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Comité de Operación Económica del Sistema Interconectado Nacional

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Methodological Considerations for vRE Grid Integration Studies in Peru

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Energynautics is a power systems consultancy firm based in Germany. It was founded in 2000 and has since then been involved in numerous research and consulting projects for governments, electricity network operators, regulators, manufacturers and investors, especially in matters relating to innovative grid design, modelling and power system integration of renewable energies.

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Summary

Context: VRE Integration Studies in Peru

With the progressive growth of variable Renewable Energy (vRE) generation projects, power system operation is expected to face operational challenges linked to the nature of vRE generation, most notably their short-term variations and their characteristic as inverter-based resources (IBR) with no inherent inertia.

Peru has excellent potential for PV generation in the south of the country, as well as wind potential with high-capacity factors spread around the coast. The RE penetration target [1] is 20% in 2030: the previous target of 5%[2] of annual generation was set in 2008 and was achieved in 2023 with large-scale wind and PV installations.

The Peruvian transmission system operator -COES- seeks support to develop a comprehensive methodology for vRE integration studies at system level. Currently, COES handles short-term operation planning and long-term transmission expansion with in-house capabilities. However, comprehensive future scenario analysis is not regularly conducted. Therefore, it is crucial for COES to acquire a flexible, updatable, and transparent methodology to conduct their own vRE integration studies.

The purpose of this report is to provide COES with information that will help enable them to:

- Develop future scenarios for the Peruvian power system, looking years to decades ahead;
- Conduct comprehensive vRE integration studies for various future scenarios;
- Regularly perform vRE integration studies with minimal external support;
- Engage the government and stakeholders with results, fostering discussions on vRE development.

It should be noted that COES as the transmission system operator in an open market system is not responsible for planning generation expansion – generation investments are made by private parties based on their assessment of market conditions. However, in order to develop robust integration studies and transmission expansion plans, COES needs future scenarios for capacity expansion. In the absence of scenario inputs and capacity expansion targets, COES will have to develop future scenarios based on their expectations of possible future conditions.

[1] Supreme Decree N° 003-2022-MINAM (2022), it sets a target of 20% by 2030

[2] Legislative Decree 1002 (2008), the 5% does not include hydropower > 20MW

vRE Integration Methodology

The methodologies for vRE integration studies used in a number of international study cases (particularly Ireland, California and Chile) deviate quite significantly in exact scope, focus areas and timing, but all essentially follow a similar structure. This structure is very similar to the one published by IEA[3] and split into multiple stages as explained in the following. Study stages are conducted sequentially. However, technical or economic issues that arise at any stage, resulting in unacceptable outcomes, may trigger an iteration into the previous stage or multiple previous stages.

1. **Set up Stage: Defining Scenarios and System Expansion.** Every study starts with a **set-up stage** in which the shape of the future power system to be analysed is defined. This includes the definition of the (initial) grid topology, the generation fleet and the expected demand growth. **Future scenarios** can be developed either by manual curation, typically from **previously existing plans or projections**, or through a **capacity expansion optimization** using a dedicated software tool such as OPTGEN-SDDP, PLEXOS or PyPSA.

2. **Dispatch Analysis: System Operation in Future Scenarios.** After future scenarios have been defined, a **dispatch analysis** has to be conducted. Detailed analysis of the system in future scenarios requires knowledge of how the system would operate under these conditions. It is usually preferred to run detailed **dispatch simulation** (also often called **production simulation**) in hourly or sub-hourly resolution for example days, weeks or entire years.. Parameters such as **instantaneous vRE penetration, production cost, curtailment and availability spinning reserves** can be directly derived from the simulation. A linearized (DC) grid model can be integrated in most production simulation software tools which allows additional analysis of **congestion** and **congestion management (redispatch)**. Operational cases for subsequent electrical analysis can easily be extracted from such simulation results.

3. **Steady-State Analysis: Power Flows and Protection.** Detailed **electrical analysis using non-linearized models** is required to obtain full details on the actual electrical condition of the grid. For this purpose, critical situations are typically pulled out of the dispatch results and loaded into a dedicated power system analysis software. **Steady state power flow analysis** is then conducted for these situations, **usually including contingency analysis,** to ensure that all operational parameters remain within the allowed bounds. This analysis can then be followed by additional steady state evaluations, such as **shortcircuit and protection analysis,** to ensure that short circuit levels remain acceptable and reliably trigger protection in fault cases.

4. **Dynamic Stability Analysis: System Response to Operational Changes and High vRE Penetration Levels.** Steady state analysis can then be followed by **dynamic stability analysis** to evaluate the capability of the system to safely transition from one state to the other. The

[3] https://iea-pvps.org/wp-content/uploads/2020/02/T14-10_2018_Wind-PV_Integration_Studies.pdf

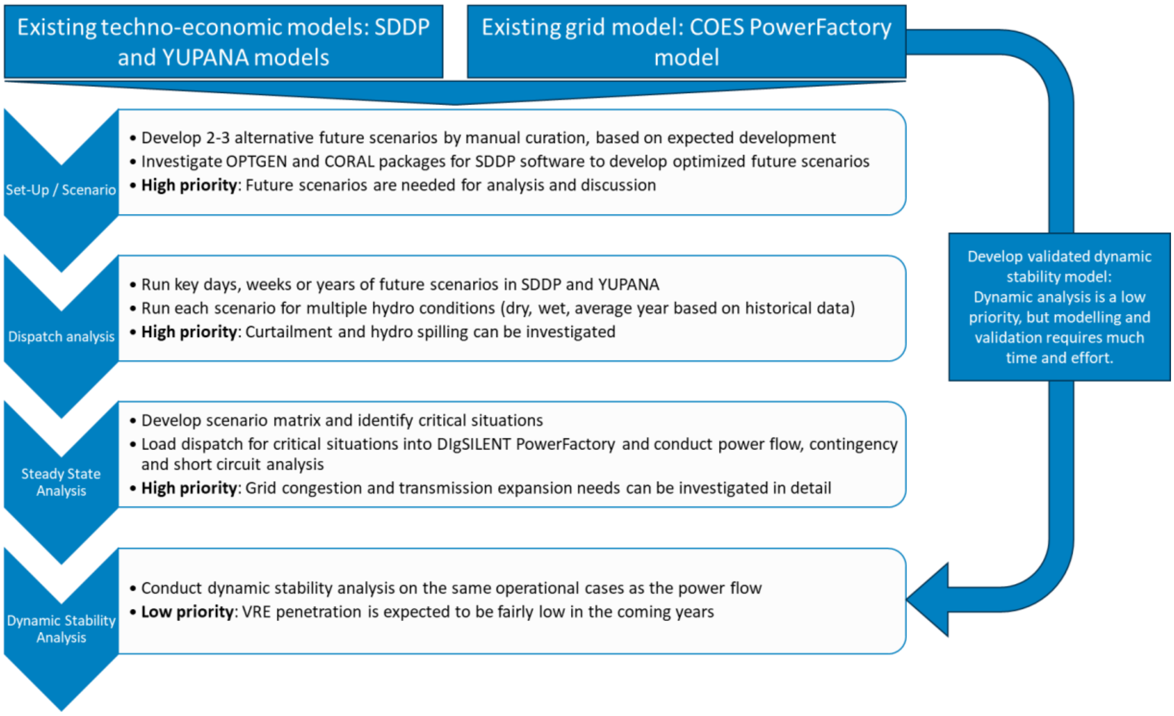
system is considered stable if it can return to a stable operational state for all (or a large number) of credibly expected events. Dynamic stability is critical in any power system regardless of VRE integration status, and is often conducted by system operators on a regular basis for the current condition. The **addition of vRE changes stability parameters**, most notably in the form of reduced system inertia, which makes frequency control more challenging. Especially for near future scenarios and **scenarios with relatively little vRE additions, dynamic stability analysis is hence often considered not to be a critical issue and often skipped**, partially also due to the high modelling and validation efforts required. Dynamic stability however does become **critical** and needs to be evaluated in detail at **higher instantaneous vRE penetration levels.**

Recommendations for Peru

The key recommendation for COES regarding vRE integration studies in the Peruvian system is to **leverage existing structures and models** wherever possible, utilizing the models currently used for short term programming to also simulate future scenarios. COES use **DIgSILENT PowerFactory as the electrical analysis software**, and **SDDP and YUPANA for dispatch simulations** on different timescales. All of these tools are up to current international standards and suitable to investigate high-vRE future scenarios.

Furthermore, it is strongly recommended to **focus the next study on scenarios with moderate (10 – 15 %) vRE contribution** and the integration of the required capacities into **COES' existing grid**. The challenges for this type of scenario are mainly updates to generation scheduling and ancillary services, as well as transmission congestion and the identification of transmission investment needs, while dynamic stability issues play a minor role. The study should hence focus on the development of near-future scenarios, dispatch analysis and power flow analysis. The stepwise process to conduct such a study is graphically displayed in **FIGURE 1Fehler! Verweisquelle konnte nicht gefunden werden.**. The **process is recommended to be executed by COES themselves**, using already **existing tools, models and databases** as much as possible, but under the **supervision and with input from an experienced international consultancy** that has conducted similar studies before in other countries.

FIGURE 1: Flowchart for COES vRE integration studies



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Abbreviations

AVR	Automatic voltage regulator
AEMO	Australian Electricity Market Operator
AGC	Automatic generation control
BAU	Business as usual
BESS	Battery energy storage system
CAISO	California Independent System Operator
CAPEX	Capital Expenditure
CCGT	Combined Cycle Gas Turbine
COES	Comité de Operación Económica del Sistema Interconectado Nacional (Peruvian
EMT	Electromagnetic transient
EV	Electric vehicle
FO&M	Fixed operation and maintenance
FRT	Fault ride-through
GFL	Grid following
GFM	Grid forming
GIGO	Garbage in garbage out
HTLS	High temperature, low sag
IBR	Inveter-based resource(s)
IEA	International Energy Agency
IEC	International Electrotechnical Commission
INDECOPI	Competition Authority
IPP	Independent power producer
ISO	Independent system operator (USA)
LP	Linear programming
LVRT	Low voltage ride-through
MILP	Mixed integer linear programming
MINAM	Ministry of Environment
MINEM	Ministry of Energy and Mines
MWG	Modelling Working Group
NEP	Netzentwicklungsplan (Grid development plan, Germany)
NEP	German grid development plan
NREL	National Renewable Energy Laboratory (USA)
NTC	Net transfer capacity
O&M	Operation and Maintenance
OECD	Organisation for Economic Cooperation and Development
OPEX	Operational expenditure
OPEX	Operationak Expenditure
OPF	Optimal power flow
OSINERGM	Regulatory Agency for Investment in Energy and Mining
PDO	Daily program of operation (COES)

PMPO	Medium term programming (COES)
PMU	Phasor measurement unit
PPA	Power purchase agreement
PSO	Weekly program of operation (COES)
PV	Photovoltaics
RE	Renewable energy
RMS	Root mean square
RoCoF	Rate of Change of Frequency
RPF	Primary frequency regulation
RSF	Secondary frequency regulation
RTO	Regional transmission organization (USA)
SCADA	Supervisory control and data acquisition
SCED	Security-constrained economic dispatch
SCOPF	Security constrained optimal power flow
SCUC	Security-constrained unit commitment
SEIN	Sistema Eléctrico Interconectado Nacional (Peruvian interconnected system)
SNSP	System non-synchronous penetration
STATCOM	Static synchronous compensator
TOP	Take or pay
TRC	Technical Review Committee
TSO	Transmission system operator
VO&M	Variable operation and maintenance
VRE	Variable Renewable Energy
WECC	Western Electricity Coordinating Council (USA)

1 Introduction

With the progressive growth of variable Renewable Energy (vRE) generation projects, power system operation is expected to face operational challenges linked to the nature of vRE generation, with the following key challenges:

— vRE generation is dependent on primary resource availability and can fluctuate significantly on different time scales;
— vRE generation must be placed where the resource is available, which can be far from the load centers, leading to increased transmission needs;
— Cost structure is different from conventional generation, high in CAPEX but very low in OPEX, leading to a preference for priority dispatch of vRE and displacement of conventional units during high vRE availability;
— vRE generation is inverter based and does hence not inherently contribute to inertia or other system stabilizing services – contributions are possible (and common) already today, but require the right equipment and parametrization of inverters.

Peru has excellent resources for PV generation in the south of the country, as well as wind resources with high-capacity factors spread around the coast. Despite the world class renewable resources and state efforts starting as early as 2008 (DL 1002) for incentivizing vRE investments, there is a considerable gap between the potential and the realization. The target for vRE penetration of 5% share of annual generation set in 2008 was realized in 2023 with large-scale Wind and PV PP commissions. The current target is to achieve 30% in 2030.One main reason for the low penetration growing rate of vRE has been the availability of domestic natural resources for electricity generation. There is natural gas at regulated prices and abundant hydropower generation. However, this outlook is evolving with the growing demand driven principally by the development of the mining industry, and the growing supply driven by interest of the private sector for vRE investments.

In **TABLE 1**, a snapshot of key system data of the Peruvian integrated system (SEIN - Sistema Eléctrico Interconectado Nacional) can be seen. SEIN has a very long grid laid mainly over the coastal region with limited meshing prone to voltage stability challenges. On the other hand, it is a very strong synchronous system with 50% of the generation sourced by the combined cycle gas turbines (CCGT) and about 45% by hydro power. The grid only has a small cross-border interconnection, which is run asynchronously and relatively rarely.

TABLE 1 SEIN system characteristics, based on 2023 data

SEIN SYSTEM CHARACTERISTICS – 2023 DATA	
vRE energy share[4] (annual generation)	5.7% (2023) 7.5% (Jan-Jun 2024)
Peak vRE Penetration (instantaneous)	15.9% (Dec. 2023)
Peak Demand	7.6 GW (Dec. 2023)
Min Demand	5.5 GW (April 2023)
Interconnectors (Ecuador/Machala, 220kV)	50/70 MW
Installed conventional capacity	13.7 GW
Installed non-convent. capacity (Dec 2022)	0.7 GW (Wind) 0.3 GW (PV)

A high penetration of vRE in an isolated system such as SEIN with no synchronous cross-border interconnection, will impact the control of operation and stability, from the perspective of frequency and voltage parameters, as well as economic effects to manage the reliability of the variability of renewable plants.

The Comité de Operación Económica del Sistema Interconectado Nacional (COES) is responsible for a safe operation of the transmission system in Peru which includes coordinating the short, medium- and long-term operation of the SEIN at a minimum cost, the best use of energy resources, planning the development of the SEIN transmission, as well as managing the short term market. There are already certain measures and tools COES is using for vRE integration, however COES has identified the need for a forward-looking methodology to prepare for increased vRE penetration in the system. For this purpose, they would like to be able to conduct in-house vRE integration studies to estimate VRE absorption capacity of the system without introducing any physical or operational changes to the existing system. However, this requires assistance for the planning and preparation.

This document provides information on the general approach and methodology of such a study, based on Energynautics' experience with conducting similar studies and review of best international practices (Australia, Chile and Ireland). The document addresses issues specific to Peru where possible, but is kept general to show a range of possibilities of addressing some of the relevant questions. Instead of being limited to the study of the existing system for a vRE integration limit, the

[4] Source: COES, solar and wind participation in the energy production

methodology allows for studying potential system scenarios as well. This feature is important for adaptability reasons, as the approach or duties of the COES may change in the future. The methodology is dissected into sub-chapters of individual system studies informing on the key data inputs/outputs, modelling parameters, processes and limitations, as well as discussion of different approaches, where relevant. The methodology is concluded with chapters on results interpretation, measures for increasing vRE penetration and recommendations for the SEIN system.

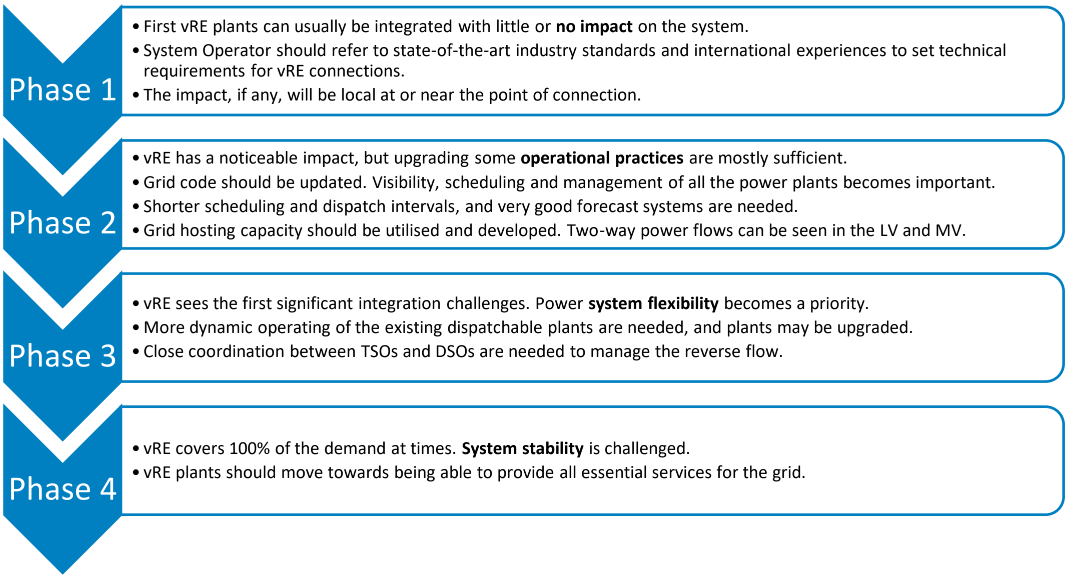
1.1 vRE Integration: General Scope

System integration of vRE encompasses all the technical, institutional, policy and market design changes that are needed to enable the secure and cost-effective uptake of large amounts of vRE in the energy system. Within the scope of this report, only technical aspects will be discussed independent of the other elements. However, the difficulty (or ease) of integrating vRE in a power system greatly[5] depends on two main factors: the properties of vRE generators and the flexibility of the power system, both of which are strongly correlated to the institutional, political and market aspects. For example, although vRE resources cannot be controlled, there can be good operational practices for grid connection requirements or forecasting to control the impact on the system. Another example could be availability of market structures incentivizing flexibility of demand and generation to accommodate for the volatility of the vRE resources. Therefore, when evaluating any system limitation, it is important to remember that there are many technical and non-technical measures, which could work without infrastructural investments as well, to push a system limit and such limits should be regarded as temporary.

Based on the large review on international vRE integration practices, OECD and IEA identified four phases of vRE integration which are differentiated the impact of the growing vRE capacity on power systems. **FIGURE 2** summarizes the important features of each phase and most important actions to be taken for ensuring smooth integration. The structure is based on the fundament that system integration challenges emerge gradually as vRE grows on the power system. Depending on the system penetration of vRE, measures and tools for integration changes.

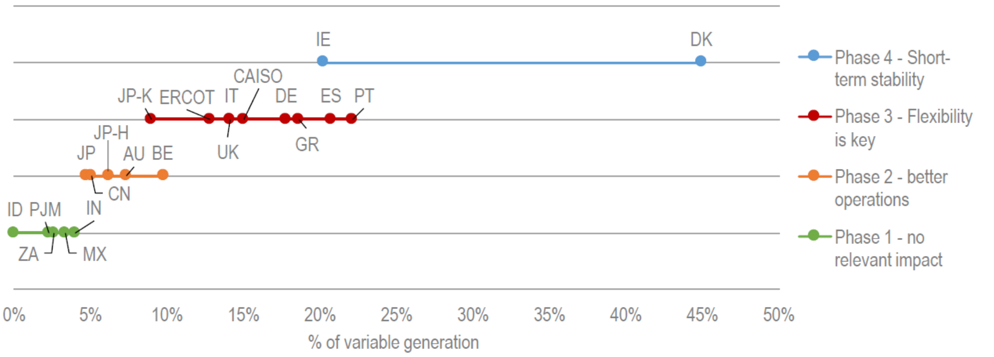
[5] There are other structural factors such as size of the system, match between demand and vRE output, interconnectivity, demand evolution etc. However, these two are chosen for limiting the scope.

FIGURE 2 Four phases of vRE integration



Although it is easy to see that there are similar structures between wide range of systems, there is no simple answer to the questions of “at what share of vRE will a certain issue arise / is each phase marked”. Despite being slightly outdated, **FIGURE 3** helps to understand that each phase can span a wide range in terms of vRE share of electricity and there is no single point of vRE share at which a new phase is entered. Therefore, vRE share cannot be considered as a single reliable metric for vRE system integration and corresponding measures.

FIGURE 3 Annual vRE generation shares in selected countries and corresponding vRE integration phases[6]



Notes: AT = Austria; AU = Australia; BR = Brazil; CL = Chile; CN = China; DE = Germany; DK = Denmark; ES = Spain; GR = Greece; ID = Indonesia; IE = Ireland; IN = India; IT = Italy; JP = Japan; JP-H = Hokkaido (Japan); JP-K = Kyushu (Japan); MX = Mexico; NZ = New Zealand; PT = Portugal; SE = Sweden; UK = the United Kingdom; ZA = South Africa. PJM, CAISO and ERCOT are US energy markets.

