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Integration of Renewable Energy into Present and Future Energy Systems

Coordinating Lead Authors:

Ralph Sims (New Zealand), Pedro Mercado (Argentina), Wolfram Krewitt †(Germany)

Lead Authors:

Gouri Bhuyan (Canada), Damian Flynn (Ireland), Hannele Holttinen (Finland), Gilberto Jannuzzi (Brazil), Smail Khennas (Senegal/Algeria), Yongqian Liu (China), Lars J. Nilsson (Sweden), Joan Ogden (USA), Kazuhiko Ogimoto (Japan), Mark O'Malley (Ireland), Hugh Outhred (Australia), Øystein Ulleberg (Norway), Frans van Hulle (Belgium)

Contributing Authors:

Morgan Bazilian (Austria/USA), Milou Beerepoot (France), Trevor Demayo (USA/Canada), Eleanor Denny (Ireland), David Infield (United Kingdom), Andrew Keane (Ireland), Arthur Lee (USA), Michael Milligan (USA), Andrew Mills (USA), Michael Power (Ireland), Paul Smith (Ireland), Lennart Söder (Sweden), Aidan Tuohy (USA), Falko Ueckerdt (Germany), Jingjing Zhang (Sweden)

Review Editors:

Jim Skea (United Kingdom) and Kai Strunz (Germany)

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Executive Summary

To achieve higher renewable energy (RE) shares than the low levels typically found in present energy supply systems will require additional integration efforts starting now and continuing over the longer term. These include improved understanding of the RE resource characteristics and availability, investments in enabling infrastructure and research, development and demonstrations (RD&D), modifications to institutional and governance frameworks, innovative thinking, attention to social aspects, markets and planning, and capacity building in anticipation of RE growth.

In many countries, sufficient RE resources are available for system integration to meet a major share of energy demands, either by direct input to end-use sectors or indirectly through present and future energy supply systems and energy carriers, whether for large or small communities in Organisation for Economic Co-operation and Development (OECD) or non-OECD countries. At the same time, the characteristics of many RE resources that distinguish them from fossil fuels and nuclear systems include their natural unpredictability and variability over time scales ranging from seconds to years. These can constrain the ease of integration and result in additional system costs, particularly when reaching higher RE shares of electricity, heat or gaseous and liquid fuels.

Existing energy infrastructure, markets and other institutional arrangements may need adapting, but there are few, if any, technical limits to the planned system integration of RE technologies across the very broad range of present energy supply systems worldwide, though other barriers (e.g., economic barriers) may exist. Improved overall system efficiency and higher RE shares can be achieved by the increased integration of a portfolio of RE resources and technologies. This can be enhanced by the flexible cogeneration of electricity, fuels, heating and cooling, as well as the utilization of storage and demand response options across different supply systems. Real-world case studies outlined throughout the chapter exemplify how different approaches to integration within a specific context have successfully achieved RE deployment by means of a combination of technologies, markets, and social and institutional mechanisms. Examples exist of islands, towns and communities achieving high shares of RE, with some approaching 100% RE electricity penetration and over a 50% share of liquid fuels for their light duty vehicle fleets.

Several mature RE technologies, including wind turbines, small and large hydropower generators, geothermal systems, bioenergy cogeneration plants, biomethane production, first generation liquid biofuels, and solar water heaters, have already been successfully integrated into the energy systems of some leading countries. Further integration could be encouraged by both national and local government initiatives. Over the longer term, integration of other less mature, pre-commercial technologies, including advanced biofuels, solar fuels, solar coolers, fuel cells, ocean energy technologies, distributed power generation, and electric vehicles, requires continuing investments in RD&D, infrastructure, capacity building and other supporting measures.

To reach the RE levels being projected in many scenarios over future decades will require integration of RE technologies at a higher rate of deployment than at present in each of the electricity generation, heating/cooling, gas and liquid fuel distribution, and autonomous energy supply systems.

RE can be integrated into all types of *electricity* supply systems, from large, interconnected, continental-scale grids to on-site generation and utilization in small, autonomous buildings. Technically and economically feasible levels of RE penetration depend on the unique characteristics of a system. These include the status of infrastructure development and interconnections, mix of generation technologies, control and communication capability, demand pattern and geographic location in relation to the RE resources available, market designs, and institutional rules.

The distribution, location, variability and predictability of the RE resources will also determine the scale of the integration challenge. Short time-variable wind, wave and solar resources can be more difficult to integrate than dispatchable reservoir hydro, bioenergy and geothermal resources, which tend to vary only over longer periods (years and decades). As variable RE penetration levels increase, maintaining system reliability becomes more challenging and costly. Depending on the specifics of a given electricity system, a portfolio of solutions to minimize the risks to the system and the costs of RE integration can include the development of complementary, flexible generation; strengthening and extending the network infrastructure;

interconnection; electricity demand that can respond in relation to supply availability; energy storage technologies (including hydro reservoirs); and modified institutional arrangements including regulatory and market mechanisms.

District heating (DH) and cooling (DC) systems offer flexibility with regard to the primary energy source, thereby enabling a gradual or rapid transition from the present use of fossil fuel sources to a greater share of RE. DH can use low temperature thermal RE inputs (such as solar or cascaded geothermal heat), or biomass with few competing uses (such as refuse-derived fuels or industrial wastes). DC systems are less common but also offer resource flexibility by being able to use a variety of natural waterways for the source of cold as well as ground source heat pumps. Thermal storage capability (hot or cold) can overcome the challenges of RE variability.

Injecting biomethane or, in the future, RE-derived hydrogen into *gas distribution grids* can be technically and economically achieved in order to meet a wide range of applications, including for transport, but successful integration requires that appropriate gas quality standards are met.

Liquid fuel systems can integrate biofuels either for cooking (such as ethanol gels and, in the future, dimethyl ether (DME)) or for transport applications when bioethanol or biodiesel esters are usually, but not always, blended with petroleum-based fuels to meet vehicle engine fuel specifications. Advanced biofuels developed in the future to tight specifications may be suitable for direct, unblended use in current and future engine designs used for road, aviation and marine applications.

Autonomous energy supply systems are typically small-scale and are often located in remote areas, small islands, or individual buildings where the provision of commercial energy is not readily available through grids and networks. The viability of autonomous RE systems depends upon the local RE resources available, the costs of RE technologies, future innovation, and the possible avoidance of construction costs for new or expanded infrastructure to service the location.

There are multiple pathways for increasing the share of RE through integration across the transport, building, industry and primary production end-use sectors, but the ease and additional costs of integration vary depending on the specific region, sector and technology.

Being contextual and complex, it is difficult to assess 'typical' system integration costs. These differ widely depending on the characteristics of the available RE resources; the geographic distance between the resource and the location of energy demand; the different integration approaches for large centralized systems versus decentralized, small-scale, local RE systems; the required balancing capacity; and the evolving status of the local and regional energy markets. The few comparative assessments in the literature, mainly for relatively low shares of RE (such as wind electricity in Europe and the USA and biomethane injection into European gas grids), show that the additional costs of integration are wide-ranging and site-specific.

To achieve higher RE shares across the end-use sectors requires planning, development and implementation of coherent frameworks and strategies. These will vary depending on the diverse range of existing energy supply systems in terms of scale, age and type. RE uptake can be achieved in all end-use sectors by either the direct use of RE (e.g., building-integrated solar water heating) or via energy carriers (e.g., blending of biofuels with gasoline or diesel at an oil refinery). Improved end-use energy efficiency and flexibility in the timing of energy use can further facilitate RE integration.

- The *transport sector* shows good potential for increasing RE shares over the next few decades, but from a low base. Currently the RE shares are mainly from liquid biofuels blended with petroleum products and some electric rail. To obtain higher shares in the future, the RE energy carriers of advanced biofuels, biomethane, hydrogen and electricity could all be produced either onsite or in centralized plants and used to displace fossil fuels. When, and to what extent, flex-fuel, plug-in hybrid, fuel cell or electric vehicles might gain a major share of the current light duty vehicle fleet partly depends on the availability of the energy carriers, the incremental costs of the commercial manufacturing of advanced drive trains, development of the supporting infrastructures, and the rate of technological developments of advanced biofuels, fuel cells and batteries. Integration of fuels and technologies for heavy duty vehicles, aviation and marine applications is more challenging. Advanced biofuels could become more fungible with petroleum fuels and distribution systems, but will need to become more cost competitive to gain greater market share. The cost and reliability of fuel cells and the limited range of electric vehicles are current constraints.

- The *building* sector currently uses RE to meet around 10% of its total consumer energy demand, excluding traditional biomass. In the future, RE can be integrated more easily into urban environments when combined with energy efficient 'green building' designs that facilitate time- and/or resource-flexible energy consumption. In rural areas in developing countries, many modest dwellings could benefit from the integration of RE technologies, often at the small scale, to provide basic energy services. RE technologies integrated into either new or existing building designs can enable the buildings to become net suppliers of electricity and heat. Individual heating systems using biomass (for cooking and space heating), geothermal (including hydrothermal and ground source heat pumps) and solar thermal (for water and space heating, and, to a lesser extent, for cooling) are already widespread at the domestic, community and district scales.

- For *industry*, integration of RE is site- and process-specific, whether for very large, energy-intensive 'heavy' industries or for 'light' small- and medium-sized processing enterprises. At the large industrial scale, RE integration can be combined with energy efficiency, materials recycling, and, perhaps in the future, carbon dioxide capture and storage (CCS). Some industries can also provide time-flexible, demand response services that can support enhanced RE integration into electricity supply systems. In the food and fibre processing industries, direct substitution of fossil fuels onsite can be feasible, for example by the use of biomass residues for heat and power. Many such industries (sugar, pulp and paper, rice processing) have the potential to become net suppliers of heat and electricity to adjacent grids. Electro-thermal processes, process hydrogen, and the use of other RE carriers provide good opportunities for increasing the shares of RE for industry in the future.

- *Agriculture*, ranging from large corporate-owned farms to subsistence peasant farmers, consumes relatively little energy as a sector. (Fertilizer and machinery manufacture is included in the industrial sector). Local RE sources such as wind, solar, crop residues and animal wastes are often abundant for the landowner or manager to utilize locally or to earn additional revenue by generating, then exporting, electricity, heat or biogas off-farm.

Parallel developments in transport (including electric vehicles), heating and cooling (including heat pumps), flexible demand response services (including the use of smart meters with real-time prices and net metering facilities) and more efficient thermal generation may lead to dramatic changes in future electrical power systems. Higher RE penetration levels and greater system flexibility could result (but also depend on nuclear power and CCS developments). Regardless of the present energy system, whether in energy-rich or energy-poor communities, higher shares of RE are technically feasible but require careful and consistent long-term planning and implementation of integration strategies and appropriate investments.

8.1 Introduction

This chapter examines the means by which larger shares of RE could be integrated into the wide range of energy supply systems and also directly into end-user sectors at national and local levels. It outlines how RE resources can be used through integration into energy supply networks that deliver energy to consumers using energy carriers with varying shares of RE embedded (Section 8.2) or directly by the transport, buildings, industry and agriculture end-use sectors (Section 8.3) (Figure 8.1).

Many energy systems exist globally, each with distinct technical, market, financial, and cultural differences. To enable RE to provide a greater share of electricity, heating, cooling and gaseous and liquid fuels than at present will require the adaptation of these existing energy supply and distribution systems so that they can accommodate greater supplies of RE. Integration solutions vary with location, scale and the current design of energy system and related institutions and regulations.

Established energy supply systems are relatively new in terms of human history, with only around 100 years elapsing since the original commercial deployment of internal combustion engines; approximately 90 years for national grid electricity; 80 years for the global oil industry; 50 years for the global gas industry; and only around 30 years for solid state electronic applications. Based upon the rate of development of these historical precedents, under enabling conditions and with societal acceptance, RE systems could conceivably become more prominent components of the global energy supply mix within the next few decades. Energy systems are continuously evolving, with the aims of improving conversion technology efficiencies, reducing losses, and lowering the cost of providing energy services to end users. As part of this evolution, it is technically feasible to continue to increase the shares of RE through integration with existing energy supply systems at national, regional and local scales as well as for individual buildings. To enable RE systems to provide a greater share of heating, cooling, transport fuels and electricity may require modification of current policies, markets and existing energy supply systems over time so that they can accommodate greater supplies of RE at higher rates of deployment than at present.

Regardless of the energy supply system presently in place, whether in energy-rich or energy-poor communities, over the long term and through measured system planning and integration, there are few, if any, technical limits to increasing the shares of RE, but other barriers would need to be overcome (Section 1.4). Specific technical barriers to increased deployment of individual RE technologies are discussed in chapters 2 through 7. This chapter outlines the more general barriers to integration (including social ones) that cut across all technologies and can therefore constrain achieving relatively high levels of RE integration. Where presented in the literature, solutions to overcoming these barriers are presented.

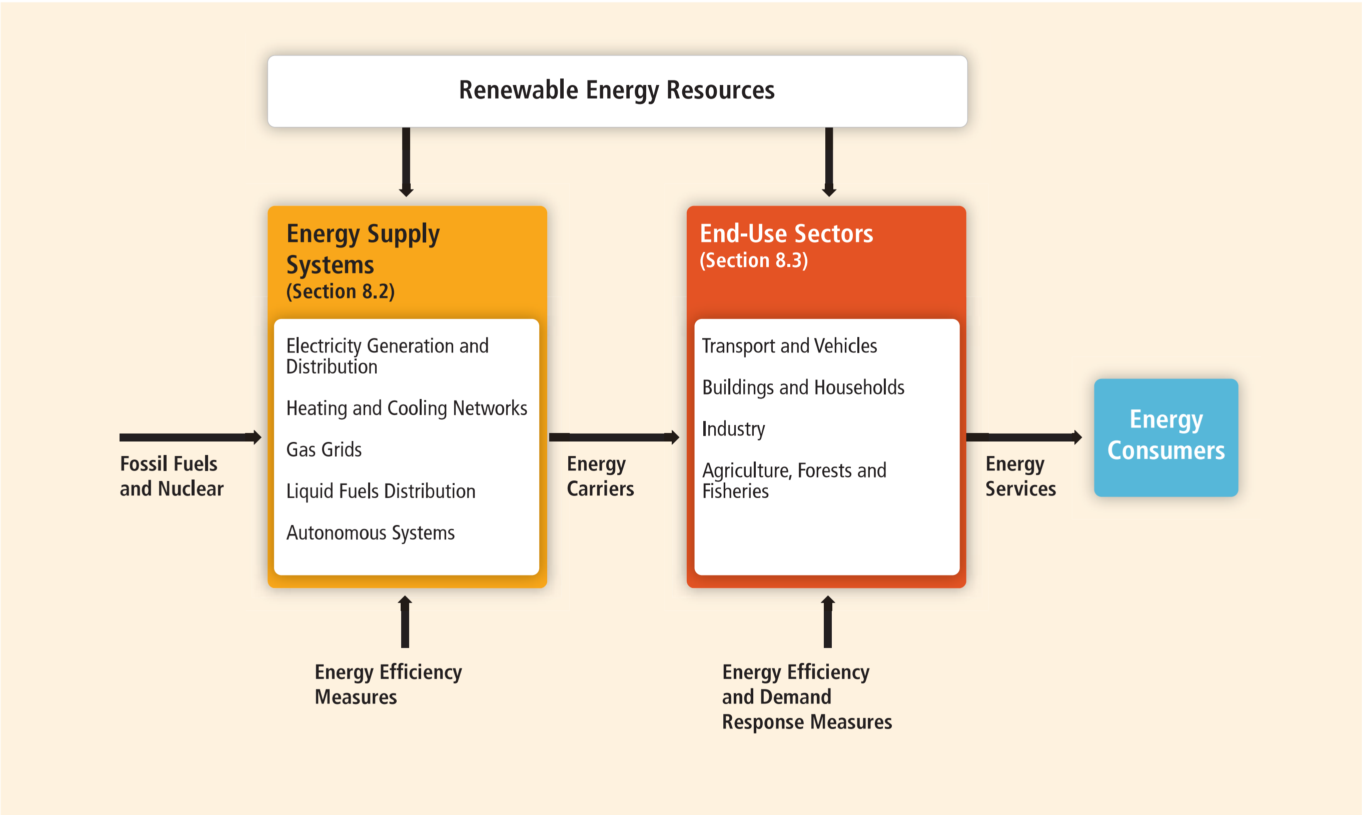

Figure 8.1 | Pathways for RE integration to provide energy services, either into energy supply systems or on-site for use by the end-use sectors.

Enhanced RE integration can provide a wide range of energy services for large and small communities in both developed and developing countries. The potential shares of RE depend on the scale and type of the existing energy supply system. Transition to low-carbon energy systems that accommodate high shares of RE integration can require considerable investments in new technologies and infrastructure, including more flexible electricity grids, expansion of district heating and cooling schemes, modifying existing distribution systems for incorporating RE-derived gases and liquid fuels, energy storage systems, novel methods of transport, and innovative distributed energy systems in buildings. The potential integration and rate of deployment of RE differs between geographic regions, depending on the current status of the markets and the varying political ambitions of all OECD and non-OECD countries.

All countries have access to some RE resources and in many parts of the world these are abundant. The characteristics of many of these resources distinguish them from fossil fuels and nuclear systems and have an impact on their integration. Some resources, such as solar, are widely distributed, whereas others, such as large hydro, are constrained by geographic location and hence integration options are more centralized. Some RE resources are variable and have limited predictability. Others have lower energy densities and different technical specifications from solid liquid and gaseous fossil fuels. Such RE resource characteristics can constrain their ease of integration and invoke additional system costs, particularly when reaching higher shares of RE.

Alongside RE, nuclear power and CCS linked with coal- or gas-fired power generation plants and industrial applications may well have a role to play in a low-carbon future (IPCC, 2007). However, for a country wishing to diversify its energy supply primarily by increasing domestic RE capacity to meet an increasing share of future energy demand, integrating a portfolio of local RE resources can be beneficial, and also make a positive contribution to improved energy supply security and system reliability (Awerbuch, 2006). Increasing RE integration can also offer a range of other opportunities and benefits (Sections 1.4.5 and 9.3) but carries its own risks, including natural variability (from seconds to years), physical threats to installed technologies from extreme weather events, locational dependence of some RE resources, additional infrastructure requirements, and other additional costs under certain conditions.

The future energy supply transition has been illustrated by many scenarios, the majority of which show increasing shares of RE over the next few decades (Section 10.2). The scenario used here as just one example (Figure 8.2) is based upon the International Energy Agency (IEA) World Energy Outlook 2010 '450 Policy Scenario' out to 2035. It illustrates that achieving high levels of RE penetration[1] will require a continuation of increasing market shares in all end-use sectors. The average annual RE growth increment required to meet this projection is almost 4 EJ/yr across all sectors; over three times the current RE growth rate.

