DELIVERABLE 4.0

ROAD MAP TOWARDS A FUTURE ELECTRICITY NETWORK

		YES	NO
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REVISION

A: First draft version of the road map part of D4.1
B: First complete draft
C: Updated with contributions from Imperial College and ETH Zürich
D: Revised following EC Feedback

CONTENTS

FIGURES

TABLES

GLOSSARY

AC	Alternating Current
BAU	Business As Usual (demand and generation scenario)
CBA	Cost Benefit Analysis
CCS	Carbon Capture and Storage (demand and generation scenario)
CHP	Combined Heat and Power
CO_2	Carbon dioxide
CoS	Cost of Security (fulfilment of N-1 criterion)
CSP	Concentrated Solar Power
DC	Direct Current
DES	Desertec (demand and generation scenario)
DSM	Demand Side Management
EFF	Efficiency (demand and generation scenario)
EMF	Electro Magnetic Fields
FACTS	Flexible AC Transmission Systems
G&D	Generation & Demand
GHG	Greenhouse gas
HVAC	High Voltage Alternating Current
HVDC	High Voltage Direct Current
ITC	Inter-TSO Compensation
LCC	Line Commutated Converter
LMP	Locational Marginal Price
MTI	Merchant Transmission Investment
NG	National Grid
OHL	Overhead line
OPF	Optimal Power Flow
PST	Phase-Shifting Transformer
PV	Photovoltaics
RES	Renewables (demand and generation scenario)
RES-E	Electricity from Renewable Energy Sources
SC-OPF	Security-Constrained Optimal Power Flow
SVC	Static VAR compensator
TSO	Transmission System Operator
UHVAC	Ultra High Voltage Alternating Current
VSC	Voltage Source Converter

EXECUTIVE SUMMARY

Scenarios for electricity demand, generation and transmission networks

Europe's electricity systems are in a transition in response to policies aimed at decarbonisation, security of supply and guaranteeing economic competitiveness and affordable energy (EC, 2011c). Especially the target of 80-95% reduction of greenhouse gas emissions by 2050 compared to 1990 levels and the drive towards more cooperation between EU member states for securing security of supply and economic competitiveness, steer the development of Europe's electricity systems and drive the need for adaptation of current electricity infrastructures in different ways. This report provides the IRENE-40 view on likely network infrastructure developments over the coming 40 years and states the stakeholder's actions which have to be implemented to realise a sustainable, secure and competitive electricity system.

The extent to which effects on the electricity network will materialise depends heavily on the development of generation mix and demand in the next decades, which is subject to a large range of unpredictable factors including fuel and CO_2 prices, technology development and the support of renewable energy.

Therefore, as a starting point, within IRENE-40 a number of different electricity generation and demand scenarios have been formulated, which provide a wide range of varying circumstances for networks linking generation and demand. Different, comparable scenarios until 2050 have been made, among others by stakeholders and research organizations like ECF (2010), Eurelectric (2011b) and IEA (2010b).[1] Furthermore, FP7 project Susplan[2] has constructed a couple of scenarios (Joode *et al*. 2011). Below the relative positions of IRENE-40 scenarios with respect to both electricity demand and generation shares in 2050 are summarized.

[1] For more details on these scenario studies the reader is referred to Nieuwenhout *et al*. (2011).

[2] Given the focus on the year 2050, another relevant FP7 project, RealiseGrid, cannot be included in this comparison given its focus on the year 2030.

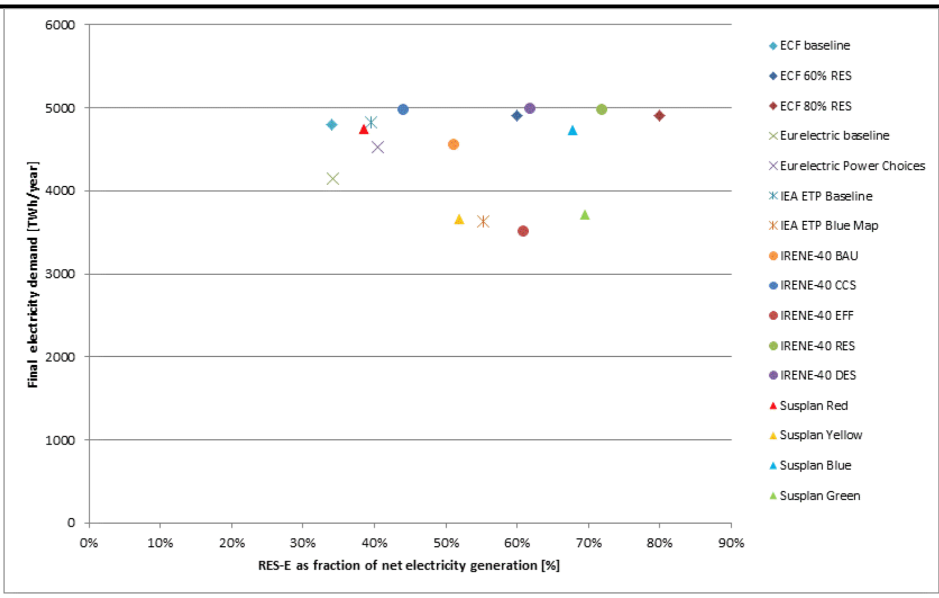


Figure 1 - Share of renewable generation in net electricity generation [%] versus final electricity demand[3]

European CO_2 emission reduction targets are a main driver for long-term energy policy. Four out of five of the IRENE-40 demand and generation scenarios were designed to meet these targets in 2050. Figure 242 shows the expected CO_2 emission reductions relative to the year 2010 for the different G&D scenarios as simulated by the high-resolution network model of RWTH and low-resolution network model of ECN.

Two key findings can be derived from this figure. First, CO_2 emission reductions in 2030 are low (10-30%) in all G&D scenarios, except for the CCS scenario, compared to 2010 figures. According to Eurelectric (2010)[4] the total CO_2 emission from the electricity sector in the EU-27 was more or less flat in between 1990-2010. Therefore the CO_2 reduction percentages as given here for the period starting in 2010 are also valid for the period 1990-2010. Second, although the EC GHG emission reduction targets of 80-95% in 2050 are achieved in the low resolution models, they are not in the high resolution network models. This can be explained by the higher amount of RES curtailment in the high resolution model (see Figure 253), which requires additional regulating power to keep supply and demand in balance. This regulating power emits additional amounts of CO_2 and therefore lowers CO_2 emission reductions.

[3] DES does not include imports of electricity from Northern Africa. If imports are included, IRENE-40 DES is located on the right hand side of IRENE-40 RES.

[4] See Figure 14 of Eurelectric (2010).

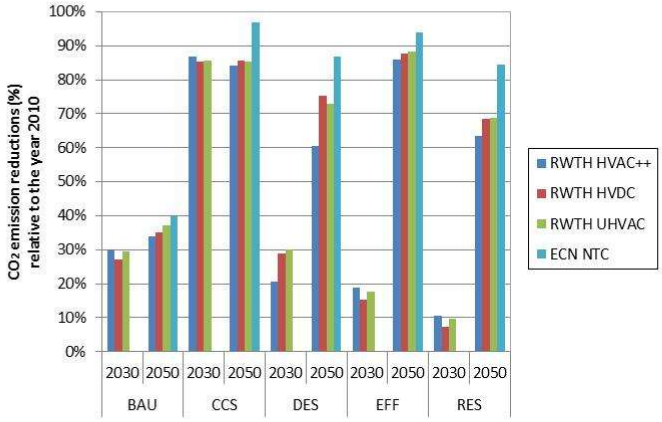


Figure 2 - EU-27+CH+NO CO_2 emission reductions in high (RWTH) and low resolution models (ECN) relative to the year 2010[5]

Figure 3 shows low curtailment levels in 2030 (all generation and demand scenarios show 2% RES curtailment at maximum), while in 2050 much higher RES curtailment levels are realized due to higher network loading. In the ECN and Imperial College models curtailment levels increase up to 4% at maximum in the DES scenario, while in the RWTH analysis curtailment ranges from 10-16% in the RES scenario. This difference is due to the fact that the low resolution models of Imperial and ECN only consider cross-border congestion while in the high resolution model of RWTH, congestion also takes place within countries.

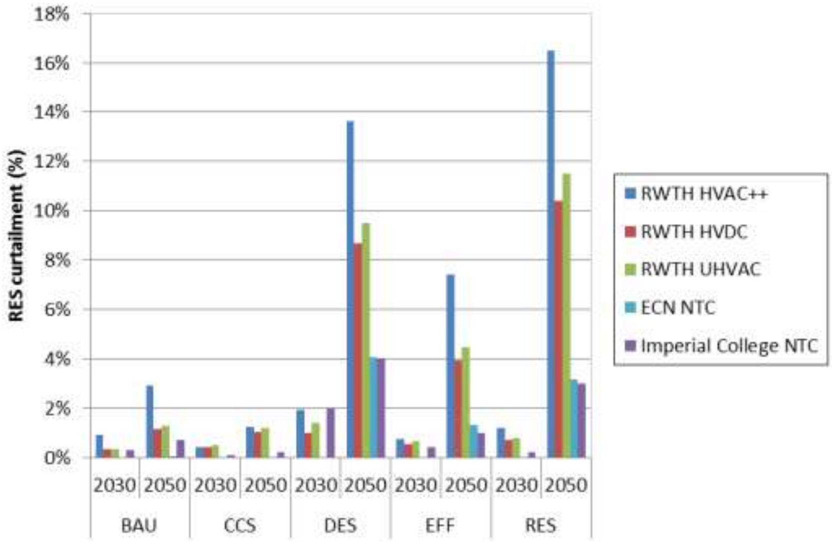


Figure 3 - EU-27+CH+NO RES curtailment in high (RWTH) and low (ECN, Imperial College) resolution network models[6]

[5] ECN figures are only available for the year 2050.
[6] ECN figures are only available for the year 2050.

Figure 4 shows that for the transmission expansion over the period 2020 to 2050, for all generation and demand scenarios, the network investment cost plus the network losses are substantially smaller than the benefits due to lower generation costs. This illustrates that the choice of network expansion after 2020 is robust in a wide range of different demand and generation circumstances.

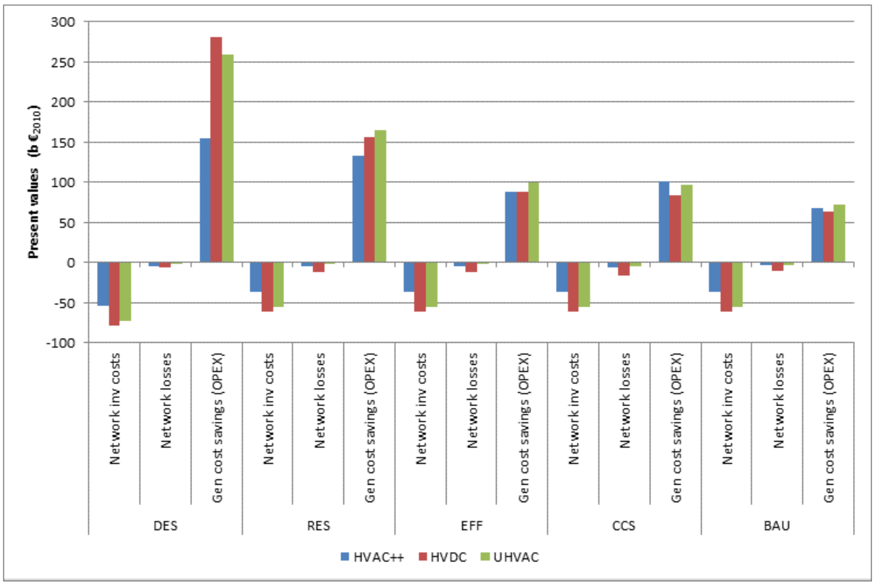


Figure 4- Present Values of benefit and cost items of additional transmission capacity w.r.t. HVAC+ in EU-27+CH+NO

[Source: ECN]

The regret matrix in Table 1 shows the difference of net benefits in 2050 between the network scenario chosen in 2030 and the network scenario which actually gives the maximum benefits in 2050 for the corresponding G&D scenario. By definition, regret is zero if the network scenario chosen in 2030 is the one which gives the maximum net benefits in that particular G&D scenario.

Table 1- Regret of network choice in 2050 under each G&D scenario

Network Choice before 2030	Regret under G&D scenario in 2050 (b€/year)					Maximum Regret
	DES	RES	EFF	CCS	BAU	
HVAC++	-54	-19	-8	0	0	-54
HVDC	0	-3	-5	-11	-5	-11
UHVAC	-11	0	0	-4	0	-11

[Source: Roehder et al. (2012)]

From the above table it can be concluded that the two overlay scenarios, HVDC and UHVAC have the lowest regret cost, and are therefore more robust than the scenario which considers expansion of current HVAC technology. When taking into account also the lower cost of N-1 network security as well as the intrinsic higher level of controllability of electricity flows in HVDC networks, HVDC is the preferred network technology scenario.

Network investment strategies

Lack of investments in the transmission network has repeatedly been identified as one of the main reasons behind the serious problems experienced by power systems all over the world over the past decade. In a restructured market environment, investing in the transmission system can enhance competition and mitigate market power but brings new challenges with respect to encouraging network investments and coordinating the interaction between regulated and commercial parts of the power system. Such challenges are the difficulty in estimating costs and benefits associated with a transmission plan for different stakeholders, the uncertainty related to future generation capacity and location, the higher demand of network flexibility and robustness and the changing power flow patterns due to competition and incorporation of RES. The worldwide investment situation is further complicated under the unbundling environment, since different countries have different organisational structures, resulting in different investment modes. Under this new environment, the definition of criteria that should guide transmission expansion decision-making amid parties with diverse interests is a critical issue, since they may differ between key stakeholders. In Europe, these stakeholders involve: a) the European Commission and policy makers, b) regulators, c) producers and power plant owners, d) consumers, e) transmission operators, owners and network planners, f) private investors, g) manufacturers.

Three network ownership models under EU legislation

To streamline the unbundling process in Europe, three main models for ownership unbundling were proposed under EU legislation: a) full ownership unbundling model (OU); b) independent system operator (ISO); c) independent transmission operator (ITO). The OU model defines separated responsibilities and rights between generation and transmission entities and should be implemented widely in EU member states from 3rd March 2012. Member states whose transmission system belongs to a vertically integrated undertaking and decide not to apply OU should either comply with an ISO or an ITO scheme. Under the ISO scheme, an independent system operator may be designated upon a proposal from the transmission system owner, in a form of ownership unbundling but with a trustee. In this case, an ISO splits the TSO tasks into system operation and ownership and maintenance of the network. As with ownership unbundling, the most important feature of an ISO is that it is independent from any generating or supply assets, which is however proved difficult to define in practice. Under this model the financing of investments decided by the ISO is a responsibility of the transmission system owner. However, problems may arise in the split between the decision maker and risk taker (investor) which can be solved by a “tendered transmission investment”, allowing also third parties to participate in the investment. Finally, under the ITO model, the transmission system operator is the entity which both owns and operates the transmission system. It remains part of a vertically integrated undertaking, but is independent in terms of its branding, decision making and management (legal unbundling). The ITO must have a supervisory body (regulatory authority) in charge of taking decisions which may have a significant impact on the value of the assets of its shareholders. The ITO model is generally acknowledged as a compromise option, inferior to the OU or ISO models.

Merchant transmission investment

Merchant transmission investment (MTI) is often considered as a solution for opening transmission investment to profit-motivated investors and fund it by trading between differently priced markets. In this case investors are attracted by congestion revenues and also by priority access allowing them to earn revenues in an early stage of the projects, thereby decreasing the payback period and the project risk. To address the problem of under-investment especially in cross-border transmission, EU policy is becoming more favourable towards MTI. In the context of IRENE-40 scenarios, the investment strategies of different stakeholders were investigated by studying the installation of HVDC cross-border lines, taking advantage of the controllability they offer. Two different objectives were studied: (a) maximization of the social welfare (referring to the objectives of regulators) and (b) maximization of the revenues of the HVDC line owners (referring to MTI). Under objective (a) an analytical method was developed, which determines the most effective line placement in order to relieve a congestion. This placement serves as an upper bound for the prospective costs of the line installation. Any line which has higher installation costs that this "upper bound" should be discarded as a possible solution. Under objective (b) an agent-based framework was developed, where each agent can decide the location and capacity of the cross-border link. The results show that the agents find it more profitable to install several parallel transmission lines on certain paths that have a high need for transmission capacity, rather than select a transmission path where they can be the sole investor. The specific interconnectors with high potential across the IRENE-40 scenarios were identified and the expected profits were estimated showing a very good fit to the current investment plans (Figure below). It was shown that there is enough room for profitable merchant transmission investments in all possible future generation scenarios, with the potential increasing for scenarios with higher shares of variable generation.

