EXPERT GROUP REPORT ON

RECOMMENDED PRACTICES

16. WIND/PV INTEGRATION STUDIES

3rd EDITION, 2024

Submitted to the Executive Committees

of the International Energy Agency Technology Collaboration Programmes

for Co-operation in the Research, Development, and Deployment

of Wind Energy Systems and for Photovoltaic Power Systems

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Edited by: Hannele Holttinen, Recognis Oy, and Niina Helistö, VTT Technical Research Centre of Finland (VTT)

With contributions by:

- *Madeleine McPherson, University of Victoria, Canada*
- *Nicolaos Cutululis, Matti Koivisto, Technical University of Denmark (DTU); Antje Orths, Energinet, Denmark*
- *Juha Kiviluoma, Technical Research Centre of Finland (VTT), Finland*
- *Emmanuel Neau, Électricité de France (EdF); Thomas Heggarty, Réseau de Transport d'Électricité (RTE), France*
- *Jan Dobschinski, Denis Mende, Markus Kraiczy, Fraunhofer Institute for Energy Economics and Energy System Technology (IEE), Gerd Heilscher (Technische Hochschule Ulm), Germany*
- *Damian Flynn, Hamed Heydari-Doostabad, University College Dublin (UCD), Ireland*
- *Enrico Maria Carlini, Terna, Italy*
- *Jose Luis Rueda Torres, Delft University of Technology (TUDelft); Germán Morales-España, Netherlands Organisation for Applied Scientific Research (TNO), Delft University of Technology (TUDelft), The Netherlands*
- *Magnus Korpås, Norwegian University of Science and Technology (NTNU), Norway*
- *Ana Estanqueiro, Antonio Couto, National Laboratory of Energy and Geology (LNEG), Portugal*
- *Lennart Söder, Henrik Nordström, Mohammad Reza Hesamzadeh, KTH Royal Institute of Technology (KTH), Sweden*
- *Bethany Frew, Barry Mather, National Renewable Energy Laboratory (NREL); Debra Lew, Julija Matevosyan, Energy Systems Integration Group (ESIG), Aidan Tuohy (EPRI), United States of America (USA).*

And review by: Silvia Moroni, Corrado Gadaleta, Terna, Italy; Julien Cabrol, Norwegian Water Resources and Energy Directorate (NVE), Norway; Jian Fu, U.S. Department of Energy (DOE), Vahan Gevorgianm National Renewable Energy Laboratory (NREL), Justin Sharp, (EPRI), United States of America; Sumanth Yamujala, Technical University of Denmark (DTU), Denmark; Eldrich Rebello, Natural Resources Canada (NRCan), Abbas Rabiee University of Laval, Canada.

Foreword

The International Energy Agency (IEA) Technology Collaboration Programmes for Co-operation in the Research, Development, and Deployment of Wind Energy Systems (IEA Wind) and Photovoltaic Power Systems Programme (IEA PVPS) are vehicles for member countries to exchange information on the planning and execution of national, large-scale wind and solar energy projects and to undertake co-operative research and development projects called Tasks.

As a final result of research carried out in the IEA Wind TCP Tasks, Recommended Practices, Best Practices, or Expert Group Reports may be issued. These documents have been developed and reviewed by experts in the specialized area they address. They have been reviewed and approved by participants in the research Task, and they have been reviewed and approved by the IEA Wind Executive Committee as useful guidelines for the development and deployment of wind energy systems. Use of these documents is completely voluntary. However, these documents are often adopted in part or in total by other standards-making bodies.

A Recommended Practices document includes actions and procedures recommended by the experts involved in the research Tasks. A Best Practices document includes suggested actions and procedures based on good industry practices collected during the research project. An Experts Group Report includes the latest background information on the topic as well as a survey of practices, where possible.

Previously issued IEA Wind Recommended Practices, Best Practices, and Expert Group Reports can be found at www.ieawind.org.

This third edition of Recommended Practices 16 is a collaboration with IEA PVPS and IEA Wind TCP Tasks on grid integration. This edition updates recommendations for wind and solar integration studies, Edition 2, to include recommendations for higher shares of wind and solar PV in the energy systems and to reflect recent findings in data and methods in use.

Preface

This Expert Group Report provides recommendations on how to perform studies of wind and solar photovoltaic (PV) integration. It is based on more than 15 years of work within the International Energy Agency Wind Technology Collaboration Programme (IEA Wind TCP) Task 25: Design and Operation of Energy Systems with Large Amounts of Variable Generation and the IEA Photovoltaic Power System Programme (PVPS) TCP) Task 14: High Penetration of PV Systems in Electricity Grids.

The report is issued as an IEA Wind TCP Recommended Practices document to provide research institutes, consultants, and system operators with the best available information on how to perform an integration study. An integration study seeks to find issues in energy systems, as well as mitigation measures, for accommodating certain amounts of generation from wind or solar energy.

The first Recommended Practices to guide the conduct of wind integration studies was released in 2013 and updated in 2018 to include solar PV. Both Edition 2 and this Edition 3 benefit from review of integration studies based on real integration experiences and improved integration study methodologies for both wind and PV. This report presents the current view of recommended methodologies for reaching very high shares of variable generation. Due to other large changes in power and energy systems (decarbonization, electrification, and energy sector coupling), future studies are seen more as multidimensional optimization, instead of one-dimensional wind and solar integration studies. The recommendations here are also valid for more general system impact studies. The field is still evolving, and future development needs are also pointed out.

This Expert Group Report describes the methodologies, study assumptions, and inputs needed to conduct a wind and PV integration study. Findings and results from previous wind integration studies are discussed in the other reports of Task 25 of Wind TCP and Task 14 of PVPS TCP.

In Recommended Practices 16, the Task 25 Expert Group developed a flow chart that outlines the phases of a complete wind integration study, updated to include integration studies for PV in Edition 2. In this third edition, the flow chart has been updated and simplified (see Figure 1.3). The flow chart describes a comprehensive yet flexible process, which can be adapted to the specific objectives and requirements of the individual study. Using the checklists provided will allow reviewers to understand what was completed in any particular study and what was not, providing a context for comparison.

The authors and reviewers of this Recommended Practices are listed at the beginning of each section.

Hannele Holttinen and Niina Helistö,	Gerd Heilscher and Roland Bründliner,
Operating Agents, IEA Wind TCP, Task 25	Operating Agents, IEA PVPS TCP, Task 14
www.ieawind.org	www.iea-pvps.org

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Executive Summary and Summary of Recommendations

Purpose

Integrating wind and solar to power systems is happening at an increasing pace. While more countries globally start tapping into renewable resources and need to make sure the power systems are able to cope with new kind of variability from wind and solar, some countries have already gained some decades of experience and are aiming to manage the operation of wind and solar dominated power systems.

The purpose of this report is to provide research institutes, consultants, utilities and system operators with the best available information on how to best perform a wind/solar photovoltaic (PV) integration study. With increasing wind and solar deployment and tremendous future potential, it is crucial that commonly accepted methodologies are applied to accurately assess integration issues and to reduce uncertainties surrounding renewables' impact.

This Recommended Practices report updates the findings regarding how to study the consequences of small and medium shares of wind and solar generation (<50% of demand) and outlines challenges and solutions to study impacts of very high wind and solar shares.

It is foreseen that this Edition 3 update for Recommended Practices will be the last report version discussing wind and solar integration. Instead, against the background of transitioning towards net zero emissions energy systems, with wind and solar generation becoming mainstream, integration studies will transform into general power system design studies at very high wind and solar shares. Future studies are seen as multidimensional optimisation for the power and energy system, instead of one-dimensional wind and solar integration studies.

Challenge

The integration studies, first conducted for wind and solar generation separately, have evolved towards examining the integration of wind and solar generation at the same time. Integration studies typically simulate a future power system with wind and solar contributions (share or penetration) varying from 5% to more than 50% of annual electrical supply. The studies seek to evaluate the potential impacts of wind and solar generation on the grid and on the operation of power generation. The characteristics of the power system being studied, and the data available, can vary significantly. In addition, goals and approaches can differ, and thus the results can be difficult to compare. The methodologies used in most studies are diverse and are still evolving, especially for studies for wind and solar dominated power and energy systems.

Approach

Experts have outlined the phases of a complete integration study, as illustrated using a flow chart (Figure i). Beginning with a base case scenario for the power and energy system in question, its technical feasibility will be analysed through the different parts of a complete study, considering operational/balancing issues, adequacy, and system dynamics, among a range of analysis phases. It is important to highlight the importance of iterations in the integration study setup. In addition to iterations back to the initial scenario assumptions – from the three feasibility checks for Operation, Adequacy, and Dynamics – iterations between network simulations and production cost simulations may also be needed, especially for network dynamics with higher wind and solar shares. The chapters can be read separately: there is some overlap and they are cross referenced where more information is relevant in another chapter.

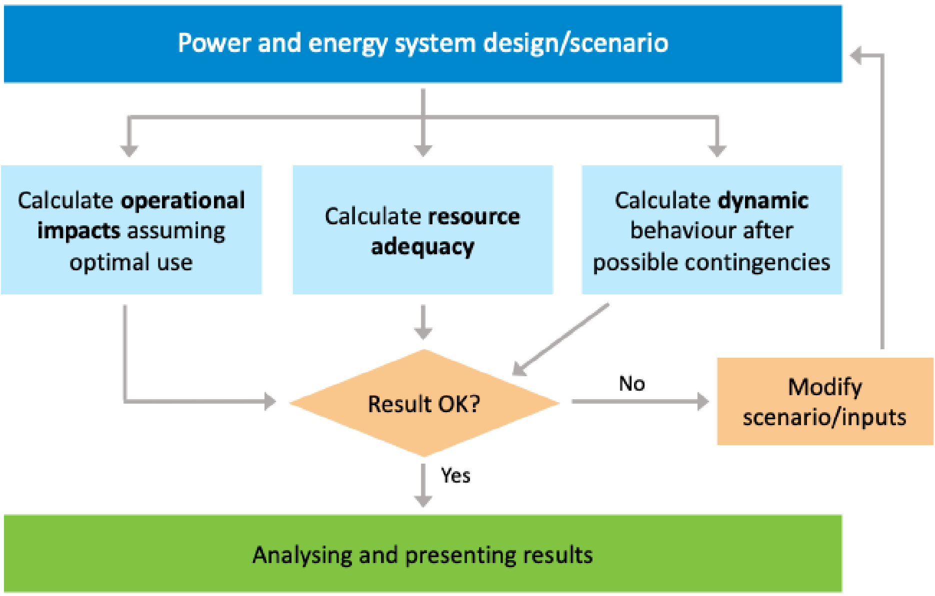

Figure i. Phases of a wind/PV integration study. Each step and iteration are verified to be "ok" for feasibility across the categories of Operational impacts, Adequacy and Dynamic behaviour. If the results show infeasibilities, or high costs, then changing scenario assumptions is recommended.

Regarding the scope of this report:

- Integration studies are focussed on future scenarios, and thus they form part of the planning phase, and are not operational, real-time tools for system operators.
- Although this report presents the main points to consider for wind and solar PV generation in terms of power flow and dynamic/transient studies, detailed recommendations on transmission planning are not included as these are established transmission system operator core know-how.
- The report focuses on technical issues because they are the same everywhere, however especially for future studies the importance to consider operational practices, including market design is highlighted.
- Power system impacts are the focus, however, coupling to other energy sectors, like heat, is important to include in the studies.

Assessing high wind/PV shares usually requires conducting studies projecting 10–30 years in the future. Such simulation results can illustrate ways to prepare for possible impacts of adding wind and solar generation. The results can show how changes to operating procedures, network code requirements, and market structures can help to ensure reliable and economic operation. When projecting beyond 10 years, other changes such as electrification impacts will be important to incorporate, with increased coupling to other energy sectors changing the passive load paradigm and increasing different forms of storage for flexibility purposes.

Contents of a Study

A wind/PV integration study should clearly describe the inputs and assumptions used and include the following:

- *Objective of the study:* Studies can be made for different reasons, like to support policy decisions or specific power and energy system planning decisions, or to understand balancing needs. This will determine important assumptions on what is included and what is excluded – especially crucial for the results will be assumptions for neighbouring power systems and assumptions for links to other energy sectors including new kinds of demand such as power2X.
- *Power and energy system data:* Includes power plant and storage data, load data, transmission network, operational practices including market structures, and coupling to energy sectors linking available flexibility such as heat.
- *Wind/PV power related data:* Detailed wind/solar generation data that fully characterize plant performance and geographical spread (co-incident with load and all weather dependent data used) as well as data on wind/PV generation and load uncertainty (forecast errors) and the location of wind/PV power plants for grid simulations.
- *Other assumptions that play a key role in results*: Links to other energy sectors, such as heat, transport, and gas; demand flexibility; scenarios of (future) conventional generation; storage and network characteristics; as well as fuel prices, taxes, CO_2 allowances, and emission limits.

Key tasks that comprise an integration study include the following:

- *Scenario setup including base case for comparison*: For future systems, this will entail capacity expansion models.
- *Data collection/synthesis and quality checking*: validating and quantifying the uncertainty of all synthetic data used including weather data.
- *Operational impacts:* Running production cost simulations to see how wind/solar power impacts the scheduling and dispatch of generation and storage, activation of demand flexibility, and estimating system operational cost. Need for flexibility from other sources (generation, storage, demand). Impact of wind and PV generation on short-term reserves as part of statistical data analysis.
- *Adequacy impacts:* Running resource adequacy analysis to assess whether reliability targets are met. Running (steady-state) network simulations to see whether the network is adequate or where reinforcements and/or changes in security architecture or network operational processes are needed.
- *Impacts on system stability:* Running dynamic simulations to ensure that power system stability is adequate, i.e., studied power system can handle possible contingencies.
- *If results achieved are not feasible or show high costs,* then changing scenario assumptions is recommended. Changes should be applied to the generation, storage, or transmission portfolio, or operational practices, including demand flexibility (an iterative process).
- *Analysing the output data and presenting the results*.

Depending on the wind and solar shares studied, some components of the study can be omitted. To begin with, at lower shares, scenarios studied need only include the power system, operated based on existing practices. The impact of wind/PV power on other power plants as well as on the need to upgrade the transmission are the main issues to assess with the main simulation tools (production cost simulation and power flow), even if transmission network is not studied in detail, and a simplified approach is oftern applied as part of production cost simulations. Even if the capacity value of wind/PV is usually not critical at low shares, it is often included in such studies.

For higher wind and solar shares, it will become important to assess impacts relating to reserve requirements within a more detailed flexibility assessment. Finally, for wind and solar dominated systems, resource adequacy and stability aspects become crucial to study in (great) detail. The power system transitions from one that is largely based on dispatchable synchronous-machine - based generation to one that is based on power electronic interfaces (for both generators and loads), with a dramatic reduction in the number of synchronous machines and the addition of new load types and energy system coupling.

Recommendations

Recommendations are outlined as checklists for each stage of the complete study. The details for each checklist can be found in the chapter in question.

The Expert Group recommends the following procedures and considerations for conducting integration studies.

Input data checklist as a summary table (for details see Section 2).In addition to time series and technical data, technology cost projections will be needed for Capacity Expansion Models and fuel cost projections for UCED.

	Resource Adequacy/ Capacity Value*	**Capacity Expansion Model**	**Unit Commitment and Economic Dispatch (UCED) including reserve requirements**	**Power Flow**	**Dynamics**
Wind/PV	Hourly time series with locational smoothing of large-scale wind/PV power, representative of power variations and time-synchronised with load data*. For robust results, 30+ years are needed.	Hourly time series capturing locational smoothing of large-scale wind/PV power, representative of (correlated) power variations and time-synchronised with load data.*	5-minute to hourly time series of at least 1 year capturing locational smoothing of large-scale wind/PV power, representative of (correlated) wind/PV variations and time-synchronised with load data.*	Wind/PV capacity at nodes, generation and load snapshots relevant for wind/PV integration, active and reactive power capabilities.	Wind/PV capacity at nodes, high and low generation and load snapshots, dynamic models, operational strategies.
Wind/PV Short-term Forecasts	Not needed for traditional resource adequacy tools.	No –reserve requrements based on short-term forecast uncertainty.	Forecast time series, or forecast error distribution for time frames of UCED, and reserve requirements.	May be needed in future.	Not needed.
Load	Hourly time series time-synchronised with wind/PV data.* At least 30 years of data for robust results.	Hourly time series based on historic data and predictions, for the full analysis period.*	5-minute to hourly time series coincident with wind/PV, for at least 1 year.* Load flexibility incorporated (flexible loads separately).	Load at nodes, snapshots relevant for wind/PV integration.	Load at nodes, high and low load snapshots. Dynamic models with capabilities and characteristics.
Load Forecasts	Not needed for traditional resource adequacy tools.	Not needed.	Forecast time series, or forecast error distribution for time frames of UCED and reserve requirements.	May be needed in future.	Not needed.
Network	Cross border capacity. Forced outage rates and mean time to repair for transmission corridors.	Transmission line capacity between neighbouring areas.	Transmission line capacity between neighbouring areas and/or circuit passive parameters.	Network configuration, circuit passive and active parameters.	Network configuration, circuit parameters, control structures.
Other Power Plants	Rated capacities, forced outage rates (ideally as a time series), mean time to repair. Hydro power limitations (dry/wet/normal year)*.	Investment cost, efficiency, fuel costs, emission factors. Ideally also operational characteristics from UCED.	Min, max on-line capacity, start-up time/cost, ramp rates, min up/down times. efficiency curve, fuel prices.	Active and reactive power capabilities, system dispatch.	Dynamic models of power plants.

* More detailed resource adequacy data guidelines can be found at www.epri.com/resource-adequacy

** Climate change impacts are recommended to be included in wind/solar/load (and hydro) data, for studies looking more than 10 years ahead. Impact of latest wind turbine and solar PV technology with higher capacity factors also important to capture.

Checklist of Key Issues: Power and Energy System Scenarios (Section 3)

- When studying small amounts of wind/PV power or short-term studies, wind/PV power can be studied by adding wind/PV generation to an existing or near future system with existing operational practices.
- For larger shares and longer-term studies, changes to the power system become increasingly necessary and beneficial – updated generation portfolio, storage assets and network infrastructure development, considering potential flexibility sources. Capacity expansion tools are recommended to construct optimized study scenarios. Additional scenarios relating to future operational practices should be studied, especially for market structures/designs, to enable flexibility.
- For wind/PV dominated power systems, modifications are so important that the system to be studied may be almost unrecognisable from the present-day system (e.g. new electrification loads, integration of inverter-based resources, reduction of synchronous machines and inertia, greater interaction with other energy sectors/carriers). Capacity expansion models should be used, while feasibility checks for operational impacts, system adequacy, and stability become much more crucial to perform. Capacity expansion tools should be improved to include:
    - Representation of demand flexibility, storage, and sector coupling, including new electrification loads and access to options other than electrical storage as these will offer crucial new flexibility sources in the future
    - Short-term balancing in order to assess the impact of wind and solar forecast uncertainty (and nowcasting tools) on the optimal energy mix
    - Grid limitations and stability constraints, including grid expansion costs, because network capacity is very important when determining optimal wind and solar capacity in different areas
    - Operational practices reflecting future system needs and services.

Checklist of Key Issues: Resource Adequacy Estimates (Section 4.1)

- Include neighbouring areas and import possibilities (with forced outage rates) during times of generation scarcity.
- Consider the impact of inter-annual resource variability as part of yearly energy reliability. Improve data, and sensitivity to capture extreme events. Current models capture correlated events, if represented in the data, which means data should span 30+ years. Forward looking data should also account for climate change impacts on resource availability and demand profiles. Temperature-correlated outages of thermal generators and common mode failures during extreme weather events should be captured.
- Include load and storage flexibility during times of high load and/or low energy resource. Chronological models are needed for assessing adequacy impacts with these resources, important for higher shares of wind and solar.
- At higher shares of wind and solar (and storage) when the energy deficit volume becomes more important, use multiple adequacy criteria and metrics to fully identify, understand, and communicate risk. These can include metrics for the loss of load hours, loss of load frequency and expected unserved energy, indicating how severe the adequacy events are on average across a certain time period.. Assess tail risks with criteria options such as metrics of the underlying distribution and severity threshold as well as through scenario-based stress tests. Assess adequacy on the seasonal and/or monthly basis as well as annually.
- Future load projections should account for the difference between electrification loads and existing loads as well as climate change impacts on demand profiles.
- For wind and solar dominated systems, consider the tradeoff between reliability targets and the cost to build additional capacity to achieve higher reliability, especially for rare events when load (price) responsiveness is insufficient

Checklist of Key Issues: Capacity Value (Section 4.1)

- Capacity value of wind and solar are heavily system-dependent and need to be updated to reflect the changing system buildout, configuration, and operations.
- Effective load carrying capability (ELCC) calculation is the preferred method, for wind and solar separately or in aggregate:
  - For low and medium shares of wind you can convolve generator capacity and forced outage to produce the capacity outage probability table (COPT) of the power system, a table of capacity levels and their associated probabilities. LOLE for each hourly demand level is calculated from the COPT table.
  - For higher shares of wind and solar it is necessary to include storage and flexible demand in the estimation, which is difficult with COPT method. A Monte Carlo simulation approach is therefore recommended, with varying load, wind/PV and hydro levels and outages.
  - For both methods, LOLE is first calculated without the presence of wind/PV generation. Then wind/PV is added as negative load and load is increased until the same LOLE is reached as without wind/PV power. Both methods require preserving the auto- and cross correlations between wind, PV, and load, and including enough data.
- For wind and solar dominated systems, it is recommended to use integrated planning approach where resource adequacy is embedded.

Checklist of Key Issues: Transmission Network Steady-State Analyses (Section 4.2)

Specific issues and recommendations regarding power flow simulations incorporating wind and solar power include:

- *Power flow cases to study*:
- For lower wind and solar shares, the chosen snapshots should include critical situations regarding wind and solar power, such as periods with high non-synchronous generation (wind, solar) and/or high-voltage direct current (HVDC) imports. This is in addition to peak load and low load situations, which are traditionally studied. The correlation between demand, wind, and solar production, specific to a particular system or region, must be considered. An evaluation of the snapshot's statistical relevance is beneficial as an input to the cost-effectiveness of implementing corrective actions – for example, as part of multi-year analysis.
- For higher wind and solar shares, probabilistic analysis is recommended (as already increasingly applied by system operators), allowing uncertainty and variability across a year to be captured, with the subsequent impacts on unit commitment and dispatch decisions affecting power flows.
- *Deterministic steady-state security analysis*: In compliance with N and N-1 security criteria, power flow analyses are performed to identify transmission network bottlenecks (congestion) and to assess the system's ability to maintain the voltage profile. By analysing the overload risk and the aggregated severity index, planners can identify whether bottlenecks should be considered severe or whether they can be solved (temporarily) via operational measures. Optimal power flow (OPF, or UCED-OPF) models can be used to analyse dynamic line rating and other grid-enhancing technologies as alternatives to grid expansion requires improved network modelling and power flow analysis.
- *Short circuit levels*: For high wind and solar shares, some synchronous generation will not be dispatched, which may lead to a reduction in the minimum short circuit level in some locations (the presence of wind and solar generation in other non-traditional locations may actually improve the fault level in those areas). This, in turn, may affect power quality, voltage step changes after shunt switching, and the operation of line commutated HVDC converters, and can lead to mal-operation of protection systems. Screening tools should be applied to assess the grid strength across the network for an extensive range of operating conditions.
- *HVDC grids:* A true DC power flow yields precise results for HVDC grids. DC power flow must be performed when DC transmission losses are considered, or when the HVDC system contains uncontrolled mesh networks. In other cases, it is often sufficient to omit HVDC transmission details, and to just represent the inflows and outflows of a given HVDC system as simple AC power sources.

Checklist of Key Issues: Distribution Grid Studies (Section 4.3)

- *Overlap and coordination with transmission grid studies:* The scope, tools, and methodologies for distribution grid studies will continue to expand and develop. A major driver is the integration of wind and PV systems at the distribution level, which entails both challenges and opportunities for distribution grid planning and operation. Stronger coordination of transmission and distribution grid studies will be required with higher wind/PV shares to access the full capabilities and flexibilities of distributed resources for the overall bulk power system. Methods that so far have only been used for analysing transmission grids will also become relevant for distribution grid analyses.
- *Distribution grid reinforcement analysis*: A comprehensive catalogue of grid planning measures should be considered as part of the grid reinforcement analysis, i.e., grid optimization, before grid reinforcement, before grid expansion. The analyses can either be performed using representative or actual grid data, if available. For comprehensive system-wide distribution grid studies, a high degree of automation for data handling is required and recommended.
- *Grid losses analysis*: A detailed study of the grid losses may deliver additional information on the effects that a further increase in decentralized generation has on the local distribution system. It is essential to consider both the location and generation profile of wind/PV sources when representing distribution grids, as they both have a significant impact on grid losses. In order to partially validate the implemented model of the grid area, the energy flow in the studied grid area can be investigated in comparison with real measurement data available at transmission level bulk supply points.
- Grid operation with high PV-shares: Analysis of grid and PV-system behaviour against the operational background including investigation of voltage management and reactive power control as well as active power reduction/setpoints in order to avoid overloads.

Checklist of Key Issues: Operational impacts (Section 5)

- Co-incident time series of wind/PV and load (for at least one year, but preferably several years), with sufficiently high temporal resolution (at least hourly, but preferably sub-hourly). The time series should capture the locational smoothing of large-scale wind/PV power, and be representative of real (correlated) wind/PV power variations. For systems with significant weather dependency from other sources, the respective time series should be time-synchronised to accurately capture, for example, the availability of hydro power, transmission (dynamic/seasonal) limits, and contributions from combined heat and power. For systems with significant hydropower, different hydrological scenarios should be considered, e.g. wet/dry years.
- Capture all relevant system characteristics and generator/load responses through operational simulations and UCED modelling.
- At higher wind and solar shares, it is important to model the impact of short- and long-term uncertainty on UCED dispatch decisions by, for example, introducing stochastic optimisation and rolling planning. Wind/PV forecasting best practices should be applied

in relation to the uncertainty associated with wind/PV power production, including the possibility of updating forecasts closer to the delivery hour.

- Model the capabilities and limitations of flexibility sources for generation (up/down ramping limits, minimum up/down times, minimum stable levels, startup and shutdown); for interconnections to neighbouring areas (preferably by explicitly modelling, in sufficient detail, the neighbouring systems); and for operational practices (which may enable or limit the accessible flexibility over different time frames).
- For higher wind/PV shares, new potential sources of flexibility should be included (heating, cooling, electric vehicles, storage, demand response), as these become increasingly beneficial to the system as the share of wind/solar increases.
- Model transmission system limitations as constraints within UCED.
- For higher wind and solar shares, congestion and N-1 security can be included directly within UCED – or analyse the transmission system using other dedicated tools with the resulting limitations included as constraints within the UCED model. In systems with very high levels of renewable generation, it may be also necessary to model additional stability constraints.
- New operating reserve targets should be estimated based upon wind, solar, and load forecast uncertainty. When calculating reserve requirements, care should be taken not to double-count uncertainty impacts, particularly if stochastic optimisation is being used.
- At higher wind/solar shares, the inclusion of dynamic reserves, faster markets, and increased market resolution is recommended.
- Assess the existing flexibility of the power system, and apply indicators (metrics) to determine whether additional flexibility options are sufficiently economically justified. Perform a cost–benefit analysis and determine the required response characteristics of existing (and new) flexibility sources to efficiently integrate the targeted level of wind/PV energy being studied.

For wind and solar dominated systems, consider appropriate modelling complexity for a given wind/PV share. Developing suitable tools or integrated data sources to cover all such aspects represents ongoing work. It is recommended to consider at least the following issues:

- *Represent grid and stability constraints in sufficient detail*: Locating grid bottlenecks through improved network modelling and power flow analyses and including power flow control or other grid enhancing technologies that aim to reduce bottlenecks and increase transfer capacity. Stability constraints, e.g. inertial floors, may be represented by system non-synchronous share limits or more directly by inertial or rotational stored energy (MWs) limits (grid-following and/or grid-forming technologies can be effective here, depending on individual system requirements); frequency control can be addressed by ensuring sufficient frequency reserves and voltage stability by confirming the availability of sufficient equipment in relevant locations.
- *Use probabilistic models and risk assessment tools*: Apply deterministic and probabilistic assessment approaches for risk-based operation using new optimisation methods and advances in (parallel, high-performance) computation as well as appropriate modelling approximations.
- *Enforce high quality information for available resources and forecast uncertainty*: Sufficiently high temporal and spatial resolution should be applied to ensure that wind and solar output is accurately represented and has a sufficiently long duration dataset to cover expected and extreme weather patterns. This should be paired with a high quality

representation of forecast uncertainty, which integrates weather-dependent aspects of the system across multiple decision cycles.

- *Represent other relevant energy sectors*: Heating, cooling, transport, and power-to-X will likely have a large influence on the economics and operation of wind and solar dominated systems, and have the potential to be major sources of flexibility provision. They should be modelled with sufficient detail and resolution, both for flexibility and process constraints. In thermal power generation dominated systems, fuels provide significant flexibility. As the share of variable power generation increases and thermal generation is replaced, the need for new sources of flexibility for longer timescales increases.
- *Represent energy storage and price-responsive loads within system services*: Demand response/storage can act as cost-effective sources of system services, but potentially complex constraints relating to service availability must be carefully modelled. This may require more detailed models of the distribution system, or the aggregation of distributed resources for bulk systems, while balancing the computational burden imposed.
- *Expand market options/products for flexibility trading*: Incorporate market options for netting of system/area/nodal/individual imbalances at different timescales.

Checklist of Key Issues: Network Simulations for Dynamics (Section 6)

The recommendations apply for higher shares of inverter-based resources (IBRs), but may also apply to power systems that contain remote areas with high IBR concentrations.

- *Selecting snapshot cases for analysis*: A wide range of stability case scenarios including worst case scenarios and foreseen operational conditions should be included. The snapshots selected need not be the same as those chosen for steady-state power flow analysis. It is also important to set up the case carefully based on comprehensive production cost simulation results. An initial screening of cases can be conveniently performed using RMS modelling, but detailed EMT analysis is required for high IBR shares.
    - Selecting snapshot cases for analysis: A wide range of stability case scenarios including worst case scenarios and foreseen operational conditions should be included. The snapshots selected need not be the same as those chosen for steady-state power flow analysis. It is also important to set up the case carefully based on comprehensive production cost simulation results. An initial screening of cases can be conveniently performed using RMS modelling, but detailed EMT analysis is required for high IBR shares.
- *Wind, PV and battery energy storage system (BESS) models:* Ensure that the models used are adapted to the characteristics of inverted-based generators and are suitable for studying each particular stability phenomenon.
    - Studies should recognize that wind plant/PV/BESS controls, as part of a coordinated control strategy(s), may offer system advantages, and hence this option should be investigated in detailed EMT studies.
    - Generic models can be used for long-term planning studies where detailed information about generation is not available or to represent generators remote to the area of study.

  - It is important to test the model to ensure that it is correctly parametrized (verification) to represent actual “as built” plant and to determine the accuracy of the model with respect to measurements (validation) for all components (conventional generators, PV and wind plants, and load).
- *(Dynamic) load modelling*: With increasing shares of wind and solar generation on the distribution network, and power systems becoming 'lighter' and weaker due to the displacement of conventional generation (reduced inertia and system strength), load characteristics will more strongly influence system performance. Existing load models should be re-evaluated, including frequency and voltage sensitivities, the time varying nature of the load composition, and hence the load models themselves should be considered. Power electronic loads and their ride-through characteristics are an emerging area of research.
- *System stability:* Different systems may experience very different dynamic issues depending on the underlying correlation between wind/PV/BESS production and system demand, the underlying flexibility and capabilities of the conventional generation portfolio, relative location of generation assets and major load centres, etc., implying that specific system studies may be required.
- *Frequency stability studies:*
  - Inertial constant, droop, and governor settings of all synchronous units are needed. In addition, the frequency control block models and settings of all IBRs (if deployed for frequency control) are required.
  - It is also important to model any protective functions in IBRs or synchronous generators that may respond to frequency or rate of change of frequency exceeding certain thresholds.
  - A reduced network representation may be sufficient.
- *Voltage stability studies:*
  - At low wind/solar/BESS shares it is probably unnecessary to perform voltage stability studies, as system stability is likely to be unaffected or even enhanced by the presence of wind turbines/PV panels. This argument is particularly true if the reactive power control capabilities of the wind turbines/PV are deployed to manage local voltages, and if they are connected at transmission level.
  - As conventional generation is displaced at higher wind and solar shares, voltage security levels may be affected in certain locations with high concentrations of wind/solar/BESS or system-wide, requiring more detailed analysis.
- *Rotor angle stability studies:*
  - Transient stability studies:
    - It can be important to include the effect of protection devices for both network and converter-interfaced generating equipment; however, boiler/steam turbine models are not required. Protection relay settings should recognize changes in the dynamic response of the system and respect any dynamic operating criteria (e.g. frequency variation range) adopted by the local transmission system operator. The ability of generation to ride through multiple voltage dips within a certain period may also need to be addressed.
    - Wind, BESS, and solar generation can provide system support during voltage dips and help to dampen oscillations, although the level of support provided is network sensitive, and the capability may also vary depending on specific grid code requirements and the priority given to active or reactive power recovery. Proper representation of the impedance connecting the plants to the grid is crucial within simulation studies.

    - To mitigate any issues discovered, fast acting reactive power response devices during and following disturbances can be applied, e.g. installing FACTS devices, synchronous compensators, and/or requiring all future wind/PV/BESS plants and conventional generators to incorporate that specific capability.
  - Small-disturbance stability studies:
    - Wind and solar generation do not generally introduce small-signal oscillatory modes, but as their presence may displace conventional generation (and associated power system stabilizers) and alter the magnitude and direction of transmission line power flows, it follows that small-disturbance stability may be impacted.
- *Resonance stability studies:*
  - Sub-synchronous torsional interaction and sub-synchronous control interaction should be investigated as part of small-signal stability analysis, particularly in relation to doubly fed (type 3) wind turbines radially connected with series line compensation. Sub-synchronous control interaction studies may also be performed for all IBRs that may become radially connected with series compensation after a number of contingencies. A range of mitigation measures including bypass filters, FACTS devices, and auxiliary (damping) controls are available.
- *Converter-driven stability studies:* Adequate models capable of capturing the harmonic power dynamics, especially in multi-converter setups, are crucial.
- *Common-mode fault events*: Network faults and/or loss of a major infeed can result in widespread voltage depressions and/or large frequency deviations and the common-mode tripping of local wind and solar generation. Consequently, the operation of associated protection systems may play a crucial role in determining system outcomes, requiring sophisticated modelling methods. Delayed active power recovery from grid code compliant generation following a widely seen network fault may similarly lead to a common-mode power reduction and frequency stability issues such as voltage dip induced frequency dips.

Checklist of Key Issues: Analysing and Presenting Results (Section 7)

- If the results show unexpectedly high and costly impacts of wind/PV power to the system, consider the iteration loops. Changing operational practices may prove cost-effective, or generation or transmission scenarios may be inadequate.
- When extracting results for the impacts, select the cases to compare with care and report the methodology and possible caveats in the findings. Comparing full scenarios are recommended, instead of extracting cost differences as integration costs.
- Present the results stating share of wind/PV (as % of annual electricity demand, not just a capacity share); size and type of power system, emphasising whether any network regions have high localised wind/PV shares.
- List main assumptions and limitations arising from these (example checklists provided).

The Future

Analytical methods are still evolving for the study of wind and solar dominated systems. There is a strong move towards integrated planning across the different domains covered. The interactions between them will be as important as the studies themselves – how capacity expansion, resource adequacy, operational and stability simulations impact each other.

As energy supply continues to transition towards renewables and wind and solar generation become mainstream, integration studies will become general power system design studies at very high wind and solar shares. We foresee that this Recommended Practices for Integration studies will be the last update, and, in future, integration studies will become standard power and energy system design studies.

List of Acronyms and Abbreviations

AC: alternating current
ASI: all-sky imagers
CBA: cost benefit analysis
CEM: capacity expansion model
CIGRE: Conseil International des Grands Réseaux Électriques
COPT: capacity outage probability table
DC: direct current
DLR: dynamic line rating
DR: demand response
DSO: distribution system operator
ELCC: effective load carrying capability
EMT: electromagnetic transient
ENTSO-E: European Network of Transmission System Operators for Electricity
ESIG: Energy System Integration Group (formerly UWIG/UVIG)
EUE: expected unserved energy
EV: electric vehicle
FACTS: flexible alternating current transmission systems
FOR: forced outage rates
FRT: fault ride through
GFM: grid-forming
GIS: geographic information system
GW: gigawatt
HV: high voltage
HVDC: high-voltage direct current
IBG: inverter-based generation
IBR: inverter-based resource(s)
IEA PVPS: The International Energy Agency Technology Collaboration Programme for Co-operation in Photovoltaic Power Systems
IEA Wind: The International Energy Agency Technology Collaboration Programme for Co-operation in the Research, Development and Deployment of Wind Energy Systems
IEA: International Energy Agency
IEEE: Institute of Electrical and Electronics Engineers
LCC: line commutated converter
LOLE: loss of load expectation
LOLH: loss of load hours
LOLP: loss of load probability

LP: linear programming
LV: low voltage
ML: machine learning
MW: megawatt
MWh: megawatt-hour
MV: medium voltage
N-1 security: security is maintained when any one of the total number of possible faults occurs
NERC: North American Electric Reliability Corporation
NWP: numerical weather prediction
OPF: optimal power flow
PCC: point of common coupling
PDF: probability density function
PLL: phase-lock-loop
P2X: power to X, using electricity to produce hydrogen and its derivatives, or chemicals etc directly for industry
PSS: power system stabilizer
PV: solar photovoltaic power
QSTS: quasi-static time-series
R&D: research and development
SSCI: sub-synchoronous control interaction
SSTI: sub-synchoronous torsional interaction
TSO: transmission system operator
TTC: total transfer capacity
UC: unit commitment
UCED: unit commitment and economic dispatch
USA: United States of America
VSC: voltage source converter
WECC: Western Electricity Coordinating Council

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1 Introduction: What to Study

Hannele Holttinen, Magnus Korpås, Emmanuel Neau, Damian Flynn, Lennart Söder, Niina Helistö, Juha Kiviluoma

Wind and solar energy will introduce more variability and uncertainty into operating a power system, due to the natural wind and solar irradiation resources and the inability to perfectly predict them. They have a non-synchronous connection to the network through power electronic inverters, instead of conventional power plants that are based on synchronous machines. The feasibility of integrating wind and solar photovoltaic (PV) power is demonstrated through case studies that analyse the impacts on power systems: integration studies. Recommendations for how to best conduct wind/PV integration studies will depend on the (annual average and instantaneous) share of wind/PV to be studied.

This report outlines recommendations to study impacts of small, medium, and high shares of wind/PV. As a convenient metric for defining “the share,” the share of wind/PV electricity from annual electrical energy (i.e., gross demand) is used. The instantaneous share of wind and solar is also important for power system dynamics, which becomes important to study when the instantaneous wind and solar share exceed 50% of the demand. For the annual average share, it is more difficult to determine what is a high or low share of wind and solar, as this depends on the particular power system characteristics (see also Section 1.3 and Müller & Vithayasrichareon, 2017): a 5–10% share of wind and solar from demand can be considered “small” in most systems, but it could be considered a “medium” share challenge for some systems. A 10–20% share may be considered “high” in some systems, while still being “moderate” for more flexible systems. Wind/solar dominated systems will have more than 50–70% share of electricity demand from wind and solar energy. It is also important to consider interconnections with neighbouring systems: a “high share” locally may be “low/medium share” when interconnections are considered. Wind and solar resources have beneficial complementarity; however, it is also important to recognise whether the share is dominated by solar PV or wind generation.

This recommendations report begins by outlining wind/PV integration issues, or the impacts that wind/PV may have on power and energy systems, as well as the phases of integration as the share of wind and solar increases. The complete integration study is illustrated as a flow chart: starting from building a scenario, proceeding through relevant issues to analyse for feasibility (balancing, adequacy, and dynamics), and finally presenting the results. Sections 2 through 7 describe activities related to the main boxes of the flow chart in Figure 1.3: Input data; Scenario development; Adequacy of generation capacity and the network; Operational impacts; Dynamic simulations; and finally Analysing and interpreting results. Each section addresses issues that are relevant to wind/PV integration, with a checklist of recommendations also provided. The report concludes with a summary of recommendations and suggestions for future work.

The report is concerned with data and methodology – for results of integration studies, the reader can refer to summary reports (Holttinen et al., 2021; PVPS, 2014 and 2017). The current report represents the third edition of the recommended practices for integration studies published by the International Energy Agency (IEA) Wind Technology Collaboration Programme (TCP) (Holttinen (Ed.), 2013 and Holttinen (Ed.), 2018 including solar PV). In the recommendations, current knowledge on planning and operating power systems with very high shares of wind and solar generation for future power systems with energy sector coupling are included.

1.1 What to Study: Overview of Wind/PV Integration Issues

In order to meet challenges of increased variability and uncertainty, there will be a need for substantial flexibility in the power system. Flexibility can be described as the ability of the power system to respond to change across different timescales. To meet the challenge of non-synchronous connection to grid, the dynamics of power systems also need to be ensured, where grid enhancing technologies, updated operational practices, and advanced capabilities from wind/solar power plants can help.

Implementing wind/PV power has impacts on power system planning, management, economics, and efficiency. Before integrating new power plants in a power system, it is necessary to assess the implications to adequacy of long timescales (years) and the implications to system balancing and dynamic stability in shorter timescales (seconds and sub-seconds). The studies can address different impacts with different timescale resolutions as well as both system-wide and local effects considered (see Figure 1.1). Grid integration challenges at the distribution level have a stronger focus on local or regional effects of wind/PV deployment.

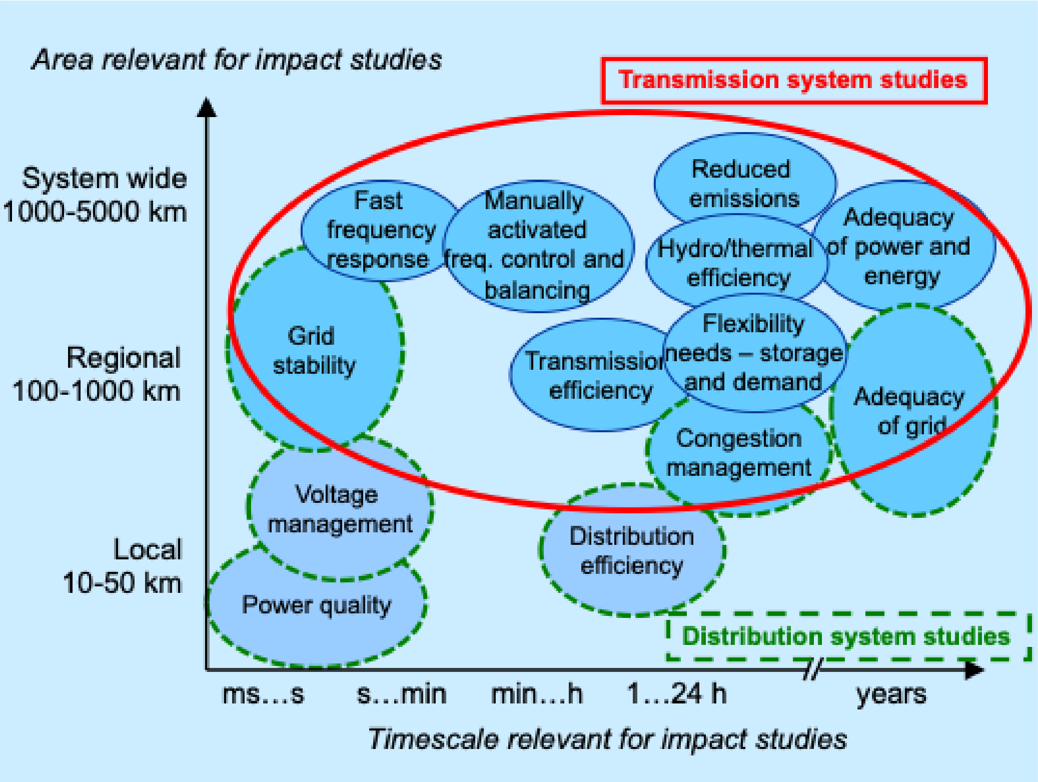

Figure 1.1. Impacts of wind/PV power on power systems, divided across different timescales and geographical areas relevant for the studies. The red line encircles those more regional scale, transmission, and power system level issues. The green dotted lines are relevant for more local distribution system issues. Transmission and distribution efficiency refers to grid losses, while hydro/thermal efficiency refers to generation losses.

Power systems worldwide are quite diverse in regard to the operational characteristics of the installed generation plants, the inherent variability and flexibility of the system load, the rules and strategies implemented in relation to treatment of imbalances and transmission capacity, and the network topology (highly-meshed versus radial grids, including interconnection to neighbouring systems). Physical flexibility (i.e., existing generation, storage, and demand capabilities), and administrative flexibility (i.e., market structure) both affect the ability to balance increased variability and uncertainty from wind/PV power. Market design also affects the efficiency and adequacy of power and transmission.

When reaching higher shares of wind and solar generation, the boundaries of the power system in focus become relevant, i.e., the impacts that are relevant depend on what is the system where high share of wind and solar is reached (Holttinen et al., 2020):

- For an area dominated by wind and solar generation but forming part of a larger synchronous power system where wind and solar shares are lower, the challenges mainly relate to balancing, local stability aspects, and efficient sharing of energy and reserves with neighbouring areas. This highlights the importance of how neighbouring regions are presented in studies.
- When a synchronous system is dominated by wind and solar generation for short periods of time (seconds to hours), system-wide stability issues begin to emerge.
- For reaching close to 100% annual energy from wind and solar generation, an additional challenge is system adequacy to meet the demand during periods with low wind and solar contributions.

The three main issues (balancing, adequacy, and dynamics) described below could be studied independently (see also Section 1.3 about phases for integration studies and Figure 1.2 showing an example of tool couplings). The main purpose of integration studies is long-term planning; however, shorter time horizons of operation also need to be studied as part of this process. For example, balancing addresses short-term operational impacts, but they can be incorporated in long-term planning in a tool such as production cost models.

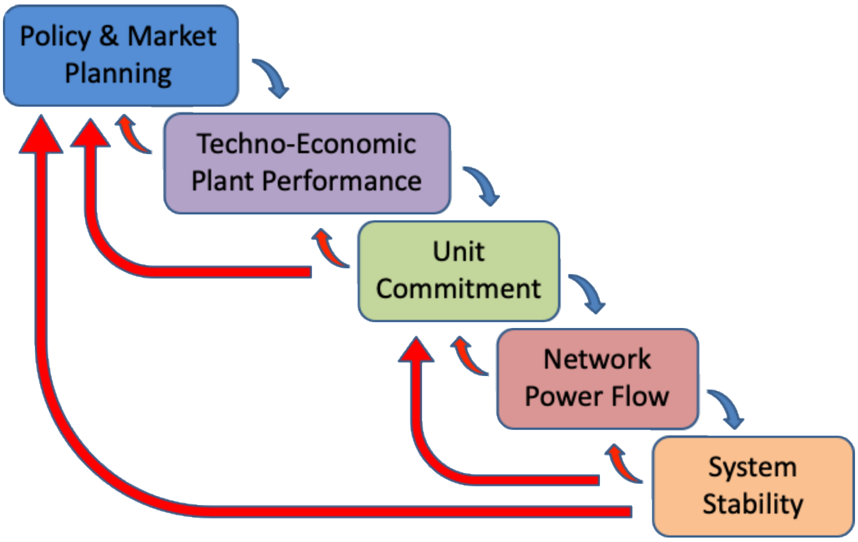

Figure 1.2. Model tool coupling: high level policy planning is followed, in turn, by techno-economic performance analysis, power flow studies, and system stability analysis (blue arrows). If any of the lower level outcomes are not considered satisfactory, the analysis process should iterate back to higher level(s), until acceptable outcomes are achieved at all levels (red arrows). (Source: University College Dublin).

1.1.1 Operational impacts: balancing and flexibility

Short-term operating reserves (timescale: seconds to 1 hour): This issue is about how uncertainties due to variability and forecast errors introduced by wind/PV power affect the allocation and use of operating reserves in the system. Power systems balance the net imbalances occurring in the system, which means that the aggregated uncertainties of wind/PV power distributed across a large, system-wide area will be combined with other uncertainties experienced by the power system, e.g. those associated with load. An increase in balancing requirements will depend on the region size relevant for balancing, initial load variations, and wind/PV variability (the smoothing effect depends on how concentrated or well distributed wind/PV power is sited).

Flexibility, efficiency, and unit commitment (UC) (timescale: hours to days): Here the issue is how variations and prediction errors associated with wind/PV power change how conventional capacity and energy storage units are operated, including both the total duration of operation (full load hours) and the manner in which the units are operated (ramp rates, partial operation, starts/stops). Incorporating wind/PV into existing planning tools is important to correctly take into account wind/PV uncertainties. Existing flexibility constraints, as well as opportunities to increase flexibilities in the system, are key. When assessing impacts for future power systems, demand flexibility and flexibilities through other energy sectors need to be carefully incorporated as well.

1.1.2 Adequacy of Power Generation and the Network

For assessing the adequacy of power generation and the electrical network, also known as resource adequacy, the timescales involved are several (10+) years ahead.

Adequacy of power generation and storage assets: Assessing total supply available during all demand situations is an estimation of the required generation and storage capacity that includes the system load demand and outage rates of production units. Generation capacity adequacy is associated with static/steady state conditions for the system, with evaluation criteria such as the loss of load probability (LOLP). Traditionally focus has been placed on peak load events, but future systems involving energy system coupling introduces considerable demand flexibility opportunities that need to be incorporated.

Capacity value of wind/solar: Assessing wind/PV power’s aggregate capacity value must take into account the effect of geographical dispersion. Many years of data are required to capture possible critical situations with wind/PV generation during peak demand hours.

Adequacy of transmission and distribution networks: Assessing adequacy can be done by analysing the frequency and level of congestion for the future power system as well as evaluating steady-state and dynamic reliability. Wind and PV generation affect the power flow in the network (timescale: hours). The specific impacts depend on the location of the wind and solar power plants relative to the load, and the correlation between wind/PV generation and load consumption. They may change the power flow direction, reduce/increase power losses and affect bottleneck situations. There are a variety of means to maximize the use of existing network infrastructure. However, grid reinforcement is often necessary to maintain network adequacy when adding significant levels of wind and PV capacity. Economic planning of transmission networks with wind and solar needs to incorporate cost benefit analyses. Transmission capacity between areas is also an enabler to integration.

1.1.3 Dynamics: Stability of the Grid

Assessing the impacts on power system dynamics (timescale: seconds) will be important when evaluating higher instant shares of wind/solar PV generation. The possibilities for supporting the system under normal and fault situations include voltage and (active/reactive) power control and fault ride through (FRT) capability, such that the control capabilities of wind/PV power plants should be carefully recognized within any study. The siting of wind/PV power plants relative to load centres will also have some influence on this issue. When significant capacities of wind/PV generation are interconnected to the distribution system, voltage stability assessment should include the expected diversity of voltage profiles, as this may impact the power system's response to faults and other abnormal conditions. For dynamics it is also essential to consider if the connection to neighbouring systems is high-voltage alternating current (HVAC) or high-voltage direct current (HVDC) as well as the possibility for fast control of HVDC interconnections.

1.2 Elements of a Wind/PV Integration Study

A complete integration study is presented as a flow chart in Figure 1.3.

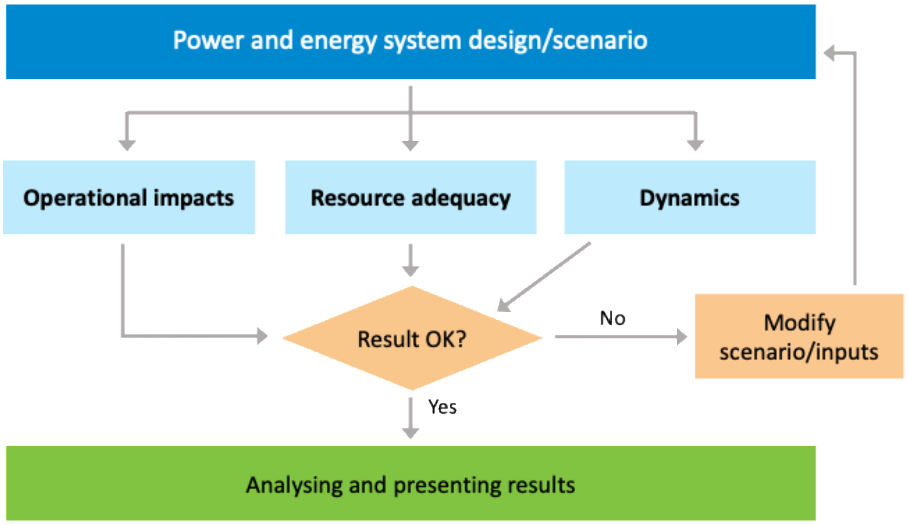

Figure 1.3. Wind/PV integration study components; flow chart showing the three main simulations for a future scenario: operational impacts, adequacy, and dynamics. The study setup includes developing future power and energy system scenarios and the required inputs. Each step and iteration are verified to be "ok" for feasibility across the categories of Operational impacts, Adequacy and Dynamic behaviour. If the results show infeasibility, or high costs, then changing scenario assumptions is recommended.

A wind/PV integration study usually begins with choosing what to study (which of the main impacts, as simulation boxes in Figure 1.3, will be performed and which will be omitted) and which geographical system to study (e.g. an electrical footprint including a subregion of the system, or the entire synchronous system). Analysis of an entire synchronous system can characterize the full set of interactions that govern power systems. However, because studying the entire system can greatly increase the complexity of the study, and may not be relevant for the phenomena of interest, part of the system is often studied, with careful modelling of interactions between the boundaries of the study area and the remaining synchronous system.