Source: Adapted from IEA (2017a), *Renewable 2017.*

However, most of the systems will not have any noticeable impact on the system at very low vRE shares (below 5%). As Peru recently marked 5.7% vRE share in 2023 (7.5% in Jan-Jun 2024), no problem or only some impact at the local point of connections can be expected. Most important tasks for further system integration of vRE at this stage are: (1) Calculation of the hosting capacity of the grid and identifying the right sites for vRE connection, (2) Developing technical requirements for connection of vRE.

The four phases outlined here should be integrated into broader energy planning to guarantee the most seamless and economically efficient deployment of vRE. This is especially crucial for the strategies detailed in Phase two, aimed at alleviating the effects of a higher participation of vRE. These strategies revolve around selecting the optimal mix of vRE technologies (wind/solar) and strategically locating them, considering factors such as geographic distribution (dispersed/concentrated, far from/close to demand centers) and grid voltage (distributed/centralized).

1.2 International Good Practice

All vRE grid integration studies are unique. Each study is tailored to address the concerns most relevant to a given power system. In general, a grid integration study involves modeling the power system using approaches that fall into one or more of three general categories: capacity expansion, production cost, and network studies.

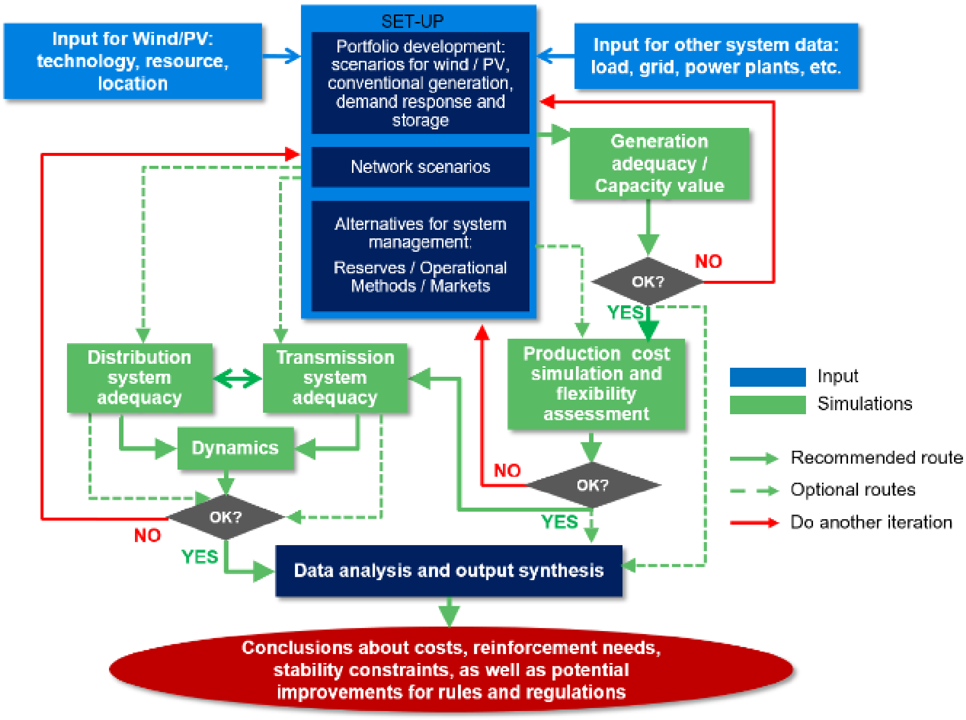
While some studies employ all three methods, many concentrate on only one or two. The choice of which analysis or combination of analyses to implement depends on policy priorities. For instance, if

[6] https://www.iea.org/reports/system-integration-of-renewables

planners are evaluating long-term energy supply, a capacity expansion analysis that focuses on generation and transmission build-out combined with production cost analysis may be preferred. Alternatively, production cost analysis might be best for enhancing system flexibility, while network power flow modeling addresses grid reliability concerns.

NREL[7] and IEA[8] both analysed independently vRE grid integration studies over 10 years and outlined flow and components of a complete integration study. Interestingly enough, both of the institutions arrived at the same conclusion. In **FIGURE 4**, methodology suggested by IEA is shown.

FIGURE 4 A complete vRE integration study, IEA diagram



When this schematic is trimmed down to structural components, the following studies in the given order are suggested:

1. Model and scenario set-ups
2. Capacity expansion study
3. Dispatch study
4. Network studies
    a. Load flow (steady-state) analysis

[7] https://www.nrel.gov/docs/fy20osti/72143.pdf
[8] https://iea-pvps.org/wp-content/uploads/2020/02/T14-10_2018_Wind-PV_Integration_Studies.pdf

b. Dynamic analysis
5. Development of roadmaps

Studying an entire system can characterize the full set of interactions that govern the power system. Conducting such a complete study is a complicated process, especially taking into account all possible iteration loops, this may not be feasible or may not be relevant for the phenomena of interest. A part of the system can also be studied with careful model construction to reflect the interactions between the boundaries of the system areas and the remaining of the synchronous area.

In this report, a complete study overview will be provided based on this structure. However, each sub-study can be run individually. One large study for planning is usually not sufficient. It is good practice to complement long-term studies with several more frequent short-term horizon studies with network studies.

At lower shares of vRE penetration, the main interests are the impact of wind/PV power on the 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, however a detailed flexibility or stability assessment is usually redundant.

BOX. International Good Practice

During the scope of the project, 5 systems (California, Ireland, Chile, Australia and Texas) were analysed to identify the most compatible methodology for SEIN and most up-to-date practices. Summary of the research can be found in **Appendix 2: International System And vRE Integration Methodologies**. Due to more distinctive system similarities (i.e. system size, fuel mix, interconnection,..), Ireland, Chile and Australia were chosen for a detailed research and analysis. Instead of adapting one of the system methodologies to Peruvian circumstances, all the methodologies will be used to give a perspective in relevant aspects. In the rest of the report, such aspects from these three systems, as well as some distinctive examples from other systems, for each sub-study parts will be shared in Country Boxes similar to this.

1.2.1 vRE Integration Limits

In none of the assessed systems, a limit on vRE connections limit or any methodology to obtain such a limit was published. Operational limits are implicitly contained in the studies, however the focus of the studies differ (as well as the studied scenarios). The results are interpreted for mitigation measures to allow further vRE integration, rather than finding a reliable static system vRE penetration limit.

1.3 Current Methodologies Applied by COES

COES already has processes in place for short-term system operation planning and long-term transmission expansion planning. COES can conduct the following studies with in-house capabilities:

- Transmission expansion study: Conducted every 2 years for 10-year planning horizon.
- Medium term program (PMPO) study: Month ahead planning for hydro optimization for 1 year (SDDP is used with a weekly resolution), which is issued every month. The objective of PMPO is to minimize the sum of the expected costs, given by the costs of thermal and hydraulic generation plus rationing costs.
- Weekly program of operation (PSO) study: Week ahead planning for dispatch (YUPANA is used with an hourly resolution), which is issued every Thursday for next Saturday to Friday horizon.
- Daily program of operation (PDO) study: Day ahead planning for dispatch (YUPANA is used with a half an hour resolution), which is issued every day.
- Primary Frequency Regulation (RPF) study: Annually, COES is required to submit to OSINERGMIN (the regulatory body) a report proposing the necessary RPF magnitude for SEIN, considering technical and economic factors as outlined in Annex 1 of PR-21[9]. COES is then responsible for implementing the approved RPF magnitude in the Medium and Short Term Programming of SEIN's operation.
- Secondary Frequency Regulation (RSF) Study: COES conducts the RSF[10] sizing study.

Currently, COES does not conduct any long-term capacity expansion studies. In 2019, COES collaborated with an external consultancy for such a study. This study assessed the current capacity for vRE integration in the power system under existing conditions, without further investments or additional technical requirements. However, COES did not have the opportunity to explore the methodology or work with the models used in the study. Thus, it is crucial for COES to obtain a methodology that is updatable, adaptable, and applicable, with well-known limitations and interpretable results, to develop actions or recommendations effectively.

[9] The PR-21 of COES sets out guidelines and methods for determining, allocating, scheduling, and assessing the SEIN Rotating Reserve linked to the RPF.

[10] The RSF in the SEIN is performed in a centralized manner through the Master Regulator (RM), which is the Automatic Generation Control (AGC) program controlled by the COES that allows to perform the RSF automatically at the level of the entire SEIN or by geographic areas. COES PR-22 establishes the criteria and methodologies for the provision of the Complementary Service of RSF.

2 Tools and Capacities

For vRE integration studies, there are numerous software tools available, varying widely in cost and capabilities. Selecting the right tools for system studies is essential to accurately reflect the complexities of each individual system. At the same time, it is important to avoid overly large and complex tools to manage costs, as well as to reduce the time and effort required.

In this chapter, possible scope and extent of the sub-studies are introduced to cover approaches of different system operators and tools at their disposal. Tools and capacities used for these studies are comparatively assessed.

2.1 Calculations / Simulations Required

2.1.1 Capacity Expansion Simulation

Capacity expansion analysis are usually the ground stone of the power sector master plans of the systems. Capacity expansion studies co-optimize the generation and transmission capacity expansion plans to identify cost-effective transmission system upgrades and expansion—including trade-offs between transmission and generation expansion. It can address various factors depending on the system, however technological advancements, fuel costs, and demand forecasts are usual parameters. These studies inform decisions regarding the type, quantity, timing, and geographical distribution of renewable energy sources like solar and wind, alongside other necessary resources, to meet policy objectives effectively. This is described in detail in section 3.2.

2.1.2 Dispatch / Production Simulation

For any future scenarios, some type of dispatch or production simulation must be performed to determine actual operational situations for grid analysis. This can be very simple – just dispatching units according to a merit order – or very comprehensive, using optimization or market simulation tools. This is described in detail in section 3.3.

2.1.3 Load Flow

Load flow calculations yield the steady state flows for each selected operational simulation. Calculations are performed for normal operating conditions (n-0) as well as for contingency conditions (n-x). For a feasible load flow, no assets may be thermally overloaded, and voltage at all busbars must remain within the allowed operational range. This requires an electrical model for network analysis (see section 2.2.1). The process is described in detail in section 3.4.

2.1.4 Short Circuit and Protection

Short circuit currents must remain below the asset short circuit rating, but high enough to trigger the relevant protection relays. The analysis requires an electrical model for network analysis (see section 2.2.1). The process is described in detail in section 3.5.

2.1.5 Dynamic Stability

While the steady-state impact of contingencies on the system is already evaluated in load flow calculations, the response of the system to the actual event – the transition from one state to the other – is not. The evaluation of dynamic stability (whether the system can safely transition from one state to the other) requires dynamic stability analysis. This requires an electrical model for network analysis (see section 2.2.1). The process is described in detail in section 3.6.

2.2 Software Tools

Appropriate software needs to be available for a vRE grid integration study. Software choices depend on study scope, budget and the experience of the staff involved. Based on the international best practice review, it can be confirmed that a grid simulation tool (e.g. PSS/E, PowerFactory, PSS SINCAL) and an optimization tool (e.g. PLEXOS, OPTGEN-SDDP, AMEBA, PLP) are used concurrently for system planning and vRE integration. Key aspects of the most common tools are described in the following.

2.2.1 Network Analysis

All grid integration studies require the availability of a grid simulation software, capable of executing load flow calculations and dynamic stability analysis. In most cases, commercial grid simulation software sites are used, with the following being most common (list is non-exhaustive):

- DIgSILENT PowerFactory (DIgSILENT, Germany);
- PSS/E (Siemens, Germany/USA);
- ETAP (ETAP, USA);
- PSS SINCAL (Siemens, Germany/USA);
- NEPLAN (NEPLAN AG, Switzerland).

General functionality is comparable, choice of software depends primarily on budget, previous staff experience and the availability of models – if the system operator has a PSS/E model available, it may be wise to continue using PSS/E. COES currently has a DigSILENT PowerFactory license which is a state-of-the-art tool for network studies and qualified staff to run the models. Therefore, it is advisable to maintain and integrate the same tool for future integration studies. PowerFactory is modular and may come with reduced functionality if a low cost license is bought. The following specifications, all offered by DIgSILENT, are relevant for COES:

- License with no node limit (cheaper licenses come limited to 50 or 200 nodes);
- Balanced and unbalanced load flow capability is part of the base package;
- Short circuit analysis is part of the base package;
- A package including RMS dynamic simulations is highly recommended if not already available;
- EMT and protection coordination packages may be useful at some point in the future, depending on studies to be conducted.

Most software sites can import data from other data formats, but export options are often limited.

Open source power system simulation software such as PyPSA or pandapower is available, but often limited to load flow calculations and either not capable or underperforming with regard to dynamic stability analysis. The key merit of open source tools is in the use for fast scenario analysis involving some economic optimization, which will be explained in the following section.

2.2.2 Economic Simulation / Optimization

Electrical analysis is by definition limited to study cases in which grid topology, generation and load conditions are pre-determined. To find the suitable simulation cases, some type of economic optimization is usually required:

- Grid topology and the generation fleet is usually determined by least-cost or least-regret planning, based on long term optimization;
- Generator dispatch in the system for each situation is usually determined by least-cost unit commitment and dispatch.

In the simplest case, situations can be created manually or using Excel sheets (for example by dispatching generators according to a simplified merit order). For more comprehensive analysis, optimization software is required. With many different options available the choice of software primarily depends on the primary focus of the studies to be conducted with it. Some tools also offer a "one stop shop", others are very focused on (and very good at) a single thing. An exemplary overview is given in **FIGURE 5**.

FIGURE 5 Selected power system optimization software options.

		Commercial tools					Open source tools			
		PLEXOS	Artelys Crystal super grid	OPTGEN /SDDP	AURORA	HOMER	Balmorel	TIMES	OSeMOSYS	PyPSA
Purpose	Generation capacity expansion	✓	✓	✓	✓	✓	✓	✓	✓	✓
	Transmission capacity expansion	✓	✓	✓	✓	✗	~	~	✓	✓
	Co-Optimization	✓				✗	✗	✗		
	Production simulation	✓	✓	✓	✓	✓	✓	✓	✓	✓
	SCOPF	✓	✓	✓	✓	✗	✓	✓	✓	✓
Modelling Horizon / Resolution	Decades	✓	✓	✓	✓	~	✓	✓	✓	✓
	Years	✓	✓	✓	✓	✓	✓	✓	✓	✓
	Hourly	✓	✓	✓	✓	✓	✓	✓	✓	✓
	Sub-Hourly	✓				✓	✓	✓	✓	✓
Size	Problem sizing	Large	Large	Medium	Large	Small	Large	Large	Large	Large
Technologies	Thermal	✓	✓	✓	✓	✓	✓	✓	✓	✓
	Hydro	✓	✓	✓	✓	✓	✓	✓	✓	✓
	VRE	✓	✓	~	✓	✓	✓	✓	✓	✓
	Storage	✓	✓	✓	✓	✓	✓	✓	✓	✓
	Demand / DSM	✓	✓	✓	✓	✓	~	✓	✓	~
Additional Requirements	Interface	✗	✓	~	✓	✓	~	~	~	~
	Support/ documentation	✓	✓	✓	✓	✓	~	~	✓	✓
	Learning/training	✗	✓	✓	✓	✓	✗	✗	✗	✗

In general, the following optimization tasks exist:

— Long-term energy planning, typically involving multiple sectors, with no detailed electrical representation;
— Power system planning involving generation and grid investment (co-) optimization;
— Production simulation and operational planning with detailed representation of grid and generator constraints.

In general, the shorter the horizon, the higher the time and spatial resolution. Resolution also impacts optimization mode: Linear programming (LP) is usually sufficient for long term energy balance planning, more complex mixed integer linear programming (MILP) is necessary for shorter time frames as well as for discrete expansion planning (buildout of discrete units instead of continuous capacities) in the long term.

For the analysis described in this document, the following functionalities are relevant:

— Generation capacity expansion planning, requiring a MILP capable optimization tool such as PLEXOS or the OPTGEN add-on to SDDP, or an open source framework such as PyPSA combined with a MILP solver software;
— Transmission-generation co-optimization, which is as of today included in the mentioned software tools;

- Generation adequacy assessment which can be performed manually based on capacity expansion results, or automated in for example PLEXOS's PASA stage or with the CORAL add-on to OPTGEN-SDDP;
- Production simulation and dispatch optimization in at least hourly resolution, with discrete unit commitment (MILP) and basic power flow functionality (DC load flow), as provided by SDDP, PLEXOS or PyPSA.

The output of economic simulation software needs to be interfaced to the electrical analysis tool. This can be done manually – via Excel, txt or CSV outputs – or in an automated fashion. Manual setup of topology and generation fleet scenarios in the electrical analysis software are the norm, while automated or semi-automated transfer of results is available for production simulation stages for some softwares. Examples are the PLEXOS-PSS/E interface, or the capability of PowerFactory to implement automated data imports using either Python scripts or the internal programming language DPL.Vice versa, grid topology information that is relevant to the optimization models is often input manually, but can in some cases also be imported automatically (PLEXOS-PSS/E combination).

The combination of SDDP and DIgSILENT PowerFactory used by COES is adequate for the analysis of production simulation scenarios and the subsequent electrical analysis. However, to create optimized future scenarios (which may constitute a best estimate of the actual future situation), the OPTGEN add-on is required in SDDP, which is available at relatively low cost. Moreover, detailed capacity adequacy assessments require CORAL, which usually comes with the OPTGEN-SDDP package. Moreover, COES' YUPANA tool could also be fed with future scenario data to perform daily dispatch optimization and test future scenarios.

The integration of variable renewable energy (into production simulation is well understood and well developed in most tools – vRE generate whenever they can according to their potential, and whenever they do not have to be curtailed for technical or economic reasons. Constraints and requirements can be implemented to reflect potential controllability of vRE and other characteristics of the power system.

However, vRE integration into long term generation capacity expansion planning is more challenging.[11] Time clustering, such as the use of weighted example days or weeks, is increasingly used instead of lower time resolution for long term optimizations to be able to fully reflect the variability of vRE, which might otherwise get lost. Moreover, capacity adequacy assessments are increasingly based on statistical approaches instead of the traditional deterministic approaches. All mentioned tools possess the capability to perform such analysis, however, careful parametrization of the relevant

[11] It is understood that actual generation capacity planning is not conducted by COES. Such exercises may however be useful to estimate future development, especially at the clear lack of national development plans.

functionalities based on a thorough understanding of the methodological principles is required. Great caution should be applied when using pre-parametrized functionality “out of the box” at it may yield non-optimal results.

BOX. Dominican Republic – Production Simulation Tool

The Dominican Republic conducted a study focused on production simulation of future scenarios, typically using MILP to fully represent all generation constraints. In this context, the following options were considered:

— Use of a commercial power system optimization software such as PLEXOS or Aurora, which is costly, but offers all functionality needed as well as the option to integrate long term investment planning;
— Use of an open source tool in conjunction with a commercial MILP solver engine (open source engines tend to not perform very well on larger MILP problems), which is cheaper but requires more software development effort as some functionalities may have to be implemented first;
— Use of the unit commitment, dispatch and SCOPF packages inside the grid simulation software (available for PowerFactory, unclear for other options), which may be sufficient but probably does not allow for the later integration of long term planning options.

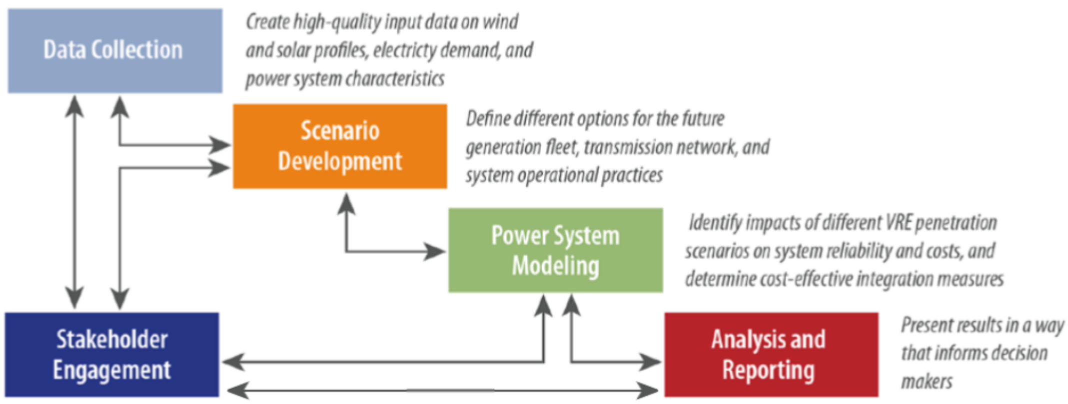
Cheaper commercial tools such as HOMER Energy are dedicated to small island systems, usually have no grid representation, and are unsuitable for the size of the Dominican power system.

The system operator (OC) finally decided to use their in-house generation planning tool in the study, a GAMS-based MILP optimization software in use since 2012. This tool fulfils the requirements mentioned above. It is structurally very similar to YUPANA, and while it has been designed to conduct day-ahead dispatch optimization, it could be used successfully to investigate example days and weeks of future high-RE scenarios. One advantage of using the actual day-ahead tool for such analysis is that shortcomings in the tool can be directly identified, and improvements can be made before the tool is actually used for real life dispatch planning.