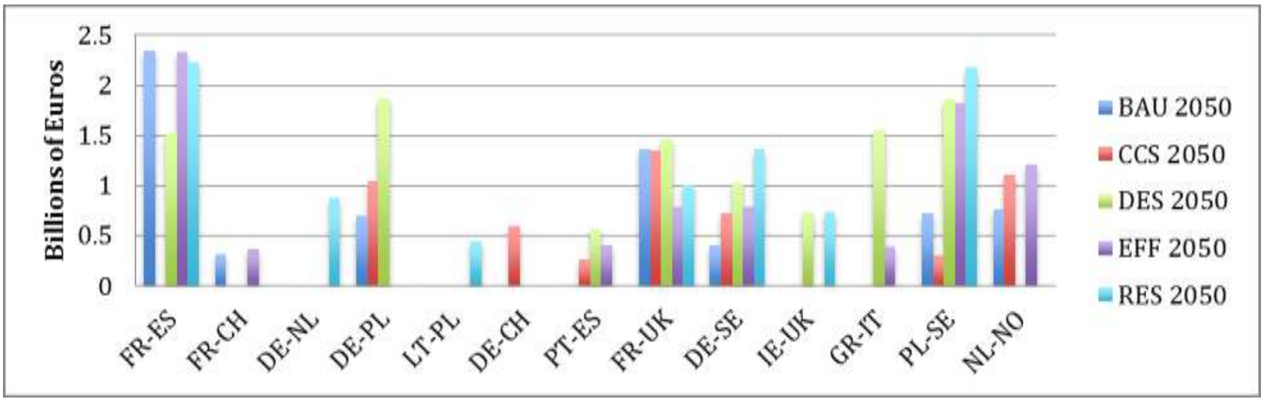


Figure 5 - Comparison of MTI Yearly Revenues per each interconnection (sum of the revenues of all parallel MTI lines installed at each interconnection) and for each generation scenario

Factors influencing network investment strategies

The main factors that influence the transmission system investment strategy were investigated, namely transmission tariffs, inter-TSO compensation schemes, TSO funding schemes, congestion management and regulatory influence. The most often used tariff systems are the postage stamp, the distance related and the nodal pricing system. The postage stamp system is a uniform tariff (price per transported energy unit), independent of the location. It is simple to implement but does not give incentives for efficient use of the grid. Distance related tariffs use flow-mile method rates to estimate costs of transmission based on the distance between generators and customers. However they provide no incentives to ISO for network investments. In the nodal pricing method the network revenues are equal to the transmission rent (TR) which is defined as the difference between what the consumers pay and what the producers are paid. It provides correct economic signals but its main problem is that the TR cannot recover the total transmission network costs. The inter-TSO compensation (ITC) mechanism provides compensation to TSO's for costs incurred as a result of hosting cross-border flows of electricity on their network. ITC is an incentive to encourage investment in the trans-national infrastructures at European level and to stimulate cross-border exchanges, by allocating costs to the countries responsible for the respective transactions. In order to coordinate and optimise network development on a continental scale, four options were brought up by the European Parliament as TSO funding schemes: use of risk sharing (including project bonds and guarantees); use of risk capital (including equity participations); use of grant support for project studies and construction; and a combination of grants, risk sharing and risk capital. Transmission congestion forces the transmission operator to dispatch a sub-optimal set of power plants resulting in higher electricity prices. Therefore congestion rents provide signals for transmission investments. In the market-driven investment process, regulatory agencies still play significant roles. Regulatory processes related to transmission assets can be divided into three parts: planning, approval and pricing. In general, regulatory behaviour on one hand provides incentives to stimulate transmission expansion and improve efficiency, and on the other hand regulates the pricing methodology in order to protect consumers' benefits. However in EU electricity transmission is a regulated business at a national level and the cost allocation to final beneficiaries is difficult for large trans-European infrastructures.

Impacts on the main stakeholders: consumers, producers and network owners

In order to assess transmission investments in the competitive environment, a technical and economic analysis was developed which measures the economic impact that alternative transmission investment decisions cause on different stakeholders, as producers, consumers and network investors, under the pathways described in the IRENE-40 scenarios. The fundamental indicators used to evaluate the economic impact of alternative investment decisions to different market participants include: a) producers' surplus, b) consumers' surplus, c) congestion surplus and d) welfare. Energy trade between two adjacent market zones occurs when the price differences are relevant and interconnection capacity is sufficient to allow price arbitrage, i.e. moving power from load in the low price zones (the exporting zone) to the high price zones (the importing zone). As can be seen in the Figure below, for interconnected systems, customers in imported zones have access to competitive offers from producers located in adjacent zones and the market price decreases resulting in a further gain in consumer surplus as customers consume higher volumes at lower prices. In exporting zones the market price increases leading to a further gain in producer surplus as producers generate additional volumes at a higher price and the zonal consumer surplus decreases in the same amount due to the higher market price. In the presence of relevant restrictions in physical capacity for the trade, the price between the two markets will differ. The price difference between the two markets multiplied with the volume of energy offered and traded from the low price zone to the high price zone is the congestion rent which accrues.

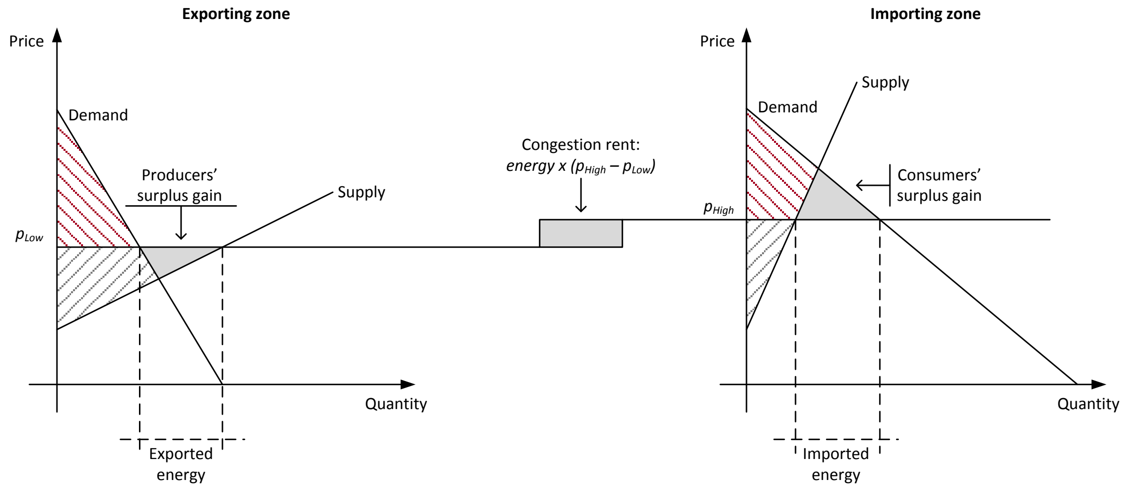


Figure 6 - Arbitrage trades between adjacent markets

Benefits of network expansion in IRENE-40 demand and generation scenarios

These indicators were evaluated across the five IRENE-40 scenarios. It was shown that cross-border interconnection creates benefits to the electric power system. It increases energy arbitrage trades, stimulates competitiveness on cross-border trading, enables customers to access to more competitive offers, removes physical congestion between adjacent markets, leads to price convergence and to market prices that are less volatile, more reliable and predictable. Further it contributes to the security of supply by increasing the ability of the interconnected markets to share capacity and reserves, facilitates sharing of operating reserves, reduces the overall operating costs for balancing the electric power system and increases the overall flexibility of the electrical power system, thereby allowing the integration of higher levels of renewable energy sources.

Different impacts on different stakeholders

The results further showed (see Figure below), that cross-border interconnection causes dissimilar impacts for different decarbonisation pathways and asymmetrical impacts (i.e. costs and benefits) to different market players such as producers, consumers and network investors. In the European continent, different importing and exporting zones are defined under the IRENE-40 scenarios. The resulting arbitrage trades shift the market equilibriums in the different zones, affecting in a different way producers and consumers on importing or exporting areas. Such asymmetrical impacts can potentially delay the development of cross-border interconnectors, since the question of who should incur the cost of investment in interconnectors arises. This dissimilar impact on interconnectors caused by different electricity market participants signals that costs may need to be allocated in accordance with the importance that each market participant places on the interconnection.

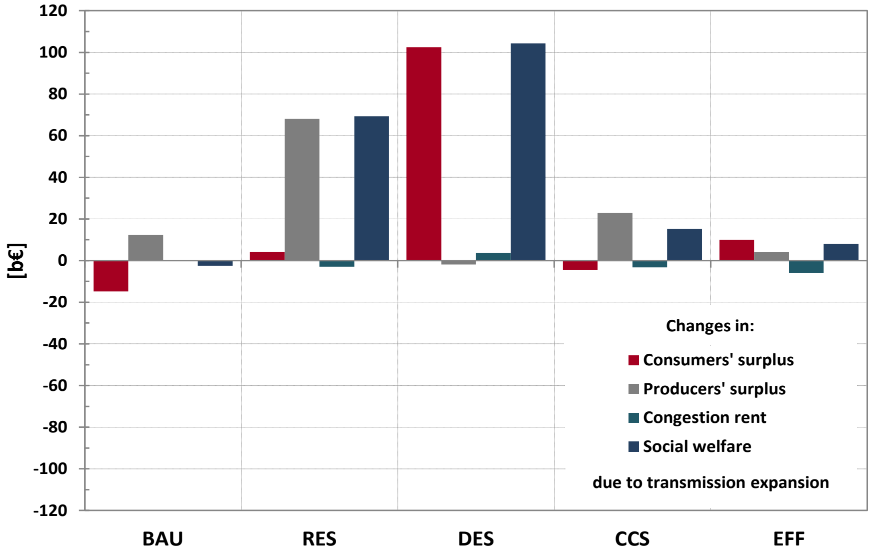


Figure 7 - Differences in benefits for the main stakeholders due to increasing network capacities across the different IRENE-40 scenarios

Transmission rent is insufficient and needs to be complemented

Further, it was shown that it is possible that investments in cross-border interconnection capacity based on merchant trading incentivise investment below the optimal capacity level. In such instances, transmission surplus becomes negative resulting in a non-profitable business and possible deferral on investment. To overcome this issue the following directions are crucially important: a) the creation of single energy market for Europe; b) the development of appropriate regulatory frameworks for network pricing and access arrangements; and c) the stimulation of competition for the procurement and development of cross-border interconnection. A key challenge associated with the delivery of electricity transmission network expansion is to establish regulatory frameworks that facilitate timely and coordinated merchant investment in cross-border interconnections. This requires synergies from all European members and in particular the intervention of regulatory agencies supported by ACER and the ENTSO-E.

Evolution of the future HVDC overlay grid

Since the 1950's when the first Line Commutated Converter (LCC) HVDC was introduced up to recently, HVDC transmission systems were used almost exclusively for point-to-point connections. However, in the last decades some large scale multi-terminal HVDC transmission projects are also been constructed, e.g. the Québec - New England transmission project in 1992, and the North-East Agra project in India, that is under construction and scheduled to be commissioned in 2014-15. Multi-terminal HVDC power transmission projects can theoretically be implemented either with LCC or VSC technology, however due to more demanding technical requirements than point-to-point connections, VSC technology with its increased controllability of both active and reactive power is most appropriate. Following after multi-terminal HVDC projects, the final step will be the implementation of an overlay HVDC grid. This will allow a cost effective long distance bulk power transmission system and controllability of power transfer to meet foreseen needs to handle the intermittent characteristics of considerable amounts of non-dispatchable renewable energy sources, such as wind and solar power, frequently located quite remote from load centers, and the need to handle larger and larger requirements for cross-border electricity trade. An HVDC grid should be able to operate independently of one or several disturbances, i.e. being capable of isolating a failure, and also to operate in different modes in the connected AC and DC systems. The evolution of the HVDC Grid will naturally come in intermediate steps. These stages for the development of the European HVDC grid infrastructure are described in table 1b.

Table 1b - Proposed development stages of HVDC network developments in Europe

Stages:	HVDC network developments	Decisions needed on:
Point-to-point connections 2012-2020	Continuation of establishing point to point connections, not yet prepared for being integrated into a multi-terminal HVDC network	• DC-breakers • Power flow control • Network restoration • Rules and regulations **Before 2020: decision on HVDC overlay technology**
Regional multi-terminal networks 2020-2030	• All new HVDC: VSC • First: primarily point-to-point • Later: integration into regional multi-terminal HVDC networks = first sections of overlay grid	
Full overlay network 2030-2050	Construction of overlay network Connecting regional multi-terminal networks	

Source: IRENE-40.

Road map for stakeholders

The IRENE-40 project has extensively studied the impact of different electricity system trajectories towards a more sustainable energy system in 2050 thereby making due allowance for different sets of uncertain factors. This chapter aims to synthesize overall results into a (qualitative) road map for electricity infrastructure into 2050 on five dimensions:

(1) Network investment strategies
(2) Cost allocation
(3) RD&D policy
(4) Public acceptance
(5) Electricity market design.

The key question is: how do stakeholders, predominantly TSOs and regulatory authorities need to deal with uncertain developments in the electricity system towards 2050? What are the key issues for different futures? Which network technologies need to be considered? And how will they know which choice to make in certain situations?

- Network investment strategies

The power system is characterised by at least three large uncertainties which impact the transmission planning by European TSOs as well as policy makers and regulators that steer and monitor the planning process, and system actors which are confronted with benefits and costs of new infrastructure (producers and consumers). These are:

- Future generation mix – high diversity of possible generation mixes
- Technology development and commercialisation of new network technologies – foresight of network technology cost reductions is imperfect and commercialisation is hindered by regulation
- Policy developments – conflicting EU and national incentives

Investment strategies are hindered by suboptimal regulation which prevents efficient hedging against these uncertainties.

One important barrier is the lack of coordination of investments in generation and network capacity. As a result, TSOs have to cope with a high diversity of possible generation and demand developments (as shown by Castro *et al*. 2012), which results in high risks for stranded assets. European TSOs are often obliged to accommodate all grid connection requests given the **'transmission follows generation'** philosophy as laid down in legislation**.** However, in practice siting of generation plants and load pockets plays a large role in the demand for network capacity. An alternative to the European 'transmission follows generation' philosophy, is **'generation follows transmission'** as applied in the US.

Achieving this paradigm shift requires a two-step approach. The first step is that *network investments precede generation investments i.e. anticipatory investments are performed*. The second step is discouraging the connection of generators at locations which is expected to result in prohibitively high overall system costs. This is implemented by obliging *generators to pay for locational specific network costs by allocating them the network costs they cause to the electricity system*. Therefore first the costs and benefits of network investments need to be assessed, in case of interconnections preferably with a social cost benefit analysis from European perspective as in recent EU legislation (EC, 2013). Subsequently, the beneficiary pays principle prescribes that network costs should be allocated based on the net benefits each stakeholder obtains from the investment.

Another barrier is the long duration of planning and implementation of grid expansion, which often takes 10 years or more. This compares with much shorter lead times of 3-4 years for most power plant types. *Reducing the lead time for grid expansion by faster permitting procedures enables faster utilization of the full potential of new power plants and better realisation of* *network investment strategies*. This is one of the important elements of the Regulation on guidelines for trans-European energy infrastructure (EC, 2013).

These recommendations are summarized in Table 2 showing also the responsible stakeholders and the expected timing of the actions.

Table 2- Network investment strategies

Recommendation	**Responsibility**	**Timing**		
		2012-2020	2020-2030	2030-2050
Reduce lead time for grid expansion by faster permitting procedures	Policy makers	↔		
Assess potential investments with social cost benefit analysis in European perspective	Policy makers, regulators	↔		
Reverse 'transmission follows generation', allowing for anticipatory investments	Policy makers, regulators, TSOs	↔		
Steer new generation with incentives to locations with lowest overall costs for society	Policy makers, regulators	↔	↔	
Allow for wider application of demand response and storage	TSOs, policy makers, regulators	↔	↔	↔

- Improving cost allocation

IRENE-40 analysis shows the asymmetrical impacts of grid expansion on both producers and consumers in different countries, which can delay the development of cross-border interconnections.

A cost benefit analysis (CBA) of (portfolios of)[7] intended grid expansion project(s) can provide more clarity over the distribution of net benefits over stakeholders. If CBA results indicate that the distribution of benefits is not in line with the distribution of network costs, it is advised to adapt the distribution of network costs according to the beneficiary pays principle in order to improve the long term efficiency of the power system. This concerns both the cost allocation between and within countries. Concerning the cost allocation between countries, it is important that effects of an interconnection on third countries are taken into account by multilateral agreements in the Regulation on guidelines for trans-European energy infrastructure (EC, 2013).

[7] Assessing portfolios of grid expansion projects has at least two advantages. First, the sequence of network investments no longer influences the net benefits of projects. Second, if the negative effects of project A on a stakeholder are compensated by project B, a portfolio of projects may be acceptable while separately project A may not take place.

Another issue is that congestion rents decrease when grid expansion takes place. TSOs do have two main sources of income: a) congestion rents through the auctioning of transmission rights, and b) network tarification. Since congestion rents are insufficient for full cost recovery of network investments, they are complemented with network tariffs. When congestion rents decrease, TSOs need to be able to recover the residual grid expansion costs by network tariffs, including the Inter-TSO Compensation (ITC) mechanism.

The ITC mechanism compensates TSOs for hosting of cross-border flows and concomitant network losses on their networks. Nowadays, the mechanism plays a marginal role in investment decisions due to limitation of the fund for transactions between TSOs to 100 million euro per year. It is an ex-post mechanism that does not take into account expected costs and benefits of new grid infrastructure as it is based on an analysis of past transit flows (Welle *et al*. 2011b, Hirschhausen *et al*. 2012). Table 3 contains the IRENE-40 recommendations to improve network cost allocation.

Table 3 - Improving cost allocation

Recommendation	**Responsibility**	**Timing**		
		2012-2020	2020-2030	2030-2050
Enable TSOs to pass through larger part of efficient grid expansion costs by network tarification	Regulators	↔		
Align network tarification with the beneficiary pays principle instead of cost socialization	Policy makers / regulators	↔	↔	
Transform the ITC to an ex-ante mechanism that takes into account expected benefits and costs of new infra and increase the fund size	Policy makers / regulators	↔	↔	
Pursue multilateral agreements over grid infrastructure with a significant effect on third countries	Policy makers	↔		

- R&D Policy

The IRENE-40 project identified the HVDC network scenario as the most promising and hence preferred network technology scenario to realize decarbonised, secure and cost-efficient power systems.

However, some parts of the class of HVDC technologies are still in earlier phase of the innovation cycle and not yet (fully) commercialized. TSOs play an important role in the demonstration and adaptation of new technologies and therefore in further commercialisation. Since TSOs are regulated the deployment of these technologies by TSOs is closely related to prevailing network regulation. The current regulatory environment governing present-day

European tends to imply biases against the application of innovative network concepts like HVDC technologies. Biases result mainly from the focus of applied incentive regulation at short-term efficiency gains at quality of supply to the detriment of long-term dynamic efficiency benefits including innovation. Hence, regulation should allow for sufficient innovation incentives in the TSO regulatory framework.

Furthermore, technical standards and associated regulation for HVDC network technologies needs to be further developed and harmonized (DC grid code, amongst others).

Finally, ENTSO-E[8] and ACER in association with related EU-wide initiatives (such as the SET Plan, framework research programme Horizon 2020 and the Intelligent Energy Europe research programme of the European Commission) will have a key role to play in coordinating RD&D activities undertaken with respect to the development and implementation of innovative technology in European transmission networks and accommodating regulatory changes by the member states.[9]

Table 4 - RD&D policy

Recommendation	**Responsibility**	**Timing**		
		2012-2020	2020-2030	2030-2050
Develop and harmonize technical standards and associated regulations for HVDC network technologies	TSOs, regulators	↔		
Enable level playing field for network technologies by introducing innovation incentives in the TSO regulatory framework	Policy makers/ regulators	↔		
Improve EU-wide cooperation in RD&D by effective platforms for exchange of regulatory experiences	Policy makers (EU)	↔	↔	

- Public acceptance

Permitting procedures for new infrastructure last on average about 10 years in many EU member states and therefore impede efficient network planning. Lengthy permitting procedures are largely due to lack of public acceptance of new grid infrastructure.

