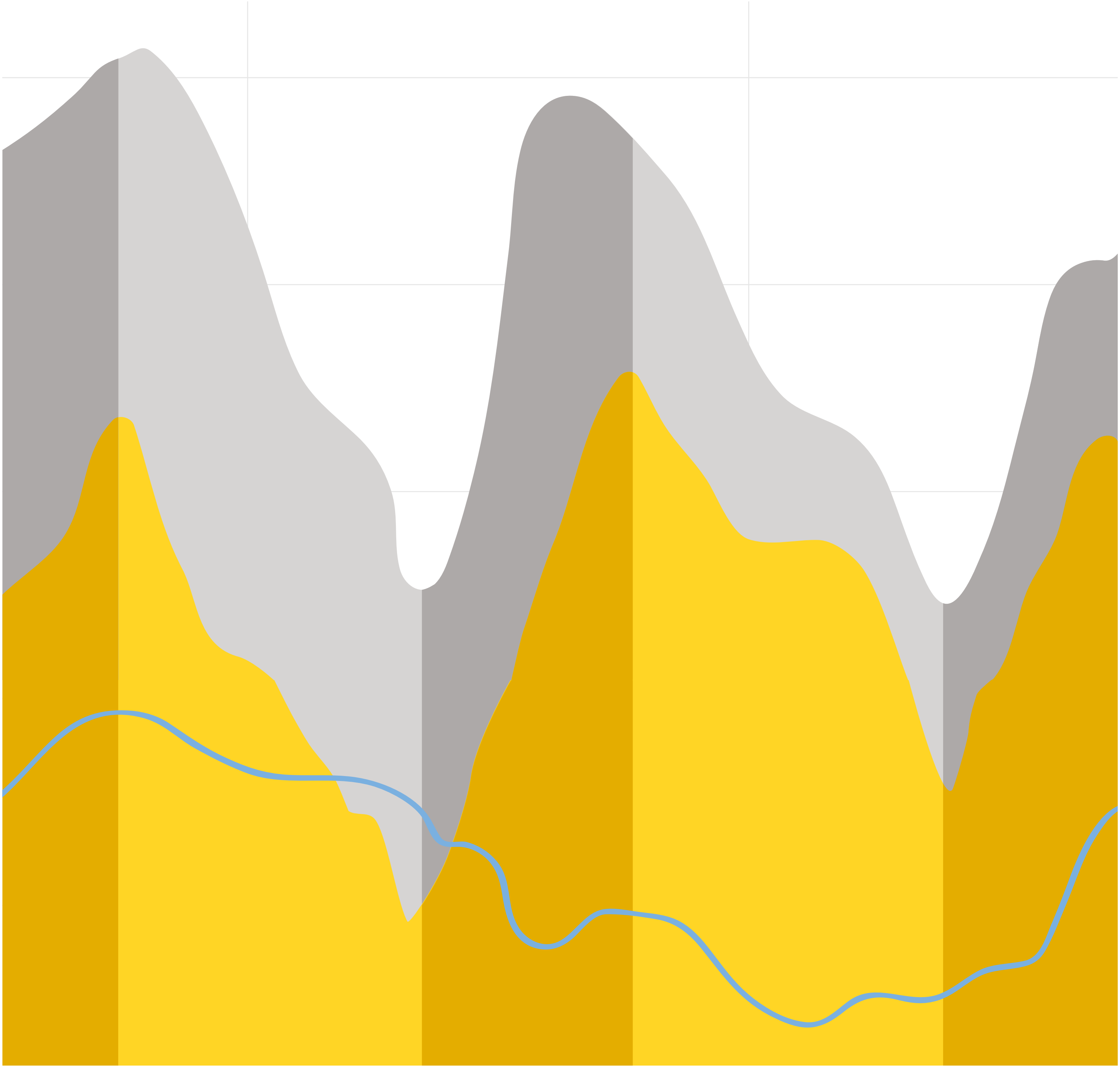
IRENA
International Renewable Energy Agency

PLANNING FOR THE RENEWABLE FUTURE

LONG-TERM MODELLING AND TOOLS TO EXPAND VARIABLE RENEWABLE POWER IN EMERGING ECONOMIES



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About IRENA

The International Renewable Energy Agency (IRENA) is an intergovernmental organisation that supports countries in their transition to a sustainable energy future and serves as the principal platform for international co-operation, a centre of excellence, and a repository of policy, technology, resource and financial knowledge on renewable energy. IRENA promotes the widespread adoption and sustainable use of all forms of renewable energy, including bioenergy, geothermal, hydropower, ocean, solar and wind energy in the pursuit of sustainable development, energy access, energy security and low-carbon economic growth and prosperity.

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ABBREVIATIONS

AC	alternating current
AVRIL	Addressing Variable Renewable Energy in Long-term Energy Planning
CC	combined cycle
CCGT	combined-cycle gas turbine
CCS	carbon capture and storage
CHP	combined heat and power
CO_2	carbon dioxide
CSP	concentrating solar power
DC	direct current
DLR	German Aerospace Center
DNI	direct normal irradiance
EAPP	Eastern Africa Power Pool
ECOWAS	Economic Community of West African States
ECP	equivalent conventional power
EDF	Électricité de France
EFC	equivalent firm capacity
ELCC	effective load carrying capability
ENTSO-E	European Network of Transmission System Operators
EU	European Union
EUE	expected unserved energy
EUR	euro
GHI	global horizontal irradiance
GIS	geographic information system
GW	gigawatt-hour
IEA	International Energy Agency
IGCC	integrated gasification combined cycle
IRENA	International Renewable Energy Agency
JRC	Joint Research Centre of the European Commission
kWh	kilowatt-hour
LOEE	loss of energy expectation
LOLE	loss of load expectation
LOLP	loss of load probability
MERRA	Modern Era-Retrospective Analysis for Research and Applications
MW	megawatt
MWh	megawatt-hour
NASA-SSE	US National Aeronautics and Space Administration Surface meteorology and Solar Energy service
NERC	North American Electric Reliability Corporation
NGCC	natural gas combined cycle
NREL	National Renewable Energy Laboratory (United States)
OCGT	open-cycle gas turbine
PC	pulverised coal

PV	photovoltaic
R&D	research and development
RAEL	Renewable and Appropriate Energy Laboratory at the University of California
REmap	IRENA's global roadmap to double the share of renewables in the energy mix
RLDC	residual load duration curve
SARI	South Asia Regional Initiative
TSO	transmission system operator
UK	United Kingdom
US	United States
USAID	United States Agency for International Development
USD	United States dollar
VRE	variable renewable energy

Note: Appendix 3 provides a list of models and tools referred to in this report, together with their abbreviations and website references to developers.

EXECUTIVE SUMMARY

Spurred on by ambitious national commitments, international agreements and rapid technological progress, national governments are increasingly choosing renewable energy to expand their power infrastructure. Renewables provided 23% of power generation worldwide by 2014. With the rapid adoption of more ambitious plans and policies, this could reach 45% by 2030 (IRENA, 2016a).

Amid this accelerating transition, the variability of solar and wind energy – two key sources for renewable power generation – presents new challenges. Energy planners have always had to deal with variability and uncertainty to some extent, but the challenges that variable renewable energy (VRE) poses to the power sector are in many ways distinct. Proactive planners, in both developed and developing economies, will aim to address these challenges directly, starting with today's long-term investment choices.

Decision makers rely increasingly on techno-economic assessments, both to inform policy development and to help set the right national targets for renewable power uptake. For that reason, the modelling of different possible future scenarios has become a critical planning tool in the power sector. Planners and modellers in certain markets have developed considerable knowledge on how to represent VRE in long-term models for power sector transition.

Findings from AVRIL ("Addressing Variable Renewable Energy in Long-term Energy Planning"), a project by the International Renewable Energy Agency (IRENA), highlight the best practices in long-term planning for, and modelling of, high shares of VRE.[1] The solutions presented here, although applicable in many countries, have been adapted to support energy planners and practitioners in developing and emerging economies, where the capacity to use the most resource-intensive methods of modelling may be unavailable.

The report includes two main parts:

Part One ("Planning the transition to variable renewables") offers guidance to energy decision makers and planners by providing an overview of key long-term issues and concerns around the large-scale integration of variable renewables into the power grid.

Part Two ("Long-term models for energy transition planning") offers guidance to technical practitioners in the field of energy modelling, specifically with a catalogue of practical VRE modelling methodologies for long-term scenario planning.

1 *This report focuses on a specific subset of the long-term energy planning field, namely techno-economic modelling of future scenarios. As such, it does not cover all issues related to long-term planning, particularly on the institutional side. For more detail on IRENA publications that cover the spectrum of issues in this field, see Appendix 1. Some key emerging areas in the techno-economic planning field, such as off-grid VRE and non-power sector coupling, are also omitted from this report; interesting planning work is emerging on these, and IRENA is following such trends closely.*

Guidance for decision makers: Planning the transition to variable renewables

Findings and recommendations from Part One of this report

Four key stages – spanning long-term to short-term time horizons – are standard in any cost-effective planning process for power sector transition. They are:

- **Long-term generation expansion planning** (typically spanning a period of 20-40 years),
- **Geo-spatial planning for transmission** (typically spanning a period of 5-20 years),
- **Dispatch simulation** (typically spanning a period of weeks to several years) and
- **Technical network studies** (typically spanning up to five years).

Although these stages are equally important, they are often practiced in a fairly decoupled manner, due to varying time horizons and institutional jurisdictions. Different modelling tools also are available for each purpose, and **planners should ensure that their overall approach is internally consistent.** Long-term modelling and scenarios should set clear parameters for successive shorter-term ones, so that models, data and policy goals are aligned across different time horizons. Achieving this goal will require more active co-ordination among stakeholders in different stages of the planning process (Chapter 1).

Feedback between actual processes and different stakeholders must be taken into account when assessing high shares of VRE in a power system. This is because some spatial and operational issues – such as the need for greater flexibility in the system and additional transmission capacity – may significantly change the cost-effectiveness of long-term planning scenarios (Section 1.2).

Planning VRE deployment: Where to focus in the long term

When planning for a high share of VRE in a power system, investments to address its deployment impact need to be taken into account, so as to avoid compromising a reliable supply of electricity.

A range of planning solutions are available to integrate the unique properties of VRE into power system operation, but the relevance of different solutions to long-term investment requirements varies.

- **Highest relevance: firm capacity.** The variability of VRE makes the concept of "capacity credit" – or the fraction of VRE capacity that is guaranteed to meet demand (known generally as "firm capacity") – crucial to reflect in plans for the long-term expansion of electricity generation. This is essential if future power systems are to have sufficient supplies to cover periods when low amounts of VRE are available. (Section 2.2)
- **High relevance: flexibility.** As VRE generation increases and contributes to greater variability and uncertainly of supply, the flexibility of a system becomes more important. While smart planning of VRE deployment can limit the challenge of balancing supply and demand, high shares of VRE are likely to require more investment in flexibility measures to maintain balance at all times. (Section 2.3)

- **High relevance: transmission capacity.** The availability of VRE resources depends on their location, and new capacity may need to be planned to transmit power from VRE resources that are far from centres of demand. Long-distance transmission lines also may need enhanced ways of controlling voltage. (Section 2.4)
- **Near-term/system-specific relevance: stability.** Improved operational practices, and other technical solutions to maintain the capability to respond to contingency events and control voltage, are available at relatively modest cost. Technical challenges relevant to long-term planning and investment may emerge only at very high levels of VRE penetration. (Section 2.5)

In presenting policy makers with a scenario for long-term electricity generation expansion, the scenario should explicitly address how to meet needs for firm capacity, flexibility and transmission capacity, specifically as driven by VRE deployment.

Investing in these three areas will have significant implications for cost-effectiveness over the long term. If institutional planning capabilities are insufficient, it could result in a substantial misallocation of capital and in a sub-optimal mix of power generation capacity. (Chapter 3)

VRE-grid integration studies typically are conducted to assess how much VRE a current system can accept. They generally are not meant to set a long-term limit on VRE penetration. While near-term technical and institutional limitations are useful to address when making long-term plans, long-term decisions are primarily economic.

Technical problems can be solved so long as there is a willingness to invest and to change operational practices. The key issue is how to reflect the costs of such solutions in long-term planning.

Guidance for decision makers: Long-term models for transition planning

Findings and recommendations from Part Two of this report

Given the importance of model-based assessment in establishing long-term pathways for power sector transitions, **models need to account for the long-term investment implications of VRE deployment.** There are several methods to achieve this. They are often complementary, but some are more complex than others.

The availability of data and modelling expertise should be the guiding principle when selecting appropriate methods to represent the impact of VRE deployment in long-term models of electricity generation expansion.

Countries are advised to start simple when improving planning for a high share of VRE, and to take a strategic approach, over time, to advancing both the scope and quality of models and the capabilities of their staff.

Best practices: Representing VRE in long-term planning models

In assessing methodologies and best practices to improve the representation of VRE in a power system, this report looks first at cross-cutting solutions (which can add value across a range of planning solutions) and then at complementary, tailored solutions, which more specifically address the needs for firm capacity, flexibility, transmission capacity and stability.

- **A cross-cutting solution (Chapter 4)**

  Increasing the resolution of models in time and space: The resolution of time and geographic space in long-term generation expansion models is typically too coarse to fully represent the planning measures needed to address VRE impact. Increasing temporal and spatial resolution can, in principle, improve the accuracy of representing VRE contributions to firm capacity, transmission capacity requirements and flexibility in these models.

  General complexity: Low to medium

- **Representing firm capacity (Chapter 5)**

  Improving "time-slice" calibration: Defining time slices (i.e., temporal model steps) more accurately, in order to capture key patterns in daily and seasonal variation, can better reveal the alignment between VRE generation and demand, making the VRE contribution to firm capacity more accurate. Defining time slices should be based on careful scrutiny of temporal variations both in load and in VRE generation, preferably for multiple years. Information on the availability of VRE (e.g., global re-analysis data) is increasingly available to support such an exercise.

  General complexity: Low to medium

  Incorporating "capacity credit": As an alternative to representing capacity credit based on the alignment of demand and supply within a model, externally defined capacity credit can be added to generation expansion models to reflect that contribution. By assigning capacity credit values to all capacity on the system, a model can be developed to ensure that system expansion maintains sufficient firm capacity. Capacity credit values can be incorporated simply as fixed throughout the model horizon, or as a function of the share of VRE. Methodologies are increasingly available to support the accurate estimation of capacity credit.

  General complexity: Low

- **Representing flexibility (Chapter 6)**

  Incorporating flexibility constraints: A system's flexibility can be represented in generation expansion models by first parameterising the ranges of operating flexibility (e.g., minimum load levels and cycling speed) for "flexibility provision" options – including dispatchable plant, storage, demand response and cross-border trade. Ramping requirements associated with the variabilities of demand and of VRE can be assessed separately and balanced collectively with available flexibility options at an aggregated system level. Using this "flexibility balance" approach, models can optimise investment in flexibility options to meet system requirements, as an additional constraint on the standard balancing of total power demand and supply.

  General complexity: Low to medium

Validating flexibility balance: As an alternative to, or in addition to, incorporating flexibility constraints, results from generation expansion planning models can be further scrutinised using more detailed tools, with different degrees of complexity. Such validation tools scrutinise operational aspects of a power system and give high-level indications about whether the energy mixes resulting from generation expansion planning models would offer sufficient flexibility.

General complexity: Medium to high

Linking with production cost models: Production cost models can be used to validate results from long-term generation expansion models, or to correct such results if necessary. Such a "coupling" approach can translate a system's needs for flexibility in operation (a focus of production cost models) into decisions around investment (a focus of generation expansion models).

General complexity: High

- Representing transmission capacity (Chapter 7)

Linking grid investment needs with VRE expansion: Transmission costs related to VRE can be assessed outside a model and then added to VRE investment costs in a generic manner (e.g., establishing and implementing a per-unit transmission cost for VRE capacity). This simplified approach does not allow any assessment of trade-offs between VRE resource quality and additional transmission capacity investment, but can reflect generic effects of VRE-driven transmission needs on VRE investments.

General complexity: Low to Medium

Site-specific representation of generation and transmission: The trade-off between VRE resource quality and additional transmission capacity investment can be assessed within a model by explicitly incorporating location-specific techno-economic characteristics of VRE. Practically, this can be achieved by incorporating clusters of VRE sites (or 'zones') as explicit options for investment. GIS-based tools and data are becoming increasingly available to allow for more accurate resource and siting assessments. Understanding and improving the representation of VRE resources in modelling will naturally help to make more accurate assessments of their associated needs for investment in transmission.

General complexity: Low to medium

- **Representing stability (Chapter 8)**

  Exploring possible constraints: Concerns about system stability at high VRE penetration levels – due primarily to operation with insufficient synchronous generators – currently may impose technical upper limits on instantaneous penetration in isolated systems. Such limits, and other potential bottlenecks in addressing near-term technical barriers, may need to be reflected as constraints in long-term generation expansion models, and explored as alternative scenarios.

  General complexity: High

Information and tools that address some of the key parameters discussed in this report – such as capacity credit, the flexibility characteristics of various resources, and transmission investment needs – are emerging, but they are scattered and are not necessarily in the public domain. Key points of reference are offered throughout this document. **As countries plan their transition to a high share of VRE, the continued mapping of new tools and data will be highly beneficial. It is essential for practitioners, policy makers and the energy modelling community to exchange planning experiences.** IRENA, in co-operation with energy planners and researchers, can provide critical support in these areas. This, in turn, should help to achieve a cost-effective long-term transition to renewables in the power sector.

LONG-TERM PLANNING FOR POWER SECTOR TRANSFORMATION

Spurred on by ambitious national commitments, international agreements and rapid technological progress, national governments are increasingly choosing renewable energy to expand their power infrastructure. Renewables provided 23% of power generation worldwide by 2014. With the rapid adoption of more ambitious plans and policies, this could reach 45% by 2030 (IRENA, 2016a).

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The opportunity: Power sector transformation with a high share of variable renewable energy

Countries around the globe are turning their attention towards renewable energy as the world aspires to accelerate deployment of these technologies. In 2014 renewable energy provided 23% of global power generation, a share that may reach 45% by 2030, as indicated in the global REmap analysis by the International Renewable Energy Agency (IRENA, 2016a). Nationally, shares of renewable energy are expected to range from as low as 18% to as high as 94% by 2030 in the 40 different REmap countries analysed by IRENA.

Reaching such high shares globally will require the use of a broad range of renewable energy technologies, based on hydropower, geothermal, bioenergy, solar, wind and ocean energy. The availability of all of these resources, apart from geothermal energy, is **"variable"** to different degrees and at different time scales – yearly, seasonal, monthly, daily, hourly and sub-hourly. Solar photovoltaics (PV) and wind generation have particularly pronounced variability, over shorter time scales, and this raises specific operational challenges when large amounts of wind and solar PV are integrated into the power system. As the proportion of these sources increases, some of the measures that are needed to integrate them have long-term investment implications that may not exist when shares of wind and solar PV remain low.

The **variable renewable energy (VRE)** sources discussed in this report refer primarily to wind and solar PV, due to their unique relationship to system integration, their rapid deployment resulting from significant improvements in performance and cost competitiveness, and their vast untapped resource potential. All of these aspects make them critical technologies for future power-sector expansion, and – although there may be near-term technical, operational, regulatory and market limitations – good long-term planning can ensure a cost-effective system transition to high VRE shares and help prepare policy makers before any technical constraints emerge.

A proactive approach: Long-term transition planning to define pathways

As the ambitious shift towards renewable energy proceeds, different **long-term scenarios** – generally defined as covering the next 20-40 years – must be developed and reviewed, specifically to assess and compare the cost-effectiveness of different transition pathways. Various modelling tools are available to support such assessments, and these are discussed in depth in this report. Energy policy making has always benefited from quantitative scenarios created with these tools, using them to define long-term policy goals and the most economic investment pathways to reach them (Mai et al., 2013).[2]

Such scenarios have been used mainly at two levels. At the first level, global or regional energy scenarios – developed by international organisations, companies or research institutes – have been used primarily to identify and raise awareness of key policy questions and their implications for the long-term development of energy systems. These scenarios can be very influential in shaping the global policy debate. Priorities in energy policy are subject to change and may focus on the environmental domain (e.g., climate change and air pollution), the social domain (e.g., energy access and development, energy security and transportation

2 *The application of long-term energy models to inform energy policy-making has been discussed extensively in the literature. For example, Decision Maker's Guide to Evaluating Scenarios, Modelling and Assumptions (Mai et al., 2013) – published by the RE-ASSUME program under the International Energy Agency Renewable Energy Technology Deployment (IEA-RETD) Implementation Agreement – addresses how energy scenarios and models have been used to inform policy decision making under uncertainty and describes common pitfalls in using such model results. The guide underlines that scenarios are not expected to predict the future and that models need to match the problem. Business-as-usual scenarios are developed as representations of the most likely outcomes under business-as-usual assumptions. They are not to be used as forecasts, but rather as points of reference against which diverse alternatives can be compared. The fact that the choice of model depends on the problem at hand suggests that there is no perfect model for universal application..*

policy) and/or the techno-economic domain (e.g., fossil resource availability, renewable energy integration and the hydrogen economy).

On the second level, national governments develop long-term energy scenarios in order to quantitatively assess the direction of future energy policy and the implications of taking one pathway of energy sector development instead of others. In many cases, governments have adopted long-term models to help develop scenarios. Such models typically explore both a baseline, or normative, scenario and alternative policy scenarios that cover a broad range of uncertainties and policy options.

Such scenarios form the basis of national long-term energy plans (often referred to as master plans), integrated energy plans or integrated resource plans, depending on the jurisdiction. A country's national energy plans – and the process of planning – equip policy makers with an understanding of the complex economic, political and environmental interrelations and uncertainties surrounding energy systems. These long-term plans feature quantitative targets for the energy mix that realise a country's overall policy goals, guiding the process of when, where and how to invest in the energy sector. Policy instruments and regulations are crafted to achieve these targets. (For more comprehensive discussion of energy planning purposes, processes and methodologies, see overviews provided in NASEO (2014), OLADE (n.d.) and Wilson and Biewald (2013)).

The process described above, of developing long-term scenarios and national energy plans, is described in this report as **"long-term energy planning"**.

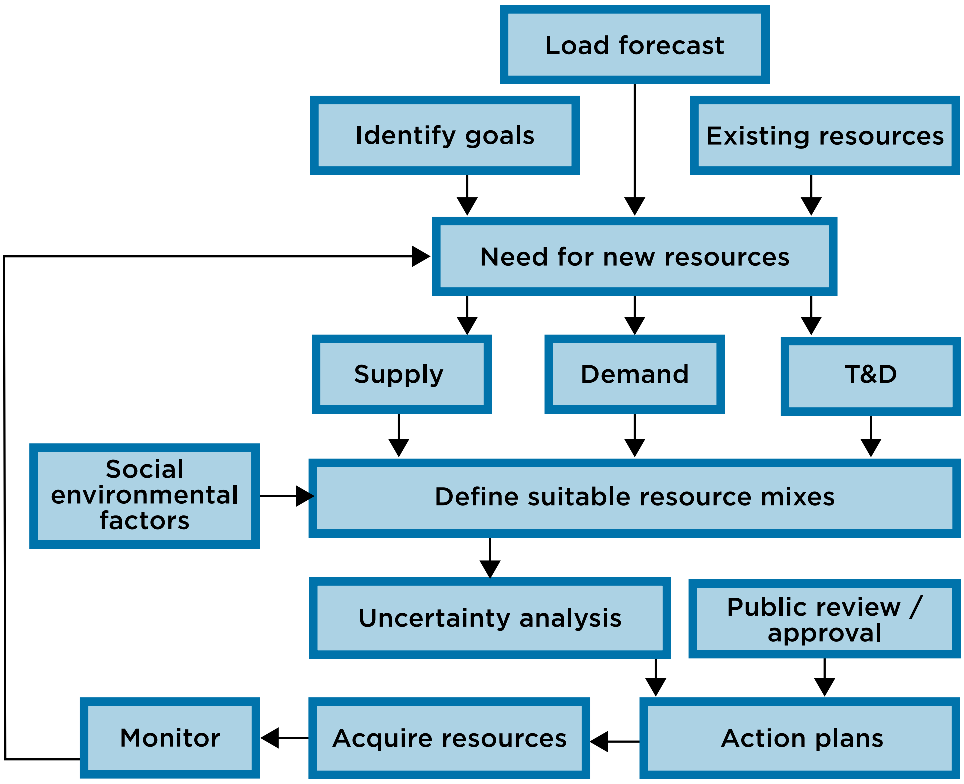
Within the process of long-term energy planning, stakeholders in the power sector often use targeted modelling tools to develop more elaborate scenarios, so as to evaluate concrete, least-cost investment pathways to providing reliable and affordable electricity. Planning the deployment of renewables can be integrated throughout this process, in order to establish effective long-term renewable energy targets as part of an overall energy master plan (IRENA, 2015a). An illustrative example of how long-term power sector planning is performed in the US context – where it is called Integrated Resource Planning – is given in Figure 1, adapted from Wilson and Biewald (2013).

A similar power sector planning process should be undertaken regardless of how the power sector is organised, whether market-based or otherwise. In either case, a long-term energy mix needs to be assessed to guide an appropriate set of policies. In a monopolised market, such a process is used by utilities to guide investments into generation. In liberalised power markets, long-term planning is important so as to craft appropriate rules and regulations to incentivise investment that aligns with long-term policy goals.

As the share of VRE increases in power systems, concerns have been raised over the suitability of existing tools and methodologies for long-term energy planning, as they may not be equipped with sufficient detail to capture the techno-economic implications of integrating these sources. While more detailed "grid integration studies" have been conducted, they typically assess how current power systems need to be reinforced to achieve a higher share of VRE, and their link with long-term planning is not very well established.

Long-term planning, when aiming at a transition to a system with a high share of VRE, needs to be adapted by ensuring clear linkages across studies that address different time horizons. In such a way, policy makers are assured that prescribed long-term renewable energy targets can be achieved without compromising the reliability of the power system, and that the long-term costs of achieving the transition have been assessed appropriately. Such an adapted approach of long-term planning for a higher share of VRE is referred to in this report as **"transition planning"**.

Figure 1: Flow chart for integrated resource planning



Source: Wilson and Biewald, 2013

Box 1 : Models and modelling tools

The difference between **"models"** and **"modelling tools"** is important to establish at the outset of this report.

Models are typically a set of mathematical equations with parameters. They are equipped with an algorithm to "solve" the equations and may have a graphical interface to help a user handle the equations and data. In this report, such interfaces are referred to as "modelling tools", which are considered as "model generators" rather than as models themselves and typically come in the form of a software package. The distinction between models and modelling tools is not always made clear, but it is relevant in the context of this report.

Many planners develop a national model using modelling tools. Indeed, developing such a model without the support of available modelling tools requires significant research and development (R&D) and is often beyond the scope of national planners. Some of the advanced solutions to improve the representation of VRE deployment impact in long-term generation capacity expansion models are "research grade". These may be difficult for national planners, who are using (somewhat inflexible) modelling tools, to implement. This report takes such limitations into account in its recommendations.

Scope, aim and intended audience of this report, and synergies with other IRENA power sector transformation work

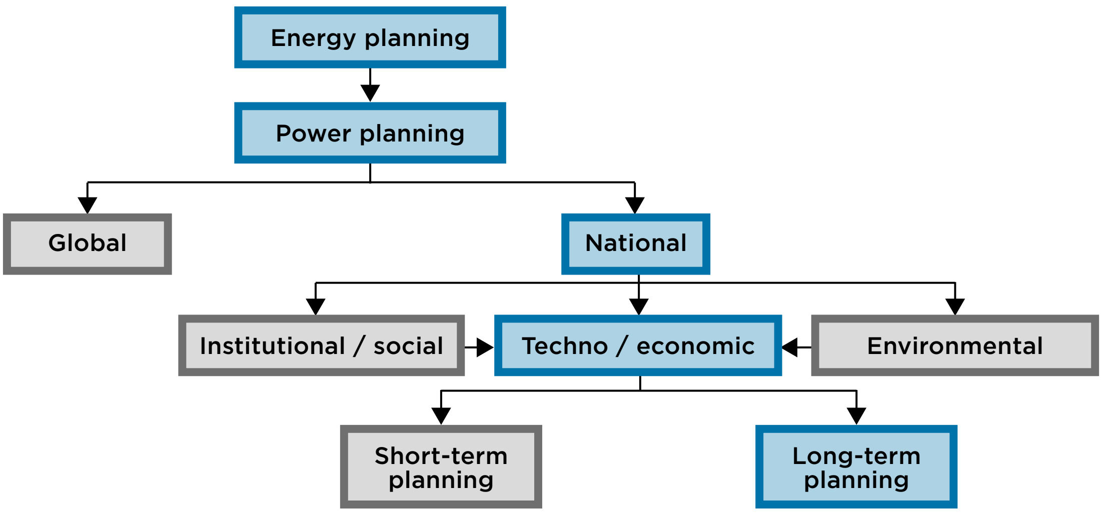
This report addresses the issues described in the previous sections and is built on findings from IRENA's **Addressing Variable Renewable Energy in Long-term Energy Planning (AVRIL) project.** This project, started in 2014, aims to help energy planners gain access to improved methodologies for assessing long-term investment strategies using long-term modelling tools, in order to plan a cost-effective, proactive transition to high shares of renewable energy.

The primary target audience of this report is energy decision makers, such as a department head within a na tional utility, as well as energy planning practitioners and officials from government, utilities and regulatory bodies in emerging economies who are tasked with scenario-based long-term planning for expanding power generation capacity, and associated policy-making. The publication also may be of interest to the research community, which may be able to identify and address existing methodological gaps in support of better long-term planning for a higher share of VRE.

In recent years, with VRE becoming a key component of energy systems, the limitations of existing models in representing the challenges of large-scale VRE integration have become better understood. The energy planning community can now access better information and better tools to reflect this emerging understanding, and this report brings together tested methodological practices to address the special characteristics of VRE in scenario-based long-term energy planning and modelling tools.

The focus is on planning solutions to support VRE deployment in the power sector, as that is primarily where challenges are experienced. Planning in the power and energy sector is not necessarily distinguished in this report, as the former is a subset of the latter. The solutions discussed in this report focus specifically on the **quantitative techno-economic aspect of power sector transformation.** The institutional aspects of the transition planning process are outside the scope of discussion.[3] Some of the institutional aspects of the transition to high shares of VRE – including stakeholder consultation surrounding energy planning, as well as regulation, market design and grid codes – have been addressed extensively in separate IRENA publications. Although linkages between long-term and near-term technical planning of VRE integration are discussed in this report, the focus is on cost-effective long-term integration, and separate IRENA publications deal more specifically with near-term planning.

Figure 2: The focus of this report in the planning field



3 *Some key emerging areas in the techno-economic planning field, such as off-grid VRE and sector coupling (i.e., linking power with other sectors like heat and transport), also are omitted from this report. Interesting planning work is emerging on these, and IRENA is following such trends closely. Although the distributed nature of some VRE is discussed briefly in this report, issues related specifically to distribution networks are not addressed.*

Full descriptions of IRENA publications that complement this report can be found in Appendix 1.

In presenting methodologies and recommendations, this report focuses on the needs of developing and emerging economies, where data availability and resources – both human and computing – may be limited. Such economies also have the potential for high growth in their energy needs, which introduces significant uncertainties in conducting long-term techno-economic assessments and further emphasises the need to increase their capacity for long-term energy planning.

For the purpose of this document, the term **"long-term energy planning models"** (used interchangeably with **"long-term generation expansion models"**) refers specifically to optimisation models that calculate capacity expansion paths on a planning time horizon of about 20-40 years. Modelling tools such as MESSAGE, TIMES, MARKAL, OSeMOSYS, WASP and BALMOREL serve as the interfaces to generate models in this category and are used to derive long-term investment plans for the energy or power sectors of many developing and emerging countries.[4]

The remainder of the report, following this introduction, is composed of two main parts. The first is intended for decision makers and energy planners and clarifies key planning concepts and modelling tools with a focus on VRE. The second is a catalogue of practical VRE modelling methodologies for long-term scenario planning and is intended for technical practitioners.

Part One ("Transition planning towards a high share of VRE") first maps the process of comprehensive power-sector planning over a range of time horizons, to situate long-term planning and modelling in this process. Key focus areas for planners are established for each time horizon within the process, and an argument for an integrated, or internally consistent, approach for transition planning is put forward.

Part One also establishes key planning solutions to address the impact of VRE deployment on power systems, as well as which solutions are most important from a long-term economic investment perspective.

Part Two ("Long-term energy planning models for transition planning") outlines different approaches that could allow better representation of VRE-driven planning in long-term models, building on the solutions highlighted in Part One. Descriptions of the approaches are complemented with examples of practical country application, as well as with references for useful data sources and methodologies.

4 *For a list of long-term planning models used for energy and power sector master plan development in selected countries, see Appendix 2. The full names of models used in abbreviated form in this report are given in Appendix 3.*

PART ONE

PLANNING THE TRANSITION TO VARIABLE RENEWABLES

In **Part One** of this report, two important sets of concepts are established and discussed in three chapters.

Chapter 1 ("The planning process") discusses power sector planning steps to address issues over different time horizons. Although the focus of the report is on long-term planning, this chapter aims to establish the links between that level and other steps that typically relate to shorter-term time horizons. The key message from this analysis is that although these planning steps often are practiced in a disconnected manner, they should be linked more clearly when planning a transition to high VRE shares, in order to capture unique VRE impacts that span time horizons.

In order to identify issues that are potentially relevant to long-term planning, **Chapter 2 ("Key planning implications of variable renewable energy deployment")** maps out the key characteristics of VRE sources, particularly in terms of their impact on functional properties of the power system, and discusses planning solutions to address that impact.

Chapter 3 ("Key investment implications of variable renewable energy deployment") then assesses which system properties and planning solutions are most relevant to long-term investment. This assessment then forms the basis for Part Two, which discusses practical methods to address these investment implications in long-term generation expansion models.

1 THE PLANNING PROCESS

This chapter aims to establish what is expected of long-term techno-economic assessment in planning the transition to a power sector with a high share of VRE. In doing so, it outlines the components of the power sector planning process, focusing on techno-economic assessments of possible pathways across different time horizons, and highlights the scope and characteristics of long-term techno-economic assessments in comparison to those for shorter-term issues (Section 1.1). Transition planning for a high share of VRE calls for a more integrated approach than is practiced traditionally, in which planning components across time horizons are internally consistent (Section 1.2).