2.3 Roles and Responsibilities

The level of stakeholder engagement varies based on the scope and purpose of the vRE integration (sub-)study and the responsible executing entity. Each country involves different actors with distinct responsibilities, necessitating coordination to harmonize their studies and duties for effective and complementary studies. vRE integration studies are crucial for stakeholders to grasp integration challenges and system impacts, enabling analysis and comparison of potential mitigation measures. A broad stakeholder base is essential to avoid overlooking critical aspects and to ensure a more realistic development of scenarios and interpretation of results, facilitating the development of acceptable roadmaps and measures. Stakeholder engagement is crucial component of studies across all the phases and tasks, as shown in **FIGURE 6**.

FIGURE 6 Main tasks in a grid integration study[12]



The typical stakeholders that should be involved in the integration studies are the following:

- The transmission system operator or the entity in charge of system operations, as they need to provide the bulk of the data and are typically the party most interested in the results;
- Government agencies such as a potential energy ministry, as they are usually involved in long-term energy planning and energy policy and may hence want to provide input to the study scenarios;
- The power system regulator as the central agency supervising the entire system.
- Electricity market operator (if available)
- Utilities (if distinct from the system operator)
- Transmission system owner and developer (if distinct from the system operator)
- vRE data providers
- Conventional and vRE plant owners, operators and developers
- Researchers and public advocates

[12] https://gtg.rmportal.net/Grid-Integration-Toolkit/grid-integration-guidebook/components-of-a-grid-integration-study

The stakeholders need to coordinate the approach and objectives of the study, as well as the scenarios and assumptions. Conflicts of interest need to be addressed early on, and compromises may have to be made especially with regard to scenario selection and renewable energy targets. To ensure stakeholder engagement and efficient development of the studies, formation of two sub-working-groups should be considered: Technical Review Committee (TRC) and Modelling Working Group (MWG). TRC is the high level group which does not involve in the day-to-day modelling activities, yet ensures technical rigor of the studies, as well as inclusion of policy and industry concerns. TRC is the steering body for determining the objectives, scenarios, reviewing the methodology, interpreting the modeling results and linking the outcome of the studies with policy. TRC ideally includes decision markers across the power sector (policy makers, operators, regulators, plant owners, technical experts etc.). MWG is the technical team that undertakes the data collection, model development, simulation and analysis efforts. MWG team should include modelling experts from the system operator and policy institutions. When MWG team should have a close collaboration and very often contact, TRC teams gatherings are less frequent, but as important.

For the SEIN integration studies, COES has a central role with relatively restricted jurisdiction for scenario and measure design. COES develops the mandatory transmission plan which considers the referential generations and transmission projects in a 10 year horizon. However, the transmission expansion study is an input for the Ministry of Energy and Mines (MINEM) to define final transmission expansion projects to be built for the next years. MINEM defines the national energy policies, regulates concessions for generation, transmission and distribution activities. Long-term planning is also responsibility of MINEM, including the development National Energy Policy. COES provides input to MINEM, if requested. Therefore MINEM could be considered as the most significant stakeholder for provision of the necessary scenario data and assess the capacity expansion study results for the next steps of the integration study.

Given COES's reliance on MINEM's involvement to advance integration studies, an alternative approach may be warranted if initial collaboration for study setup proves challenging. COES could initiate the first phase of the studies independently, utilizing internally developed scenarios and assumptions. Subsequently, they could engage MINEM to review the findings and, ideally, enhance collaboration for subsequent study iterations.

There are also two other actors whose support should be sought: Regulatory Agency for Investment in Energy and Mining (Osinergmin) and other private institutions. Osinergmin controls and enforces the compliance with legal and technical regulations. They are responsible for publishing the regulated tariffs and monitoring power purchase processes of the distribution companies. Unlike in most of the other system, the regulator does not have as strong jurisdiction over the transmission system and control of the system operator, MINEM contains these powers. Nevertheless, Osinergmin's involvement for scenario design and measures for increasing the vRE integration limit could be relevant.

With regard to private sector stakeholder engagement, this is usually limited to obtaining data from IPPs, industrial customers or other agents. Planning and planning studies are usually subject to government entities and the system operator (utility, TSO, ISO or RTO, which may or may not be a private company). It is however sensible to present the results to private sector stakeholders, as they may be able to provide constructive feedback. Whether this is done at the interim results stage, or later on, depends on the nature of the study and the involved stakeholders. Therefore, the private sector is a valuable stakeholder for taking into consideration the availability of the private energy sector to comply with the expansion scenarios, cost assumptions and resulting revenue projections for the sustainability of their investments.

The Ministry of Environment (MINAM), competition authority INDECOPI, and other third level stakeholders could review the studies for providing feedback, however their contributions are nor crucial for the completion of the studies.

3 Methodology

In this chapter, each sub-study for vRE integration is discussed in detail in terms of modelling, scenario selection and simulation. Sections shed light on the common problems and/or comprises for setting up vRE integration models, as well as conditions, parameters and advantages/disadvantages of troubleshooting options. In the final section, a high level of conclusion is provided on how to interpret and integrate results of different studies for increasing vRE system integration.

3.1 Preparatory Work

3.1.1 Data Requirements and Data Collection

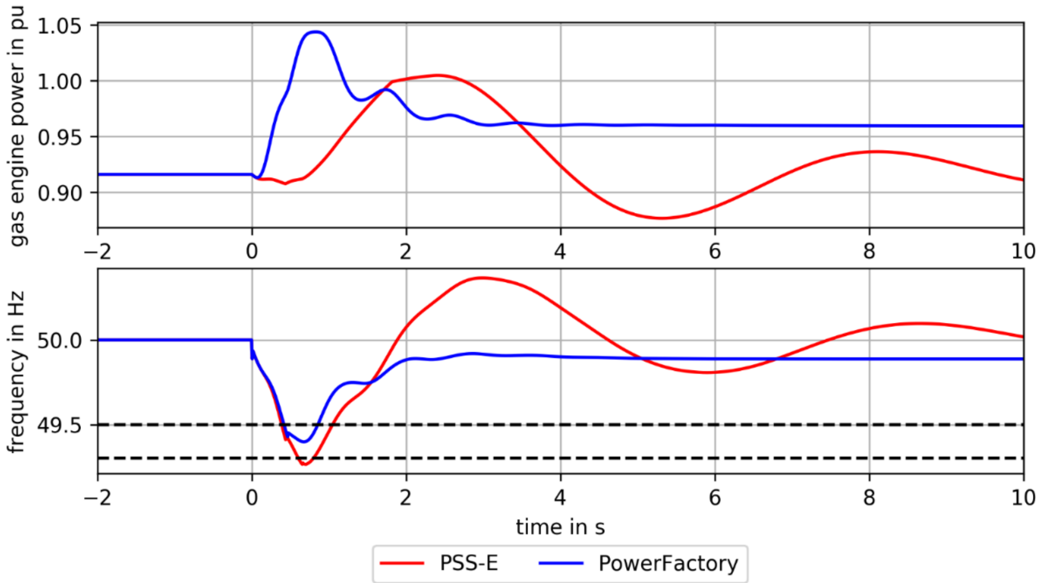
Input data, in the form of technical and economic information about the power system under analysis, is probably the most critical point of any grid integration study. Availability of data varies depending on which entities are involved in the study. Grid studies commissioned to outside consultants often suffer from either the non-availability of sufficiently detailed and accurate data, or from delays in data collection. A study conducted by the COES, which represents one of the focal entities of the Peruvian power system, may not experience these problems to the same extent as the COES should have access to most existing power system data already. However, some data items may simply not be available at all, and estimations or assumptions may be necessary.

The data requirements for each part of the study are provided in Appendix 1: Data Requirements. For consistency purposes, data sets, specifically cost and price projections, to be acquired externally should be preferred to be from the same entity. The following items are often the most critical ones subject to non-availability or inaccuracy:

- Economic data of privately owned generators (= all generators in open market systems) for dispatch / production simulation, which may have to be estimated from fuel cost and their bidding behaviour in the market;
- Technical flexibility of privately owned generators, as some of the technically available flexibility may be "hidden" behind economic motives (example: An IPP may have a generator with a technical minimum load of 30 % of rated output, but estimate that it is not economically reasonable to operate it below 60 %. They will then usually provide 60 % as the technical minimum, when it is really the economic minimum under present market conditions, which may of course change in the future.)
- Validated dynamic generator models for dynamic stability analysis are often not available. While grid codes today often require the delivery of certified manufacturer models at connection of a new generator, that type of data is usually not directly available for older units, and also often difficult to impossible to obtain. Use of standard models is common practice, but this results in reduced accuracy of results (**FIGURE 7**), and the models need to be parametrized appropriately

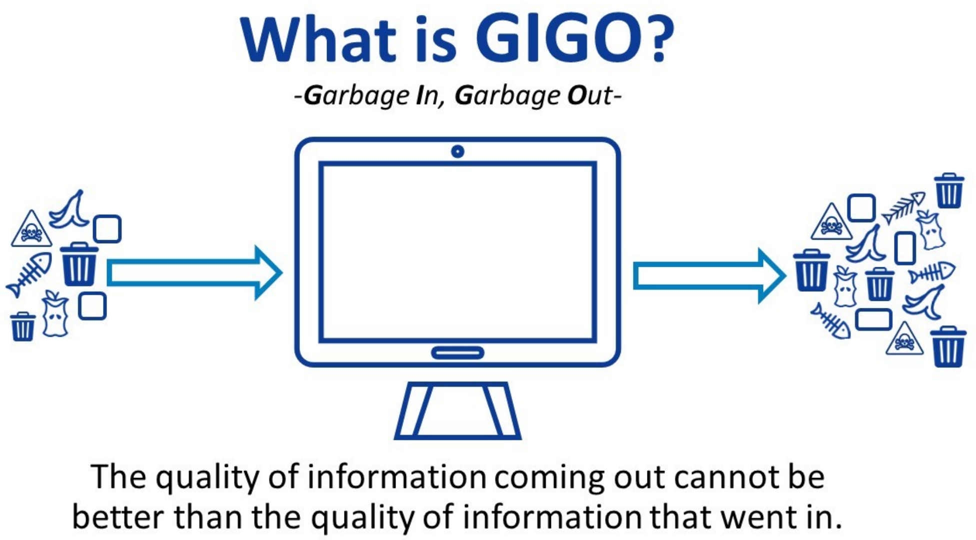
as well (to avoid issues like the one shown in **FIGURE 7**). Some amount of validation / cross checking of the entire system model can be used to increase accuracy.

FIGURE 7 Difference in response between standard dynamic generator models (gas engine genset) with standard parameters in PSS/E and PowerFactory.



In light of these issues – some of which cannot entirely be prevented – it is wise to not underestimate the time necessary for data collection and agreement on assumptions. Moreover, study results should be assessed critically, taking into account assumptions and simplifications, to avoid "garbage in, garbage out" issues (**FIGURE 8**). Some issues – such as imprecise cost information or forecasting accuracy – can be avoided by including appropriate sensitivity analysis in the methodology.

FIGURE 8 GIGO problem.



3.1.1.1 Time Horizon and Scenario Selection

A scenario represents a potential future configuration of the electric generation system. In grid integration studies, scenarios serve as a foundation for analysing how different future power generation options, including renewable energy, as well as transmission networks and operational practices, impact the cost, operation, and goals such as emissions reduction of the power system.

Creating scenarios is a crucial early step in grid integration studies, requiring input from the key stakeholders. Scenarios typically define system conditions over specific future target years. Depending on the scope and purpose of the integration (sub-)study, modelled time horizon and studies scenarios vary. Time horizon can be between one year and multiple decades, whereas the scenario parameters can involve socio-economic indicators or fault conditions.

Capacity expansion studies are conducted over a time horizon of more than a decade and typically include some form of least-cost or least-regret planning based on multiple framework scenarios and sensitivities. Scenarios are explorative and includes the key drivers of the power system development, such as policies, renewable targets, technological advancements, demand projections, etc.

Dispatch studies are usually conducted for example years, months, weeks or days selected from the expansion time horizon. These studies are conducted to improve operational planning and identify the need for grid expansion/reinforcements based on a number of development scenarios. Dispatch studies do not contain any investment planning, therefore generation fleet of each year is usually pre-determined as a result of the expansion study. There are multiple development scenarios studied to hedge planning uncertainty regarding speed of vRE development and demand growth. In the study, usually a key years over the time horizon are simulated to reduce the computational effort and capture the paradigm changes.

Network studies can be considered as verification steps to test the applicability of the expansion and dispatch studies. These are usually tested for the extreme case scenarios within previously studied time horizons and addressing smaller time intervals. Load flow studies can cover an entire year horizon in case linearized DC model is applied. However, in case AC flow simulations network studies are usually limited to a few time-steps and several minutes corresponding to periods of system stress. Network studies can also be conducted to evaluate the impact of individual new generation sites, often conducted by IPPs/EPCs as grid impact studies as part of the application and approval process, and represent the rest of the model as ceteris paribus.

It is typical to derive at least three scenarios in the integration studies:

- Status Quo Analysis: This scenario focusses on the current power system and usually used for the verification purposes to ensure a model is producing realistic results. The model results run on the status quo scenario are compared against the actual system operation results. This is important to test the modelling assumptions and build stakeholder confidence in the results of future year scenarios.
- Reference or Business-as-Usual (BAU) Scenario: This scenario assumes that operational practices and policies will maintain same in the future, existing plans are executed, and planning criteria remain the same.
- Advanced Scenario: This scenario sees much larger vRE integration in comparison to BAU scenario for the target year. There are usually multiple high renewable scenarios to reflect different pathways of vRE integration to the system (low wind-high solar, high wind-high solar, solar concentrated on a specific region, a large interconnector build-out etc.).

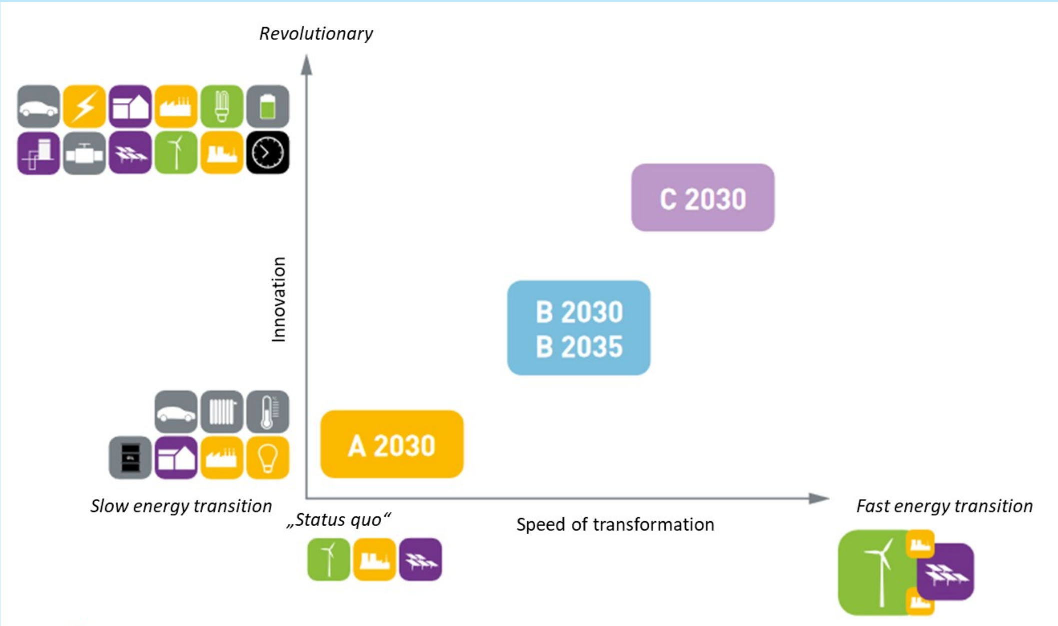
Other scenarios can be added as necessary. It is common to include for example different demand projections in each scenario (sub-scenarios), add different development pathways to an advanced scenario (potentially with focus on different technologies, such as separate high wind and high PV scenarios).

The inputs and assumptions which have been kept constant across the scenarios can also become subject of a sensitivity analysis. The following are the usual sensitivities explored for high renewable scenarios; changes to power system operation assumptions, changes to market operation assumptions, changes to infrastructure assumptions and changes to power system characteristic assumptions (demand profile, alternative fuel price trajectories etc.).

BOX. Germany – Scenario Development

A simple example of such scenario development is given in **FIGURE 9**, taken from the German grid development plan NEP 2030 (2016), with a study horizon of 15-20 years. It defines a business-as-usual scenario (Scenario A), an ambitious scenario with high vRE capacities and a high degree of sector coupling and enabling technologies deployed (Scenario C), and a "most likely" scenario in between (Scenario B). All scenarios are analysed for a time horizon of 15 years – in this case only for the single target year without any intermediate key years – and the "most likely" scenario is also analysed for a year 20 years out.

FIGURE 9 Scenarios used in the German network development plan (Netzentwicklungsplan) NEP 2030 (2017).[13]



3.1.2 Assumptions

The ideal methodology for studies 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

[13] https://www.netzentwicklungsplan.de/archiv/netzentwicklungsplaene-2030-2017

practice and, assumptions and simplifications make these studies feasible. However, it is important when conclusions are drawn to consider the consequences of the assumptions chosen.

Different types and volumes of data will be needed for the different integration (sub-)studies and each study will necessitate some assumptions to be able to deal with the problem size and complexity. For example, in a capacity expansion study, it is usually a common practice to represent the transmission system only based on net transfer capacities. Whereas, this assumption should be avoided for the load flow studies.

The basic set-up assumptions will have a crucial impact on the results of the study. Specifically for portfolio development, how the vRE is added to the system, i.e. replacing the existing fleet, added to the existing fleet or an optimized portfolio, has direct impact on the results. The following assumption areas usually play a significant role in the results:

— Unit commitment time-steps and whether dispatch can be changed as new information becomes available close to real-time
— Level of detail modelling the generation, e.g. multiple modes of operation
— Links to gas markets and heat demand
— Demand response possibilities
— Network characteristics and level of detail in representation (i.e. nodal, zonal, interconnection to the neighboring systems)
— Fuel and emission prices
— Technology costs and remunerations

Furthermore, there are assumptions underlying the input data set preparations and methodologies, such as capacity value calculations, generation profiling, demand aggregation, etc. These assumptions can have also direct and indirect impact on the study results.

It can be the case the assumptions made for a study became misleading in the future, which then might require refreshment of the study. It is advisable to identify the assumption which constitute great uncertainty or risk, and conduct a follow-up sensitivity analysis on them.

3.1.3 Analysis of Current Condition

vRE integration studies require data on not only the wind/PV power, but also other power plants, loads, and the transmission and/or distribution grid topology and characteristics. Understanding the current power system conditions is essential for both modeling and scenario development. This involves finding a good compromise in accurately reflecting these conditions. For verification purposes, models are typically run with a reference scenario that mirrors the current system, allowing results to be compared against historical data. This understanding provides a baseline for assessing the impact of integrating vRE and the effectiveness of respective measures.

It is crucial to develop assumptions, modeling frameworks, and improvement measures that are grounded in the current system. The existing system provides a baseline for evaluating technology, economics, and politics outcomes of the study inputs and outputs. Understanding the current energy landscape is essential for informed decision-making in model setups and ensures that renewable integration pathways are technically feasible, economically viable, environmentally sustainable, and socially acceptable.

3.1.4 Flexibility and Reserve Assessment

The expected main challenge for isolated or weakly interconnected systems is power system flexibility, which includes the key issue of frequency control and spinning reserves. Spinning reserves (primary and secondary) address flexibility needs in the very short term, between market gate closure and real-time operation. In traditional power systems without large vRE shares, reserve demand is usually calculated as follows:

— Primary reserve is dimensioned by security criteria, i.e. by the largest credible generation contingency;
— Secondary reserve is dimensioned by the expected load-generation imbalances between market gate closure and real time operation, often as a percentage of the load;
— There is often an additional requirement that enough secondary reserves need to be available to fully replace the primary reserves after activation, hence, the magnitude of secondary reserve dispatched always needs to be larger than that of the primary reserve.

The introduction of significant shares of vRE into a system will impact the demand for spinning reserve in the following ways:

— Short-term variability in the range of seconds to minutes, especially from large PV units, may increase the need for primary reserves. In most cases however, the maximum fluctuation is smaller than the largest credible contingency the reserves are based on, hence, primary reserve needs usually do not change.[14] This issue however needs to be evaluated when determining the maximum size of individual single site PV installations.
— Variability in the range of minutes, both from wind and PV installations, may increase the need for secondary reserves.

[14] Primary reserve requirements can however change at very high shares of non-synchronous vRE in the system as system inertia decreases and RoCoF increases. Primary reserves may then be required to react faster. This is however largely independent of vRE fluctuations.