The main reason for public resistance seems to be the lack of effective stakeholder engagement in the decision making process. It is important that stakeholders perceive themselves as co-owners of grid expansion decisions. Therefore, the social, political, economic and cultural

8 See e.g. the ENTSO-E R&D Plan (ENTSO-E, 2011b).
9 Examples are the network codes being designed by ENTSO-E, consistent with framework guidelines from ACER and the EC Mandate 490 on the interoperability of smart grids.

context of the project as well as characteristics of the used technologies are important for stakeholder engagement and should be taken into account (Welle *et al*. 2011b).

The IRENE-40 project has paid attention to the characteristics of the applied technologies, especially the corridor width of several network technologies. Resulting recommendations are highlighted in Table 5.

Table 5 - Public acceptance

Recommendation	**Responsibility**	**Timing**		
		2012-2020	2020-2030	2030-2050
Stimulate network innovation to reduce impacts of grid expansion on local communities	Policy makers	↔	↔	↔
Further development of network components that allow for undergrounding	Network technology manufacturers	↔	↔	↔

- Capacity markets

The IRENE-40 project analysed the magnitude of the missing money problem for peaking units (based on gas and oil input) in different future scenarios. It shows that there is a need for capacity markets, although the extent to which capacity markets have to be developed depends heavily on developments in the electricity generation mix as well as the level of integration between EU member states. A larger share of renewables increases the need for capacity markets, while more demand response, for example via smart meters, interruptible contracts and various smart grid concepts, and a higher level of network integration could relieve the problem of insufficient investment in peaking capacity.

When capacity markets are adopted across the EU, their implementation should be coordinated and harmonized in order to minimize distortions for the internal energy market. The implementation of 27 different capacity markets in 27 different EU countries will most likely be the end of the internal energy market as there will no longer be a level playing field in electricity generation across Europe.

Table 6 - Capacity markets

Recommendation	**Responsibility**	**Timing**		
		2012-2020	2020-2030	2030-2050
Improve possibilities for demand response and network integration to reduce the need for capacity markets	Policy makers / regulators	↔	↔	↔
Harmonize national capacity market designs for level playing field in electricity generation	Policy makers	↔		

1 INTRODUCTION

1.1 EUROPEAN POWER TRANSMISSION TOWARDS 2050: THE KEY CHALLENGES

Europe's electricity systems are in a transition in response to policies aimed at decarbonisation, security of supply and guaranteeing economic competitiveness and affordable energy (EC, 2011c). Especially the target of 80-95% reduction of greenhouse gas emissions by 2050 compared to 1990 levels and the drive towards more cooperation between EU member states for securing security of supply and economic competitiveness, steer the development of Europe's electricity systems and drive the need for adaptation of current electricity infrastructures in different ways.

The development of Europe's energy systems has significant implications for the electricity network infrastructure. First of all, the increase of electricity production from renewable energy sources (RES-E) such as wind turbines which are generally located further from areas with highest demand, increases the distance between generation and demand and hence the need for electricity infrastructure. In addition, the higher variability and lower predictability of electricity production from intermittent renewable energy sources (RES-E) such as wind and solar also increases peaks of power flows and complexity of system operation. Besides, at some times transmission networks have to transport larger amounts of electricity due to excess electricity produced by decentralised generation (solar PV, dispersed wind, CHPs) in distribution networks. Finally, the drive for more cooperation between member states, for example regarding the locations of renewable electricity generation where the wind blows hardest or the sun shines most, will increase electricity exchanges and therefore the demand for interconnection capacity. With all these changes, security of supply has to remain on a high level.

The extent to which these effects on the electricity network will materialise depends heavily on the development of generation mix and demand in the next decades, which is subject to a large range of unpredictable factors including fuel and CO_2 prices, technology development and the support of renewable energy. Developments of the generation side have to be taken for granted by European transmission system operators (TSOs) under the current "transmission follows generation" paradigm. Hence, TSOs face large uncertainty over the future development of their power systems.

This uncertainty adds to existing uncertainties in the planning of transmission networks, which include several issues that can be associated with electricity market failures and sub-optimal institutional conditions.

First, the long lifetime of network assets (often 40-60 years) means that current investments affect power systems in 2050. Capital costs of these network assets are entirely paid upfront and hence sunk after realisation. Hence, future network cannot be developed from scratch and the value of investments should be assessed both for current and likely future circumstances in order to prevent stranded network assets.

Second, lumpiness and economies of scale of network investments imply that network investments do not meet exactly current demand for network capacity, which suggests again that network planning should be optimized over time. On the one hand temporarily overdimensioning network investments may be useful to anticipate new generation and demand developments, on the other hand stranded network assets need to be avoided.

Third, new network technologies will become available which may be more cost-efficient at a certain point in time depending on learning effects. Since foresight of prospective cost reduction is imperfect, the timing of deployment of new technologies is an important issue for transmission planning.

Fourth, the unbundling of electricity generation, trading and supply parts of electricity networks means that, while electricity networks remain regulated, generation and network development are no longer the responsibility of one entity, the system operator. Instead, generation is liberalized and left to commercial entities. Incentives have to be set to optimally coordinate generation and network developments. Current European and national incentives are often conflicting, which implies additional uncertainty for TSOs.

All in all, there is a high need for thorough scientific advice on actions that enable TSOs and other stakeholders to hedge against this increasing technological, economic and institutional uncertainties. A wide range of actions is possible relating to technology development and shaping a better policy framework. The question is which actions do really help the electricity system and its stakeholders?

This translates in the following research question: *Which stakeholder actions are necessary for the transition towards a more optimal electricity system infrastructure, for society and stakeholders in 2050?*

A more optimal electricity system is defined as a system that achieves the policy objectives for 2050 in order to arrive at a sustainable, secure and cost-efficient electricity system. It is analysed that the realisation of the HVDC technology network scenario is required for the realisation of such an optimal electricity system. Stakeholder actions need to be taken to remove the main barriers for this network scenario. Therefore, a comprehensive set of essential stakeholder actions is identified and analysed on their socio-economic impact for society and individual stakeholders. For obtaining a clear and well-structured overview of these actions in time, actions are put in a timeframe linked to a possible and likely development pathway of the HVDC network technology scenario.

1.2 ROADMAP SCOPE AND OUTLINE

The infrastructure roadmap is built upon the results of earlier work by all FP7 IRENE-40 project partners. Chapter 2 starts off with an overview of developed generation and demand scenarios. Subsequently, it is evaluated whether assumed GHG emission reductions are realized in model simulations. Next, modelling results of the IRENE-40 scenarios are compared to other generation and demand scenarios developed for the period up to 2050.

Chapter 3 describes the network technology scenarios that were specially designed for this purpose - with great care and after intensive consultations with key stakeholders - to cover a wide range of possible network evolutions in the run-up to this roadmap's time horizon: year 2050. Special overlay networks using a mix of conventional and innovative state-of-the-art network technologies are constructed for testing the robustness of networks in accommodating different generation and demand developments.

This approach highlights the roadmap's so-called preferred network technology scenario. This technology scenario is identified as most promising in the network analysis, covering the three policy perspectives sustainability, security of supply and affordability.

Important economic and regulatory barriers and bottlenecks for realization of this network technology scenario, as well as policy options to overcome them are highlighted in Chapter 4. These policy options are analysed on their socio-economic impact for society and individual stakeholders.

2 GENERATION AND DEMAND SCENARIOS 2020-2050

This chapter first describes the construction of generation and demand (G&D) scenarios and the main goals and assumptions made. Subsequently, Section 2.2 evaluates whether the scenarios deliver the expected results. This is followed in Section 2.3 by an assessment of IRENE-40 scenarios compared to other generation and demand scenarios for the period up to 2050. Section 2.4 concludes.

2.1 DESCRIPTION OF FIVE GENERATION AND DEMAND SCENARIOS

Main characteristics Generation & Demand scenarios

For the purpose of simulating the need for development of the European transmission networks for the next 40 years (until 2050), five generation and demand scenarios which cover a wide range of possible future developments in generation and demand have been constructed:

- Business-As-Usual (BAU)
- Carbon, Capture and Storage (CCS)
- Desertec (DES)
- High Efficiency (EFF)
- Renewables (RES).

It should be noted that no (order in) likelihood is attached to the different scenarios. However, the generation and demand scenarios are defined in such a way that the resulting scenario space covers the most relevant generation and demand developments as observed today.

In the generation and demand scenarios, three major determinants of the future grid infrastructure are varied widely:

- Generation capacities: overall system size, portfolio of (intermittent) renewables, CCS and other generation technologies as well as their geographical location
- Electricity demand: level and variability (with allowance for the impact of demand side management) as well as its geographical location
- Role of import of renewable energy from outside Europe.

Four of the five scenarios (CCS, DES, EFF, RES) are formulated assuming compliance with the EU policy objective to achieve greenhouse gas emission reductions of 80-95 percent in 2050 compared to 1990 levels. Hence, the four scenarios should achieve RES-E levels of 80% as a minimum.

This required realistic assumptions over a range of variables which shape electricity production with concomitant CO_2 emissions in the future on the one hand as electricity demand on the other. Four classes of assumptions are distinguished.

First, the power system needs sufficient flexibility in order to balance supply and demand at all the hours of the (future) years. Hence, assumptions have been made for the available flexibility of generation and demand, notably in the RES and DES scenarios. It is likely that scenarios with high penetration levels of intermittent generation (solar PV and wind) require more flexibility to balance supply and demand. Hence, following ECF (2010) it is assumed that back-up power is needed in the order of 22% of installed intermittent generation capacity.[10] It is assumed that demand side management (DSM) provides 5% of the required flexibility in the RES and DES scenarios by shifting 5 percent of the daily electricity demand to other periods of the day, flattening the hourly residual demand curve.[11] The remaining 17% of flexibility is assumed to be provided by gas turbines which can be regulated in a relatively short timeframe compared to other fossil fuel generators. The latter restriction is levied upon each G&D scenario.

Second, for security of supply purposes each country wants to be sure that there is sufficient electricity available to cover demand at all hours of the year. Hence, a simple generation adequacy criterion is applied for 2050 (because this is the most demanding year for most of the scenarios). For each country, the installed firm capacity (all forms of electric power generation, except intermittent renewables) should be at least 125% of annual peak load. If no sufficient firm capacity is available in a country, an additional amount of gas turbine capacity is assumed. For the RES scenario, this implies that an additional 107 GW of gas turbines needs to be installed, which is equivalent to almost 5% of total installed capacity in 2050. This gas turbine capacity is built up as from the year 2030.

Third, predicting electricity production for a detailed electricity generation technology classification in 2050 requires assumptions about development of fuel and CO_2 prices, generation technology efficiencies, wind speeds and wind power curves and solar radiation. Furthermore, assumptions on network losses and curtailment had to be made.[12] These assumptions have been described in depth by Nieuwenhout *et al*. (2011).

Fourth, predictions of electricity demand in the future differ considerably. Hence, the consortium developed three demand curve projections:

- High demand for the CCS, DES and RES scenarios
- Low demand for the EFF scenario
- Intermediate demand for the BAU scenario.

All demand curve projects are based on historical data and trends provided by ENTSO-E, which have been adjusted to capture changes in energy demand due to economic, political, social and technological factors.

The BAU scenario is extrapolated using assumptions of EC (2009a) for the period 2020-2030. Electricity demand in the two alternative demand scenarios is either higher or lower than in the

[10] In the ECF 80% RES scenario it is assumed that 270 GW of back-up plants is required in 2050, which is equivalent to 22% of installed intermittent capacity.

[11] The residual demand curve is the curve which results from subtracting hourly final electricity demand by intermittent generation.

[12] No model runs with G&D scenarios were possible to check internal consistency when scenarios were formulated, since network models still had to be constructed.

BAU case. Following relevant long-term energy demand scenarios, it was observed that a lower bound would be a constant demand for the period 2020-2050. Hence, this was assumed for the EFF scenario. On the other hand, the combined impact of increased demand due to rising incomes and fuel changes due to the introduction of electric transport and heating, may lead to an increase in electricity demand.We have chosen 4,900 TWh per year as future demand level for RES, DES and CCS scenarios in 2050 as being in line with some other studies (e.g. ECF, 2010 and IEA, 2010). This results in a substantial difference (40%) of demand levels between the 'high' and 'low' demand cases as shown by Figure 8.

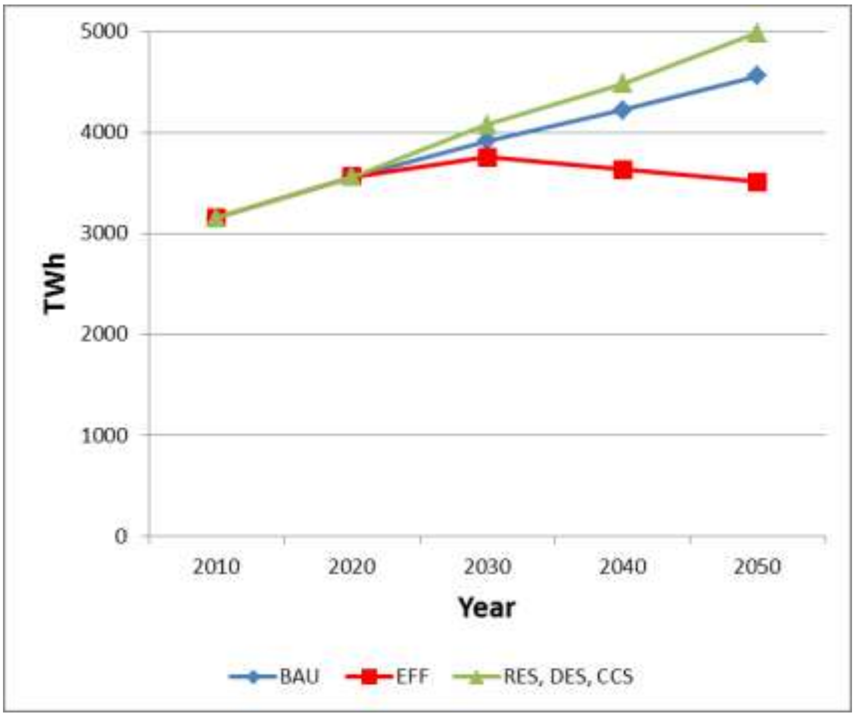


Figure 8 - Final electricity demand levels for EU-27+CH+NO in the five G&D scenarios

Hence, the need for future grid expansion can be analyzed under substantial different circumstances.

All scenarios assume the same demand and generation mix in 2010 and 2020 and only differ from 2030 onwards. For renewable energy sources in 2010 and 2020 the National Renewable Action Plans (NREAPs) have been used as input for both installed capacities per country as well as average full load hours for both EU-27 and EU-27+CH+NO. The BAU scenario extrapolates current trends in order to act as a reference scenario. Table 7 provides a short summary of the most important characteristics of the resulting five scenarios.

Table 7 - Overview of the five IRENE-40 Generation & Demand scenarios

Scenario	Short description
BAU	80% CO_2 reduction in 2050 not achieved
CCS	Substantial contribution from CCS to attain 80% goal
DESERTEC	Import from Africa to achieve 80% goal
EFFICIENCY	Lower electricity demand than other scenarios
RES	High contribution of RES to 80% goal

2.1.1 BAU scenario

Business-as-Usual scenario

Main characteristics:

- Electricity generation mix is diverse, composed of conventional thermal, nuclear and RES power units
- Fossil fuels remain a key energy source (39% of installed capacity in EU-27+CH+NO in 2050)
- RES deployment meets the 2020 targets, but further uptake is slow
- Low carbon and renewable energy technologies moderately contribute to the electricity generation capacity in 2050 (about 58%)

Legend : Fossil-fuel : Nuclear : Wind : Solar

The BAU scenario provides a baseline for the way the European power sector could develop in a business-as-usual case. It serves as a reference scenario for other scenarios which analyse the impact of a large intermittent renewable supply, and a rapid uptake of low-carbon base load technologies.

It is assumed that in the BAU scenario current trends are continued and therefore GHG emissions reductions in 2050 are relatively low. After 2020, the deployment of generation technologies in the BAU scenario is extrapolated from PRIMES Baseline scenario (EC, 2009a). Hence, conventional thermal power plants still dominate supply. CCS technology is deployed mostly in pilot projects, and its commercial uptake is slow. Gas and coal fired power plants equipped with this technology constitute only a relatively small share of the total installed capacity (5% in 2050). Total installed nuclear power capacity in Europe declines from a level of 122 GWe in 2020 to 115 GWe in 2050. Several Member States build new plants for replacement of older facilities which reach their end-of-life and therefore will be decommissioned. In Germany and Switzerland a nuclear phase-out will take place. RES installed capacity grows at a yearly rate of about 0.5-1.5% per decade in each Member State implying a considerable growth slow-down after 2020. This results in a diverse power supply, which is more flexible than the supply in the other four scenarios since the share of gas (without CCS) and hydro power plants is the highest of all scenarios.

The total installed generation capacity in Europe is calculated by an iterative process with above assumptions, resulting in electricity production figures which match electricity consumption for the years 2020, 2030, 2040 and 2050 respectively. Figure 9 shows the installed capacity of the three main types of technology. Figure 10 illustrates the generation capacity shares of the conventional generation technologies, whilst Figure 11 displays the RES generation capacity shares in EU-27+CH+NO in the BAU scenario.