Building up the power and energy system scenario will be the first major step, either starting from the existing power system or choosing the power technology mix, the network, and the demand

and flexibility options for a future scenario. Higher shares of wind/solar generation will replace existing generation capacity, and often optimized portfolios, including additional storage, will need to be developed as well as introducing new transmission assets. Changes in power system operational and management practices may need to be made from the start to accommodate large shares of wind/PV power generation. This involves checking the available flexibility options in the power system. Allocation, procurement, and the use of reserves may also need to be changed to a more holistic and cost-effective approach. Input data that characterize wind/PV power as well as the underlying power system are required to enable relevant simulation studies. The basic scenario assumptions will have a crucial impact on the study results.

Scenarios including wind/PV generation are then analysed for their feasibility. Simulations of the operation of power plants in the system give information on flexibility, ramping needs, curtailment, and the production costs (operational costs for the power system, and also market prices as the value of generation for each time step). Investigations of transmission and/or distribution grid include steady state analyses for power flow, voltage profiles, and short-circuit power. For higher wind and solar shares, system adequacy is important to check, both for the transmission network and for the generation and storage capacity needed to ensure resource adequacy for all load situations. More detailed power system stability simulations and flexibility assessment are necessary when studying higher shares of wind/PV power capacity.

Reliability constraints associated with any of these simulations (operational, adequacy, and dynamics) will likely require a number of iterations to suitably adjust the inputs and scenario setup for the study. The installed capacity of the remaining power plants (i.e., generation portfolio) or the transmission/distribution grid can be changed. Remedial actions to the network, or operational system management methods, can be applied, including those required for additional storage capacity and the activation of demand flexibility.

Analysing and interpreting results is the final phase in a study. Often, the studies try to quantify wind/PV impacts by comparing simulation results from no (or little) wind/PV generation with future higher levels of wind/PV power. Differences in costs and reliability metrics can be assessed, and flexibility needs and sources can be studied. Curtailed wind and solar can provide an indication of a lack of flexibility. It can also be an indication that flexibility measures are provided by wind and solar generation. The benefits of wind/PV power to the system can also be quantified, for example as reduced emissions and reduced fuel costs. It is also important to state as transparently as possible the assumptions made in the study when presenting the results.

1.3 Phases of Wind/PV Integration

Often, studies are conducted in phases. Some impacts can only be seen with medium-to-high wind/PV power shares, implying that some components of the flow chart can be omitted. More details need to be included as the share of wind/solar share in the system increases. Studies can first include more local issues before evolving to study more system-wide issues. Examples of evolving integration studies with increasing detail can be seen for the synchronous power system of Ireland in the All-Island Grid Study (AIGS, 2008), Facilitation of Renewables Studies (EirGrid and SONI, 2010) and the Delivering a Secure Sustainable Electricity System – DS3 programme (EirGrid, 2015). Another example is the synchronous system of the United States Western Interconnect: Western Wind and Solar Integration Study phases 1 (WWSIS, 2010), 2 (Lew et al., 2013), and 3 (Miller et al., 2014) (https://www.nrel.gov/grid/wwsis.html).

An example of wind and solar integration challenges, as phases of increasing wind and solar shares is given in the IEA Status of Power System Transformation (2019). Six phases are described: phases 1 and 2 do not yet require an integration study; phase 3 would represent a first, simple integration study; phase 4 includes increasing detail being captured; and finally phases 5 and 6 require fully detailed new future scenarios with energy sector coupling (Figure 1.4).

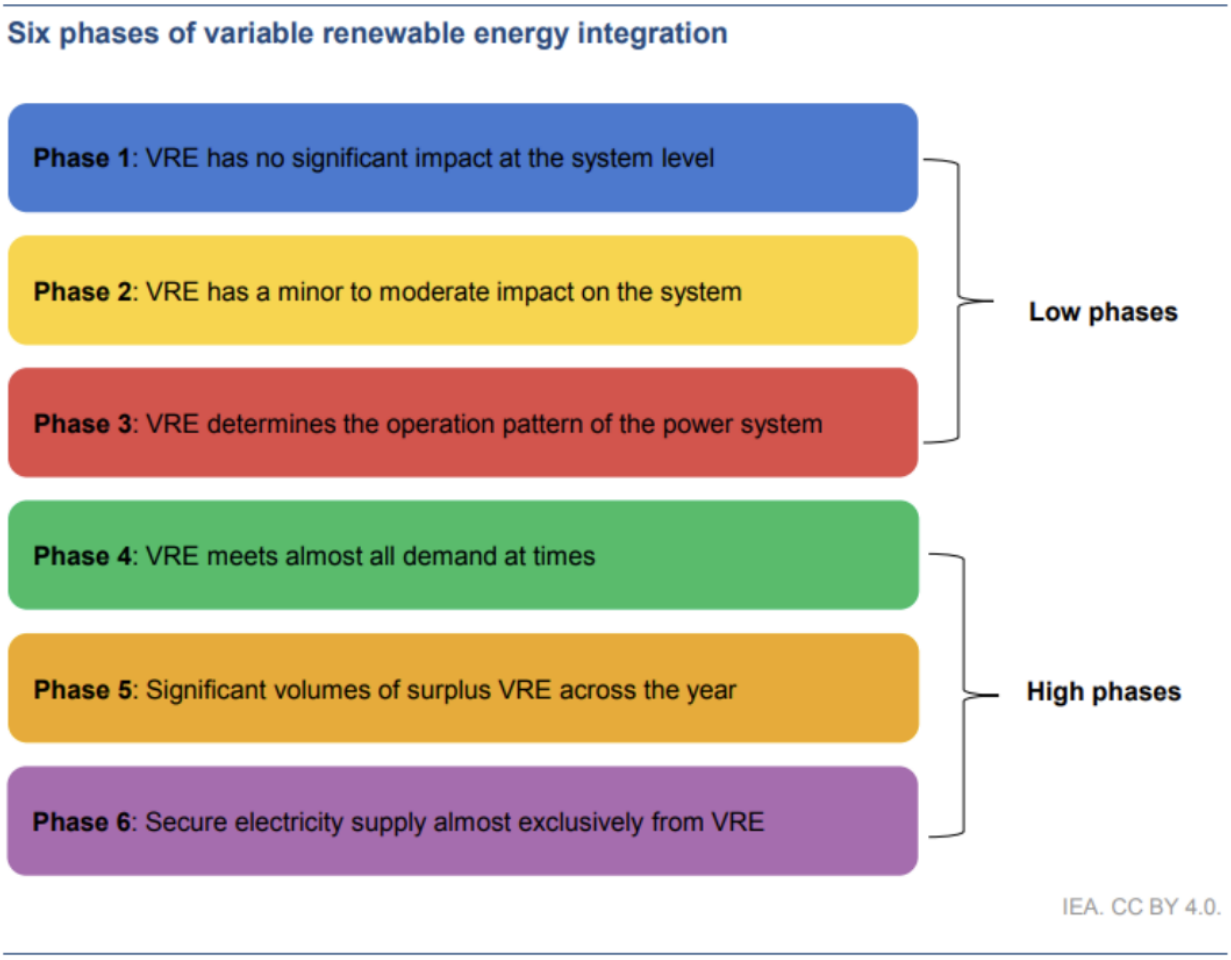

Figure 1.4 Phases of a variable renewable energy integration study. (Source: IEA, 2024)

Grid integration challenges at the distribution level focus primarily on local or regional effects of wind/PV deployment, such as local voltage rise or overloading of grid assets. Solar PV and wind challenges on distribution grids are similar, but not exactly the same, e.g. related to voltage control, storage needs, reactive power supply, and flicker (for wind see Tande (2000)). Grid integration challenges for distribution systems with increasing shares of distributed generation is highlighted for distributed PV in Stetz et al. (2014) (Figure 1.5):

- *Phase 1:* Low to medium PV/wind share in a few distribution grids – local consumption still exceeds local generation (uni-directional distribution grids). Distributed PV/wind may cause local over-voltage or over-loading issues, but have no or low impact on transmission system operation. In Phase 1, distributed generation usually plays a passive role; for example, generators provide maximum active power feed-in.
- *Phase 2:* High PV/wind share in a few distribution grids – local generation can exceed local consumption (bi-directional distribution grids). A major challenge for the distribution system operator (DSO) is to increase the hosting capacity of the distribution grids for

distributed energy resources. From a transmission perspective, the necessity of re-dispatches or congestion management can increase, especially in regions with high PV/wind deployment. In Phase 2, distributed generation is usually required to provide additional ancillary services to support the grid (for example, reactive power control for voltage management, or active power curtailment for congestion management).

- *Phase 3:* High PV/wind share in many distribution grids and a system-wide high PV/wind share – major PV/wind integration challenges are determined especially at transmission level, such as balancing, adequacy, and stability issues. In Phase 3, wind and solar generation are an integral part of the power system, and they are also required to provide additional ancillary services for transmission system operation (e.g. frequency control for balancing challenge).

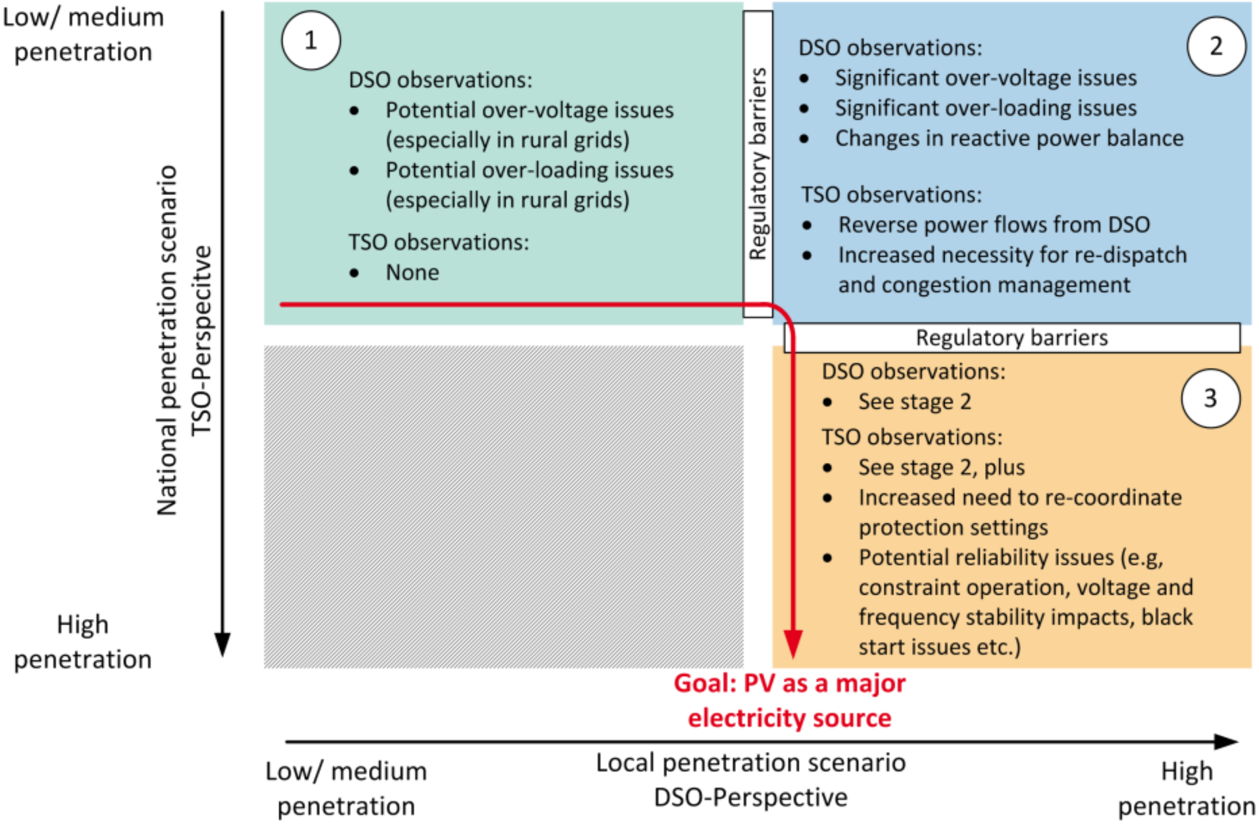

Figure 1.5. PV share and challenges for the transmission and distribution system operators (TSO and DSO). (Source: Stetz et al., 2014).

For this report, we focus on three main phases, low/medium/high shares of wind and solar generation:

- *Phase 1/low share of wind/solar:* At lower shares, the main interests are the impact of wind/PV power on other power plants, and the need to upgrade the transmission network (production cost simulation and network adequacy). Impacts to reserve requirements may also be addressed.
- *Phase 2/medium share of wind and solar:* The challenges include balancing and efficient sharing of electricity and reserves with neighbouring areas. This highlights the importance of how neighbouring regions are presented in studies. Both generation capacity adequacy (including capacity value of wind/PV) and network adequacy are often studied, and a more

detailed flexibility assessment is useful. Local stability aspects, or specific issues for the power system can also be studied (e.g. low inertia linking to frequency stability; voltage stability in some locations).

- *Phase 3/wind and solar dominated power systems:* As a synchronous system gets closer to 100% wind and solar for short periods of time, system-wide stability issues begin to emerge. Also network protection, harmonics, and other technical areas need to be assessed. Where problems are identified, a wide range of mitigation measures can be considered, particularly in operational time frames (e.g. demand side response, dynamic line rating, modified grid codes, new ancillary services, control room software tools) and planning time frames (e.g. alternating current (AC) and direct current (DC) network upgrades, flexible alternating current transmission systems (FACTS) and network control devices, flexible generation, energy storage). When approaching 100% yearly energy from wind and solar generation, together with neighbouring areas, a challenge on top of these is the adequacy issue, to meet high demand at low wind and solar contribution. For power systems reaching 100% wind and solar shares, without synchronous generation, such as hydro or nuclear units, staying online, new paradigms of non-synchronous operation may be searched for.

1.4 Enablers for Wind/PV Integration

Increased variability and uncertainty due to wind/PV power can increase the need for flexibility in power systems. Flexibility means the ability to adjust generation output level, or demand, up or down to regulate the system in response to changes. At present, this flexibility is mostly managed using conventional power plants. Figure 1.6 shows a general view of flexibility options and their relative cost-effectiveness.

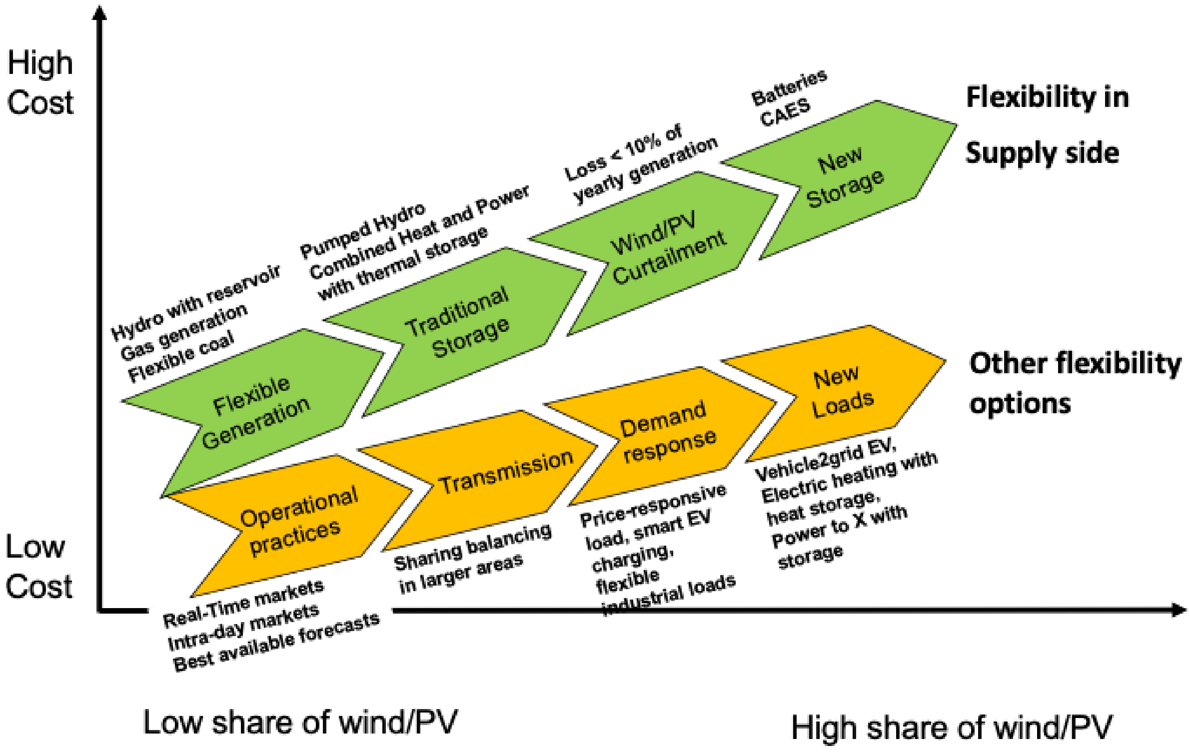

Figure 1.6. Cost of increased flexibility in power systems, general trend.

Operational measures can both decrease the need for flexibility and increase the range of flexibility options. Enabling transmission possibilities and aiming for large market/balancing areas sharing balancing requirements will reduce the (relative) amount of flexibility needed due to aggregation benefits, and pooling all flexibility resources can enable easier management of supply-demand balancing. Faster markets allow for a reduction of uncertainties and the need for flexibility. Introducing new market mechanisms can enable full use of existing flexibility in generation and demand with better cost-effectiveness than building new assets just for flexibility.

New flexibility can be added as flexible power plants, transmission lines, and storage capacity. When flexible conventional power plants reduce their output, they save their fuel for later use. Wind/PV power plants can also be used to provide flexibility; however, reducing the available output level of power plants to provide regulation involves a loss of energy. This means that it should only be used when other, more cost-effective, options are not available. Smart (actively controlled) grids can enable the use of load flexibility (demand side management) and take advantage of distributed generation flexibility.

Although the focus for wind and solar integration is on the power system, links to other energy carriers become increasingly important when assessing operational conditions and performing adequacy assessments. Figure 1.7 depicts energy system integration, showing power system links to other energy carriers and energy sectors, and storage elements enabling wind and solar integration. Energy system integration will enable access to more cost-effective flexibility resources, for example from heat and transport sectors as well as synthetic fuel production. For wind and solar integration, the focus is on the power system. However, links to other energy vectors become increasingly important when assessing operational conditions and performing adequacy assessments.

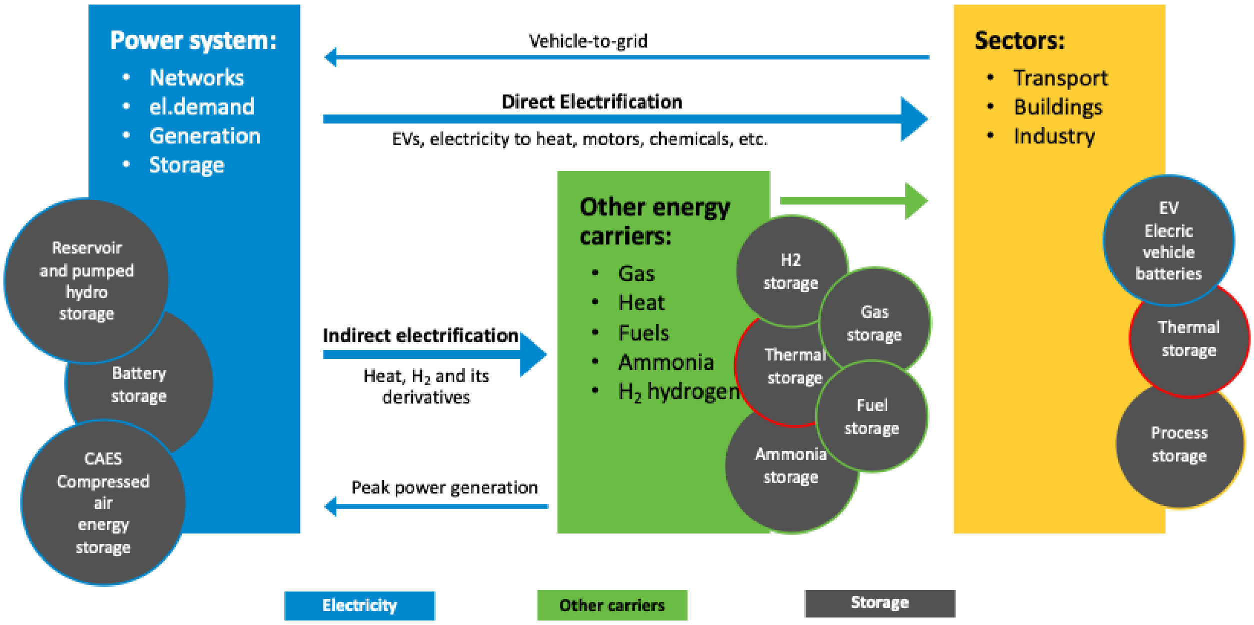

Figure 1.7. Link from the power system to other energy carriers and energy sectors, arrows showing energy flow, and storage as access to flexibility.

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2 Input Data

Hannele Holttinen, Jan Dobschinski, Emmanuel Neau, Matti Koivisto, Debbie Lew, Antonio Couto, Ana Estanqueiro, Magnus Korpås, Aidan Tuohy, Gerd Heilscher (Review: Eldrich Rebello, Justin Sharp)

This chapter describes all the data required in a wind/PV integration study, including generation, demand, storage, and grid. These are illustrated in the outer blue input boxes in the wind/PV integration study flow chart (Figure 2.1).

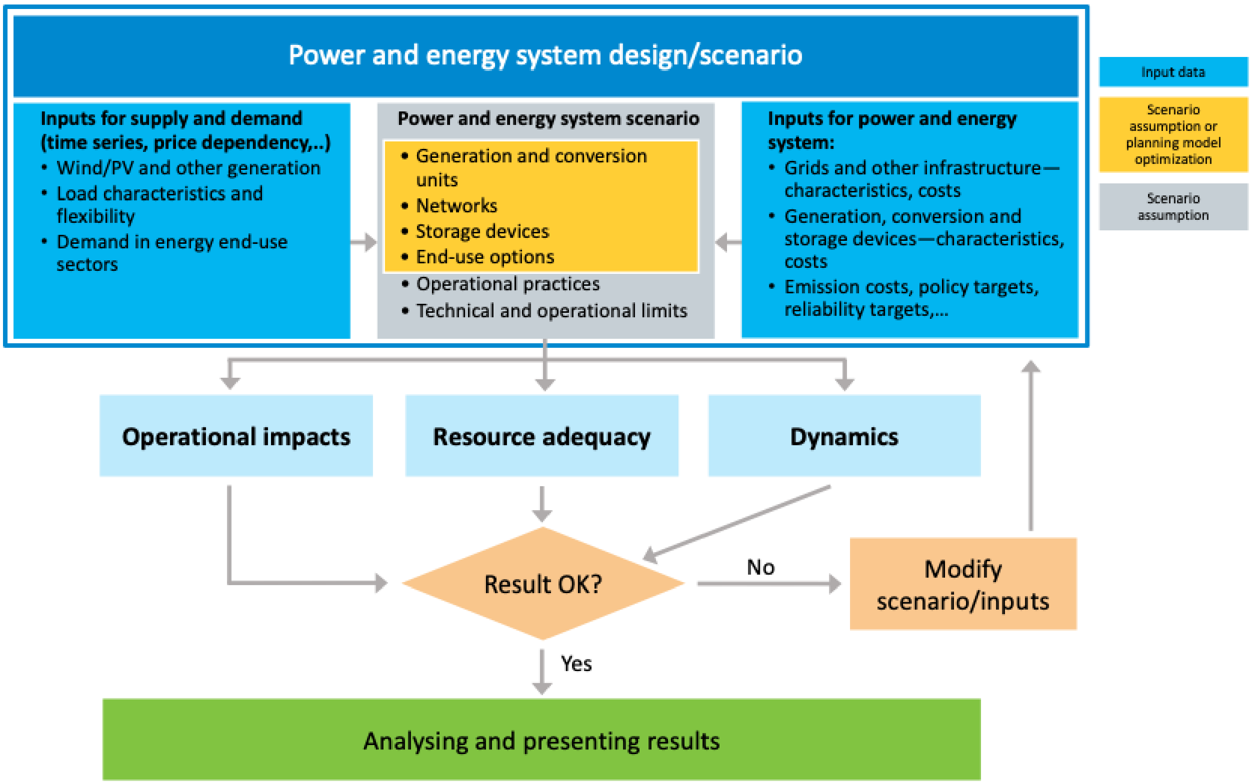

Figure 2.1. Wind/PV integration study flow chart showing the detail in inputs needed for a wind/PV integration study in blue boxes.

For wind and solar power, an accurate representation of their energy output and uncertainty (forecasts) will be needed, time-synchronized with demand and other weather dependent generation, as well as more details on power plant behaviour in the grid. Wind/PV integration studies also require data on other power plants, loads, and storage resources. The transmission and/or distribution grid topology and characteristics need to be detailed for assessing the impacts on the network. The assumptions regarding all these data (as well as omitting some data needed) will impact the results on potential impacts of large amounts of wind/PV power in a power system.

A complete description of the power system is needed to capture interactions between all flexibilities, including wind and solar capabilities to cope with variability and uncertainty (Figure 2.2 example for the European energy system also in https://tyndp.entsoe.eu/explore/the-scenario-building-process). For future power systems, couplings with other energy sectors with available flexibilities is important to capture. Also, potential impacts of climate change to any input data become relevant when study horizons reach year 2050 and beyond (IEA, 2022).

Different types and volumes of data will be needed in the different simulation tools that could comprise a study. Recommendations are summarized in Table 2.2 on page 41.

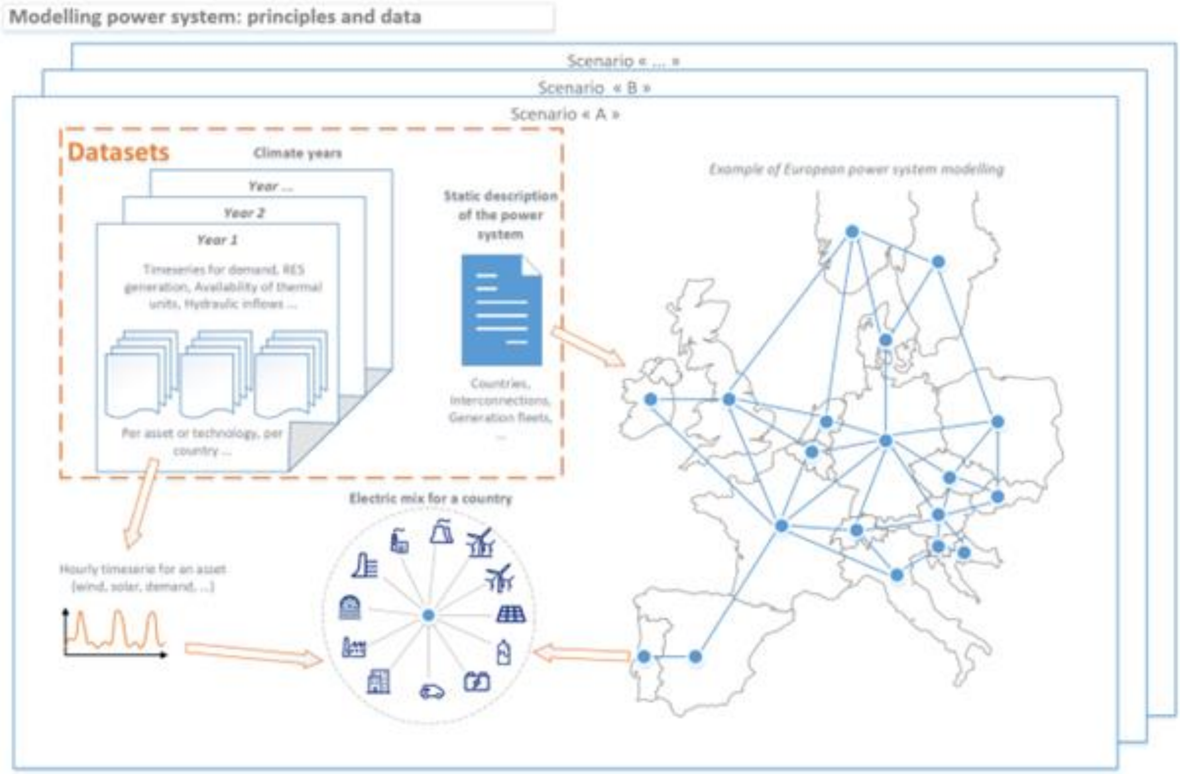

Figure 2.2. Example of European power system modelling (Source: Oueslati & Neau, 2023).

2.1 Wind and Solar PV Data

Jan Dobschinski, Hannele Holttinen, Matti Koivisto, Emmanuel Neau, António Couto, Ana Estanqueiro, Magnus Korpås, Jose Rueda Torres, Gerd Heilscher

Data for wind and solar PV power production should capture the generation capability, with characteristics of the variability and forecast uncertainty. It is important to capture the smoothing impact: reduction of (relative) variability and uncertainty, relevant to the power system geographical area. The accurate modelling of variability and uncertainty in the studied area is one of the main challenges for wind and solar PV studies. Extreme ramps and forecast errors should be captured in a realistic way, because even a few time steps with large errors can drive overall results – either overestimating the impacts of wind/solar or underestimating the results for adequacy of generation and flexibility.

In general, the basic data requirements for wind and solar PV as input in integration studies are similar. For larger areas, the smoothing effect – reducing (relative) variability and forecast errors – will be more pronounced for wind than for solar energy (Koivisto et al., 2018).

There are many linkages between variables in the weather and climate system and the electricity system (ESIG, 2023b). It is necessary that both wind and PV time series are based on temporal co-incident weather data, to represent realistic conditions. These data should also be co-incident (time-synchronised) with other weather-dependent data like demand and hydro inflow.

The detail of the data as well as the important characteristics to be considered will vary according to the simulation (see Table 2.1 on page 17 and Table 2.2 on page 41).

2.1.1 Generation Time Series

Wind/solar power production time series of a certain length and of a certain temporal and spatial resolution is needed in any wind/solar integration study of future power systems (Jourdier, 2020). In general, data can be obtained from measurements (real generation time series) and numerical model output data (simulated time series).

It is evident that the aggregation of dispersed wind/PV power plants in a larger area leads to a reduction of variability, i.e., the sum of the individual production and forecast error time series leads to smoothed aggregated time series (Dobschinski, 2014). However, it is important to note that if wind/solar installations are already evenly distributed over the entire area, further installations have only little or no impact on the smoothing effect. Representative wind/PV data for an integration study should incorporate the variability and smoothing impact of the system area with anticipated, dispersed wind/PV sites because variability is a key driver of the study results.

For wind power, correlation of wind power plants' outputs is generally smallest at the shortest timescales, increasing somewhat at longer time intervals: the second and minute variability of large-scale wind power is generally small, whereas the variability over several hours can be large even for distributed wind power (Murcia Leon et al., 2021). The smoothing effect for variability can be seen as less steep ramps as well as lower peaks of generation. The size of the area and the way wind power plants are distributed is crucial: larger areas decrease the number of hours of zero output – one wind power plant can have zero output for more than 1,000 hours during a year, whereas the output of aggregated wind power in a very large area is always above zero. Geographic characteristics of the surrounding area can have a significant influence on the correlation of variability from site to site. Offshore wind resources have been found to be generally more coherent over a larger area, resulting in less variability due to more stable winds but increasing ramps compared to land-based wind power where the feed-in behaviour differs significantly more from site to site (Cheneka et al., 2020). Some weather conditions can lead to reduced smoothing impact; for example, cold fronts can span several hundred kilometres where even dispersed wind power plants will not mitigate this kind of extreme event affecting an entire country or balancing area (Lacerda et al., 2017).

For solar energy, the output of a single solar PV system might dramatically change within short timescales, even within several seconds. These changes might even be larger than clear sky irradiation, due to cloud enhancement effect. The variability of the PV output is further characterized from very short term (seconds to minutes), intraday, monthly to seasonal up to interannual timescales (IEA PVPS, 2024). However, for solar, the main variability due to daily patterns is easier to catch than for wind power. The variability due to partly cloudy weather might be large in smaller areas, but generally will smooth out with wider area deployment and longer timescales in which cloud formations are no longer characterising the solar variability, and the overall daily generation curve will resemble a nearly bell-like curve. (Hoff & Perez, 2012). Although there still might be extreme ramps in single feeders/low voltage (LV) networks, medium voltage (MV) feeders/areas already are large enough to lead to some first smoothening. Additionally, the larger the area in the West-East direction, the smoother the morning and evening ramps of solar are due to a wider spread in sun rise and fall times.

Adding diversity will reduce the variability (Vrana et al., 2023). In addition to increasing geographical area and dispersion inside an area, technology mix can add diversity. For example, low specific power turbines and tracking solar can show different variability compared to existing installations, and including a mix of high and low wind turbines as well as a mix of optimal and non-optimal orientation of solar PV panels will allow for more generation to be available when the wind or solar resource is scarce. The overall variability of the generation can be reduced by planning for optimal mix of wind and solar power (Koivisto et al., 2018), and using hybrid power plants is also adding diversity.

In a first rough approximation, existing measurement and model data can be used to extrapolate the characteristics of future anticipated wind and solar power plants, but it only works well if we assume no changes in locations or technology for wind and solar power plants. When assessing impacts for future power systems, the expected future expansion of wind and solar energy should be estimated as realistically as possible in terms of location, capacities installed, and technologies available, including detailed area analyses with regard to exclusion areas and distance regulations. Siting the power plants in the most realistic manner is also important for the transmission studies to model how they are located relative to consumption centres and grid infrastructure.

There will be different requirements on datasets for different studies (Table 2.1).

Table 2.1. Requirements for generation time series input data of wind power/PV generation for integration studies.

	Resource Adequacy and Capacity Value	Unit Commitment and Economic Dispatch (UCED) including Reserve Requirements	Capacity Expansion Model (CEM) for the basic generation and storage mix
Temporal resolution	Typically, hourly data are enough.	Dependent on the resolution of the dispatch, typically 5 minutes to 1 hour.	Hourly. Preferably full-year but representative days may be applied for large systems and studies with multiple energy carriers.
Spatial resolution	System-wide time series. It is more important to catch the levels of wind/PV output during peak load situations than to incorporate spatial smoothing effect of short-term variability.	System-wide time series, incorporating spatial smoothing effects. If a load flow calculation is required, wind and PV time series aggregated on transformer station level are needed.	System-wide time series, incorporating spatial smoothing effects.
Length of investigation period	Long time series especially for wind power, more than 30 years improves the assessment catching extreme low winds during peak loads. For longer term studies, incorporate climate change impacts on resource.	UCED: One year of data is usually enough, but more years are better, especially include high-wind year to capture possible variability. Reserve requirements: longer time series including extreme events improve the assessment.	Snapshot of years for optimization of capacity expansion - most consistent use of CEM spans several decades.
Time synchronization	Coincident wind, PV, and load time series, and, if applicable, also of other weather-dependent generation (data based on time-synchronised wind, solar irradiation, temperature, and rain).	Coincident wind, PV, and load time series, and other weather-dependent generation (data based on time-synchronised wind, solar irradiation, temperature, and rain).	As for Resource Adequacy. Dynamic line rating models should also rely on the same weather data as used for generation and load.
Technology characteristics	Offshore and land-based wind; low wind technology; solar tracking technology and different orientation; wind and solar PV mix, to capture generation characteristics when a resource is scarce.	Offshore and land-based wind; low wind technology; solar tracking technology and different orientation; wind and solar PV mix, to capture the generation characteristics.	Offshore and land-based wind; low wind technology; solar tracking technology and different orientation; wind and solar PV mix, to capture the generation characteristics.

When modelling energy systems towards 2050 and beyond, the impacts of the changing climate can be considered using climate model scenarios. Significant uncertainty is noted in modelling climate change impacts on wind and solar generation (IPCC, 2022). As climate change impacts the demand, with increasing cooling and decreasing heating, as well as hydro power, bioenergy, and thermal generation, the use of synchronous data, i.e., taking all weather variables from the same model to generate “electrical” data (demand, wind/PV generation, hydro inflows…), is highly recommended as there are important dependencies between the variables.

For resource adequacy and capacity value assessment (See Section 4.1; a data guideline for resource adequacy studies available at www.epri.com/resource-adequacy (EPRI, 2023)):

- A temporal resolution of 1 hour is usually adequate for this type of study, because variability of wind generation in timescales of less than 1 hour does not impact the results.

- Because the relationship between wind, PV, and load is a key factor for this type of study, coincident time series are crucial, especially for the future energy systems where electrification of loads will increase weather dependency (e.g. heat pumps).
- To capture the extreme events of long duration low-sun low-wind (dunkelflaute), many years of data are needed. For capacity value of wind, seven years were needed to produce robust results for Ireland (for the 10 years studied in Hasche et al., 2011). For Finland, 14 years (from 35 years of data) still resulted in 10% uncertainty in results (Milligan et al., 2016), and for France, 30+ years of data were needed to capture all statistics and extreme events (EdF, 2015). Therefore, it is recommended to use several decades of data for resource adequacy.
- For longer term studies, the extreme events of correlated weather phenomena become important (Novacheck, 2021; Outten & Sobolowski, 2021). Climate projection data may be needed – not so much for wind and solar energy for which climate change is not expected to substantially impact future resources over large areas, but it may impact demand and hydro power resources and the necessity for synchronous data (IPCC, 2022; Bukovsky & Mearnas, 2020).

For capacity expansion models (CEMs) (see Section 3.2), a simplified representation of operational details is traditionally used in order to obtain a tractable optimization problem:

- A reduced amount of hourly data is usually adequate, like a set of representative weeks instead of a full year of data. If a set of representative weeks is used, statistical transformations can be used to scale the wind and solar generation distributions to match long-term distributions for better representation in capacity development modelling (Gea-Bermúdez et al., 2020; Scott et al., 2019). When wind and solar become dominating parts of the system, this should be improved and recommended practice is multi-year with full hourly resolution (Jafari et al., 2020). However, compromises due to computational and/or data issues may be necessary also in future, which means that the iterations, as explained in the flow chart of this report, will become increasingly crucial to make.
- The spatial resolution is also simplified, aggregating for each technology/resource and representing some only using a time-series. This simplified approach can overlook the full wind and PV resource potential within a region (or a control zone), in case different production patterns are seen, especially for areas with a diversified topography influencing the spatial distribution of wind generation resources. Neglecting these factors may hinder the i) selection of the most suitable solutions for both power source and the spatial location of additional power capacity and ii) the added value of the statistical power smoothing potential (Couto & Estanqueiro, 2020).
- Usually snapshot year(s) are used for optimization of capacity expansion – most consistent use of CEM would span several decades.
- For longer term studies, climate change impacts should be considered. The changes in wind and solar resource are expected to differ locally, depending on climate models and areas. For some areas, there is consensus in the way wind resources should evolve, like a decrease of wind speed in the Mediterranean region, and an increase in Northern Europe (Carvalho et al., 2021). These modifications in the wind resource can impact the results of the optimised capacity expansion in location and in technology (Sliz-Szkliniarz et al., 2019). To be consistent, hypotheses of future wind generation have to be based on future wind projections, towards year 2050 or even 2100 rather than looking at the past 40 years.

For unit commitment and dispatch (UCED) simulations (see Section 5):

- The required temporal resolution depends on the model. The minimum requirement to capture wind and PV variability is using chronological, hourly generation data. However, 5- to 15-minute data will capture more variability impacts (Melhorn & Flynn, 2015) and may be useful especially for PV to capture the morning and evening ramps. As most meteorological datasets are available on hourly (or potentially half-hourly) resolution, getting representative 5- to 15-min simulated data may require significant additional modelling and lead to higher uncertainties compared to hourly resolution (Murcia Leon et al., 2022; Koivisto et al., 2020; Murcia Leon et al., 2021).
- It is important to have data from enough wind and solar power plant sites to cover the dispatch area. The spatial resolution of wind datasets may need to be higher than for solar PV. This is due to PV's high correlation to the temporally predictable solar resource and wind's potentially varied output over even relatively small regions.
- The generation time series of wind and PV have to be co-incident with load data (and, if it forms a significant part of the generation mix, to hydro power data).
- One year of data may be enough for some studies, but other studies may aim to quantify year-to-year differences, therefore needing several years of data. There is some evidence that higher wind years have somewhat higher variability (Holttinen et al., 2011). It is thus recommended to include data from a windy year to make sure the variability of wind is not underestimated.
- For longer term studies with high shares of variable renewable energy, it recommended to include the impact of climate change on the resource. Changing wind variability may have impact on back-up and storage needs (IPCC, 2022; Bukovsky & Mearns, 2020).
- For operating reserve requirements, that are often part of unit commitment and dispatch simulations, capturing larger possible forecast errors is important for setting reserve requirements (see Section 2.1.2 on Forecast time series). Different time resolutions of data used will impact on time resolutions needed for reserve requirements: using 5-min resolution in the UCED, could have 1 min resolution data to inform additional reserves needed for AGC; or day ahead hourly data with 15-min real time being used to calculate an uncertainty product.

<u>For power flow analysis (see Sections 4.2–4.3):</u>

- The spatial distribution should be that of the grid under investigation, i.e., the nodes of a transmission or distribution grid. It is crucial to choose a realistic future distribution of power plants connected to these nodes (Wolff et al., 2007).
- Using relevant wind/solar power plant technologies (high/low hub height, fixed/tracking solar, east-west or south-facing, etc.) for the future plants is important.
- Because power flow calculations are rather time-consuming, usually snapshots (several single points in time) are considered. Ideally the extreme cases are taken from a very long time series (from wind/PV/load/other generation worst case combination). In cases where acquiring such data is not possible, different extreme situations of wind power generation, other generation, and load are combined, chosen such that they could realistically occur simultaneously. For example, using nameplate data for the wind/PV generators can lead to an over-estimation of the maximum PV/wind generation event. For PV, the AC-connection value should be taken, instead of the DC (watt-peak, Wp) value. For the quantification of the probability of extreme load events, the frequency of occurrence is necessary for the situations used.
- For wind/solar dominated systems, a few snapshots will not be sufficient. Power flow calculations will also be part of operational planning and move towards stochastic power

flow simulations where multivariate distributions of wind and solar can be considered (Dalton et al., 2021). Statistical methods to identify cases of most interest from UCED to power flow can be used, like clustering.

- For a detailed time-series analysis at the distribution system level (e.g. variability analysis for voltage regulation), the wind and PV data requirements are usually high, for both spatial resolution ($d < 10$ km) and temporal resolution ($t \leq 10$ min). As such data are usually not available for most distribution integration studies, characteristic generation profiles for generators and loads are typically considered. This approach is suitable for the assessment and comparison of different voltage regulation strategies and components (e.g. PV reactive power control, on-load-tap changers, etc.), but it often does not appropriately represent the smoothing impact of wind/PV generation across the footprint of the distribution system being studied.

For system stability studies (see Section 6): Time series calculations are rarely performed and mostly the wind input is kept constant for each calculation's case.

Using real generation time series

Ideally, one would have actual high-resolution wind and solar generation data from all sites included in the study, and those would be input to the integration study. Using existing generation data will provide realistic smoothing characteristics and can be applied for studies with lower shares of wind and/or PV.

A notable advantage of measured time series compared to simulated data is the representation of variability in timescales of less than one hour due to the fact that modelled time series are mostly based on weather data with a temporal resolution of one hour. The simulation of realistic variability can significantly benefit from the use of measured data.

Disadvantages up-scaling measured, historical data to future wind/solar generation time series are:

- Capturing sites that are outside the data – these can add to smoothing impact, as well as alter the generation profile, especially when adding different topology or offshore wind.
- Capturing smoothing of variability – if data have too few measured power production sites, simple up-scaling of data from existing wind plants to represent an increased level of wind capacity is an incorrect procedure and will result in higher per unit variability than would be the case in reality. The same applies for PV data on partly cloudy days, when the variability of a single plant is high.
- Capturing the generation profile for new technology – especially future wind generation profiles from new wind turbines with larger rotors, higher hub heights, and capacity factors will be different from the turbines installed 10 years ago. Different solar PV technology will also impact the profiles.
- Capturing different shares of technologies – larger share of offshore wind or share of roof-top and large solar power plants.
- Capturing year to year differences in generation – measured data may be available only from a few years (depending on the vintage of the installed fleet), which may not be sufficient for all studies.

In principle, the use of measured data only makes sense if the characteristics of the data well represent the energy mix in space and time within the considered study. Studies of future scenarios with lead times of more than 10 years hardly benefit from the use of current measurement data due to their non-representative nature.

Validation and cleaning of the measured time series data is a necessary step because erroneous data values can impact the results of the studies. Often problems in data show as artificial peaks in the data, for example suddenly a 0 in between two higher numbers. In historical measured generation data, there may be aspects other than wind or solar related variability included that would need to be taken out when upscaling the data to represent future system operations: curtailment or providing down regulation as requested for system operators (Sørensen et al., 2020); planned or unplanned maintenance; or self-consumption. For solar PV, the partially cloudy conditions present significant challenges for the accuracy of upscaling algorithms; single small clouds over a representative PV power plant upscaled to present a higher solar share of the regional PV power production would underestimate the solar generation when most of the region has little cloud cover.

A smoothing effect can be incorporated in a time series by sliding averages of the data, filtering out some of the fast variability. More advanced statistical techniques could be applied to this problem if sufficient data are available to support wind plant behaviour depending on local weather, topography, and other factors.

If the data already contain enough sites and turbines/panels to reach the smoothing effect possible from the area in question, then the uncertainty when up-scaling will be low, and it can produce realistic time series. However, when the data is not covering adequately the area in question, there are potential changes in resource due to climate change, as well as changes in technology and strategic management of the power fleet impacting the capacity factors, then simulated data is recommended, at least to complement the existing data available from historical measurements.

Using simulated generation time series

If the wind and PV generation data needed for grid integration studies cannot be derived from actual measurements, it is recommended to use simulated data based on numerical weather prediction (NWP) models for wind and either satellite and/or NWP data for solar. Data estimated using measured prediction correlation approaches combining observed (after control quality checks) and NWP/satellite data can also be a reliable solution.

Using model data for wind can capture larger areas and better mimic future scenarios of sites, and the models provide tens of years of data (Murcia Leon et al., 2022; Koivisto et al., 2019). In these simulations, solar radiation and wind speed at hub height are extracted on small geographic grids (such as a 2-kilometer square) at locations that represent potential future wind/PV plant development. To represent large plants, the simulated outputs from appropriate geographic grid cell locations are combined.

For NWP, there are analysis and reanalysis data available. The first-mentioned models are calculated as a start initialization as part of the daily weather forecast. It should be noted that larger model updates can also lead to changes in quality and characteristics. Such inconsistencies in time can negatively influence the results of the downstream system studies.

It is recommended to use reanalysis models that do not undergo any model changes and are therefore consistent over time. The reanalysis also includes more observation data than real-time weather forecasts, as some of the data are only provided with a delay. Some currently established global reanalysis data for energy system analysis are:

- ERA5 from the European Centre for Medium-Range Weather Forecasts. ERA5 is the fifth generation European Centre for Medium-Range Weather Forecasts reanalysis for the global climate and weather for the past eight decades. Data are available from 1940 onwards with an hourly time resolution and a spatial resolution of 0.25º x 0.25º (Hersbach et al., 2023).
- The Modern-Era Retrospective analysis for Research and Applications, Version 2 [MERRA-2] from the National Aeronautics and Space Administration [NASA] provides data beginning in 1980 with an hourly time resolution and a spatial resolution of 0.5º × 0.625º (GMAO, 2015).
- The new Destination Earth (DestineE) initiative is an ambitious initiative of the European Union to create a digital twin – an interactive computer simulation – of the complete planet (DestineE). As extreme weather becomes increasingly frequent and changes in climate more pronounced, there is an urgent need to forecast these events with even greater accuracy, to predict their impact on the whole environment. It is expected that the weather datasets created in DestinE will also play an important role in energy system analysis.

Although reanalysis provides global information with a coarse resolution, more detail can be achieved by using limited area/regional models such as Weather Research and Forecasting [WRF] or the High Resolution Limited Area Model [HIRLAM]. These models can describe the behaviour and evolution of air masses and treat explicitly the inherent phenomena of atmospheric turbulence and stratification as well as other types of nonlinear atmospheric phenomena important for wind and solar generation, up to a maximum spatial resolution of 1×1km.

Most climate projections have 3-hour or 6-hour resolution (even many downscaled ones). This means that for simulation tools of hourly resolution, data will need to be interpolated, and could miss some of the short-term variability. For power systems covering a large geographic area with strong smoothing impact and relatively non complex terrain this could be acceptable.If sub-hourly data are needed, it is common to capture the short-term variability characteristics from actual, operating wind power plants and apply that to future hypothesized wind plants. Stochastic simulation overlaid on NWP data is also an option (Murcia Leon et al., 2021).

Measurements still play a crucial role in validating and improving the models and determining parameters used in the simulations:

- Bias adjustment is often needed for wind generation (Murcia Leon et al., 2022).
- The variability of the simulated data can be checked by comparing it with measured large-scale wind power production data – this requires detailed information about existing wind installations (knowledge of their locations, hub height, turbine type, etc.) to mimic the actual installations. Standard deviation of wind generation time series, P(t), and especially the statistical properties of the temporal variability time series, P(t)-P(t-1) can be checked. Examples of the standard deviations of variability time series are seen in Figure 2.3 for hourly variation and in Figure 2.4 for 10-minute variations. The probability distribution of temporal variability (P(t)-P(t-1)) can also be checked for correct frequency of extreme variations (ramps). If needed, more smoothing impact can be incorporated by sliding averaging, for example. When modelling offshore wind generation and when analysing onshore wind in small geographical regions, variability for sub-hourly resolution may need to be added, for example by stochastic simulation (Murcia Leon et al., 2021).

When data are simulated for future sites where measurement data do not currently exist, it is best if datasets for all weather-related generation and load are generated from the same NWP model runs. This ensures that the physics of the atmosphere is consistent for wind, solar, hydro, and load, and helps to avoid erroneous ramps in power output that may arise from ad hoc time series creation methods (Delenne et al., 2015).

When incorporating climate change impacts, it is recommended to analyse multiple models and scenarios. As the different climate models show different biases (Luzia et al., 2023), it is important to bias correct the models when doing model-to-model comparisons and when comparing to NWP-based data, such as ERA5. There are significant differences between different climate models and scenarios (Luzia et al., 2023; Outten & Sobolowski, 2021; Bukovsky & Mearns, 2020; Fernández et al., 2019; Bartók et al., 2019; Zittis et al., 2019). As the climate models are still evolving, there are potential caveats to using data from them, like the signal to noise ratio of impacts driving the majority of the uncertainty in the study. It is recommended to study the baseline system for which there is verifiable data first before estimating climate change impacts by running the study again, with climate change accounted for in the weather data. Even then, it must be noted that a) there is little confidence in wind and solar resource changes, and b) temperature impacts, while having reasonable confidence are not verifiable. There are no current means of validating any climate data for the future.

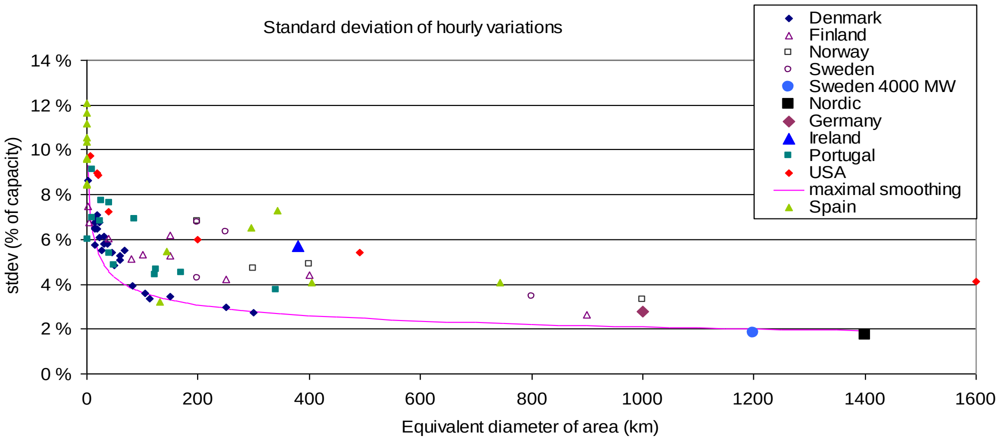

Figure 2.3. Indication of smoothing effect in the data, from standard deviation of the time series of hourly variations of wind power production; the size of the area is estimated as equivalent to the diameter if the area were a circle (Source: Holttinen et al., 2009).

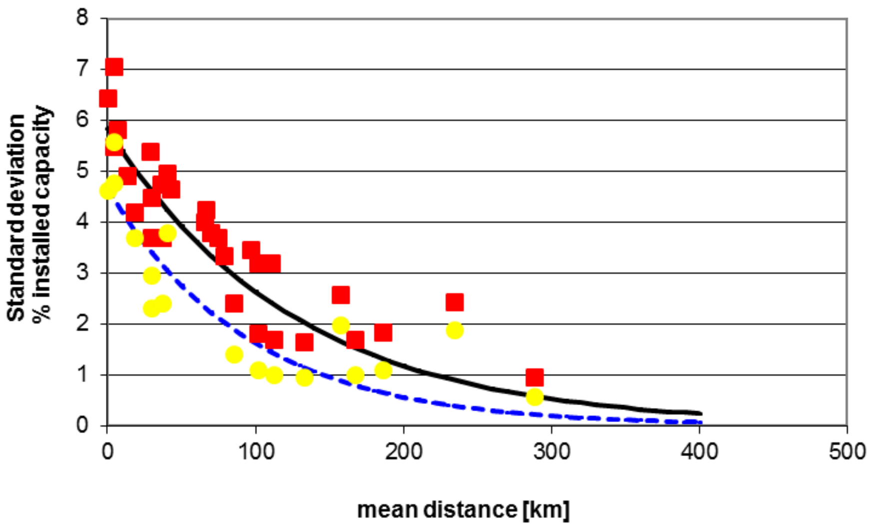

Figure 2.4. Standard deviation in percent of installed capacity for 10-minute (circles), 30-minute (boxes), 10-minute-fitted (dashed), and 30-minute-fitted (continuous line) change of total wind power as a function of mean distance between all wind power stations (Söder et al., 2012). Mean distance is calculated from a representative rectangle covering the area of the wind power plants.

