption of weather conditions (Year 2010) and future heavy deployment*
	Fluctuations regulated by LFC	■PV: 10% of hourly generation output ■Wind power: 15% of facility capacity
Conventional Resources	Installed capacity of each block	■Thermal: current installed capacity + partial expansion is taken into consideration（keeping 5% of supply reserve margin） ⁎ Generation output of each unit is respectively dispatched. ■Run-off-river: current installed capacity ■Pumped storage : current installed capacity + power plants under construction
	Balancing capability	■Thermal: 5% of rated capacity ■Pumped storage : 20% of generation output (Variable speed machine also has balancing capability during pumping operation.)

* Source) PV generation: T. Oozeki, J. Fonsec, T. Takashima, K. Ogimoto, “Dataset of photovoltaic system output for power system analysis”, Study group of Frontier Technology and Engineering, Metabolism Society and Environmental Systems (2011), the Institute of Electrical Engineers of Japan

Wind power generation: K. Ogimoto, T. Ikegami, K. Kataoka, T. Saitou “Wind Firm Generation Data Collection and Analysis in Japan for Power Demand and Supply Analysis”, the National Convention of the Institute of Electrical Engineer of Japan (2012), the Institute of Electrical Engineers of Japan

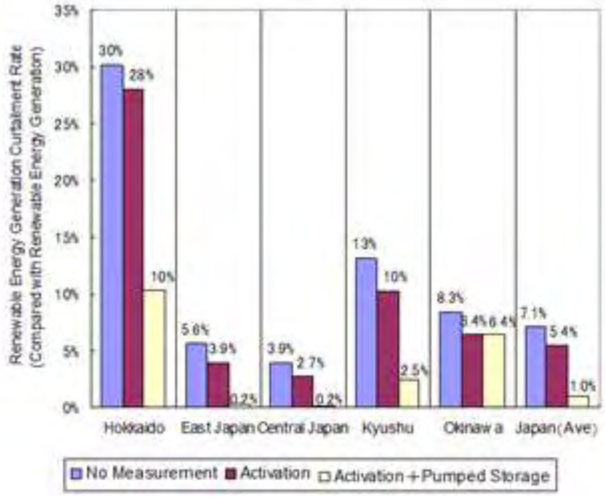


Figure 4.7.3-4: Generation Curtailment Rate of RE
(Capacity of deployed renewable energy : higher-order case)

(4) Sensitivity analysis of the areas where wind power is deployed

In order to analyze the effects caused by the local differences, the total deployed capacity of in Japan is kept the same level and the capacity of Hokkaido and Tohoku is proportionally divided.

Required generation curtailment rate in each block after active implementation of demand activation and pumped-storage plant utilization. The deployed capacity of wind power in Japan as a whole and other blocks are set the same as the initially assumed capacity (Japan: 32,520 MW, Central Japan: 8,570 MW, Kyushu: 4,930 MW, Okinawa: 410 MW).

When the deployed capacity of Hokkaido is 1,000 MW (Tohoku: 17,610 MW), the generation curtailment rate of Hokkaido decreases to 2.6%, while the rate of Tohoku slightly increases to 0.3%. As a result, the national average decreases to 0.7%.

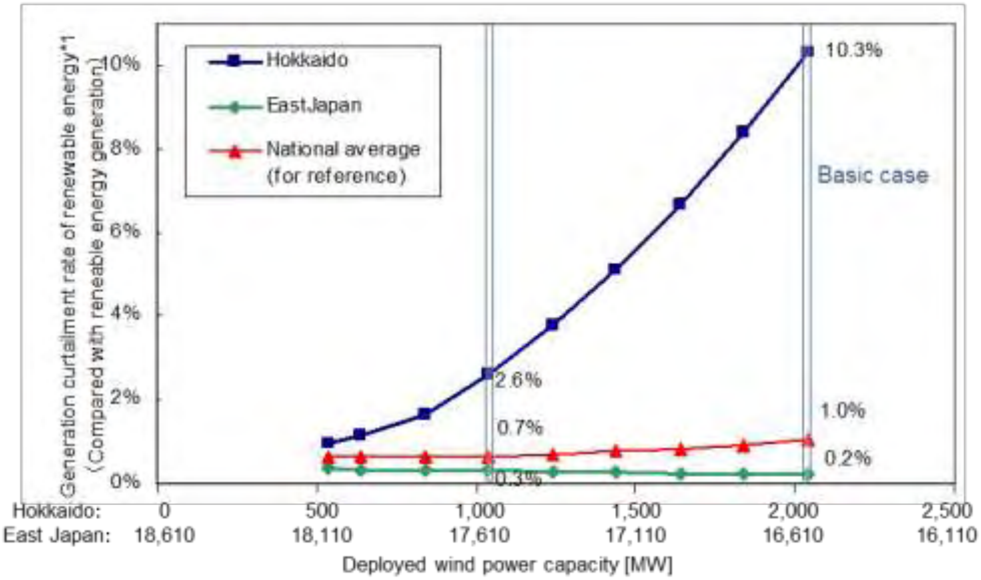


Figure 4.7.3-5: the generation curtailment rate of Hokkaido decreases

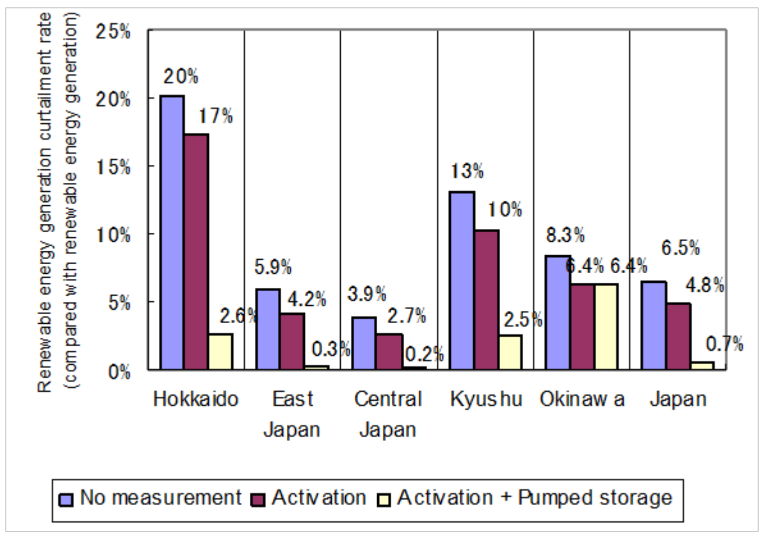


Figure 4.7.3-6: Wind Power Generation Curtailment Rate in accordance with local differences of introduced areas
(Deployment capacity of renewable energy : higher-order case)

[B] System augmentation analysis: energy supply and demand circa 2030

The nuclear accident due to the Great East Japan Earthquake and a following tsunami on March 11, 2011 has seriously affected the energy policy of Japan. After the accident, there is a concentrated discussion on the future energy demand-and-supply in Japan including the substantial deployment of renewable generation including Photovoltaic (PV) and wind which have variable and partially predictable nature of generation.

However, for the sustainable energy/power demand and supply for the sustainable society, we need to pursue the essential targets of the energy system (1). This study, based on a power demand and supply analysis of Japanese ten power system in 2030 including the evaluation of balancing capability of a power system, discusses the future generation mix including PV.

(1) Methodology

ESPRIT is a tool to investigate long-term electricity demand by using one function that analyzes probable demand, including the optimization of connections for flows between interconnected systems, and another function concerning plans for the least expensive energy sources. Based on the demand curve for the specific time period (week, month, or season), the characteristics of the unit of generated electricity (rated current, efficiency, fuel type, minimal load, number of days for the planned shutdown, and accident rate), and the cost of fuel, ESPRIT analyzes optimum annual maintenance schedules. The next step is to use the load duration curve for each time period examined to arrive at the optimal load allocation, accounting for the possibility of generator failure, thereby determining the quantity of power of each power generation unit.

After the probabilistic economic load dispatch, ESPRIT has a functionality to check the hourly balancing capability of a power system and to improve load dispatch by putting thermal generators into partial loading (See Figure 4.7.3-7), introducing new pumping and generation operation of pumped storage power plants, and, eventually, generation curtailment of PV and wind generation (5). It is important that the generation curtailment of variable renewable generations can reduce their expected generation variation to reduce the requirement of balancing capability of a power system

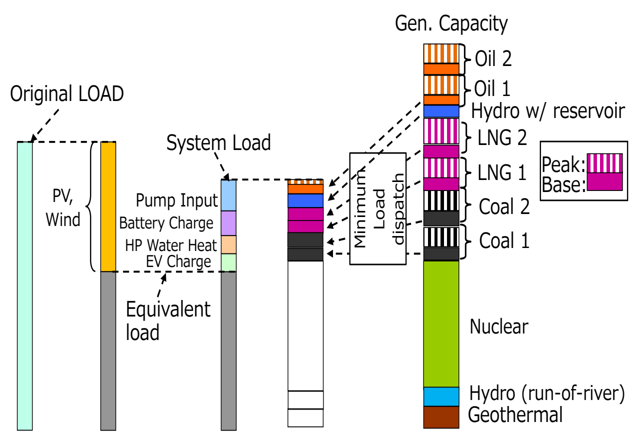


Figure 4.7.3-7： Minimum load dispatch for Max balancing capability

As a result of the analysis, indices are calculated regarding such aspects as operating costs (fuel costs and power-outage costs), supply reliability (loss of load probability, expected unserved energy, etc.), and the volume of CO_2 emissions.

(2) Preconditions and assumptions

ESPRIT modeled each of the 10 power grids that exist in Japan, each operated by a different power company, while taking into consideration the Power Supply Plans of power companies for 2010 and 2011, the Japan Long-Term Energy Outlook, and the Japanese government's Basic Energy Plan. Scenarios are then devised (as shown in Table 1) for situations based on four basic nuclear scenarios: (1) Pre-disaster plan; (2) Continuation of nuclear development (including scenario 2b, where nuclear power is eliminated in 40 years); (3) Suspension of nuclear development (and elimination in 40 years); and (4) Elimination of nuclear power within five years (including scenarios 4b and 4c, depending on whether thermal power or renewable generation is aggressively expanded to pick up the slack). Comparisons are made of the proportion of nuclear generation capacity under each scenario (Figure 4.7.3-8).

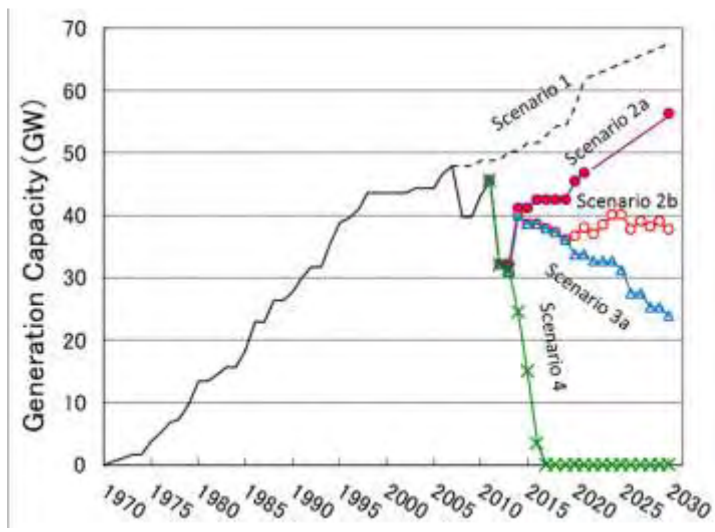


Figure 4.7.3-8: Generation Capacity

Table 4.7.3-4 : Scenarios for Nuclear Power

No.	Scenario	Shape in 2030
1	2010 Plan	The outlook before the 3.11 disaster, which is based on the Long-Term Energy Demand and Supply Prospect in 2008 and the Energy Basic Plan in 2010 of METI. 14 new reactors will be built by 2030 with a 90% utilization factor. PV of 53 GW, Wind of 10 GW
2a	Continued Nuclear Development	Continued nuclear development with some delay. Existing nuclear units will be demolished after 60 years of operation. PV of 80 GW, Wind of 28 GW
2b	Continued Nuclear Development, 40 year life	Continued nuclear development with some delay. Existing nuclear units will be demolished after 40 years of operation. PV of 80 GW, Wind of 28 GW
3a	No Nuclear Development, 40 year life	No new nuclear development Existing nuclear units will be demolished after 40 years of operation. PV of 80 GW, Wind of 28 GW
4a	Abolition in 5 years	No new nuclear construction. Existing nuclear units will be demolished in 5 years PV of 80 GW, Wind of 28 GW
4b	Abolition in 5 years, and aggressive fossil fuel power development	No new nuclear construction. Existing nuclear units will be demolished in 5 years. To compensate, 37.5 GW coal and natural gas-fired power plants will be additionally developed to compensate for the reduction of nuclear power. PV of 80 GW, Wind of 28 GW
4c	Abolition in 5 years, and aggressive PV and wind development	No new construction. Existing nuclear units will be demolished in 5 years. PV of 160 GW, Wind of 160 GW will be developed to compensate for the reduction of nuclear power.

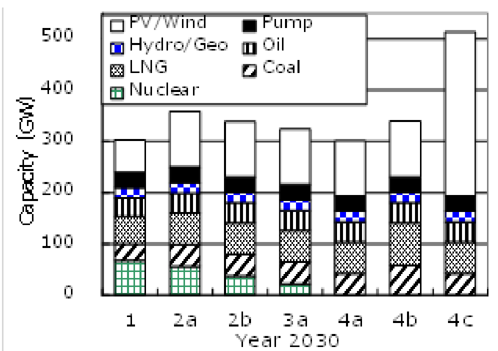
The "augmentation" of thermal power indicated in the pre-disaster forecast scenario was premised solely on the schedule for phasing out thermal plants powered by coal or natural gas over a 40-year period, starting in 2020, and on the announced limitation of oil-fired thermal plants. The construction of new thermal plants up to 2020 is based on the utilities' Power Supply Plans, but from 2021 onward a scenario has been formulated for common use that seeks to ensure a minimum reserve margin of 10% in scenario 2b through the introduction of highly efficient coal-fired thermal plants (including some using integrated gasification combined cycle generation) and highly efficient natural gas combined-cycle powered plants.

The deployment of PV generation assumes situations where solar panels are installed on new houses, existing houses, and other structures, while that of wind power is calculated according to the wind resources in each power system. Meanwhile, for scenario 4b, in which nuclear power is eliminated within five years while thermal power is augmented, the shortfall from the reduction in nuclear power generation (nearly 38 GW by 2030) would be made up for by the active use of thermal power. In scenario 4c, where nuclear power is eliminated within five years and renewable energy is augmented, PV and wind power would be introduced to the maximum extent, given the level of demand, with cumulative capacity of each power source reaching the level of

160 GW by 2030. The condition all the scenarios have in common is that power demand, which is assumed according to the Basic Energy Plan, falls steadily due to the pursuit of low carbon emissions after 2020. The Fukushima Daichi and Daini Nuclear Power Stations will be shut down permanently or out of operation.

(3) Share of installed capacity and generation

Electricity demand in 2030 will have decreased compared to the level in 2020. One portion of the generation shortfall arising from reduced nuclear power capacity will be made up for by the introduction of renewable energy, but from scenario 2a, where nuclear development continues, through scenario 4, where nuclear power is eliminated within five years, the shortfall from reducing nuclear power will mainly be bridged by increased use of coal- and natural-gas-fired thermal plants, including new facilities stipulated under the Basic Energy Plan, and by greater use of the oil-fired plants whose utilization rate was planned to be low.



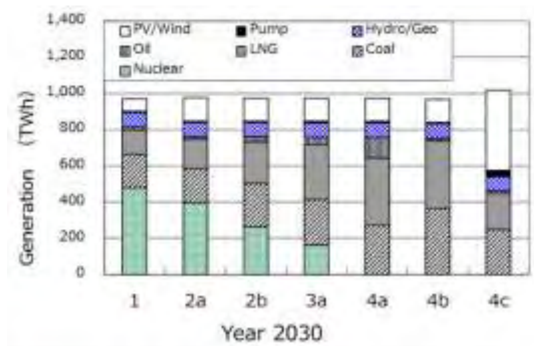


Figure 4.7.3-9: Capacity of each Scenarios **Figure 4.7.3-10**：Generation of each Scenarios

Comparing the three specific cases listed under scenario 4, where nuclear power is eliminated within five years, we see that the augmentation of thermal power in the case of 4b involves increased power generation from coal and liquefied natural gas, leading to a major decrease in the amount of the more costly oil-powered thermal power. In the case of 4c, where renewable energy is augmented, the extremely large-scale introduction of PV and wind power plants will lead to a decrease in electricity generated from thermal plants powered mainly by oil and natural gas, as well as an some increase in pumped-storage hydropower plants.

(4) Costs of fuel and of power generation development

Figures 4.7.3-11 and 4.7.3-12 indicate the fuel costs up to 2030 under each of the scenarios, as well as the combined cost of fuel and power generation development.

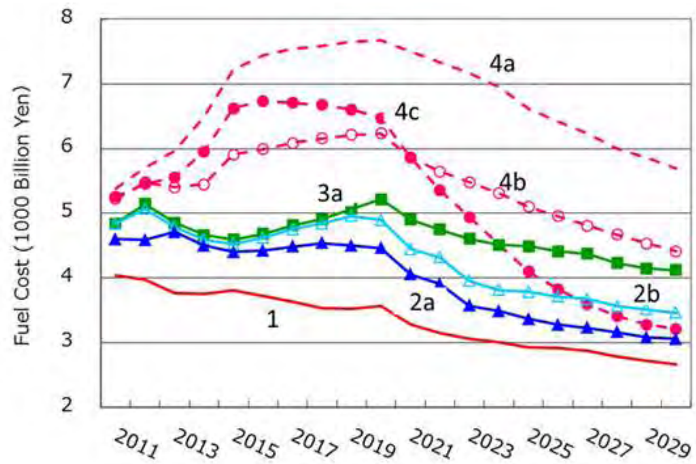


Figure 4.7.3-11： the fuel costs up to 2030 under each of the scenarios

In Figure 4.7.3-11, the annual fuel costs from the rise in thermal power generation as of 2020, compared to the pre-disaster outlook, are estimated to be an increase of 1 trillion yen under scenario 2a (continued nuclear development), of 2 trillion yen under scenario 3 (suspension of nuclear development and elimination within 40 years), and of 4.5 trillion yen under scenario 4a (elimination of nuclear power within five years). Leading up to 2030 there will be a reduction in energy demand stemming from advances in energy conservation, renewable energy and highly efficient thermal power will be introduced, and the number of newly developed facilities will decrease in the case where nuclear development continues. In scenario 4a, though, it will not be possible to greatly bridge the cost gap compared to 2020, whereas great reductions in fuel costs can be expected under scenario 4b or 4c.

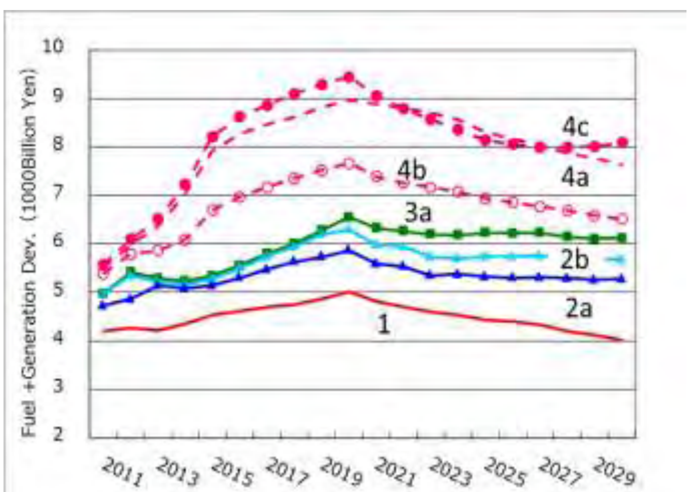


Figure 4.7.3-12：the fuel costs up to 2030 under each of the scenarios

Figure 4.7.3-12, for its part, indicates the annual costs by adding the power generation development expenditures (with an assumed discount rate of 5%) to the fuel costs for each of the energy sources, with a 10-year investment recovery span for solar power, 20 years for wind power, and 40 years for system power supply. Under scenarios 2a to 4a, the savings in fuel costs from the increased use of thermal, PV, and wind power will offset the cost of developing those energy sources. Looking at scenarios 4a, 4b, and 4c, we can see that whereas the annual costs decrease in the case of 4b through the lower fuel costs resulting from expanding thermal power, under scenario 4c the development costs required for the large-scale generation of PV and wind power will result in higher overall costs. This suggests that excessive boosting of renewable energy will have economic drawbacks.

In every scenario excluding scenario 1, where renewable energy is introduced on a large scale, problems arise in power system operation regarding balancing of supply and demand because of fluctuations in renewable power generation resulting from such factors as time of day or weather. This situation may require curtailment of PV and wind power generation, in turn harming their economic viability. The amount of generation curtailment will rise along with the increased use of PV and wind power. Calculation results show that scenario 4c would result in a curtailment of PV and wind generation of around 20% or more, dependent on the characteristics of the fluctuation and countermeasures, and the amount of this curtailment would increase rapidly with the introduction of renewable energy on a larger scale.

(5) Carbon emission volume

Figure 4.7.3-13 shows the quantity of CO_2 emissions. An increase in thermal generation would lead to an increase in emissions under each scenario, ranging from 50 million to 250 million tons. In scenario 4b, where nuclear power is phased out within five years and thermal power increased, there would be no major improvement in carbon emissions even by 2030, but the outcome will be influenced by the increase in the ratio of coal-fired plant operation. In scenario 4c, meanwhile, where the elimination of nuclear power within five years is balanced by increases in renewable energy, the large-scale introduction of solar and wind power will contribute to lower CO_2 emissions.

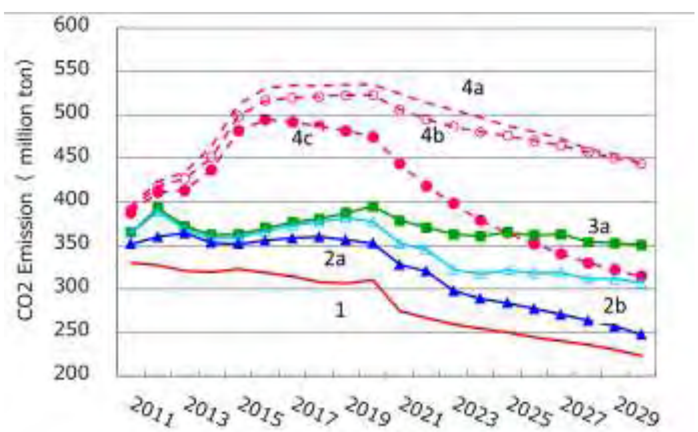


Figure4.7.3-13：CO_2 emissions up to 2030 under each of the scenarios

(6) Consideration for Best-Mix

The power demand and supply analysis indicated that, if construction of new nuclear plants and/or operation of existing nuclear plants are restricted in Japan, even with the maximum possible deployment of renewable generation such as PV and wind power, much of the unavailable nuclear generation will be substituted by an increase of the generation of fossil fuel power plants. The substitute will lead to a substantial increase of fuel cost and construction cost and CO2 emissions of fossil fuel power plants as the current situation in Japan where almost all nuclear power plants are not in operation.

In addition, even if a large deployment of PV and wind power is possible with a drastic price reduction (Scenario 4c), the excessive penetration of renewable energy has a possibility to make difficult problems of heavy capital cost and unstable power system operation due to the shortage of the balancing capability. The issue of the balancing capability will lead to a substantial curtailment of the variable renewable generation to decrease their economy. Figure.12 shows an example of the increase of the renewable generation curtailment with the scenario 4c.

Some further analysis indicates the possibility to resolve the issue of balancing capability of a power system with the heavy penetration of variable renewable generation through the total optimization of the system balancing capability (flexibility) including demand activation. The demand activation considered in the analysis is an next effective technology for balancing not only during emergency period but also in every-day operations for a power system with high penetration of renewable energy generation. The realization of demand activation accompanied by developments in information technology will make it highly effective to realize the future best “demand-supply mix” of a power system.

4.7.4. Issues and Solutions for PV Penetration

(1) General

In March 2011, the Government Revitalization Unit of the Japanese cabinet held a subcommittee meeting on regulatory and institutional reforms and compiled a draft final report on the energy sector, including 183 items relating to energy sector regulatory reform. Many of the reform items had to do with the acceleration of various kinds of renewable energy, including PV generation, to enable the evolution of Japan’s energy system after the March 2011 earthquake. Various ministries are responsible for the reform items, many of which mitigate regulatory and institutional barriers, such as those in the procedures for renewable energy integration, siting, and approval.

Currently, developers constructing large-scale PV power plants face many challenges. Successful implementation depends on the effectiveness of full-fledged deregulation and the timing of the changes. Unnecessary regulations will increase investment costs, thus reducing the profit of the power generation businesses that install PV systems. Among the obstacles, regulations on land use are key. Several ministries involved in land use are greatly affected by the legacy legislation listed in Table 3, and subsequently, PV project planning and approval are also greatly affected. For example, approval for converting agricultural land into a site for PV power generation requires many time-consuming steps.

Generally, it takes a large amount of time to achieve deregulation because it requires coordination among many entities to confirm compliance with existing laws and ordinances, to coordinate stakeholders, to conduct safety checks, to work with many different ministers and agencies, and more. To effectively deregulate, persistent efforts must be made to clarify issues under current regulations, and continued appeals must be directed to concerned parties. It is therefore important for the Japanese PV industry to work hard to identify irrational regulations by means of industrial associations.

There will likely be a need in the future for a comprehensive examination of energy integration, taking into consideration technical and cost issues related to such factors as electricity sources, demand activation, predicted electricity generation, and the operations of electrical systems, as well as the achievement rate and applicability in the case of each technology developed, unit costs for fossil fuels, and uncertainties such as CO_2 restrictions—and these evaluations must take place over the medium to long term.

(2) From [A] system operation analysis

Though the model structures and parameters need to be considered further, the suggestions at this point are as follows:

- There are uncertainties about the output characteristics of PV and wind power when they are heavily deployed. Further measurement and analysis of PV and wind power output data is necessary to elaborate assessment of the effect on the power system and improve countermeasures to be taken.
- Integral operation by utilizing interconnection would have a great potential to balance demand and supply as well as maintain balancing capability. To accomplish the above operation, it is necessary to deal with limitation of interconnection among local areas and spread of adverse effects caused by an accident, etc.

  Required generation curtailment of renewable energy could be reduced by demand activation and increased pumped-storage plant utilization. It is essential to increase acceptability of users and effectiveness of the countermeasures in order to make the most of activation and generation curtailment in practical operation. It is expected that necessary technologies for activation and generation curtailment as well as new value-added products are developed and diffused, and the related policies are established at the same time. As countermeasures for the power system, it is necessary to develop technologies for balancing capability of thermal power and cost-effective interconnection in the power system. It would be necessary to consider policies to promote construction of factories and data centers in areas where countermeasures should be conducted.

There are also several points of consideration as follows:

- When thermal plants with low output operation increase to maintain balancing capability, generating efficiency decreases, and fuel costs and CO_2 emissions increase. The impacts caused by the above reasons need to be assessed in the future.
- Although active utilization of pumped storage is assumed in the analysis, periodic inspection, reservoir capacity, and weekly based operation should be also considered in a practical operation. If the above practice is made, the generation curtailment of renewable energy would increase because additional demand decreases.

- This analysis focuses on balancing capability of demand and supply as power system control. In practical operation, distribution voltage increase, power flow fluctuation, and instable synchronous operation should be also considered. The generation curtailment of renewable energy would increase when the above issues are considered. Power system management would be necessary to solve these problems.

(3) From [B] system augmentation analysis

As Japan moves forward in its rebuilding and recovery efforts for its energy and power generation systems and devises policies to cope with the situation, it will be important to determine measures for the short term as well as the medium and long term, including initiatives to counter a large-scale rise in fuel costs resulting from the loss of nuclear power plants. In the short term it will be important to adopt measures for energy conservation that can be continued into the future, while in the longer term plans must be formulated with an eye to future energy demand, drawing on lessons learned from the 2011 disaster.

The analysis of electricity demand for 2030 indicates that if the operations of new and existing nuclear plants are placed under restrictions, it will be difficult to make up the shortage with solar and wind power even with the maximum possible boosts to their capacity. This will mean that thermal power will play a major role in replacing nuclear power in the energy mix, leading to unavoidable major increases in fuel costs and CO_2 emissions (as seen in scenario 4a). It also shows that major increases in the most efficient thermal power generation using coal and natural gas, along with large-scale introduction of solar and wind power, would make it impossible to bring the costs associated with energy supply or CO_2 emissions down to the levels envisioned in the government's Basic Energy Plan. A large-scale increase in solar and wind power would make it difficult to adjust the energy supply as needed, meaning a high probability of considerable restrictions in the energy available, given current technology. The analysis shows that future rollouts of renewable energy, if they are to go beyond a limited scale, will require technological breakthroughs.

Various means have been devised up to now with regard to security for electricity and energy demand, but it is necessary to strengthen approaches from various new perspectives, such as preparations for major blackouts, which the disaster has revealed to be insufficient. Moreover, the large-scale nature of thermal and nuclear power facilities, along with the restriction of wind resources to certain locations in Japan, make it unavoidable to position electric-power development in areas that are distant from the centers of demand. The nation will need a new electrical grid designed with the introduction of more solar power and new needs like electric-vehicle recharging in mind. Coming up with the "best mix" (including transmission and distribution facilities) is therefore important. In particular, the demand activation described in this analysis will be a vital approach in securing supply adjustment capability throughout the power system as a whole, balancing the demand side with the supply side—not only in cases of natural disasters and other emergencies but also at the development stage of renewable energy. It will be important to aim for steady implementation of demand activation in tandem with the crafting of information infrastructure and systems.

4.7.5. R&D for Transmission-Level Challenges

Japanese Renewable Energy Law stipulates that electric utilities must not refuse grid connection for electricity generated from PV systems, except for the conditions stipulated by the ministerial ordinance under "securing of preferred grid connection rights of the law.

PV generators must, however, agree to curtail generation when power generation is reasonably expected to exceed the demand-supply balance limit or transmission-distribution capacity limit after the necessary operational efforts and procedures have been taken. To make large shares of PV and wind generation a reality, the flexibility of the power system must be enhanced. This additional flexibility will come not only from the traditional generator, but also from demand activation (automatic demand response), PV and wind generation forecasting, and curtailment and enhanced power system operation.

In Japan, there are many research and technology development projects being conducted relating to the integration of variable renewable generation.

(1) National smart grid demonstration project[8]

METI's Smart Grid Demonstration Project for Next-Generation Optimal Control of the Power Transmission and Distribution Network(FY 2010–FY 2012) address the two major issues regarding PV integration into a power system. One issue is related to voltage in distribution networks; the other concerns the power supply and demand balance across the entire power system. The METI projects deal with these issues by establishing the following four groups:

- ✔ Group 1 deals with the optimal allocation and control of voltage-regulating devices.
- ✔ Group 2 is addressing the development of high- performance power electronic devices for distribution networks.
- ✔ Group 3 is concerned with the optimal control of customer appliances for demand-supply balance. (see Figures 4.7.5-1, -2)

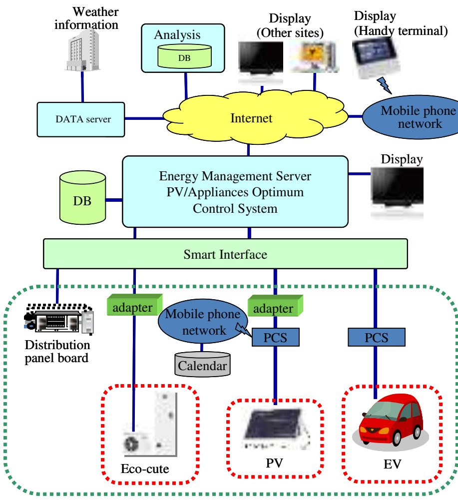


Figure 4.7.5-1 : Schematic configuration of equipments of experimental facilities in the University of Tokyo.

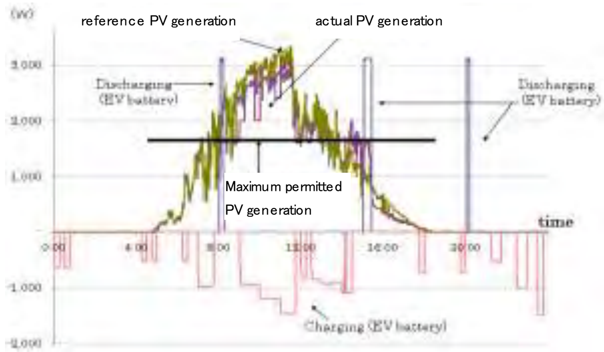


Figure 4.7.5-2 : Experimental result of integrated operation of PV and EV under smart interface.

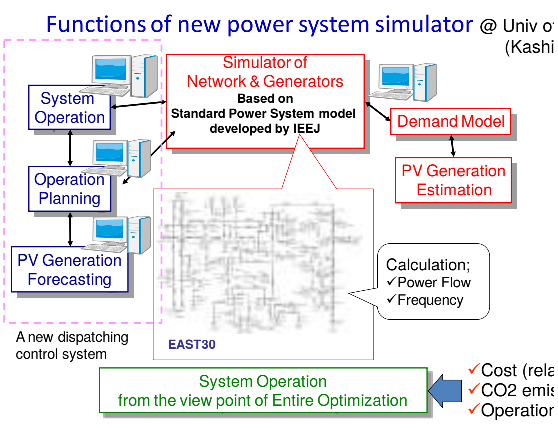


Figure 4.7.5-3 : Schematic image of supply-demand balance in a day with a massive amount of PV systems.

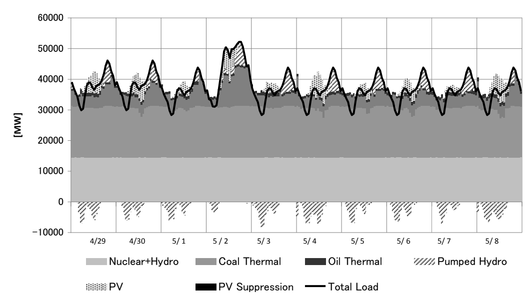


Figure 4.7.5-4 : Results of supply-demand analysis of IEEJ EAST30 model under the integration of 28GW of PV systems in Japan

✔ Group 4 is developing solutions for the optimal planning and operation of a power system that take into consideration generation forecast and demand (see Figures 4.7.5-3, -4).

Japan's emerging solutions for optimal planning have also been accumulating and analyzing synchronized 10-second irradiation data from more than 300 sites across Japan to understand the variability of the solar resource.

(2) National project for PV generation forecast

This effort is taking place as part of METI's Demonstration Project of Forecast Technologies for PV Generation (2011–2013), which is a joint project of weather service companies, manufactures, research institutes, and Japan's 10 power companies, as shown in Figure 4.7.5-5.

The other project for developing forecasting technologies is called R&D for the High-Performance PV Generation System of the Future and is being conducted by Japan's New Energy and Industrial Technology Development Organization (NEDO). The Japan Meteorological Agency has joined the project along with other collaborators, including weather service companies, universities, and national institutes; together they are studying PV system technologies, as shown in Figure 4.7.5-6. The project also aims to improve the numerical weather prediction model for PV system operations.

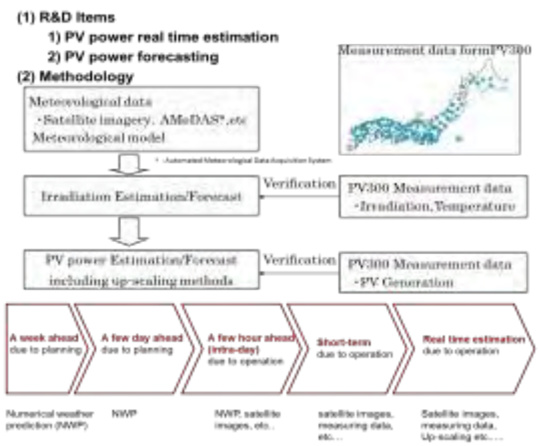


Figure 4.7.5-5 : METI's Demonstration Project of Forecast Technologies for PV generation. *Automated meteorological data acquisition system.

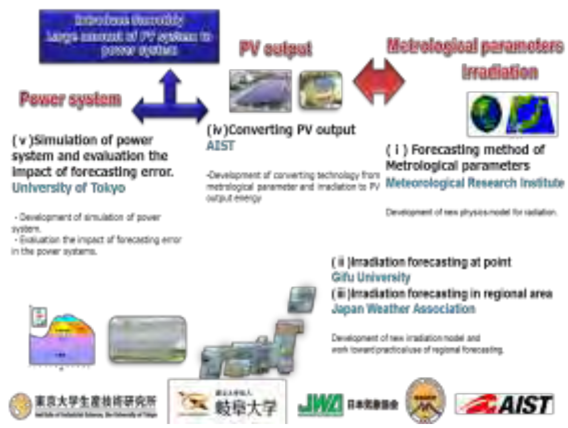


Figure 4.7.5-6 : NEDO's R&D project for PV output power forecasting.

(3) Power system security assessment with high penetration of photovoltaics, [9]

It is important to ensure power system stability (rotor angle stability, frequency stability, and voltage stability) following transmission system faults with high penetrations of renewable energy (primarily PV).

However, the influence of transmission-system faults on the power system has not yet been fully investigated with high penetrations of PV. Therefore, it is important to clarify the influence and countermeasures against power system stability for the future power system.

Reinforcement of power system simulator

To evaluate the effects of PV on power system stability, the Central Research Institute of Electric Power Industry (CRIEPI) has reinforced its Power System Simulator. CRIEPI's Power System Simulator has been a powerful tool for comprehending various abnormal phenomena through realizing severe faults in power systems and finding solutions to various stability problems. The simulator was expanded for the following two purposes:

1) Understanding the influence of high penetrations of PV power generation on rotor angle stability, frequency stability, and voltage stability of power systems
2) Developing numerical models of PV for dynamic time-domain simulations.
Through these studies, technologies will be developed that can realize high penetrations of PV without hampering power system stability.

The schematic diagram of the reinforced Power System Simulator is shown in Figure 4.7.5-7. The light blue part of the figure is the reinforced part. These include PCS(Power Conditioning System) s for PV, a DC power supply emulating PV cells (solar cell simulator), an inverter that can emulate load, battery, etc., a model 66 kV transmission line, a model wind power generators and their control system, a resistive and rotating load, a transformer, and communication equipment. Figure 4.7.5-8 shows PCSs for PV, and Figure 4.7.5-9 shows the 66 kV transmission line emulator.

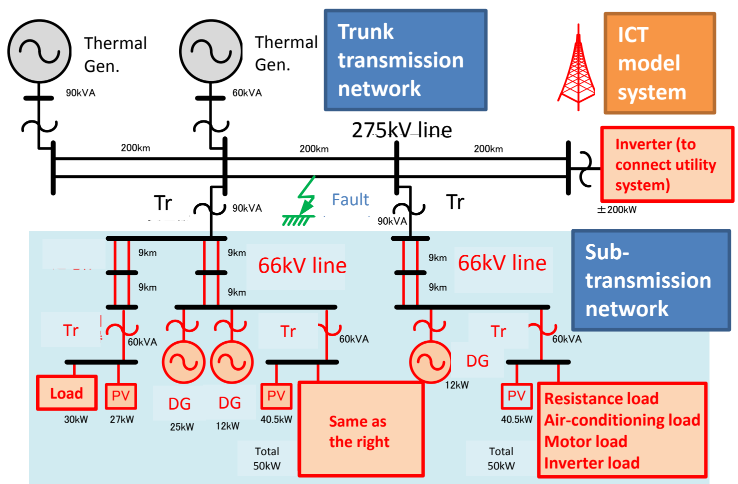


Figure 4.7.5-7: Schematic diagram of CRIEPI's reinforced Power System Simulator

Figure 4.7.5-8: PCSs for PVs

Figure 4.7.5-9: 66kV transmission line emulator

The current research using the Power System Simulator is focused on the following topics:

(1) Evaluation of the influence of power system faults on the transmission system
(2) Experimental tests for extracting the characteristics of the PCS, which consists of the PV inverter with anti-islanding protection
(3) Establishment of the numerical PV models for time-domain simulation
(4) Development of the countermeasures to ensure power system stability for the future power system.

Experimental verification of the fundamental influences of transmission-system faults on the power system with a high penetration of PV

In order to evaluate the fundamental influences of transmission-system faults on the power system with a high penetration of PV, rotating synchronous generators G1 (100 kVA) and G2 (90 kVA) , 275 kV and 66 kV transmission line models, DC power resources that can emulate PV solar panels, and residential-use PCSs for PV (Latest PCS [50]) were installed in CRIEPI's Power System Simulator. Figure 4.7.5-10 shows a test system in the simulator. It is assumed that the synchronous generator G2 could be replaced with the PCSs for PV due to the high penetration of PV. The power transfer limit of G1 was used for the evaluation criterion for the testing systems, which consist of "G1+G2" or "G1+PCSs".

As a result, the power transfer limit of "G1 + PCSs" was approximately 35% lower than "G1+G2". Figure 4.7.5-11 shows an example of test results of the rotor angle oscillation of G1. In the case of the "G1+G2" system, the rotor angle of G1 was well-damped after opening three-phase transmission lines (3LO) between BUS2 and BUS3. On the other hand, in the case of the "G1+PCSs" system, the rotor angle of G1 was not damped following the same disturbance (3LO).

Moreover, the experimental tests revealed that the PCSs of PV could be stopped for a short period depending on the system configurations, such as the length of the 275 kV or 66 kV equivalent transmission line model, the number of the connected PCSs of PV, and the various types transmission-system faults.

[50] Latest PCS model that has new islanding detection relay named AICOT (Anti-Islanding COntrol Technology).