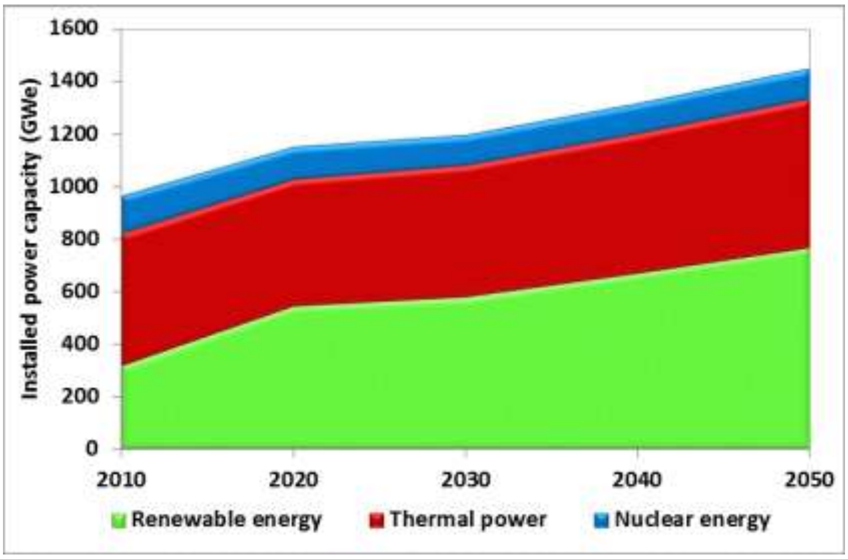


Figure 9 - Installed generation capacity in BAU scenario for EU-27+CH+NO

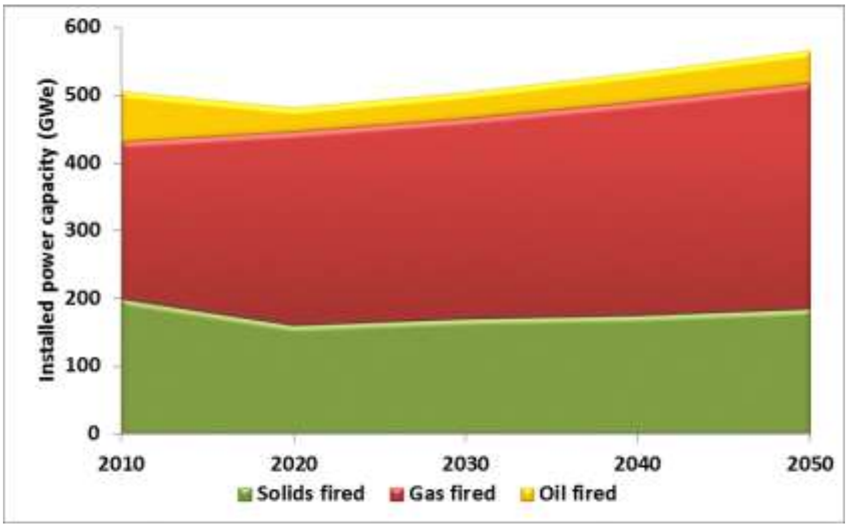


Figure 10 - Installed conventional generation capacity in BAU scenario for EU-27+CH+NO

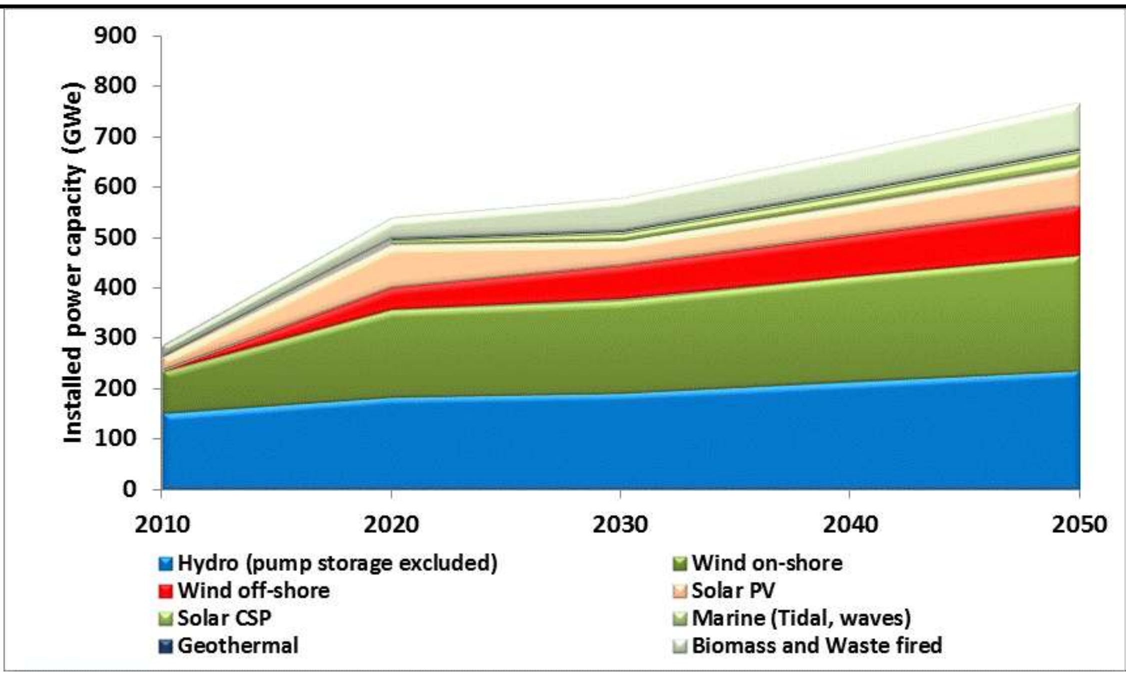


Figure 11 - Installed renewable generation capacity in BAU scenario for EU-27+CH+NO

2.1.2 CCS scenario

Carbon Capture and Storage scenario

Main characteristics:

- CCS technology matures successfully, deploying steadily from 2030 onwards, in 2050 28% of total generation capacity consists of capacity with CCS (474 GW_e).
- RES are supported as one of several low-carbon technologies, without priority
- Like all other scenarios, nuclear power capacity in the EU declines from 140 GW_e in 2010 to 115 GW_e in 2050
- Low-carbon energy sources make up 85% of installed capacity in 2050

Legend : Fossil-fuel : Nuclear : Wind : Solar
: Fossil-fuel with CCS

In the CCS scenario, the EU sets ambitious GHG emissions reduction targets for 2050. The target is expected to be achieved by thermal power plants out-fitted with CCS, being complemented by nuclear power and renewable electricity capacity. CCS technology makes a successful transition from pilot projects to a commercially mature viable option by 2030. After that, its deployment both by adding to existing power plants and integration into new power plants develops explosively, all over Europe. Carbon capture and storage is applied as to three generation technologies: CCGT, IGCC and CHP gas units. Attaining the emission reduction target in the CCS scenario is achieved by applying CCS technology to all of the remaining fossil fuel fired capacity. In 2050, 474 GW of CCS generation capacity is assumed to be installed.

When CCS becomes commercially viable by 2030, modern gas-fired CCGT plans continue to replace old coal-power facilities. This shift from coal to gas continues in the period 2030-2050, triggered notably by high CO_2 prices.

RES deployment is lower than in the RES scenario, but higher than in the BAU scenario. The composition of the generation park differs substantially, with a larger role in the CCS scenario for solar PV and a smaller role for wind offshore (Figure 14). Total RES deployment increases slightly with 1.7-2.4% per year so that, together with nuclear power and CCS, the installed capacity of low-carbon technologies reaches 85% of the EU total in 2050. Figure 12 shows the installed generation capacity in Europe and Figure 13 shows the subdivision for the fossil-fuelled production capacity in the CCS scenario.

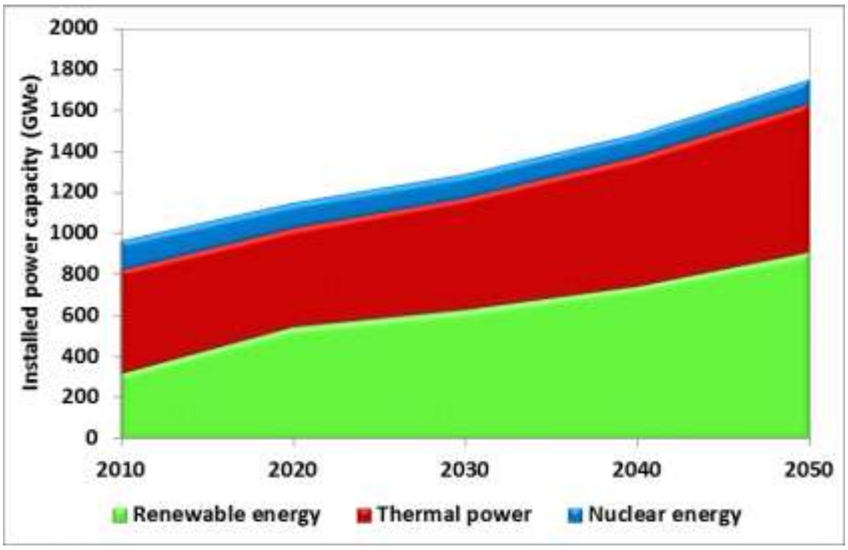


Figure 12 - Installed generation capacity in CCS scenario for EU-27+CH+NO

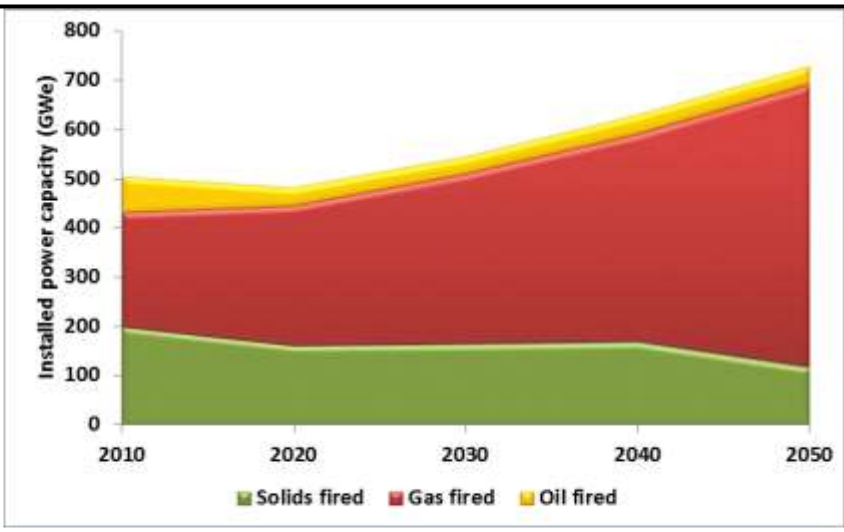


Figure 13 - Installed conventional generation capacity in CCS scenario for EU-27+CH+NO

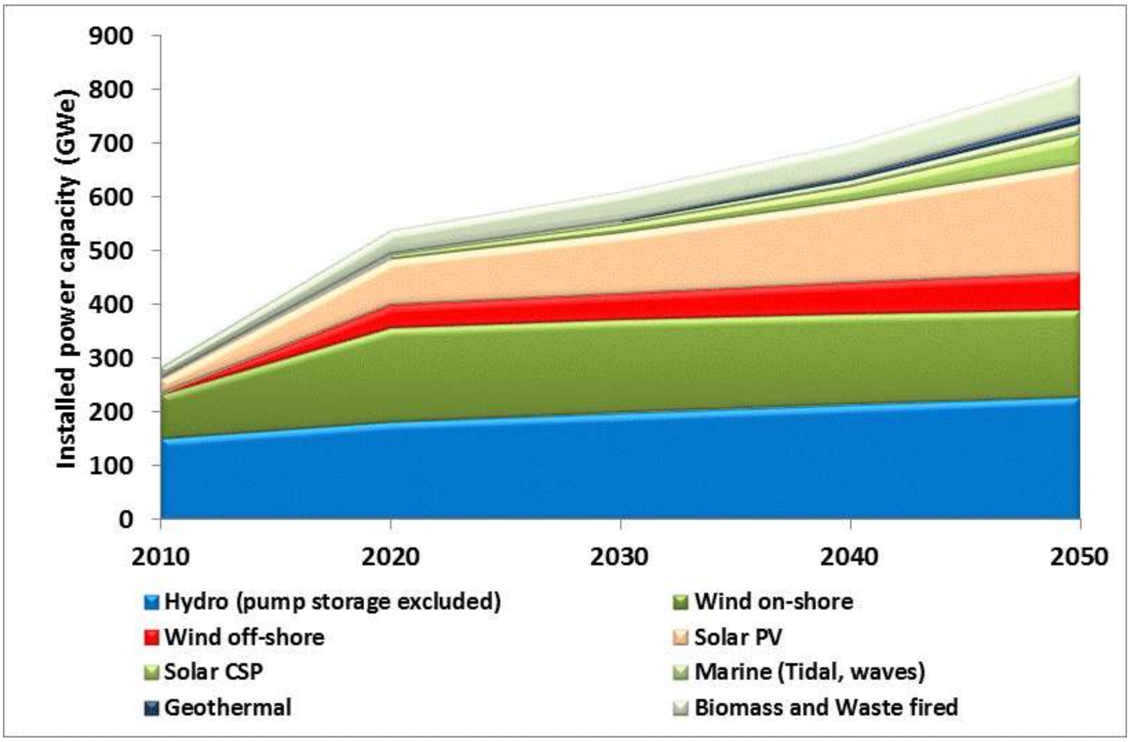


Figure 14 - Installed renewable generation capacity in CCS scenario for EU-27+CH+NO

2.1.3 DES scenario

Desertec scenario

Main characteristics:

- Government policy strongly supports the deployment of RES after 2020
- RES dominates electricity supply in 2050
- Solar power plants in North Africa are expected to supply 15% of Europe’s electricity demand in 2050
- Demand side management provides 5% of the required flexibility by shifting 5% of the daily electricity demand to other periods of the day

Legend : Fossil-fuel : Nuclear : Wind : Solar

The DES scenario assumes strong development of renewable energy, similar to the RES scenario which is described below, with the difference that part of Europe’s electricity will be generated in North Africa, and then transported via electricity “highways” to Europe entering at Spanish and Italian borders.

The Desertec initiative[13] aims to supply up to 15% of the electricity required in Europe by 2050 from solar power generation in North Africa (IEA, 2010a). However, the Desertec initiative is a long-term initiative and it is therefore unclear if and when it would start supplying power to Europe. We assumed that it will start delivering 3% of EU final electricity demand by 2030, 6% by 2040 and finally 15% in 2050. Figure 15 illustrates the resulting installed electricity capacity in the European Union. Power plants installed in North Africa as part of Desertec are physically located outside the EU, but supposed to be fully dedicated to the supply of electricity to Europe.

The sources of electricity from Desertec will be an unspecified mix of renewable energy and daily storage. Concentrated Solar Power (CSP) units will be technically able to provide this, but also a mix of solar CSP, wind and PV would also be able to provide a generation profile which is flat on a daily basis when combined with energy storage.

Desertec electricity will be imported in two EU-27 countries: Spain and Italy, with an assumed distribution of 45% and 55% respectively. Maximum daily generation of all Desertec installations

[13] http://www.dii-eumena.com

combined amount to 111 GW. When transmission capacity is limited to 80% of the annual peak generation to achieve a higher utilization of the interconnectors, the required transmission capacities are shown in Table 8 below.

Table 8 - Required transmission capacities between North Africa and Europe for the DES scenario assuming capacities for 80% of peak generation (in GW)

	2030	2040	2050
Morocco-Spain	8.0	16.0	40.0
Tunesia-Italy	9.8	19.6	48.9
Total	17.8	35.5	88.8

[Source: Nieuwenhout *et al*. (2011)]

In the DES scenario, the installed capacity of renewable technologies in Europe is calculated in such a way that in 2050, the electricity generated by these technologies in the EU plus the electricity imported through Desertec would equal the electricity generated by renewable technologies in the RES scenario. Hence, for both scenarios the contribution of renewable electricity to meet total demand is the same. However, in the DES scenario renewable generation in Morocco and Tunisia produces 15% of the European electricity demand in 2050. The maximum of the daily average electricity production in 2050 will be around 111 GW per year. An optimal transmission capacity has not been determined yet, but is estimated to be in the range from 80-100 GW.

As a result of the import from Morocco and Tunisia, implementation of the DES scenario would result in a lower growth of the total installed renewable generation capacity in the EU-27+CH+NO (see Figure 17) compared with the RES scenario. Hence, no further growth of CSP in Europe is assumed after 2020, and the total installed capacity of solar PV in Europe is reduced compared to the RES scenario to make up for the required difference. This reflects the fact that CSP and PV energy potentials in Africa are cheaper than in Europe. Furthermore, more flexibility of gas power plants is required to balance supply and demand (Figure 16).

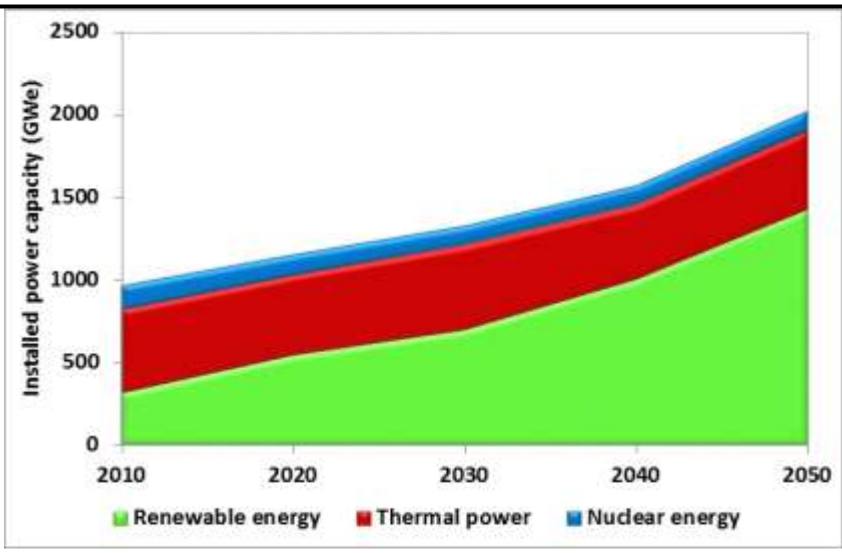


Figure 15 - Installed generation capacity in DES scenario for EU-27+CH+NO

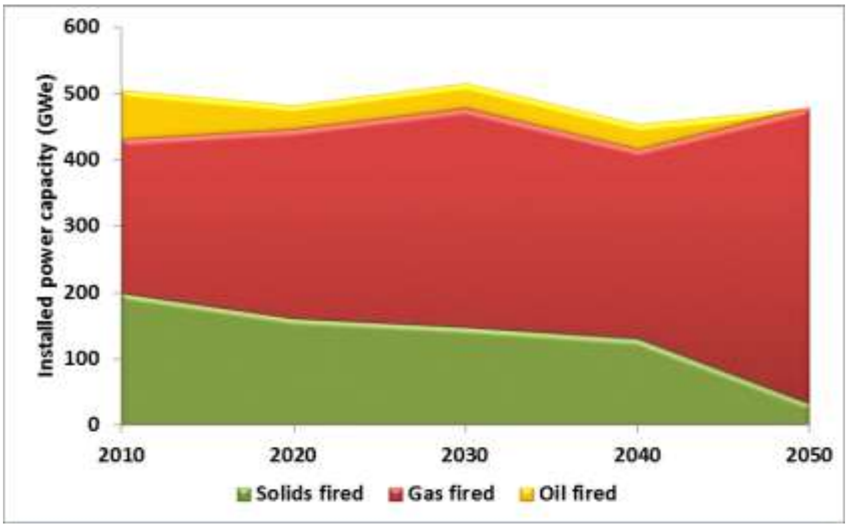


Figure 16 - Installed conventional generation capacity in DES scenario for EU-27+CH+NO