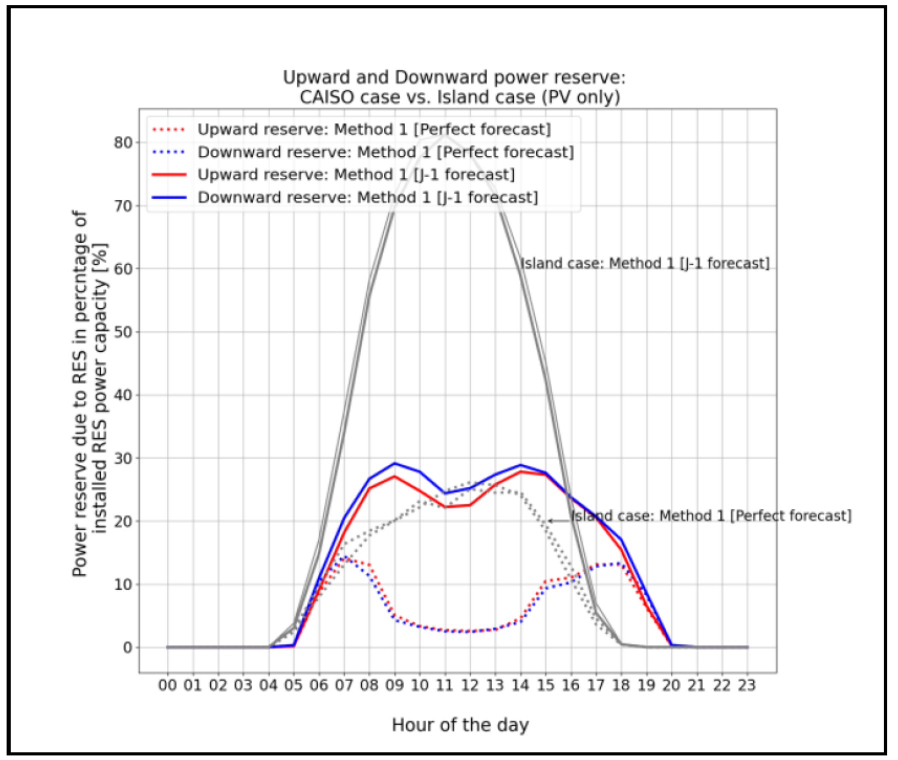
— Uncertainty – the potential difference between the vRE forecast at market gate closure and real-time operation – usually increases the need for secondary reserves.

The risk of insufficient reserve (i.e., the probability that the scheduled generation plus reserves will not be sufficient to supply the load) must be identified. If the risk is realized, power is imported from neighbouring balancing areas, if available. For example, a system operator can accept addressing 95% of the variations in net load (load minus wind/PV power) of the balancing area, based on existing operating practice of balancing area reliability metrics in use. In case the system does not have an interconnection, the inherent risk should correspond to an acceptable loss of load expectation due to insufficient operational reserves.

BOX. CAISO vs. Island System (Hawaii) – Reserve Requirement

The additional reserve demand is determined by the variability and uncertainty of vRE, as exemplarily shown in **FIGURE 10**.

FIGURE 10 PV reserve requirement depending on topology (island vs large system) and forecast (perfect vs persistence).[15]



Analysis of reserve demand, depending on VRE distribution and installed VRE capacities, needs to be performed before the actual simulations to correctly input the findings into the production simulation model. Constraints may eventually have to be refined in an iteration between production simulation and electrical analysis, but the basic parameters should be evaluated before the initial analysis. Key items are the following:

— Expected short-term fluctuations of individual generation sites and of the entire vRE portfolio, dependent on vRE availability and/or time of day. This analysis should be based on measured data from actual vRE installations. Portfolio fluctuation values are highly dependent on spatial distribution of vRE.
— Expected forecast uncertainty per technology (but for the entire wind resp. PV fleet in the system) between market gate closure and real-time operation. This value is highly dependent on the

[15] Source: F. Bourry and S. Miladinova, Artelia, "Evaluation of Advanced Reserve Sizing Methods Based on RE Variability and Uncertainty", 11th Solar & Storage Integration Workshop, Berlin 2021.

market lead time, i.e. a day-ahead market will see much higher vRE uncertainty than an intra-day market with a lead time of 15 or 60 minutes.

— Capturing larger possible forecast errors is important for estimation of the operating reserve requirements. As the "tails" of the probability density function (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. It is recommended to perform a sensitivity analysis to be able to estimate the impact of the used forecast error simulation on the final results.

From this analysis, the demand for spinning reserve – mainly secondary reserve – can be estimated as an input to production simulation. When splitting the reserves into different categories, it is essential not to double count sources of variability and uncertainty. If the amount of tertiary reserves increases, then they normally include also the increase of secondary reserves.

vRE may furthermore impact the requirements for the response speed of reserves, especially when operating at high system non-synchronous penetration (SNSP) levels. As synchronous generators are being replaced by inverter-based resources (IBR), system inertia is reduced, and the rate of change of frequency (RoCoF) at load-generation imbalances increases. Reserves with a faster response may hence be needed, this analysis is however part of the dynamic frequency stability analysis.

Beyond the short-term time domain, vRE may impose additional flexibility requirements on the system:

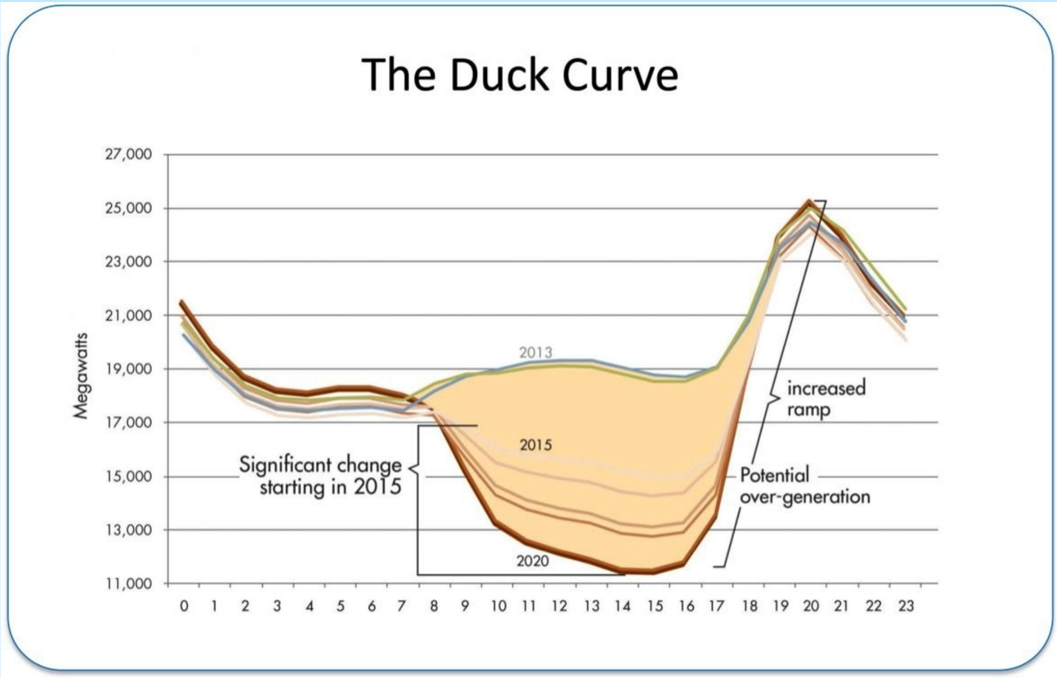
— The diurnal pattern of PV, which is fairly predictable, but leads to the "Duck Curve" (Figure 11) in which a great amount of additional flexibility may be required in the evening hours.
— Variability of wind in the range of hours up to a day, which is also fairly predictable (given adequate forecasting tools or providers) but requires reaction from conventional units that may have to be started up or shut down.

These issues will usually become apparent in production simulation results, it is however diligent to conduct some degree of pre-analysis to estimate whether the required flexibility is even available in the system. Careful modelling of flexibility parameters in the production simulation model is paramount in this regard.

BOX. CAISO – PV Penetration and Flexibility

Increasing levels of PV penetration leads to very steep load profile changes in California, leading to the famous "Duck Curve" phenomena shown in **FIGURE 11**.

FIGURE 11 The Duck Curve in California, as predicted in 2013.[16]



3.1.5 Role of Distributed Resources

While the current focus in the Peruvian system is on utility scale vRE installations, the situation can dramatically change very quickly if the right incentives are set by government, regulator or distribution companies. Especially rooftop PV can be rolled out extremely quickly if the conditions are right, and transmission system impact will be quite visible within a timespan of only a few years.

In many systems, PV connections particularly have a high share at the distribution level. When the penetration level is low, the integration issues are limited at the low voltage level with a focus on local impacts of the PV deployment, such as voltage issues and reduction in the hosting capacity. However, as the amount of distributed resources increase, their impact can be tangible on the transmission level and should be accounted for the planning and vRE integration studies.

[16] CAISO. Fast Facts: What the Duck Curve Tells us About Managing a Green Grid. http://www.caiso.com/Documents/FlexibleResourcesHelpRenewables_FastFacts.pdf.

In terms of modelling and scenario building, distributed PV and wind generators do not need to be treated differently for grid integration. For the transmission system studies, distribution grid connected vRE should be aggregated at substation level and the most convenient representation of this aggregation is in terms of net load to be able to monitor the impact of the reverse flows. One of the challenges and important aspects of including these aggregated nodes to be able to model the profile of the net load per sub-station, which usually requires long-term measurement campaigns and monitoring of trends for behavioural change (i.e. batteries, demand response, EVs, etc.).

Impact of distributed vRE penetration for system modelling and integration challenges can be categorized in three levels:

- First level, when there is still uni-directional power flow and vRE penetration is low and at few distribution grids. vREs play a passive role and the maximum active power feed-in is provided by the generators. There is not much impact to be expected on the grid beyond some voltage issues at the distribution grid.
- Second level, when bi-directional power flow starts in a few distribution grids. Depending on the local concentration, distributed vREs might lead to congestions in the transmission grid which should then me represented in the models depending on the severity. Whereas, the distribution grid is challenged with the decreasing hosting capacity (which is not a concern for the scope of modelling for the transmission system).
- Third level, when there is a high share of distributed vRE generation in the system. This level marks that the transmission system operator and planning should already account for possible voltage stability and balancing issues. Similar to aggregated model reflecting net load for power flow simulation, a reactive power net contribution based on the aggregated profile can be modelled for studying the voltage stability per substation or simply an average power factor can be preferred. Secondly, inverter based resources provide less short circuit current in comparison to the synchronous assets. In case of a very large distributed vRE penetration, there might be an impact on the transmission level short circuit current provision. In that case, there might be a need for re-coordination of protection settings, as well as ancillary service provision from the distributed assets and inclusion of these new parameters in the system studies.

In summary, to account for the distributed assets in the integration studies focused on transmission system, there are two parameters; very (area) concentrated generation and large amounts of generation. In such systems, the need arises for communication and control of many of these small assets, which is clearly much harder than managing large assets due to the infrastructural and organizational reasons. However, for the transmission system integration studies of Peru, such high level of penetration should not be a matter of concern for the next foreseeable future, unless there is a drastic policy change.

3.2 Scenarios and Capacity Expansion Studies

Every study starts with a set-up stage in which the shape of the future power system to be analysed is defined. This includes the definition of the (initial) grid topology, the generation fleet and the expected demand growth. Future scenarios can be developed either by manual curation, typically from previously existing plans or projections, or through a capacity expansion optimization using a dedicated software tool such as OPTGEN-SDDP, PLEXOS or PyPSA. Capacity expansion models seek to optimize generation and transmission system investment and operational costs over a long time period and provide an outlook on how the power system might evolve overtime. The study seeks answers to *How much to invest?, What to build?, How many units to build?, Where to build?, When to build?*. Even if no dedicated capacity expansion planning is conducted in a system – as it is the case in most open market systems where generation capacity is added by private investors based on market condition – such calculations can be very useful to develop future scenarios as a best estimate on how the system might develop.

QUICK SUMMARY: SCENARIOS AND CAPACITY EXPANSION

Inputs: Government plans and targets, market development forecasts, demand projection, current grid topology and generation fleet, cost structure (CAPEX and OPEX) of existing and potential future generation technologies

Outputs: Initial* or optimized grid topology and generation fleet for one or multiple future scenarios, high level estimations of power system economics.

Direct use of results: Inform and support government planners and/or market parties about the power system implications of their long term plans at very high level.

Software and modelling requirements: Manually curated scenarios have no specific software requirements. Optimized future scenarios require a cost model in a linear or mixed-integer optimization software such as OPTGEN-SDDP, PLEXOS or PyPSA

*potentially subject to revision if issues are found in subsequent stages

Technical and economic constraints in the system in questions, such as the market structure, the operational regime and the requirements for ancillary services also need to be analysed at this point. Updates or changes in any of the mentioned fields can be integrated here if already expected, or at a later stage as an output of the study.

Depending on the scope of the study, capacity adequacy analysis can be incorporated to the expansion simulations, or conducted on pre-made scenarios. In the adequacy assessment, capacity value of different generation types are estimated which represents the reliability to meet the demand. Adequacy analysis is specifically important for the high vRE scenarios, as the capacity value of the RE technologies are typically lower than the conventional generators due to the intermittency. Adequacy analysis can be considered as a pre-screening step. The result of the capacity expansion or scenario building studies are filtered through the capacity adequacy assessment before being fed into the dispatch studies. In case of failing, the generation portfolio of the expansion should be revised, which can be an iterative process.

Sections 3.2.1 through 3.2.3 explain the principles of expansion planning using optimization tools, while section 3.2.4 focuses on simplified approaches and manual curation of scenarios.

3.2.1 Modelling and Validation

Selection of key technical constraints and using appropriate geospatial and temporal resolutions are the central concerns in improving the accuracy of the analysis and demonstrating the robustness of the modeling for capacity expansion.

Modelling horizon for the capacity expansion studies are usually mid-to long term, e.g. 20-50 years. In these studies, system dispatch is modelled in a reduced form with the selection of representative days or weeks in a year. Along the horizon, each year should have representation of the seasonal constraints and intraday variability. High spatial resolution (e.g. 10-km cells for solar and 1-km cells for wind) vRE resource data is important to capture spatial variability of wind and solar resources and reflect corresponding grid integration impacts. As the resolution of the data gets finer, there is better accuracy in estimating the resources. However, higher resolution has the tradeoff of requiring higher computing power to deal with deal with the data and volve the model, and increased effort to analyze the output. In general, geographic resolution in the study should, at minimum, reflect the scale at which decisions are made (for example with multiple control areas, multiple states or jurisdictions). Spatial data sets can be bought from a vendor or developed in-house with measurements and prediction models. In either case, the datasets should be validated and calibrated against actual historic meteorological data.

There can be three different approaches to the modelling; (1) applying system specific data, operational and economic parameters over an existing capacity expansion model, (2) adapting an existing model to incorporate vRE characteristics, such as capacity value, intra-day variability, geographic diversity, (3) building a new model reflecting all the unique characteristics of vRE resources and power system. Effort and customization increases from the first to the last option.

Typical grid operation constraints and rules which are represented in the capacity expansion model are as follows:

- Load constraint: Generation should match the load at all times. At each time slice (of all representative days), model ensures that generation satisfies the load locally or via using the transmission.
- Reserve margin: There is a certain room in form of firm capacity for ramp-up available to the system operator in case the peak load exceeds the expectations by a certain percentage. Therefore the available capacity should be a certain percentage over the peak load to account for the reserve margin.
- Operating reserves: Depending on the operating reserve types of the individual system under investigation, some corresponding constraints can be involved. Given certain technologies have certain start-up times, ramp rates, certain reserves are usually sourced by a specific type of technology. For example, spinning reserve requirement can be expressed in proportion to the demand.

Both wind and solar generation might display a generation outcome different than expected both driven by intermittency and operational limitations to transfer the generated power. To account for reliability and contribution of vRE to support generation during the times of peak demand, contribution factors can be integrated into the model. With some statistical approach, a certain percentile can be identified per vRE technology to contribute to the peak demand. These contribution factors can be used in the capacity expansion model to estimate vRE contribution for meeting the reserve margins.

Retirement of the under-utilized or old (>50 years) generation assets should be enabled in the model to further reduce the system costs. Keeping such units in service increase total maintenance and operational costs of the system. Retirement decisions can be optimized linearly to allow partial retirement, and a rounding method can be applied to decide whether this “partial” retirement should refer to the entire generator.

Due to coarseness of the capacity expansion model, unit commitments can usually not be modelled accurately. To avoid unreasonable duty cycles, constraints, such as minimum capacity factor or minimum operating level, can be introduced to the baseload units. Furthermore, inter-temporal constraints should be introduced to reflect the energy limits through use of capacity factor constraints or generic constraints. For example, reservoir hydro generation is influenced by seasonal water precipitation, as well as the decisions to use the existing water in the dam throughout the year. A recycle constraint ensuring the same water storage level at the end of simulation period can be introduced for reservoir hydro assets.

BOX. AEMO – Capacity Expansion Model

There are two variants of the capacity expansion models that Australian system operator conducts: Single Stage Long-Term (SSLT) model and Detailed Long-Term (DLT) model. As Australia has a very strong reliance on the gas generators in the fuel mix and has large domestic gas resources, SSLT model co-optimizes gas and electricity systems and displays the interdependencies. SSLT models the longest time horizon and provides input to DLT on projected gas generator retirements and developments. DLT models the power system isolated from the gas market and optimizes generation and transmission capacity expansions. DLT model slices the horizon into multi-step and provides more granular capacity outlook approach in comparison to SSLT.

In **TABLE 2**, summary of the Energy Systems Integration Group workshop held in 2022 for evaluating the modelling practices for capacity expansion studies is presented.

TABLE 2 Good capacity expansion modelling practices by ESIG[17]

CATEGORY	GOOD	BETTER	BEST
Geographic Scope	Pre-defined sub-regions with minimal customization	Pre-defined sub-regions which can be aggregated or decomposed	Nodal representation of the regions available.
Spatial and Temporal Scope	Single weather year for vRE profiles Aggregated generation profiles	Multiple weather years Small aggregations / individual siting profiles	Many decades of weather year to capture broad variations in vRE Diverse resource siting profile Transmission requirements for vRE incorporated
Model Scope and Integration	Output requires processing to be used in other models	Output can be directly processed in dispatch and adequacy models	Dispatch, adequacy and load flow models can be integrated with the modelling process in an iterative fashion
Co-optimization	Energy Capacity	Energy Capacity Transmission Ancillary Service	Includes “better” options Can include scarcity signals Can include stochastic risk analysis

[17] https://www.esig.energy/capacity-expansion-modeling-for-transmission-planning/

		Fuel Supply Market and env. policies	
Capacity Adequacy	Reserve margin adequacy Basic capacity value	Reserve margin adequacy Complex capacity value calculation including interaction with enabling technologies (e.g. BESS)	Adequacy screening and feedback iteration Includes outage and availability for all resource types (weather, fuel, etc.)
Energy Adequacy and Chronological Dispatch	Load duration curve with limited or no linking between intervals and chronology	24h chronological dispatch over representative time slices Time series sampling and clustering reflecting peaks and load-renewable relation	8760h chronological dispatch Representative time-slices with 24h dispatch with stochastic sampling Allows energy-only resource build-out
Transmission Representation	Transport model Defines transfer limits between zones	Transport model Different voltage or transmission types Losses included	Transport or nodal model that can utilize DC power flow Granular model with components Sub-zonal transmission needs identifiable
Transmission Investment	Transmission investment needs are not selected by the model, but can be evaluated via sensitivity analysis	Co-optimized with resource expansion in each zone CAPEX used Distinction between AC/DC lines and voltages based on cost and losses only	Multiple selection criteria used for investment decision Investment options are available at granular system level

3.2.2 Scenario Selection

The further an energy scenario looks into the future, the more uncertainty is introduced. Single scenarios are rarely helpful, but must be combined with, and compared against, diverse alternatives as part of a larger strategic exercise.

Capacity expansion studies are well-suited to test the possible outcomes of different policies in the long-term. Policy indications can be woven into the scenarios, such as carbon policies (price, covered sources, total vs covered emissions, compliance period etc.). For the capacity expansion studies, key inputs are listed in the Appendix, among which cost of new builds, cost of retirements, fixed and variable operating costs are the main parameters. The scenarios can be constructed with tunning of the inputs listed, however to be able to effectively compare different scenarios to each other, it is preferrable to keep most of the parameters constant. There are also international examples keeping the scenarios intentionally diverse, reflecting a range of current and future trends in energy consumption, consumer energy investments, and technology costs. Scenarios are traditionally built around the demand growth and key sectoral uncertainties or policies, for example renewable energy targets, offshore wind generation, coal retirement, exploitation of gas reserves, electrification of heating, etc. For construction of realistic scenarios, stakeholder engagement is a requirement.

Making a prediction of what the electricity demand will be in the future is a multi-layered task. Demand projections should not overlook the peaking patterns and impact of the temperature. A historical relationship analysis per demand sector can be undertaken and total demand projections can be found after the projections are completed for each sector. Demand projections should have a baseline, represent exogenous and endogenous factors, elasticity, as well as energy efficiency. These projections are usually based on a multiple linear regression model which involves economic parameters with a particular attention to the effects of new, large energy users.