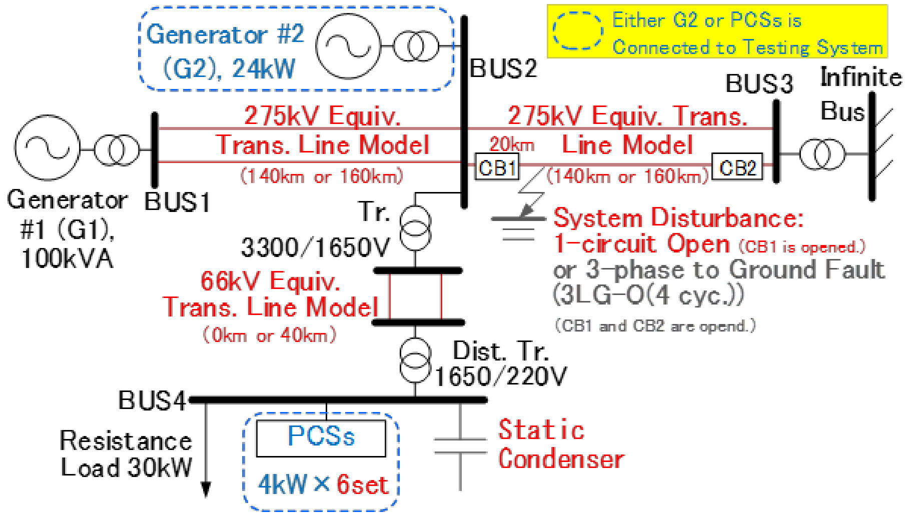


Figure 4.7.5-10： Test systems in CRIEPI's Power System Simulator

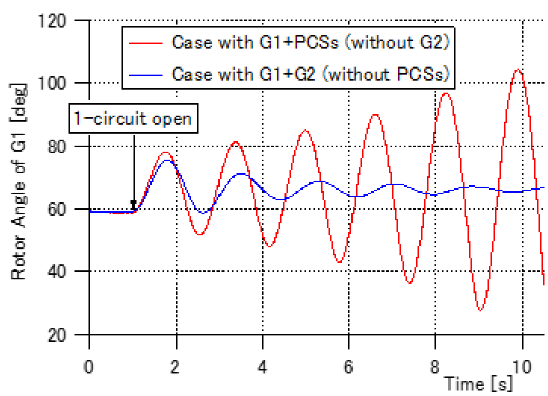


Figure 4.7.5-11: An example of test results of the rotor angle oscillation of G1

4.7.6. Reference

[1] Electricity Review Japan 2013 by Federation of Electric Power Companies of Japan
http://www.fepc.or.jp/english/library/electricity_eview_japan/index.html/

[2] RTS Corporation, "PV Market in Japan 2011/2012," June 2012.

[3] RTS Corporation, "Database of MW-Scale PV Projects in Japan ed.3," August 2012.

[4] I. Kaizuka, T. Ohigashi, H. Matsukawa, and H. Yamaya, RTS Corporation, "Deployment of PV Systems in Japan," IEEE-PVSC 38, June 2012.

[5] M. H. Yamada, NEDO and O. Ikki, RTS Corporation, "IEA PVPS National Survey Report 2011 Japan," June 2012.

[6] K.Ogimoto, I.Kaizuka, Y.Ueda, T.Oozeki, "A Good Fit," IEEE Power and Energy magazine, Vol.11, No.2, pp.65-74 (2013).

[7] Subsidy for measures to support introduction of residential PV systems
FY2011 ： Masamichi YAMAMOTO, NEDO, Osamu IKKI, RTS Corporation, National Survey Report of PV Power Applications in Japan 2011
FY2012 ： Hiroyuki YAMADA, NEDO, Osamu IKKI, RTS Corporation, National Survey Report of PV Power Applications in Japan2012
Source ： NSR

[8] K. Ogimoto, A. Yokoyama, J. Baba, S. Yamada, S. Sakano, S. Ashidate, DEMONSTRATION TEST OF INTEGRATION OF CENTRALIZED AND DISTRIBUTED ENERGY MANAGEMENT FOR PV INTEGRATION, EUPVSEC,5CO.7.3 (2013)

[9] K. Yamashita, K. Shirasaki and Y. Kitauchi, "Fundamental Impact Following Faults in High Voltage Network with large scale of photovoltaics using CRIEPI's Power System Simulator," CIGRE Asia-Osceania Regional Council (AORC), Tokyo, May, 2014.(to be published).

4.8. Italy

(Italian renewable energy scenario 2020 with 25 GW installed PV and 13 GW installed wind, calculation of the day-ahead balancing reserve)

4.8.1. Power System

The Italian grid is synchronously interconnected with the ENTSO-E Continental Europe area with the exception of the island of Sardinia, which is asynchronous and linked to the mainland by two high-voltage (HV) DC links. The extra-high-voltage (EHV) transmission levels are 220–380 kV while the HV level is operated at 132 kV and 150 kV.

(1) Power industry and market

The power system is market regulated. The electricity market consists of: day-ahead and intra-day market sessions; and ancillary services market sessions. The day-ahead market hosts most of the electricity sale and purchase transactions. The intra-day market allows market participants to modify the day-ahead schedules. The ancillary services market is used by the Italian TSO, TERNA, in order to get the resources needed for operating and controlling the power system.

The largest generation company owns 40 GW of generation capacity (conventional and renewable) with a share of 25% of the entire Italian electricity market (data referred to 2012 [1]).

(2) Demand and supply mix

The Italian electricity balance for 2012 is summarized in Table4.8.1-1. The PV production was 5.6% of the total demand.

Table 4.8.1-1: Italian electricity balance in 2012 [2]

Type of generation	[GWh]
Hydro production	43,322
Thermal production	204,796
Geothermal production	5,238
Wind production	13,119
PV production	18,323
Total net production	**284,798**
Pumping consumption	2,627
Net production allocated for consumption	**282,171**
Import	45,369
Export	2,281
Electricity supplied	**325,259**

4.8.2. Penetration of PV and of Other Generation

(1) Italian PV market

The Italian PV market grew impressively during the years 2011 and 2012 due to an appealing incentive policy. In 2012, 148,135 PV plants with a total capacity of 3.8 GW were installed; these new installations increased by 45% the total number of plants [3].

(2) FIT program

Italy introduced the first FIT scheme in 2005 in order to grant incentives for electricity generated by PV plants connected to the grid. Five FIT schemes were introduced; as of December 2013, the number of incentivized operating PV plants was 526,463, with a capacity of 17 GW. The yearly cost of the total FIT scheme is €6.6 billion.[51]

(3) Future prospects

Further solar development is planned in the last National Energy Strategy (March 2013 [4]) at "grid parity" condition (about 1 GW/year up to 2020). In order to reach the new national renewable energy goal for 2020 of 35%–38% of gross electricity consumption (about 120–130 TWh/year of renewable energy production), the allocated investment resource is about €11.5–12.5 billion/year for 20 years. In order to implement this energy strategy, new energy support mechanisms are currently under discussion (January 2014).

4.8.3. Case Study

This section describes the main results concerning the evaluation of the balancing reserve needed in operation planning for the market-regulated Italian system [5]. The PV forecast is included in the operation planning performed in the context of the Italian energy market by means of the application of the methodology proposed and described in the previous section Paragraph 3.1.5. In particular, this section shows the total reserve aimed to ensure the fulfillment of load demand in case of deviations from the expected values of demand itself, wind generation, or solar PV generation, and in case of unexpected unavailability of thermal generation due to forced outages. Moreover, a focus on the influence of the different uncertainty factors is presented here.

(1) Year 2020 scenario set-up

The horizon year 2020 is considered; the corresponding scenario was determined by an extrapolation of 2010. Therefore, the wind and solar PV power generated in 2020 is based on the meteorological conditions that occurred in 2010. Table 4.9.3.-1 shows the hypothesized values of installed power in the six Italian market zones; the total installed

[51] Data updated at December 6, 2013 and available on the GSE website: http://www.gse.it/en/Pages/default.aspx

solar PV power is 25 GW, and wind is 12.68 GW including both onshore and offshore wind farms (no distinction is made in the treatment of the two topologies of wind installations). This assumption is largely in compliance with the Italian Energetic National Strategy "SEN" for renewable growth (23 GW of PV by year 2016 foreseen) and takes into account the effects of the present global crisis, which will certainly affect the future incentives for new installations. For the sake of completion, the actual installed power is also shown.

Table 4.8.3-1: Solar PV & wind installed power – Hypothesis for 2020 vs. present situation

Year 2020 (Adopted hypothesis)							
Installed power [MW]	**North**	**C-North**	**C-South**	**South**	**Sicily**	**Sardinia**	**Italy**
Solar PV	10,729	3,098	3,299	5,400	1,687	787	25,000
Wind (on & offshore)	568	785	1,827	5,143	2,561	1,796	12,680
End of year 2012 (present situation)							
Installed power [MW]	**North**	**C-North**	**C-South**	**South**	**Sicily**	**Sardinia**	**Italy**
Solar PV	7,236	2,017	2,252	3,357	1,123	587	16,572
Wind (onshore)	89	90	1,495	3,631	1,749	987	8,041

The following Figure4.8.3-1 depicts the hypothesized profile of the hourly national load in 2020. Typically, a relevant load reduction is observed in August and on holidays and weekend days; this reduction involves a high decrease of needed balancing reserve because the standard deviation of the load forecast error is essentially proportional to the load forecast itself (see chapter 3.1.2). The average value of the load is 41 GW; the maximum is about 60 GW, whereas the minimum is 23 GW.

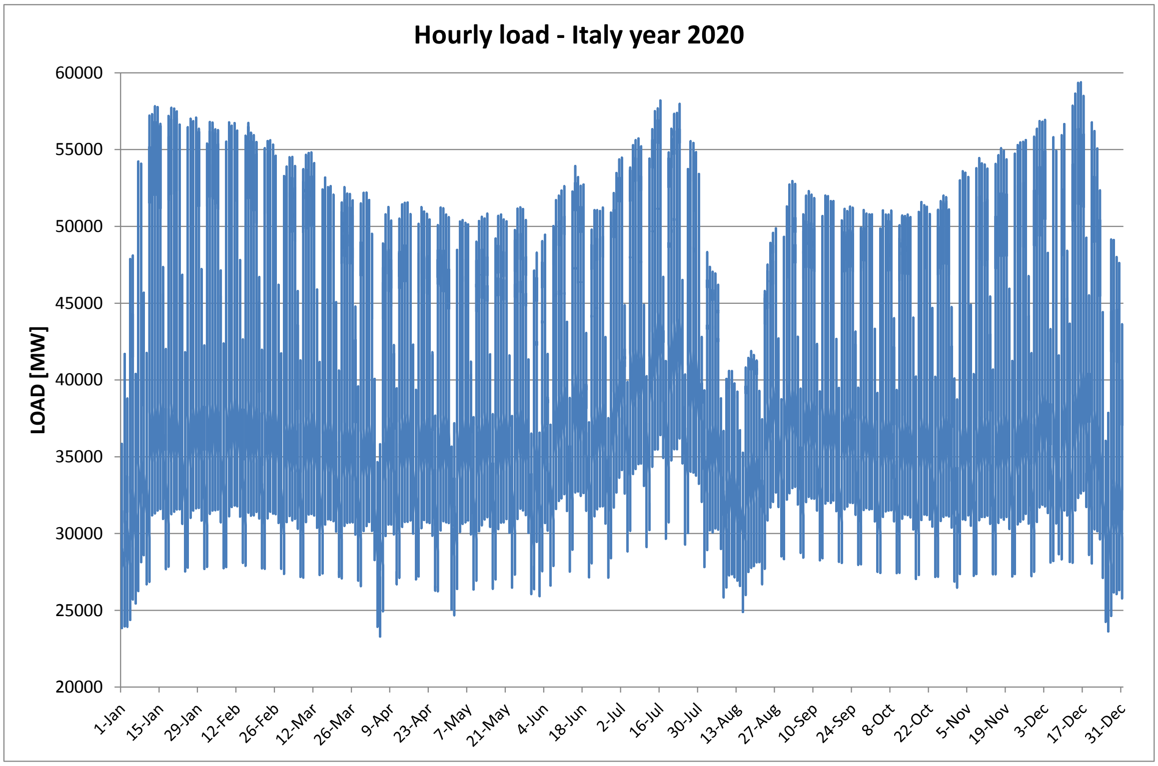


Figure 4.8.3-1: Profile of the hypothesized hourly Italian load for 2020.

High variability usually characterizes the wind generation profile; this can also be seen in the adopted hypothesis of wind generation presented in Figure4.8.3-2.

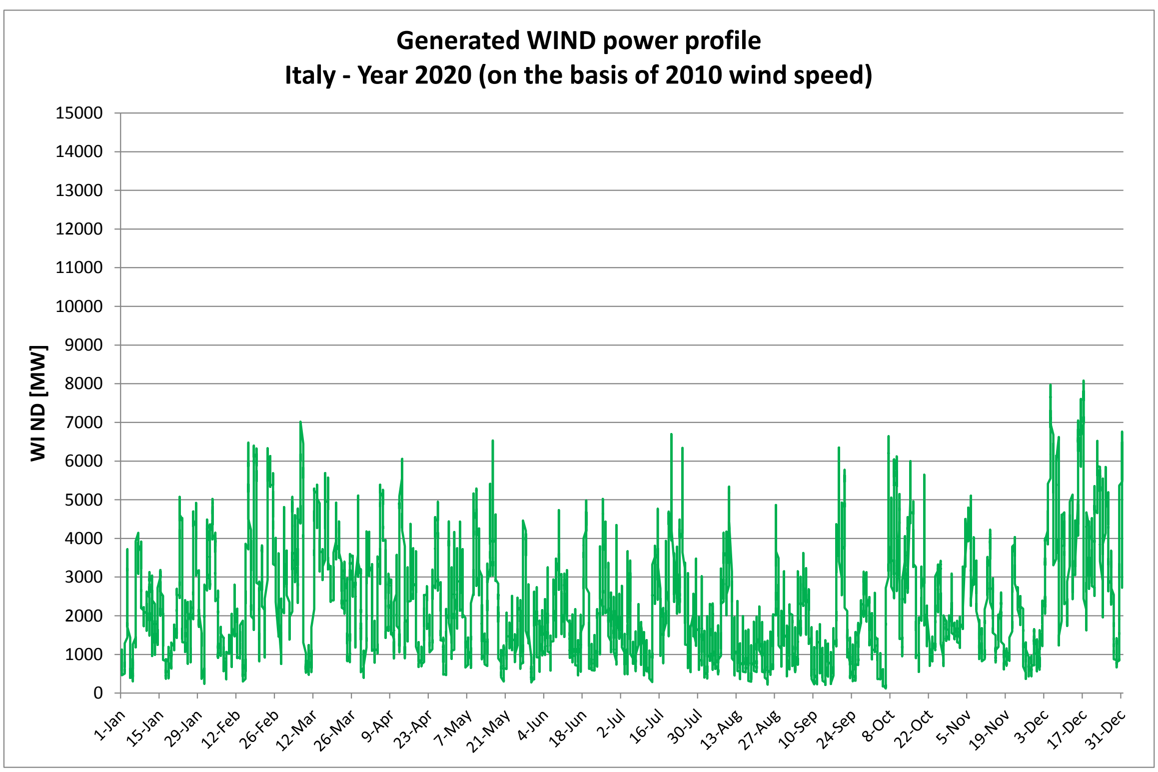


Figure 4.8.3-2: Profile of the hypothesized hourly wind-generated power for 2020.

2020 PV-generated power Figure4.8.3-3) is characterized by a typical profile during the year with some exceptions due to meteorological conditions occurring during the reference year 2010.

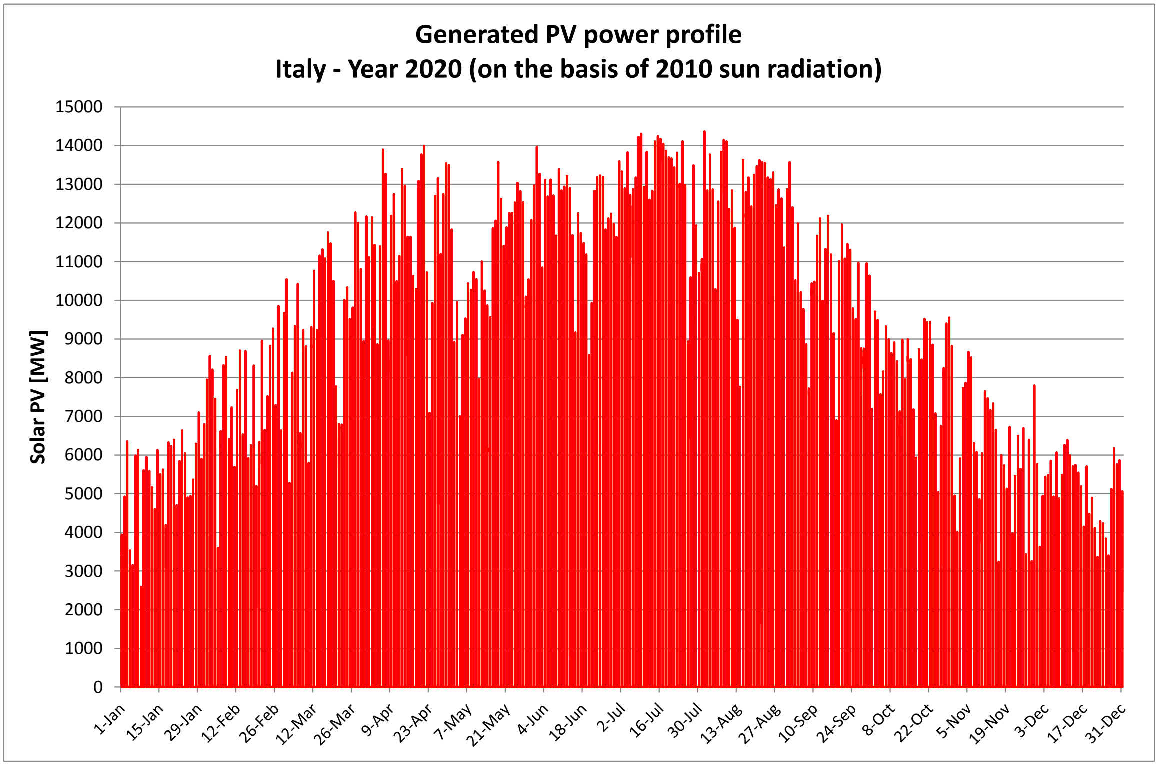


Figure 4.8.3-3: Profile of the hypothesized hourly solar PV-generated power for 2020.

The distribution of solar PV generated power (Figure 4.8.3-4) is more disperse than the wind one because of its large variability between daylight and night hours, especially in summer.

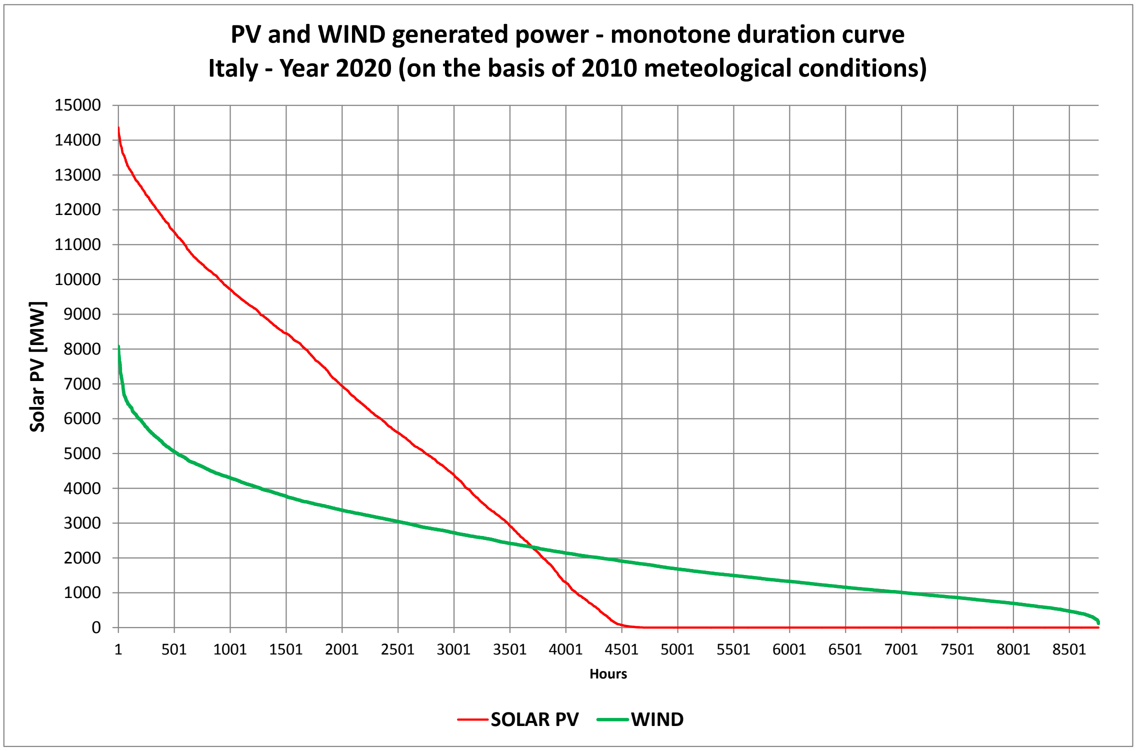


Figure 4.8.3-4: Duration curve of solar PV and wind generated power for 2020.

The following Figure 4.8.3-5 shows the hypothesized profile of the power generated by the thermoelectric power plants in the entire Italian system. The average value is 19,355 MW with a maximum of 25,872 MW and a minimum of 10,017 MW.

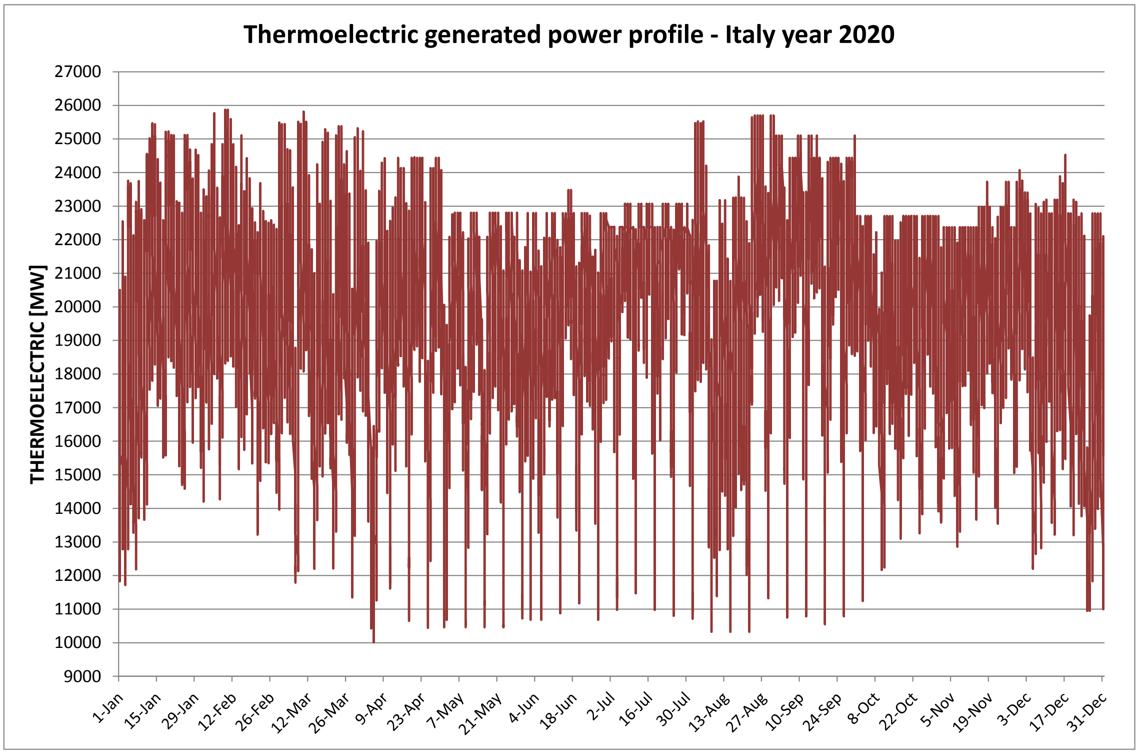


Figure 4.8.3-5: Profile of the hourly thermoelectric generated power for 2020.

Two relevant parameters for the balancing reserve calculation in each zone are the average value, per thermoelectric unit, of the generated power, and the number of units hourly in operation (see Table 4.8.3-2). Given the average generated power value and the probability of full forced outage of the thermoelectric unit, the number of units highly affects the balancing reserve because the higher the units, the higher the probability of loss of more than one unit.

Table 4.8.3-2: Number and average generated power of the thermoelectric units in operation in the six market zones for 2020

Year 2020	North	C-North	C-South	South	Sicily	Sardinia
Average number of units	35	5	9	14	5	4
Maximum number of units	42	7	10	15	6	4
Minimum number of units	27	4	5	8	5	2
Average gen. power. per unit [MW]	252	197	315	320	211	273

Other typologies of generation are not shown in this chapter because they are not taken into account for the balancing reserve, e.g., hydro is considered highly reliable in compliance with the grid code adopted by the Italian TSO TERNA.

(2) Results and notes

The results concerning the needed balancing reserve are shown in this section. First, the total needed reserve is presented, and then the influence of hypothesized renewables is described.

Total balancing reserve in the whole Italian system

Figure 4.8.3-6 depicts the monotonic duration curve of the calculated hourly demand of balancing reserve in the entire Italian system; these values are the hourly sum of the needed reserves in the six market zones.

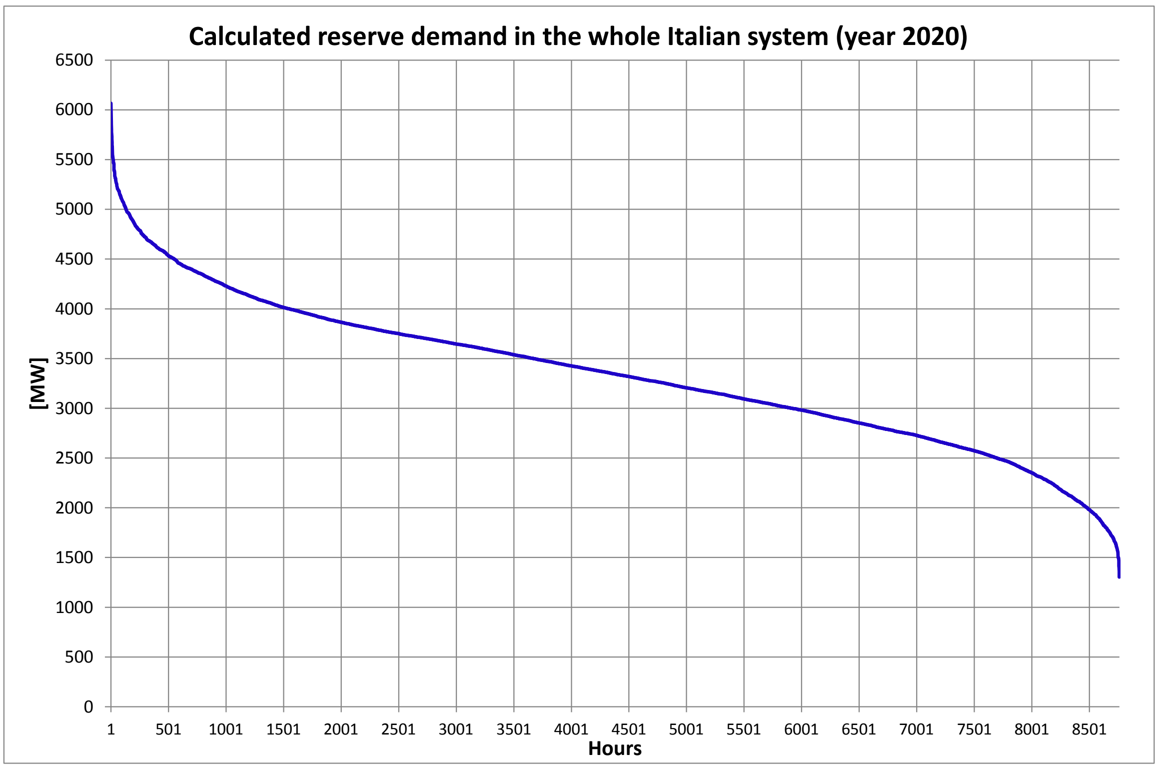


Figure 4.8.3-6: Monotonic curve of the hourly balancing reserve on the Italian system for 2020.

The average value of the reserve demand is 3,347 MW (8% of the average hourly load in Italy). The maximum is 6,066 MW calculated at 12:00-13:00 on Tuesday, May 4 (13% of the corresponding load of 47 GW in the whole Italian system); the corresponding Table 4.8.3-3 summarizes the detail about this hour and the subdivision among the six market zones.

Table 4.8.3-3: Hour involving the maximum needed reserve (12:00-13:00 on Tuesday, May 4)

	Load [MW]	**Wind Gen. [MW]**	**PV Gen [MW]**	**Clearness sky index CI [p.u.]**	**Thermal Gen. [MW]**	**Number Thermal units**	**Reserve [MW]**
North	26,296	372	2,734	0.1	9,200	35	2,102
C-North	5,428	79	826	0.45	1,385	7	550
C-South	7,474	253	904	0.39	1,956	10	689
South	3,523	1,539	1,624	0.44	3,304	15	1,551
Sicily	2,674	959	488	0.38	1,018	5	693
Sardinia	1,520	1,196	295	0.42	986	4	481
ITALY	46,915	4,398	6,870		17,850	76	6,066

It's worth noting that the northern area needs the greatest balancing reserve because it has the largest load (load uncertainty is defined in percentage of load); the most PV generated power even if it's characterized by heavy cloudy conditions (clearness sky index $CI = 0.1$ involving a lower uncertainty; see also Figure 3.1.2-4); and the most thermal-generated power with the largest number of thermal units in operation (this number involves a high probability of one-unit outage and a not-negligible probability of loss of more than one unit). It is also important to underline that, in the remaining market zones, the intermediate value of the clearness index $CI \approx 0.4$ involves a remarkable percentage of uncertainty in the PV generation (ref. Figure 3.1.2-4).

The minimum calculated reserve value is 1,304 MW at the nighttime hour 0:00-1:00 of Tuesday, January 5 (see Table4.8.3-4). Also in this case, the northern area has the maximum needed reserve because it has the largest load, the maximum number of thermal units in operation, and maximum total power generated by this kind of generation.

Table 4.8.3-4: Hour involving the minimum needed reserve (00:00-01:00 on Tuesday, January 5)

	Load [MW]	**Wind Gen. [MW]**	**PV Gen [MW]**	**Clearness sky index CI [p.u.]**	**Thermal Gen. [MW]**	**Number Thermal units**	**Reserve [MW]**
North	14,602	25	0	*Night hour*	6,259	30	455
C-North	3,357	0	0	*Night hour*	1,071	5	108
C-South	4,902	145	0	*Night hour*	1,727	5	239
South	2,768	152	0	*Night hour*	5,249	14	368
Sicily	2,115	35	0	*Night hour*	1,018	5	84
Sardinia	1,341	24	0	*Night hour*	1,146	4	50
ITALY	29,085	381	0	*Night hour*	16,471	63	1,304

Influence on reserve of the renewable wind and solar PV generation

It is certainly worth assessing the impact on the total needed balancing reserve of the renewable and not programmable generation by PV and wind, which are characterized by a given uncertainty around their respective forecasts. For the sake of simplicity, thermal forced outages are considered, in this paragraph, deterministic events with null uncertainty; this assumption is in compliance with the present practice of the Italian TSO TERNA[52]. The remaining uncertainty, on the basis of the adopted methodology, concerns load, wind, and solar PV with forecast errors assumed as uncorrelated Gaussian stochastic variables with resultant total forecast error, which is still Gaussian with a standard deviation:

$$\sigma_{L-W-PV} = \sqrt{\sigma_L^2 + \sigma_W^2 + \sigma_{PV}^2}$$

Taking into account the above formulation, it's easy to highlight the separate influence of wind and solar PV, respectively.

[52] See also: enclosure 22 (Selection procedure of the needed resources for the scheduling phase of the Italian ancillary services market) of the Italian code for transmission, dispatching, development, and security of the grid. Italian version available at: http://www.terna.it/default/Home/SISTEMA_ELETTRICO/codice_rete.aspx.

Influence of wind and PV

Before analyzing the individual balancing needs due to solar PV, it is important to quantify the combined impact of "WIND+PV" sources, as it is crucial for the balancing reserve provisioning in the Dispatching Services Market (MSD). Moreover, a brief description of the individual impact of wind is suitable in order to highlight the difference from that of solar PV.

The following Table 4.8.3-5 summarizes the maximum, minimum, and average values of the hourly reserve needed to face imbalances due to "WIND+PV" uncertainty. Moreover, data concerning the hourly "WIND+PV" generation are shown; the ratio between the average generated power by PV and wind is useful to understand the different influence on reserve highlighted in the six Italian market zones characterized by different penetration levels of PV and wind generation.

Table 4.8.3-5: Influence of wind and PV generation uncertainty on the needed balancing reserve (horizon year 2020)

Hourly reserve for "WIND+PV" forecasting errors [MW]	**North**	**C-North**	**C-South**	**South**	**Sicily**	**Sardinia**	**ITALY**
Maximum	892	306	429	1,320	560	380	3,737
Minimum	0	0	0	25	1	0	47
Average	56	44	128	678	300	173	1,379
Hourly generated power by "WIND+PV" [MW]	**North**	**C-North**	**C-South**	**South**	**Sicily**	**Sardinia**	**ITALY**
Maximum "WIND + PV"	6,186	2,329	3,019	6,029	2,849	1,914	20,360
Average "WIND + PV"	1,358	534	801	1,748	745	413	5,599
Ratio: $\frac{Average\ GEN_{PV}\ [MW]}{Average\ GEN_{WIND}\ [MW]}$	13.8	2.9	1.4	0.8	0.5	0.4	1.4

It can be observed that in the market zones where PV generation is much higher than wind (North, C-North), there is a high deviation of maximum reserve value from the average annual reserve (ratio of 16 and 7 between maximum and average). The reason for this high deviation is, as already mentioned in chapter ((3), that at night and in very sunny/cloudy daylight hours the solar output is very predictable with low uncertainty. A lower deviation of the highest needed reserve from the average value is instead present where wind generation is greater than that of solar PV (especially in the south, Sardinia, and Sicily). In other words, the solar PV involves the highest values of needed reserve for few hours compared with wind requirements. This can be seen in the following Figure 4.8.3-7 depicting the monotnic curves of the needed balancing reserve in each market zone, with a 95% confidence level: in particular, the reserve values (vertical axis) are shown with the corresponding number of covered safe hours (horizontal axis).

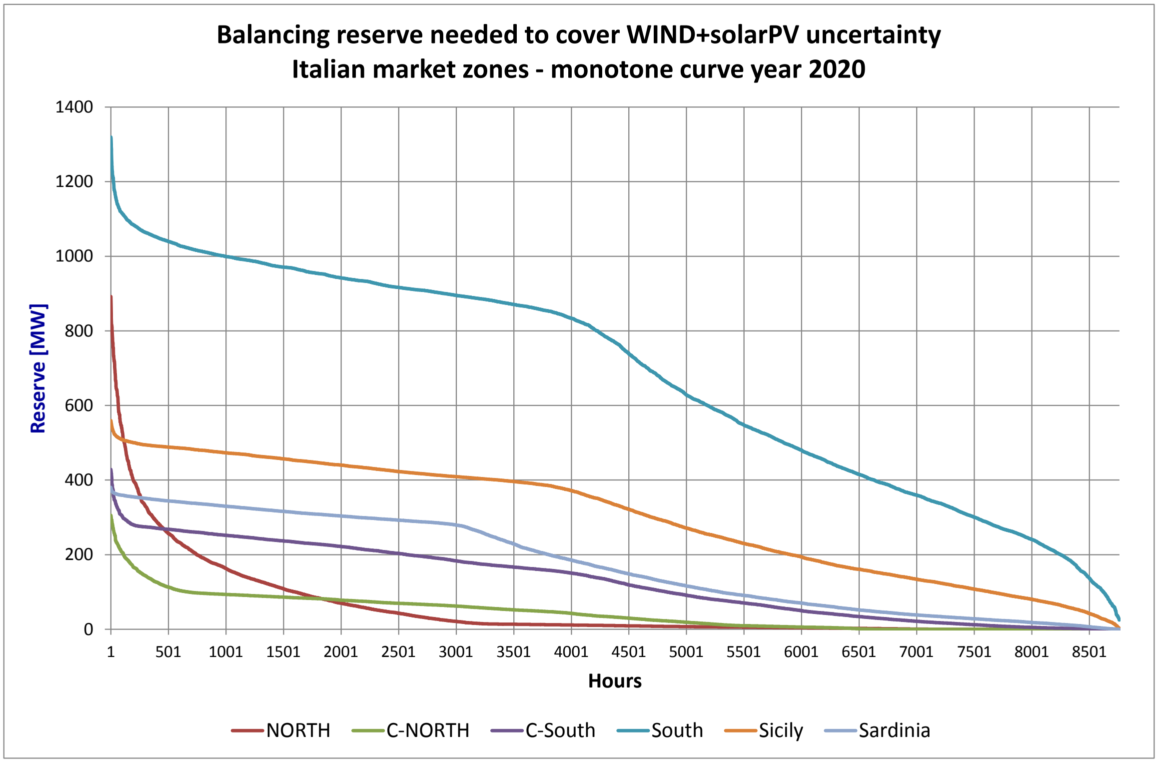


Figure 4.8.3-7: Balancing reserve for "WIND+PV" uncertainty in six Italian market zones for 2020.

For the sake of convenience, the contents of the previous graphs are summarized in Table 4.8.3-6. 80% secure yearly hours in North and C-North (PV prevalent) require a much lower reserve compared with the 100% case. Conversely, South, Sicily, and Sardinia, having mainly wind generation, require, in 60%–80% of hours, a reserve close to the maximum needs.

Table 4.8.3-6: Balancing reserve needed to face "WIND+PV" uncertainty vs. secure hours/year

Monotonic duration curve of needed balancing reserve for "WIND+PV" forecasting errors; 8760 hours/year								
Hour/year in security	**Percentage of secure hours**	**North**	**C-North**	**C-South**	**South**	**Sicily**	**Sardinia**	**ITALY**
8,760	100%	892	306	429	1,320	560	380	3,737
7,008	80%	87	83	230	956	448	309	1,882
5,256	60%	14	52	167	870	396	228	1,621
3,504	40%	6	13	80	588	250	102	1,234
1,752	20%	1	0	21	359	134	38	802

Influence of wind

The following Table 4.8.3-7 reports the results, for each market zone, of the needed balancing reserve due to wind generation; it highlights an average allocation of reserve that is relevant compared with the maximum value. In particular, in the 8,760 yearly hours the average reserve is the 54% of the maximum (average of 1,200 MW vs. maximum of 2,236 MW).

Table 4.8.3-7: Influence of wind on the balancing reserve (horizon year 2020)

Hourly reserve for "WIND" forecasting errors [MW]	**North**	**C-North**	**C-South**	**South**	**Sicily**	**Sardinia**	**ITALY**
Maximum	20	109	284	1,069	507	363	2,236
Minimum	0	0	0	5	1	0	33
Average	4	27	107	614	284	166	1,201
Hourly generated power by WIND [MW]	**North**	**C-North**	**C-South**	**South**	**Sicily**	**Sardinia**	**ITALY**
Maximum	546	785	1,546	3,333	1,972	1,500	8,078
Average	92	136	338	970	489	298	2,323

In order to secure 80% of the yearly hours, a significant demand of balancing reserve is needed (see: Table4.8.3-8 and Figure4.8.3-8): 1,726 MW are needed compared to the not-much-higher value 2,236 MW required to cover the whole year. This is mainly due to wind's availability also in the nighttime hours. Moreover, it is worth remembering that wind uncertainty (in other words, the standard deviation of the forecast wind error) is reasonably assumed as a percentage value of the installed wind power, which slightly depends on the considered hourly time horizons and is independent of the forecast. Consequently, a high ratio between the balancing reserve (needed to cover wind uncertainty) and the generated wind power may be observed: more than 50% for the average values and 28% for the peak values (even if these do not occur simultaneously).

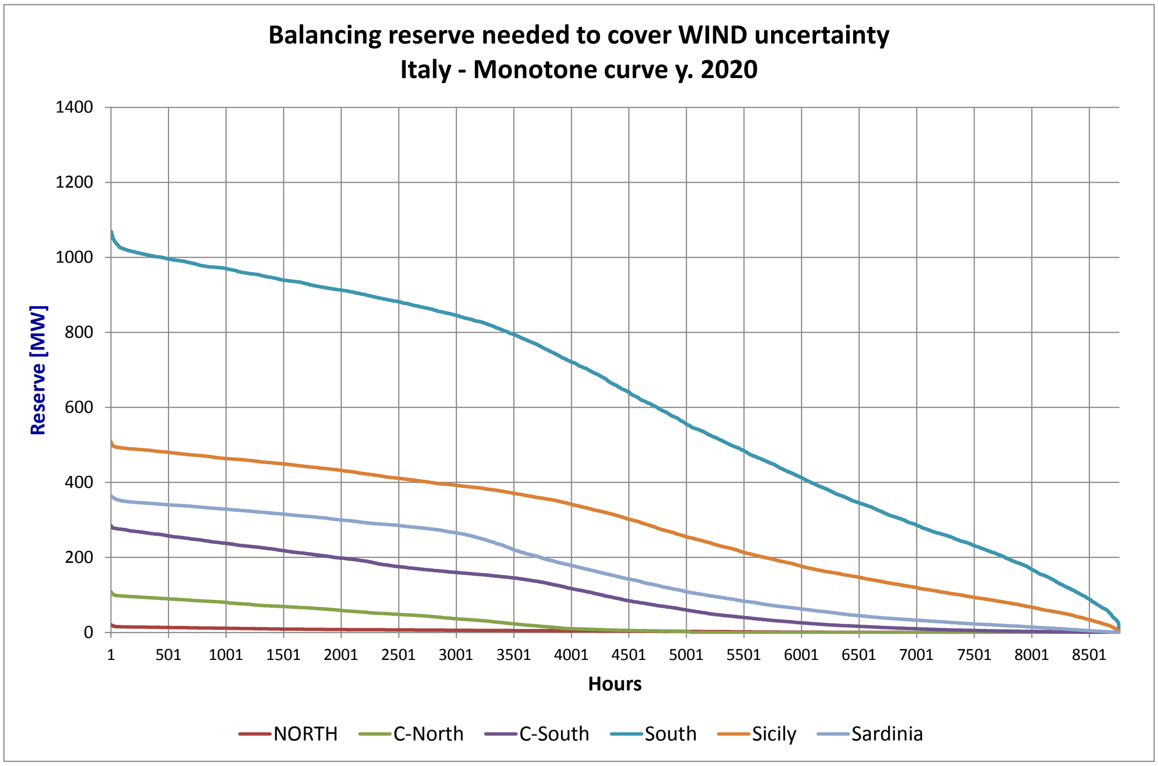


Figure 4.8.3-8: Balancing reserve for wind uncertainty in six Italian market zones – Year 2020.

Table 4.8.3-8: Balancing reserve needed to face wind uncertainty vs. secure hours/year

Monotonic duration curve of needed balancing reserve for "WIND" forecasting errors 8,760 hours/year								
Hour/year in security	**Percentage of secure hours**	**North**	**C-North**	**C-South**	**South**	**Sicily**	**Sardinia**	**ITALY**
8,760	100	20	109	284	1,069	507	363	2,236
7,008	80	7	64	207	923	440	307	1,726
5,256	60	3	22	144	791	369	219	1,433
3,504	40	0	0	47	517	233	95	1,045
1,752	20	0	0	9	284	118	32	645

Influence of solar PV

The analysis of the reserve aimed to cover only PV uncertainty highlights the large difference between the maximum and average needs of balancing reserve.