2.1.2 Forecast Time Series

Forecast errors for wind and solar power are relevant for UCED and reserve requirements. Through reserve requirements they are a measure of uncertainty in capacity expansion models. They are not usually used for grid simulations and do not impact the resource adequacy or capacity value estimates significantly – for both of these they may be considered in more detailed studies for future high share of wind and solar systems.

Forecasts for wind and solar use similar sources (NWP models) especially for long-term horizon. For short-term horizon (minutes to several hours), solar power can benefit from satellite or sky cameras, which demonstrate superior performance compared to NWP models or even autoregressive forecasts.

There is considerable aggregation benefit (smoothing impact) also for the forecasts: the uncertainty for both wind forecasts and solar forecasts will be reduced when aggregated. Wind and PV forecast errors can also balance each other because individual error contributions for any time instant can be either positive or negative (Zhang et al., 2013; Couto & Estanqueiro, 2023). Forecast errors depend on:

- Forecast horizon – the horizons relevant for studying impacts of wind and solar depend on the operational practices and market requirements of the power system or balancing area under study. The forecast accuracy improves as the forecasting horizon decreases, as shown for wind power in Figure 2.5.
- Local conditions (e.g. weather conditions and terrain complexity) and layout of wind/PV power plants (e.g. size and geographical spread).
- For regional/national forecasts, the number of wind and solar power plants, their size, and their spatial distribution.

- The weather prediction model used as input as well as the statistical approach and the meteorological input parameters used. The error depends on the variance of the quantity to be forecast; i.e., the smoother the target variable, the easier it is to predict.
- The amount and quality of the measured data used as input to the forecasting system.

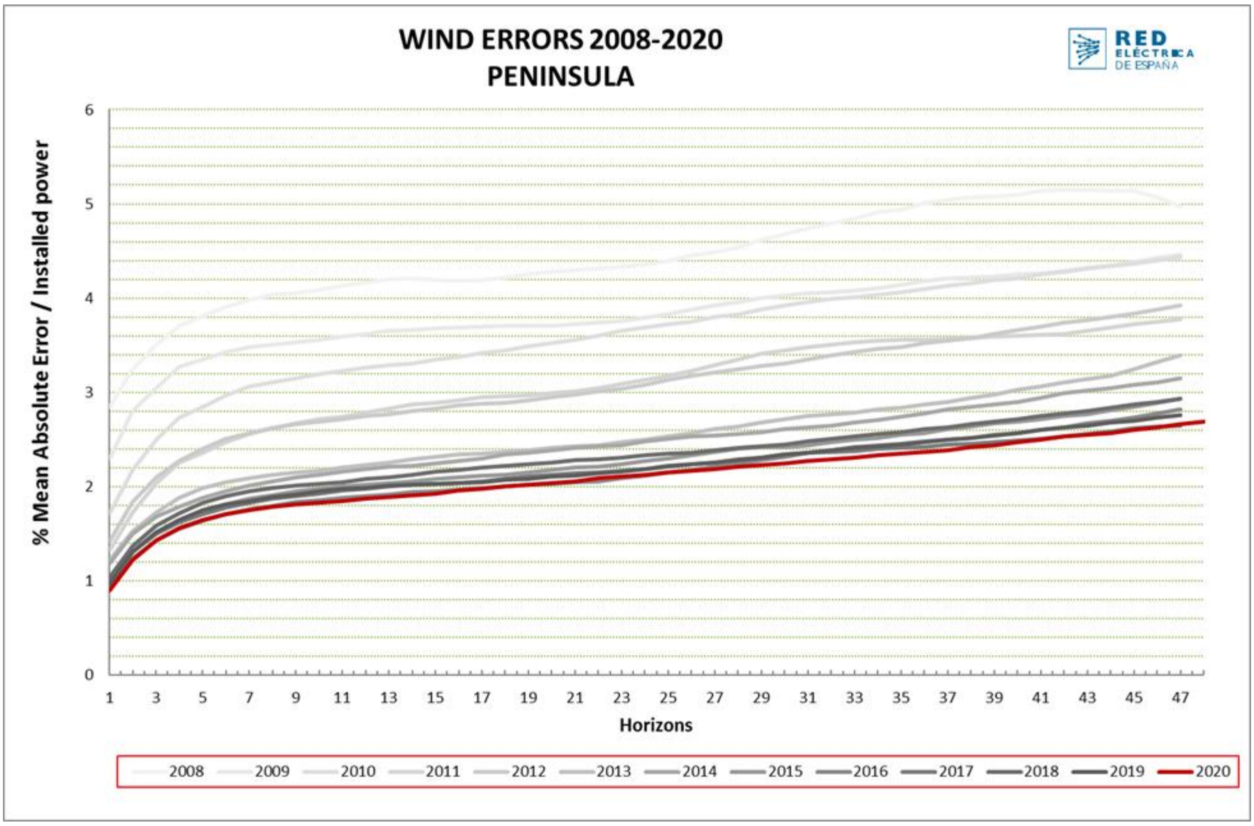

Figure 2.5. Improvement of forecast accuracy for 1…48h forecast horizon, from year 2008 to 2020 in Spain (Source: Holttinen et al., 2021).

Prediction systems established on the market have already achieved a high-quality standard (Messner et al., 2020). In Spain (Figure 2.5) the mean absolute error in 2020 was close to 1% of installed capacity for the first hours, about 2% for 20 hours ahead, and about 2.4% for 48 hours ahead. Internal evaluations by the Fraunhofer Institute for Energy Economics and Energy System Technology show normalized root mean squared forecast errors for all of Germany of about 3% for day-ahead and about 1% for a 1h-intraday forecasts averaged over 2022.

For solar PV, the mean absolute error in Germany of day-ahead forecasts of single plants is about 8.5% of capacity and reduces to about 1.7% for system-wide aggregations. The values are from the Fraunhofer Solar Power Forecast System based on 2023 weather forecasts from the Integrated Forecasting System of the European Centre for Medium-Range Weather Forecasts and a reference dataset of 107 solar plants. With respect to shorter lead times, the integration of PV measurements leads to further error reductions (Tuohy et al., 2015). As shown in Kraiczy et al. (2021), different approaches in forecasting PV might also lead to different assessments of necessary measures in congested grids. Therefore, using better PV forecasts, i.e., by shorter forecasting horizons or advanced PV forecasting approaches, can improve the congestion forecasting at the distribution level (Altayara et al., 2021).

Different input data and models are suitable for different forecast horizons, generally with a decreasing spatiotemporal resolution with increasing forecast horizon (see Figure 2.6):

- Short-term irradiance forecasts up to 10–20 minutes ahead resolving irradiance ramps with a temporal resolution of minutes or even less are derived from all-sky imagers (ASIs).
- Irradiance forecasts up to several hours ahead with typical resolutions of 10–15 minutes are derived from satellite images covering large areas.
- Irradiance forecasts from several hours to days ahead essentially rely on numerical weather prediction (NWP) models, which have the capability to describe complex atmospheric dynamics, including advection as well as the formation and dissipation of clouds.

State-of-the-art PV power forecasting services do not rely on a single forecasting model but integrate different inputs and models. Prominent examples are intraday forecasting systems up to several hours ahead integrating online measurements, satellite-based forecasts, and NWP model forecasts or day-ahead forecasting systems combining different NWP models, both using statistical and/or ML algorithms for forecast optimization (IEA PVPS, 2024).

For regionally aggregated PV power, an additional challenge is that PV power is not measured at a sufficient resolution for most plants in many countries, and information on PV systems is incomplete. However, because of spatial smoothing effects, forecast errors of regionally aggregated PV power (normalized to installed power) are much smaller than for single PV plants, depending on the size of the region and the set of PV plants contributing.

Probabilistic forecasts provide specific uncertainty information for each forecast value, depending on the weather conditions, and they allow for better risk management.

Improvements such as those observed in recent years will not be readily achievable in the future, (the increasing of meteorological data assimilated in the NWP models has been one of the reasons for the improvements in recent years). With further wind and solar installations, an increase in absolute forecast errors can be expected. Forecast error reduction needs to be estimated to the extent realistic in future generation scenarios. However, such an assessment is very complex, as it has to take into account assumptions and links between different disciplines, such as meteorology, digitalization and data science (especially new artificial intelligence technologies), and computation time optimization. Development of methodologies for the combined forecast of the hybrid generation of wind and solar may enable reduction of forecast errors (Couto & Estanqueiro, 2023).

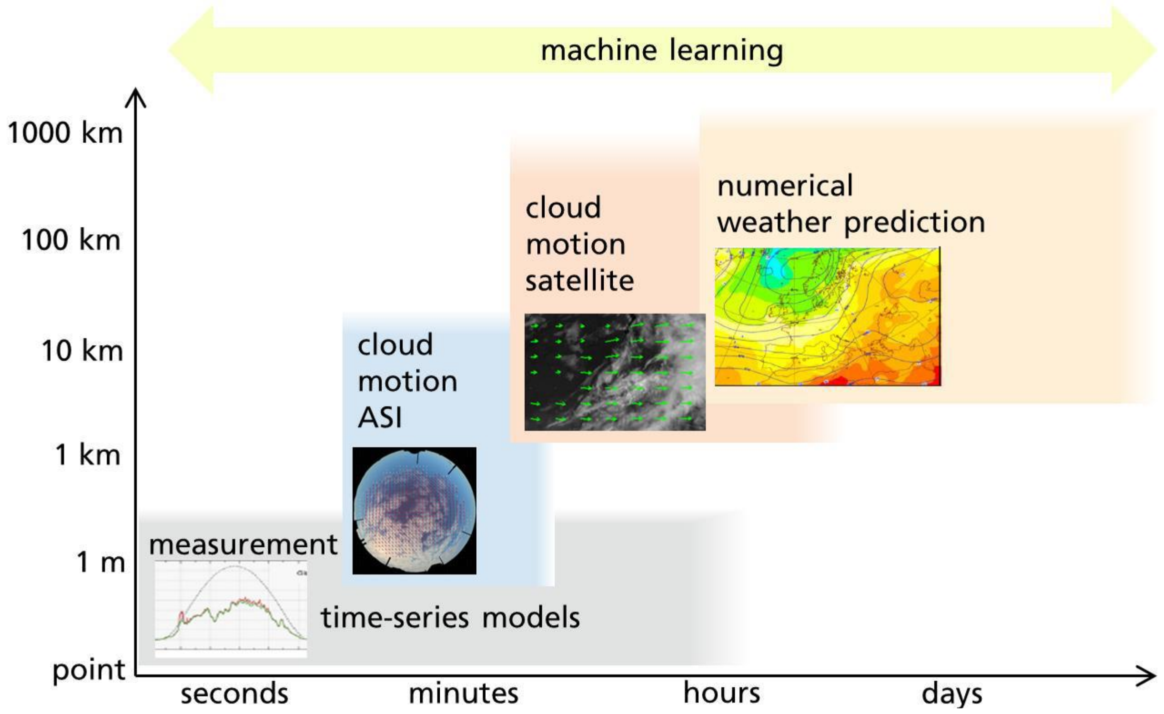

Figure 2.6 Different forecasting methods suitable for various spatial and temporal scales. Empirical and/or physical models are combined with statistical and/or ML models for forecast optimization. The spatial scales of the forecasting methods are defined by spatial resolution and spatial coverage. The temporal scales are defined by temporal resolution, update frequency, and forecast horizon (Source: Fraunhofer ISE from IEA PVPS, 2024).

Forecast error inputs can be made by simulating the future forecast errors (Nuno et al., 2018). Simulation of forecasts is not trivial. Spatial dependencies depend on the forecasting horizon, resulting in complex modelling. Forecast dataset must have the same co-variance to the "model truth" dataset as to actual wind and solar "ground truth". See WIND Toolkit (Draxl et al., 2015).

It is recommended to differentiate between estimations for average errors and extreme errors. Improvements of the rare extreme errors are much more difficult than improving average error scores, and characterizing them would require several years of data to obtain results with adequate statistical reliability. A few suggestions:

- When using short-term forecasts with horizons of 2–3 hours, extreme situations can be forecasted better, reducing the largest errors.
- When using historical data taken from forecasts performed in the past, the challenge is to get the improvements in forecast accuracy for future forecast errors right, particularly if a more dispersed and larger area will be used. A dedicated forecast system can be set up to produce the forecasts for the dataset needed. In Olauson (2018), generation is simulated from reanalyses, and up to 1-week-ahead synthetic forecasts are based on meteorological "reforecasts" and some statistical post-processing. In OSMOSE D2.1 a method for wind, solar, and demand is set up.
- Forecast error distributions can be used to form the time series. The error distributions for different situations can vary greatly (e.g. by time of day, delay-time, and period of the year, or for specific meteorological conditions). These distributions, taking into account that

large errors are more frequent than in a Gaussian normal distribution, are band-limited and have fat tails capturing the rare events (Figure 2.7). Moreover, they depend on wind generation level (Figure 2.8). Efforts have been made in estimating the correlation between wind power plant generation forecast errors (Giebel et al., 2007), and Menemenlis et al. (2012) summarizes a methodology for their aggregation. In Miettinen et al. (2020), a method for estimating distributions of forecast errors is based on the area size and dispersion of wind power plants. However, it has to be noted that simulated forecast error time series will not capture the complete characteristics of the weather-dependent variability together with their spatial and temporal correlations.

For unit commitment and economic dispatch (UCED) simulations, a time series of forecast errors along with the generation data is needed. The measure of uncertainty is reflected in the reserve requirements, but the full detail of how unit commitment decisions and final dispatch are impacted needs time series of uncertainties as forecast errors.

For capacity expansion models the measure of uncertainty, such as reserve requirement, is needed to capture the short-term flexibility needs (Bødal et al., 2020).

For estimating reserve requirements, if only the wind/PV induced reserve requirements are calculated and no UCED simulation is performed, only the probability density functions (PDFs) of the forecast errors for wind and solar power are needed, rather than the complete time series. This can be combined with other contributions to the reserve requirements (i.e., PDFs for load forecast errors and power plant outages). Importan things to capture:

- Usually, the short-term variability over a few seconds up to a minute timescale is independent for each wind or solar plant, resulting in the nearly complete cancellation of such variability within a balancing area. If the timescale is very short, automatic reserve requirements need to be studied and second/minute variability needs to be separated from 10- to 60-minute variability. See, for example, King et al. (2012).
- Data periods having extreme, rare forecast error cases are important. As these “tails” of the PDF differ from year to year, it is better if the PDF is derived from a time series of multiple years to have better representation and accuracy (Dobschinski et al., 2010).
- For higher shares of wind and solar, dynamic reserve setting is recommended. For that, a probabilistic forecast based on a historical training period with already observed forecast error data can be used; it is recommended that it be based on multiple years of error data. For an ensemble prediction system, the reliability should be confirmed. The advantage of a reliable ensemble prediction system is the ability to forecast extreme events (also error events) that have not been predicted recently (Dobschinski et al., 2017).
- For longer term studies with high shares of wind and solar, the modelling of extreme forecast errors should also consider potential forecast improvements within the next few decades. The impact of climate change on the resource as well as extreme events of correlated weather phenomena should also be considered. As these present challenges and uncertainty within integration studies, it is recommended to perform a sensitivity analysis to be able to estimate the impact of the forecast error simulation used on the final results.

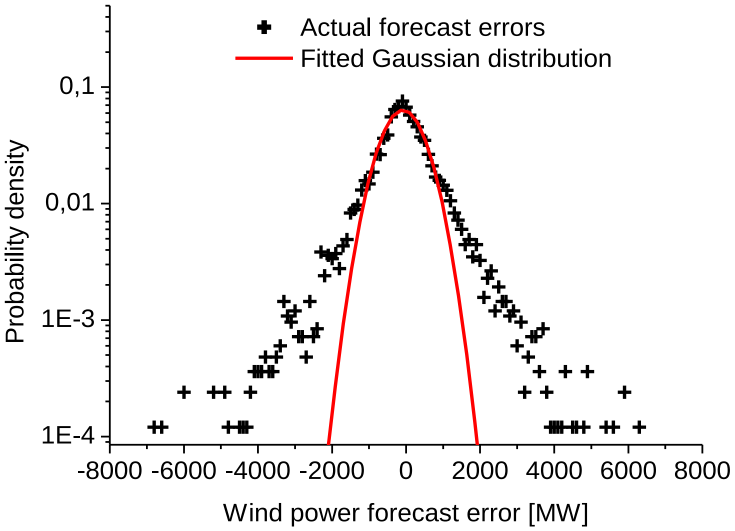

Figure 2.7. Larger forecast errors are more probable than a normal distribution would estimate (Source: Lange et al. 2006).

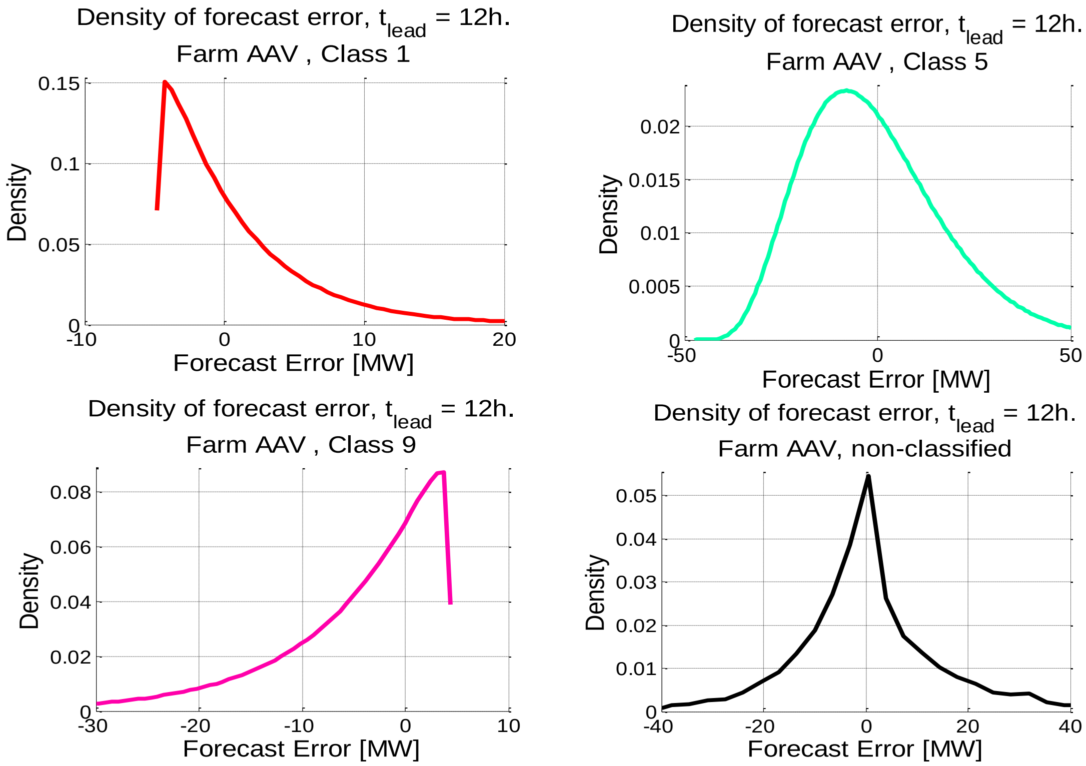

Figure 2.8. Forecast error distributions for different generation levels (top left for low forecasted generation, top right for medium generation level and bottom left for high generation). The bottom right graph corresponds to the case with all the data (no classification with respect to the generation level) (Menemenlis et al., 2012).

2.1.3 Wind and Solar Power Plant Capabilities

System integration studies must consider the characteristics of power plants, including relevant control features that enable wind and solar power plants to respond according to the power system needs. Specific control performance and related parameter values are prescribed by the local network operator in so-called grid codes (in the United States, these are named technical interconnection requirements). A minimum for future systems could be taken from the relevant IEC and IEEE standards: IEEE P2800-2022 as a key resource; IEC 61400-27 (wind models), IEC 62934:2021 (wind/solar integration), and IEC TS 63102:2021 (grid code compliance assessment).

The relevant capabilities to consider are as follows:

- For system dynamics analysis (see also Section 6 Dynamics):
- Fault Ride Through
- Active power frequency response, including very fast (inertial) response
- Reactive power or active power prioritisation options
  - Providing services such as damping, and grid forming capabilities.
- For steady state analysis (see also Section 4.2/4.3):
  - Active power
  - Reactive power.
- For Unit commitment and Economic dispatch and reserves (see also Section 5):
  - Active power frequency response (automatically responding reserves)
  - Balancing power (manually responding reserves or balancing/real-time market operation)
  - Controlled storm shutdown to reduce the largest downward ramps, especially for tightly spaced offshore wind power plants.

If no detailed track of PV/wind capabilities is available, the PV/wind capabilities can be included as a study variant.

For grid simulations, power plants are incorporated in the model tools by component models. The model complexity will depend on the study application (Flynn et al., 2017; Yamashita et al., 2018). Depending on the nature of the analysis, the models should incorporate the underlying electrical machine and power electronic/control system dynamics, supported by the grid code requirements (e.g. droop characteristics, imposition of ramping limits, over/under frequency response, voltage/reactive power controls, and fast frequency response). See also Section 6.2.3.

Power plants connected at higher voltage levels in distribution or transmission grid are both visible and controllable by the system operator. Connection in lower voltage levels (for rooftop solar PV) usually complicates getting real-time measurement data (less observability of changing output) and the possibility to control the output from system operators if needed. This can initially be taken into account in a simplified approach by considering two categories of solar PV and wind plants: distributed, which only modifies the net load shape (load minus wind/PV); and utility scale power plants, which the system operator can control for curtailment or reserve purposes. The active operation of highly utilized MV and LV distribution networks is a fundamental change in planning and operation of future smart grids.

Smart inverter functions, such as fault ride through, active power frequency response, remote active power dispatch, and/or voltage/reactive power control are increasingly requested for solar PV and wind systems in the distribution level. The dynamics of the controller can change when the regulations change, and existing inverters can also be updated to include new capabilities, for example different response times (Kraicz, 2021; Altayara et al., 2024, Arnold et al., 2024; Bucher et al., 2024)

Active power (for steady state studies and UCED, power flow analysis, etc.): Active power represents all possible control functions, enabling ramping up and down, delta, etc. This control enables wind and solar plants to provide frequency control and balancing services responding at different timescales (inertial, primary, secondary, tertiary reserve). The capability of active control of the electrical power output should be regarded in combination with wind and solar forecasting and on-line monitoring. Information and communication technology and communication signals introduce a delay and reliability issue relevant to consider in very fast response services.

Reactive power (for steady state and dynamic stability studies): Reactive power capability represents the control features enabling voltage control and maintaining voltage stability in the network, more or less independent of their actual active power production. Reactive power capability is defined both at maximum (rated) active power and below rated power.

Fault-Ride-Through (FRT) needs to be modelled in the stability studies (see also Section 6). The disconnection of wind turbines (and also PV) due to faults can result in a large loss of active power infeed in some systems. FRT assessment considers the capability of power plants to remain connected when (severe) voltage drops occur in the network as a consequence of unexpected network faults like short circuits and to continue stable operation during and after a network fault, while respecting minimum acceptable voltage levels and duration limits specified by the so-called FRT envelopes (Figure 2.9). In order to support the network voltage, and with the intention of preventing collateral impacts on angular or frequency stability, it is necessary to carefully tailor FRT requirements for effective fast regulation of active versus reactive current injections by the power plant, also ensuring a safe and effective deployment of the post-fault active power recovery capability. Typically, the FRT requirements are specified in the form of a voltage envelope (EWEA, 2012), which indicates the retained voltage level, U_{ret}, the voltage, U_{clear}, at fault-clearance time, t_{clear}, and the recovery voltage level after time t_{rec} (EWEA, 2012). The rising sloped line in the FRT profile neither represents physical wind turbine behaviour nor grid voltage-time behaviour (which in practice is oscillatory), but instead encloses the envelope of minimum voltage levels to be considered (to remain connected or not) against time after initiation of the network fault.

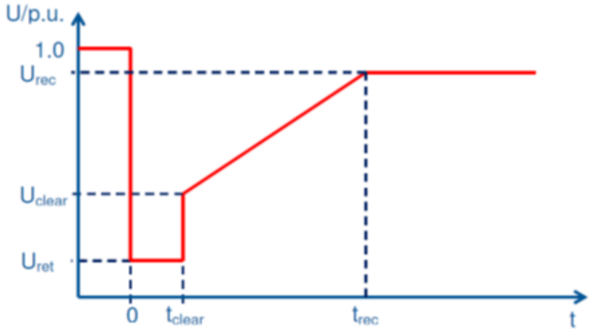

Figure 2.9. Generic fault-ride-through profile specified by the voltage at the connection point during and after a network fault (EWEA, 2012).

For wind/PV dominated systems, some plants will be required to provide more support to the grid, with so called grid forming capabilities (see also Section 6.2.3)

For offshore wind power plants connected via HVDC transmission, the modelling requirements depend heavily on the study scope. In many cases, it is sufficient to limit the modelling to the onshore HVDC inverter and use a simplified aggregated wind plant model. Such an approach is particularly valid when onshore voltage and reactive power issues are in focus, because the DC stage decouples reactive power flows in the offshore AC system from the onshore grid. However, when discussing active power control and system frequency support, the relation between the HVDC controller, the centralized plant controller, and the individual turbine controllers must be addressed (Zeni et al., 2014).

2.2 Power Plant Data – For other power plants than wind/PV

Hannele Holttinen, Juha Kiviluoma, Lennart Söder

The behaviour of remaining power plants and their responses to increased variability in the power system must be accurately described by the input data. Wind/PV integration studies will be influenced especially by the availability of flexible (quick-start and high-ramp-rate) units. The merit order can change, as prices for different fuels used in the generation mix can change considerably. These assumptions will also drive conclusions regarding emission and carbon abatement. The future power plant mix as well as their capabilities will be different than the current one – especially for higher shares of wind and solar (see Section 3 on Scenarios).

Again, the level of detail will vary for different simulations:

For resource adequacy and estimating the capacity value of wind/PV power:

- The forced outage rates of all power plants are the main inputs. Ideally they could be represented as a time series, and mean time to repair MTTR as well as EFOR (or similar) for generators would also be needed. Temperature dependence and any other common cause outage related issues are important to capture as well. The main transmission lines could be represented similarly. The planned outages for maintenance can be scheduled not to coincide with critical times of peak load (or scarcity of wind/solar generation), so only the forced outage rates per power plant are used – for higher shares of wind and solar some optimisation could be needed.
- For capacity value assessment, conventional generation uncertainty can be represented by the capacity outage table computed using the unit's outage replacement rate (see Section 4.1 Effective Load Carrying Capability Method). With higher shares of wind and solar, Monte carlo methods (chronology) are needed in order to capture also storage and demand flexibility. With high shares of wind/PV power, also the adequacy during the seasons when the outages are traditionally planned needs to be studied, to plan the distribution of the power station planned outages. For longer term studies, power plant susceptibility to failures related to extreme weather events and common mode failures under cold weather become important (Novacheck, 2021; Outten & Sobolowski, 2021).

For unit commitment and economic dispatch (UCED) simulations:

- Plant technical characteristics and constraints including ramp rates, minimum up and down times and start/stop costs, minimum stable levels, and heat rate curves for efficiency/losses. Details of capability with respect to various active power frequency control timescales.
- Fuel prices, particularly relative prices of different technologies. It is often desirable to consider multiple fuel price scenarios.
- Details such as forced and scheduled outage rates allow simulation of power plant outages due to failures and maintenance. The cost impacts of increased cycling of plants can be included when studying higher shares of wind and solar (Lew et al., 2013).

- For combined heat and power units, additional plant-specific data are needed for both extraction units and back pressure units as well as data for connected heat storage tanks and heat demand of connected district heating systems.
- For hydro power plants with reservoirs or pumping possibilities, the storage capacity as well as constraints of the river systems that impact the flexibility need to be taken into account. The variability of inflows over different time horizons (day/week/year) is important to capture. Hydro power plants without reservoirs upstream can be modelled in the same way as wind, i.e., based on statistical time series of water inflows.

Capacity expansion planning studies generally require similar data as UCED simulations and, additionally, investment cost data. However, at very high shares of wind/PV and with fewer inflexible power plants in the system, the ramp rates and other plant technical characteristics can become less important. This applies especially to large systems. On the other hand, fuel price and technology cost scenarios have a particularly important role. For existing hydro power plants with reservoirs, flexibility can be increased by adding the possibility of investing in higher production capacity or introducing pumped storage schemes.

Network studies will require information on the location of power plants as well as their active power and voltage control capabilities and short-circuit characteristics.

For stability simulations, the dynamic behaviour and capabilities are modelled. Generic models of synchronous generation-based plants are well established and have been developed and validated over many decades. However, it remains the case that the dynamic characteristics of individual units should be compared against actual responses, if available, from disturbances such as switching of power lines, loss of generation or loads, and balanced faults (see also Section 6). The control capabilities of power plants are evolving, as are the grid codes.

2.3 Load Data

Hannele Holttinen, Debbie Lew

Traditionally, long-term load forecasts are based on econometric and statistical models that consider the effects of economic growth, population, energy efficiency, etc., in various sectors that impact residential, commercial, and industrial loads. For years, energy efficiency in some regions has offset economic and population growth and yearly electricity consumption has remained flat. This is changing with electrification and in some regions load is already growing (ESIG, 2023a).

For longer term studies, bottom-up forecasting is developing, considering electrification of transportation, buildings, and industry as well as distributed energy resources such as rooftop solar and distributed battery energy storage (ESIG, 2023a; example of how electrification alters load profiles for future U.S. system in Mai et al., 2018). This includes both predicting adoption rates as well as customer consumption behaviour. In addition, new, large loads such as hydrogen production, data centres, cryptocurrency, electrification of industrial heat, and ultra-fast vehicle charging stations can drive significant load growth (Figure 2.10). Finally, climate change impacts on weather affect loads, in some cases directly, such as heating and cooling needs, and other cases indirectly, such as the impact of cold on electric vehicle charging.

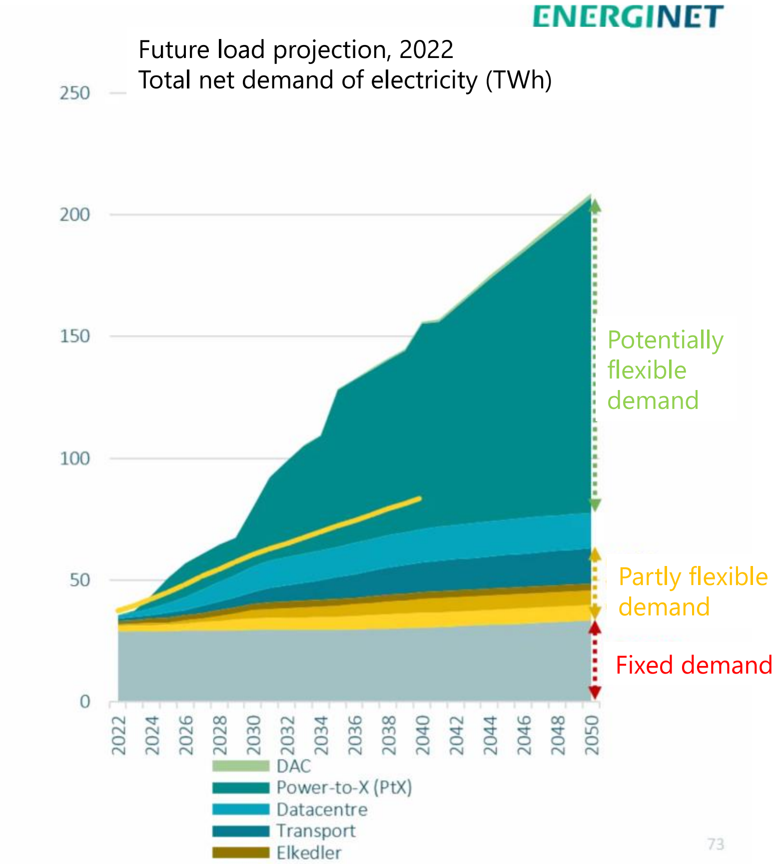

Figure 2.10. Future load – some of it will be partly flexible and some of it potentially flexible also on longer timescales than hourly and daily (yellow line is projection from AF22). DAC is direct air capture and Elkedler electric boilers (Source: Danish Energy Agency, Analyseforudsætninger til Energinet, 2023 AF23, in Danish).

It is important to model load separately from behind-the-meter generation, such as rooftop solar, rather than simply modelling the net load of a premise. In aggregate, a region may have such a large amount of rooftop solar that clouds or dunkelflaute events (low-solar, low-wind) can have a significant impact, or that grid code and ride-through settings can threaten reliability.

Data requirements for different simulation tools vary:

- <u>For unit commitment and economic dispatch (UCED) simulations</u>, both load and load forecast time series are needed. The measure of uncertainty is reflected in reserve requirements, but the full detail of how unit commitment decisions and final dispatch are impacted needs time series of uncertainties as forecast errors.
- <u>For resource adequacy and capacity expansion model tools</u>, time series of load are sufficient. For capacity value calculations it is essential to capture the correlations of wind and solar energy in extreme cold spells (for winter peaking systems) or heat waves (for summer peaking systems) using real data from several years.
- <u>Network studies</u> will also require information on the location of (future) load. For power flow and dynamic calculations, traditionally knowledge of representative peak and low load situations were sufficient, but different load cases with wind and solar power levels that can produce challenging situations are needed on top of studying only peak and low load situations.

Time series of load should be coincident to wind/PV data to capture any underlying correlations and have the same time step (usually hourly, or 10–15 minutes). Constructing future load time series has traditionally relied on historical data of daily, weekly, and seasonal patterns, considering temperature dependence where relevant (with temperature data coincident with wind and solar PV data). However, scaling up old diurnal profiles for weekdays and weekends will no longer work when new loads with significant flexibility, such as electrified transportation and heating, are added. Future load data become more complex and also require an understanding, or even an iterative modelling loop, of retail electricity pricing and customer energy resource programs, because pricing and program incentives will affect customer consumption behaviour. Separating the future load to price responsive and fixed load will be needed (see also the following Section 2.4).

Time series of load forecasts (or forecast errors) is needed for UCED modelling and for scheduling energy transfer in advance. In order to allocate reserves, uncertainties of the load forecast, together with other uncertainties of the power system, have to be considered. If historical load forecast time series data are not available from the system operators, they can be simulated. Forecasts of load are usually based on the time series technique; autoregressive-moving-average model; or more complex methods such as expert systems (Rahman & Bhatnagar, 1988), artificial neural networks (Bakirtzis et al., 1996; Chen et al., 2001), or hybrid methods (Song et al., 2006). For temperature dependent loads, two parts need to be considered: one temperature dependent, another part non-temperature dependent. With regard to uncertainties of load forecasts, error in forecast is usually modelled through a Gaussian distribution with a mean of zero (Doherty & O’Malley, 2005), so that the only parameter that needs to be set is the standard deviation of the load forecast error, which depends on the forecast period. The forecast accuracy of new electrification loads is more challenging to take into account until historical data are available – and their flexibility (price responsiveness) will probably evolve as time passes.

Dynamic models of load: The load itself also has dynamic characteristics, including sensitivity to frequency and voltage variations and encompassing motor loads with inertia. Ideally, the load representation should vary with time of day, time of year, and perhaps be regionally distributed, making it particularly difficult to represent accurately. Not using an appropriate load dynamic model can impact the results for wind/PV integration impact (Miller et al., 2014). Load models are also improving (Milanovic et al., 2013; Arif et al., 2017).

2.4 Storage, Demand Flexibility, and Energy System Coupling

Magnus Korpås, Juha Kiviluoma, Hannele Holttinen

Different forms of storage are possible sources of flexibility for future power systems with large amounts of variable generation. They can offer both fast response with a wide spectrum of power system services as well as longer term flexibility. They can also provide reactive power management and congestion management in future distribution grids exhibiting more observability and control. Electricity storage costs are decreasing (O’Malley et al., 2017) and are increasingly built into power systems in conjunction with solar and wind power plants (hybrids). Investment costs and the number of cycles per year will determine the cost-effectiveness of storage for balancing and grid support services. Pumped hydro and compressed air energy storage costs also depend on location.

The increasing decarbonization of energy sectors with electrification brings more links between energy sectors and access to other than electricity storage. These inputs need to be included as well, and may include, for example, power-to-heat with heat storage options and heat demand flexibility and gas networks and storage for hydrogen, synthetic gases, and hydrogen derivatives. (Figure 2.11)

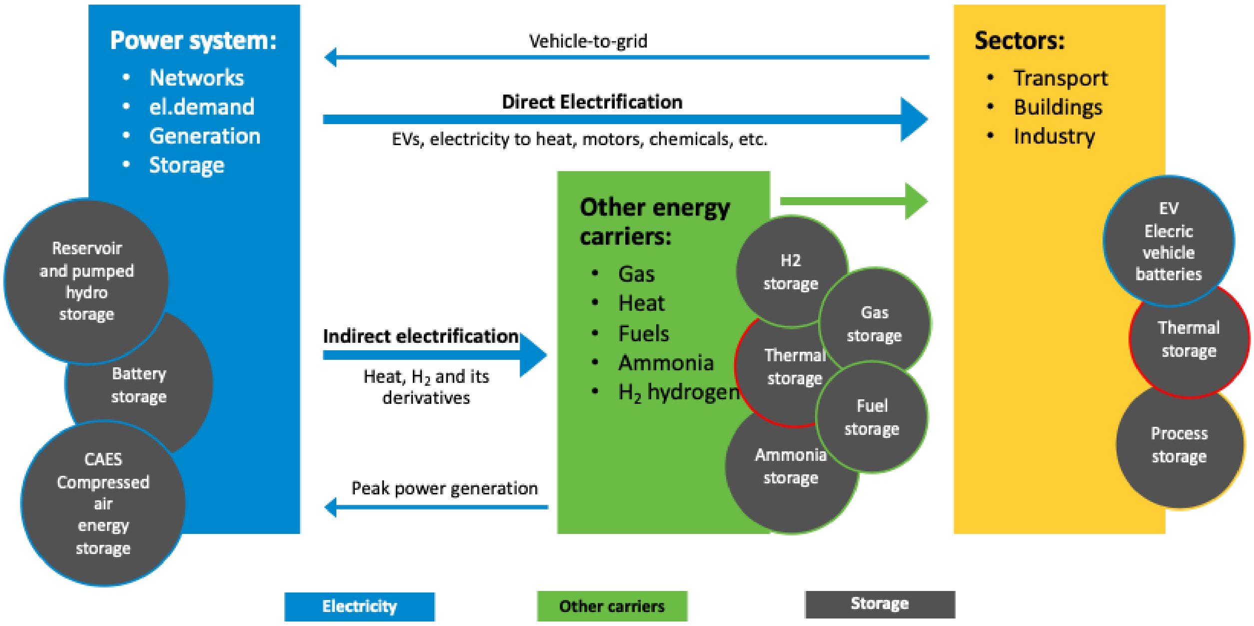

Figure 2.11. Interaction between the power system and other sectors with access to flexibility through energy flows and storage.

Traditional demand flexibility through demand response (DR) means shifting electric loads in time (usually up to some hours) or reducing the consumption at higher prices (peak shaving). New electrification demand and energy system coupling will bring also longer duration flexibility to the power system, shifting, for example, the charging of (some) electric cars to following day, using heat from thermal storage to postpone heat pump operation, or not using electrolysers for industrial power-to-X processes during high price days (depending on size of the storage embedded, could be a week). See, for example, NREL Electrification Futures Report (Mai et al., 2018) for an in-depth analysis of how potential electrification scenarios might impact the demand side in all major sectors of the U.S. energy system, including transportation, residential and commercial buildings, and industry, both in terms of overall consumption patterns as well as the flexibility of newly electrified loads.

Electricity storage, traditional demand response, and energy system coupling related demand flexibility will all impact resource adequacy assessment, portfolio development (capacity expansion model optimization result), and production cost/UCED simulations. They can enable optimal use of networks and impact the transmission and distribution network adequacy. The storage technologies and demand response can also provide grid support and improve the stability and long-term dynamics of power systems.

For UCED simulations, it is important to take into account the temporal restrictions of demand flexibility and storages. Demand shifting has a limited time of use before the loads need to be turned on again (e.g. many industrial processes and space heating) and may require a recovery period after activation. Electricity storage has a limited power and energy capacity that constrains its use. These factors become especially important when uncertainty is included – and it should be included, because otherwise the simulated use of DR and storage will be more optimal than is actually possible. There are multiple, very different possible sources of DR, which have different benefits, costs, and constraints (Nolan et al., 2014). From the modelling perspective, the challenge is to collect reasonable data about the possibilities of DR in the future:

- Industrial loads typically have a high variable cost because it is expensive to idle industrial processes. However, they may be large sources of controllable megawatts (MWs), and it can be cost-efficient to equip some of them with (partial) response capabilities for the purpose of automatic and/or manually activated frequency reserve. They can also be useful in peak load situations and industrial loads with some form of process storage available could therefore offer short-term flexibility with much lower variable costs (Foslie et al., 2023).
- Heating and cooling needs in households and commercial and office buildings as well as control of lighting (Kiviluoma & Meibom, 2010).
- Large fleets of electric vehicles with controllable charging and possibly vehicle-to-grid technology (Kempton & Tomić, 2005).
- Hydrogen production, storage, and potential re-electrification (Korpås & Greiner, 2008).

There are requirements to provide demand response services to grid operators. Frequency control is an example – the decrease or increase of temperature set point of electrical heating proportionally to the frequency deviation in order to counteract the frequency behaviour (European Demand Connection Network Code for demand response (Regulation 2016/1388).

Hydrogen can be produced through electrolysis in a flexible manner if coupled with sufficient hydrogen storage capacity and/or other hydrogen resources such as natural gas reforming with carbon capture and storage (CCS) (Bødal et al., 2020). A key consideration in integration studies including hydrogen flexibility is proper modelling of the hydrogen demand, in the form of a predicted time-series or a hydrogen market if electrolysis is only part of the hydrogen production portfolio. Hydrogen flexibility can in its simplest form be modelled with a “cut-off price” or alternative costs; the electrolysis plant is only operating when the electricity price is less than this level, assuming that hydrogen can be supplied from other sources. However, to determine the true flexibility potential of hydrogen, it is also necessary to model the electrolysis plant in more detail, including short-term and long-term storage as well as all auxiliary sub-systems that requires electricity. The latter is important when estimating the flexibility potential, as compressors and other sub-systems may limit the efficient operating range of the electrolysis plant and start/stop costs, ramping capability and so forth. Finally, (part of) the hydrogen could be produced to provide fuels for backup, peaking, and balancing power with seasonal storage. This is more sensitive to cost of energy.

2.5 Grid Data

Grid data needed for network models is described in detail in this section, for transmission system and distribution system.

2.5.1 Transmission Grid and Interconnection Data

Enrico Maria Carlini, Til Kristian Vrana, Hannele Holttinen

For network models, the representation of the grid is by topology, line rating, and impedance. Connected loads and generation power plants as well as operational methods such as dynamic line rating (DLR), must also be adequately represented depending on the scope of study (i.e., steady state power flow or dynamic/transient).

HVDC lines can be represented in a similar way as AC lines, where line rating (mostly publicly available) and resistance (can be estimated from public data) are sufficient for power flow calculations. Additional electrical parameters (e.g. inductance) are needed for studying dynamics, which also can be estimated based on public data. HVDC converter stations and other controlled devices like reactive compensation units, phase shifting transformers, etc., are challenging to model correctly for the control system part that is highly relevant for dynamic studies. Physical data like voltage and power ratings are often available, but information on their control structure and implementation is also needed. If the control system modelling is limited to being only a best guess based on experience, the possibility of incorrect modelling should always be kept in mind. The relevance of this problem is steadily increasing with the growing share of such devices in the power grid. The models suitable for an HVDC link embedded in an AC network, associated with most of the technical performance AC/DC interaction issues, are introduced in CIGRE 536 (2013), both for steady-state studies and for electromechanical dynamic studies with the associated controls. A summary of the main dynamic modelling schemes is provided in CIGRE (2007).

A robust transmission expansion plan is important for longer-term studies with high shares of wind and solar. The details of the network modelled should also be commensurate with study objectives – more detail needed for more detailed studies. Renewable sources are often distributed over large areas and far from demand centres. For future power systems, new long-distance transmission capability and transmission strategies may be required to deliver large amounts of power over long distances. Transmission planning is often one of the main goals for network simulations. However, transmission scenarios are also important to consider in other simulation models.

For lower shares of wind and solar, transmission limits are not traditionally considered in resource adequacy and loss-of-load calculations. If there are concerns about bottlenecks in transmission during critical peak load situations, the loss-of-load probability can be calculated for different sub-areas.

For higher shares of wind and solar, the assumptions regarding availability and limits of interconnections may be critical for balancing and resource adequacy results (Ibanez & Milligan, 2012). For resource adequacy, the main transmission lines should be modelled similarly as generation plants for forced outages and time to repair. A simplified transmission grid is often considered for unit commitment and dispatch (UCED) and resource adequacy simulations. UCED models are evolving to also include transmission, and DC power flows are available in several models, increasing the accuracy of the model. Traditionally, the simplest simulation methods have been used, assuming copperplate (i.e., perfect transmission capability) inside areas and modelling only the key transmission paths between areas or transmission zones. Transmission limits between areas can be set by net transfer capacities (NTC) available from operational data. In regions that use locational marginal pricing, such as market areas in the United States, it is already common to develop a nodal transmission model that has more detail on the transmission network.

It is challenging to consider the flexibility option from neighbouring areas through interconnectors in cases where including all neighbouring areas will make the simulation task too large. Assuming a completely flexible interconnection capacity at all times will usually overestimate the flexibility available, and not taking into account an existing interconnection will underestimate the flexibility available. These are important assumptions impacting the results (Holttinen et al., 2009). An approach of taking immediate neighbouring areas with (almost) as much detail as the studied area and neighbouring areas further with less detail can be used.

2.5.2 Distribution Grid Data

Denis Mende, Markus Kraiczy

Distribution network data are needed in detail for dedicated distribution grid studies. Additionally, a representation of the distribution grid for larger transmission system models is needed for detailed studies when a large share of generation is distribution-connected. When representing the distribution grid for transmission networks, it is important to preserve the necessary details, but still have the models feasible for simulations.

The data handling usually depends on available data information and analysis methods, which depend on the scope of the study. Common approaches to data handling can be divided to the following scopes:

- For analysis of new algorithms, methods or other solutions for distribution grid. Use of open and available benchmark grid data (e.g. Meinecke 2020; Strunz et al. 2009; Christie, 1999) is appropriate for testing new algorithms when the analysis focuses on easy-to-compare results and transparency. Exemplary scope and best practices include testing new local or central operation management strategies for improved voltage control (e.g. Bonfiglio et al., 2014 using the CIGRE 2009 network), reactive power provision for transmission system operators (TSOs), congestion management, island system mode, and network reconfiguration.
- For detailed analysis of a single or a few distribution grid sections (local or regional scale). Available data information is usually detailed (generation, consumption, and grid configuration). Exemplary scope and best practices include detailed PV/wind interconnection studies, power quality analysis (e.g. FRT), local voltage stability analysis, and detailed assessment of operational methods (Wang et al., 2017).
- For comprehensive distribution grid studies on regional or system wide scale.

Methods and best practices include:

- Analysis of representative grids in detail – a determination of representative grids is often performed by clustering/taxonomy of distribution grids/feeders (Schneider et al., 2008; Broderick et al., 2014; and Von Meier et al., 2015).
- Analysis of bulk system – automated (simplified) analysis techniques, possibly with assumptions of simplified grid data, e.g. topology (Büchner et al., 2014; Höflich et al., 2012; and Jäkel et al., 2015).

Although network models for high and medium voltage networks are often available, at least at the DSO operating the respecting grid, usually no detailed information is available on the LV level for all grid sections as well as generation, consumption, and grid configurations. This significant lack of data leads to a need for further assumptions and/or data derivation. Many DSOs currently are working on network models for their LV networks in order to be able to automatically assess status, expansion/reinforcement needs, and the future development of their network area. Exemplary scope of studies includes the analysis of grid reinforcement costs due to wind/PV integration (hosting capacity), distribution grid bulk system behaviour (grid stability), and distribution efficiency analysis.

2.6 Checklist of Recommendations for Input Data

Recommendations regarding the input data are summarized in Table 2.2. It is recommended to base the input data of an integration study on co-incident weather data such as wind, solar radiation, temperature (impacting also the demand), and rain (impacting also the hydro power).

For lower shares of wind and solar, existing historical measurement data can be used to extrapolate the characteristics of future anticipated wind and solar power plants as a first rough approximation. However, this only works well if we assume no changes in locations or technology for wind and solar power plants. For studies with high shares of wind and solar energy, the time series of wind and solar should be based on model data with anticipated locations and technology for the wind and solar power plants.

With electrification of demand and decarbonizing power generation, there will be more weather dependency in future systems. For study horizons of year 2050 and beyond, the impact of climate change should be considered by the use of data based on climate models projections – relying on several regional climate models for more robust projection of climate data (and resulting data for the electricity system). It is not only a question of wind/PV potential evolution in the future influenced by climate change, but a matter of capturing all situations regarding electric system balancing:

- Demand with electric heating and air cooling, with cold and heat waves (with a double effect: increase of global temperature and potential increase of electric heating in winter, and effective development of air conditioning in most countries) and other uses such as desalination associated with droughts
- Hydro power subject to droughts, and a more difficult inter-annual management of hydro storages
- Thermal availabilities that could be influenced by global warming and drought (but also floods)
- Biomass potentials that could be affected by changes of rainfall and temperature
- Meteorological limit values for determining the capacity of overhead lines may have to be adjusted due to climatic changes
- Most importantly, the conjunction of situations that could be not well covered by historical (example: both a wind and solar drought [“dunkelflaute”] with a cold wave in a large part of northern Europe) or spatial evolution of these events that could impact electric grid.

Table 2.2. Recommendations for input data needed for the integration study model tools (detail on wind/PV generation data in Table 2.1). In addition to time series and technical data, technology cost projections will be needed for Capacity Expansion Models and fuel cost projections for UCED.

	Resource Adequacy/ Capacity Value*	Capacity Expansion Model	Unit Commitment and Economic Dispatch (UCED) including reserve requirements	Power Flow	Dynamics
Wind/PV	Hourly time series with locational smoothing of large-scale wind/PV power, representative of power variations and time-synchronised with load data**. For robust results, 30+ years are needed.	Hourly time series capturing locational smoothing of large-scale wind/PV power, representative of (correlated) power variations and time-synchronised with load data**.	5-minute to hourly time series of at least 1 year capturing locational smoothing of large-scale wind/PV power, representative of (correlated) wind/PV variations and time-synchronised with load data**.	Wind/PV capacity at nodes, generation and load snapshots relevant for wind/PV integration, active and reactive power capabilities.	Wind/PV capacity at nodes, high and low generation and load snapshots, dynamic models, operational strategies.
Wind/PV Short-term Forecasts	Not needed for traditional resource adequacy tools.	No –reserve requrements based on short-term forecast uncertainty.	Forecast time series, or forecast error distribution for time frames of UCED, and reserve requirements.	May be needed in future.	Not needed.
Load	Hourly time series time-synchronised with wind/PV data**. At least 30 years of data for robust results.	Hourly time series based on historic data and predictions, for the full analysis period**.	5-minute to hourly time series coincident with wind/PV, for at least 1 year**. Load flexibility incorporated (flexible loads separately).	Load at nodes, snapshots relevant for wind/PV integration.	Load at nodes, high and low load snapshots. Dynamic models with capabilities and characteristics.
Load Forecasts	Not needed for traditional resource adequacy tools.	Not needed.	Forecast time series, or forecast error distribution for time frames of UCED and reserve requirements.	May be needed in future.	Not needed.
Network	Cross border capacity. Forced outage rates and mean time to repair for transmission corridors.	Transmission line capacity between neighbouring areas.	Transmission line capacity between neighbouring areas and/or circuit passive parameters.	Network configuration, circuit passive and active parameters.	Network configuration, circuit parameters, control structures.
Other Power Plants	Rated capacities, forced outage rates (ideally as a time series), mean time to repair. Hydro power limitations (dry/wet/normal year)*.	Investment cost, efficiency, fuel costs, emission factors. Ideally also operational characteristics from UCED.	Min, max on-line capacity, start-up time/cost, ramp rates, min up/down times. efficiency curve, fuel prices.	Active and reactive power capabilities, system dispatch.	Dynamic models of power plants.

* More detailed resource adequacy data guidelines can be found at www.epri.com/resource-adequacy

** Climate change impacts are recommended to be included in wind/solar/load (and hydro) data, for studies looking more than 10 years ahead. Impact of latest wind turbine and solar PV technology with higher capacity factors also important to capture.

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3 Power and Energy System Scenarios

Lennart Söder, Niina Helistö, Hannele Holttinen, Emmanuel Neau, Juha Kiviluoma, Magnus Korpås, Madeleine McPherson, Mohammad Reza Hesamzadeh, Ana Estanqueiro. Review: Sumanth Yamujala, Aidan Tuohy

This chapter describes the grey/yellow system design choices box (Figure 3.1) of the wind/PV integration study flow chart. It covers the setup of the study and main assumptions regarding portfolio development, including transmission, generation, and storage scenarios and system management procedures.