For reference, Appendix 2 presents a mapping of different types of assessment tools to the different planning stages identified in this chapter. This mapping establishes that different tools address different planning questions, and that long-term planning tools (or other models) are not necessarily meant to address all planning questions at once.

Appendix 3 goes on to present over 30 different examples of planning tools used in national and regional studies.

Key points of Chapter 1

Four key stages – spanning from long-term to short-term time horizons – are standard in any cost-effective planning process for power sector transition. They are:

- Long-term generation expansion planning (typically spanning a period of 20-40 years),
- Geo-spatial planning for transmission (typically spanning a period of 5-20 years),
- Dispatch simulation (typically spanning a period of weeks to several years) and
- Technical network studies (typically spanning up to five years).

Although these stages are equally important, they are often practiced in a fairly decoupled manner due to varying time horizons and institutional jurisdictions. Different modelling tools also are available for each purpose, and planners should ensure that their overall approach is internally consistent. Long-term modelling and scenarios should set clear parameters for successive shorter-term ones, so that models, data and policy goals are aligned across different time horizons. Achieving this goal will require more active co-ordination among stakeholders in different stages of the planning process.

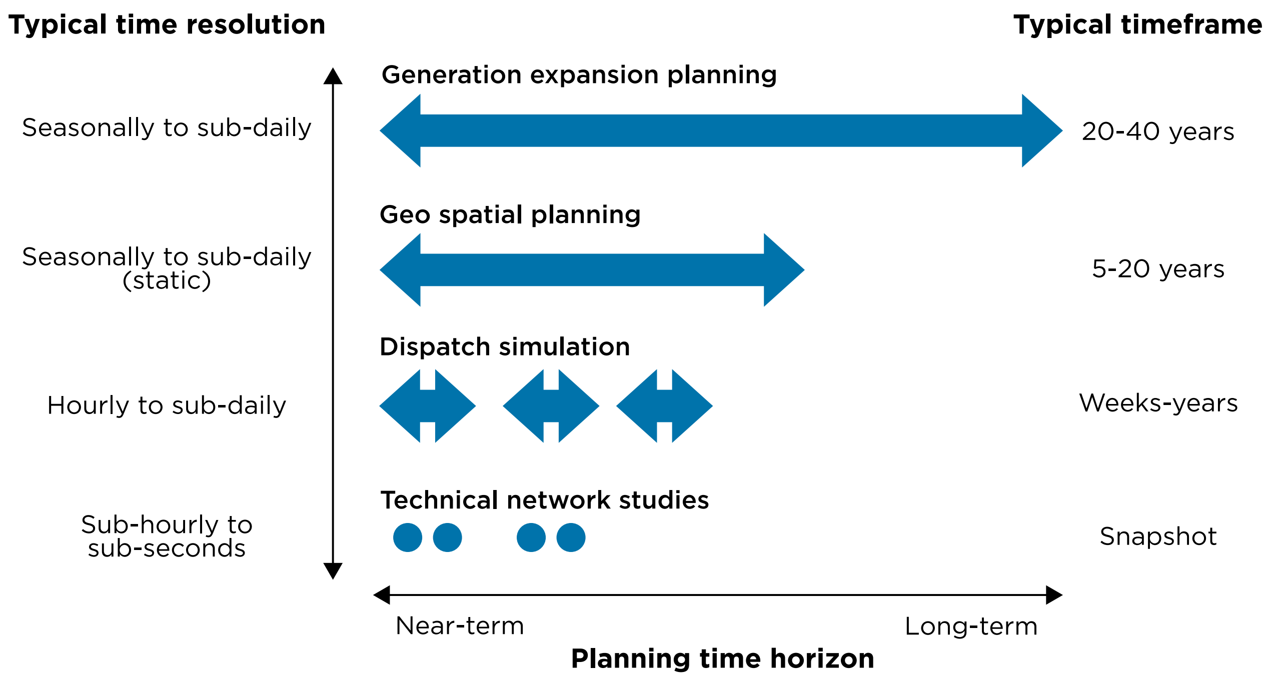
Feedback between actual processes and different stakeholders must be taken into account when assessing high shares of VRE in a power system. This is because some spatial and operational issues – such as the need for greater flexibility in the system and additional transmission capacity – may significantly change the cost-effectiveness of long-term planning scenarios.

1.1 Outlining planning components: Techno-economic assessments across planning time horizons

Thorough techno-economic assessments of possible pathways are critical in planning the transition to a power system with a high share of VRE, as they elucidate the implications of alternate policy choices. With that information, decision makers can take future actions more proactively and construct policies to meet multiple objectives that often are interrelated. Both near-term and long-term implications should be considered in the overall transition planning process, so as to understand and ensure the most cost-effective transition while meeting the non-techno-economic goals of a country's energy policy. By building assessments on meaningful stakeholder consultation, decision makers also can ensure that a consensus is established around the legitimacy of results (NASEO, 2014; OLADE, n.d.; Wilson and Biewald, 2013).

Four key planning components are defined in Figure 3. Although depicted as separate, some of these steps are often combined in the actual execution of techno-economic assessments, as discussed later. In the figure, three time dimensions also are distinguished: the planning **time horizon**, which refers to how far in the future the specific planning analysis is relevant; the **timeframe**, which refers to the overall period of time that is subject to techno-economic analysis; and the **time resolution**, which refers to the granularity, or level of detail, of analysis within the timeframe. The discussion below focuses on planning aspects in relation to the time horizon; the issues of timeframe and time resolution are discussed fully in Appendix 2, in relation to modelling tools for each planning step.

Figure 3: Transition planning components and time horizon



The four defined steps, and their associated planning time horizons, are:

1. **Generation expansion planning –** typically with a long planning horizon, 20-40 years or more. Such plans represent a broad political commitment to integrate renewable energy and are often linked with long-term targets. Frequently, they are published as an energy/electricity sector master plan.
2. **Geo-spatial planning –** primarily addresses the site location of VRE projects and the economics of long-term transmission expansion needs over 5-20 years or more. Some countries practise long-term (15 years plus) transmission development planning while others focus only on current or near-term (e.g., 5 years) network planning, often combined with technical network studies (see " Technical network studies" below).
3. **Dispatch simulation –** within a planning timeframe of weeks to a year (or a few years at most) during which the generation capacity mix in an energy system remains constant. It is applied either to a current system or to a system at a future point in time.
4. **Technical network studies –** used for detailed static or dynamic analysis of a system at a point in time, and typically applied to the current and near-term (e.g., 5 years) planning horizon, or longer-term for less detailed analysis. It primarily addresses network security issues so as to identify security bottlenecks in the grid, such as voltage control and stability.

Generation expansion planning is the central focus of this report. Table 17 in Appendix 3 presents a survey of tools used for generation expansion planning in the official national energy/electricity master plans of a selected group of countries. Many of the master plans surveyed in the Appendix have planning horizons of about 20 years. Common purposes of the generation capacity master plans include laying out the energy mix for future renewable target years, assessing economic and policy implications and their sensitivity to future uncertainties, and exploring alternative policy scenarios. Expertise in long-term scenario making often resides within a ministry responsible for energy policies or at governmental energy research institutions.[5] In some cases, countries use modelling expertise within utility companies to elaborate power sector investment strategies.

Geo-spatial planning, often in combination with technical network studies, is normally an integral part of the transmission planning conducted by transmission system operators (TSOs), regulators or the TSO-responsible unit within a utility. Geo-spatial planning refers here to planning practices that define a long-term vision for developing transmission lines, primarily on economic grounds. Traditional planning may not have considered this process of significant importance. However, a higher share of VRE may introduce a trade-off between the cost of transmission and the productivity of renewable generation,[6] which raises the profile of geo-spatial planning in the overall planning process. Geo-spatial analysis itself is practised at a wide range of complexity, from drawing lines on a map to using sophisticated geo-spatial planning tools. Results from that analysis can establish alternative transmission scenarios, to be further scrutinised by technical network studies.

Dispatch simulation primarily analyses the best use of all available power plants, considering different dispatch patterns and maintenance scheduling, and sometimes takes into account transmission congestion that may influence their utilisation. It may be executed for a day, a week or years ahead of real-time operation. TSOs may use such simulations for operational planning of dispatch (e.g., a day or a week ahead), and power generators

5 In some countries, domestic expertise is limited and consultancy firms are contracted for this purpose, which could result in limitations in adaptability as well as in the scope for timely updates.

6 The trade-off refers to the potential benefit of locating renewable generation in areas with higher-quality resources against the cost of transmission investment. For example, there may be times when the cost of new transmission capacity, or increased congestion in existing capacity, outweighs the benefit of a marginally higher-quality VRE resource. The trade-off is driven mainly by the fact that transmission is often less costly when compared with generation, and that renewable resources vary dramatically with location (Madrigal and Stoft, 2012) may use it for fuel budgeting and maintenance planning (e.g., years ahead). Policy and regulatory bodies also use them to inform policy and regulatory decisions made during the planning process. Dispatch simulation is increasingly undertaken as a part of "VRE integration studies", following recommendations by the research community (IEA Wind, 2013).

Technical network studies may be used to complement geo-spatial planning. For a longer-term study, or for a study of many transmission capacity expansion alternatives, so-called steady-state technical network studies can be performed to gauge operation outcomes at a broader level of reliability criteria. For a study that requires more detailed operational results – e.g., one in which the economic alternatives to expand transmission are limited, or if other screening processes render an exhaustive identification of alternatives unnecessary (see Madrigal and Stoft, 2012) – shorter-term technical network studies with highly detailed steady-state and dynamic reliability criteria are required.

The techno-economic assessments that accompany the steps described above are often conducted with tools that are tailored to their respective planning scope. For the sake of convenience in this report, these tools are categorised as **long-term energy planning models; geo-spatial planning models; production cost models;** and **network analysis models** (subdivided into static and dynamic grid models). Distinctions among these modelling types are not always stringent: advanced tools tend to cover multiple planning features. The tools used to assess near-term impact typically have narrower system boundaries and higher levels of detail, in terms of space, time and technical representation. Those used to assess long-term impact, by contrast, have wider system boundaries and longer planning time horizons and typically are associated with lower level of detail. For further discussion of the scope of these models, see Appendix 2.

Beyond the components described above and in Figure 3, comprehensive transition planning also involves planning for institutional changes. These include, for example, dispatching rules, power market design, regulatory frameworks and subsidy schemes, and permitting processes (IRENA, forthcoming-**d**). As discussed in the introduction to this report, these institutional planning aspects are outside the scope of analysis here, as they are covered by other IRENA publications (see Appendix 1). That is not to say, however, that institutional aspects are not involved in techno-economic assessments: institutional parameters play an integral role in defining scenario set-ups, and the techno-economic implications of alternative institutional parameters can be assessed to support decision making.

1.2 Moving towards a more integrated approach for transition planning

Investing in power sector infrastructure requires long lead times, and – given the long life of resulting projects – future investment options are influenced greatly by investments that are made today. Having a clearly specified long-term transition plan with an accompanying investment strategy allows transition planning components to be executed proactively, as opposed to taking a reactive approach triggered by the need to fix immediate, visible problems. Merely taking a short-term view is likely to result in delays, possible adequacy issues and economic inefficiency in the long term.

Avoiding near-term inefficiencies due to a poorly specified long-term transition plan requires a more integrated approach, which moves from long-term through short-term planning steps, and establishes clear, internally consistent feedback loops within techno-economic assessments.

Initially, a top-down approach to techno-economic planning and assessments is logical: steps would move from high-scope planning to high-detail analysis. First, long-term generation expansion planning defines future capacity mix. Having established that mix, a network investment plan is developed. The network topology and capacity mix are used to assess optimal dispatch, and that is used in analysis of load flows and stability to find weaknesses in system operation and to identify needs for network enhancements. Currently, routine analysis by power system operators often covers part of this process, performing optimal dispatch, then load flow and stability, analyses of the network. Planning consultancy firms often offer a planning service package in such a sequence.[7]

Such a top-down approach to planning and assessment is crucial to ensure a cost-effective transition, but in many cases the planning steps described above are made in a fairly decoupled way. This has the potential to create issues if left unaddressed in the often complex transition to high shares of VRE.

For example, planning for generation expansion cannot be done in isolation when assessing a long-term energy mix with high shares of VRE, because VRE investment is often constrained by location, and the costs of additional investment in transmission also must be accounted for. Decoupling the planning of generation and transmission investment may result in a system operator curtailing or rejecting the take-up of more renewable energy.

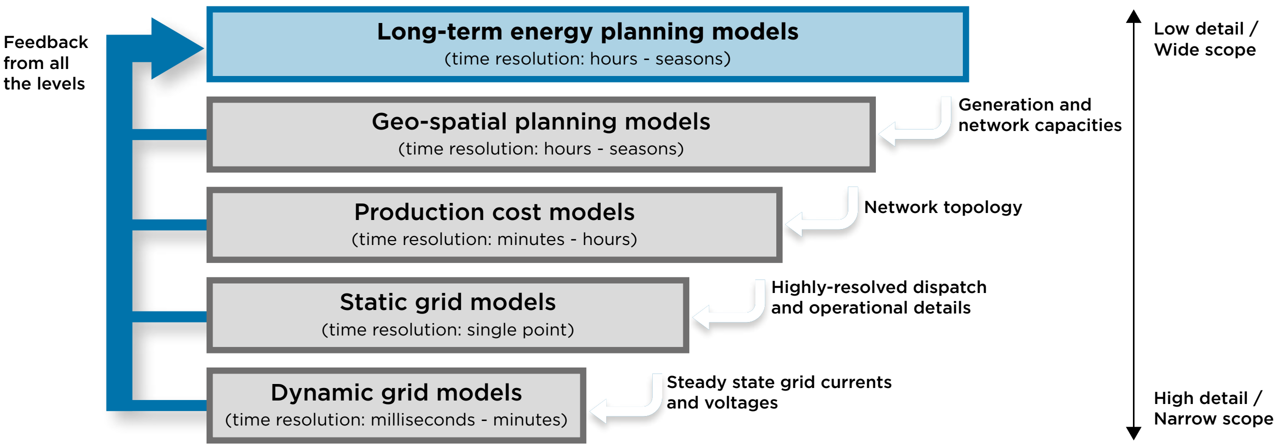
In a decoupled approach, long-term plans are also sometimes presented without any reference to the relevance (or irrelevance) of short-term reliability issues. If short-term issues have accessible solutions, this has potential to create misplaced concerns among policy makers and system operators, who may begin to think that ambitious renewable energy targets derived from long-term plans are at odds with the reliable short-term provision of electricity.

These issues of oversight and misplaced concern are common if steps in the planning and assessment process are not internally consistent and do not clearly address, in detail, the technical and economic implications of operating power systems with high shares of VRE. Establishing feedback loops within the long-term transition planning process and ensuring consistency across data sources and datasets employed at different stages can address the concerns of system operators and policy makers. A successfully integrated approach would ensure that the essential technical and economic impact of VRE deployment on the functional properties of power systems, rather than being overlooked, is accurately represented in all assessments and policies.

The following two chapters go on to discuss the key implications of VRE deployment on long-term planning in more detail, and identify which system properties are most relevant when constructing an integrated long-term transition plan.

7 A three-step approach in the style described here is proposed by Mercados (AF-Mercados EMI, 2011). It starts with least-cost planning (optimising production and network expansion with a time horizon of 30 years), followed by a simulation of production and the network (with a time horizon of 10 years) and then simulation of the power system for normal and extreme load conditions

Figure 4: Tools and analyses for energy system planning with feedback



Box 2: Changing the planning paradigm: example of geo-spatial planning

The process of transmission expansion planning across the world is well documented in Madrigal and Stoft (2012).

Long-term planning identifies overall transmission needs for a 5-20 year timeframe, given demand growth, the targeted energy mix, interconnection policies and VRE locations, among other factors. Short- to mid-term planning – from the immediate future to the next two to five years – may or may not be directly linked to specific transmission projects. The mainstream approach for transmission planning is traditionally "reactive" – e.g., responding to individual interconnection requests, or addressing transmission bottlenecks when they force inefficient use of generation assets – and often involves delays due to long lead times for transmission projects.[8] Proactive planning approaches, driven by the principle of long-term co-optimisation of transmission and generation planning, are increasingly being deployed as congestion in (or lack of) transmission becomes a prominent hurdle for renewable energy expansion.

8 The speed of network expansion has been identified as a common barrier for increasing the use of wind power in China, the US, Germany and Spain. In China, delays in grid expansion and lack of grid control and management technologies have caused massive curtailments: 17.5% in 2011 and 21.7% in 2012 (Lacerda and van den Bergh, 2016).

2 KEY PLANNING IMPLICATIONS OF VARIABLE RENEWABLE ENERGY DEPLOYMENT

VRE-based power generators have distinct properties compared to conventional power generators, and those properties, in turn, have unique impacts on the functional properties and operation of a power system. Since planners must ensure that a reliable supply of power is maintained as the share of VRE in a system increases, they also should ensure that the rest of the system adapts in a co-evolutionary way.

Numerous measures allow for proactive system adaptation to VRE. The key solution at the planning level is to acknowledge and prepare for these measures – especially in terms of their associated costs – at different stages.

The primary purpose of this chapter is to establish a key group of unique VRE properties (Section 2.1) and how they impact planning towards a high share of VRE (Sections 2.2 to 2.5). Section 2.6 summarises this discussion and links it to Chapter 3, which evaluates the relative importance of particular VRE impacts in relation to long-term investment, primarily from an economic perspective.

Key points of Chapter 2

When planning for a high share of VRE in a power system, investments to address its deployment impact need to be taken into account, so as to avoid compromising a reliable supply of electricity.

A range of planning solutions are available to integrate the unique properties of VRE into power system operation:

- **Planning for firm capacity.** The variability of VRE makes the concept of "capacity credit" – or the fraction of VRE capacity that is guaranteed to meet demand (known generally as "firm capacity") – crucial to reflect in plans for the long-term expansion of electricity generation. This is essential if future power systems are to have sufficient supplies to cover periods when low amounts of VRE are available.
- **Planning for flexibility.** As VRE generation increases and contributes to greater variability and uncertainly of supply, the flexibility of a system becomes more important. While smart planning of VRE deployment can limit the challenge of balancing supply and demand, high shares of VRE are likely to require more investment in flexibility measures to maintain balance at all times.
- **Planning for transmission capacity.** The availability of VRE resources depends on their location, and new capacity may need to be planned to transmit power from VRE resources that are far from centres of demand. Long-distance transmission lines also may need enhanced ways of controlling voltage.
- **Planning for stability.** Improved operational practices, and other technical solutions to maintain the capability to respond to contingency events and control voltage, are available at relatively modest cost. Technical challenges relevant to long-term planning and investment may emerge only at very high levels of VRE penetration.

2.1 Key properties of variable renewable energy

The five main properties of VRE generators that distinguish them from conventional generators (discussed more fully in Sections 2.2 to 2.5) are as follows:

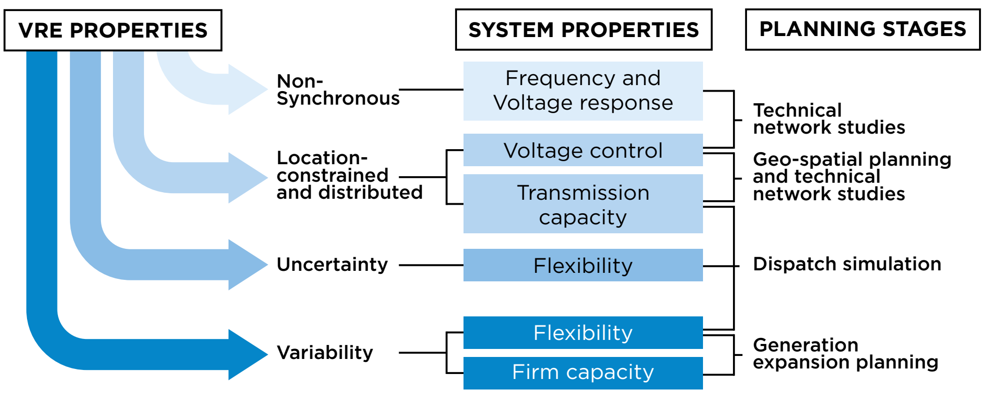
1. Due to its **weather-dependent nature**, VRE is limited in dispatchability (i.e., the ability to control its output) and has **variable seasonal and diurnal** (i.e., within-day) patterns of production.[9]
2. VRE generation can be forecast, but some **uncertainty** in forecasts remains.
3. VRE is **location constrained**, because its primary energy source cannot be transported, and VRE generators normally are built where the resources they need are good. These places may be far from centres of demand.
4. VRE resources are considered **non-synchronous** power sources (i.e., sources that have a power electronic interface with the grid, rather than a rotating mass that is directly connected).[10] Under certain circumstances, they may pose challenges to the maintenance of system stability, which traditionally relies on the "inertia"[11] provided by synchronous generators.
5. VRE generators are not necessarily connected to the transmission level of grid infrastructure and thus often feature as distributed generation.

These characteristics influence either the nature of, or requirements for, certain functional properties of the power system, the most important being: **firm capacity**, **flexibility**, **transmission capacity**, **voltage control**, and **frequency and voltage response**. These system properties are defined and discussed further in subsequent sections.

Figure 5 schematically summarises which properties of VRE influence particular system-level functional properties, and where in the transition planning process those influences typically are considered.[12] The figure does not intend to display a comprehensive overview of VRE impact on system operation; rather it focuses on the key areas in which VRE deployment has potential to influence the planning of power systems beyond straightforward changes to operational practice or technology adaptation. For a more detailed overview of VRE impact on system reliability and security, particularly in the context of developing and emerging countries, see Pöller (2014). The discussion in this section draws heavily on this literature as well.

The economic implications of this picture, related specifically to long-term investment priorities, are discussed in Chapter 3.

Figure 5: Key links between variable renewable energy, power system properties and planning



9 Sources that demonstrate pronounced variability within a short time period (e.g., sub-hourly), such as solar and wind, also are referred to as intermittent energy sources.

10 A machine that has a rotating mass directly coupled to the grid is often referred to as synchronous. The European Network of Transmission System Operators (ENTSO-E) defines a "synchronous power generating module" as a "set of installations which can generate electrical energy such that the frequency of the generated voltage, the generator speed and the frequency of network voltage are in a constant ratio and thus in synchronism" (ENTSO-E, 2011).

11 Inertia is defined as the "stored rotating energy in a power system provided by synchronous and induction generation" (NERC and California ISO, 2013).

12 Note that VRE deployment does not necessarily influence the ability of a power system to provide the functional properties displayed; it may only require a different level of that provision.

2.2 Planning for adequate firm capacity

Firm capacity is the amount of power generation that can be guaranteed to meet demand at any given time, even under adverse conditions (EIA, n.d.). Due to their variability – or, more specifically, due to the temporal mismatch between their variable generation and the variability of demand – VRE generators do not necessarily contribute their full capacity to firm capacity. They provide electricity, but their generation is weather-dependent, and not all of their nameplate (i.e., maximum) capacity can always be relied upon when determining adequacy, for example for times of peak demand.

The fraction of VRE capacity that can be relied upon as firm capacity is known as its **"capacity credit"**. This should not be confused with the concept of "capacity factor": capacity credit is determined primarily by how closely VRE generation matches demand, whereas capacity factor is determined primarily by the availability of VRE resources independent of the demand profile. Box 3 provides some common definitions of capacity credit used in the literature.

The capacity credit of VRE is normally evaluated in so-called generation adequacy studies, prepared and published by responsible authorities under respective jurisdictions.[13] **Generation adequacy** refers to the availability of sufficient generation to meet demand (i.e., firm capacity) at all times. The exact terminology and the methods of measurement to define the concept of generation adequacy vary across jurisdictions. A typical generation adequacy study, for example, would consider the firm capacity of all power generation capacity on a system in any future year, and whether it is sufficient to cover peak demand. The sufficiency of firm capacity is normally determined by policy makers, and it may be

Box 3: Definitions of "capacity credit" in the literature

Capacity credit is the contribution that a given generator makes to overall system generation adequacy. This concept is sometimes also referred to as "capacity value". Madaeni et al. (2012) define capacity value as "the contribution of a power plant to reliably meeting demand" and "the contribution that a plant makes toward the planning reserve margin".

More technical definitions of capacity credit reflect primarily the metric used to quantify the concept. For example, Mills and Wiser (2012a) define capacity credit as "the amount of conventional generation that can be displaced without reducing the level of reliability relative to what it would have been without the VRE", while Holttinen et al. (2009) refer to "the amount of additional load that can be served at the target reliability level with the addition of the generator in question".

Three commonly used metrics to measure capacity credit include equivalent conventional power (ECP), equivalent firm capacity (EFC); and the Effective Load Carrying Capability (ELCC) (Madaeni et al., 2012) sets out the following definitions:

- ECP: the amount of a different generating technology that can replace the new generator while maintaining the same system reliability level;
- EFC: the amount of a different fully reliable generating technology that can replace the new generator while maintaining the same system reliability level;
- ELCC: the amount by which the system's loads can increase (when the generator is added to the system) while maintaining the same system reliability.

Some detailed examples of capacity credit calculations for generation adequacy studies, along with example ranges for wind and solar PV, are presented in Box 11 in Section 5.2.

13 *For example, in ENTSO-E (2015), generation adequacy is assessed over a 5-10 year forecast, using a concept of reliably available capacity (RAC). The contribution of VRE to RAC is evaluated at the hour of the expected daily peak, using solar and wind load factor during that hour. In OFGEM (2014), the equivalent firm capacity (EFC) of wind is used to represent capacity credit and reflects the average contribution of wind power to the UK de-rated margin (i.e., reserve margin above peak demand). More probabilistic metrics of generation adequacy, such as loss of load expectation (LOLE), loss of load probability (LOLP) and expected unserved energy (EUE), also are used commonly (CEER, 2014).*

affected by a system's technological mix, the size of generation units, and their operational characteristics and strategies, as well as by market designs (Welsch et al., 2014a). The resulting margin of firm capacity required above peak demand is sometimes referred to as a **reserve margin**, and typically ranges from about 10 to 25% of peak capacity.[14]

Given the importance of having sufficient firm capacity to system reliability, understanding the relevant range of capacity credit values for VRE and matching the timing of VRE supply patterns with that of load patterns are key elements in long-term generation expansion planning. Temporal mismatch may cause a period when too much VRE is produced, which could lead to its being curtailed, or to a period of no production, which other capacity would be required to cover.

Good statistical temporal matching, on the other hand, results in a higher capacity credit for VRE. In some geographical areas, for example, solar irradiance often coincides with the need for air conditioning, and so solar PV's supply curve matches well with the overall pattern of electricity demand. The capacity credit of solar PV in such a system is likely to be high, particularly compared to what it would be in systems where peak demand occurs in the evenings, when sunlight is not available.

The capacity credit for a given VRE technology is also specific to its location. When aggregated VRE sources are from dispersed, distant sites – and thus meteorological conditions are less correlated – the capacity credit is higher than from sites in one concentrated location. Planning for a balanced mix of VRE deployment over a large geographical area may smooth out seasonal and daily variability in supply, and this could increase the capacity credit of combined sources.

14 *In North America, for example, a reserve margin in the range of 12-17% is observed across North American Electric Reliability Corporation (NERC) sub-regions (Short et al., 2011). Reserve margins do not always fall within the specified range, however – e.g., in the UK, where projected winter reserve margins have been below 5% in recent years (OFGEM, 2015).*

2.3 Planning for system flexibility

In order to keep a power system secure and reliable, demand and supply must be balanced at all times.[15] Dealing with variability in the balancing process is not a new issue for power system operation, as demand has always been variable to some extent. The same can be said about uncertainty: the variability of demand is not necessarily known and has to be forecast by system operators in order to construct a dispatch schedule for supply.

However, as the share of VRE supply increases in a system, the variability of VRE generation can potentially become more rapid, frequent and significant. Accordingly, the variability of **"residual load"** (also known as "net load", i.e., demand minus VRE generation) also increases. The ability of the non-VRE portion of the power system to adjust its generation to meet residual load under normal operating conditions is referred to here as **"flexibility"** (see Box 4 for a discussion of other definitions of the term).

To be clear, such flexibility is required primarily because of the rate of change in the residual load, rather than the mismatch between demand and VRE generation (which was discussed in the previous section). Rapid changes in residual load make it more challenging to balance total demand and total supply at all times.[16] A sufficient amount of flexibility is required to accommodate those changes. Insufficient flexibility could lead to load shedding (if the system cannot ramp up during periods of low VRE generation) or to VRE curtailment (if the system cannot ramp down during periods of high VRE production), in order to maintain balance and keep the system secure.

In a more flexible system, dispatchable power plants need to be prepared to ramp up and down more quickly, more often and at a higher magnitude in order to accommodate the variable power generated from VRE. Typically, hydropower and gas-fired plants offer such fast ramping. With technical enhancements, other generating technologies that normally are considered to be inflexible – including VRE sources themselves – also can contribute to system flexibility (Jacobs et al., 2016).

Other than the ramping capacity and products offered by power plants, the most common flexibility measures include storage technologies, demand response and cross-border trade. Storage technologies smooth out the variability of supply by shifting its timing, while demand-response measures similarly smooth out variability of demand, also by shifting its timing: both aim at better matching demand and supply. Cross-border trade increasingly is used as a source of flexibility and provides access to additional generating resources when VRE suffers from low availability, or helps to evacuate it when it is being overproduced.[17]

Reserve capacity set up to respond to uncertainty[18] also is considered to be part of flexibility, and this sub-component sometimes is studied more exclusively due to its near-term relevance to operation planning. Reserve requirements are set by authorities to cope with unexpected deviations under both normal and emergency operating situations. Definitions of different types of reserves (and the requirements for them) are highly dependent on the jurisdiction.[19]

15 *The balance between demand and generation at a given point in time is indicated by the system frequency (Lannoye et al., 2012). System operators aim to maintain frequency within a prescribed range, since a large enough imbalance between demand and supply can cause frequency deviation that results in system damage or failure.*

16 *For example, the timeframe relevant to the variability of wind and solar PV typically starts at about 10-15 minutes (during which the total output of wind and solar generation is expected to be relatively constant) (IRENA, forthcoming-a; Pöller, 2014), or even shorter in a small and isolated system where the whole system may be influenced by the same local climatic condition. Dispersing VRE resources over large geographical areas, or combining various technologies that use different resources (commonly uncorrelated, and sometimes correlated complementarily), typically can smooth out the variability of a portfolio of generators (IEA, 2014).*

17 *While limiting VRE curtailment is an important driver of such measures (generating electricity from VRE has nearly zero marginal costs, so excessive curtailment may be considered as a sign that a system is badly designed), for planning purposes a strategic amount of curtailment may be part of a cost effective solution. Investing in additional sources of flexibility – such as new flexible plants or storage options – only to accommodate a short period of extreme variability is likely to be less cost effective than accepting some curtailment. A well-crafted long-term planning can help to design a system that can optimally minimise such a loss.*

18 *The uncertainty is inherent in system variability, and to a large extent, is addressed by forecasting. The variability of VRE generation (together with the variability of the load) is forecast for a given dispatch-schedule timeframe, and a dispatch schedule is made accordingly. More accurate forecasting can reduce errors in the scheduling process. Deviations from the scheduled output level are still expected to occur, however, partly through inherent limits to forecasting and partly because dispatch scheduling time horizons are coarse compared to those typical for VRE variability. Using a five-minute dispatching schedule (as in Denmark, for example) instead of the commonly deployed one-hour one reduces such deviations from the scheduled output.*

Planners must ensure, through both long-term generation expansion planning and dispatch simulation, that the flexibility that has always been required of power systems is maintained and built upon alongside high shares of VRE.

Box 4: Definitions of "flexibility" in the literature

"Flexibility" is increasingly recognised as key to integrating VRE. Definitions of the concept vary in scope and detail, however, which leads to different metrics for measurement (an issue fully discussed in Section 6.1).

The International Energy Agency (2012) refers to flexibility as having three categories: stability, balancing and adequacy. Most definitions, implicitly or explicitly, define flexibility within the context of balancing, which refers primarily to regulation, load-following and scheduling. While balancing is linked with frequency control under normal operating conditions, stability is linked with post-contingency responses to get frequency and voltage back to a normal level.

Some definitions of flexibility make explicit reference to its balancing aspect, describing it as "the extent to which a power system can adjust the balance of electricity production and consumption in response to variability, expected or otherwise" (IEA, 2011) or "the ability to make adjustments necessary to balancing supply and demand and maintain system reliability" (Dragoon and Papaefthymiou, 2015). The definition of operational flexibility used in EPRI (2014) is more detailed in this respect, describing it as "the ability to ramp and cycle resources to maintain a balance of supply and demand on timescales of hours and minutes through reliably operating a system at least cost".

Other definitions implicitly assume that "fluctuations" and "changes" are those occurring under normal operating conditions. These include definitions such as: "the ability of the power system to adapt to the growing fluctuations of supply and demand while, at the same time, maintaining system reliability" (from the Council of European Energy Regulators, 2016), "the ability of the power system to respond to change in different time scales" (from the experts report on wind integration studies from the IEA Wind Taskforce 25 (IEA Wind, 2013)) and "the ability of a power system to respond to changes in electricity demand and generation" (from the National Renewable Energy Laboratory (NREL); see (NREL, 2015)). Sudden changes due to a contingency event (such as the failure of a generation unit in a system) are implicitly excluded. An important distinction here is that, under normal operation, needs are driven by weather conditions, whereas those following a contingency are not necessarily driven by VRE.

In Milligan et al. (2015), also from NREL, flexibility is defined to include time horizons of a month to sub-seconds, but an explicit statement is made to exclude from its assessment the shortest time interval (in which inertia response is used as the first line of defence).

Müller (2013) describes the flexibility concept as usually referring to maintaining the active power balance of a power system on a time scale of a few minutes to several hours, but it also has been applied to issues relating to the reactive power balance in power systems, and to active power balance at shorter time scales (it has been termed "technical flexibility"). Ulbig and Andersson (2015) explicitly include contingency response as a part of flexibility.

In this report, the concept of flexibility is defined narrowly, limited to within the balancing context under normal operating conditions.

19 Ela et al. (2011, 2010) provide an overview of definitions used in various jurisdictions and illustrate how the same terminologies are used to refer to different concepts. Below are some examples of how reserves with different activation times are referred to in various systems:

- *ENTSO-E: primary (30 seconds), secondary (15 minutes), tertiary (after 15 minutes)*
- *Irish system: regulating (30 seconds), operating (primary, 15 seconds; secondary, 15-75 seconds); tertiary, 5 minutes), replacement (20 minutes to 4 hours), substitute (4-24 hours), contingency (after 24 hours)*
- *NERC: Spinning (10 minutes), non-spinning (within 20 minutes), supplementary (30 minutes).*

2.4 Planning for transmission capacity and voltage control

The availability of VRE resources is location-specific: unlike coal or natural gas, the primary energy from wind and solar cannot be transported in its original form. This can constrain where plants can be sited. If a wind or solar resource location is far from centres of demand, power will need to be transported over long distances at a high voltage level. In some cases, geographic concentration of VRE deployment also may cause congestion in the existing transmission network.