Taking into account the solar radiation in Italy, null PV generation is certainly expected in the following hourly ranges:

0:00-5:00 and 21:00-24:00 for all the days of the "Legal time" period (in Italy, Legal time covers the warmer period from the last Sunday of March to the last Sunday of October)

0:00-6:00 and 19:00-24:00 in the “Solar time” period (annual cold period complementary to the Legal time).

In these time ranges, no balancing reserve has to be allocated to overcome possible unexpected variations in PV-generated power. Therefore, a total amount of 3,361 hours of the year are not to be considered for the balancing reserve allocation.

Taking into account the remaining 5,399 daylight hours, reserve values needed in the six market zones and in the whole Italian system are shown in the following Table4.8.3-9.

In the entire Italian system, the needed average reserve (189 MW) is about the 9% of the maximum demand (2,087 MW) for PV uncertainty.

Table 4.8.3-9: Influence of PV on the balancing reserve (5,399 daylight hours only; horizon year 2020)

Hourly reserve for “PV” forecasting errors [MW]	**North**	**C-North**	**C-South**	**South**	**Sicily**	**Sardinia**	**ITALY**
Maximum	892	293	266	524	133	62	2,087
Minimum	0	0	0	0	0	0	0
Average	84	26	27	38	9	4	189
Hourly generated power by PV [MW]	**North**	**C-North**	**C-South**	**South**	**Sicily**	**Sardinia**	**ITALY**
Maximum	5,938	1,779	2,119	3,441	1,131	496	14,366
Average	2,056	646	751	1,262	415	186	5,316

The reserve values needed to cover the PV uncertainty in the 80% of the 5,399 daylight hours are very low when compared with the maximum values covering 100% of the hours. This is true for all six market zones as shown in Figure 4.8.3-9 and Table 4.8.3-10.

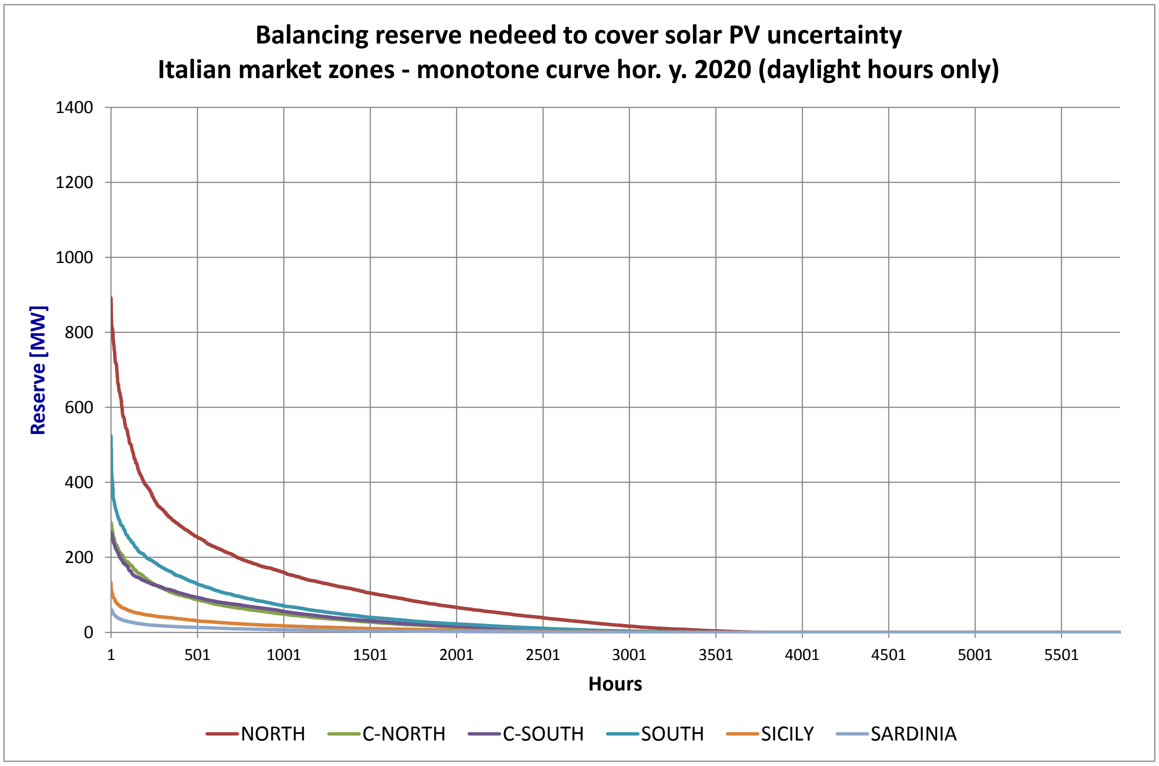


Figure 4.8.3-9: Balancing reserve for solar PV uncertainty in six Italian market zones for 2020.

Table 4.8.3-10: Balancing reserve needed to face solar PV uncertainty vs. safe daylight hours

Monotonic duration curve of needed balancing reserve for PV forecasting errors, daylight hours only (5,399 hours)								
Hour/year in security	**Percentage of secure hours**	**North**	**C-North**	**C-South**	**South**	**Sicily**	**Sardinia**	**ITALY**
5,399	100	892	293	266	524	133	62	2,087
4,319	80	148	45	50	66	16	6	334
3,239	60	57	11	12	19	5	2	118
2,160	40	9	2	1	1	0	0	26
1,080	20	0	0	0	0	0	0	0

In conclusion, while wind generation requires a relevant share of balancing reserve to cover the 80% of the yearly hours, the PV generation balancing needs are relevant for a very low percentage of the applicable daylight hours. The impact of PV on the balancing reserve needs in daylight hours is limited by low uncertainty (forecast error's standard deviation) in the case of very sunny or very cloudy hours when PV generation is very predictable. Moreover, the PV uncertainty can be reasonably expressed as a percentage of the maximum generable power, which changes according to the season and the daily hour. The ratio between the balancing reserve (needed to cover PV uncertainty) and the generated PV power is lower than that observed for wind: less than 15% for the peak values (even if these do not occur simultaneously) and even less for average values (about 4%).

(3) Conclusions of the Italian study case

The proposed statistical methodology for the calculation of the balancing reserve was applied to the horizon year 2020 and is based on a 95% confidence level; it takes into account the uncertainties of solar PV, loads, and wind in addition to possible forced outages of traditional thermoelectric generators. The reserve was assessed in the contexts of the MSD and in all the six Italian market zones (North, Central North, Central South, South, Sicily, and Sardinia). The resulting total reserve in the Italian system varies from 1,300 MW minimum to 6,070 MW maximum, with 3,350 MW average value.

The influence of renewable wind and solar PV energy was assessed, and it was observed that solar PV requires a very low average reserve (9% of its maximum value) even if it is calculated only in daylight hours (5,400 daylight hours per year). Wind generation instead requires a sustained average value of balancing reserve, which is the 54% of its maximum value, calculated in the total 8,760 hours of the year. Consequently, considering the reserve needed for all non-dispatchable renewable generation (PV and wind), in the market zones where PV generation is much higher than wind (North, C-North) there is a high deviation of maximum reserve value from the average annual reserve to be allocated. Conversely, a lower deviation from the average is present where wind generation prevails over solar PV (especially in the South, Sardinia, and Sicily). The performed study shows that solar PV generation appears to require less balancing reserve than wind, comparing reserve to actual generation; this is due to the fact that PV maximum generation varies according to the season and the daily hour, unlike wind, whose maximum may happen at any moment. In addition, PV uncertainty is limited in cases of very sunny or very cloudy conditions.

4.8.4. Issues and Solutions for PV Penetration

(1) Voltage and frequency issues

The PV capacity in Italy is mainly linked to the LV and MV distribution network. As of December 2012, only 229 PV plants are connected to the HV level [3]; 96% of the installed plants (458,265) are connected to the LV level; only 20,000 PV plants are instead connected on MV level, but they represent 63.3% of the total installed power capacity. Notwithstanding the connection to the distribution level, the significant increase in PV infeed has also gained significant influence on the transmission system operation. The Authority for Electric Energy and Gas (AEEG) defines, by means of resolutions 99/08 and 328/2012 [7], the technical and economical procedures for new connection facilities. According to these resolutions, the CEI[53] standards represent the main national technical references for connections on distribution network. In particular,

[53] CEI: Italian Electrotechnical Committee (Comitato Elettrotecnico Italiano: http://www.ceiweb.it/it/).

CEI standard 0-21 (last update 2012 [8]) and CEI standard 0-16 (last update 2013 [9]) set the technical rules for connection on LV and MV levels, respectively.

The requirements for distributed generation connection as set out by the above standards have also recently been endorsed in the recent annex A70 [5] of the Italian Transmission Grid Code. All the generating plants with rated power $P_N \geq 1kW$ and connected at the MV or LV distribution levels after March 31, 2012 must stay connected in cases of normal and emergency conditions; the operating ranges are $85\%V_{NOM} \leq V \leq 110\%V_{NOM}$ and $47.5 \leq f \leq 51.5$ Hz with the exception of PV plants connected to the LV level between April 1, 2012 and June 30, 2012 (op.rg. 49≤f≤51Hz). Additional requirements are stated in the case of PV plants connected to the MV level after June 30, 2012 or to the LV level after December 31, 2012: 1) active power modulation with frequency droop 2.4% in the over-frequency range $50.3 \leq f \leq 51.5\text{Hz}$; 2) low-voltage fault ride-through (LVFRT) capability in cases of rated power no less than 6 kW. In the case of PV plants with rated power higher than 6 kW and connected before April 1, 2012, a technological adjustment (retrofitting) is also required [10],[11].

Concerning the PV plants connected to the HV level, the Annex A68 [12] of the Transmission Grid Code requires continuous operation in the ranges $85\%V_{NOM} \leq V \leq 115\%V_{NOM}$ and $47.5 \leq f \leq 51.5H$. Active power modulation in the case of over-frequency and a LVFRT capability are also required.

(2) Energy storage

Energy storage is considered a means to increase PV penetration in the power system; a recent study [13] promoted by the Italian Association of Electrotechnic and Electronic Companies (ANIE) pointed out the economic benefits that can be reached by means of: the reduction of the overgeneration curtailment; the evening peak load shaving with the consequent reduction of needed thermoelectric generation capacity; and the reduction of the grid asset costs due to lower values of transmitted power.

(3) Smart grids

The biggest Italian utility for electric energy supply has recently promoted the “Isernia” Project [14] aimed to combine distributed generation with a reliable and safe management of the system under real operating conditions. Innovative models for the protection, automation, and management of power generation in the distribution network will be tested. The project lasts three years (from 2011 to 2014) and involves a €10 million investment.

4.8.5. R&D for Transmission-Level Challenges

In general, the smart grid concept may facilitate grid operation in the context of large penetrations of renewable energy sources. Accordingly with the principle of smart grids, new storage systems at the transmission level may facilitate the management of renewable energy plants.

The Italian TSO included in its Grid Development Plan [15],[16] a pilot project concerning the installation of “energy intensive” storage batteries for a total amount of

35 MW on two 150 kV directors in the southern area (Campobasso – Benevento 2 – Volturara – Celle San Vito and Benevento II – Montecorvino); this project is aimed to improve the flexibility in managing renewable energy plants and to increase the hosting capacity of the grid. Further “energy intensive” battery storage will be evaluated in the coming years on the basis of the experimental results on the above directors.

A second project [16] was presented by the Italian TSO to the Electricity and Gas Authority (AEEG) and has already been approved by the Italian Ministry of Economic Development (MiSE) as part of the 2012 Defense Plan. This project aims to increase the operation security in the power systems of the two major Italian islands (Sicily and Sardinia) by means of 40 MW of innovative “power intensive” storage systems. The TSO is going to implement two phases: the first step concerns 16 MW of “pilot” multi-tech storage plants (8 MW in Ottana in Sardinia, and 8 MW in Caltanissetta in Sicily); the second step concerns the subsequent installation on a broader scale of the remaining 24 MW (12 MW in Sicily, and 12 MW in Sardinia). In the first step, performances of the considered different technologies will be validated together with their integration into the control and defense systems of the grid. The tested batteries will be supplied by a broad selection of national and international companies. Moreover, the host will develop activities for smart grid applications involving Italian and foreign universities and research institutes.

4.8.6. References

[1] Italian Authority "AEEG" report 331/2013/I/EEL (2013): "Rapporto annuale dell'Autorità per l'Energia Elettrica e il Gas in materia di monitoraggio dei mercati elettrici a pronti, a termine e dei servizi di dispacciamento: anno 2012 consuntivato." Available at: http://www.autorita.energia.it/allegati/docs/13/331-13.pdf.

[2] Italian Transmission System Operator TERNA: "*Provisional operation data of Italian Transmission System 2012.*" Available only in Italian at: http://www.terna.it/LinkClick.aspx?fileticket=IevKjDxBNPA%3d&tabid=506&mid=721.

[3] GSE "Gestore dei Servizi Energetici" (2013); "Rapporto Statistico 2012 – Solare Fotovoltaico" available at: http://www.gse.it/it/Statistiche/RapportiStatistici/Pagine/default.aspx.

[4] Ministry of Economic Development (2013): Italy's National Energy Strategy. Available at: http://www.sviluppoeconomico.gov.it/images/stories/documenti/SEN_EN_marzo2013.pdf.

[5] A. Iaria, E. Gaglioti: "Valutazione dei requisiti di riserva terziaria di sostituzione a salire nel Sistema Elettrico Italiano." Paper on the Italian magazine *L'Energia Elettrica,* Vol. 90 of July/August 2013 review. Info at: http://www.aeit.it/r01.5/rivistaEE.html.

[6] TERNA, annex A70 of the Italian Transmission Grid Code (2012): "Regolazione tecnica dei requisiti di sistema della generazione distribuita." Available at: http://www.terna.it/default/Home/SISTEMA_ELETTRICO/codice_rete.aspx.

[7] Italian Authority "AEEG" TICA procedure: "Testo Integrato per le Connessioni Attive" implemented by resolution number 99/08, 2008 July 23rd (last update with AEEG Resolution number 328/2012/R/eel, 2012 July 26th). The procedure is available at: http://www.autorita.energia.it/it/docs/08/099-08arg.htm.

[8] CEI standard number 0-21 (2012): "Reference technical rules for the connection of active and passive users to the LV electrical utilities." Available at: http://www.ceiweb.it/it/comunicati/news/234-norma-cei-0-21-aggiornamento-dicembre-2012.html.

[9] CEI "Comitato elettrotecnico Italiano" standard number 0-16 (2013): "Reference technical rules for the connection of active and passive consumers to the HV and MV electrical networks of distribution Company." Available at: http://www.ceiweb.it/it/comunicati/news/331-norma-cei-0-16-edizione-dicembre-2012-con-aggiornamento-maggio-2013.html.

[10] Italian Authority "AEEG" resolution number 84/2012/R/eel (2012): "Interventi urgenti relativi agli impianti di produzione di energia elettrica, con particolare riferimento alla generazione distribuita, per garantire la sicurezza del sistema elettrico nazionale." Available at: http://www.autorita.energia.it/it/docs/12/084-12.htm.

[11] Italian Authority "AEEG" resolution 243/2013/R/eel (2013): "Ulteriori interventi relativi agli impianti di generazione distribuita per garantire la sicurezza del sistema elettrico nazionale. Modifiche alla deliberazione dell'autorità per l'energia elettrica e il gas 84/2012/r/eel." Available at: http://www.autorita.energia.it/it/docs/13/243-13.htm.

[12] TERNA, annex A68 of the Italian Transmission Grid Code (2012): "Impianti di produzione fotovoltaica: requisiti minimi per la connessione e l'esercizio in parallelo con la rete AT." Available at: http://www.terna.it/default/Home/SISTEMA_ELETTRICO/codice_rete.aspx.

[13] ANIE, Federazione Nazionale Imprese Elettrotecniche ed Elettroniche (2013): "RESIDENTIAL ELECTRICAL STORAGE SYSTEMS." Info available at: http://www.anie.it/browse.asp?goto=2340&livello=4&IdDocumento=43289&IdRevisione=98642.

[14] ENEL Group: project "Isernia." Info available at: http://www.enel.com/en-GB/innovation/smart_grids/development/isernia_project/.

[15] Italian Transmission System Operator TERNA: "*The National Electricity Transmission Grid Development Plan.*" Summary available at: http://www.terna.it/default/home_en/electric_system/grid_development_plan.aspx (full version only in Italian language).

[16] TERNA plus: "STORAGE SYSTEMS - TERNA'S INVESTMENTS." Info available at: http://www.ternaplus.it/StorageSystem.htm.

4.9. Thailand **(Reference report)**

(Summary report as observer in the meeting)

Introduction

Thailand is a country located in the southeast region of Asia. Electric Supply Industry in Thailand consists of three utilities, namely the Electricity Generating Authority of Thailand (EGAT), Metropolitan Electricity Authority (MEA) and Provincial Electricity Authority (PEA). EGAT is responsible for generation and transmission grids of high voltage levels, while MEA and PEA are responsible for distribution levels. The total installed capacity of the Thai power system in October 2012 is 32,290.22 MW including generations from EGAT power plants, Independent Power Producers (IPPs), Small Power Producers (SPPs), Very Small Power Producers (VSPPs) and power imports from neighboring countries. The maximum electrical demand is 26,121.1 MW, occurred on April 26, 2012.

Fuel gas is the major resources for producing electricity in Thailand about 70% of total fuel consumption. Cost is one of major driving factors of using gas as the main fuel resource in Thailand. In order to reduce the high portion of fuel gas consumption, an effort is made to promote Renewable Energy (RE) in transmission and distribution levels in form of Small Power Producer (SPPs) and Very Small Power Producer (VSPPs). This can be seen from Thailand Power Development Plan 2010 version 3 (PDP 2010.v3) and Alternative Energy Plan 2012-2021 (AEDP 2012-2021).

The Power Development Plan 2010 version 3 has been prepared to promote the use of RE in Thailand. It uses Alternative Energy Development Plan 2012 – 2021 as a guide for targeting RE in the Thai power system. The AEDP 2012 – 2021 aim is to “promote the production and use of renewable and alternative energy, being able to replace fossil fuels at least 25% within 10 years”. The Ministry of Energy has adopted AEDP for Power Development Plan, which has the target of additional 9,201 MW within 2021. Figure 4.9.0-1 shows various types of renewable as new energy sources to replace fossil fuel-based power plant.

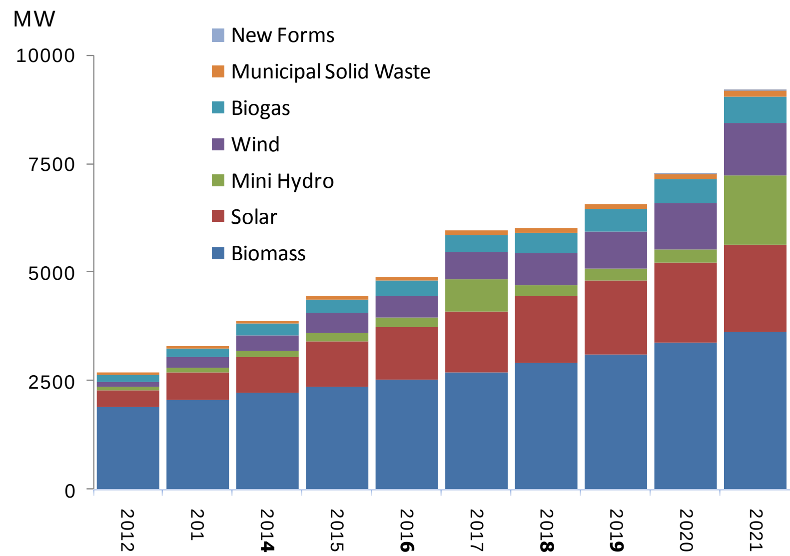
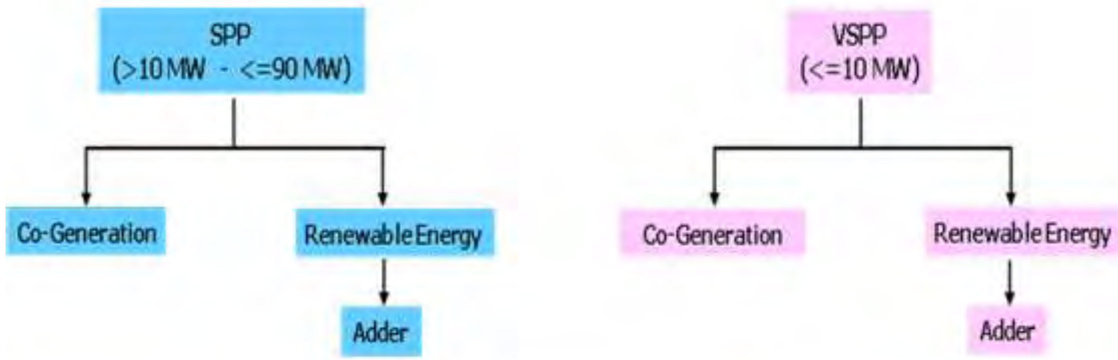


Figure 4.9.0-1: Renewable Energy Plan in Thailand AEDP 2012-21021**.**

From Figure 4.9.0-1, in 2021, Thailand plans to add 9,201 MW of Renewable energy sources including Solar 2,000 MW, Wind 1,200 MW, Mini Hydro 1,608 MW, Waste 160 MW, Biomass 3,630 MW, Biogas 600 MW and New forms of alternative energy sources 3 MW.

In order to help the developers cover the capital investment cost, incentive pricing scheme called "Adder" is introduced to add up the additional payment to RE SPPs/VSPPs. Figure 4.9.0-2 shows the adders of SPPs and VSPPs in Thailand. From the Figure, additional capital cost of renewable energy such as Photo Voltaic (PV), wind, etc. is compensated by the adders. For PV SPPs, the the adder is as high as 6.5 Baht/kWh. The power producers based on PV may receive electricity price of 9.2 baht/kWh, which include normal price of 2.7 Baht/kWh and adder of 6.5 Baht/kWh. It is noticed that the adder is allocated from the Energy Conservation Promotion Fund managed by the Government.



Type of RE	All provinces, (Baht/kWh)	3 Southernmost Provinces, 4 Districts in Songkhla (Baht/kWh)
Waste - Landfill & Digestor - Thermal Process	2.50 3.50	3.50 4.50
Wind	3.50	5.00
Solar	6.50 8.00*	9.50
Biomass	0.30	1.30
Biogas	0.30	1.30

Type of RE	All provinces, (Baht/kWh)	3 Southernmost Provinces, 4 Districts in Songkhla (Baht/kWh)	Adder for diesel replacement (Bath/kWh)	Year Supported
Biomass Installed Capacity ≤ 1 MW Installed Capacity > 1 MW	0.50 0.30	1.50 1.30	1.50 1.30	7
Biogas Installed Capacity ≤ 1 MW Installed Capacity > 1 MW	0.50 0.30	1.50 1.30	1.50 1.30	7
Small Hydro 50 kW ≤ < Inst. Cap. < 200 kW Installed Capacity < 50 kW	0.80 1.50	1.80 2.50	1.80 2.50	7
Waste - Landfill & Digestor - Thermal Process	2.50 3.50	3.50 4.50	3.50 4.50	7
Wind Installed Capacity ≤ 50 kW Installed Capacity > 50 kW	4.50 3.50	6.00 5.00	6.00 5.00	10
Solar	6.50 8.00*	9.50	9.50	10

Figure 4.9.0-2: Adders for SPPs and VSPPs in Thailand.

4.10. USA

4.10.1. Power System

The United States electric grid is divided in three major sections called interconnections. All the electric generators in each interconnection operate at a 60 Hz synchronized frequency and are electrically interconnected. The sections of the grid located in the Contiguous United States are the Western Interconnection, the Eastern Interconnection and the ERCOT interconnection[54] (Figure 4.10.1-1) (NERC 2011).

The North American Electric Reliability Corporation (NERC) oversees the bulk-power system in the U.S. by developing and enforcing reliability standards.[55] NERC works with eight regional entities (shown in Figure 4.10.1-1) to improve the reliability of the bulk-power system in their respective territories. Over 100 Balancing Authorities work under the oversight of 12 wide-area Reliability Coordinators[56] to balance electricity generation and demand throughout the U.S.

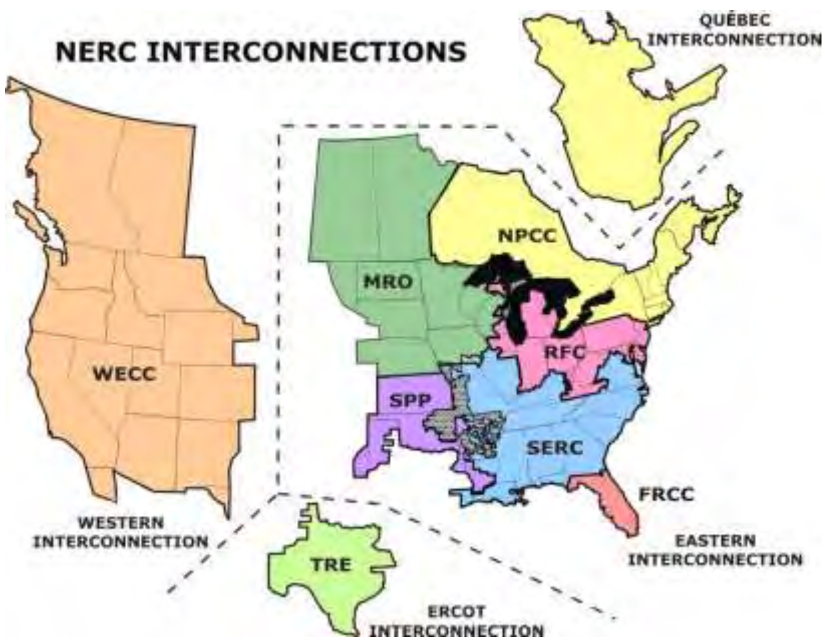


Figure 4.10.1-1: Interconnections in the North American power grid. Source: North American Electricity Reliability Corp.

(1) Regulation

Generally speaking, interstate transmission and wholesale power sales are regulated at the federal level by the Federal Energy Regulatory Commission (FERC), whereas states regulate retail sales and the operation of distribution networks. Traditionally, utilities had been regulated as monopolies throughout the country until the 1990s when some states began to restructure their electric markets. In restructured markets, the

[54] The other North American grid is the Québec Interconnection.
[55] NERC also oversees parts of Canada and Mexico.
[56] http://www.nerc.com/pa/rrm/TLR/Pages/Reliability-Coordinators.aspx

distribution grid is still traditionally regulated (i.e., considered a monopoly), but competition is allowed in the generation of power (RAP 2011). Today, about a third of the states have restructured electricity markets.

At the bulk-power level, in 1996 FERC required owners of transmission systems to offer open access to their infrastructure by other utilities and separate their transmission and power marketing functions. To facilitate nondiscriminatory access to transmission infrastructure, Independent System Operators (ISOs) and Regional Transmission Organizations (RTOs) coordinate, control and monitor the use of the transmission grid in their respective territories. Important functions of RTOs and ISOs include managing the wholesale energy markets in their regions, ensuring the reliability of the grid, and performing regional infrastructure planning.

(2) Utilities and Electricity Sales

There are over 3,700 electricity providers in the U.S. Of these, roughly 52% are utilities owned by local governments or power districts[57], 25% are cooperatives owned by their customers[58], 8% are investor-owned utilities (IOUs), and 12% are power marketers operating at the wholesale or retail levels[59]. The rest are independent electricity transmission companies and power agencies owned by states or the federal government. In terms of retail sales, roughly 54% of the total megawatt-hours (MWh) are sold by IOUs, 19% by power marketers, 14% by publicly-owned utilities and 11% by cooperatives (EIA). The total electricity retail sales in the U.S. in 2012 were roughly 3.7 million gigawatt-hours (GWh)[60].

(3) Power Mix

The dominant source of electricity generated in the U.S. is coal, which represented 37% of the total generation in 2012. Natural gas has been steadily growing as a source of electricity for over two decades. In 2012 it provided 30% of the electricity generated. Renewable energy accounted for 12% of total generation, with hydroelectric plants producing most of the power.

[57] These publicly-owned utilities are often generically called municipal utilities, or munis, and are most common in densely populated areas, like cities or bigger towns.
[58] Cooperative utilities are most common in rural areas.
[59] Typically, power marketers do not own generation, transmission or distribution assets.
[60] http://www.eia.gov/state/seds/data.cfm?incfile=/state/seds/sep_fuel/html/fuel_use_es.html&sid=US

Table 4.10.1-1: Electricity net generation in 2012, all sectors. Source: EIA, NREL

Source	Thousand MWh	% of total
Coal	1,517,203	37.3%
Natural Gas	1,230,708	30.3%
Nuclear	769,331	18.9%
Hydro	276,535	6.8%
Wind	140,089	3.4%
Biomass	57,565	1.4%
Petroleum	22,900	0.6%
Geothermal	16,791	0.4%
Solar PV	12,775	0.3%
Other	19,021	0.5%

Between 1990 and 2012, the electricity generation mix of the U.S. has undergone significant changes (Figure 4.10.1-2). The share of natural gas in total generation grew from 12% in 1990 to 30% in 2012[61]. In the same period, coal fell from 53% of total generation to 37%. The more abrupt decline of coal in the generation mix since 2008 can be attributed to factors such as low natural gas prices, relatively high coal prices, and weak growth in electricity demand. These trends are generally expected to continue in the short term. Stronger mercury and emission regulations have also resulted in the retirement of some of the coal-fired plant capacity (EIA 2013b). With respect to renewable energy, solar PV installed capacity has increased at an annual rate of at least 50% since 2007 and the cumulative capacity of wind power quadrupled in six years, between 2007 and 2012.

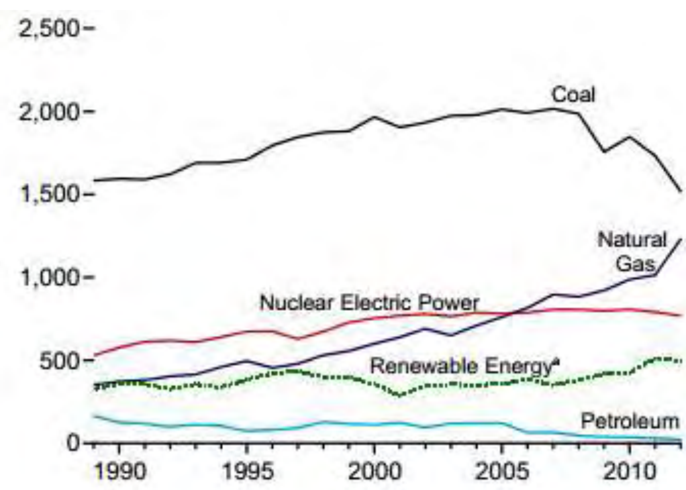


Figure 4.10.1-2: Major sources of electricity in the U.S., 1989-2012 (Thousand GWh). Source: EIA, Monthly Energy Review, March 2013.

[61] In 2012 alone, the share of natural gas power generation grew from 25% at the beginning of the year to 30% at the end.

4.10.2. Penetration of PV and Other generation

In the U.S., solar photovoltaic (PV) generation capacity grew by a factor of more than 20 between 2006 and 2012 and currently accounts, together with Concentrated Solar Power (CSP), for 0.3% of annual electricity generation (Gelman 2013).

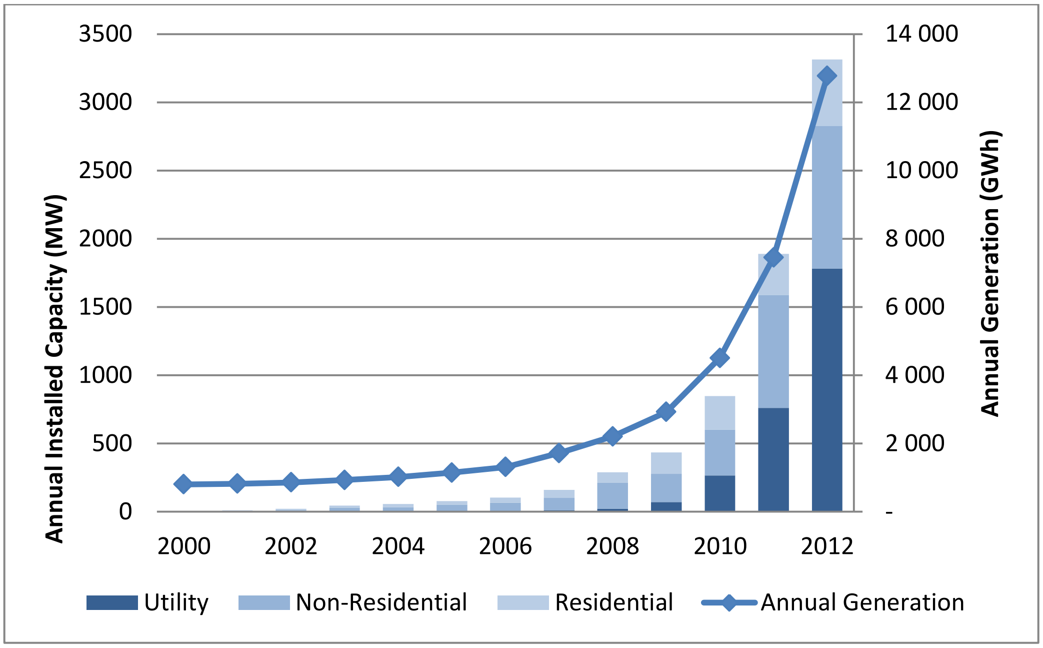


Figure 4.10.2-1: Annual PV capacity additions and annual generation in the U.S. Source: SEIA/GTM Research 2013, EIA 2013.

The growth of solar PV can be partially attributed to policies at the federal and state levels. The federal government offers a 30% investment tax credit (ITC) for residential and commercial systems. The ITC was implemented in 2006 and is set to expire by the end of 2016. Currently, 29 states and the District of Columbia (DC) have renewable portfolio standards (RPS) that establish targets for increased generation of renewable electricity. Additionally, 16 states and DC have a specific target for solar or distributed energy of up to 4% of retail sales. States have also implemented financial incentive programs (Bird et al. 2013).

Another important factor in the rapid adoption of solar PV systems in the last few years is the accelerated decline in installed prices. Figure 4.10.2-2 shows the median values for installed residential and commercial PV system prices, per watt. Between 2009 and 2012, installed prices have declined by around 30%. Installed costs at the utility scale have followed a similar trajectory, although with a much more marked variation between projects (Figure 4.10.2-3) (Barbose, 2013).

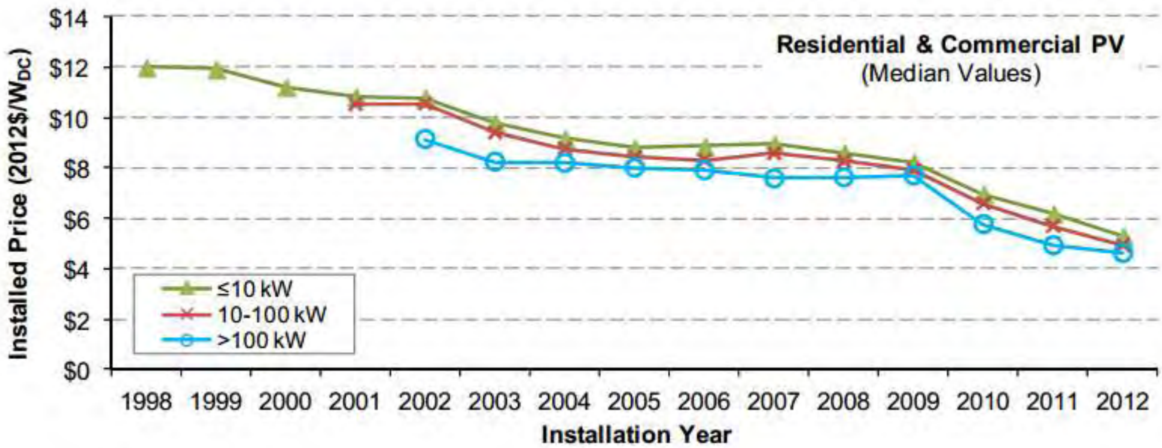
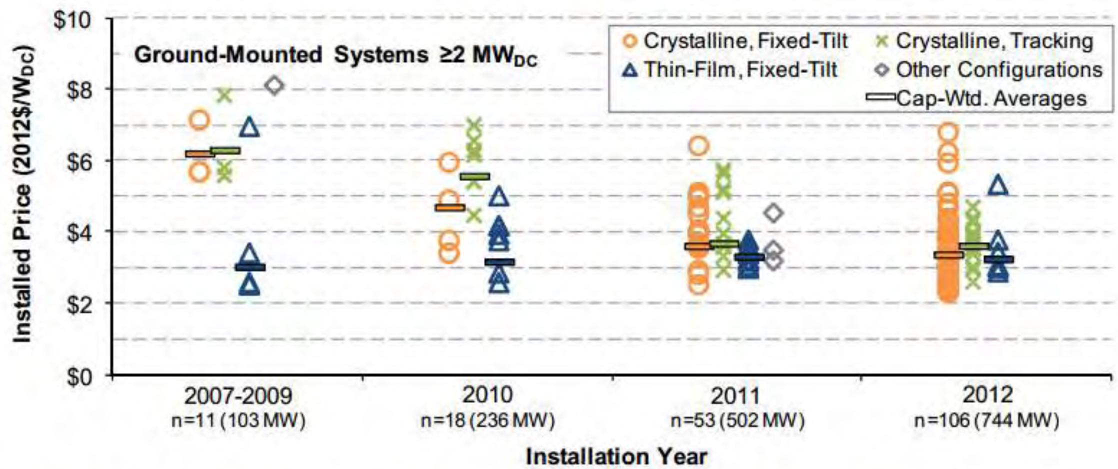


Figure 4.10.2-2: Installed residential and commercial PV prices.
Source Lawrence Berkeley National Laboratory (Barbose 2013).



Notes: Other Configurations includes a thin-film system with tracking, two systems with silicon ribbon modules, and a system with a combination of fixed and tracking arrays.

Figure 4.10.2-3: Installed Price of Utility-Scale PV over Time.
Source Lawrence Berkeley National Laboratory (Barbose 2013).

Other Renewable Energy Generation

The share of renewable energy in the electric mix of the U.S. was relatively steady at about 9% of total generation in the 2000s. In 2012, renewables accounted for 12.4% of the total generation and 14% of the total capacity (Figure 4.10.2-4).

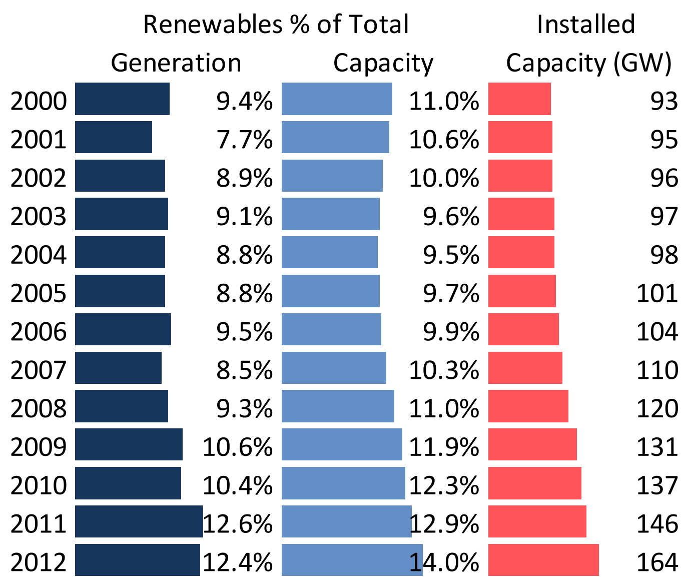


Figure 4.10.2-4: Renewable energy generation and capacity in the U.S.
Source: Renewable Energy Data Book, NREL.

Although conventional hydropower has historically been the major source of renewable energy in the country, its share of total generation has steadily declined over the years. In 1990, hydropower represented 82% of all the renewable energy generated, compared to 56% in 2012. In contrast, wind's share of total renewable energy generation has grown from less than 1% in 1990 to 28% in 2012 (EIA 2013b).

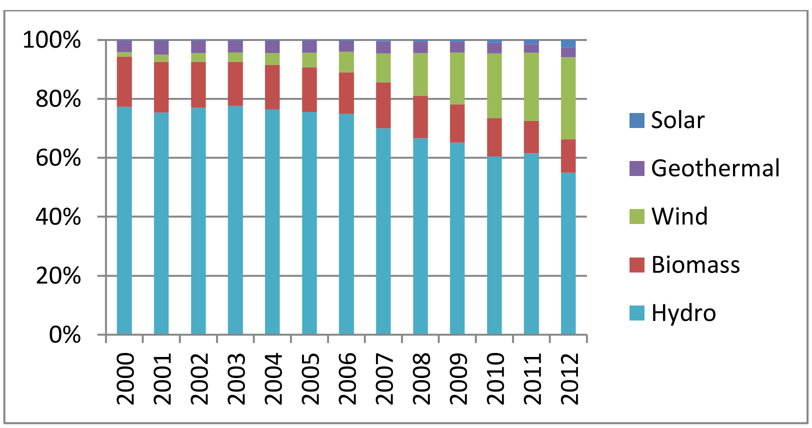


Figure 4.10.2-5: Renewable energy technology mix, 2000-2012. Source EIA 2013.

4.10.3. Case Study

Impacts of High Penetrations of Solar PV on Bulk System

The Western Wind and Solar Integration Study Phase 2 examined the impacts of increasing variable renewable generation up to a level of 33% on the power system operated by a subset of the transmission providers in the Western Interconnect. The high penetration cases examined included 1) a high solar case including 25% solar and 8% wind; 2) a high wind case including 25% wind and 8% solar, and 3) a high mixed renewables case including 16.5% wind and 16.5% solar. The study assessed the operational and systems effects of integrating high penetrations on the bulk power system (Figure 4.10.3-1).