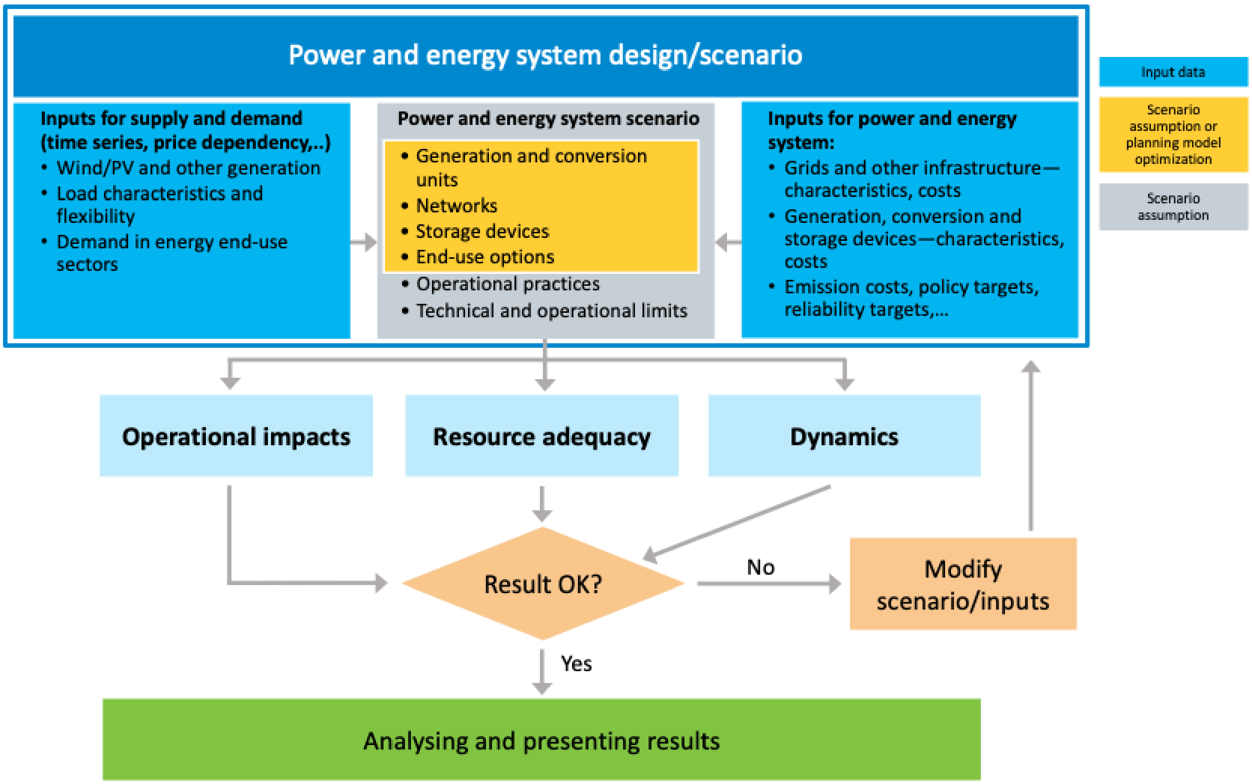

Figure 3.1. Wind/PV integration study – scenarios set up by assumptions on future demand, generation, storage, and transmission assets (gray), or by using capacity expansion (planning) model optimization (yellow).

The main decisions regarding portfolio development for future scenarios to study are:

- Whether the current system (with slight foreseeable changes) or a future power system is studied. In most cases, the higher shares of wind/PV power will be relevant for a future system, most likely in the 2030–2050 time frame. This means that adding wind/PV will replace older conventional generation capacity.
- The size of the area studied, for example, one balancing area or the whole synchronous power system. How to take neighbouring areas into account in the study?
- Assumptions of emissions and policy to reach emission targets will heavily impact the generation portfolio.
- The future demand – traditionally a simple growth rate for a known demand profile was sufficient, but for future systems electrification with different demand profiles and flexibilities needs to be taken into account.

- What will be the degree of coupling of energy sectors (aka energy systems integration) as well as relevance (and costs) of new energy vectors, e.g. (green) hydrogen, or (green) hydrogen-based fuels.
- What are the (relative) prices for different fuels used in the generation mix? The answer will determine which generating units are on the margin, which generating units are displaced by wind/PV power, and which are cycled more frequently to help manage the increase in variability and uncertainty.

The future scenarios can be constructed either by i) giving assumed inputs for capacities installed, for example, from the known or targeted generation, transmission, and storage capacities; or ii) capacity expansion simulations may be used to produce optimised generation, transmission, and storage portfolios for higher shares of wind and solar (when wind and solar capacities are inputs) or for different decarbonization scenarios (when wind and solar capacities are parts of the optimization).

Capacity expansion tools enable assessing the best combination of new resources, where not only the investment costs, but also operational costs are included. A "green field study" allows optimizing all new resources including capital costs. The other option is a "brown field study", where some resources are assumed to exist, so their capital costs are not included in the optimisation.

Shares of wind and solar may need to be decided in scenario assumptions, if they are not part of the variables in the capacity expansion tool. If this is a result from a capacity expansion tool, then an optimal share of wind and solar will depend on future cost development assumptions, emission goals or costs as well as assumptions for flexibility – on top of the wind/solar resource.

The process of transmission planning is in this report seen as an iteration between Section 3 Scenarios (for transmission); Section 4.2 checking steady state network adequacy; and Section 6 checking dynamics of the power system. For the case of distributed PV (and wind), it is more likely that the distribution system will be the subject of reinforcement (see Section 4.3). Transmission will be needed when wind/PV resources in remote areas are deployed. Transmission reinforcement often becomes cost-effective for future high wind/PV shares, and also other changes can make it necessary.

Transmission is often an assumption for simpler assessments; however, optimisation is increasingly used, in particular for offshore wind and grid development (Kristiansen, 2019). Planning can be done with co-optimization of resource and transmission or with iterative processes that check the transmission needed for a given resource solution and capacity expansion tools often optimize transmission capacity between areas. For transmission investment decisions, in many cases a cost benefit analysis (CBA) is performed. This process is not described in this report – an example set of criteria to assess the profitability of transmission reinforcements is presented in the European Network of Transmission System Operators for Electricity (ENTSO-E) ten year network development plans (https://tyndp.entsoe.eu/explore/what-is-the-cost-benefit-analysis-framework). It is important to recognize that transmission has many benefits in addition to the production cost benefits (which sometimes are the only benefit calculated) and that these benefits vary depending on the type of transmission (ESIG, 2022). For example, interregional transmission may have significant resource adequacy and resilience benefits while the transmission to connect wind/PV plants may have significant production cost savings and avoided capital costs. However, transmission development in most countries is a more complex process including non-cost factors such as politics, regulations, land rights disputes, and public acceptability, among others. In addition to determining the least cost buildout according to a capacity expansion model, scenarios that account for social and political barriers to transmission expansion can provide an important perspective. Energy transition brings more uncertainty to transmission planning. IEA TCP ISGAN recommendations for scenarios highlight the importance of including electrification, enabling deep decarbonisation, and further developing cost benefit analysis to weigh multiple metrics and assess all benefits of transmission to the energy system (ISGAN, 2023).

Reliability of the studied system needs to be checked for operational impacts, adequacy, and dynamics – important iterations back to scenarios are presented in the flow chart (Figure 3.1), where both data and assumptions as well as scenario setup can be modified based on the results of the more detailed simulation tools. The feasibility of the studied scenario can also be checked regarding the cost recovery of investments and existing power plants – whether energy only market prices will be sufficient in future.

3.1 Current and Future Power and Energy System Scenarios by Assumptions

Future scenarios can be determined based on fixed assumptions on the development of generation portfolio, storage and transmission assets. It is also possible to take a future scenario built up for a large area (like ENTSO-E scenarios for Europe https://tyndp.entsoe.eu/explore/the-scenario-building-process) as basis for a particular study. Smaller changes to current and anticipated systems can be made. However, when more changes happen, like assets are withdrawn as wind and solar are added, the resulting portfolio may not be the most optimal nor consistent with the assumptions behind the original scenarios, and capacity expansion models are recommended (see Section 3.2).

Considerations regarding generation portfolio and storage assets include:

- What will the composition of the generator fleet be in the future years, and will storage assets be invested in? The mix of inflexible base load units relative to more flexible resources will make a large difference in how difficult it is to integrate wind/PV power:
    - If large amounts of wind/PV power are expected, then conventional base load units (with high investment cost and low operational costs) may become uneconomic due to too few hours to operate, and they may be replaced by plants with lower investment costs, higher operational costs, and more flexible generation.
    - Will there be sufficient quick-start units in the future system? If so, the unit commitment problem is not so complex, nor as important. On the other hand, if there is a significant amount of slow-start generation or generation with high minimum run levels, unit commitment will become a more significant binding constraint.
    - Storage for short- and long-term flexibility: Energy storage devices can provide multiple services to the power system, and optimizing the future portfolio may not be able to take into account all benefits: balancing at short (hourly) and long (seasonal) timescales, shorter response grid support and grid bottleneck handling. Access to new storage from energy sector coupling (thermal storage impacting electricity demand for heat; hydrogen derivative storage impacting electricity demand for power-to-x).
- What are the relative prices for different fuels used in the generation mix? The answer will determine which generating units are on the margin, and therefore which generating units are displaced by wind/PV power, and which generation cycles more frequently to help

manage the increase in variability and uncertainty. This will also impact the results of operational cost savings.
- Assumptions of emissions and policy to reach emission targets will also heavily impact the generation portfolio.
- Capital cost assumptions of flexibility sources/generation technologies can highly impact the uptake of inter and intra-regional sources of flexibility i.e., investments in transmission expansion or alternative solutions such as energy storage.
- What weather data or weather year should be considered when modelling energy system scenarios? The assumptions can drive demand for electricity and heating, generation mix, and even electricity prices.

For most regions in the world, less wind power capacity is needed than PV capacity to meet target energy shares as the capacity factors of wind turbines are higher than solar PV panels. Solar belt (lower latitudes) has ample solar resource, and in some regions rather limited wind resource where solar would easily dominate the renewable energy mix. Seasonal variations in solar resource at northern latitudes could also affect the optimized portfolio.

Transmission networks help efficiently integrate wind and solar power. Increasing network capacity provides a means to get the electricity to where it is consumed, and also enables the sharing of flexibility between neighbouring areas. Network scenarios are an important input for simulations, and they can also be an output of the study – how much new transmission/distribution is needed to accommodate the foreseen wind/PV power. This usually means iterations from the power flow simulations (Section 4.2) back to the network scenarios. Meeting ambitious targets that have been set for wind/PV energy will often require upgrades to the existing network infrastructure and the construction of new lines. However, if congestion of the existing transmission or distribution network is not severe, curtailing wind/PV power or maximizing the use of existing lines may be more cost-effective, and faster, than building new lines.

Updated scenarios and models for electricity demand and other energy carriers has become more important due to several factors:

- Electrification leads to higher electricity consumption with load patterns that are different from present loads. Simple extrapolation of historical data is not sufficient, and new load models must be integrated in the integration studies.
- Load flexibility is expected to play a more central role in power system balancing as conventional flexible generation is reduced due to emission goals and/or costs.
- Some of the new and potentially flexible electric loads are linked to other sectors, such as heat, gas (hydrogen, etc.), and transport.

An example of electrification scenarios impacting the demand side in the U.S. energy system for transportation, residential and commercial buildings, and industry, both in terms of overall consumption patterns as well as the flexibility of newly electrified loads is in Figure 3.2. An example of future flexible demand in Denmark is in Figure 2.10.

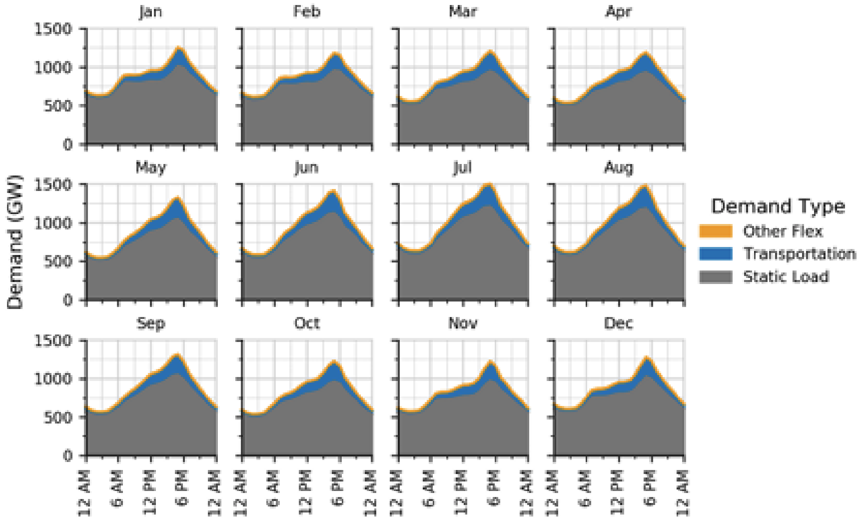

Figure 5. Flexible and inflexible load in 2050 under high electrification with high DSF

The hours in the x-axis correspond to the local time of each balancing area. The figure shows the general flexible and inflexible demand trends throughout the day without time-shifting cross time zones. Other Flex = all non-transportation flexible demand.

Figure 3.2. Potential electrification impacts for demand sectors in the United States (DSF is demand side flexibility) (Source: National Renewable Energy Laboratory Electrification Futures Report, Mai et al., 2018).

3.2 Optimising a Future Scenario by Capacity Expansion Tool

For longer term studies, capacity expansion simulations enable optimized generation and transmission capacity under different technology cost, performance, and policy assumptions, e.g. fuel and CO_2 prices or phase-out of certain technologies. These model tools are recommended for optimising the future generation mix for a higher share of wind/PV in power systems. CEMs can be called generation or transmission expansion planning models if they limit the scope of certain power system assets.

Integrated generation and transmission capacity expansion tools have benefits especially at higher shares of wind and solar (ESIG, 2022) or higher decarbonization goals (where wind and solar capacities become part of the model output). An integrated approach is also important because storage or transformation into other energy carriers via, e.g. power-to-X can, in some instances, mitigate transmission infrastructure needs. Transmission expansion can, in some cases, provide complementary flexibility benefits to the system as storage or demand-side flexibility, and as such it is important to test scenarios operational feasibility with adequate representations of transmission, flexible demand, and storage together.

A simplified representation of operational details (as well as analysis period and time resolution) can be employed in planning models to obtain a tractable optimization problem. However, for future wind and solar dominated systems, short-term balancing, with operational practices reflecting future system needs and services, will be important to model more in detail to see the impact of wind and solar forecast uncertainty on the optimal capacity mix. For wind and solar dominated power systems, capacity expansion tools should also include grid limitations and stability constraints, including grid expansion costs, because network capacity is very important when determining optimal wind and solar capacity in different areas.

Energy storage can be represented in various ways in capacity expansion models, and adds complexity to the solution procedure due to the inter-temporal constraints for the energy storage level:

- Batteries and other short-term storage technologies can be adequately accounted for in models that use representative days, because they typically have hourly to daily storage cycles.
- Hydropower storage and other long-term storage types may need a full-year, and even multi-year time resolution to capture the value of storage to handle seasonal variations in demands and renewable energy inflows. See Levin et al. (2023) for a thorough discussion on how to represent energy storage in capacity expansion models.
-
- With electrification, surplus electricity can be stored indirectly through other energy carriers (thermal storage, hydrogen, synthetic fuels, etc.). Energy sector coupling will be able to provide storage both at a shorter timescale (hours and days) but potentially also at the longer timescales (weekly, even seasonal with thermal storage), and thus assist with the energy adequacy challenge (for Energy System Integration Group (ESIG) research and development (R&D) needs, see O'Malley et al. (2019) and Section 4.1).

Updated scenarios and models for electricity demand and other energy carriers will become more important when assessing impacts for future power systems due to electrification demand linked to other energy sectors, and load flexibility playing a more central role in power system balancing as conventional flexible generation are reduced. One challenge is to incorporate flexible electricity demand from other sectors and maximize the total welfare of the entire system. A robust way of modelling future demand is still evolving:

- Electrification leads to higher electricity consumption with load patterns that are different from present loads. Demand projection used to be growth projection or efficiency projection with simple extrapolation of historical data. Now a 'load transition' is an integral part of the energy transition, and new load models must be integrated in the integration studies. The first methodologies include assuming some % of the load is flexible, and adding constraints in operational simulations to represent flexible load as an asset (See also Sections 2.3 and 2.4).
- Some of the new electric loads are linked to other sectors, such as heat, gas (hydrogen etc) and transport which can magnify flexibility in the electricity demand. As these energy sectors are more interlinked, it will be necessary to establish models and analysis tool that consider the interplay between the energy carriers in more details, and as such push the system border for integration studies towards full energy system models beyond electricity. Linking a power system model to an end-use model is one method of presenting future electricity demand from other energy sectors in power system capacity expansion model tools. (Figure 3.3 and Figure 3.4, also Figure 1.2)

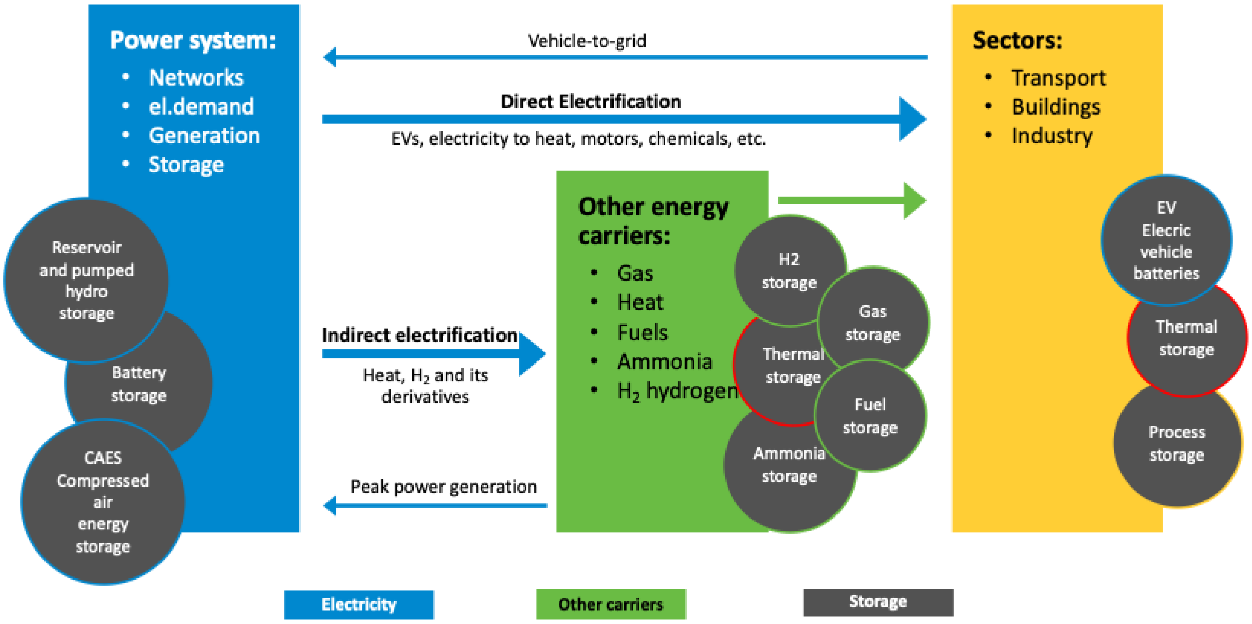

Figure 3.3. Interaction between the power system and other sectors – high level graph indicating the storage opportunities.

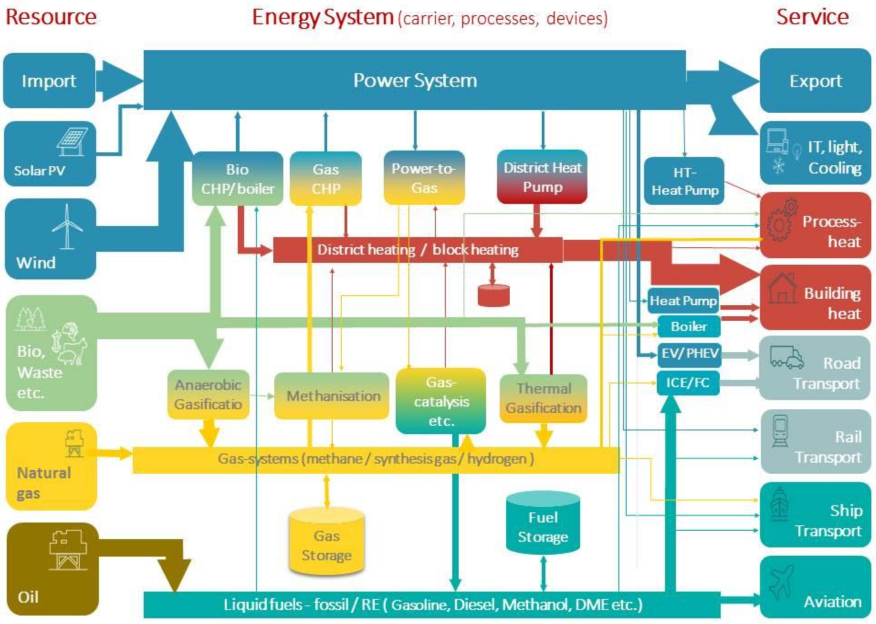

Figure 3.4. Interaction between the power system and other sectors – a detailed graph showing estimated energy flow in the Danish energy system for 2035 (Source: Orths & Hansen, 2019).

Energy system coupling will also add complexity to transmission planning due to the linked infrastructures, and there is a need for improved expansion planning tools in future. Also the operation of the electricity network given its connecting gas-heating-transportation networks becomes more challenging and it needs improved practices. Electric power system, natural gas system, district heating system and urban transport system are already integrated and they can have bidirectional flow of energy and information. Gas-fired power plants connect the electricity transmission network to natural gas transportation network, heat pumps are connecting technologies between the electricity distribution network and the district heating system. Electric Vehicle (EVs), Hydrogen Vehicles (HVs) and hybrid fuelling stations connect the natural gas network to the electricity distribution network. In this integrated energy infrastructure, the electricity transmission-distribution network has an active role in connecting all the other types of networks together. A complicating factor is that the interconnected electricity-gas-heating-transport networks cannot be expanded in isolation and new coordinated expansion practices are required (Wei & Wang, 2020).

The scenario for generation, storage and transmission asset portfolio from capacity expansion model optimization needs to be checked for cost recovery, to guarantee profitability of all assets in the electricity mix that are required for security of supply. When considering capacity adequacy together with energy adequacy and ramping adequacy, it would be beneficial to supplement capacity expansion models with analysis of the revenue sufficiency of market participants, see e.g (Wogrin et al 2021). The market operation will also impact whether that optimized capacity will be built. For example, energy-only markets based on marginal cost may not provide sufficient revenue for future high shares of wind/PV or the required flexible resources, and market design to enable cost recovery is another research topic (Estanqueiro et al., 2023).

For electricity network investments, cost recovery approaches can be categorized in three groups: (a) regulatory approach, (b) merchant-regulatory approach and (c) merchant approach (Hesamzadeh et al., 2020; Biggar & Hesamzadeh, 2020). Energy regulators usually require a cost benefit analysis from transmission system operators to justify new infrastructure buildout (see for example ENTSO-E CBA, 2022). Multi-value of transmission can also be considered (ESIG, 2022).

Capacity expansion models have been driven by the need to know which investments should be made – however, the ability to pinpoint that might become more limited when the energy system approaches 100% wind and solar. Investments are driven by expected profits, which are influenced by market prices, bilateral contracts as well as subsidies and taxes, all becoming more difficult to predict when moving towards 100% wind and solar, and more electrification.

Finally, it is important to keep in mind that planning level analysis has insufficient consideration of the three sub-problems of reliability, flexibility and stability. Consequently, studies that try to demonstrate feasible wind/solar dominated energy systems will need to iterate between the planning and other analysis to check the feasibility of the scenarios. New constraints may be added to existing model tools, or they can be linked with more detailed analytical tools (Helistö et al., 2019). With large wind/PV share (>50–70% in yearly energy), changes are so important that the system to study becomes completely different from the one we know, e.g. integration of power electronic interfaces, inverter-based resource (IBR), reduction of synchronous machines and inertia. Also resource adequacy is challenging to capture with planning models, because it requires multi-year time series. This means that conclusions merely from “simple” studies regarding viability of such a system must be taken with great care, and additional and more complete studies will be needed – recommendation is to check the feasibility of the scenarios coming out of planning models as pointed out in the flow chart (Figure 3.1).

3.3 Operational Practices and Markets

Operational practice among different power system operators varies significantly, and this can complicate system impact analysis. There are differences in the time periods associated with scheduling and dispatch, and there are also differences in the forecast period and notification period used to perform the processes necessary to execute reliable movement to a new dispatch point. The market services and products, definitions and availability of the various grid support services (ancillary services such as various reserve types for frequency control) are not the same from system to system, and operational reliability metrics also vary.

Practice with scheduling, dispatch and grid support services (called ancillary services, or essential reliability services) can have a significant impact on the efficient integration of wind/PV energy:

- Rolling unit commitment (Tuohy et al., 2009) has been shown to help with integration because new information can be incorporated into operational decision-making when it becomes available, allowing for changes in the unit commitment stack, subject to physical constraints.
- Larger electrical balancing areas and faster economic dispatch can impact reserve requirements and allow access to more flexibility compared to smaller balancing areas and longer dispatch periods (King et al., 2011).
- Closer to real time operation – continuously updating forecasts and using online-measurements of wind and solar – will reduce the amount of deviations that need to be corrected at balancing markets (or balancing timescale where no markets exist). This also impacts the size of allocated reserves.
- Grid support from wind/PV plants (frequency and voltage control) is important to take into account at larger shares of wind/PV. More recent market designs allow for wind and solar, and other distributed assets to bid their available flexibility to ancillary services markets. This will help to reduce curtailments at high wind and solar generation, as thermal power plants are not needed online to provide grid support (van Hulle et al., 2014; Kiviluoma et al., 2012).
- Allowing all possibilities for the demand side to participate in balancing and reserve markets (from large industry facilities to aggregated EVs). This will reduce the need for flexible (thermal) generation and potentially costly energy storage investments.
- In some cases, it may be economic to curtail wind/PV generation when there are transmission constraints or other constraints imposed by the inability to turn down large base-load units that do not occur frequently. Integration studies can directly simulate this by using a downward-dispatch price offer for wind/PV, allowing the production simulation model to economically curtail if, and when, it is economic.

For systems undergoing a first-ever integration study, the current operating practices may be used as a starting point, to establish a baseline from which changes can be evaluated. Another approach is to use existing practice in the study to determine whether this is sufficient to integrate the studied level of wind/PV energy. If operational problems emerge from the simulation, then alternative assumptions and scenarios could be developed to assess whether new methods of operation can be used to more efficiently integrate wind/PV energy – especially where market structures are inhibiting access to flexibility creating unnecessary imbalance costs at higher shares of wind and solar. Examples include reducing dispatch times and/or lockdown periods so that the latest information about wind/PV can be incorporated into the dispatch, intraday trading, and sharing balancing with neighbouring areas.

Understanding best operational practices at high wind and solar shares, with emerging storage as well as energy system coupling, can be part of the study to determine suitable market rules and market operation practices for reliable and cost-efficient integration of wind/PV power. An integration study should consider new market products and market designs as well as market regulations affecting in the background, and determine whether the existing ones are sufficient and how they could be improved to enable higher shares of wind and solar. Some operational and market questions include:

- Will markets evolve to include products that enhance flexibility or will fast dispatch/balancing be sufficient? Will there be reserve markets over different timescales? Will there be dynamic scheduling (of generation, load, or imbalance) that will have an impact on integration? When setting reserve requirements, is it allowable to deploy contingency reserves for significant wind/PV ramp events, and if so, what are the criteria for doing so?
- Will there be broader reserve-sharing regions? What is the assumption regarding balancing areas/zones, and what is the appropriate modelling approach to account for interchange that correctly captures actual (or future) practice?
- Will reliability-based balancing criteria be the same in the future? This would have a significant impact on wind/PV integration studies.
- What are the impacts of different capacity markets, capacity remuneration schemes and investment support mechanisms (e.g. contracts for differences) on electricity markets, the need for new flexibility sources, and the share of wind and solar in power systems? Will electricity markets with marginal pricing remain efficient in the presence of these mechanisms?

3.4 Conclusions and Checklist: Scenarios

The study assumptions regarding generation, storage, and transmission assets, as well as future demand and degree of sector coupling, will have a crucial impact on the results. The main issues to decide in the study setup are:

- How far in the future is the studied system assumed to exist? If it is rather close in time, then most of the existing infrastructure and other power plants will remain. If it is further in the future, new, more flexible technologies can be assumed to replace old ones. Wind/PV power is added by replacing some existing (older) generation, adding to an otherwise unchanged system, or through capacity expansion optimization.
- How to take neighbouring areas into account in simulations.
- Assumptions regarding available flexibility and operational practices to use it – both in demand and supply and from electrification and energy system coupling.
- Price projections for fuels and emissions and policy to reach emission targets.

As future systems are experiencing large changes of energy transition (and load transition), it is recommended to try to include all in optimisation, and not determine beforehand. This means using capacity expansion tools, that also need to be improved and extended.

It is recommended to study several options for operational practices and market design, to understanding best operational practices for the power system in question with high shares of wind and solar and storage.

With large wind/PV share (>50–70% in yearly energy), changes are so important that the system to study becomes completely different from the one we know. This means that the feasibility of the scenarios constructed from planning models have to be checked with additional and more complete studies: all three iteration rounds in Sections 4, 5 and 6 for Adequacy, Operational impacts and Dynamics need to be performed.

The main recommendations are as follows:

Checklist of Key Issues: Power and Energy System Scenarios

- When studying small amounts of wind/PV power or short-term studies, wind/PV power can be studied by adding wind/PV to an existing or foreseen system, with existing operational practices.
- For larger shares and longer-term studies, changes in the assumed remaining system become increasingly necessary and beneficial: expedient generation portfolio, storage assets and network infrastructure development, taking into account potential sources of flexibility. Capacity expansion tools are recommended to construct optimized scenarios to study. Additional scenarios for operational practices should be studied especially for market structures/design to enable flexibility.
- For wind/PV dominated power systems, changes will be so important that the system to study becomes completely different from the one we knew in recent past (e.g. new electrification loads, integration of inverter-based resources, reduction of synchronous machines and inertia, closer interaction with other energy sectors/carriers). Capacity expansion models should be used, and all the feasibility checks for Operational impacts, Adequacy and Dynamics become more crucial to perform. Capacity expansion tools should be improved to include:
  - representation of demand flexibility, storage and sector coupling including new electrification loads and access to other than electrical storage as these will be crucial new flexibility sources in future;
  - short-term balancing, in order to see the impact of wind and solar forecast uncertainty (and nowcasting tools) on the optimal energy mix;
  - grid limitations and stability constraints, including grid expansion costs, because network capacity is very important when determining optimal wind and solar capacity in different areas;
  - operational practices reflecting future system needs and services.

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4 Resource and Grid Adequacy

Bethany Frew, Aidan Tuohy, Niina Helistö, Juha Kiviluoma, Lennart Söder, Damian Flynn, Thomas Heggarty, Antje Orths, Denis Mende, Hannele Holttinen, Emmanuel Neau, Debbie Lew, Madeleine McPherson, Ana Estanqueiro. Review: Jian Fu, Corrado Gadaleta.

The simulation boxes of the wind/PV integration study flow chart relating to the adequacy of the studied portfolio are now discussed (Figure 4.1 green boxes). Once a future scenario is constructed, the adequacy of the generation capacity and network (the grid) should be assessed. The generation and storage portfolio can be checked for the probability of loss-of-load events, considering several years, or decades, of weather data impacting generation and demand profiles, along with forced outage rates for conventional generators and, if possible, also transmission lines. In addition, the transmission and distribution network adequacy can be checked using steady state power flow analyses, including credible contingencies and challenging load and generation flows – part of the network planning process. For higher wind and solar shares, Section 6 (Dynamics) will consider non-steady state (transient) analyses for transmission planning, while Section 5.3 will discuss flexibility adequacy.

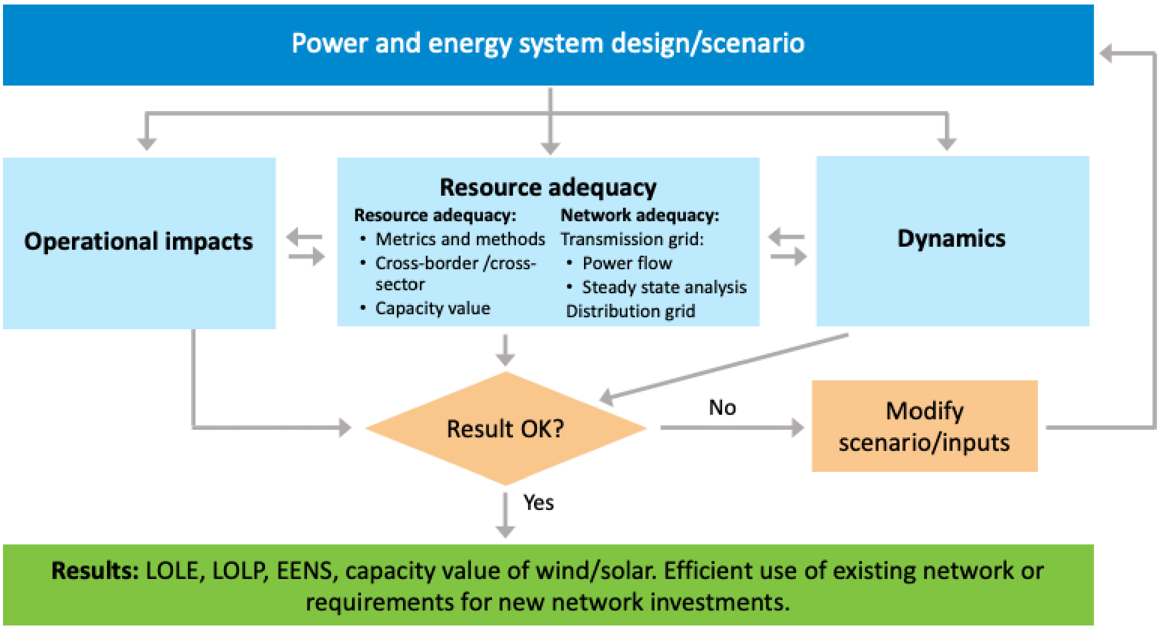


Figure 4.1. Wind/PV integration study components: Resource and network adequacy.

4.1 Resource Adequacy

Resource adequacy considers the availability of power plants to serve the demand for all instances (according to a certain level of risk of lost load), and covering generation capacity, energy, and flexibility adequacy. Traditionally, focus is placed on generation capacity adequacy, and particularly on peak demand periods, capturing those (rare) occasions when simultaneous occurrence of high load and generator failures could occur. If capacity adequacy is insufficient, the standard way to improve system adequacy is to assume the availability of more peak load power plants.

With high shares of wind and solar generation the assessment of capacity adequacy needs to evolve to better capture future risks. This entails incorporating more years of data and climatic projections to assess low-probability high-impact events. In addition, correlated failures due to weather events should be considered, such as common mode failures and even “black swan” events that are very rare, as well as coordinated cyberattacks. Increased weather dependency for both generation and demand (with heating and air conditioning and increasing electrification) requires an assessment of *energy* adequacy – even with sufficient installed capacity there may be insufficient energy resource to meet electrical demand requirements. Similarly, other aspects of resource availability, including the ability of resources to provide adequacy *flexibility* and provide certain *grid services*, are also being considered by some as components of the overall resource adequacy paradigm,

In wind and solar dominated power systems other options beyond backup generation capacity become relevant for managing insufficient resource adequacy. These include the role of flexible demand and electricity storage as well as capacity contributions from neighbouring regions. Back-up capacity will be a costly option in large quantities, and cost efficiency of resource adequacy becomes relevant with higher wind and solar shares.

4.1.1 Resource Adequacy Metrics

A common probabilistic-based metric used for resource adequacy is the loss of load probability (LOLP) or, when aggregated across multiple time periods, loss of load expectation (LOLE). This reflects the probability that the load cannot be met due to a lack of available generation, storage or transmission capacity. LOLE represents the expected number of hours (or days) during which the load will not be met over a defined time period. LOLE is commonly used by regulators to define reliability targets for system planning studies. The LOLE targets vary from one country to the next, e.g. 3 hours per year in Great Britain, France and Belgium, 8 hours per year in Ireland, or 0.1 days per year in North America (Söder et al., 2019).

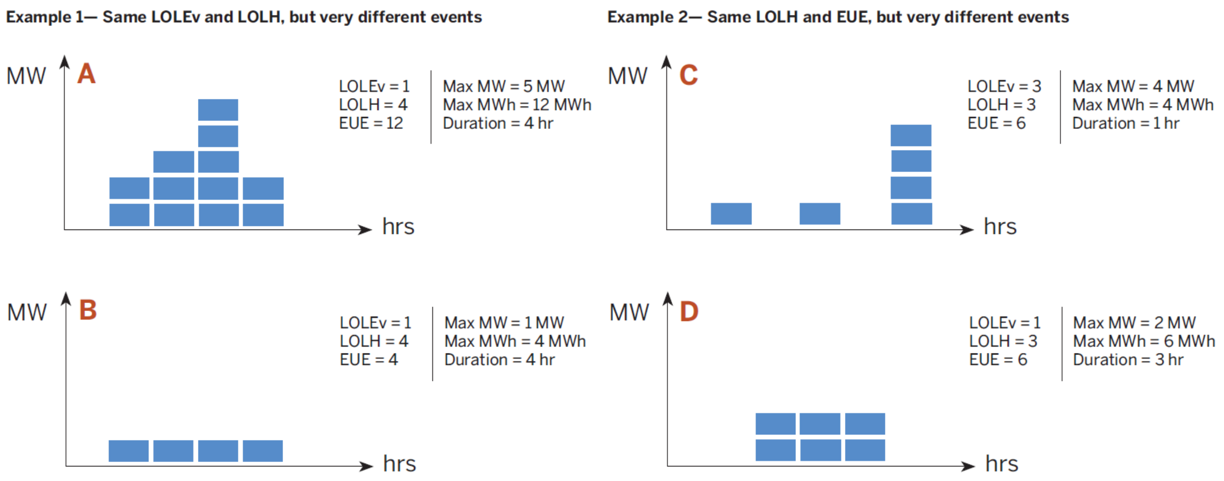
By dividing the investment cost of the highest marginal cost generator, expressed in €/MW, by the value-of-lost-load (VOLL) expressed in €/megawatt-hour (MWh), a theoretically optimal value for LOLE can be obtained, expressed in hours. In practice, VOLL is notoriously difficult to determine, and depends on electricity use, outage frequency, duration, time, notice period, etc. (see Table 15 of ENTSO-E guidelines for a review of VOLL, as used in Europe (ENTSO-E, 2020)).

Another common metric is the planning reserve margin (PRM), which reflects the additional installed capacity above peak load, expressed as a percent of peak load. PRM is a non-probabilistic metric that affords simplicity and transparency, but this simplicity makes it a less robust metric, especially with increased variability and uncertainty due to weather-driven resources, electrification, extreme weather events, and correlated outages. While PRM can be mapped to probabilistic-based metrics, that mapping must be conducted regularly, and it requires a number of assumptions, such as the capacity credit of each resource type (NERC, 2023). The capacity credit (or capacity value) quantifies the contribution to resource adequacy (more details can be found in Section 4.1.3). The capacity credit is highly sensitive to the system buildout, weather/climate, and load assumptions.

LOLE only gives an indication of the expected number of hours or days of shortfall over a certain time period and lacks information on the magnitude, frequency and duration of the outage(s). Additional probabilistic-based metrics are needed to capture information on frequency, duration, timing, and magnitude of shortfalls (ESIG, 2021b). Examples include loss of load events (LOLEv) or loss of load frequency (LOLF), which are both metrics that represent the expected number of adequacy events over a certain time period, with an adequacy event defined as a contiguous set of hours with a shortfall. The metric includes both multi-day events and multiple events per day. If

LOLE is used to represent the expected number of days of shortfall, loss of load hours (LOLH) can be used to represent the expected number of hours of shortfall. Expected unserved energy (EUE) and expected energy not served (EENS) are metrics that represent the average amount of unserved energy (i.e., MWh) within a certain time period, thereby providing information on magnitude. EUE, or normalized EUE (NEUE), usually normalized to the total load over the assessment horizon, has more recently been considered a superior option to LOLE (ESIG, 2024).

All of the above metrics reflect aggregate, average values that do not distinguish between individual events and/or do not capture the full set of characteristics of an event. For example, the illustrative graphic in Figure 4.2 shows how a system can achieve the same metrics, but for very different events, which highlights how a given metric (or two) can miss critical aspects of an event. It is therefore recommended to keep all these metrics to get more detailed information on the events.

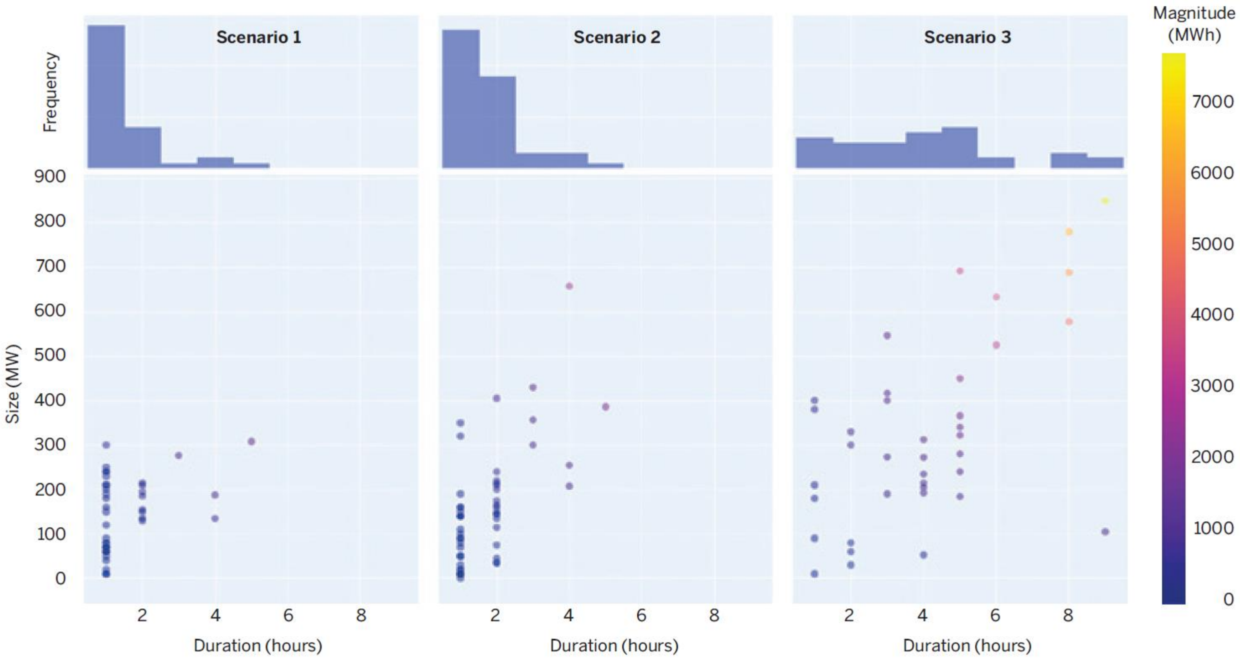


Each block represents a one-hour duration of capacity shortfall, and the height of the stacks of blocks depicts the MW of unserved energy for each hour. A: a single, continuous four-hour shortfall with 12 MWh of unserved energy; B: a single, continuous four-hour shortfall with 4 MWh of unserved energy; C: three discrete one-hour shortfall events with 6 MWh of unserved energy; D: a single, continuous three-hour shortfall with 6 MWh of unserved energy.

Source: Energy Systems Integration Group.

Figure 4.2. Four different capacity shortfall events highlighting the difference in shortfall events and how traditional metrics alone can fail to capture them (Source: ESIG, 2021b, https://www.esig.energy/reports-briefs).

Furthermore, with evolving power system configurations/attributes and climatic conditions, the fundamental concept of risk and overall resource adequacy paradigm are being revisited. One solution is to implement a multi-criteria framework whereby the constituent set of metrics provide a more complete picture of resource adequacy (ESIG, 2024; EPRI, 2024). This includes the previously mentioned dimensions of frequency, magnitude, duration, and timing (as shown in the example in Figure 4.3 for all but timing dimension), as well as other aspects that capture economics or tail risks (extreme events). Tail risk criteria options include metrics of the underlying distribution, severity threshold (e.g. value at risk (VaR) or conditional value at risk (CvaR)), daily LOLP limit, and survey results for ranking (ESIG, 2024).



Source: Energy Systems Integration Group.

Figure 4.3. Scatter plot of size, frequency, and duration of shortfall events with reliance on energy limited resources. Similar loss of load expectation events can have very different frequency and size of events (Source: ESIG, 2021b, https://www.esig.energy/reports-briefs.)

4.1.2 Resource adequacy assessment methods

Well established traditional generation capacity adequacy assessment methods (Billinton & Allan, 1996) that can take into account wind and solar generation (Keane et al., 2011) are available for lower wind and solar shares. For high wind and solar shares these need to be reconsidered, accounting for two driving factors: chronological grid operations must be analysed, and correlated events must be accounted for (ESIG, 2021b):

- Increasing importance of energy-limited resources (wind, solar, storage and demand response) make it essential to understand the full year of chronological operation of the grid. Specific attention must be paid to hourly, seasonal, and inter-annual resource variability. The sequence of variability is key, as energy-limited resources, such as storage or demand response, require either a preceding period or subsequent period of high production to be useful for grid reliability.
- Previous resource adequacy analyses have focused on shortfalls caused by random, discrete mechanical failures of large generating units. In contrast, shortfalls in future will increasingly be caused by multiple, correlated events caused by common weather patterns. Resource adequacy analysis must increasingly shift its focus to these correlated events.

The above items underscore the need for greater data granularity and model detail to capture the growing level of uncertainty and complexity in power systems as the wind and solar share increases – among a multitude of other factors. This includes probabilistic resource adequacy models coupled with production cost modelling, where the lines between these traditionally siloed domains is increasingly blurred. One example of how operational decision can impact resource adequacy outcomes is shown in Figure 4.4. This example show three instances of an energy-limited resource scheduling during a loss-of-load event. In each case, the total battery storage available is equal to 6 units (blue boxes), and the total unserved energy (EUE) is equal to 14 units (green boxes). However, decisions of the battery storage scheduling changes the LOLH, maximum shortfall magnitude, and event characteristics.

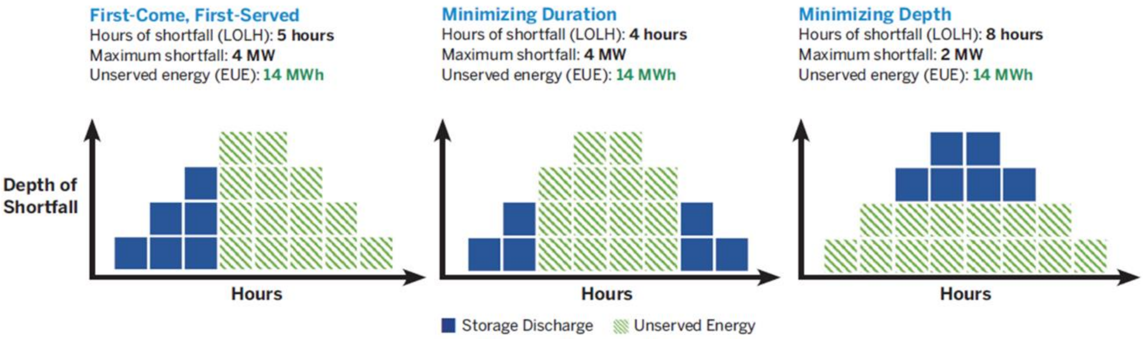


Figure 4.4. Battery storage scheduling can influence resource adequacy metrics. (Source: ESIG, 2024, https://www.esig.energy/new-resource-adequacy-criteria).

The combined effect of numerous system stresses – extreme weather, equipment failures, fuel limitations – all on top of an evolving resource and supply mix is requiring more granular and detailed resource adequacy modelling. An example showing how multiple sources of system stress can compound resource adequacy outcomes is shown in Figure 4.5.

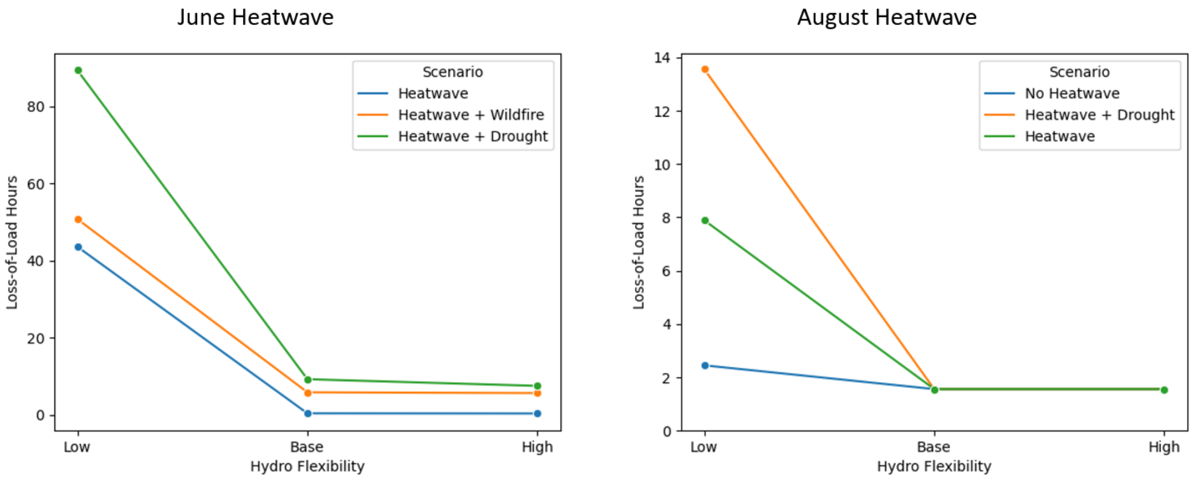


Figure 4.5. Resource adequacy impacts with various levels of hydro flexibility (low, mid, high) and extreme weather events for a study in the U.S. Pacific Northwest (Source: Datta et al., 2023).

For larger shares of wind and solar, methods still need to improve the representation of (Holttinen et al., 2020):

- *Large, connected areas*: Increasingly, larger areas are being interconnected by transmission, and methods must improve to represent the adequacy sharing potential when a larger geographical area is connected via limited capacity transmission. Transmission is an important enabler of resource adequacy and neighbouring grids and transmission can be modelled as a resource that directly contributes, such as a capacity resource with an availability. Multi-area Monte Carlo techniques are emerging (ENTSO-E, 2023; Tómasson & Söder, 2017a).

- *Storage*: storage devices need to be more fully represented. For example, incorporating state-of-charge limitations is an important consideration during adequacy events (Byers & Botterud, 2019). Doing so requires including chronology into planning models, which can prove to be computationally expensive. Studies trying to capture energy storage and demand response impacts within generation capacity adequacy are emerging (ENTSO-E, 2023).
- *Flexible demand*: Load participation fundamentally changes the resource adequacy construct, as time varying demand flexibility contributes to adequacy. This applies for both new and existing loads. Traditionally, the load was treated as an exogenous parameter. Increasingly, adequacy assessment methods must consider at least some of the load as optimisation variables (particularly important for electric vehicle charging, electrolysers, electrified industrial processes such as heat). Expected unserved energy (EUE) has a price, and part of the demand can still be fixed with exogenous inputs, but more sophisticated methods are required to model the behaviour of flexible demand to represent it as a price sensitive demand.
- *Distribution networks*: integrating much of the demand side flexibility depends on a robust distribution system that can connect flexibility in loads as well as generation units. Leveraging demand side flexibility can be limited by distribution network bottlenecks. This means that analyses should account for the distribution system topology.

(1) *Weather dependency*: resource adequacy calculations are dependent on several weather-linked parameters (such as temperature, wind speed, irradiation) As weather driven resources provide a greater share of generation, data should be extended in order to reach desired confidence levels. Chronological operations must be modelled across many weather years. Also, climate change will have an increasing impact on weather patterns and the severity of extreme events. Sources of system stress include heatwaves, cold events, wildfires, storms and droughts. These conditions can impact wind. For example, strong storm events can shut down large parts of planned offshore wind generation. Perhaps more importantly, periods of low wind speeds across entire continents pose a significant risk. Cold events can also impact traditional elements of the grid, such as natural gas operations. Longer-horizon data should include necessary variables at sufficient spatial-temporal resolution, coincident and physically consistent in space and time across weather variables with sufficient accuracy and fidelity; cover multiple decades with a consistent methodology and validated against real conditions with uncertainty quantified, documented transparently, and in detail, including limitations and a guide for usage; periodically refreshed to account for scientific and technological advancements (ESIG, 2023a). See also Section 2 Input data.

- *Sector coupling* across transport, heating, cooling, gas, hydrogen, etc. Electric vehicles, space heating and air conditioning, represent largely untapped resources, where there can be flexibility regarding when to charge/heat/cool. This can be treated in a similar manner to demand flexibility (3), however, power conversion to products such as synthetic fuels and fertilizers (i.e., storage capability) will play an important role in resource adequacy calculations, and make the dimensionality of adequacy calculations even more challenging. Several methods are emerging to represent this, such as linking distinct sector-specific (transport, building, power) system models, parameterizing a virtual generator that represents a flexible demand type using exogenous data, or applying machine learning methods that are trained on sets of model runs.