1 The terms 'shares' and 'penetration levels' of RE are used loosely throughout the text to indicate either the percentage of total installed capacity or total energy that comes from RE technologies.

In the 2010 World Energy Outlook (IEA, 2010b), the 22 EJ of final consumption RE (excluding traditional biomass) in 2008 is almost quadrupled in 2035 in the 450 Policy Scenario. This is due mainly to the power sector where the RE share in electricity supply rises from 19 to 32% over the same period. Government support for RE, projected to rise from USD 44 billion in 2008 to USD 205 billion in 2035, is a key driver along with projected lower RE investment costs and higher fossil fuel prices.

To achieve such increased shares of RE in total energy supply by 2035 and beyond will require overcoming the challenges of integration in each of the transport, building, industry and agriculture sectors. In order to gain greater RE deployment, strategic elements need to be better understood as do the social issues. Transition pathways for increasing the shares of each RE technology through integration should aim to facilitate a smoother integration with energy supply systems but depend on the specific sector, technology and region. Multiple benefits for energy consumers should be the ultimate aim.

Successful integration of high shares of RE with energy systems in recent years has been achieved in both OECD and non-OECD countries, including:

- Brazil, with over 50% of light duty transport fuels supplied from sugar cane ethanol (Zuurbier and Vooren, 2008) and 80% of electricity from hydro (BEN, 2010);

- China, where two-thirds of the world's solar water heaters have been installed (REN21, 2010);

- Denmark, with around 20% (7,180 GWh or 25.84 PJ) of total power supply in 2009 generated from wind turbines (Section 7.4) integrated with other forms of generation (mainly national coal- and gas-fired capacity, but also supported by interconnection to hydro-dominated systems) (DEA, 2009);

- Spain, where the 2000 Barcelona Solar Thermal Ordinance resulted in over 40% of all new and retrofitted buildings in the area having a solar water heating system installed (EC, 2006); and

- New Zealand and Iceland where the majority of electricity supply has been generated from hydro and geothermal power plants for several decades.

It is anticipated that increased urbanization will continue and that the 50% of the 6.4 billion world population living in cities and towns today will rise by 2030 to 60% of the then 8.2 billion people (UNDP, 2007). There is potential in many of these growing urban environments to capture local RE resources and thereby help meet an increasing share of future energy demands (MoP, 2006 Droege et al., 2010). The potential exists to integrate RE systems into the buildings and energy infrastructure as well as to convert municipal and industrial organic wastes to energy (Section 2.2.2). However, local government planning regulations

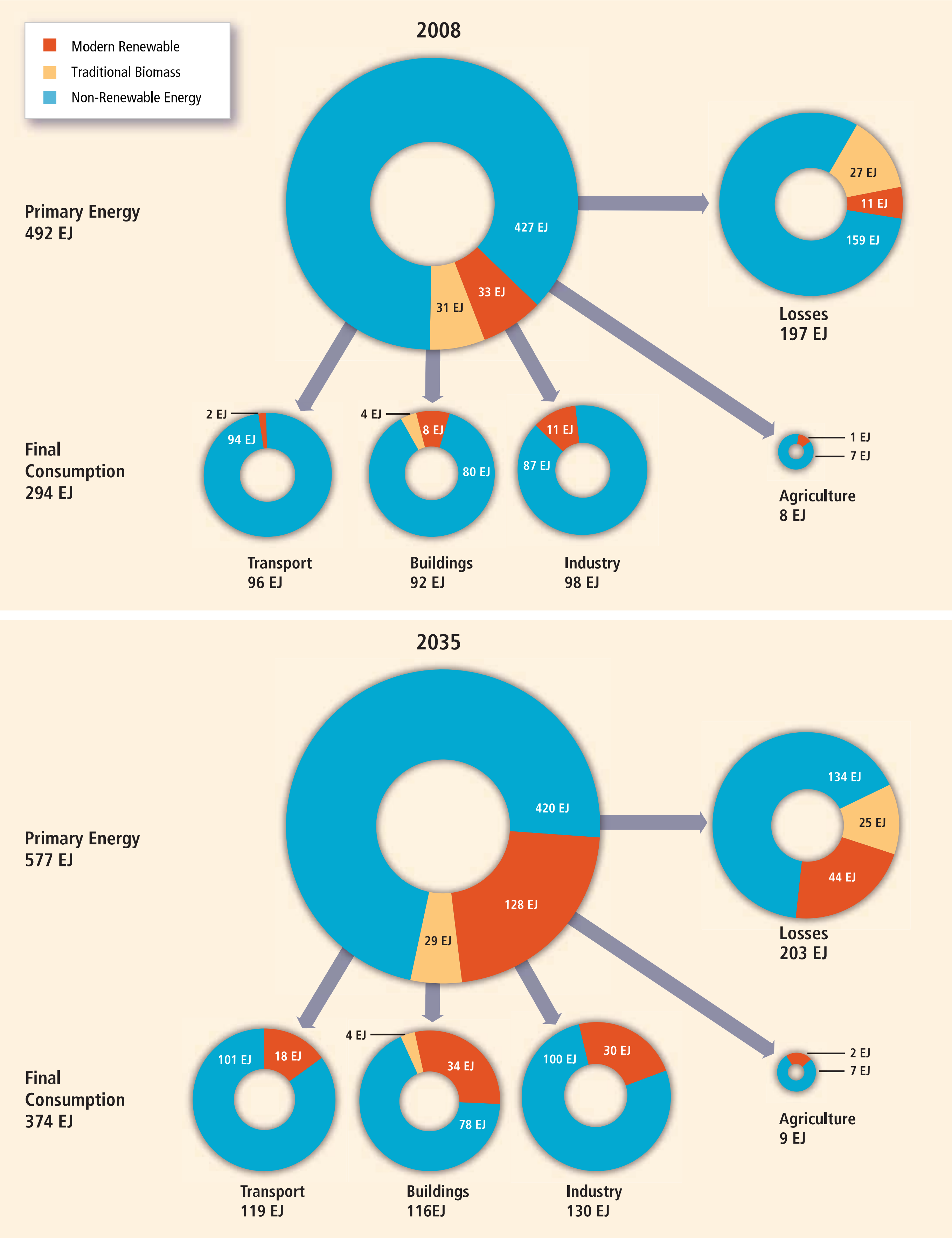
Modern Renewable
Traditional Biomass
Non-Renewable Energy
2008
Primary Energy
492 EJ
427 EJ
33 EJ
31 EJ
27 EJ
11 EJ
159 EJ
Losses
197 EJ
Final
Consumption
294 EJ
2 EJ
94 EJ
4 EJ
8 EJ
80 EJ
11 EJ
87 EJ
1 EJ
7 EJ
Agriculture
8 EJ
Transport
96 EJ
Buildings
92 EJ
Industry
98 EJ
2035
Primary Energy
577 EJ
420 EJ
128 EJ
29 EJ
134 EJ
25 EJ
44 EJ
Losses
203 EJ
Final
Consumption
374 EJ
101 EJ
18 EJ
4 EJ
34 EJ
78 EJ
100 EJ
30 EJ
2 EJ
7 EJ
Agriculture
9 EJ
Transport
119 EJ
Buildings
116EJ
Industry
130 EJ

Figure 8.2 | (Preceding page) RE shares (red) of primary and final consumption energy in the transport, buildings (including traditional biomass), industry and agriculture sectors in 2008 and an indication of the projected increased RE shares needed by 2035 in order to be consistent with a 450 ppm CO_2eq stabilization target.

Notes: Areas of circles are approximately to scale. Energy system losses occur during the conversion, refining and distribution of primary energy sources to produce energy services for final consumption. 'Non-renewable' energy (blue) includes coal, oil, natural gas (with and without CCS by 2035) and nuclear power. This scenario example is based upon data taken from the IEA World Energy Outlook 2010 (IEA 2010d) but converted to direct equivalents (Annex II.4). Energy efficiency improvements above the baseline are included in the 2035 projection. RE in the buildings sector includes traditional solid biomass fuels (yellow) for cooking and heating for 2.7 billion people in developing countries (Section 2.2) along with some coal (UNDP and WHO, 2009). By 2035, some traditional biomass has been partly replaced by modern bioenergy conversion systems. Excluding traditional biomass, the overall RE system efficiency (when converting from primary to consumer energy) remains around 66% over the period.

may constrain the deployment of some RE technologies in the short term (IEA, 2009b).

Many energy scenarios have incorporated a wide range of energy efficiency initiatives (Sections 1.1.3 and 10.1). These reduce future energy demand baseline projections significantly across the building, industry, transport and energy supply sectors (IPCC, 2007). Lower energy demand reduces the required capacity, and hence cost, of an integrated RE system, which might facilitate having a greater share of RE in a growing energy market (Verbruggen, 2006; Pehnt et al., 2009a). For example, a building owner or developer could be encouraged to initially invest in energy saving measures and energy efficient building design before contemplating the installation of RE systems and hence reduce the installed capacity needed to meet the energy demand of the building occupiers (IEA, 2009b).

Integration of RE into the energy supply and infrastructure system of many OECD countries raises different challenges than those of non-OECD countries. For example, RE integration into dense urban regions that already have high shares of RE, or where cross-border energy supply options are possible, differs markedly from integration of RE into a small autonomous energy system in a remote rural region with limited energy infrastructure. In such districts, small-scale, distributed, RE systems may be able to avoid the high investment costs of constructing infrastructure presently deficient (ARE, 2009).

A technology that is successful in one region may not be so in another, even where RE resource conditions and supportive enabling environments are similar. Successful deployment can depend upon the local RE resources, current energy markets, population density, existing infrastructure, ability to increase supply capacity, financing options and credit availability. For any given location and energy market, issues relating to the integration of a RE project can be complex as there can be impacts on land and water use, adherence to national and local planning and consenting processes, variance due to the maturity of the technology (IEA, 2008b), co-benefits for stakeholders, and acceptance or rejection by the general public (as also would be the case for a fossil fuel, nuclear or CCS project).

8.1.1 Objectives

The objectives of this chapter are to

- assess the literature regarding the integration of RE into current and possible future energy systems;
- present the constraints that can exist when integrating RE into current electrical supply systems, heating and cooling networks, gas grids, liquid fuels and autonomous systems, particularly for RE shares that are significantly higher than at present; and
- determine whether increasing RE integration within present energy supply systems and facilitating the increased rate of deployment of RE technologies in the transport, building, industry and agricultural sectors are feasible propositions.

The chapter examines the complex cross-cutting issues that relate to RE integration across centralized, decentralized and autonomous energy supply systems and into the wide range of end-use technologies, buildings and appliances used to provide desirable energy services (heating, cooling, lighting, communication, entertainment, motor drives, mobility, comfort, etc.). These issues include energy distribution and transmission through energy carriers, system reliability and quality, energy supply/demand balances, system flexibility, storage systems, project ownership and financing, operation of the market, supply security and social acceptance. Regional differences between the integration of various RE systems are highlighted.

Due to the very specific nature of any individual energy supply system, it was not possible to provide general guidance on which policy intervention steps to follow logically in order to increase the share of RE through integration. The unique complexities of energy supply systems, due to their site-specificity, future cost uncertainties, and deficit of analysis in the literature, prohibited a detailed evaluation of the additional costs of RE system integration and deployment (other than for wind power; Section 7.5.4). The inability to determine 'typical' integration costs across the many differing systems and present them as 'representative' is a barrier to wider RE deployment and modelling scenarios. Further analysis would be useful.

8.1.2 Structure of the chapter

Section 8.2 discusses the integration of RE systems into existing and future centralized supply-side systems for both OECD and non-OECD regions. Where relevant, the benefits of system design and technology components to facilitate integration, operation and maintenance strategies, markets and costs are discussed.

Section 8.3 outlines the strategic elements, including non-technical issues, needed for transition pathways for each of the end-use sectors in order to gain greater RE deployment. The current status, possible pathways to enhance adoption of RE, related transition issues, and future trends are discussed for transport, buildings, industry and primary production.

Both sections endeavour to emphasize that though common solutions to RE integration exist there are sometimes differences between:

- RE integration into centralized, high voltage electricity systems, district heating schemes, and liquid fuel and gas pipelines, and
- RE integration into distributed, small-scale, energy systems such as low voltage electricity grids, heating and cooling of individual buildings, and liquid or gaseous fuel production for local transport use.

The case studies illustrate what has already been achieved, under a given set of circumstances.

8.2 Integration of renewable energy into supply systems

Energy supply systems have evolved over many decades to enable the efficient and cost-effective distribution of electricity, gas, heat and transport fuel energy carriers to provide useful energy services to end users. Increasing the deployment of RE systems requires their integration into these existing systems. This section outlines the issues and barriers involved as well as some possible solutions to overcome them in order to achieve increased RE penetration. The complexities of the various electricity supply systems and markets operating around the world result in marked differences in the approach to integration. Prerequisites for efficient and flexible energy conversion, mutual support between energy sectors, and an intelligent control strategy include coherent long-term planning and a holistic approach. Over time this could result in an inter-linked energy system to provide electricity, heating, cooling and mobility rather than having distinct sectors for each as at present. A significant increase in global electricity demand could result from a higher share being substituted for current fossil fuel demands in the heating and transport sectors.

8.2.1 Integration of renewable energy into electrical power systems

Modern electrical power systems (the grid) have been developing since the late 19th century and take different forms around the world. Some systems are very advanced and highly reliable but are at different scales, for example the Eastern Interconnection in the USA that serves 228 million consumers across 8.85 million square kilometres contrasts with smaller, more isolated systems such as Ireland serving a population of 6.2 million across 81,638 km^2 (NISRA, 2009; CSO, 2010). Other systems are not as well developed but are rapidly evolving. For example, China installed an average of 85 GW of plant per year from 2004 to 2008 and in the same period increased its electricity consumption by over 50% (J. Li, 2009). Other systems are not well developed either in terms of access or quality (e.g., many parts of sub-Saharan Africa). Autonomous and/or micro-scale systems also exist to serve small communities or single buildings or industrial plants (Section 8.2.5). Despite their variations, these systems have a common purpose: the provision of a reliable and cost-effective supply of electricity to loads by appropriate generation and use of network infrastructure.

The versatility of energy in electrical form, the ability to transport it across large distances (nearly) instantaneously, and its necessity for the deployment of modern technology and the advancement of economic and social development has resulted in a dramatic increase in the demand for electricity. This increase is projected to continue in a wide range of scenarios, including some of those that keep greenhouse gas (GHG) concentrations in the atmosphere below 450 ppm (e.g., IEA, 2010d; see also Section 10.2). The provision of modern energy services is recognized as a critical foundation for sustainable development (e.g., DFID, 2002; Modi et al., 2005; UNEA, 2009). This growth of electricity demand coupled with the geographically dispersed nature of many renewable sources makes electricity an attractive energy vector to harness RE where adequate network infrastructure is available. With the development of electric vehicles and heat pumps, electricity is also taking a growing share in the transport and heat markets (Kiviluoma and Meibom, 2010; Sections 8.3.1 and 8.3.2). Additionally, with the development of inexpensive and effective communications systems and technologies as well as smart meters, the electrical power system is experiencing dramatic change.[2] All these potential developments—RE, demand side participation, electric vehicles and any new thermal generation (i.e., fossil fuel or nuclear)—need to be integrated into electrical power systems. They collectively and individually pose common and unique challenges.

This section is comprised of three sub-sections that focus on the integration issues for renewable electricity and begins with a brief description of the basic principles of electrical power systems—how they are designed, planned and operated (Section 8.2.1.1). This is followed by a summary of the pertinent integration characteristics of renewable electricity sources and a high-level description of the integration

2 The term 'smart grid' is often used to refer to this mixture of new technologies but it is not used in this report.

challenges that result (Section 8.2.1.2). Finally, integration experiences, studies and options for existing and future electrical power systems are provided (Section 8.2.1.3).

8.2.1.1 Features and structures of electrical power systems

The first power plant used direct current (DC) that could transport electricity to consumers living close to the power station. However, a few years after the construction of this first power plant, alternating current (AC) electricity systems were developed (El-Sharkawi, 2009). Alternating currrent systems allow greater flexibility in the transmission of electricity across the various voltage levels in the electricity network and, as such, almost all electrical power systems across the world today use AC. However, DC is still used in the transmission of electricity over long distances, for interconnection of AC systems (sub-sea and over land), and in some very small domestic stand-alone systems. DC technology is developing rapidly and new application domains are being developed (Breuer et al., 2004; EASAC, 2009).

Integration of RE into any electrical power system poses a number of challenges (many shared with other technologies and developments) for the designers and operators of that system. In order to appropriately address these challenges, a basic understanding of the characteristics of electrical power systems is required and some salient elements of planning, design and operation are discussed here (Bergen and Vittal, 2000).

Electricity demand (including losses in the electrical power system) varies with the needs of the user; typically at a minimum at night and increasing to a peak during working hours. In addition, there are normally differences between working days and weekends/holidays and also between seasons; most systems also show an annual growth in consumption from year to year. Therefore, generators on a system must be scheduled (dispatched) to match these variations throughout the year and appropriate network infrastructure to transfer that power must be available. This balancing (of supply and demand) requires complex operational planning from the management of second-to-second changes in demand to the longer-term investment decisions in generation and transmission assets. The balancing is carried out by the system operator in balancing areas (or control areas), which often are parts of large interconnected AC systems.

In order to maintain an AC power system at its nominal frequency (e.g., 50 Hz in Europe and 60 Hz in North America), the instantaneous power supplied to the system must match the demand. Insufficient power results in a decreased frequency while excess power leads to an increased frequency. Either scenario is a threat to the security of the system, since the generators, interconnectors and loads that constitute the system are physically designed to operate within certain limits, and must be removed from the system once these limits are violated in order to ensure their integrity.

The electrical machines employed in the generation of electricity (and in the conversion of electricity to end-use energy) are an important component within electrical power systems. The traditional machine used for generation is the synchronous machine (El-Sharkawi, 2009). This machine is directly connected and synchronized to the frequency of the system. A synchronous electrical power system consists of (i) a network that connects (ii) synchronous generators to the (iii) demand. The network can further be divided into the transmission network, where large generators and consumers are connected and high voltages are used to transmit power over long distances; and the distribution network, which is used to transmit power to consumers at lower voltage levels and connect distributed generation. Synchronous machines maintain synchronism with one another through restoring forces that act whenever there are forces tending to accelerate or decelerate one or more generators with respect to other machines (Kundur, 2007). As a result of this, synchronous machines can detect and react to events on the system automatically; in particular inertial response to a frequency change. Generators also have governors that detect and react to frequency changes and this coupled with inertial response is of benefit to AC power systems as it allows for the support of frequency on an almost instantaneous basis.