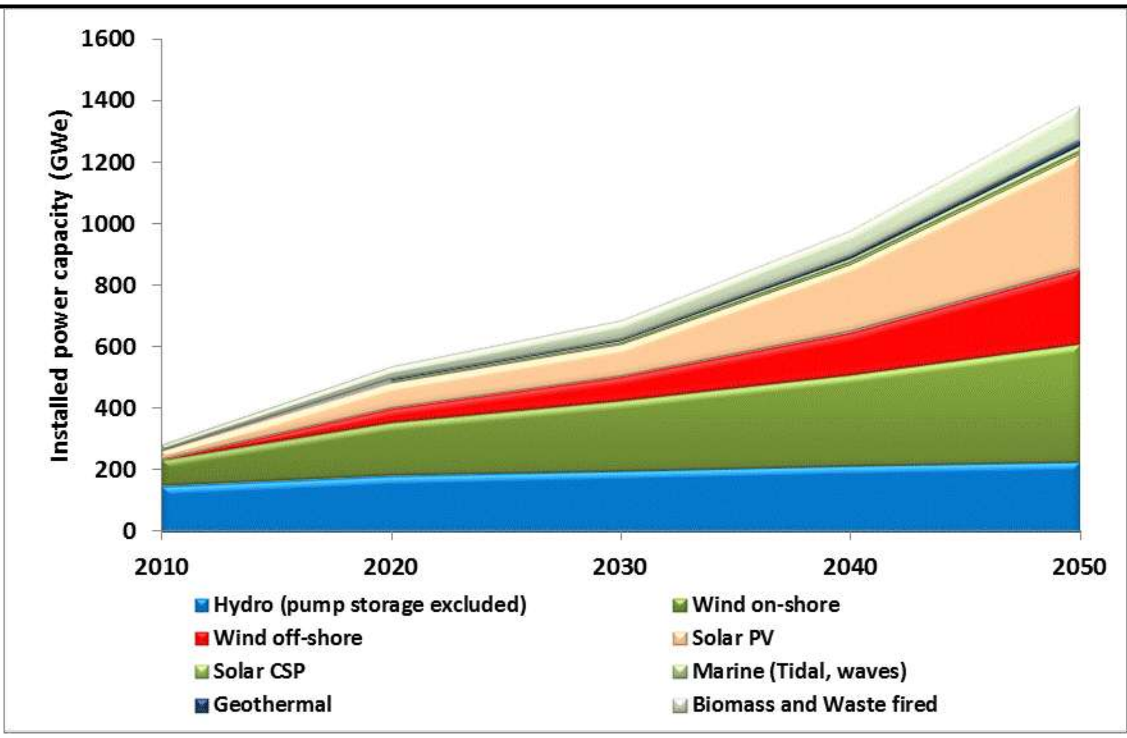


Figure 17 - Installed renewable generation capacity in RES scenario for EU-27+CH+NO

2.1.4 EFF scenario

In this scenario continued strong efficiency improvements almost cancel the demand growth due to volume effects and structural (fuel shift) effects. Final demand for electricity in 2050 is at equal level as expected demand for 2020.

For the renewable electricity sources, a total share of 60% of required generation in 2050 is foreseen, with a division over the different technologies to be similar to the 60% RES scenario of ECF (2010).

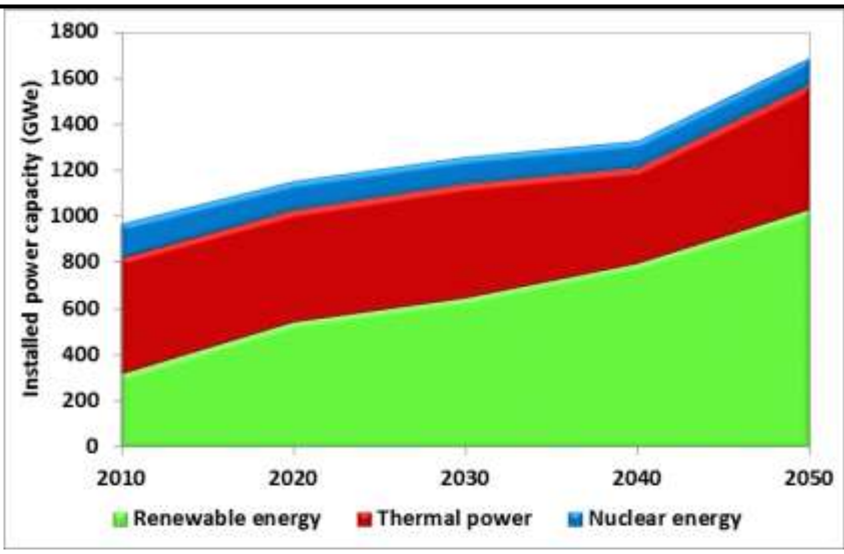


Figure 18 - Installed generation capacity in EFF scenario for EU-27+CH+NO

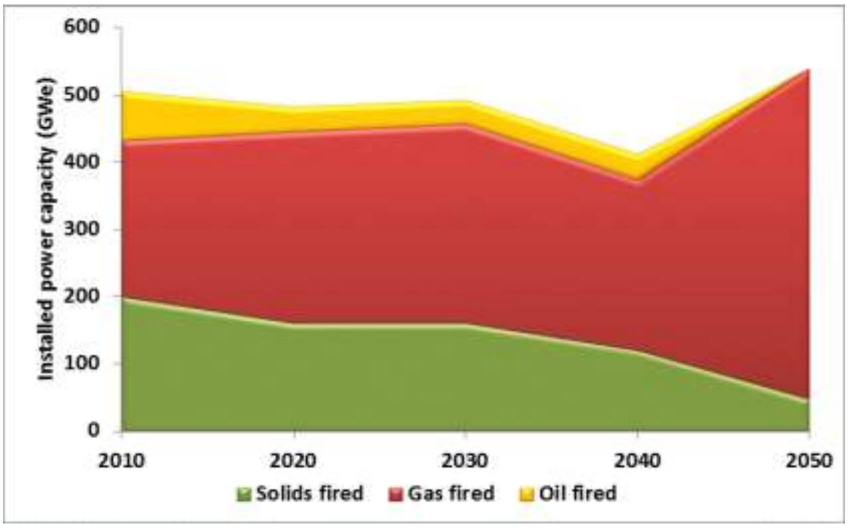


Figure 19 - Installed conventional generation capacity in EFF scenario for EU-27+CH+NO

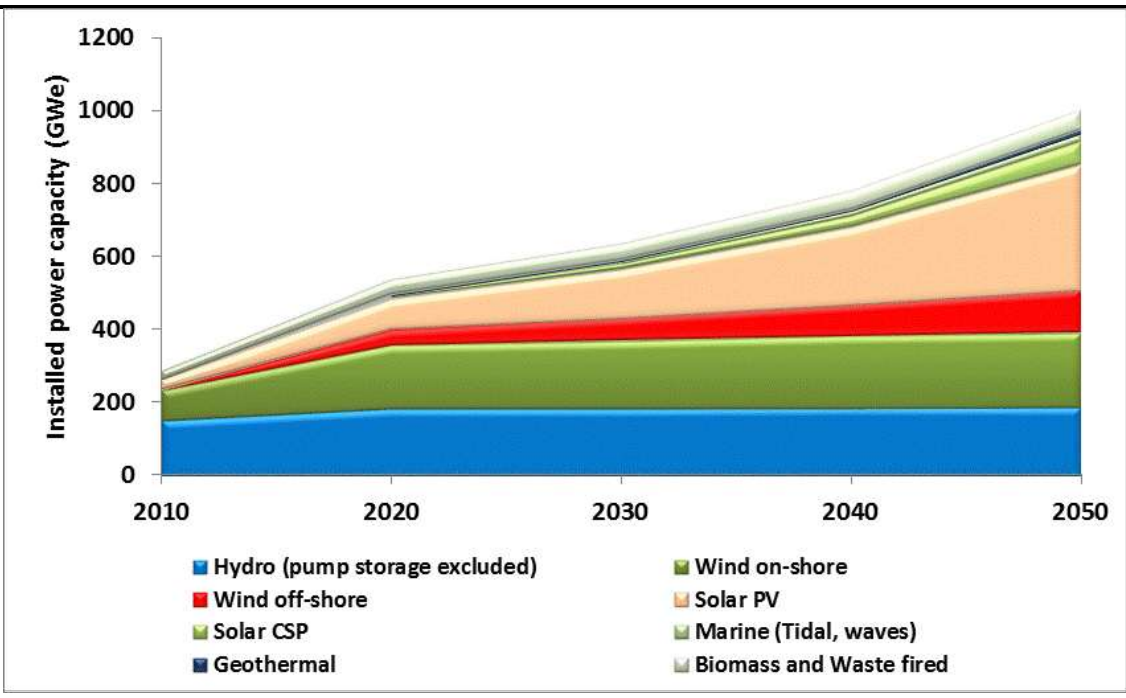


Figure 20 - Installed renewable generation capacity in EFF scenario for EU-27+CH+NO

2.1.5 RES scenario

Renewables scenario

Main characteristics:

- Government policy strongly supports the deployment of RES after 2020
- RES dominates electricity supply in 2050
- EU-average shares of the different renewable sources in installed generation capacity is in accordance with ECF's 80% renewable scenario
- Fossil fuel fired capacity decreases from 53% in 2020 to 23% of electricity generation in 2050
- Demand side management provides 5% of the required flexibility by shifting 5% of the daily electricity demand to other periods of the day

Legend : Fossil-fuel : Nuclear : Wind : Solar

In the Renewables Scenario (RES), ambitious GHG targets and strong policy support are assumed to drive the deployment of renewable technologies, replacing conventional power plants (coal, oil and gas) even before technical end-of-life. This includes large clustered offshore and onshore wind farms in the northwest, solar and wind in the south, and hydropower and biomass in central and northern Europe.

In this RES scenario, electricity from renewable energy sources is expected to amount to 80% of total electricity generation in 2050. EU-wide totals for electricity generation in 2050 from the different renewable energy sources have been chosen to be the same as in the 80% RES scenario of ECF (2010). For 2010 and 2020, again projected installed renewable capacity and generation from the NREAP have been used (Beurskens *et al*. 2011). A constant growth rate per renewable electricity source has been assumed for the period 2020-2050 in between the NREAP values for 2020, and the EU-27 wide totals for the different renewable technologies in 2050. The similarity with the ECF 80% RES scenario ends at the aggregate, EU-27 level since the distribution among the individual countries differs. For hydro, wind, biomass and geothermal generation, the 2020 installed capacities were used as starting values. The growth rates of these renewable technologies for each country were chosen to be equal to the overall growth rate of the technology to achieve the 2050 contribution to electricity generation. This implies that the growth rate in each country is the same.

For solar PV, the growth rate per country was chosen to depend on the solar potential: high if the equivalent full load hours is more than 1400 hours per year, low for countries with equivalent full load hours of less than 1000 hours per year, and intermediate for equivalent hours between 1000 and 1400 hours per year. The growth in PV after 2020 is assumed to be stronger in the regions with the highest solar potential. 50% of the increased volume growth is assumed to take place within the high potential countries and only 5% in low solar potential countries. A further division per country takes place based, linearly depending on electricity demand.

Solar CSP is treated as follows. Since CSP technology relies on direct radiation, it is assumed to be only relevant for countries with equivalent solar hours of more than 1400 hours per day, which are CP, GR, IT, PT and ES. France has an average below 1400 hours, but in the south of France the potential is known to be sufficient, and France has already plans for CSP outlined in the NREAP. Bulgaria does not yet have plans for CSP up to 2020, but it is assumed to have sufficient future potential after 2020. This leads to a list of seven CSP countries: BG, CP, FR, GR, IT, PT and ES. The share of growth in CSP in these seven countries was chosen to be based on the estimated PV potential in these countries in 2040 according to the RSolve-E project (see Nieuwenhout *et al*. 2011). For the resulting development of the renewable generation capacities in time, see Figure 23.

Nuclear capacity shows a small decrease from 140 GW in 2010 to 115 GW in 2050. Production capacity of fossil fuelled generation with CCS technology increases to 32 GW in 2050.

The installed capacity of thermal power plants is more or less constant (see Figure 21), whilst the share of installed gas fired plants is increasing (Figure 22). This reflects among others the procedures for achieving enough flexibility by deployment of back-up power as well as for ensuring generation adequacy, which were explained before.

However, note that the fossil-fuel production will decrease since the number of full load hours of fossil fuel power plants is assumed to decrease over time.

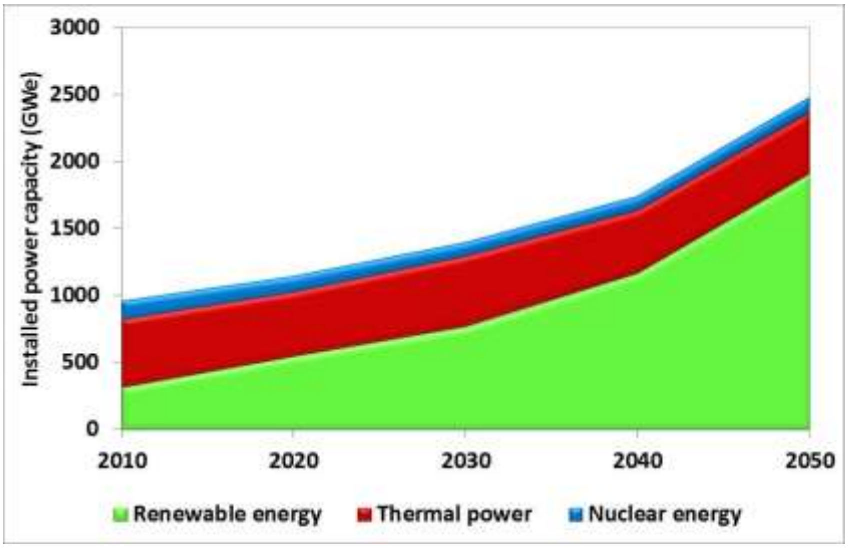


Figure 21 - Installed generation capacity in RES scenario for EU-27+CH+NO

[Source: Nieuwenhout et al. (2011)]

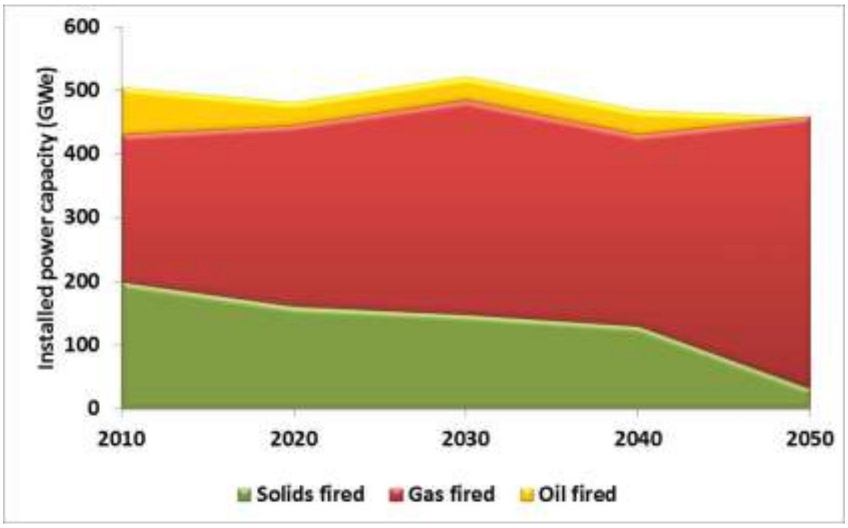


Figure 22 - Installed conventional generation capacity in RES scenario for EU-27+CH+NO

[Source: Nieuwenhout et al. (2011)]

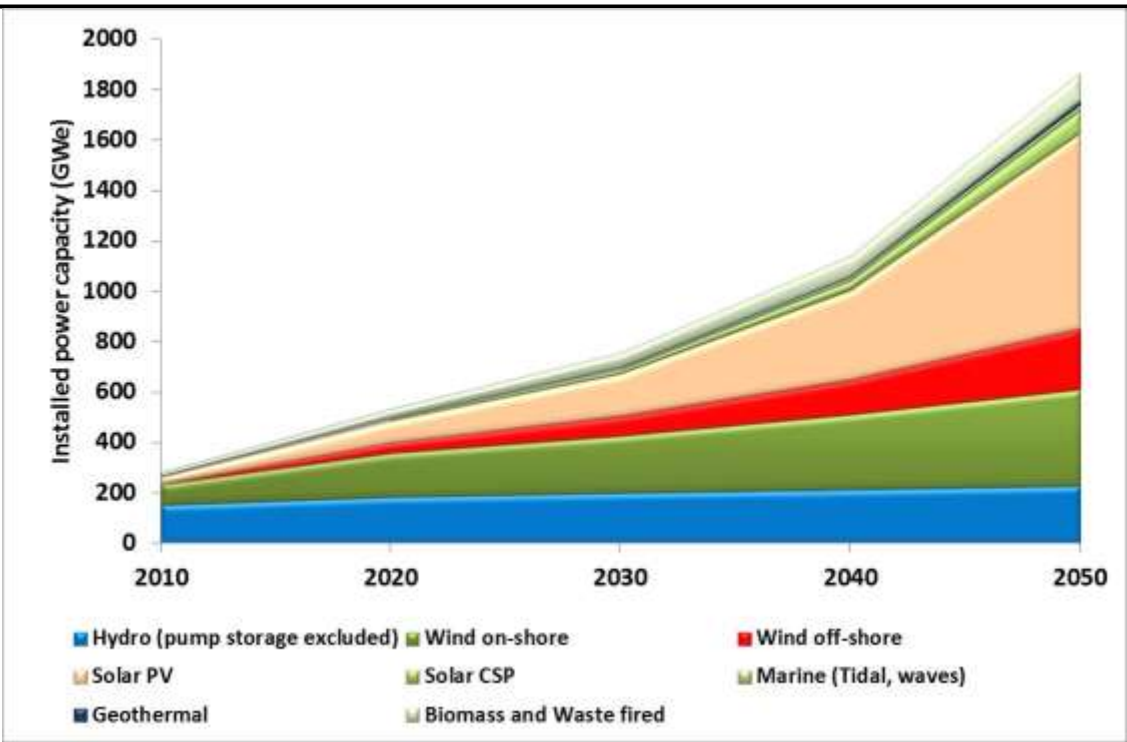


Figure 23 - Installed renewable generation capacity in RES scenario for EU-27+CH+NO

[Source: Nieuwenhout et al. (2011)]

2.2 REALISED GENERATION FIGURES IN LOW AND HIGH RESOLUTION MODELS

Validation of the results

As mentioned in Section 2.1, the G&D scenarios (except for BAU) were constructed with the aim of achieving 80-95% emission reduction in 2050 compared to 1990 figures. Hence, the question is whether the envisaged emission reductions were achieved in the model runs and whether deviations can be explained.