A lack of sufficient transmission capacity has been a major issue in some countries and has resulted in significant delays in implementing VRE projects or in a high degree of curtailment of VRE generation (Kies et al., 2016; Lacerda and van den Bergh, 2016). A lack of strong grid infrastructure often is a particular challenge in developing and emerging countries, and their electricity networks may need to be substantially reinforced and extended, regardless of VRE deployment, especially in view of the fact that many countries' overall generation and demand are growing.

For these reasons, sufficient and well-sited transmission capacity must be in place for generation expansion.

Having a strong and extensive transmission grid in place allows a system to benefit from the smoothing out of VRE variability from geographically dispersed VRE sites, which requires balancing of generation over large areas.

If the expansion of VRE does require the development of longer high-voltage transmission lines in a particular context, planners also should be aware of any additional challenges this poses to voltage control. Longer transmission lines, and the unique properties of VRE sources themselves, could require greater investment in voltage control assets in the network.[20]

At the distribution level, VRE connected at low and mid voltage also has the potential to violate voltage limits, if unequipped with modern voltage control capabilities.

Despite the potential importance of the need to reinforce the distribution grid to accommodate high VRE deployment if it occurs at the level of the distribution network, this aspect is outside the scope of the current report, given that the priorities of many emerging economies focus more on the expansion of transmission-level generation capacity.

20 *This is due to the fact that over longer distances, maintaining the appropriate amount of reactive power capability, which system operators rely on to balance electricity at the nodes of the transmission network, typically becomes more challenging (irrespective of a type of generation capacity). For VRE generators in particular, due to their non-synchronous nature (see Section 2.5 for detail), additional measures may need to be taken to equip them with modern control functions and capabilities so as to allow them to support voltage control. Some legacy solar PV and wind installations may not be equipped with such capabilities, which could cause voltage control problems, especially when their penetration in a particular system is high. However, state-of-art technologies typically come with these capabilities, and various smart grid technologies also can be used to address this issue, particularly at a distribution level.*

2.5 Planning for stability (frequency and voltage response)

A critical role of system operators is to maintain both frequency and voltage within acceptable limits. In less technical terms, **frequency** is the parameter of a power system that indicates whether there is an imbalance between "active" power generation and consumption, while **voltage** is the parameter that indicates imbalance in "reactive" power (Lannoye et al., 2012; Pöller, 2014).[21] Sudden system failures, referred to in this report as **"contingency events"**, can cause both voltage and frequency to go beyond accepted limits. Such contingency events are driven primarily by factors independent of VRE-specific qualities, such as the loss of a large generator (renewable or conventional), transmission line or sub-station in the power system. The ability to return to a state of normal operation following a contingency event is referred to as **"stability"**.[22]

While deployment of VRE does not necessarily influence the occurrence of contingency events, it changes the system's ability to respond to contingency-driven imbalances in active power (indicated by frequency) and reactive power (indicated by voltage).

In the face of an active power imbalance following a contingency event, system operators can deploy successive "**contingency reserves**" with different response times to maintain the system's frequency stability.[23] How much frequency drops immediately following a contingency event (within a few seconds) is influenced by so-called **"system inertia"**. Inertia is provided by the rotating masses connected to the grid, and generators with such rotating masses are called **"synchronous"** generators. Conventional thermal generators are synchronous generators, whereas VRE generators are non-synchronous.[24] Although inertia, therefore, is traditionally associated with conventional generators, wind generators can mimic synchronicity through so-called synthetic inertia, drawn from their rotating blades.

Due to the dynamics described above, if large-scale VRE penetration leads to moments when a significant amount of wind or solar generation displaces non-VRE generation, system inertia may not be sufficient to maintain stability during contingency events.[25] Smaller systems, which are more susceptible to smaller contingency events than bigger systems, may have to be particularly vigilant on this potential issue. In the process of transition, some power systems may be required to limit instantaneous VRE penetration to maintain system stability, or to deploy alternative technology solutions that provide frequency stability services. These include active power control services available to some types of VRE, or other fast frequency response assets such as energy storage systems and demand response. Regional interconnection also could expand the balancing area and accordingly increase the available inertia within an interconnected system.

On the network side, voltage levels disturbed by a contingency event also need to be stabilised immediately afterwards, by balancing the reactive power in the affected area (i.e., maintaining voltage stability).

21 ***Active power*** *can be thought of broadly as power that is actually consumed, and is balanced at a system level, while* ***reactive power*** *refers to power that assists in the delivery of active power, controls voltage and is balanced locally. ENTSO-E (2011) defines active power as, "the real component of the apparent power at fundamental frequency, expressed in watts or multiples thereof such as kilowatts ('kW') or megawatts ('MW')", and reactive power as "the imaginary component of the apparent power at fundamental frequency, usually expressed in kilovar ('kVAr') or megavar ('MVAr')".*

22 *Stability has a number of elements. Kundur et al. (2004) propose a classification of various stability phenomena, suggesting that power system stability has three main aspects: rotor angle stability, frequency stability and voltage stability. These are then further divided into sub-categories.*

23 *The amount of contingency reserves required by a system depends mainly on worst-case assumptions regarding large, unplanned power plant outages, and not on the variability of wind and solar energy (Pöller, 2014). Contingency reserves can be provided by both VRE and conventional generators. However, VRE is not typically chosen to participate in such reserves on economic grounds, as it would entail operation with limited output.*

24 *Wind and PV inverters are "inertia-less" generators, meaning that they do not have any inertia (PV-inverters) or that the corresponding inertia is decoupled from the grid (variable speed wind generators) and will not release any energy to the grid in the case of frequency drops (Pöller, 2014).*

25 *In more technical terms, increasing non-synchronous generator penetration will effectively displace traditional synchronous generation in the system dispatch, reducing synchronous inertia in a system (O'Sullivan et al., 2014; Pöller, 2014).*

Although modern wind and solar PV generators are equipped with capability to participate in voltage control, if such an event takes place during a period of high wind and solar generation – in which many synchronous generators are disconnected – and VRE generators are located far from the affected area, sufficient reactive power may not be made available for balancing due to its limited ability to be transferred over long distances (Pöller, 2014). This impact typically can be mitigated at moderate cost by installing additional reactive power compensation assets.[26]

While this section describes the planning implications of high shares of VRE for two central areas of system stability (i.e., frequency and voltage stability), VRE deployment also has a number of more nuanced impacts on other aspects of stability. For a more detailed overview of the impacts of VRE deployment on system stability, see Pöller (2014).

26 IRENA (forthcoming-a) discusses devices for voltage compensation in greater detail.

2.6 Summary of long-term planning solutions for reliability with variable renewable energy

The sections above have discussed properties of a power system that can be affected by VRE deployment. In order to summarise the implications of this for long-term planning and to discuss them in the context of planning a reliable power system, this section has adopted a matrix from DNV GL (unpublished-a). The key system properties identified above – firm capacity, flexibility, transmission capacity, voltage control and stability – are placed in the matrix in Table 1. The matrix is formed by two axes. The first refers to **adequacy** and **security**, two principal dimensions for describing the **reliability** of a power system. Security has an additional dimension, **stability**.[27]

Adequacy refers to the availability of sufficient generation and network capacity to serve the load at all times, particularly during peaks. **Security** refers to the robustness of the power system in continuing operation during both normal and contingency situations, i.e., through reducing both the risk of contingency events occurring, and their impacts (Kundur et al., 2004; Pöller, 2014).[28] **Stability** more specifically refers to the robustness of the power system in continuing to operate during contingency events.

The second axis distinguishes generation and networks. Demand-side measures and storage are broadly included under generation here, while networks include transmission and distribution grids.

There is clearly a diverse range of properties to consider while planning power systems to accommodate high shares of VRE, influencing different stages in the planning process, and different aspects of reliability. Deploying measures to maintain the system properties identified in this chapter often has material investment implications, and some are more significant (and thus particularly relevant for long-term planning) than others. The following chapter presents such an assessment.

Table 1: Power system reliability: areas of focus for transition planning

	Generation	Networks
Adequacy	Firm capacity	Transmission capacity
Security of operation	Flexibility	Voltage control capability
	Stability (frequency and voltage response)	

27 Pöller (2014) points out that different definitions are found in the literature for the terms reliability, security and stability, and refers to a summary in Kundur et al. (2004) as one of the most relevant and most widely accepted definitions: "Reliability of a power system refers to the probability of its satisfactory operation over the long run. It denotes the ability to supply adequate electric service on a nearly continuous basis, with few interruptions over an extended time period. Security of a power system refers to the degree of risk in its ability to survive imminent disturbances (contingencies) without interruption of customer service. It relates to robustness of the system to imminent disturbances and, hence, depends on the system operating condition as well as the contingent probability of disturbances. Stability of a power system refers to the continuance of intact operation following a disturbance. It depends on the operating condition and the nature of the physical disturbance."

28 While the focus of this report is at the scale of planning time horizons, system security assessments also are carried out at a more granular scale during system operation (e.g., "day-ahead congestion forecast", "contingency analysis", etc.) (Pöller, 2014).

3 KEY INVESTMENT IMPLICATIONS OF VARIABLE ENERGY DEPLOYMENT

Chapter 2 discussed how the characteristics of VRE change the requirements for particularly important functional properties of an entire power system, such as firm capacity, flexibility, transmission capacity, voltage control and stability. This chapter examines the investment implications of those changes, with the specific aim of segregating those that have major long-term implications for investment from those with more modest long-term ones. This will provide a foundation for the discussion in Part Two on how to better reflect these implications in long-term planning models.

Key points of Chapter 3

Various solutions exist for integrating the unique properties of VRE into power system operation, but some are more relevant than others to the long-term planning process:

- Most relevant: plan for firm capacity
- High relevance: plan for flexibility
- High relevance: plan for transmission capacity
- Near-term/system-specific relevance: plan for stability

In presenting policy makers with a scenario for long-term electricity generation expansion, the scenario should explicitly address how to meet needs for firm capacity, flexibility and transmission capacity, specifically as driven by VRE deployment.

Investing in these three areas will have significant implications for cost-effectiveness over the long term. If institutional planning capabilities are insufficient, it could result in a substantial misallocation of capital and in a sub-optimal mix of power generation capacity.

VRE grid integration studies typically are conducted to assess how much VRE a current system can accept. They generally are not meant to set a long-term limit on VRE penetration. Although near-term technical and institutional limitations are useful to address when making long-term plans, long-term decisions are primarily economic.

Technical problems can be solved so long as there is a willingness to invest and to change operational practices. The key issue is how to reflect the costs of such solutions in long-term planning.

The purpose of long-term transition planning is to identify a path for a cost-effective transition to a power system with a high share of VRE. With that in mind, the long-term investment implications associated with measures to promote VRE are crucial to assess. As discussed in Chapter 1, a full assessment of power system reliability is not designed to be performed over the long-term planning time horizon (e.g., 20-40 years plus). Rather, planning considerations (as summarised in Table 1, Section 2.6) should ideally be linked, so as to allow feedback into long-term generation expansion decisions. For that reason, economic implications must be considered, particularly where they are relevant to long-term investment.

Table 2 summarises the assessment of the long-term investment implications of power system reliability aspects (as identified in Table 1). While continuing the previous chapter's matrix of focus areas for transition planning, Table 2 suggests, by way of colour codes, how relevant each area is to long-term investment. This prioritisation is based on two main factors: economic impact on the cost competitiveness of different generation options, and the potential to create operational and technical constraints that may limit future VRE deployment.

Ensuring sufficient firm capacity is assessed to be the most relevant; ensuring flexibility and transmission capacity are assessed to be highly relevant; and frequency response from generation assets may be relevant for certain systems with a very high share of VRE. Voltage control capability and voltage response are assessed to have low long-term investment implications, despite their importance to operational planning with much shorter time horizons and the need for an inclusive planning process that acknowledges the critical links between short- and long-term perspectives (as discussed in Chapter 1).[29]

These assessments are further elaborated in the sections below.

Firm capacity: most relevant to long-term investment

Investment in the capacity to provide generation adequacy in a system with a high share of VRE is likely to be the most relevant to long-term planning. This is intuitive, given that significant investment will be required in VRE capacity itself for a large-scale transition. Investment to ensure sufficient firm capacity is especially important in many emerging countries, where rapidly growing electricity demand (sometimes around 5-10% a year) urgently requires capacity expansion.[30]

Understanding VRE's contribution to firm capacity (the concept of capacity credit discussed in Section 2.2 and elaborated in Section 5.2) over the course of a long-term generation expansion plan can have significant investment implications. For example, a temporal match between future demand and VRE supply profiles could substantially improve the contribution of future VRE capacity investments to firm capacity, possibly leading to reducing the need for peak-capacity investment. Neglecting hypothetically low capacity credits at high VRE penetration could lead to insufficient capacity to cover demand at all times and entail further investment to meet generation adequacy requirements.

Table 2: Long-term investment implications for transition planning

	Generation	Networks
Adequacy	Firm capacity	Transmission capacity
Security of operation	Flexibility	Voltage control capability
	Stability (frequency response...and voltage response)	

Most relevant — High relevance — Relevant in certain systems — Near-term relevance

29 The broad categorisations of relevance to long-term planning presented here are supported by a number of more in-depth studies on the overall system cost of VRE integration. See, for example, Ueckerdt et al. (2013) and Hirth et al. (2015)

30 This sentiment is echoed in Pöller (2014).

Notably, non-conventional measures, such as storage deployment and demand-side response, also can act as alternatives to investment in firm capacity.

In certain systems, the nature of investment in capacity will be affected by lower utilisation of non-VRE generators as VRE deployment increases. For example, in mature power systems with existing and dispatchable generation capacity – which traditionally covers a near-stable (or even declining) demand – the shift to high shares of VRE can result in systematically lower use of existing non-VRE generators. Such a systematic change in generation patterns can result in an enduring change in the competitiveness of power plants in a liberalised market context. Although questions about the recovery of investment costs for those plants affected by system transition need to be addressed in the near term, such questions are likely to become less significant as the mix of generation capacity develops over the long term towards greater flexibility.

Flexibility: high relevance to long-term investment

As discussed in Section 2.3, ensuring power system flexibility requires a design that complements the variability of VRE in the most cost-efficient way. Failing to deliver such a design could lead to VRE generation being excessively curtailed, which may imply cost-inefficient utilisation of VRE.[31] Developing countries with rapidly growing demand may have an advantage in the design of flexible power systems, as there is less risk that existing inflexible plants become sunk costs.

The central question regarding long-term investment for flexible system design surrounds the optimal mix of flexible generation and other flexibility measures to complement VRE's fluctuating output. The economic viability of investing in unconventional power system flexibility measures, such as storage and demand-side management, also needs to be assessed.

As a power system's share of VRE grows, the costs linked to the limited flexibility of power plants – including the opportunity cost of not dispatching less-expensive inflexible plants in favour of dispatching more-flexible but more expensive generators – may increase. While the system's overall fuel cost saving due to VRE penetration may likely surpass the potential cost increase, long-term investment decisions that do not take into account the implications of balancing related costs in a more flexible system may turn out to be sub-optimal.

Transmission capacity: high relevance to long-term investment

In most cases, if VRE resources are not located near the existing electricity transmission network, increasing the share of VRE ultimately will require additional investments in the grid.

Given that investment in generation often has higher absolute cost implications than transmission, a sequential approach of first defining the generation mix, then the optimal transmission capacity for that mix, is logical in principle, and often practiced. However, if the site specificity of VRE resources requires additional transmission expansion – and corresponding investment – ignoring transmission costs in planning long-term generation expansion may result in a sub-optimal investment strategy.

Furthermore, an economic trade-off may exist between transmission capacity investment and resource quality of generation at a given site: there may be times when the cost of new transmission capacity, or increased congestion in existing capacity, outweighs the benefit of a marginally higher-quality VRE resource.

Accounting for transmission investment in long-term planning of the generation mix may produce materially different results. Implementing a feedback loop or link between planning stages (discussed further in Chapter 7) can allow for more cost-effective investment.

31 This is because the marginal production costs of VRE are near zero. As noted in Section 2.3, however, a strategic amount of curtailment may be part of a cost-effective planning solution.

Frequency response at the generation level: system-specific relevance to long-term investment

As discussed in Section 2 .5, if frequency stability is to be regained after a contingency event, there needs to be enough inertia and contingency reserves (reserves that can be deployed immediately following the contingency event) in the system in order to provide a response. Although VRE does not contribute to system inertia, VRE operation can be adapted to support frequency response (an adaptation referred to as synthetic inertia).[31] The long-term investment implications of such operational adaptation are likely to be marginal when compared to the investment needs for power generation.

Other technical solutions, including batteries, can support frequency response (IRENA, 2015b) and have been implemented in small-island systems achieving high shares of VRE. However, there are no examples yet of large interconnected systems that are balanced through renewable power.

Stability constraints due to lack of system inertia may be relevant to long-term transition planning limiting long-term VRE investment opportunities. In Ireland, for example, a 50% maximum instantaneous penetration level of VRE was enforced (EirGrid and SONI, 2016). Whether such technical limits exist in different contexts, what their actual values would be, and how technological progress may affect them in the future, depend greatly on the specific system involved – although, as a general rule, such considerations are most acute for smaller and isolated systems.

Voltage-control capability and voltage response: mainly relevant to near-term investment

Investment in control equipment and network enhancements is necessary to ensure voltage-control capability and to maintain a system's secure operation with a high share of VRE.[33] To address voltage control and stability issues, planning must also consider additional investment in reactive power compensation devices.[34] The actual level of investment required in these areas is determined following criteria set out in the relevant grid codes, and can be system-specific. The topology of a network plays a big role, and evaluating the need for investment requires detailed network analysis. Typically, the investment required for voltage control is moderate or negligible compared to what is needed for power generation.

The impact of VRE generators on voltage control, therefore, may be assigned a low priority in planning long-term generation expansion, except where a system is isolated. Measures to mitigate their impact on voltage control and voltage stability are readily available, and could be implemented at a comparatively low cost. Such adjustments are not expected significantly alter the long-term generation expansion path.

From concepts to modelling tools

This chapter has identified key aspects of VRE impact with long-term investment implications.

Our assessment suggests that firm capacity, flexibility and transmission capacity have particularly significant long-term investment implications, whereas the other aspects discussed have limited long-term investment relevance, except in smaller or isolated systems.

Based on this assessment, Part Two discusses how these important long-term investment implications are addressed in typical long-term planning tools, and presents different approaches that can better represent VRE impact from an investment perspective.

32 For an overview of inertia response and frequency control techniques for renewable energy sources, see Dreidy et al. (2017).

33 As mentioned in Section 2.4, modern VRE generators are themselves equipped with advanced voltage control capabilities.

34 IRENA (forthcoming-a) discusses this topic in greater detail.

PART TWO

LONG-TERM ENERGY MODELS FOR TRANSITION PLANNING

Part Two of this report presents practical methods to represent, as effectively as possible, the impact of variable renewable energy (VRE) deployment on power system investment over the course of future decades. The focus is on the planning areas that were identified in Part One as being relevant for long-term investment.

Chapter 4 focuses on the challenge of the granularity of long-term generation expansion models in time and geographical scope. The resolution of these models typically is too coarse to represent VRE's impacts on the key power system properties identified in Chapter 3, and increasing the resolution can, in principal, help better capture such impacts.

Chapters 5-8 provide a catalogue of more specific practical methodologies to better represent VRE impacts in long-term generation expansion models, centred around representing firm capacity (Chapter 5), flexibility (Chapter 6), the transmission capacity of a grid (Chapter 7), and stability constraints (Chapter 8) in recent, innovative planning studies.

Part Two as a whole is not designed to evaluate and compare different modelling tools per se, but rather to identify elements of the design and application of the various models available. The purpose is to improve the representation of VRE in long-term planning and generation expansion models. Modelling tools, meanwhile, continue to evolve and improve.

4 A COMMON CHALLENGE: LONG-TERM MODEL RESOLUTION

Long-term energy planning models used for generation expansion planning have a long (15-40 years plus) planning horizon. As discussed in the Introduction, such models are used to define investment paths and to inform long-term strategic decision making over the development of a national energy system, alongside long-term policy goals. Utility companies sometimes use more elaborated models, focusing only on the power sector, to define an optimal generation capacity expansion path. For reference, Table 17 in Appendix 3 summarises long-term planning models used in an extensive range of official national energy/electricity master plans.

The long planning time horizon of these models is, somewhat by definition, their key common feature. This limits the level of detail in representing time periods in models, often because of limited computational capability to solve a model within a practical time. Section 4.1 discusses how temporal and spatial resolution is typically represented in long-term planning models, and how altering it can influence results. Section 4.2 discusses how increasing model resolution would improve the representation of VRE's impact across the range of system properties noted in Part One.

Readers are reminded that "models" and "modelling tools" are distinguished in this report (see Box 1 in the Introduction). The targeted beneficiaries of this report are likely to use "modelling tools" to generate models, rather than to invest in R&D for their own model development. This distinction is relevant as it limits the solution sets discussed throughout these sections.

Key points of Chapter 4

Given the importance of model-based assessment in establishing long-term pathways for power sector transitions, models need to account for the long-term investment implications of deploying VRE that were identified in Part One. There are a number of methods to achieve this, and they often are complementary, but some are more complex than others. Some are research grade, and energy planners in many developing and emerging countries that lack extensive modelling R&D may have difficulty implementing them.

The availability of data and modelling expertise should be the guiding principle when selecting appropriate methods to represent the impact of VRE deployment in long-term models of electricity generation expansion.

Countries are advised to start simple when improving planning for a high share of VRE, and to take a strategic approach, over time, to advancing both the scope and quality of models and the capabilities of their staff.

Increasing the resolution of models in time and space: The resolution of time and geographic space in long-term generation expansion models is typically too coarse to fully represent the planning measures to address the various impacts of VRE that are identified earlier in this report. Increasing temporal and spatial resolution can, in principle, improve the accuracy of representing VRE contributions to firm capacity, transmission capacity requirements and flexibility in these models.

General complexity: Low to medium

4.1 Model resolution in time and space

Typically, two different temporal resolutions are incorporated in long-term generation expansion models. The first is used to describe the development of capital stocks and investment decisions. It has a very coarse granularity, using time steps of up to about five years. This is normally sufficient for the purposes of generation expansion planning given the long lifetimes of infrastructure and power plants, and the long planning horizon of 15-40 years plus.

The second temporal resolution aims at representing the operation of the power system – accounting for both the intra-annual variability of VRE supply and load – and the resulting flexibility requirements and relevant technical characteristics of dispatchable power plants.

In order to represent the variability of demand, the 8 760 hours that make up a year are broken down into time blocks (referred to here as **"time slices"**) that capture seasonal, weekly and daily variations. A rather small number of representative time slices – typically in the range of 12 to 64 – is used in long-term generation expansion models. To illustrate: seasonal demand variation can be represented by the four seasons; weekly demand variation can be represented by two contrasting types of day (weekdays versus weekends); and daily variation can be represented by four six-hour blocks – totalling 32 time slices (see Figure 6). Different modelling teams take different approaches in the way they define the time slices.

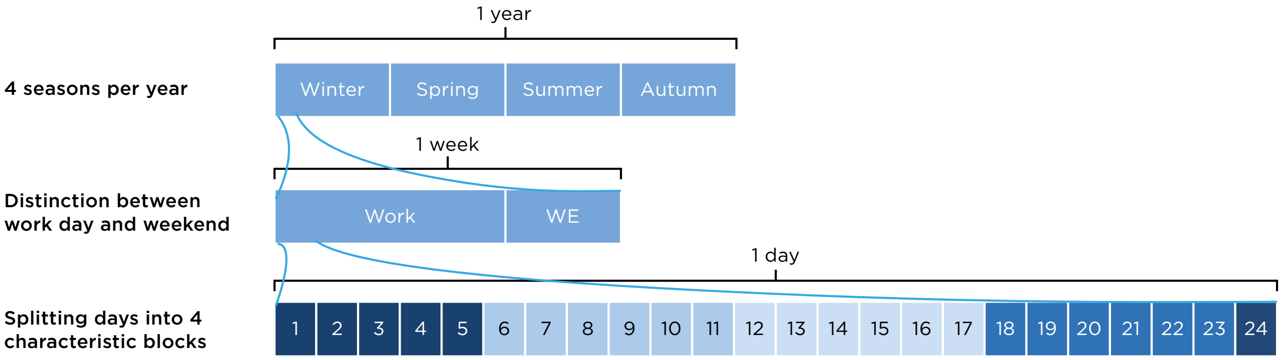
When VRE is only a negligible part of the power system, such time slices are defined primarily according to the variability of demand (and according to the seasonality of river or reservoir levels, in a system with a high share of hydropower). As VRE increasingly penetrates the system, however, models need to capture the variability of its supply as well.

Insufficient capture of the variability of supply could lead to a sub-optimal or even an inadequate capacity mix, as the costs linked with periods of VRE over- or under-production are insufficiently represented, and the need for flexibility in the system may be underestimated.

The geographical resolution in long-term generation expansion models is, furthermore, typically insufficient to capture certain impact of VRE that are driven by their location constrained nature.

The entire geographical area of these models is often divided into multiple sub-regions, allowing the spatial distribution of load, VRE resources and non-VRE resources to be reflected. These sub-regions are represented in generation expansion models as **nodes**, which are associated with the aggregated demand of a given sub-region. Countries within a bigger region – or sub-regions within a country – can be represented by multiple nodes, and investment and trade in electricity nodes are determined to maximise benefits from the differences in the nodes' costs in generating electricity at any time.

Figure 6: Example of time slice definitions (32 time slices per year)



However, the geographical resolution – represented by the number of nodes in a model – is typically limited in long-term generation expansion models. A country model application, for example, often has only one regional node, and thus transfers of power within the country (i.e., via domestic transmission lines) are not analysed. Regional applications of such models often incorporate regional nodes – where each country is represented by a node – thus allowing international power transfers to be assessed.

Although the geographical resolution of long-term generation expansion models is typically too coarse to represent VRE's location specificity – and thus is not suited to representing long-term transmission investment needs accurately – models with multi-regional nodes can provide a first-order approximation of the quantity and cost of the expansion of transmission that would be needed to accommodate increasing levels of VRE. The resulting scenarios also provide a somewhat co-ordinated expansion of generation and transmission capacities.

Box 5: Survey of modelling tools for generation expansion planning in the literature

Several comprehensive survey studies on energy planning tools have been published in recent years (see brief summaries below).

These results, however, need to be used with caution. The models continue to evolve, particularly with ever-increasing computing capabilities. Multiple versions of models have been released, and new functionalities tend to be added. The assessments below are static, made at the time of evaluation (with two of them conducted more than five years ago). Because IRENA experts do not have hands-on experience with all of the tools mentioned, the accuracy of the assessments made in the respective publications was not independently verified.

Connolly et al. (2010) survey 37 computer tools for analysing renewable energy integration into various energy systems. Their features are assessed based on feedback from the developers of the tools: 24 out of 37 tools have scenario timeframes longer than a few years, and 13 of these have external user-bases beyond their developers; 12 of these 13 (listed in Table 3) cover either the energy sector as a whole (8 tools) or just the electricity sector (4), the other one is a tool for a single-project assessment. As of the date of the survey (2009), Invert, LEAP, Mesap PlaNet, PERSEUS and RETScreen had simulated an electricity sector based on 100% renewable energy.

The authors define key model attributes to classify types of modelling tools. They are, among others:

- **Simulation:** simulates how a particular energy system supplies a given set of energy demands
- **Equilibrium:** seeks to explain how supply, demand and prices behave in an economy – or part of it – with several-to-many markets
- **Top-down:** determines increases in energy prices and demand using general macroeconomic data
- **Bottom-up:** first identifies and analyses energy technologies before working options for investment and alternatives
- **Operation optimisation:** optimises how an energy system operates
- **Investment optimisation:** optimises investments in a given energy system.

Table 3: Characteristics of selected long-term energy planning tools

	Sectoral Scope	Simulation	Equilibrium	Top-down	Bottom -up	Operation optimisation	Investment optimisation	Training needs	
								Basic	Advanced
BALMOREL	electricity (+ partially heat)	Y	partial	Y	Y	Y		2 weeks*	
EMCAS	electricity (+ partially transport)	Y		Y		Y		2 weeks	1 week
ENPEP-BALANCE	energy		Y	Y	Y			1 week	2 weeks
Invert	energy	Y			Y		Y	1 day	
LEAP	energy	Y		Y	Y			3-4 days	
MARKAL/ TIMES	energy		Y	partial	Y	Y*	Y	some months	
MESSAGE	energy		partial		Y	Y	Y	2 weeks	Several months*
MiniCAM[35]	energy	Y	partial	Y	Y				Several months
Mesap PlaNet	energy				Y		Y	5 days	
PERSEUS	energy		Y		Y		Y	2 weeks	
RETScreen	electricity				Y		Y		
WASP	electricity	Y			Y*	Y*	Y		4-6 weeks

*Based on IRENA experts' experience, some evaluations have been modified from the original publication.
Adapted from Connelly et al., 2010

Hall and Buckley (2016) survey energy system modelling in the UK, as discussed in 110 academic publications. These mention a total of 96 models: 86 papers mention the MARKAL model, 15 mention MESSAGE, followed by POLES, PRIMES (9 papers) and BREHOMES, ESME (8 papers). Twenty-two models are discussed and classified according to purpose: "general (forecasting, exploring, back casting); specific (energy demand, energy supply impacts, environmental appraisal, integrated approach, modular build-up); model structure

35 IRENA notes that this model name has been officially changed back to GCAM since the time of the author's original publication (degree of endogenisation on demand and supply sides); geographical coverage (global, regional, national, local, single project); sectoral coverage (energy, other specific sectors, overall economy); time horizon (short, medium, long-term); and time step (minutely, hourly, monthly, yearly, five yearly, user-defined)." Nine UK policy papers since 2008 are also reviewed, with 14 models mentioned (MARKAL most frequently).

Af-Mercados EMI (2011) surveys and evaluates 22 commercial power sector optimisation modelling tools. Five of them are planning tools with long-term planning horizons, four are dispatch and planning tools (see Table 4), and the rest are dispatch modelling tools. The evaluation is thorough and is focused on their suitability to model a power system with VRE.

Table 4: Characteristics of selected long-term power sector planning tools

	Dispatch or planning	Objective function	Generation or network	Stochastic modelling	Reliability considered	Renewable energy volatility	Forecasting errors	Hydro modelling*
AURORAxmp	D&P	not clear	G	Y (only for dispatch)	Y	Y		2
EGEAS	P		G	Y				0
WASP	P	system cost minimisation	G	Y	Y	N	N	1
EMCAS	D&P	system cost minimisation and maximisation of revenue of agents	G			scenario approach		1
GEM	P	system cost minimisation	G&N		Y	N	N	1
Optgen	P	system cost minimisation	G&N	Y	Y	Y	N	4
PLEXOS	D&P	system cost minimisation	G&N	Y	Y	Y	Y	2
Ventyx System	P	minimisation of net present	G&N	Y	Y	Y		2
Optimizer		value of revenue requirements						
UPLAN	D&P	system cost minimisation and maximisation of consumer surplus	G&N	Y	Y	Y	Y	3

* *Refers to hydropower resource modelling, scored according to how the value of water is calculated: Score 0 = not capable of modelling or no information available, score 1 = fixed energy, score 2 = fixed energy or calculation of approximation, score 3 = one type of water value calculated, score 4 = Stochastic Dual Dynamic Programming*

Source: Af-Mercados EMI, 2011

Krishnan et al. (2015) review models that co-optimise generation resources and transmission investment, distinguishing those used for national or regional-scale policy analysis from those used for detailed transmission planning. National Energy Modeling System (NEMS), ICF Integrated Planning Model (IPM), MARKAL/TIMES and WASP-IV are listed as examples of the former category. Examples of the latter are given in Table 5. Types of transmission investment representation in these models are distinguished based primarily on the model fidelity: the alternative current (AC) model, the direct current (DC) model, transshipment (or network flow) model and hybrid models.[36] "Continuous" investment refers to a decision on how many transmission lines are to be built, while "binary" investment refers to a simplified decision whether or not a candidate transmission project is to be built.

Table 5: Summary of existing co-optimisation models for planning generation and transmission

Model name	Transmission investments	Sectors	Time step / horizon
COMPETES	AC/DC continuous	Electric	Samples of hour/yearly (sequential if multiple years)
GENTEP	AC/DC binary/continuous	Electric (includes micro-grid)	Hourly or monthly or yearly/ multi-years
Iterative gen-trans co-optimisation	AC/DC binary/continuous	Electric	Hourly or monthly or yearly/ 40 years
LIMES	Continuous	Electric	Aggregate hours (6 hours per time slice) in sampled days/40 years
Meta-Net	Transshipment continuous	Electric, fuel, transportation	Hourly/yearly (sequential if multiple years)
NETPLAN	Transshipment continuous	Electric, fuel, transportation	Hourly or monthly or yearly/ 40 years
Prism 2.0: US-REGEN	Transshipment continuous	Electric, fuel, transportation	Samples of hour/yearly (sequential if multiple years)
ReEDS	DC (single stage lag in line impedance update)	Electric	Samples of hour/40 years (2-year sequence)
REMix	AC/DC continuous	Electric/heat	hourly/multi-year
Stochastic Two-stage optimisation model	AC binary	Electric	Hourly or daily/50 years (multi-stages)
SWITCH	Continuous	Electric	Sampled hours in sampled days/ multi-year

Adapted from Krishnan et al., 2015

36 *An AC model consists of a complete representation of real and reactive power flows in the transmission network, governed by electrical flows, which are expressed in terms of a non-linear function of network and network parameters (impedances). A DC model is a linearised approximation of a non-linear AC model and it does not incorporate voltage variables. A transshipment model similarly represents the transmission network to transportation pipelines, which move a commodity between nodes in a network subject to an efficiency parameter representing transportation losses. It does not incorporate voltage variables and the relationship of real power transfers with the bus angle difference and line impedance (Krishnan et al., 2015).*

4.2 A cross-cutting solution: increasing temporal and spatial resolution

Generation expansion planning models are not designed to assess the full impact of VRE deployment on power system operation and reliability. Yet the key investment implications of the impact in each of these areas can be represented, to various degrees, in generation expansion planning models. Based on these investment implications, focus areas for transition planning for a high share of VRE were identified in Part One (Chapter 3), as summarised in Table 2. However, the low temporal and spatial resolution of models typically used for generation expansion planning limits the representation of these investment implications.