Matching demand and supply (balancing) on a minute-to-minute basis is generally done by control of generation. This is known as regulation/load following and requires small to medium variations in the output of the power stations. It is usually controlled automatically or by a central electricity system operator, who is responsible for monitoring and operating equipment in the transmission system and in power generating stations. Dispatchable units are those that control their output between a minimum and maximum level. The output of some units such as wind generators cannot be fully controlled. Even here, however, some level of control is possible through a reduction of the output of the units, although such control strategies also lead to lost production. Units such as wind generators are therefore considered partially dispatchable as opposed to dispatchable.

Over slightly longer time periods (e.g., 30 minutes to 6 to 24 hours), decisions must be made regarding which power stations should turn on/turn off or ramp up/ramp down output to ensure the demand is met throughout the day (e.g., to meet low demand at night and high demand during the day). This is usually done using a method known as unit commitment (Wood and Wollenberg, 1996). Unit commitment involves complex optimizations that are conducted, typically one to two days ahead, to create an hourly or half-hourly schedule of generators required to reliably meet the forecasted demand at least cost. These schedules will usually instruct some units to run at their maximum capacity all day (these are known as base load units), some units to turn on in the morning and off at night (mid-merit units) and some units to just turn on during times of peak demand (peaking units). The running regime of a unit depends mainly on its operation cost (i.e., fuel used and efficiency), as well as other characteristics such as how long it takes to turn on or off, and the degree to which it can quickly change its output power.

Organized electricity markets have emerged in some countries/regions and they coordinate how the costs of the generators are included in the unit commitment methods. Trading of electricity between producers and consumers can be done in power exchanges (pools) or on a bilateral basis (Schweppe et al., 1988; Stoft, 2002). Sometimes these markets run on very short time horizons, for example, five minutes before the electricity is expected to be needed (Harris, 2006; AEMO, 2010), and in other cases the markets operate days, weeks or even months before the electricity is required. An important market parameter is the gate closure time, which is the time difference between bidding of generators into the market and the actual delivery of power. Properly functioning markets support the long-term financial investment in appropriate generation capacity and network infrastructure to ensure supply meets demand in a reliable manner and at least cost.

It should be noted that the principle of energy balance also applies to the smallest stand-alone autonomous systems. An autonomous electrical power system is one without interconnections to other systems and that cannot access the larger variety of balancing resources available to larger systems. In island systems, or developing economies, a common solution is often to use small autonomous systems in order to avoid the costs of transmission lines to areas with comparatively low consumption. Balancing in many such cases is provided by expensive battery energy storage and/or diesel generators and dump load resistors to absorb surplus energy that cannot be absorbed otherwise (Doolla and Bhatti, 2006). Autonomous systems can be as small as individual homes or groups of homes working on the low voltage distribution grid, sometimes referred to as microgrids (Tsikalakis and Hatziargyriou, 2008). Though the basic principles of electric power system operations do not differ between large interconnected networks and small autonomous systems, the practical implications of those principles can vary. Autonomous systems are addressed to some degree in this section, but are also covered in a more-dedicated fashion in Section 8.2.5.

Over an annual time frame, it is necessary to ensure that the electricity system always has enough generation capacity available to meet the forecasted demand. This means that maintenance schedules must be coordinated to ensure that all generating units and network infrastructure do not shut down for maintenance at the same time, while also considering the fact that units will break down unexpectedly. In addition, planning must also be done over much longer time horizons (5 to 20 years). The construction of generators and networks involves long lead times, high capital requirements, and long asset life and payback periods. Therefore, the electricity sector requires significant long-term planning to ensure that generation will continue to meet the demand in the decades ahead and network infrastructure is developed in a timely and economic manner.

A further important planning consideration is the geographic spread of generation. If a generator is located close to a demand centre then less transmission capacity will be required to deliver the electricity to the end user and less electricity will be lost in transmission

Electrical demand cannot always be met and there are many well known reliability metrics that can quantify this (Billinton and Allen, 1988), though the metrics themselves can vary widely among different electric power systems. For example, the value of lost load is different in a modern industrial economy than in a developing one. Electric systems that can accept lower levels of overall reliability may be able to manage the integration of RE into electrical power systems at lower costs than systems that demand higher levels of reliability, creating a trade-off that must be evaluated on a case-by-case basis.

A reliability metric known as the capacity credit[3] (also known as capacity value) (Keane et al., 2011a) gives an indication of the probability that a particular type of generation will reliably contribute to meeting demand, which generally means that it will be available to generate electricity during the peak demand hours. This is an important metric in the planning of future electricity systems. If a type of generation has a low capacity credit this indicates that its available output tends to be low during high demand periods. The total capacity credit for all generation on the system needs to be sufficient to cover peak demand with a certain level of reliability; usually systems also require an additional margin for reliability purposes (planning reserves). The capacity credit of generation depends on the generator availability (mechanical and fuel source), and the coincidence with electrical power system demand (in particular times of high demand).

To ensure system security and reliability, electrical power systems are designed and operated to withstand specific levels of contingencies. Generation contingencies result from the sudden loss of significant generation capacity; this could be the loss of a large generating unit or loss of a network connection. Reserves are carried by the system operator, usually in the form of other generators operating at reduced output, which rapidly replace the power that was lost during the contingency. Transmission systems are typically designed to withstand the loss of any single critical element, such as a transmission line, such that on the system (i.e., post fault), no other element on the network is overloaded and the system stays within prescribed limits. Faults on electrical power systems are detected and cleared by protection that continuously monitors the system for such events. Electrical power system protection is also critical to the maintenance of system integrity since generators and other critical equipment can be disconnected from the system if a fault on the system is not cleared quickly enough. Many of today's larger power systems use advanced energy management/network management systems to configure their systems in a secure manner, thus allowing them to withstand these contingencies, for example, fault ride through (FRT) capability of generators (and the associated capability

3 Note that capacity credit is different than capacity factor. The capacity factor of a power plant is the average output typically expressed as a percentage of its maximum (rated) output.

of providing frequency and voltage support during the fault). In order to ensure reliability and proper operability of the network, generators and large consumers connected to the network have to comply with the connection requirements published in the codes of the network operators. These include, for example, grid codes in Ireland (EirGrid, 2009) and Germany (Transmission Code, 2007) and connection standards in the USA (CAISO, 2010).

The power flows on the overhead lines and cables (feeders) of the system require careful management to ensure satisfactory voltage levels throughout the system and to respect the rating limits of individual feeders (El-Sharkawi, 2009). The power must be delivered to the loads via these feeders, and its efficient and reliable delivery is crucial. Key variables in this task are thermal ratings (heating caused by losses), voltage levels and stability limits. These requirements are managed at the planning stage when the network is designed and built and also on a shorter time frame as the network is reconfigured, generator output adjusted to influence the flows, or other control technologies employed to support system voltages (El-Sharkawi, 2009).

The AC nature of the electrical power system results in different voltages throughout the system, in the first instance determined by the demand and generation in the local area. In order to ensure an electricity supply of required quality and reliability, the voltages throughout the system must be maintained within defined limits. This is a challenge to the design and operation of electrical power systems across the world. The voltage levels can be affected by the size and characteristics of generators, transmission lines and consumers, and the design and location of these is one of the key parameters available when designing a reliable and economic electrical power system. Reactive power is a critical component of voltage control. It is distinct from the active power that supplies energy to loads and arises from the AC nature of modern electrical power systems (Taylor, 1994). The effective supply and demand of reactive power is a critical system support service in any AC electrical power system. Network users such as generators supply the different technical services, also called ancillary services, that are needed for proper operation of the network in normal operation (e.g., reactive power supply) and during network faults. Some of these services are delivered on a bilateral commercial basis, though ancillary service markets are emerging in many parts of the world (Cheung, 2008).

8.2.1.2 Renewable energy generation characteristics

Renewable electricity sources depend on energy flows in the natural environment, thus their power generation characteristics are very different in general from other generation based on stockpiles of fuel (with the exception of biomass-fuelled plants). In particular, they reflect the time-varying nature of the energy flows. Here, each of the RE generation technologies is dealt with in turn as it appears in Chapters 2 through 7. This section highlights supply characteristics of the technologies that are of direct relevance to integration into electrical power systems, namely: (a) variability and predictability (uncertainty), which is relevant for scheduling and dispatch in the electrical power system; (b) location, which is a relevant indicator of the need for electrical networks; and (c) capacity factor, capacity credit and power plant characteristics, which are indicators relevant for comparison for example with thermal generation. These particular characteristics are outlined below, and a very brief summary for a selection of the technologies is given in Table 8.1. Further details are available in Chapters 2 through 7.

Bioenergy

Dedicated biopower plants are similar to fossil-fuel-powered plants in several respects; additionally, bioenergy can be blended with fossil fuels in fossil fuel plants that use co-firing. Biopower plants are powered by storable solid, gaseous or liquid fuel, and use similar types of technology and thermal cycles for the prime mover (e.g., steam turbine, diesel engine; Section 2.3.3). Temporal characteristics and output predictability are thus partly determined by operational decisions, and in part by the plant and biomass fuel availability, which can depend on how the fuel is prepared, stored and supplied to the plant and can exhibit daily, monthly, seasonal and annual variations.

The location of biopower plants is often determined by proximity to the fuel supply or fuel preparation plant. Biopower plant location is not as dependent on resource location as other renewable technologies as fuel can also be transported to the plant. A limitation to transporting fuel over long distances is the relatively low energy content of biomass fuels (in terms of kWh/m^3 or kWh/kg (kJ/m^3 or kJ/kg)). The high transport cost of biomass fuels means that it is generally more economical to locate the plant close to the fuel source (Section 2.3.2). Small biopower plants are very often connected at the distribution level. A single large plant, on the other hand, may be connected at the transmission level. The capacity credit of biopower plants is similar to combined heat and power (CHP) plants and thermal plants.

Biomass electricity production is often operated in CHP plants to achieve better fuel efficiency. As a result, there may be little flexibility in plant dispatch if the operation is heat-load driven. However, when heat storage is available, electricity can be produced in a flexible way (Lund and Münster, 2003; Kiviluoma and Meibom, 2010). Also, control characteristics (power, voltage) of biopower plant are similar to CHP and thermal plants. Plant sizes are mostly in the range from a few hundred kW to 100 MW and larger, particularly when co-fired with fossil fuels.

Direct solar energy

Direct electricity generation from solar takes two distinct forms: photovoltaic solar power (solar PV) in which sunlight is converted directly to electricity via the photovoltaic effect in a semiconductor; and concentrating solar power (CSP) in which a working fluid is heated to high temperature and used to drive a heat engine (e.g., a Rankine steam cycle or a Stirling cycle) that is connected to an electrical generator (Section 3.3). For both forms of generation the variability of the primary source, the available solar irradiation, is dependent on the level of aerosols in the atmosphere, the position of the sun in the sky, the potential

Table 8.1 | Summary of integration characteristics for a selection of renewable energy technologies.

Technology		Plant size range (MW)	Variability: Characteristic time scales for power system operation (Time scale)	Dispatchability (See legend)	Geographical diversity potential (See legend)	Predictability (See legend)	Capacity factor range (%)	Capacity credit range (%)	Active power, frequency control (See legend)	Voltage, reactive power control (See legend)
Bioenergy		0.1–100	Seasons (depending on biomass availability)	+++	+	++	50–90	Similar to thermal and CHP	++	++
Direct solar energy	**PV**	0.004–100 modular	Minutes to years	+	++	+	12–27	<25–75	+	+
	CSP with thermal storage*	50–250	Hours to years	++	+**	++	35–42	90	++	++
Geothermal Energy		2–100	Years	+++	N/A	++	60–90	Similar to thermal	++	++
Hydropower	**Run of river**	0.1–1,500	Hours to years	++	+	++	20– 95	0–90	++	++
	Reservoir	1–20,000	Days to years	+++	+	++	30–60	Similar to thermal	++	++
Ocean energy	**Tidal range**	0.1–300	Hours to days	+	+	++	22.5–28.5	<10	++	++
	Tidal current	1–200	Hours to days	+	+	++	19–60	10–20	+	++
	Wave	1–200	Minutes to years	+	++	+	22–31	16	+	+
Wind energy		5–300	Minutes to years	+	++	+	20–40 onshore, 30–45 offshore	5–40	+	++

*Assuming CSP system with 6 hours of thermal storage in US Southwest. **In areas with Direct Normal Irradiation (DNI) > 2,000 $kWh/m^2/yr$ (7,200 $MJ/m^2/yr$).

Notes:

Plant size: range of typical rated plant capacity.

Characteristic time scales: time scales where variability significant for power system integration occurs.

Dispatchability: degree of plant dispatchability: + low partial dispatchability, ++ partial dispatchability, +++ dispatchable.

Geographical diversity potential: degree to which siting of the technology may mitigate variability and improve predictability, without substantial need for additional network: + moderate potential, ++ high diversity potential.

Predictability: Accuracy to which plant output power can be predicted at relevant time scales to assist power system operation: + moderate prediction accuracy (typical <10% Root Mean Squared (RMS) error of rated power day ahead), ++ high prediction accuracy.

Active power and frequency control: technology possibilities enabling plant to participate in active power control and frequency response during normal situations (steady state, dynamic) and during network fault situations (e.g., active power support during FRT): + good possibilities, ++ full control possibilities.

Voltage and reactive power control: technology possibilities enabling plant to participate in voltage and reactive power control during normal situations (steady state, dynamic) and during network fault situations (e.g., reactive power support during FRT): + good possibilities, ++ full control possibilities.

shadowing effect of obstacles (buildings, trees, etc.) and cloud cover. Depending on weather conditions, the latter two can be quite variable over time scales as short as seconds (Woyte et al., 2007). Because of their specific differences, the generation characteristics of solar PV and CSP are discussed separately.

Solar PV

The electrical output of PV panels changes nearly instantaneously as the solar radiation incident on the panels changes. The variability of a large solar PV plant will to some degree be smoothed due to the footprint of the plant, particularly over very short time scales (roughly less than about 10 minutes for plants of the order of about 100 MW) (Longhetto et al., 1989; Kawasaki et al., 2006; Curtright and Apt, 2008; Mills et al., 2009a; Marcos et al., 2011). The degree to which the variability and predictability of solar plants is smoothed will depend on the type of solar plants, the size of the individual plants, the geographic dispersion between sites, and prevailing weather patterns.

The aggregate variability of multiple solar plants will be smoothed by geographic diversity because clouds do not shade and un-shade dispersed plants simultaneously. This smoothing effect can substantially reduce the sub-hourly variability of the aggregate of several solar plants (Wiemken et al., 2001; Mills et al., 2009a; Murata et al., 2009; Hoff and Perez, 2010; Mills and Wiser, 2010). It can also lead to lower aggregate short-term forecast errors for multiple solar plants (Lorenz et al., 2009, 2010). This smoothing effect of geographic diversity was shown to lead to comparable variability for similarly sited wind and solar plants in one region of the USA (Mills and Wiser, 2010).

Solar electricity predictions have forecast errors in cloudy weather. There is no production during the night, and the morning and evening ramps as well as the overall diurnal variation are predictable. Locally, for distribution network control, prediction errors can be significant but decrease relatively in larger systems (Lorenz et al., 2009).

Although the solar resource varies from region to region, the sun does shine everywhere. This increases the versatility with which solar PV can be sited in contrast to many other more location-dependent renewable resources. With regard to the impact on network infrastructure, small and medium size solar PV is typically installed near to demand and connected at the distribution level. At low penetrations on distribution feeders (PV capacity < 100% peak load on feeder), PV may offset the need for distribution upgrades (where peak demand on the feeder occurs in daylight) and reduce losses. Large size PV plants, on the other hand, can be located far from the load centres, which typically requires additional network infrastructure.

Capacity factors of solar PV range between 12 and 27%. The lower capacity factors are for fixed tilt PV systems while the higher capacity factors typically utilize single axis tracking. Estimates of the capacity credit of PV range between 25 and 75% (Pelland and Abboud, 2008; Xcel Energy, 2009; GE Energy, 2010), though lower values are possible at high levels of solar penetration and in electricity systems where demand patterns and PV output are poorly correlated. Additional analysis indicates the potential for high capacity credit at low solar PV penetration when, as in many cases, there is a high degree of coincidence between solar PV production and demand (Perez et al., 2008). Network-connected PV systems use inverters for grid interfacing, enabling in principle control of electrical characteristics relevant for grid integration (McNutt et al., 2009). With additional controls it is possible for PV to even provide active power control through the plant inverters (Achilles et al., 2008), although this is always at a loss of PV production. Typical plant sizes range from a few kW to 100 MW but are increasing in size.

Concentrating solar power (CSP)

The smoothing effects due to geographic diversity for CSP are similar to those of solar PV. CSP, however, includes intrinsic thermal storage in its working fluid and thus can have substantial thermal inertia. Thermal inertia, to a degree, smooths the effects of short-term variations in solar radiation. This thermal inertia can be further enhanced through the storage of additional heated fluid. Adequate thermal storage coupled with an increased size in the solar collector field further smoothes plant output due to passing clouds and allows for extended plant operations into or through the night.

CSP plants can only use the direct-beam portion of solar irradiance. Sites with high direct normal irradiance, greater than approximately 2,000 $kWh/m^2/yr$ (7,200 $MJ/m^2/yr$), are usually found in arid and semi-arid areas with reliably clear skies that typically lie at latitudes from 15° to 40° N or S and at higher altitudes (IEA, 2010c). The size of the plant in relation to local land availability determines the plant location, which is not necessarily close to load centres and therefore may often require new transmission infrastructure.

Capacity factors of CSP plants range from 22 to 26% without thermal storage and can reach as high as 74% with more than 10 hours of thermal storage (DOE and EPRI, 1997; Herrmann et al., 2004). In principle, without storage, the capacity credit of CSP can be similar to solar PV (Xcel Energy, 2009), whereas with storage, CSP's capacity credit could be 89 to 93%, or nearly as high as for thermal plants (GE Energy, 2010). Aside from the increased capacity factor and capacity credit, thermal storage allows CSP plants to provide improved dispatchability (i.e., from partially dispatchable to dispatchable). CSP plants with significant storage have similar electrical power plant characteristics to non-renewable thermal units and thereby enhance the overall grid flexibility to accommodate a larger share of variable energy sources. Plant sizes range from 50 MW to 250 MW and larger.

Geothermal energy

Geothermal resources can be utilized in a variety of sustainable power generating modes, including continuous low power rates, long-term (decades) cycles of high power rates separated by recovery periods, or uninterrupted high power rates sustained with effective fluid reinjection. Geothermal energy typically provides base load electrical generation, but it has also been used for meeting peak demand. Geothermal plants represent major investment and have low variable costs and thus would tend to be operated at maximum, sustainable rated output. Operating in a flexible manner may be possible in some cases but it also may impact efficiency (D.W. Brown, 1996). As a result, while it may be possible to balance demand and/or variable generation with geothermal resources (Bromley et al., 2006), the overall economic effectiveness of this approach requires detailed evaluation at specific sites.