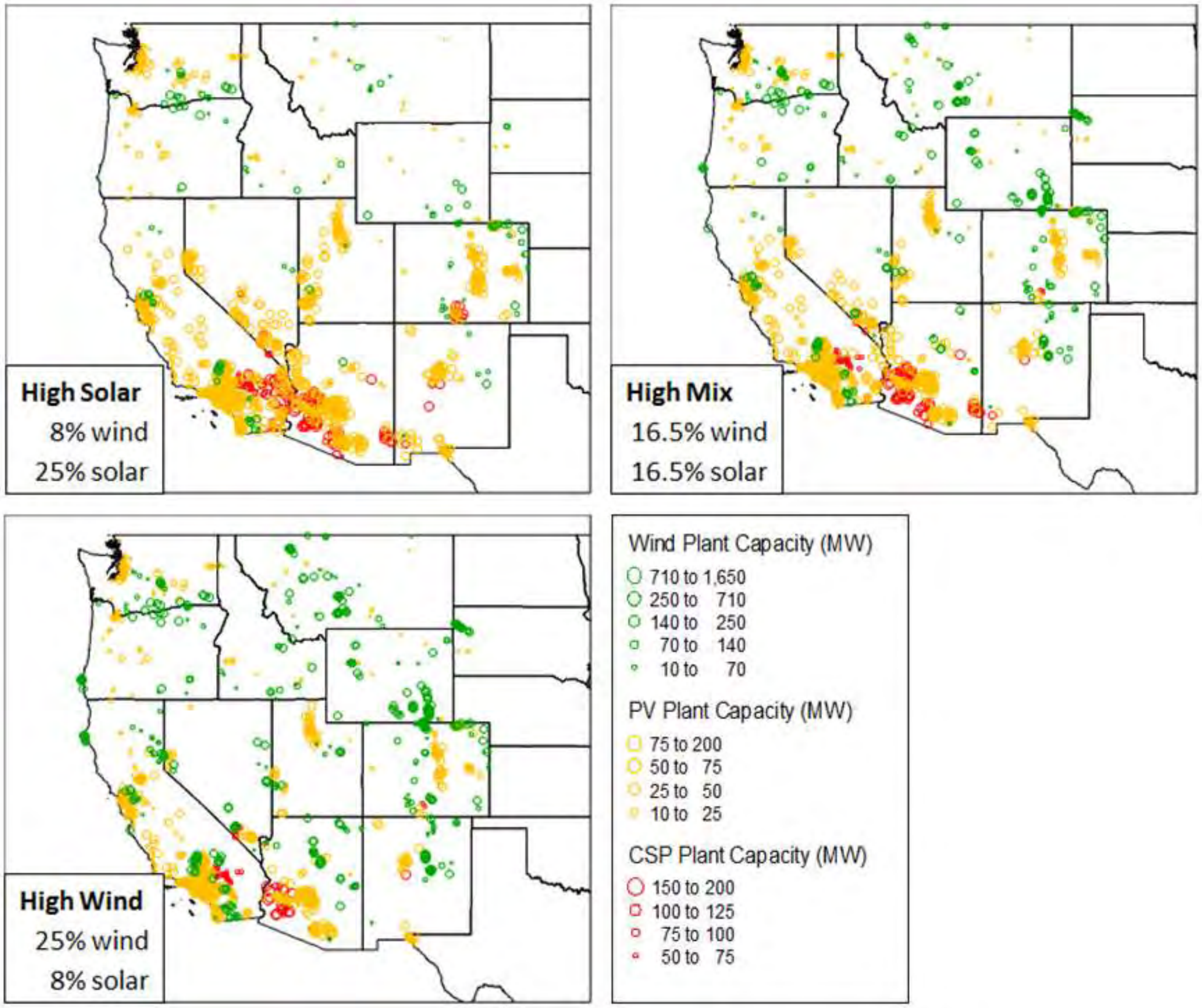


Figure 4.10.3-1 : Three high penetration scenarios considered in the Western Wind and Solar Integration Study Phase II (WWSIS-2).

(1) Solar variability issues.

Sun movement causes the greatest variability (at the bulk power level). Solar variability is greater than for wind.

PV plant output varies as a result of weather related effects (i.e., cloud cover) as well and the movement of the sun over the course of the day. There is a substantial and rapid increase in output at sunrise and a substantial decline at sunset, creating a diurnal cycle that contributes to the variability of PV plant output. The diurnal variability has a more significant impact than cloud cover on the bulk power system at high penetrations of PV, although the weather-related variability can affect the distribution system.

Figure 4.10.3-2 shows that the variability on the power system increases substantially at sunrise and sunset for both the high wind and high solar scenarios. The figures compare load and the variability of load over the course of the day with the net load (load minus solar) for a high solar penetration scenario (including CSP) in the Western U.S. The bottom figure shows that the high solar scenario results in a double peak in net load (load minus solar output) in the morning and in the evening. The variability in net load increased substantially at sunrise and sunset.

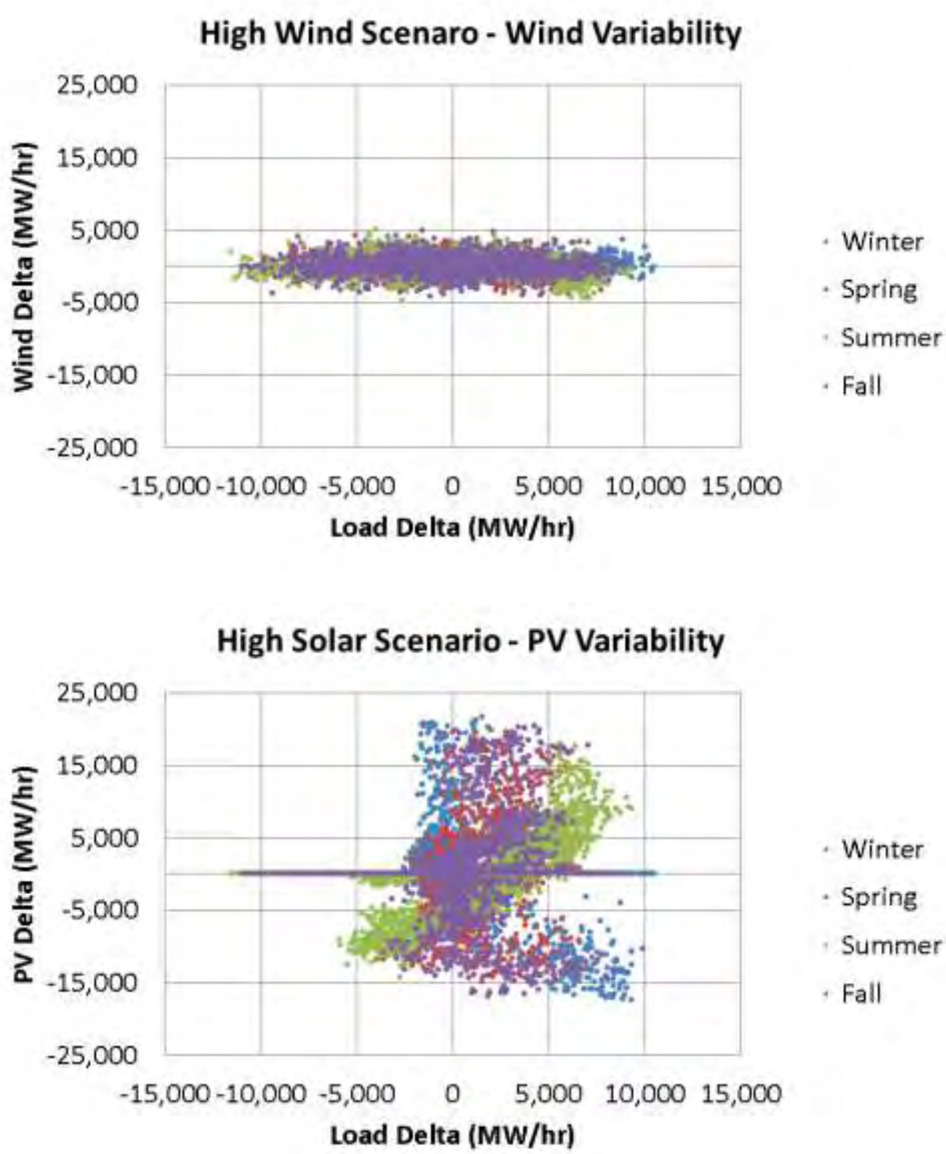


Figure 4.10.3-2: Hourly wind production change versus hourly load change for the high wind scenario (top) and hourly PV production change versus hourly load change for the high solar scenario (bottom). Note: The colors depict different seasons. Source: WWSIS-2 (2013).

Figure 4.10.3-3 below shows the weather variability component of solar variability for the High Solar Scenario. Comparing this to Figure 4.10.3-2 above, it shows that the weather-related component of variability is relatively small and that the diurnal variability is dominant.

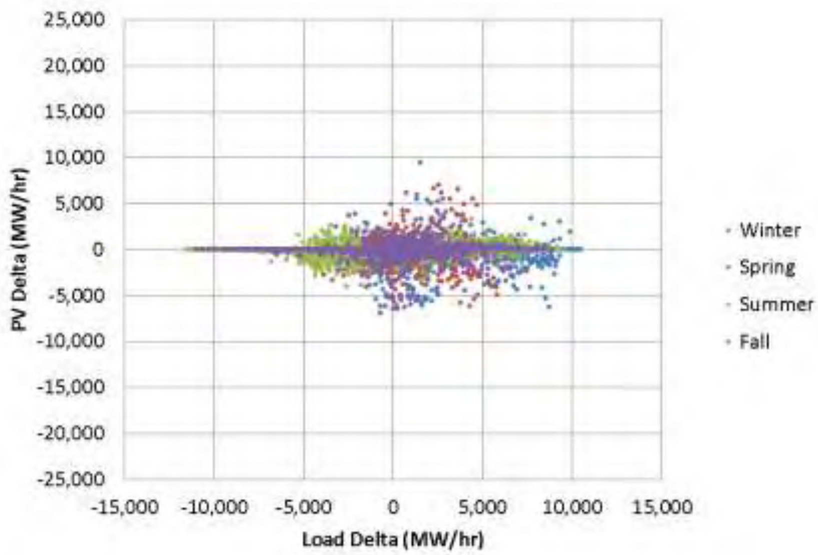


Figure 4.10.3-3 : Weather variability component of PV variability for the High Solar Scenario. Source: WWSIS-2 (2013).

(2) Probability of extreme events with variability of high penetrations of solar

In some hours of the year, the variability or uncertainty of renewable energy generation can pose substantial challenges for grid operators. For example, steep ramps in generation (either increases or decreases) or periods of minimum load when there is too much power available can pose challenges.

Figure 4.10.3-4 shows that there are more periods of large changes in power output over the course of 5 minutes for high solar penetrations than high wind or load-only cases. Solar also dominates system variability on an hourly basis, with most of the impacts occuring at sunrise or sunset. Because the path of the sun is known for every hour of the year, the variability can be accomodated by system operators, compared to rapid changes in wind energy output, for example, that are less certain.

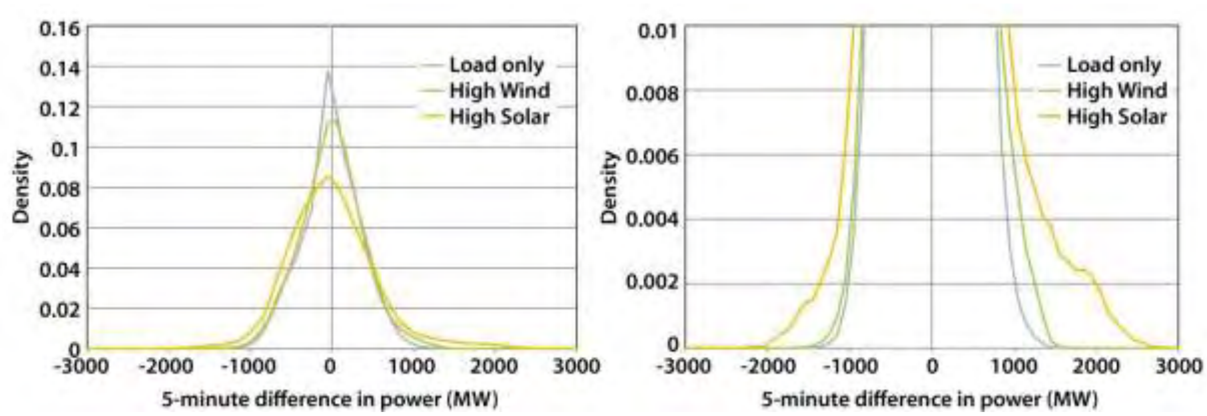


Figure 4.10.3-4: Distributions of 5-minute changes in power output for load only and the net load for the High Wind and High Solar Scenarios (left) and an enlargement of the tails of the distribution (right). Source: WWSIS-2 (2013).

A high solar energy scenario modeled in the WWSIS2 study, found the steepest positive ramp in net load (load minus solar generation) occurred on an afternoon in February when evening loads were increasing while solar generation was declining as the sun was setting. Figure 4.10.3-5 shows the up-ramp in net load of 26 GW as a result of the change in solar output during the hour. The modeling found that CSP with thermal storage was not dispatched to help meet the rapid increase in net load but rather saved for the next day because other capacity was available to meet the system need at reasonable prices.

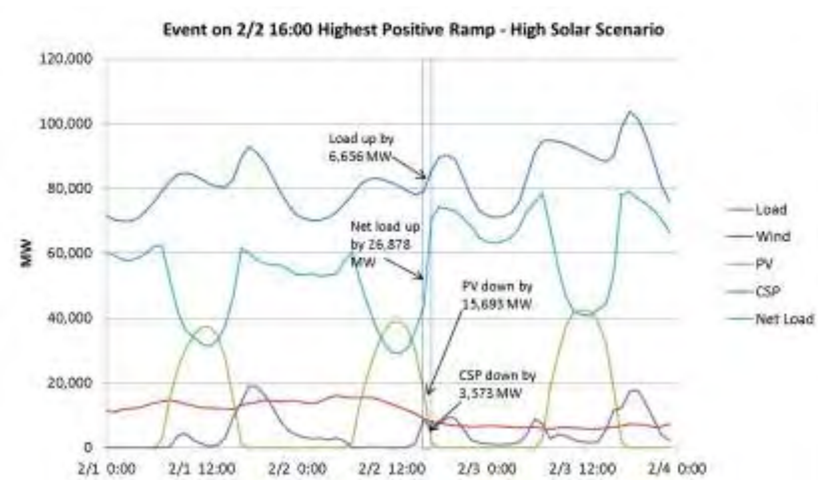


Figure 4.10.3-5: Highest hourly positive ramp (up-ramp) of 26,878 MW in the High Solar Scenario occurs on February 2 at 16:00.

For the high solar scenario, the largest down ramp in net load occurred on a morning in April as shown in Figure 4.10.3-6. In this case, solar energy (PV and CSP) increased rapidly at sunrise and while load was increasing at this time, the large amount of solar generation caused the net load to decline rapidly. If such a rapid ramp causes problems for system operators, one approach would be to curtail solar during the sunrise ramp and possibly use the solar for balancing reserves.

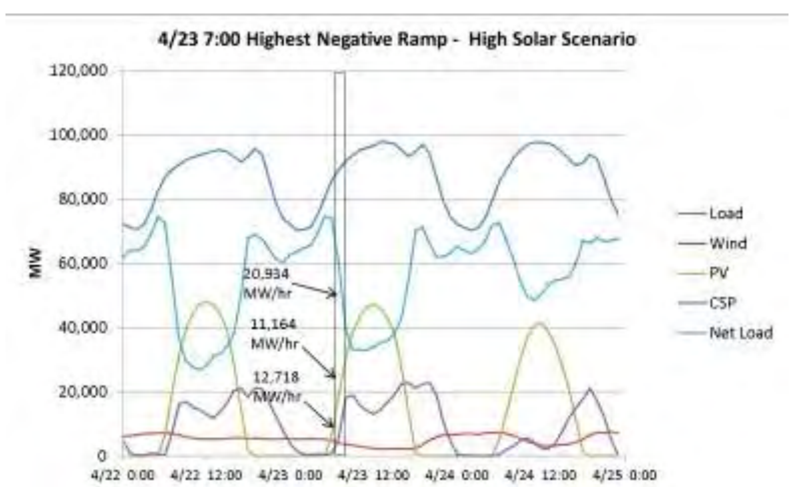


Figure 4.10.3-6: Highest hourly negative ramp (down-ramp) of 20,934 MW in the High Solar Scenario occurson April 23 at 7:00.

Minimum net loads can be a concern, because of potential impacts associated with running fossil-fuel generators at their minimum levels. With high penetrations of wind on systems, net loads may occur at night when winds are strong. However, adding high penetrations of solar can shift this condition to daytime. In the high solar scenario modeled in the WWSIS2 study, the minimum net load was reached in March at noon as a result of the combination of high PV output and relatively low spring loads (see Figure 4.10.3-7). In this case, both wind and CSP contribute to the minimum net load, although some CSP is stored and saved for the evening peak.

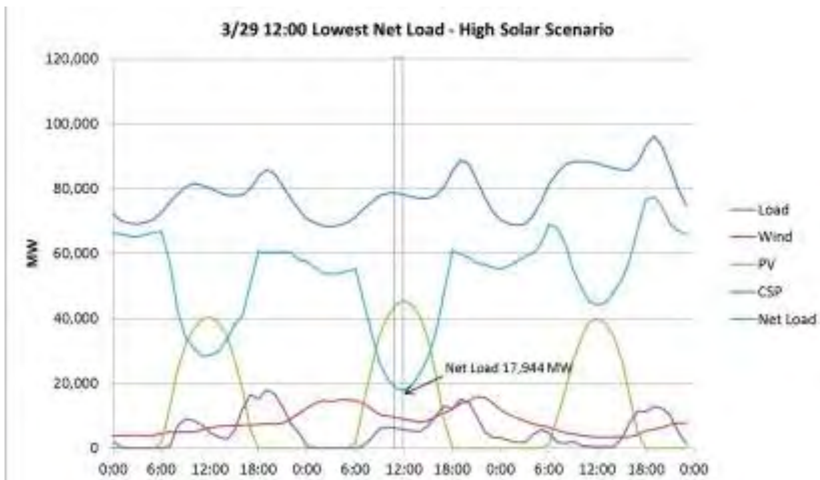


Figure 4.10.3-7: Minimum net load is 17,944 MW at noon on March 29 in the High Solar Scenario.

(3) Bulk Power System Impacts of High Penetrations of Solar

Solar has very different impact on the system than wind. Solar backs down coal midday. Solar curtailment occurs midday. Solar needs thermal to help meet evening peak.

Higher penetrations of solar and wind energy, which have no fuel costs and hence zero marginal costs, result in the displacement of conventional generation sources with higher marginal costs, such as natural gas and coal. Figure 4.10.3-8 shows the dispatch stack of resources in the summertime for a high wind scenario (top) and a high solar scenario (bottom). In the high wind scenario, which also includes solar, gas combined cycle plants are primarily displaced by the renewables. In the high solar scenario there is also some displacement of coal generation.

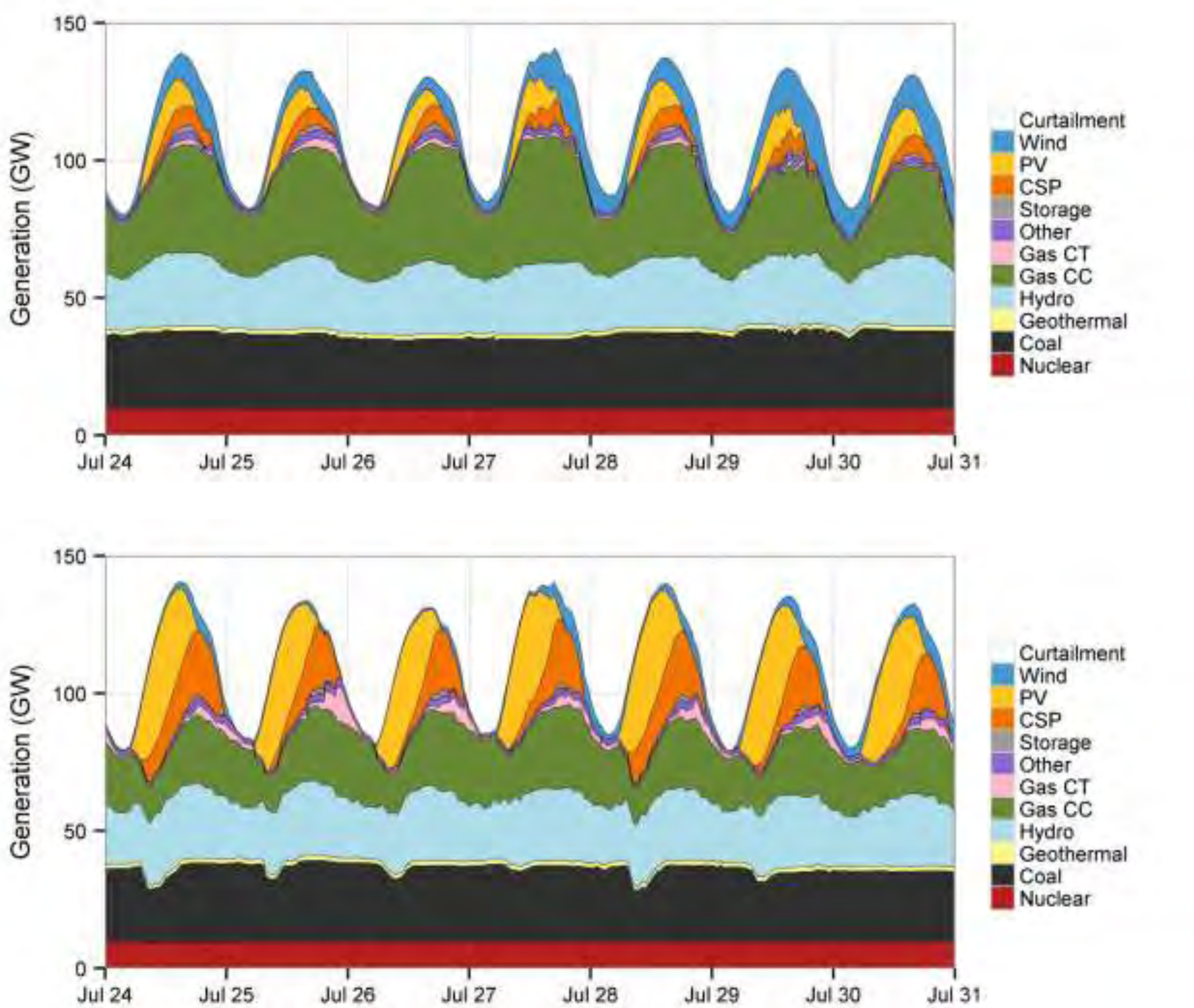
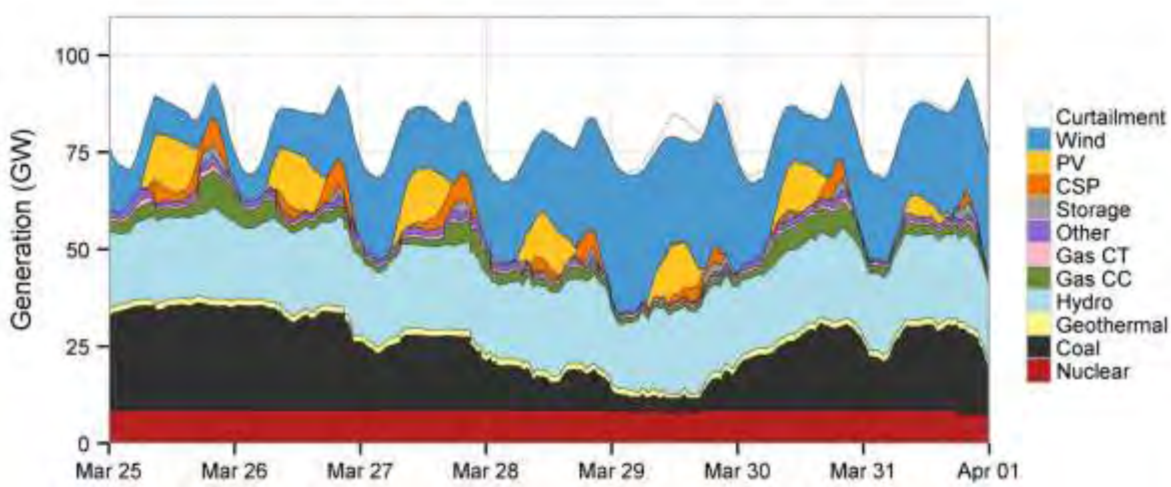


Figure 4.10.3-8: Five-minute dispatch stacks for the (top) High Wind, and (bottom) High Solar Scenarios for a week in July. Source: WWSIS-2 (2013).

In the spring, when loads are typically lower and wind and solar generation are high, the displacement of conventional resources is greater. In addition, impacts on cycling conventional plants can be greatest in the spring. Figure 4.10.3-9 shows the resource mix for the spring week in March in which the minimum net load was reached. This week is one of the most challenging for grid operators because low loads are combined with high solar and wind output. In the high wind scenario (which includes solar), the wind and solar displace almost all of the gas generation (much of which is combined cycle) and significantly reduce coal generation, assuming a gas price of $4.60/MMBtu. Because some generators reached their minimum output levels, some solar and wind generation were curtailed during the week.

In the high solar scenario, the impact was substantially different, with solar causing significant ramping of coal generators daily. The substantial amount of solar generation available at midday resulted in curtailment of wind and PV as well.



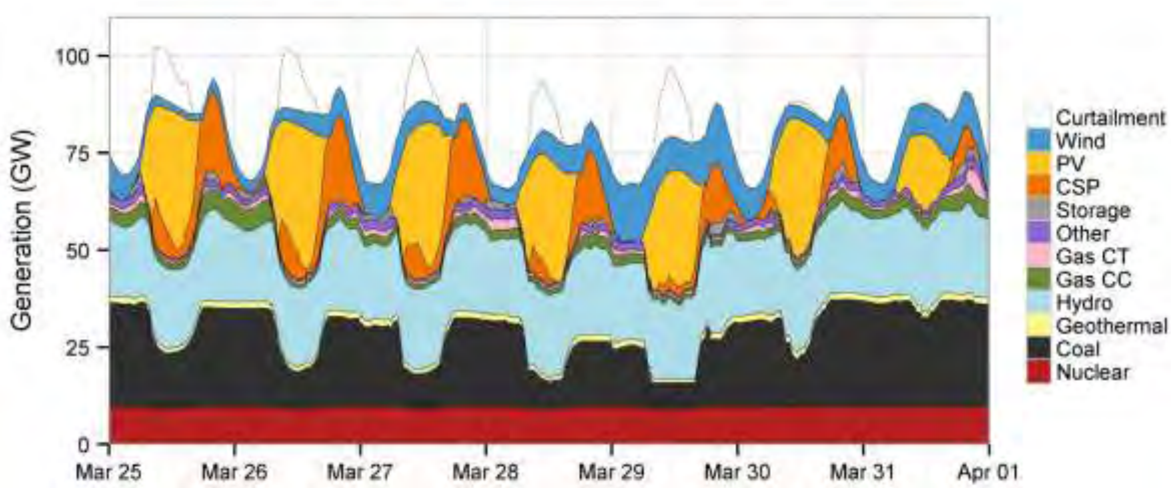


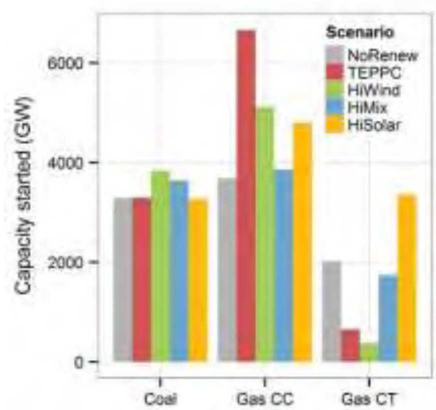
Figure 4.10.3-9: Five-minute dispatch stacks for the (top) High Wind and (bottom) High Solar Scenarios for a week in March. Note: This week represented the minimum net load condition. Source: WWSIS-2 (2013).

Production simulation modeling on a 5-minute basis for WWSIS2 (2013) found that the system was able to balance load and generation adequately with few violations of system reserve requirements. The system uses the least costly method to flexibly balance load and generation. In summer months, capacity is more important to balance the system than flexibility. In the spring when there are high levels of wind and solar generation and low loads, system flexibility is needed for balancing, such as ramping hydro units, curtailing wind and solar, or cycling fossil plants.

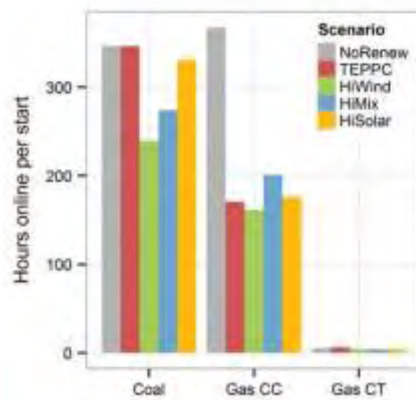
(4) Cycling and Ramping of Fossil Plants and Emissions Impacts

In the high solar scenario, coal units are ramped up and down each day. In the high wind scenario, coal units are shut down and restarted weekly or longer. In both scenarios, combustion turbines are run for only several hours at a time and shut down and restarted frequently. Figure 4.10.3-10 the impacts on cycling of fossil plants over the course of a year associated with several scenarios of high penetrations of solar and wind. The high solar scenario increased the number of ramps of gas and coal units by an order of magnitude compared to the no renewables scenario and required somewhat more ramping of coal units than the high wind scenario.

(a)



(b)



(c)

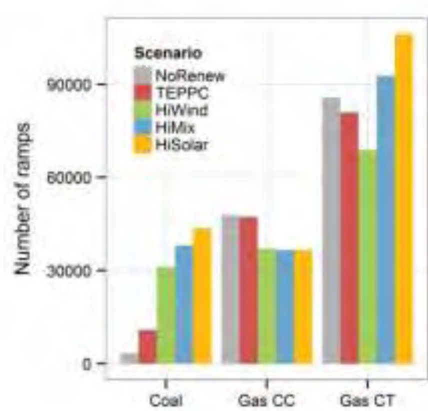


Figure 4.10.3-10: (a) Capacity started, (b) average number of hours online per start (must-run CTs have been excluded), and (c) total number of ramps for each plant type by scenario for 1

year.

Regarding impacts on gas plants, renewables reduce the runtime of combined cycle (CC) units by about half even in moderate wind and solar penetration scenarios. Increasing the penetration of wind and solar on the system increases and then decreases the number of times CC units are started. The amount of ramping of CC units decreases with high penetrations of renewables. With respect to combustion turbines (CTs), the high wind scenario shows a substantial reduction in CT generation and cycling of CT units. The high solar scenario shows a larger number of CT starts compared to a scenario with no renewables, partly because in the evenings load increases to peaks while PV generation falls off at sunset.

Figure 4.10.3-11 provides insight into impacts on the cycling and ramping of coal units. The committed coal capacity is shown by the solid line and the dispatched capacity is shown by the shaded area, with the white area in-between showing the amount that coal is backed down. In the top two scenarios with little renewables, the coal plants run at nearly full output, most of the time. In the high wind and solar penetration scenarios, coal is ramped significantly in the spring. Coal units are shut down roughly each week and coal units are ramped up and down daily, especially under the high solar scenario. In the summer, coal is not ramped as much except for some ramping during the day that occurs under the high solar scenario.

Modeling also showed that it is important to consider plant wear-and-tear costs in dispatch optimization, because it can substantially alter the dispatch mix. The High Wind Scenario was modeled with and without wear-and-tear start costs and showed almost no impact on the generation mix annually, but showed a large change in CC and CT unit starts.

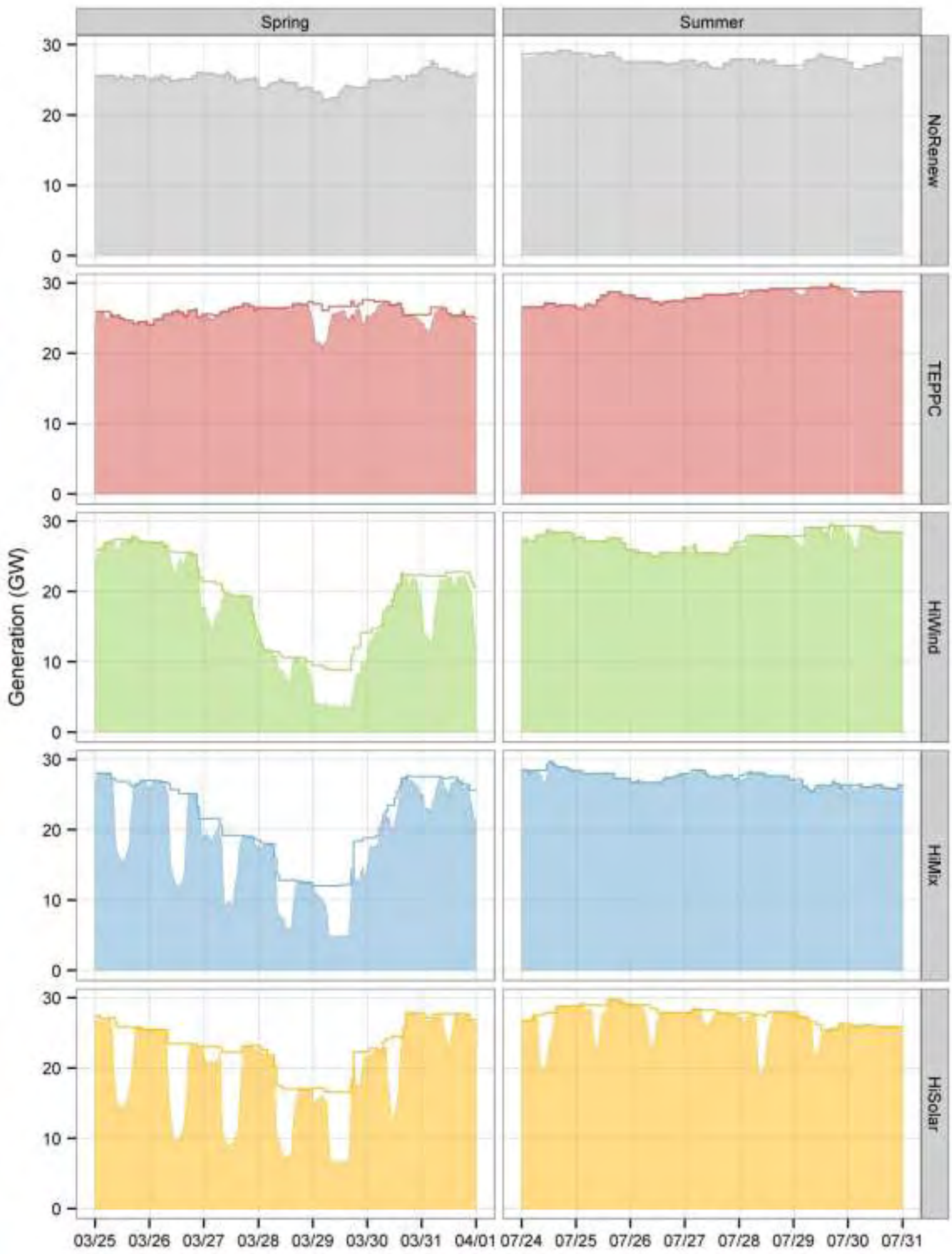


Figure 4.10.3-11: Capacity committed (solid line) and dispatched (shaded area) for coal units during March and July sample weeks. Source: WWSIS-2 (2013).

(5) Emissions Impacts of Cycling and Ramping Fossil Plants

Changes in the operation of fossil-fuel plants induced by solar and wind can modestly increase or decrease CO_2, NOx, and $S0_2$ emission rates, depending on the generation mix and the level of wind and solar on the system. Changes in emissions rates can result from running fossil fuel plants at part loads, which is less efficient, increasing the number of times units are started, and ramping plants up and down. Table 4.10.3-1 below shows the avoided emissions per MWh of wind and solar in high penetration scenarios.

Table 4.10.3-1: Emissions Avoided per MWh of Wind and Solar—Considering Part-Load, Ramping, and Start Impacts. Source: WWSIS-2 (2013).

Scenario	Avoided CO_2 (lb/MWh)	Avoided NO_X (lb/MWh)	Avoided SO_2 (lb/MWh)
High Wind	1,190	0.92	0.56
High Mix	1,150	0.80	0.44
High Solar	1,100	0.72	0.35

In general, CO_2 emissions rates of coal, CC and CT units are only modestly affected by adding wind and solar to the system. The analysis for the WWSIS-2 (2013) study found that generally emissions rates for coal and CC plants showed up to a 1% improvement under the high wind and solar scenarios. The most significant impact was an increase of about 2% in CT emissions rates from cycling in the high wind scenario. These results are for an entire power system and impacts on individual units can vary, also assumptions about gas prices affect results.

NO_x emissions impacts can be positive or negative, but overall effects on NO_x are modest. New starts have a neglible effect on NO_x emission, while ramping of units was found to reduce avoided NO_x by 2% to 4% in high wind and solar scenarios. Running coal plants at part loads was found to have an emissions benefit, with avoided NO_x improvements of 4% to 6%. Impacts also differ by plant type. Coal unit impacts were negligible, while CC unit emissions rates increased by up to 5%. CT emissions rates were most affected with increases of about 10% in the high solar case (with less wind), but were reduced by 10% in the high wind case (with less solar). Overall, the modeling of high penetration wind and solar scenarios found a net improvement in avoided NO_x emissions of 1% to 2% when cycling and ramping of units was taken into consideration.

SO_2 emissions impacts are also modest and vary depending on the mix of wind and solar. The net impact of ramping and starts reduced avoided emissions by 2% to 5%, with ramping effects contributing to most of the change. The impact of running plants at part-load was not studied. Overall, the high solar scenario was found to increase SO_2 emissions rates by 2%, while the high wind scenario reduced emissions rates by 1%.

(6) Curtailment of Solar and Wind

In some instances when thermal units reach minimum generation thresholds or if there is transmission congestion, grid operators may need to curtail wind and solar. Scenarios of high solar penetrations found the greatest amount of curtailment although still modest, with about 5% of the solar generation being curtailed as shown in Figure 4.10.3-12. The curtailment occurred primarily in midday when solar generation is highest. The high wind scenario showed wind curtailment of about 3%, mostly at night when wind output is high and loads are low. The scenario with a balanced mix of wind and solar showed the lowest amount of wind and solar curtailment, at less than 2%.

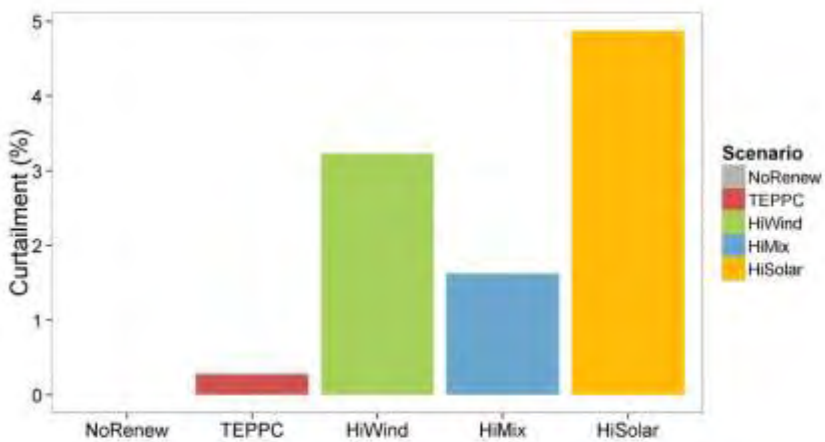


Figure 4.10.3-12: Curtailment as a percentage of potential wind and solar generation.

4.10.4. Issues and Solutions for PV Penetration

(1) From Phase II of the Western Wind and Solar Integration Study (WWSIS-2)

Geographic diversity of solar reduces cloud cover impacts

The magnitude of the effect of cloud cover on PV plant output is influenced by both the size and number of PV plants. Small PV systems, such as rooftop systems, can have substantially variable output as a result of fast-moving clouds that affect performance, but small systems have little effect on the bulk power system. They may however have effects on the distribution system, which is not the focus of this discussion. The variability of small systems declines as they are spread out geographically across the power grid, reducing the possibility that clouds will affect all distributed systems at once. Thus, the variability is smoothed out with a large number of dispersed systems. Large PV systems can have a more significant impact on the grid, but the large size of these systems helps reduce the variability. Clouds typically do not cover the entire area of the plant at once, but rather move across the plant, affecting only a portion of the project at once.

Figure 4.10.4-1 demonstrates how variability is smoothed with a larger number of PV plants at diverse sites. The figure, which is based on plants in Southern California, shows the highly variable output of one and two PV plants and how the variability is smoothed when the output of 25 plants is aggregated.

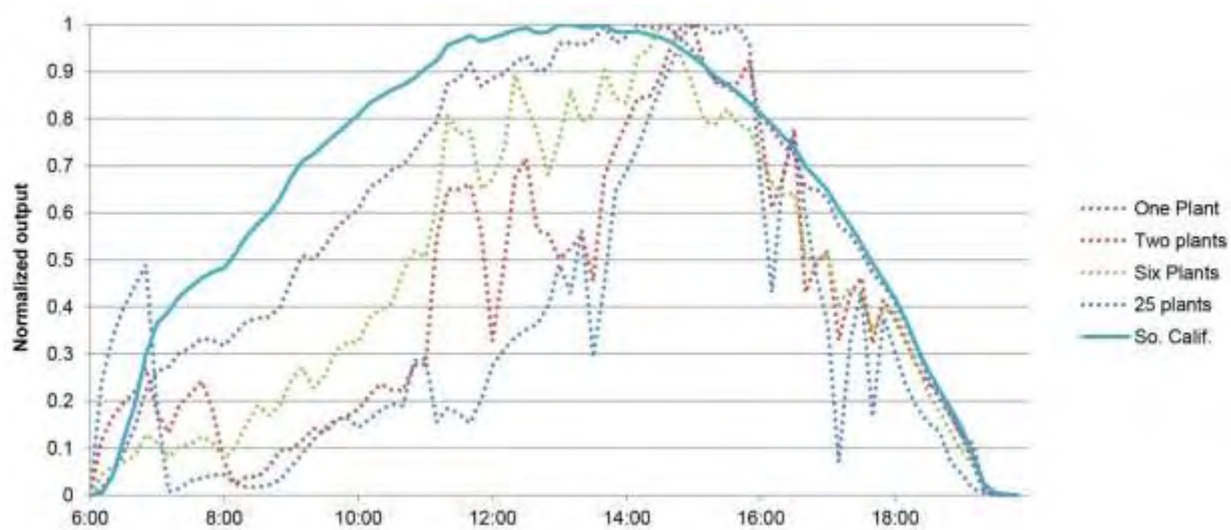
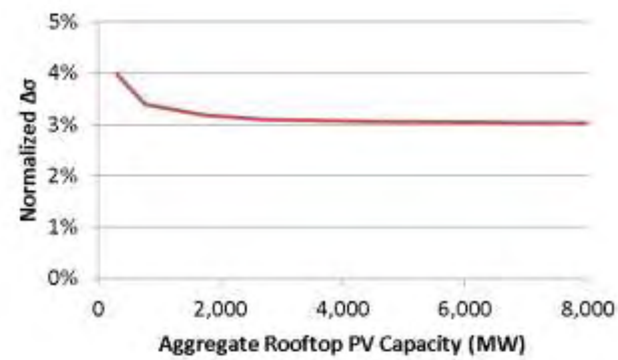


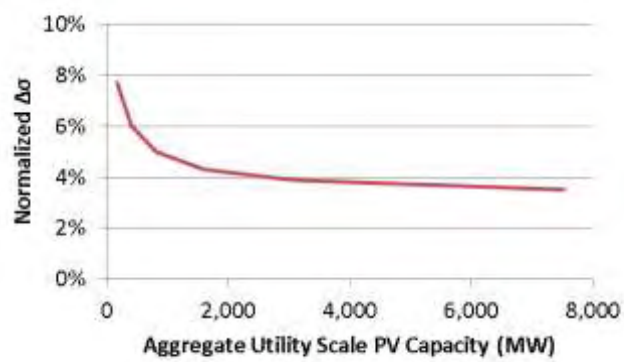
Figure 4.10.4-1: Normalized PV output for increasing aggregation of PV plants in Southern California for a partly cloudy day. Source: WWSIS-2 (2013).