Increasing a long-term generation planning model's temporal and spatial resolution can, in principle, help to better capture the economic impact of VRE deployment: it does so by capturing the potential alignment of VRE supply and variable demand, the time-linked operational constraints of a power system (e.g., flexibility) and grid investment needs, among other aspects. Increasing model resolution also may function as an enabling requirement for implementing other solutions, something that will be discussed at times in the remainder of Part Two.

Increasing resolution alone is not always sufficient to address some of the key impacts of VRE in a long-term generation planning model. To make this solution effective, it needs to be accompanied by other modelling improvements, which are the focus of subsequent chapters. Notably, in any modelling exercise, the appropriate level of detail is commonly espoused to be a function of the question asked, with more not necessarily being better (Merrick, 2016). Any given number of time slices or spatial clusters can be defined either wisely or poorly. Methods of better defining time slices, rather than merely increasing them, are discussed in Section 6.1.

In addition, temporal and spatial resolution can be increased only to a limited extent, because a model's computational time exponentially increases as the task becomes more complex.[37] Furthermore, increasing a model's resolution of time and space requires detailed datasets and calibration expertise, which may not be readily available to energy planners in all countries.

Given the particular importance of increasing temporal and spatial resolution, we discuss these aspects further below. The improvement of temporal and spatial definition is discussed throughout the following chapters where relevant.

Effects of increasing time resolution

When the temporal generation profile of VRE is well aligned with the temporal profile of demand, the value of the VRE source is considered to be high. With everything else being equal, investing in such VRE sources makes better economic sense than investing in those sources that are worse-aligned with the temporal profile of demand. Models with coarse time resolution are not able to take into account such economic implications appropriately in assessing the long-term capacity mix.

Box 6 lists some studies that investigated, within long-term energy models, the effects of increasing temporal resolutions on capacity and generation mix. As these studies demonstrate, the selection of a certain temporal resolution in a long-term generation expansion model strongly influences the resulting long-term generation and capacity mix. As the number of time slices is increased, a given model can often be seen to show VRE deployment more favourably. Specifically, models with a higher time resolution tend to suggest that cost-effective long-term investment decisions lie less in inflexible baseload generation and more in flexible dispatchable generation. In other words, time resolution appears to be crucial to improve the representation of VRE deployment and the resulting investment implications in generation expansion models.

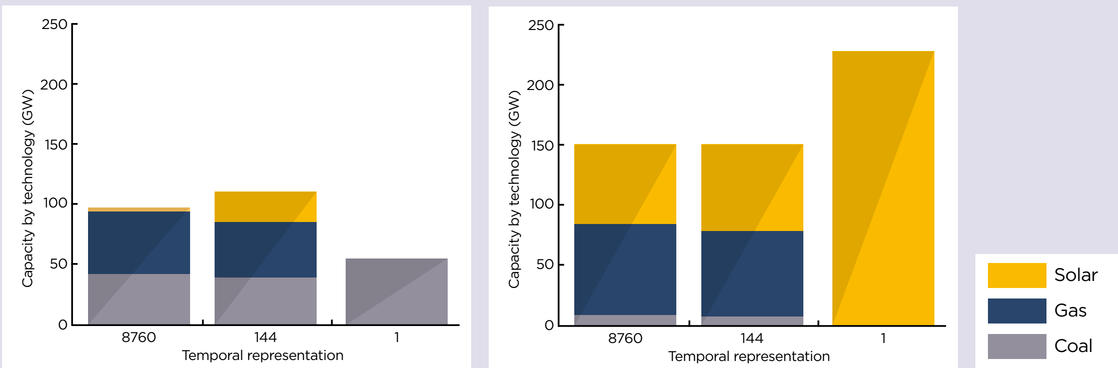
One cannot, however, generalise that reduced time resolution would either overestimate or underestimate the resulting share of VRE (Merrick, 2016).

37 For example, an elaborated model run may take days or weeks. Such run times could serve as a significant impediment to model development and analysis tasks (21st Century Power Partnership, 2016).

Box 6: Long-term generation expansion models: increasing time slices and its impact on results

Generic (Merrick, 2016): A simple mathematical model is constructed in this study to investigate the impact of model time resolution choice on generation and capacity mix. Three time resolutions are analysed: 8 760, 144 and 1 (the number of periods per year); 144 periods are based on 2 days from each month, and 6 blocks from each of these days. A representation of 144 periods overestimates the correlation between demand and solar PV, in comparison to the 8 760-period representation. Figure 7 shows that regardless of the PV cost assumption, the 144-period representation overestimates solar PV compared with the 8 760-period representation, while the 1-period representation either overestimates or underestimates depending on the PV cost assumption.

Figure 7: Optimum capacity mix by temporal representation, with USD 1 per Watt PV case (left) and USD 0.5 per Watt PV case (right)



Belgium (Poncelet et al., 2014): A simplified **TIMES** model, inspired by the Belgian power system, is developed in this study with a planning time horizon of 40 years. Two versions of the model are developed, one using 12 time slices per year and the other using 8 760 time slices per year. In both models, a renewable electricity generation target share of 50% is imposed at the end of the planning period. The results of the models with low and high temporal resolutions are compared and differ in their anticipated curtailment and capacity mix. The model with a high resolution selects a more diversified VRE portfolio and invests more in mid-load plants (combined-cycle gas turbines – CCGTs). It also better captures the benefit of solar PV and invests more in the technology. By contrast, the lower-resolution version anticipates no curtailment. By using an operational (production cost) model, the low-resolution alternative's long-term generation expansion plan is shown to fail to achieve the desired policy target, and to be costlier than the plan put forward by the high-temporal-resolution one.

Germany (Nahmmacher et al., 2014): A **LIMES-EU** model is developed in this study for the European Union with a planning time horizon of 40 years, configured with 8 to 800 time slices per year. The concept of seasons is not adopted in defining the time slices, but clusters of days with a similar load/solar/wind profile are defined: for each cluster a day is represented with 8 intra-day types. A carbon dioxide (CO_2) reduction target is also imposed. The simulation results show that a lower number of clusters over-represents the contribution of wind (over 40% of generation from wind with an 8 time slice case, versus 30% with 800 time slices). With a higher number of clusters, nuclear is selected to meet the CO_2 reduction goals (20% in the 800 time slice case). Solar PV's contribution remains rather constant across the time slices, presumably because the intra-day time slices are kept constant at 8.

Switzerland (Kannan and Turton, 2012): A **TIMES** model for electricity in Switzerland is developed in this study with a planning time horizon of 110 years. A year is divided into 4 seasons, 3 day types and 24 intra-day types. Two scenarios are generated using a low-time-resolution model (2 day types and 2 intra-day types) and an hourly resolution one, and the results are compared. In both scenarios, the low-resolution model invests more in baseload technologies and less in more flexible generation (for example, gas combined cycle). In one of the scenarios, the share of solar PV in 2080 is significantly higher in the high-resolution model than in the low-resolution one (28% versus 15%) due to a better capture of diurnal matching between solar generation and demand. The authors note that, despite good data availability for Switzerland, the effort in preparing for this high time resolution was substantial and that they needed to make a number of assumptions.

São Miguel Island, Portugal (Pina et al., 2011): A **TIMES** model for São Miguel Island is developed in this study with a planning horizon of 20 years. A year is divided into 4 seasons, 3 day types and 24 intra-day types (making a total of 288 time slices). The 24-hour division in each day enables the model to optimise the system, taking into account the existence of peak and off-peak hours and hourly variations in the production of renewable electricity. At least 25% of the electricity in each hour needs to be generated from thermal engines to represent the needs of the spinning reserve. The optimal penetration level of wind generation is analysed, and the results are compared with the results obtained with a lower-time-resolution version of the same model. The results indicate that lower-resolution models (with fewer than 8 daily time slices) overestimate wind capacity compared with the 1-hour resolution model. It is noted that changing the daily resolution from 12 to 24, and further to 48 (30-minute intervals), would not alter the results significantly.

Texas (Nicolosi et al., 2011): A **THEA** model was developed in this study for the Texas electricity market with a planning time horizon of 22 years. Three versions of the model are developed with different numbers of time slices, 8 760, 288 and 16. The wind share of generation is set as an out-of-model assumption (exogenous). In one scenario, it is 4.8% at the end of the planning period (no increase from its start); in the other, it is 25%. Under both scenarios the low-resolution model under-represents the need for peaking plant capacity (e.g., open-cycle gas turbines (OCGTs), or gas/diesel reciprocating engines) and for total capacity requirement. This outcome is more pronounced in the high-wind scenario. In that scenario, the low-resolution model over-represents nuclear (35% versus 50%) and under-represents gas (30% versus 20%). As this scenario's temporal resolution increases, the mix of conventional generation tends to move away from baseload plants towards intermediate and peaking ones that can cost-effectively meet the decreased capacity factor and flexibility needs of wind generation.

It is important to note – in addition to the caveats discussed earlier in this section regarding the appropriateness of the time resolution being driven by the question at hand – that the benefit of introducing higher temporal resolution needs to be assessed against the uncertainty of future evolution in demand levels and patterns (e.g., from improvements in efficiency, the diffusion of air conditioning, the rate of electrification or the uptake of electric vehicles), as well as against the uncertainty of VRE generation patterns (e.g., due to a change of climatic conditions, or technological improvement in harnessing solar and wind energy). Defining the temporal pattern of demand and, to a lesser degree, that of VRE, involves large uncertainties, given the long planning time horizon. This is particularly so when planning for a system in developing countries where energy demand is expected to increase rapidly, and where the shape may change radically from what it is currently. Given that even the most sophisticated tools are less useful without good data, high uncertainty in the evolution in the pattern of demand may not warrant the benefit of an unlimited increase in temporal resolution.

Effects of increasing spatial resolution

As noted in parts of Chapter 2, the physical location of VRE sites can affect VRE capacity credit, reflecting the different availability of resources and their temporal profiles. It also affects the flexibility needs of a system, which are driven by variability – something that can be collectively smoothed out with a greater geographical spread of sites. Having greater spatial resolution, or multiple nodes, in a model can thus allow for better analysis of transmission investment needs, by taking into account the flexibility options enabled by transmission between nodes, as well as the trade-offs between new transmission and the site-specific resource quality of VRE generation.

Some generation expansion models incorporate a greater amount of spatial detail by linking directly to GIS data. Examples are included in Box 7. GIS data is pre-processed in these models and used in optimising long-term investment.

Box 7: Models incorporating a greater amount of spatial detail

Regional Energy Deployment System (ReEDS) model (Short et al., 2011): From NREL, the **ReEDS** model is a generation expansion model with a planning horizon of 44 years, and covers the contiguous US. It uses 365 resource supply regions, which are further grouped into 134 balancing areas. Much of the data put into the model comes from a detailed GIS model of the transmission grid and solar and wind resources, together with existing power plants. The fact that renewable resources are geographically disaggregated allows the model to calculate transmission distances and to assess the benefits of having dispersed installations – such as PV arrays, wind farms or concentrated solar power (CSP) plants – supplying electricity to a demand region.

Resource Planning Model (RPM) (Mai et al., 2015): From NREL, **RPM** is a generation expansion model with a planning time horizon of over 20 years, and covers all or parts of western states in the US. It includes 17 521 nodes, 4 300 generation units and 21 086 transmission lines. One or some of 36 balancing areas are defined as "focus regions": 100 solar and 100 wind resource regions (zones) are produced for each version of RPM with a different focus region. These zones are built from 10-kilometre gridded hourly time series for 2006 for solar generation and from arc-minute (~2 kilometre) gridded 10-minute resolution time series data for 2004, 2005 and 2006.

Solar and wind energy integrated with transmission and conventional sources (SWITCH) model (RAEL, 2015): From the Renewable and Appropriate Energy Laboratory (RAEL) at the University of California, Berkeley, the **SWITCH** model is a generation expansion model that explicitly considers multiple load areas and transmission investment between those areas. Each load area is characterised with unique hourly time series for load, solar and wind availability data. The model comes with a post-optimisation dispatch tool. It has been applied to: the western US (with 50 load areas, a planning time horizon of 15 years and 144 time slices per year) (Nelson et al., 2012); Nicaragua (with 16 load areas, a planning time horizon of 16 years and 288 time slices per year) (de Leon Barido et al., 2015); China (with 33 load areas, a 40-year planning time horizon and 144 time slices per year) (He et al., 2016); and Chile (with 23 load areas, a 20-year planning time horizon and 288 time slices per year) (Carvallo et al., 2014).

REMix (Borggrefe et al., 2014): Developed by the German Aerospace Center (DLR), the **REMix** model combines a long-term linear optimisation model (REMix Opti-Mo) with a high-resolution (i.e., 5 x 5 kilometre grid) renewable energy potential GIS dataset with hourly availability of renewable energy technologies (REMix-EnDaT). REMix OptiMo has 16 regional clusters (Europe and North Africa). An investment decision is optimised for a given year (e.g., 2020, 2030, 2050), without considering existing infrastructure. A year is represented by 8 760 time slices (hourly resolution). REMix-EnDaT provides maximum installable capacities and hourly time series of renewable power generation.

From general to impact-specific solutions

As explained above, increasing model resolution alone will not necessarily improve the representation of the impact of VRE deployment, nor of implications for investment, as defined in Part One of this report. More issue-specific solutions are available to better represent the key system properties – i.e., firm capacity, flexibility, transmission capacity and frequency response – so as to provide a more accurate basis for long-term planning decisions. The remaining chapters present these solutions in more detail. Many are complementary, but some are more complex than others.

Some of the solutions relate to better preparation of input data and parameters – including better analysis of VRE's temporal and spatial availability, better characterisation of the technical parameters of power plants, and better definition of constraints that emulate the system-wide impact of deploying VRE. Data and supporting tools for this type of input data preparation are increasingly available.

Research-grade solutions are at the other end of the spectrum. They may be more difficult for energy planners in many developing and emerging countries to implement in the absence of extensive modelling R&D. They include some ways of linking long-term models with supplementary tools – particularly linking such generation expansion models with separate production cost models. This can help to validate – or even to correct – the results of long-term planning models. It is state-of-art, at least in the European context (Hidalgo González et al., 2015), but requires substantial expertise.

The availability of data and modelling expertise therefore should be the guiding principle for selecting appropriate solutions to improve the representation of VRE impact in long-term generation expansion models. Countries are advised to start simple when improving energy planning for a high share of VRE, and to take a strategic approach, over time, to advancing the scope and quality of models and the capabilities of their staff.

5 REPRESENTING FIRM CAPACITY

As discussed in Part One (Chapter 2), generation adequacy is a key concept in long-term generation expansion planning. It refers to sufficient availability of firm capacity: capacity that can be counted on to serve the load at all times, especially during peak hours. The temporal matching of VRE supply and system demand profiles determines VRE's contribution to firm capacity – its capacity credit – and has important economic implications. Representing these implications in generation expansion models is critical to make cost-effective investments.

Finer and better-defined representation of time within a long-term generation expansion model would make it possible to capture the temporal match between VRE availability and demand profile more accurately. Better capture of that matching can translate into more accurate capture of VRE's economic value, and capacity credit for VRE can be implicitly derived by a comparison of model results with different VRE levels. A simplified approach – of introducing the exogenously defined capacity credit in a model constraint – also has been practiced, and can be applied in parallel to better-defined time slices.

This chapter discusses the modelling solutions above in more detail. Section 5.1 describes ways to improve time slice definition for a better alignment with the VRE temporal profile. Section 5.2 then presents methodologies for integrating externally-defined capacity credit into long-term energy planning models.

Key points of Chapter 5

Improving "time slice" calibration: Defining time slices (i.e., temporal model steps) more accurately, in order to capture key patterns in daily and seasonal variation, can better reveal the alignment between VRE generation and demand, making the VRE contribution to firm capacity more accurate. Defining time slices should be based on careful scrutiny of temporal variations both in load and in VRE generation, preferably for multiple years. Information on the availability of VRE (e.g., global re-analysis data) is increasingly available to support such an exercise.

General complexity: Low to medium

Incorporating "capacity credit": As an alternative to representing capacity credit based on the alignment of demand and supply within a model, externally-defined capacity credit can be added to generation expansion models to reflect that contribution. By assigning capacity credit values to all capacity on the system, a model can be developed to ensure that system expansion maintains sufficient firm capacity. Capacity credit values can be incorporated simply as fixed throughout the model horizon, or as a function of the share of VRE. Methodologies are increasingly available to support the accurate estimation of capacity credit.

General complexity: Low

5.1 Better calibration of time slices using variable renewable power generation data

The capacity credit of VRE is implicitly computed in a long-term generation expansion model by comparing outcomes of multiple scenarios with different levels of VRE. It can be determined by analysing how much VRE can replace conventional capacity, i.e., the difference in conventional capacity between two scenarios, divided by the difference in the VRE (Nicolosi et al., 2011). Inefficient capture of variation by inadequately defined time slices can result in overstating or understating the capacity credit, which would misrepresent the real value of the capacity investment in VRE.[38]

The time slice approach used in generation expansion models is a way of approximating variation, in terms of both supply and demand. The variability of VRE is typically represented by capacity factors associated with each time slice. The full range of real-life variability is under-represented in models due to the averaging implied by taking relatively coarse time slices (Poncelet et al., 2016a). As discussed in Chapter 4, increasing the number of time slices can help to better capture system variability, in principle. This is made more effective, however, when the time slices are wisely defined to match VRE's daily and seasonal generation profiles (and hydro seasonality) better with corresponding demand profiles.

In order to wisely define appropriate time slices, to reflect the actual pattern of variability, VRE outputs (either realised or potential) need to be carefully scrutinised. Pre-modelling analysis of VRE data would ideally be conducted at an hourly resolution, using historical data over multiple years (see Box 9 for useful sources for VRE data and supporting tools).

Solar irradiance has distinct daily and seasonal patterns. This is less the case for wind, particularly on a daily basis, as its patterns are often influenced by the prevailing local meteorological conditions at a given time. Seasonal variation is particularly relevant for both resources at higher latitudes, and there may be a temporal complementarity between global solar irradiance and wind speed.[39] Understanding this complementarity can help in planning for the two VRE sources and ease overall variability.

In order to visualise the challenge of representing VRE production patterns, Figures 8 to 10 present plots of actual VRE generation profiles against approximated ones using highly aggregated time slices. Load, solar PV output and wind output are presented for the whole of Europe, and plotted against time-aggregated approximation made using 16 time slices, with 4 seasons, 2 day types (weekday and weekend) and 2 intra-day types (day and night). Each graph shows the original data in hourly resolution for one week each in summer and in winter, together with aggregated data for the same periods.

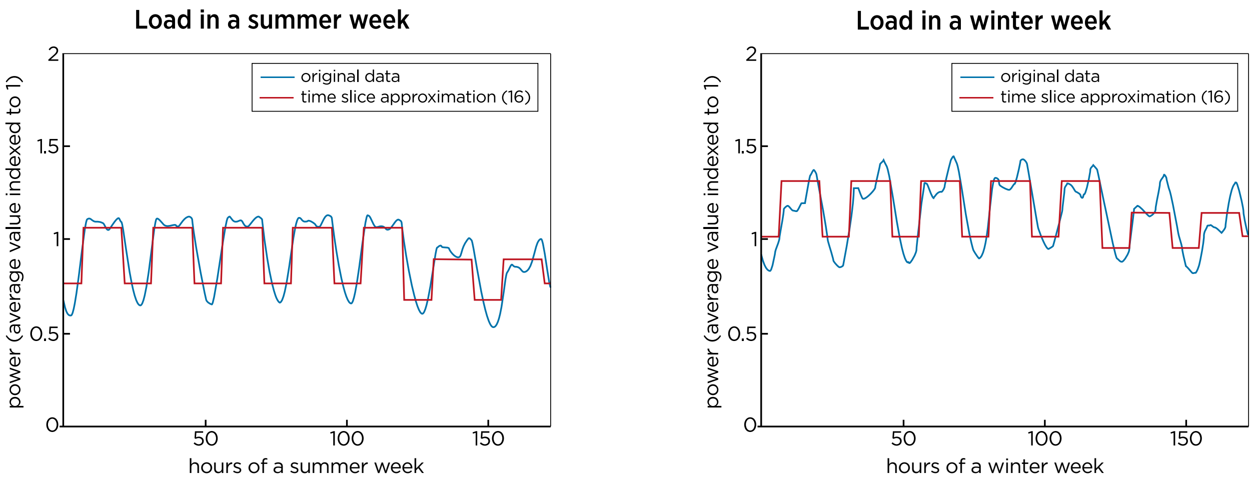
Figure 8 shows that this highly aggregated approximation captures the variability of the load fairly well. By contrast, Figure 9 shows that capturing the variability of VRE supply with this approximation is difficult, especially for wind. Averaging causes solar PV's daily peaks to be under-represented by about 50% – and all of wind's variability is lost by this time slice approximation, since wind power does not have a distinct daily profile and can vary substantially between days.

Adding further intra-day time slices substantially increases the capture of solar PV's variability. This can be seen in Figure 10, which plots the original data with four intra-day types, instead of the two types presented in Figure 9.

38 For example, in the Texas case study presented in Box 6, where two scenarios with exogenously defined wind shares (low and high) are compared under three different time slice model configurations, one additional outcome of this scenario comparison is the implicit capacity credit for the additional wind capacity. In 2030 the wind capacity difference between the low- and high-wind scenarios is 32 gigawatts (GW). The difference in conventional capacity between the scenarios in the low-resolution case is 3 GW, in the medium-resolution case is 2 GW and in the high-resolution case is 1.4 GW, which equals a capacity credit of 9.3%, 6.4% and 4.3%, respectively. Using lower temporal resolutions therefore is found to overstate the capacity value of wind energy, suggesting that the resulting capacity mix under the low-resolution case misrepresented cost-optimal investment.

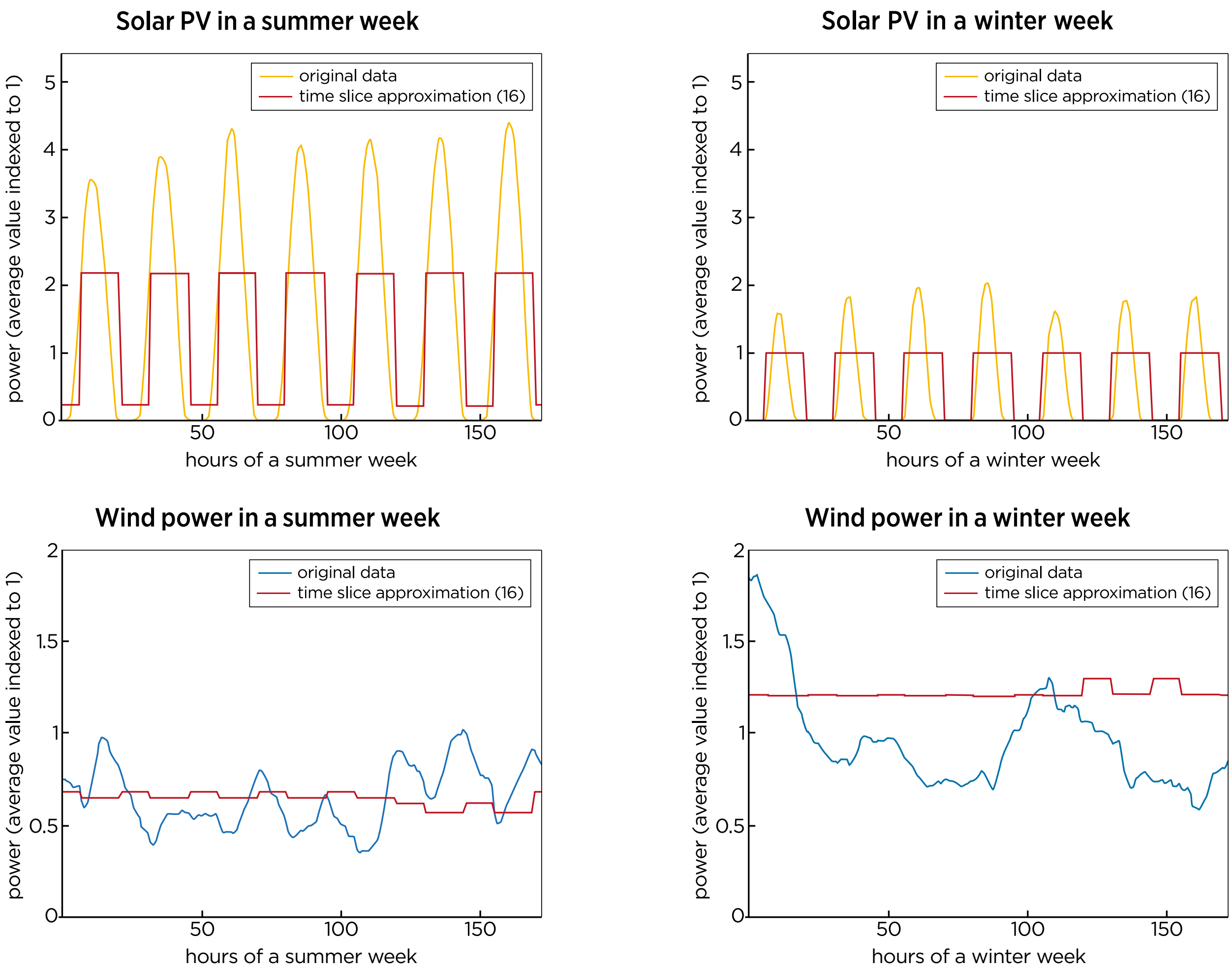
39 For example, the solar resource may be high in the summer when wind is low, and vice versa in the winter; there is some evidence to support this in Europe (Golling, 2012).

Figure 8: A time slice approximation of demand for a summer and a winter week in Europe



Source: Ueckerdt et al., 2016

Figure 9: Solar PV power and wind power for a summer and a winter week in Europe, compared to a time slice approximation with 16 time slices



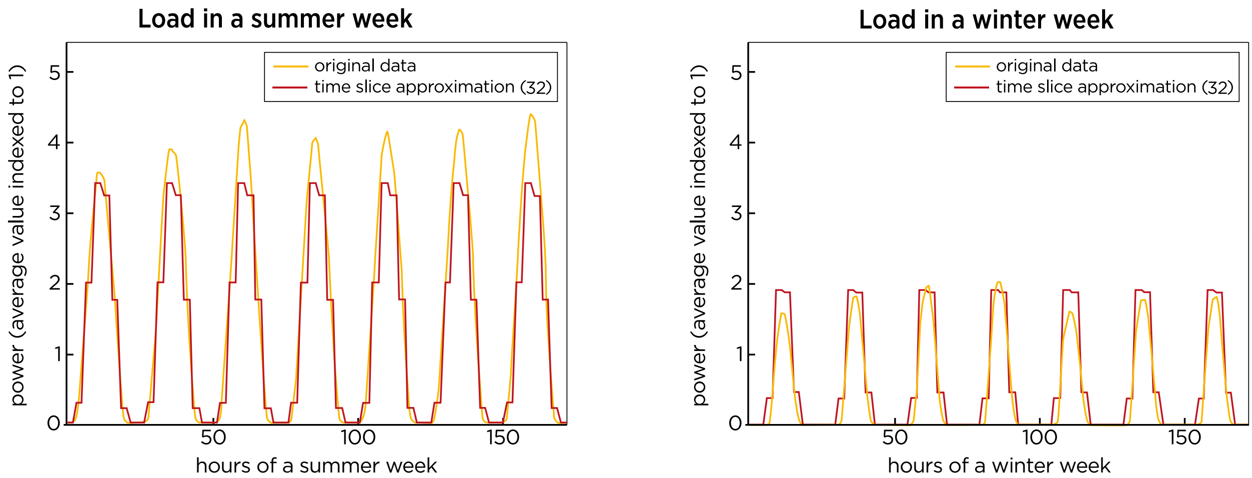
Source: Ueckerdt et al., 2016

It is important to note that the benefits of increasing time slices are not necessarily universal – increases can have different results for the representation of solar, wind, or load, and for intra-day or seasonal application.

While shorter intra-day time slices can significantly improve the representation of variability in solar output, they do not do so for wind, given its relatively less pronounced daily production pattern. This dynamic can be seen in Figure 11, which presents the effect of increasing intra-day time slices on the capture of demand, wind and solar variability in a German context, by averaging quarter-hourly data sets for demand, wind power consumption and solar power consumption for 2007 over different hour-resolutions across the year (Ludig et al., 2011).[40]

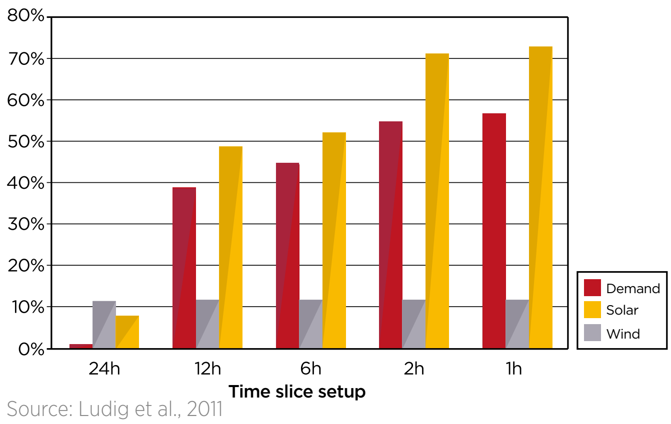
Defining seasonal time slices, which reflect seasonal patterns of VRE availability and/or demand changes, would improve the capture of variability in both solar and wind, as seasonal patterns for both sources exist in many areas of the world. Figure 12 provides an example of distinct seasonal wind patterns across different regions in the US.

Figure 10: Solar PV data and approximation with 32 time slices for a summer and a winter week in Europe. Daily peaks of solar PV can be much better captured with 32 compared to 16 time slices



Source: Ueckerdt et al., 2016

Figure 11: Share of variability covered by time slices of different length in Eastern Germany

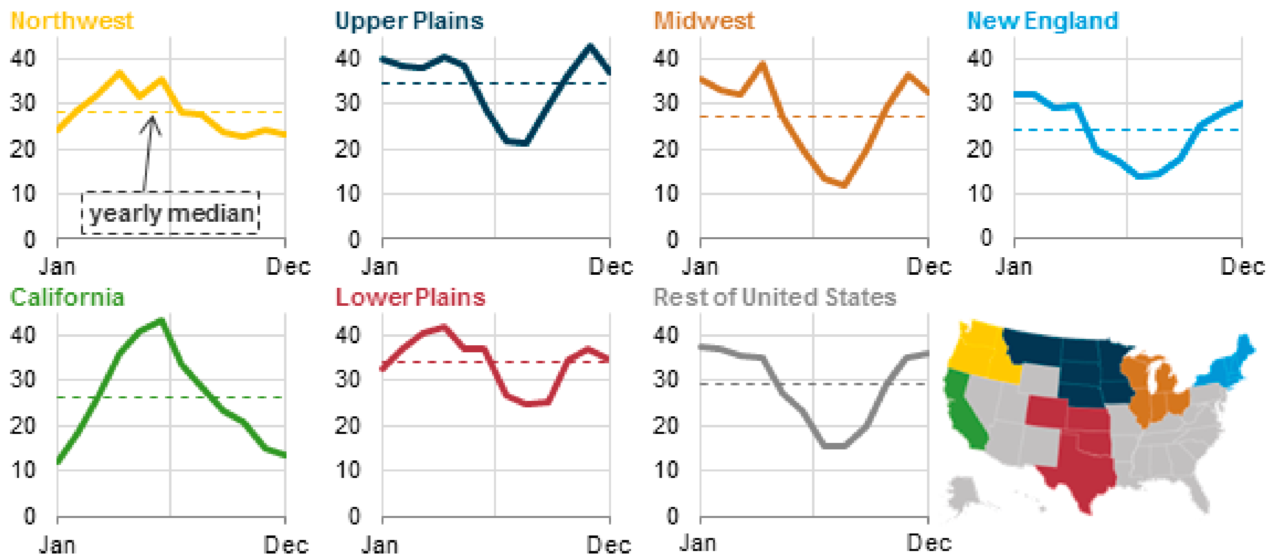


Source: Ludig et al., 2011

40 *Similar results are found in Poncelet et al. (2016a), where increasing the number of time slices from 12 (4 season and 3 intra-day types) to 288 (4 seasons, 3 types of day, 24 intraday types) only marginally improves the capture of temporal matching between load and wind availability. The findings are based on the analysis of Belgium data.*

In parallel to efforts to more precisely represent variability of VRE production patterns, a so-called **peak time slice** – corresponding to short peak demand hours – is sometimes incorporated in model design. This allows for better representation of capacity requirements during such particularly important peak periods, which otherwise could be lost in the time slice averaging process. With VRE, partitioning time slices for peak pricing hours where demand is high and VRE generation is low is a particularly promising approach. The challenge is knowing a priori which hours those peak pricing ones might be, as that would endogenously depend on the level of VRE deployment (Merrick, 2016).

Figure 12: Monthly median wind plant capacity factors (%) in the US, 2001-13



Source: EIA, 2015

Box 8: Country application examples: better calibration of time slices in generation expansion models

Swaziland (IRENA, 2016b): A **SPLAT** Swaziland model – a MESSAGE-based energy sector model – is developed in this study with a 25-year planning time horizon. A year is divided into 5 seasons, 10 intra-day blocks for weekdays and 6 intra-day blocks for weekends (a total of 80 time slices per year), based on the analysis of seasonal and diurnal data on potential VRE generation at promising sites, and on a time-varying tariff structure to reflect the demand pattern. The input values of electricity demand, as well as wind and solar capacity factors of VRE for each site, are determined by the mean values of the data points belonging to each time slice.

Eastern Germany (Ludig et al., 2011): A **LIMES** (Long-term Investment Model for the Electricity Sector) model is developed in this study for Eastern Germany with a planning time horizon of 95 years. Based on the analysis of quarter-hourly datasets for demand, wind power consumption and solar power consumption for 2007, as presented in Figure 11, a year is divided into 16 time slices (4 seasons and 4 six-hour blocks of a day). The input values for electricity demand as well as wind and solar capacity factors are determined by calculating the mean values of the data points belonging to each time slice.