High-temperature hydrothermal-type geothermal reservoirs are geographically specific, and thus power generation will not always be near to population and load centres. Adding new geothermal resources often necessitates extending the transmission network and thus involves infrastructure investments (e.g., Mills et al., 2011). However, in the future enhanced geothermal systems will in principle have the potential of locating closer to demand (Tester et al., 2006). For new geothermal plants, capacity factors of 90% or higher are typically achieved (DiPippo, 2008), possibly declining over time with ageing. Geothermal plants use heat engines to drive electrical generators and as such they are in general dispatchable to the degree that dispatching the plant does not degrade the geothermal reservoir. In some cases it may be possible for geothermal plants to provide other network services such as frequency response and voltage control similar to thermal generation. The high availability of geothermal plants in California led to an estimated capacity credit of close to 100% (Shiu et al., 2006). Geothermal plant sizes can vary from small Stirling engine-based generators of a few kW up to steam plants of over 100 MW.

Hydropower (run-of-river, reservoir, pumped storage)

In addition to hydropower resources providing a source of RE, the generation characteristics of hydro resources further offer flexibility to the power system to manage the variable output of other renewable resources. Through integrated strategies, hydropower can buffer fluctuations in supply and demand, increasing the economic value of the power delivered (US DOE, 2004). Hydropower plants can be classified in three main categories according to operation and type of flow: run-of-river; reservoir based (storage hydropower); and pumped storage.

Run-of-river hydro facilities can exhibit substantial daily, monthly and seasonal variations depending on the precipitation and runoff in the catchment, and are built to operate with this variability. Some run-of-river plants may have limited balancing storage (e.g., diurnal) for meeting daily peak demand during periods of low water availability. Variability and predictability can also be influenced by hydrological restrictions, for example from mutual influences of plants operated in cascade along a given river. There can also be limits due to minimum flow in rivers or other similar hydrological factors. Variations in the water availability are in general well predicted at time scales relevant for system operation. In-stream technology using existing facilities like weirs, barrages, canals or falls generates power as per available water flow without any restriction and storage (Section 5.3.1).

For reservoir-based hydropower, when water is available, the electrical output of the plants is highly controllable and can offer significant flexibility for system operation. The reservoir capacity can vary from short term to seasonal to multi-seasonal. The energy storage in the reservoir allows hydro plants to operate in base load mode or as load following plants (Sections 5.3 and 5.5). Just like run-of-river hydro, the hydro plant flexibility can be limited by legally binding restrictions concerning minimum levels in the reservoirs, minimum river flows and other possible restrictions.

Pumped storage plants pump water from a lower reservoir into an upper storage basin using surplus electricity and reverse flow to generate electricity during the daily high demand period or other periods that require additional flexible generation (such as periods with high ramps). Pumped storage is a net consumer of energy due to pumping losses (not an energy source) (Section 5.3.1.3).

The geographic diversity potential of run-of-river hydropower is good; limiting factors are topography and precipitation conditions. The location of reservoir hydropower plants is very much geographically restricted and construction of large plants often requires substantial transmission network investments. Pumped hydro plants are similarly limited by economic constraints to areas that have suitable topography.

Capacity factors for run-of-river systems vary across a wide range (20 to 95%) depending on the geographic and climatological conditions, as well as technology and operational characteristics. For reservoir hydro, capacity factors are often in the range of 30 to 60% (Section 5.3.1.2). The capacity credit of run-of-river and reservoir hydro depends on the correlation of stream flows with periods of high demand and the size of the reservoir, as well as plant operational strategies. Hydro systems with large multi-seasonal reservoirs have capacity credits comparable to thermal plants (i.e., 97% in British Columbia, Canada; Wangdee et al. 2010). Such high capacity credit does depend on the size of the storage (Haldane and Blackstone, 1955; Billinton and Harrington, 1978) and the availability of other sources of energy during periods of regional drought (Barroso et al., 2003). A survey across a broad range of hydrologic and demand conditions for hydro lacking seasonal storage found capacity credits ranging between roughly 0 and 90% (Grimsrud et al., 1981). Some reservoir-based hydropower plants may be designed to operate as peaking power plants resulting in a low capacity factor but with a relatively high capacity credit (Section 5.5). The capacity factor and capacity credit for pumped storage are dependent on the energy storage capacity and the operational strategy, but the capacity credit would be expected to be high.

Electrical power plant characteristics of reservoir hydro plants using synchronous generators are similar to thermal generation; in fact, reservoir hydro can often provide rapid power control possibilities in excess of those possible with thermal units. Run-of-river plants use a variety of conversion systems, including variable speed systems with power electronic converters. As a consequence, electrical output characteristics of these run-of-river plants in terms of power and voltage control possibilities are comparable to wind power plants. The size of hydropower plants range from a few kW to over 20 GW.

Ocean energy (wave, tidal range, tidal and ocean currents, OTEC, salinity gradient)

Ocean energy comprises several different types of plant: wave energy; tidal range (due to the rise and fall of sea level, i.e., tidal barrages); tidal and ocean currents; Ocean Thermal Energy Conversion (OTEC); and salinity gradient. Virtually all ocean energy technologies are at best at the development or demonstration stage. Therefore, data are scarce in the scientific literature and much of what is available is heavily dependent on simulation studies with little operational field data.

The different forms of ocean energy are driven by very different natural energy flows and have different variability and predictability characteristics. Wave energy is a spatially integrated form of wind energy and daily variability may to some extent be less than wind energy. Seasonal variability has been reported to be similar to wind (Stoutenburg et al., 2010), however this is device dependent. Initial work on wave models and data shows that output can be forecasted and the models perform particularly well during high production situations (ECI, 2006). Forecasting performance for wave energy is reported to be comparable to wind and solar (Reikard, 2009).

Generation from both tidal range and tidal currents is variable in most configurations but production profiles are (almost) completely predictable. Phase differences in tidal currents between different locations within the same electrical power system could be exploited to realize significant power smoothing (Khan et al., 2009). Ocean currents have low variability at power system operational time scales. OTEC derives from thermal gradients that are reasonably well understood and near-continuous base load operations would be expected. Salinity gradient power generation is at an early stage of research and should the technology become commercial it is likely that plants would operate at constant output.

Although all ocean technology requires access to the ocean, the appropriateness of specific locations varies by the type of ocean technology. Wave energy can be collected on or reasonably near to the shore, and perhaps in the future further out into the oceans. Tidal plants and ocean current plants may locate in very specific locations, usually necessitating network infrastructure investments (University of Edinburgh, 2006). Large collections of ocean energy generators will also result in temporal smoothing of the power output (Salter et al., 2002), but are located some way from land and/or load centres.

There are a few studies with indicative values for capacity factors and capacity credit. Radtke et al. (2010) have shown that tidal range can have very low capacity credit (i.e., less than 10% for the example studied), while the capacity factor of tidal range is expected to be 22.5 to 28.5% (Section 6.3.3). Bryans et al. (2005) report capacity factors of 19 to 60% and capacity credit of 10 to 20% for tidal current. The higher end of the capacity factor and capacity credit range is achieved by downsizing the electrical generator and curtailing output during peak tidal currents. Stoutenburg et al. (2010) report capacity factors of 22 to 29% and capacity credit of 16% for wave energy off the coast of California. For Scottish wave energy, a capacity factor of 31% has been reported (University of Edinburgh, 2006).

Tidal range uses synchronous generators, and has electrical characteristics similar to thermal plants. Wave devices usually make use of power electronic converters for grid connection. Equally, tidal and ocean current turbines tend to be variable speed and thus converter connected. The electrical plant characteristics of wave, tidal current and ocean current may therefore be comparable to wind power plants. Plant sizes are 0.1 to 300 MW for tidal range, and will vary depending on the number of modules for other ocean energy technologies.

Wind energy

The electrical output of wind power plants varies with the fluctuating wind speed, with variations at all time scales relevant for power system planning, scheduling and operations (Holttinen et al., 2009). The variability of aggregated wind power output diminishes with geographical dispersion and area size, because of the decreasing correlation of wind speeds (Section 7.5.1). Prediction accuracy of wind power plant output decreases with the time span of prediction horizon, and improves with area size considered (Chapter 7). Control systems at the wind turbine, wind plant and area level (e.g., groups of distributed wind power plants) can be used to reduce the power output fluctuations when needed for secure power system operation (e.g., during extreme weather and low load situations), but at the cost of lost production.

In general, wind power plants are distributed over existing networks. However, access to areas of high wind resources, for example offshore or remote onshore, often requires extension of existing transmission networks.

Wind capacity factors depend on wind climate and technology used. Fleet-wide wind capacity factors are of the order of 20% to as high as 40% for onshore wind depending on the location, and even higher for offshore wind (Section 7.2). The capacity credit of aggregated wind power at low to medium penetrations is around 5 to 40%, depending on location, and diminishes with increasing penetration level (Section 7.5). Electrical power plant characteristics are determined by the type of conversion system and control characteristics of wind power plants. Although many existing wind plants have induction generators, as a general trend, modern wind power plants are connected to the power system via power electronic converters, and can be equipped to provide grid services such as active power, reactive power and voltage control, frequency response (inertial type response) FRT and power system support during network faults (Section 7.5.3). Recent onshore wind power plant sizes have typically ranged from 5 to 300 MW and offshore from 20 to 120 MW, though smaller and larger plant sizes do exist, including the recently commissioned 500 MW Greater Gabbard offshore plant in the UK.[4]

Challenges with integrating renewable resources into electrical power systems

Most RE resources are location specific. Therefore, renewable-generated electricity may need to be transported over considerable distances. For example, China's windy regions are often far from population and load centres. Scotland's tidal current resource is a long distance from a significant population. In the USA, the largest high quality wind resource regions and land with significant biomass production are located in the Midwest, a significant distance from the predominantly coastal population. In many of these cases, additional transmission infrastructure can be economically justified (and is often needed) to enable access to higher quality (and therefore lower cost) renewable resource regions by electricity load centres rather than utilizing lower quality renewable resources located closer to load centres. Many renewable sources can also be exploited as embedded generation in distribution networks, which may have benefits for the system when at moderate penetration levels, but also can pose challenges at higher penetration levels (e.g., voltage rise, see Masters (2002)).

Also, as discussed above, certain RE sources lack the flexibility needed to deal with certain aspects of power system operation, in particular balancing supply and demand. This is because they are subject to significant variability across a wide range of time scales important to electrical power systems and also experience more uncertainty in predicted output. Furthermore, renewable plants may displace non-renewable plants that have heretofore provided the required flexibility. Some renewable sources (hydropower with reservoirs and bioenergy) may help to manage this challenge by providing flexibility. However, overall balancing will become more difficult to achieve as partially dispatchable RE penetrations increase. Particular challenges to system balancing are situations where balancing resources are limited (e.g., low load situations with limited operational capacity).

Furthermore, increased penetration of RE production will require renewable generators to become more active participants in maintaining the stability of the grid during power system contingencies. Depending on local system penetration, network faults can trigger the loss of significant amounts of generation if the renewable generation resources are concentrated in a particular section of the power system and connection requirements have not properly accounted for this risk. A solution is to require renewable capacity to participate when possible in transient system voltage control thus supporting recovery from network faults (EirGrid, 2009, 2010b).

There are also challenges with regard to very short-term system balancing (i.e., frequency response). At high penetration levels the need for frequency response will increase unless supplementary controls are added (Pearmine et al., 2007). Many of the renewable technologies do not lend themselves easily to such service provision. In addition, RE interfaced through power electronics may displace synchronous generators, thereby reducing the overall system inertia and making frequency control more difficult. Research and development is in progress to deliver frequency response from time variable sources such as modern wind turbines,[5] and some equipment with frequency response and inertial response is already available (Section 7.7). This is a subject of ongoing research (Doherty et al., 2010) and development (Miller et al., 2010).

The output of the different renewable sources is not in general well correlated in time, so if power systems include a wide range of renewable sources, their aggregate output will be smoother thus easing the challenge of electrical power system balancing. Such a portfolio approach to generation should thus be assessed, but as noted above, many of the renewable resources are highly geographically specific so that beneficial combinations of renewable sources may not always be practicable.

Lastly there is the additional challenge of managing the transition from the predominant generation mixes of today to sustainable sources required for the low carbon power systems of the future. Major changes will be required to the generation plant mix, the electrical power systems infrastructure and operational procedures if such a transition is to be made. Specifically, major investments will be needed and will need to be undertaken in such a way, and far enough in advance, so as to not jeopardize the reliability and security of electricity supply.

8.2.1.3 Integration of renewable energy into electrical power systems: experiences, studies and options

As electrical power systems worldwide are different, there cannot be one recipe that fits all when examining the integration of RE. Dispatchable renewable sources (hydro, geothermal, bioenergy, CSP with storage[6]) may require network infrastructure but, in many cases, may offer extra flexibility for the system to integrate variable renewable sources (hydropower in particular). Partially dispatchable RE technologies (wind, solar PV, certain forms of ocean energy), on the other hand, will pose additional challenges to electrical power systems at higher penetration levels.

There is already significant experience in operating electrical power systems with large amounts of renewable sources (e.g., 2008 figures on an energy basis are: Iceland 100%; Norway 99%; Austria 69%; New Zealand 64%; and Canada 60% (IEA, 2010b)). High percentages of

4 www.sse.com/PressReleases2011/FirstElectricityGeneratedGreaterGabbardWalney/.

5 It is worth noting that older wind technologies provided this response inherently, although not as well as synchronous generation (see Mullane and O'Malley, 2005).

6 CSP without additional storage is partially dispatchable and with several hours of storage can be considered dispatchable.

renewable electricity generation generally involve dispatchable renewable sources, in particular hydropower and geothermal (e.g., 2008 figures on an energy basis are: Norway 99% hydro; Iceland 75% hydro and 25% geothermal (Nordel, 2008)). Large shares of bioenergy are not so common in electrical energy systems, but Finland produces 11% of its electrical energy from bioenergy (Statistics Finland, 2009). A number of other countries have managed operations with more than 10% of annual supply coming from wind energy. In addition, integration studies provide insight into possible options for future systems to cope with higher penetration of partially dispatchable renewable sources.

This subsection addresses the integration of RE in three ways. First, it discusses actual operational experience with RE integration. Second, it highlights RE integration studies that have evaluated the potential implications of even higher levels of RE supply. Finally, it discusses the technical and institutional solutions that can be used to help manage RE integration concerns. This section has a focus on the developed world as this is where most experience and studies exist to this point. Autonomous systems are covered here to a degree, while issues associated with such systems are covered in a more dedicated fashion in Section 8.2.5.

Integration experience

It is useful to distinguish between experience with RE generation plants that can be dispatched (hydro, bioenergy, geothermal, CSP with storage) and variable renewable sources that are only partially dispatchable (wind, solar PV, and certain types of ocean energy).

Dispatchable renewable sources (bioenergy, CSP with storage, geothermal, hydro)

Experience from biopower plants is similar to that from fossil fuel thermal power plants in power system operation. As the plants are, at least in principal, dispatchable they can also offer flexibility to the power system. Even with CHP plants there are ways to operate the plants so that the electricity production is not totally dependent on the heat load. In Finland, for example, the larger plants use back pressure turbines equipped with auxiliary condensing units making it possible to maintain efficient electricity production even when heat load is low (Alakangas and Flyktman, 2001). Experience from Denmark shows that when operating with thermal storage, small biopower CHP plants can provide electricity according to system needs (market prices) and thus help in providing flexibility (Holttinen et al., 2009).

A renewable integration cost report from California, analyzing real data from CSP plants from 2002 to 2004 shows consistently high generation during peak load periods given the natural tendency of solar generation to track demand that is largely driven by cooling loads. The auxiliary natural gas boilers on some of the CSP plants in the studied region augmented solar generation during the peak demand periods. The variability and ramping of the CSP plants was reported to be of the same (relative) magnitude as for wind power (Shiu et al., 2006).

Adding new geothermal resources has often meant extending the transmission network and thus infrastructure investments. For example, in New Zealand the construction of a 220 kV double circuit is planned to facilitate development of geothermal generation (up to 800 MW) in the North Island of New Zealand (TransPower, 2008; W. Brown, 2010). Geothermal resources typically produce power (and heat) on a stable basis and there is considerable experience with their use, mostly operating like base load units (Shiu et al., 2006). In California, the existing geothermal generation was assessed for integration impacts based on real output data from the years 2002 to 2004 and was found to impose a very small regulation cost. Because of the very low forced outage rates for geothermal units (0.66%) and low maintenance rates (2.61%) during the 2002 to 2004 period, geothermal plants were also able to provide more capacity credit to the system than the benchmark units (Shiu et al., 2006).

Adding new hydropower resources has meant extending the transmission network and thus required network investments. Examples include northern Sweden, northern Italy, the USA, and northern Quebec, Canada (Johansson et al., 1993) and more recently in China (X. Yang et al., 2010). The large seasonal and interannual variability of hydropower is usually tackled by building large reservoirs where possible. Aggregation of different regions can help in smoothing hydro resource variability, since the changes over weeks and years are not exactly the same in neighbouring areas. The experience from Nordic countries (Sweden, Norway, Finland, Denmark) shows that the large differences in inflow between a dry and a wet year (up to 86 TWh (309 PJ) when mean yearly hydro production is 200 TWh (720 PJ)) can be managed with strong interconnections to the large reservoir capacity of 120 TWh (432 PJ) in Norway and Sweden and thermal power availability in Finland and Denmark (Nordel, 1996, 2000). Interconnection to neighbouring systems has been shown to have a large impact on the way hydro is used, since it influences the plant mix and thus changes hydro scheduling (Gorenstin et al., 1992).

The operational cost of hydropower plants is very low; the challenge for scheduling is to use the limited amount of water as efficiently as possible (Sjelvgren et al., 1983). The flexibility of hydropower is often used as an effective balancing option in electrical power systems (Pérez-Díaz and Wilhelmi, 2010). Switzerland has a flexible hydro system with both reservoirs and pumping facilities, and that system is currently used for daily balancing in the whole interlinked system including Germany, France and Italy (Ochoa and van Ackere, 2009). The flexibility of hydropower can be observed by comparing the changes in the daily prices in different countries. In hydro-dominated systems the price differences are relatively small since water is easily moved from low price periods to high price periods until the price difference is small (Sandsmark and Tennbakk, 2010). Hydropower is a low cost balancing option for daily load following, as can be seen from the Nordic day-ahead market. Sandsmark and Tennbakk (2010) show that the normalized average hourly prices during working days, 2001 to 2003, varied much less in the

Nordic hydro-dominated system than in Germany where thermal power is used for balancing.