Figure 4.10.4-2 compares the variability of rooftop PV, utility-scale PV, and wind and how it changes with larger amounts of capacity on the power system. Data are derived from plants in Southern California. The definition of variability here is one standard deviation of the hourly change in output. The variability of wind fell most rapidly with the aggregation of plants and reached a level of about 1%. In comparison, utility-scale PV variability exhibited a slower decline and reached a level of about 4%, while rooftop PV systems reached a level of about 3%. The rooftop PV systems analyzed here began as an aggregation of many small systems and as a result shows little benefit in reducing variability with further aggregation of plants.

(a)



(b)



(c)

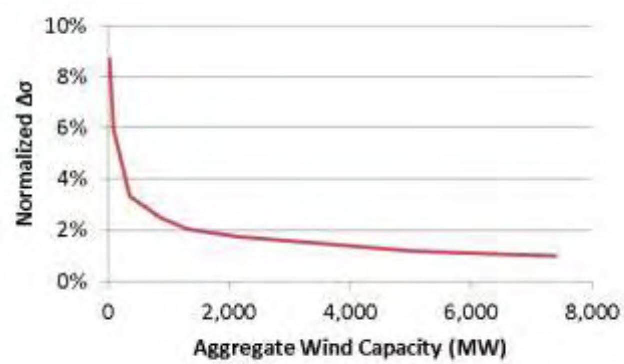


Figure 4.10.4-2: Normalized variability as a function of aggregate capacity for (a) rooftop PV, (b) utility-scale PV, and (c) wind. Note: Observe the difference in y-axis scales. Δσ is one standard deviation of the hourly change in output. Source: WWSIS-2 (2013)

(2) From the Phase I of the Western Wind and Solar Integration Study

The following findings are derived from the Western Wind and Solar Integration Study , Phase 1 (WSSIS-1 2010). The study examined the impacts on the power system of increasing variable renewable generation up to a level of 35% of the system's production. Of that 35%, 30% of the power was produced by wind, and 5% was produced by photovoltaic solar power, and concentrating solar power. The study assessed the effects of integrating that renewable generation into Western U.S. power grid.

Large balancing areas or cooperation

Large balancing areas or cooperation among balancing authorities can provide multiple benefits to mitigate the challenges associated with increased variable renewable generation. Chief among those benefits are the ability to decrease aggregate variability in both power supply and demand, and the operational cost savings that accompany more efficient use of reserves across multiple balancing areas.

Having access to greater geographic and technological diversity of generation across larger balancing areas helps to smooth localized weather and power production anomalies and provide a more stable and predictable power supply. Similarly, on the demand side of the power system, cooperation across balancing areas allows access to a diversity of load, which smoothes demand fluctuation anomalies and provides a destination in one balancing area for excess power generated in another. Figure 4.10.4-3 below demonstrates a visual representation of the reduced variability from combining balancing as renewable penetration levels increase.

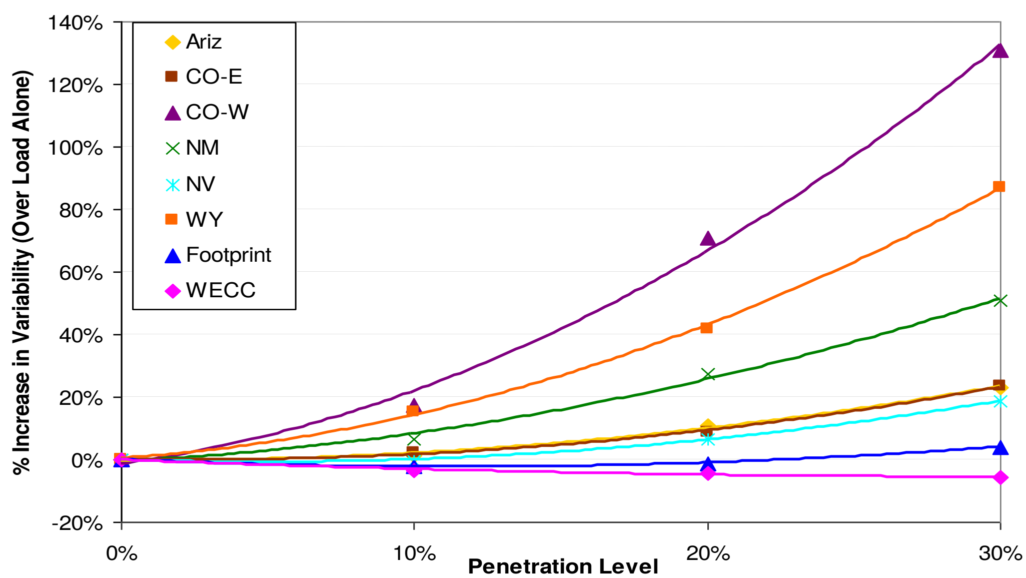


Figure 4.10.4-3: The effect of balancing area cooperation on variability of generation over variability of load. Source: WWSIS-1 (2010).

More efficient use of reserves can help smooth variability and lead to decreased operating costs if the aggregate need for reserves across multiple balancing areas can be reduced. WWSIS1 2013 found that in the Western U.S. approximately $2 billion in operational cost savings can be realized if the Western ISOs were to pool reserves and cooperate across balancing areas instead of operate independently of one another (see Figure 4.10.4-4).

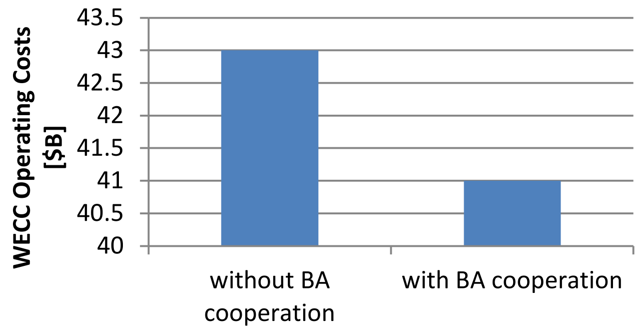


Figure 4.10.4-4: Potential reserve cost savings with cooperation among balancing areas. Source WWSIS-1 (2010).

Sub-hourly scheduling

Sub-hourly scheduling can provide benefits to power systems with greater levels of variable renewable penetration. Due to the inter-hour variability of variable renewable generation, hourly scheduling can lead to greater use of regulation reserves within the hour during periods of large, expected ramp events. Further, the scheduled use of these reserves can lead to a lack of available reserves to compensate for unexpected inter-hour variability during ramp events. Figure 4.10.4-5 below demonstrates the substantially reduced requirement for combined cycle plants to provide regulating reserves (at 30% wind penetration levels) when sub-hourly scheduling is used compared to hourly scheduling.

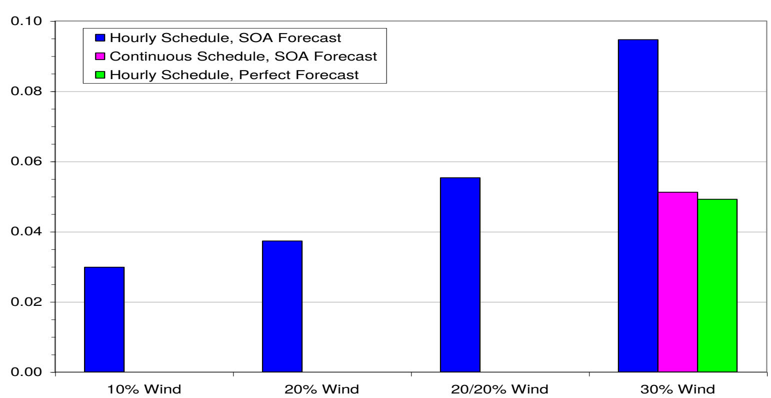


Figure 4.10.4-5: Requirements on combined cycle regulation reserves can be halved with sub-hourly dispatch scheduling and for systems with higher levels of variable renewable generation. Source: WWSIS-1 (2010).

Demand Response

Demand response, or the ability for a utility or power system operator to call on load to curtail power usage in times of system demand peaks, can be a powerful tool for system operators in balancing increased production variability that accompanies greater degrees of renewable penetration. WWSIS-1 (2010) found that increasing the size of the utility/system operator's demand response program to account for the small number of annual hours for which a contingency reserve shortfall is expected is a more cost-effective option to address variability concerns than increasing spinning reserves for the entire year.

Figure 4.10.4-6 below demonstrates reserve shortfall curves for a 30% variable renewable penetration scenario, and the effect of increasing spinning reserve availability. Increasing demand response to avoid reserve shortfalls for the 89 hours over the course of the year in which there is a shortfall in contingency reserves is more cost effective than increasing reserves for the entire year to plan for such expected shortfalls.

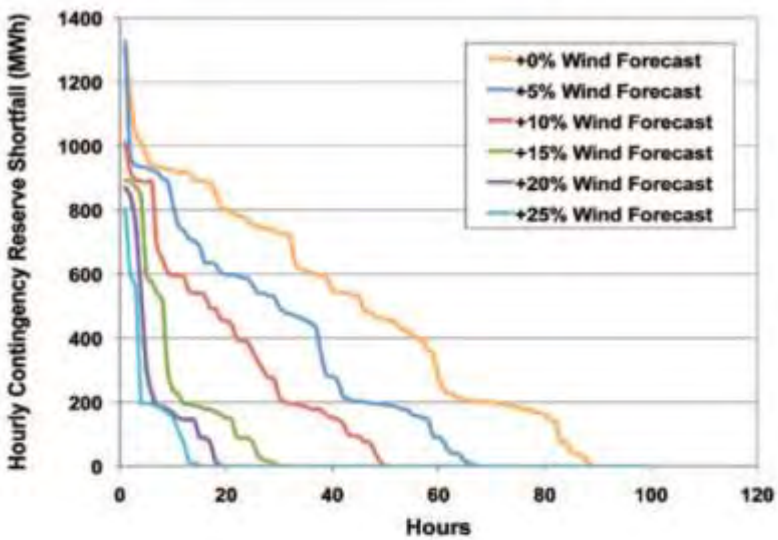


Figure 4.10.4-6: Hourly reserve shortfall for 30% variable renewable generation scenario, given varying increases to spinning reserves. Source: WWSIS-1 (2010).

Use of Storage

The use of energy storage technologies –including pumped hydro, compressed air, thermal storage, networks of charging electric vehicles, flywheels, and fuel cells -- could substantially decrease the effects of power production variability of wind and solar on the grid. Storage can offer a number of benefits to electric grids including improved reliability, ancillary services, smoothing variable renewable power generation, as well as economic benefits of arbitrage from storing energy during periods of low electricity prices and releasing and selling electricity during periods of high prices. Typically, the greatest drawback to the deployment of energy storage technologies is a current lack of economic feasibility or the need for geographically optimal conditions, such as in the case of pumped storage facilities.

The use of storage to smooth the variability of wind and solar on the grid could also yield economic benefits if reserves could be diminished or dispatched more efficiently. Maintaining higher levels of spinning reserves to integrate higher levels of variable renewable generation, will carry with it the economic costs associated with keeping those assets spinning. Consequently, any solution – such as storage – that could potentially decrease production variability and reduce the need for spinning reserves, carries with it the potential to decrease operating costs.

Analysis of high penetration renewable energy scenarios in the Western U.S., found that storage was not economically viable under system operating conditions. WWSIS-1 (2010) examined price arbitrage opportunities for pumped storage hydro facilities and found that they were not adequate to cover the costs of a new pumped storage facility. WWSIS-1 (2010) found that at 10% and 20% wind energy penetration scenarios, there was not sufficient variability in spot prices to economically justify storage because gas-fired generation was on the margin. While variations in spots prices were found to increase with a 30% wind energy scenario, storage was still not found to be economically viable. Although there were periods of large price electricity price differentials that would economically benefit storage, the unexpected nature of the events meant that storage units could not be readily scheduled to take advantage of them.

Generation Flexibility

Flexibility of generation is important for managing the variability of wind and solar generation. For a 30% renewable energy penetration case, WWSIS-1 (2010) found that decreased flexibility of either the coal or hydropower plants made system operations more challenging and lead to higher operating costs.

WWSIS-1 (2010) examined the effect of increasing coal generation flexibility on operating costs of a system with 30% renewable generation. As can be seen in Figure 4.10.4-7 below, operating costs increased substantially if the minimum level at which coal plants were allowed to run is raised from 50% to 70% of capacity.

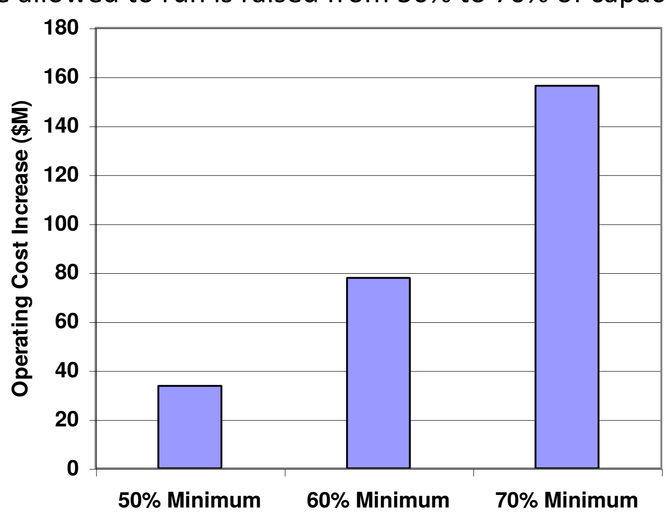


Figure 4.10.4-7: Decreasing the flexibility of coal generation led to greater increases in operating costs in a 30% variable generation penetration scenario. Source: WWSIS-1 (2010).

Hydropower can also be a source of flexible generation because it can be ramped, started or stopped quickly. WWSIS-1 (2010) found substantial cost savings in higher penetration renewable scenarios if the hydropower is adjusted to account for day-ahead renewable energy forecasts. While the impacts are minimal at lower penetrations of renewables, at the 30% penetration level, cost savings were $200 million annually. If hydropower were substantially constrained and were dispatched at a steady generation level (e.g., to maintain steady river flows), the cost of operating the system would increase by nearly $1 billion annually. These findings, as shown in Figure 4.10.4-8, demonstrate that taking maximum advantage of hydropower flexibility is important for maintaining efficient system operations with higher penetrations of variable renewable generation.

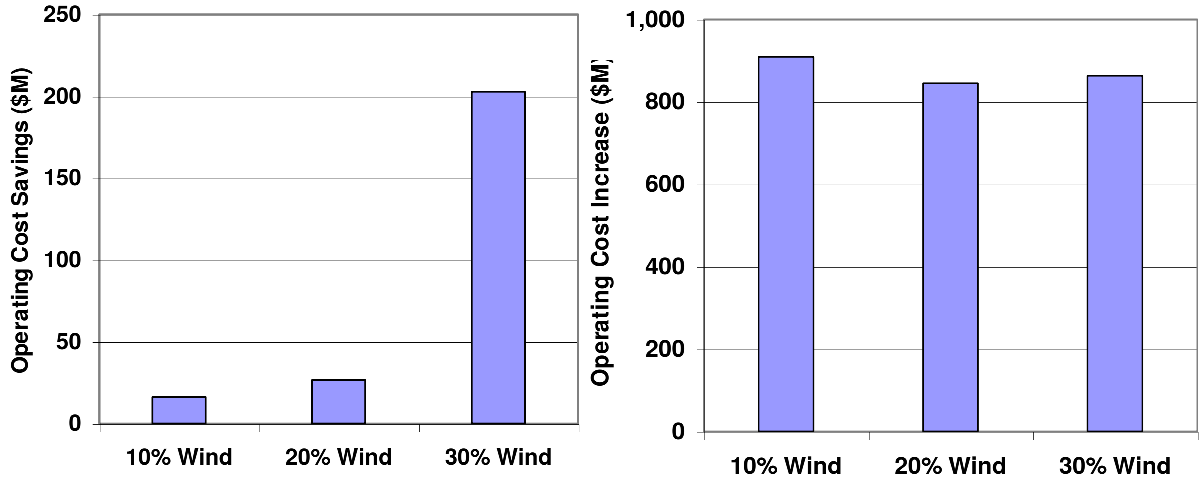


Figure 4.10.4-8: Operating cost savings of dispatching hydro to net load (left), and operating cost increase of hydropower with constant output (right). Source: WWSIS-1 (2010).

4.10.5. R&D for Transmission level Challenges

The scope and nature of the challenges associated with the uncertainty and variability of wind and solar energy generation vary depending on the specific configuration and operation of each electric grid. Many mitigation options exist, but the optimal solutions depend on factors such as the generation mix in the electric grid, the regulatory environment, the market structure, and others. As more utilities and system operators implement mitigation strategies to cope with increasing levels of wind and solar energy generating capacity in their grids, the knowledge base on mitigation mechanisms improves. However, several questions remain unanswered. Highly sophisticated simulation models will continue to play a crucial in identifying the most effective mechanisms and lower the costs of mitigation (Bird et al. 2013b).

(1) Eastern Renewable Generation Integration Study – ERGIS

The Eastern Renewable Generation Integration Study (ERGIS) will analyze two strategies for reaching 30% combined wind and solar targets in the U.S. Eastern Interconnect and inform stakeholders about the operational impacts of these two strategies. Particular attention will be paid to understanding sub-hourly and regional impacts of high penetrations of wind and solar generation. This is the largest study of its kind in terms of scope and modeling resolution. NREL's investigation into integration challenges and methods for analyzing proposed solutions will create a foundational resource for future transmission scale analyses.

Answering questions about high penetrations of variable generation requires the development of a robust generation and transmission database that is thoroughly vetted with stakeholders and validated with historical results where appropriate. NREL will work with the ERGIS Technical Review Committee (TRC), a team composed of regional and national experts on renewable energy generation and power systems, to vet key assumptions, methodology, and preliminary results.

In its final study year, ERGIS will focus on analyzing work completed in previous years to determine how new operational practices and tools can be applied to minimize the production costs of 30% combined wind and solar generation. This will involve running a variety of simulations to test mitigation options.

(2) Western Wind and Solar Integration Study (WWSIS) - Phase 3

The third phase of this study will examine large-scale stability and frequency response with high solar and wind penetrations in the U.S. Western Interconnection, and identify means to mitigate adverse performance impacts via transmission reinforcements, storage, advanced control capabilities or other alternative means. A distinguishing feature of this project is the detailed analysis of re-commitment and re-dispatch procedures, based on WWSIS-2 production simulation results, to build a credible case with high penetrations of wind and solar.

(3) Solar integration National Dataset

The goals of the Solar Integration National Dataset (SIND) project are to create a new national solar database with higher temporal and spatial resolution and to provide public access to this data to reduce the costs and risks of integrating solar power systems into the electric power grid. The Solar Integration National Dataset (SIND) Toolkit will enable researchers to perform regional variable generation integration studies by providing complete, current, and coherent solar power data, information, and tools.

Variable generation integration studies have evolved from determining if high penetrations of variable generation are possible to evaluating the challenges of and solutions for an electric power system with them. As system topology, operation practices, and power markets evolve, system operators will need to rapidly simulate new conditions. The foundation of system simulations is a coherent dataset that accurately represents the conditions systems are likely to experience.

4.10.6. References

[1] Office of Energy Efficiency and Renewable Energy (EERE). 2013. "Learn More About Interconnections." Accessed December 5. http://energy.gov/oe/information-center/recovery-act/recovery-act-interconnection-transmission-planning/learn-more.

[2] Lew, D., G. Brinkman, E. Ibanez, B. M. Hodge, M. Hummon, A. Florita, and M. Heaney. 2013. "The Western Wind and Solar Integration Study Phase 2". NREL/TP-5500-55588. National Renewable Energy Laboratory (NREL), Golden, CO. http://www.osti.gov/scitech/biblio/1095399.

[3] GE Energy. 2010. "Western Wind and Solar Integration Study". NREL/SR-550-47434. http://www.nrel.gov/docs/fy10osti/47434.pdf.

[4] American Public Power Association (APPA). 2013. "2013-14 Annual Directory & Statistical Report."

[5] The Regulatory Assistance Project (RAP). 2011. "Electricity Regulation in the US: A Guide."

[6] U.S. Energy Information Administration (EIA). 2013. "Monthly Energy Review". DOE/EIA-0035(2013/03). http://www.eia.gov/totalenergy/data/monthly/archive/00351303.pdf.

[7] U.S. Energy Information Administration (EIA). 2013b. "Annual Energy Outlook 2013 with Projections to 2040". DOE/EIA-0383(2013), 1081575. http://www.osti.gov/scitech/biblio/1081575.

[8] National Energy Policy Development Group. 2001. *Reliable, Affordable, and Environmentally Sound Energy for America's Future: Report of the National Energy Policy Development Group*. DIANE Publishing.

[9] Gelman, R. 2013. "2012 Renewable Energy Data Book (book)". DOE/GO-102013-4291. National Renewable Energy Laboratory (NREL), Golden, CO. http://www.osti.gov/scitech/biblio/1104592.

[10] "Role of Electricity Markets and Market Design in Integrating Solar Generation: Solar Integration Series. 2 of 3 (brochure)." 2001. DOE/GO-102011-3199. National Renewable Energy Laboratory (NREL), Golden, CO. http://www.osti.gov/scitech/biblio/1013270.

[11] Barbose, Galen. 2013. "Tracking the Sun VI: An Historical Summary of the Installed Price of Photovoltaics in the United States from 1998 to 2012."

[12] Bird, L., J. McLaren, J. Heeter, C. Linvill, J. Shenot, R. Sedano, and J. Migden-Ostrander. 2013. "Regulatory Considerations Associated with the Expanded

Adoption of Distributed Solar”. Golden, CO: National Renewable Energy Laboratory (NREL).
http://www.nrel.gov/docs/fy14osti/60613.pdf.

[13] Solar Energy Industries Association (SEIA), and GTM Research. 2013. “2012 U.S. Solar Market Insight Report.”
http://www.seia.org/research-resources/us-solar-market-insight.

[14] North American Electric Reliability Corporation (NERC). 2011. “Balancing and Frequency Control, A Technical Document Prepared by the NERC Resources Subcommittee”. Princeton, NJ.
http://www.nerc.com/comm/oc/rs%20landing%20page%20dl/related%20files/nerc%20balancing%20and%20frequency%20control%20040520111.pdf.

[15] Bird, L., M. Milligan, and D. Lew. 2013b. “Integrating Variable Renewable Energy: Challenges and Solutions”. NREL/TP-6A20-60451. National Renewable Energy Laboratory (NREL), Golden, CO.
http://www.osti.gov/scitech/biblio/1097911.

4.11. *Europe（Reported by EPIA and 3E（including Belgium Case））*

4.11.1. The Electricity mix in Europe in 2013

The electricity mix in Europe is the result of contrasting developments in all its countries, pushed by different interests, local specificities, and political will. Figure 4.11.1-1 and Figure 4.11.1-2 illustrate the evolution of the installed capacity in Europe from 2009 to 2011 and a forecast for 2020.

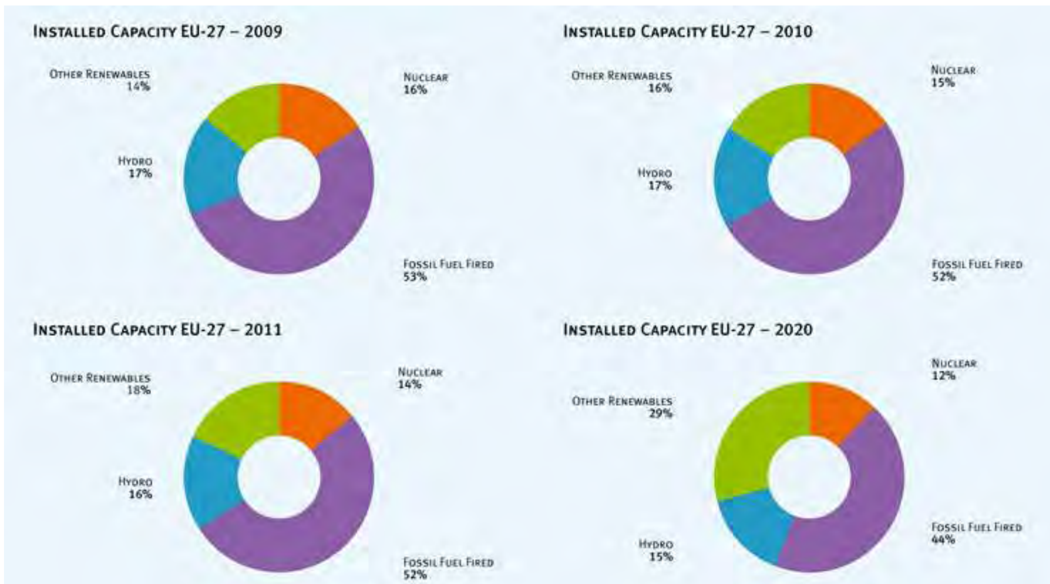


Figure 4.11.1-1: Evolution of the installed capacity in the EU-27, [1]

		2010	2011	2012
EU27 + CH, NO, TK	Nuclear	134,964	126,958	126,119
	Fossil Fired	486,643	494,914	491,444
	Renewables	274,175	310,306	346,573
	Pumped Hydro	81,055	61,564	63,192
	Total Capacity	961,929	1,000,178	1,036,425
EU-27	Total Capacity	863,385	897,416	928,852

Figure 4.11.1-2: Total installed capacity (MW), [1]

Total installed capacity rose to 929 GW at the end of 2012 in Europe. At the same time, the share of renewables reached for the first time 25% of the electricity demand, with nuclear at 24%. Most of the new net installations are gas, wind, and PV, while other conventional sources of electricity are declining (Figure 4.11.1-3).

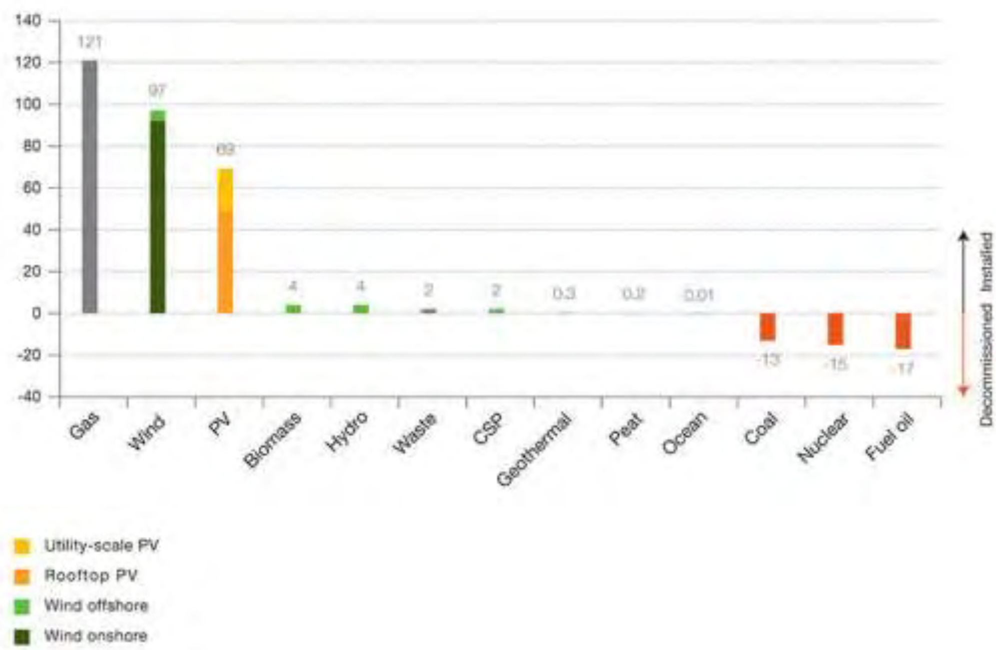


Figure 4.11.1-3: Net generation capacity added in the EU 27 2000 - 2012 (GW), [2]

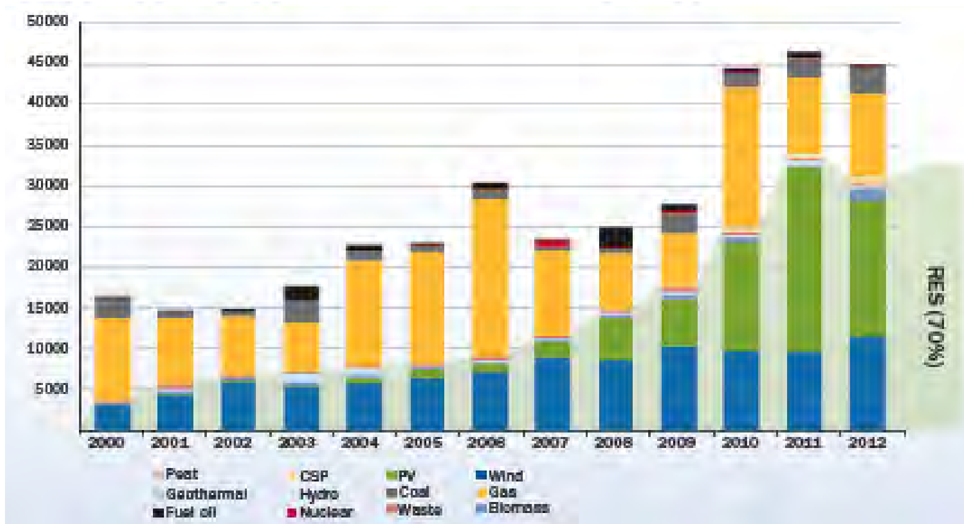


Figure 4.11.1-4: Installed power generating capacity per year and RES share (MW), [1]

Looking at the trends over the last 12 years (Figure 4.11.1-4), PV is gaining on gas and wind, with more than 69 GW installed in Europe. For the second year in a row, PV in 2012 was the number-one electricity source in the EU in terms of added installed capacity (Figure 4.11.1-3) with between 16.7 GW and 17.3 GW (IEA PVPS [3]) connected to the grid (EPIA [2]). The remarkable progress made by PV over the last four years should be compared with the stability of wind development and the fluctuating development of gas. Gas reached a peak in 2010, with more than 20 GW newly connected to the grid, before falling to slightly less than 10 GW in 2011 and more than 10 GW of new installations in 2012.

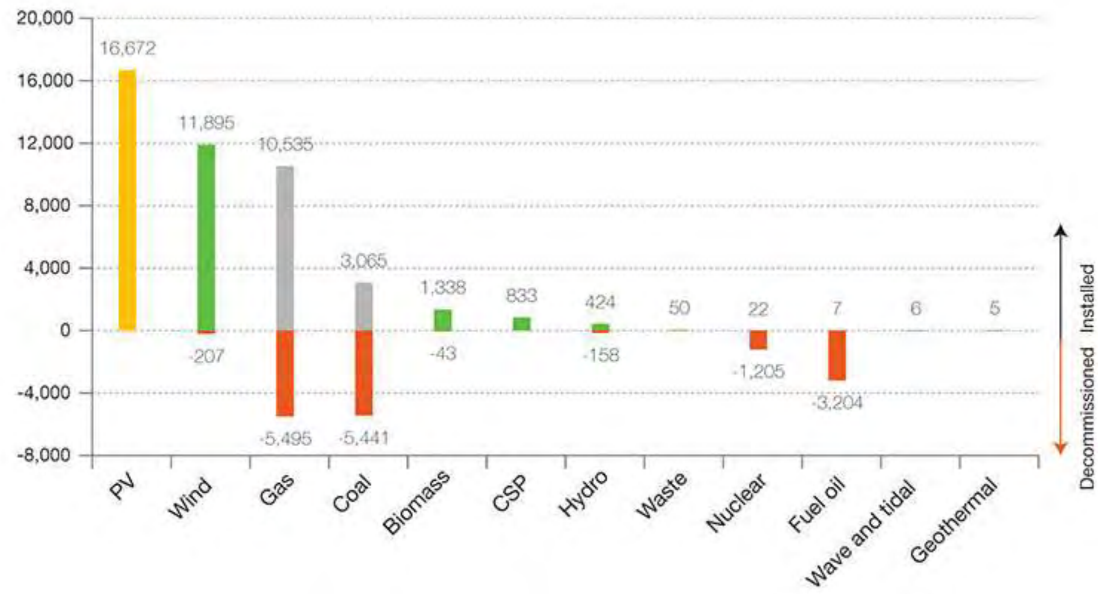


Figure 4.11.1-5: Power generation capacities added in the EU-27 in 2012 (MW), [2]

Including decommissioning, power generation capacities from gas fell from 10.5 GW to a mere 5.4 GW in 2012 (Figure 4.11.1-5). Traditional electricity sources such as nuclear, coal, and fuel oil have been decommissioned more often than newly installed. Fuel oil lost the most in 2012, followed by coal and nuclear.

Figure 4.11.1-6 shows a slightly different perspective if PV and wind are split according to their market segments: rooftop PV takes first place, while large PV installations (utility-scale PV) take fourth place. Onshore wind, which remains an important source of new electricity installations, stayed in second place, while the fast-growing offshore wind positions itself at the same level of biomass, with slightly more than 1 GW installed and commissioned.

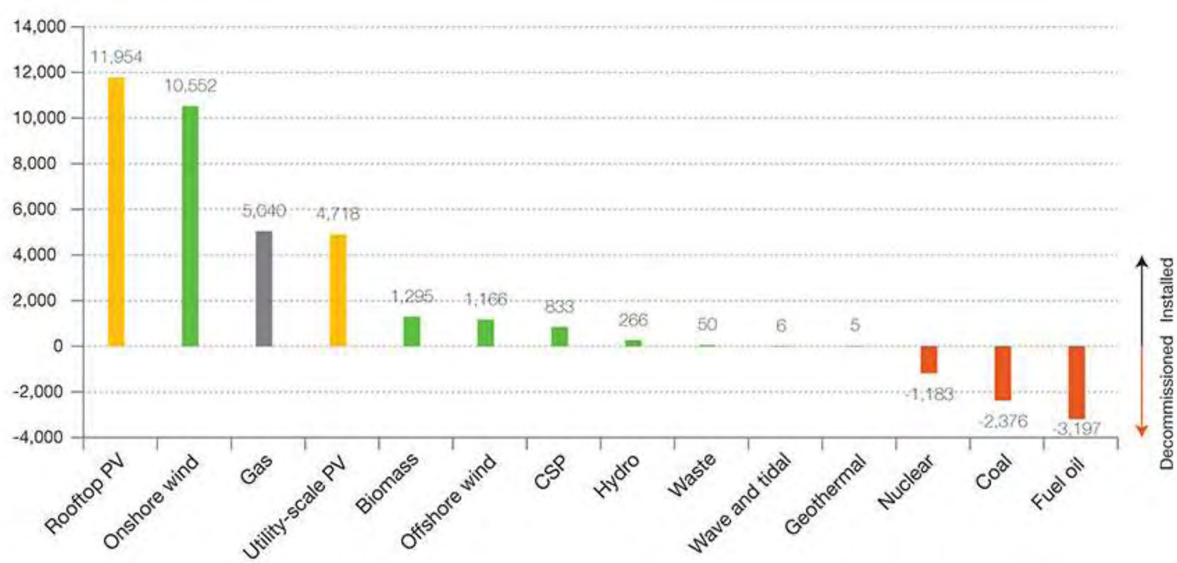


Figure 4.11.1-6: Net power generation capacities added in the EU-27 in 2012 (MW), [2]

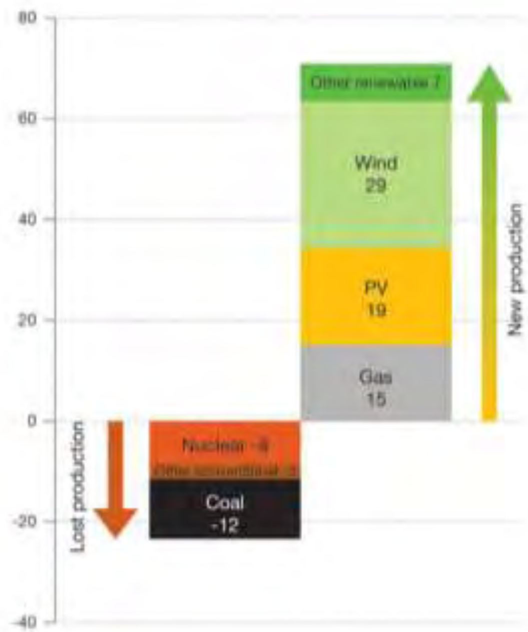


Figure 4.11.1-7: Theoretical balance of new electricity production in the EU-27 in 2012 (TWh), [2]

Due to the lower full load hours of PV compared to wind and gas, 2012 PV additions will provide around 19 TWh of new electricity during a complete operational year, compared to 29 TWh from the new wind installations and 15 TWh from gas power plants running in average 3,000 hours a year (Figure 4.11.1-7).

It could be argued that gas power plants running only 3,000 hours a year are being operated at lower than their theoretical production level. However, this reflects the reality of the electricity market in Europe in 2011 and 2012. More interesting, the energy that will be produced by new PV and wind installations in 2012 based on 2011 additions represents enough electricity to compensate for the decommissioning of nuclear, fuel oil, and coal power plants in 2012.

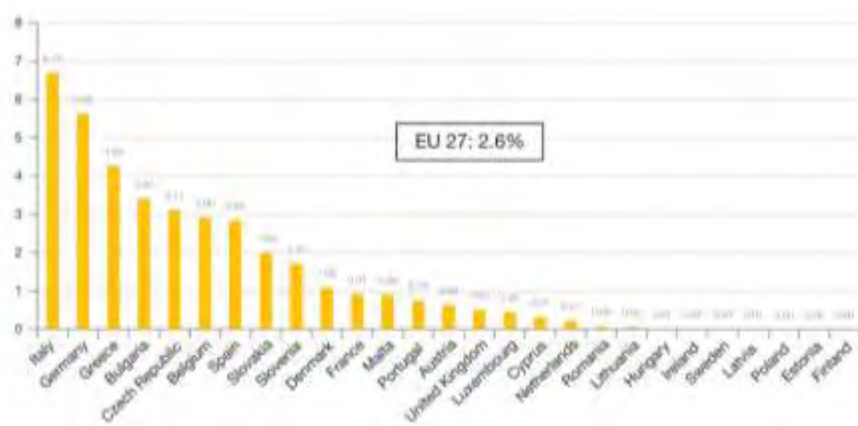


Figure 4.11.1-8: PV contribution to the electricity demand in the EU-27 in 2012, [2]

Based on the cumulative capacity connected to the grid at the end of 2012, PV can currently provide roughly 2.6% of the electricity demand in Europe, up from 1.15% at the end of 2010 and 2% at the end of 2011. In Italy, more than 6.7% of the electricity will come from PV systems connected in 2012. In Germany, PV reached more than 5.6%, and it reached 4% in Greece. Belgium, Bulgaria, and other countries are progressing rapidly as well (Figure 4.11.1-8). In most EU countries today, PV can be considered as peak power generation. Indeed, it produces during the day, at the time of the mid-day peak, competing directly with other peaking generators.

The speed at which PV has developed introduces new challenges for electricity system operation. Figure 4.11.1-9 compares the level of PV penetration with regard to the electricity demand (which remains quite low) and the maximum instantaneous penetration for a set of countries. In Germany 45% has been already reached, while numbers above 20%–25% have been recorded in several countries (left part of Figure 4.11.1-9).

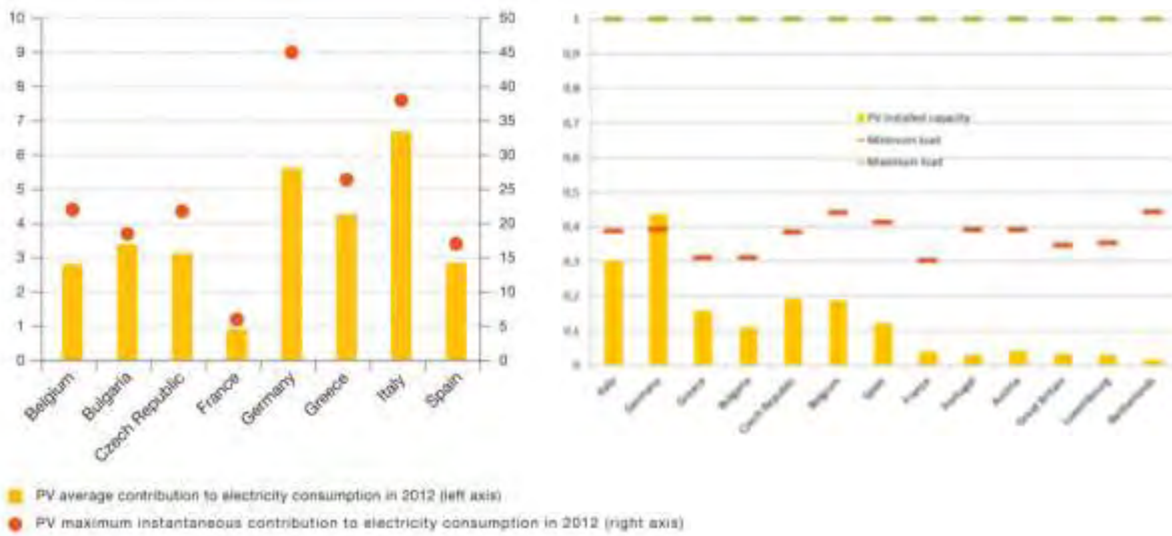


Figure 4.11.1-9: Annual average, maximum instantaneous PV penetration, minimum load and maximum load in 2012, [2]

A similar exercise is also presented in the right part of Figure 4.11.1-9, in which the installed PV capacity is plotted against the minimum and maximum load for several countries for 2012. While it is assumed that all PV systems are not producing at full capacity at the same time, an installed capacity close to the minimum load (which often occurs in Europe in the summer, during sunny weekends) is a good indicator that PV already impacts system operation today.