BOX. AEMO – Scenario Development

TABLE 3 summarizes the key parameters for each of the scenarios, AEMO uses for capacity expansion. AEMO is one of the examples of the system operators preferring very diverse scenario sets strongly driven by economic parameters. In each of the scenarios, national targets for emission reduction is achieved, however with different means and extents

TABLE 3 Parameter selection of AEMO for capacity expansion model scenarios[18]

Parameter	*Green Energy Exports*	*Step Change*	*Progressive Change*
National decarbonisation target	At least 43% emissions reduction by 2030. Net zero by 2050	At least 43% emissions reduction by 2030. Net zero by 2050	At least 43% emissions reduction by 2030. Net zero by 2050
Global economic growth and policy coordination	High economic growth, stronger coordination	Moderate economic growth, stronger coordination	Slower economic growth, lesser coordination
Australian economic and demographic drivers	Higher (partly driven by green energy)	Moderate	Lower
CER uptake (batteries, PV and EVs)	Higher	High	Lower
Consumer engagement such as VPP and DSP uptake	Higher	High (VPP) and Moderate (DSP)	Lower
Energy efficiency	Higher	Moderate	Lower
Hydrogen use	Faster cost reduction. High production for domestic and export use	Medium-Low production for domestic use, with minimal export hydrogen.	Low production for domestic use, with no export hydrogen.
Hydrogen blending in gas distribution network[A]	Up to 10%	Up to 10%	Up to 10%
Biomethane/ synthetic methane	Allowed, but no specific targets to introduce it	Allowed, but no specific targets to introduce it	Allowed, but no specific targets to introduce it
Supply chain barriers	Less challenging	Moderate	More challenging
Global/domestic temperature settings and outcomes[B]	Applies Representative Concentration Pathway (RCP) 1.9 where relevant (~ 1.5°C)	Applies RCP 2.6 where relevant (~ 1.8°C)	Applies RCP 4.5 where relevant (~ 2.6°C)
IEA 2021 World Energy Outlook scenario	Net Zero Emissions (NZE)	Sustainable Development Scenario (SDS)	Stated Policies Scenario (STEPS)

BOX. EirGrid – Scenario Development

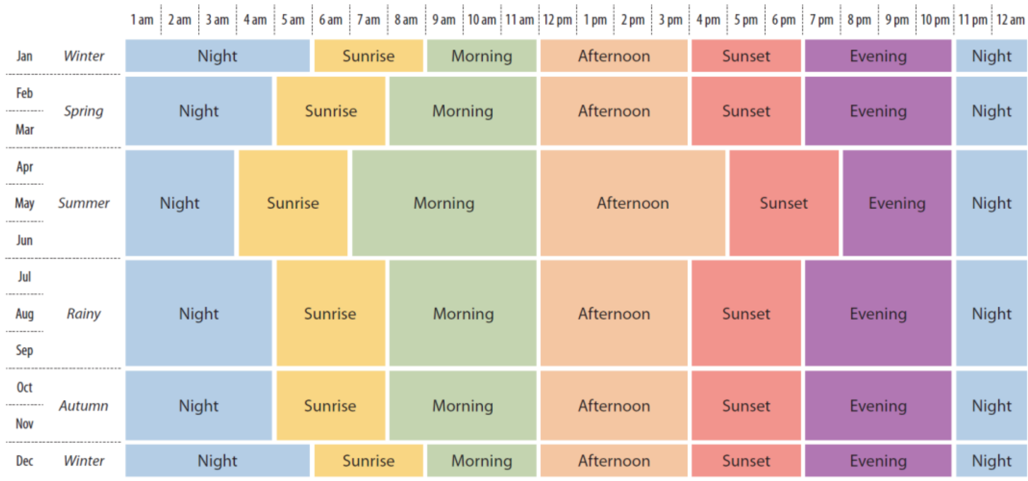
Ireland has a relatively small system with limited industrial load, however constituting about 50% of the entire demand . For Ireland, a key driver of electricity demand is the data centers which keep growing in number across the country. EirGrid engages with the data centers to examine load profiles and amounts of the new projects in the connection or development process. To include such projects in the future demand projections, Eirgrid takes into account of various factors including other completed projects of respective company, financial closure, planning permissions, etc. The differences contribute to forming various demand scenarios. Nevertheless, data centers are not the only drivers shaping the scenarios.

[18] https://aemo.com.au/-/media/files/major-publications/isp/2023/2023-inputs-assumptions-and-scenarios-report.pdf

3.2.3 Simulation

Increased temporal resolution increases representation of potential contribution and reliability of vRE resources and changing patterns in the demand. For example, a NREL study for India used 35 time-slices per year to simulate important temporal relationships in the power system, shown in **FIGURE 12**. Sun-set time-slice for example can capture ramping down solar generation, when the demand is peaking. Other approaches include using representative chronological periods and using randomly sampled periods.

FIGURE 12 Example time-slices for a capacity expansion simulation[19]



Due to the large problems size, some simplifications has to be undertaken usually. These may include:

— Aggregating demand into representative clusters (as explained previously)
— Simplifying the network representation (e.g. using static Net Transfer Capacity (NTC) limits for the interconnectors, known as Transport Model)
— Breaking the optimization into smaller steps
— Relaxing convergence thresholds

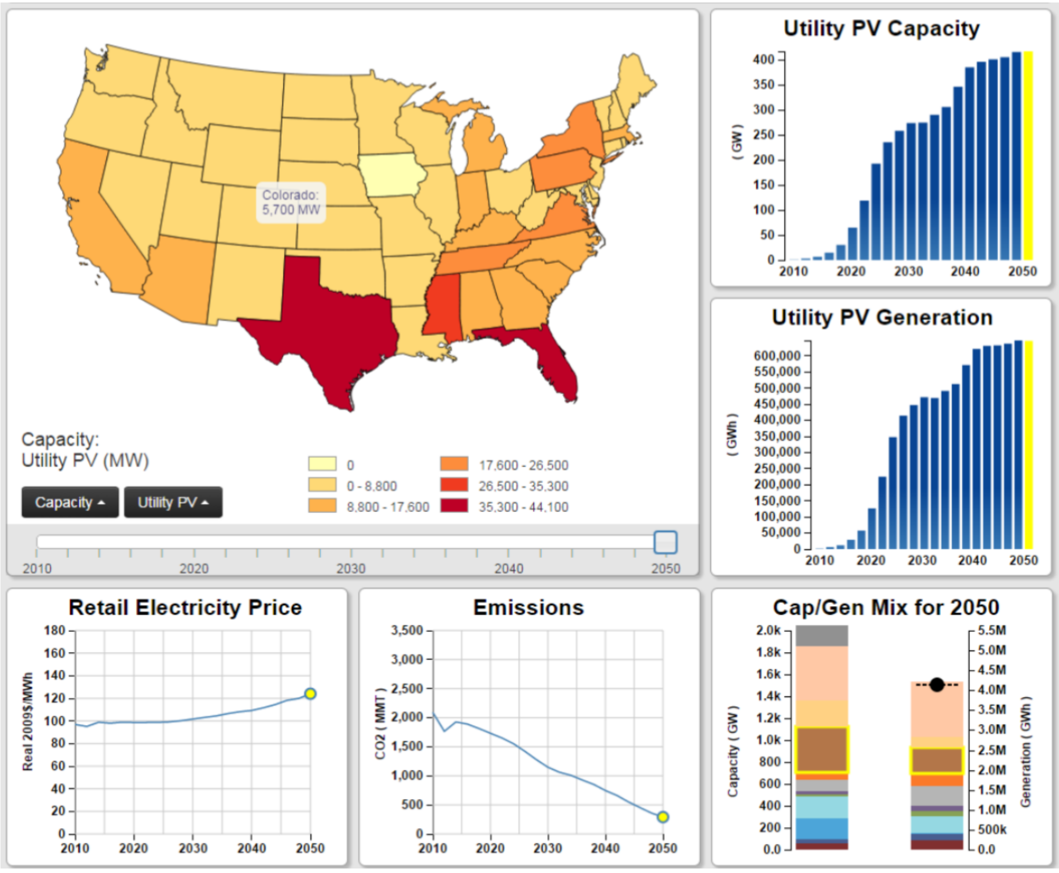
For linear build-outs for transmission and generation capacity expansion, there are two methods available; discrete and continuous sizing. The discrete method reflects the blocky nature of construction with more accurate cost estimation, however requiring more computations power due to mixed integer programming demands. Continuous sizing allows incremental builds which are unrealistic for conventional generation (e.g. 31.4MW CCGT) with less certain costs. However, this decreases the computational overhead. To balance accuracy and practicality, continuous sizing

[19] https://www.nrel.gov/docs/fy20osti/76153.pdf

method can be applied in the model and the results can be manually adjusted to ensure realistic project sizes and costs. For interconnectors and conventional generators, the results referring to minimum 50% of a notional size should be validated, whereas renewable generation can remain scalable to any size.

Typical outputs of a capacity expansion study are annual generation, generation and transmission capacity builds and retirements (cost effective and location specific), emissions, fuel consumption and power prices. **FIGURE 13** shows results of a capacity expansion model for USA identifying the least-cost mix of power system resources.

FIGURE 13 Example capacity expansion model result, specific screen for the utility scale PV[20]



3.2.4 Simplified Approaches

Especially for near-future analysis or for the first iteration of future scenario, it may be neither feasible nor necessary to run a full capacity optimization exercise. For vRE integration studies, what is needed

[20] https://scenarioviewer.nrel.gov/

is a somewhat realistic projection of the future topology of the power system – this can of course be the output of a capacity optimization run, but other sources can also be utilized which are listed in the following:

- If a capacity expansion simulation has been conducted in the past and the results are deemed to be realistic, it can obviously be used as input data to subsequent study stages.
- If plans for future investments in generation and transmission already exist, it is advisable to use such plans and manually curate scenarios for future years on that basis. Sensitivity analysis can then be conducted to evaluate the impact of potential changes to the plan.
- Especially for near-future scenarios, it is often a good idea to evaluate the requests for connection of new generation capacity, or the interest expressed by investors, and manually curate scenarios out of that. Sub-scenarios may be created by distinguishing investments into "committed", "likely" and "potential" brackets or similar categorizations.
- Extreme far-future scenarios, such as for example "100 % RE by 2050", may be based on relatively simple assumptions.
- Simple scenarios, such as "what if 50% of installed generation capacity were wind power" can be generated relatively easily. While they usually lack realistic implementation plans, such scenarios can be very useful in exploring the limits and boundaries of a system and also investigate the best connection points in the follow-up study stages.

3.3 Dispatch Simulation

After future scenarios have been defined, some form of dispatch analysis has to be conducted. Detailed analysis of the system in future scenarios requires knowledge of how the system would operate under these conditions. In the simplest case, only a few operational scenarios have to be developed for electrical analysis, which can be done manually based on operational data and expected changes in the system. However, especially for far-future or more ambitious high-vRE scenarios, it is usually preferred to run more detailed dispatch simulation (also often called production simulation) in hourly or sub-hourly resolution for example days, weeks or entire years. Operational cases for electrical analysis can easily be extracted from such simulation results, and more detailed techno-economic analysis can (and should) also be conducted. Knowledge of the hourly unit commitment and dispatch allows to investigate the techno-economic impact of increased vRE shares, including the analysis of parameters such as instantaneous vRE penetration, production cost, curtailment and spinning reserves. A linearized (DC) grid model can be integrated in most production simulation software tools (security constrained unit commitment, SCUC, and security constrained optimal power flow, SCOPF) which allows additional analysis of congestion and congestion management (redispatch).

QUICK SUMMARY: DISPATCH ANALYSIS

Inputs: Grid topology and generation fleet for one or multiple future scenarios, merit order table and historical operational data for simplified analysis, detailed techno-economic data of all generators, load and vRE time series as well as operational constraints for detailed analysis.

Outputs: Estimated dispatch for key situations for simplified analysis, hourly or sub-hourly security constrained dispatch including production cost results, curtailment, ancillary services, congestion and congestion management for detailed production simulation.

Direct use of results: Detailed analysis results show the techno-economic impact of additional vRE and delivers detailed economic data. This can be used to show the actual operational implications of a scenario or plan to government planners or market parties. If a grid model is included, analysis of congestion allows to identify potential needs for transmission investments.

Software and modelling requirements: Simplified analysis can be done in an Excel sheet. Detailed dispatch simulation requires a mixed integer optimization tool such as SDDP or PLEXOS, and a techno-economic base (market) model which has been benchmarked against historic operational data.

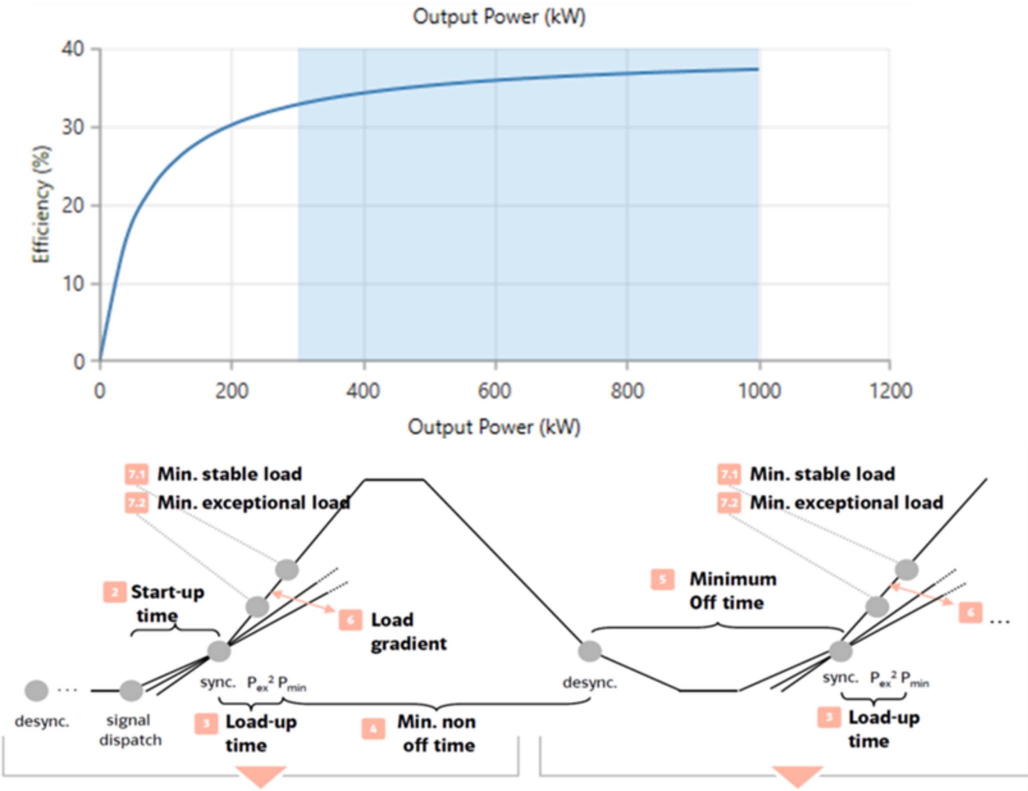
3.3.1 Modelling and Validation

3.3.1.1 Base Model

The first step towards an encompassing techno-economic system model is the setup of a base model. This model contains the following:

- Models of existing and planned generators based on their technical data (flexibility parameters, efficiency curve, maintenance schedule, see Figure 14) and raw economic data (i.e. fuel cost, VO&M and FO&M), potentially including estimates for IPP generators;
- Hourly time series for renewable resources (wind speed, insolation, hydro inflows, biomass availability);
- Linearized (DC) transmission system model;
- Load time series and load distribution to transmission substations;
- Load projection (demand growth).

FIGURE 14 Efficiency curve and flexibility parameters of a conventional generator.[21]



Running production simulation with this model yields a "perfect world" result in which all generators are dispatched to achieve the overall lowest generation cost according to their technical capabilities and economic parameters. This result will be somewhat unrealistic due to the fact that some technical constraints, such as ancillary services, uncertainty of vRE and system stability constraints, and economic constraints such as take-or-pay Power Purchase Agreements (PPA), are neglected. The model is however the basis of all further modelling, and the result can be used as a benchmark for the more detailed economic results, as it is the theoretically achievable optimum.

3.3.1.2 Modelling of PPAs and Dispatch Constraints

To achieve more realistic results, additional real-life dispatch constraints need to be modelled in detail, which include both technical and economic constraints. These include, but are not limited to:

— Modelling of PPAs, including prices, minimum capacity factors, lead times and minimum loads (which may all deviate from the base model values);

[21] Source: Top – Energynautics, bottom – E.on Energy Research Center, no longer available online.

- Modelling of reserves (based on both contingency criteria and expected fluctuations) and restrictions on reserve allocation;
- Modelling of the currently used hydro dispatch strategy;
- Modelling of uncertainty and dispatch lead times (day-ahead and/or intra-day);
- Integration of security constraints, such as (n-1) or (n-2) constraints in the security constrained optimal power flow (SCOPF).

3.3.1.3 Benchmarking

The model needs to be set up based on the configuration of a past year for which real operational data is available. It needs to be benchmarked against those and fine-tuned to achieve realistic results.

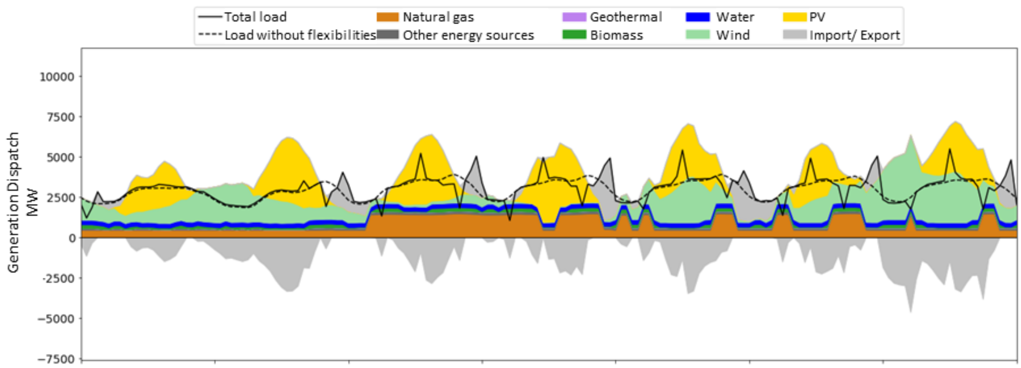
3.3.2 Future Scenarios

Future scenarios are analysed by modifying demand, generation and grid structure to reflect a specific point in the future according to some previously compiled scenario. This could either be exogenous inputs from pre-existing plans (potentially from other entities), or inputs from previous simulation stages. The latter can for example be implemented using PLEXOS by running subsequent long term, medium term and short term optimization stages, or in OPTGEN-SDDP by optimizing the generation fleet in OPTGEN and then performing production simulation in SDDP (potentially with capacity adequacy analysis in between, which might trigger another OPTGEN iteration).

Production simulation will be executed in the simulation tool of choice, preferably using mixed integer optimization (MILP) and a linearized security-constrained optimal power flow. Simulations will be executed for whole years in hourly resolution, and for key example days in sub-hourly resolution to adequately quantify the need for short term flexibility and the impact of vRE fluctuations.

Optimization results include the active power output, fuel consumption and generation cost of each generating unit for all hours of the years, as well as the overall generation cost and the cost of spinning reserves. Results can be graphically displayed for quick overview (see **FIGURE 15**).

FIGURE 15 Graphic display of production simulation result in PyPSA from a previous Energynautics project.

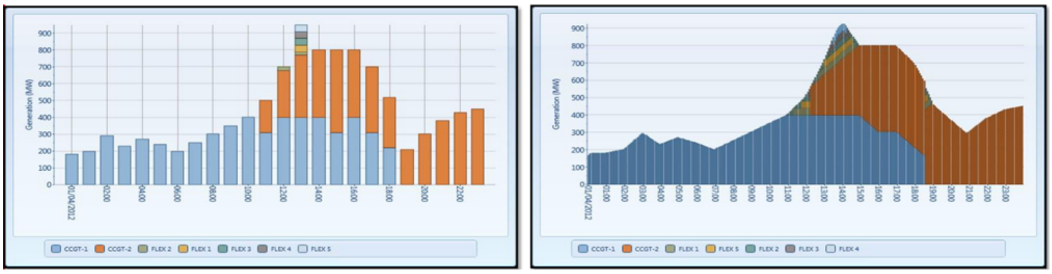


3.3.3 Simulation and Time Resolution

Dispatch simulation is typically done in hourly steps in the first iteration. Depending on the time horizon of the study, it may neither be feasible nor necessary to run that type of simulation across the entire time horizon. It is advisable to focus on a number of key years, or even key days, weeks or months, depending on load, hydro and vRE patterns that dominate the system. A typical approach would be to select 2-4 example years for a study spanning two decades – this could be either based on fixed time steps (key year every 5 years) or based on the years with the greatest expected paradigm changes in the scenarios. Alternatively, one typical summer and one winter week could be simulated for each year. The former approach yields more detailed results including full costs for the key years, while the latter makes the calculation of annual costs less precise but yields results for every year along the way.