Partially dispatchable renewable sources (solar PV, ocean, wind)

Partially dispatchable renewable sources pose greater challenges to system operators. In essence these sources of generation cannot be fully controlled (dispatched) since they reflect the time-varying nature of the resource. The main way in which they can be controlled is through reduction of the output. This is in contrast to dispatchable generation that can be controlled by increasing or reducing fuel supply.

Solar PV penetration levels remain quite limited despite high growth rates of installed capacity in certain countries. For example, in Germany where active programmes of PV installation have been successful, about 10 GW of PV were installed by the end of 2009, producing 1.1% (6.6 TWh or 23.76 PJ) of German electrical energy in 2009 (BMU, 2010). Local penetration levels of PV are already higher in southern parts of Germany (Bavaria has the largest concentration of installations), however, and reinforcements have been needed in certain distribution networks, mainly in rural areas with weak grid feeders and high local penetration levels. In strong urban grids there has only been a marginal need for grid reinforcement. There is concern that severe grid disturbances with strong frequency deviations can be worsened by large amounts of PV systems (Strauss, 2009). Due to this, the German guideline for the connection to medium-voltage networks requires a defined frequency/power drop for frequencies above 50.2 Hz (BDEW, 2008). Protection systems in distribution grids also have to be adapted to ensure safety (Schäfer et al., 2010). In general, these adaptations and guidelines indicate that it is important that solar PV become a more active participant in electrical networks (Caamano-Martin et al., 2008). In Japan, several demonstration projects have provided experience with technologies related to over-voltage protection through reverse power flow control by generation curtailment and battery control, prevention of islanding (Ueda et al., 2008), and verification of grid stabilization with large-scale solar PV systems (Hara et al., 2009). In the USA, some infrastructure investments have been driven by solar energy. California has approved the Sunrise Powerlink, a 193 km, 500 kV line that will connect high-quality solar areas in the desert (for both PV and CSP plants), as well as geothermal resources, to the coastal demand centre of San Diego (U.S. Forest Service, 2010).

Some initial reports are also emerging that analyze the variability of groups of PV plants (Wiemken et al., 2001; Murata et al., 2009; Hoff and Perez, 2010; Mills et al., 2011). Local weather situations like clouds, fog and snow are factors that cause variability and challenge short-term forecasting. All of these studies, using data from different regions of the world, indicate that the variability of groups of PV plants is substantially smoothed relative to individual sites, particularly for sub-hourly variability. Day-ahead forecast errors using weather prediction models have been shown to provide forecasts with only slightly lower accuracy (still <5% forecast error normalized to installed power) (Lorenz et al., 2010).

Operational ocean energy capacity is effectively in the form of a few individual plants, typically of modest capacity, thus no extensive integration experience with larger installations or collections of plants exists.

The majority of the experience with partially dispatchable RE integration comes from the wind sector (Section 7.5.3.2). West Denmark has a 30% wind penetration and has hit instantaneous penetration levels of more than 100% of electricity demand coming from wind power (Söder et al., 2007). But West Denmark is a small control area that is synchronously well connected to the much larger Continental Europe system. Ireland has a small power system with very limited interconnection capacity to Great Britain. Ireland has an 11% wind energy penetration level (2009) and has coped with instantaneous power penetration levels of up to 50% (EirGrid, 2010b). Section 7.5.3.2 provides further information on the Danish and Irish systems. Spain and Portugal are medium size control areas with relatively weak synchronous connections to the rest of the Continental Europe system. They both have about 15% wind energy penetration and have coped, at times, with 54 and 71% instantaneous power penetration levels, respectively (Estanqueiro et al., 2010). There are also several wind-diesel systems where wind provides a large part of the energy for autonomous systems (e.g., in Alaska, USA, the Cape Verde islands, Chile and Australia (Lundsager and Baring-Gould, 2005)).

Many systems report the need for new grid infrastructure both inside the country/region as well as interconnection to neighbouring countries/regions. Grid planning includes grid reinforcements as well as new lines (or cables) for targeted wind power. Wind power is normally not the only driving force for the investments but it is a major factor (e.g., Ireland (EirGrid, 2008); Germany (Dena, 2010); Portugal, (REN, 2008); Europe (ENTSO-E, 2010); the USA (MTEP, 2008)). In the USA, a lack of transmission capacity to move the wind energy from the best wind resource areas, most of which are remote, to the distant load centres has been clearly identified. A challenge for transmission planning is to resolve the timing conflict of financing for the wind plants needing transmission access (i.e., wind plants can be permitted and constructed in 2 to 3 years while it may take 5 to 10 years to plan, permit and construct a transmission line). Another related issue is the need for cost recovery certainty (see Chapter 11). At the regional level in the USA, Texas has addressed these issues with the establishment of a Competitive Renewable Energy Zone (CREZ) process, which allows transmission to be built and paid for in advance of the construction of the wind plants. The completed CREZ transmission projects will eventually transmit approximately 18.5 GW of wind power. The estimated time of completion is the end of 2013 (CREZ, 2010). This model is being applied to other parts of the USA and is beginning to be explored in Europe. In Portugal, the investments reported for added transmission capacity to integrate wind production have been USD_{2005} 185 million in the period 2004 to 2009 for increasing wind penetration from 3 to 13% (Smith et al., 2010a). The network investment plan for the period 2009 to 2019 is another USD_{2005} 138 million dedicated to the connection of wind and other (comparatively small) independent producers (REN, 2008). China has rapidly become the world's largest market for wind power plant installations, and is therefore also beginning to confront the challenges of transmission and integration. Much of the wind power plant construction is occurring in northern and north-western China, in locations remote from major population centres, and is necessitating significant new transmission infrastructure (e.g., Liao et al., 2010; Liu and Kokko, 2010; Deng et al., 2011). The pace of wind power plant construction has also created a lag between the installation of wind power plants and the connection of those plants to the local grid (e.g., Liao et al., 2010; Deng et al., 2011).

In North Germany, a transitional solution allowing curtailments of wind power was made while waiting for the grid expansion in order to protect grid equipment such as overhead lines or transformers from overloads (Söder et al., 2007). Germany has also changed the standard transmission line rating calculation to increase the utilization of the existing grid. Dynamic line ratings, taking into account the cooling effect of the wind together with ambient temperature in determining the transmission constraints, can increase transmission capacity and/or delay the need for network expansion (Abdelkader et al., 2009; Hur et al., 2010). In the UK, some wind projects accept curtailments in order to lower the connection cost to the (distribution) grid that otherwise would need reinforcements (Jupe and Taylor, 2009; Jupe et al., 2010). Curtailment was particularly high in Texas in 2009 with 17% of all potential wind energy generation within the Electric Reliability Council of Texas curtailed (Wiser and Bolinger, 2010).

Many countries have already experienced high instantaneous wind penetration during low demand situations. Wind power is usually last to be curtailed. However, when all other units are already at minimum (and some shut down), system operators sometimes need to curtail wind power (Söder et al., 2007) to control frequency. Denmark has solved part of the curtailment issues by increasing flexible operation of CHP and by lowering the minimum production levels used in thermal plants (Holttinen et al., 2009). Experience from both Denmark and Spain shows that when reaching penetration levels of 5 to 10%, an increase in the use of reserves can be required, especially for reserves activated on a 10 to 15 minute time scale although, so far, no new reserve capacity has been built specifically for wind power (Söder et al., 2007; Gil et al., 2010). In Portugal and Spain, new pumped hydro is planned to be built to increase the flexibility of the power system, mainly to avoid curtailment of wind power (Estanqueiro et al., 2010). In small power systems such as those on islands, system balancing is more challenging due to a lack of load aggregation (Katsaprakakis et al., 2007). Power system operators have reported challenging situations for system balancing caused by high ramp rates for wind power production during storms when individual wind power plant production levels can drop from rated power to zero over a short time span, due to wind turbines cutting out. Due to aggregation effects, the impact on the power system/control area is often spread over 5 to 10 hours, however, and these events are rare (once in one to three years) (Holttinen et al., 2009).

In Ireland some curtailments have been due to concerns about low inertia (Dudurych, 2010b) and consequently susceptibility to instability in the system due to high instantaneous wind penetration and low system load. Currently, the issue of low inertia is unique to small systems like Ireland and possible solutions are being investigated (EirGrid, 2010b). In order to allow higher instantaneous penetration levels, the capability of wind power plants to provide (some) ancillary services must be improved. Equally, flexible balancing plants that can operate at low output levels and deliver stabilizing services would facilitate high instantaneous penetrations.

Low inertia has not, as yet, caused a problem for larger power systems but is being investigated (Vittal et al., 2009; Eto et al., 2010). Concerns about frequency regulation and stability have resulted in instantaneous penetration limits in the range of 30 to 40% for wind power on some Greek islands, including Crete (Caralis and Zervos, 2007a; Katsaprakakis et al., 2007; RAE, 2007). Frequency control and frequency response requirements associated with integration of Danish wind generation are reported to be virtually nonexistent (Eto et al., 2010) because the contribution of Danish wind generation is comparatively small in the large interconnected Continental Europe and Nordic systems (Denmark is connected to both). Experiences reported by the system operators in the Iberian Peninsula (Spain and Portugal) are consistent with those in Denmark in that no significant frequency impacts have been observed that are the result of wind power variation (Eto et al., 2010).

Formal forecasting methodologies are now implemented by system operators in many countries with high wind penetration (e.g., Denmark, Spain and Germany), with user acceptance/demonstration trials taking place in countries elsewhere (Ackermann et al., 2009; Grant et al., 2009). In Australia, the experience from a real-time, security-constrained, five-minute dispatch spot market, associated derivative and frequency control ancillary services markets, and a fully integrated wind energy forecasting system show that markets can in principle be designed to manage variable renewable sources (MacGill, 2010). Managing the variability and limited predictability of wind power output in China is made more complex by (1) China's reliance on coal-fired generation and the relatively low capacity of more flexible generation sources, especially in the regions where wind development is most rapid; (2) the still-developing structure of China's electricity and ancillary services markets; (3) the limited historical electricity trade among different regions of China; and (4) grid code requirements for wind plant installations that, historically, have been somewhat lenient (e.g., Yu et al. 2011). As a result of some of these factors, wind power plant curtailment has become common, especially in northern China. In Japan, the low flexibility of the power system has led to the development of certain options, such as requiring batteries in wind farms to reduce the night time variability (Morozumi et al., 2008).

There are short- and longer-term impacts of wind energy on wholesale electricity prices (Section 7.5.3.1). In Denmark, the Nordic electricity market is used for balancing wind power. The system operator balances the system net imbalance during the hour and passes this cost to all generators that have contributed to the imbalance, as balancing costs. Balancing costs for wind power are incurred when there are differences between the wind generation bid into the market (according to forecasts) and the actual production. The balancing cost of Danish wind power from the Nordic market has been approximately USD_{2005} 1.37 to 2.98 per MWh (0.38 to 0.82 USD_{2005}/GJ) of wind energy (Holttinen et al., 2009). The Danish case also shows how interconnection benefits the balancing task: when Denmark is separated from the Nordic market area due to transmission constraints, the prices become very volatile with day-ahead market prices going to zero during windy low-load periods and with balancing prices also being affected (Ackermann and Morthorst, 2005; see also Section 7.5.3.2). There is already some initial experience in Germany and in the Denmark/Nordic market about how wind power impacts day-ahead electricity market prices—during hours with a lot of wind, the market prices are lowered (Munksgaard and Morthorst, 2008; Sensfuß et al., 2008). Other experience shows that wind power will increase the volatility in market prices when there is a high wind penetration in the market (Jónsson et al., 2010). Chapter 7 discusses the short- and longer-term impacts of wind energy on wholesale electricity prices (Section 7.5.3.1).

In Spain, the reliability impact of wind generation of greatest concern has been when network faults (for example short circuits) occur (Smith et al., 2010a). This concern is in part due to the older wind turbines deployed in Spain not being capable of FRT. Large amounts of wind power can therefore trip off the grid because of a short-lived transient disturbance of the grid (voltage drop). This problem has been addressed by new grid code requirements for wind power that have been adopted in many systems (Tsili and Papathanassiou, 2009) (Section 7.5.2.2). Germany has also changed the grid code to require FRT capability from wind turbines as simulated cases showed the possibility of losing more than 3,000 MW of wind power in a rather limited area in North Germany (Dena, 2005; Holttinen et al., 2009). The USA has also adopted a FRT requirement in FERC Order 661-A (FERC, 2005) as have a number of other jurisdictions (see Section 7.5.2.2 for more detail on grid codes for wind energy). The grid codes also require wind turbines to provide reactive power and in some regions also to take part in voltage and frequency control (Söder et al., 2007). Work in Spain has shown that wind power plants can contribute to voltage support in the network (Morales et al., 2008).

In Germany, wind and solar power have already created problematic flows through neighbouring systems (mainly the Netherlands and Poland; Ernst et al. (2010)).

Also of some concern is the possibility of low wind power production at times of high load. However, so far wind power has been built as additional generation and thus no problems with capacity adequacy were reported at least until 2007 (Söder et al., 2007).

Events in Germany in 2006 (UCTE, 2006) suggest that more and better information is needed in the control rooms of system operators, and also at the regional level (Section 7.5.3.2). Indeed, experiences from Denmark, Germany, Spain, Portugal and the USA show that system operators need to have on-line real-time variable renewable generation data together with forecasts of expected production (Holttinen et al., 2009). This can be challenging as variable renewable generation is sometimes from small units and is often connected to the distribution system. In Spain and Portugal, decentralized control centres have been established to collect on-line data and possibly to control smaller variable renewable power plants (Morales et al., 2008; J. Rodriguez et al., 2008). Experience from the USA shows that when most of the generation is connected to the transmission system, this is not as much of a problem, due to the requirement that wind plants provide supervisory control and data acquisition (SCADA) capability to transmit data and receive instructions from the transmission provider to protect system reliability (FERC, 2005).

Experience of a more institutional nature is the processing of large numbers of grid-connection applications that has led to group processing procedures in Ireland and Portugal (Holttinen et al., 2009; EirGrid, 2010a). Also the assessment of grid stability has required model development for wind turbines and wind power plants (Section 7.5.2.1). One high level experience that applies to integrating any form of generation into electrical power systems is the public opposition to overhead network infrastructure (Devine-Wright et al., 2010; Buijs et al., 2011). Evidence of this can be seen in Ireland and Denmark where needed transmission investment (not necessarily related to RE integration) is being opposed vigorously and burial options are being considered (Ecofys, 2008; Energinet.DK, 2008). Burying low voltage distribution networks is common practice, technically not challenging, but is more expensive. Burying high voltage transmission is rare, technically challenging and can be very costly (EASAC, 2009). The related issue of planning and permitting RE technologies is dealt with in detail in Section 11.6.4.

Results from integration studies for variable renewable sources

Numerous studies of RE integration have been undertaken over recent decades. It should be reiterated that integration issues are highly system specific and resource related and consequently there is a wide diversity of results and conclusions. To date most integration studies have focused on increasing levels of wind energy (typically above existing experience). Some recent large-scale studies look at both wind power and other renewable sources like solar and wave energy. There are very few dedicated and comprehensive solar or ocean integration studies, but there are some smaller-scale studies. Some of the results obtained from wind integration studies can also be applied to solar and wave integration.

The specific issues investigated in the wind integration studies vary and the methods applied have evolved over time, with studies building upon the experience gained in previous efforts (Section 7.5.4). Best practices are emerging and models are being improved (Smith et al., 2007; Söder and Holttinen, 2008; Holttinen et al., 2009). The main issues studied are the feasibility of integrating high levels of wind energy, the impact on the reliability and efficiency of the power system and the measures required to facilitate the increased levels of wind energy. Impacts typically considered include: effects on balancing at different time scales (e.g., any increase needed in reserves or ramping requirements); effects on the scheduling and efficiency of other power plants; impacts on grid reinforcement needs and stability; and impacts on generation adequacy and therefore long-term reliability. The large-scale studies briefly outlined below have been selected to illustrate key issues arising from wind integration into electrical power systems.[7] More detail on wind integration at low to medium penetration levels (i.e., <20%) can be found in Section 7.5.4.

A Danish analysis concluded that integration of a 50% penetration of wind power into the electricity system in Denmark by 2025 is technically possible without threatening security of supply (EA Energy Analyses, 2007). To do so would require new power system architectures that integrate local grids and consumers into system operation, coupling power generation, district heating (Section 8.2.2) and transport (Section 8.3.1), together with improved wind power forecasts and optimal reserve allocation. A strong transmission grid with connections to international markets will be needed, supported by a framework for improved international cooperation and harmonized operational procedures. In particular, the international electricity market must efficiently handle balancing and system reserve provisions across borders. Also, demand response would have to play a greater role as wind power penetrations increase (Energinet.DK, 2007; Eriksen and Orths, 2008).

The European Wind Integration Study (EWIS) and TradeWind are the first studies that examined wind integration at a European continental level. EWIS was led by a system operator consortium, and analyzed up to 185 GW of wind in 2015 (EWIS, 2010). TradeWind was led by a wind industry representative organization, the European Wind Energy Association, and analyzed up to 350 GW of wind in 2030 (TradeWind, 2009). Both studies identified the main interconnection upgrades needed (a total of 29 lines for 2015 by EWIS and a total of 42 lines for 2030 by TradeWind) and concluded that those interconnections would bring technical and economical benefits for the system in the short and long term. EWIS results pointed out that significant changes are needed in dispatch and interconnectors will be used more extensively. Additional measures needed to maintain system security include faster protection schemes, more reactive power compensation devices, faster ramping of other plants, and additional protection measures when using dynamic line rating for increasing network capacity. Future wind plants need to be equipped with state-of-the art FRT capability. The joint operation of the European network needs to be better coordinated, and dedicated control centres for renewable sources should be implemented similar to those in Spain (Morales et al., 2008; J. Rodriguez et al., 2008). Large-scale storage and demand side management were not found to bring significant benefits. The costs for upgrading the network for 185 GW wind by 2015 were found to be approximately 5.6 USD/MWh[8] (approximately 1.6 USD/GJ), while the additional deployment of reserves were estimated at 3.6 USD/MWh[8] (approximately 1.0 USD/GJ) (EWIS, 2010). TradeWind calculated the economic benefits of an offshore meshed transmission grid in the North Sea that could connect 100 GW wind power and improve electricity trade across the countries around the North Sea. Finally, the wind power capacity credit was found to be significantly higher when cross border transmission capacity in Europe was increased (TradeWind, 2009).