United States (Short et al., 2011): A **ReEDS** model with a planning horizon of 44 years is developed in this study for the United States. It divides a year into 17 time slices (4 seasons and 4 intra-day blocks: night, morning, afternoon and evening) with an additional summer peak time slice. The peak time slice represents the 40 highest-demand hours of summer between 1 p.m. and 5 p.m.

More advanced approaches are emerging for time aggregation as sets of (not necessarily consecutive) "representative" days or weeks, selected on the basis of their similarity in the availability of VRE (e.g., high and low wind days).[41] Such an approach would allow the better representation of "non-average" days, whose variability otherwise would have been averaged out. This improves the capture of variability over the concept of a season defined as a set of consecutive days. Using a well-selected set of representative days has been shown to capture temporal matching more accurately, even with only a limited number of time slices, especially for wind. Adding such clusters of periods with similar VRE pattern would allow better representation of "non-average" periods, especially for wind, which tends to have a less pronounced production pattern over days and seasons. This approach does, however, have several drawbacks: assessing inter-season storage options (e.g., through hydropower dams) is challenging, as is the matching of time slices across different regions to analyse inter-regional trade.

Another variant of this advanced approach is clustering hours or days, based on the similarity of the alignment of demand and VRE generation. Such an approach is aimed at adding an additional layer to conventional time slice definitions, which are commonly set as intra-day blocks (consecutive hours) and seasons (consecutive days and weeks).[42]

Examples of models with such novel approaches are summarised in Nahmmacher et al. (2016) and presented in Table 6.

Table 6: Examples of models with time slice approaches that deal specifically with more complex variable renewable energy fluctuation patterns

Model name	Region	Applied in	No. of time slices	Time slice specifications	Data basis
GEMS + CEEM	Germany	DENA (2005)	432	4 seasons, 3 demand days and 3 wind in-feed days per season, 12 time slices per day	1994 - 2003
DIMENSION + INTRES	Europe	Golling (2012)	192	2 seasons, 8 combinations of low/high wind days over all regions, 12 time slices per day	2006 - 2009
DIMENSION	Europe	Nagl et al. (2013)	7200	10 simulated weather years with 30 days (2 seasons) each, hourly resolution	2006-2010
US-REGEN	US	Blanford and Niemeyer (2011)	50	50 randomly selected weighted combinations of load and wind in-feed	2007
LiMES-EU+	Europe & Middle East and North Africa	Haller et al. (2012)	49	4 seasons, 3 VRE situations, 4 time slices per day (plus one peak time slice)	2009
URBS-EU	Europe	Schaber et al. (2012)	8064	8 years with 6 representative weeks each, hourly resolution	2000-2007
-	Texas US	de Sisternes and Webster (2013)	696	4 weeks (each 7 days) with hourly resolution (plus one peak day)	2009

Source: Nahmmacher et al., 2016

41 *For an overview of "representative days" and "weeks" methods, see Merrick (2016).*

42 *For example, using data from Belgium, Poncelet et al. (2016a) showed that adding a time slice level to distinguish between three types of wind regimes (high, medium, low) to the original 12 time slices (leading to a total of 36 per year, in addition to 4 season and 3 intra-day types) reduces errors significantly in capturing the variability, while increasing the number of intra-day types from 3 to 24 (increasing the total number of time slices from 12 to 288) added only a marginal benefit.*

Supporting data and tools for better calibration of time slices

As noted earlier in this section, historical analyses of load and VRE production (and/or availability) variation are needed in order to better calibrate time slices. Forward-looking VRE generation profiles can be established synthetically, by using data on wind speed and solar irradiance to represent "typical" daily and seasonal profiles.[43]

Examples of VRE datasets available online, and other supporting tools to help planners calibrate time slices better, are given in Box 9.

Box 9: Supporting data and tools: Better calibration of time slices using variable renewable energy generation data

IRENA's Global Atlas (IRENA, n.d.), a GIS repository of renewable energy resource information with rich visualisation, provides entry points for GIS data providers.

High-resolution wind and solar time-series data, on a global scale, typically reside in the commercial domain and can be difficult for energy planners to obtain.

Time-series data with a coarse resolution are available in the format of so-called reanalysis data:[44] 3-D meteorological data, interpolated in time and space, from a finite set of imperfect, and not necessarily representative, irregularly distributed observations on a regular grid. These data combine surface and upper air observations, satellite data and the results of prediction models. When they are combined with diagnostic/prognostic meteorological models[45] (also referred to as numerical weather prediction models in Gonzales Aparicio and Zucker (2015) – coarse reanalysis data can be downscaled by taking into account information on land use and topography, which typically are available at a much finer resolution.[46]

Some useful global data sources from which wind speed and direction, Global Horizontal Irradiance, and Direct Normal Iirradiance can be downloaded for free (with some restrictions) include:

- SoDa Service from MINES ParisTech and Transvalor S.A. (Mines ParisTech and Armines, 2004) provides free access to wind speed and wind direction data from MERRA (©NASA), and solar irradiance values from HeliClim (©Armines/Transvalor) as well as from NASA-SSE (©NREL)
- PVWatts Calculator from NREL (n.d.) provides solar PV generation profiles using site-specific data collected through the Solar and Wind Energy Resource Assessment (SWERA) project (outside North Africa)

43 *A statistical method of developing a synthetic diurnal wind profile from empirical data has been established and tested in Golling (2012). The method accounts for average wind fluctuations and gradients, which are typically cancelled out when diurnal profiles are created by empirical averages of just wind speed*

44 *Well-known reanalysis data include: ERA-Interim (1979 to present, with 6-hour intervals and 80-kilometre resolution – about 0.7 degree) from the European Centre for Medium-Range Weather Forecasts (ECMWF, n.d.); NCEP/NCAR Reanalysis data from the National Center for Atmospheric Research (1948 to present, with 6-hour intervals and 2.5-degree resolution) (NCAR, 2016a); and MERRA (Modern-Era Retrospective Analysis for Research and Applications) from NASA (1979 to the present, with 3-hour intervals with 0.5-degree latitude and 0.66-degree longitude resolution, or with 6-hour intervals with 1.25-degree resolution) (NASA, 2016).*

45 *Examples include: the CALMET model from Exponent (2014); the Weather Research and Forecasting model (WRF) from NCAR (n.d.); and the 5th generation mesoscale model (MM5) from Pennsylvania State University and NCAR. The NCAR Global Climate Four-Dimensional Data Assimilation (CFDDA) Hourly 40-kilometre Reanalysis dataset is developed using MM5 1985 to 2005, with hourly intervals with 40-kilometre resolution (NCAR, 2016b).*

46 *A similar approach has been applied to future meteorological conditions, derived by global climate models at a coarse resolution, and downscaled by regional climate models and empirical statistical downscaling techniques (Gonzales Aparicio and Zucker, 2015).*

- Wind Potential Analysis from European Weather Consult (EWC) (2016) provides free trial access for up to one year to MERRA data (see footnote 44) corrected for observation data
- Renewables.ninja (Pfenninger and Staffell, 2016) provides free access to solar irradiation data, temperatures and wind speeds calibrated from a reanalysis dataset MERRA (©NASA) and CM-SAF SARH (©2015 EUMETSAT) and allows simulation of power outputs for solar PV and wind generation.

Validating time slice calibration

Mathematical algorithms (e.g., optimisation) are rarely used in defining appropriate time slices[47], and expert judgments more often are applied. For that reason, visual inspection of the so-called **residual load duration curve (RLDC)** is helpful in validating their time slice definition and complementing expert judgment. Residual load – also referred to as "net load" – is derived by subtracting the power generated by VRE from electricity demand at any given time. The RLDC – drawn by sorting the hourly residual load data for one year in descending order (see Figure 13) – captures the correlation of load profile with VRE supply (Ueckerdt et al., 2015).

The RLDC can be constructed from modelled residual load data – approximated using time slices – and compared to actual RLDC. Visually inspecting the errors in a replicated RLDC can help to validate time slice design, as mentioned earlier.[48] Figure 14, for example, shows hourly RLDCs compared against five different designs (in this example, they correspond to different numbers of time slices, i.e., 876, 438, 146, 73 and 24 a year). this shows how well different designs reproduce the actual RLDC. This particular example shows that some of the designs with a lower time resolution cannot replicate RLDC well, particularly for solar PV.

There are important considerations to take when assessing a given time slice definition; for example, if the time slice approximation results in a RLDC that is too flat, it can result in (Poncelet et al., 2016a):

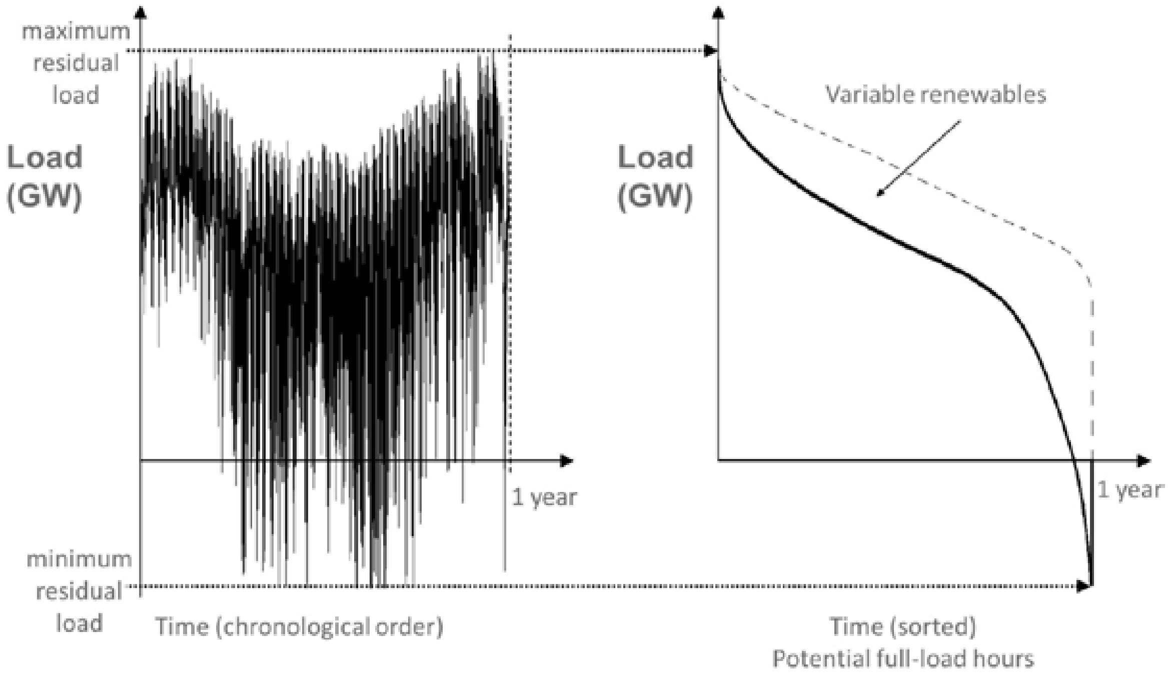
1. the peak residual load to be underestimated,
2. the residual load in periods of high VRE generation to be overestimated, and
3. periods of excess electric energy generation (periods where RLDC becomes negative) potentially being underestimated.

The first issue – underestimating peak residual load – implies that the capacity credit of VRE is overestimated. This means that the model results may not reflect sufficient firm capacity. An additional constraint to ensure sufficient firm capacity is crucial to obtain generation portfolios which can achieve a reasonable security of supply (this constraint is discussed in Section 5.2). The second issue – overestimation of the residual load during the period of high VRE production (or equally, underestimation of the VRE production) – results in an overestimation of the number of full load hours that can be obtained by baseload technologies. Finally, underestimating the excess generation due to high VRE production can result in an overestimation of the potential uptake of VRE.

47 *Exceptions include Golling (2012), Nahmmacher et al. (2016) and Poncelet et al. (2016b).*

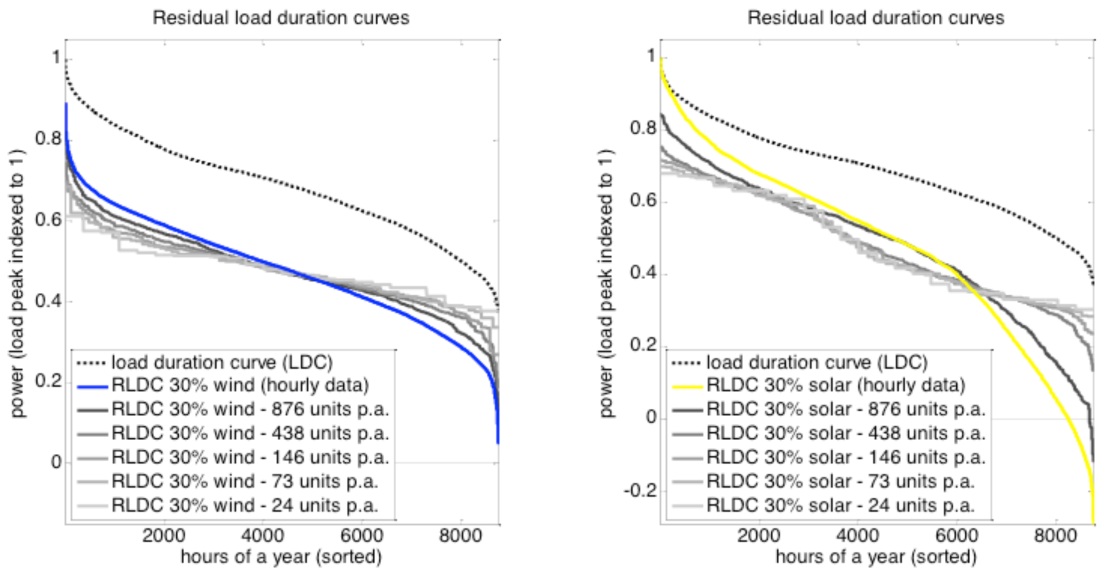
48 *It is worth noting that the RLDC has also been used beyond validation purposes. An approach that uses the RLDC directly in a model, as substitute to time slices, has been implemented in models with particularly large geographical dimensions (e.g, world divided into several regions) and long-term time horizons (e.g., 100 years) – models that are typically designed to assess long-term build-up of global carbon emissions (e.g., Johnson et al. (2016), Ueckerdt et al. (2016, 2015b)). Unlike a time-slice approach, which defines a year with time slices of constant demand and supply, the RLDC approach defines a year with a simplified RLDC, parameterized by base-load capacity, intermediate-load capacity, peak capacity, and overproduction of VRE (Ueckerdt et al., 2015b). The shape of the RLDC changes endogenously as the share of VRE increases, using sets of parameters that are pre-defined outside of the model for different combinations of solar and wind shares. Due to the loss of chronological information, the approach has the same drawbacks as the advanced approaches discussed above.*

Figure 13: Schematic presentation of residual load (in chronological order, left), and RLDC (right)



Source: Ueckerdt et al., 2015a

Figure 14: RLDC for wind power (left) and for solar PV (right) for hourly data (8 760 hours per year) compared with approximated RLDC with a reduced temporal resolution of 876, 438, 146, 73 and 24 units per year



Based on Ueckerdt et al. 2016)

5.2 Adding capacity credit constraints

As noted in the previous section, improving time slice definition is limited by the extent to which time slices can be increased, due to computational limitations. Thus a simplified constraint that represents the contribution of VRE to firm capacity – its capacity credit – can be introduced to ensure that generation adequacy is sufficiently represented. [49]

In long-term generation expansion models themselves, capacity credit is normally incorporated as an exogenous parameter, calculated outside of the model. By assigning capacity credit values to different types of power plants, including VRE, a model can be developed to ensure that the expansion of capacity would result in sufficient firm capacity. The system's reserve margin, defined in Section 2.2 as the policy-driven percentage of firm capacity above peak demand, can be placed in the model as a constraint or target which modelled expansion must meet.

The capacity credits used in generation expansion models can be estimated for a specific power system, using hourly load and VRE supply data from that system, or based on general conservative values founded in engineering judgement (see Box 10 for examples). Where possible, distinct capacity credit estimates should be employed for different regions.

Capacity credit values can be incorporated independently of the share of VRE, or as a function of that share. In either case, the capacity credit value itself or the value of the functional relationship may be kept static throughout the model horizon, or it can be made dynamic. Such a function can be defined separately for each aggregated technology. Alternatively, capacity credits can be defined for wind and solar PV combined, accounting for their correlation by using a single capacity credit function. Some models also assign capacity credit to non-VRE, taking into account unplanned maintenance needs.

Box 10: Country application examples: better representation of capacity credit

Ireland (Welsch et al., 2014a): An **OSeMOSYS** model for Ireland is developed in this study with a planning horizon of 30 years. A year is divided into 4 seasons and 2 intra-day blocks (making a total of 8 time slices). The model ensures that the capacity credit of all the system's generators always exceeds load by 20% by incorporating a constraint on its reserve margin. The capacity credit for wind is endogenously modelled as a function of wind penetration levels, the annual capacity factor of a wind generator, the availability of conventional plants and a geographic dispersion coefficient, following a methodology used in Voorspools and D'haeseleer (2006).

Europe (Nijs et al., 2014): A **JRC-EU-TIMES** model is developed in this study with a planning horizon of 50 years for 28 EU countries. Each year is divided into 4 seasons and 3 intra-day blocks (making a total of 12 time slices). A reserve capacity constraint is introduced to ensure that the sum of the total capacity of power plants and storage technology is bigger than the peak demand. In defining the total capacity of power plants, the capacity of solar PV and wind is not counted, while 50% of hydropower capacity is counted.

United States (Short et al., 2011; Sigrin et al., 2014): A **ReEDS** model is developed in this study for the United States with a planning horizon of 46 years. A year is divided into 4 seasons and 4 intra-day blocks with additional peak time (a total of 17 time slices) and into 356 spatial clusters called resource supply regions. Each technology in the model is given a specific capacity credit to define its contribution to the reserve margin for each time slice. All types of dispatchable power plants, including concentrated solar power (CSP) with storage, contribute their entire (nameplate) capacity towards it. Reserve margin constraints in models require firm capacity to exceed a pre-defined margin in all time slices. Capacity value is calculated internally before linear programming is performed for that period. The capacity credit is computed using a simplified

49 For an overview of the concept of capacity credit, including technical definitions, see Section 2.2.

algorithm that approximates the effective load carrying capability (ELCC; see the discussion below under supporting data and tools) for each time slice, for every two-year period. The capacity credit for each time slice is based on the average capacity factor for the hours that it spans.

United Kingdom (Anandarajah et al., 2009): A UK **MARKAL** elastic demand (MED) model for the UK is developed in this study with a planning horizon of 50 years. A peak demand constraint is specified, with the capacity credit specified differently for different types of technologies depending on their capacity. For example, a 28% capacity credit is specified for wind (both onshore and offshore) with capacity of 0-5 GW, 18% for onshore and offshore wind, tidal and wave with capacity of 5-15 GW, and 8.6% for offshore wind above 15 GW. These parameters were calculated by use of an external tool, **WASP**.

Supporting data and tools to derive the capacity credit

Unlike the raw data for time slice calibration discussed in the previous section, the data source for capacity credit estimates resides primarily in various system-specific calculations that already have been performed, or in general estimation methodologies.

Estimates of capacity credit have been used by many utilities in the US – and by some system operators in Europe – in planning the expansion of generation, as well as in adequacy studies. Broadly speaking, there are two approaches for estimating capacity credit: methods based on reliability, and ones based on approximating time periods.

The reliability-based methods use metrics such as **equivalent conventional power (ECP)**, **equivalent firm capacity (EFC)** and the **effective load carrying capability (ELCC)** to quantify the concept of capacity credit. They refer to the amount of conventional generation that VRE can replace (ECP), the amount of fully reliable generation technology that VRE can replace (EFC) and the amount of demand that VRE can support to increase (ELCC) while maintaining the same level of system reliability (Madaeni et al., 2012). A general consensus is emerging that the preferred metric to evaluate VRE's capacity credit is the ELCC (Rogers and Porter, 2012).

In evaluating the system reliability with these metrics, probabilistic reliability indicators such as loss of load probability (LOLP), loss of load expectation (LOLE) and loss of energy expectation (LOEE) are used.[50]

Calculating probabilistic evaluations of the adequacy of generation requires multiple simulations of a power system, with and without the VRE in question. This presents computational challenges, and several methodologies have been used to emulate the process more simply for the purposes of capacity credit assessment. Overviews of those methodologies are provided in Holttinen et al. (2009), Madaeni et al. (2012), NERC (2011) and Rogers and Porter (2012). For example, one simplified approach, by Garver, approximates ELCC based on a change of LOLE when VRE is added, with LOLE estimated by a formula that uses chronological load and VRE supply data (Madaeni et al., 2013).

Time-period-based approximation methods evaluate capacity credits during critical periods for a system – primarily peak load hours – approximating them by a capacity factor for the VRE in question during such times (NERC, 2011). Capacity factor is taken to be the electricity generation over a given time period, divided by the product of nameplate capacity and the number of hours in that period. In 2012, a survey showed that 10 out of 24 system operators in the US used the peak-

50 LOLP is the probability that the load will exceed the available generation at a given time. LOLP as a definition gives the amount of time of system malfunction, but it lacks information on the importance (severity/amount of megawatts missing) of the outage. LOLE may be either the number of hours (usually expressed in hours per year) during which the load will not be met over a defined time period, or the number of days (usually expressed in days per year) during which the daily peak load will not be met over a defined time period. LOEE is the number of megawatt-hours, usually per year, of load that will not be met over a defined time period (Holttinen et al., 2009).

time-based approach in their planning studies (Rogers and Porter, 2012). Holttinen et al. (2016) point out that time-period-based methods are potentially unreliable for wind power assessment, as individual years may have a large deviation of generation during peak load hours.

The World Energy Outlook (IEA, 2015) uses another simplified approach, calculating VRE's capacity credit as the difference between peak load and the peak of the residual load (the load minus the VRE supply at a given time), divided by the VRE's capacity. This difference is interpreted as the generation capacity that is not required due to the existence of the VRE capacity, i.e., this VRE capacity is considered "firm".

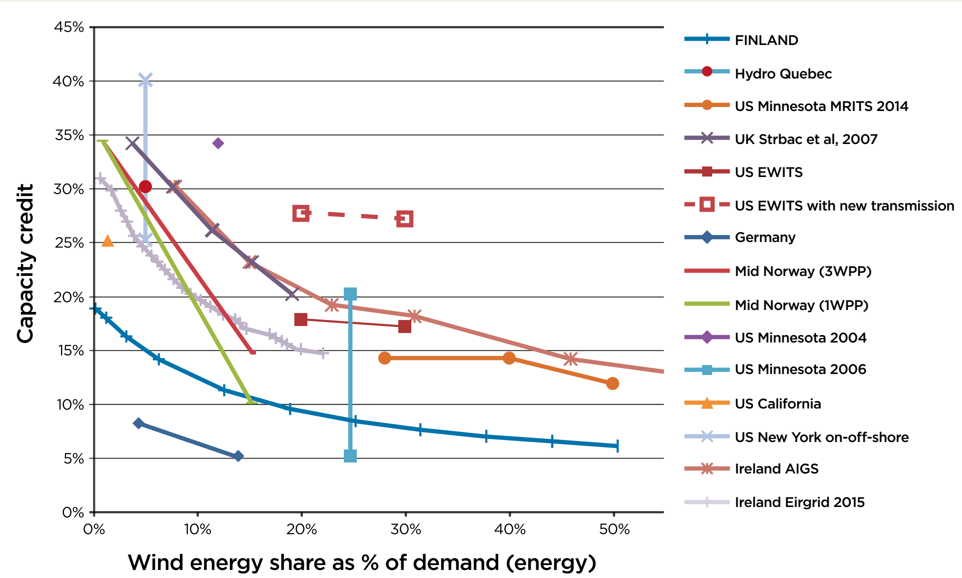
As an alternative to the methodologies described above, a rule-of-thumb approach is still widely used in generation adequacy studies. A survey conducted in October 2013 for European countries revealed that four countries consider VRE as non-available (0% available), while another four take a pre-defined percentage (5%, 7%, 20%) as available generation. Only two countries conduct detailed modelling based on meteorological data, hub heights (for offshore wind farms) and detailed co-ordinates for generation sites (CEER, 2014).

Box 11: Existing estimates: capacity credit

A large body of literature estimates capacity credits for US and European power systems.

A review of studies for wind generators by Holttinen et al. (2016) shows that, when the production of wind power is strongly correlated with high load periods, capacity credit is calculated to be up to 40% of its installed capacity. When the local characteristics of wind correlate negatively with the load profile of a system, however – and in scenarios with a higher proportion of wind, capacity credit falls to 5%. The review also shows that most countries have a capacity credit of 20-35% of installed capacity for the first 5-10% share of wind. For a 20% share of wind in a system, the capacity credit is above 20% of the installed capacity (see Figure 15).

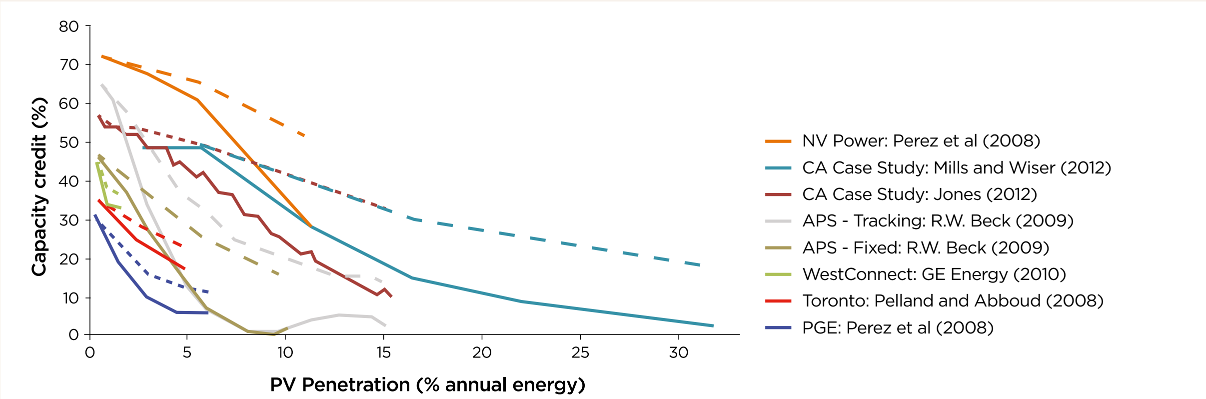
Figure 15: Capacity credit of wind power, results from eight studies



Source: Holttinen et al., 2016

For solar PV, capacity credit values range from 52% to 93% in the western US, depending on location and the plant's ability to track the sun (Madaeni et al., 2013). Another study shows that capacity credit is high (60-80%) in the US for a low penetration of solar and decreases with higher penetrations in systems where peak demand is much higher in summer than at the winter peak. By contrast, capacity credit is smaller, about 33%, for the systems of Portland, Oregon, where summer and winter peak load values are about the same (Perez et al., 2008).

Figure 16: PV capacity credit estimates with increasing penetration levels



Source: Mills and Wiser, 2012b

The literature on VRE capacity credits for developing and emerging countries is scarce. Studies of the Mexican and South African power systems find capacity credit values for wind generators to settle around 20-30% depending on their siting and on wind's share of the mix (Pöller, 2014). A specific study of wind capacity credit in Mexico by Yáñez et al. (2014) finds that the capacity credit starts around 50% and decreases to about 25% at a penetration rate of 15%, when the wind sites are diversified.

While examples of different capacity credit estimates are presented in this box, readers are reminded that figures are not directly comparable when they are derived using different methods (Holttinen et al., 2009).

6 REPRESENTING FLEXIBILITY

In addition to securing generation adequacy in a power system, by ensuring sufficient firm capacity exists to meet demand (Chapter 5), long-term transition planning also must ensure that enough flexibility is present to address fluctuations in demand and in variable renewable energy. High penetration levels of VRE are likely to increase the variability that the rest of the system will need to accommodate, and at a shorter time scale (i.e., less than an hour upwards).

As discussed in Chapter 4, long-term generation expansion models are not typically designed to capture balancing needs at a sub-hourly level. If long-term investment decisions ignore such needs for flexibility, they tend to underestimate the value of investments in flexible power plants and other system services. This results in a long-term energy mix that is potentially both economically and technically inefficient.

This chapter discusses three kinds of solutions to overcome the common limitations of representing flexibility in long-term energy planning models. Section 6.1 discusses ways to implement certain modelling constraints on flexibility provision – in particular "flexibility balancing" constraints, which can mimic the balancing requirements in high-VRE power systems. Section 6.2 discusses simplified validation tools to assess system flexibility. Finally, Section 6.3 discusses an approach that links generation expansion models with production cost models, to achieve a more granular understanding of flexible operating requirements.

Key points of Chapter 6

Incorporating flexibility constraints: A system's flexibility can be represented in generation expansion models by first parameterising the ranges of operating flexibility (e.g., minimum load levels and cycling speed) for "flexibility provision" options – including dispatchable plants, storage, demand response and cross-border trade. Ramping requirements associated with the variabilities of demand and of VRE can be assessed separately and balanced collectively with available flexibility options at an aggregated system level. Using this "flexibility balance" approach, models can optimise investment in flexibility options to meet system requirements, as an additional constraint to the standard balancing of total power demand and supply.

General complexity: Low to medium

Validating flexibility balance: As an alternative to, or in addition to, incorporating flexibility constraints, results from generation expansion planning models can be further scrutinised using more detailed tools, with different degrees of complexity. Such validation tools scrutinise operational aspects of a power system and give high-level indications about whether the energy mixes resulting from generation expansion planning models would offer sufficient flexibility.

General complexity: Medium to high

Linking with production cost models: Production cost models can be used to validate results from long-term generation expansion models, or to correct such results if necessary. Such a "coupling" approach can translate a system's needs for flexibility in operation (a focus of production cost models) into decisions around investment (a focus of generation expansion models).

General complexity: High

6.1 Incorporating constraints on flexibility provision

Flexibility is provided primarily by dispatchable power plants, demand response and cross-border trade. These flexibility options can help improve the response to fluctuations in residual load.

Because flexibility is defined in reference to time (e.g., the ability to increase output within a given span of minutes), higher time resolution in a generation expansion model would enable better representation of flexibility provided by power plants, and by other sources of flexible operation by power plants and other flexibility options. A model's ability to represent flexibility provision also depends on its technology resolution – i.e., some models operate at a technology-type level, while others consider individual power plants and corresponding technical load-following constraints and cycling costs (Poncelet et al., 2016a).

Generation expansion models with lower time resolution implicitly assume that power plants are fully flexible within a given time slice, and costs related to cycling are ignored. Case studies show that ignoring these restrictions for flexible operation may result in sub-optimal long-term investment decisions.[51]

While representing these constraints directly in a generation expansion model is difficult due to their resolutions, simplified representation of these constraints has been practiced, as discussed below.

Parameterising flexibility supply

Dispatchable power plants provide their flexibility through part-loaded synchronised generators and quick start/shutdown generators. The contribution of part-loaded synchronised generators is limited by their ramp-up rate as well as by their maximum capacity (in the case of ramp-up) or their minimum level of stable generation (in the case of ramp-down) (Ma et al., 2012).

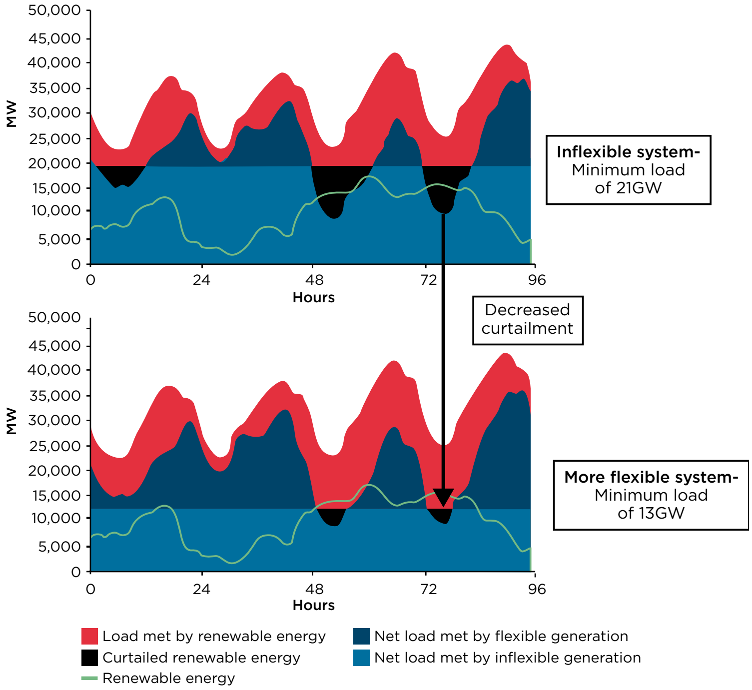
The five key technical parameters that determine the flexibility of dispatchable plants are:

- **The ramp rate** (or ramping gradient) of a power plant: the rate at which a generator can change its output (in MW/timeframe, e.g., minute or hour).
- **Start-up times:** the time required for power to start up. Cold, warm and hot starts are distinguished depending on how long a power plant has been down.
- **Minimum load levels:** the minimum generation at which a power plant can be operated stably before it needs to be shut down. A plant can adjust its output between this and its rated capacity.
- **Minimum down and up times:** the lower limits of the time that a plant needs to be offline or online. In principle, these are not strict technical limits, but are supporting guidelines to avoid wear and tear that leads to high costs over the lifetime of a power plant.
- **Partial load efficiency:** the reduced efficiency of a power plant operated below its rated capacity.

How these parameters can be implemented in generation expansion models depends on the time and technical resolution of the model. Generation expansion models can incorporate these technical parameters to various degrees, depending on those resolutions. Simplified incorporation of the parameters into generation expansion models is discussed below.

51 *For example, Nweke et al. (2012) develop a model for the South Australia system using the long-term planning module of* ***PLEXOS*** *with a planning time horizon of 20 years, and 200 time slices per year. The model is run under two settings, one with operational constraints (i.e., minimum stable level, minimum up-and-down times, and start cost and shut-down costs) and one without them. The results show that the run with operational constraints significantly limits the investment in wind, compared to the run without (42% of the total capacity in comparison to 61%), builds more gas and geothermal plants and retires more existing coal.*

Figure 17: Impacts of minimum generation on curtailment in Texas



Source: Denholm and Hand, 2011

Among the above technical parameters, minimum load is relatively straightforward to implement in long-term generation expansion models. Specifying the minimum load of different technologies can help to reflect how much excess VRE generation exists during periods of high VRE generation, due to limited flexibility of the rest of the power system to operate down. This point is illustrated in Figure 17, where an example from Texas shows how curtailment is reduced when the minimum load is reduced.[52]

Other technical parameters that describe flexibility are sometimes represented by constraints to limit how given technologies – including dispatchable plants, storage, demand response and interconnectors – can change their output across different time horizons. Typical parameters found in the literature are discussed in the following subsection.