4.11.2. Penetration of PV and Other generation

System Augmentation Analysis: Energy Supply and Demand Circa2030

(1) The EU PV Market in 2012

With more than 17 GW of new PV capacity in 2012 (compared to 22.4 GW in 2011), Europe has increased its cumulative capacity base to 70 GW (Figure 4.11.2-1). This impressive performance was driven mainly by two markets: Germany and Italy.

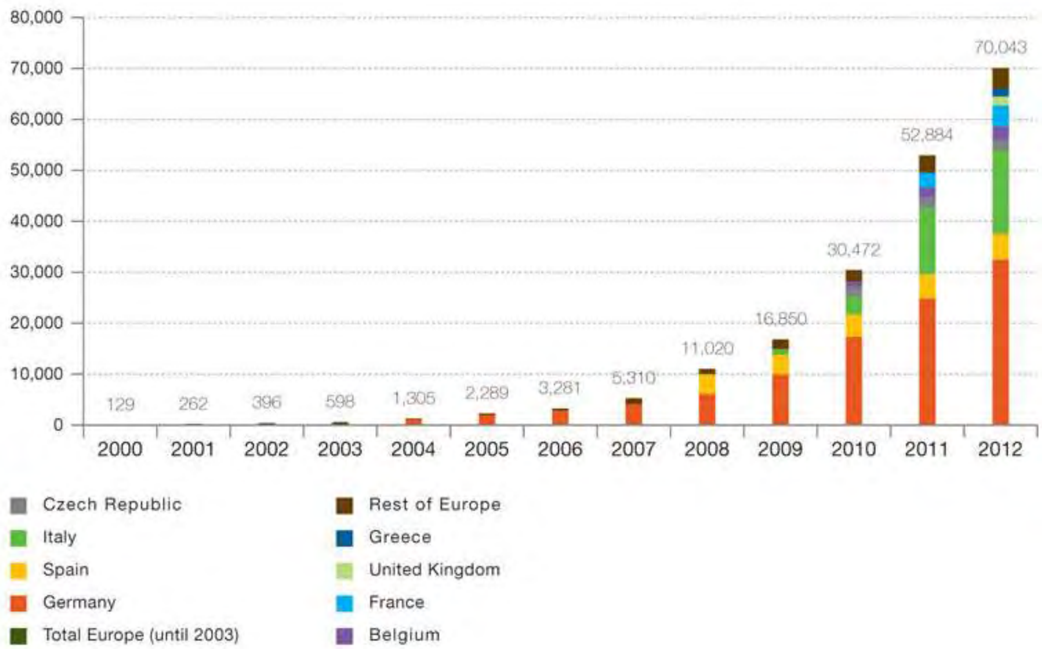


Figure 4.11.2-1: Evolution of the European cumulative installed capacity 2000-2012 (MW), [2]

The overall decline in Europe's PV market in 2012 hides various realities at the national level; the market evolution was very different from one country to another. Even in Germany, the apparent market stability is the result of a chaotic evolution, due to regulatory changes and hectic responses from investors. This was accompanied by a progressive evolution in market dynamics, with 2012 showing PV gradually becoming less reliant on direct incentives. With PV's levelized cost of energy (LCOE) now lower than the retail price of electricity, at least in the residential and commercial segments in Germany, PV development can be at least partially driven by self-consumption rather than only feed-in tariffs (FITs).

In Italy, 3.4 GW of PV were added in 2012. This is a significant decrease from the major boom seen in 2011 of 9.45 GW. After the rush of 2011, the Italian market has returned to a level that nevertheless remains high. Having reached a financial cap for FITs, the Italian market will experience the transition to the post-FIT era faster than many expected.

France scored third place among European countries in 2012, thanks again to previously installed projects finally being connected in 2012 along with a limited contribution from new installations. With 1.08 GW of PV in 2012, the country is still performing well below its theoretical potential and below its 2011 level of 1.76 GW. While the government recently pushed for an additional 1 GW of capacity, the constraints on market development remain significant.

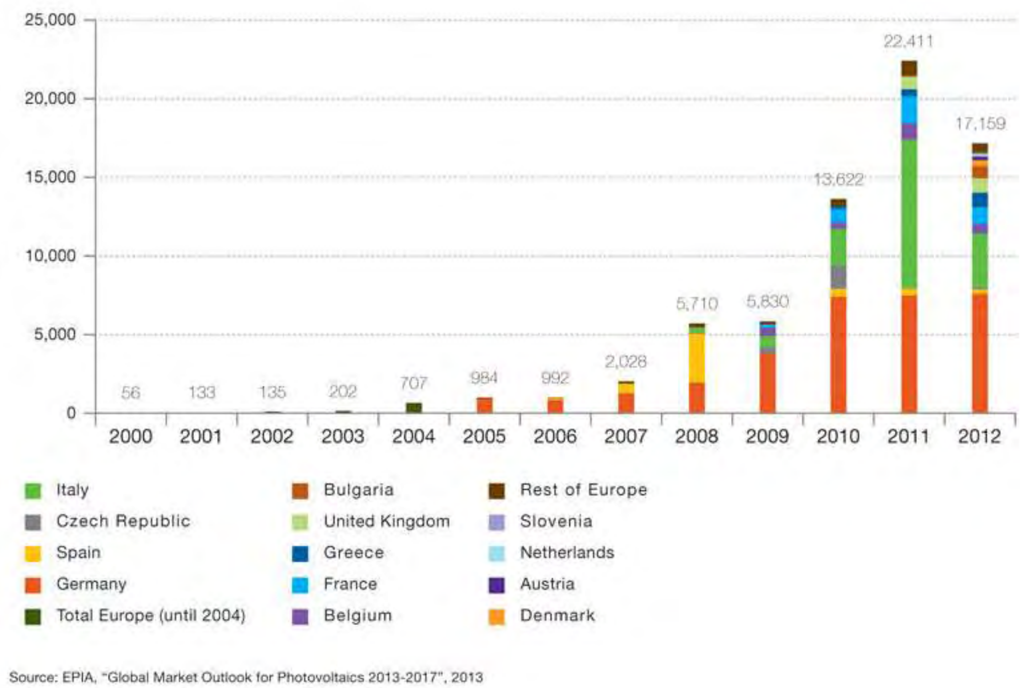


Figure 4.11.2-2: Evolution of European new-grid-connected PV capacities 2000-2012 (MW), [2]

In the UK, which installed 925 MW in 2012, the long-term prospects of PV remain quite positive even if the speed at which the market develops is not so impressive. Greece installed almost 1 GW (912 MW) in 2012, a record level for this country hit by an extremely hard recession, and 2013 could be a good year as well despite more restrictive conditions. Bulgaria experienced a boom in 2012, with 767 MW installed before the government reacted with harsh retroactive measures to slow the market growth; in 2013 the country's market will most likely slow down significantly. Belgium installed again a quite high level of 599 MW, in a context of strong political concern over the cost of support schemes. This could lead to a relatively low market in 2013. Denmark was one of the surprises of the year, with 378 MW, but the boom could stop in 2013. Austria installed 230 MW and Switzerland 200 MW. They have contributed marginally to market development, even if the numbers they have reached are the result of a major market growth.

In Spain, the government imposed an unexpected moratorium on FITs, destroying what remained of the PV market; only 276 MW were connected to the grid in 2012 in this country, which should be among the European leaders. The long-expected net-metering scheme was never introduced, and there are doubts as to whether it ever will be, given the government's fear of creating another boom. Ukraine experienced impressive growth in 2011 with almost 190 MW connected, thanks solely to the development of two very large power plants by one company. In 2012, 182 MW were installed, and the potential remains significant.

The European PV market remains quite heterogeneous, with very diverse segmentation from one country to another. Figure 4.11.2-3 highlights this fact. The market segmentation has been split to distinguish among ground-mounted systems, commercial and industrial rooftop applications, and residential applications.

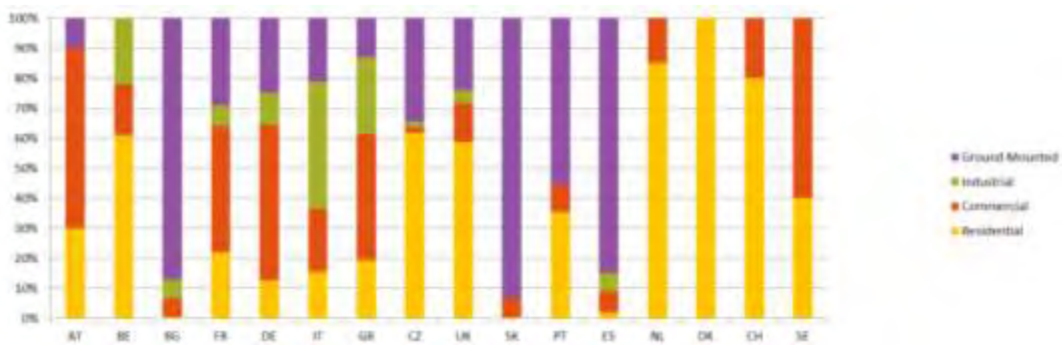


Figure 4.11.2-3: European PV cumulative capacity segmentation in 2012, [2]

The segmentation is not classified according to standard sizes, as system size largely depends on the respective structure of support schemes, country by country. In general, the commercial segment should be distinguished from the residential segment not only according to the system size but also the nature of the investor (private or public) and the regime of retail electricity prices he is submitted to. The same classification can be applied to distinguish between commercial and industrial segments, according to the electricity price contracts.

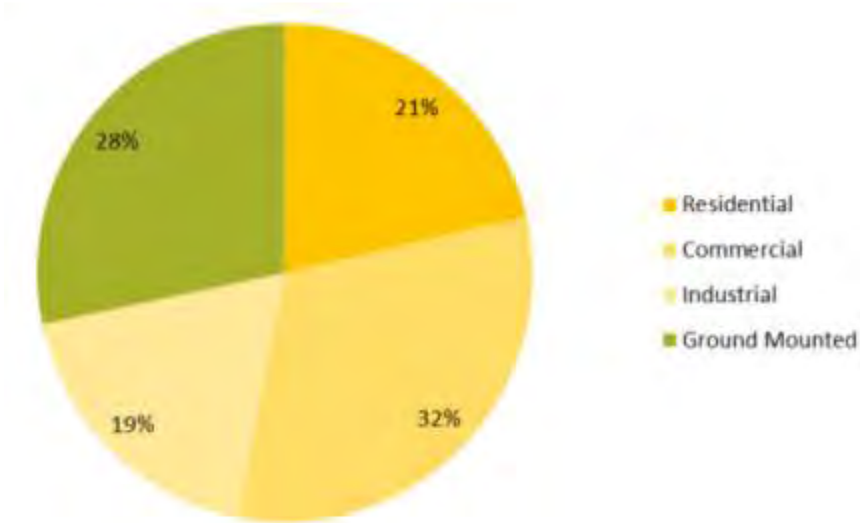


Figure 4.11.2-4: Market Segmentation in Europe in 2012, [2]

Market segmentation in Europe remained roughly stable in 2012 (Figure 4.11.2-4) compared to 2011. However, given the recent changes in regulatory frameworks, the ground-mounted segment will probably decline considerably in Europe in 2013. Overall, a very large share of the market in Europe is concentrated in the commercial and industrial rooftop segments; this trend will continue, based on the foreseen evolution of the legal framework.

1) Current support schemes and future evolutions

PV development in the last 10 years has been powered by the deployment of support policies, aiming at reducing the gap between PV's cost of electricity and the price of conventional electricity sources. These support schemes took various forms depending on the local specificities and evolved to cope with unexpected market evolution or policy changes.

In 2012, the price of PV systems and accordingly the cost of producing electricity from PV (LCOE) had dropped to levels that are in some countries close or even below the retail price of electricity. However, PV systems are not yet fully competitive, and the development of PV still requires adequate support schemes and ad hoc policies with regard to electricity grids connections, building use, and many other factors. Growing discontent towards the historical cost of support schemes grew in 2012 in several countries, pushing governments to either reduce support for PV deployment or to opt for retroactive changes.

The variety of PV market segments was well managed through a limited set of adequate support measures until 2012. Most successful PV deployment policies based themselves on either feed-in tariff policies (most of the time without tendering process) or direct incentives (including tax breaks). Other support measures remained anecdotal in the history of PV development.

With the declining cost of PV electricity generation, the question of "alternative" support schemes has gained more importance in several countries. The emergence of schemes promoting the local consumption of PV electricity is now confirmed, and some countries rely on these schemes only to ensure PV deployment.

Instead of national support schemes, several countries favor private contracts to purchase PV electricity (PPA :Power Purchase Agreement) from utility-scale power plants, while in several European countries the same plants are being banned from official support schemes.

Policies targeting the entire electricity system remain marginal, with several countries running RPS systems but few with real PV obligations.

(2) Power Scenarios for 2020 and 2030

1) Forecast of PV in Europe until 2017

Considering newly connected systems, 2012 showed the first PV market decline in Europe since 2000, mainly due to the end of the boom in the Italian market (which was the world's largest in 2011) while the rest of the European market stabilized. Had Italy experienced a more reasonable market level in 2011, the PV market would have stabilized from 2010 to 2012 or experienced slight growth. Overall, the future of the European market is uncertain for the coming years. The drastic decrease of some FIT programs will push some markets down in 2013, though a few emerging markets in Europe could offset any major decline. Given these new conditions, and according to EPIA forecasts, the short-term prospects for the European markets are stable in the best case or declining. In a business-as-usual scenario, without support from policymakers for PV, the transition could be quite painful over the next two or three years. In a policy-driven scenario, the market could stabilize in 2013 and grow again from 2014 onwards, driven by the approaching competitiveness of PV and emerging markets in Europe (Figure 4.11.2-5).

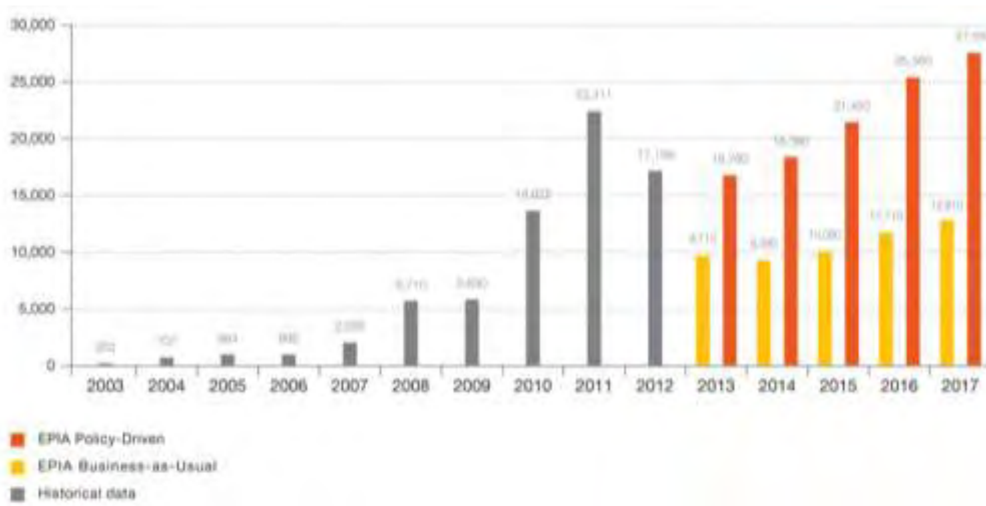


Figure 4.11.2-5: European annual PV market scenarios until 2017 (MW), [2]

2) Potential and targets in the EU

Different EPIA reports published in 2012 [2] and 2013 [5] identify three possible PV deployment scenarios until 2020 that represent PV's real potential based on technology and market trends:

i The **Baseline** scenario envisions 4% of the electricity demand in Europe provided by PV in 2020. This represents about 130 GW of cumulative capacity by 2020. In 2030, PV could represent up to 10% of the electricity demand.

ii The **Accelerated** scenario, with PV meeting 8% of the demand, is based on the maximum PV growth in Europe that is possible with the current market trends. This represents about 200 GW of cumulative capacity by 2020. In 2030, PV could target up to 15% of the electricity demand.

iii A third case, which assumes that all regulatory, perceptual, and technical barriers are lifted to allow the PV market to grow in most countries at a very fast speed, is called the **Paradigm Shift** scenario. This foresees PV supplying up to 12% of EU electricity demand by 2020. This represents about 390 GW of cumulative capacity by 2020.

EPIA has compared various PV market forecasts until 2017 against the three scenarios developed in the "Connecting the Sun" report [5] as well as the National Renewables Action Plans (NREAPs). For instance, Table 4.11.2-1 compares the cumulative installed capacity at the end of 2012 in most EU markets, the official National Renewable Energy Action Plan target for PV, by 2020 and the necessary yearly market to reach this 2020 target (linear projection).

Table 4.11.2-1: NREAPs vs. reality of PV markets in the EU 27 in MW, [2]

	Cumulative installed capacity in 2012	NREAPs' 2020 target for PV	Necessary yearly market until 2020	Target reached in...	Market in 2011	Market in 2012
Austria	418	322	n/a	reached in 2012	92	230
Belgium	2,650	1,340	n/a	reached in 2011	996	599
Bulgaria	908	303	n/a	reached in 2012	105	767
Czech Republic	2,072	1,695	n/a	reached in 2010	6	113
Denmark	394	6	n/a	reached in 2010	10	378
France	4,003	4,860	107.1	2013-2014	1,756	1,079
Germany	32,411	51,753	2417.8	2016-2020	7,485	7,604
Greece	1,536	2,200	83	2013-2014	426	912
Hungary	4	63	7.4	2013-2015	2.5	n/a
Italy	16,361	8,000	n/a	reached in 2011	9,454	3,438
Netherlands	266	722	57	2014-2016	58	125
Poland	7	3	n/a	reached in 2012	1	4
Portugal	244	1,000	94.4	2016-2020	47	49
Romania	30	260	28.7	2013-2015	1.6	26
Slovakia	523	300	n/a	reached in 2011	321	15
Slovenia	198	139	n/a	reached in 2012	46	117
Spain	5,166	8,367	400.2	2016-2020	472	276
Sweden	19	8	n/a	reached in 2011	4	8
United Kingdom	1,829	2,680	106.4	2013-2014	813	925
Rest of EU 27*	62	360	37.3	2016-2020	22	7
Total EU 27	**69,100**	**84,381**	**1910.12**	**2013-2014**	**22,117**	**16,672**

* Rest of EU 27 includes Cyprus, Estonia, Finland, Ireland, Latvia, Lithuania, Luxembourg and Malta.

Target already reached in 2010-2012: Country has significantly underestimated PV's potential.
Target to be reached by 2013-2015: Country has underestimated PV's potential.
Target to be reached by 2016-2020: Country has either properly estimated PV's potential (Germany) or has set measures constraining the market to meet the set target not earlier than 2020 (Netherlands, Portugal, Spain).

The same analysis for Europe is shown on Figure 4.11.2-6, where the three different 2020 EPIA scenarios [5], the two forecasts for 2017 [2], and the NREAPs are also presented.

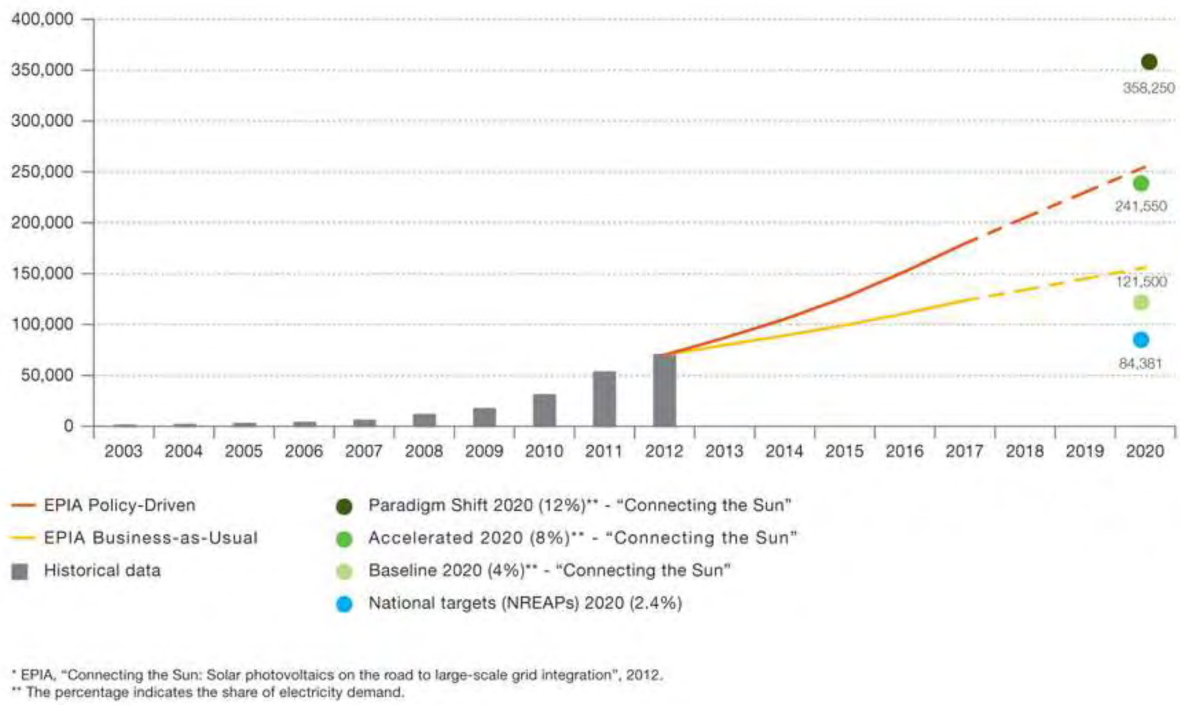


Figure 4.11.2-6: European PV cumulative capacity forecasts compared with EPIA's 2020 scenarios* and NREAPs targets (MW), [2]

The **Business-as-Usual** scenario for PV until 2017 that used to be aligned with the 4% target now appears to be slightly higher. This represents an improvement from previous EPIA forecasts, which estimated that growth would not quite reach the 4% target by 2020. Thus, it looks reasonable to expect that 4%–5% penetration for PV could be reached even in the low growth case.

The **Policy-Driven** scenario for PV until 2017 appears almost in line with the Accelerated scenario. It targets PV to cover about 8% of the electricity demand by 2020. While this scenario of reaching 8% by 2020 looks coherent and in line with optimistic market expectations. It is clear today that this 12% scenario is no longer a realistic option and would require tremendous market developments, which are unsupported by public policies in Europe for the time being.

The **NREAPs** as devised in 2009 are far from the reality of today's PV market. Apart from in Germany and Greece, market evolution in most countries could easily overtake the action plans. The extent to which they have underestimated the market developments in 2010, 2011, and even further in 2012 is obvious.

For EPIA, the potential for 2020 is at least twice as high as the levels foreseen in the NREAPs, pushing towards 200 GW capacity or even more in Europe by 2020. Possible revisions of the action plans will need to take into account the rapid increases in installations over the last year.

The same forecasting exercise has also been conducted by EPIA for 2030 (Figure 4.11.2-7), and the three scenarios have been extrapolated. In 2030, PV could represent up to 10% of the electricity demand in the **Baseline** scenario and up to 15% of the electricity demand in the **Accelerated** scenario. The **Paradigm Shift** scenario, based on the assumption that all barriers are lifted and that specific boundary conditions are met, foresees PV supplying up to 25% in 2030.

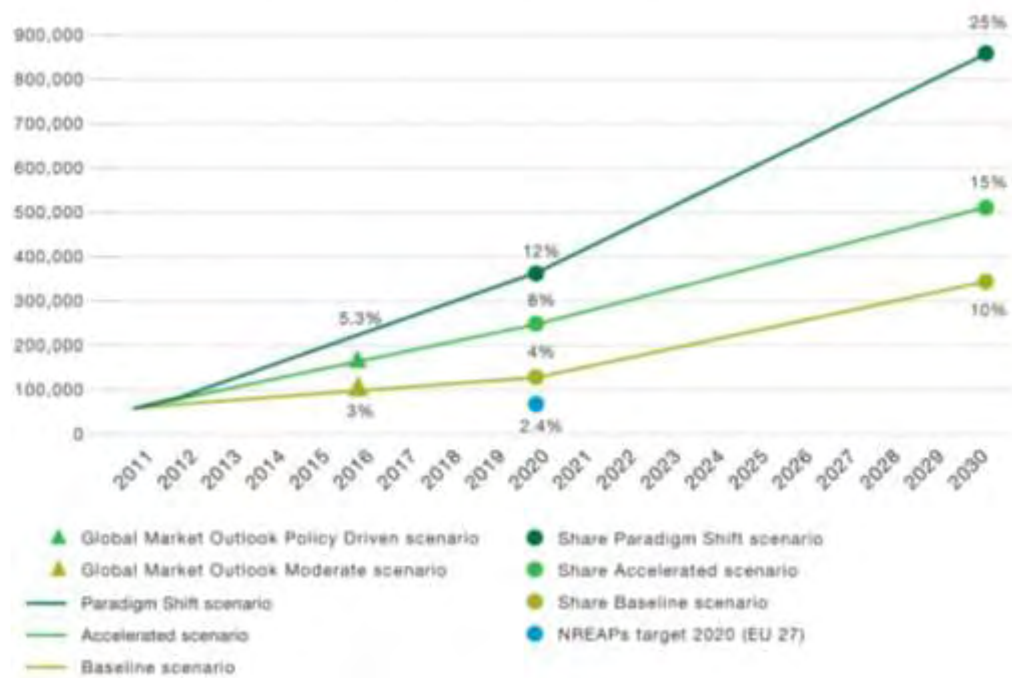


Figure 4.11.2-7: Projected penetration of PV in Europe until 2030 (MW), [2]

Considering the wider context of the evolution of the EU electricity mix, these scenarios also take into account the contribution of the two major variable renewables: PV and wind, which can work together effectively to meet a significant share of Europe’s electricity demand (Figure 4.11.2-8). The assumption of 30% wind penetration comes from the European Wind Energy Association’s figures. This exercise will help to understand better certain needs of the future power system.

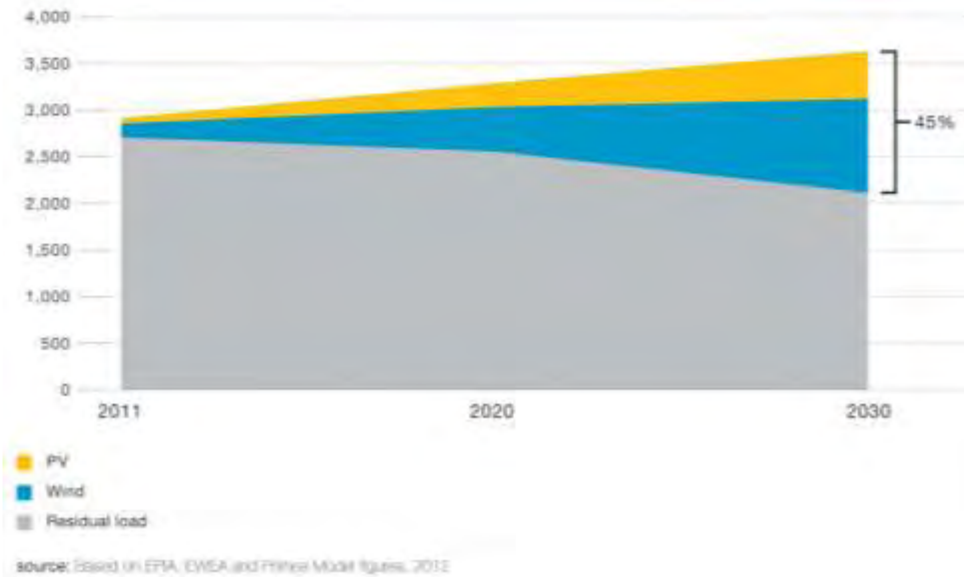


Figure 4.11.2-8: Projected PV and wind contribution to final EU 27 electricity demand until 2030 (TWh), [5]

4.11.3. European Case study

(1) Introduction

In the following section, the main challenges for system integration of variable renewable energy into the European power system are described. This work focuses on the overall power system, and therefore most issues discussed are only relevant for the transmission-grid level. However, this does not mean that issues at lower voltage levels are considered of lower importance. In fact, as PV is a distributed renewable energy source, there are a variety of integration challenges to be solved at the distribution level.

In order to draw an all-encompassing picture of the challenges that come along with high shares of renewables in the European power system, the most relevant system integration studies published within the last two years were identified. The studies are briefly characterized, and the key focus is described. Subsequently, all challenges for the integration of high shares of variable renewable energy generation, in particular of PV generation, are discussed.

1) REserviceS Project – Deliverable 2.2: *System needs for ancillary services, November 2012 [6]*

The REserviceS project (see 4.12.5(2) 2-5), is the first study to investigate wind- and solar-based grid support services at the EU level. D2.2 explores the different challenges that occur at different penetration levels of variable renewables at the hand of experiences in different national power systems across Europe. As in almost all analyzed countries, wind power capacity is significantly higher than the installed PV capacity, and it is difficult to separate the effect that is due solely to PV.

The analysis is split into an investigation of the needs for frequency support and thus reserve power and the needs for voltage-supporting measures in a system with high shares of variable renewables.

2) The Impact of Dispersed Generation on Continental Europe's Security of Supply, March 2013 *[6]*

Over the last decade, the penetration of distributed energy sources has increased significantly. These generating units have been subjected to connection requirements compliant with the operation principles for passive loads. For these units, the loss-of-mains detection (loss of connection of the main network) is often performed by measuring frequency deviations and triggers generators' disconnection to avoid unintended islanding. However, if applied to a large number of units, deterministic frequency thresholds can put the system at risk in case of frequency deviations.

The work presented in this ENTSO-E report aims to assess the risk for the security of the interconnected system due to the large amount of existing distributed generation with disconnection settings (over- and under-frequency) and identify needs for solutions like retrofit programs.

3) Final report of the Smooth PV project, May 2013 [8]

Smooth PV (see 4.12.5(2) 2-6) is a project that worked out the impact of high shares of PV on the power system. Several simulation tools were developed and studies were performed. The work covers both the implications at the transmission level as well as for the distribution grid. The findings relevant for the distribution grid will be disregarded in the following. The power flows in the European transmission grid were modeled extensively assuming different scenarios and also including assumptions on future storage deployment and grid extension. A focus was on the capacity credit of PV and thus on the contribution of PV to the security of supply in the European power system.

The study names PV variability, ramp rates, and uncertainty about future generation as key general issues. Ramp rates were, however, only studied based on literature research and not explicitly for Europe. The findings on ramp rates in the study are therefore not discussed in detail. The study further investigates the need for grid extension in Europe in case of heavy PV deployment.

4) PV parity, Grid Integration Cost of Photovoltaic Power Generation, September 2013 [9]

The PV Parity project, co-financed by the Intelligent Energy Europe program of the EC, aims to identify and promote the use of some measures that could complement or replace the existing support schemes for the deployment of PV installations throughout Europe.

A subtask dedicated to grid integration has been conducted by an expert team from the Imperial College of London. The PV Parity deliverable “Grid Integration Cost of Photovoltaic Power Generation” presents the approaches and the results of quantifying PV system integration costs in 11 key EU markets. The aim is to assess the feasibility of installing up to 480 GW of PV by 2030 (EPIA accelerated scenario), covering 15% of the European electricity demand. The report shows that not only it is technically feasible but also that the costs of implementing the necessary system integration measures are relatively modest.

5) Connecting the Sun (CTS), September 2012 [5].

CTS is the first study that focuses on PV system integration in Europe. So far there were of course a variety of integration studies carried out as the dena grid study I [10] and II [11], EWIS [12], TradeWind [13], and OffshoreGrid [14], to name a few. These studies either disregarded PV generation completely or treated PV as a less relevant generation source in view of needed infrastructure measurements and system security. CTS closes this study gap and clearly shows the relevance of PV for the operation and stability of the European power systems, and explains and studies the issues that need to be considered in light of rapid deployment of PV capacity in Europe.

(2) Issues of Heavy Deployment of Variable Renewable Energy.

The studies investigated show a large overlap of several issues, including the following:

i **PV variability**: There are different levels of variabililty depending on the size of a portfolio and its spread across an area. The highest variability is observed for single PV systems, while the PV generation of larger portfolios shows a significant smoothing effect. Furthermore, PV generation is only available during the day. The variability is often claimed to be a large challenge for the integration of PV generation. Whether this is true and what aspects variability effects, however, need further investigation. From the perspective of the operation of a transmission system, which is subject of this report, the variability of single PV systems has no relevance, as a TSO always sees the aggregated generation of a large number of PV systems in its balancing zone (Adressed and/or investigated in: Smooth PV, PV Parity, CTS).

ii **Residual load ramps due to PV generation**: PV generation increases in the morning hours, reaches its peak around midday, and decreases during the afternoon. Particularly during the evening hours, a PV generation decrease often coincides with an increase in demand, which results in steep residual load curves (or net load) which need to be followed by other flexible generation systems. These ramps, which already today are considered a challenge to system security by many TSOs, will increase with further PV deployment (Adressed and/or investigated in: Smooth PV, CTS).

iii **Capacity credit**: The capacity credit of a generation source is defined as its contribution to meeting the peak demand in a power system. As wind and PV are weather-dependent generation sources. they are not always available during peak demand hours. Therefore. a firm conventional generation source needs to be ready in order to meet the peak demand at all times. This so-called stand-by capacity is associated with high costs (Adressed and investigated in: Smooth PV, PV Parity, CTS).

iv **Transmission grids expansion**: It can be considered a consensus in Europe that heavy deployment of renewables needs to be accompanied by reinforcement and expansion of the transmission grid. New transmission capacity, in particular between countries (interconnector capacity), is a source of system flexibility, helps to share balancing power between the regions, smooths renewable generation, and facilitates the implementation of an integrated European electricity market. The costs are considered comparatively low compared to other measures, e.g., storage construction, but new transmission line projects face strong public opposition, leading to lengthy development processes (Adressed and/or investigated in: Smooth PV, PV Parity, CTS).

v **PV generation forecast uncertainty and increased need for ancillary services**: From the perspective of system generation, it is desirable to forecast PV generation as accurately as possible. Snow and fog forecasts are considered a serious difficulty. If fog or snow is not forecasted accurately, steep PV ramp may happen without warning, posing a risk to safe system operation. Ancillary services, namely voltage and frequency support services, have traditionally been supplied by the conventional power fleet. There have been flexible conventional power units that could provide the desired reserve power, and there was a large amount of synchronous generators that could easily adapt the power factor for voltage support. When the sun is shining and the wind is blowing, large shares of this conventional power plants are no longer online and the traditional resource for frequency and voltage support is significantly decreased. It is therefore a question whether conventional power plants need to be kept as must-run units to provide these services or whether wind and PV can provide them instead (Adressed and/or investigated in: REserviceS, Smooth PV).

vi **Inappropriate grid codes**: Grid codes define several requirements that PV systems and others generators must fulfill in order to be connected. Among others, some requirements aim at facilitating their integration into the existing power systems. Requirements may vary depending on the voltage level and the penetration of PV (and other distributed generators) in a specific location, which could be a distribution grid, a country, or even a synchronous area. These locational specificities can lead to requirements for reactive power capabilities, active power management, fault ride-through, etc.

One of the major issues in Europe at the moment, known as the frequency disconnection or “50.2 Hz” issue, is related to the possible mass disconnection of PV systems when the frequency reaches a specific value. Frequency disconnection requirements were adopted in several countries as a result of safety concerns about unintented islanding at a time when distributed generation was marginal. During the major system disturbance in Europe on November 4, decentralized generation (mainly wind turbines) massively switched off after the disturbance happened (as they were required to do). This sudden loss of generation severely aggravated the situation. If the same extreme event were to occur at midday during the summer, more than 20 GW of PV systems would instantaneously disconnect from the grid at the EU level.

Such a massive disconnection of PV systems would accelerate the possible cascading breakdown process—but with a proper definition of the disconnection settings, PV can easily support TSOs in the case of an extreme over-frequency event. National grid codes have been revised in some of the key countries (Germany, Italy, Belgium, and Spain) to integrate new frequency requirements (active power reduction in case of over-frequency). For the existing PV installed capacity, retrofit programm are already underway in countries like Germany and Italy and under analysis in several other countries (Adressed and/or investigated in: REserviceS, Smooth PV, ENTSO-E report, CTS).

1) PV generation variability

Smooth PV states that systems spread across larger areas show a relatively smooth production curve (Figure 4.11.3-1). Thus, in a sufficient large balancing zone, the TSO’s operation will not be affected by rapidly changing PV production and ramps; distribution of PV plants over only 1 km will have a significant impact on the rapid power fluctuations of the aggregated power generation from the plants caused by passing clouds.

The same results are found by the authors of CTS, which shows through PV generation time series that across larger regions PV generation shows very smooth shapes. When looking at the PV generation across Europe and across time zones, it becomes clear that the peak PV production does not coincide anymore and is smoothed over about 2 hours when considering the PV generation in Bulgaria and Italy. The authors also highlight that this characteristic can only be fully exploited when a strong transmission grid allows transferring the power across this area.

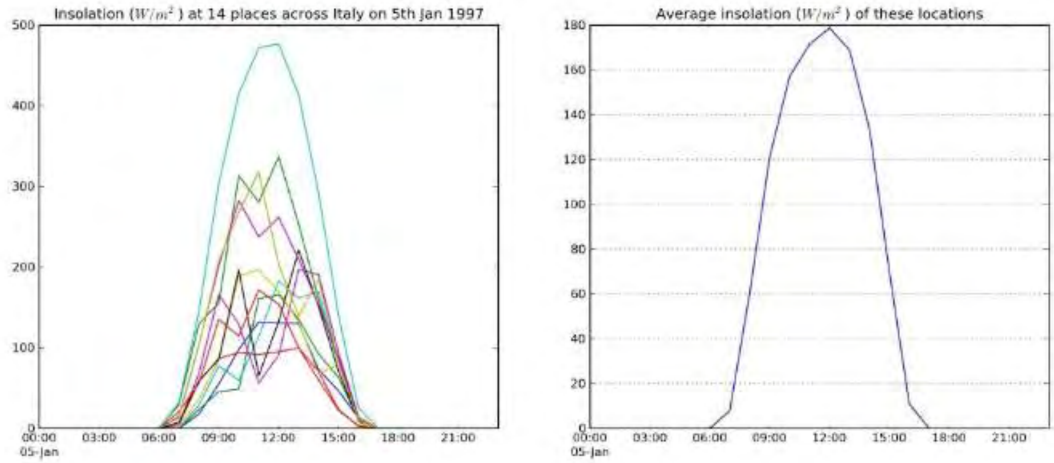


Figure 4.11.3-1: Insolation at 14 distinct locations in Italy (left) and the average over the 14 locations (right) on a specific day in winter, [8]

An interesting point in the discussion of PV variability is added by CTS's investigation of joint PV and wind production. It is impressively shown that the PV and wind production do not correlate when looking at seasonal or weekly generation (Figure 4.11.3-2). In fact, they even perfectly complement each other. While during winter there is a high contribution from wind power and lower PV generation, the reverse is true during the summer months.

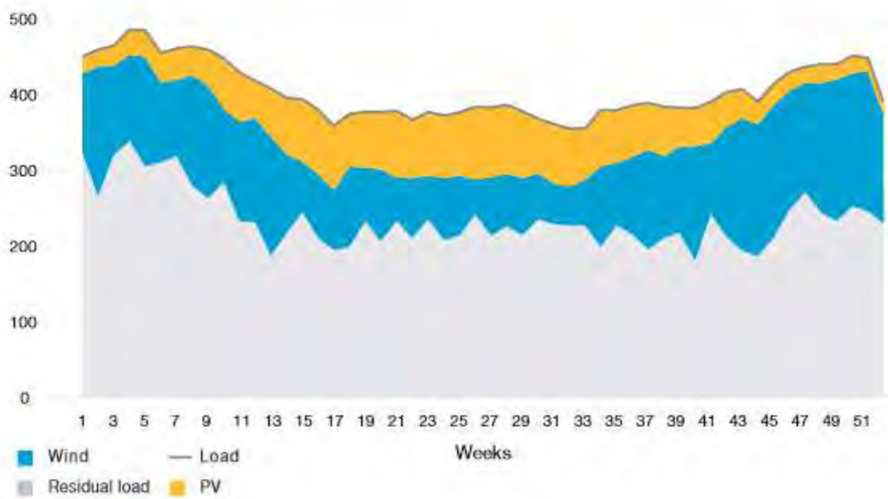


Figure 4.11.3-2: Complementary wind and PV generation in Europe over one year, [5]

However, in view of the discussion below on the capacity credit of PV and wind, it must be emphasized that appropriate storage capacities are needed to shift the power generation and reduce the need for conventional peak power in the case of large-scale PV penetration. Still, the analysis (see 4.12.4.3) clearly proves that already with daily and weekly storage from pumped storage plants, the complementary character of PV and wind generation can be exploited. This is an advantage, as the costs for storage generally increase when longer storing times are needed.

2) Residual load ramps due to PV generation

Flexibility is the key requirement for planning and operating the power system with a large share of variable renewables, as has been emphasised by the International Energy Agency [4]. Flexibility expresses the capability of the power system to maintain the security of the supply when rapid changes occur in production and/or demand. Flexibility can be provided by four types of assets: interconnections, storage, DSM, and flexible generation.

Only a proper mix of these assets will limit the costs of the transition. For example, if only flexible generation were implemented, high costs would incur for keeping the full power fleet online while operating systems during a limited time. On the other hand, there is a risk of under-investment in flexible generation due to market uncertainties for plant operators.

In order to evaluate how much up- and down-ramping will be required from other flexible sources, an analysis was carried out in CTS to identify the variability of the residual load. The scenarios developed by EPIA and EWEA(European Wind Energy Association)were used for this analysis. In order to facilitate the calculation, no interconnection constraints between countries have been taken into account. The residual load difference within 1, 8, and 24 hours was analyzed (Figure 4.11.3-3). The duration curves for EU-27 countries show at how many hours of the year certain ramps are required to cover the residual load difference within the analyzed time intervals.

For example, the 1-hour ramp curves show how much PV and wind affect the variability of the residual load and therefore how much flexibility will be required within an hour (vertical axis) and for how long (horizontal axis).

As seen in Figure 4.11.3-3, the ramping needs are not dramatically impacted by the increasing share of PV and wind until 2020. Looking to 2030, the story is completely different. The EU system flexibility will need to be increased to cope with the variable renewable penetration foreseen by EPIA and EWEA.