The U.S. Eastern Wind Integration and Transmission Study (EnerNex Corporation, 2010) examined three scenarios representing alternative build-outs of 20% wind energy, and a single build-out of 30% wind energy. The study found that new transmission would be required for all scenarios to avoid significant wind curtailment. In spite of the diverse locations of wind energy in the various scenarios, there is a common core of transmission that is required in each scenario. The study found that large regional control areas and significant changes in markets, tariffs and operations would be required. New transmission was found to enlarge the potential operating footprint, which decreases loss of load expectation and increases wind capacity credits. The wind capacity credit ranged from 16 to 23% in the lowest of three years, to 20 to 31% in the highest year. Adding new transmission increased the capacity credit of wind power by about 2 to 10 percentage points, depending on the year, scenario build-out and transmission additions.

The US Western Wind and Solar Integration Study (GE Energy, 2010) looks at a large regional electrical power system and finds that 30% wind and 5% "solar energy penetration is operationally feasible provided significant changes to current operating practice are made" (GE Energy, 2010). The changes include greater control area cooperation and sub-hourly generation and interchange scheduling. At penetration levels of 30% all available flexibility from coal and hydropower plants was found to be crucial for the operation of the power system. Up to a 20% penetration level relatively few new long distance interstate transmission additions were required assuming full utilization of existing transmission capacity. Wind was found to have a capacity credit of 10 to 15%, solar PV was 25 to 30% and CSP with six hours of thermal energy storage was 90 to 95%.

High system RE penetrations in the limited capacity and weakly interconnected Irish electricity system are anticipated to give rise to demanding integration challenges. Studies (AIGS, 2008; EirGrid, 2010b) have shown that 42% renewable sources including 34% wind is technically feasible at modest additional cost. Nonetheless, there will be a need for extensive transmission infrastructure development and a complementary flexible generation plant portfolio. Dynamic studies were also identified as a need, and the first stage of these was completed in 2010 (EirGrid, 2010b). It was confirmed that the technical performance of renewable and non-renewable generation to support high levels of renewable generation (mainly wind) is important. Operational limitations for non-synchronous generation, which may alter the fundamental characteristics of the electrical power system, may result in some curtailment of renewable generation but these operational restrictions will not prevent achievement of national targets for RE penetration (i.e., 40% electrical energy). However, these limitations will result in significant

7 Some of the studies also investigate other renewable sources but are dominated by wind.

8 Conversion to 2005 dollars is not possible given the range of study-specific assumptions.

curtailment if higher targets are set (assuming non-synchronous generation technology) and the economic barriers could be very significant. Similar operational limitations have also been reported for other island systems (Papathanassiou and Boulaxis, 2006).

The Hawaii Clean Energy Initiative (NREL, 2010) specifically identifies up to 400 MW of wind energy capacity offshore from Molokai and Lanai that could be brought by undersea cables (AC and/or DC) to Oahu as part of a diversified portfolio of RE technologies. The goal is 40% renewable electrical energy penetration. To accommodate the expected very high instantaneous penetration levels, the thermal generation minimum online level may need to be lowered and ramping capabilities increased. State-of-the-art wind and solar forecasting were also recommended.

There are also some studies on integration of wind in autonomous systems. On some islands, the maximum allowed wind power penetration has been restricted (Weisser and Garcia, 2005). Several studies have shown that this fixed limit does not guarantee system security and in some instances is not necessary. It has also been shown that it is possible to operate the power system of Crete with a high level of wind penetration while maintaining a high level of security when adequate and appropriate frequency and voltage control response from the other units are available (Karapidakis, 2007). Caralis and Zervos (2007b) investigate the use of storage in small autonomous Greek island systems where wind penetration is restricted for operational and dynamic reasons. They found that storage may reduce operational costs.

Many studies have specifically looked at the cost effectiveness of electricity storage to assist in integrating wind (Ummels et al., 2008; Denholm et al., 2010; Holttinen et al., 2011; Tuohy and O'Malley, 2011). Outside of autonomous energy systems, where storage may be more essential (Section 8.2.5), these studies have found that for wind penetration levels of as much as 50%, the cost effectiveness of building new electricity storage is still low when considering the need for wind integration alone due to the relatively higher cost of storage in comparison to other balancing options (excluding hydropower with large reservoirs and some pumped hydro). As and if storage costs decline, a greater role for storage in managing RE variability can be expected.

In general, the higher penetration studies have often been from island systems (Hawaii, Ireland). In such cases, the studies can be and need to be more detailed (AIGS, 2008; EirGrid, 2010b; NREL, 2010). Moreover, island systems (Hawaii, Ireland, Greek islands) are interesting as they can hit large penetrations faster, providing important early lessons for larger electric systems, and frequency control is more challenging. Another important trend, however, has been to study even larger areas in order to capture the impacts of variable renewable sources on a system wide basis, taking into account potentially valuable exchange possibilities (TradeWind, 2009; EnerNex Corporation, 2010; EWIS, 2010; GE Energy, 2010).

A useful attempt has been made to summarize the results of a number of recent wind integration studies (Holttinen et al., 2009). The studies cover different penetrations and systems and exhibit a wide range of results. Important conclusions include:

- Required increase in short-term reserve of 1 to 15% of installed wind power capacity at 10% penetration and 4 to 18% of installed wind power capacity at 20% penetration. The increased reserve requirement was calculated for the worst case (static, not dynamic) and does not necessarily require new investments for reserve capacity; rather generators that were formerly used to provide energy could now be used to provide reserves. The reserve requirements will be lower if shorter time scales are used in operation (gate closure time in markets).

- Increase in balancing costs at wind penetrations of up to 20% amounted to roughly 0.14 to 0.56 US cents/kWh[9] (roughly 0.4 to 1.6 USD/GJ) of wind power produced (see also Section 7.5.4.2). Balancing costs reflect increased use of reserves and less efficient scheduling of power plants. Though there is an increase in balancing costs and less efficient scheduling of power plants, the studies show a significant overall reduction of operational costs (fuel usage and costs) due to wind power even at higher penetration levels. Wind power is still found to lead to emission savings even with the increased integration effort (Denny and O'Malley, 2006; Mills et al., 2009b; Section 7.6.1.3).

- Capacity credit of wind is in the range of 5 to 40% of installed capacity depending on penetration, wind regime and correlation between wind and load (Keane et al., 2011a).

- The cost of grid reinforcements due to wind power is very dependent on where the wind power plants are located relative to load and grid infrastructure. Grid reinforcement costs roughly vary from 0 USD/kW to 378 USD/kW,[9] reflecting different systems, countries, grid infrastructure and calculation methodologies. The costs are not continuous; there can be single very high cost reinforcements. There can also be differences in how the costs are allocated to wind power.

While no large-scale and comprehensive studies have been conducted solely on the integration of solar there is a substantial body of work on the topic appearing in the literature. As PVs are installed predominantly locally, there is the possibility of reducing grid losses to the extent that the production coincides with demand (Wenger et al., 1994; Chowdhury and Sawab, 1996). At higher penetration, however, upgrades may be required to enable power to flow from the distribution feeder back to the transmission system without incurring large losses (Paatero and Lund, 2007; Liu and Bebic, 2008). In addition, voltage rise in distribution grids is an issue for PV integration (Widén et al., 2009). Thomson and Infield (2007), however, show that in a typical urban UK network with a very high PV penetration level (2,160 Wpeak on half of all houses), only small increases in average network voltages occur. Different studies propose solutions in order to avoid grid reinforcement such as

9 Conversion to 2005 dollars is not possible given the range of study-specific assumptions.

decentralized voltage control with reactive power (Braun et al., 2009). This could be performed by the PV inverters themselves (Stetz et al., 2010) or by other measures used for smart voltage control. Besides supporting frequency control and performing decentralized voltage control, other ancillary services could be provided by smart PV inverters. Such inverters can perform filtering/compensation of harmonics and support the fault behaviour of the power system with appropriate FRT capabilities (Notholt, 2008). In Japan, the target for PV is 28 GW in 2020 and 53 GW in 2030, which would supply around 3 and 6% of the total demand, respectively. Several demonstration projects in Japan addressed grid stabilization with large-scale PV systems by controlling PV generation and local demand (Kobayashi and Kurihara, 2009).

In some locations, adding solar PV to the system near demand centres may avoid the need to expand the transmission network. Kahn et al. (2008) illustrates a case in California where adding PV near coastal load centres would negate the need for significant transmission investments when compared with other renewable sources, in particular the transmission built to access solar PV, CSP, and geothermal in the desert described in the previous section. This benefit is likely to depend on local conditions and therefore vary greatly from region to region.

The capacity credit of solar varies in different parts of the world and by solar technology. In some electrical power systems due to high cooling demand at the peak load period, CSP with thermal energy storage can provide a capacity credit comparable to a thermal generator (GE Energy, 2010). The capacity credit for PV and CSP without thermal storage is much more dependent on the correlation of peak demand and the position of the sun (Pelland and Abboud, 2008; Perez et al., 2008; Xcel Energy, 2009; GE Energy 2010). The capacity credit of solar PV will drop as deployment increases (a similar characteristic to wind, see Section 7.5.2.4) due to the high degree of correlation between solar PV plants from the deterministic change of the position of the sun (Perez et al., 2008).

Managing the short-term variability of solar PV will be somewhat similar to that of wind power. The variability of solar PV systems can be considerable in partly cloudy weather and also with fog or snow (Lorenz et al., 2009; Mills et al., 2011). The ramping up and down during morning and evening of solar output, even if highly predictable and sometimes coinciding with load ramping, can also impose a large variation for electrical power systems with large amounts of solar PV energy (Denholm et al., 2009).

At increasingly high penetrations of solar PV and CSP without thermal storage (>10% annual energy production), the net demand (demand less solar production) will become increasingly low during the middle of the day when the sun is shining, while the night time net demand will not be reduced by these solar resources. Power systems with inflexible power plants may find it challenging to provide energy through the night, ramp down during daylight hours and then ramp back up at night. Inflexible electrical power systems are expected to therefore find integrating high levels of PV and CSP without thermal storage difficult without curtailing a significant amount of solar energy production (Denholm and Margolis, 2007).

Limited research exists in the published literature about ocean energy integration, but one review compared the integration of ocean energy with wind energy (Khan et al., 2009). Since there is little or no operational experience with ocean energy, the results are based only on simulations with little real data to validate the results. At an overall system level, however, the variability of ocean energy output is not expected to pose any greater challenges than the variability from wind power. However, short-term output fluctuations of wave energy plants could be greater than those from wind plants. Ocean wave resources are expected to have greater predictability than wind power because estimation of wave characteristics involves reduced uncertainties when compared to wind owing to its slower frequency of variation and direct dependence on wind conditions.

Bryans et al. (2005) explore methods of deployment and control of tidal current, including the down rating of the generator relative to turbine size and operational output reduction, to reduce the capital cost, increase capacity factor and reduce the impact on the grid system. The capacity credit (10 to 20%) and capacity factor (19 to 60%) of tidal current were also quantified. Denny (2009) used an electricity market model to determine the impact of tidal current generation on the operating schedules of the other units on the system and on the resulting cycling costs, emissions and fuel savings. It is found that for tidal current generation to produce positive net benefits for the case study, the capital costs would have to be less than USD_{2005} 560/kW installed, which is currently an order of magnitude lower than the estimated capital cost of tidal current (Section 6.7).

Studies show that combining different variable renewable sources will be beneficial in smoothing the variability and decreasing overall uncertainty. A study undertaken in California, where the system load peak is driven by space cooling demand, shows that the average solar and wind plant profiles when considered in aggregate can be a good match to the load profile and hence improve the resulting composite capacity credit for variable generation (GE Energy Consulting, 2007). It should be noted that the negative correlation between wind and solar in California is not universal; there are many sites where positive correlation exists (e.g., Ireland, where the wind tends to peak in the late afternoon (Hasche et al., 2010). The combination of wind and hydro in British Columbia, Canada, was shown to lead to an improved capacity credit for hydro by using wind power to conserve water stored in the reservoir (Wangdee et al., 2010). Likewise, the independence of wind power and stream flows can reduce the risk of energy deficits in hydro-dominated systems (Denault et al., 2009). Additional analysis specifically on wind-hydro coordination is part of the ongoing IEA Wind Task 24.[10]

An analysis of high penetrations of RE in Denmark found that a mixture of wind, wave and solar power minimizes excess generation of RE. Wind

10 http://www.ieawind.org/Annex_XXIV.shtml

energy consistently contributed 50% of the RE mixture. The wave and solar share changed depending on the overall RE fraction (H. Lund, 2006). The potentials for reductions in variability when combining wave and wind energy have been reported for Scotland (University of Edinburgh, 2006), Ireland (Fusco et al., 2010) and California (Stoutenburg et al., 2010). How much of the reduction in variability is associated with the geographic diversity as opposed to the different resources remains an open question. Similarly, any benefits of technology diversity should be compared to the costs of diversifying the RE mix relative to the cost of a less diverse portfolio.

In summary, the results of integration studies for variable renewable sources vary depending on the system being analyzed, the level and type of renewable sources being considered and the methods and available data used in the analysis. However, some general messages can be drawn from the results. Studies show clearly that combining different variable renewable sources, and resources from larger geographical areas, will be beneficial in smoothing the variability and decreasing overall uncertainty for the power systems. The key issue is the importance of network infrastructure, both to deliver power from the generation plant to the consumer as well as to enable larger regions to be balanced; the options described below all need to be considered using a portfolio approach. There is a need for advanced techniques to optimize the infrastructure capacity required for variable renewable sources that have low capacity factors (Burke and O'Malley, 2010). The requirement to balance supply and demand over all time scales raises the need for access to flexible balancing resources (flexible generation, demand response, storage; NERC, 2010b) as well as the need to use advanced techniques for demand and supply forecasting and plant scheduling (NERC, 2010a). There is also a need for market or other mechanisms to ensure that all the complementary services necessary to balance supply and demand over all time scales are provided at a reasonable cost (Smith et al., 2010b; Vandezande et al., 2010).

Integration Options

The general form of the solutions required to accommodate a high penetration of renewable sources is largely known today. There is already considerable experience operating power systems with large amounts of renewable sources, and integration studies have also offered valuable insights into how high penetrations of renewable sources can be successfully achieved. This section examines in more detail the most important options identified to date. This should not be taken as a complete or definitive list since the future will no doubt open up new options and strategies. In addition, these options should not be viewed as competing in all circumstances, or that focussing on a single option will resolve all issues. Instead, for most electrical power systems, many, if not all of the options considered will be required, although the degree to which each is important may vary from one electrical power system to the next and over time (see Section 8.2.5 for a discussion of the autonomous systems and which of these options may be most appropriate in those circumstances).

Improving network infrastructure

Strengthening connections within an electrical power system, and introducing additional interconnections to other systems, can directly mitigate the impact of variable and uncertain RE sources. With strengthened connections, electrical energy can more easily be transmitted from where it is generated to where it can be consumed, without being constrained by bottlenecks or operational concerns. This argument also holds true for other generation and distributed loads, such that additional transmission may be viewed as of value to the entire system, rather than an integration cost associated with renewable generation. However, with much of this renewable generation being connected at the distribution level in some countries, greater cooperation and transparency will be required between distribution system operators and transmission system operators (Sebastian et al., 2008). Network expansion and refurbishment is an ongoing process to ensure security of supply and economic efficiency and to realize internal energy markets (ENTSO-E, 2010). Operating as part of a larger balancing area, or sharing balancing requirements across electrical power systems, reduces the integration cost associated with renewable generation and reduces the technical and operational challenges. The opportunity then also exists to exploit the geographical diversity of supply from RE sources to reduce net variability and uncertainty. This may also enable a wider range of renewable sources to be accessed, bringing further potential aggregation benefits due to the imperfect correlation between different renewable sources: for example, the concept of bringing together the solar-rich regions of northern Africa and the Middle East with the windy regions of mainland Europe (Pihl, 2009).

While power systems have traditionally employed AC connections to link dispersed generation to dispersed loads, there can be advantages to using DC connections instead (Meah and Ula, 2007). For example, for long point to point transmission lines (>500 km approximately) there will be a capital cost saving, while for underground or sub-sea connections, issues surrounding reactive power requirements are drastically reduced (Velasco et al., 2011). Consequently, DC connections are increasingly seen as attractive for capturing energy from offshore renewable sources, and for creating sub-sea interconnections between neighbouring countries/regions. However, issues surrounding meshed (rather than point-to-point) high voltage DC (HVDC) grids remain to be resolved (Henry et al., 2010). The investments required to put in place such infrastructure will be substantial and the value they add to the system needs to be carefully assessed (EASAC, 2009).

Employing communications technology to monitor and control larger electrical power system areas will enable more efficient use of the network infrastructure and reduce the likelihood of bottlenecks and other constraints. The cost of implementation of a secure and reliable communications and network infrastructure, however, could well be high, depending on previous investment in the networks and the geographical location of potential renewable generator sites relative to the existing network. The variability and uncertainty of some renewable sources may result in local network constraints, but such concerns may be solvable if the renewable (or embedded) generation can provide network support services such as reactive power (Keane et al., 2011b). This capability exists for modern wind generators, although incentives to exploit it are generally lacking (Martinez et al., 2008). Opportunities to realize the potential of flexible AC transmission system (FACTS) devices (which already exist, but have only been installed in small numbers) and other power flow control devices may also develop, as and when system stability issues arise (X.-P. Zhang et al., 2006; Hingorani, 2007; Tyll and Schettler, 2009).

Delivering new network infrastructure will face institutional challenges, in particular to provide incentives for the required transmission investments and to ensure social acceptance of new overhead lines or underground or sub-sea cables (see also Sections 11.6.4, 11.6.5 and 8.2.1.3). Investment in new transmission is, for example in Europe, the business of transmission system operators who recover their costs through transmission usage system charges. In some situations it is possible to divide the costs between different stakeholders. An effective framework should anticipate the need for transmission upgrades, so as not to inhibit investment in desirable new generation capacity (renewable or otherwise). Public opposition to new transmission lines can develop, traditionally linked with visual impacts (Devine-Wright et al., 2010), environmental concerns and the perceived impacts of electromagnetic fields on human health (Buijs et al., 2011). Underground cables are an available, but not necessarily preferable, option to alleviate such problems: cable reliability and maintenance concerns are potentially higher, and the investment cost will be much higher. With long underground connection distances (i.e., over 50 km approximately), DC will be the preferred technology (Schultz, 2007).