For ramp rates, the relevant timeframe for ramping requirements, driven by the variability of VRE, could be as short as 15 minutes. This would be much shorter than the shortest time slice in typical generation expansion models, and, as a result, such models cannot normally directly represent ramping needs from VRE. For this reason, an additional constraint is practiced which demands that the ramping requirements be met by available flexibility options. In this approach, the ramping capability of power plants can be represented as the capacity for different categories of ramp rate (e.g., X MW for 15 minutes ramping, Y MW for one hour) for each technology modelled, and a system-wide synthetic flexibility capacity can be computed, to be balanced against the ramping requirement due to VRE. A generation expansion model can then take these into account, optimising investments to meet flexibility requirement constraints. Such an approach - referred to here as a **"flexibility balancing"** approach — demands that flexibility requirements are separately analysed and established (a process discussed further in the following section).

A range of practical examples of flexibility parameterisation are presented in Box 12.

52 *The upper chart represents a case that thermal generators cannot cycle below 21 GW. This is the result of baseload plants that cannot cycle, or thermal plants that must not be switched off because they are acting as reserves to accommodate uncertainty in the net load and increased ramp rates The lower chart shows a case where this collective minimum generation level is lowered to 13 GW. Such system-level overall minimum loading constraints depend largely on the mix of generation technologies in the system (Denholm and Hand, 2011).*

Box 12: Country application examples: representing power system flexibility in long-term generation expansion models

Global (Johnson et al., 2016): A global **MESSAGE** model with 11 world regions is developed in this study with a planning time horizon of 100 years and one time slice per year. Flexibility needs are derived via a residual load duration curve (RLDC), which is pre-defined for different regions at different combinations and shares of solar PV and wind. The RLDCs are constructed synthetically using hourly time-series data for VRE supply and load.

The fraction of the peak demand that is met by baseload is determined by the tail of the RLDC, and all generation above the baseload fraction defines the flexibility needs. For thermal power plants, two options – flexible operation and baseload operation – are introduced, and the sum of the flexible fraction of power plants needs to meet the system flexibility requirement. The flexible fraction of the operation is parameterised by an "operating reserve coefficient". Flexible operation incurs penalties in the form of increased operation and maintenance costs (due to the increased wear and tear from fast ramping of units, and from starting and stopping units more frequently) and in reduced efficiency. Example of these parameters are given in Table 7.

Furthermore, the negative RLDC implies excess VRE generation over demand, which is optimised either to be curtailed or stored for a later use.

Table 7: Flexibility parameters by technology

Technology	Operating reserve coefficient (fraction of generation)	Cycling-related variable operation and maintenance cost (USD/MWh)	Efficiency penalty (% reduction)
Coal/biomass combustion and gas combined-cycle	0.53	0.58 - 1.56	6%
Gas and oil combustion	0.86	9.24 - 9.36	8%
Gas/hydrogen combustion turbine	1	12.47	N/A
Carbon Capture and Storage and nuclear	0.2	1.28 -1 .39	14%
Coal/biomass gasification	0	N/A	N/A
Hydropower	0.66	N/A	N/A
Geothermal	0.32	N/A	N/A
Flexible CSP	1	N/A	N/A
Baseload CSP	0.5	N/A	N/A
Utility-scale hydrogen fuel cell	1	N/A	N/A
Electricity storage	1	N/A	N/A

*N/A: not applicable
Source: Johnson et al., 2016

Germany (Ueckerdt et al., 2015b): A **REMIND-D** model for Germany with a 100 year planning time horizon is developed in this study using the RLDC approach (see footnote 48) with a specific feature to address flexibility balance following Sullivan et al. (2013). Flexibility coefficients are attributed to each generating technology to represent the fraction of its generation that is considered to be flexible (if positive) and the additional flexible generation that would be required for each unit of the technology's generation (if negative). These coefficients are used in a flexibility constraint, which demands flexibility requirements associated with load (annual demand multiplied by the negative coefficient) and VRE (generation multiplied by the respective negative coefficient) are met by flexibility provided by other generation technologies (generation multiplied by the respective coefficient) in the model. The coefficients (Table 8) are taken from Sullivan et al. (2013), and are based on expert judgements, informed by a generic unit-commitment model for the US.

Table 8: Flexibility coefficient by technology

Technologies	Flexibility coefficient (fraction)
Load	-0.1
Wind	-0.08
Solar PV	-0.05
Geothermal	0
Nuclear	0
Coal	0.15
Bio power	0.3
Gas-CC	0.5
Hydropower	0.5
H2 Electrolysis	0.5
Oil / gas steam	1
Electricity storage	1

Source: Sullivan et al. (2013)

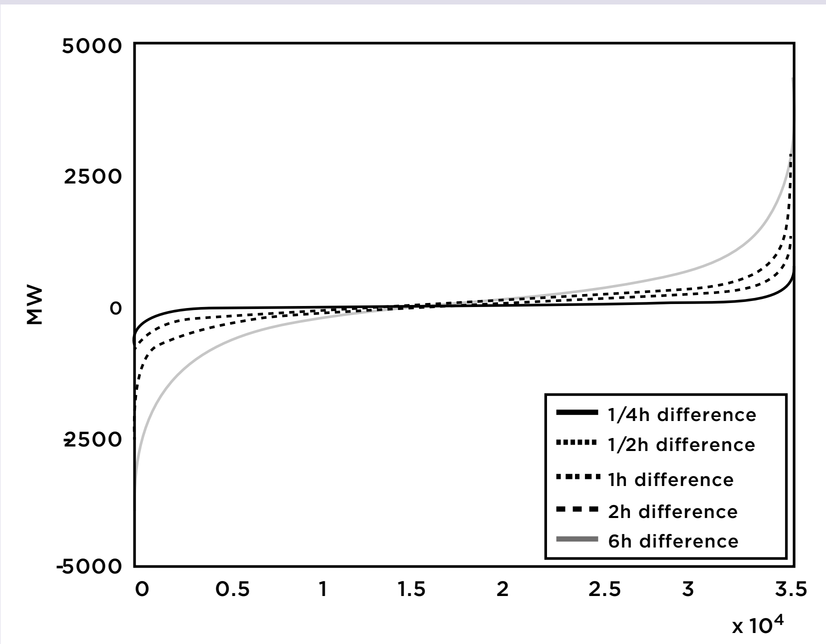
Europe (Hidalgo González et al., 2015; Quoilin et al., 2015): A **JRC-EU-TIMES** model is developed in this study with a planning horizon of 50 years for 28 EU countries. Each year is divided into 4 seasons and 3 intra-day blocks (making a total of 12 time slices). Each intra-day block has two sub-periods: one with and one without excess variable VRE. Excess VRE generation (excess beyond demand) is defined within each time slice and is to be balanced via flexibility options, including flexible demand (mainly heat-related electricity appliances), curtailment, storage or conversion into another carrier (e.g., production of hydrogen by electrolysis). The amount of excess generation is defined as a linear function of the solar PV capacity factor and the installed capacity of solar PV, wind and dispatchable power plants. The function is parameterised based on statistical analysis of a unit commitment model **Dispa-SET** operation results for a wide set of simulations with alternative configurations of the power system. In addition, baseload power plans are allowed to vary their output on a seasonal basis only, while storage is modelled to move energy only between the time slices of a same season.

Ireland (Welsch et al., 2014a, 2014b): In this study, flexibility balance is represented in an open-source energy system model (**OSeMOSYS**) of the Irish system up to 2050. The model has 12 time slices, representing 4 seasons and 3 parts of the day. Ramping requirements are defined both for five minutes and for longer intervals (referred to in the paper as spinning and replacement reserves, respectively), and these are met by a combination of technologies, each with unique ramping capabilities. The ramping requirement is externally defined for given set targets for wind penetration. Two sub-technologies are modelled for both CCGT and OCGT – one which operates at near-maximum capacity, and another that can ramp down to a part load with reduced efficiency. The former can meet ramping needs over five minute intervals, while the latter is able to meet ramping needs over longer periods. The model further incorporates the minimum stable generation level, which limits cycling of generation technologies between that level and the maximum online capacity.

Global (Pietzcker et al., 2014): Eleven regions, collectively representing the whole world, are analysed in this study using the **REMIND** long-term generation expansion model, with a 95-year planning time horizon. The need for flexibility – more specifically different types of storage (battery, hydrogen electrolyser, hydrogen turbine) and curtailment – is assumed to increase linearly with VRE's share of total electricity production, although the first 7% is exempted (based on empirical experience that at a lower level of penetration, the existing flexibility of a system can absorb the VRE fluctuation). Storage and curtailment needs are able to be parameterised for each technology at different penetration levels.

Eastern Germany (Ludig et al., 2011): A **LIMES** (Long-term Investment Model for the Electricity Sector) model is developed in this study for Eastern Germany with a planning time horizon of 95 years. The model has 12 times slices per year, which sufficiently cover the variability of solar PV and demand, but not the full variability of wind (see Eastern Germany example in Box 8). To overcome this, the flexibility requirement due to wind variability is investigated. Figure 18 shows how wind power generation changes over time, sorted by size for different intervals of time (e.g., the largest increase within two hours was 2 691 MW, the largest fall was 2 645 MW). Based on this analysis, constraints requiring fast-ramping backup capacity and supplementary generation to balance VRE fluctuations are parameterised as a function of the model's VRE capacity. Fast-ramping backup capacity is considered to be provided by gas and oil turbines, natural gas combined-cycle (NGCC), hydropower and storage.

Figure 18: Fluctuation of wind power production, sorted by size for different intervals of time (the x-axis displays the number of observations in the dataset)



Source: Ludig et al., 2011

Supporting data for parameterising flexibility provision

Data generally are available to provide either detailed or indicative information to parameterise the abilities and limitations of flexibility measures. Below is an overview of relevant parameters for the main sources of flexibility: dispatchable power plants, storage, demand response and interconnectors for cross-border trade.

Dispatchable power plants

Power plants that traditionally have provided baseload generation – including nuclear, coal, biomass, certain steam turbines with oil and gas fuel, and, to a certain degree, CCGT – typically (but not always) have limited flexibility.[53] Those designed to operate as mid-merit-order plants – including flexible CCGT, more flexible coal, biogas and CSP – are more flexible. Those used to cover peak load – including reservoir hydropower and OCGT – are highly flexible (IEA, 2014).

Box 13 summarises key technical parameters determining such scales of flexibility.

Box 13: Flexibility parameters of dispatchable plants

The key parameters that define the flexibility of power plants, as detailed in various publications, are summarised below. Seven sources are used, denoted as: A (Schröder et al., 2013), B (IEA, 2014), C (Welsch et al., 2014a), D (Poncelet et al., 2016a), E (Vuorinen, 2016), F (Bruynooghe et al., 2010), G (Hout et al., 2014) and H (Ulam-Orgil et al., 2012). The maximum ramp rate is expressed as a percentage of net capacity per minute; start-up time is expressed in hours; minimum load is expressed as a percentage of net capacity; minimum up time and down time is expressed in hours; and part load efficiency (efficiency loss at minimum load) is expressed in percentage (%) or percentage points (% pt). The design characteristics of plants – rather than the fuel they use per se – lead to very different flexibility profiles (IEA, 2014).

While Tables 8 to 13 present useful sources of information, further innovation may help increase the flexibility of power plants. Using current parameters for assessing future energy systems may overestimate the challenge of integrating VRE.

Nuclear: Nuclear power plants also are typically run in baseload mode. Their flexibility is often regulated on safety grounds, but nuclear is operated with some flexibility in counties where its share in the system is high (see Table 10).

Table 9: Flexibility parameters for nuclear power plants found in the literature

	Maximal ramp rate	Start-up time (cold/hot)	Minimum load	Minimum up/ down time	Part load efficiency	Source
Nuclear	5		50	24/48		D
Nuclear	0.25-10	24-50 /<0.3	40-50	6-48 / 4-48	5%	A
Nuclear	0-5	N/A / 2-48	40-100			B
Nuclear	1-5					E
Nuclear	5					F
Nuclear	20*		50	8 / 4		G

* % of capacity in one hour

53 *These technologies can be made to operate flexibly, with a range of new-build and retrofit options available (see, for example, the discussion of coal flexibility in Cochran et al. (2013)).*

Coal: Coal power plants traditionally have been run as baseload generators, and so are generally inflexible. However, they are increasingly being designed for more flexible operation (see Table 9).

Table 10: Flexibility parameters for coal power plants found in the literature

	Maximal ramp rate	Start-up time (cold/hot)	Minimum load	Minimum up/ down time	Part load efficiency	Source
Coal	0.6-8	NA / 2-7	20-60			B
Coal (2020)	17.9*		64.3			C
Coal (Mongolia)	10-20					H
Standard coal (subcritical)	0.58-8	7.3-10 / 3	25-50	3-15 / 2-15	4%	A
Subcritical pulverised coal plants	3		40	6 / 4	2% pt	D
(Ultra-) supercritical pulverised coal plants	4		50	6 / 4	2% pt	D
Advanced coal (supercritical)	0.66-8	4-12 / 1-5	20-50	4-6 / 4	2% pt	A
Lignite	0.6-6	NA / 2-8	40-60			B
Lignite (new)	0.58-4	6-12.8 / 4	40-50	4 / 4		A
Lignite (old)	0.58-8	10-12.8 / 6	40-60	4-6 / 4-8	10%	A
Lignite and Pulverised coal (PC) (before 2010)	40**		40	8 / 4		G
Lignite and PC (2010)	50**		35	8 / 4		G
Lignite and PC (after 2010)	50**		30	8 / 4		G
Steam turbine plants	1-5	1-10				E
Integrated gasification combine cycle (IGCC) (before 2010)	30**		45	8 / 4		G
IGCC (before 2010)	40**		40	8 / 4		G
IGCC (after 2010)	40**		35	8 / 4		G
IGCC	4		50	4 / 1	8% pt	D
IGCC (2050)	12*		47.7			C

* % of capacity in five minutes; ** % of capacity in one hour

Oil and gas: OCGT plants are typically flexible, and a subset of them, used as peaking plants, is highly flexible. CCGT plants are typically less flexible (see Table 11).

Table 11: Flexibility parameters for oil and gas power plants found in the literature

	Maximal ramp rate	Start-up time (cold/hot)	Minimum load	Minimum up/ down time	Part load efficiency	Source
OCGT	0.83-30	<1 / <0.17	10-50	0-6 / 0-6	20%	A
Gas OCGT	7-30	NA / 0.1-1	0-30			B
OCGT (2020)	10*		55			C
OCGT (2050)	16.9*		17			C
OCGT	17.5		10	1 / 1	21% pt	D
OCGT	100**		10	1 / 1		G
Aeroderivative gas turbine	20	5-10				E
Industrial gas turbine	20	10-20				E
Combustion engine bank CC	10-100	NA / 0.1-0.16	0			B
CCGT	0.83-12	2-5 / 0.5-2	30-50	1-6 / 1-6	5-9%	A
CCGT	5-10	0.5-1				E
CCGT	7	3 / NA	40			F
CCGT (2020)	16.9*		42.2			C
CCGT - new (2020)* **	12*		52.9			C
CCGT	7		50	4 / 1	8% pt	D
Gas CCGT	0.8-15	NA / 3	15-50			B
NGCC (before 2010)	50**		40	1 / 3		G
NGCC (2010)	60**		30	1 / 3		G
NGCC (after 2010)	80**		30	1 / 3		G
Oil	1-20	1 / NA	10-50	1-6 / 1-6	-	A
Steam (oil / gas)	0.6-7	NA / 1-4	10-50			B
Distillate oil	10.1*		10.1			C
Gas engines	10-85	3-10 min				E
Diesel engines	40	1-5 min	30-50			E
Heavy oil			20-35			H
Diesel oil						H

* % of capacity in five minutes; ** % of capacity in one hour; *** According to the authors of Source C, the higher minimum load figures from this source for newer CCGT represent an observed trend in the Irish market, and may not necessarily be representative

Hydropower plants: Hydropower with a reservoir is highly flexible, with a low minimum load and a quick start up time (see Table 12).

Table 12: Flexibility parameters for hydropower plants found in the literature

	Maximal ramp rate	Start-up time (cold/hot)	Minimum load	Minimum up/ down time	Part load efficiency	Source
Hydro reservoir	15-25	NA / <0.1	5-6			B
Hydro run-of-river	5	NA / 0.16	50			B
Hydropower	12.8*		13.7			C
Pumped storage	17.1*		3.4			C

* % of capacity in five minutes

Combined heat and power (CHP): In most countries current CHP operational practice prioritises covering heat demand, making its electricity generation very inflexible (see Table 13). However, in Denmark, where electric boilers are installed, CHP plants are operated flexibly, even allowing even for negative generation (i.e., consumption of electricity) (IEA, 2014).

Table 13: Flexibility parameters for combined heat and power plants found in the literature

	Maximal ramp rate	Start-up time (cold/hot)	Minimum load	Minimum up/ down time	Part load efficiency	Source
CHP - coal	2-4	NA / 5-9	50-80			B
CHP - CCGT	2-8	NA / 2-3	40-80			B
CHP - steam turbine (oil / gas)	2	NA / 4	100			B
CHP	90*		10	1 / 1		G

* % of capacity in one hour

Other: See Table 14.

Table 14: Flexibility parameters for other types of power plants found in the literature

	Maximal ramp rate	Start-up time (cold/hot)	Minimum load	Minimum up/ down time	Part load efficiency	Source
Peat (2020)	34.6*		69.2			C
Bioenergy	8	NA / 3	50			B
Biogas (2020)	0*		22.7			C
Waste (2020)	0*		23.8			C
Biomass (2050)	0*		34.2			C
Geothermal	5-6	NA / 1-2	10-20			B
Wind onshore (2020, 2050)	0*		0			C
Solar (2050)	0*		0			C
Solar CSP	4-8	NA / 1-4	20-30			B

* % of capacity in five minutes

Table 15: Flexibility parameters of selected storage technologies

Technology	Typical power capability (MW)	Discharge time
Pumped hydropower	100-5,000	Hours
CAES*	100-300	Hours
Li-ion battery**	0.001-20	Minutes to hours
NaS battery***	0.001-5	Hours
Lead acid battery	1-200	Hours

*Compressed air energy storage; ** Lithium-ion; *** Sodium-sulphur
Source: IEA, 2014

Storage

Electricity storage systems are used primarily to shift the timing of electricity supply and demand, by storing and then dispatching energy.[54] They can help smooth the production profile of VRE generators by avoiding abrupt fluctuations in generation due to changes in weather conditions, and by allowing predetermined generation profiles. The most common form of electricity storage (at 99% of total installed capacity) is pumped hydropower. Other forms, including batteries, are becoming increasingly important (IRENA, 2015c). All of the storage options described in this subsection can start up quickly, within minutes or seconds.

The flexibility of storage systems is characterised primarily by:

- Power capability (MW): the amount of power that an installation can provide, and
- Storage capacity (MWh): the amount of energy that an installation can store and discharge per cycle.

Parameters for key storage technologies are summarised in Table 15.

Demand response

Demand response comprises techniques for reducing the load on an electric system during peak electricity usage or when renewable output drops. It includes: direct load control by utilities (typically used with large commercial and industrial customers), voluntary load reduction (typically activated by price signals) and dynamic demand (automated adjustment of power usage). Demand response can act as a virtual peaking plant, with known ability to ramp up to full capacity in five minutes – and even faster in the future (IRENA, 2013a).

Box 14: Country application examples: demand-response assessment

Western United States (Olsen et al., 2013): A comprehensive methodology is developed in this study to assess future profiles of demand-response availability and is implemented using 13 end-use loads within the Western Interconnection for the calendar year 2020. Annual load profiles are evaluated to obtain an estimate of the available amount to enable participation in several options – an energy and a capacity product, and three ancillary services – for each hour of that year. The availability profiles that result serve as inputs to a production cost model. This type of exercise can be useful for gauging the scale and characteristics of providing demand-side flexibility in a balancing approach.

54 *Electricity storage can provide other important services that help integrate VRE into a power system. They include: ancillary services such as regulation (frequency and primary response), reserves, voltage support, black start; transmission infrastructure services (transmission upgrade deferral and transmission congestion relief); distribution infrastructure services (distribution upgrade deferral and voltage support); customer energy management services (power quality, power reliability, retail electric energy time-shift, and demand charge management) (Akhil et al., 2013; IRENA, 2015b, 2015c). As discussed in Section 2.3, weather-driven variability of VRE does not necessarily influence system-level need for ancillary service, but it does influence system-level ability to provide these services. The need for ancillary service is not discussed in the context of flexibility but rather in the context of contingency response.*

Interconnectors for cross-border trade

Interconnectors allow the flexibilities of power systems to be shared by enabling the transfer of power from a surplus to a deficit area. The benefits are greater when areas with different generation and load characteristics are connected, although the flexibility of the interconnector depends on operational agreements between the interconnected systems. Best practices suggest that flexibility can be deployed by this means on an hour-by-hour basis (IRENA, forthcoming-d). Outside Europe and the US, however, trading agreements based on long-term bilateral power purchase agreements (PPAs) are common.[55] Using interconnection capacity for short-term trade has been less common, and institutional frameworks for such exchanges may be underdeveloped in many power systems (IEA, 2014).

Incorporating flexibility balance

A "flexibility balancing" approach has been practiced in some long-term modelling exercises to incorporate a system's flexibility needs. It requires calculating a "flexibility requirement" for an entire system, based on the variabilities of demand and VRE, and balancing it with a range of flexibility provision options at an aggregated system level. This level of balancing in the model represents an additional constraint to the standard balancing of total power demand and supply. Some practical examples of the flexibility balancing approach were given in Box 15.

The flexibility requirements for a given source of VRE – or for a system as a whole – can be established by analysing fluctuations in both VRE generation and the load pattern. These analyses, discussed alongside specific examples in Box 16 below produce metrics (often expressed in units of capacity or production) that measure flexibility requirements over different timeframes, to be filled by flexible supply or system services. Some requirements may be established on the basis of carefully scrutinised empirical or synthetic data, while others exist as "rules of thumb", based on informed expert opinions.[56] Flexibility requirements for different ranges of probability (e.g., a rare occurrence of extreme variability) may need to be established and implemented in long-term generation expansion models so as to assess the "right" level of curtailment within a range of probabilities.

Such an approach provides a first-order approximation for meeting a system's flexibility needs, but it does not ensure that ramping services actually would be available to be deployed at a given point in time, because availability depends on a power plant's operating status at that moment. A model's ability to represent operational status depends on the time resolution of its dispatch representation. Due to the limited ability of long-term models to represent dispatch, the above approach also does not fully account for operational status, as well as for the costs related to additional wear and tear from heavy ramping duty at dispatchable power plants. Solutions for linking long-term models to more detailed representations of dispatch in production cost models are discussed in Section 6.3.

Supporting data and tools for parameterising flexibility requirements

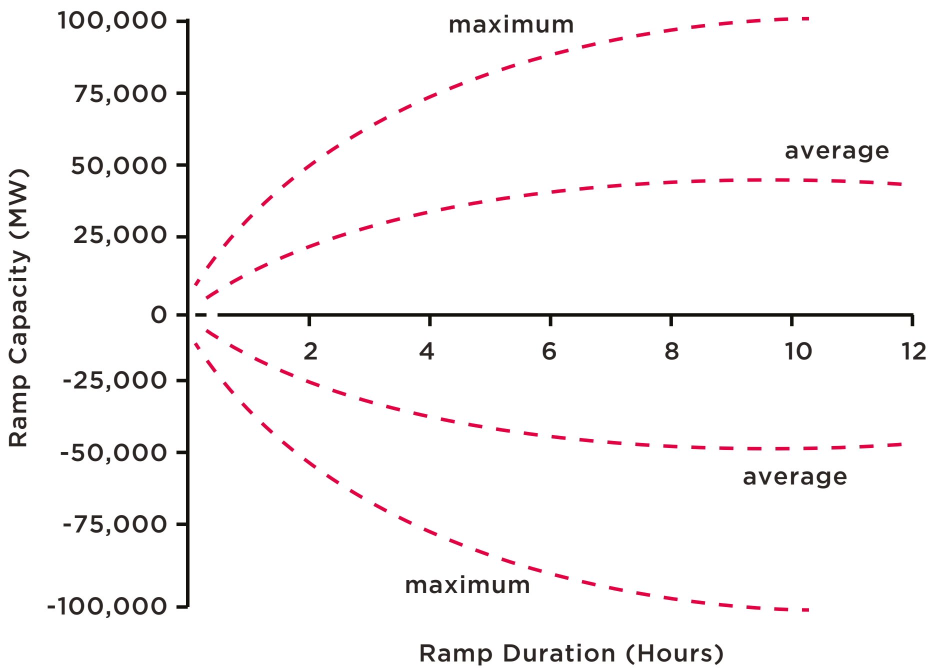
In general, the flexibility requirements for a system can be calculated in a straightforward manner by analysing chronological VRE and load data, and determining the rate and scale of fluctuations in the residual load (the load minus VRE generation at a given point in time). The resulting metrics are often referred to as **"ramping requirements"** or **"ramp rate requirements"**. Notably, this terminology does not preclude flexibility provision by demand-side and storage measures, which can make important contributions.

55 Case studies of 12 regional markets and cross-border power projects from 2010 (ESMAP, 2010) indicate that 7 of those analysed have been operated primarily based on such long-term bilateral trade agreements (Greater Mekong Sub-region, Southern Africa Power Pool, Argentina-Brazil Garabi Project, Nile Basin Initiative, Mozambique Cahora Bassa project, Mali Manantali project, Laos Nam Theun 2 project).

56 While a link between VRE share and flexibility deployment may be established, it is highly system dependent, as it depends on how much flexibility already exists in the system and how VRE collectively fluctuates. It is thus important to note that the "rules of thumb" are accordingly highly system specific and cannot be applied directly to other types of systems (Jones, 2014).

An analysis of load and wind generation data from 28 balancing authorities (ranging from 2 GW to 15 GW in size) in the Western US shows that the ramping requirement is larger at longer time intervals (ramp duration), provided that anomalies in the data are cleared up (King et al., 2011). Sub-hourly ramping requirements, for example, would be relatively small compared with hourly and multi-hourly ones. This is illustrated by ramp rate envelopes, shown in Figure 19, which are plotted as the maximum (in a year) and average (an average of daily maxima) ramp rate requirements for different ramp durations. Similar plots can be drawn for different percentiles of data. More specific examples of flexibility requirement parameterisation are provided in Box 15.

Figure 19: Sample ramp rate envelopes according to the percentile of data

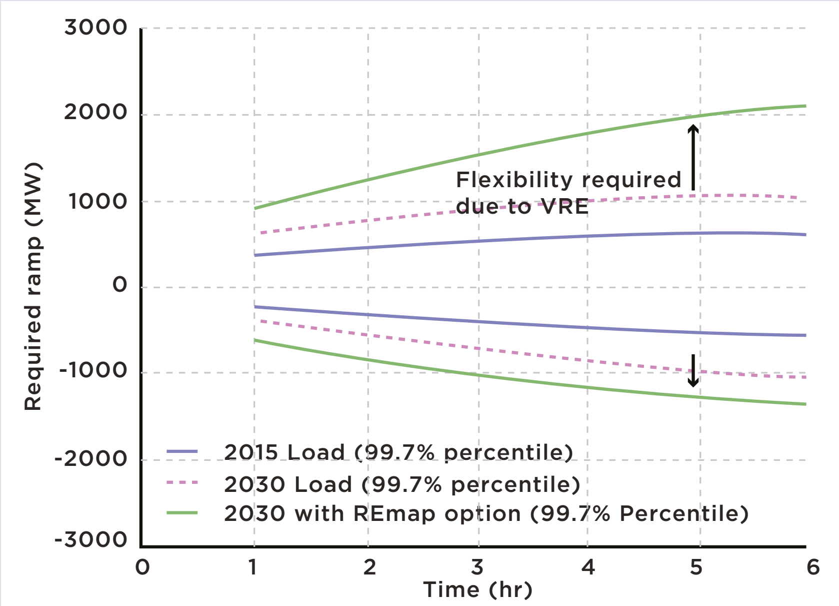


Source: King et al., 2011

Box 15: Country application examples: flexibility requirements in practice

Dominican Republic (IRENA, 2016c): An ambitious renewables scenario for 2030 suggests that the installed capacity of solar PV and wind would reach 4.1 GW (against a 4.6 GW peak). At this level of VRE penetration, a one-hour ramp requirement would be around 1 000 MW, and a six-hour ramp requirement would be around 2000 MW. Of these amounts, around 400 MW for a one-hour requirement and 1000 MW for a six-hour requirement are due to the variation of VRE beyond pure load variation.

Figure 20: Ramp duration curve for 2015 and 2030 with REmap variable renewable energy, average ramp rate envelopes for 2015 and 2030



Source: IRENA, 2016c

Barbados (GE Energy Management Energy Consulting, 2015): A reserve to respond to short-term (less than 10 minutes) variability in wind and solar power output is computed in this study based on an analysis of 10-minute-resolution data on wind and solar generation. The 99.9 percentile fluctuation of combined wind and solar output is found to be about 16 MW (for 45 MW of distributed PV, 20 MW of central PV and 15 MW of wind) and about 5 MW for wind alone.

Western United States (PacifiCorp, 2015): Ramp reserve (the capacity to follow predicted VRE and load variations in all timeframes) and regulation reserve (the capacity set aside to meet forecasting errors) are estimated separately in this study, based on historical data of load and wind generation at 10-minute intervals. In practice, ramp reserve is computed as an inter-hourly variation, calculated as the difference of residual load (load minus wind generation) at the start of each hour. Regulation reserve is determined from intra-hourly variation: deviations from scheduled wind output and scheduled load are computed for every 10 minutes and hour as forecasting errors. Reserve requirements for each month at different forecast levels are determined by applying a 99.7% percentile confidence interval. For a system with a share of wind amounting to 2.5 GW of its total 12 GW capacity, the additional reserve required due to wind variation alone is estimated to be 12 MW (for ramp reserve) and 174 MW (for regulation reserve). For comparison, the corresponding reserve requirement (both ramp and regulation) due to variation in load is estimated to be 441 MW.

Unspecified (generic Europe) (Welsch et al., 2014b): Ramping needs for half-hour and four-hour timeframes are estimated in this study to be “three times the sum of the root-mean-square of standard deviations of demand and wind forecast. The standard deviation of the demand forecast error is assumed to be +- 1% over the half-hour interval, and +-2% over the four-hour interval”. The standard deviation of the wind forecast error is assumed to be +-1.4% and +-6%. The capacity of the largest plant (1.6 GW) is added to the upwards ramping needs to account for the contingency reserve. For a hypothetical system with a peak demand of 126 GW, the maximum upwards ramping needs for a half-hour interval is estimated to be 6.5 GW, and downwards is estimatedto be 4.9 GW. Four-hour ramping needs are estimated to be 17.1 GW for upwards and 15.5 GW for downwards.

Ireland (EirGrid and SONI, 2013): This study finds that at the current wind penetration level (1.8 GW in 2012), ramp rates of +/- 300-350 MW/hour are common. In the future, when up to 6 GW of wind generation will be installed, the corresponding ramp rate could be +/- 1 200 MW/hour.

6.2 Validating flexibility balance in a system

As discussed in the previous section, adding constraints to long-term generation expansion models under a flexibility balance approach is often a first-order approximation of flexibility needs and measures, given the issue of time resolution. The results from such a model can be further scrutinised using more detailed assessment tools, to validate whether there is sufficient flexibility in place.

Supplementary tools with different degrees of complexity have been proposed and applied to assess flexibility in demand and supply for power systems (see Box 16). These tools are based on a chronological assessment of variability – introduced by load as well as by VRE – at different time horizons. Flexibility in supply is assessed primarily through the ramping capability of power plants at different time horizons, allowing a snap-shot assessment of the operation of a current or future power system.

Full assessment requires a simulation of dispatch, which can be done though a production cost model, an approach discussed in Section 6.3.

Box 16: Flexibility assessment tools

InFLEXion (EPRI, 2016, 2014): InFLEXion was developed by the Electric Power Research Institute (EPRI) in the US, and a beta version has been released (EPRI, 2015). However, neither the tool nor its application are fully available in the public domain. It provides a screening level to a more detailed assessment of the flexibility of a power system, depending on data availability, and consists of a chronological assessment of ramping needs (upwards and downwards for a set time duration) and of the frequency of their occurrence by the hour of the day and by month. The flexible resources available are compared with the required ramping needs in order to assess flexibility system-wide. Flexibility can be drawn from online (the so-called spinning reserve) and offline sources: online flexibility is limited to a range between the current production level and maximum output. InFLEXion assesses the flexibility that the resource fleet can technically offer in each period, taking into account the dispatching pattern. Three flexibility metrics are computed, based on chronological analysis of flexibility requirements and supply – the period of flexibility deficit, expected unserved ramping and insufficient expectation of the ramping resource. Unlike FAST2 below, the tool does not explicitly assess flexibility resources beyond dispatchable generators – such as storage, demand response and interconnectors.

FlexAssessment (Hidalgo González et al., 2015): Developed by EDF R&D as part of a suite of planning models used for internal purposes, FlexAssessment is similar to the InFLEXion tool described below in that it assesses flexibility based on chronological dispatch and uses the number of periods of insufficient flexibility as an assessment metric. It is used to validate the robustness of simulated operation, as suggested by EDF's production cost model (CONTINENTAL). A feedback loop is being established into the capacity expansion model (MADONE) to incorporate flexibility requirements so as to correct for operational inconsistencies that FlexAssessment suggests.

Revised Flexibility Assessment Tool (FAST2) (IEA, 2014; Müller, 2013): Developed by the IEA, FAST2 allows an initial, high-level assessment of power system flexibility based on a chronological hourly matching of load and VRE supply. It calculates flexibility requirements from hourly load and VRE generation data over a period and matches it against flexibility provisions from flexible plants, interconnections, demand-side response, pumped hydropower storage and interconnectors – while taking into account existing inflexibility due to the minimum generation requirements of dispatchable plants. Its output is the number of hours with insufficient flexibility for different hypothetical levels of VRE penetration. Such an assessment can be conducted, in the long-term planning context, as ex-post validation of model results for a single future year.

6.3 Coupling with production cost models

Production cost models have been used to validate, and in some cases to correct, results from long-term generation expansion models to complement their inherent limitations in time resolution (and the level of operational detail linked with it). Such an approach – often referred to as a **"coupling"** approach – can translate flexibility requirements in operation (the focus of production models) into flexibility investment decisions (the focus of generation expansion models). Examples of their application in particular countries are given in Box 17, and a detailed description of the general model category can be found in Appendix 2.