Hourly resolution is typically enough to determine overall generation patterns and synthesize operational situations for analysis in electrical studies. However, some flexibility constraints and issues, especially considering the interaction between vRE and the conventional fleet, may be lost as they take place in the sub-hourly range. Available flexibility may hence be overestimated, and the cost of tapping that flexibility underestimated. Given a detailed enough model, it is hence recommended to run at least some example days per year in sub-hourly resolution (down to 5 or 10 minutes) to quantify the potential error and analyze sub-hourly flexibility in more detail (see **FIGURE 16** for an example).

FIGURE 16 Dispatch simulation results in hourly (left) and 5 minute resolution (right), with obvious differences in the operation patterns of individual generators. [22]



3.3.4 Security Constrained Optimal Power Flow Results

A security-constrained optimal power flow (SCOPF) inside the production simulations already respects some contingency security criteria, such as the provision of an adequate amount of spinning reserves, and (n-x) security grid wise. In this regard, it is a simplified – because linearized – version of the steady state contingency analysis described in section 3.4.3.2. Because it inherently neglects voltage control and reactive power, it is only an approximation and will have to be fine-tuned with the full AC results later on.

The final SCOPF results also indicate which lines or grid areas are frequently congested, and allow for cost benefit analysis of grid expansion and reinforcement options.

3.3.5 Simplified Approaches

Especially if electrical analysis is the focus of a study – for example, if stability analysis for a number of high-vRE penetration scenarios is to be analyzed – production simulation may simply serve as a means to produce operational scenarios with realistic generator dispatch for single hours. If a well-developed production simulation model including the relevant scenarios is at hand, it is usually easiest to pull operational situations out of the results from it. However, if this is not the case, or electrical analysis needs to be performed on a high number of scenarios, simpler approaches may be necessary and sufficient.

The easiest way to calculate a dispatch situation for a single hour is to work with a merit order table, which shows which generators would usually be committed for a certain net load situation (demand minus vRE generation). However, additional information on potential out of merit order dispatch for reserves, inertia constraints or grid congestions is required. This information is typically available to the grid operator, and can also be updated iteratively based on the results of the electrical analysis.

[22] Source: Energy Exemplar.

Some electrical analysis software sites such as DIgSILENT PowerFactory offer linear optimal power flow (OPF) functionality, which requires manual unit commitment for each situation and the calculates the optimum dispatch including reserve and grid constraints, or even full MILP SCOPF tools. The latter are usually not well developed enough to feasibly run full production simulation for entire years, but can be used to compute SCUC and SCOPF for individual hours or short time frames.

3.4 Load Flow Studies

While some estimations of system stability and power flows in the grid can be made based on dispatch simulation results, especially if a grid model is included, more detailed electrical analysis using non-linearized models is required to obtain full details on the actual electrical condition of the grid. For this purpose, critical situations are typically pulled out of the dispatch results and loaded in to a dedicated power system analysis software. Steady state power flow analysis is then conducted for these situations, usually including contingency analysis, to obtain the actual active and reactive power flows on all lines and transformers as well as the bus voltages on all transmission substations. These values need to be within the allowed operational ranges for normal operation and under contingency conditions. This analysis can then be followed up by further steady state analysis such as short circuit and protection analysis to make sure that short circuit levels remain acceptable and reliably trigger protection in fault cases.

QUICK SUMMARY: LOAD FLOW STUDIES

Inputs: Transmission grid model, load and generation dispatch for key operational situations.

Outputs: Asset loading, voltage at all substations (all for normal and contingency conditions)

Direct use of results: Results either show the feasibility of scenario and dispatch, or allow for more targeted analysis of investment needs or changes in scenario. Voltage issues found in this type of analysis may also be used to improve operational regimes or revise grid codes.

Software and modelling requirements: AC load flow model of the entire transmission system in a dedicated grid simulation software such as DIgSILENT PowerFactory or PSS/E.

Steady-state power system anlysis is based on load flow simulations and describes the static behavior of the system, either during normal operation or after a contingency has occurred and the dynamic changes in voltage and frequency have settled. It can hence be divided into two separate parts:

- Load flow analysis for normal, undisturbed operational scenarios;
- Contingency analysis, where load flows calculations are conducted for situations after a number of pre-defined contingencies (often all relevant (n-1) cases).

The normal operation load flow analysis yields asset loading and voltages at all busbars in the system, all of which need to be in the required operational ranges for the operational scenario to be considered feasible.

If all parameters are inside the bounds, contingency analysis is conducted. Parameters need to remain inside a certain range, which may be larger than the normal operational range, after contingencies.

Steady-state analysis results show congestion and voltage issues in the grid. Operational scenarios output from a production simulation software that already contains a linearized SCOPF should generally be convergent and mostly feasible. The reactive power control strategy can however only be implemented in the full non-linearized ("AC") load flow and may reveal the need for voltage-based operational constraints that need to be considered during dispatch and hence fed back into the production simulation.

Steady-state load flows are also the basis for dynamic stability analysis and hence need to be convergent and feasible for dynamic calculations to make any sense:

- Normal operation load flows show that the system works within its operational boundaries during undisturbed operation;
- Contingency analysis shows that the system can operate stably after the outage of one or more elements;
- Dynamic stability analysis shows the transition between the two states, hence both previous states need to be feasible for it to yield meaningful results. (Dynamic stability analysis is not limited to only contingencies and can provide further results which are addressed in the next subsection.)

With regard to investment planning, load flow calculations allow for the identification of frequently congested grid areas. In conjunction with the congestion cost that can be determined from the dispatch simulations, cost-benefit analysis of grid expansion or reinforcement options can be conducted.

3.4.1 Modelling and Validation

Load flow simulations require a grid model of the system to be analysed in the grid simulation software of choice. Such a model must represent in detail the part of the system that is directly relevant to the study – the transmission and possibly the subtransmission grid in case of comprehensive system studies – and include simplified models of all other synchronously connected system parts, for example load representations of distribution grids.

Such models are usually already available at the responsible grid operator or owner, or potentially other entities such as the market operator. If that is not the case, the model will to be compiled from ETED's asset lists and generator data from the respective agents.

In either case, the model needs to be validated with real load flow data from SCADA readouts as far as possible.

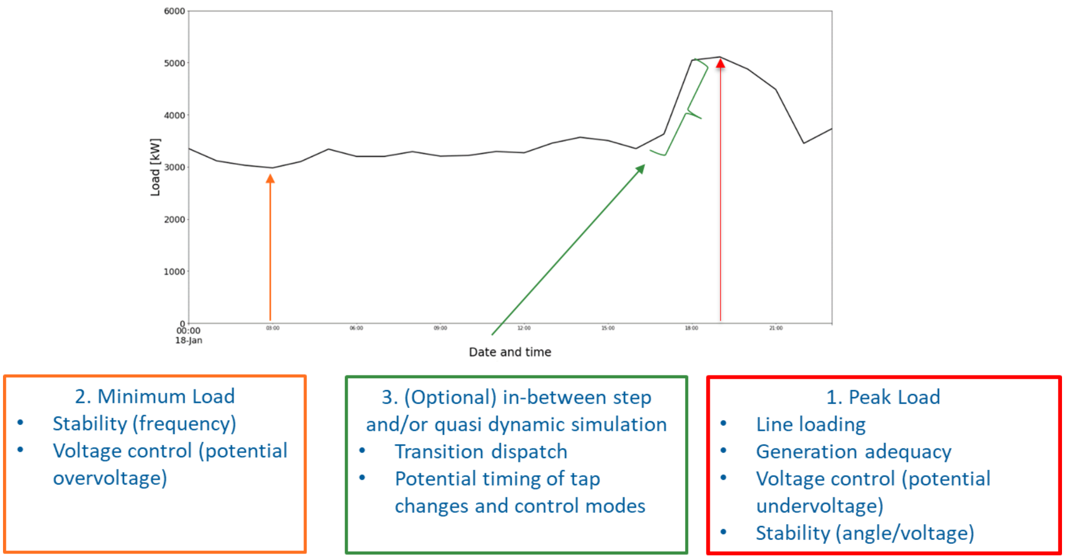
3.4.2 Scenario Selection

Load flow simulation cases are selected from dispatch simulation results, with the focus on situations that are expected to be especially critical. Full electrical analysis for all 8760 hours of a year is theoretically possible, but costly and usually adds little value.

Operational scenarios output from a production simulation software that already contains a linearized SCOPF should generally be convergent and mostly feasible. The reactive power control strategy can however only be implemented in the full non-linearized ("AC") load flow and may reveal the need for voltage-based operational constraints that need to be considered during dispatch and hence fed back into the production simulation.

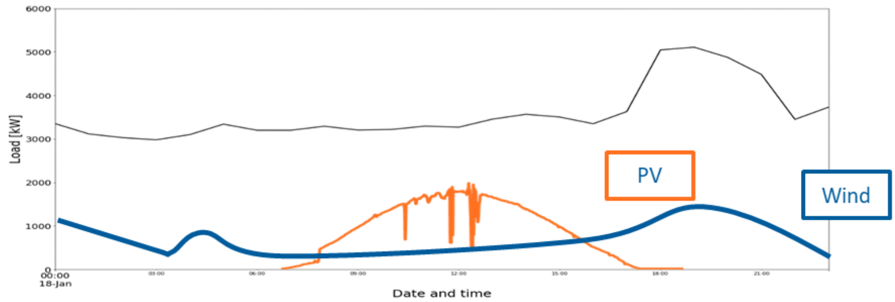
Load flow simulations in traditional power systems based on hydro and thermal resources typically focus on system conditions during peak and minimum load as the critical cases, sometimes with seasonal differences included (winter peak and summer peak etc.), as shown in **FIGURE 17**.

FIGURE 17 Classical load flow analysis scenarios typically focus on peak load and minimum load cases.



The situation becomes more complex with the introduction of vRE to the system. The primary interest is still in the situations with the highest and lowest grid and generator loading, but such situations may now be increasingly decoupled from the load curve and more and more dependent on vRE feed-in (**FIGURE 18**). The development of a scenario matrix with the goal of identifying the most critical situations is therefore crucial. The number of analysis cases usually increases.

FIGURE 18 With a significant vRE share in the mix, simulation scenario selection can be more complex.



Time	Load	VRE scenario: low wind, low PV	low wind, high PV	high wind, low PV	medium wind, medium PV	high wind, high PV
06:00	low	traditional scenarios	X	CRITICAL	X	X
12:00	medium		RELEVANT	RELEVANT	CRITICAL	CRITICAL X
18:00	high		X	RELEVANT	X	X

These should still be considered – the system needs to work properly even without VRE

There is some significant VRE impact to be expected here

These can be expected to be the most critical cases

Due to the load flow study cases serving as the basis for dynamic stability simulation, dynamic stability issues should already be considered in the selection of study cases. In general, the following type of situations are most interesting:

— Situations in which particular lines are most highly loaded (thermal line loading, undervoltage issues, transient stability);
— Situations with very low line loading (overvoltage issues);
— Situations with the highest system non-synchronous penetration (SNSP) and situations with the lowest system inertia, which are usually the same (voltage control, dynamic frequency and voltage stability).

Moreover, traditional load scenarios and power system specific extraordinary situations still need to be evaluated, all with different levels of vRE availability. The system may for example react differently during peak load conditions with high SNSP than during low load conditions with high SNSP, and differently depending on where the majority of vRE power is generated and which conventional units remain online.

3.4.3 Simulation

3.4.3.1 Normal Operation

No assets should be thermally overloaded, and all bus voltages should be within the prescribed bounds during normal operation. This is the main result yielded by the power flow analysis for each study case.

Especially voltage values may be out of bounds in initial simulations, which can often be traced to improperly configured voltage controllers in the system model. The same is true for asset overloading by reactive current. In all cases, voltage and reactive power control in the model should be thoroughly reviewed, as this may allow for issues to be alleviated without changing unit commitment or active power setpoints of generators (which would induce a feedback round into the production simulation model, see section 3.3).

If this is insufficient, a feedback loop into the dispatch simulation model is inevitable, introducing additional constraints obtained from the AC load flow. Examples of such constraints would be the out of merit order commitment (forced dispatch or must-run constraint) of a generator for voltage control in a certain area, or the reduction of active power carrying capacity of a line during times when high reactive power transfers can be expected.

3.4.3.2 Steady State Contingency Analysis

Steady state contingency analysis evaluates the impact of asset contingencies on the power flows and voltages in the system. This is typically done through a series of power flows, one for each credible contingency case, a functionality that can be automated in most grid simulation software sites. Work flow is as follows:

- Definition of a list of relevant contingencies (potentially including double and triple contingencies) that the system must be able to withstand;
- Execution of load flow series;
- Evaluation of results – all flows and voltages should be within range, ranges may be extended compared to the normal operation case.

Results show the grid conditions post contingency and should be evaluated in the same way as the normal operation load flow results. Boundary violations can likewise be transferred into additional dispatch constraints.

The power system response during the contingency is not evaluated in the steady state contingency, but subject to dynamic stability analysis. It makes sense to align the contingency lists for both types of simulation in this regard.

3.4.3.3 PV and QV Curves

To assess voltage stability, and stability margins, the QV and PV curves for the most critical busbars in the system are determined for pre and post contingency situations. The most critical busbars are the ones with the biggest slope dU/dQ, when comparing the pre and post contingency load flow. Further busbars can be added to the analyses depending on their strategical importance. For these busbars the PV and QV curves are calculated for all relevant contingencies and the stability margin will be determined. This will be done in an automated way.

QV curves (**FIGURE 19**) show the resulting reactive power consumption, when varying the voltage at a busbar, while keeping the active power at the busbar constant. The power system can only be operated stably on the right side of the curve, when the slope is positive. Consequently the nadir shows the stability limit and the difference from the operation point to the nadir is the stability margin. Some simulation tools (e.g. PowerFactory) have a built in function, to determine the QV curve starting from the operation point and then varying the reactive power/ voltage to determine the QV curves automatically.

PV curves (**FIGURE 20**) are determined in a similar way. The difference to the QV curves is that the reactive power (or power factor) is kept constant, while the active power at the consider busbar is varied. The maximal possible active power before it starts decreasing again, is the stability limit. The difference from the operation point to this point is the stability margin.

FIGURE 19 Example QV curves for three busbars

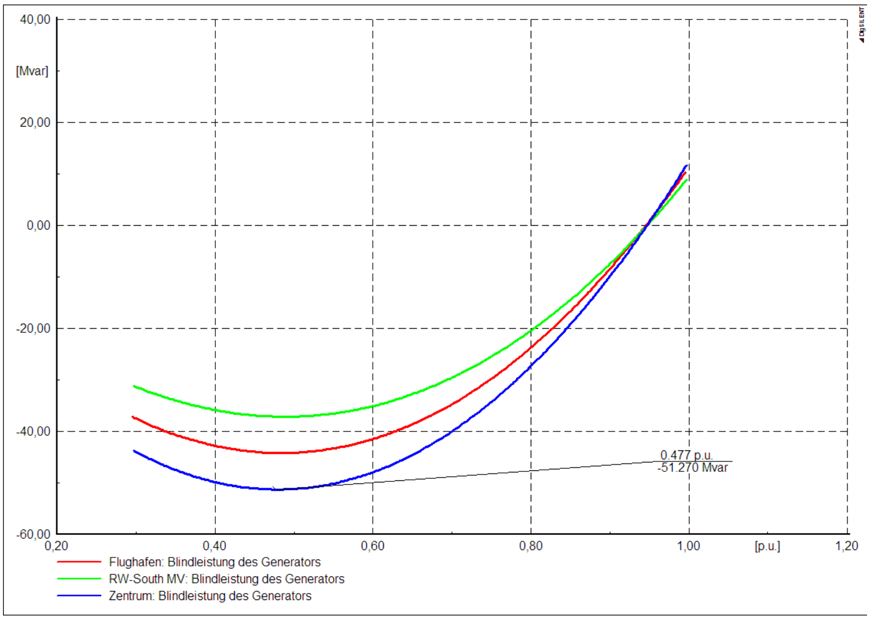
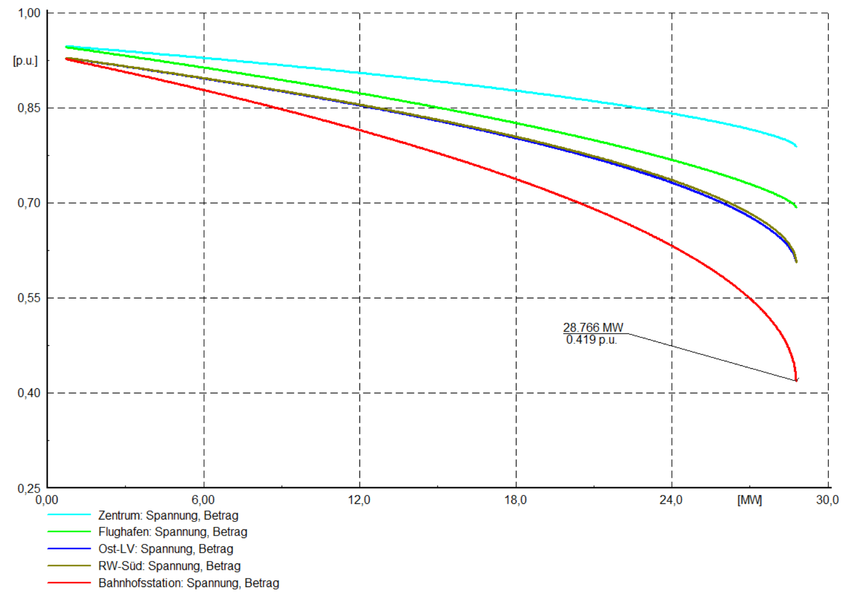


FIGURE 20 Example PV curves for five busbars



3.5 Short Circuit and Protection

Load flow analysis can be followed up by further steady state analysis such as short circuit and protection analysis to make sure that short circuit levels remain acceptable and reliably trigger protection in fault cases.

QUICK SUMMARY: SHORT CIRCUIT AND PROTECTION

Inputs: Transmission grid model, load and generation dispatch for key operational situations, protection layout (for detailed protection analysis)

Outputs: Short circuit levels at all substations, information on whether protection can reliably clear faults in all situations.

Direct use of results: TSO internal, revision of grid codes, revision of protection settings

Software and modelling requirements: AC load flow model of the entire transmission system in a dedicated grid simulation software such as DIgSILENT PowerFactory or PSS/E, modelling of protection relays and their settings.

For high wind/PV shares, some synchronous generation will not be dispatched, which may lead to a reduction in the minimum short-circuit level and a reduced short circuit ratio. The impact of the short-circuit currents on the operation of the protective relay system should also be investigated.

3.5.1 Modelling and Validation

Electrical models as described in section 3.4 can usually be used to also conduct short circuit and protection coordination studies, given that the software comes with the functionality required and the corresponding packages have been procured. In the Peruvian case, DIgSILENT PowerFactory comes with short circuit capability within the base package, and additional, more detailed protection coordination packages are available.

In terms of modelling, for short circuit calculations, the short circuit contribution of all generators mist be modelled. This is a standard parameter for synchronous machines as it is an inherent characteristic linked to the physical layout of the machine. For inverter based generators such as vRE, short circuit current is controlled by software and limited by the inverter rating. The exact short circuit behavior needs to be modelled according to grid code requirements and/or actual behavior of existing assets, if known.

Detailed protection analysis and coordination requires modelling of all protection relays and their settings according to the actual condition. This data is usually available to the TSO.

3.5.2 Scenario Selection

Short circuit currents at all substations must be within limits (upper limit of asset rating and lower limit of safe triggering of protection) and the protection scheme must reliably work for all situations. Choosing the most critical operational scenarios for simulation is permissible, as everything else in between can reasonably be assumed to work properly as well. Hence, the scenario selection described in section 3.4.2 can be applied.

3.5.3 Simulation

Short circuit calculations can be performed in an automated fashion for a set of contingencies for all substations in most software sites. Short circuit currents at all substations must be within limits for all situations.

Protection simulation adds the actual response of the protection relays, which is also typically automated.

3.6 Dynamic Stability Analysis

Steady state analysis can then be followed by dynamic stability analysis to evaluate the capability of the system to safely transition from one state to the other. State transitions are usually events such as short circuits, asset outages or steep changes in load or vRE feed-in. Dynamic stability analysis is conducted for critical operational situations and requires a convergent load flow calculation as a precondition. The event is then introduced and a simulation is executed for a timeframe of seconds to minutes in millisecond resolution to simulate the system’s response to the event. The system is considered stable if it can return to a stable operational state for all (or a large number) of credibly expected events. Dynamic stability is critical in any power system regardless of vRE integration status, and is often conducted by system operators on a regular basis for the current condition. The addition of vRE changes stability parameters, most notably in the form of reduced system inertia, which makes frequency control more challenging. The impact is however relatively low unless very high instantaneous vRE penetration levels are reached, and in most cases, other challenges are found and have to be addressed before dynamic stability becomes an issue. Especially for near future scenarios and scenarios with relatively little vRE additions, dynamic stability analysis is hence often considered not to be a critical issues and often skipped, partially also due to the high modelling and validation efforts required. Dynamic stability however does become critical and needs to be evaluated in detail at higher instantaneous vRE penetration levels. The exact threshold depends on system characteristics, but is usually in the range of 30-50% instantaneous penetration.

QUICK SUMMARY: DYNAMIC STABILITY ANALYSIS

Inputs: Transmission grid model, dynamic models of all generators, load flow results for key operational situations.