Increased generation flexibility

Thermal generation provides most of a power system's existing flexibility to cope with variability and uncertainty, through its collective ability to ramp up, turn down and cycle as needed (Troy et al., 2010). An increasing penetration of variable renewable sources implies a greater need to manage variability and uncertainty, and so greater flexibility is required from the generation mix. This can imply either investment in new flexible generation or improvements to existing power plants to enable them to operate in a more flexible manner. Retirement of existing inflexible generation may further accelerate this process, whereas the use of storage hydropower has been found to facilitate operational integration. Thermal power plants can be designed or retrofitted to ramp up and down faster and more frequently, but this will in general have a cost, both in capital and operational terms (Carraretto, 2006). A challenge is to achieve all of these aims in such a way that unit efficiency is not lowered so much that costs and emissions are significantly increased (Denny and O'Malley, 2006). Variable renewable generators can also be a focus for a degree of flexibility, for example limiting the rate at which they increase their output, and providing local voltage support for the network. Such capabilities are increasingly standard for wind generation (Z. Chen et al., 2009), but much less so for other variable renewable technologies. Increasing the flexibility of the generation fleet can occur progressively as power plants are modernized and investors see the need for more flexible operation to better respond to system or market needs. A significant future issue will be that as more variable generation comes online, dispatchable generation may be displaced thus reducing the amount of flexibility available. Ensuring that future power plants can maintain stable and profitable operation at output levels lower than at present will help to address this concern, but system operators will need to carefully monitor the dynamic stability of the power system to ensure safe and secure system operation.

In parallel with increasing targets for RE sources in electrical power systems across the world, it should also be noted that non-renewable options for low carbon generation, such as nuclear and fossil fuel with CCS are also in active development. With technology choices being made for economic, technical, social and political reasons, RE generation must recognize factors that may help, or in some cases hinder, future growth. For example, deployment of newer technologies such as integrated gasification combined cycle (IGCC) with carbon capture and sequestration and further deployment of nuclear technology (fission and also possibly fusion in the distant future) could have impacts on RE integration. These technologies may, for example, lack the required flexibility to help integrate variable renewable sources (Q. Chen et al., 2010), meaning that high penetrations of both RE and IGCC/CCS or nuclear may pose special integration challenges.

Synergies and connections also exist between the electricity sector and other energy sectors, so, for example, combining electricity and heat allows for greater flexibility in the electricity side as thermal storage options are already cost effective (Kiviluoma and Meibom, 2010). RE will also have impacts on the dispatch of gas deliveries in the systems where it is mainly gas power plants that react to increasing flexibility needs (Qadrdan et al., 2010).

Demand side measures

Flexible elements of demand, such as remotely switched night storage heating (Fox et al., 1998), have long been used, and often with good cost efficiency (Buckingham, 1965), to aid system operation. However, implementations tend to be proprietary in nature, installed over small geographical areas and with limited demand controllability actually offered. The development of advanced communications technology, with smart electricity meters linked to control centres, offers the potential to access much greater levels of flexibility from demand. One of the key opportunities is to make domestic demand flexible. Through pricing electricity differently at different times, and in particular higher prices during higher load periods, electricity users can be provided with incentives to modify and/or reduce their consumption. Such demand side management schemes, in which individual discretionary loads respond to price signals and/or external response 'request' signals, are seen as having a large potential (Brattle Group et al., 2009; Centolella, 2010). Thermal loads are ideal and include air conditioning, water heating, heat pumps and refrigeration, since the appliance can be temporarily switched on/off without significant impacts on service supply due to intrinsic energy storage (Stadler, 2008). Water desalination, aluminium smelting, ice production, production line inventory, oil extraction from tar sands and shale deposits etc. can offer a similar flexibility (Kirby, 2007; Kirby and Milligan, 2010). Commercial entities may be particularly attractive, as installations will tend to be larger (load served), they are more likely to participate in schemes that deliver cost savings and they may be more willing to invest in necessary equipment. Electric vehicles represent an emerging load, but uncertainty exists about public uptake, battery performance and daily charging patterns. Vehicle battery charging, or even vehicle battery discharging, is potentially a further example of a discretionary load that can be controlled to assist in daily electrical power system operation (Kempton and Tomic, 2005).

All forms of demand side management require consumer engagement, in terms of changes in behavioural patterns, social acceptance and privacy/security issues. The implications of these various factors are not fully understood at present and more research is required. In addition, the amount of peaking plant that can be replaced by demand side measures is not fully understood (Earle et al., 2009; Cappers et al., 2010). Furthermore, a market or incentive system is required. Real-time electricity pricing (or some approximation) may be more widely adopted, whereby the electricity cost to the user more accurately reflects the cost of supply. However, demand side schemes are required that not only enable consumers to participate but actively encourage such behaviour, and correctly allocate charges and payments where required.

Although demand side measures have historically been implemented to reduce average demand or demand during peak load periods, demand side measures may potentially contribute to meeting electrical power system needs resulting from increased variable renewable generation. The low capacity credit of some types of variable generation, for instance, can be mitigated through demand side measures that reduce demand during peak load periods (Moura and de Almeida, 2010). Additionally, demand that can quickly be curtailed without notice during any time of the year can provide reserves (Huang et al., 2009), which have the potential to reduce electrical power system costs and emissions associated with short-term balancing of variable generation (Strbac, 2008; GE Energy, 2010). Demand that is flexible and can be met at anytime of the day can also participate in intra-day balancing, which mitigates day-ahead forecast errors for variable generation (Klobasa, 2010). Demand that responds to real-time electricity prices, on the other hand, may mitigate operational challenges for thermal plants that are expected to become increasingly difficult with variable generation, including minimum generation constraints and ramp rate limits (Sioshansi and Short, 2009). Challenges with managing electrical power systems during times with high wind generation and low demand, meanwhile, may be mitigated to a degree with demand resources that can provide frequency regulation (Kondoh, 2010). Off-peak electrical vehicle charging increases electrical demand and may reduce curtailment of variable renewable generation in high penetration scenarios (Lund and Kempton, 2008; Kiviluoma and Meibom, 2011).

The economic viability of any of these demand side measures should be evaluated relative to meeting the system needs with other resources, including renewable resources. Ultimately, however, accessing the flexibility of demand to mitigate variable renewable resources will depend on the integration of the demand side into system planning, markets and operations along with adequate communication infrastructure between power system operators and load aggregators/customers. It will also be necessary to engage, inform and provide incentives to users to participate in such schemes.

Demand side participation may have a particular role in small autonomous systems where there is limited access to other balancing resources.

Energy storage

At any given time, the amount of energy stored at plants in the form of fossil fuels or water reservoirs is large (Wilson et al., 2010). The amount of energy that can be converted into electricity and then converted back into stored energy, called electricity energy storage, is currently much more modest. The most common form of large-scale electrical energy storage is the mature technology of pumped hydro storage. Since the first pumped hydro storage plant was built in the late 1920s, over 300 plants with approximately 95 GW of pumped hydro capacity have been built in the world (Deane et al., 2010). Additionally, two large-scale commercial compressed air energy storage plants have been operating in Germany and the USA since 1978 and 1991, respectively, and a number of additional facilities are being planned or are under construction (H. Chen et al., 2009). Electrical energy storage is used in power systems to store energy at times when demand/price is low (i.e., off peak during the night /weekend) and generate when demand/price is high (i.e., at peak times during the afternoon). In addition, energy storage units can be very flexible resources for an electrical power system, and if correctly designed can respond quickly when needed (Mandle, 1988; Strunz and Louie, 2009). Technologies such as batteries or flywheels that store smaller amounts of energy (minutes to hours) can in theory be used to provide power in the intra-hour timeframe to regulate the balance between supply and demand in microgrids or in the internal network of the energy user (behind the electricity meter). Whether such technologies will be widely deployed will depend on capital costs, cycle efficiency and likely utilization (H. Chen et al., 2009; Ekman and Jensen, 2010). However, coupled with demonstration programs, market rules and tariffs are gradually being introduced to provide incentives for the participation of new technologies (Lazarewicz and Ryan, 2010; G. Rodriguez, 2010). Battery technology is an area of active research, with costs, efficiencies and other factors such as lifetime being improved continuously.

By storing electrical energy when renewable output is high and the demand low, and generating when renewable output is low and the demand high, the curtailment of RE will be reduced, and the base load units on the system will operate more efficiently (DeCarolis and Keith, 2006; Ummels et al., 2008; Lund and Salgi, 2009; Denholm et al., 2010; Loisel et al., 2010; Tuohy and O'Malley, 2011). Storage can also reduce transmission congestion and may reduce the need for, or delay, transmission upgrades (Denholm and Sioshansi, 2009). In autonomous systems, in particular, storage can play a particularly important role (Section 8.2.5).

When using storage to assist the integration of variable generation, storage should be viewed as a system asset to balance all forms of variability, including demand variations, as opposed to dedicating a storage unit to a single variable source. It is generally not cost effective to provide dedicated balancing capacity for variable generation in large power systems where the variability of all loads and generators is effectively reduced by aggregation, in the same way as it is not effective to have dedicated storage for outages of a certain thermal power plant, or to have specific plants following the variation of a certain load.

Market prices or system costs should determine how the storage asset is best used. The value of storage depends on the characteristics of the power system in question: its generation mix; its demand profile; connectivity to other systems; and the characteristics of the variable renewable generation plant (Tuohy and O'Malley, 2011). This is true for all power systems, including small autonomous systems (Caralis and Zervos, 2007a; Katsaprakakis et al., 2007). Storage must ultimately compete against increased interconnection to other electrical power systems, greater use of demand side measures, and the other options outlined here (Denny et al., 2010). The most effective choice is likely to be system specific and the economics will be affected by any specific electricity market incentives. Large-scale development of energy storage at the present time, however, remains questionable due to the generally high capital cost and inherent inefficiency in operation, unless these costs and inefficiencies can be justified through a reduction in curtailment, better use of other flexible resources or more efficient operation of the system more generally (DeCarolis and Keith, 2006; Ummels et al., 2008; GE Energy, 2010; Nyamdash et al., 2010; Tuohy and O'Malley, 2011). At the same time, storage technologies have attributes that have not, to this point, been fully valued in all electricity markets. For example, storage technologies that can provide ancillary services and very fast injections of energy for short periods of time may be able to provide virtual inertia particularly on isolated or weakly connected power systems (Wu et al., 2008; Delille et al., 2010). As these additional benefits are valued and as storage costs decline, the role of electrical storage in balancing supply and demand and assisting in RE integration is likely to increase.

Improved operational/market and planning methods

Existing operational, planning and electricity market procedures are largely based around dispatchable generation and predictable load patterns. The software tools that support these activities are largely deterministic in nature. In order to cope with increased penetrations of variable and uncertain generation, however, there is a greater need to identify sources of flexibility in operating the system, to develop probabilistic (rather than deterministic) operations and planning tools (Bayem et al., 2009; Papaefthymiou and Kurowicka, 2009) and to develop more advanced methods to maintain the electrical stability of the electrical systems. More fundamentally, real-time operations and long-term planning have traditionally been viewed as separate, decoupled activities. With high renewable penetrations, the two processes must come closer together such that a system is planned that can actually be operated in an economic and reliable manner (Swider and Weber, 2007).

To help cope with the variability and uncertainty associated with variable generation sources, forecasts of their output can be combined with stochastic unit commitment methods to determine both the required reserve to maintain the demand-generation balance, and also the expected optimal unit commitment (Meibom et al., 2011). This ensures less costly, more reliable operation of the system than conventional techniques. Wind (generation) forecasting systems have been developed that include ensemble probabilistic forecasting, and the technology is reaching maturity, with high forecast accuracies now achievable (NERC, 2010a Giebel et al., 2011). Forecasting systems for other variable RE sources (e.g., wave and solar) will need to be developed in parallel with commercial implementation of the devices. In addition, future forecasting systems, for all renewable sources, must include the ability to adequately predict extreme conditions, persistent high or low resource availability and exceptional power ramp rates (Greaves et al., 2009; Larsen and Mann, 2009).

Moving to larger balancing areas, or shared balancing between areas, is also desirable with large amounts of variable generation, due to the aggregation benefits of multiple, dispersed renewable sources (Milligan et al., 2009). Institutional changes may be required to enable such interaction with neighbouring systems and electricity markets (e.g., policies on transmission pricing), with the underlying assumption that adequate interconnection capacity is in place. The creation of the European Network of Transmission System Operators for Electricity as the first continental transmission system operators association with legal obligations to establish binding rules for cross-border network management and a pan-European grid plan follows this principle. Similarly, by making decisions closer to real time (i.e., shorter gate closure time in markets) and more frequently, a power system can use newer, more accurate information and thus dispatch generating units more economically (TradeWind, 2009; EWIS, 2010; Weber, 2010). Using a higher time resolution (intra-day, with resolutions of five minutes or less) provides a better representation of variability and the required balancing (Milligan et al., 2009), and so also enables more optimal decisions to be made closer to real time. In addition, institutional or electricity market structures must evolve such that they can quantify the flexibility requirements of the power system, and put measures in place to reward it (Arroyo and Galiana, 2005). In addition, reduced utilization of thermal generation may require an examination of market mechanisms to reduce investor risk (e.g., capacity payments, longer-term contracts) (Newbery, 2005, 2010).

Advanced planning methods are also required to optimally plan the upgrade and expansion of the electrical networks to ensure that variable generation can be connected in an efficient manner, especially considering the large geographical and remote areas that will sometimes be involved. Methods should ensure best usage of the existing transmission and distribution networks, as well as the best locations for upgrades or extensions (Keane and O'Malley, 2005). Planning methods should also move from 'snapshot' type studies, where the times of greatest system risk are well known, towards studies that consider the variable nature of renewable generation, recognizing correlations between different renewable sources and daily/seasonal patterns, and how this can cause risk at different times throughout the year (Burke and O'Malley, 2010). New metrics, similar to those already used in long-term resource planning, also need to be developed to ensure that sufficient short-term flexibility is planned for (NERC, 2009; Lannoye et al., 2010). This will require an understanding of the variability and uncertainty that variable renewable sources bring to different time scales, and how these increase the existing load variability and uncertainty in the short and long term (capacity adequacy). Detailed modelling of all sources of flexibility will be required, including generation and demand response, such that planning studies reflect the operational potential (NERC, 2010b,c).

On-line stability analysis tools must also be developed to ensure that the electrical power system is secure and robust against plausible eventualities (Dudurych, 2010a; P. Zhang et al., 2010), with optimal network configurations determined, and system recovery strategies identified in advance. Effective operation and management of the potentially large numbers of generation units will be very challenging and require a sophisticated information and communication infrastructure (J. Rodriguez et al., 2008). The emergence of more sophisticated network monitoring and control, coupled with demand side management and storage options, will ease the integration of RE sources into electrical power systems, but the control systems and decision-making systems required to monitor and manage the resulting complexity at both the distribution network level and transmission network level remain to be developed.

Summary and knowledge gaps:

RE can be integrated into all types of electrical power systems, from large interconnected continental-scale systems to small autonomous systems. System characteristics including the network infrastructure, demand pattern and its geographic location, generation mix, control and communication capability combined with the location, geographical footprint, and variability and predictability of the renewable resources determine the scale of the integration challenge. As the amounts of RE resources increase, additional electricity network infrastructure (transmission and/or distribution) will generally have to be constructed. Time variable renewable sources, such as wind, can be more difficult to integrate than non-variable renewable sources, such as bioenergy, and with increasing levels maintaining reliability becomes more challenging and costly. These challenges and costs can be minimized by deploying a portfolio of options including electrical network interconnection, the development of complementary flexible generation, larger balancing areas, sub-hourly markets, storage technologies and better forecasting and system operating and planning tools.

Parallel developments such as a move towards the use of electric vehicles, an increase in electric heating (including heat pumps), demand side control through the use of smart meters and thermal generation are providing complementary physical flexibility and together with the expansion of renewable power generation are driving dramatic changes in electrical power systems. These changes also include altered institutional arrangements including regulatory and market mechanisms (where markets exist), in particular those required to facilitate demand response and that reward the desired electrical power system portfolio. In addition, should variable RE penetration levels increase, deployment could increase in both developed and developing countries and the range of technologies could become more diverse (for example, if ocean energy technologies become competitive).These changes and developments lead to several gaps in our knowledge related to integration options that may become important in the future, including:

- Fundamental characteristics of future power systems due to wide spread deployment of non-synchronous generation, aspects of which were explored in EirGrid (2010b);
- Protection and interoperability of meshed HVDC networks, relevant for the connection of offshore wind and ocean energy (Henry et al., 2010);
- Changes to protective relaying to ensure system reliability and safety (Jenkins et al., 2010);
- New probabilistic methods for planning in the context of high proportions of variable stochastic generation (Bayem et al., 2009);
- Greater understanding of inter-area constraints and operational challenges (GE Energy, 2010);
- Changes in the non-renewable generation portfolio (e.g., impact of retirements, flexibility characteristics and the value of possible fleet additions or upgrades) (Doherty et al., 2006);
- Quantification of the potential for load participation or demand response (McDonough and Kraus, 2007) to provide the grid services needed to integrate RE (Sioshansi and Short, 2009; Klobasa, 2010);
- Impacts of the integration of the electricity sector with other energy sectors (Lund and Kempton, 2008);

- Integration needs in new and emerging markets that differ from those in which variable renewable sources have been integrated in the past (e.g., China);

- Benefits and costs of combining multiple RE resources in a complementary fashion (H. Lund, 2006); and

- Better market arrangements for variable renewable and flexible sources (Glanchant and Finon, 2010; Smith et al. 2010b).

8.2.2 Integration of renewable energy into heating and cooling networks

Heating, cooling and hot water account for a large share of energy use, particularly in the building and industry sectors. These energy services can be provided by using a range of fuels and technologies at the individual building level (Section 8.3.2) as can process heat and refrigeration for individual industries (Sections 8.3.3 and 8.3.4). District heating and cooling (DHC) is the alternative approach and this section deals with RE integration into such distribution networks.

8.2.2.1 Features and structure of district heating and cooling systems

DHC networks enable the carrying of energy from one or several production units, using multiple energy sources, to many energy users. The energy carrier, usually hot or cold water or steam, is typically pumped through underground insulated pipelines to the point of end use and then back to the production unit through return pipes. The temperatures in district heating (DH) outward pipes typically average 80 to 90°C, dropping to 45 to 60°C in return pipes after heat extraction. Heat exchangers are normally used to transfer the heat from the network to a hydronic heating system with radiators or to a hot water system (Werner, 2004).

Heat and CHP production have historically been dominated by oil and coal but, after the oil crises in the 1970s, oil was replaced by other fuels in most systems. In Western Europe, where DH systems commonly occur, the most popular fuels are natural gas and coal, although oil and biomass (Section 2.4; Figure 2.8) are also used. Coal still dominates in China and Eastern Europe. Waste heat from industrial processes, heat from waste incineration, geothermal heat and solar heat are feasible alternatives but less commonly used (Oliver-Solà et al., 2009).