- *Resilience*: adding resilience to resource adequacy methods is emerging as an important suggestion. These stressful conditions are a critical and appropriate part of the risk assessment. The ESIG Task Force on RA Criteria recommends to specifically include extreme events, as tail risks can have a disproportionate impact on reliability and costs, and they should be quantified in resource adequacy criteria (ESIG, 2024). The European Ten-year Network Development Plan includes an assessment of the resilience of the system (ENTSO-E, 2024). Transmission is also a critical component, where the resilience benefits can be quantified by assessing the severity of the events in terms of unserved load and duration – the reduction in unserved energy attributed to transmission lines during loss-of-load events remaining after resource adequacy improvements (see ESIG, 2022 p. 43).

Finding the right resource solutions to improve future resource adequacy involves quantifying the size, frequency, duration, and timing of capacity shortfalls (ESIG, 2021b). Reliability criteria and adequacy metrics should reflect the needs of society: which critical loads must be served, and which can be flexible – for example, by what percentage, for each type of consumer and area of the network. Reliability targets could also be revisited, allowing more hours/events per year, and rolling load shedding when load (price) responsiveness is insufficient. Reliability criteria should be transparent and economic – relying solely on building peaking, reserve capacity will incur high costs in a wind and solar dominated power system.

Even if sufficient capacity is installed, the required energy to power the resources may not be available to generate the electricity needed – this is defined as energy adequacy. If one, e.g. has large installed capacity in storage and/or hydropower, then one can get enough MW production only if there is sufficient energy stored. Analysing energy adequacy has previously been of interest for hydro dominated systems, but for very high wind and solar shares this will become more important: to have enough storage for “low energy availability”. In a market based power system, this will lead to high prices during these situations and if there is flexible demand, which reacts on prices, this will mitigate the challenge. The statistical energy criteria is explained in (Söder, 1999).

Energy adequacy can be analysed with scheduling or planning models, but representing a sufficiently long time horizon makes this challenging. This includes chronology considerations, where operational decisions in one time step can impact a resource’s energy availability many timesteps downstream. The growing presence of storage – particularly longer duration storage that spans weeks, months, or years as well as yearly resource variations is another challenge. Novel ways of enabling computationally tractable representation of these multi-timescales for long duration storage are being explored (Guerra et al., 2024).

The European Resource Adequacy Assessment ERAA (ENTSO-E, 2022), is a good example of a reference methodological framework. Coordination of 39 different Transmission System Operators is needed, and data consistency is ensured by different common databases, such as the Pan-European Market Modelling Data Base and the Pan-European Climatic Database. The whole of Europe is modelled using 56 bidding zones, looking 10 years ahead, concentrating on 4 target years within this period. For each target year, the European system is simulated at an hourly granularity. It is exposed to 35 years of reanalysis weather data, which, combined with generation availability time series that include random outages, are used to construct Monte Carlo years. Demand is partly weather dependent, and both explicit and implicit demand side response is considered. Some of the interconnectors between bidding zones are modelled used a flow-based approach, others using Net Transfer Capacities. Reliability standards are evaluated using expected energy not served (EENS) and LOLE. As well as the pure “adequacy” part of the assessment, the process also performs an Economic Viability Assessment, to evaluate the likelihood of plant being retired, moth-balled, or newly built. This requires an iterative procedure (Figure 4.6). Plant profitability is evaluated based on the energy-only market principle. If reliability standards are not met, the need for additional capacity justifies the need for a capacity mechanism to be implemented/renewed.

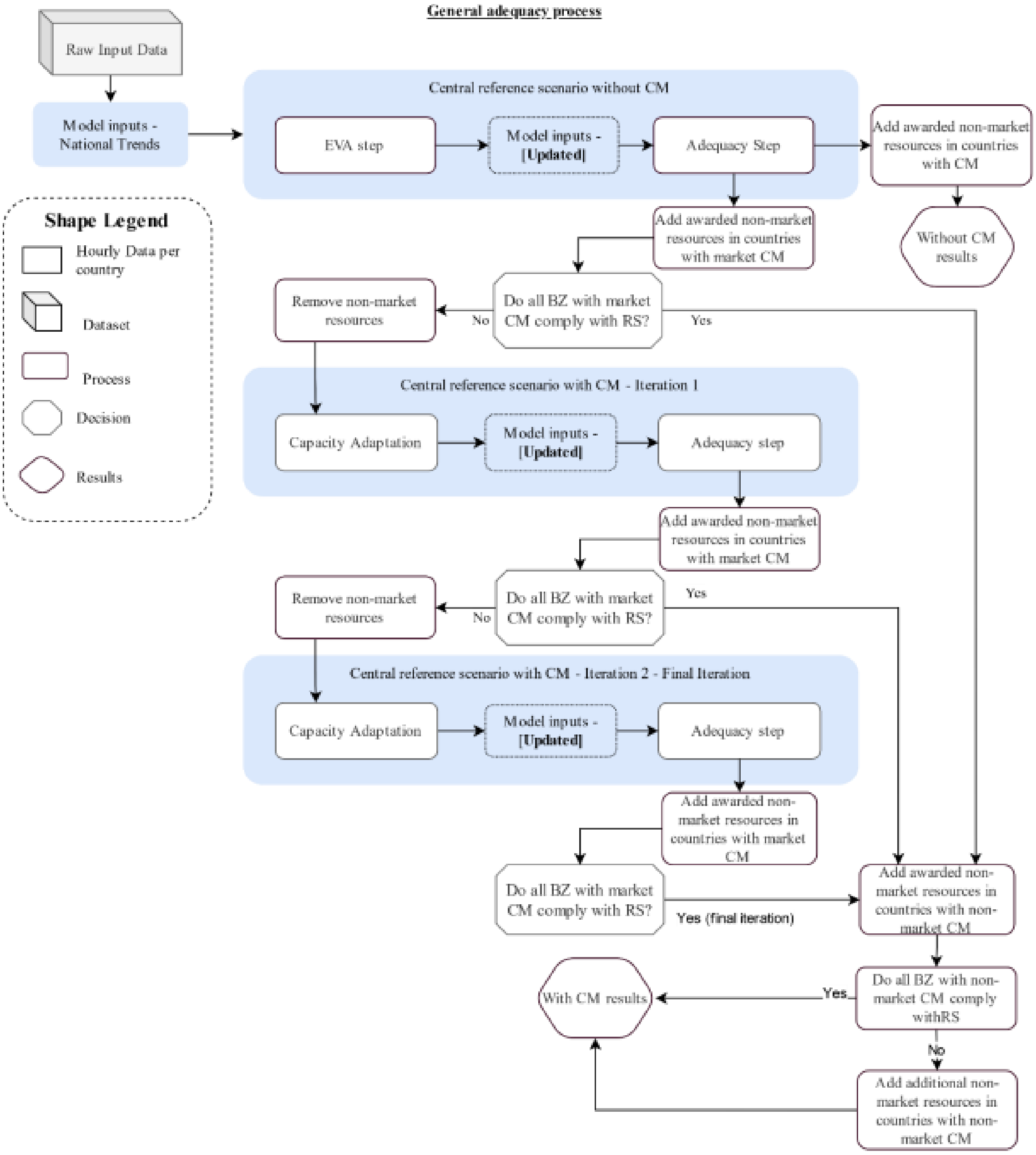


Figure 4.6. Overview of the European Resource Adequacy Assessment (ERAA) process (Source: ENTSO-E, 2022). CM = capacity mechanism. EVA = Economic Viability Assessment. BZ = bidding zone. RS = Reliability of supply.

An extensive survey of the current state and remaining gaps of resource adequacy modelling, available in (https://msites.epri.com/resource-adequacy), include a range of case studies across the U.S. to highlight key considerations and challenges with resource adequacy modelling. A summary of modelling approaches for various set of technologies and suggested level of fidelity based on the system and technology share are provided in (EPRI, 2023a). A set of 7 key gaps was identified requiring further research (EPRI, 2023b):

1. Need for improved and more detailed resource adequacy metrics.
2. Holistic integration of resource adequacy with other planning activities.
3. Improved load forecasting considering weather impacts, electrification, and climate change.
4. Identification and analysis of outlier, high-impact, low-probability, events.
5. Capturing winter risk associated with fuel supply and weather-dependent outages.
6. Interregional coordination.
7. Incorporating consistent and correlated weather datasets.

4.1.3 Assessing Capacity Value of Wind and Solar Generation

Estimating the capacity value of wind and solar generation to the power system can be useful for long-term planning or capacity markets. Capacity value, or capacity credit, or capacity accreditation, is the impact of a specific (generation) asset to the generation capacity adequacy of the whole power system. One overarching recommendation – regardless of the wind and solar share level – is to implement technology-agnostic capacity value approaches to ensure non-discriminatory treatment across all resource types (wind, solar, storage, thermal, demand-side, etc.) (ESIG, 2023b).

The modelling tools for the generation capacity adequacy of the whole system can be used to assess the capacity value of a certain asset. The metric that can be used to denote the capacity value is the effective load carrying capability (ELCC) (Garver, 1966). For wind and solar dominated power systems, capacity value becomes difficult to assess: ELCC will work for small to medium shares of wind and solar, after which demand flexibility and storage becomes crucial to include in the calculations.

New wind power and/or PV generation will add generation capacity to the power system, and, as such, their direct impact to capacity adequacy can only be positive, or at worst negligible, close to zero. Adding wind/PV capacity will also influence the profitability of existing and planned power system assets, however, the long-term capacity impacts of any new asset are difficult, if not impossible, to discern (a system property where the causal chains are likely not separable).

Using storage to improve the effective capacity value of wind/PV generation in future systems is possible. From a power system perspective, the approach so far has been to calculate wind and PV capacity value separately, and then permit storage to be one option (from the system point of view) to address potential problems in capacity adequacy. When storage system operation is determined from a single PV/wind power plant point of view, while providing potential value in eased interconnection, higher potential revenue, etc., the overall system ultimately operates in a non-optimal way from a capacity value perspective. Due to complementarities between wind and PV, a system achieves operational benefits and greater production with a combination of both resources compared to a single technology.

General recommendations for how capacity value is used should be noted (ESIG, 2023b):

- Be cautious if using capacity credits – in isolation – as the basis for ensuring reliability.
- Consider accreditation methods that evaluate not only a resource's capacity, but also energy availability during periods of high risk.
- Accredit all resource types using similar metrics and methods.

- Align incentives in capacity accreditation and real-time performance, in order to not only simulate availability during typical risk periods but ensure performance during actual scarcity events.
- Evaluate methods to simplify and streamline accreditation calculation techniques.
- Ensure that the foundational pillars are clearly communicated to stakeholders.

Methodologies and Modelling Tools

Capacity value studies in various power systems have been undertaken using a variety of methodologies (see Holttinen et al. (2009) or Holttinen et al. (2016) for comparisons). Across systems, the general trend has been that wind and solar capacity value decreases with increasing installed capacities. This is due to the correlation between the output of new and existing wind and solar power plants. New plants tend to produce during those hours when there is already generation, and not so much during those hours when the generation is more limited.

An important characteristic of wind power is its spatial diversity. This means that the capacity value increases relative to larger region sizes (Holttinen et al., 2009; Holttinen et al., 2016) – larger areas reduce the number of hours of low wind output, due to the smaller probability of very low output across the entire system.

The existing or targeted reliability level in the power system can greatly impact the capacity value of both conventional power and wind/PV power (Clark et al., 2005). When the reliability level is lower and LOLE higher, there is relatively more value in any added capacity than for those cases when LOLE is very low.

As the correlation between wind/PV generation and peak load situations strongly influences the results, many years of coincident load and wind/PV data are needed. The resulting answer cannot be relied upon if sufficient data of the required quality are not available (Hasche et al., 2011; Milligan et al., 2017).

The recommended method for determining the capacity value of wind and solar generation is the effective load carrying capability (ELCC) calculation, up until higher shares of wind and solar when demand flexibility and storage becomes crucial to include in the calculations.

Recommended Effective Load Carrying Capability (ELCC) Method

The Institute of Electrical and Electronics Engineers (IEEE) Wind and Solar Power Coordinating Committee's Wind Capacity Value Task Force proposed a preferred methodology to calculate the capacity value of wind power (Keane et al., 2011). For power systems dominated by wind and solar generation, flexibility in storage and demand should be taken into account, as discussed in previous sections 4.1.1 and 4.1.2. In addition, the question of capacity value will become irrelevant, and instead assessing the holistic resource adequacy of the system will be key.

The same method is equally valid for assessing the capacity value of solar power generation. The method can be applied to both separately, but in some cases, it could be informative to apply the method for aggregated wind/PV, including installed storage capacity:

1. Conventional generation units are modelled by their respective capacities and forced outage rates (FOR). Each generator capacity and FOR is convolved via an iterative method to produce the analytical reliability model (capacity outage probability table (COPT)) of the power

system. The COPT is a table of capacity levels and their associated probabilities (Billinton and Allan, 1996). The cumulative probabilities give the LOLP for each possible available generation state. Run-of-river hydro is usually treated by its time series. Usually decades of data of how run-of-river hydro generates during peak loads are available.

2. The COPT of the power system is used in conjunction with the hourly demand time series to compute the LOLE without the presence of wind/PV generation. Wind/PV power cannot be adequately modelled by its capacity and FOR because availability is more a matter of resource availability than plant availability. Time series for the wind/PV power output is treated as negative load and combined with the load time series, resulting in a load time series net of wind/PV power. In the same manner as above, the LOLE is calculated. It will now be lower (and therefore better) than the original LOLE.
3. The load data are then increased across all hours using an iterative process, with the LOLE recalculated at each step until the original LOLE is reached. The increase in the load is the ELCC, or capacity value, of the wind/PV generation.

For higher shares of wind and solar, ELCC method with Monte Carlo simulation approach with varying load, wind/PV and hydro levels and outages is better than using COPT (steps 1 and 2 above). When generating Monte Carlo scenarios, auto- and cross correlations can be captured between wind, PV and load, the use of energy limited storage, weather dependent outages and other factors (Tómasson & Söder 2017a and c) and have also been applied in large real multi-area systems (Terrier, 2017; ENTSO-E ERAA, 2023), and also for the estimation of multi-area capacity credit (Tómasson & Söder, 2017b).

4.1.4 Checklist: Resource Adequacy Estimates

Checklist of Key Issues: Resource Adequacy Estimates

- Include neighbouring areas and import possibilities (with forced outage rates) during times of generation scarcity.
- Consider the impact of inter-annual resource variability as part of yearly energy reliability. Improve data, and sensitivity to capture extreme events. Current models capture correlated events, if represented in the data, which means data should span 30+ years. Forward looking data should also account for climate change impacts on resource availability and demand profiles. Temperature-correlated outages of thermal generators and common mode failures during extreme weather events should be captured.
- Include load and storage flexibility during times of high load and/or low energy resource. Chronological models are needed for assessing adequacy impacts with these resources, important for higher shares of wind and solar.
- At higher shares of wind and solar (and storage) when the energy deficit volume becomes more important, use multiple adequacy criteria and metrics to fully identify, understand, and communicate risk. These can include metrics for the loss of load hours, loss of load frequency and expected unserved energy, indicating how severe the adequacy events are on average across a certain time period.. Assess tail risks with criteria options such as metrics of the underlying distribution and severity threshold as well as through scenario-based stress tests. Assess adequacy on the seasonal and/or monthly basis as well as annually.
- Future load projections should account for the difference between electrification loads and existing loads as well as climate change impacts on demand profiles.

- For wind and solar dominated systems, consider reliability targets, allowing more hours/events per year, and rolling load shedding when load (price) responsiveness is insufficient.

Checklist of Key Issues: Capacity Value

- Capacity value of wind and solar are heavily system-dependent and need to be updated to reflect the changing system buildout, configuration, and operations.
- Effective load carrying capability (ELCC) calculation is the preferred method, for wind and solar separately or in aggregate:
  - For low and medium shares of wind you can convolve generator capacity and forced outage to produce the capacity outage probability table (COPT) of the power system, a table of capacity levels and their associated probabilities. LOLE for each hourly demand level is calculated from the COPT table.
  - For higher shares of wind and solar it is necessary to include storage and flexible demand in the estimation, which is difficult with COPT method. A Monte Carlo simulation approach is therefore recommended, with varying load, wind/PV and hydro levels and outages.
  - For both methods, LOLE is first calculated without the presence of wind/PV generation. Then wind/PV is added as negative load and load is increased until the same LOLE is reached as without wind/PV power. Both methods require preserving the auto- and cross correlations between wind, PV, and load, and including enough data.
- For wind and solar dominated systems, it is recommended to use integrated planning approach where resource adequacy is embedded.

4.2 Network Adequacy: Transmission Grid

Damian Flynn, Debbie Lew, Nicolaos Cutululis, Til Kristian Vrana, Antje Orths, Ana Estanqueiro, J Charles Smith, Enrico Maria Carlini, Hamed Heydari-Doostabad, Hannele Holttinen, Niina Helistö

Transmission planning includes ensuring the adequacy and security of the transmission grid, such that the transmission grid (potentially including new lines) (Section 3 Scenarios) is feasible and secure during normal conditions, and during likely contingency events. In this section, a brief description is given of what should be checked for the transmission grid, to assess the adequacy of the network for the assumed power plant portfolio. A case study definition is first proposed for steady-state analysis, before proceeding to more detailed assessments. Finally, a checklist is given. See Section 6 for simulation studies relating to power system dynamic simulations as well as aspects related to detailed grid calculations, such as models for short circuit analysis and inclusion of protection systems.

It is noted that the incorporation of generation 'must-run' and locational constraints within operational simulations (production cost/market model simulationsm see Section 5) may have implicitly addressed some known network and stability issues. More detailed analyses can include steady-state power flow; N-1 contingency analyses (where security is maintained when any one of the total number of possible faults occurs); contingency assessment and stability analyses; power quality and harmonic analyses.

The chosen deployment of wind generation (including different wind turbine technologies and wind profiles/wind distributions) and solar generation (including different solar PV and concentrated solar technologies, and residential uptake of installations) can also be evaluated against existing network code requirements, to consider different mitigation or participation options.

Steady state analyses, for snapshot cases of production cost/market model simulation runs, can also provide inputs to the production cost/market model simulation as well as result in an iterative process between the transmission scenarios (Section 3 Scenarios) and power flow simulations. In case of deficiencies, a wide range of options should be considered before new network reinforcement investments are applied. Depending on the likely frequency of occurrence and severity of the consequences, options range from a revised economic dispatch/unit commitment for the system to modified control and/or supervisory schemes, and enhancing network functionality (e.g. introducing load-tap-changing or phase-shifting transformers). To see the effectiveness of options without reinforcing the network, similar simulations can be conducted as part of transmission planning, whereby objectives include relieving existing congestion and maintaining (or improving) the security of supply (transmission adequacy).

A host of system conditions must be analysed as part of a transmission expansion plan, which is done via probabilistic modelling. With low shares of wind and solar, it is probably sufficient to study those steady-state issues which are historically associated with a particular system (see an example of Ireland (EirGrid and SONI, 2009, p. 5)). It will be important to understand whether an increasing wind and solar share tends to exacerbate, or improve, known operational issues. At higher wind and solar shares it is prudent to study a much broader spectrum of contingencies and analyses, firstly through a high-level scanning approach and then adopting a more in-depth approach, as interesting and challenging issues are revealed.

4.2.1 Study Case Definition for Steady-State Analysis

Steady-state and dynamic studies have traditionally involved snapshot analyses of well-known cases of greatest system stress, e.g. annual peak load. However, depending on the correlation of diurnal/seasonal load patterns with wind/PV generation output, periods of system stress may potentially occur over a much broader range of the year.

From a (steady-state) power flow perspective, high-low cases might be best for assessing network loading, reverse power flows, etc. However, from a stability perspective, those cases of interest could be entirely different (See Section 6). Recognizing the capabilities of wind and PV technologies added to the system should form part of any investigation.

A simplistic approach can consider system demand and wind/PV generation as independent variables, which may limit the number of additional cases considered, e.g. low demand coupled with high wind/PV production, but the likelihood of occurrence of such scenarios may not be significant. Where possible, wind/PV and demand time series should be used to capture any underlying correlation.

Consequently, a number of credible power flow base cases (linked to market model simulations) that represent high shares of wind and/or solar generation should be created. These cases need to reflect:

- High/low load
- High/low solar power output

- High/low wind power output
- High/low import or export (to neighboring systems)
- Full/empty storage.

Such an approach might result in 2^5 = 32 cases, but this number could be reduced by focusing on those cases that would represent some of the more challenging conditions for the system. In addition, uncommon but extreme low load days, e.g. bank holidays, and/or high load days could also be considered, as well as winter and summer variants. Rather than identifying here a definitive set of scenarios to be considered, the peculiarities of a particular system need to be recognized, e.g. underlying correlation between wind/PV production and high/low demand periods, and the resulting probability of occurrence of extreme scenarios, the locational distribution of wind and solar generation sites relative to each other and to demand hubs.

The cases should be created through market model simulations, where several approaches with different levels of complexity are available to represent transmission networks (e.g. total transfer capacity, security-constrained unit commitment, power transfer distribution matrix, DC power flow, AC power flow – see also Section 5.1.8). Clustering and statistical techniques can help to identify potential cases of interest.

When wind/PV generation substitutes for conventional generation, some conventional units may be dispatched down while still providing generation. Recognising changes in the unit commitment and economic dispatch as wind/solar generation are added to the system is of key importance, and will have later implications for interpreting any stability analysis results (Miller et al., 2014). For higher wind and solar shares, the choice of appropriate climate years is important, and multi-year analysis should be considered in order to capture less common, but threatening, events.

As part of the scenario setup, locational issues need to be recognized, whereby, for example, significant wind/PV generation is located in one region while high demand hubs are located elsewhere, leading to an assessment of the network's ability to transfer power from source to sink. Future demand needs to be assessed more carefully, as electrification may add 50–150% to current demand levels.

Given that wind/PV power often presents net load situations that are quite different from more traditional load scenarios, probabilistic analyses is a recommended future option when determining the most favourable transmission grid reinforcements and associated investments – when availability of statistical data allows. Probabilistic analyses capture the uncertainty and variability across a year, with many possible combinations of load, generation, and power exchange considered. The limitations of only representing a small subset of expected operational snapshots are thus avoided, while enabling possible congestion in the grid to be estimated in terms of duration and quantity as well as quantifying the yearly energy production from each wind/PV power plant and the risk for the producer of being curtailed due to system or local constraints. Moreover, a probabilistic approach allows consideration of uncertainty factors, such as the forced outage of transmission equipment, generation units, and the variability of wind/PV generation. Through yearly based probabilistic simulations, the expected frequency of network overloads (hour/year) and the quantity of overloads (MWh/year) can be identified. Market operational analysis for congestion purposes can also be performed.

4.2.2 Power Flow Calculation

Power flow analyses are performed to check possible bottlenecks (congestion) in the transmission network and to assess the system's capacity to maintain the voltage profile. When bottlenecks are caused by thermal considerations, then power flow analysis, also considering re-dispatch, is sufficient, otherwise dynamic studies are needed. The impact of wind/PV energy production on the voltage profile differs according to the type of renewable energy units (e.g. PV generators, asynchronous generators, doubly fed asynchronous generators, synchronous generators connected via converters). Therefore, depending on the assumed technology and the network connection rules, an appropriate level of reactive power absorption/production and controllability should be simulated to determine the need for reactive compensation and to assess the conformity of the voltage profiles. In power flow calculations, DC transmission infrastructure is simpler to represent than AC transmission infrastructure (see Section 4.2.7).

Steady-state studies may also choose to consider emerging opportunities and benefits for implementing dynamic line rating or other grid-enhancing technologies, such as power flow controllers and the use of SVC/STATCOMs [static volt-ampere reactive compensator/static synchronous compensators] and other FACTS devices, for the transmission network. See Section 4.2.8 for more information on grid-enhancing technologies.

4.2.3 Steady-State Contingency Analysis

Contingency analysis serves to understand the behaviour of a system in case of loss of network assets. The critical network element and contingency limits the amount of energy that can be transported to the demand centres. These elements have to be defined and a contingency analysis to be performed. That analysis can be performed by conducting power flow calculations deterministically for all possible N-1 situations considering the critical network elements, or stochastically by, for example, Monte Carlo simulation. Initially, a first screening to identify potential transmission bottlenecks caused by additional wind/PV generation can be performed, although final decisions on optimal network reinforcements should be taken after a more comprehensive probabilistic analysis (see Section 6.4).

4.2.4 Weak Grids - Short Circuit Level Calculation

The short-circuit power ratio, calculated at each bus, highlights the response (traditionally known as the “stiffness” or "strength") of the power system during a fault, and thus is an indicator for the quality of the power supply (namely voltage quality) at a certain location. Short-circuit levels across the network are characterized both before and after the addition of wind/PV power (inverter-based resources). For high wind/PV shares, some synchronous generation will not be dispatched, which may lead to a reduction in the short-circuit level and a reduced short circuit ratio. This, in turn, may affect the power quality in certain situations: it may affect the magnitude of voltage step changes after shunt switching, the operation of line commutated HVDC converters and PV/wind turbine power electronic controls. System stability assessments are critical for weak grid areas, which can be first identified using steady-state grid strength screening tools. Mitigation measures can be provided by grid-supporting technologies, such as grid-forming controls for IBRs, or synchronous condensers.

The impact of short-circuit currents on the operation of the protective relay system should also be investigated. The reduction in short-circuit levels may increase the risk of wrong or non-reaction of protection systems, which must be avoided. In addition, local power quality may be affected, and its impact should be assessed. Screening tools should be applied to assess the grid strength across the network for an extensive range of operating conditions.

4.2.5 Harmonic Issues and Modelling

Traditionally, harmonic distortion has not been a major cause of concern at transmission voltage levels, because the majority of the non-linear loads were connected at lower distribution voltage levels, and the network is mostly comprised of overhead line circuits. Harmonic issues in electrical systems can distort the voltage and current waveforms, leading to unwanted harmonic frequencies in the system. These harmonics can cause various detrimental effects such as increased losses, overheating and vibration of equipment, electromagnetic interference with communication systems, resonance effects and reduced equipment lifespan (Das, 2015; Owen, 1998).

The proliferation of renewable source generation connections utilising power electronic converters introduces new challenges regarding the management of harmonic distortion levels. Moreover, these renewable connections are frequently implemented using underground cable circuits at high voltage (HV) and extra high voltage (EHV) transmission levels. The transmission network is usually weak at these remote locations and the incremental connection of generation utilising power electronics can cause a further reduction in system strength by displacing conventional synchronous units in the generation merit order dispatch. The combination of new harmonic injections introduced by the power electronic converters, and the resonance amplification effects introduced by the new HV/EHV cable connections, can drive the harmonic distortion levels at the point of connection (PoC), and further into the transmission network, outside planning levels.

Harmonic levels can be estimated using a combination of analytical techniques, online measurements and vendor data, but the process can be challenging due to diverse topologies and harmonic limitations at the source (Das, 2015). It is also crucial to consider the system impact, emphasising that the source impedance at the point of connection of the harmonic-producing loads will affect the harmonic emissions. Against this background, it is noted that detailed information and guidance on how best to model and analyse harmonic issues is at worst lacking and at best scattered across a range of documents which are often difficult to access. However, in order to address harmonic issues effectively, accurate modelling of harmonic sources and their impact on the system is crucial (CIGRE, 2019; Das, 2015; Hu et al., 2023). Here are key aspects of harmonic modelling for wind and solar power plants:

- Converter harmonics primarily result from hardware nonlinearities and imperfections in the switching mechanism. Sideband harmonics of the switching frequency can be calculated analytically, but kHz-range converters pose challenges due to dead-time and switching device non-linearities, for which no commonly available analytical method exists.
- Harmonic phase angles are crucial, especially in harmonic studies with external background sources. The stochastic nature of phase angles among wind turbines facilitates harmonic summation at the point of common coupling (PCC). Acquiring additional information on stochastic phase angle behaviour at relevant harmonic orders is recommended. More generally, the summation law for combining harmonic sources (with unknown phase angles) should be applied with great care (Koo and Emin, 2016).
- The nature of the closed-loop controls of power converters can influence the overall harmonic impedance, particularly within the typical bandwidth of current controls, up to a few hundred Hertz. Harmonic emission is contingent upon various factors including converter topology, the presence of applied harmonic filters, and the short-circuit current

at the PCC. In wind generation systems, even harmonics can arise from unsymmetrical half waves and may manifest during rapid load changes.

- Manufacturer-specific harmonic models for PV inverters are often not made available. Consequently, PV systems are often idealised as constant current sources for harmonic studies, neglecting critical factors such as the interaction between the output filters and the grid impedance, or the influence of background distortion on current emissions. However, these factors can significantly impact certain frequency ranges and they must be carefully considered.
- For individual scenarios, seasonal variations in damping and shifts in harmonic resonance frequencies should be assessed by considering different demand levels, with the status of any reactive compensation device clearly defined for each demand level. Generation plant should not be decommitted unnecessarily at different demand levels, in order to avoid overly pessimistic results, leading to over-investment in corrective measures (Val Escudero et al., 2017).
- The impact of network contingencies, outages of transmission lines, transformers, generators, converter bridges, reactive compensation devices, etc. should be evaluated. The number of nearby outages, considered as part of a contingency, should balance likelihood of occurrence against mitigation cost. The system operator should specify security criteria in typical situations for planning and operational conditions.

Although the focus here is on wind and solar PV integration, and the harmonic issues associated with their power electronic nature, it must be recognised that multiple other sources of harmonics can exist in power systems, and these additional sources must be carefully modelled and analysed as part of a comprehensive harmonic study. Additional harmonic sources include HVDC interconnectors (notably line-commutated converters), FACTS devices, electric arc furnaces, variable frequency drives (as found in commercial and industrial environments), passive filters, and electric vehicles (uncontrolled rectifiers and DC/DC power converters). Numerous technologies are available and continuously evolving to control harmonics at source (Das, 2015). Three primary methodologies are commonly applied for limiting harmonics: passive filters, active filters, and alternative technologies, such as phase multiplication, operation with higher pulse numbers, active wave-shaping techniques, etc. The most suitable strategy will depend on various factors, such as the currents and voltages involved, and specific system parameters including the short-circuit level at the PCC.

4.2.6 Modelling Distribution-Connected Wind/PV

An inherent difficulty in suitably representing the distribution network is that when modelling a contingency, the area over which a transmission-level fault causes a significant voltage sag needs to be determined and the aggregated response of the many distribution-connected wind/PV plants is a function of the considerable voltage diversity present in the distribution system. This voltage diversity is present due to the relatively high impedance of the distribution circuit, compared to transmission lines, and the distributed and somewhat variable loading of distribution circuits.

The most common approach to account for the voltage stability impacts associated with high levels of distribution-connected wind/PV is to aggregate the distribution-connected wind/PV using a simple model which attempts to approximate the impact of voltage diversity (WECC REMTF, 2014), and then use the resulting voltage sensitive model within a traditional transmission-level voltage stability analysis. Industry wide consensus regarding the best practices for tuning the aggregate distribution-connected wind/PV model parameters has not yet been formed, but analytical methods involving both transmission- and distribution-level modelling have been proposed (Boemer et al., 2017; Mather & Ding, 2016; ESIG, 2023c).

4.2.7 HVDC Grids

Til Kristian Vrana, Damian Flynn, Debbie Lew

HVDC can provide benefits over AC including cost-effectiveness for long-distance transmission, lower right-of-way needs, better power flow control, support for weak grids, and long-distance capabilities underground and underwater. Because wind and PV plants are often located far from load centers, or even offshore in the case of wind, and because high levels of wind and PV can lead to weaker grids, HVDC is increasingly considered as an option for power transfer.

The DC transmission infrastructure itself is relatively simple to represent, compared to the AC transmission infrastructure, due to the nature of direct current:

- Only two instead of three conductors
- No reactive power/current
- Constant values in steady state (unlike the 50 Hz fluctuation of all AC quantities).

The calculation is therefore comparatively straightforward: a true DC power flow, which yields precise results rather than approximations (when AC networks are analysed using simplified DC power flow approaches).

For power flow calculations, when the DC transmission losses are neglected, it is often sufficient to omit HVDC transmission details, and to just represent the inflows and outflows of a given HVDC system. This will mean that the HVDC converter stations are modelled as simple AC power sources, supplying the exact set points (minus converter losses) for active and reactive power. When the HVDC system contains uncontrolled meshes, the power flow in the DC system has to be calculated a priori, to determine if the active power set points of the converter stations result in a viable flow on the DC lines. This DC power flow has to be also calculated when the DC transmission losses are to be considered.

For stability analysis, more complex issues arise for HVDC modelling, and the type of converter (line-commutated converters (LCCs) versus voltage-sourced converters (VSCs)) is critical. A VSC has advantages in weak grid situations, such as pockets of high wind/PV/storage resources, and can enhance stability. The presence of HVDC transmission infrastructure, especially future HVDC grids, can make the development of network simulations somewhat challenging (mainly where dynamic modelling and stability assessments are required). The details are outlined in Section 6.2.3.

4.2.8 Offshore Network Infrastructure

Confirming the transmission network design (upgrades) for the final volume of installed wind power has particular relevance for the case of offshore grid expansion planning. Offshore infrastructure that interconnects several countries is associated with socioeconomic benefits due to increased trading opportunities between different market areas. This can also allow for connections to remotely located offshore wind plants through future multi-terminal HVDC systems. The sum of these benefits should be compared against the network infrastructure investment costs. The infrastructure configuration that yields the highest socioeconomic net benefit should be identified, in order to facilitate a coordinated planning process. The highest socioeconomic benefit is defined in this context as the lowest operational plus investment costs for the entire system considered. Offshore infrastructure expansion planning is a task that requires complex modelling, including offshore network infrastructure configurations and assumptions on availability of specific assets, such as DC circuit breakers (3E et al., 2011; NSCOGI, 2012; PROMOTiON, 2017, ENTSO-E 2024). The required external inputs include detailed generation and network data (capacity, costs, etc.) for the onshore grid, and offshore infrastructure cost data (Vrana & Härtel, 2023). A comparison between the benefits from direct connectors, tee-in connectors, or hub-to-hub connectors for the offshore transmission network is recommended. It should be noted that offshore network infrastructure usually develops in a modular way, based on case-by-case investigations of potential offshore hybrid projects, i.e., combinations of two functionalities (connecting offshore wind to an onshore system and interconnection of market zones/countries, as, for example, in the Kriegers's Flak project.

Attempts to develop a masterplan for a larger area have been developed, but they should be understood as an investigation of the overall potential (NSCOGI, 2012; ENTSO-E, 2014; ENTSO-E, 2016). With the new legal mandate from EC 869/2022, ENTSO-E has to elaborate an offshore network development plan for each European sea basin. The first edition has been published in January 2024 (ENTSO-E 2024), applying linear optimisation for the Pan-European system. This exercise is based on the European Member States' non-binding targets and is to be repeated every two years. From 2026 onwards, the Offshore Network Development Plan [ONDP] will be fully integrated in the European Ten-Year-Network-Development-Plan [TYNDP] process, giving a high level view of the corridor needs across the sea basins.

4.2.9 Grid-Enhancing Technologies

Increasing wind and solar reliance may cause additional bottlenecks at transmission and distribution level. Grid-enhancing technologies can reduce the (immediate) need for new transmission, or bridge the gap until transmission can be upgraded. These may include dynamic line rating (DLR), topology optimization, greater use of high temperature low sag (HTLS) conductors, FACTS devices, and power flow control technology (Choudante & Bhole; 2018). Grid-enhancing technologies can provide significant benefits in terms of production cost savings and avoided wind curtailment (DOE, 2022, Tsuchida et al., 2021). Using UCED models to analyse these alternatives to grid expansion requires the capability to adequately represent the alternatives, including improved network modelling and power flow analysis.

Power flow controllers (PFC) adjust the impedance of specific lines in a network to improve utilisation of the entire network by pushing power away from overloaded lines and pulling power onto underutilised lines. Topology optimization reconfigures the grid network by using existing breakers to switch specific components off, and allowing power to reroute so that it does not overload any single line. These grid-enhancing technologies are operational tools and require additional control and communication as well as an assessment that the resulting network is secure against credible contingencies.

Assessment of the transmission capacity of overhead transmission lines traditionally applies a model of the static thermodynamic equilibrium of lines for the most unfavourable seasonal weather conditions. This methodology, usually known as "Seasonal Line Rating" (SLR), aims to ensure safe operation of the networks, not allowing the maximum temperature of the conductor to be exceeded, with the line always exceeding a minimum distance from the ground (Karimi et al., 2018). For example, reference values between 0.5 and 0.61 m/s for wind speed, and between 1000 and 1150 W/m-2 for irradiance, are used in Portugal. For seasonal line ratings, the reference value for the air temperature is seasonally adjusted, and the wind direction is not taken into account. From a meteorological point of view, this set of values is conservative and, operationally, the transmission capacity of the lines varies constantly, adjusting to the prevailing weather conditions. Thus, the use of numerical DLR models, by using (almost) real-time meteorological data, can safely allow the optimal use of existing assets (Couto et al., 2020).

The meteorological parameters that may influence the thermal state of an electric overhead conductor include the speed, direction, and turbulence of the wind, the ambient temperature and the solar irradiation. Also the topology of the high-voltage network and its electrical characteristics (type and number of lines, their impedances or susceptances, nominal operating voltage, etc.), and the loads will have an influence. In thermodynamic equilibrium the heat absorbed by the conductor, i.e., its thermal gains, equals the heat dissipated by the conductor, i.e., its thermal losses, and the conductor is in a steady-state. Taking into account all, we get terms for Joule heating, magnetic heating, solar heating, corona heating, convective cooling, radiative cooling and evaporative cooling (all in W/m). Because these different terms do not have the same order of magnitude, it is a common practice to use only the most relevant effects. Most power lines use a multi-layered structure the manufacturers set the conductor’s layers of cable winding in opposite directions, to reduce the magnetic effects. Thus, the magnetic effects are only important for cables with a steel core and an odd number of layers, in particular one or three layers of aluminium. Given that the maximal temperature limit imposed on the power lines is usually less than 90ºC, the radiative cooling is also comparatively weak and is also not considered in most cases. As a consequence, apart from the transmitted current, the most impacting factors terms of the equilibrium equation of the cables are the meteorological parameters, among them the ambience temperature (heating effect) and the wind characteristics (a cooling effect). Both IEEE and CIGRE have developed methodologies to represent the dynamic behaviour of overhead transmission lines, that include different levels of simplification of the thermodynamic equilibrium equation (Iglesias et al., 2014; IEEE, 2007).

DLR is a natural match for wind plants because high winds imply both higher (wind) power production as well as potentially higher power transfer. Due to the correlation between the additional capacity of the lines and the increase in wind generation due to high wind speeds, there is additional cooling of the conductors caused by wind conditions, and hence it is possible to increase the operating margin of the (local) grid. For radial connection transmission lines serving exclusively wind plants, this high correlation between wind speed cooling effects and the loading of the transmission line, allows that DLR may be used in the design phase of the line.

DLR can be implemented in a matter of months rather than years. The use of DLR leads to a 10 to 30% increase in the estimated transmission capacity, which can help to avoid possible grid congestion in 80% of cases and forced curtailment of wind and solar production (Couto et al., 2020; Duque et al., 2018). In addition, by avoiding the use of line capacity values higher than those determined by DLR, it makes possible to preserve the safety of transmission systems, avoiding line degradation and line disconnection (Teng et al., 2018). Thus, the use of DLR models can, in the long term, avoid or postpone the eventual construction of new lines, and in the short term, avoid network congestion and the separation of markets in price areas as well as wind and solar production restrictions and the degradation of lines. It should be noted that the introduction of dynamic line rating, as with many other initiatives, implies the upgrading of energy management systems, the integration of external measurements, the availability of real-time contingency analysis, etc. A sufficiently long period is needed to obtain results with statistical significance. Preventive efforts should be undertaken (e.g. monitoring the identified critical sector) to avoid eventual risks.

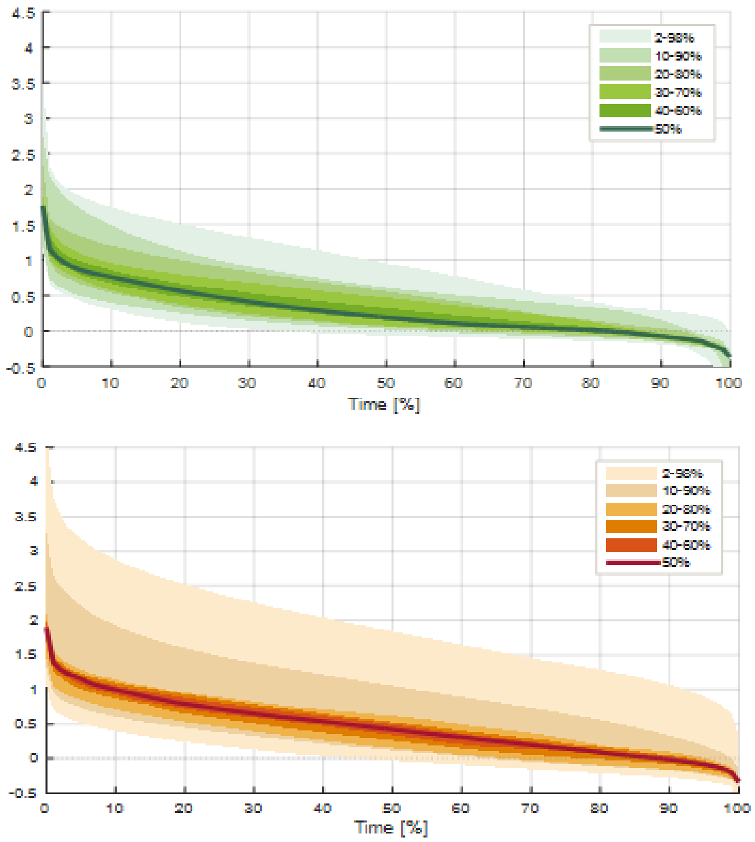


Figure 4.7. Normalised ratio between dynamic line rating analysis against the design limits for case study in Portugal for wind (green) and for solar (orange) - percentiles of lines (green and orange scale) and percentage of time associated during an entire year.

Example of the impact of the DLR against the design limits (normalised ratio between these two parameters) over the data time horizon of one year is presented in Figure 4.7. The percentage of power lines at a given power level interval observed over a given time interval is presented using percentiles. The benefits of the DLR are seen in most of the power lines. However, some of the lines present negative values, occurring when high levels of solar radiation and air temperature and low wind velocities occur near the very limits of the model used to assess the cables' thermal balance.

There are some differences when studying wind and solar: the percentile distribution range for a specific time is higher for solar than for wind case study. This result is explained by the weather conditions that present high variation amid the lines in a region. For wind, the 2% percentile shows only positive values for 33% of the time. For solar, this value increases to 44%, and some power lines can benefit across the entire year from the DLR analysis (ratio always above 0).

4.2.10 Options To Improve Transmission Network Adequacy

Problems encountered in power flow or dynamic analyses can normally be resolved by reinforcing the transmission grid. The volume of network reinforcements required is a common outcome from grid integration studies – and the main result from the transmission planning process. Transmission capacity problems associated with wind/PV power integration may be of concern for only a small fraction of the total operating time. In these cases, network investments can be avoided or postponed by maximizing the use of existing transmission lines (Grid enhancing technologies such as DLR, FACTS, see Section 4.2.9). It is also important to note that grid reinforcements should be compared against the option of curtailing wind/PV, or adjusting the operation of other generation, in cases where grid adequacy is insufficient for only part of the time, or only for some production and load situations.

Alternatives might include application of power-to-X (P2X) conversion to different energy carriers, such as hydrogen, which might reduce the need to "transport" electricity and build more electricity network, but instead use existing/new gas/hydrogen/liquid fuel infrastructure (Brown et al., 2018). In Europe, legislation sets requirements for multi-sectoral assessment when planning energy transmission networks (The European Trans-European Networks for Energy (TEN-E) EU 869/2022, Art. 11). A joint model for electricity and gas has already been required before, triggering joint ENTSOs scenarios; but with the latest legislation further considerations like gap analysis across energy carriers are required.

Constraints associated with the underlying transmission network are also an important input to production cost simulations. The above options can be viewed as forming an iterative loop back to modifying operational practices, capacity expansion and transmission grid inputs to the simulations (see Chapter 3).

4.2.11 Checklist: Transmission Network Steady-State Analyses

Checklist of Key Issues: Transmission Network Steady-State Analyses

Specific issues and recommendations regarding power flow simulations incorporating wind and solar power include:

- ➢ *Power flow cases to study*:
  - ❖ For lower shares of wind and solar, the snapshots chosen should include critical situations regarding wind and solar power, such as periods with high non-synchronous generation (wind, solar) and import via HVDC. This is in addition to peak load and low load situations traditionally studied. The correlation between demand, wind and solar production, specific to a particular system or region, must be taken into account. An evaluation of the snapshot’s statistical relevance is beneficial as an input to the cost-effectiveness of implementing corrective actions – for example, as part of a multi-year analysis.
  - ❖ For higher shares of wind and solar, moving towards probabilistic analysis is recommended (as already increasingly applied by system operators), allowing uncertainty and variability across a year to be captured.
- ➢ *Deterministic steady-state security analysis:* In compliance with N and N-1 security criteria, power flow analyses are performed to identify transmission network bottlenecks (congestion) and to assess the system’s ability to maintain the voltage profile. By analysing the overload risk and the aggregated severity index, planners can identify whether bottlenecks should be considered severe or whether they can be solved (temporarily) via operational measures. Optimal power flow (OPF, or UCED-OPF) models can be used to analyse dynamic line rating and other grid-enhancing technologies as alternatives to grid expansion requires improved network modelling and power flow analysis.
- ➢ *Short circuit levels:* For high wind and solar shares, some synchronous generation will not be dispatched, which may lead to a reduction in the minimum short circuit level in

some locations (the presence of wind and solar generation in other non-traditional locations may actually improve the fault level in those areas). This, in turn, may affect power quality, voltage step changes after shunt switching, and the operation of line commutated HVDC converters, and can lead to mal-operation of protection systems. Screening tools should be applied to assess the grid strength across the network for an extensive range of operating conditions.

- *HVDC grids:* a true DC power flow yields precise results for HVDC grids. DC power flow has to be calculated when DC transmission losses are to be considered or when the HVDC system contains uncontrolled meshes. In other cases, it is often sufficient to omit HVDC transmission details, and to just represent the inflows and outflows of a given HVDC system as simple AC power sources.

4.3 Network Adequacy: Distribution Grids

Denis Mende (originally for Ed.2 from Barry Mather, Markus Kraiczy, Steffen Meinecke, Chenjie Ma, Martin Braun)

Interconnection at the distribution system is often favourable (particularly for smaller systems) due to lower interconnection costs and more easily met system requirements. For systems in which significant amounts of distribution-connected PV and wind are to be included, it may be beneficial to investigate the expected distribution system impacts in dedicated studies. The impacts of distribution-connected wind and PV in aggregates need to be analysed, as outlined for the transmission system in Section 4.2. However, it is important to also consider the potential impacts on the distribution system to which they are connected.

In the distribution level, power flow and short circuit analysis are widely used for wind/PV integration studies. However, with increased wind/PV generation and application of demand response units in the distribution level, the necessity for quasi-static time series (QSTS) simulations and dynamic stability analysis increases. The use of QSTS especially increases due to variable nature of wind and PV, leading to variable power flows over time which oftentimes cannot be analysed by single power flow scenarios alone.

The focus of this section is on distribution grids with a strong connection to neighbouring or upstream networks, even if they also are inverter dominated. For island grids and/or micro-grids, additional studies may be required. The following list shows different simulation methods and selected objectives of distribution grid integration studies:

- Power flow/time series analysis:
  - Hosting capacity (section 4.3.1)
  - Contingency, congestion management and grid reinforcement (section 4.3.2)
  - Voltage variability and reactive power control algorithms (section 4.3.3)
  - (Active power) Flexibility assessment of distributed energy resources (section 4.3.4)
  - Grid losses analysis (section 4.3.5).
- Short circuit analysis:
  - Protection studies.
- Dynamic stability analysis:
  - Fault-ride through and anti-islanding detection studies

    - Development of dynamic distribution grid representations (Section 6.2.5).

In this section, an overview of best practice examples for selected distribution study objectives is presented and high-level recommendations are derived. Hosting capacity analyses (see section 4.3.1) are used to analyse the adequacy of the grid for particular PV/wind/demand scenarios. This includes the maintaining of an acceptable level for the voltage magnitude, the thermal loading of grid assets, and the power quality in the distribution grid. In case the grid hosting capacity is reached for a defined wind/PV/demand scenario, distribution grid reinforcement (see section 4.3.2) may be required to ensure the adequacy of the grid for additional PV and wind connections. Furthermore, wind and PV deployment affects the voltage variability in the distribution level and can affect the operation of voltage regulator. To ensure that existing voltage regulator (e.g. on-load tap changers, capacitor banks) are operating as designed and intended, a voltage variability analysis can be performed in the distribution level (see Section 4.3.3). The impact of distributed wind/PV integration on the grid losses can be studied by detailed grid losses analysis (see Section 4.3.4). Many other types of distribution studies including protection, reverse power flow, contingency analysis, dynamic generator response, unintentional islanding, flicker and harmonic studies, are also completed when necessary.

4.3.1 Hosting Capacity Analysis

Distribution-level power flow studies often aim to check the maximum amount of wind or PV on the existing networks without needing to complete any grid reinforcements. Often hosting capacities for circuits are computed to inform and screen wind/PV interconnections to eliminate the need to complete interconnection-specific studies until total generation has exceeded the precomputed hosting capacity. Note: the hosting capacity of a circuit is not the overall limit for wind/PV integration as grid reinforcement and other operational changes can be used to greatly increase deployable wind/PV level in a certain area of the distribution system. Hosting capacity analysis results have been used to generate maps of entire regional distribution power systems, again to inform the interconnection process.

Certain salient operating conditions (including demand, wind and solar generation) are investigated to estimate the impact of the proposed amount of wind and/or PV expected on an individual circuit (Seguin et al., 2016). The resulting (if respectively modelled also unbalanced) three-phase voltage profile is often the output, effectively bracketing the voltage profile envelope expected on the circuit for the modelled operating condition. This envelope is then evaluated to ensure voltages on the distribution circuit are within acceptable limits for the entire range of expected operation. If voltage violations are found mitigation measures can be investigated and their costs considered to determine the least-cost mitigation strategy.

Different types of hosting capacity analysis are as follows:

- Deployment scenario independent hosting capacity analysis
- Locational hosting capacity analysis.

Deployment scenario independent hosting capacity analysis provides the maximum amount of wind/PV that can be integrated on a circuit regardless of where the wind/PV interconnects to the system. This type of analysis usually uses 100s or 1,000s of deployment scenarios which are randomly determined and each deployment scenario is evaluated and graded for wind/PV impacts at increasing levels of wind/PV generation (Rylander & Smith, 2012; Mende et al., 2012). The lowest level of wind/PV that causes a distribution circuit impact that is above the planning criteria limits (e.g. a circuit overvoltage, thermal overload, etc.) within all the scenarios in this Monte Carlo method is selected as the hosting capacity of the entire circuit. This sort of hosting capacity is valuable when distribution utilities and developers are trying to inform the interconnection process of many wind/PV systems such as the connection of many residential roof-top systems.

Locational hosting capacity analysis simply computes the maximum wind/PV that can be interconnected at every modelled node on a distribution circuit (Rylander et al., 2015). The additional of locational hosting information better informs where the connection of larger wind/PV systems will be easier. However, as soon as a wind/PV system is connected (or planned for connection) to the distribution system a new calculation of remaining locational hosting capacity must be completed in order to take into account the possible reduction of previous locational hosting capacities (i.e., as deployment scenarios change analysis needs to be repeated).

Additionally, there are two general methods for determining hosting capacity which are:

- Iterative hosting capacity calculations
- Streamlined/linearized hosting capacity calculations.

Either calculation method can be applied to either deployment scenario independent or locational hosting capacity analysis. Iterative hosting capacity calculations simply increase the amount of wind/PV on a circuit, computing and grading expected circuit impacts at each generation level, until an impact that is higher than the acceptable planning levels is reached. This type of analysis can require considerable time and/or computational resources to complete due to the potentially large number of power flow solutions required.

Streamlined/linearized hosting capacity calculations require less computational resources by effectively linearizing the power flow solutions in order to directly calculate the wind/PV generation levels at which unacceptable circuit impacts begin to occur. The increased speed of the hosting capacity calculation comes at the cost of potential error in hosting capacity numbers. Of course, the two calculation methods can be easily combined to provide relatively fast hosting capacity analysis and improved levels of hosting capacity accuracy if required.

Similarly, the impact of other devices on the grid hosting capacity can be evaluated. Especially electrification (e.g. increasing numbers of heat pumps and electric vehicles) not only increases the need for more generation (which can be limited by the hosting capacity of a local area), but also increases demand. Additionally, because wind/PV generation and increasing demands from heat pumps and/or electric vehicles oftentimes do not peak at the same times or might even be negatively correlated, a hosting capacity analysis for both generation and demand may become necessary.

4.3.2 Contingency, Congestion Management, and Distribution Network Reinforcement

There are various reasons for grid reinforcement needs in the distribution level. The conventional reasons are high operational costs of grid assets, aging of grid assets, changes in planning and operation principles by the distribution system operator (DSO) or changes in the grid supply task. Also the integration of wind and PV, as well as increased distribution grid transit flows, can be a relevant driver for grid reinforcement in the distribution level, as discussed in this section.

A widespread and economically worthwhile strategy to handle overloading of grid assets or voltage violations is the so-called NOVA principle, describing the strategy to realized grid optimization before grid reinforcement and before grid expansion measures. Therefore, operational solutions or reconfigurations within the existing grid infrastructure should be considered, before grid reinforcement or even grid expansions are implemented. However, the grid optimization potential is even for conventional grid assets multilateral and sometimes not easy to model. Therefore, many grid reinforcement studies neglect, or only partially consider, this first and very important step. Measures of grid optimization for example include: the adjustment of voltage regulator set points, the application of smart inverter functionalities (if applicable), the relocation of feeder separation points, adjustment of the MV/LV transformer tap position, the implementation of dynamic line rating functionalities as well as the usage of general flexibilities connected devices (generating as well as consuming) provide. Flexibility assessment and further operational issues will also be addressed in section 4.3.4.