Production cost models simulate decisions on economic unit commitment and dispatch at hourly time resolutions or less, typically over a timeframe of one year, and directly consider the operational constraints associated with flexibility issues discussed in the previous section. Simulating dispatch requires inputting a pre-fixed capacity mix, which is, in turn, an output of generation expansion models. The primary metric for comparison is made up of generation outputs from both models for a given capacity mix, and it is interlinked with curtailment of generation. Inefficiently representing flexibility needs and provision in long-term generation expansion models may suggest a capacity expansion mix with insufficient flexibility, which – when run through a production cost model – may result in large curtailment in order to retain the secure operation of a system.[57]

Economic dispatch decisions by production cost models can account for short-term (hourly or shorter) variability in VRE and load, and for technical constraints on the flexible operation of generation units (e.g., minimum up and down times, ramp-up and -down constraints, start-up times, part-load efficiencies) and the costs associated with them.

Most "coupling" attempts are unidirectional (i.e., from long-term generation expansion models to production models) and are aimed primarily at validating improved features of long-term generation expansion models (e.g., through imitating some of the operational constraints, with higher time resolution). Important, and less important, operational constraints can be identified through such validation exercises (e.g., Deane et al., 2015; Poncelet et al., 2016a; Welsch et al., 2014a). The findings, however, may be highly system-specific: global understanding still has to be built on what is important in which types of systems.

Other coupling attempts aim to introduce feedback loops from production cost models into capacity expansion models, so as to correct for inconsistencies and, ultimately, to find convergence between the outputs from the two model types. After running through a production cost model, capacity or capacity factor can be adjusted to correct for production inconsistencies. This bi-directional "coupling" of models is the most sophisticated mode, and the adjustment of capacity based on production cost model results is often based on expert judgment, rather than on systematic criteria. Moreover, the reliable convergence of the two models requires further research.[58]

Another type of feedback loop into long-term generation expansion models is the introduction of model constraints parameterised through a production cost model run. Production cost models can compute aggregated parameters that reflect the technical and economic impacts of VRE, including flexibility requirements (as discussed in Section 6.1), VRE balancing costs, capacity reserve demand and capacity credit for VRE.

This model coupling approach is emerging as the most preferred solution, at least in Europe (Hidalgo González et al., 2015), but applying it requires a high degree of model expertise as well as computational resources and data, and has been done mostly at a research-grade level.

57 *As shown in Poncelet et al. (2014), VRE may be curtailed instead of operating more flexible units, if start-up costs do not economically justify such operation. Silva et al. in Hidalgo González et al. (2015) show that the MADONE model for Europe – developed using the TIMES model framework with 288 time slices – systematically underestimates generation from mid-merit technologies when compared with the results from their production cost model (the CONTINENT model with investment loops)*

58 *An alternative to this approach, of incorporating feedback loops from production models into generation expansion models, is emerging – a group of models that incorporates investment decisions into production models. For an example of this emerging approach, see de Sisternes et al. (2016).*

Box 17: Country application examples: soft-linking

Ireland (Deane et al., 2015): In this study, soft-linking methodology is applied to the Irish **TIMES** model (a generation expansion model with 12 time slices in a year), coupling it with a **PLEXOS** model (a dispatch model for the power sector applied with half-hourly temporal resolution). The power sector results – capacity mix and electricity sector demand – are taken from the Irish TIMES model for 2020 and used as inputs to the PLEXOS model. This system is simulated in PLEXOS to calculate the optimal generation mix, which is then compared to the generation mix from the Irish TIMES. The comparison shows that more flexible resources are deployed in the optimal generation mix from the PLEXOS model than in the one from the TIMES model, including increased production of CCGT generators, reduced use of inflexible coal generation and greater use of pumped storage to provide spinning reserve. The results of this study identify an overestimation of installed wind capacity in the original TIMES results, leading to 8% of wind generation curtailment. This insight is fed back into TIMES through a constraint on annual generation for this resource.

Greece (Tigas et al., 2015): A **TIMES** is developed in this study to to analyse the Greek energy system with a planning horizon of 38 years and with 14 geographical clusters. A year is divided into 4 seasons and 4 intra-day blocks (a total of 16 time slices in a year). The model is soft-linked with **PropSim** (Probabilistic simulation for electricity), an in-house modelling tool, to compute a synthetic residual duration curve based on externally defined hourly load and VRE generation time-profile data, and to simulate the operation of a power system for a given time interval. Peak-load capacity requirement and the balancing units' capacity required to cover the residual load hourly variation, as well as the storage capacity required to restrict energy curtailment, are then computed. These requirements are fed back into the TIMES-Greece model (including the costs linked to balancing units and storage), together with the corrected utilisation factors of VRE in each geographical cluster. The two models are used iteratively until the solutions from them converge.

Europe (DNV GL Energy, 2014): In this study the **PLEXOS** model (a production cost model with a capacity expansion module) provides generation capacities for Europe, which are then included in the DSIM (Dynamic System Investment Model, developed at Imperial College), which optimises short-term operation of the European power system on an hourly basis for a full year. It also assesses transmission network reinforcements, annual production costs and additional generation capacity to meet reliability requirements.

Portugal (Pina et al., 2013): A framework that soft-links the **TIMES** long-term energy planning model to the **EnergyPLAN** short-term operational model is applied in this study to Portugal for a 2005 to 2050 horizon. Each year of results from TIMES is used to create an installed generation capacity mix within the EnergyPLAN model, which simulates constraints over the amount of installed capacity that the system can handle per year, subject to certain criteria. If the installed capacity from renewable sources does not produce 90% of available yearly output in EnergyPLAN, it is revised downwards so that it produces the maximum energy available to it. The results show that this soft-linking approach can avoid overinvestment and reduce the production of excess electricity.

Tokyo, Japan (Zhang et al., 2013): This analysis soft-couples a long-term planning model with an hour-by-hour simulation model, and applies the integrated model framework to the Tokyo area. If the capacity mix provided by the long-term model does not allow for balancing power supply and demand in every hour of a year, the mix is adjusted to increase the capacity of peaking gas power plants in the simulation tool until full balancing is achieved. These adjustments are then fed back into the long-term model.

United States (NREL, 2012): In this study, the long-term generation expansion model **ReEDS** is validated by the production cost/stationary network analysis model GridView (developed by ABB) for the US power system. GridView uses ReEDS' scenario results for transmission and generation capacities in 2050 as an input, and separately explores the hourly operation of the power system, also considering a DC load flow assessment and numerous operational constraints. Most importantly, GridView finds that the ReEDS' transmission system is sufficient to serve all hourly loads in the high-penetration renewable electricity futures that are modelled (80% renewable energy, with nearly 50% VRE). In this way, highly resolved models can validate whether long-term model results for investment in transmission are technically sufficient and realistic in cost terms.

East Africa (SNC-Lavalin and Parsons Brinckerhoff, 2011): Two models are soft-linked in this study: **OPTGEN**, a long-term model for determining the least-cost expansion plan (generation and transmission) of a multiregional hydro-thermal system, and **SDDP**, a probabilistic multi-area hydro-thermal production costing model. Given the OPTGEN model's investment decisions, SDDP provides an operational analysis which is then fed back into OPTGEN. The modelling approach is used to develop the Eastern Africa Power Pool Master Plan for 2013-2038.

7 REPRESENTING TRANSMISSION CAPACITY

As discussed in Chapter 2, variable renewable energy is constrained by its location. Sites with good VRE resources may be located far from demand centres or existing transmission lines. VRE therefore is likely to need more substantial investments in transmission than most thermal power plants, which are less location-constrained. As a result, for some VRE projects, proximity to demand centres may compensate for a less attractive quality of the resource. There also may be trade-offs between investing in centralised VRE with substantial transmission costs and in distributed VRE, which does not require significant grid infrastructure investment.

In addition to the more generic solutions for better transmission representation discussed in Section 4.2, which involve increasing the spatial resolution of a generation expansion model, this chapter presents two specific approaches for better incorporating the transmission cost requirements of VRE deployment into long-term modelling. Section 7.1 discusses a simplified model representation of VRE-linked transmission investment needs in the model. Section 7.2 then discusses approaches to have better spatial representations in generation expansion models, based primarily on pre-processed GIS resource data.

Key points of Chapter 7

Linking grid investment needs with VRE expansion: Transmission costs related to VRE can be assessed outside a model and then added to VRE investment costs in a generic manner (e.g., establishing and implementing a per-unit transmission cost for VRE capacity). This simplified approach does not allow any assessment of trade-offs between VRE resource quality and additional transmission capacity investment, but can reflect generic effects of VRE-driven transmission needs on VRE investments.

General complexity: Low to medium

Site-specific representation of generation and transmission: The trade-off between VRE resource quality and additional transmission capacity investment can be assessed within a model by explicitly incorporating location-specific techno-economic characteristics of VRE. Practically, this can be achieved by incorporating clusters of VRE sites (or ”zones”) as explicit options for investment. GIS-based tools and data are becoming increasingly available to allow for more accurate resource and siting assessments. Understanding and improving the representation of VRE resources in modelling will naturally help to make more accurate assessments of their associated needs for investment in transmission.

General complexity: Low to medium

7.1 Linking grid investment needs with variable renewable energy expansion

A first-order approximation of transmission investment costs associated with VRE deployment may be established by rule of thumb, through linking such investment needs with the share of VRE in a system. The grid investment costs associated with one unit of VRE capacity, for example, can be parameterised to increase with this share to account for the need for new connections. The increasing cost of transmission investment can represent the need for increasingly long-distance lines as VRE generation outgrows nearby centres of energy demand. Two practical examples of such an approach are given in Box 18.

Supporting data and tools for linking grid investment needs with variable renewable energy expansion

A number of existing sources have attempted to estimate additional costs of transmission due to VRE expansion, covering a range of different systems. For example, a survey of grid reinforcement costs related purely to wind power in Denmark, Germany, Ireland, the Netherlands and Portugal (by Holttinen et al., 2011) suggests that additional investment is in the range of EUR 50 to EUR 270 per kW of wind at penetration between 15% and 55% of gross demand (energy). Another survey (DNV GL, unpublished-a) shows that the transmission cost of VRE integration into the grid is in the range of USD 1/MWh to USD 12.5/MWh in Europe, and much higher – USD 12-29/MWh – in the Eastern US. Such studies can provide the basic data necessary to incorporate first-order transmission cost estimates for future VRE expansion.

If existing studies of VRE-driven transmission costs are unavailable, DNV GL (unpublished-a) presents a more general methodology to estimate transmission and distribution requirements that follow from national generation expansion plans. The methodology begins by developing a “virtual” transmission grid, specifying nodes for VRE generation and load centres, and estimating distances between nodes using Google Earth. Each node can be represented by an aggregated set of nodes if necessary.

Box 18: Country application examples: representing transmission capacity in long-term generation expansion models

Global (Pietzcker et al., 2014): A **REMIND** model with a 100-year planning time horizon, covering 11 regions to collectively represent the world, is developed in this study with a specific feature to address transmission grid costs associated with VRE deployment. Transmission grid costs are assumed to increase with VRE’s share of the total electricity production, although the first 7% is exempted on the assumption that it would serve more localised demand. The extra length of transmission grid necessitated by the expansion of VRE is estimated using a formula based on the maximum grid length for a given generation level. For each kW of electricity replaced by VRE per year, the formula adds a high-voltage direct current (HVDC) grid of 210 kW kilometres for solar PV, 4 800 kW kilometres for CSP and 2 630 kW kilometres for wind.

Southern Africa (IRENA, 2013b): Eleven Southern African countries are modelled in this study to assess generation expansion scenarios with renewables, using the **MESSAGE/SPLAT** model with a planning time horizon of 20 years. Each country represents a separate node. Based on prior analysis, USD 365/kW is added to wind investment costs to account for additional transmission investment, although this cost is omitted for capacity under a 5% share of generation. The study also differentiates between transmission and distribution efficiency losses in delivering electricity to three generically represented consumer groups (industry – low transmission loss; urban – modest transmission and distribution losses; rural – high transmission and distribution losses) and can therefore assess the competitiveness of distributed renewable energy (no transmission and distribution required) against VRE with grid extension.

A synthetic residual load curve is then created for each node over the course of the forecast horizon, and the tail of the curve – the negative residual load – is taken to be the VRE generation that needs to be transmitted to other nodes (or otherwise curtailed). The transmission investment costs for a given set of nodes is reached by multiplying the transmission capacity, distance, transmission technology costs and multipliers reflecting topologies.

Under this particular methodology, distribution capacity expansion is assessed using a more generic approach, assuming linear cost increases after a certain threshold level. The parameters to define the threshold level and the slope of the linear function are taken based on subjective expert assessments. Those assessments are based on factors such as strong correlation between VRE production and peak load, weak grid (low headroom), use of demand response and smart grid technologies, and capped injection by rooftop solar PV.

Examples of the approaches described above are discussed in Box 19.

Box 19: Country application examples: assessing transmission and distribution investment needs

Dominican Republic (Jil, 2016): Building on the DNV GL (unpublished a, b) methodology, the need for transmission investment to incorporate 2,300 MW of wind and 1,760 MW of solar PV in 2030 is is estimated for the Dominican Republic in this study. Sixteen nodes are defined, and, using Power Factory software (a network analysis tool; see Appendix 2 for details), transfer capacity limits between each pair of nodes are assessed for the current system. Building on that, residual load duration curves (RLDC) are established for each node in 2030. The assessment is made for three scenarios, differentiated by assumptions on transmission capacity margins. The results indicate that about USD 50 million to USD 170 million of investment in transmission (corresponding to 520 MW to 2,050 MW of transmission capacity addition) is required to accommodate solar PV and wind at the specified levels.

Morocco (DNV GL, unpublished b): Using the methodology described in the section above, transmission and distribution expansion needs associated with wind penetration levels of 3,100 MW for 2020 and 6,200 MW for 2030 are estimated in this study. These levels correspond to 35% and 57% of expected peak load in the respective years. For transmission lines, eight nodes are defined, and it is estimated that 6,400 MW and 9,800 MW of investment would be needed to accommodate the additional wind capacity in the respective years. This translates into USD 590 million and USD 1,200 million, respectively (with an assumption of 5% curtailment). With 0% curtailment, the transmission investment costs almost double, while with 10% curtailment, the cost falls by about 20%, in both 2020 and 2030. Solar PV installation – 721 MW by 2030 (corresponding to 1.5% of total consumption) – would require additional investment in the distribution network. An indicative assessment shows that at up to about a 15% share of total production, investment needs at the distribution level are negligible. Beyond that point, EUR 4/MWh may be required as a network reinforcement cost.

Europe (Scholz et al., 2016): The ADVANCE project makes use of the very detailed, hourly dispatch and investment power sector model REMIX to scan a large range of VRE shares and mix of solar and wind in order to analyse the resulting need for grid extension. These detailed scenario results can then be used to parameterise a grid cost function that can be implemented into long-term models. A similar parametric study by Schaber et al. (2012) contains a systematic analysis of transmission grid extensions and associated costs as a function of the share and mix of VRE in Europe.

7.2 Site-specific representation of generation and transmission needs

As discussed in Section 4.1, nodes are often implemented in long-term generation expansion models to represent the particular demand and supply of an area, and investment in transmission capacity can be optimised jointly with generation expansion.

By introducing more nodes in the model, and characterising them with better node-specific demand and VRE availability data (ideally with temporal profiles), transmission investment needs associated with different VRE locations can be assessed more realistically. While more robust, this approach does require significant VRE data pre-processing efforts.

As an alternative to analysing transmission investment needs between a given set of nodes, another approach exists to incorporate impacts of VRE's general site-specific nature on transmission needs.

This can be achieved by incorporating clusters of VRE sites (or **"zones"**) as explicit options for investment, distinguished by such techno-economic characteristics as VRE generation profiles (i.e., temporal availability and the resulting capacity factors), together with the costs that they would incur for additional transmission (based on proximity to existing infrastructure and site topography). Such costs can be assessed separately prior to the modelling analysis. Information on VRE zones, and their associated techno-economic characteristics, are increasingly available through global GIS datasets and are becoming more accessible for planning purposes. More specific examples of these sources of information are discussed in Box 21 in the following sub-section.

Box 20 presents a range of practical country-level experiences with the use of GIS data for generation capacity expansion model.

Box 20: Country application examples: site-specific representation of generation and transmission

Swaziland (IRENA, 2016b): In this study, a **SPLAT** Swaziland model – already discussed in Box 8 – incorporates 5 solar PV zones and 17 wind zones as separate investment options. Capacity factors for each time slice, infrastructure costs (new transmission line to connect to the nearest sub-station, and road construction to connect to the nearest road infrastructure), maximum generation capacity, and suitable turbine types (for wind) are defined for each zone, based on hourly VRE generation profile data for 14 years, as defined in IRENA and LBNL (2015). Trade-offs between good VRE resources far from existing transmission lines, and the cost of new transmission investment to reach those resources, are assessed by incorporating a transmission cost mark-up to site-specific costs.

Greece (Tigas et al., 2015): A **TIMES** model is developed in this study to analyse the Greek energy system with a planning horizon of 38 years, and includes 14 regions representing different economic characteristics for a single set of renewable energy sources. The model is designed to optimise investment in renewable energy sources, which then drive transmission investment in different regions. Technical constraints, such as congestion and overloading, are explicitly taken into account in assessing transmission investment, by incorporating direct current power flow analysis into the model.

Nicaragua (de Leon Barido et al., 2015): A **SWITCH** model is developed in this study to to analyse the Nicaraguan power system with a planning time horizon of 16 years, using 16 "load zones". The model makes use of high-resolution hourly profiles of national electricity demand and power production for every generation unit, which are available as open-access data from the Nicaraguan National Dispatch Center. Synthetic hourly load profiles as well as VRE availability profiles (in a form of hourly capacity factor) for solar and wind are developed for the 16 load zones analysed. The hourly profiles are further developed into 24 typical daily profiles, with 12 intra-day blocks, and incorporated into the model. The model then takes into account the maximum transfer capacity of transmission lines, modelling them as a generic transportation network with maximum transfer capabilities equal to the sum of the thermal limits of individual transmission lines between each pair of load zones. It does not model the electric properties of the transmission network.

Chile (Carvallo et al., 2014): A **SWITCH** model is developed in this study to to analyse the Chilean power system with a planning time horizon of 20 years, using 23 "load zones". The load zones are defined to represent the geographical division and marginal cost subsystems used by system operators. Existing load and generation are allocated to these nodes based on their location in the power grid, and future projects are assigned to the particular load area in which they will be built. Existing transmission is reduced to corridors between adjacent and non-adjacent load areas, and future transmission is built based on existing corridors and potential new corridors defined by the user. Using the model, a scenario is developed to investigate the impacts of restriction on transmission expansions. Analysis shows that such limitation would result in curtailment of VRE, with additional coal power plants needed to compensate this. The results indicate the importance of transmission lines for accessing flexibility across load zones. While restricted transmission expansion would reduce transmission-related costs by 20%, it would increase generation-related costs over sevenfold for the same amount of VRE generation on the grid.

Supporting data and tools for site-specific representation of generation and transmission needs

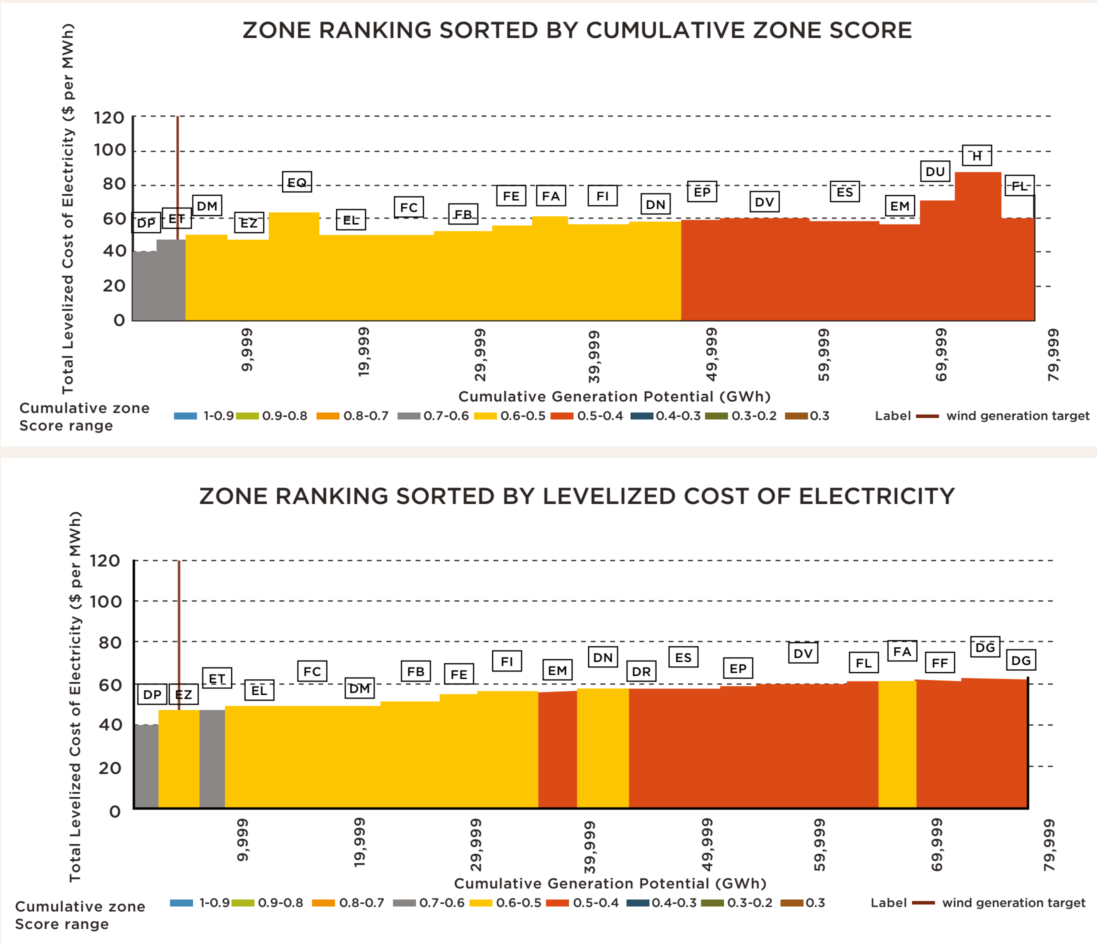
To support the characterisation of different nodes, or zones of VRE resources, GIS-based maps of relevant resource data are increasingly available. These can enable planners to better represent and understand the investment implications of VRE location in the process of generation expansion planning.

Specific examples of this type of data, from IRENA's Global Atlas tool, are discussed in Box 21.

Box 21: Useful data sources: GIS data for transmission assessment

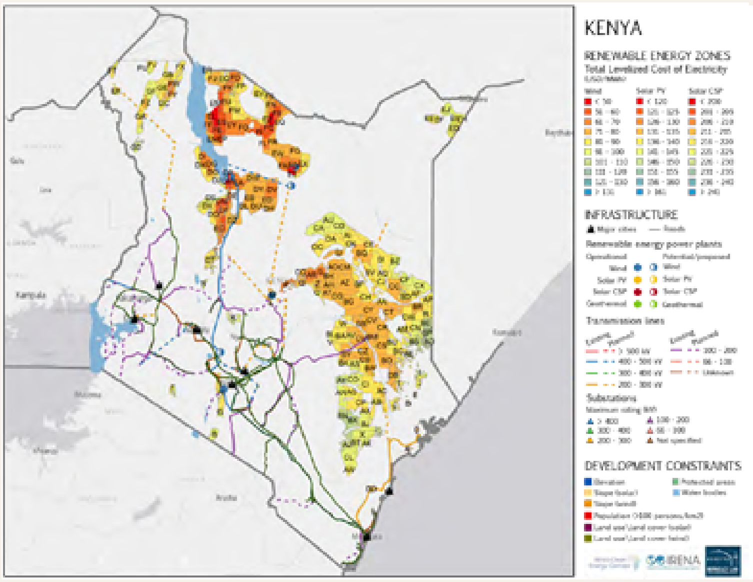
Southern and Eastern Africa (IRENA and LBNL, 2015) In this study, multi-criteria analysis for planning renewable energy identifies geographical zones with good renewable energy resources and provides planners with techno-economic parameters for identified zones. It assesses wind, solar PV and CSP. Parameters included capacity factors, distances to load centres, existing transmission and road infrastructure, and environmental footprint, among others. Based on these, each identified VRE zone is characterised with a unique levelised cost of electricity (LCOE), taking into account not only capacity factors, but also transmission investment and infrastructure costs, and (in the case of wind) suitable types of turbines.

Figure 21: Zone ranking sorted by levelised cost of electricity (above) and by cumulative zone score



Source: IRENA and LBNL, 2015

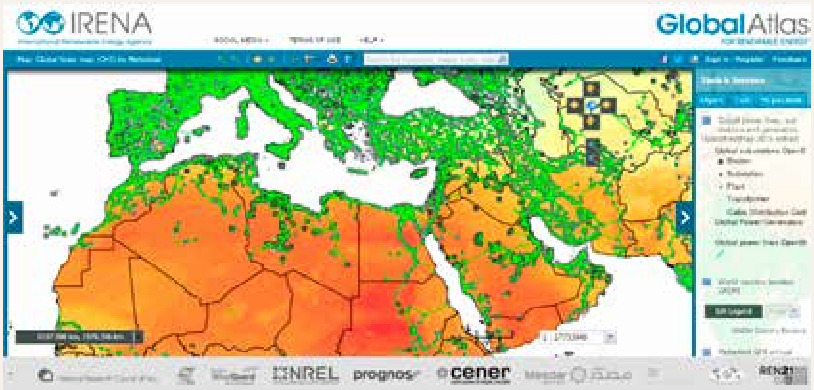
Figure 22: Kenya wind zones as shown in the interactive PDF map



Source: IRENA and LBNL, 2015

Global (IRENA, n.d.): IRENA's Global Atlas hosts GIS data on power sector infrastructure. These include "Global power lines, substations, and generators" from the OpenStreetMap 2015 extract (© OpenStreetMap contributors)[59], "Transmission lines" from the ECOWAS Regional Centre for Renewable Energy and Energy Efficiency (ECREEE)[60] and "Power and Gas Grid Map of South Asia" from NREL[61] .

Figure 23: Excerpt from IRENA's Global Atlas (layer: global power lines, substations and generators)



Source: OpenStreetMap 2015 Extract © OpenStreetMap contributors

59 This map shows the power lines, substations and power generators for the whole world. The power lines have been reviewed for positional accuracy using Google satellite maps. Most of the lines checked on the map seem to correspond with their actual location, as confirmed by high-resolution aerial images from the satellite maps. Limitations on the dataset include incompleteness in certain areas and less information on the voltage capacity of some of the lines. This dataset was extracted from the OpenStreetMap initiative. OpenStreetMap® is open data, licensed under the Open Data Commons Open Database License (ODbL) by the OpenStreetMap Foundation (OSMF).

60 The dataset gives information on low, medium and high voltage transmission lines that was originally compiled for the World-Bank-led Infrastructure Consortium for Africa (ICA). In 2012 the dataset was updated by ECREEE. Grid connections in the ECOWAS region are represented, as estimated by the Environmental Systems Research Institute.

61 NREL's Power and Gas Grid Map of South Asia was prepared for the US Agency for International Development (USAID) under the SARI/ Energy program, for selected South Asian countries, and covers the transmission lines and power plant infrastructure as of 2006.

8 REPRESENTING STABILITY CONSTRAINTS ON VARIABLE RENEWABLE ENERGY PENETRATION

Key points of Chapter 8

Exploring possible constraints: Concerns about system stability at high VRE penetration levels – due primarily to operation with insufficient synchronous generators – currently may impose technical upper limits on instantaneous penetration in isolated systems. Such limits, and other potential bottlenecks in addressing near-term technical barriers, may need to be reflected as constraints in long-term generation expansion models, and explored as alternative scenarios.

General complexity: High

As discussed in Section 3.1, maintaining both inertia and frequency response capability is relevant in long-term transition planning due to the consequences of these for stability in certain power systems with a dominant share of VRE. Small and isolated systems are more likely to be faced by such challenges sooner than large interconnected ones.

VRE can, technically, provide services that contribute to the stability of power systems – e.g., reactive power support, frequency support, contingency reserves, balancing services and black start[62] – and advanced grid codes already take into account the need for active VRE participation in providing them (Dragoon and Papaefthymiou, 2015; IRENA, 2016d). Nonetheless, at a very high share of VRE, a lack of inertia – leading to insufficient frequency response capability – may force system operators to consider technical limits on instantaneous VRE penetration (the VRE share of overall generation at a given time).

For example, DigSILENT and Ecofys (2010) estimated that a restriction on instantaneous penetration of inertia-less generation of 70% needs to be in place in the Irish power system for the year 2020 if no inertia – such as emulated inertia from wind turbines – is added to the system. Determining an appropriate level for such a limit, however, requires running dynamic stability studies, which need a high level of technical detail on a system.

Due to their requirements for data, stability studies are more meaningfully applied in assessing a present system or a configuration in the very near future, and may not be as suitable for assessing a hypothetical system in the distant future, particularly in emerging countries where systems are expected to evolve dramatically. Although technical VRE penetration limits may be suggested under the configuration of a current system, they may not necessarily persist in the long term. Yet, long-term generation expansion models could still incorporate indicative limits on VRE's instantaneous penetration as one of the scenarios for different levels of interconnection envisaged for the future.

The same principle can be applied to the incorporation of other operational constraints into generation expansion scenarios. Operational bottlenecks of current systems are typically identified through so-called VRE integration studies (e.g., World Bank, 2013). Such studies may be either technical or institutional, and include, for example, transmission bottlenecks and limitations in interconnectivity to neighbouring systems.

62 *As per ENTSO-E (2011), black start refers to "the procedure of reestablishing the electricity supply within a control area after a total disruption of the supply".*

CONCLUSIONS

Techno-economic modelling of future scenarios for the power sector has become a critical tool in planning the transition to renewable energy. Decision makers increasingly rely on model assessments to inform the development of policy and national renewable targets. A large body of knowledge has now been developed in this field, particularly around how to represent VRE in long-term models of generation expansion.

Long-term planning priorities, largely in the context of developing and emerging countries, were assessed in this report. We found the most relevant areas of focus to be ensuring firm capacity, flexibility, transmission capacity and – in certain contexts – stability. Addressing these priorities explicitly in long-term generation expansion planning scenarios is critical for building consensus across stakeholders, who often are responsible for planning with different areas of focus and time horizons.

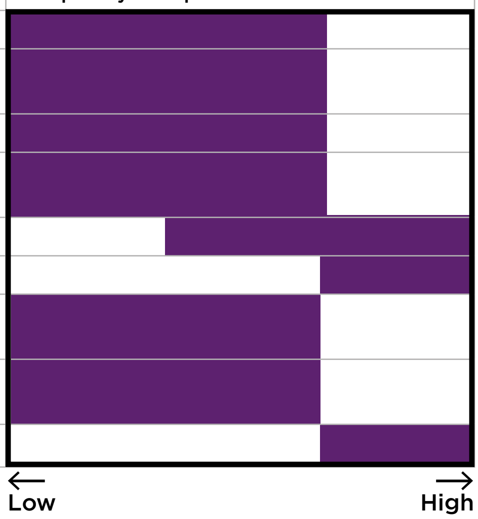
Modelling tools to support long-term planning are increasingly capable of dealing with larger amounts of data, and new modelling solutions are consistently being invented and implemented. In emerging economies, where data availability and technical resources may be limited, the guiding principle for selecting appropriate solutions to improve the modelling of VRE deployment for long-term planning should be the availability of data and modelling expertise. Countries are advised to start simple when improving energy planning for a high share of VRE, and to take a strategic approach, over time, to advancing the scope and quality of models and the capabilities of their staff.

Many of the solutions presented here can be readily implemented within existing generation expansion tools, or regardless of the tools in use. For example, pre-processing of VRE data to extract key temporal and spatial features does not necessarily require major resources. Using pre-defined constraints or parameters to mimic more complex changes due to VRE deployment also can be implemented quickly using standard tools. More advanced solutions include the use of supplementary tools, such as the visualisation of load duration curves, to validate model results and the accuracy of VRE representation. The most advanced solutions involve linking generation expansion models with production cost models for such validation, or corrective, purposes.

Table 16 lists the range of solutions discussed in this report and includes a highly indicative assessment of their implementation complexity. In reality, planners must first understand the details of a solution, including its requirements and alternatives, before gauging its complexity in the context of specific national circumstances. The difficulty of implementation also is likely to evolve over time as solutions are constantly reassessed and improved.

Table 16: List of the solutions discussed in this report

Planning impact addressed	Solutions	Complexity of implementation
All	Increasing temporal and spatial resolution (Section 4.2)	
Firm capacity	Better calibration of time slice using VRE generation data (Section 5.1)	
Firm capacity	Incorporating capacity credit (Section 5.2)	
Flexibility	Incorporating constraints on flexibility provision (Section 6.1)	
Flexibility	Validating flexibility balance in a system (Section 6.2)	
Flexibility	Coupling with production cost models (Section 6.3)	
Transmission capacity	Linking investment needs with VRE expansion (Section 7.1)	
Transmission capacity	Site-specific representation of generation and transmission needs (Section 7.2)	
Stability constraints	Representing stability constraints (Chapter 8)	



In addition to planning solutions for large-scale VRE deployment, this report provided a number of key points of reference for data and tools to aid in implementing solutions.

Collecting data systematically, and mapping tools better, will continue to be major drivers of countries' ability to plan long-term transitions to a high share of VRE. New knowledge about, and experiences of, long-term planning with VRE are growing rapidly. Exchanging experiences in planning among practitioners, policy makers and the energy modelling community is essential, as we are still in the learning process. IRENA – and energy planners and researchers – can help improve these key areas, and thus to accelerate a cost-effective power sector transition to renewable energy.

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APPENDIX 1: Description of other IRENA power sector transformation work

The focus of this report is on methodologies for techno-economic assessment of long-term generation capacity expansion. IRENA publishes additional materials that address other aspects of planning a transition to higher shares of VRE. In particular, institutional aspects including regulation, market design and grid codes, as well as short-term network planning methodologies, have been extensively addressed in a number of IRENA publications, which are listed below. These aspects are not discussed fully in the present report, and references are made as appropriate.