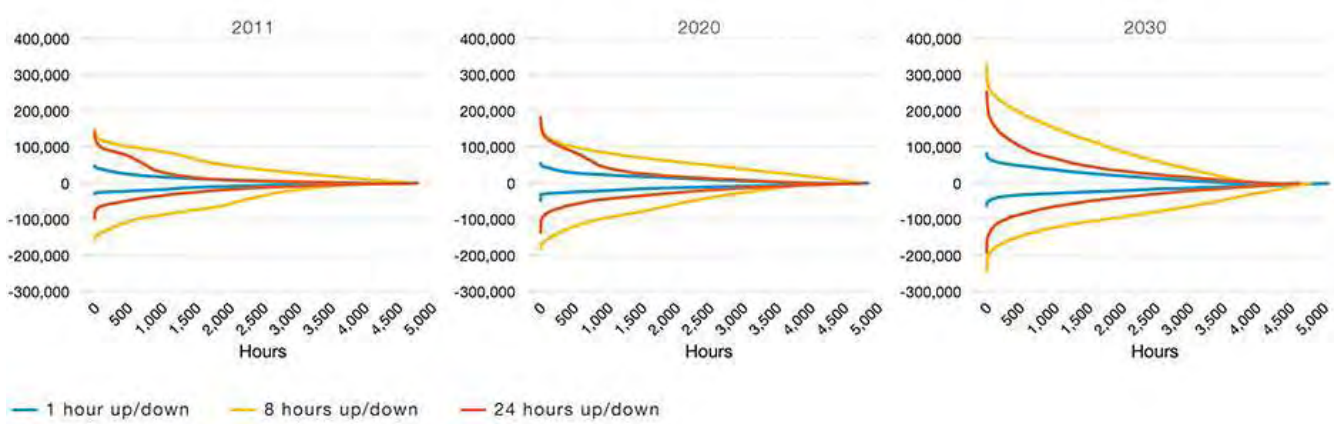


Figure 4.11.3-3: 2011, 2020 and 2030 ramping requirements in the EU 27 (MW), [5]

A separate ramping analysis was also conducted to examine in detail the impact of each component of the residual load on the future ramping needs. Figure 4.11.3-4 shows the comparison of the maximum up-ramping for 2011, 2020, and 2030. For each of those years the maximum ramping requirements are presented separately for the load (without any PV or wind), for the load minus the PV generation (RES_PV), for the load minus the wind generation (RES_wind), and for the residual load (RES).

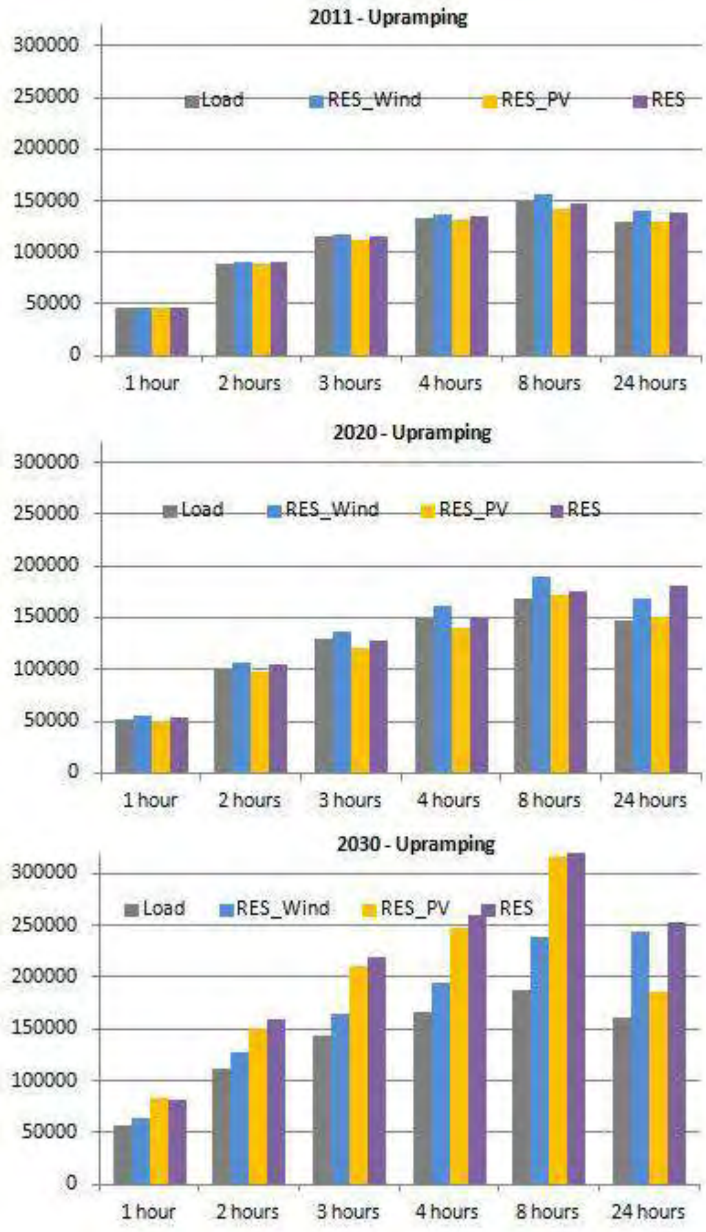


Figure 4.11.3-4: 2011, 2020 and 2030 contribution to ramping requirements in the EU 27 (MW), [5]

Some important conclusions that can be drawn from Figure 4.11.3-4 are: 1) there is no maximum ramping increase due to PV for 2011 and 2020. In fact, PV even reduces the maximum ramping requirement. 2) The ramping requirement increase will still be driven by the load until 2020. 3) Beyond 2020, additional flexibility will be needed, with PV having a more significant impact on the 8-hour requirement and wind on the 24-hour requirement.

For 2030, results can be explained by the fact that the sun goes down during the evening when the peak demand occurs. The up-ramping and down-ramping show more or less the same behavior pattern for each of the three years examined.

Ramp rates were also studied by the Smooth PV project based on several literature sources. Concerning changes, simulations results show that on the minute time-scale, 10 km² service areas must be prepared to variations of 15.9% due to cumulus clouds. This number decreases to 5.5% for areas of 1,000 km² and 2.7% for 100,000 km² areas.

Looking at the possibility of losing the complete PV generation due to an incoming squall line, it will take 1.8 minutes for a square-shaped area of 10 km² (with a uniform distribution of the installed capacity) and 5.5 minutes for a larger service area of 100 km².

While fast but rather small fluctuations can be easily balanced, the real challenge is posed by the steep and high ramps that occur only for a few hours and in the worst-case scenario require additional flexible sources. This in particular raises the question of whether it is possible for the conventional power fleet to follow these high ramps, considering that a cold start of conventional power can require up to 16 hours.

In fact, an analysis of the ramping capabilities of conventional power plants also done in CTS [5] showed that the current flexibility from those sources can meet the ramps until 2020. However, even if the new power plants can easily meet these ramps, the flexibility of the existing fleet and moreover the access and valorization of the existing flexibility is an issue. Beside the technical aspects of this discussion, much needs to be done to redesign the market rules in order to better valorize flexible assets.

To achieve the variable renewable penetration foreseen in 2030, additional flexibility will be required so as to reduce the periods during which part of the conventional power fleet will have to be operated in standby mode to respond quickly to any balancing needs. Additional flexibility can be provided by a combination of dispatchable renewables (hydro, biomass, geothermal, etc.) as well as innovative storage options and DSM. Because region-wide PV production ramps can be forecast quite accurately, coordinated actions can be planned for these few hours.

3) Capacity credit of PV

The analyzed studies agree on the fact that PV's contribution to meeting the peak demand in the EU or its member states is considerably low. However, the results were obtained by a straightforward analysis of load curves and PV generation time series. This approach gives a good estimate for the capacity credit, but experts agree that for a more accurate estimation of the capacity credit, a statistical approach is needed that also takes into account the availability statistics of the thermal power fleet and other renewables. The capacity credit is ultimately determined by the overall power generation mix in the country or region. A statistical approach will attribute PV generation to a higher but still low capacity credit.

CTS [5] investigated the capacity credit of PV generation by looking at the PV generation time series for 2011 and the load curves of the same year for different countries and for all of Europe. It was found that only for the case of Italy PV generation effectively reduced the peak demand by about 1.5 GW. For all other countries, the PV contribution during the peak demand hours was zero or considerably low.

The Smooth PV project [8] concludes that the capacity credit of PV in Europe is zero. This is due to the fact that the highest demand often occurs when the sun is not shining in particular for northern countries. In the case of Germany, the peak demand occurs in the evening hours in winter. For southern countries, this can be different when the peak occurs midday, for example, due to the use of air-conditioning. However, it was shown that “in all countries some of the top 1% of the highest demand hours fall into a period of no solar radiation, i.e. night hours” (cp. the “min” row in Table 4.11.3-1).

Table 4.11.3-1: PV generation during the 1% highest demand hours, [8]

Country	Min	Max	Mean	Median	Mode
AT	0%	51%	10%	2%	1%
BE	0%	52%	5%	1%	0%
BG	0%	52%	6%	0%	0%
CH	0%	69%	17%	10%	1%
CZ	0%	41%	9%	6%	1%
DE	0%	33%	4%	1%	0%
DK	0%	36%	3%	0%	0%
EE	0%	15%	2%	1%	0%
ES	0%	72%	9%	2%	0%
FI	0%	12%	2%	0%	0%
FR	0%	69%	14%	8%	0%
GB	0%	20%	3%	1%	0%
GR	0%	70%	49%	59%	66%
HU	0%	68%	5%	1%	0%
IE	0%	2%	0%	0%	0%
IT	0%	72%	39%	40%	66%
LT	0%	25%	4%	1%	1%
LU	0%	73%	9%	3%	0%
LV	0%	48%	9%	2%	0%
NL	0%	28%	5%	1%	0%
NO	0%	63%	11%	4%	0%
PL	0%	28%	2%	0%	0%
PT	0%	57%	2%	0%	0%
RO	0%	39%	4%	1%	0%
SE	0%	46%	8%	2%	0%
SI	0%	70%	6%	1%	0%
SK	0%	35%	4%	1%	0%

However, when wind and PV generation are considered together, there is a significant contribution to the reduction of the residual peak load. CTS finds about 14 GW of firm capacity contributed by PV and wind generation together in 2011. Still, there is no doubt that flexible generation or storage is needed to complement variable renewable generation. CTS shows in this regard that PV generation in particular can be complemented with storage capacities.

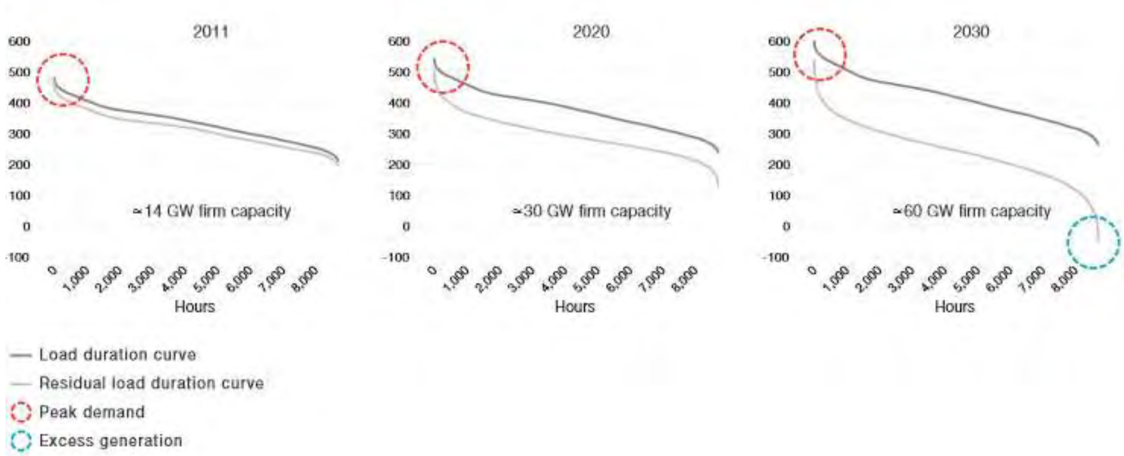


Figure 4.11.3-5: Capacity credit of wind and PV in Europe (GW), [5]

4) Transmission grid expansions

There is consensus in Europe that grid infrastructure reinforcements and expansions are a cost-effective measurement for the integration of renewables. A large number of system integration studies have looked into this issue and found evidence to support the above statement [10][11][12][13][14]. Therefore, most of the studies investigated here do not further analyze this topic, but stress the point that grid expansions are a prerequisite for the cost-efficient integration of PV and wind.

CTS, for instance, assumes the necessary grid expansions to be carried out as a basis for the detailed assessment of other issues as the smoothing effect of PV generation across countries or the use of the storage capacity to increase the capacity credit of the PV storage system. The authors emphasize that grid expansions are a comparably cheap measure to increase the flexibility of the European power system.

Nevertheless, the authors of CTS are certainly aware that grid expansions are not popular and face strong opposition from local initiatives, particularly when the construction of new overhead lines is discussed. In fact, there are several examples of grid infrastructure projects that are far behind schedule.

The Smooth PV report investigated the optimal mix of storage deployment and grid infrastructure measurements and concludes that about 40% of Europe’s demand can be met by PV generation with low curtailment, without major extensions to the transmission grid and a feasible amount of storage capacity. Note that this statement is certainly not supported by all stakeholders and experts and seems to be slightly optimistic. The Smooth PV report further found that an optimal coordination of generation capacity development, storage capacity development, and grid expansions until 2050 is largely beneficial over scenarios in which, e.g., storages are deployed but the grid is only extended marginally. This subject is developed further in section 4.11.4 of the European case study.

5) PV generation forecast uncertainty and need for ancillary services

As the PV penetration in a specific power system increases, the availability of accurate PV generation forecasts becomes more and more important. Current system operation strategies are designed to cope with a certain amount of uncertainty due to generator outages and the difficulty of accurately predicting the demand. Today, deviations from the forecasted generation and consumption are primarily handled by the balancing reserves constituted by conventional generators. As penetration of variable renewables like wind and PV is likely to increase the complexity of dispatch planning, the reliability of forecasting is currently a subject of intensive R&D work.

REserviceS claims that "the main impact of variable renewables are due to more variability and uncertainty that will result in more balancing needs and can impact frequency control." In particular, when PV and wind generation is high, there will be a lower amount of conventional power units online to provide these balancing services and inertia. The All Island TSO Facilitation of Renewable Studies (FoR studies, EirGrid and SONI, 2010) determined that the TSOs of Ireland and Northern Ireland can achieve the renewable energy targets securely and effectively by 2020 and can securely manage the system provided that the system non-synchronous penetration (SNSP) level in real-time operations remains below 50% (Figure 4.11.3-6). SNSP is a measure of the non-synchronous generation on the system in an instant. It is a ratio of the real-time MW generation from wind and HVDC(high-voltage direct current)imports to demand plus HVDC exports.

The studies indicate that a SNSP level of up to 75% is achievable by 2020 with the development of enhanced system operational policies, tools and practices, the investment in the required transmission and distribution infrastructure, and the evolution of the appropriate complementary portfolio. Some curtailments of wind power have already been made recently in Ireland due to concerns about low inertia and consequent instability risk in the system. So far, the issue of low inertia is limited to small systems like that of Ireland. Possible solutions are currently being investigated, such as wind power plants providing ancillary services or flexible balancing plants operating at low output levels and delivering stabilizing services. However, the reduction of inertia leading to more pronounced frequency deviations still needs to be studied further for larger systems like that of continental Europe.

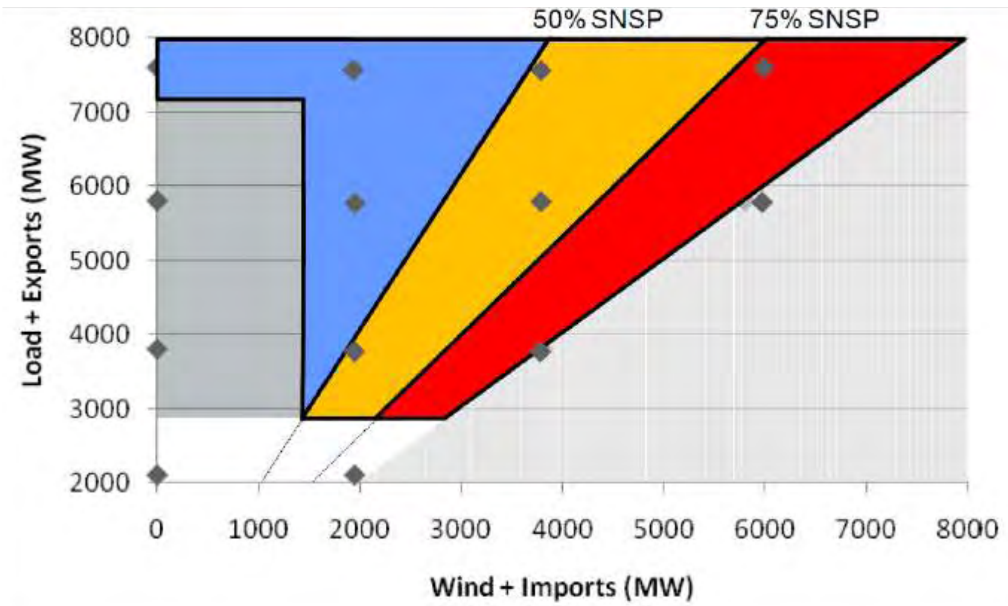


Figure 4.11.3-6: System operability Regions load and HVDC exports vs. Wind generation and HVDC imports (Blue – operable, Amber – need actions to be achieved, Red – unlikely to be feasible even with significant mitigation actions), [15]

REserviceS states that it is therefore necessary that PV and wind provide frequency support services if services cannot be provided by flexible demand or network components at lower costs. Of course, the impact of renewables on the need for frequency support is system specific. If a larger balancing area is considered and there is abundant interconnection capacity to neighboring systems, the impact of renewable generation is less pronounced compared to the case of a small system with low interconnection capacity. Authors of the Smooth PV report also state that the problem tends to be aggravated for markets with longer dispatch blocks, as shorter timeframes allow inclusion of short-term changes in the PV generation forecast and subsequent adjustment of the plants' scheduling.

At the same time, the authors of the REserviceS report admit that there are a variety of other changes in the power system (e.g., new balancing zone delimitations, cooperation for frequency balancing on European level, and new reserve market designs) that have an equally strong impact on the balancing needs. Thus, from empirical data it is difficult to quantify the impact of renewable sources. However, in theory there is a clear increase in reserve requirement that comes along with increased wind and PV power (even if the impact of the latter has been analyzed less than that of wind). This is well shown by plotting the results of several system integration studies as shown in Figure 4.11.3-7. Without giving further evidence, the authors state that a similar dependency can be expected for PV generation, particularly in view of the ramping of residual load occurring in the evening hours when a load increase coincides with a PV generation decrease.

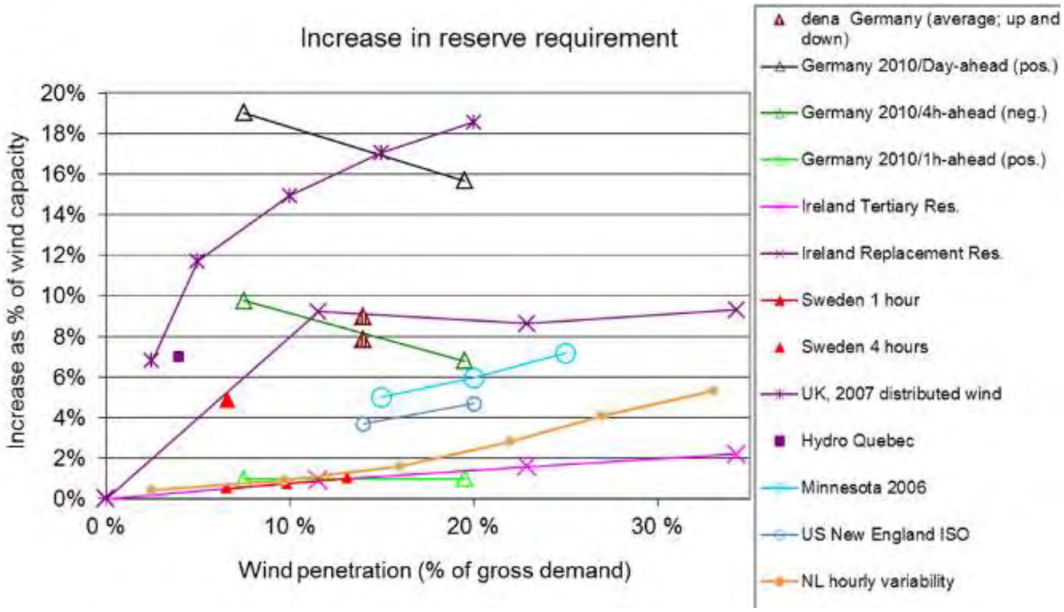


Figure 4.11.3-7: Increase reserve requirement due to wind power increase, [6]

Concerning voltage support services, REServiceS states that voltage management by TSOs will need to be adapted as renewable generation, mainly wind, is generally located further away from load centers than is conventional generation. If wind power replacing conventional power is a less flexible source for reactive power compensation, then most conventional power plants, TSOs will in particular, have narrower reactive power ranges at their disposal. The authors conclude with a general statement: "*Although it is difficult to quantify the full impact of the reduced and changing nature of reactive power control on the management of voltage, the estimated levels will present significant operational issues in the future. Systematic practices, tools and policies are needed clearly reflecting the issues involved.*"

The authors do not explicitly discuss the impact of PV generation, stating that reactive power provision by PV generation is rather an issue for the distribution grid level. Nevertheless, following their logic, it is clear that PV will also replace conventional synchronous generators and therefore reduce the availability of conventional reactive power sources. Furthermore, the report does not clarify whether it is possible to provide reactive power from distributed PV generators at the distribution grid level to the TSO for transmission system management.

The latter is still a heavily disputed topic today and an obvious research gap that needs to be closed in particular in view of the excellent capabilities of PV systems in reactive power control.

6) Inappropriate Grid codes– the frequency disconnection settings issue

In parallel to the increasing deployment of renewable and decentralized energy production, the quality of the common European power system has also decreased due to the restructuring of electricity markets and the related operational boundary conditions. Increasingly often and for longer time periods, the system frequency of the continental European system deviates from the set point by reaching values lower and higher than 49.9 Hz and 50.1 Hz, respectively. Reaching these values leads to the activation of 50% of the positive or negative primary control reserve.

Due to badly designed grid codes, the disconnection settings for most of the distributed generation currently connected are in the range of 50.2–50.3 Hz for over-frequency and around 49.7–49.5 Hz for under-frequency, while the mandatory range to remain connected within the transmission system is 47.5–51.5 Hz.

Knowing that the current installed capacity for distributed generation corresponds to a multiple of the available primary control reserve, the risk of serious system disturbance due to an uncoordinated and massive disconnection of generation can no longer be excluded. It can be foreseen that the system balance might only be managed by the activation of large-scale load shedding. In March 2013, ENTSO-E published a report describing the analysis performed for defining the necessary amount of distributed generation that will need to be retrofitted by changing the frequency disconnection settings.

For the authors of the report, the coincidence of a steady-state frequency deviation and the loss of approximately 2,000 MW of load (for instance, the loss of the HVDC link between France and Great Britain) can drive the system to 50.2 Hz. The disconnection of a large amount of generation capacity due to the frequency disconnection settings would cause large power imbalances and consequently very high frequency transients. These can only be managed by a large amount of under-frequency load shedding (Figure 4.11.3-8). There is a severe risk of the system collapsing. The ongoing PV retrofit programs in Germany (300,000 systems) and in Italy (12,000 systems) are essential for the overall system security. After completion of the two programs, the security risk will be reduced. However, the remaining un-retrofitted installed capacity is still too high, and further actions (Figure 4.11.3-9) should be determined (for 50.2 Hz, 49.8 Hz, and 49.5 Hz).

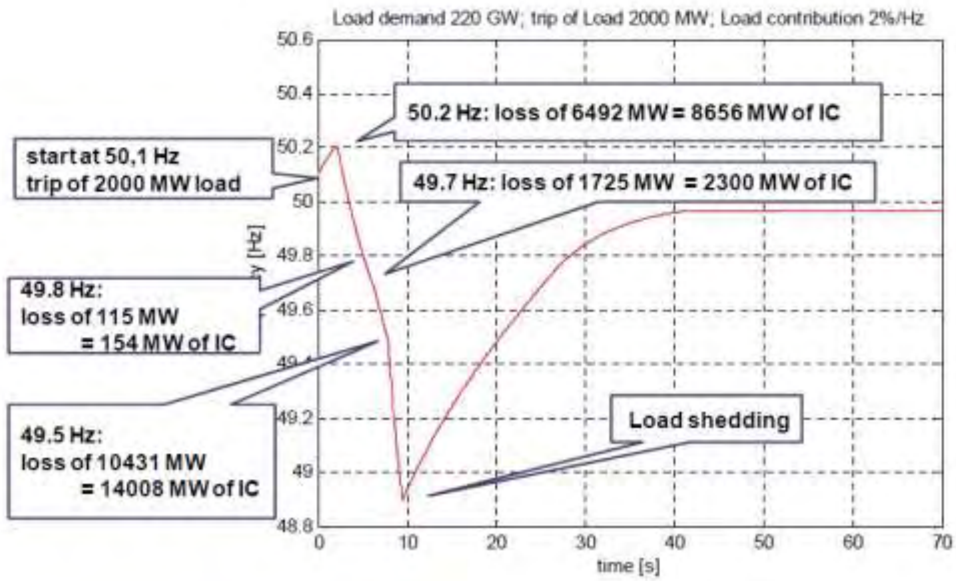


Figure 4.11.3-8: Simulation of 2 GW load loss with the actual retrofit program in DE and IT, [7]

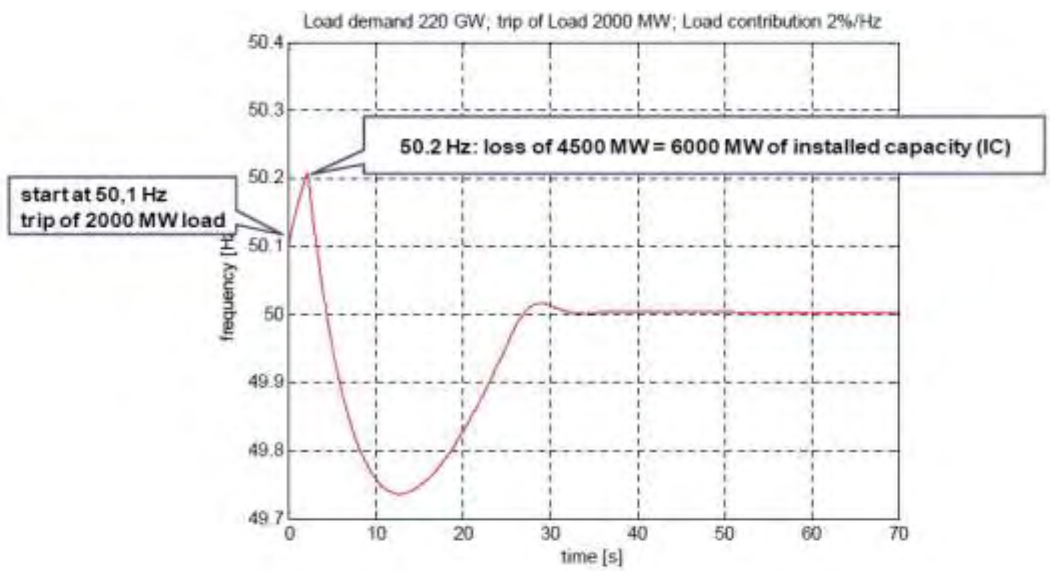


Figure 4.11.3-9: Simulation of 2 GW load loss with additional retrofit for 50,2 Hz, [7]

The authors also provide several recommendations. Among them, two have a specific impact on the characteristics of PV inverters:

i Automatic reconnection after a severe frequency transient is permitted, but specific logics are required in order to avoid reconnection during restoration phase and to guarantee a maximum total gradient of the PV power generation after the resynchronization.

ii No automatic disconnection in the frequency range from 47.5 Hz to 51.5 Hz shall take place. This should be implemented in all European countries as soon as possible.

4.11.4. Solutions for High level PV Penetration: power system planning

This section describes a measure aimed at addressing only one of the challenges identified in section 3 of the European Case Study: namely, the need for transmission grid expansion in case of large-scale PV deployment.

(1) European Coordinated planning - Ten Years Network Development Plan

European laws request ENTSO-E to “adopt a non-binding Community-wide ten-year network development plan” (TYNDP) [16] with the objective to ensure greater transparency regarding the entire electricity transmission network and to support the decision-making process at the regional and European levels. The first official TYNDP was released on July 5, 2012, two years after the pilot TYNDP publication in 2010. The second official TYNDP is expected to be released in December 2014.

The TYNDP 2012 package is an eight-document suite comprising the TYNDP report itself but also the Scenario Outlook and Adequacy Forecast (SOAF) and six Regional Investment Plans. These eight reports jointly deliver a structured, systematic, and comprehensive vision for grid development in the coming 10 years in Europe. They describe significant investments in the European power system, which are required to achieve European energy policy goals.

Grid development requires the anticipation and consideration of the long term. Notwithstanding the ongoing Electricity Highways 2050 project (see 4.11.5 (2)), ENTSO-E developed four visions up to 2030 to examine the challenges and opportunities for TSO's development of longer-term scenarios. Within these visions, two scenarios have been used as a basis for the TYNDP 2012:

- i The Scenario "EU 2020" has been built top-down, based on the European 20-20-20 objectives and the NREAPs (see 2.2.2).
- ii The Scenario "SAF-B" extrapolates information from market players' present investment perspectives in a bottom-up approach.

Both scenarios, however, match the European 20-20-20 objectives.

According to these two scenarios, the net generating capacity will increase by about 250 GW (i.e., 26% of the 2012 capacity) in the coming decade. Almost all the increase can be explained by renewable energy development (about 220 GW). The figure, however, hides the important decommissioning by 2016 of obsolete fossil-fuel-fired units (not compliant with the emissions thresholds set by another EU directive) partly substituted by the commissioning of new conventional power. ENTSO-S stated that the major shift in the generation mix will therefore induce a massive relocation of generation means and more volatile flows, requiring the grid to adapt.

Market studies also conducted in the framework of the TYNDP also hint at the resulting gross electricity exchange patterns by 2020. As shown in Figure 4.11.4-1, Italy, the UK, Poland, and the Baltic states remain major importing countries. France and Scandinavia are the larger exporters, as is the case today (however, exchanged volumes are higher). Germany, Spain, and Portugal experience high exchange volumes, but for both imports and exports, which results in an overall balance. Rather logically, the highest volumes are exchanged in the heart of Europe. Market studies conducted by ENTSO-E essentially show larger, more volatile power flows over a larger distance across Europe, mostly north to south from Scandinavia to Italy, between mainland Europe and the Iberian Peninsula, and Ireland and the UK, or east to south and west in the Balkan Peninsula. Investment in the grid is needed to avoid worsening of current congestion and the development of new congestion.

Figure 4.11.4-1: Simplified expected electricity exchanges patterns in 2020 between ENTSO-E countries, [16]

About 100 bottlenecks have been identified by ENTSO-E on the European network by the end of the decade; ENTSO-E further mentions that about 60% of the concerns are primarily related to market integration (either between price zones, or intra-price zones), with about 30% primarily related to generation connection and 10% primarily related to the security of the supply. However, for ENTSO-E, 80% of the bottlenecks are related directly or indirectly to renewable energy integration. The north-south internal corridors in Germany are typical examples of the latter.

Consequently, over 100 transmission projects of pan-European significance have been identified to address and solve the abovementioned concerns in the coming decade (among them, 40% are interconnectors) about 76% of the investment items in the TYNDP 2012 package were previously included in the TYNDP 2010 and are hence confirmed. 24% are new, which is slightly more than the expected regular turnover of the TYNDP process.

Overall, there has been substantial delay in the delivery of one-third of the investments, mostly because of social resistance and longer than initially anticipated permitting procedures, leading to project reengineering. As displayed in Figure 4.11.4-2, projects of pan-European significance total about 52,300 km of new or refurbished extra high voltage routes, split rather equally between the two five-year sub-periods. This represents a 25% increase compared to the TYNDP 2010, especially with individually long-stretching new investments: +3,000 km of subsea routes are envisioned, (developing in total 10,000 km of offshore grid key-assets) and+7,000 km of routes are inland, mostly to bring to load centers the power generated on the borders of the European territory.

Figure 4.11.4-2: Projects of pan-European significance in terms of volumes, [16]

Projects of pan-European significance are very diverse. They develop grid transfer capability (GTC) ranging from a few hundred MW to more than 4 GW (Figure 4.11.4-3).

Globally, comparing the situation before and after grid reinforcement, the analyses conducted by ENTSO-E show that transmission projects of pan-European significance will help alleviate total generation operational costs by about 5%.

Figure 4.11.4-3: Projects of pan-European significance – volumes, [16]

To conclude the report, ENTSO-E conducted an economic analysis of the future investment needs. Total investment costs for projects of pan-European significance amount to €104 billion, of which €23 billion is for subsea cables. The figures are in line with the previous analysis of the TYNDP 2010. This effort is significant for TSO's financial means. It equates, however, to about €1.5–€2/MWh of power consumption in Europe over the 10-year period, i.e., only around 2% of the bulk power prices or less than 1% of the total end-users' electricity bill.

The full report series can be found on the ENTSO-E website: https://www.entsoe.eu/major-projects/ten-year-network-development-plan/.

(2) Transmission cost for large scale PV deployment

In the framework of the European project PV Parity, an expert team from the Imperial College of London evaluates the impact of PV technology on the capacity of main European grid and the increased operating cost due to increased operating reserves to deal with the variability of PV. For this purpose they have employed the Imperial College Dynamic System Investment Model (DSIM) [17] to calculate the system operating cost and the incremental network capacity needed to facilitate the increasing installed PV capacity across Europe.

The model optimizes generation and transmission investment decisions as well as the short-term operation of the entire European system on an hourly basis, including plant dispatch and scheduling of reserve and frequency regulation services to ensure sub-hourly (seconds to minutes) balancing of the system. The model takes account of system adequacy and security requirements.

DSIM provides information on the amount of transmission capacity needed in the system to maximize the overall benefits. This enables quantification of the increased network capacity caused by incremental changes in installed PV capacity.

On the other hand, DSIM also estimates the system operating cost, mainly driven by generation costs (fuel, no-load, and start-up cost). This operating cost includes the carbon prices and also the effect of running a generator part-loaded to provide operating reserves. As installed PV capacity increases, the operating reserves also increase to hedge the risk of uncertainty caused by unit unavailability or changes in PV energy sources, among other causes. By comparing the operating costs of two different scenarios, with and without an increase in operating reserves, the authors of the report have been able to derive the changes in system balancing cost due to increased PV capacity.

However, the present report will only describe the part of the study covering the need for transmission grid extension. For further reading, please consult the PV Parity website: http://www.pvparity.eu/.

1) Description of the methodology

As the impacts of PV on the European transmission system depend on the reference case selected, the authors of the study used two key target years are as reference cases, i.e., 2020 (240 GW) and 2030 (485 GW) based on the EPIA scenarios (see 2.2.2). The installed PV capacity is increased incrementally from 5% to 15%, and the changes in transmission investment proposed by DSIM are used to evaluate the associated network cost. Some additional studies have also been carried out by increasing the PV capacity in a specific target country by 50%. For the 2030 sensitivity study, only one additional case study has been carried out by the authors: a 5% increase of the PV capacity uniformly across Europe compared to the PV capacity in the 2030 reference case. It should also be mentioned that the authors assumed that the reference EU grid transfer capacity is that proposed by ENTSO-E for 2020 in the TYNDP 2012 (see 4.12.4 (1)).

In addition to uniform distribution of incremental changes in PV capacity, the authors have also evaluated the impact of incremental changes in selected target countries such as Italy, France, Germany, Spain, and the UK. The results of this analysis can be found in the PV parity report [9].

2) Results

Figure 4.11.4-4 (a) shows the capacity of European main transmission system proposed by ENTSO-E and Figure 4.11.4-4 (b) shows the required network capacity proposed by the Imperial College of London's DSIM to accommodate 240 GW of PV in Europe by 2020. It can be observed visually that some of the corridors, particularly the Spain – France interconnectors, need reinforcing beyond the proposed capacity by ENTSO-E to accommodate the projected PV 2020 scenario.

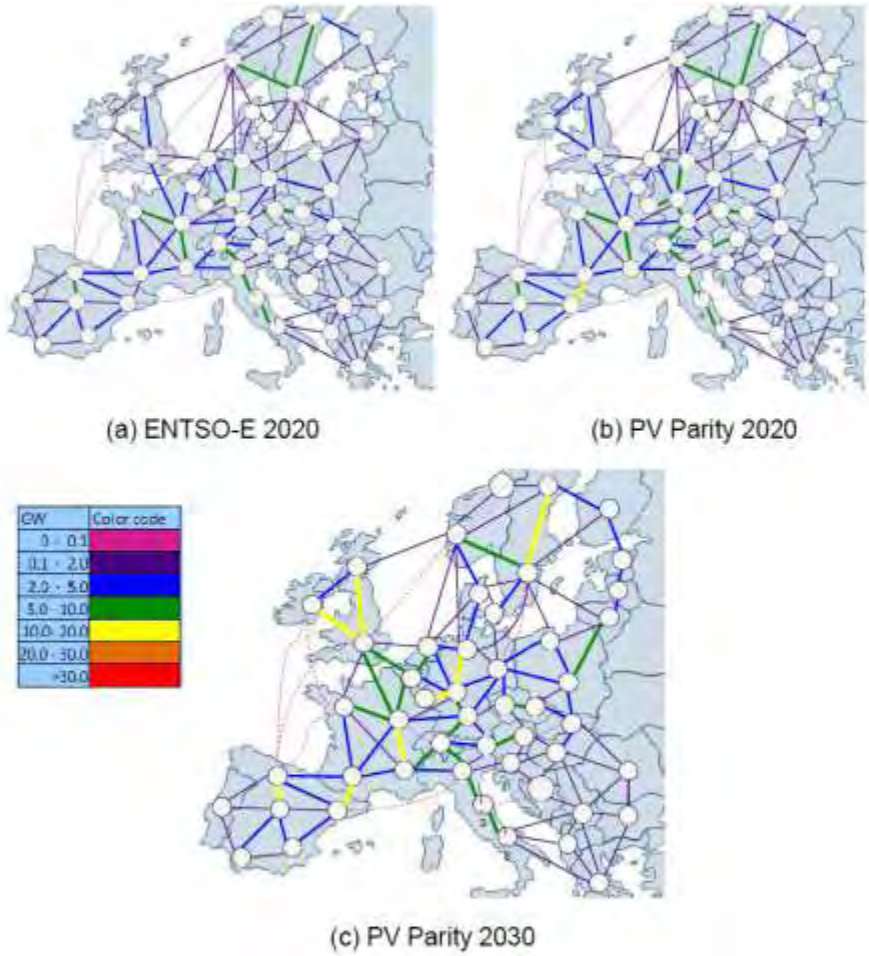


Figure 4.11.4-4: Impact of PV on the European Transmission grid as analysed by the PV parity project, [9]

Additional proposed network investment can be seen in Figure 4.11.4-4 (c), which shows the optimal capacity to accommodate the 485 GW of PV capacity included in the 2030 scenario. It is important to note that not all network investments shown here are driven by PV. Some are driven by other technologies, particularly wind power in the northern part of Europe and also the projected increase of load.

The results of Imperial College of London *analyses are* summarized in Table 4.11.4-1, showing *that the additional EU* transmission *grid cost* due to *PV by 2020 is modest* (*less than €0.5/MWh* of the electricity generated by PV). *Even with further increasing the installed capacity* in *a particular country up to 50%, the additional cost of PV is still relatively modest. This is likely to be* a consequence of *the availability of sufficient capacity margin provided by the 2020* transmission *capacity proposed by ENTSO-E* in their TYNDP 2012.

By 2030, higher deployment of renewable power generation including wind power and PV has increased demand for new investment in the European transmission grid. It is illustrated in Table 4.11.4-1 (c) that the capacity of many interconnectors, both cross-border or within the member states, needs to be upgraded. In this condition, the transmission cost of increasing PV capacity rises to €2.8/MWh.

Table 4.11.4-1: Additional EU transmission grid cost due to PV, [9]

Increase in PV installed capacity from the ref. case	Δ grid cost (M€/year)	Δ annual energy output (TWh)	Additional Grid EU cost (€/MWh)
2020 EU : 5%	4.38	12.9	0.3409
EU : 10%	9.73	25.7	0.3782
EU : 15%	15.42	38.6	0.3997
Spain:50%	0.92	17.6	0.0523
Italy:50%	2.80	25.0	0.1120
France:50%	1.16	25.3	0.0459
Germany:50%	8.55	27.6	0.3103
2030 EU: 5%	70.	25	2.80

It is important to note that in the Imperial College of London's model, the utilization of network capacity has been efficiently shared across different generation technologies including renewables. With regards to wind power, the characteristics of wind energy output are complementary to the characteristics of PV. Wind is strong in winter and during evenings, while solar is strong in summer and during daytime, as shown in Table 4.11.4-1. This allows power flows to utilize the same network capacity while optimizing the use of different renewable sources. This effect is important to drive down the transmission cost of PV.

The authors further mentioned that high PV penetration may also trigger reinforcement for local transmission, which is excluded in our analysis. The impact of PV on transmission is also affected by many other factors that cannot be evaluated in isolation, e.g., changes in load and generation mixes and generation operating cost, renewable energy profiles, etc.

For these reasons, the results of the Imperial College analysis should be considered as a worst-case scenario (even if they are quite low in terms of €/MWh), as alternative options like storage, curtailment of PV power, strategic spreads of the PV installed capacity, and DSM have not been included.

For the latter, the authors mentioned that the use of DSM could further drive down the cost of EU transmission grid expansion due to PV by 20%.

Storage and a strategic spread of the installed PV capacity could also play a crucial role for cost-efficient PV integration in the EU transmission grid. These two solutions have been extensively analyzed in the framework of the CTS and Smooth PV projects. The results of these analyses are briefly described in the following sections.

(3) Analysis of the storage capacity needs

1) PV and daily storage

The authors of the CTS study stated that daily storage is well suited for PV peak generation. This is because it is guaranteed that PV generation (in a large region) is available every day with a well-predictable peak that always occurs around midday. As the peak demand in Europe occurs in the evening hours, the time shift between peak PV generation and the peak demand normally does not exceed eight hours.

Figure 4.11.4-5 shows simulation results for the EPIA 2030 scenario (480 GW) that reflect this PV storage compatibility for a summer month. A storage power of 100 GW with average storage use around 45% in spring and summer and 40% in autumn and winter has been assumed to run the simulation. Daily storage complements PV, especially in summer, significantly flattening the residual load (after storage). The same effect can also be seen on a winter day. However, the flattening of the load curve is reduced, due to larger variations of the load and lower PV production.