To answer these questions, we compared the results of electricity capacity and generation in the four scenarios developed using low-resolution models, with calculations based on high-resolution models (Table 9).

Table 9 - Low and high resolution models used

Low-resolution models used	High-resolution models used
NTUA	RWTH HVAC++
ECN	RWTH HVDC
Imperial College	RWTH UHVAC

The most fundamental difference is between the low resolution models of NTUA and high resolution models of RWTH. Compared to the latter the former class of models is characterised by a less detailed network topology that does not account for congestion within countries and also does not allow for identification of network reinforcements within countries. NTUA and ECN models are characterised by exogenous implementation of generation and transmission capacity, while the Imperial College model endogenously optimizes transmission capacity and peak generation capacity. For a more detailed description of NTUA and ECN models is referred to Natemeyer *et al*. (2012) and for the Imperial College model to Castro *et al*. (2012). The high resolution models of RWTH are described in detail in Chapter 3.

Results of the validation: CO_2 emissions reductions

Figure 24 shows the realised CO_2 emission reductions relative to the year 2010 for the different G&D scenarios as simulated by the high-resolution network model of RWTH and low-resolution network model of ECN.

Two key findings can be derived from this figure. First, CO_2 emission reductions in 2030 are low (10-30%) in all G&D scenarios, except for the CCS scenario, compared to 2010 figures. According to Eurelectric (2010)[14] the total CO_2 emission from the electricity sector in the EU-27 was more or less flat in between 1990-2010. Therefore the CO_2 reduction percentages as given here for the period starting in 2010 are also valid for the period 1990-2050. Second, although the EC GHG emission reduction targets of 80-95% in 2050 are achieved in the low resolution models, they are not in the high resolution network models. This can be explained by the higher amount of RES curtailment in the high resolution model (see Figure 25), which requires additional regulating power to keep supply and demand in balance. This regulating power emits additional amounts of CO_2 and therefore lowers CO_2 emission reductions.

[14] See Figure 14 of Eurelectric (2010).

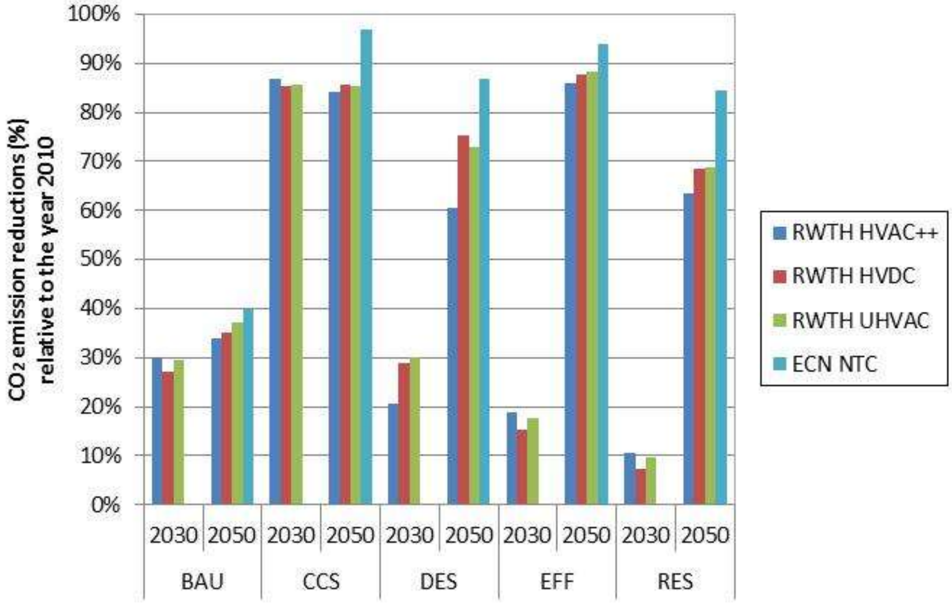


Figure 24 - EU-27+CH+NO CO_2 emission reductions in high (RWTH) and low resolution models (ECN) relative to the year 2010[15]

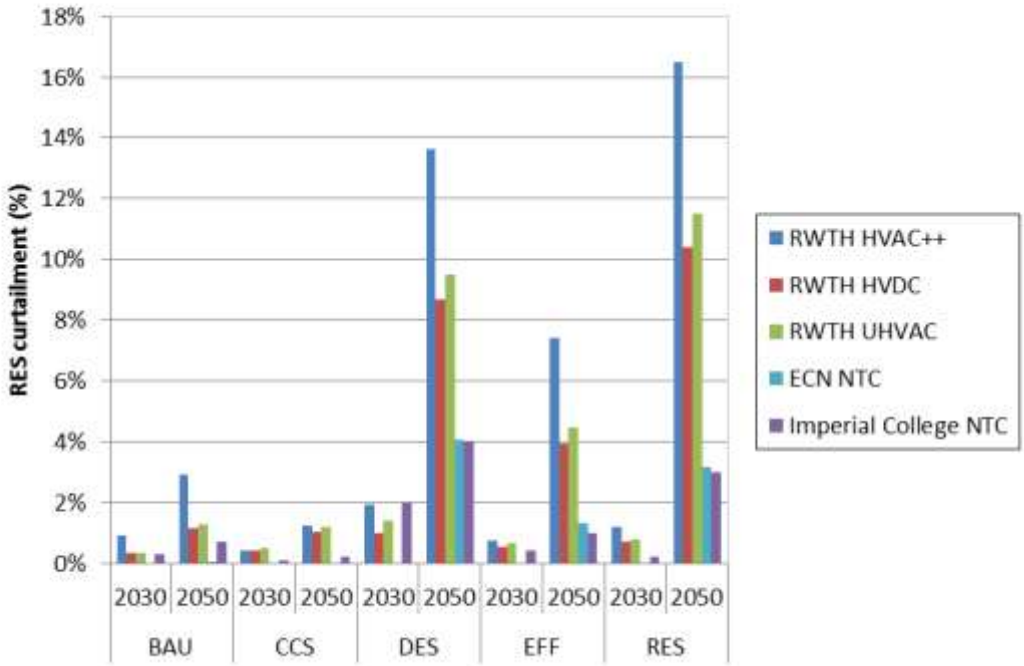


Figure 25 - EU-27+CH+NO RES curtailment in high (RWTH) and low (ECN, Imperial College) resolution network models[16]

[15] ECN figures are only available for the year 2050.
[16] ECN figures are only available for the year 2050.

Figure 25 shows low curtailment levels in 2030 (all G&D scenarios show 2% RES curtailment at maximum), while in 2050 much higher RES curtailment levels are realized due to higher network loading. In the ECN and Imperial College models curtailment levels increase up to 4% at maximum in the DES scenario, while in the RWTH analysis curtailment ranges from 10-16% in the RES scenario.

Differences between the low resolution models of ECN and Imperial College and the high resolution model of RWTH can be explained by:

- Higher network granularity of RWTH analysis, curtailment within countries is taken into account, while the Imperial College analysis considers only cross-border curtailment
- Different modelling approaches; ECN and Imperial College deploy optimization methods. The cross-border capacities of the Imperial College analysis is the starting point for the high resolution model of RWTH. RWTH has added network reinforcements within countries based upon load-flow analysis with heuristic flow identification.

Results of the validation: shares of renewable energy
Another important question is whether the envisaged shares of electricity from renewable energy sources (RES-E) is realized. Examples of realized electricity generation are shown below for BAU, CCS, DES, EFF and RES scenarios respectively. Results are shown for the high resolution HVDC network scenario constructed by RWTH (see Chapter 3).[17] Again, figures are shown for 2030 and 2050 in order to show developments in time.

2.2.1 BAU scenario

The business-as-usual scenario shows a nearly constant share of renewable electricity in total electricity production (see Figure 26).[18] Since a specific RES-E goal was not defined for the BAU scenario, this result cannot be qualified. The share of nuclear and gas fired generation decreases only marginally in the overall generation mix: they still provide 44% of electricity. Biomass and solar CSP show a 2% growth in the total renewables generation mix. The relative share of intermittent renewables (onshore and offshore wind as well as solar PV) is constant around 19-20% of total generation.

[17] Since this network technology scenario is selected as preferred network scenario in Chapter 3, these results are most relevant. Results for the UHVAC and HVAC network scenarios differ somewhat due to differences in curtailment and network losses. However, the shown production figures are representative for the other network scenarios.
[18] Figures in Section 2.2 are inspired by Joode *et al*. (2011).

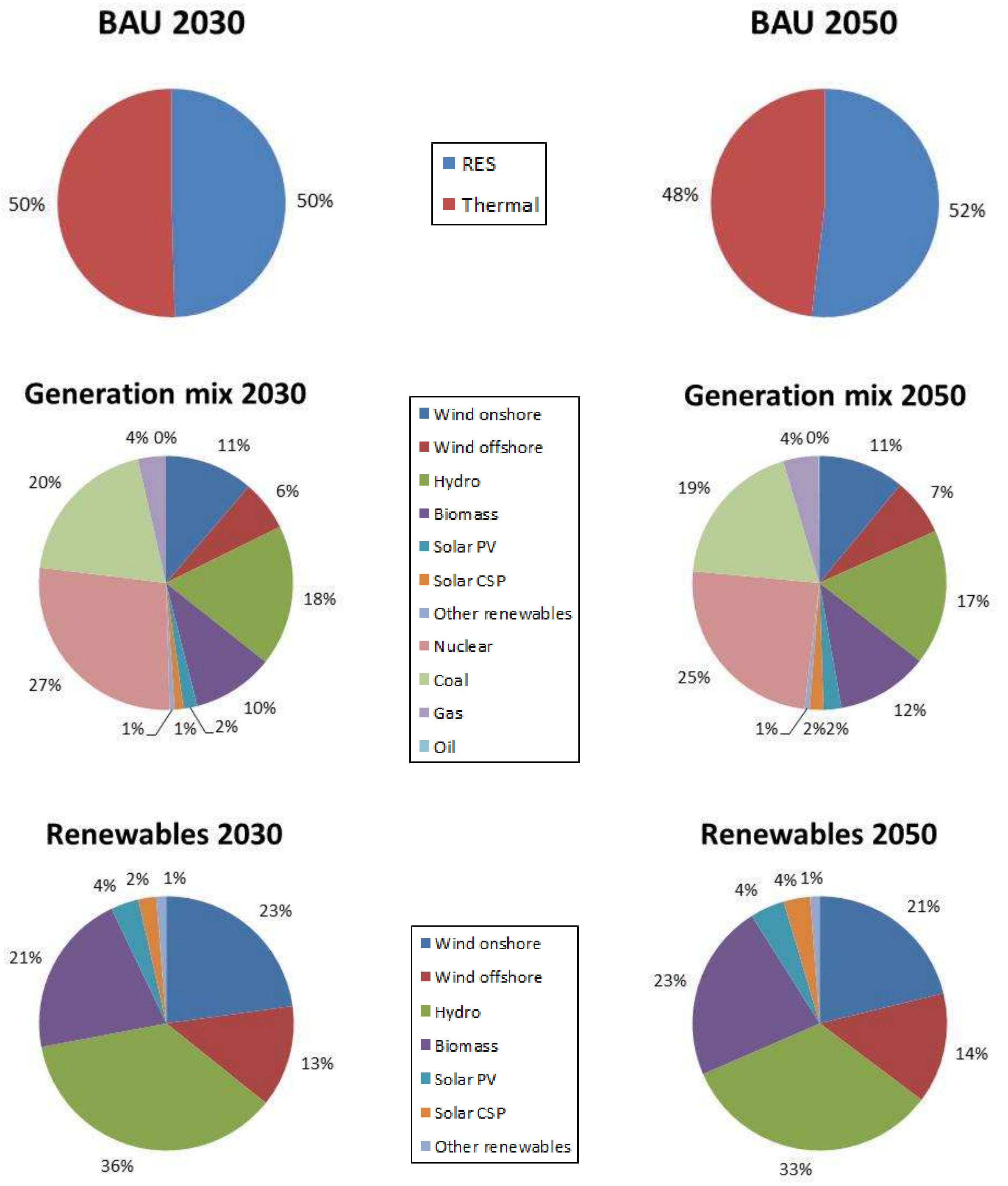
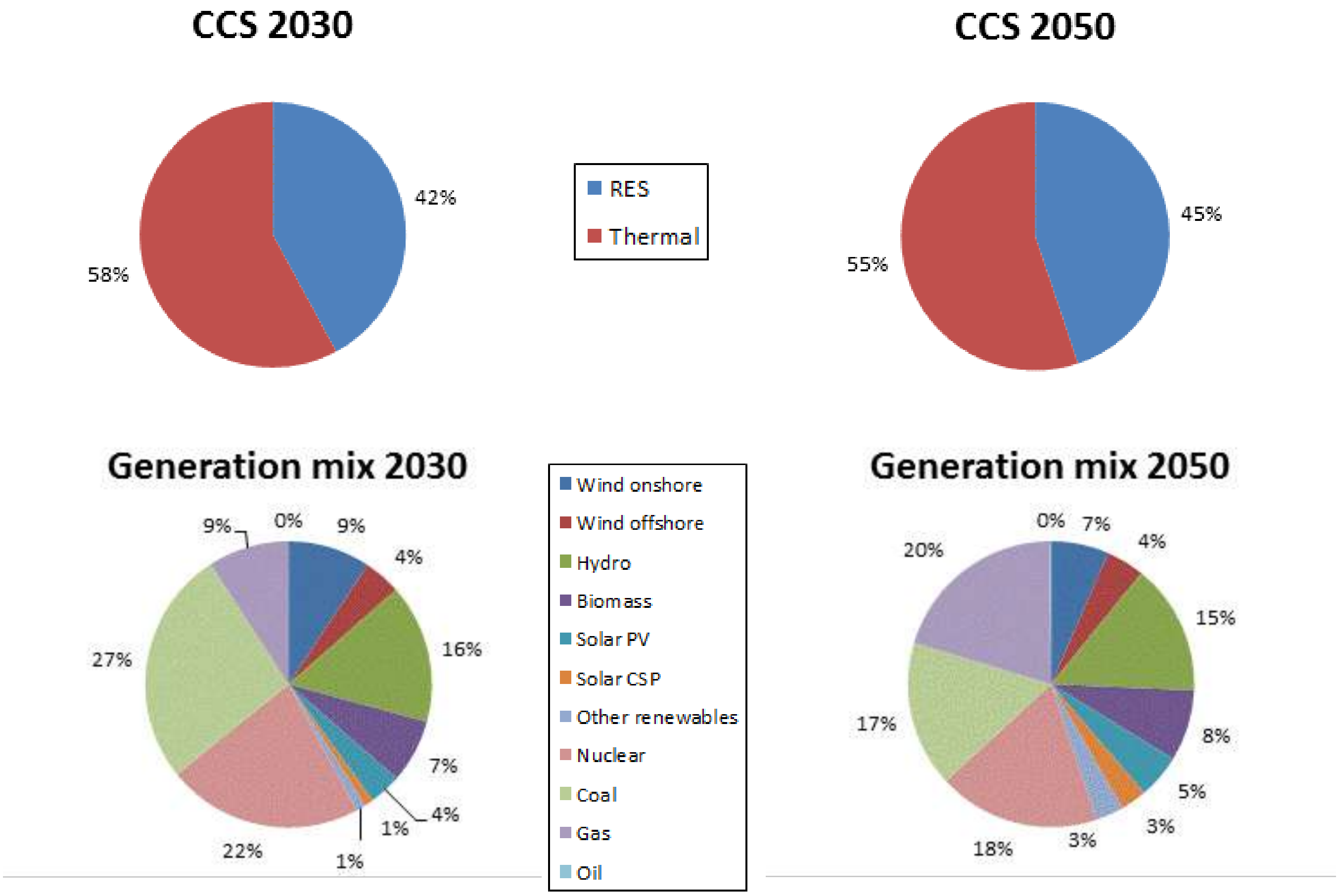


Figure 26 - EU-27+CH+NO generation mix in the BAU scenario[19]

[19] Total RES values reported by RWTH have been subdivided over renewable generation technologies by using the subdivision made in Nieuwenhout *et al*. (2011). This holds for all G&D scenarios.

2.2.2 CCS scenario

In the Carbon Capture and Storage scenario 77% of electricity is decarbonised, which means that the 80-95% GHG emission reduction goal is not achieved. Again, this results from higher than expected RES-E curtailment in the high resolution model. The scenario shows the same minor increase of the renewables share in total electricity generation as the BAU scenario in this case up to 45% (Figure 27). However, the share of gas fired generation increases considerably in order to allow for the deployment of CCS. Generation units deployed by CCS provide 32% of total net electricity production in 2050. RES generation is characterized by a major decline of wind onshore (with 8%), while the share of solar (both PV and CSP) as increases substantially with 7% of total RES generation.