Large DHC systems offer relatively high flexibility with respect to the energy source. Centralized heat production in DHC facilities can use low quality fuels often unsuitable for individual boilers and furnaces in buildings.[11] They also require pollution control equipment. Improved urban air quality and the possibility to cogenerate heat and electricity at low cost were, and still are, important motivations for DH (IEA, 2009c).

A good example of a central DHC plant is in Lillestrøm, Norway (Figure 8.3). It uses several energy sources, including a heat pump based on sewage effluent, to deliver heat and cold to commercial and domestic buildings. This system, and other DHC systems generally, includes an accumulator tank for hot water storage to even out fluctuations in demand over the day(s) to facilitate more stable production conditions (Section 8.2.2.4). The total investment is estimated to be around USD_{2005} 25 million with completion planned in 2011.

Different production units dispatch heat in optimal ways to meet the varying demand (including the use of dedicated fast-response boilers and storage to meet peak demand). Higher overall system efficiencies can be obtained by combining the production of heat, cold and electricity and by using diurnal and seasonal storage of heat and cold. Using heat and cold sources in the same distribution network is possible and the selection of conversion technologies depends strongly on local conditions, including demand patterns. As a result, the energy supply mix varies widely between different countries and systems (Werner, 2006a).

DHC systems can be most economically viable in more densely populated urban areas where the concentration of heating and cooling demand is high. DHC schemes have typically been developed where strong planning powers exist and where a centralized planning body can build the necessary infrastructure, such as centrally planned economies, American university campuses, countries with utilities providing multiple services as in Scandinavia, and urban areas controlled by local municipalities. Urbanization creates opportunities for new or expanded DHC systems, as demonstrated on a large scale in China (Section 8.2.2.6). Development of DHC systems in less dense or rural areas has been restricted by the relatively high costs of distribution and higher heat distribution losses (Oliver-Solà et al., 2009).

Development and expansion of most DHC systems took place after 1950 in countries with cold winters, but earlier examples exist, such as New York in 1882 and Dresden in 1900. World annual district heat deliveries have been estimated at nearly 11 EJ (Werner, 2004) (around 10% of total world heat demand; IEA, 2010b) but the data are uncertain. Several high-latitude countries have a DH market penetration of 30 to 50%, and in Iceland, with abundant geothermal resources, the share has reached 96% (Figure 8.4).

District cooling (DC) is becoming increasingly popular through the distribution of chilled or naturally cold water through pipelines, possibly using the pipes of a DH network in higher latitudes to carry water to buildings where it is passed through a heat exchanger system. The supply source, normally around 6 to 7°C, is returned at 12 to 17°C (Werner, 2004). Alternatively, heat from a DH scheme can be used during summer to run heat-driven absorption chillers.

11 An example is a DHC in Kalundborg, Denmark (Section 2.4.3) that has several bioenergy components, including a pilot lignocellulosic ethanol plant.

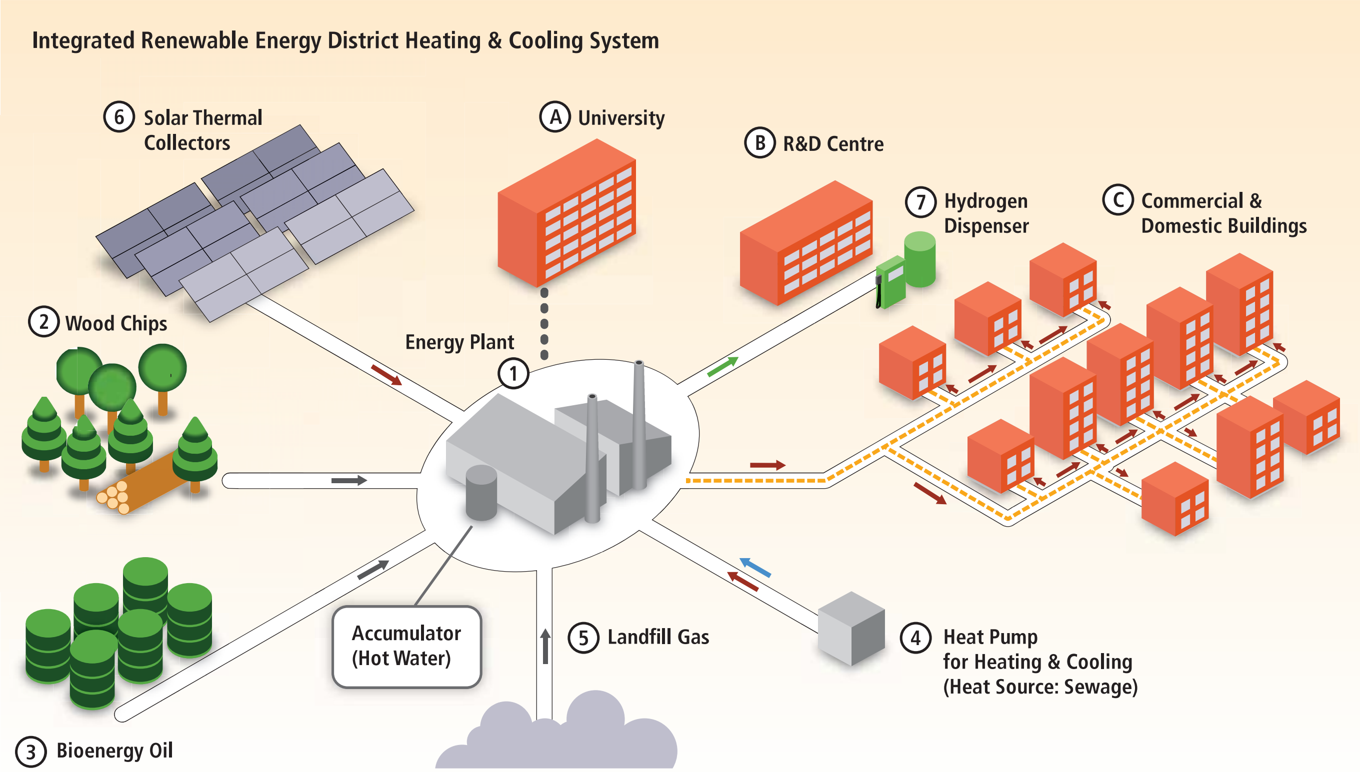

Figure 8.3 | An integrated RE-based energy plant in Lillestrøm, Norway, supplying the University, R&D Centre and a range of commercial and domestic buildings using a district heating and cooling system that incorporates a range of RE heat sources, thermal storage and a hydrogen production and distribution system (Akershus Energi, 2010).

Notes: (1) Central energy system with 1,200 m^3 accumulator tank; (2) 20 MW_{th} wood burner system (with flue gas heat recovery); (3) 40 MW_{th} bio-oil burner; (4) 4.5 MW_{th} heat pump; (5) 1.5 MW_{th} landfill gas burner and a 5 km pipeline; (6) 10,000 m^2 solar thermal collector system (planned for completion in 2012); and (7) demonstration of RE-based hydrogen production (using water electrolysis and sorption-enhanced steam methane reforming of landfill gas) and fuel cell vehicle dispensing system planned for 2011.

Cooling demands in buildings are tending to grow because of increased internal heat loads from computers and other appliances, more stringent personal comfort levels and modern building designs having greater glazed areas that increase the incoming heat levels (IEA, 2007c). Recent warmer summers in many areas have also increased the global cooling demand, particularly to provide greater comfort for people living in many low-latitude, developing countries as their economies grow. Several modern DC systems, from 5 to 300 MW_{th} capacity, have been operating successfully for many years including in Paris, Amsterdam, Lisbon, Stockholm and Barcelona (IEA, 2007d).

8.2.2.2 Characteristics of renewable energy in district heating and cooling systems

Over the past two decades, many DHC systems have been switched from fossil fuels to RE resources, initially in the 1980s to reduce oil dependence, but since then, to reduce carbon dioxide (CO_2) emissions. Centralized heat production can facilitate the use of low cost and/or low grade RE heat sources that are not suitable for use in individual heating systems. These include refuse-derived fuels, wood process residues and waste heat from CHP generation, industrial processes or biofuel production (Egeskog et al., 2009). In this regard, DHC systems can provide an enabling infrastructure for increased RE deployment.

The potential contribution and mix of RE in DHC systems depends strongly on local conditions, including the availability of RE resources. For biomass or geothermal systems it is not a technical problem to achieve high penetration levels as they can have high capacity factors. Hence many geothermal and biomass heating or CHP plants have been successfully integrated into DH systems operating under commercial conditions.

- Woody biomass, crop residues, pellets and solid organic wastes can be more efficiently used in a DH-integrated CHP plant than in individual small-scale burners (Table 2.6). Biomass fuels are important sources of district heat in several European countries where biomass is readily available, notably Sweden and Finland (Euroheat&Power, 2007). In Sweden, nearly half of the DH fuel share now comes from biomass (Box 11.11).

- Near-surface and low temperature geothermal resources are well suited to DH applications. Due to the often lower costs of competing fuels, however, the use of geothermal heat in DH schemes is

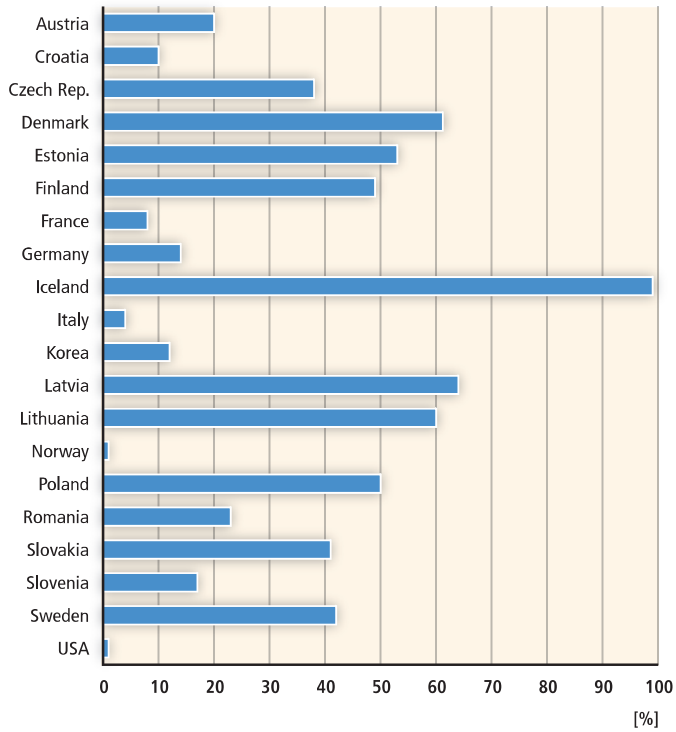

Figure 8.4 | Share of total heat demand in buildings supplied by district heating schemes for selected countries (Euroheat&Power, 2007).

low (with the exception of Iceland), even though the global technical potential of the resource is high (Section 4.2).

- The global installed capacity of solar thermal collectors in 2009 was 180 GW_{th} (Section 3.4.1) but only a small fraction was used for DH (Weiss et al., 2009). Solar thermal DH plants are found mainly in Germany, Sweden, Austria and Denmark (Dalenbäck, 2010). In Denmark, several have large-scale collector areas of around 10,000 m^2 (Epp, 2009). At solar shares of up to 20%, the large number of customers connected to the DH system ensures a sufficiently large demand for hot water even in summer, so that high solar heat yields (~1,800 MJ/m^2) can be achieved. Higher solar shares can be achieved by using seasonal thermal storage systems, for which integration into a DH system with a sufficiently high heat demand is an economic prerequisite. Pilot plants with a solar share of more than 50% equipped with seasonal heat storage have demonstrated the technical feasibility of such systems (Section 8.2.2.6).

Using RE through electricity sources in DH systems in situations with low or even negative electricity prices is possible through heat pumps and electric boilers, with thermal storage also an option (Lund et al., 2010). Through CHP plants, DH systems can also export electricity to the grid as well as provide demand response services that facilitate increased integration of RE into the local power system. Thermodynamically, using electricity to produce low grade heat may seem inefficient, but under some circumstances it can be a better economic option than spilling potential electricity from variable RE resources (Section 8.2.1).

DC systems that utilize natural aquifers, waterways, the sea or deep lakes as the source of cold can be classed as a RE resource. The potential for such cooling is difficult to estimate but many cities are located close to good water supplies that could easily provide a source of cold. Deep water cooling allows relatively high thermodynamic efficiency by utilizing water at a significantly lower heat rejection temperature than ambient temperature (Section 8.2.2.6). Often lake or sea water is sufficiently cold to cool buildings directly, which can, at times, enable the refrigeration portion of associated air-conditioning heat pump systems to be only operated to provide additional cooling when needed. All the excess building interior heat is transferred directly to the water heat sink.

To use RE cooling most efficiently in buildings from a quality perspective, a merit order of preferred cooling can be set up (as can also be done for heating) (IEA, 2007c). The order will differ due to specific local conditions and costs, but a typical example could be to supplement energy efficiency and passive cooling options by including active compression cooling and refrigeration powered by RE electricity; solar thermal, concentrating solar power, or shallow geothermal heat to drive active cooling systems (Section 3.7.2); and biomass-integrated systems to produce cold, possibly as tri-generation. The Swedish town of Växjö, for example, uses excess heat in summer from its biomass-fired CHP plant for absorption cooling in one district, and an additional 2 MW chiller is also planned (IEA, 2009b).

Ground source heat pumps can be used in summer for space cooling (air-to-ground) at virtually any location, as well as in winter for space heating (ground-to-air). They use the heat storage capacity of the ground as an earth-heat sink since the temperature at depths between 15 and 20 m remains fairly constant all year round, being around 12 to 14°C. They are commercially available at small to medium scales between 10 and 200 kW capacity.

8.2.2.3 Challenges associated with renewable energy integration into district heating and cooling networks

To meet growth in demand for heat or cold, and goals for integrating additional RE into energy systems, expansion of existing networks may be required. A DHC piping network involves up-front capital investment costs that are subject to large variations per kilometre depending on the local heat density and site conditions for constructing the underground, insulated pipes. Network capital investment costs and distribution losses per unit of delivered heat (or cold) are lower in areas with high annual demand (expressed as $MJ/m^2/yr$, MW_{peak}/km^2 or GJ/m of pipe length/yr). Area heat densities can range up to 1,000 MJ/m^2 in dense urban, commercial and industrial areas down to below 70 MJ/m^2 in areas with dispersed, single family houses. Corresponding heat distribution losses can range from less than 5% in the former to more than 30% in the latter. The extent to which losses and network costs are considered an economic constraint depends on the cost and source of the heat. Under certain conditions, areas with either a heat density as low as 40 $MJ/m^2/yr$, or a heat demand of 1.2 GJ/m of pipeline/yr, can be economically served by district heating (Zinco et al., 2008).

Energy efficiency measures in buildings and new building designs that meet high energy efficiency standards will reduce the demand for heating or cooling. As more buildings are built or retrofitted with low-energy and energy efficient designs, the total energy demand or density for existing DHC systems may decrease over time. Energy efficiency measures can also flatten the load demand profile by reducing peak heating or cooling demands. In these cases, the profitability of supplying district heat from either new DH plants or extending existing networks would be reduced (Thyholt and Hestnes, 2008). In Norway, Germany and Sweden the competition between low-energy building standards and DH development has received attention by policymakers working to design local or national energy policies (Thyholt and Hestnes, 2008). At the same time, while energy efficiency may be a challenge to the general economic viability of DH due to lower heating densities in the network, it may also facilitate higher shares of RE energy in individual heating systems (Verbruggen, 2006; IEA, 2009b).

The technical and economic challenges of heating and cooling using RE sources are not necessarily associated with the integration of the heat or cold into existing DHC networks that can be injected into a system for few additional costs. The challenges are instead primarily associated with assuring a consistent and reliable resource base from which the heat and cold can be produced.

- Combustion of wood residues or straw fuels can be challenging due to the varying composition of the fuel, the associated additional plant costs for storage and handling, fuel purchase costs and the need for a logistical supply chain to provide reliable supplies of biomass (Section 2.3.2).

- Extraction of geothermal heat is reliable but may entail local environmental impacts (Section 4.5).

- The variable nature of solar energy can be a challenge (Section 3.2) but is partly overcome by thermal storage. If used for DC, the need for diurnal and seasonal storage can be low because peak cooling demands often correlate relatively well with peak solar radiation levels.

In terms of cooling, the distance away from demand of the water to be used as the source of cold may also need costly infrastructure investment in order to integrate with DC systems. When using solar energy or biomass for absorption cooling, the challenges closely reflect those for heating.

In less densely populated areas, or those without a strong, centralized planning body, institutional barriers may pose challenges to developing or increasing the use of DHC, thereby posing indirect challenges to increasing the share of RE in the DHC networks. Constructing new capacity or expanding existing DHC networks usually requires planning consents and coordination of stakeholders and institutions.

8.2.2.4 Options to facilitate renewable energy integration

RE sources can be integrated into existing systems by replacing and retrofitting older production units or incorporating them into the designs of new DHC systems. DHC networks can be constructed or extended where a growing number of customers seek RE supply sources. These can be more cheaply integrated into existing systems at the slow natural rate of capital building stock turnover, or dedicated policies can speed up the grid connection process.

New technological options for heating

As new RE technologies are developed, additional technical options for increasing the shares of RE in DH systems are presented. Fuel switching and co-firing of biomass in existing fossil fuel-fired heat-only or CHP boilers present an option in the near term. The suitability of biomass fuels, their moisture contents, and whether they need to be pulverized or not, depend on the existing boiler design (whether grate, circulating or bubbling fluidized bed).

Heat from geothermal and solar thermal sources can be more readily integrated into existing DH systems. Enhanced geothermal systems (EGS) could be operated in CHP mode coupled with DH networks. The commercial exploitation of large heat flows is necessary to compensate for the high drilling costs of these deep geothermal systems (Thorsteinsson and Tester, 2010). Such a large heat demand is usually only available through DH networks or to supply major industries directly (Hotson, 1997).

Storage options

Heat storage systems can bridge the gap between variable and unsynchronized heat supply and demand. The capacity of a thermal storage system can range from a few MJ up to several TJ; the storage time from hours to months; and the temperature from 20°C up to 1,000°C. These wide ranges are made possible by choosing between solids, water, oil or salt as different thermal storage materials together with their corresponding storage mechanisms.

A hot water storage system design depends on the local geological and hydro-geological conditions, and the supply and demand characteristics of the DHC system. For short-term storage (hours and days) the thermal capacity of the distribution system itself can act as storage (Figure 8.5). Longer-term seasonal storage, usually between winter and summer, is less common. In this case, the main storage options include underground tanks, pits, boreholes and aquifers (Heidemann and Müller-Steinhagen, 2006). With geological storage, relatively small temperature differences are employed. In aquifers, heat may be injected during the