Regulatory oversight of long-term power system planning, a project being implemented with the Council for Scientific and Industrial Research (CSIR) of South Africa and the Regulatory Assistance Project (RAP) of the United States, analyses the key institutional aspects surrounding developing and implementing long-term electricity plans in Southern Africa. It aims to propose an appropriate governance structure to support a long-term plan with a higher share of renewable energy.

Practitioner's guide to grid integration of variable renewable energy – electricity (draft), prepared in co-operation with Energinet (IRENA, forthcoming-d), maps out the planning process for integrating VRE into a power system. It gives an overarching issue list, covering the overall planning of the energy system (the topic of this report), system operation, merit order of dispatch and the power market, the regulatory framework and subsidy schemes, and the permitting process.

Planning of electricity grids in small-island developing states with variable renewable energy – a methodological guide (draft), prepared in co-operation with Tractebel (IRENA, forthcoming-a) elaborates on VRE integration planning methodologies in small-island states. It covers mainly network and system operation planning.

Methodology for the stability assessment of isolated power systems (draft), prepared in co-operation with Darmstadt University of Germany (IRENA, forthcoming-b), discusses the methodology for stability assessment (technical network studies as defined in Figure 3 of this report).

Study on investments in renewable energy grid integration technologies (draft), prepared in co-operation with (DNV-GL, unpublished-a) describes a screening methodology to assess investment needs in transmission and distribution networks so as to connect and integrate renewable power generation capacity into existing and expanding grid infrastructure.

Scaling up variable renewable power: the role of grid codes, prepared in co-operation with Energynautics GmbH (IRENA, 2016d), particularly discusses the process and best practices to elaborate and to implement a grid connection code to support technical integration of VRE into electricity grids.

Adapting market design to the growing VRE generation and to the changing ownership structure in the electricity sector, prepared in co-operation with Comillas University (IRENA, forthcoming-c), discusses how governments can adapt their market rules and policies to take into consideration the evolution of the ownership structure in the electricity sector and to efficiently support the growth of renewable energy.

APPENDIX 2: Planning support tools

Specific tools are tailored to different scopes of planning. The discussion in Section 1.1 mentioned four categories of major planning steps with different time horizons: **generation expansion planning**; **geo-spatial planning**; **dispatch planning**; and **technical network studies**. Four modelling categories are identified for each step: **long-term energy planning models**; **geo-spatial planning models**; **production cost models**; and **network analysis models** (subdivided into static and dynamic grid models). Distinctions among these modelling types are typically not stringent: advanced tools tend to cover multiple planning features. The tools used to assess near-term impacts typically have narrower system boundaries and higher levels of detail, in terms of space, time and technical representation. Those used to assess long-term impacts, by contrast, have wider system boundaries, have longer planning time horizons and typically are associated with low levels of detail.

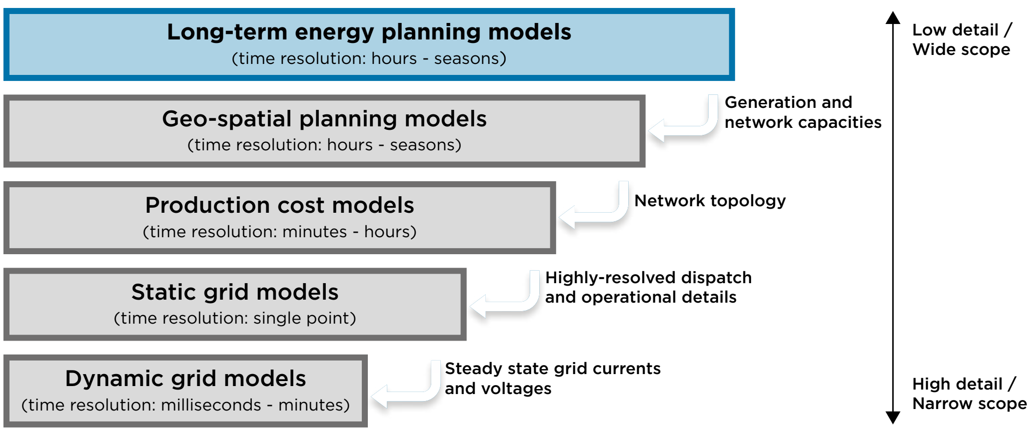
Figure 24 summarises how these models interact in a somewhat hierarchical manner. Typical characteristics of modelling tools relevant to each type are discussed below, and examples of commonly used modelling tools are given. Full names of abbreviated tools mentioned in this section are given in Appendix 4, along with the developers of the tools and links to the relevant websites.

Long-term energy planning models

Long-term energy planning models – generally characterised by a wide scope and low level of temporal detail – determine the optimal long-term mix of technologies and the investment paths that lead to it. They are used by national and regional energy planners to develop energy master plans and to inform energy policy decision makers, and their time horizon typically ranges from 20 to 40 years, or even longer, in this context. They also are used for national or regional planning studies of energy sub-sectors such as the power sector, where investment decisions for generation capacity – whether at an aggregated or individual project level – are determined for each year, or at specific time intervals (e.g., every five years) during the planning time horizon.

Long-term planning models dedicated to the power sector have been developed to capture more sector-specific detail, without the exercise becoming computationally unwieldy. These aim primarily to calculate a path for power generation expansion which combines technologies that collectively meet variable demand: thus they are referred to here as **"generation expansion models"**. Typically, they cannot model detailed system dispatch for analysis over long planning time horizons, and instead employ reduced-form dispatch approaches in such cases (Diakov et al., 2015). Long-term planning models also typically optimise power trade and transfer capacities between regional clusters, when these are defined.

Figure 24: Tools and analyses for energy system planning and how they can interact



Examples of long-term generation expansion modelling tools used in national and regional energy planning include MESSAGE, TIMES, MARKAL and OSeMOSYS, while dedicated power sector models include WASP, BALMOREL and PLEXOS-LT. Common features of long-term generation expansion modelling tools are discussed in Chapter 5.

Geo-spatial planning models

Better availability of GIS data and tools is making it easier for planners to assess the location-specific techno-economic performance of renewables, and investment needs for clusters of renewable energy projects. Various geo-spatial planning models have been developed to assist such assessments. Geo-spatial planning models are increasingly used to assess alternative geo-referenced network topologies, replacing expert-judgement-based assessment. Such an assessment needs to factor in siting considerations for generation and the location of load centres, as well as physical topography and land use (e.g., mountain, valley and water bodies). This process of analysing network topography is a typical starting point for more detailed technical network studies.[63]

Greater geo-spatial detail around various aspects of energy systems may be of less relevance to a system with predominantly thermal generation plants. Although locational constraints around air pollution and water are increasingly impacting site selection for thermal generators, their techno-economic attributes are not typically location-specific, and using expert knowledge to draw on a map might provide sufficient levels of geo-spatial detail for high-level planning purposes.

As location-constrained VRE becomes an increasingly important part of future energy systems, geo-spatial models may have an important role to complement decision making around long-term generation expansion, allowing it to take into account the economic trade-off between location-specific VRE productivity and transmission investment needs. State-of-the-art tools also are beginning to incorporate GIS elements into system-level optimisation models, but a generic method for such integration is not yet commonly available. Expanding static geo-spatial information into more dynamic energy planning is something that could be considered as a high priority for institutions and future research.

Further detail around the more recent uses of geo-spatial planning described above can be found in Chapter 7, along with examples. Specific examples of actual GIS software often used in the renewable energy context are ArcGIS (e.g., ESRI, 2010), Quantum GIS, gvSIG, ILWIS and Global Mapper.

Production cost models

Production cost models simulate routine power system operations at a relatively high time resolution – an hour or less. They use detailed information on loads, transmission and the fleet of generators; minimise the costs of production; and follow reliability requirements (Diakov et al., 2015). They also assess the cost of optimal unit commitment and economic dispatch of a power system[64], typically in a one-year timeframe, during which the mix of capacity is held constant.

This category of models typically requires such inputs as generation unit capacity by type, and sometimes includes the location of plants and network topography. Some of these inputs can be fed in from the outputs of long-term energy planning and geo-spatial planning models. The operational constraints of individual power plants – such as the minimum generation limit, minimum up/down times, ramp rates and start-up costs – are normally taken into account in production cost models, and many of them also take into consideration network constraints for economic dispatch.

63 *For example, a full economic assessment of alternative transmission topologies, which would account for other trade-offs such as network congestion versus VRE curtailment, requires the production cost and static grid models described further below.*

64 *Unit commitment is the process of deciding the on/off status of generating units at each power station for dispatch during the next days. Economic dispatch is the process of deciding the power outputs from the committed generation units. The simulation of optimal unit commitment or dispatch is not limited to production cost models: standalone unit commitment and/or dispatch models are also available without explicit cost-quantifying functionality, and are often used for real-time scheduling or other operational analyses.*

Production cost models are suited to evaluate the techno-economic implications (including the impacts on market prices) of alternative operating policies, and market architectures (e.g., capacity markets and ancillary services). Such models also can be used to verify whether a given mix of generation capacity is flexible enough to supply load at all times. Normally, investment costs are outside the scope of production cost models, so they are not meant to serve as the sole basis for long-term investment decision making.

Commercial and non-commercial production cost modelling software is available. Examples include PLEXOS (which also includes a capacity expansion module), PROMOD, U-Plan, GTMax (Generation and Transmission Maximization), GridView, GRARE, EnergyPLAN, Dispa-SET and SIVAEL.

Network analysis models

Network analysis typically is conducted at two levels: static network analysis (i.e., load-flow analysis) and dynamic network analysis (i.e., grid stability studies).[65] Both types of analyses are implemented to evaluate a network at a particular given point in time – for a given capacity mix, for a given network infrastructure and its topography, and for a given dispatch scenario (all of which together are referred to as an "operational point"). They both aim to evaluate technical bottlenecks in a system so as to maintain the required levels of reliability (for a definition of a "reliable" power system, see Section 3.6).

Load-flow analysis is performed using **static grid models**, so as to assess needs for enhancing the grid, primarily to avoid network congestion. For planning purposes, this often is combined with geo-spatial analysis to assess the adequacy of a set of alternative network topologies (i.e., whether a transmission network has sufficient transport capacity) for a given year, or with a production cost model to assess thereliability of cost-optimal dispatch for a given network topography. A simple version of load-flow analysis[66] is often directly incorporated in a production cost model.

Stability studies are performed using **dynamic grid models**, in order to simulate how a power system reacts after a disturbance (referred to in this report as a contingency event) and to check if it returns to normal operational conditions afterwards. This dynamic simulation has a temporal resolution of milliseconds, and is performed within a timeframe of seconds to minutes. Such studies require detailed representation of the network and typically focus on assessing the system in the present- to near-future, rather than at a point far ahead, due to the detail necessary for the analysis.

Dynamic grid modelling tools are typically available as add-ons to a load-flow analysis model package. Examples of commercially available tools for load-flow and stability analysis include PowerFactory (DIgSILENT GmbH), PSS®E (Siemens PTI), NEPLAN (NEPLAN AG), ANATEM (CEPEL), ETAP (ETAP), EUROSTAG (Tractebel), PowerWorld Simulator (PowerWorld Corporation) and PSLF (GE).

65 Detailed descriptions of these analyses are given in IRENA (forthcoming-a)..

66 A simplified variant of full load flow is called DC load flow. In a DC flow model, the representation of voltage is simplified. A full load flow model is referred to as AC load flow. In a full AC load flow model, each node is characterised by four variables: active-power injection, reactive power injection, voltage angle and voltage level (Delarue, 2009).

APPENDIX 3: Long-term planning tools used in selected countries

Table 17 summarises the long-term energy planning tools used in official energy/electricity master plan documents in selected countries. The information was collected from publicly available sources and was not validated by the countries. Studies conducted by foreign consultancy firms or research institutions are included only if officially endorsed by the relevant authorities. Master plans at a subsector level (such as renewable energy master plans) are also excluded from this list. The table focuses on tools primarily used to develop and assess long-term generation capacity expansion paths. Most countries use model-generating software (modelling tools) rather than developing original model frameworks.

Table 17: Long-term planning tools used in selected countries

Country	Responsible institution	Models	Scope	Planning document	Source
Africa					
Botswana	Ministry of Finance and Development Planning	MESSAGE, WASP, and MAED	Energy system 2009-2016	National Development Plan 10	Botswana Ministry of Finance and Development Planning, 2009
Ghana	Energy Commission	MESSAGE, LEAP, and RETScreen	Energy system 2006-2020	Strategic National Energy Plan	Ghana Energy Commission, 2006; Lee and Leal, 2014
Kenya	Energy Regulatory Commission	MAED (for load forecasting), WASP (for system expansion plan optimisation), VALORA-GUA (for short term hydro-thermal system optimisation), and PSSE (for transmission planning)	Power system 2011-2031	Updated least cost power development plan. Study period: 2011 -2030	Kenya Energy Regulatory Commission, 2011
Republic of Mauritius	National Energy Commission	WASP	Energy system 2019-2025	Making the right choice for a sustainable energy future: the emergence of a "green economy"	National Energy Commission of Mauritius, 2013
Morocco	Office National de l'Electricité et de l'Eau Potable (ONEE)	WASP-IV (for capacity expansion) and VALORAGUA (for dispatch optimisation for electric systems)	Power system		IRENA, 2015c; Filali, 2015
Namibia	National electricity company	PROVIEW and PLEXOS	Power system		IRENA, 2016e
Nigeria	Energy Commission	MAED and MESSAGE	Energy system 2009-2030	National Energy Masterplan	Energy Commission of Nigeria, 2014
South Africa	Ministry of Energy	OSeMOSYS	Energy system 2010-2030	2012 Integrated Energy Planning Report	South Africa DOE, 2013a

South Africa	Ministry of Energy	PLEXOS (for electricity sector planning)	Power system 2010-2030	Integrated Resource Plan for Electricity, 2010-2030	South Africa DOE, 2013b
Tunisia	Tunisian Company of Electricity and Gas	WASP	Power system		IRENA, 2015c; Bali, 2015
Zimbabwe	Electricity supply authority	WASP	Power system		IRENA, 2016e
Asia and Pacific					
Afghanistan	Ministry of Energy and Water	PSS®E	Energy system 2015-2032	Islamic Republic of Afghanistan: Power Sector Master Plan	FICHTNER GmbH & Co. KG, 2013
Australia	Bureau of Resources and Energy Economics	E4cast	Energy system 2014-2050	Australian Energy Projections to 2049-2050	BREE , 2014
Bangladesh	Ministry of Power, Energy and Mineral Resources	PDPAT and PSS®E	Energy system 2011-2030	Power System Master Plan 2010	MPEMR, 2011
New Zealand	Ministry of Business, Innovation & Employment	SADEM, GEM, and PRM	Energy system 2010-2050	Electricity demand and generation scenarios	MBIE, 2016
Philippines	Philippine Department of Energy	MESSAGE (for energy sector planning), WASP (for power sector planning)	Energy system 2012-2030	Philippine Energy Plan 2012-2030	Philippine Department of Energy, n.d.
Latin America and Caribbean					
Bolivia	Ministerio de Hidrocarburos y Energía [Ministry of Hydrocarbons and Energy]	OPTGEN (for generation optimisation) and SDDP	Electricity system 2015-2025	Plan eléctrico del estado plurinacional de Bolivia 2025 [Electrical Plan for the Plurinational State of Bolivia]	Ministerio de Hidrocarburos y Energía, 2014
Brazil	MIPE2, MSR, MELP and MESSAGE	MIPE2, MSR, MELP and MESSAGE	Energy system 2010-2030	Plano Nacional de Energia 2030 [National Energy Plan 2030]	Brazil MME and EPE, 2007
Dominican Republic	Comision Nacional de Energia [National Energy Commission]	SUPER OLADE	Energy system 2004-2015	Plan Energético Nacional [National Energy Plan]	Comisión Nacional de Energía, 2004
Jamaica		META	Energy system 2013-2030	Jamaica Sustainable Energy Roadmap: Pathways to an Affordable, Reliable, Low-Emission Electricity System	Makhijani et al., 2013
Mexico	Secretaría de Energía [Ministry of Energy]	PIIRCE (Programa Indicativo para la Instalación y Retiro de Centrales Eléctricas [Indicative programme for the installation and retirement of power plants]), PLEXOS	Power system 2016-2030	Programa de Desarrollo del Sistema Eléctrico Nacional (PRODESEN) 2016-2030 [Development Programme of the National Electricity System 2016-2030]	Secretaría de Energía, 2016; Delgado Contreras, 2016

Panama	Secretaria Nacional de Energia [National Ministry of Energy]	OPTGEN (for generation optimisation) and SDDP	Energy system 2015-2050	Plan Energético Nacional 2015-2050 [National Energy Plan 2015-2050]	Secretaria Nacional de Energia, 2016
Panama	Empresa de Transmisión Eléctrica S.A. [Electricity Transmission Company]	OPTGEN (for generation optimisation) and SDDP	Electricity system 2015-2029	Tomo II: Plan Indicativo de Generación (Plan de Expansión del Sistema Interconectado Nacional 2015-2029) [Volume II: Indicative Generation Plan (Expansion plan for the national interconnected system 2015-2029)]	ETESA, 2016
Uruguay	National Directive of Energy	WASP (for expansion planning) and SimSEEE (for adequacy assessment)	Power system		Echinope, 2014
Europe					
Germany	Umweltbundesamt & Fraunhofer-Institut für Windenergie und Energiesystemtechnik (IWES) [Department of Environment & Frauenhofer Institute for Wind Energy and Energy System Technology], Kassel	SimEE	Energy system 2010-2050	Energieziel 2050: 100% Strom aus erneurbaren Quellen [Energy Target 2050: 100% Electricity from Renewable Energy Sources]	Thomas et al., 2010, p. 205
Greece	Ministry of Environment, Energy & Climate Change	TIMES-MARKAL, ENPEP, WASP, and COST	Energy system 2010-2020	National Renewable Energy Action Plan in the Scope of Directive 2009/28/EC	MEECC, 2010
Italy	Italian Government	PRIMES and TIMES	Energy system 2013-2050	Strategia Energetica Nazionale: per un'energia più competitiva e sostenibile [National Energy Strategy: for more competitive and sustainable energy]	Government of Italy, 2013
Lithuania	Lithuanian Energy Institute	MESSAGE	Energy system 2014-2050	Study for National Energy Strategy update, 2016	LEI, 2016, 2015
Poland	Ministry of Economy	WASP IV and MAED	Energy system 2010-2030	PROGNOZA ZAPOTRZEBOWANIA NA PALIWA I ENERGIĘ DO 2030 ROKU [Demand forecast for fuels and energy until 2030]	Ministerstwo Gospodarki, 2009

Russian Federation	Energy Research Institute of the Russian Academy of Sciences (ERI RAS), Analytical Center for the Government of the Russian Federation (ACRF)	TIMES	Energy system 2015-2040	**Эволюция мировых энергетических рынков и ее последствия для России** [Evolution of world energy markets and the consequences for Russia]	Makarov et al., 2015
US					
US	PacificCorp	System Optimizer	Power system 2016-2025	2015 Integrated Resource Plan Update	PacifiCorp, 2015
US	Northwest Power and Conservation Council	AuroraXMP, RPM, GENESYS, and TRAP	Power system 2016-2035	Seventh Northwest Conservation and Electric Power Plan	Northwest Power and Conservation Council, 2016
US	Dominion	Strategist, AuroraXMP, and Promod IV	Power system 2016-2031	Dominion Virginia Power's and Dominion North Carolina Power's Report of Its Integrated Resource Plan	Dominion, 2016
US	Tucson electric power	AuroraXMP	Power system 2015-2028	2014 Integrated resource plan	Tucson Electric Power Company, 2014

APPENDIX 4: List of the models mentioned in this report

Table 18 summarises, for ease of reference, the list of the models mentioned in the report.

Table 18: List of the models mentioned in the report, institutions that developed them, and websites for further information

Model abbreviation	Model name	Institution	Webpage
ANATEM	Analysis Electromechanical Transients	Eletrobras – Centro de Pesquisas de Energia Electrica (CEPEL) [Eletrobras – Center of Electrical Energy Research]	www.cepel.br/produtos/anatem-analise-de-transitorios-eletromecanicos.htm
AuroraXMP	AuroraXMP	EPIS, LLC	http://epis.com/aurora_xmp/
BALMOREL	BALMOREL	Elkraft System	http://eabalmorel.dk/
BREHOMES	Building Research Establishment Housing Model for Energy Studies	Building Research Establishment (BRE)	www.bre.co.uk/filelibrary/pdf/rpts/Fact_File_2008.pdf
CEEM	Com-generation in European Electricity Markets	Institute of Energy Economics – University of Cologne (EWI)	www.ewi.uni-koeln.de/
COMPETES	COMPETES	Energy Research Centre of the Netherlands	www.e-highway2050.eu/consortium/partners/ecn-the-netherlands/
CONTINENTAL	CONTINENTAL	EDF R&D	www.edf.fr/groupe-edf/premier-electricien-mondial/activites/recherche-et-developpement
DIMENSION	A Dispatch and Investment Model for European Electricity Markets	Institute of Energy Economics – University of Cologne (EWI)	www.ewi.research-scenarios.de/en/models/dimension/
Dispa-SET	Dispa-SET	JRC's Institute for Energy and Transport	https://setis.ec.europa.eu/publications/jrc-setis-reports/dispa-set-20-unit-commitment-and-power-dispatch-model
DSIM	Dynamic System Investment Model	Imperial College London	www.gov.uk/government/uploads/system/uploads/attachment_data/file/48553/5767-understanding-the-balancing-challenge.pdf
E4cast	E4cast	Australian Bureau of Agricultural and Resource Economics (ABARE)	www.industry.gov.au/Office-of-the-Chief-Economist/Publications/Documents/aep/aep-2014-v2.pdf
EGEAS	Electric Generation Expansion Analysis System	Electric Power Research Institute (EPRI)	www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000003002001929

EMCAS	Electricity Market Complex Adaptive System	Center for Energy, Environmental, and Economic Systems Analysis (CEEESA)	http://ceeesa.es.anl.gov/projects/emcas.html
EnergyPLAN	EnergyPLAN	Aalborg University	www.energyplan.eu/
ENPEP	Energy and Power Evaluation Program	International Atomic Energy Agency (IAEA)	www.iaea.org/OurWork/ST/NE/Pess/PESSenergymodels.html
ENPEP-BALANCE	ENPEP-BALANCE	Argonne National Laboratory	http://ceeesa.es.anl.gov/projects/Enpepwin.html#balance
ESME	ETI's Energy System Modelling Environment	Energy Technology Institute (ETI)	www.eti.co.uk/modelling-low-carbon-energy-system-designs-with-the-eti-esme-model/
EUROSTAG	EUROSTAG	Tractebel	www.eurostag.be/en/products/eurostag/the-reference-power-system-dynamic-simulation/
FAST2	Revised Flexibility Assessment Tool	International Energy Agency (IEA)	www.iea.org/publications/freepublications/publication/The_power_of_Transformation.pdf
FlexAssessment	FlexAssessment	EDF R&D	www.edf.fr/groupe-edf/premier-electricien-mondial/activites/recherche-et-developpement
GEM	Electricity Authority's Generation Expansion Model	New Zealand Electricity Authority	www.mbie.govt.nz/info-services/sectors-industries/energy/energy-data-modelling/technical-papers/energy-modelling-methodology
GEM-E3	General Equilibrium Model for Economy-Energy-Environment	National Technical University of Athens (NTUA/E3M-Lab), Katholieke Universiteit of Leuven (KUL) [Catholic University of Leuven], Corvinus University of Budapest	http://ledsgp.org/wp-content/uploads/2015/09/GEM-E3-documentation.pdf
GEMS	German Electricity Market Simulation	Institute of Energy Economics – University of Cologne (EWI)	www.ewi.uni-koeln.de/
GENESYS	Genetic Optimization of a European Energy Supply System	RWTH Aachen University	www.genesys.rwth-aachen.de/index.php?id=projekt&L=3
GENTEP	Tool for the stochastic co-optimization of generation and transmission expansion planning	Illinois Institute of Technology (IIT)	https://ezmt.anl.gov/document/29/file
GRARE	Grid Reliability and Adequacy Risk Evaluator	Centro Elettrotecnico Sperimentale Italiano (CESI) and Terna	www.cesi.it/grare
GridView	GridView	ABB	http://new.abb.com/enterprise-software/energy/bmarket-analysis/gridview

GTMax	Generation and Transmission Maximization model	Argonne National Laboratory	http://ceeesa.es.anl.gov/projects/Gtmax.html
InFLEXion	InFLEXion Flexibility Screening and Assessment Tool	Electric Power Research Institute (EPRI)	www.epri.com/abstracts/Pages/ProductAbstract.aspx?productId=000000003002000333
INTRES	INTRES	Institute of Energy Economics – University of Cologne (EWI)	http://kups.ub.uni-koeln.de/4856/
Invert/EE-Lab	Invert/EE-Lab	Technical University of Wien	www.invert.at/
IPM	Integrated Planning Model	ICF International Inc	www.icf.com/solutions-and-apps/ipm
Iterative gen-trans co-optimisation	Iterative gen-trans co-optimisation	Iowa State University	https://ezmt.anl.gov/document/29/file
LEAP	Long-range Energy Alternatives Planning	Stockholm Environment Institute	www.energycommunity.org/Default.asp
LIMES-EU	Long-term Investment Model for the Electricity Sector of Europe	Potsdam Institute for Climate Impact Research	www.pik-potsdam.de/research/sustainable-solutions/models/limes
MADONE	MADONE	EDF R&D	www.edf.fr/groupe-edf/premier-electricien-mondial/activites/recherche-et-developpement
MAED	Model for The Analysis of Energy Demand	International Atomic Energy Agency (IAEA)	www.iaea.org/OurWork/ST/NE/Pess/PESSenergymodels.html
MARKAL	MARKet ALlocation	International Energy Agency (IEA)	http://iea-etsap.org/index.php/etsap-tools/model-generators/markal
MELP	Modelo de Expansão de Longo Prazo [Long-term expansion model]	Eletrobras – Centro de Pesquisas de Energia Electrica (CEPEL) [Eletrobras – Electrical Power Research Center]	www.cepel.br/produtos/melp-modelo-de-expansao-de-longo-prazo.htm
MESAP/ PlaNet	Modular Energy System Analysis and Planning Environment	Institute for Energy Economics and Rational Energy Use (IER, University of Stuttgart) – Seven2one	www.seven2one.de/de/technologie/mesap.html
MESSAGE	Model for Energy Supply Strategy Alternatives and their General Environmental Impacts	International Atomic Energy Agency (IAEA)	www.iaea.org/OurWork/ST/NE/Pess/PESSenergymodels.html

META	Model for Electricity Technology Assessment	Energy Sector Management Assistance Program (ESMAP) – World Bank Group	http://esmap.org/META
Meta-Net	Market Equilibrium and Technology Assessment Network Modelling System	Lawrence Livermore National Laboratory	http://digital.library.unt.edu/ark:/67531/metadc664399/m2/1/high_res_d/197814.pdf
MiniCAM	Mini-Climate Assessment Model	Pacific Northwest National Laboratory	www.pnl.gov/main/publications/external/technical_reports/PNNL-14337.pdf
MIPE	Modelo Integrado de Planejamento Energético	Postgraduate Engineering Programs Coordination Programme Co-ordination Unit (COPPE) of the Federal University of Rio de Janeiro (UFRJ)	www.coppe.ufrj.br/
MSR	Modelo de Projeção da Demanda Residencial de Energia [Residential Energy Demand projection model]	Postgraduate Engineering Programs CoordinationProgramme Co-ordination Unit (COPPE) of the Federal University of Rio de Janeiro (UFRJ)	www.epe.gov.br/mercado/Documents/S%C3%A9rie%20Estudos%20de%20Energia/20091222_2.pdf www.ppe.ufrj.br/
NEMS	The National Energy Modelling System	Energy Information Administration, U.S. Department of Energy	www.eia.gov/outlooks/archive/0581(2009).pdf
NEPLAN	NEPLAN	NEPLAN AG	www.neplan.ch/neplanproduct/en-electricity/
NETPLAN	National long-term Electric and Transportation infrastructure Planning software	Iowa State University	www.ece.iastate.edu/~vkrish/software.html
OptGen	OptGen – Model for generation expansion planning and regional interconnections	PSR	www.psr-inc.com/softwares-en/?current=p4040
OSeMOSYS	Open Source Energy Modelling System	Division of Energy System Analysis KTH Royal Institute of Technology	www.osemosys.org/
PDPAT	Power Development Planning Assistant Tool	Tokyo Electric Power Company (TEPCO)	www.tepco.co.jp/en/corpinfo/consultant/benefit/6-power-e.html
PERSEUS	Programme-package for Emission Reduction Strategies in Energy Use and Supply-Certificate Trading	Institute for Industrial Production (IIP), Karlsruhe Institute of Technology	www.iip.kit.edu/65.php

PLEXOS	PLEXOS® Integrated Energy Model	Energy Exemplar	http://energyexemplar.com/
POLES	Prospective Outlook on Long-term Energy Systems	Enerdata	www.enerdata.net/enerdatauk/solutions/energy-models/poles-model.php
PowerFactory	PowerFactory	DIgSILENT	www.digsilent.de/index.php/products-powerfactory.html
PowerWorld Simulator	PowerWorld Simulator	PowerWorld Corporation	www.powerworld.com/products/simulator/overview
PRIMES	A computable price-driven equilibrium model of the energy system and markets for Europe	National Technical University of Athens (NTUA)	www.e3mlab.ntua.gr/e3mlab/index.php?option=com_content&view=category&id=35&Itemid=80&lang=en
PRISM 2.0: US-REGEN	PRISM 2.0: U.S. Regional Economy, Greenhouse Gas, and Energy Model	Electric Power Research Institute (EPRI)	www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000003002000128
PRM	Ministry's Project Rank Model	New Zealand Ministry of Business, Innovation & Employment	www.mbie.govt.nz/info-services/sectors-industries/energy/energy-data-modelling/technical-papers/energy-modelling-methodology
Promod	Promod	ABB	http://new.abb.com/enterprise-software/energy-portfolio-management/market-analysis/promod
ProPSim	Probabilistic Production Simulation	Center for Renewable Energy Sources and Saving (CRES), Public Power Corporation S.A.-Hellas	https://setis.ec.europa.eu/system/files/Slides%20-%2018%20Giannakidis%20(CRES).pdf
PSLF	PSLF	General Electric (GE)	www.geenergyconsulting.com/practice-area/software-products/pslf
PSS®E	Power Transmission System Planning Software	SIEMENS	http://w3.siemens.com/smartgrid/global/en/products-systems-solutions/software-solutions/planning-data-management-software/planning-simulation/pages/pss-e.aspx

ReEDS	Regional Energy Deployment System	National Renewable Energy Laboratory (NREL)	www.nrel.gov/analysis/reeds/
REMIND	REMIND	Potsdam Institute for Climate Impact Research	www.pik-potsdam.de/research/sustainable-solutions/models/remind
REMix	REMix	DLR Institute of Engineering vvThermodynamics	www.dlr.de/Portaldata/41/Resources/dokumente/institut/system/Modellbeschreibungen/DLR_Energy_System_Model_REMix_short_description_2016.pdf
RETScreen	RETScreen	Natural Resources Canada	www.nrcan.gc.ca/energy/software-tools/7465
RPM	Regional Portfolio Model	Northwest Power and Conservation Council	www.nwcouncil.org/energy/rpm/rpmonline
RPM	Resource Planning Model: An Integrated Resource Planning and Dispatch Tool for Regional Electric Systems	National Renewable Energy Laboratory (NREL)	www.nrel.gov/analysis/models_rpm.html
SADEM	Ministry's Supply and Demand Energy Model	New Zealand Ministry of Business, Innovation & Employment	www.mbi.e.,govt.nz/info-services/sectors-industries/energy/energy-data-modelling/technical-papers/energy-modelling-methodology
SDDP	Stochastic hydrothermal dispatch with network restrictions	PSR	www.psr-inc.com/softwares-en/?current=p4028
SimEE	SimEE	Fraunhofer Institute for Wind Energy and Energy System Technology (IWES)	www.bee-ev.de/fileadmin/Publikationen/Studien/100119_BEE_IWES-Simulation_Stromversorgung2020_Endbericht.pdf
SIVAEL	SIVAEL	Energinet.dk	www.energinet.dk/DA/El/Udvikling-af-elsystemet/Analysemodeller/Sider/Sivael.aspx
SPLAT	System planning test model	IRENA	www.irena.org/sapp
Stochastic two-stage optimisation model	Stochastic two-stage optimisation model	VU Amsterdam, The John Hopkins University	www.eprg.group.cam.ac.uk/wp-content/uploads/2014/01/Binder11.pdf

Strategist	Strategist	ABB	http://new.abb.com/docs/librariesprovider139/default-document-library/strategist_br.pdf?sfvrsn=2
SUPER OLADE	Sistema Unificado de Planificacion Electrica Regional [Power System Generation and Inter-Connection Planning Model]	Organizacion Latinoamericana de Energia (OLADE) [Latin American Energy Organization]	www.olade.org/producto/super-2/descripcion/?lang=en
SWITCH	Solar and wind energy integrated with transmission and conventional sources	University of California, Berkeley	https://rael.berkeley.edu/project/switch/
System optimizer	System optimizer	Ventyx – ABB	http://ventyx-system-optimizer-model.software.informer.com/ http://new.abb.com/enterprise-software
THEA	The High Temporal Resolution Electricity Market Analysis Model	University of Cologne	http://kups.ub.uni-koeln.de/4612/
TIMES	The Integrated MARKAL-EFOM System	International Energy Agency (IEA)	http://iea-etsap.org/index.php/etsap-tools/model-generators/times
TRAP	Trapezoidal approximation model	Northwest Power and Conservation Council	www.nwcouncil.org/media/7149907/7thplanfinal_appdixk_rsrvplusreliability.pdf
UPLAN-NPM	UPLAN Network Power Model	LCG Consulting	www.energyonline.com/products/uplane.aspx
URBS-EU	URBS-EU	Technical University of Munich	https://mediatum.ub.tum.de/doc/1163646/1163646.pdf
US-REGEN	US Regional Economy, Greenhouse Gas, and Energy Model	Electric Power Research Institute (EPRI)	http://eea.epri.com/models.html
VALORAGUA	VALORAGUA	International Atomic Energy Agency (IAEA)	https://inis.iaea.org/search/search.aspx?orig_q=RN:19024153
WASP	Wien Automatic System Planning Package	International Atomic Energy Agency (IAEA)	www.iaea.org/OurWork/ST/NE/Pess/PESSenergymodels.html

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