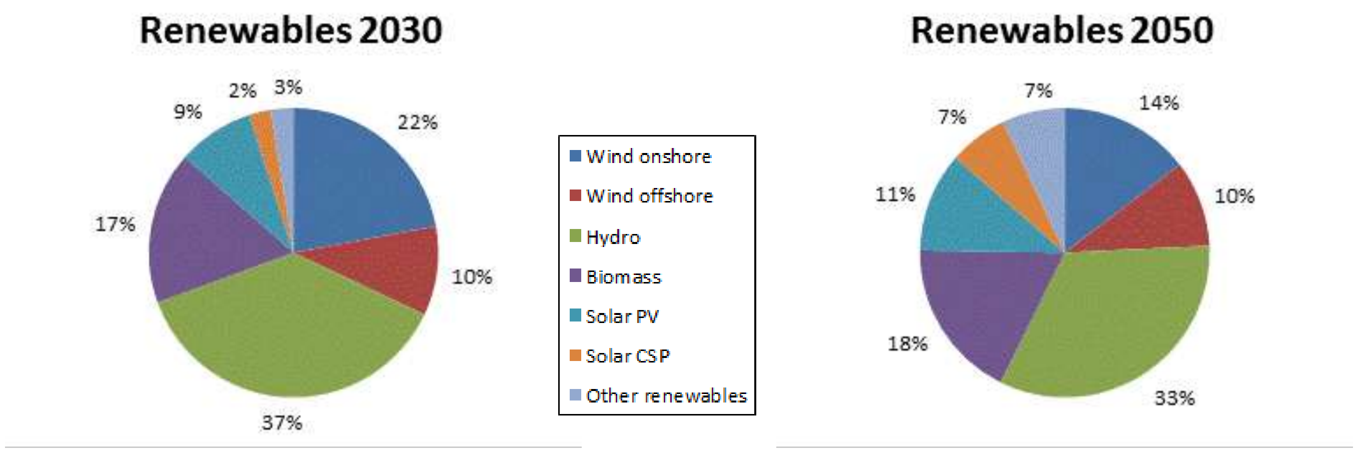
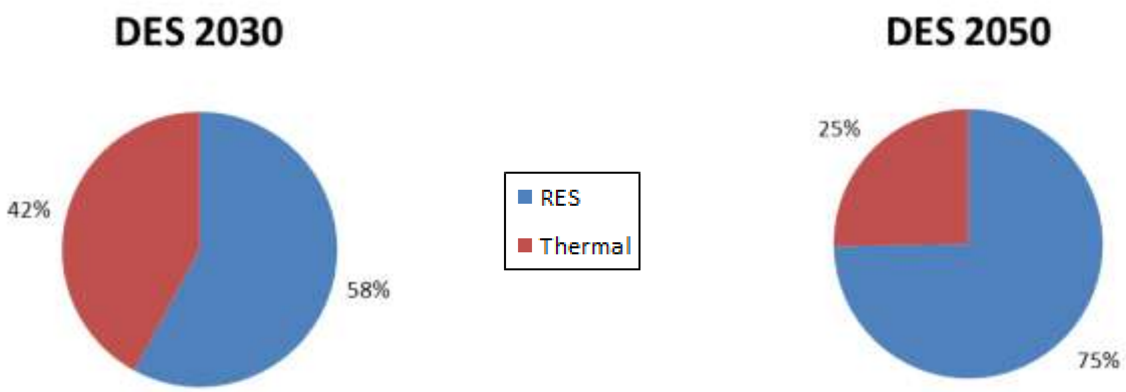


Figure 27 - EU-27+CH+NO generation mix in the CCS scenario

2.2.3 DES scenario

Figure 28 shows the generation mix for the DES scenario including the import from Northern Africa. The share of RES generation in overall generation increases by almost 20%. However, this is not enough to achieve the 80-95% GHG emission reduction goal. This results from higher than expected RES-E curtailment in the high resolution model as well as flexibility requirements. Concerning the distribution of RES-E, especially the share of wind offshore and solar PV technologies increases while the share of hydro decreases. Concerning thermal generation, the share of nuclear and especially coal fired generation decreases substantially while the share of gas fired generation increases in order to provide the flexibility for fulfilment of back-up and generation adequacy requirements.



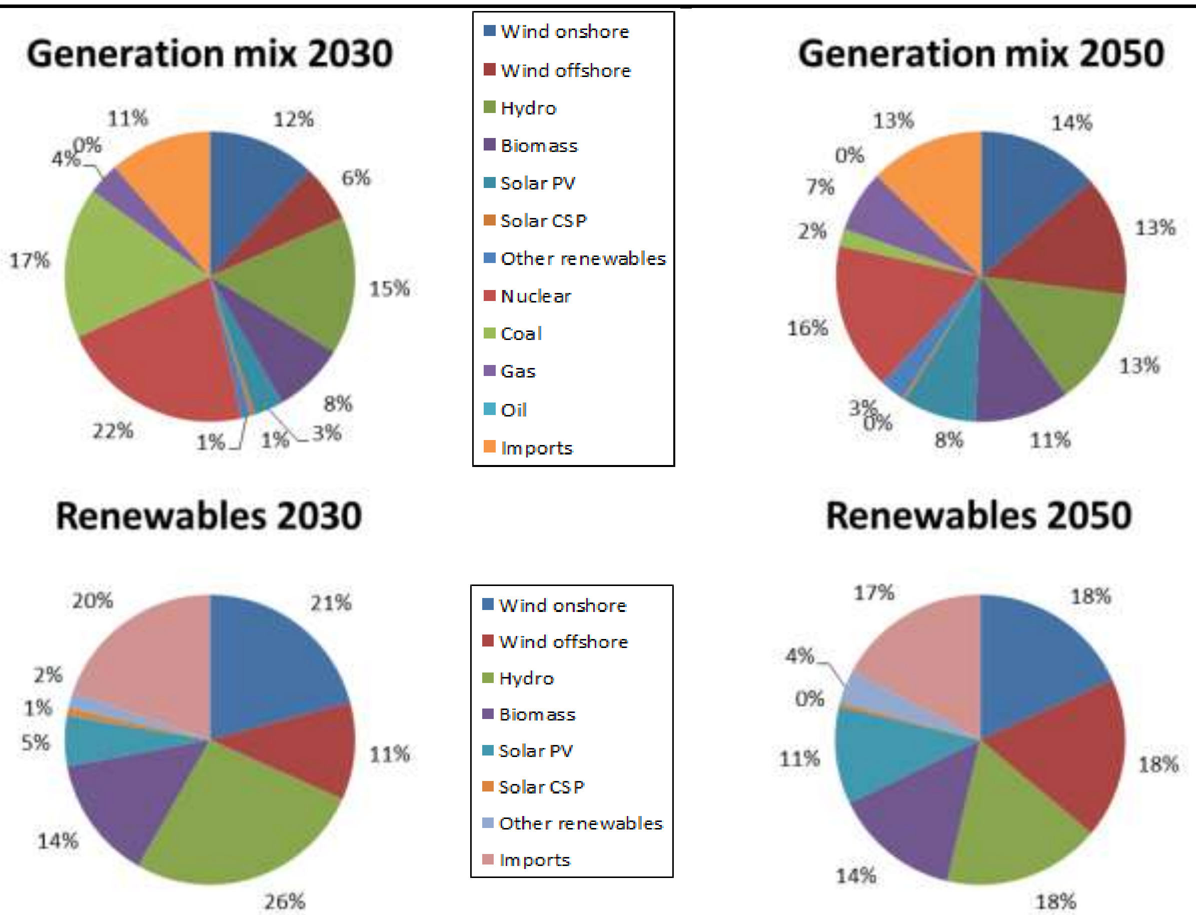


Figure 28 - EU-27+CH+NO generation mix in the DES scenario

2.2.4 EFF scenario

The high efficiency scenario is characterised by a substantial lower electricity demand as well as an envisaged 60% RES share. Figure 29 shows that the latter share is realized in the high-resolution model. Again, the share of solar technologies in the renewable generation mix increases, while shares of wind onshore and hydro decrease. Concerning fossil-fuelled generation, the 17% decrease of the share of coal in the 20 years period is most remarkable.

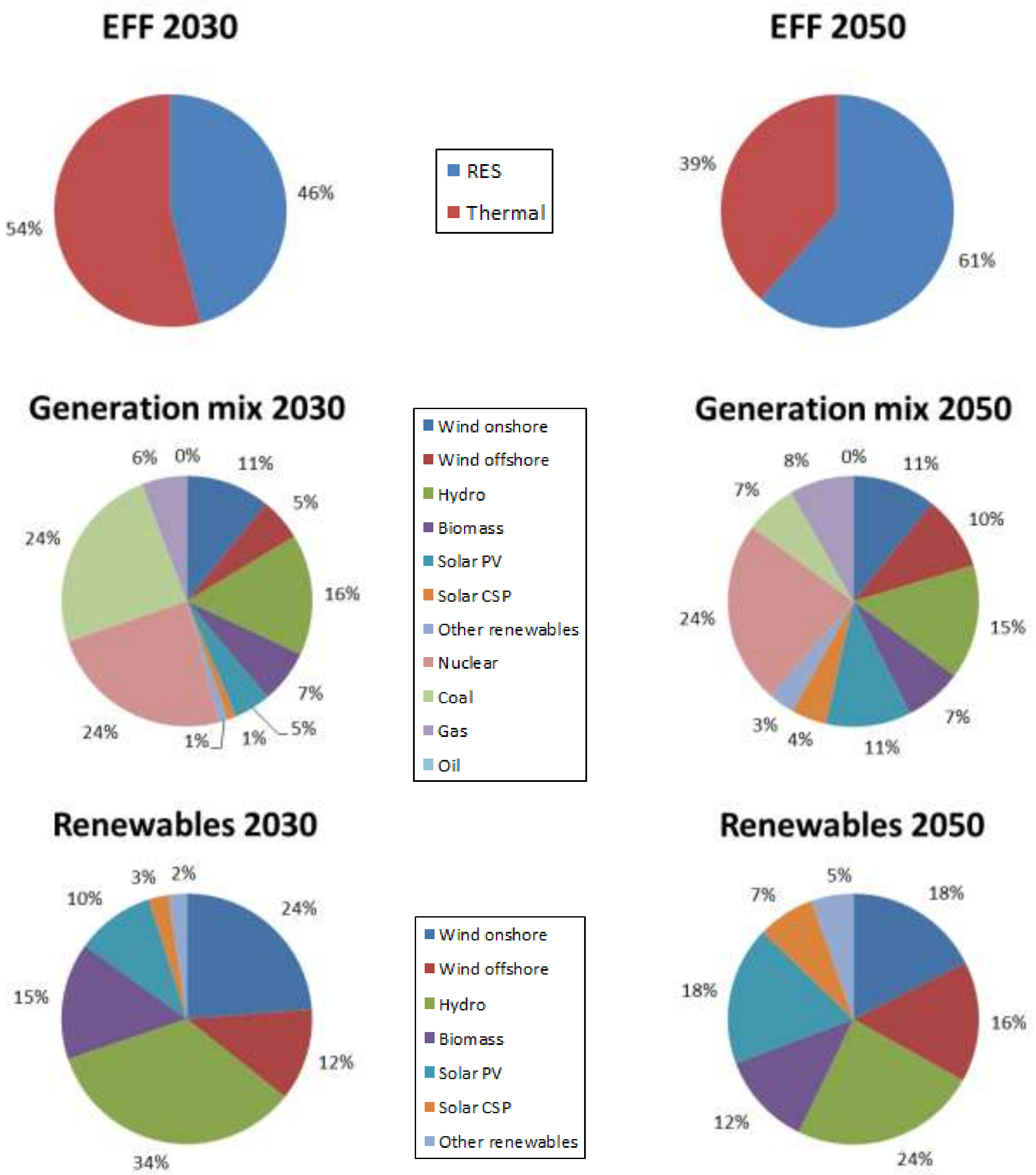


Figure 29 - EU-27+CH+NO generation mix in the EFF scenario

2.2.5 RES scenario

As Figure 30 illustrates, the renewables scenario does not reach the envisaged 80% of renewable electricity generation in the high-resolution model. Like the lower than envisaged CO_2 emission reductions, this can be explained by the higher RES curtailment in high-resolution network scenarios that take into account congestion within member states, instead of only congestion between member states. This also explains the higher need for additional production from gas-fired generation to cover demand in 2050 compared to 2030. Main growth of RES-E originates from solar and offshore wind technologies, mainly at the expense of coal generation.

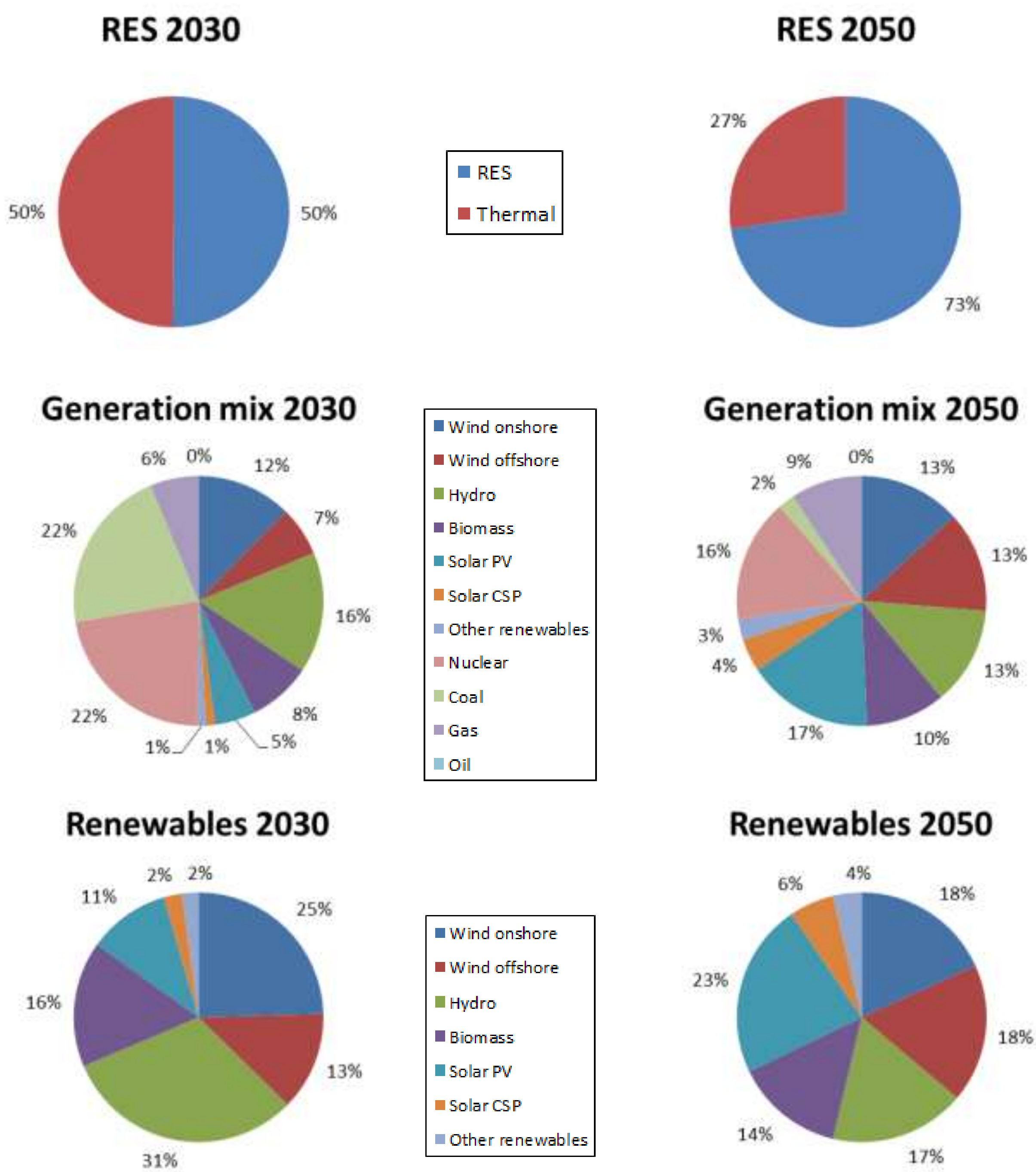


Figure 30 - EU-27+CH+NO generation mix in the RES scenario

2.3 HIGH-RESOLUTION SCENARIO RESULTS COMPARED TO OTHER 2050 G&D SCENARIOS

In the past already different scenarios until 2050 have been made, among others by stakeholders and research organizations like ECF (2010), Eurelectric (2011b) and IEA (2010b).[20] Furthermore, FP7 project Susplan[21] has constructed a couple of scenarios (Joode *et al*. 2011). Below the relative positions of IRENE-40 scenarios with respect to both electricity demand and generation shares in 2050 are summarized.

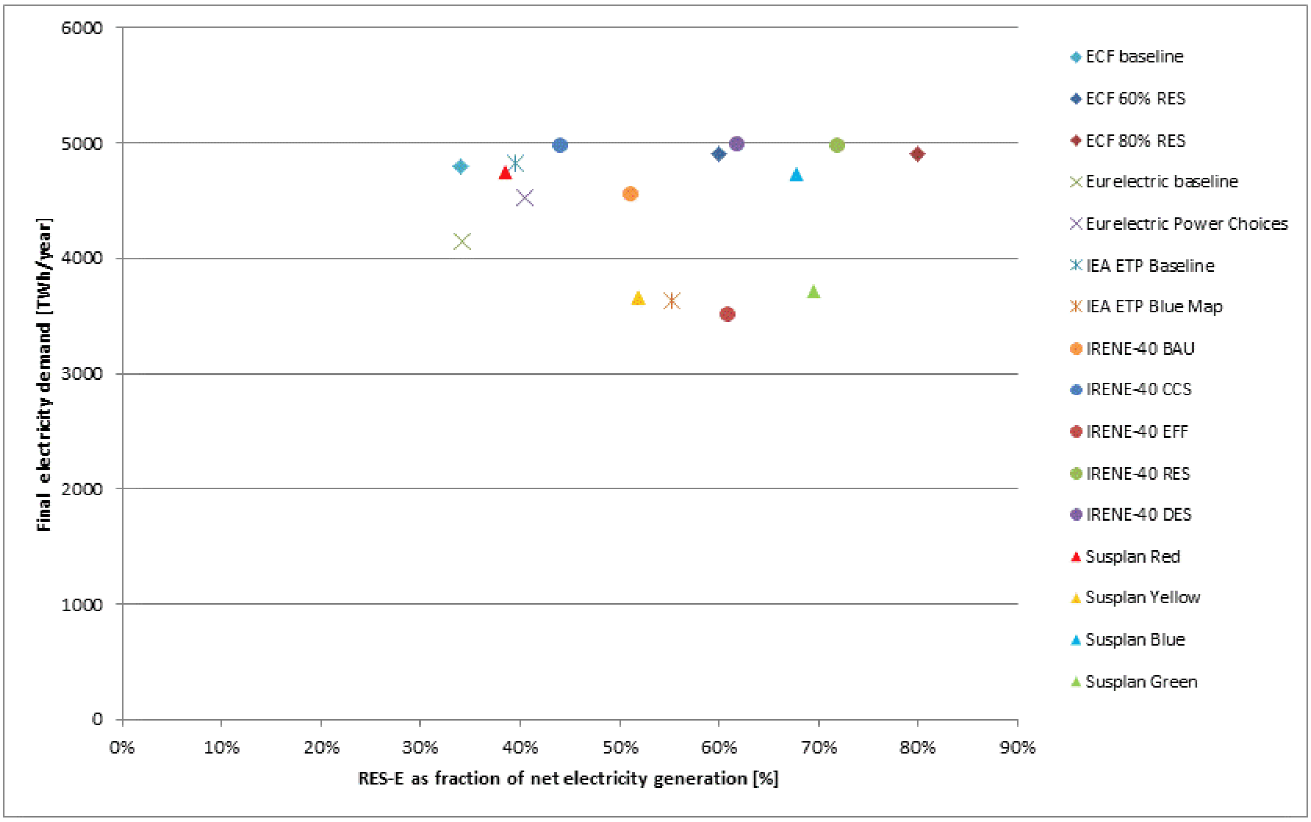


Figure 31 - Share of renewable generation in net electricity generation [%] versus final electricity demand[22]

The IRENE-40 RES scenario shows high shares of renewable and intermittent renewable generation[23], but is exceeded considerably by the ECF 80% RES scenario (see Figure 31 and Figure 32). The same holds for the IRENE-40 DES scenario despite the import of renewable energy from North Africa. Although calibrated upon the ECF 80% RES scenario, the RES-E share of the

[20] For more details on these scenario studies the reader is referred to Nieuwenhout *et al*. (2011).
[21] Given the focus on the year 2050, another relevant FP7 project, RealiseGrid, cannot be included in this comparison given its focus on the year 2030.
[22] DES does not include imports of electricity from Northern Africa. If imports are included, IRENE-40 DES is located on the right hand side of IRENE-40 RES.
[23] Intermittent generation is equal to electricity originating from wind generation (onshore and offshore) and solar-PV.