Dynamic line rating approaches oftentimes can help to increase the hosting capacity in systems that are wind-dominated, rely on overhead-lines as main transmission/distribution elements and in which the line loading limits the grid hosting capacity. In these cases, high wind speeds on the one hand side are causing possible overloads due to increased power transfers, but on the other hand also lead to an increased cooling of overhead lines, therefore allowing higher currents in operating while keeping conductor temperatures within specified limits. The actual evaluation of the resulting potential for higher usage of existing lines may be challenging and is depending on several further factors and the local situation/installation (e.g. line routing through valleys, interconnectors, wire clamps, measuring devices) and therefore needs detailed analysis including quite specific information.

Exemplary reinforcement measures include line and transformer replacements, e.g. the increase of the rated line/transformer capacity. Compared to transmission systems, distribution grid reinforcement analysis is less focused on-line conductor and tower configuration and optimization, especially if large parts of the distribution system are realized as underground installations. Planning permissions for new lines are obtained usually much faster in the distribution level. However, because of simple protection coordination, a radially operated topology is usually a hard grid planning condition for medium and low voltage grids in many utilities. Figure 4.8 shows a simplified flow chart for distribution grid reinforcement studies.

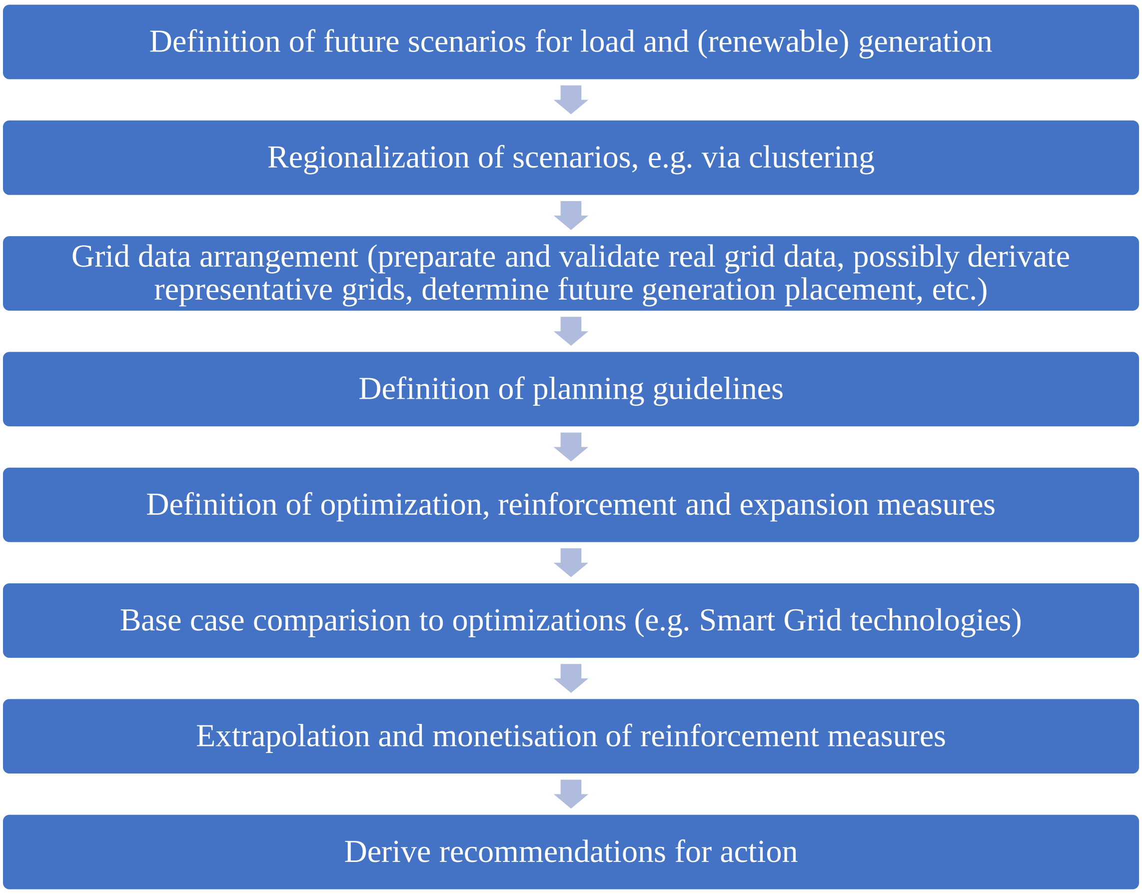


Figure 4.8. Flow diagram of system-wide distribution network integration study.

In recent years, various system-wide network reinforcement studies based on respective methods have been conducted in Germany, to estimate the future power system reinforcement costs with increasing renewable generation (Büchner et al., 2014; Scheidler et al., 2018). These studies employ procedures similar to Figure 4.8. In the medium and low voltage level distribution grid reinforcement studies on a regional or system-wide scale are often performed on representative networks, due to the very large quantity of MV and LV systems (see Section 2.5.2). Therefore, the selection of the representative networks, e.g. via clustering, is a very sensitive and important task for the overall accuracy of the study.

In recent works by Scheidler et al. (2018, 2016), Thurner et al. (2018) and Braun et al. (2018), distribution grid reinforcement studies are conducted for a large quantity of real distribution grids (see Section 2.5.2 Distribution Grid Data). This approach requires comprehensive real grid information and a high degree of automation for data handling and grid simulation. This approach can cover the very high diversity of distribution grids in detail and can potentially achieve a very high accuracy of the grid reinforcement studies.

Finally, when presenting the results, it is important to put the wind/PV integration driven reinforcement costs in contrast with generally necessary reinforcements, such as replacing outdated grid assets with new equipment.

4.3.3 Voltage Variability Analysis and Test of Control Algorithms

A variability analysis of a distribution circuits operation over a relatively long period of time (e.g. a year) is completed to estimate the distribution-connected wind and/or PV's impact on automatic voltage regulation equipment. Such equipment (line regulators and switched capacitor banks as examples) is used widely in North America and increasingly used in Europe to manage distribution-system-level variability due to integrated PV. Gaining an understanding of how PV impacts the use and cycling of voltage regulation equipment is often the primary driver for voltage variability analysis due to the potentially shortened lifetimes of the equipment or requirement of more frequent maintenance if operated excessively due to variable PV generation and thus incurring increased operation cost.

Variability analysis study methods vary in complexity and accuracy. One relatively simple variability classification includes only the analysis of wind/solar resource data related to wind and PV generators connected to a distribution circuit (Mather, et al., 2014). In this case, the resources of wind and/or solar are analysed to determine the likelihood of large generation ramps (either loss of generation, return of generation, or both) over a time period. Then, considering the likelihood of such events, a level of loss/return of generation is chosen as the representative high-impact case (an event that has high impact but also happens often enough to be of concern for distribution-level power quality). Distribution power flow analysis is completed for these scenarios by simply translating resource variability to generating power variability using simply wind/PV system models and the voltage variations expected are calculated. If such voltage variations are extreme, resulting in over- or under-voltage situations, some level and form of mitigation is necessary as distribution utilities are required to supply voltage to customers within a specific voltage range. Further, if voltage variations are large enough (i.e., larger than half the voltage deadband of an automatic voltage regulation device) mitigation for potential over-operation of the device may be necessary. Such mitigation typically entails relocating the automatic voltage regulation device or changing its voltage control parameters.

More realistic variability analysis can be completed through the full-scale QSTS simulation of a distribution circuit over an entire year (Reno et al., 2017). In this case, time-aligned load and resource data at a relatively high temporal resolution are needed to effectively simulate the operation of the circuit. Variability analysis using QSTS simulations usually requires at least two yearlong simulations, one to set the baseline operational parameters and one to see how a proposed wind/PV system will impact the system. The overall number of automatic voltage regulation equipment operations over the simulated year is usually sufficient to determine the impact of wind/PV variability on the circuit. Additional metrics addressing other distribution voltage concerns, such as flicker, conservation voltage reduction, etc., can be calculated as well from the data collected during circuit simulation.

4.3.4 Flexibility Assessment of Distributed Energy Resources and TSO/DSO Interaction

In a power supply system with an increasing share of wind/PV in the distribution grid, there is a growing need for generators and demand response units to provide ancillary services or market flexibilities. Therefore, flexibility assessments are becoming of increased relevance also in the distribution level. For example, several studies (e.g. Marten et al., 2013; Ali & Mutale, 2015; Kaempf et al., 2015; Wang et al., 2017; Wang et al., 2021; Liu et al., 2023) analyse the potential of distributed generators to provide reactive power flexibility at the TSO/DSO network interface.

Furthermore, wind and PV curtailment, economic dispatch and/or frequency control in the distribution grid will likely increase in power systems with a high share of distributed generation. Therefore, an improved coordination of transmission system and distribution system operation and planning is required, to access the flexibility of distributed generators and demand response units within the distribution level (see IEA PVPS TCP Task 14 Activity 2.7 and IEA ISGAN TCP Annex 6 activities). An overview of possibilities and needs of ancillary services with focus on PV systems is e.g. given in the IEA PVPS report “PV as ancillary service provider”. In power systems with highest shares of renewables such as wind and PV there will be increasing times when the actually available generation capacity overshoots the demand in increasing amount. While initially methods of grid reinforcement (see above) allow a further feed-in and transport to demand centres, in an overall overpowered system active power management in general will become an issue. Focussing on PV, the IEA PVPS report “Active Power Management of Photovoltaic Systems – State of the Art and Technical Solutions” (Kraiczy et al., 2021) therefore gives an overview of possibilities and general concepts of active power management.

4.3.5 Analysing Grid Losses

The integration of distribution grid connected wind/PV and other distributed generators (DGs) also has a significant impact on the distribution grid losses. Grid losses are often considered as a key efficiency indicator of a DSO by regulators in different countries (ERGEG, 2008). In addition, a reliable estimation of grid energy losses is of both technical and economic interest to DSO companies. In general, wind and PV power generation close to loads can decrease losses. However, due to the fluctuating generation pattern, wind/PV can impose extra loading peaks on low voltage (LV) grids, which lead to high losses, even at relatively low shares of generation. In the medium voltage (MV) level, reversed power flows from LV level as well as large generators may lead to either decrease or increase of grid losses. Therefore, the determination of grid losses for a large area can be highly complex.

Conventional methods for loss estimation, e.g. the application of loss formula (Gustafson & Baylor, 1989) and load profile-based method (VDEW, 2000), are not suitable in current context due to the lack of consideration of DGs. Rao & Deekshit (2006) compare the existing estimation results using loss formula against an extensive amount of measurement data on several typical LV feeders over long time. They further apply the measurement data in improving the loss formula parameters. This study gives a good practice in applying loss formula in the new context.

Marinopoulos et al. (2011) investigate the impact of DGs on grid losses based on stochastic models. By varying a parameter of installed PV plants at different penetration rates as well as positions, a probabilistic model is created by combining the extensive stochastic modelling of PV and measurement data for the demand side. Annual power flow calculations are applied on models to determine losses of an urban radial distribution feeder. Results may be of interest for dimensioning, siting and cost allocation in distribution systems with DGs. In another study, Shulgin et al. (2012) take a close look on the impact of network configurations on distribution grid losses. A modified stochastic model is proposed in (Shulgin et al., 2012), in which a power covariance matrix is introduced and investigated. Test results show that energy losses are determined with sufficient accuracy and reliability for practical purposes. This method is strongly relevant in cases grid data are available.

In order to deal with a large amount of LV feeders, Heckmann et al. (2013) presented a strategy for determining distribution grid losses from a combined method of annual power flow simulation and statistical analysis. By detailed analysis of geographic information system (GIS) data, a large quantity of LV grids are classified by feeder length and weighted loads. Typical grids are further investigated in annual simulations. Energy losses of a large grid area are thus estimated by combination of typical loss behaviour, grid features as well as allocated consumption and generations. Furthermore, the development of grid losses at MV level is exemplarily studied on representative grid models. Dashtaki & Haghifam (2013) present a loss estimation algorithm which uses a similar concept as Heckmann, et al. (2013), i.e., clustering LV feeders and detailed loss calculation of “average” feeders. Numerical simulation results show that the proposed algorithm gives an estimation of feeder losses with error of less than 10%.

In the following, we show recommendations and guidelines from the work of (Heckmann et al., (2013) as well as their recent methodological developments, for estimation of energy losses in distribution grids.

- Data collection:
    - Collecting network data (e.g. from GIS database and/or, grid asset database) as well as the generation and consumption information regarding to generation/load tariff type, annual energy and geographical locations.
- Modelling:
    - Converting grid topologies from a GIS database into electrical power flow models.
    - Parameterizing electrical equipment e.g. transformers and lines, from real assets data.
    - Mapping of generation and consumption data to the grid model.
- Methodology:
    - Optional/depending on calculation methods/speeds: Clustering distribution grids based on their characteristics (features), recommended methods: Principal Component Analysis, Neural Network, k-Means Clustering etc.
    - Yearly simulation of certain amount of reference grids in each cluster, to determine typical grid losses for similar grids.
    - Simulation of additional grids for validation purpose; validation of clustering models by comparing simulation and estimation results.
    - Extrapolation of typical losses onto other grids in each cluster, accumulation of the results to the whole grid area under investigation.

This general approach can be further improved by integrating real measurement profiles or other control mechanisms. For instance, power measurement profiles in ¼-h (or higher) resolutions provide more realistic behaviour of large generators or consumers. By comparing power flows at the HV/MV transformer nodes, aggregated energy of generation and consumption at lower level grids can be validated.

It can also be extended for discussing other research questions related to grid losses. Optimal DG sizing and placement strategy, which identifies the best positions for new DG units, can locally balance the generation and demand and therefore reduce losses. Demand side management (DSM) may coordinate and synchronize generation and demand temporally, so that transportation losses on feeders can be avoided twice. Other measures with an impact on grid losses, e.g. adjustment of grid operation voltage, active power curtailment, and reactive power provision of DGs, can also be addressed by further implementations.

4.3.6 Development of Dynamic Distribution Grid Representations

Due to the massively increasing penetration of distribution grids by inverter-based generators (IBG), also the dynamic behaviour of the connected IBGs, but especially of the distribution system itself becomes more and more relevant. On the one hand dynamic distribution grid modelling therefore has the goal to investigate dynamics in the distribution system itself, on the other hand dynamic distribution grid representations can be used to analyse the impact of distribution system dynamics on the transmission and overall system. Hence, the modelling and evaluation of aggregated dynamics of IBG-dominated distribution grids can help to understand future overall system dynamics. An overview on different types of dynamic studies and questions to be answered is given in Section 6.2.

4.3.7 Checklist: Distribution Grid Studies

Checklist of Key Issues: Distribution Grid Studies

- *Overlap and coordination with transmission grid studies:* The scope, tools and methodologies for distribution grid studies will continue to expand and develop. A major driver is the integration of wind and PV systems at the distribution level, which entails both challenges and opportunities for distribution grid planning and operation. Stronger coordination of transmission and distribution grid studies will be required with higher shares of wind/PV to access the full capabilities and flexibilities of distributed resources for the overall bulk power system. The methods that so far have been only used for analysing transmission grids will also become relevant for distribution grid analyses.
- *Distribution Grid Reinforcement Analysis*: A comprehensive catalogue of grid planning measures should be considered as part of the grid reinforcement analysis, i.e., grid optimization, before grid reinforcement, before grid expansion. The scope of the study, the analyses can either be performed using representative or actual grid data, if available. For comprehensive system-wide distribution grid studies, a high degree of automation for data handling is required and recommended.
- *Grid Losses Analysis*: A detailed study of the grid losses may deliver additional information on the effects a further increase in decentralized generation has on the distribution system they are connected to. It is essential to consider both the location and generation pattern of wind/PV when representing distribution grids, as they both have a significant impact on the grid losses. In order to partially validate the implemented model of the grid area, the energy flow in the studied grid area can be investigated in comparison with real measurement data available at transmission level bulk supply points.
- Grid operation with high PV-shares: Analysis of grid and PV-system behaviour against the operational background including investigation of voltage management and reactive power control as well as active power reduction/setpoints in order to avoid overloads.

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5 Operational impacts

Damian Flynn, Juha Kiviluoma, Hannele Holttinen, Henrik Nordström, Thomas Heggarty, Lennart Söder, Magnus Korpås. Review Julien Cabrol, Silvia Moroni, Enrico Carlini, Aidan Tuohy.

Using a capacity expansion tool, or otherwise, a future generation portfolio can serve (Section 3) to recognise expected generation investments and retirements, and respect renewable energy targets, capacity adequacy considerations, etc. However, it is also critical to ensure that the resulting portfolio is operable, in terms of ensuring sufficient flexibility to cope with demand variability and uncertainty, renewable generation variability and uncertainty, profitability and unforeseen (dimensioning) events. By expanding out the wind/PV integration study flow chart, Figure 1.3, emphasis can now be placed on the operational impacts, Figure 5.1, for a given scenario. Operational feasibility is commonly assessed by simulating the operational dispatch of the power system using a production cost simulation tool, such as unit commitment and economic dispatch (UCED). The fundamental concepts behind a production cost simulation methodology, and the specifics of representing generation, storage, transmission and demand in the models, are described. Subsequently, reserve requirements are presented, given their importance for wind (and solar) integration studies, and, finally, the chapter concludes by considering an assessment of flexibility needs.

The UCED model may directly, or indirectly through locational constraints, recognise the impact of transmission network related constraints on the commitment and dispatch of individual generating units. Similarly, stability related, and other, constraints can be considered as part of the UCED optimisation process. Steady-state power flow, and optimal power flow, in conjunction with network adequacy, are addressed in Section 4.2, while stability issues, and associated constraints, are addressed in Section 6.

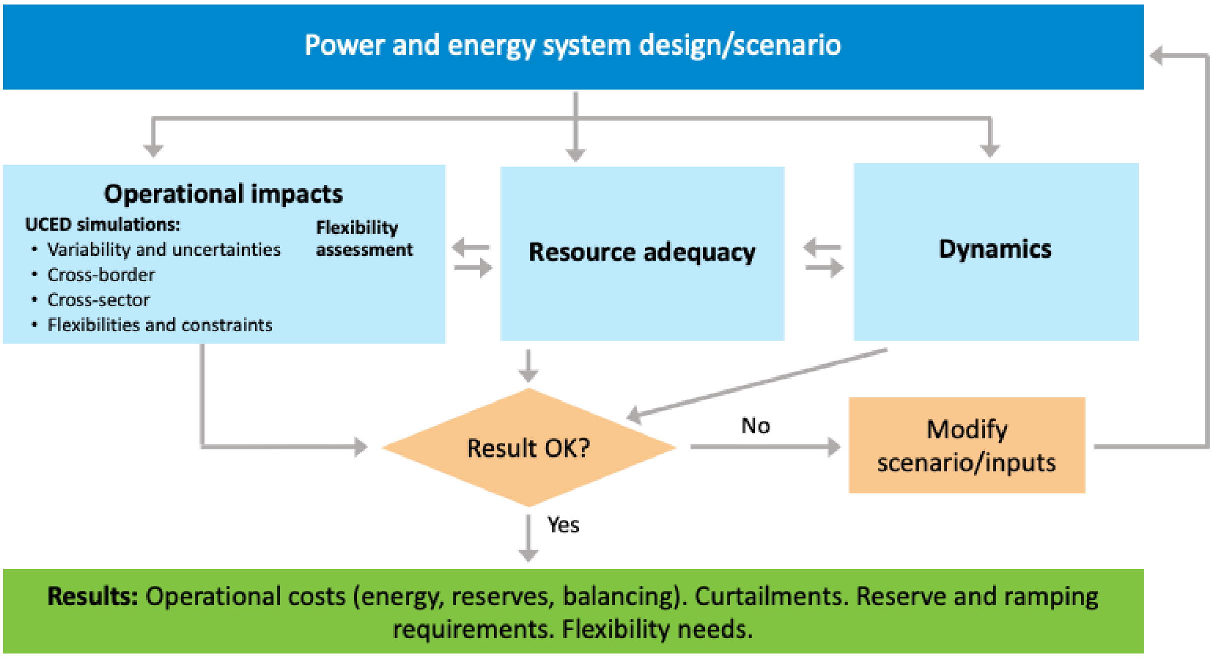


Figure 5.1. Wind/PV integration study flow chart for studying operational impacts, incorporating scheduling and dispatch decisions and a flexibility assessment.

5.1 Production Cost Simulations

In order to assess the operational feasibility of a given scenario, e.g. sufficient ramping capability to follow net demand variations, as well as to evaluate the impacts of wind and solar generation on operating costs, plant utilisation, emissions, or other features, power and energy system simulations are typically employed. These simulations involve optimising the scheduling of generation, storage and flexible load resources to meet the expected demand over various time frames, e.g. one day, one week, one month, one year, while considering all relevant costs (e.g. fuel cost, carbon tax, plant startup) and constraints (system, physical, and operational) and the expected wind/PV power production over the time horizon considered. Production cost simulation, or market model, is a general term for the types of models being used, where unit commitment and economic dispatch (UCED) type models are mainly employed to optimise the provision of short-term (hours to days) energy balance in the power system, while also considering other constraints, such as maintaining sufficient reserve (against contingencies, load uncertainty, renewable generation variability and uncertainty). The fundamental principles of production cost simulations are first introduced, in terms of a typical simulation methodology and the modelling of generation, demand and electrical networks.

5.1.1 What Should a Production Cost Simulation Include?

Studying the feasibility of a scenario often requires a trade-off between the spatial and temporal granularity of the model and manageable data input requirements and the computational burden. As described in Section 3 (Power and Energy System Scenarios), a number of sensitivities should be performed, in order to recognise a range of future uncertainties, e.g. fuel prices, generation portfolios, demand range, and flexibility options. For the model components considered here, focus is placed on the physical features which should be incorporated in order to robustly assess the operational feasibility of a given scenario.

For power systems with low shares (typically less than 10–15% of annual energy contribution) of wind and solar generation, renewables variability is generally not a major operational issue, and certain modelling simplifications can be justifiable in order to allow faster and/or more comprehensive models, e.g. hourly resolution models, ignoring generator ramping constraints, renewable forecast errors and associated reserves.

For a system with a high wind/PV share (typically greater than 30–40% of annual energy contribution), the level of renewable generation uncertainty and intra-hour variability can noticeably increase. The increased uncertainty and variability will increase the need for flexible resources, which can be used to re-dispatch the system (at relatively short notice), and provide reserves for continuous balancing associated with intra-hour variability or deterministic deviations during hour change. However, such issues may, to a certain extent, be resolved by expected changes to electricity market structures, in terms of access to intra-day markets, development of flexibility related system services, etc. Recognising the physical feasibility of short-term operational plans can ensure that the resulting generation schedule remains operable despite realised uncertainties.

For wind and solar dominated systems, great care must be taken to consider renewables variability and uncertainty, system stability issues, etc., in sufficient detail, while sector integration measures should also be considered towards achieving cost-optimal solutions.

If all relevant operational limitations and constraints are not accurately and fully captured, then unrealistic levels of flexibility are likely to be assumed, and the true impact of wind/PV generation will be misrepresented. On the other hand, the availability of additional sources of flexibility should also be considered, as the ability to integrate higher shares of renewables is likely to be enhanced. Depending on the time horizon for the study new sources can be assumed to be installed (e.g. battery storage, heat pumps) and demand response as well as renewable generation flexibility can be enabled. In addition, it is also possible to extend the coverage to incorporate other energy sectors (Helistö et al., 2019).

5.1.2 Production Cost Simulation Methodology

Production cost/market model simulations are generally performed using constrained optimisation models, whereby total generation costs are minimised subject to physical constraints, such as supply and demand balance, generation limits and transmission limits. In addition of studying the impacts of a given power system scenario, similar optimisation approaches can be applied to schedule electricity markets and determine energy pricing. It follows that the recommendations presented here for production cost simulations for large shares of wind and/or PV power can be largely applied to the mechanics of energy markets.

Operational flexibility requirements can be assessed by allocating operating reserves (see also Section 5.2). In theory, stochastic models can capture the procurement of operating reserves by including various scenarios of real-time realisations with a high time resolution. However, the computational burden of the production cost simulation will likely increase. Hence, it is more common to set operating reserve requirements explicitly based on historical data and forecasted conditions. The required operating reserves can then be procured as part of a co-optimisation with energy in the production cost simulation, as is the operational practice in several markets, however, it is still common in many places for reserve and energy optimisation to be performed separately, and this can also be reflected in the market modelling. If operating reserve requirements are included in a stochastic model, it is important to acknowledge which uncertainties the operating reserves are intended to cover, and which they are not, such that unnecessarily large safety margins are not enforced.

Optimisation Methodology: Two main optimisation methodologies have mostly been used to formulate and solve UCED models:

- Mixed integer linear programming (MILP) enables integer variables to be included, such as those associated with the start up or shutdown of a generating unit. The impact of these integer effects is particularly significant at higher shares of renewables (Shortt et al., 2013). For example, with high instantaneous shares of wind and/or PV, the minimum number and the location of online generators becomes very important in terms of achieving a generation schedule that is physically realisable. However, for large systems with many individual units, mixed integer programming (MIP) models can have prohibitively long run times.
- For larger, interconnected areas, linear programming (LP) is often used, whereby on-off decisions are replaced by continuous variables, such that integer inflexibilities due to, for example, the fact that minimum stable generation levels and minimum up/down times of individual units cannot be well represented. LP models can be useful for high level approximations, and to provide rough estimates for longer periods of time, and for large systems with relatively low shares of wind and/or PV generation. However, LP models are not suitable for capturing the inflexibilities and operational detail of systems targeting high shares of wind power that may, for example, drive curtailment of variable renewables.
- Hybrid approaches exist within commercial tools that offer a trade-off between run time and integer variables. One such approach is rounded relaxation whereby continuous

variables are used to represent integer decisions, which are subsequently rounded to zero or one depending on their final value. In addition, various decomposition approaches can be applied, and they are often made available in commercial tools.

Capturing uncertainty: Production cost simulations commonly represent short-term operational planning of a power system for a particular time horizon, e.g. one day, one week. For particular timescales, there are various uncertainties that flexible sources must be able to handle, e.g. wind/PV generation forecasts and load forecasts, outages of transmission lines and generators, as well as the sub-hourly variability of individual technologies. The modelled level of uncertainty will depend on the time frame considered, e.g. day-ahead uncertainties are likely to be much larger than hour-ahead uncertainties. A rolling (day-ahead) optimisation approach can be adopted based on available (demand and renewable generation) forecasts, with the option to include intra-day commitment/dispatch updates based on updated forecasts.

Two common approaches can be applied to recognise and handle the uncertainties, either implicitly or explicitly. An implicit approach adopts stochastic modelling techniques, whereby a range of future scenarios is considered (consisting of a combination of various realised uncertainties, e.g. different wind and/or solar PV generation time series). The system resources are then scheduled such that they can handle all (or an acceptable number of, perhaps based on likelihood of occurrence) scenarios. Alternatively, adopting an explicit approach, acceptable margins are defined (based on the expected uncertainties), which must always be satisfied, as part of co-optimisation with energy in a production cost simulation. The latter approach is by far the most commonly adopted, such as for specifying operating reserve requirements.

Stochastic optimisation methodologies: Numerous methodologies have been proposed for implicitly handling uncertainty in a production cost simulation model. Stochastic optimisation with rolling planning (Tuohy et al., 2009) has been used to explicitly represent the uncertainty as a function of the forecast lookahead. Here, stochastic scenarios for load demand, wind and PV generation, and generator and transmission line availabilities are used in place of deterministic demand and renewable generation time series. Such a high-fidelity approach can capture all relevant uncertainty impacts on the power system, but the data requirements and computational burden can be onerous. The need to produce stochastic scenarios that sufficiently represent the actual uncertainty can add significantly to the cost and complexity of the study. Longer run times also imply that fewer macro level scenarios can be considered.

Robust optimisation techniques can also be applied as an alternative methodology to capture uncertainty impacts in UCED simulations (Jiang et al., 2012; Street et al., 2011; Wang et al., 2017). The statistical uncertainty is translated into a bi-level Min(max-min) optimisation problem to determine the worst-case scenario. Computationally efficient single-level robust reformulations can be applied to address variable renewable energy uncertainty (Morales-España et al., 2018). Effectively, the approach trades model complexity against stochastic fidelity, but the downside is that a more pessimistic viewpoint on uncertainty is obtained from the results, given that the robustness constraints are often driven by the worst-case uncertainty scenario, but the level of conservatism can also be controlled by the so-called budget of uncertainty (Morales-España et al., 2018).

As power systems transition towards higher renewable shares, and with growing variability and uncertainty levels, a change from a deterministic risk assessment mindset to something more probabilistic is required. Many models are capable of probabilistic scheduling, but there has been low industry uptake, despite the increasing availability of confidence intervals and probabilistic data associated with renewable energy forecasts. Leveraging computational power, better datasets, more user-friendly interfaces and probabilistic tools presents an opportunity to reduce flexibility requirements, while increasing generation availability with subsequent cost reductions and reliability benefits.

5.1.3 Wind and Solar PV Modelling

The variability of wind/PV power generation should be representative of the expected variation in the study time frame, for the studied power system area, incorporating the spatial and temporal smoothing impact on aggregated variability due to multiple, dispersed generation locations. It should also be recognised that there will be some level of correlation (temporal and spatial) between the power production of different weather-based renewable technologies (such as wind and PV), hydropower, and also with the (regional) load profiles. Consequently, where possible, renewable generation and demand time series profiles should be curated together, rather than independently. In addition, multiple years of data should ideally be applied as inputs to UCED models, recognising inter-annual variations in weather patterns, such as “wet”, “windy” and “sunny” years, with knock-on impacts on system demand profiles.

Capturing the impacts of wind/PV power variability requires simulations at sufficiently high temporal and spatial resolution. An hourly resolution is often considered sufficient, but 10–15 minute timesteps can better capture ramping constraints associated with some conventional (thermal and nuclear) power plants, particularly as the renewable share is increased and the combined ramping capability available from (online) thermal (and other) power plants reduces, due to thermal plant being displaced. The growing contribution from large offshore wind power plants also emphasises the potential value of sub-hourly modelling to fully capture the ramping impacts. Higher time resolution issues can often be captured explicitly (by running the simulations at a sub-hourly resolution using sub-hourly input data) or implicitly (by including constraints which capture the issue indirectly, such as through ramping constraints). It should be noted that the sub-hourly ramp rates associated with renewable generation profiles may, at times, be noticeably higher than the “average” hourly ramp rate, so care is required (See also Section 2.1).

Particularly for higher wind and solar shares, the associated forecast uncertainty needs to be considered. In comparison to load forecasting, wind forecasting accuracy tends to improve more when considering hour(s) ahead time frames rather than day-ahead, and estimates for future, improved forecast accuracy should be used for future power system studies (See also Section 2.1).

For higher wind and solar shares, recognising the potential contribution of renewable generation to provide operating reserve is also important, but forecast uncertainty should be factored in when considering the ability to provide system services. In addition, it should be recognised that weather variations, in addition to affecting renewable generation output, can also affect the demand profiles, e.g. cooling and heating loads, as well as network operational limits, e.g. dynamic line rating. Where possible, all sources of uncertainty should be considered together in order to recognise the underlying correlations. The value of probabilistic methods to capture the uncertainty increases at higher wind and solar shares when asking questions such as: How much of the demand can be considered flexible? What is the instantaneous synchronous inertial support? Is there sufficient frequency control available?

5.1.4 Thermal Power Plant Modelling

Input data for thermal power plants should be sufficiently detailed to capture variable O&M costs, operational costs (including heat rate curves, start-up costs (associated with hot, warm and cold starts) and emission costs, constraints (including run-up rates, ramp rates, and minimum stable levels, and minimum up/down times, derating/increased unavailability of conventional generation) and system (ancillary) service capabilities including, for example, operating reserves and frequency control capabilities.

In addition to simple ramp up and ramp down limits, which apply between consecutive time steps in a unit commitment (UC) model, it is also important to consider whether there is sufficient online ramping capacity to meet (expected) net demand variations over longer periods of time, mainly due to wind/PV forecast errors. Such concerns are particularly relevant for systems with high shares of wind and/or PV generation and low interconnection capacity, which may require additional constraints to be incorporated within the UCED model to ensure sufficient ramping capability for the system (see also Section 5.2). If the UCED model operates at a sub-hourly resolution then startup and shutdown trajectories for the thermal units should be considered, particularly for higher wind and solar shares. For longer time horizons, i.e., one or more hours, some of the required ramping capability could be supplied from offline, fast-starting units. Co-optimisation of energy, ancillary services, and ramping is already emerging as a system operational practice in some regions, e.g. the Minnesota Independent System Operator MISO in the USA, while some systems, such as Ireland and Northern Ireland, also include various (1 hour, 3 hours, 8 hours) ramping system services to address potential wind forecast errors.

Wear and tear costs due to ramping can also be included within models, but at a computational cost (Troy et al., 2012).

Where appropriate, it may be necessary to include more detailed data on flexibility limitations, particularly in relation to balancing and system service provision (for example, minimum and maximum activation durations and lead times). Plant flexibility can also be increased from the existing generation portfolio, by, for example, retrofitting thermal power plants to support higher ramp rates, and to operate stably at lower generation levels.

Conventional generation (and transmission outage) uncertainties can also be considered—particularly when system reliability is a concern, and where generation/transmission outages and renewable forecast errors are seen to interact. Various statistical models exist to represent forced outages and maintenance outages. For example, a forced outage rate and a mean repair time are often used to represent unit forced outages as a semi-Markov process, which can be simulated to produce a unit forced outage schedule. Alternatively, thermal unit outages can be modelled probabilistically, using, for example, a Poisson distribution (Doherty & O'Malley, 2005). For deterministic models, forced outages should be expected, but they will only impact the available capacity for the duration of the outage. However, within a stochastic optimisation model, generator outages can instead be included as an additional source of uncertainty. Maintenance outages are usually simulated using a reliability assessment model. It may also be appropriate to consider common mode failures of thermal (and other) plant, due to, for example, (very) low/(very) high ambient temperatures affecting the reliable operation of categories of similar plant, or, alternatively, a number of gas-fired power plants being supplied through a common gas supply network.

5.1.5 Hydro Power Modelling

Hydropower with reservoirs can offer significant flexibility to the power system on multiple timescales. Modelling hydropower can however be challenging due to the wide variety of constraints these plants face, both operational, environmental and regulatory limitations can apply

(Stoll et al., 2017). For example, hydro power plants along the same river path can be coupled, river flows and reservoir levels can be restricted to a minimum or maximum (at certain times of the year), and ramping restrictions can apply. Accurate representation of these constraints is important to capture hydropower plants' ability to respond to the increasing need for flexibility driven by wind and solar adoption.

In order to ensure that interactions with wind and PV generation are fully captured, time series hydro input data should be co-incident with input wind/PV/load data. UCED in systems with a significant mix of thermal and hydro power plants with reservoirs poses a particular challenge, due to the need to optimise the storage content across the year (accounting for weather patterns), while UCED for thermal plants is normally performed on a daily or weekly optimisation horizon. Particularly in the latter case, the concept of "water value" is normally introduced to capture the long-term value of water storage for reservoir hydro systems, as the "fuel" cost of water is zero. Short-term operational models can use the water values as boundary conditions for optimising the usage of stored water over the course of a week, for example. These water values can be generated by long-term operational planning models, which take into account uncertainty in hydro inflows, ambient temperature, and wind and solar generation on a multi-year basis (Helseth et al., 2023).

5.1.6 Electrical Storage Modelling

Demand response and energy storage can offer valuable sources of flexibility in systems with high shares of wind and/or PV, generation and careful consideration should be given regarding their inclusion in unit commitment models. Although there are many different kinds of storage, they mostly offer the same benefits to the system, i.e., "charging" the storage during low marginal cost (market price) periods, and "discharging" during high cost periods. In addition, storage devices can often offer system services, such as frequency support, synthetic inertia, voltage support and congestion management. Irrespective of the storage type, a number of parameters are typically specified, such as power capacity, energy capacity, and charging and discharging efficiencies. Different types of storage include:

- Primary energy storage, such as gas, hydro reservoirs, or solar thermal power (heated salt provides a heat source for a thermal power plant at night).
- Full cycle electrical storage, such as pumped hydro storage, batteries and hydrogen storage, including both electrolysis and electrical generation based on hydrogen. The same equipment consumes power or generates power as required, subject to energy capacity limitations.
- User consumption storage, with a common example being electric heating, whereby the "thermal inertia" of a heated building(s), or perhaps a district heating pipe network, enables the electrical consumption to be reduced (avoided) during high price periods. Similarly, air conditioning loads provide thermal inertia, such that the electricity consumption during high price periods can be reduced (avoided). Scheduling when electric vehicles are charged can also help to shape the demand profile, particularly if V2G (vehicle to grid) capability is available, whereby energy stored in the vehicle batteries can be discharged to the grid. A future option might be hydrogen storage, positioned between an electrolyser and the final end use, e.g. electro-fuels. Consequently, the electrolyser can produce hydrogen when electricity prices are low, and store it for later use as a product in its own right.
- User product storage, e.g. aluminum smelting and chemical industries, whereby the production plant stops (slows) production during high electricity price periods. In other words, products can be sold continuously, but they are not produced continuously (Foslie et al., 2023).

User consumption and product storage are further described in Section 5.1.7 below on demand side modelling.

Storage resources may possess energy storage capacities that require optimisation over periods longer than a typical daily optimisation, such that consideration should be given regarding how this is best accomplished. Common approaches include attributing a shadow price to the energy remaining in the store at the end of the optimisation period, or performing a simpler optimisation (often an LP model) over a longer period to create daily storage targets. For systems with high wind and PV shares, the storage strategy should ideally also consider short-term uncertainty in wind speeds and solar irradiance, given the inherent flexibility of such technologies (Aaslid et al., 2022). For longer duration storage (weeks to months), scenario decomposition techniques and uncertainty representation similar to hydropower optimisation (see previous section) could be applied to capture the trade-off between producing now and storing for later use. Other, simplified modelling techniques typically rely on so-called “representative days”, which can be acceptable for planning purposes (Scott et al., 2019) but not so for operational purposes, due to the lack of continuous time representation (chronology).

5.1.7 Demand Modelling

Electrical demand has traditionally been seen as an input parameter to production cost simulation models, and tends to vary as a seasonal function of ambient temperature as well as time of day. However, as other energy sectors (gas, heating, cooling, industry, transportation, etc.) are decarbonised through electrification, the electrical demand profile should become increasingly flexible. This flexibility, or demand response, should be reflected in production cost simulation models by including responsive demand profiles, perhaps by load sector, as optimisation variables rather than input parameters (see also Sections 2.3, 2.4, 3.1 and 3.2).

Demand response may take a number of different forms depending on the nature and flexibility of the resource:

- Some load types can be disconnected for periods of time, most helpfully at times of peak demand, perhaps based on consumer (full/partial) visibility of the marginal electricity price. Such types of demand response are usually referred to as demand shaving (or load/peak shaving).
- Other forms of demand response require a certain level of energy consumption but are flexible (to some degree) regarding when that energy is consumed. The resulting demand response is commonly referred to as demand shifting (or load shifting) and can be similar in effect to the flexibility afforded by storage. For demand shifting resources, there are normally additional timing constraints regarding the period within which the (daily) energy demand must be satisfied.

Demand response can be represented by either defining a price sensitivity (for demand shaving), or by including physical constraints (for demand shifting). Certain load types may be suitable for both demand shaving and demand shifting, or partially suitable for demand shifting. If this is the case, a combination of price sensitivity and physical constraints is required. In either case, the complexity of the flexible demand representation will be increased, to recognise, for individual load types, their seasonal variations (e.g. space heating), daily and weekly utilisation patterns (e.g. EV driving and parking profiles), price elasticity, etc. (Kiviluoma et al., 2022b). For future scenarios, which may incorporate new and emerging load types, various modelling assumptions will potentially be required when specifying the input data.

A number of responsive load types incorporate storage capability, other than electrical storage, such as thermal storage or coupling to other energy sectors. It is important that the storage limitations are suitably included as constraints within the demand response model. Additionally, sector coupling requires that other sectors are modelled in sufficient detail, as, for example, the stored fuel might be delivered by, or have alternative uses in, a different energy sector (Orths & Hansen, 2019). Progress has been made in proposing suitable modelling approaches (Orths et al., 2019; Brown et al., 2018), although it is recognised that further developments are required (Heinen et al., 2018). More sophisticated "energy system" modelling tools may be required for planning applications, recognising the need to co-ordinate and schedule across several energy sectors beyond electricity (Ihlemann et al., 2022).

5.1.8 Network modelling

Production cost simulations are commonly performed for power systems where internal (network) power flows will impact on the generation dispatch, in order to avoid network overloads, ensure regional voltage support, etc. Hence, the transmission network must be suitably modelled. Ideally, the full transmission network would be represented, with the exact spatial location of all generators and loads considered. However, in order to reduce UCED complexity, generators and loads are often aggregated to a reduced number of areas or nodes, with transmission lines (or networks) connecting them together (copper plate model). Within an area/node the transmission network is typically neglected, but it is important that all potential transmission bottlenecks are visible to the optimisation process.

As with adequacy concerns in Section 4, access to local flexibility across regions and borders will be more important at higher wind and solar shares. For example, electricity prices, and/or wind/solar generation, and/or reserve availability, in one part of the system can impact the ability to integrate wind/solar generation in another part of the system. In addition, simulating larger areas, perhaps neighbouring countries, connected together through transmission networks, enables renewables variability smoothing effects to be recognised, with impacts on system balancing requirements. This is more critical for wind power, as solar PV generation is generally coincident on a system-wide scale, except for systems which cover relatively large distances east to west. However, for both wind and solar generation, there are likely to be complementary sources of flexibility in neighbouring regions, and ensuring access to these will offer cost benefits. To better capture these spatial impacts, simulation of, at least, the relevant neighbouring areas is required or, indeed, simulation of the entire neighbouring power system or market area.

The transmission network between areas and nodes can be modelled in various ways. The simplest approach is to aggregate all lines between two nodes/areas as a single interconnection, and to constrain the transferred power to not exceed the total transfer capacity (TTC). Grid congestion adjustments in UC models can be added, when likely congestion points are identified. Such an approach is commonly adopted by TSOs to manage power flows between market areas. These TTCs are usually lower than the thermal capacities of the connecting lines between market areas; consideration is given to transmission constraints within each area/node to limit the flows between areas.

The scope of UCED simulations can be expanded to include an explicit representation of the transmission network, known as security-constrained unit commitment. In such cases, DC power flow equations are typically included in the model to represent transmission constraints. Explicitly including transmission constraints can be particularly important in the context of PV and wind interactions, which may limit production at a local level or introduce operational benefits.

However, due to the increased data and computational requirements, explicit representation of transmission is not always included in UCED models, particularly when the system size is large or stochastic unit commitment is being used.

An alternative option is to model all transmission lines between areas/nodes using a power transfer distribution (PTDF) matrix, to determine the power flow across each line, with the power flow constrained by the thermal limit of each line. Using the power transfer distribution factor (PTDF) approach provides a better reflection of the network topology than using TTC values. An AC optimal power flow (OPF) model should be applied to fully reflect the network topology, but the resulting problem is a non-convex optimisation, which requires knowledge of a mix of nodal voltages and/or reactive power input/output as input data. Due to problem complexity, AC-OPF is rarely applied in production cost simulation models, but given certain assumptions, AC-OPF can be formulated as a convex DC-OPF problem. DC-OPF only requires active power inputs and voltage phase angles as optimisation variables and is more commonly applied in production cost simulation models, particularly if a detailed spatial resolution (nodal model) is applied. In summary, several approaches are available to represent transmission networks, with the choice of approach dependent on the purpose of the study, the spatial resolution of the production cost simulation model, and the network topology of the studied system.

5.1.9 Changes to Operational Practices/Market Paradigm

In order for a study to reflect reality, existing/expected future balancing principles (market structures) should be considered as part of the modelling process.

With high levels of wind and/or PV generation being implemented, possible modifications to the optimisation paradigm include:

- Moving from hourly resolution models to 5–15-minute resolution enables a greater understanding of short-term balancing issues, while multiple years of weather data can provide additional insights into resource adequacy issues due to inter-annual variability.
- The operational costs for a power system, based on deterministic simulations, are estimated by assuming sufficient margins to manage uncertain forecasts. A traditional approach is to assume “spinning reserves” being obtained from either thermal or hydro power. However, for forward looking studies, batteries, particular loads (such as EVs), and renewable energy (such as wind and solar power) present alternative options. It is, therefore, important that the optimisation (UCED) tool is supplied with a full range of flexibility options, and that the optimisation process is allowed to select the most appropriate reserve options.

Table 5.1 outlines how typical power system operational rules may need to be adapted as the share of wind/PV power increases. It follows that the analytical models used to perform the UCED studies must also evolve to fully recognise the complexities and opportunities associated with future scenarios.

Table 5.1. Evolution of short-term energy balancing with increasing shares of wind/solar energy (updated from Kiviluoma et al., 2012).

		Scheduling Frequency	
	Explanation	**Once per Day**	**More Regular Scheduling**
Dynamic Reserve Procurement	Reserve requirement is based on dynamic forecast error estimates for different time horizons	Wind/PV power increases tertiary reserve requirement significantly, but the impact is more limited when forecast uncertainty is accounted for dynamically	Combined impact of more frequent UC intervals and dynamic reserve procurement enables the tertiary reserve requirement to be kept at a low value, most of the time
Stochastic Unit Commitment	Optimisation of UC decisions across several scenarios for possible wind/PV and demand outcomes	Improves reliability and yields more optimal UC outcomes	Reduces tertiary reserve procurement and improves UC optimality
Scheduling Resolution	Scheduling period is shortened (e.g. from hourly to 5 minute resolution)	Ramps within the scheduling period are reduced, which lowers the regulating reserve requirement; scheduling accuracy is improved	

Day(s)-ahead, intraday and short-term markets are typically well captured in modelling tools, and they have been explored for balancing and system services. It is also common to include several (neighbouring) countries, and sub-systems, in electricity market-based studies. However, anticipated changes to future market designs, arising from increasing shares of wind and solar generation, will need to be addressed:

- Increased utilisation of low marginal cost energy sources necessitates a new approach for the governing economics of power systems. Future market mechanisms should also consider the risk of significant volumes of unprofitable generation being retired early, which could jeopardise generation capacity adequacy.
- Recent years have also seen growing interest in different local market designs, including how electricity and flexibility are traded between different end-uses, e.g. peer-to-peer technologies. How local markets should link to each other, and to system level markets, is an open question, particularly for locations which are expecting large growth in distributed energy storage and/or behind-the-meter PV. It is challenging to develop system level models which realistically account for resources connected to low voltage grid levels. Aggregation models are crucial for studying the future interplay between large-scale and small-scale wind and solar generation, and flexible technologies.

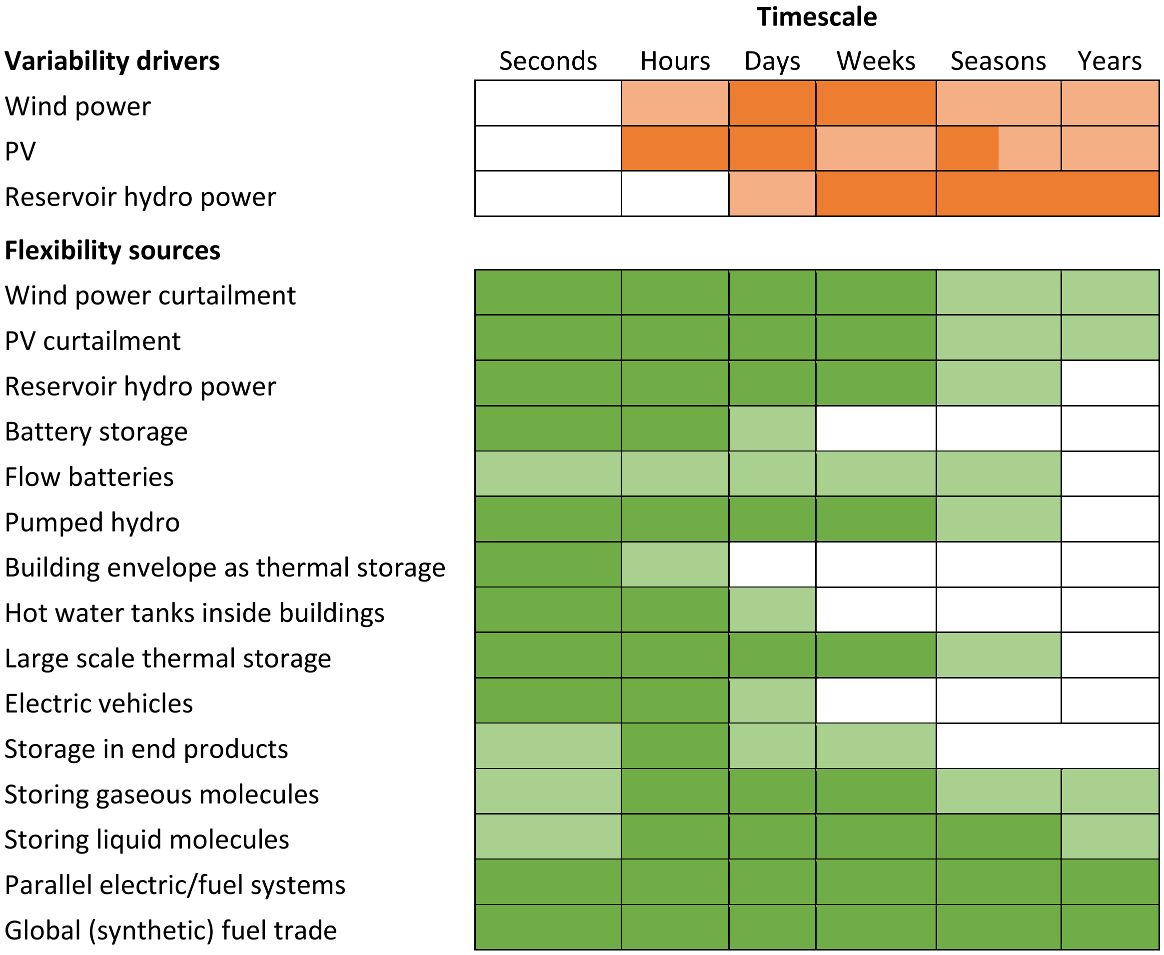
As power systems evolve towards 100% (annual energy) renewable scenarios, additional factors need to be considered. Incorporating additional technical details, e.g. network related constraints or stability related constraints, within the UCED model (Brown et al., 2018), or, alternatively, linking together different models, e.g. AC power flow, natural gas network, in order to perform an integrated assessment (EPRI, 2018). UCED models could capture issues such as frequency control, low inertia operation, sufficient locational voltage control capability, and short-circuit power (Flynn et al., 2017; Holttinen et al., 2020), while recognising technical limitations. These models need not be complex, but they must suitably address all costs and constraints that impact dispatch and commitment decisions. Setting up such approximations may require offline studies. Stability constraints, e.g. inertial floors may be represented by system non-synchronous share limits, or more directly by inertial or rotational stored energy (MWs) limits (unless grid forming technology is in use) (Daly et al., 2019); frequency control can be addressed by ensuring sufficient frequency reserves, and voltage stability by confirming the availability of sufficient equipment in relevant locations.

Increasing wind and solar energy shares may cause more bottlenecks at transmission and distribution level. In order to identify potential generation curtailment, more detailed network modelling and power flow analysis is needed. UCED models can also be used to analyse alternatives to grid expansion, if those alternatives are represented in the model. There are various ways to reduce the (immediate) need for new transmission, including dynamic line rating schemes, greater use of high temperature low sag (HTLS) conductors, FACTS devices, optimization of asset utilisation, automatic tripping of generation and emergency load shedding, and power flow controllers (Choudante & Bhole, 2018; Keyvani, 2022). Future alternatives might include power-to-X (P2X) conversion to different fuels, which might reduce the need to "transport" electricity, and thus to build more grid, but instead use existing/new gas/hydrogen/liquid fuel infrastructure (Brown et al., 2018).

Electrification of end-uses offers potential for flexibility in different timescales as depicted by Figure 5.2.

Changes in dispatch paradigm may finally occur (near) 100% renewable scenarios, with extended periods of very low market prices and some extremely high prices, both framed by high market volatility (Helistö et al., 2017; Stanley et al., 2023). Electrification of other energy sectors, an increased volume of price responsive loads, etc. may evolve in parallel, potentially leading to a paradigm shift in how the system is dispatched and balanced (Kiviluoma et al., 2022a). A transition towards flexible, price responsive demand might invert the dispatch operation, i.e., flexible demand is dispatched to match the available generation.

Stability issues, system splits, locational voltage support, etc. may also be of increasing concern. Despite the uncertainty and complexity, system operation should be prepared for, and robust against, all reasonable outcomes.



	Timescale					
Variability drivers	Seconds	Hours	Days	Weeks	Seasons	Years
Wind power		▨	■	■	▨	▨
PV		■	■	▨	■ ▨	▨
Reservoir hydro power			▨	■	■	
Flexibility sources						
Wind power curtailment	■	■	■	■	▨	▨
PV curtailment	■	■	■	■	▨	▨
Reservoir hydro power	■	■	■	■	▨	
Battery storage	■	■	▨			
Flow batteries	▨	▨	▨	▨	▨	
Pumped hydro	■	■	■	■	▨	
Building envelope as thermal storage	■	▨				
Hot water tanks inside buildings	■	■	▨			
Large scale thermal storage	■	■	■	■	▨	
Electric vehicles	■	■	▨			
Storage in end products	▨	■	▨	▨		
Storing gaseous molecules	▨	■	■	■	▨	▨
Storing liquid molecules	▨	■	■	■	■	▨
Parallel electric/fuel systems	■	■	■	■	■	■
Global (synthetic) fuel trade	■	■	■	■	■	■

Figure 5.2. Estimated timescales for the drivers of variability and sources of flexibility (darker colour – primary impact, lighter colour – secondary impact, white – not usually relevant) (Adapted from Kiviluoma et al. 2022).