Outputs: Stability parameters or violations thereof for all situations analyzed.

Direct use of results: Results show whether the power system can be operated stably under a future scenario or not. If not, revisions of grid code requirements and/or operational regimes, or introduction of new operational limits may be necessary. Results are key inputs to such revisions.

Software and modelling requirements: AC load flow model of the entire transmission system and validated dynamic models of all generators in a grid simulation software capable of RMS dynamic stability analysis, such as DIgSILENT PowerFactory or PSS/E.

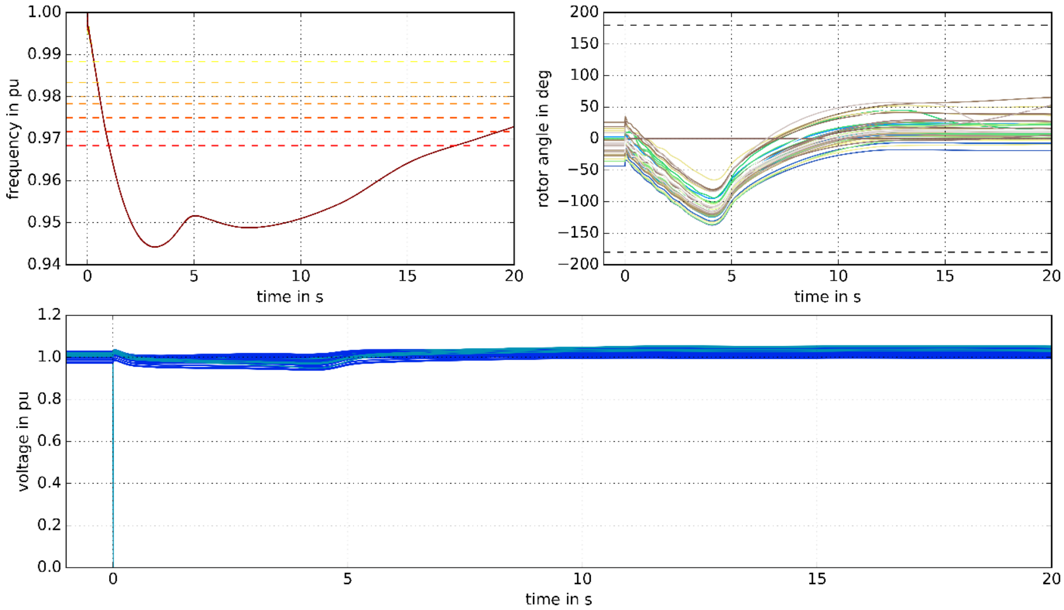
Dynamic stability described the capability of the power system to return to a stable operational state after a disturbance. The following disturbances are usually relevant:

- Contingencies such as generator trips, short circuits and load feeder disconnections, as discussed in the previous sections;
- Short-term active power fluctuations from vRE.

A short list of relevant contingencies and expected worst case short-term fluctuation events needs to be developed and agreed on during the study (preferentially at an early stage, see section 3.1.2).

Dynamic RMS simulations have to be conducted for each event to assess dynamic frequency stability, dynamic voltage stability and transient (rotor angle) stability (**FIGURE 21**). All these three aspects of stability will be analyzed in each event that is simulated. However, some events or scenarios are more prone for problems with a specific stability aspect, e.g. short circuits are most problematic for rotor angle stability, while loss of loads or generation are more problematic for frequency stability.

FIGURE 21 Example dynamic simulation results, showing frequency trace (top left), rotor angle difference between generators (top right) and voltage traces from all substations (bottom).



If cases of dynamic instability are found, there are typically two ways to address the problem:

— The corresponding situation needs to be avoided and adequate dispatch constraints need to be introduced.
— Technical properties or capabilities of grid assets need to be changed, such as the FRT envelope and dynamic fault current provision of generators, or underfrequency load shedding settings on load feeders.

3.6.1 Dynamic Modelling

For the dynamic simulations, the same system model like for the load flow studies can be used if the software is capable of performing dynamic analysis. A convergent steady state AC power flow is a prerequisite to RMS dynamic analysis However, the model needs to be enhanced with dynamic elements:

— Generators: Ideally manufacturers can provide simulation models, that include all of the relevant elements below. If not, generic models will be applied. Generator models include:
    — Dynamic parameters of synchronous machines, e.g. transient and subtransient reactances, inertia, saturation curves, time constants
    — Model and parameters of excitation systems of synchronous machines

  - Controller models and their parametrization (governors, automatic voltage regulators (AVR), including limiters, e.g. over excitation limiter, reactive power controller, Power System Stabilizers, applied characteristics, e.g. P(f), Q(U), etc.)
  - For vREs that have not been built yet generic models (WECC or IEC) will be used. This is also possible for existing plants, if no manufacturer model is available.
- Protection and load shedding: All protections and load shedding procedure in the system should be replicated in the model. This includes most likely protection against over- and undervoltage, over- and underfrequency and overcurrents.
- Dynamic behavior of other elements: If applicable the dynamic behavior of loads (e.g. frequency response) and other elements such as STATCOMs should be implemented in the model.

As already mentioned previously, data collection is a crucial aspect of the system study. It should be tried to collect the above-mentioned data as complete as possible. If data is missing or not available, assumptions based on experience should be made or generic models and parameters should be used. However, this impacts the accuracy of the study.

3.6.2 Validation of Control Systems

Following the setting up of the simulation model it should be validated with measurement data. By validating the model and tuning it, if necessary, the simulation results of the study become significantly more reliable.

The model to be validated is the model of the current state of the grid without any future expansions. If measurement data of single generators are available, the models of these generators can be validated separately.

For validating the model, measurement data of events in the grid are required. Good events for validation of the model are similar events like the ones that are used later on for the stability analysis, such as fault ride through (FRT), load trips or generator trips.

All measurement data that is available of such events, is helpful for the validation of the model. Of course, the more data is available, the better it can be validated. The following data can be used for validation:

- Voltage at several busbars in the system (at least magnitude, if available voltage angle measured with phasor measurement units (PMUs))
- Active and reactive power flow over certain lines
- Active and reactive power from generators

- Frequency

In the simulation model, the same events that happened in reality will be replicated. The quantities that are available as measurement data will be plotted together with the corresponding simulation results and deviations will be assessed.

To improve the model accuracy, the following measures can be applied:

- Tuning of model parameters: Typically, there are uncertainties in the physical parameters of synchronous machines and other elements. Model accuracy can be enhanced by varying reactances, resistances, inertia constants, time constants, saturation, etc. Especially, when parameters have not been available and assumptions had been made, there is a large potential for model improvement.
- Adaption of controller models and their parametrization: If generic models have been used to represent governors and AVRs, it might turn out that these models are not sufficiently accurate. In this case, other more sophisticated generic models can be used, or the used ones can be enhanced with additional elements. Additional elements can be completely new elements, such as over excitation limiters or stator current limiters or small adaptions, e.g. additional time constants. In addition to adding new elements, also the controller parameters can be adapted. Especially the PI-parameters of controllers as well as time constants and delays have a large influence on the dynamic behavior of generators.

3.6.3 Scenario Selection

In Figure 15 (page 54) , example results of a dispatch simulation are shown. Since there are countless different dispatches and states that the system can have, it is infeasible to analyze all of them in dynamic simulations. Consequently, the most critical situations have to be chosen for detailed dynamic simulations as outlined in section 3.4.2.

The most critical situations are highly dependent on the peculiarities of the examined power system. Possibly additional scenarios, such as highest loading of a critical line have should be examined as well. This has to be decided by the grid operator.

The starting point and prerequisite for each dynamic simulation is a stable, steady state load flow of the considered scenario.

3.6.4 Simulation

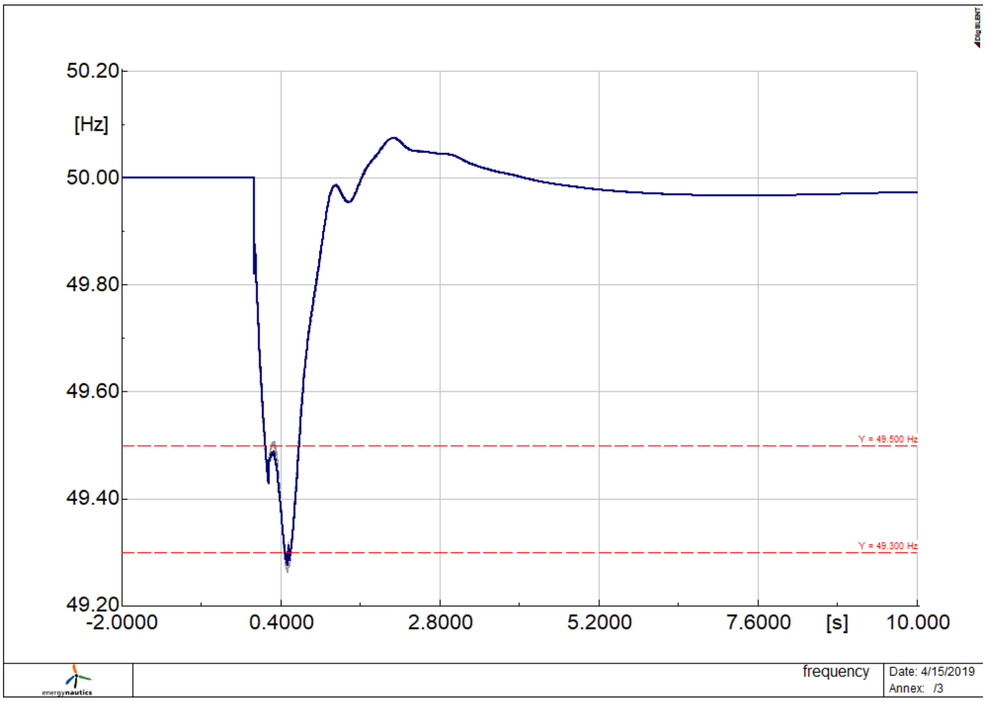
3.6.4.1 Frequency Stability Analysis

Every contingency in a power system leads to frequency excursions. In the beginning, stored energy taken from the inertia of the system will be discharged and dampen the frequency excursion. Afterwards, speed controllers of each directly coupled synchronous generator will react to these frequency deviations based on their primary control setting and increase or decrease the active power delivered to the system. Consequently, for the frequency analyses, the primary (and secondary) control scheme needs to modelled accurately.

Usually wind and solar power plants are connected with inverters to the grid, and hence do not provide inertia. Thus, if large amounts of renewables that replace conventional generation are connected, there is less inertia in the grid, which worsens the frequency response, because the ROCOF increases. This negative effect can be counteracted by implementing frequency support controls on the inverters.

Even when the system returns to a stable operating point after a contingency, in some cases it happens at the expense of shedding load. In **Fehler! Verweisquelle konnte nicht gefunden werden.**, the frequency response of a system after a severe loss of generation is depicted. In this case the system can be stabilized, however some loads have to be shed to do so (relays get activated at dashed lines).

FIGURE 22: Frequency in loss of generator contingency, with two loads shed



To analyze frequency response the following events should be simulated for the scenarios listed in section 3.4.2.

- Loss of the largest generator (n-1 generator contingency)
- Loss of the largest load (N-1 load contingency).
- Loss of renewables
- Fast fluctuation of renewables
- Other events, e.g. line outages depending on the system.

It is expected that the most critical case will be the loss of a generator during high vRE penetration, because typically renewables cannot provide upwards reserve. If controlled properly, vREs can reduce their power fast during over-frequency events, hence the loss of a load is expected to be less severe. the simulations will be used to determine appropriate settings for the frequency response of vREs.

Depending on the simulation results, the following measures can be applied to improve the stability of the system. They will be implemented in the model and their effectiveness will be checked.

- Must run constraints: Increase minimum of connected synchronous generators (more inertia).
- Increase the generator headroom and/or fraction of generation contributing (more available primary control).

- Retrofitting the available generation technologies (faster primary control).
- Adapt inverter controls and make them mandatory (grid code adjustments, leading to more fast-frequency-response or primary control).
- Grid expansion.
- New load control schemes and load shedding.
- New technologies such as batteries to provide frequency response

3.6.4.2 Voltage Stability Analysis

These dynamic voltage stability analyses will be conducted in addition to the steady state analyses, that are discussed in section 3.4. Voltage stability issues typically occur, when

- (long) transmission lines are highly loaded
- voltage sources are too far from load centers
- newly connected power plants do not contribute enough to reactive power
- synchronous generators reach the maximum of their over excitation limiters
- loads interact unfavorably with changing voltage

Many of these issues are actually load flow problems and should be avoided with a proper dispatch. This will be analyzed already in the previous load flow studies. However, following a contingency, e.g. a loss of a line, the system might reach an unplanned situation and hence experience voltage stability issues. Contingencies to be analyzed regarding voltage stability are for example:

- loss of generators (conventional and renewable) near load centers resulting in large power flow towards the load center
- loss of lines

Voltage instability can occur due to cascading outages, e.g. when a generator near a load center trips, which leads to high loading of a line and causes it to trip as well, which overloads other lines, etc. Consequently, all relevant elements, such as protection, excitation systems, behavior of automatic generation control, behavior of tap-changing transformers voltage dependency of loads, etc. need to be modeled accurately. The difference of these analyses to the contingency analyses conducted previously is, that here not only the steady state is considered, but also the transient behavior before a new steady state is reached. Even if both steady states, before and after a contingency, are stable, it might come to issues during the transient. This is examined through the simulations here.

To increase the voltage stability, the reactive power provision of renewable generators can be tuned (e.g. Q(U) or cosphi(P) characteristic) or additional elements for reactive power control can be installed. Another possibility is to adapt the dispatch to prevent running into dangerous operation points.

3.6.4.3 Rotor Angle Stability Analysis

Rotor angle stability means that no pole slips occur (rotor angles < 180°) which means all generators stay synchronized to each other. Issues with rotor angle stability occur in case of short circuit, when suddenly no electrical power can be evacuated into the grid, due to the low voltage, but the mechanical input power is not decreased and hence the machine accelerates.

The most severe scenarios are the ones, where the synchronous generators are already highly loaded and consequently already have a high rotor angle in steady state. Another critical situation is, when generators at different locations in the grid are only weakly coupled, e.g. by a long transmission line.

To assess the rotor angle stability short circuits will be simulated in the grid at the most critical busbars. In the simulations, the short circuits will be cleared after the time, the protection would also need in reality to react. If instabilities are observed the clearing time will be reduced stepwise to determine the critical clearing time.

The rotor angles of all generators will be monitored and plotted to analyze their angle stability. For an accurate analysis, all relevant protection schemes have to be included in the model. Besides, the excitation systems and AVRs of the generators have to modeled precisely.

If there issues with angle stability are observed, the main measures can enhance the stability are:

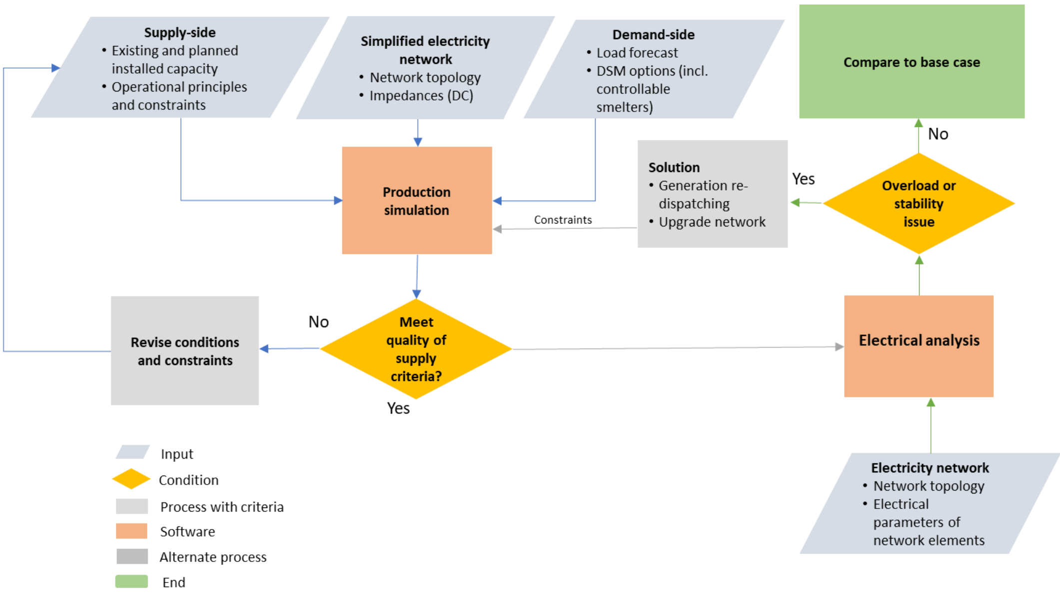
- Decrease of fault clearing time
- Tuning of AVRs for faster reaction
- Tuning of voltage support from vRE (typically the reactive current during fault is proportional to the voltage dip, adjustable with “k-factor”)

3.7 Interpretation of Results

Grid adequacy and stability impact the dispatch solution, thus, the electrical analysis and the production simulation need to be linked. The general process is shown in **FIGURE 22**. When analyzing simulation results, it is possible to iterate back to earlier stages, including rethinking initial assumptions. Generally, the better the technical properties of generation and grid are represented in the production simulation, the less iterations are needed.

There is a great importance of the model set-up and portfolio selection and influence on the results. If a situation or entire scenario is found to be technically or economically infeasible, changes need to be made to the optimization model to alleviate the issue, and the model needs to be rerun to yield a feasible result (unless “this scenario does not work” is an acceptable solution, which may be the case in multiple-scenario scoping studies). In case the impact of the integration proves to be possible, yet costly, possible remedies could be sourced from operational practices. Options are manifold and depend on the exact nature of the issue. These are explained in the following subsections.

FIGURE 22 Basic workflow between production simulation and electrical analysis.



Quantifying the costs of integrating vRE or conducting broader cost-benefit assessments for vRE integration is complex. Costs associated with vRE include reserves to manage their variability, increased thermal generator cycling costs due to more frequent dispatch changes, transmission expansion to reach optimal resource locations, and stranded investments in conventional generators displaced by renewables. These costs are not exclusive to RE; they occur with any new resource addition. Additionally, these costs are difficult to calculate or observe directly due to the intricate interactions within the power system.

The best analytical approach involves modeling system operating costs with and without vRE, and comparing them. Since vRE have zero operating costs, their scenarios will always show lower operating costs compared to those relying on conventional resources. The apparent increase in costs due to reserves and cycling is actually seen as a reduction in the savings on operating costs, primarily influenced by the fuel costs of conventional energy sources. Therefore, meticulous analysis and communication are crucial in grid integration studies to accurately reflect these dynamics.

3.7.1 Limiting Factors and Metrics

Scenarios or individual operational situations may end up infeasible for a number of reasons and in multiple different ways, which require different solutions. In short, the following types of infeasibility are common and can be addressed as described:

- Economical infeasibility at scenario level: A long term optimization scenario with a number of additional constraints, such as a high renewable energy target or certain fossil fuel offtake requirements, may result in very high overall cost (very common for 100 % RE scenarios as of today). Such a scenario can be discarded if cost exceeds the acceptable limits (or the scenario has been exogenously defined), or it may be re-run with additional constraint on maximum cost, or it may be re-run with some of the main constraints alleviated (such as reducing the RE target to 90 or 95 %).
- Economic infeasibility at production simulation level: A scenario may yield acceptable cost results in the more high level, lower resolution, time clustered expansion stage of a study, but end up very expensive in day-to-day operation in the production simulation. Such issues occur if key characteristics of the system have been removed for simplification, such as spinning reserve constraints or grid constraints. This is an indicator that these constraints need to be better represented in the scenario / expansion stage, which will either result in high cost becoming visible there already, or in an altogether different and more economic solution.
- Technical infeasibility at scenario / expansion level: A scenario may result in underserved load or other violations. Such a scenario is infeasible and requires recalculation with better inputs and constraints.
- Technical infeasibility at production simulation level: A scenario may have inadequate grid or generation capacity to serve the load, or provide sufficient reserves and this characteristic may become visible only later during actual production simulation. This is also an indicator of oversimplification and requires better representation of system characteristics in earlier stages.
- Technical infeasibility at steady state (load flow) analysis level: An operational case may result in violations of thermal loading and voltage constraints, or violations of (n-1) security. This generally indicates inadequate constraints in the production simulation, which may either be the result of inaccurate modelling or assumptions, or the need for updated operational procedures (see section 3.7.2). It may also identify a need for additional enabling technologies (see section 3.7.3) or updates in regulation (see section 3.7.4).
- Technical infeasibility at dynamic simulation level: Operational cases may show stability issues. If stability constraints have been previously known, this indicates inadequate representation of such constraints in previous simulation stages. If this is not the case, it indicates required changes in the system as explained in section 3.7.

It should be noted that re-running scenario or dispatch optimization with updated technical constraints may result in wildly different results, and potentially in economic feasibility issues. As explained in the following sections, there may be different solutions to the same problem with different cost impacts. Analysis should strive to identify the least cost or least regret option for each issue.