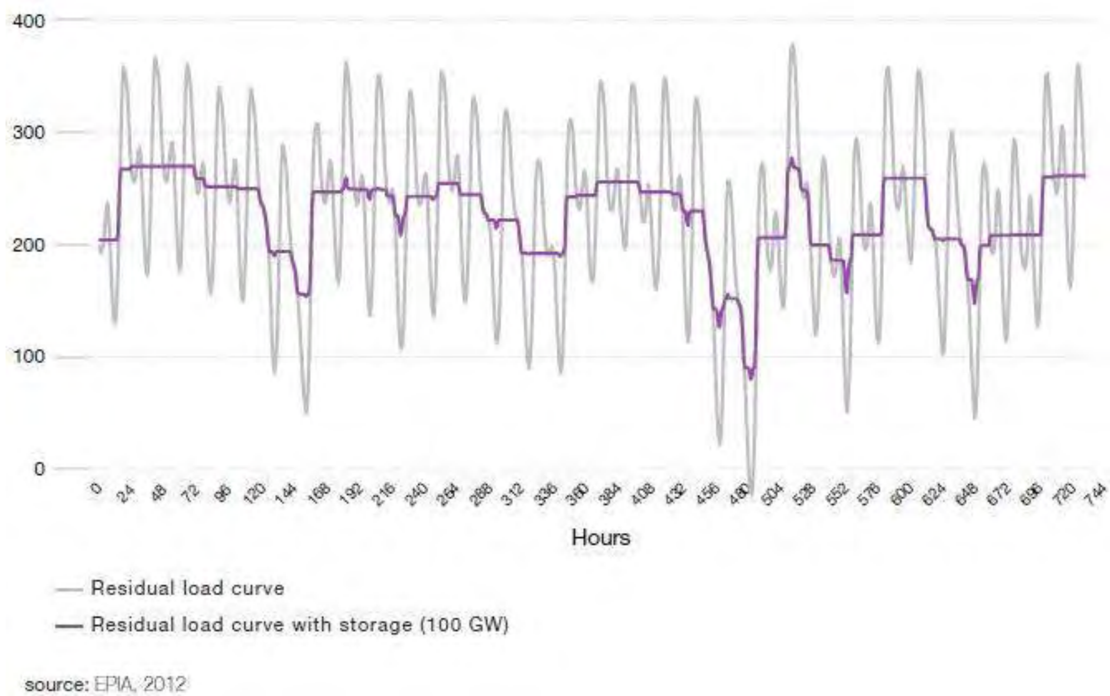


Figure 4.11.4-5: Impact of a 100 GW storage capacity on the Residual load curve in August, [5]

Storage can flatten the residual load curve by significantly reducing the peak demand on one hand and avoiding excess generation on the other. The former effect has a positive impact on the reduction of flexible standby capacity; the latter is a significant solution to excess generation (which wastes green energy) at the EU level that might be seen on some days in 2030. Further calculation results showed that storage has a positive significant impact on ramping as well.

Daily storage is already available today in the form of pumped storage plants, and there is further potential for new capacity in Europe. This does not yet take into account Norwegian storage capacity that might be connected to the central European power system via an offshore grid. In total, existing, planned, licensed, and Norwegian capacity can add up to about 80 GW. When combined with DSM techniques, this could total 100 GW, the assumption used in this analysis.

Further capacity might be built up by installing CAES(Compressed Air Energy Storage)storage capacities. In addition, batteries that run about two cycles a day, and therefore may shift the PV peak to demand peaks, might be used in the short or mid-term, as their costs are decreasing. For these cost reasons, the daily profile pattern of PV is a beneficial match. Finally, EVs can play a role here by being recharged at noon, for example, at a company's charging point. In conclusion, the assumption used in this analysis—that storage and DSM techniques can offset 100 GW of peak PV production—is a realistic one even without taking into account possible deployment of decentralized storage. An optimization analysis as described below shows that for the PV scenario considered, beyond 150 GW there is no benefit to increased daily storage power capacity.

2) Analysis of the storage need

In order to estimate the storage size (power and capacity) that optimally matches PV production, a number of storage simulations were run by the authors of the study using the 2030 scenario. The simulation was carried out with JModelica with the goal of flattening the residual load profile. The storage was varied in peak power and storage capacity. The storage power was set to 50 GW, 100 GW, 150 GW, and 200 GW. The storage size was for each of these storage powers set to 3 hours, 6 hours, 12 hours, and 24 hours of full load (e.g., 100 GW storage power would have the storage capacities of 300 GWh, 600 GWh, 1200 GWh, and 2400 GWh).

For each of these storage power and storage size combinations, the optimization was set to flatten the residual load profile. For evaluation, the residual load duration curve was plotted in order to see how much the minimum and maximum values of the residual load were reduced.

Figure 4.11.4-6 shows the potential of different storage power and size combinations to reduce the peak residual load. We can see that the full peak clipping potential is only reached when there is also a sufficiently high storage size. In case of 50 GW storage power, 150 GWh (three full load hours) is sufficient, while for 100 GW, 600 GWh is needed. For greater than 150 GW storage powers not even having 24 hours of storage capacity, the full 150 GW peak reduction is reached.

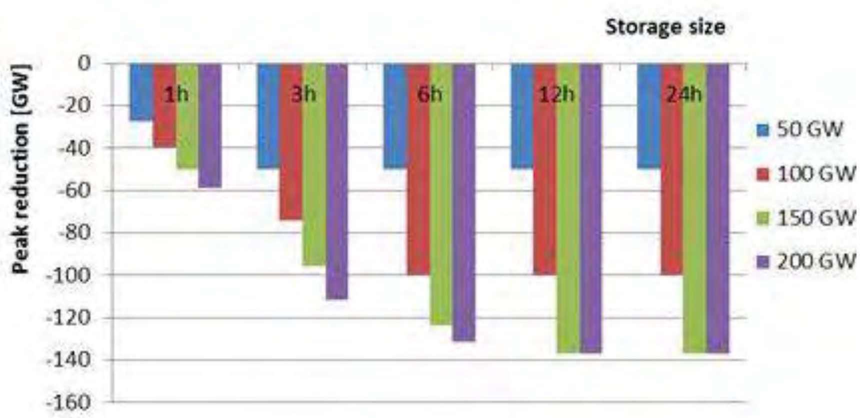


Figure 4.11.4-6: Peak reduction potential by different storages power and sizes, [5]

Cost-efficient daily storage, which is already available at relatively large scale, is perfectly well suited to be combined with PV generation. Energy storage will increase the security of the electricity supply, contribute to the avoidance of excess generation problems, reduce costly standby requirements, and provide further ancillary services to the grid (e.g., black-start). All storage options have to be considered depending on the application. Findings show that daily storage and DSM techniques can offset about 100 GW of peak PV production, without taking into account decentralized storage deployment. No real added value is brought to the system beyond 150 GW of daily storage capacity.

(4) Maximum feasible amount of PV in the European transmission grid

With the expected increasing PV capacity, PV-generated electricity will cover the complete feeder or regional demand in certain hours, and excess PV generation will occur. This excess energy will either be transported to supply consumers in other regions, stored, or curtailed. Even today, the lack of adequate transmission system capacity leads to curtailment of wind power. Although issues associated with PV systems currently predominate at the distribution level, large-scale PV development will lead to similar effects, especially if current postponements of grid expansion measures are taken into account. Large-scale deployment of storage capacity is currently limited by location scarcity for mature technologies like pumped hydro storage plants, the limited maturity of certain technologies, and their high cost. For the latter two factors, a large improvement can be expected in the coming decades. In the light of these restrictions, PV electricity could be curtailed, which may decrease the economic attractiveness of the technology.

In order to assess the influence of the abovementioned factors, the German company Energynautics conducted a series of simulations in the framework of the Smooth PV project. These simulations are based on a proprietary EU transmission grid model and were carried out in DIgSILENT PowerFactory looking at future utilization of grid-connected PV systems. Energynautics determined the optimal spread of installed PV capacities using power flow simulations. From these simulations, the authors derived several possible projections of future PV capacity growth starting with the amount required to supply the complete European load on a sunny summer weekend, and then increasing this amount linearly.

Furthermore, the effect of optimally located and operated storage on PV utilization was investigated by the authors in several scenarios representing various amounts of storage. The results for each investigated case are summarized by the annual load coverage of PV and the amount of curtailed PV energy. From that, the authors gave some hints about the maximum feasible amount of installed PV capacity in Europe while minimizing curtailed PV energy. It should be emphasized that issues concerning power system operation based on large amounts of non-synchronous generation have been assumed to be solvable by the authors, allowing the operation of an inverter-dominated power system.

The principal question aimed to be answered by the authors in this analysis is how efficiently power available from PV installations can be utilized at the European level. This depends on how much power generated by PV is consumed locally, how much of the excess power can be transported to other locations, and how much power can be stored provided storage capabilities are in place.

1) European transmission grid model

Energynautics conducted the simulations using DIgSILENT PowerFactory with their in-house 200 nodes model representing the load and generation centers in Europe in an aggregated way.

Although the model is tailor-made for AC load flow calculations, optimal power flow calculations (OPF) were conducted in DC for this study. The year 2050 was chosen as an indicative target for the estimation of the electricity consumption. Regarding the transmission network, the authors used the assumption that all projects from the ENTSO-E's TYNDP 2012 are implemented representing the status in 2020. From this point onwards, no further expansion of the transmission grid is considered until 2050. With this assumption, the authors aim to provide a good understanding of the role that the transmission grid plays in terms of PV curtailment. A representation of the model's nodes and lines is shown in Figure 4.11.4-7.

Figure 4.11.4-7: Energynautics aggregated model of the European high-voltage transmission grid, [12]

2) Determination of the minimum PV capacity under transmission grid constraints

Before conducting the calculations of PV utilization under constraints, the authors defined a base case scenario for the installed PV capacity. For that purpose the authors defined the installed PV capacity to cover 100% of the load on a clear-sky summer weekend day at noon (one of the day's load peaks) in all modeled countries. The load profiles for each country in 2050 have been developed by the Institute of Energy Economics at the University of Cologne (EWI) based on ENTSO-E 2011 data.

Hence, the authors performed a DC optimal power flow (OPF) calculation with the objective function set to minimize generation costs. This optimization mode led to the maximization of the power output of generators located in areas with high irradiation. The OPF was then configured by Energynautics to respect the thermal limits of the lines while still prioritizing the PV generation from sunny locations. With grid restrictions in place, this led to a PV distribution similar to the demand distribution totaling 770 GWp of installed PV capacity. This distribution and number represent the base case to be used for simulations of the complete year.

With the base case defined, the authors performed simulations of the complete year for different scenarios. These calculations consist of hourly OPF simulations using hourly demand and irradiation data for Europe as an input for the model. The scenarios analyzed are based on four options in terms of PV installed capacity starting from the base case, i.e., 770 GWp and reaching a maximum of 1,925 GWp by steps of 395 GWp, and three different storage assumptions. These assumptions are based on the curtailed PV energy calculated by the different whole-year simulation for 770 GWp and 1,155 GWp of PV without storage. Table 4.11.4-2 gives an overview of the scenarios considered by Energynautics for their simulations.

Table 4.11.4-2: Scenarios defined by Energynautics for their simulations, [18]

Installed PV, GWp	Total storage capacity in Europe in GWh		
	Scenario 1	*Scenario 2*	*Scenario 3*
770; 1155; 1540; 1925	none	290	1540

3) Results

The results of the power flow simulations of complete years according to the distribution of PV installations of the base case and the assumptions and the scenarios are defined in Figure 4.11.4-8

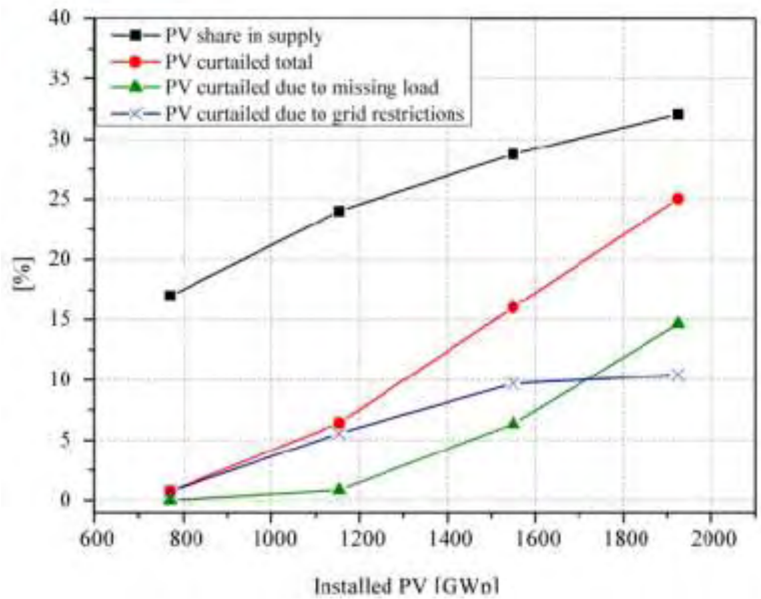


Figure 4.11.4-8: Calculation results for scenario 1 (no storage), [18]

By introducing transmission restrictions, the authors developed PV projections for 2050 characterized by a well-distributed placement of PV capacities matching the distribution of the demand. Curtailment of PV associated with excess PV energy and insufficient transmission capacity has been assessed by the conduction of optimal power simulations of a complete year for a total installed capacity proportionally increased from 770 GW up to nearly 2,000 GWp. The influence of strategically placed and dimensioned storage capacities has also been determined by Energynautics through several simulation scenarios demonstrating a potential for significant reduction of curtailed PV energy.

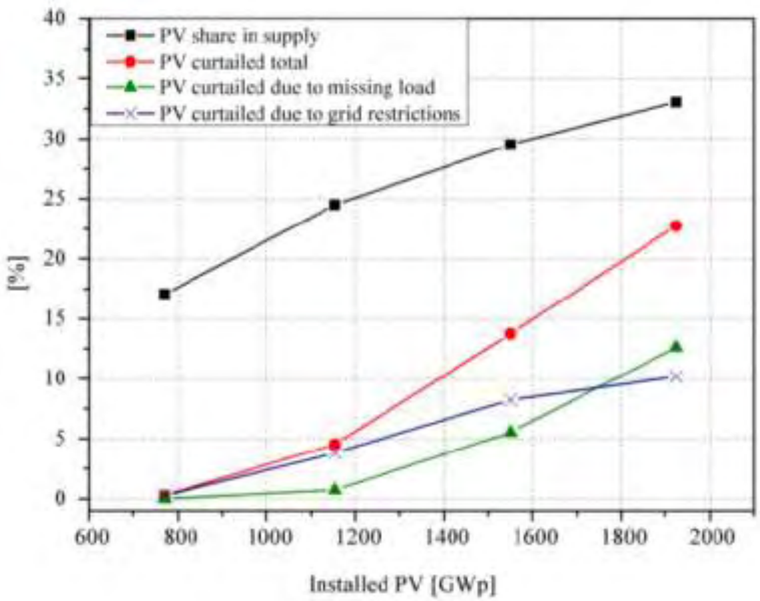


Figure 4.11.4-9: Calculation results for scenario 2 (290 GWh of storage), [18]

The authors also found that with 1,540 GWh storage capacity in the system, approximately 1,550 GWp of PV, covering about 33% of the annual consumption, could be integrated in the European power system with only a 5% annual curtailment of PV energy. DSM could provide a further shift in the diurnal load cycle, helping to keep the PV power and demand in the system well correlated.

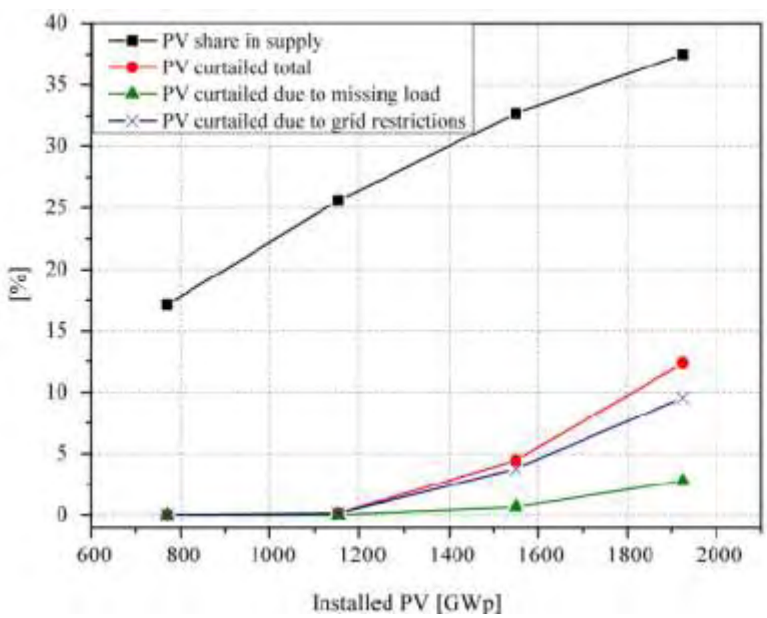


Figure 4.11.4-10: Calculation results for scenario 3 (1540 GWh of storage), [18]

Finally, Energynautics stated that appropriate grid enforcement could further reduce the amount of curtailed PV energy. For example, PV's share in load coverage could be increased up to 38%, which, however, would lead to 12% curtailment unless necessary grid extension or additional storage capacity is provided. For the authors, further expansion of installed PV capacity aiming at increasing PV's share in the load supply would necessitate disproportionately high storage and grid extension to keep the amount of curtailed energy low.

The complete methodology and assumptions used by Energynautics for the analysis described here above can be found in the Smooth PV final report [8] and the accompanying paper [18].

4.11.5. R&D for Transmission level Challenges

(1) R&D Roadmap

The Strategic Energy Technologies Plan (SET-Plan) supports European energy and climate policies through technology innovation. It aims to coordinate efforts at the national and EU levels through joint strategic planning and effective implementation mechanisms. European Industrial Initiatives are industry-driven strategic technology alliances to address key low-carbon energy technologies. The European Electricity Grid Initiative (EEGI) is one of them and has, according to its roadmap, different strategic objectives:

i To transmit and distribute up to 35% of electricity from dispersed and concentrated renewable sources by 2020 and a completely decarbonized electricity production by 2050;

ii To integrate national networks into a market-based, truly pan-European network, to guarantee a high quality of electricity supply to all customers and to engage them as active participants in energy efficiency;

iii To anticipate new developments such as the electrification of transport; and

iv To substantially reduce capital and operational expenditures for the operation of the networks while fulfilling the objectives of a high-quality, low-carbon, pan-European, market-based electricity system.

The EEGI Roadmap 2010–2018 and Implementation Plan 2010–12 were prepared by ENTSO-E and EDSO for smart grids and approved in June 2010. In 2013, an upgraded version was produced in order to cover new research, innovation, and knowledge needs in response to recent EU energy policy evolutions. The innovation activities cover the full value chain of activities performed by network operators grouped into five TSO and

DSO clusters, as shown in Figure 4.11.5-1. It summarizes the priorities of focus for the projects launched in the period 2014–2016 regarding both transmission and distribution aspects.

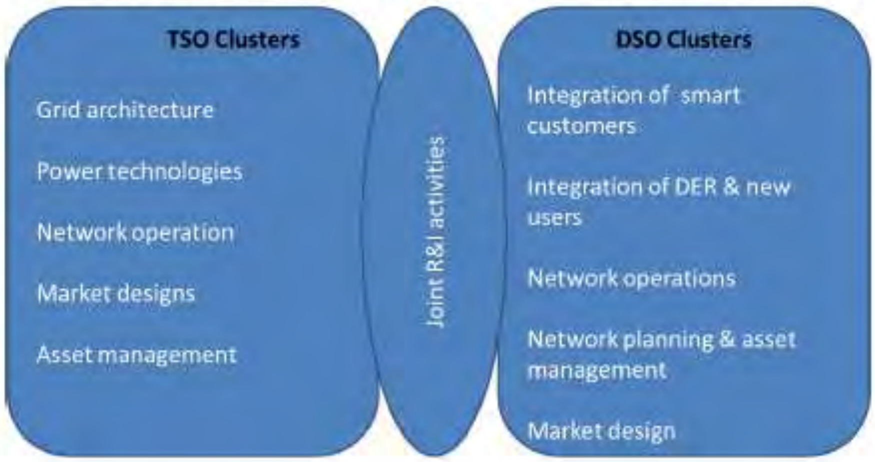


Figure 4.11.5-1: Research and innovation activities of the EEGI roadmap, [18]

The roadmap-upgrading exercise launched in early 2012 has allowed transmission and distribution operators to shape up upgraded clusters (and their functional objectives) for their research and innovation activities. As shown in Table 4.11.5-1, ENTSO-E proposes five research and innovation clusters that cover the value stages brought by transmission operators to the entire electricity system.

Table 4.11.5-1: The five innovation clusters of TSOs , [18]

Cluster	Name	Functional Objective	Full names of Functional Objectives
C1	Grid architecture	T1	Definition of scenarios for pan-European network expansion
		T2	Planning methodology for future pan-European transmission system
		T14	Towards increasing public acceptance of transmission infrastructure
C2	Power technologies	T3	Demonstration of power technology to increase network flexibility and operation means
		T4	Demonstration of novel network architectures
		T5	Interfaces for large-scale demonstration of renewable integration
C3	Network operation	T6	Innovative tools and methods to observe and control the pan-European network
		T7	Innovative tools and methods for coordinated operation with stability margin evaluation
		T8	Improved training tools and methods to ensure better coordination at the regional and pan-European levels
		T9	Innovative tools and approaches for pan-European network reliability assessment
C4	Market designs	T10	Advanced pan-European market tools for ancillary services and balancing, including active demand management
		T11	Advanced tools for capacity allocation and congestion management
		T12	Tools and market mechanisms for ensuring system adequacy and efficiency in electric systems integrating very large amounts of RES generation
C5	Asset management	T15	Developing approaches to determine and to maximize the lifetime of critical power components for existing and future networks
		T16	Development and validation of tools which optimize asset maintenance at the system level, based on quantitative cost/benefit analysis
		T17	Demonstrations of new asset management approaches at EU level

Jointly, ENTSO-E and EDSO4SG identified five functional objectives (see Table 4.11.5-2) requiring intensive collective research and innovation by TSOs and DSO(Distribution System Operator)s on the topics below.

Table 4.11.5-2: The joint TSO/DSO innovation cluster , [18]

Cluster	Name	Functional Objective	Full names of Functional Objectives
TD	Joint TSO/DSO Activities	TD1	Increased observability of the distribution system for transmission network management and control
		TD2	The integration of demand side management at DSO level into TSO operations
		TD3	Ancillary services provided through DSOs
		TD4	Improved defense and restoration plan
		TD5	Methodologies for scaling-up and replicating

The EEGI Roadmap 2013-2022 and the implementation plan 2014-2016 are available at: http://www.gridplus.eu/eegi

The topics described both in the EEGI Roadmap and the implementation plans are covered by several EU and national projects. Some of these are briefly presented in the following sections.

(2) Projects

1) E-Highways 2050

- Modular Development Plan of the Pan-European Transmission system 2050

Following the study “Roadmap towards a Modular Development Plan on the Pan-European Electricity Highways System 2050” performed by ENTSO-E members, a consortium of 28 partners, involving a wide spectrum of stakeholders, proposes the development and implementation of a top-down long-term planning approach, to be coordinated by the French TSO RTE France. The approach begins with the Pan-European Transmission Network as proposed by the TYNDP 2012 (see 4.1), which is assumed to be in line with the 2020 EU energy targets.

The overarching objective of E-Highways 2050 is to develop a top-down planning methodology to provide a first version of a modular and robust expansion plan for the Pan-European Transmission Network from 2020 to 2050, in line with the pillars of European energy policy.

The manufacturing industry is helping to identify standardization efforts to accompany the optimization of future investments. Beyond the top-down scenario-based approach, a parallel, improved optimization route is being investigated to propose a methodology potentially leading to a more robust expansion plan. Thus, further recommendations will be made to improve the delivered planning methodology in view of accompanying ENTSO-E efforts from 2020 to 2050. The study will also identify the needs for additional R&D, including demonstrators in further research projects, for instance.

According to the project description, the E-Highways 2050 modular long-term planning approach can be broken down into five steps (see Figure 4.11.5-2).

Figure 4.11.5-2: The modular long-term planning approach

Step 1, Energy generation and consumption scenarios: Development and application of an approach to design different long-term energy generation, exchange, and consumption scenarios, based on macro-economic data.

Step 2, Power localization scenarios: Using the assumptions about the generation mix, exchanges and consumption by area are developed. Stochastic inputs (such as renewable generation, uncontrollable consumption, or failure modes of generation units) with their temporal and spatial correlations are simulated. Power adequacy between generation, exchanges, and consumption should be ensured probabilistically.

Step 3, Simulation of load flows with potential overloads and/or weak points: The use of market and network simulation techniques to identify feasible and efficient pan-European grid architectures under each of the 2050 scenarios chosen above.

Step 4, Viable grid architecture option: Verification that the grid architecture options selected alleviate critical issues focusing on overload problems and possible voltage and/or stability problems for a given level of system reliability. In return, this must allow some of the successful architectures to become part of the final modular development plan between 2020 and 2050.

Step 5, Implementation of the retained architecture: The development of implementation routes from 2020 to 2050, proposed on the basis of cost/benefit analyses, appropriate wider socio-economic considerations and grid governance models able to address issues such as cross-border power flows.

The top-down innovative planning methodology considers the whole electricity supply chain, taking into account all the relevant technical/technological, economic/financial, and regulatory/socio-political dimensions needed to develop efficient, yet sustainable, grid architecture options that will meet future energy supply requirements. Furthermore, the scenarios on generation, storage capacities, and consumption patterns are worked out in detail, based on stakeholder consultations and in-depth work with professional associations.

More information is available at: http://www.e-highway2050.eu/e-highway2050/.

2) iTESLA: Innovative Tools for Electrical System Security within Large Areas

Pan-European transmission system security issues are likely to become more and more challenging in the coming years. New challenges will result in more complex system operation and a grid working closer to its operational limits, and therefore a need for a major revision of operational rules and procedures. As a consequence, coordinated operation initiatives have already emerged in different regions of the pan-European electricity transmission system (for instance, CORESO(Regional Coordination Service Centre) and TSC). These coordination initiatives will not be fully efficient without a common toolbox that allows the different TSOs to increase coordination and harmonize operating procedures.

The overarching goal of the iTESLA project is to develop and validate an open interoperable toolbox able to support the future operation of the pan-European grid. More precisely, this toolbox will support the decision-making process from two days ahead to real time to perform accurate security assessment taking into account the dynamics of the system; and to provide a risk-based assessment taking into account the different sources of uncertainties (in particular, those brought by variable power generation), the probabilities of contingencies, and the possible failures of corrective actions.

Worldwide, there are only a few tools that are able today to perform dynamic security assessment; none of them take into account uncertainties (see Figure 4.11.5-3).

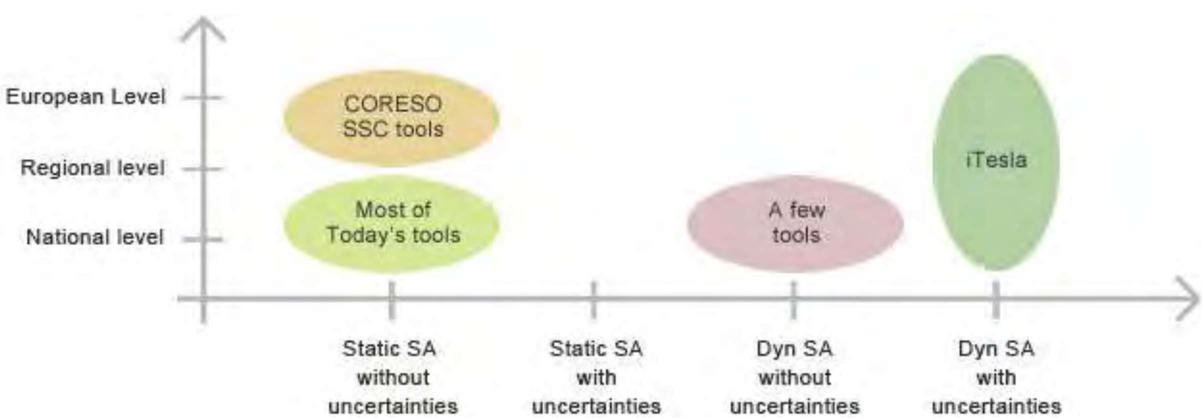


Figure 4.11.5-3: Overview of the existing tools available today to perform dynamic security assessment

The iTESLA toolbox will be the first computing environment to allow for an account of uncertainties at regional, national, and pan-European levels when performing dynamic security assessment. The iTESLA toolbox will build on the results of the EC-supported PEGASE(Pan-European Grid Advanced Simulation And State Estimation) project as much as possible. The computational engine for time-domain simulations will be based on the prototypes developed in the PEGASE project, and the security assessment will benefit from optimization modules developed in the framework of the validation of the worst-case approach.

The iTESLA toolbox shall bring forward a major innovation: carrying out operational dynamic simulations in the frame of a full probabilistic approach, thus going further than the current "N-1" approach and optimizing the transit capacities of the grid at different spatial (national, regional, pan-European) and time (two days ahead, day-ahead, intra-day, real-time) scales.

The toolbox shall be available through a flexible IT(Information Technology) platform that will allow TSOs to address singular, regional, or pan-European network simulations of their own system, of coordinated regional systems, or of the whole pan-European system, provided that adequate system data are made available at the suitable level.

Coordinated by RTE(Reseau de Transport d'elecricite), the iTESLA project joins six TSOs (Belgium, France, Greece, Norway, Portugal and United Kingdom), CORESO, and a pool of 13 R&D providers. iTESLA has been launched in January 2012 and will run until the end of 2015.

More information is available at: http://www.itesla-project.eu/.

3) Twenties

A group of TSOs from Belgium, Denmark, France, Germany, Spain, and the Netherlands collaborated with two generator companies, three power technology manufacturers, two wind turbine manufacturers, and R&D organizations in order to bring answers by 2015 to the following questions:

i What are the valuable contributions that variable generation and flexible load can bring to system services?

ii What should the network operators implement to allow for offshore wind development?

iii How to give more flexibility to the transmission grid?

iv Overall, how scalable and replicable are the results within the entire pan-European electricity system?

These four intertwined overarching goals have been addressed through a set of six high-level demonstration projects:

Syserwind	System services provided by wind farms, which aim at testing the provision of new active and reactive power control services to the system (EMS level) using improved systems, devices, and tools, but keeping the current hardware at the wind farm level.
Derint	Large scale VPP(Virtual Power Plants) integration, aiming at improving wind integration based on intelligent energy management of central CHPs, offshore wind, and local generation and load units in the distribution grid.
DC Grid	Technical specification towards offshore HVDC networks, which assess main drivers for the development of offshore HVDC networks.
Storm Management	Offshore wind farm management under stormy conditions, which demonstrates shut-down of wind farms under stormy conditions without jeopardizing the safety of the system.
Netflex	Network-enhanced flexibility, which demonstrates at the regional level how much additional wind generation can be handled thanks to dynamic line ratings (DLRs), coordination of controllable devices (PSTs & HVDCs) and usage of WAMS.
Flexgrid	Improving the flexibility of the transmission grid, demonstrating that the current transmission network can meet the demands of renewable energy by extending system operational limits and maintaining safety criteria.

Even though the project focuses on wind energy, the outcomes of the Twenties project can be easily applied to PV energy.

More information is available at: http://www.twenties-project.eu/

4) REserviceS

REserviceS (Economic grid support from variable renewables) is the first study to investigate wind- and solar-based grid support services at the EU level. It will provide technical and economic guidelines and recommendations for the design of a European market for ancillary services, as well as for future network codes.

Electricity grids must be operated safely and efficiently, and technical services provided to transmission and distribution system operators are an essential part of ensuring this. Such services include controlling the frequency and voltage as well as providing reserves. Generally, these so-called ancillary services are provided by large dispatchable power plants. As the share of renewables in the overall energy system continues to rise—regionally expected to meet up to 50% of electricity demand by 2020—a drastic change in strategy for the procurement of ancillary services is required.

REserviceS encourages the efficient and economic deployment of large shares of renewable energy sources by exploring how wind and PV plants can provide such services in the future European power system. The project also investigates the opportunities and costs of providing ancillary services from wind and PV systems by analyzing different aspects following a stepwise approach (Figure 4.11.5-4).

Step 1, System needs for ancillary services: The first phase of the project has set the common study framework. The consortium published technical specifications, system needs, and costs of ancillary services and a table with explanatory notes on ancillary services, as well as the findings on ancillary services costs.

Step 2, Wind and PV ancillary services capabilities and costs: The second step consisted of a technical and economic assessment of the capabilities of and costs for wind and PV plants to deliver ancillary services, today and in the future. The reports on capabilities and costs for ancillary services by wind power plants and PV systems describe the technical options and related costs for the provision of ancillary services specifically from wind energy and PV technologies. Both reports focus on the set of ancillary services defined during phase 1 of the project.

Figure 4.11.5-4: A stepwise approach for the definition of recommendations for a future EU markets for ancillary services

Step 3, Wind and PV ancillary services in future systems: The REserviceS project carried out case studies aiming at investigating the need for ancillary services in transmission and distribution networks, and the costs and options for delivering these services. Various scenarios with different shares of wind and solar PV were chosen.

Through this effort, REserviceS will encourage the completion of a single EU electricity market with cost-efficient integration of variable renewables, improved grid management, and increased electricity system security by providing recommendations for a future EU market for ancillary services. The final outcome of the REserviceS study will be published in September 2014. The publication will contain techno-economic input for market design, policy, and network codes.

More information is available at: http://www.reservices-project.eu/.

5) Smooth PV

Smooth PV—Smart Modeling of Optimal Integration of High Penetration of PV—is a project with the objective to develop advanced modeling and simulation tools using the software tool DIgSILENT/PowerFactory in order to evaluate the impact of large-scale penetration of PV. The project was led by the company Energynautics.

The main project outcomes are simulation tools that allow the evaluation of the impact of high PV penetration on power system operation. A detailed report summarized the findings of the simulations, focusing on the technical and economic impact of high PV penetration in the distribution network and in the overall European power system.

More information is available at: http://www.smooth-pv.info/index.html.

6) Market4RES

The Market4RES project focuses on electricity market design to support more efficient integration of renewable electricity into the pan-European electricity system in line with the 2020 objectives and further towards the forthcoming 2030 targets. The project consortium anticipates that new market mechanisms are needed to complement the European Integrated Target Model (TM) expected to be fully implemented by 2015, including harmonized rules at the European scale for day-ahead price coupling, cross-border intra-day continuous trading and long-term cross-border capacity allocation.

Crucial concerns remain about the suitability of existing instruments to trigger the new investments required to reach a progressive de-carbonization of the electricity sector in a cost-effective way, while ensuring system adequacy and security of supply.

The Market4RES consortium, composed of TSOs, utilities, research centers, consulting companies, and renewables associations, will address these issues together with relevant stakeholders via two separate work streams:

i **Assuming the current generation fleet as an input and current implementation status of the target model:** The focus is on determining appropriate, yet novel, instruments (and their subsequent accompanying national energy policies) for increased renewable electricity generation in support of the 20/20/20 targets;

ii **Assuming the future generation fleet (beyond 2020) as a result of current market designs, and taking into account possible future changes in market design beyond the existing TM**: The focus is on developing necessary additions or complementary instruments to the current design, which will induce investment incentives and phase-out support schemes in the long term without compromising system adequacy or security of supply.

The first work stream will provide specific recommendations on market conditions required for increased renewable energy integration in the existing European electricity system up to 2020. The second work stream goes beyond the existing scope of the European TM for electricity trading. It looks at the market incentives for electricity generation investment in support of the 2050 decarbonization roadmap.

The project is led by the research center Sintef and will start in April 2014 for a period of 30 months.

4.11.6. References

[1] Eurelectric, “Power Statistics 2012”, 2012

[2] EPIA, “Global Market Outlook for Photovoltaics 2013-2017”, May 2013

[3] IEA PVPS, “IEA PVPS Trends 2013”, 2013

[4] IEA, “Harnessing Variables Renewables: A Guide to the Balancing Challenge”, 2011

[5] EPIA, “Connecting the Sun: Solar Photovoltaics in the Road to Large-Scale Grid Integration” Sep. 2012

[6] Juha Kiviluoma, Hannele Holttinen, Nicolaos Cutululis, Andrej Gubina, Andrew Keane, and Frans Van Hulle, “REserviceS D2.2 - Ancillary services: technical specifications, system needs and costs,” D3.1, 2012.

[7] ENTSO-E, “Dispersed generation impact on the CE region security,” Mar. 2013.

[8] T. Ackermann, S. Cherevatskiy, T. Brown, R. Eriksson, A. Samadi, M. Ghandhari, L. Söder, D. Lindenberger, C. Jägemann, and S. Hagspiel, “SMART MODELING OF OPTIMAL INTEGRATION OF HIGH PENETRATION OF PV–SMOOTH PV”, 2013

[9] D.Pudjianto,“Grid Integration Cost of Photovoltaic Power Generation“, IEE PV Parity Project, 2013

[10] Deutsche Energie Agentur GmbH (dena), “dena-Netstudie, Energiewirtschaftliche Planung für die Netzintegration von Windenergie in Deutschland an Land und Offshore bis zum Jahr 2020,” 2005.

[11] Deutsche Energie-Agentur, “dena-Netzstudie II, Integration erneuerbarer Energien in die deutsche Stromversorgung im Zeitraum 2015 2020 mit Ausblick 2025,” Berlin, 2010.

[12] Wilhelm, Winter and et al., “European Wind Integration Study (EWIS) - Towards a successful integration of large scale wind power into European electricity grids,” 2010.

[13] F. Van Hulle and et al., “TradeWind - Developing Europe’s power market for the large-scale integration of wind power, Integrating Wind,” 2009.

[14] J. De Decker, A. Woyte, C. Srikandam, J. Völker, C. Funk, K. Michalowska-Knap, J. Tambke, and G. Rodrigues, “The IEE Project OffshoreGrid: Objectives, Approach and First Results,” in *Proc. 8th International Workshop on Large-Scale Integration of Wind Power into Power Systems as well as on Transmission Networks for Offshore Wind Power Plants*, Bremen, 2010.

[15] Eirgrid/Soni, FoR studies, 2010

[16] ENTSO-E, “Ten Years Network Development Plan 2012”, 2012 https://www.entsoe.eu/major-projects/ten-year-network-development-plan/

[17] D. PUdijanto, M. Castro, G. Strbac and E. Gaxiola, “Transmission Infrastructure Investement Requirements in the Future European Low-Carbon Electricity System”, Proc. 10th International Conference on European Energy Market Conference, Stockholm, 27-31 May 2013

[18] S. Cherevastskiy, E. Tröster, “Determining The Maximum Feasible Amount of Photovoltaics In the Euopean Transmission Grid Under Optimal PV Utilisation”, Smooth PV project, 2012 http://www.smooth-pv.info/doc/App02_ENA_Maximum_Feasible_PV.pdf

[19] European Electricity Grid Initiative, “Research and Innovation Roadmap 2013-2022”, January 2013

5. Conclusions and Future Work

5.1. Conclusions

The ST3 working on High penetration solutions for central PV generations scenarios, , reviewed the impacts of PV Penetration, the counter measures for system operation and augmentation planning, and market design including the impact of other variable renewable generation in order to envision the future PV penetration into a power system in the scope of transmission system level. The report published by the ST3 discusses also the state-of-art methodology of power system operation planning and augmentation planning and presents case studies of system operation and augmentation planning including issues, solutions and R&D activities of the member countries.

Through the study conducted by the TASK14, it has been revealed that the major issues of increasing PV penetration at transmission level is the demand supply balancing due to the increased variability of PV and other variable renewable generation and due to decreased flexibility of the traditional generation fleet. Countermeasures are the additional flexible resources such as flexible generation, demand activation and geographical smoothing of PV generation by stronger transmission system including interconnections.

In order to optimize the utilization of the flexible resources in terms of economy and stable operation, generation forecast technologies have also a crucial role to play. To realize the best use of the power system technologies, power markets have been continuously improved including closer to real time gate closure time for bidding and shorter (sub-hourly) trade intervals. Capacity markets concepts, a market for generating capacities, emerge also as a compliment to the energy-only market in order to address remuneration issues.

The methodologies of power system operation and augmentation have been adapted to accommodate the flexible resources, geographical diversity, generation and demand forecast uncertainty and improved market designs.

From the case studies TASK14 member countries have shown the wide range of efforts for PV penetration including following aspects:

- PV integration studies with various aggressive penetration targets under a variety of power system conditions, from a continent-wide system to an island or an area,
- Evaluation and optimization of new flexible resources based on the analysis of detailed operational impacts
- Research and Development of new flexible resources and system operation including generation forecast
- Optimization of a total power system operation and market design improvement
- Participation of many stakeholders such as regulators, TSOs (ISOs), utility, generators, manufacturers, research Institutes, consultancy companies and Renewables associations

For PV to become a major electricity source, power systems have to be transformed stepwise to facilitate the increased need for flexibility. The required flexibility at each PV penetration level will be mitigated through the geographical and technological smoothing effect of the weather dependent PV variability. And there are a large numbers of existing and potential flexible resources including traditional generation fleet, control of variable renewable generation, demand activation, innovative storage technologies, transmission lines and interconnection, innovative centralized and decentralized energy management, power markets evolutions, etc…

The case studies have shown that all stakeholders, including regulators, operators, manufacturers, researchers, power customers have been practicing their efforts to realize high penetration of PV through technological but also regulatory innovation. There are enough technological potential to accommodate the transition to a high PV penetration. But increased efforts will be required in the area of regulations including whole sale and retail market and centralized and decentralized operations so as to realize the optimum evolution of a power system.

5.2. Future Work

PV generation varies cyclically in a year and in a day, and irregularly due to climate. The large penetration of PV generation are causing the issues not only of voltage and power flow fluctuation in a local distribution system but also issues of the demand-supply balance of the power systems where the high PV penetration is realized. The demand and supply balance issues are resulting in the difficulties in the operation of the power systems in the aspects of frequency regulation, load following, load-dispatching and the market operation.

In order to realize high PV penetration to a power system, it is crucial to evaluate the impacts, identify the countermeasures and envision the future power system. From grid interaction and penetration related aspects, it is needed to identify gaps in current PV system technology and electric power systems and analyze how large numbers of PV installations can be successfully integrated with total power system including the technology of smart grids.

Accordingly, as future work of the Subtask 3, it is recommendable to survey the resources for flexible transmission system operation, surveys and case studies of innovative transmission system operation with generation forecast in two steps, and surveys and case studies of asset optimization for high PV penetration in the following structure:

- Identification of existing and future flexibility resources for flexible transmission system operation
- Evaluation of capability of innovative power system operation of the transmission level with generation forecast
- Evaluation of transmission stability of a power system with flexibility resources
- Recommendation of Asset optimization for high PV penetration

IEA INTERNATIONAL ENERGY AGENCY

ISBN 978-3-906042-26-8

9 783906 042268 >