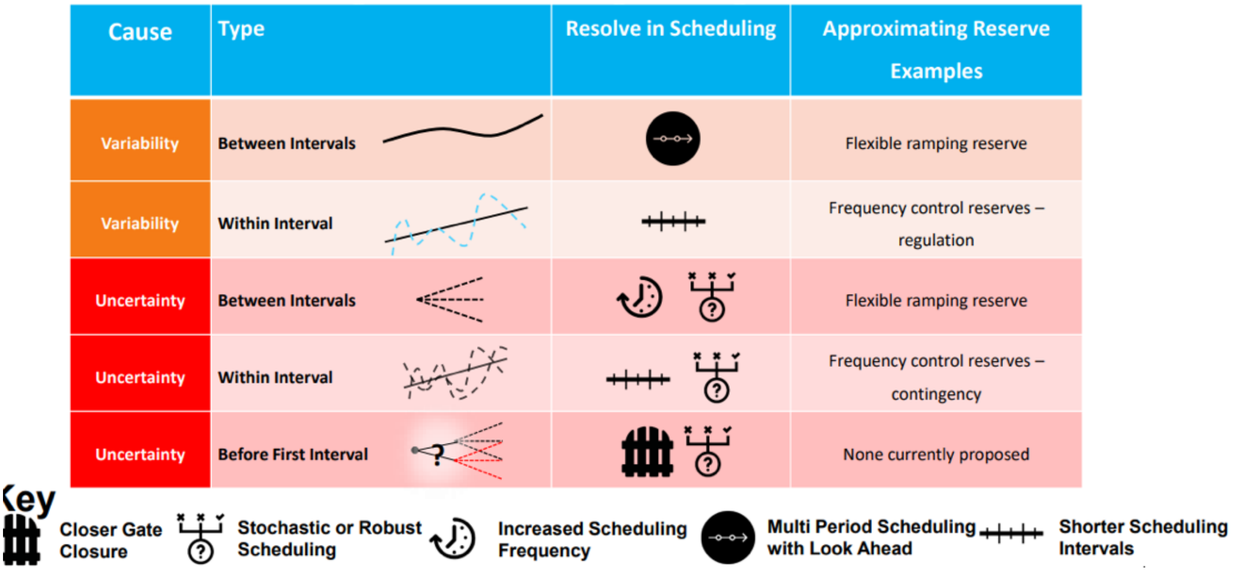
5.2 Operating Reserve Requirements

Power system scheduling involves scheduling generator outputs to meet the forecast demand profile, while implicitly handling the associated uncertainties. System operators also carry reserves to balance demand against generation in real-time, and to respond to sudden and unexpected outages. The impact that wind/PV energy has on procuring operating reserves has been extensively studied, accounting for forecast uncertainty while balancing reserve adequacy against economic provision for both wind energy (Holttinen et al., 2012a) and solar PV energy (NREL, 2013).

System reserves, or ancillary services, are allocated (dimensioned and scheduled) for a diverse range of conditions, and they are required to respond across multiple timescales. For balancing, fast responding frequency control services, and real-time (balancing) markets are commonly used – individual systems may require different services, and increasing wind and solar shares can also drive the need for new reserve products, e.g. fast frequency reserve. Other system services include voltage control, damping, synchronisation, protection and system restoration (O’Malley et al., 2023). These later aspects have not generally been considered in analyses for increased reserve requirements due to wind/PV power, but they could form part of studies for future wind/solar dominated systems, including stability aspects (see also Section 6).

The term “operating reserve” is commonly defined as the active power capacity that can be deployed to assist with generation/load balancing and frequency control. Contingency reserve is carried to protect against large generation failures, but large wind/PV power ramp events are typically not included, and must be considered separately (Holttinen et al., 2012b; Gil et al., 2010). To determine the reserve target(s), the response needs across multiple timescales should be considered: a simple approach distinguishes reserve responses operating automatically (seconds timescales), and reserve activated manually as needed (from minutes to a few hours timescales).

It is important to note that the time steps chosen for dispatch and market operation will influence the reserve requirements. For example, markets with a 5-minute scheduling resolution can automatically extract balancing needs from those generators that must ramp their output to meet the schedule for the next market period (Kirby & Milligan, 2008; Milligan et al., 2011). As shown in Figure 5.3, it follows that different approaches (scheduling characteristics vs. new reserve products) can be adopted to address variability and uncertainty concerns across different timescales.



Cause	Type	Resolve in Scheduling	Approximating Reserve Examples
Variability	Between Intervals	●	Flexible ramping reserve
Variability	Within Interval	┼┼┼┼	Frequency control reserves – regulation
Uncertainty	Between Intervals	◷ ?	Flexible ramping reserve
Uncertainty	Within Interval	┼┼┼┼ ?	Frequency control reserves – contingency
Uncertainty	Before First Interval	▥ ?	None currently proposed

Key

▥ Closer Gate Closure

? Stochastic or Robust Scheduling

◷ Increased Scheduling Frequency

● Multi Period Scheduling with Look Ahead

┼┼┼┼ Shorter Scheduling Intervals

Figure 5.3. Management of operational flexibility through scheduling strategy or reserve product design (Source: EPRI, 2019).

Clearly, offline analysis and modelling is required to provide realistic estimates of the reserve requirements as the share of wind/PV power increases. In addition, estimates are required concerning the uncertainty and variability of demand, wind/PV generation, and other generation sources. Some reserves may be allocated for real-time variability only. For wind and solar power, the forecast horizon is a crucial assumption, because uncertainty at shorter timescales will reduce more significantly than that for demand. Demand forecasts are often based on standard load profiles with fewer updates.

In addition to uncertainties associated with power forecasts and plant outages, uncertainty also affects how different power system components behave within scheduling dispatch intervals. Within a dispatch interval, wind/PV generation and system demand will fluctuate, while dispatchable generation (and HVDC interconnectors) have certain limitations regarding their ramping speed. Sub-hourly models for simulating behaviour within dispatch intervals can be applied (Kanellas et al., 2019; Nordström et al., 2022), but for the power system to ensure a continuous (sub-hourly) balance between generation and demand, sufficient volumes of flexible resources must be available to address the flexibility needs of the system.

The input forecasts must be consistent with operating practice, which will likely be somewhat particular for each system. In some cases, there may be anticipated future changes in operating procedures, such as significant changes in transmission capacity, balancing methods, or unit commitment practices. Such issues should be recognised within planning studies to better understand their impact on integrating wind/PV generation, while replicating input data structures and operating practices.

A common approach for determining the need for operating reserves for wind/PV integration studies is to compare the uncertainty and variability before and after the addition of wind/PV generation, noting that additional reserves would be required to maintain a desired reliability level. Traditionally, the term "reliability" refers to assuring resource adequacy to accommodate rare events in long-term planning, while also maintaining secure short-term operation, on timescales spanning from a few minutes to a few days ahead.

Several methods can be applied to calculate the impact of wind/PV generation on operating reserves (Ela et al., 2010; Ela et al., 2011; Holttinen et al., 2012a; Menemenlis, 2012; Milligan et al., 2010; NREL, 2013).

Generally, the following steps are recommended:

1. The risk of insufficient reserve, i.e., probability that scheduled generation including reserves is not sufficient to supply the demand, must be identified. If the risk is realised, power should be imported from neighbouring balancing areas. For example, 95% of the variations in net load (load minus wind/PV power) for a balancing area could be covered, based on existing operating practices for balancing area reliability metrics. When considering an entire synchronous system without interconnection, the risk level should correspond to an acceptable loss of load expectation due to insufficient operational reserve.
2. Operating reserve should be calculated for the appropriate timescales, aligning with existing operational practices. Typically, different reserve types are associated with (a) automatically responding in seconds to minutes timescales, and (b) manually activated on timescales of multiple minutes to several hours. When splitting reserve types into separate categories, it is very important not to double count sources of variability or uncertainty. For example, if the volume of 4-hour reserves increases then they normally also include an increase in the 2-hour reserves.
3. Simple statistical methods can be applied to combine the variability and uncertainty from wind/PV and demand (and generation); however, it is not valid to assume that demand and generation errors can be represented by normal uncorrelated distributions, and using standard deviation values (n-sigma method). Statistical methods can be suitably adjusted by, for example, applying a desired level of exceedance, or by performing analysis to determine the appropriate distribution.
4. Net load related reserves should not be static. Dynamic reserve setting (for example, for each hour, or for each day) will be cost-effective for higher shares of wind and solar. Variability and forecast uncertainties depend on meteorological conditions and consequently will vary over time. When wind/PV generation is low, there is little need for upward reserve from conventional plants: fixed reserve levels will lead to varying risk levels, while, conversely, maintaining a constant reliability or risk level will require varying reserve requirements. A further step is to consider the value at risk, which will also change depending on the power

system state (Meyruey, 2016). Given that wind power variability tends to be highest with turbines operating in their mid-output range as well as during storms, dynamic reserve methods have been proposed and developed that recognise such observations (EWITS, 2010). Similarly, PV uncertainty will be lower on clear days compared to cloudy days, while high solar power variability is often observed during times with fast moving clouds (Lave, 2012).

5. It should be noted that an increased reserve requirement, due to wind/PV power, does not necessarily imply a need for additional reserve capacity. There is a link between the availability of, and the need for, reserve. Wind/PV generation, when available, can provide down regulation (reduced power output), when other, more cost-effective, options have been depleted. For up regulation (increased power output) wind/PV power would need to curtail its output beforehand, implying a revenue loss. However, at high wind/PV production the power prices are often low, which means that the cost of decreasing solar/wind (to keep margins for up-regulation) is low. Also, at high wind/PV levels, other power plants are often operating at a reduced output with the ability to provide up regulation.

Larger balancing areas can take advantage of the limited correlation between demand and wind power changes in neighbouring areas, such that the reserve requirement is reduced, assuming that network bottlenecks do not restrict the need to trade reserve. There is more benefit in sharing the balancing needs for systems, compared against the balancing needs that wind and solar generation might impose – an example can be seen from historical reserve requirements in Germany (Kuwahata & Merk, 2017). For solar PV generation, larger balancing areas can enable regions with high PV capacity to link with regions with low (none) PV capacity (Bloom et al., 2016). However, the higher correlation of PV generation between regions (during clear sky conditions) means that such benefits are more quickly diminished compared to wind generation, as increasing PV capacity is installed, or if neighbouring regions have achieved similar PV shares.

5.3 Flexibility Assessment

The term “flexibility” generally refers to the power system’s ability to cope with variability and uncertainty, over multiple timescales. The need for flexibility is typically considered to be driven by evolutions in residual load (load minus non-dispatchable generation). The provision of flexibility can be obtained by modulating flexible generation (including renewable curtailment) or flexible demand, but also by smoothing variations and uncertainty over time (storage), over space (network interconnection), or over energy carriers (sector coupling).

Historically, flexibility was not considered to be a crucial limiting factor for power system planning, compared to capacity and energy adequacy, given that it was often conveniently provided by thermal and hydro power generation, along with, in some regions, network interconnection. However, with increasing wind and solar power shares, variability and uncertainty are increasing, over multiple timescales, making flexibility a key aspect of system planning (Heggarty et al., 2019). Consequently, a range of common questions can be asked: How much flexibility does a power system need? How flexible is a particular flexibility source? How flexible is a power system? Which sources are providing flexibility to a power system?

As many thermal generation plants are being phased out due to their environmental impact, other flexibility sources will need to pick up the slack, and to scale up their support to meet growing flexibility needs:

- Interconnection: as well as smoothing geographical variations, it also allows other flexibility sources to be shared between neighbouring countries.

- Storing electrical energy and returning it to the power system at a later point in time, is an obvious solution – depending on the cost efficiency and availability of other options.
- Sector coupling, which allows energy to be stored using a different energy carrier, without necessarily returning it to the power system, may be relatively cheaper, and just as valuable. Strengthening the links between the power system and the transport sector (via electric vehicles), the heat sector (via heat pumps) and the hydrogen sector (via electrolysis) could unleash a vast flexible demand potential, provided that consumer responses are suitably coordinated in their actions using appropriate signals (Kiviluoma et al., 2022). If poorly managed, however, sector coupling could potentially make the flexibility problem more challenging. Note that much of this new flexible load potential is connected to the distribution network, requiring new forms of TSO-DSO coordination, which recognise (capacity, voltage profile, etc.) limitations associated with the distribution network.

Flexibility can be separated into planning and operational timescales. Operational timescale concerns relate to how existing assets can be best managed to match inter-annual, seasonal, weekly, and daily cycles and uncertainty in residual load patterns. In contrast, multi-year planning timescales involves determining how the system will need to evolve to manage future flexibility needs, while also proposing investment, market and regulatory designs to incentivise such evolutions.

Flexibility assessment on operational timescales is typically managed implicitly using standard unit commitment and economic dispatch models. For example, assessing the flexibility needs for low/medium shares of wind and solar generation can be based on a simple tool, such as IRENA FlexTool (IRENA, 2019). For an initial illustration of available flexibility sources, a flexibility chart can be created. However, such an approach will only show the generation mix at a general level, and it is not sufficient for detailed flexibility analysis (Yasuda et al., 2023). A more detailed assessment could be applied as a post-processing outcome of UCED to check the ability of all relevant assets to ramp up/down as required across different time horizons (Heggarty et al., 2020; Lannoye et al., 2012; Lannoye et al., 2015; EPRI, 2019).

For higher wind and solar shares, a system model needs to incorporate sufficient temporal granularity to express flexibility needs, and sufficient technical detail to characterise operational constraints on flexibility sources (ramping rates, minimum power output, minimum up and down time, etc.). Addressing the uncertainty aspects of flexibility assessments may require more complex modelling methods, such as simulating the sequence of individual market actor short-term decisions, as they are exposed to updated information, or stochastic programming.

Flexibility assessment on planning timescales is a topic of ongoing development. Due to computational burden concerns associated with standard capacity expansion models it is challenging to include sufficient temporal granularity and technical detail to accurately express the flexibility needs and provision as well as to be able to appropriately represent other flexibility sources such as interconnection and sector coupling.

5.4 Recommendations for Studying Operational Impacts

Checklist of Key Issues: Operational Impacts

- ➢ Co-incident time series of wind/PV and load (for at least one year, but preferably several years), with sufficiently high temporal resolution (at least hourly, but preferably sub-hourly). The time series should capture the locational smoothing of large-scale wind/PV power, and be representative of real (correlated) wind/PV power variations. For systems with significant weather dependency from other sources, the respective time series should be time-synchronised to accurately capture, for example, the availability of hydro power, transmission (dynamic/seasonal) limits, and contributions from combined heat and power. For systems with significant hydropower, different hydrological scenarios should be considered, e.g. wet/dry years.

- Capture all relevant system characteristics and generator/load responses through operational simulations and UCED modelling.
  - At higher wind and solar shares, it is important to model the impact of short- and long-term uncertainty on UCED dispatch decisions by, for example, introducing stochastic optimisation and rolling planning. Wind/PV forecasting best practices should be applied in relation to the uncertainty associated with wind/PV power production, including the possibility of updating forecasts closer to the delivery hour.
- Model the capabilities and limitations of flexibility sources for generation (up/down ramping limits, minimum up/down times, minimum stable levels, startup and shutdown); for interconnections to neighbouring areas (preferably by explicitly modelling, in sufficient detail, the neighbouring systems); and for operational practices (which may enable or limit the accessible flexibility over different time frames).
  - For higher wind/PV shares, new potential sources of flexibility should be included (heating, cooling, electric vehicles, storage, demand response).
- Model transmission system limitations as constraints within UCED.
  - For higher wind and solar shares, congestion and N-1 security can be included directly within UCED – or analyse the transmission system using other dedicated tools with the resulting limitations included as constraints within the UCED model. In systems with very high levels of renewable generation, it may be also necessary to model additional stability constraints.
- Increased operating reserve targets should be estimated based upon wind, solar, and load forecast uncertainty. When calculating reserve requirements, care should be taken not to double-count uncertainty impacts, particularly if stochastic optimisation is being used.
  - At higher wind/solar shares, the inclusion of dynamic reserves, faster markets, and increased market resolution is recommended.
- Assess the existing flexibility of the power system, and apply indicators (metrics) to determine whether additional flexibility options are sufficiently economically justified. Perform a cost–benefit analysis and determine the required response characteristics of existing (and new) flexibility sources to efficiently integrate the targeted level of wind/PV energy being studied.

For wind and solar dominated systems, consider appropriate modelling complexity for a given wind/PV share. Developing suitable tools or integrated data sources to cover all such aspects represents ongoing work. It is recommended to consider at least the following issues:

- *Represent grid and stability constraints in sufficient detail*: Locating grid bottlenecks through improved network modelling and power flow analyses and including power flow control or other grid enhancing technologies that aim to reduce bottlenecks and increase transfer capacity. Stability constraints, e.g. inertial floors, may be represented by system non-synchronous share limits or more directly by inertial or rotational stored energy (MWs) limits (unless grid-forming technology is in use); frequency control can be addressed by ensuring sufficient frequency reserves and voltage stability by confirming the availability of sufficient equipment in relevant locations.

- *Use probabilistic models and risk assessment tools*: Apply deterministic and probabilistic assessment approaches for risk-based operation using new optimisation methods and advances in (parallel, high-performance) computation as well as appropriate modelling approximations.
- *Enforce high quality information for available resources and forecast uncertainty*: Sufficiently high temporal and spatial resolution should be applied to ensure that wind and solar output is accurately represented and has a sufficiently long duration dataset to cover expected and extreme weather patterns. This should be paired with a high quality representation of forecast uncertainty, which integrates weather-dependent aspects of the system across multiple decision cycles.
- *Represent other relevant energy sectors*: Heating, cooling, transport, and power-to-X will likely have a large influence on the economics and operation of wind and solar dominated systems, and have the potential to be major sources of flexibility provision. They should be modelled with sufficient detail and resolution, both for flexibility and process constraints. In thermal power generation dominated systems, fuels provide significant flexibility. As the share of variable power generation increases and thermal generation is replaced, the need for new sources of flexibility for longer timescales increases.
- *Represent energy storage and price-responsive loads within system services*: Demand response/storage can act as cost-effective sources of system services, but potentially complex constraints relating to service availability must be carefully modelled. This may require more detailed models of the distribution system, or the aggregation of distributed resources for bulk systems, while balancing the computational burden imposed.
- *Expand market options/products for flexibility trading*: Incorporate market options for netting of system/area/nodal/individual imbalances at different timescales.

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6 Dynamics

Nicolaos Cutululis, Julia Matevosyan, Robert Erikson, Niina Helistö, Jose Luis Rueda Torres, Damian Flynn. Review Vahan Gevorgian.

This section covers the simulation parts relating to the power system dynamic simulations made in order to check the feasibility of the studied power and energy system scenario (flowchart shown in Figure 6.1). Maintaining a (nearly) constant frequency and voltage during normal operation and shortly after the occurrence of disturbances is the paramount role of a power system operator. Once adequacy (See Section 4.2 on steady-state tests for grid adequacy) and operational simulations (See Section 5) have indicated that a given wind/solar PV integration scenario is potentially feasible, more detailed analyses can be performed, to assess whether the combination of plant portfolio and high voltage networks are sufficient to cope with both temporary disturbances and significant failures.

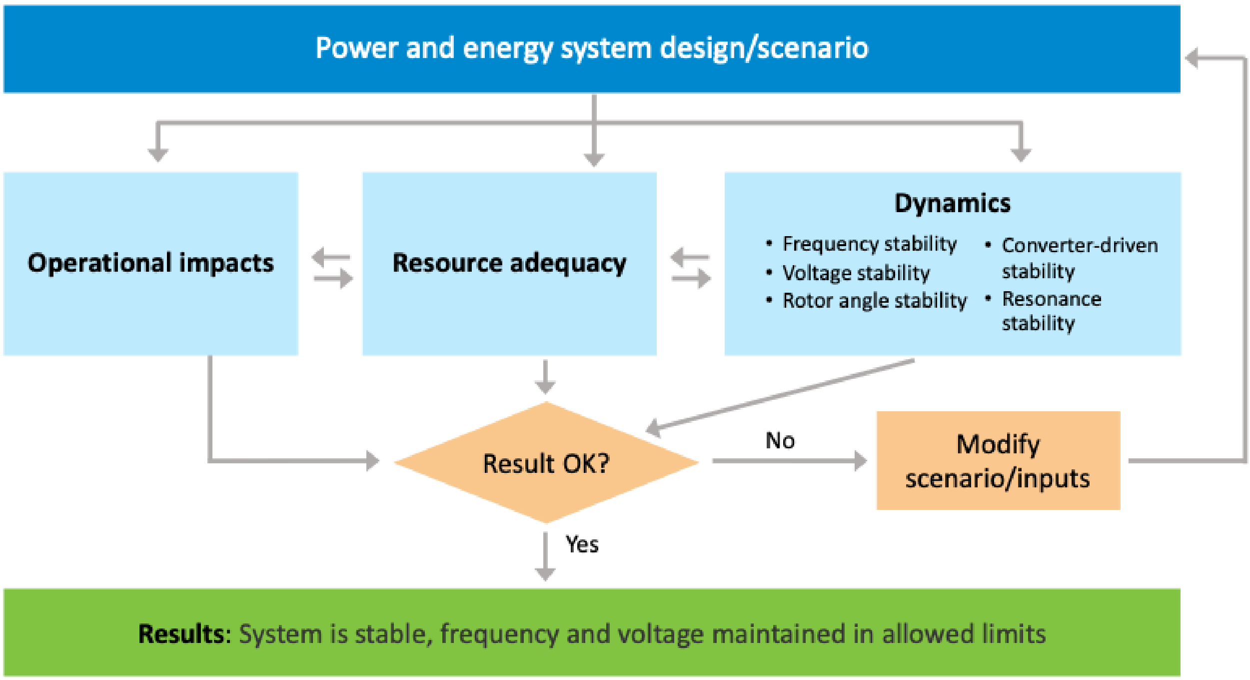


Figure 6.1. Wind/PV integration study: dynamics.

Dynamic studies for impacts of wind and solar are usually conducted once the share of wind and solar is large enough to dominate the power system during some hours of the year. Accurate dynamic models of all inverter-based resources (IBRs such as wind, solar and battery energy systems) will be important to include in the power system dynamic studies for future scenarios. In addition to system-wide dynamic stability analysis with high share of wind-PV resources also the dynamic impact and reliable/stable interconnection of new wind and PV resources is relevant.

With low wind and solar shares (10–20%) it is generally sufficient to study those steady-state and dynamic issues which were historically associated with a particular system. It will be important to understand whether an increasing wind and solar share tends to exacerbate or improve known dynamic issues. It is noted that the incorporation of generation 'must-run' and locational constraints within production cost simulations may have implicitly addressed some known stability issues. However, if dynamic studies result in additional need for "must run" in a given system, it is good to distinguish what purpose any given "must run" is serving, for operational (UCED) simulations and dynamic simulations, to check that they are adequate.

At higher wind and solar shares it may be prudent to study a much broader spectrum of contingencies and analyses, firstly through a high-level scanning approach and then adopting a more in-depth approach as challenging issues are revealed. If the dynamic simulations reveal deficiencies, then a wide range of options should be considered, depending on the likely frequency of occurrence and severity of the consequences, ranging from a revised economic dispatch/unit commitment for the system, to modified control and/or supervisory schemes, and grid reinforcement and/or enhancing network functionality, e.g. introducing load-tap-changing or phase-shifting transformers. An iteration loop can be formed to the portfolio setup (power system design/scenario, Chapter 3) relating to transmission scenarios.

The chosen deployment of wind generation (including different wind turbine technologies and wind distributions) and solar generation (including different solar PV and concentrated solar technologies and residential uptake of installations), with potential battery storage, should also be evaluated against existing network code requirements and considering different mitigation or participation options from wind and solar power plants to any dynamic simulation deficiencies.

This section starts with stability definitions, followed by an overview on the tools and models for dynamic simulations, and it concludes with stability analyses for systems with high shares of IBRs.

6.1 Stability Definitions

Power system stability is the ability to remain stable during normal operating conditions and return to acceptable stable operating condition after being subjected to a disturbance. While stability of a highly complex and dynamic system can be defined in different terms, we adopt here the definition given in (Hatziargyriou et al, 2021). It categorizes power system stability into five types (Figure 6.2):

- **Frequency stability** is the ability to maintain the system frequency under normal operating conditions and following a major imbalance between generation and load, e.g. tripping of the most heavily loaded lines or the largest generator infeed.
- **Voltage stability** is the ability to maintain an acceptable voltage profile under normal operating conditions and after being subjected to a disturbance.
- **Rotor angle stability** is the ability of the interconnected synchronous machines in a power system to remain in synchronism under normal operating conditions and to regain synchronism after being subjected to a small or large disturbance.
- **Converter driven stability** can be classified into two parts: fast and slow interaction. Fast converter-driven interactions occur between the control systems of power-electronic-based systems and fast-response components of the power system or other power electronic-based devices. Slow converter-driven interactions occur between the control systems of power electronic-based devices and slow-response components of the power system.
- **Resonance stability** is characterized by oscillations that occur in the sub-synchronous frequency range of 5–45 Hz. Depending on where these oscillations occur, they can be classified into various types, such as sub-synchronous resonance (SSR), sub-synchronous torsional interaction (SSTI), and sub-synchronous control interaction (SSCI). Resonance stability covers the effect of HVDC and FACTS on torsional and of DFIG controls on electrical resonance stability.

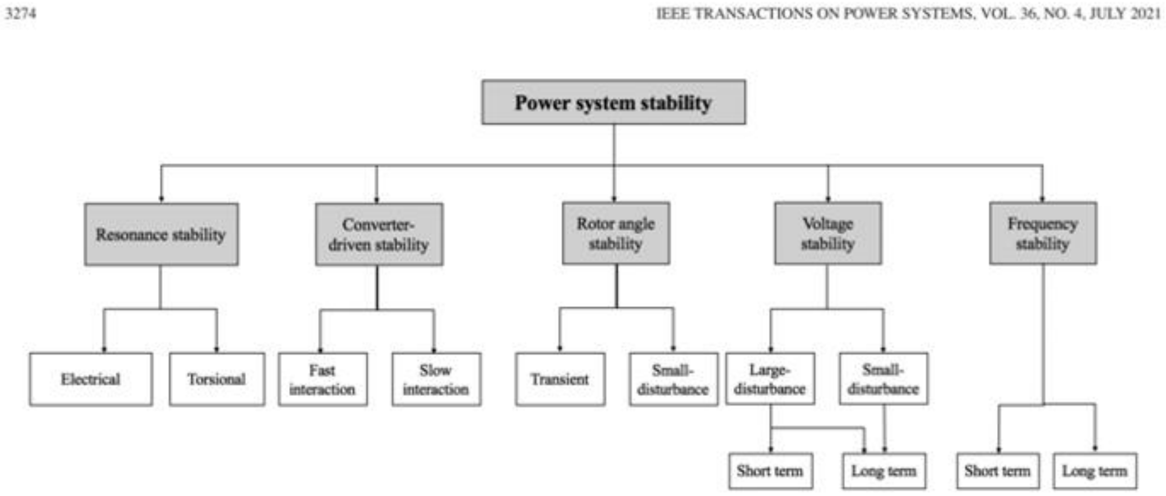


Figure 6.2. Power system stability categorization (Source: Hatziargyriou et al., 2020).

Multiple paradigm shifts will impact on both power system stability and the manner by which it is analysed (see Figure 6.3). These challenges call for more detailed models, more advanced tools for stability assessment, and new ways to control wind and solar power plants to mitigate the challenges (Heard et al., 2017, MIGRATE, 2019).

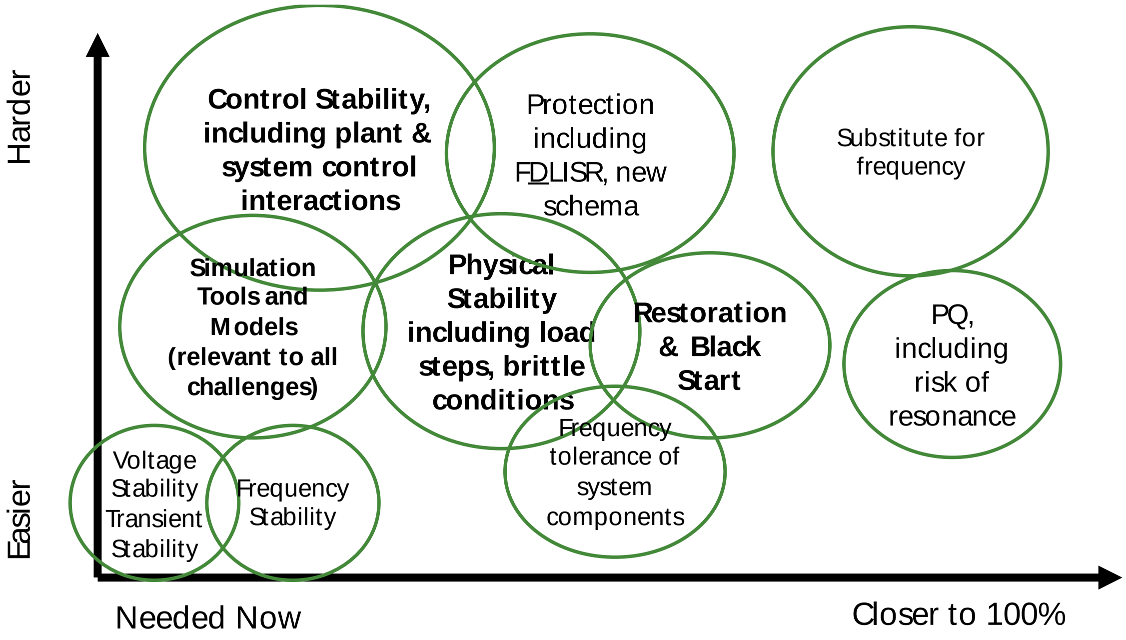


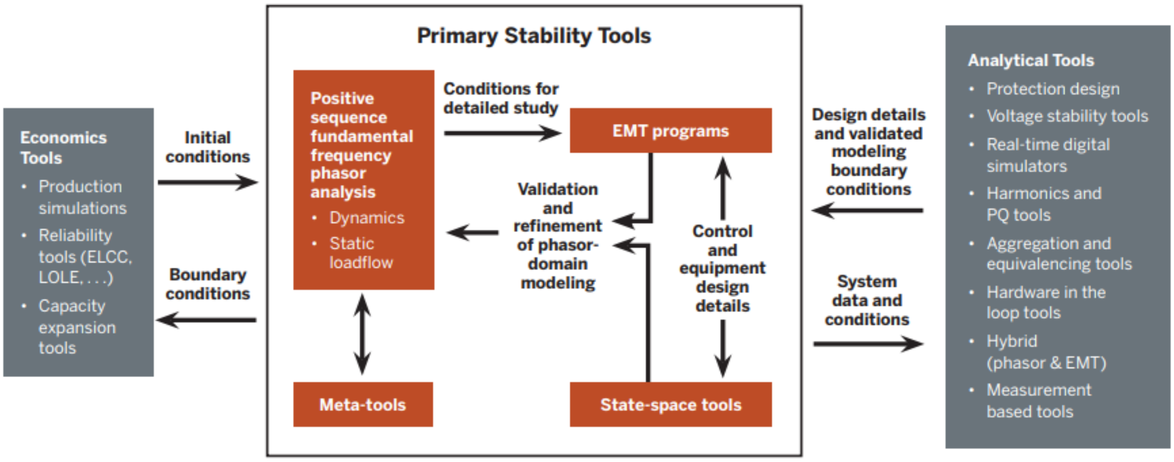
Figure 6.3. Summary of challenges and gaps for stability to achieve higher wind and solar shares versus difficulty to resolve them (FDLISR is fault detection, location, isolation, and recover; and PQ is power quality. Adapted from Holttinen et al., 2020).

6.2 Simulation Tools and Models to Capture Inverter-based Resources

A comprehensive overview of stability tools that can be used to assess integration of higher shares of IBRs can be found in (Miller et al., 2021; GPST "Stability Tools Inventory: Status and Needs", 2022). The publication has focused on tools for planning, with less emphasis on situational awareness and related operations tools. Figure 6.4 shows how stability tools fit together with other tools.

The modelling depth to be considered is related to the timescale of the stability phenomenon that is excited by the considered disturbance/failure. Detailed electro-magnetic transients (EMT) models, including inner and outer control loops are used for the study of fast dynamic phenomena, whereas simplified models (e.g. positive-sequence fundamental frequency RMS), which usually include only outer control loops and simplified inner control loops, are used for the case of slow dynamic phenomena.

FIGURE 27
Stability Simulation Environment



Source: HickoryLedge.

Figure 6.4. Linkages between stability tools and other tools (Source: Energy Systems Integration Group ESIGESIG, 2022).

6.2.1 RMS Tools and Models

Power system studies have typically been performed using positive-sequence fundamental frequency (RMS) tools, with models representing physical and control behaviour in the cycles-to-seconds time frame (Holttinen et al., 2018). An aggregated plant model approach has been adopted to approximate IBR plant behaviour to assess frequency, voltage, and rotor angle stability as well as some slower electro-mechanical interactions. Such approaches have served the industry well. For example, low inertia/high rate of change of frequency issues, and available solutions, have been studied and known about for decades (Flynn et al., 2016; EirGrid & SONI, 2016).

RMS tools and models, however, are not capable capturing faster dynamics of some control loops in IBRs, therefore at higher shares of IBRs, RMS tools may not be sufficient and electro-magnetic transient studies are needed. See (EPRI, 2022) for discussion on capabilities and limitations of various types of IBR models and various power system simulation domains.

6.2.2 Electromagnetic Transient Tools and Models

Increasing focus has been placed on improving how wind, solar and battery plant controls are represented in positive-sequence fundamental frequency models, but the stability of fast inner-loop controls is more challenging, both in reality and to represent within models. Simulation requires smaller time steps and more complex structures to represent IBR non-linear behaviour.

The stability of phase-lock-loop (PLL) controls used by IBRs for synchronization is highly important for determining if each IBR will stay connected and stable during and after a large disturbance. In positive sequence fundamental frequency tools, such controls are highly simplified or idealized, which works well for the majority of system conditions seen today. However, at certain share of IBR, numerical instability in phasor domain models start to appear, or some stability issues may be overlooked because phasor domain model doesn't have fast control loops represented. Specific details of PLL controls must be accurately represented, to determine when they may become unstable. To further weaken the value of positive sequence fundamental frequency tools, new issues are emerging, such as control interactions between multiple IBRs or IBRs and other grid equipment due to weak (high impedance) grids or sub-synchronous resonance, and non-fundamental frequency behaviour.

Electro-magnetic transients (EMT) tools, with much faster time steps and much more detailed control representations, are required to assess these phenomena. Note that for system impact studies in EMT, an aggregated plant model approach is still used but the aggregate model itself has high level of details compared to positive sequence models. However, due to high computational intensity and high modelling effort, EMT tools are not well suited for very large systems with thousands of elements. It is therefore unavoidable to reduce the geographical size of the network model to be simulated, but it remains a challenge to determine the “relevant” part of the grid model to be included. There are established methods for this (e.g. MIIF Multi Infeed Interaction Factor), but their use is still based on assumptions and their correctness not mathematically proven. Ongoing research attempts to close this gap and to more precisely identify the relevant part of the grid to be included in a simulation. The excluded part of the network could still be simulated simultaneously by means of Co-simulation. This approach, marrying RMS and EMT tools, is seen as one solution approach, balancing computational burden against model fidelity.

Recently published CIGRE Technical Brochure TB881 provides an excellent reference on the topic of IBR modelling in EMT (CIGRE, 2022)

6.2.3 Models for Inverter-Based Generators, Loads, and High Voltage Direct Current

For simulation tools, the dynamic characteristics of all generators and the load are required, as are increased detail on the configuration and electrical parameters of the transmission and distribution networks. The capabilities of wind, solar and storage technology are evolving, as are the grid code requirements for these types of resources. All IBR capabilities and limitations that may impact their performance in operations need to be captured in the models describing their dynamic characteristics.

Generator and storage modelling

For studies assessing IBR dominated grids, the models as well as simulation tools and simulation domain need to be carefully considered – the inability of wind, solar and battery storage models to appropriately capture their dynamic responses to disturbances is one bottleneck for assessing reliability of future power systems. The modelling complexity required will depend on the nature of the analysis, balanced against the size of the system and computational power available.

For large scale system studies, given that access to manufacturer models is often limited, it is standard practice to utilise generic wind turbine dynamic models developed by the Western Electricity Coordinating Council (WECC) and International Electrotechnical Commission (IEC, 2015; WECC REMWG, 2021), and which are intended for short-term (10–30 s) analyses. These capture the minimum performance required by most grid codes for the four basic types of wind turbine. Models for large PV systems and BESS have been developed from the previously developed WECC wind plant models, as many commonalities exist between PV systems, BESS and wind plants comprised of full-scale power converter connected (‘type 4’) wind turbines (Hansen et al., 2006; WECC, 2014, WECC, 2021). Verified generic EMT models are a necessary future development for wider-area planning type studies (see https://www.epri.com/pvmod). Note that for shorter term planning studies, as well as any grid impact assessment and grid code compliance studies, manufacturer and site-specific models of each specific generator should be used.

Some features that need to be in the component models for different stability studies include:

- **Frequency stability studies** require the inertia, droop and governor settings of all synchronous units and frequency control block model and settings of all IBRs (in case those are required to provide frequency control) in order to both simulate individual unit responses and the combined system response to major faults or contingencies, and to assess changes in frequency regulation capacity. It is also important to model any protective functions in IBRs or synchronous generators that may respond to frequency or rate of change of frequency exceeding certain threshold. Due to higher rates of change of frequency and lower frequency nadirs associated with lower inertia systems it may also be prudent to evaluate the adequacy of existing conventional generator models (Meegahapola & Flynn, 2015). A reduced network representation may be sufficient (EDF R&D, 2015; O'Sullivan et al., 2014).
- **Small signal stability studies** require automatic voltage regulator (AVR) including power system stabilizer (PSS) settings and governor controls for synchronous generation. Unit commitment may need to consider whether an appropriate arrangement of PSS-enabled generators has been dispatched. IBRs are also capable of controlling voltage and in some cases (rarely though) may have power oscillation damping POD functionality (to serve similar function as PSS). All of these control capabilities with correct settings should be included in the IBR models.
- **Transient stability analysis** alongside with all relevant IBR controls must also consider the effect of protection devices or protective functions for both network and IBRs. However, boiler/steam turbine models are not required.

In addition to modelling the response of **small-scale wind, PV, and storage systems**, the aggregate response of distribution-connected generation and storage system also depends on the distribution systems to which they connect. Industry consensus on how best to determine aggregate model parameters, for example, for distribution-connected PV has not yet been formed, but analytical methods involving both transmission- and distribution-level modelling have been proposed (Boemer et al., 2017; Mather & Ding, 2016). Development of adequate dynamic distribution models with distributed wind, PV, storage systems, etc. is increasingly required. Here, especially, the complexity and diversity associated with the distribution level can represent a major challenge. Examples of methods for representing distributed resources exist for phasor-domain transient studies (EPRI, 2019) and for EMT studies (EPRI, 2021).

The technical performance of both renewable and non-renewable generation to support high shares of wind/PV generation is clearly important. Particularly, at higher wind/PV shares, validated manufacturer and site-specific comprehensive wind turbine/PV power plant models will be required to accurately assess the dynamic power system characteristics (Coughlan et al., 2007; NERC, 2009). For existing generating units, both conventional and from renewable energy sources, it is, therefore, essential that simulation models of individual components have been fully validated before analysis begins. On the contrary, for planned generation power plants, as explained in CIGRE (2007), generic models can be adopted. At the planning stage, a further complexity is added, because, in many cases, the planner may not be aware of the specific equipment that will be installed, particularly the control schemes associated with the new conventional and renewable generating units. The latest vintage of generic models with state-of-the-art capabilities is recommended for modelling future IBRs. Generic models of synchronous generation-based plant are well established and have been developed and validated over many decades.

Beyond modelling the standard control requirements for wind turbines and PV generation, e.g. maximum power point tracking, voltage and reactive power support, the available control modes, capabilities and internal protective functions of such generation technologies can significantly impact the power system. It is, therefore, increasingly important that such capabilities are incorporated within the generation models in order to best understand their implications and provide fair comparison with alternative approaches. For example, modelling of internal IBR protection or protective functions is important to reflect when IBR may trip due to external grid conditions. In North America, major event analysis conducted by the North American Electric Reliability Corporation (NERC) in each disturbance event highlights importance of IBR performance requirements as well as importance of accurate modelling and studies (event reports available at https://www.nerc.com/pa/rrm/ea/Pages/Major-Event-Reports.aspx).

An effort is being undertaken by a WECC working group to develop a generic grid forming IBR model. The advantage of one of the proposed models is that it allows a study engineer to represent and test benefits of future grid-forming (GFM) IBRs with any of four different GFM control strategies that have been proposed in the literature. This approach also allows to study a power system with a mix of GFM IBRs with different control strategies. These control strategies are:

- Droop based GFM
- Virtual synchronous machine based GFM
- Dispatchable virtual oscillator based GFM
- PLL based GFM.

EPRI Memorandum from November 2021 provides more detailed specifications of the model along with its parameters followed by testing and validation results. In September 2023 WECC approved a phasor domain model for droop-based GFM IBR. The model is now included in the list of WECC Approved Dynamic Models (WECC, 2024) and implemented in PSS/E, PSLF and Power World Simulator.

The generic grid forming IBR models can be used to investigate the benefits of grid forming inverters for a power system. For specific system impact studies, it is recommended that manufacturer and site-specific models reflecting the capabilities of particular IBR are used.

Load modelling

Although the main focus has been on converter-interfaced generation, the load-side has to be considered in a similar manner. There is an increasing trend for loads having power electronic interfaces (e.g. light-emitting diodes and electric vehicle chargers). With the converter control being tailored for the needs of the load, the share of constant power loads is increasing, adding negative damping to the power system. With an increasing amount of, for example, air conditioning loads, load side behaviour varies with time of day and time of year.

The increasing shares of wind and solar generation on the distribution network, and with power systems becoming 'lighter' and weaker due to the displacement of conventional generation (reduced inertia and system strength), implies that load characteristics will more strongly influence system performance.

The shift towards power electronics loads also results in more complex load behaviour when considering fast timescales. The impacts of control structure and time constants cannot be modelled with simple constant power, current or impedance assumptions. Also, for EMT-simulations, greater emphasis needs to be placed on detailed load modelling.

Existing load models should be re-evaluated, and the time varying nature of the load composition, and hence the load models themselves, should be considered.

CIGRE published a technical brochure on modelling and aggregation of loads in flexible power networks in 2014, covering the key areas of load modelling practices (https://www.e-cigre.org/publications/detail/566-modelling-and-aggregation-of-loads-in-flexible-power-networks.html). The publication provides a set of recommendations and procedures for development and validation of load models.

The composite load model, which is the state-of-the-art model for aggregated representation of load, was developed by EPRI. A summary of the history behind the composite load model development can be found in (EPRI, 2020). The model is capable of accounting for the dynamic behaviour of a wide variety of consumer equipment as well as the effect of voltage regulation from a distribution feeder. The composite load model is available in all commonly used commercial positive sequence fundamental frequency simulation tools.

Another important aspect is the appearance of behind-the-meter generation, altering the "load" behaviour. With increasing amounts of such generation assets, advanced load modelling becomes increasingly important. Aggregated impacts of behind-the-meter generation can be represented as a part of the composite load model described above. The model allows inclusion of both utility-scale distributed generation and residential behind-the-meter generation or storage. AEMO recently published two reports validating load models (both in positive sequence and EMT) with and without distributed generation based on actual disturbance events (AEMO, 2024).

For frequency stability, and particularly for larger systems, the self-regulating effect of the load can impact severe disturbances: simulation results can be sensitive to how the load is modelled. Fast-acting load response may also be included. Timing and shape of the response (proportional vs. step-response) depends on load characteristics and specifications imposed by a system operator.

HVDC Transmission Infrastructure

A growing number of wind power plants are located far offshore and connected via HVDC transmission to the existing onshore grid. Modelling only the onshore HVDC inverter is sufficient for onshore AC grid considerations in most cases, in conjunction with a simplified aggregate wind plant representation. However, if power control and system frequency support are under consideration, then representation of the HVDC controls, individual turbine controls and the overall plant controller should be incorporated (Sakamuri et al., 2017).

Unlike steady-state analysis, where representation of the DC transmission infrastructure may be sufficient, leading to a DC power flow, stability analysis for HVDC systems is somewhat more complex (CIGRE, 2021; CIGRE. 2024; ENTSO-E, 2019). The challenges are generally caused not by the DC network itself, but by the AC-DC HVDC converter stations that interface the HVDC transmission infrastructure with the AC grid. The behaviour of these converters is determined mostly by their controllers and not by the physical properties of the devices (as would be the case for a synchronous machine). Different synchronous machines often have similar technical parameters, because they are constructed in a similar way: variations can stem from various technologies for the excitation system, different number of pole pairs, etc. However, HVDC converter station controllers can behave in a totally different manner (constant power control, constant voltage control, droop, etc.), and their control mode can easily be changed.

There are three converter types in use, which all show a different fault response:

- Voltage Source Converter – VSC (ABB HVDC Light generation 1-3)
- Modular multi-level converter – MMC
- Current source converter – CSC (Line Commutated Converter – LCC or alternatively capacitor commutated converter – CCC), also known as classical HVDC converters.

When simulating a network with HVDC transmission assets, introducing modelling assumptions is unavoidable. The control details (model and settings) of existing HVDC assets are usually not publicly available, making it challenging to implement their real behaviour. Most studies, however, consider future scenarios, where future HVDC transmission assets would be considered, and their technology details and control mechanisms cannot easily be foreseen. Consequently, simulation conclusions, such as the system is stable, should always be treated with caution, and variations should be applied to the input assumptions (Vrana et al., 2012). Stability might depend on many factors (e.g. the control mode of the HVDC stations).

For offshore plant, with fast transients in the millisecond range, the dynamics of the DC system are important, which will require detailed models to be simulated with shorter time steps (Asmine et al., 2011). When considering dynamic analysis, HVDC converter stations usually behave in a highly non-linear manner for transient stability simulations. While for small-signal assessment, linearization can be effective, the large-signal response can be hard to predict with simplified models. Essential control features, such as IGBT (insulated-gate bipolar transistor) overcurrent protection, can lead to a non-linear non-time-invariant fault response, which is hard to express through a simple single number such as the short-circuit-level.

Software packages that focus on the power system (electromechanical) dynamics of interest can accurately simulate wind power plants connected through a voltage source converter (VSC)-

HVDC (van der Meer et al., 2010). Adopting a combined simulation strategy, i.e., stability simulation for AC grid dynamics, and electromagnetic transient simulations for DC grid dynamics, can provide an acceptable simulation speed and accuracy.

The number of HVDC transmission assets is steadily increasing in several parts of the world, especially Northern Europe, and also China. This leads to the observation that the above challenges are growing in importance over time. An example study considering a large number of HVDC assets can be seen in Vrana et al. (2012).

6.2.4 Models for Short Circuit Analysis

The purpose of short-circuit analysis is to determine the magnitude of the currents that flow during a fault to ensure that circuit breakers are dimensioned to clear such fault currents and for protection coordination. Short-circuit analysis is complicated by the difficulty in estimating the short-circuit impedance of VIBRES inverters (Burman et al., 2011; Plet & Green, 2014), due to their different fault ride through characteristics (Kroposki et al., 2017; Muljadi et al., 2010; WECC, 2014).

Most generic solar PV and wind turbine models developed for positive-sequence simulators do not include sufficient detail for accurate short-circuit analysis with very high VIBRES shares. This is critical for performance assessment under unbalanced faults, and correct operation of control loops (such as the PLL) (WECC, 2014; IEEE/NERC, 2018). In addition, these generic models assume that the inverters operate in a grid-following mode, undermining the validity in an inverter-dominated grid. Consequently, EMT (electromagnetic transient) modelling, employing high fidelity control representations, becomes essential for short circuit analysis.

6.2.5 Inclusion of Protection Systems

The fault-current contribution of wind and solar power plants is usually limited to not more than 120% of the rated value. This might be the most critical aspect of the transition from synchronous machines to power electronics. The fault current provision by a synchronous machine cannot be replicated by converter controls (without unacceptable extra costs associated with overrating the converter). Additionally, the response time depends on the inverter controls (Keller & Kroposki, 2010).

These short-circuit characteristics of wind and solar power plants significantly impact protection coordination. Relays which are designed to distinguish between normal over currents and fault currents might operate incorrectly (Kroposki et al., 2017; Muljadi et al., 2010; WECC, 2014). The fault current might not contain sufficient negative- and zero-sequence components for proper operation of directional relays (Kroposki et al., 2010).

On HV transmission lines, distance or impedance-based protection is common. This relies upon the voltage-behind-reactance principle, whereby the short circuit current is determined by a source voltage and the total driving point impedance feeding the fault. The fault behaviour of (grid-following) wind and solar power plants, however, is based upon the injection of a controlled current, which depends on the control design and parameterization as well as the disturbance type, pre-fault conditions, and even point-on-wave timing of the disturbance. Consequently, distance protection may false-trip with higher wind and solar shares by confusing the ratio of voltage to current.

Efforts are ongoing to develop wind and solar power plant current injection models for short circuit and relay coordination simulation tools. Communications based distance protection (such as permissive overreaching transfer trip or under-reaching transfer trip schemes or directional blocking schemes) and differential protection may improve selectivity and security, but with added cost and complexity. Protection schemes which recognize emerging technologies, e.g. grid-forming controls, and advanced protection methods for fault detection, location, isolation and recover (FDLISR), represent a further step for the future.

6.3 Stability Analyses for Systems with High Shares of Inverter-based Resources

The need to assess the impacts of wind/PV generation on power system dynamics becomes increasingly important at higher shares: once the studied instantaneous share of wind and solar energy exceeds 30–50% on a synchronous system. Low instantaneous shares of wind and PV generation are unlikely to have a significant impact on system stability, beyond those issues normally seen for a particular system. The stability issues of concern for a particular system will depend on system size, wind/PV/BESS/HVDC distribution relative to the load and other generation, along with the UC and network configuration. Operational challenges are likely to be first seen during the night (wind only) or seasonal low-demand periods when instantaneous wind and/or PV penetration may be high, even in cases when the annual energy contribution is still not very high. There also may be weak grid cases where share of IBR in remote part of the grid is high but not high at a system-level.

Dynamic studies are required in order to ensure that the system is robust against a variety of system events and disturbances. Iterations should loop back to transmission enhancement because one of the outcomes of dynamic analyses might also suggest a review of the selected transmission reinforcements, e.g. ensuring a critical clearing time above predefined thresholds to warrant system stability. Another outcome may be need for additional must run units (for inertia in interim before sufficient share of grid forming resources is available) and additional amounts/types of reserves needed for frequency stability.

6.3.1 Types of Stability Studies

Dynamic power system stability studies are essential for ensuring secure operation. These studies address various stability phenomena subject to particular system concerns, and can include studies related to the different stability types listed in Section 6.1.

These studies encompass a range of analyses aimed at understanding and enhancing the stability of the power system under diverse conditions. It is noteworthy that a single type of study may cover multiple stability phenomena, emphasizing the interconnected nature of power system dynamics.

Combinations of the categories can also be envisaged, e.g. voltage dip induced frequency dips (McMullan et al., 2014; Rather & Flynn, 2017). Additional interactions may result between the transmission and distribution networks, e.g. the loss of distributed generation due to transmission-level faults from protection activation and sympathy tripping (O'Sullivan et al., 2014). For the latter case, generators connected to the distribution system often have voltage, frequency and/or RoCoF trip and/or ride-through settings which are effectively a compromise between bulk system stability and distribution system protection concerns. Additionally, older generators may have been interconnected without considering bulk system impacts or prior to implementation of specific grid code requirements and therefore have inferior performance capabilities compared to more modern generators. These voltage-related operational settings lead to the possibility that transmission-level faults which suppress the voltage over a relatively wide-area could affect a large number of distribution-connected wind/PV plants, which in aggregate become a potentially significant contingency (Miller et al., 2014). Frequency or RoCoF related tripping of distributed wind/PV may also lead to system-wide frequency events.

With appropriate dynamic data, studies can consider a wide range of issues:

- Determine if the grid is sufficiently robust to sustain both temporary disturbances and significant (dimensioning) contingencies, and capable of recovering satisfactorily from those events.
- Evaluate the chosen deployment of new generators or loads against existing grid code requirements, while considering different mitigation or participation options that the regulatory regime allows.
- Evaluate dynamic impacts from newly connecting generation or load to the power system
- Investigate the impact of different distributed generation locational distributions on stability issues, e.g. voltage stability assessment.
- Assess the transmission limits when these are set by a combination of transient stability, small-signal stability and/or voltage stability concerns.
- Assess the impact of sub-synchronous interactions as part of small signal stability analysis, including sub-synchronous resonance, sub-synchronous torsional interactions and sub-synchronous control interactions (Flynn et al., 2017).
- Determine the optimal measures to avoid the risk of wind/PV generation curtailment due to dynamic constraints. This can be made either through adopting “soft measures”, e.g. appropriate controller settings, introducing flexibility-based ancillary services, coordinated protection schemes, or through “hard measures”, e.g. additional network reinforcements, constructing/retrofitting both wind/solar and flexible generation plant. Iterative feedback may be required to the generation portfolio and transmission scenarios, and production cost modelling stages.