3.7.2 Operational Procedures

Updated operational procedures can alleviate many power system issues at relatively low cost, especially in the early stages of vRE integration. The definition of a fixed or dynamic vRE feed-in limit is such a measure, but likely one of the more expensive ones – it results in curtailment of vRE and hence in economic losses, which need to be carefully evaluated. It should hence be considered a last resort measure, and if it is applied, it should be applied dynamically based on actual system conditions, and not as a blanket value such as a certain SNSP percentage.

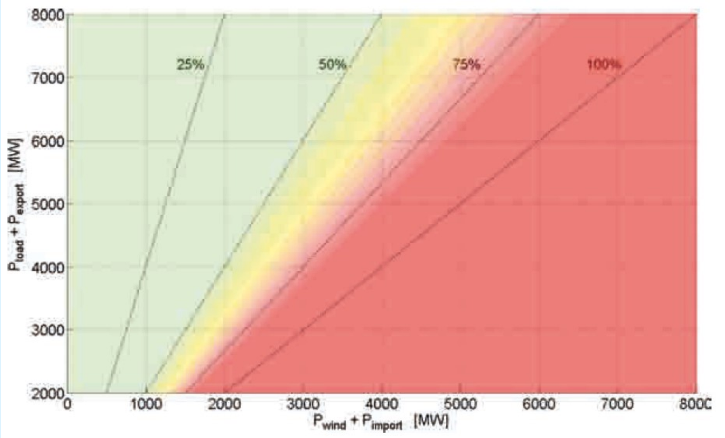
Following are the common operational measures for improving vRE integration to the system:

- Shortening of dispatch intervals and scheduling (both for active power and ancillary services) (day ahead to hourly to quarter hourly etc)
- Bringing unit commitment deadline closer to the real-time to increase forecast accuracy and reduce imbalances in the system – allowance to update the unit commitment before dispatch
- Introduction of trading close to real time, if market places are available to unlock short-term price signals
- Introduction of local flexibility markets or other means of allowing spatial resolution of price signals for cost competitive congestion alleviation
- Allowance of contribution of vRE for ancillary services, specifically for downward regulation
- More long term dispatch planning accommodating hydrological situation and weather forecasts, frequent updates
- Dynamic calculation of reserve requirements instead of blanket value (may have economic impact, but this can go both ways)
- Real time estimation of inertia based on committed synchronous units (you need to take action when it becomes too low, but especially in early stages this usually results in that you see that you have more inertia than you thought)
- Increase of ROCOF threshold requirements
- Better use of existing technology – for example, activate free governors on more units even if no reserve is dispatched to them (operators may not like it though)
- Locational grid charging can be considered manipulate distribution of the vRE plants

BOX. EirGrid – SNSP Calculation

Based on over 60 dispatch cases reflecting variety of technical issues, all island power system developed an operational matrix and identified the key issues limiting the desired level of SNSP (~75%). **FIGURE 23** represents SNSP levels which are expected to show no technical hurdles (green) towards red, when the technical issues become increasingly critical. This matrix was developed for the current system topology and explores the necessary adaptations and investments to accommodate for the anticipated SNSP levels.

FIGURE 23 Indicative range for operation of all island power system. Dashed lines indicate SNSP levels[23]



3.7.3 Enabling Technologies

Some enabling technologies are usually required once a certain share of VRE is present in the system. Different options can be chosen to mitigate limitations to stability and grid capacity, and those need to be integrated in the simulations and evaluated for feasibility.

Options include the following:

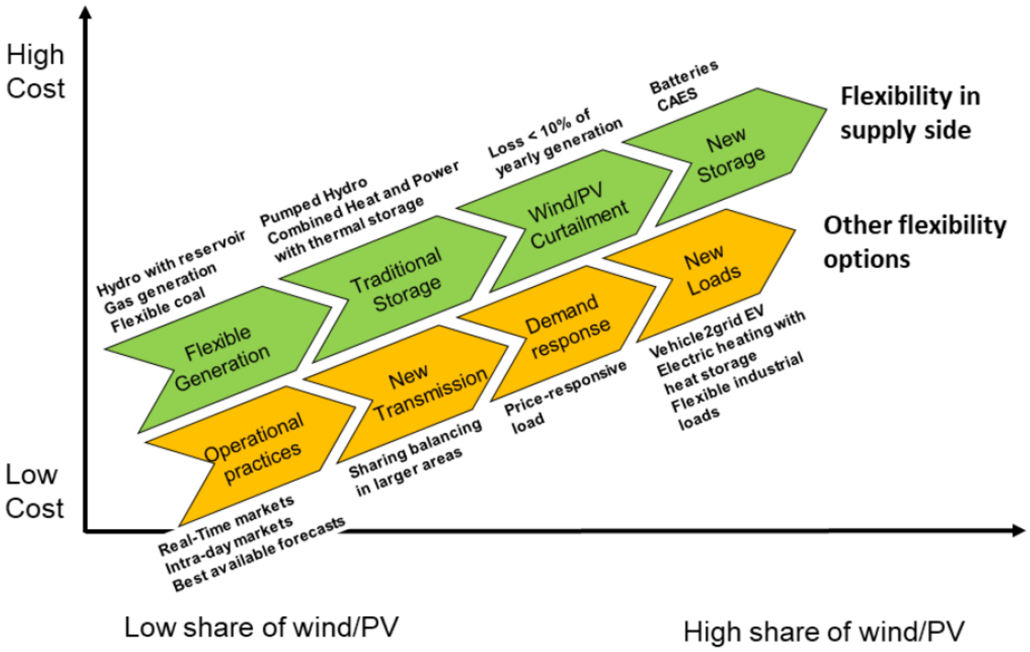
— Implementing state-of-the-art, centralized forecasting systems, and using these effectively for scheduling of power plants and other operational decisions.
— Battery energy storage systems (BESS) with different functionalities and use cases:
— Arbitrage or peak shaving BESS that charge during high-vRE (low price) hours and discharge during low-vRE (high price) hours, reducing curtailment;
— BESS for spinning reserve and stability contribution;
— Grid-forming (GFM) BESS for reserve and inertia contribution.
— Uprating or reconductoring of lines to alleviate grid constraints, especially if new lines cannot feasibly be built, or are too expensive:

[23] https://cms.eirgrid.ie/sites/default/files/publications/Facilitation-of-Renewables-Report.pdf

- High temperature low sag (HTLS) conductors which can carry higher currents;
- Dynamic line rating (DLR) based on weather conditions and/or measurements, allowing higher ampacities on cooler and/or windier days.
- Reactive compensation to provide reactive power and additional voltage control, as reactive power demand grows with higher line utilization, while conventional power plants that traditionally provide the service are displaced;
- Reactive power, dynamic response and power flow control using inverter based Flexible AC Transmission Systems (FACTS) such as STATCOMs or UPFCs;
- Installation of phase-shifting transformers (also called “quadrature boosters”) for power flow control;
- Improvements in SCADA infrastructure, monitoring and controllability of the system, including introduction or expansion of automatic generation control (AGC) for balancing;
- Installation of synchronous condensers or retrofitting of conventional and hydro units to act as synchronous condensers at no active power output, providing inertia, short circuit current and reactive power.

Fehler! Verweisquelle konnte nicht gefunden werden. provides a general view of flexibility options including technology and operational measures, and their relative cost effectiveness.

FIGURE 24 Measures for increasing power system flexibility[24]



3.7.4 Regulation and Grid Codes

Regulation and grid codes play a significant role in vRE integration. Market and operational rules need to be set up so they can cope with increased vRE penetration and variability, and grid codes need to be in place to ensure system compatible behavior from all generators, including vRE. Insufficiently developed regulation can be a major barrier to vRE integration, even if little technical barriers exist.

Regulation first and foremost plays a role as an input in vRE integration studies:

— Regulation on capacity adequacy and reliability criteria have to be respected in capacity expansion planning;
— Market or dispatch rules directly impact production simulation results;
— Grid codes and requirements for generators determine the required behavior of generators on the grid and hence their modelling for electrical studies.

Furthermore, vRE integration studies can be used to generate inputs to update and revise regulation:

24 https://www.researchgate.net/publication/332963810_Recommended_Practises_for_Wind_and_PV_Integration_Studies_IEA-Wind_and_IEA-PVPS_Expert_Group_Report_162#pf32

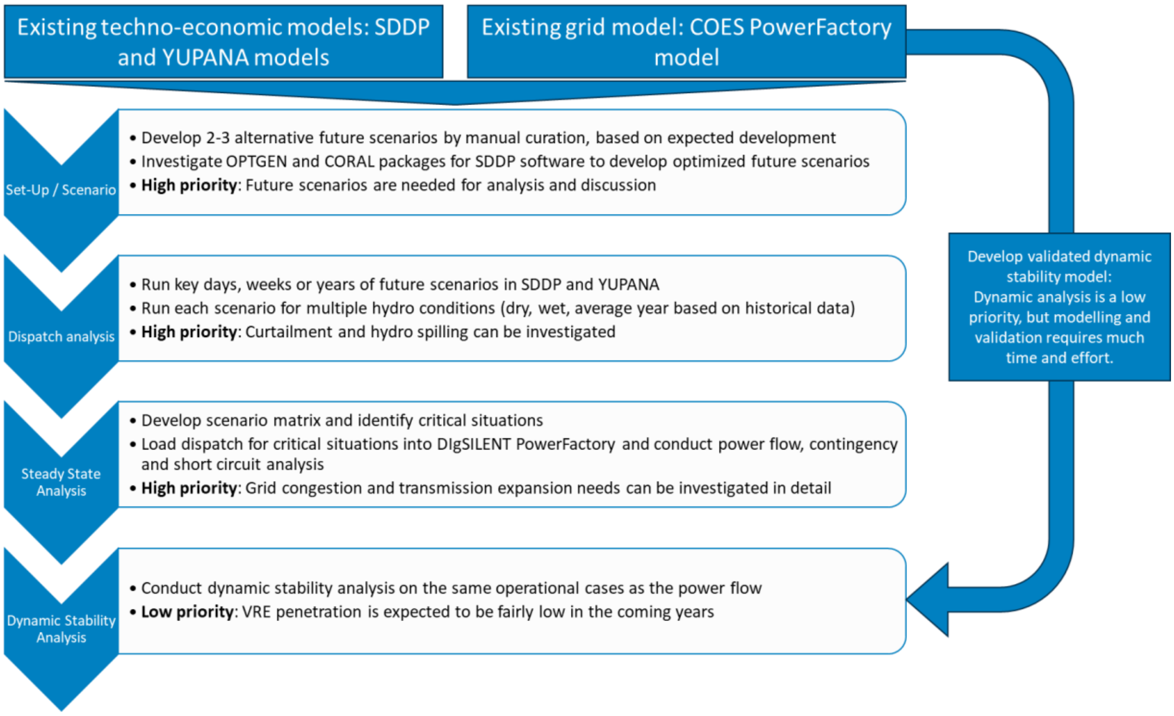
— Capacity adequacy and planning criteria may have to be revised with increasing vRE shares;
— Market and dispatch rules may be changed to accommodate vRE flexibility;
— Grid codes and technical requirements can be revised based on the results of grid analysis. This is fairly important, as inadequate technical requirements can be a major barrier to vRE integration, while a good grid code can facilitate vRE integration at relatively little additional cost.

4 Recommendations

The key recommendation for COES for vRE integration studies in the Peruvian system is to **make use of existing structures and models** as much as possible, and use the models currently used for short term programming also to execute simulations of future scenarios. COES use **DIgSILENT PowerFactory as the electrical analysis software**, and **SDDP and YUPANA for dispatch simulations** on different timescales. All of these tools are up to current international standards and suitable to investigate high-vRE future scenarios.

Furthermore, it is strongly recommended to **focus the next study on scenarios with moderate (10 – 15 %) vRE contribution** and the integration of the required capacities into **COES' existing grid**. The challenges for this type of scenario are mainly updates to generation scheduling and ancillary services, as well as transmission congestion and the identification of transmission investment needs, while dynamic stability issues play a minor role. The study should hence focus on the development of near-future scenarios, dispatch analysis and power flow analysis. The stepwise process to conduct such a study is graphically displayed in **Fehler! Verweisquelle konnte nicht gefunden werden.**. The **process is recommended to be executed by COES themselves**, using already **existing tools, models and databases** as much as possible, but under the **supervision and with input from an experienced international consultancy** that has conducted similar studies before in other countries.

FIGURE 24: Flowchart for COES vRE integration studies.



Since Peru currently lacks a well-defined vision of its power sector in the long-term, the **development of future generation scenarios for analysis** is a key factor for successful integration studies. It is recommended that COES develop **near-future scenarios based on existing plans** and potentially extrapolate those into scenarios 10 and 20 years ahead as a second step. In an open market system, such scenarios are necessarily only a best estimate, and the development of a number of alternate scenarios is recommended to investigate the impact of different development paths. Scenario development can be conducted manually, but COES are encouraged to **investigate the OPTGEN addition to SDDP**, which would allow them to run generation capacity expansion optimization, and the CORAL add-on which is used for adequacy analysis. While it is understood that COES does not actually have the mandate to plan the generation fleet, an **optimized future scenario** – and variations thereof with different constraints and costs – may be a **good estimation of future development**, serve as a scenario for technical analysis, and facilitate discussion with the responsible government entities. Based on such future scenarios, it is recommended to prioritize dispatch analysis in SDDP and/or YUPANA, and follow up with **more detailed grid analysis in the form of AC power flows** in DIgSILENT PowerFactory. The main challenges in integrating higher vRE shares into the Peruvian system, at least in the foreseeable future, are expected to be related mainly to generation scheduling, curtailment and hydro spilling issues, and to transmission congestion and the potential need for transmission investments. Information on these are key outputs of dispatch simulation and load flow studies.

RMS dynamic stability analysis is a lower priority, as it is expected that a number of other challenges need to be resolved before the Peruvian system even reaches vRE penetration levels where dynamic stability becomes an issue. It is however recommended that COES **start developing a dynamic stability model** of the system in DIgSILENT PowerFactory, if it is not already available. Setting up a validated dynamic stability model requires considerable time and effort as well as a large amount of data, so it is best to start early. With the structure of the Peruvian system, **some dynamic stability issues can be expected at some point, potentially even without any vRE impact**. Long and highly loaded lines tend to cause transient stability issues, and frequency control with hydro units can be challenging in the primary control domain due to the inherently delayed response from hydro turbines.

EMT simulations, which are typically conducted on individual generation facilities or on system partitions to investigate electromagnetic effects at very high RE penetration levels in higher resolution are **not expected to be required in the short term**. DIgSILENT PowerFactory is however capable of executing such simulations as well.

Appendix 1: Data Requirements

Capacity Expansion Studies

Key inputs for the capacity expansion model are the following:

- Accurate location of current transmission lines and generators
- Annual demand profile and forecast;
- Fuel and emission price projections;
- Investment cost of generation and transmission (and grid interconnection) technologies;
- Operational and maintenance costs of generation types;
- Typical meteorological year for vRE resource availability (should have spatial resolution over long periods of time, e.g. 30 years);
- Land-use data-sets for identification of non-usable areas (e.g. national parks, areas with religious/cultural significance, etc.);
- Aggregated fleet level conventional and vRE generator characteristics;
- Generation and transmission investment constraints.

Dispatch / Production Simulation

Key data required for the dispatch model are the following:

- Generator list with location, connection point and installed capacity per generator/block;
- Fuel type(s) and efficiency curve for each generator/block;
- Fuel price, availability and energy content;
- Non-fuel OPEX (startup cost, VO&M, FO&M) per generator;
- PPA conditions (for IPPs in single buyer markets);
- Reservoir size, turbine factor and hydro inflow (time series, multiple years) for hydro units;
- Historical generation time series or reanalysis wind speed and insolation time series for vRE generators;
- Information on operational constraints and ancillary services (such as must run constraints, reserve requirements etc.);
- Dispatch time series, at least one year in hourly resolution, including all generators, for model validation;
- Day-ahead and intra-day prices in market based systems, historical data of at least one year in hourly resolution;

- Load time series (one year, hourly resolution) and load distribution (by transmission grid node, time dependent);
- Load flow model of the grid (from load flow study).

Load Flow Studies

Load flow studies require a load flow capable grid model in the grid simulation software of choice. If no such model is available, data on the complete (transmission) grid infrastructure needs to be compiled from asset lists, focusing on the following:

- Substation topology and location;
- Line data including length, conductor type, number of circuits, tower topology, impedance, rating, connected nodes;
- Transformer data including ratio, impedance, tap changer settings and capabilities, location;
- Generator connections, rating, capability curves, voltage control regime;
- Data on other grid assets such as compensators etc.;
- Grid maps and single line diagrams can be very helpful.

If a grid model is already available, it may need updates and/or validation. The following data is helpful for that:

- Updated asset lists, grid maps and single line diagrams;
- Updated generator lists;
- SCADA readouts from act least a couple of operational situations (generator dispatch and resulting line loadings and node voltages) to validate the model;
- General information on voltage control at each node (which is typically one of the weak points of most models).

Dynamic Stability Analysis

Dynamic stability analysis requires, first and foremost, a load flow model. This load flow model will be enhanced with dynamic models of all generators and potential other elements. A list of required data is given below:

- Generators: Ideally manufacturers can provide simulation models, that include all of the relevant elements below. If not, generic models will be applied. Generator models include:
- Dynamic parameters of synchronous machines, e.g. transient and subtransient reactances, inertia, saturation curves, time constants
- Model and parameters of excitation systems of synchronous machines

- Controller models and their parametrization (governors, automatic voltage regulators (AVR), including limiters, e.g. over excitation limiter, reactive power controller, Power System Stabilizers, applied characteristics, e.g. P(f), Q(U), etc.)
- For vREs that have not been built yet generic models (WECC or IEC) will be used. This is also possible for existing plants, if no manufacturer model is available
- Protection and load shedding: All protections and load shedding procedure in the system should be replicated in the model. This includes most likely protection against over- and undervoltage, over- and underfrequency and overcurrents.
- Dynamic behavior of other elements: If applicable the dynamic behavior of loads (e.g. frequency response) and other elements such as STATCOMs should be implemented in the model

Furthermore, the following data can be used to improve the model:

- High resolution fault recorded data from real life grid events;
- Measurement results of unit tests of generators

Other Data

All power system information available should be considered and can be useful. Previous power system studies are of special interest in this regard, as they usually contain relatively comprehensive, even if partially outdated, information.

Appendix 2: International System And vRE Integration Methodologies

The following table is comprised of data based on the available sources online. System data information is based on 2023 statistics, whereas study analysis is an approximation from different studies made available across the years (most up-to-date versions were preferred).

	IRELAND	CALIFORNIA	TEXAS	AUSTRALIA (NEM)	CHILE
Current Phase of vRE Integration	Phase 4	Phase 4	Phase 4	Phase 3	Phase 3
Fuel Mix Characteristics	Wind (35%) + Natural Gas (50%)	Natural Gas (40%) + PV (30%)	Natural Gas (50%) + Wind (20%)	Coal (58%) + Wind (13%) + PV (16%)	Hydro (25%), Coal (23%), NG (19%), PV (17%), Wind (11%)
Oversupply Issues (Curtailment)	High	Low	Medium	Medium	Medium
Oversupply approximation (Total annual curtailment/Total annual generation)	4%	1%	2%	2%	3%
Distributed Generation	High (Wind)	Very high (PV)	Low (PV)	Very high (PV)	Low (PV)
DER approximation (DER capacity/total transmission connected generation capacity)	14%	20%	1%	23%	3%
Hydro sourced Flexibility (to move around vRE)	None	Very limited	No	Yes	Yes
Localized PV Generation	No	Not particularly	Yes	Yes (East)	Yes (North)

Availability of studies online	Very high	Medium	Medium	High	Medium
km of transmission lines	7000	42000	75000	40000	37000
Studies:					
Generation Adequacy Study	Yes	Yes	Yes	Yes	Yes
Least Cost Dispatch and Flexibility Study	Yes	N/A	Yes	Yes	Yes
Tx and Dx System Adequacy Study	Yes	Yes	Yes	Yes	Yes
Dynamic Study	Yes	(part of interconnection studies)	Yes	Yes	Yes
Tx Operational Studies (Reserve Design, Inertia Management, Voltage Support etc)	Yes	Yes	Yes	Yes	Yes
Market:					
Nodal vs Zonal	Zonal	Nodal (previously Zonal)	Nodal	Zonal	Nodal
Settlement Periods	30 min	5 min	5 min	5 min	60 min
vRE Integration Approach	Policy Driven	Policy Driven	Least-Cost	Policy Driven	Policy Driven
System Characteristics:					
Annual Generation	34TWh	203TWh	429TWh	200TWh	88TWh
vRE Energy Share (from Annual Generation)	46%	32%	31%	29%	38%
Peak vRE Penetration	75%	97.6%	72%	70%	75%

Peak Demand	7GW	52GW	85GW	36GW	12GW
Min Demand	2.6GW	11GW	30GW	11GW	7GW
Interconnectors	0.5GW (only HVDC)	8GW (synchronous connection)	N/A	N/A	0.2GW (only HVDC)
Installed Conventional Capacity	8.5GW	55GW	90GW	41GW	19GW
Installed vRE Capacity	5.7GW	21GW (+15GW embedded PV)	45GW	37GW	15.5GW

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