Stability study cases

To capture the dynamic behaviour of the power system, stability study cases are created from different scenarios. Of particular interest are periods of time when there is a high share of non-synchronous generation online, when large exports of wind/PV power occur across an area, and when there is low online headroom available from conventional generation. These snapshots include:

- Worst-Case Scenarios: Examining situations where the system is subjected to extreme conditions, such as simultaneous multiple contingencies, peak demand periods or peak non-synchronous generation periods
- Foreseen Operational Conditions: Analysing stability under various anticipated operating conditions, considering factors like renewable energy integration, load fluctuations, and changes in generation patterns.

It is important to set up the cases carefully, for example, based on comprehensive generation expansion and production cost simulation – not simply replacing the same volume of conventional generation online by the addition of wind/PV plant, as several (conventional) generators could be reducing their output but remain online. Understanding the new commitment and dispatch patterns with the addition of wind and solar generation is important and should be carefully considered when setting up the stability cases and interpreting the obtained results.

Importance of modelling system services

Accurate modelling of system services is pivotal for a realistic representation of the power system. Stability studies will require much greater detail concerning the generating units than UCED simulations. The analyses should already recognize a range of dynamic issues, e.g. ramping capabilities of committed units, spinning reserve requirements, local network constraints. It is crucial to model the contributions of existing system services accurately. For instance, assuming that all units will contribute equally to frequency control may not align with the actual system's characteristics. This emphasizes the need to reflect the intricacies of the existing system accurately in stability studies.

Further examples of stability phenomena to be studied

As conventional generation is displaced at higher shares of wind and solar, voltage security levels may be affected in certain locations, and so requiring more detailed analysis. A slow recovery of wind/PV generator outputs following a nearby voltage dip may be sufficiently large to cause a significantly large demand-generation induced frequency dip, a so-called voltage dip induced frequency dip event (Rather & Flynn, 2017).

The disconnection of wind turbines (and also PV and BESS) due to faults can result in a large loss of active power infeed in some systems, making it important to accurately assess the extent of voltage depressions (both in terms voltage magnitude and size of the affected area) and the threat to frequency stability. For example, recent disturbance event that started as a normally cleared fault in Odessa Texas in 2022 resulted in unexpected generation disconnection or active power reduction totalling 2.6 gigawatts (GW), including 1.7 GW of PV (NERC, 2022). This is just 0.2 GW short of the largest contingency (simultaneous trip of two nuclear units) that Texas grid is designed to survive without shedding firm load. The effect of protection systems of IBRs can thus play a crucial role, and its simulation may require more sophisticated calculation methods (van der Meer et al., 2010; CIGRE/CIRED, 2018). However, the converter controls of PV plants, BESS and wind turbines complicate the analysis of voltage stability. This argues for the continued development and support of accurate and field-tested PV and wind turbine models for use in stability analysis programs.

Periods of wind/PV power export from one region to another may result in voltage angle differences across a synchronous area beyond typical levels and may threaten rotor angle stability, both from a small-disturbance and transient stability point of view (Eftekharnejad et al., 2013; Quintero et al., 2014). Significant reverse power flow from former load feeders can also occur.

Transient stability of critical synchronous generators may be reduced when other synchronous generators are de-committed (reducing online inertia and synchronizing torque) and replaced with wind/PV at medium- or low-voltage levels, located behind a relatively large impedance, even if the wind turbines, for example, are equipped with grid-code compliant reactive current boosting (Boemer et al., 2011). Similar effect may be caused by wind/PV at high-voltage levels but far away.

Wind and solar generation does not generally introduce small-signal oscillatory modes, but as their presence may displace conventional generation (and associated power system stabilizers), and alter the magnitude and direction of transmission line power flows, it follows that small-disturbance stability may be impacted. Small signal stability studies with a system model that uses black-box models of the inverters is tricky as equation-based approach will not work. Impedance-based stability analysis may be needed to resolve this issue.

Torsional resonance stability refers to the interaction between the shaft of a synchronous generator and the electrical system, which is an electromechanical phenomenon. The main risk of torsional interaction is high amplitude sub-synchronous oscillations in the shaft eigenfrequency, which can cause damage to the shaft. This phenomenon may occur due to grid resonance frequencies that are caused by series compensation, matching with the shaft eigenfrequency. This can cause slowly increasing or poorly damped torsional vibration (SSTI) or sub-synchronous resonance torque amplification [SSR TA], causing high instantaneous stress for the shaft. The SSTI phenomenon can also be caused by the interaction between the generator shaft and HVDC converter and FACTS systems, or converter-connected generation. LCC type HVDCs are known to decrease damping in the 5–25 Hz frequency range.

Electrical resonance stability may become an issue when converter-connected systems are connected in the vicinity of a series compensated network. This subclass of electrical stability is often referred to as SSCI. The instability of SSCI is a known issue when DFIG-type wind power plants are connected in the vicinity of a series compensated network. The dynamic resistance of DFIG is typically negative in the majority of sub synchronous frequencies, especially when the wind power plant is operating on partial power, due to the inherent characteristics of the induction generator. Converter controls have a significant impact on the DFIG's characteristics in sub-synchronous frequencies, as the rotor currents are controlled by the converter, providing opportunities to improve the response at sub-synchronous frequencies and improve damping. When left unmitigated, sub-synchronous interaction between the wind power plant and a series compensated network can result in significant sub-synchronous currents and voltages that may cause damage to the grid equipment and wind power plants.

Fast converter-driven interactions can manifest in various ways, such as oscillations in the range of hundreds of hertz to several kilohertz (kHz). These interactions may occur between fast inner-current loops and passive system components, or between inverters located close by. To ensure stability, the frequency response of the converter impedance is evaluated alongside the grid impedance, as negative resistance in the converter impedance at certain frequencies can result in instability or low stability margins.

On the other hand, slow converter driven stability is typically an issue when converter connected generation is linked to a weak grid or when controllers, like voltage controller, are not correctly tuned. When the inner-current control loop and PLL response in low-short circuit ratio connection points become oscillatory, it could lead to instability. This is due to the PLL's inability to synchronize quickly with the network voltage or high gains in the inner-current control loop and PLL. In some cases, controllers can be retuned to mitigate these oscillations. However, if the oscillations become unstable, it could lead to growing low-frequency oscillations that might damage grid equipment or trip IBRs. Slow converter driven instabilities are more likely to occur when the IBR active power is high.

It is crucial to evaluate the frequency response of converter impedance and grid impedance and ensure controllers are correctly tuned to avoid the risks associated with converter driven stability. As the field of power systems continues to evolve, understanding and addressing these instabilities will be increasingly important for maintaining stable and reliable power grids.

One important outcome of stability studies in future should be determining the optimal ratio of GFM and GFL resources under any dispatch scenario (in terms of stability).

6.3.2 Assessment Criteria

Limits of stability criteria should be defined for stability assessment. Based on the assessment, critical events can be identified. It is important to cover the protections set up in stations, i.e., which components will disconnect based on the outcomes (currents, voltages, frequency) of the original event.

6.3.3 Mitigation Measures

If from the above studies stability issues are identified, a system operator will need to mitigate these issues. The mitigation measures depend on the type of instability that is encountered and generally include but are not limited to

- Implementation of stability related constraints, e.g. limiting IBR output through implementation of transmission constraints on relevant transmission interphases, setting a limit on how many synchronous machines (or grid forming resources) need to be online under certain grid conditions.
- Ensuring sufficient amounts of various reserves are available based on expected system conditions – relevant for frequency stability concerns
- IBR control parameter tuning – this may address a variety of stability concerns including control stability related issues. Individual IBR controls may be tuned to improve the performance of that IBR, e.g. in a weak grid area. Control tuning of multiple IBRs in electric vicinity from each other may help with control stability issues. Note that such tuning may be challenging due to IBR ownership and OEM model confidentiality issues.
- Installing transmission equipment to improve stability of a power system, such as, for example, dynamic reactive power compensation equipment, synchronous condensers etc. Synchronous condensers may be further enhanced (with a flywheel and additional controls) to improve system inertia and damping.
- Grid forming IBRs or grid forming transmission devices (such as grid forming STATCOM) may be helpful, particularly to improve stability in weak grid and low inertia systems.
- Building new transmission lines – this may address multiple stability concerns associated with weak grid conditions as it may decrease impedance between a weak grid area and areas where strong voltage sources are available. This measure can also address steady-state voltage stability concerns related to long-distance high-power transfer. This is an expensive and time-consuming mitigation measure.

6.4 Black Start and System Restoration

The challenge of black-starting an isolated system in the absence of synchronous generators is closely tied to the ability of IBR inverters to create the voltage waveform and provide system "stiffness" (maintain a fixed frequency and voltage). If one or more of these sources can "form the grid", in relative proximity to some load, then they can initiate the restoration procedure. However, a restoration sequence must account for the capabilities and constraints of the relevant generation sources, energy storage technologies, and power electronics interfaces. Key requirements include:

- Large in-rush currents for electromagnetic grid devices, e.g. transformers and motors, as required for a cold start (cold-load pickup)

- Capacitive charging currents for non-energized transmission lines and transformers, while maintaining voltages within acceptable limits
- Operation for sufficiently long time, such that other resources can come online, and subsequent removal of the black-start resource(s) does not jeopardize system restoration
- Ability for the multiple hierarchies of controls to remain stable, with no other synchronous sources, to form the voltage waveform and provide system "stiffness".

Detailed studies, or field trials, with full black-start capabilities involving integrated storage and wind/PV are scarce (Colthorpe, 2017), although black-start operation using multiple inverters has been engineered to restore a system from distributed resources with decentralized control (Seo et al., 2019). Further R&D is essential to ensure compatibility with present-day systems and maintain system reliability. The issue of inrush currents during energization of transformers, lines and motor starts need to be addressed during black start studies. For example, soft start option in GFM inverters can be used – slower buildup of the voltage from zero to full level to avoid in-rush.

Finally, it should be noted that the economics of providing such support from the above resources is unclear, while market mechanisms to incentivize investment decisions and commit available capacity need to be developed. In power systems with a significant share of synchronous machine based hydropower, black start capability from IBR might not be a priority, even in a sustainable future.

6.5 Checklist: Network Simulations for Dynamics

Checklist of Key Issues: Network Simulations for Dynamics

The recommendations apply for higher shares of IBRs but may also apply in power systems that have remote areas with high IBR concentration.

- *Selecting snapshot cases for analysis*: A wide range of stability case scenarios including worst case scenarios and foreseen operational conditions should be included The snapshots selected need not be the same as those chosen for steady-state power flow analysis. It is also important to set up the case carefully based on comprehensive production cost simulation results.
  - Screening for stability issues that require more detailed EMT simulations: For wide-area studies historically have been done in a phasor domain (RMS simulations), however in weak grid areas with high concentration of IBRs, increasingly faster transient phenomena need to be studied. Large-scale EMT studies, however, are computationally heavy and time consuming. It is therefore prudent to use various available screening methods to select a sub-set of snapshot cases that require more detailed analysis as well as to limit area of study as much as possible to reduce computational burden, while still capturing all relevant phenomena and interactions.
- *Wind, PV and battery energy storage system (BESS) models:* Ensure that the models used are adapted to the characteristics of inverted-based generators and are suitable for studying each particular stability phenomenon.
  - Studies should recognize that wind plant/PV/BESS controls, as part of a coordinated control strategy(s), may offer system advantages, and hence this option should be investigated in detailed EMT studies.

    - Generic models can be used for long-term planning studies where detailed information about generation is not available or to represent generators remote to the area of study.
    - It is important to test the model to ensure that it is correctly parametrized (verification) to represent actual "as built" plant and to determine the accuracy of the model with respect to measurements (validation) for all components (conventional generators, PV and wind plants, and load).
- *(Dynamic) load modelling*: With increasing shares of wind and solar generation on the distribution network, and power systems becoming 'lighter' and weaker due to the displacement of conventional generation (reduced inertia and system strength), load characteristics will more strongly influence system performance. Existing load models should be re-evaluated, including frequency and voltage sensitivities, the time varying nature of the load composition, and hence the load models themselves should be considered. Power electronic loads and their ride-through characteristics are an emerging area of research.
- *System stability:* Different systems may experience very different dynamic issues depending on the underlying correlation between wind/PV/BESS production and system demand, the underlying flexibility and capabilities of the conventional generation portfolio, relative location of generation assets and major load centres, etc., implying that specific system studies may be required.
- *Frequency stability studies:*
    - Inertial constant, droop, and governor settings of all synchronous units are needed. In addition, the frequency control block models and settings of all IBRs (if deployed for frequency control) are required.
    - It is also important to model any protective functions in IBRs or synchronous generators that may respond to frequency or rate of change of frequency exceeding certain thresholds.
    - A reduced network representation may be sufficient.
- *Voltage stability studies:*
    - At low wind/solar/BESS shares it is probably unnecessary to perform voltage stability studies, as system stability is likely to be unaffected or even enhanced by the presence of wind turbines/PV panels. This argument is particularly true if the reactive power control capabilities of the wind turbines/PV are deployed to manage local voltages, and if they are connected at transmission level.
    - As conventional generation is displaced at higher wind and solar shares, voltage security levels may be affected in certain locations with high concentrations of wind/solar/BESS or system-wide, requiring more detailed analysis.
- *Rotor angle stability studies:*
    - Transient stability studies:
        - It can be important to include the effect of protection devices for both network and converter-interfaced generating equipment; however, boiler/steam turbine models are not required. Protection relay settings should recognize changes in the dynamic response of the system and respect any dynamic operating criteria (e.g. frequency variation range) adopted by the local transmission system operator. The ability of generation to ride through multiple voltage dips within a certain period may also need to be addressed.
        - Wind, BESS, and solar generation can provide system support during voltage dips and help to dampen oscillations, although the level of support provided is network sensitive, and the capability may also vary depending on specific grid

code requirements and the priority given to active or reactive power recovery. Proper representation of the impedance connecting the plants to the grid is crucial within simulation studies.
    - To mitigate any issues discovered, fast acting reactive power response devices during and following disturbances can be applied, e.g. installing FACTS devices, synchronous compensators, and/or requiring all future wind/PV/BESS plants and conventional generators to incorporate that specific capability.
  - ❖ Small-disturbance stability studies:
    - Wind and solar generation do not generally introduce small-signal oscillatory modes, but as their presence may displace conventional generation (and associated power system stabilizers) and alter the magnitude and direction of transmission line power flows, it follows that small-disturbance stability may be impacted.
- ➢ *Resonance stability studies:*
  - ❖ Sub-synchronous torsional interaction and sub-synchronous control interaction should be investigated as part of small-signal stability analysis, particularly in relation to doubly fed (type 3) wind turbines radially connected with series line compensation. Sub-synchronous control interaction studies may also be performed for all IBRs that may become radially connected with series compensation after a number of contingencies. A range of mitigation measures including bypass filters, FACTS devices, and auxiliary (damping) controls are available.
- ➢ *Converter-driven stability studies:* Adequate models capable of capturing the harmonic power dynamics, especially in multi-converter setups, are crucial.
- ➢ *Common-mode fault events*: Network faults and/or loss of a major infeed can result in widespread voltage depressions and/or large frequency deviations and the common-mode tripping of local wind and solar generation. Consequently, the operation of associated protection systems may play a crucial role in determining system outcomes, requiring sophisticated modelling methods. Delayed active power recovery from grid code compliant generation following a widely seen network fault may similarly lead to a common-mode power reduction and frequency stability issues such as voltage dip induced frequency dips.

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7 Analysing and Presenting the Results

Hannele Holttinen, Lennart Söder, Niina Helistö, Juha Kiviluoma, Ana Estanqueiro, Aidan Tuohy.

When there is a change in a power system of any kind, this will have an impact on several other components. This relates to new loads, new transmission lines in a system, new interconnections to other systems, new power plants of any kind and storage. Here we discuss the specific case of wind/PV power integration, but the same methods could be used also to study other changes in the system. If wind/PV power is compared with other investments, then an integration study should also be performed for the other alternative.

When analysing simulation results, it is recommended to iterate back to earlier stages in the flowchart (Figure 7.1), including rethinking initial scenario and assumptions. If the impact of wind/PV power proves difficult or costly to manage, more flexibility in operational practice could be the solution. This underlines the importance of the main setup and scenario chosen as the basis for the results, as wind/PV integration study main setup chosen will have crucial impacts on the results.

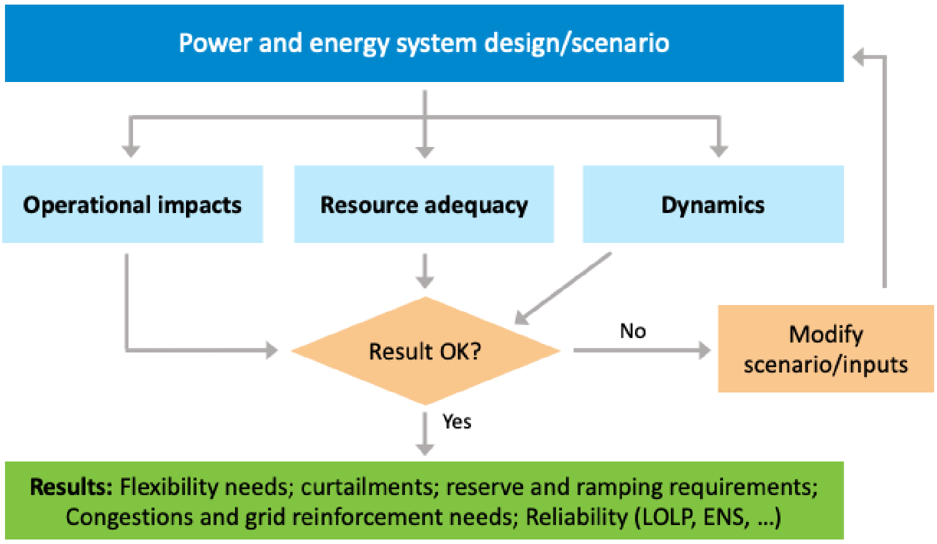

Figure 7.1. Wind/PV integration study components: data analysis and output synthesis.

Main assumptions regarding access to enablers like flexible transmission to neighbouring areas, flexible generation, storage or demand assets will influence the results. Both technical flexibility of power plants and demand side as well as operational flexibility of management of system operation can change for future systems.

At higher shares, the methods and tools used for planning and operation need to be adapted. Successful wind/PV integration means changing the operation of the power system from how systems have been traditionally operated. Energy system integration (electrification from heat and transport sectors and power to X options) will also bring new flexibility possibilities.

A comparison of results of different studies is challenging. It is important to present results using metrics that other studies have used to state the wind/PV share and the size of the power system as well as all relevant assumptions and limitations of the methodology chosen (Holttinen et al., 2009; Holttinen et al., 2012). Results of integration studies should be discussed in detail to keep in mind the assumptions made and their impact to results (either over- or underestimating the issues studied).

This section starts with general discussion about the challenges of determining integration costs – analysing costs and benefits. The following sections summarise results from the simulation chapters Adequacy, Operational impacts and Dynamics. Main differences of wind and PV in integration studies are listed in Section 7.5. How to present the results with a list of limitations in the assumptions is discussed in Section 7.6.

7.1 Comparison of Costs and Benefits

Many studies have aimed to estimate integration costs. In practice it is challenging, if not impossible to separate system costs to different generators in an accurate way.

From the basic definition of integration cost, the following is concluded:

- Integration cost should in principle be possible to calculate for any power system investment (e.g. power plant, major energy user, or grid expansion). Examples of how integration costs may be incurred by other types of power plants, such as new base load generation and new higher contingency levels, are presented in Milligan et al. (2011). Stark (2015), developed a consistent framework for integration costs of many aspects of the power system in addition to wind/PV. It is important to identify what types of costs are being assesssed (transparency), ensure they are treated fairly, and simulations are accurate. How they are applied is also important: they can show how different pieces of the system fit together. Results of this kind of analysis cannot be added to cost of energy in a capacity expansion.
- Integration costs of wind/PV power should be compared to something, like integration cost of other production forms, or the production costs of wind/solar (levelized cost of energy or LCOE), or market value of wind/PV power (weighted average price being paid in the market for wind or PV compared to weighted average market price paid by demand).
- Integration costs do not include the costs for installing new power plants (capital costs) and connecting them to the existing grid – all costs that are borne by the power plant operators are not included in the power system's cost of integrating them.
- Integration cost depends on the assumptions regarding the generation mix in the replaced and remaining system and operating costs. During periods of increasing levels of installed wind/PV power, the composition of both existing plants and additions will significantly influence the ability of the power system to integrate wind/PV power in a cost-effective way. Likewise, the transmission configuration and any potential extensions, along with operating procedures, can significantly influence the results.

There are three main categories of integration costs (Müller et al., 2018):

- Grid infrastructure cost: If transmission/distribution grid expansion or reinforcement is needed, above the cost of connecting wind/PV power to the grid, this could be considered as part of integration costs. However, except in the case of a radial connection, additional transmission typically provides a reliability benefit beyond the benefit of connecting the generator in question, and thus allocation of this cost to wind/PV power only is not accurate. ENTSO-E Guideline for Cost Benefit Analysis of Grid Development Projects (CBA 2.0) addresses this issue (ENTSO-E, 2015).
- Balancing costs refer to the cost to the system of accommodating the short-term variability and uncertainty of wind/PV power. This cost consists of the increase in the use of operating

reserves and the balancing (market) that is used to maintain the system balance. The approach usually taken is to quantify the incremental increases in costs for power systems after accounting for the energy cost. Although it is difficult to extract the cost of variability and uncertainty from wind/PV integration, it is relatively straightforward to assess the total operational cost for both no-wind/PV and wind/PV cases, and these operational costs can be compared. Similarly, comparing the simulations with deterministic wind/solar generation (perfect foresight) and with forecast errors day-ahead and intra-day incorporated would give indication of the cost of short-term uncertainty. When estimating increases in operating costs, it is important to note whether a market cost has been estimated or the results refer to technical costs for the power system. Technical cost is the increase in the costs that the power plants actually see, whereas a market cost can include a profit to the producers that provide extra flexibility. This means that a market cost includes transfer of money from one actor to another actor, while technical cost implies a cost for the whole system.

- The so-called profile cost is the most controversial part of integration costs. Some studies have introduced the capacity cost of wind power as integration cost. This is a controversial concept and is not widely accepted. Wind power has a relatively low capacity value (which may range from 5–40% of rated capacity) compared to many other types of generation (which can range up to 90% or more of rated capacity). If additional generation must be added to the system to compensate for wind power's low capacity value, the increase in back-up power needs to consider energy-equivalent generation sources, as all MWs of installed wind and solar do not need backup. The cost used for this back-up capacity, only used for critical peak load hours, should be the open cycle gas turbines or similar peaking capacity (Söder & Amelin, 2008) New flexible loads can provide similar service in future.
- The value of the capacity credit of wind/PV power can also be stated and considered when the amount of required total installed capacity is to be calculated.

The main challenge lies in how to choose the non-wind/PV case to be able to extract the wind/PV-induced costs only. For cost of variability, finding a base case of comparison is very challenging if not impossible. The total costs for power systems may increase due to wind/PV power, but the operating costs of power systems will be reduced due to the use of wind/PV power. This is because the bulk of operating costs come from fuel costs and wind/PV power will replace fossil fuel use. At the same time costs due to emissions are also reduced. The integration cost is then actually the difference of full credit for operating cost reduction compared with cost for system operation with increasing variability introduced by wind/PV power. The attempt of capturing cost of variability by comparing simulations with flat wind/PV energy to varying wind/PV energy (EnerNex, 2006; Meibom et al., 2009 for wind power) has serious caveats as the two simulated cases will also result in other cost differences than just the variability cost (Milligan & Kirby, 2009).

The costs from transition would include stranded costs from previous investments, that are not considered integration costs – the comparison should be for the final case of integration, where the remaining system is optimized.

Comparing total costs for different future power systems, including both investments for capacity and operational costs, gives a more holistic view of the costs and is easier to compare. A fair comparison between power systems with differing amounts of wind/PV power should in principle have systems with the same reliability but also common levels of CO_2 emissions, or at least take the CO_2 emission costs into account. When different alternatives for the future power system expansion are to be considered, the total performance from economic, reliability, security, and environmental point of view are to be considered. The same requirements from all these aspects should be compared. Cost-benefit analyses can be carried out that examine the all-in cost and benefits of wind/PV power compared to other generation and transmission options, including capital and operating cost. These cost benefit comparisons are recommended over wind/PV integration cost estimates, which cannot be rigorously defined.

7.2 Impacts on Adequacy

This section addresses results from simulations to evaluate wind and solar impacts on future power system resource adequacy, including sufficient capacity of generation and storage to cover the critical demand situations as well as sufficient transmission and distribution network capacity across the system.

7.2.1 Security of supply

Resource adequacy is traditionally measured as loss of load probability or expectation (LOLP/LOLE). For higher shares of wind and solar it becomes necessary to analyse the scarcity events more in detail, with Expected Unserved Energy (EUE) and Loss-of-load Hours (LOLH), analysis of tail risks and scenario-based stress tests.

For mitigation of scarcity events, simple addition of peaking plants will become a costly option, and alternatives should be explored, for example keeping existing power plants as a reserve, or finding longer duration storage for power systems in new demand, like P2X new loads linked with storage buffer for the product produced, or thermal storage with power to heat. For resource adequacy, the capacity value of wind/PV power is often relevant to calculate. For moderate shares of wind energy, the capacity value will be lower than for conventional power plants. It is usually close to average power produced during times of peak load situations and will decrease with higher wind shares (Holttinen et al., 2009; Holttinen et al., 2016). Increases in wind capacity, particularly at lower shares, tend to smooth overall wind power in the aggregate. On first order, this tends to provide a greater proportion of capacity at peak capacity times than the incremental increase in solar PV capacity (Madaeni et al., 2012).

For solar PV, the daily energy is spread only to a 5- to 19-hour period (depending on season and location). In summer peaking systems, the capacity value tends to be high, at least for the smaller shares of solar PV. Concentrating the generation to fewer hours causes the incremental capacity value of PV to decrease at a faster rate than the incremental capacity value of wind power in most locations.

For wind and solar dominated power systems, capacity value becomes difficult to assess, the recommended method (ELCC) will work for small to medium shares of wind and solar, after which demand flexibility and storage becomes crucial to include in the calculations.

7.2.2 Network Adequacy, Congestions and Reinforcement Need

The impact of wind/PV power on transmission/distribution losses and grid bottleneck situations can be significant in some cases and therefore may need to be assessed. Depending on its location, wind/PV power may at its best reduce bottlenecks, but at another location result in more frequent bottlenecks.

The traditional method of detailed calculation for a limited amount of snapshot load and generation situations can give indications on whether the siting of wind/PV plants relative to load and other generation will increase or decrease the grid losses and bottleneck situations. A full estimation involves assessing how often certain load levels occur and simulating a large part of the cases. An example of a round-the-year approach can be seen in Ciupuliga et al. (2012), where many combinations of load and generation can be studied by looking at one or more years with hourly resolution.

Results from power flow simulations (see sections 4.2) will reveal the need for transmission reinforcements. If transmission adequacy needs associated with wind/PV power integration are of concern for only a small fraction of the year, network investments can potentially be postponed using, for example, curtailment, re-dispatch, dynamic line ratings or topological modification to increase transmission line capacity. Also, co-ordinated control using FACTS devices or VSC-HVDC or demand response can be used. For these analyses also, more simulations than just a few snapshots are needed.

Transmission cost is the extra cost in the transmission system when wind/PV power is integrated. Either all extra costs are allocated to wind/PV power, or only part of the extra costs are allocated to wind/PV power – grid reinforcements and new transmission lines often benefit also other consumers or producers and can be used for many purposes, such as increased reliability and/or increased trading. One difficulty with assigning transmission cost to any specific generator (except in the case of a radial connection) is that additional transmission typically provides a reliability benefit beyond the benefit of connecting the generator in question.

The costs of grid reinforcement needs due to wind/PV power, on a $/MW or $/kilowatt-hour [kWh] wind/PV basis, cannot be directly compared from plant to plant or from country to country. Grid reinforcement needs and costs will depend on where the wind/PV power plants are located relative to load and grid infrastructure. In addition, costs are dependent on the "grid situation" at the time the generator is connected. The same wind/PV power plant, connected at a different time, may lead to different grid reinforcement costs. Moreover, the grid reinforcement costs ($/MW) are not continuous; there can be single, very high-cost reinforcements.

Cost-benefit analyses of transmission measures should also take account of the positive or negative impact of wind/PV on transmission losses and grid bottleneck situations. Economic planning of transmission network with wind and solar need to capture the whole picture – 8,760 hours of power flow with cost and benefit analyses.

7.3 Operational Impacts: Balancing, Ramping, Flexibility and Curtailments

Balancing related impacts are impacts on reserve requirements (see Section 5.2) as well as several operational impacts that can be extracted from production cost simulations (unit commitment and economic dispatch, see Section 5.1):

- Positive impact of lower operating costs due to avoided fuel used
- Positive impact of decreased emissions
- Decrease of operating time of conventional units
- Increased need for flexibility – and provision of flexibility from power plants (including wind and solar), demand and storage (see Section 5.3 Flexibility Assessment)
- Increased ramping of thermal and hydro power plants; decreased efficiency; increased cycling costs (including start-up costs as well as ramping costs with wear-and-tear costs and reduced reliability)
- Curtailments

- Impact on market prices; market value of wind and solar energy; cost recovery for power plant.

Increasing levels of wind/PV in power systems can have significant impacts on other types of generating plants. The impacts can be separated into two categories: markets and physical impacts. Market impacts occur due to the almost zero marginal cost of wind/PV, displacing other generation in the merit order and subsequently depressing the electricity price. This impact is coupled with the physical impact of reduced running hours for other generation, compounding the revenue loss, as well as more starts and ramping (Troy et al., 2010).

Moderate to high wind/PV energy shares can induce cycling impacts on the conventional generation fleet. These impacts include starts and stops, and more frequent and steeper ramping. This may result in increased wear and tear and the need for more maintenance as well as running in less-than-optimal conditions. The result is a potential increase in cycling costs. The cycling costs are difficult to estimate, and it is the subject of much debate and analysis (Lefton, 2004). Integration studies should consider this if data can be made available, see, for example, Troy et al., 2012; Lew et al. 2012a and 2012b.

It is not straightforward to set the assumptions in the scenario development phase (see Section 3.1) in a way that the output of the production cost simulations will be able to capture costs related to wind/PV power integration, see also Section 7.1. Basically, there will be two simulation runs, to be able to subtract the costs and get a proxy for wind/PV integration cost. Total costs and benefits of different portfolio rather than wind/PV power integration costs is a recommended approach (an example can be seen in AIGS (2008) for wind power). Different portfolios of generation mix, with different amounts of wind/PV power, should be constructed with a capacity expansion (planning) tool plus a reality check.

Studies are evolving to include different enablers like flexibility. Overall, one should consider what forms of flexibility are relevant to consider in the timescale of the study, taking into account the cost of flexibility. Storage will bring an extra layer of uncertainty and complexity in the simulations.

Regarding wind/PV power impacts on reserves:

- Estimating reserve requirements should consider aggregated wind and solar and demand uncertainties as well as different timescales of reserves/frequency control without overlapping. A dynamic, varying reserve requirement (over a day for example) would be needed for higher shares of wind and solar.
- Estimating the increase in operational cost from obtaining this additional reserve can usually be calculated by taking the difference in production cost from two production simulation runs, one that includes the extra reserve, and the other that does not include this reserve.
- A wind/PV integration study can examine some of the alternative approaches for providing operating reserves. Reserves usually come from existing flexible generation, and they may be able to provide increased amounts of up- and down-regulation when operating part load, due to wind/PV. In addition, part of the increased reserve can come from non-spinning resources or market products, also including demand side and storage options. Changes in operational practices will impact the need and availability of services: such as shorter market time-steps, shorter gate closure times and allowing smaller bid size.

- Capabilities to provide reserve from wind and solar power plants should also be taken into account as they can usually provide down-regulation. With larger shares of wind and solar, their generation may be curtailed at times. This opens possibility to provide reserve from wind and solar power plants, as operating in de-loaded mode gives room for providing both up- and down-regulation (the estimation of available headroom for up-regulation type services on AGC time interval basis to avoid over-curtailment or penalties for providing the awarded services can still be improved).

7.4 Impacts on Dynamics

Low instantaneous shares of wind and PV generation are unlikely to have a significant impact on system stability. However, once the studied instantaneous share of wind and solar energy exceeds 30–50% on a synchronous system, stability studies can reveal notable impacts of wind/PV generation on power system dynamics. The impacts will depend on system size, wind/PV/BESS/HVDC distribution relative to the load and other generation, along with the UC and network configuration. Even in cases when the annual energy contribution is still not very high, operational challenges may be seen during the night (wind only) or seasonal low-demand periods when instantaneous wind and/or PV penetration may be high. Likewise, the studies may also reveal challenges related to weak grids where the share of wind and solar is high in remote parts of the grid where but not high at a system-level.

Dynamic studies can be carried out to determine whether the system is robust against a variety of system events and disturbances. Dynamic studies can also reveal the performance of new generators or loads against existing grid code requirements, and dynamic impacts from newly connected generation or load on the power system, impacts of different distributed generation locational distributions, impacts on transmission limits and impact of sub-synchronous interactions. As power system dynamics are interconnected, a single study may cover multiple stability phenomena. The studies may reveal additional needs and requirements related to grid reinforcement, inertia, controller settings, amounts/types of reserves for frequency stability, etc., as well as helping to determine the optimal measures among them to avoid the risk of wind/PV generation curtailment due to dynamic constraints. Results can be used to set constraints or instantaneous limits, though they should be treated with caution as they will change with new technology and operational practices.

Important result of wind/solar integration studies is the needed changes in the operational practices, including required grid support services from wind and solar power plants.

7.5 Main Differences Between Wind and PV in Integration Studies

Often, a target for the share of energy being supplied by renewable resources is used. How to allocate this to wind and solar will need some consideration. Wind and solar resources vary, but usually they have different capacity factors (average generation as a percentage of nominal generation capacity). Capacity factors for PV normally vary between 10–30%, depending mainly on latitude and cloudiness. Typical capacity factors for new wind power plants are between 25–50%, depending on the wind resource and turbine characteristics.

The solar generation diurnal pattern creates well-defined times of additional flexibility requirements within the power system, with more downward capacity needed in the mornings as PV power picks up and more upward capacity needed in the evening as PV production drops. Due to the predictability of these patterns, the economic and reliability impacts can be mitigated through good operational practices like dynamic flexibility reserve requirements.

For example, a 10% annual wind energy share means that wind energy could potentially be generated at any hour of any day, subject to resource characteristics. Conversely, a 10% energy share for solar will only occur during daylight hours; thus, an energy-equivalent share of solar will have concentrated impacts during approximately half of the day compared to wind energy.

Another important factor is the correlation of generation with peak load situations. In systems with a summer peak, caused by a high use of air-conditioning, the capacity value of PV is significantly higher than in a system with a winter peak and a low amount of sunshine in the winter.

Data resolution: The spatial and temporal resolution of the data should match the intended goals of the study and the resolutions utilised in the power system simulations. Because of wind's more varied output over even relatively small regions, the spatial resolution of wind datasets may need to be higher than the resolution for PV. However, the temporal resolution of PV resources may need to be higher than wind due to the speed of the physical processes involved (like clouds), although this will depend on the size of area.

Years of data needed (differences between years): Rare, but important, resource-driven events (i.e., fast-moving weather fronts across a large area) are less predictable for wind than for solar PV. An integration study may need to include longer periods of time to appropriately capture the impact of wind than that of solar energy. However, the longest set of data needed would set requirements for others to capture relationships (e.g. if 30 years of data is needed for wind, then also 30 years of data would be needed for solar and load).

Measured versus simulated data: Use of satellite and NWP data is easier for PV. Oftentimes, the "clear-sky" pattern of solar power output is used for simulating solar forecast data. This can have implications on short-term (hour-ahead) forecasts in integration studies. While wind studies often rely on the persistence method, a modified "persistence of cloudiness" method should be adopted for solar power, to account for the diurnal patterns that are known a priori.

Controllability of wind/PV power plants: Solar PV is installed in both smaller capacities (roof-top solar) and larger utility scale projects. This results in two categories of solar PV being considered: distributed PV, which classically only modified the net load shape (starting to change and becoming more flexible); and utility scale PV, which the system operator can control for curtailment or reserve purposes. This is also valid for smaller wind power projects. However, new wind power plants typically connect at higher voltage levels in distribution or transmission grid and are often both visible and controllable by the system operator.

Because the same weather processes drive wind power, solar power, and load, it is key that these data are co-incident to ensure the capture of the interactions and temporal correlations. When data are simulated for future sites where measurement data do not currently exist, it is best if these datasets are generated from the same numerical weather prediction model (NWP) runs. This ensures that the physics of the atmosphere is consistent for both generating technologies, and it helps to avoid erroneous ramps in the power output that may arise from ad hoc time series creation methods.

7.6 How to Present the Results

In order to evaluate the results and compare with previous work and other studies, it is important to consider the setup of the study as well as the methods and data that provided the results. Comparisons with different power systems should also be made with care, as different systems have a different starting point and ability to integrate variable generation.

Comparing results from the integration study to previous work is easier if some basic things about the study are reported:

- *Share of wind/PV power studied:* The share of wind/PV power can be expressed by various measures. Often either energy or capacity metrics are used: wind/PV power production as a percentage of gross demand (energy) and wind/PV power capacity as a percentage of peak load (capacity).
- *Power system size and general characteristics:* power system size as peak load and general characteristics like summer/winter peaking, thermal or hydro dominated system.
- *Interconnection capacity*: as simple share of wind/PV metric neglects the presence of interconnecting capacity with neighbouring countries, and cross-border interconnections are often the key to efficient power system operation, the cross-border capacity should be stated. Wind/PV share can be presented in terms of wind/PV capacity in percentage of the sum of minimum load and cross-border capacity to highlight the challenge of managing high wind/PV events.
- *Basic assumptions regarding flexibility:* flexibility, or inflexibility of power plants, demand and available storage, including operational practices.
- *How wind/PV power is added:* What are the differences in scenarios for wind/PV and non/low-wind/PV cases?
- *Resulting curtailment of wind/PV* in final results. The net generation of wind/PV power is relevant. The results regarding curtailed wind and solar can indicate lack of flexibility in the power system. The amount of curtailed energy can be used for example regarding investment decisions, for transmission, storage or new demand.
- *Method and simulation tool limitations.* The checklist below (Section 7.7) can be used to benchmark the simulation method(s) used in the study: whether there is tendency in the results to over- or underestimate the issue studied.

Many wind/PV integration studies give estimated impacts as an increase in reserve requirements (MW), increase in grid reinforcement needs (length for different kV lines). Many studies give the results in less comparable ways, like impacts on the scheduling of other power plants and exports, impacts on the stability of the transmission grid, and impacts on adequacy of power. Different metrics for costs include monetary value per megawatt-hour of wind/PV or per megawatt-hour of total consumption (reflecting the increase in consumer price). There are also results as a percent of more wind/PV power production needed to cover extra losses.

Important result of wind/solar integration studies is the needed changes in the operational practices, including required grid support services from wind and solar power plants.

Regarding reserve requirements, there is no simple way of presenting the result of dynamic, varying reserve requirement. One approach would be to present it as a duration curve or a range over an average reserve level, or violin plots, with at least 1 year of data.

Novel, emerging methods for presenting the results of larger studies are very useful in illustrating the changes in power exchanges and dispatch situations with large amounts of wind and solar (Bloom et al., 2016) and in visualisation at www.youtube.com/watch?v=jx9_4GNkbIQ.

7.7 Checklist for Study Limitations Arising from Assumptions

The results of a study will depend on assumptions and modelling framework, along with the input data. The ideal methodology for simulations would mean taking all possible market and grid dynamic aspects into account and cover several years with a small time step (less than a second). This is impossible in practice, although the simulation tools are developing to this direction. Limitations arise from the simulation tools and from assumptions that need to be made when simulating the system operation. An important challenge is the uncertainty in the basic scenario concerning units and loads and prices in a future system when higher amounts of wind/PV power will happen. When conclusions are drawn, it is important to consider the consequences of the assumptions chosen to find out whether the approach has been conservative or whether some important aspects have been omitted, producing either high or low estimates for the impacts.

The setup for the study may give rise to limitations. For example, comparing one system with and one without wind/PV power, where the remaining system is the same, the prices (set by marginal costs) will be lower in the system with wind/PV power, because units with highest marginal costs will be replaced whenever there is high wind or/and solar generation. This is mainly a result of study setup and is generally valid for any kind of generation investments.

There are other examples of limitations that arise if the iteration loops in the flow chart are not used (see Figure 1.3). Making a generation expansion plan before the wind/PV integration study with no time to re-plan and re-run based on the initial results may show results where wind/PV integration is very costly, or not feasible. Another example is that large amounts of wind/PV power will result in more volatile prices (high prices during high load/low wind/PV, low prices during high wind/PV/low load), which in reality will result in changed behaviour of consumption as well as investments in flexible power plants, storage and/or transmission to neighboring systems. Reliability constraints from transmission or capacity adequacy or reserve margins will require an iteration to change the installed capacity of the remaining power plants, the transmission grid, the operational methods or the operating reserves.

Examples of what to list for key assumptions:

- Whether wind/PV power is added as an energy source only, or whether the wind/PV power will support new load growth and/or displace existing or new generating capacity.
- The level of detail regarding the simulation model, including the time step, whether uncertainty (forecast errors) is taken into account, other aspects of operating reserves and operational practices that are relevant.
- Source of the wind/PV power data for generation and forecasts; methods used to simulate the data:
  - Whether multiple forecast timescales are used
  - How the modelled forecast technology compares to current state-of-the-art and expected future forecast errors.
- Unit commitment time steps and whether UC and dispatch is repeated as new information becomes available closer to real-time.
- Assumptions regarding environmental restriction, including emission pricing.
- Method for calculating operating reserve increase due to wind and solar.
- Level of detail in representing the transmission system:
  - Nodal or zonal
  - How are interconnections with neighbouring systems modelled?
- Level of detail on modelling generation, including multiple modes for combined cycle plants, run-of-river versus reservoirs in hydro systems, etc.
- Level of detail on modelling demand, demand response and demand flexibility (including links to other energy sectors like heat, transport, industry P2X).

- Whether operating and market rules are based on current practice or potential future practices.
- The level of investment in other generation and transmission:
    - Generation mix, amount of storage
    - Flexibility characteristics of the generation mix.
- Whether perfect competition is assumed in the electricity markets
- Whether wind/PV plant controls are allowed to provide for balancing and ancillary services from wind/PV plants and the impact that has on integration.

Enablers for cost-efficient integration of wind/PV power include flexible intra-day markets, continually updated wind/PV power forecasts, flexible trading with neighbouring systems, large geographical spreading of total wind/PV power, price sensitivity and flexibility in the demand, expansion of the transmission network, and a cost-efficient use of system wide balancing resources. Important issues include how the larger footprint is taken into account (use of interconnections) and whether the balancing is performed in an isolated system versus within a larger system. This is also important from a reliability point-of-view because smaller synchronous systems do not usually use as high reliability targets.

The matrix developed in (Söder & Holttinen, 2008), with summary of different issues to be considered (updated from Task 25 summary report Holttinen et al., 2009) can be used as a check-list Table 7.1.

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Table 7.1. Summary of issues/possible limitations in integration studies.

Setup		
A	Aim of Study	1 what happens with x GWh (or y GW) wind/PV 2 how much wind/PV is possible 3 other:
M	Method to Perform Study	1 add wind/PV energy 2 wind/PV also replaces capacity 3 load is increased same amount of GWh as wind/PV 4 optimal system design 5 other: For capacity value also: (a) chronological, using wind/PV power and load profiles (b) probabilistic
D	Design of System	1 constant remaining system 2 optimized remaining production capacity and storage 3 optimized remaining transmission 4 changed operation due to wind/PV power 5 reliability targets met 6 cost recovery for power plants checked 6 other:
Simulation Detail		
R	Resolution of Time	1 day/week 2 hour 3 minute/second DURATION of simulation period:
P	Pricing Method	1 costs of fuels etc. 2 prices for trading with neighbors, historical market prices 3 perfect market simulation (each actor maximizes its benefit according to some definition considering the physical and legal constraints) 4 market dynamics included (different actors on the market make investments or change their behaviour depending on the market prices) 5 other:
S	Simulation Model of Operation	1 deterministic simulation, one case 2 deterministic simulation several cases 3 deterministic planning with stochastic wind/PV forecast errors 4 stochastic simulation several cases 5 other:
D	Dynamics	1 not taken into account 2 frequency stability 3 frequency and other stability categories 4 other:

Table continues to the next page

Uncertainty and Balancing		
I	Imbalance Calculation	1 only wind/PV cause imbalances 2 wind/PV+ load forecast errors cause imbalance 3 wind/PV+ load + production outages cause imbalances 4 other:
B	Balancing Location	1 dedicated source 2 from the same region 3 also outside region 4 other:
U	Uncertainty Treatment	1 transmission margins: 2 hydro inflow uncertainty: 3 wind/PV forecasts: (a) assume no knowledge and large margins for wind/PV 0…full capacity, (b) assume perfect forecast for wind/PV, (c) persistence forecasts for wind/PV, (d) best available forecasts, specify what level of forecast error assumed 5 load forecasts considered: 6 thermal power outages considered: 7 other: TIME HORIZON for forecasts assumed in the simulation (1–2 hours…day-ahead)
Power System Details		
G	Grid Limit on Transmission	1 no limits 2 constant MW limits 3 consider voltage 4 N-1 criteria 5 dynamic simulation 6 other MULTI-AREA SIMULATIONS: limits inside the whole area and limits outside the simulated area separately
H	Hydro Power Modelling	1 head height considered 2 hydrological coupling included (including reservoir capacity) 3 hydrological restrictions included (reservoir level, stream flows) 4 availability of water, capacity factor, dry/wet year 5 hydro optimization considered 6 limited, deterministic run-of-river 7 interaction with hydro resources not significant 8 other:
T	Thermal Power Modelling	1 ramp rates considered 2 start/stop costs considered 3 efficiency variation considered 4 heat production considered 5 other:
W	Wind/PV Power Modelling	1 time series: (a) measured wind speed + power curve (how many sites)/measured solar irradiance + PV system azimuth and tilt (b) wind power from wind power plants (how many sites)/PV power from PV plants (c) reanalysis wind speed + power curve (how many sites)/satellite-derived solar irradiance + PV system azimuth and tilt (d) time series smoothing considered (how) 2 wind/PV power profiles: (a) climatic, e.g. lowest/highest temperature, (b) hour of day, (c) season, e.g. only winter, (d) load percentile 3 coincident wind/PV data with load or not 4 scenarios for future wind/PV power distribution; specify geographical distribution of wind/PV 5 other:

7.8 Checklist: Analysing and Presenting Results

Checklist of Key Issues: Analysing and Presenting Results

- If the results show unexpectedly high and costly impacts of wind/PV power to the system, consider the iteration loops. Changing operational practices may prove cost-effective, or generation or transmission scenarios may be inadequate.
- When extracting results for the impacts, select the cases to compare with care and report the methodology and possible caveats in the findings. Comparing full scenarios are recommended, instead of extracting cost differences as integration costs.
- Present the results stating share of wind/PV, size and type of power system.
- List main assumptions and limitations arising from these (example checklists provided).

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8 Conclusions and Future Work

Wind/solar integration studies have been maturing continuously as the state of the art advances, with each study generally building on previous ones. The recommendations in this document are based on current knowledge, and they will evolve as new knowledge in the area is obtained. Integration studies can be performed for any kind of changes to a power system, because all changes often have technical and economic impacts on other parts of the system – wind and solar integration studies are becoming more general system studies for the energy transition.

A comprehensive power and energy system study has many inputs and is built on numerous assumptions, which should be clearly described in the study. These may include the following:

- *Objective of the study:* What is included, and what is excluded – neighbouring power systems and links to other energy sectors including new kinds of demand such as power2X.
- *Power and energy system data:* Includes power plant and storage data, load data, transmission network, and operational practices including market structure and coupling to energy sectors linking available flexibility such as heat.
- *Wind/PV power related data:* Detailed wind/solar generation data that correctly characterize plant performance and geographical spread (co-incident with load and all weather dependent data used) as well as data on wind/PV and load uncertainty (forecast errors). Location of wind/PV power plants for grid simulations.
- *Other assumptions that play a key role in results*: Links to other energy sectors, such as heat, transport, and gas; demand flexibility; scenarios of (future) conventional generation; storage and network characteristics; as well as fuel prices, taxes, CO_2 allowances, and emission limits.

Key tasks that comprise a wind/solar integration study include the following:

- Scenario setup including base case for comparison – for future systems, this will entail capacity expansion models.
- Data collection and quality checking
- Operational impacts: Running production cost simulations to see how wind/solar power impacts the scheduling and dispatch of generation and storage, activation of demand flexibility, and estimating system operational costs. Need for flexibility from other sources (generation, storage, demand). Impact of wind and PV on short-term reserves as part of statistical data analysis.
- Adequacy impacts: Running resource adequacy analysis to assess whether reliability targets are met. Running (steady-state) network simulations to assess whether the network is adequate, or where reinforcements and/or changes in security architecture or network operation process are needed.
- Running dynamic simulations to ensure that power system stability is adequate.
- If results achieved are not considered satisfactory, changes should be applied to the generation, storage, or transmission portfolio, or operational practices, including demand flexibility (an iterative process).
- Analysing the data and presenting the results.

Depending on the wind and solar shares studied, some components of the study can be omitted. How a low share is defined will depend on the power system's characteristics. Depending on the load and wind/solar resource, challenging high share situations can already occur before 10% yearly share in some systems, while only being of concern at higher than a 20% share in other systems. To begin with, at lower shares, scenarios studied need only include the power system, operated based on existing practices, and the main simulation components – production cost simulation and power flow – to see the impact of wind/PV power on the other power plants as well as the needs to upgrade the transmission network. Even if the capacity value of wind/PV power is usually not that critical at low shares, it is often included in such studies. In addition, in many studies the transmission network is not studied in great detail, and a simplified approach is applied as part of production cost simulations. For higher wind and solar shares, it will become more relevant to assess impacts relating to reserve requirements within a more detailed flexibility assessment. Finally, for wind and solar dominated systems, capacity adequacy and stability aspects become crucial to study in (great) detail, as the power system transitions from one that is largely based on fully dispatchable synchronous machine based generation to one that is based on power electronic interfaces (for both generators and loads), with a dramatic reduction in the number of synchronous machines the addition of new load types and energy system coupling.

Iteration cycles are extremely important, from modifying the scenario setup and operational practices, as part of ensuring the reliability of the system, and also enabling more cost-effective integration. The modelling assumptions will have crucial impacts on the results. The recommendations regarding simulation analysis are given as checklists, and include how to consider wind/PV power within the modelling tools as well as how to model the system to capture wind/PV impacts. The results of integration studies should be discussed in detail, while keeping in mind the assumptions made and the weaknesses of the study approach.

Some studies compare one or more wind/PV power scenarios with alternatives. The details of these comparisons and assumptions regarding each scenario should be made very clear, given that there are challenges in choosing the non-wind/PV case such that the differences are due to wind/PV addition alone.

For wind and solar dominated energy systems, traditional study methodologies and models require re-examination. Simultaneous changes of electrification and energy sector coupling (load transition) will parallel the increases in wind and solar energy. There is need for further development of models and methods of study, but some key issues can be identified across the challenges for adequacy, operational impacts, and system stability:

- *Larger areas*: The entire synchronous system is relevant for stability studies, and sharing of resources for balancing and adequacy purposes will be more beneficial.
- *New technologies*: All tools need to be modified to enable new types of (flexible) demand and storage, while also facilitating further links through energy system coupling.
- *More data and detail in models*: More wind/solar detail needs to be captured. More data will be needed to capture higher resolution and larger areas. Extended time series will be needed to ensure resilience for weather dependent events: covering extreme events and variability of the resources. All such issues will increase the modelling computational burden. As the data is synthesised, it must be validated to understand how it's error and uncertainty characteristics will impact the study.
- *Model integration*: Increased importance of integrated planning and operations methodologies, tools, and data. Operational and planning timescales/models need greater overlap. Flexibility needs and plant capabilities must be incorporated within adequacy methods, and stability concerns must be considered for network expansion planning and operating future grids.

Issues identified in system studies are mainly technical, but solving them also requires identification of the most economically advantageous solutions, and ensuring that the right policies are in place in sufficient time:

- Economic implications will be seen particularly for resource adequacy, when determining a cost optimal future generation mix and transmission buildout that is robust to future uncertainties. Traditional planning, relying on peak power as backup, may yield high cost increases for wind and solar dominated systems, unless the evolution of flexibility and price responsive loads from electrification and other energy sectors are taken full advantage of. Modified reliability targets could yield acceptable results with considerably lower cost increases.
- Identified operational issues will also have economic implications, such as the sharing of system balancing and reaching out to all flexibility sources.
- Stability issues for wind and solar dominated systems will be mostly technical in nature, but solutions may potentially be implemented through updated grid code requirements (enforcement) and/or through the creation of new system services (incentive), depending on the severity and timeliness of the identified need, and the ability of existing assets to support the need.

Market design is important to study for high wind and solar shares to incentivise operational flexibility and resource adequacy with investment cost recovery in systems with high wind/PV share, and to enable effective use of wind/PV capabilities for power system support (for example when running in curtailed mode). A wind and solar dominated energy system would also imply changes in consumer engagement.

There is a strong move towards integrated planning across the different domains covered. The interactions between them will be as important as the studies themselves – how capacity expansion, resource adequacy, operational and stability simulations impact each other.

As energy supply continues to transition towards renewables and wind and solar generation become mainstream, integration studies will become general power system design studies at very high wind and solar shares. We foresee that this Recommended Practices for Integration studies will be the last update, and, in future, integration studies will become standard power and energy system design studies.