IRENE-40 RES and DES scenarios is somewhat smaller than expected due to curtailment and higher than planned utilisation of gas-fired power plants in high resolution models. The Susplan Blue and Green scenarios show also renewable shares which are lower than ECF 80% RES scenario but quite comparable to IRENE-40.[24]

Concerning final electricity demand in the high-resolution modelling results, IRENE-40 CCS, RES and DES scenarios show the highest final electricity demand values, in the order of 4,900-5,000 TWh per year, although differences with ECF scenarios and IEA ETP Baseline by definition are very small. Susplan Red and Blue scenarios show figures that are slightly below 4,800 TWh. In contrast, IRENE-40 EFF shows the lowest final electricity demand values, slightly lower than IEA blue map and Susplan yellow and green scenarios. Other scenarios are in between both scenario categories. Hence, IRENE-40 scenarios cover the whole final electricity demand range of other relevant 2050 scenarios considered.

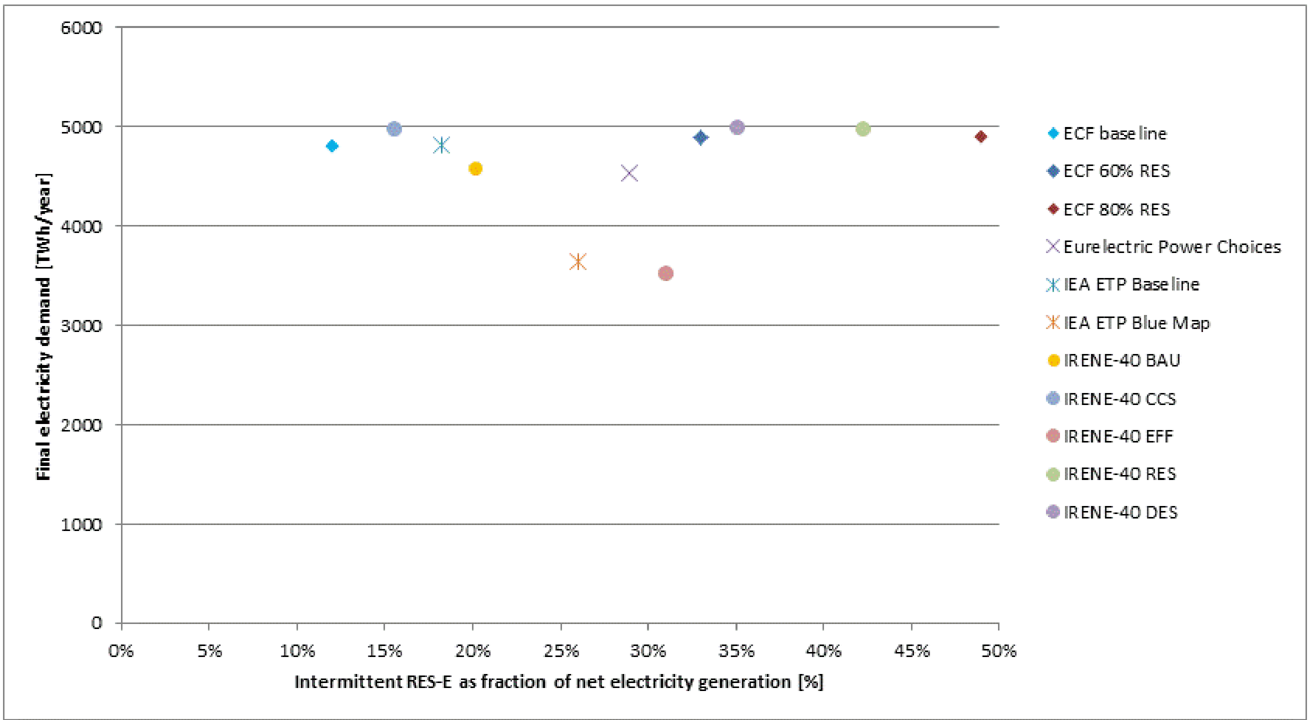


Figure 32 - Share of intermittent renewable generation in net electricity generation [%] versus final electricity demand[25]

[24] Susplan does not distinguish between offshore and onshore wind as well as between Solar PV and CSP respectively. For the latter reason, the intermittent RES-E share of Susplan scenario cannot be calculated.

[25] Again, DES does not include imports of electricity from Northern Africa.

2.4 CONCLUSIONS

This chapter started off by describing the construction of the G&D scenarios, their drivers and the main assumptions made. Four of the five scenarios (except BAU) were constructed assuming compliance with the EU policy objective to achieve GHG emission reductions of 80-95% by 2050 compared to 1990 levels.

Validation of the results with network models showed that realised CO_2 emission reductions in high resolution models are lower than expected for the CCS, DES and RES scenarios (ranging from 73-77%). This can be explained by the higher amount of RES curtailment in high resolution models which lowers the RES-E share and requires additional regulating power to keep supply and demand in balance. This regulating power emits additional amounts of CO_2 and therefore lowers CO_2 emission reductions. This shows the necessity of considering congestions and network reinforcements within countries when assessing the viability of long-term G&D scenarios with high shares of renewables.

Up to now, other EU-wide studies constructed only G&D scenarios based on low resolution models. This explains also the position of the IRENE-40 scenarios to these other studies. While IRENE-40 scenarios cover the whole final electricity demand range of other relevant 2050 scenarios the ECF 80% RES scenarios shows a higher RES-E share.

All in all, the G&D scenarios were quite useful for illustrating the diverse network developments in different possible electricity system futures.

3 DEVELOPMENT OF NETWORK SCENARIOS FOR THE PERIOD 2020-2050

3.1 POINTS OF DEPARTURE FOR NETWORK SCENARIO DEVELOPMENT

Within the IRENE-40 project, different network scenarios have been designed and investigated that are able to accommodate the generation and demand developments as depicted in Chapter 2, whilst meeting a set of key design criteria related to three different policy perspectives:

- Sustainability (Natemeyer *et al*. 2012)
- Security of supply (Chatzivasileiadis *et al*. 2012)
- Competitiveness or affordability of energy (Castro *et al*. 2012)

These studies are published in the D3.1 report (Gaxiola *et al*., 2012).

Methodology of developing the network scenarios

For all network scenarios, the cross-border network reinforcements for 2050 as identified by Castro *et al*. (2012) based upon economic static optimisation have been taken as point of departure for all years of analysis (2030, 2040, 2050). In fact, all network reinforcements are assumed to be realized already before the year 2030.

Complementary, for provision of a more detailed picture these cross-border network capacities have been divided over possible interconnection corridors, which have been analysed in higher granularity. Network extensions within countries have been identified by load flow analysis and heuristic flow methods by Roehder *et al*. (2012). Specific network technologies have been attached to the network reinforcements.

A congested line has been reinforced when the simulation of the RES 2050 G&D scenario showed that a component is utilized for 90% or more, for more than 2,000 hours a year. It has been assumed that the RES G&D scenario is the scenario with the highest demand for network reinforcements and hence covers the other generation and demand scenarios adequately as well.

Furthermore, network reinforcements have been performed to address ecological weak network points (EWNP). These EWNPs are defined as “points and regions in the grid where a substantial amount of energy from intermittent renewable energy sources remains unused as the network is unable to completely transmit it to the load centres”, Natemeyer *et al*. (2012). EWNPs are identified by integrating the electricity production of intermittent renewables into the optimal power flow as dispatchable generators providing power at a zero cost level.[26]

Taking these conditions for reinforcement, a congested line is reinforced by:

- Voltage upgrade (if voltage < 300 kV)

[26] For more details of the methodology for identification of EWNPs refer to Natemeyer *et al*. (2012).

- Line replacement (if rating < 2,500 MVA in case of onshore overhead lines (OHLs), or if rating < 2,000 MVA in case of subsea cable)
- Network reinforcement by either new lines or cables and supporting equipment such as conversion technologies (including transformers), dependent on network scenario at hand as well as type of connection required (HVDC or UHVAC overlay versus HVAC extension).

3.2 THREE NETWORK TECHNOLOGY SCENARIOS

Since it is important to identify network scenarios that meet all three different policy objectives, Roehder *et al*. (2012) developed three overarching network scenarios (European lay-outs), applying the design criteria and procedures described in section 3.1. These scenarios differ by the main *network technologies* considered:

- **HVAC++ network**, mainly 380 kV AC OHL technology supplemented by Phase-Shifting Transformers (PSTs) and Flexible AC Transmission Systems (FACTS) for higher power flow controllability
- **HVDC overlay network** operating on 500 kV, in addition to the existing HVAC+ network
- **UHVAC overlay network** operating on 750 kV and supplemented by PSTs and FACTS for higher power flow controllability, in addition to the existing HVAC+ network.

In these scenarios, all reported network extensions are incremental to a network reference scenario: the HVAC+ scenario. The HVAC+ scenario is based upon the existing transmission system in 2010 plus the grid expansions foreseen by ENTSO-E until 2020 (ENTSO-E, 2010). No grid expansions after 2020 are assumed.

Network extension figures for these three network technology scenarios, both corridor length and concomitant investment cost figures, are shown in Table 10.

Table 10 - Required investments and investment cost figures

Network components	Technology		Investment needs			Unit cost	Total investment costs		
	AC/DC	OHL/cable	HVAC++	HVDC	UHVAC		HVAC++	HVDC	UHVAC
			Line length [km][27]			[€2030/ km]	[m€2030]		
Transmission technologies									
750kV 3900MVA single circuits	UHVAC	OHL	0	0	65.956	1.100.000	0	0	72.552
400kV 3000MVA double circuits	HVAC	OHL	39.701	23.017	22.166	1.672.000	66.380	38.484	37.062
500kV 2500MW bipole	HVDC	OHL	0	87.786	0	925.000	0	81.202	0
500kV 2000MW XLPE bipole	HVDC	Cable	8.081	8.081	8.081	1.347.000	10.885	10.885	10.885
Subtotal							*77.265*	*130.572*	*120.498*
Conversion technologies			# components			[€2030/MVA]	[m€2030]		
750/380kV 500MVA Transformer	UHVAC		0	0	680	19.000	0	0	6.460
400/220kV 1000MVA Transformer	HVAC		688	683	683	10.510	7.231	7.178	7.178
400/400kV 1630MVA PST	HVAC		200	0	230	20.000	6.520	0	7.498
300MVAr SVC	(U)HVAC		11	0	51	200.000	660	0	3.060
500kV 2000MW VSC module	HVDC		48	180	48	83.000	7.968	29.880	7.968
Subtotal							*22.379*	*37.058*	*32.164*
Total							99.644	167.630	152.663

[Source: RWTH, presentation: ECN]

[27] Line lengths of single and double circuits are not comparable with each other, hence they cannot be summed up.

The following section provides a short summary of the characteristics of the three network technology scenarios: HVAC++, HVDC overlay and UHVAC overlay network scenarios.

HVAC++ network scenario

As a result of the weak network point analysis for the RES scenario, about 500 crucial extension projects have been identified and are implemented in the HVAC++ scenario. Furthermore, cross-border transmission capacities have been upgraded with additional physical network capacity equivalent to 262 GW of network capacity available for trading purposes (NTC).

The total number of reinforced HVAC lines amounts to 575 lines. As Table 10 shows about 200 PSTs have been incorporated in the cross-border transmission lines increasing the power flow controllability between the connected countries. The overall development is complemented by the installation of further network components such as transformers (687 substation upgrades) and switchgear.

In addition to the new HVAC lines, cross-border network capacity between Britain and Scandinavia to Continental Europe are upgraded by five additional HVDC subsea interconnections:[28]

- France – UK
- The Netherlands – UK
- Denmark – Norway
- Germany – Sweden
- Norway – Great Britain.

Additionally HVDC subsea interconnections are operated between:

- Ireland – Great Britain
- Bosnia and Herzegovina – Italy.

The transmission system's primary voltage level for its HVAC network is fixed at 380 kV with some exceptions of 330 kV and 220 kV. In total 40,000 km of new lines (resulting in 88,000 km of circuits) need to be build, resulting in investments of about 99 b€ based on 2030 cost figures. Figure 33 below presents the resulting grid being used in the HVAC++ scenario for the decades 2030 onwards. Enhancements of the HVAC network are highlighted in red color, new HVDC subsea cables are highlighted in light blue.

Note that the long-distance energy transmission in this network scenario is limited; this results in a significantly higher curtailment level than in the HVDC and UHVAC network scenarios, as shown in Section 2.2.

[28] Interconnection consist of several HVDC systems (2-5) with a power rating of 2,000 MW and operating operating at 500 kV (cables + voltage source converter modules).

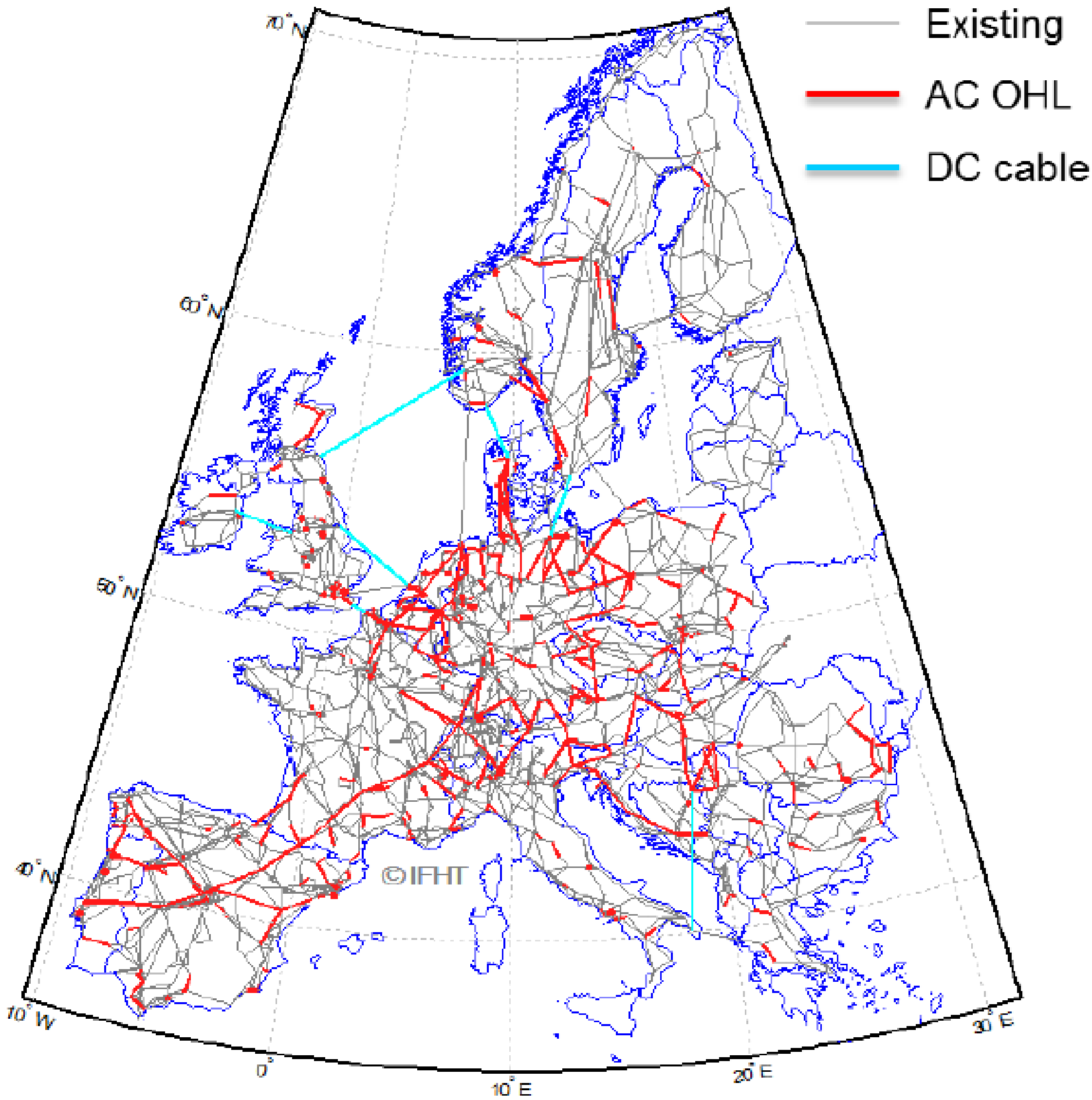


Figure 33 - HVAC++ network scenario grid expansion

[Source: Roehder *et al*. 2012]

HVDC overlay network scenario

Considering the high levels of curtailment in the HVAC++ scenario, this scenario supplements the HVAC system with 69 HVDC overhead lines, to be added and also the 7 subsea HVDC cables included in the HVAC++ network scenario. The operation of the HVDC network requires about 180 2,000 MW VSC modules to be installed.

Furthermore, the HVAC network needs to be extended for the establishment of robust links between the overlay network and the underlying 380 kV grid as well as further necessary reinforcements within the HVAC transmission system. This requires about 23,000 km of double circuits (46,000 km of circuit length) with concomitant 400/220 kV transformers and leads to additional investment needs of € 46 billion based on 2030 investment cost figures.

Again, cross-border transmission capacity has been upgraded in several places with additional physical network capacity equivalent to 262 GW of network capacity available for trading purposes (NTC).

Figure 34 shows the results of extension of the HVDC network. The figure does not show the foreseen extension of the HVAC network. The black numbers on the lines indicate the number of transmission systems, each having a physical transmission capacity of 2,000 MW (sea cable) and 2,500 MW (onshore OHL) respectively. The red numbers indicate the number of parallel 2,000 MW VSC modules to accommodate the transport of power.

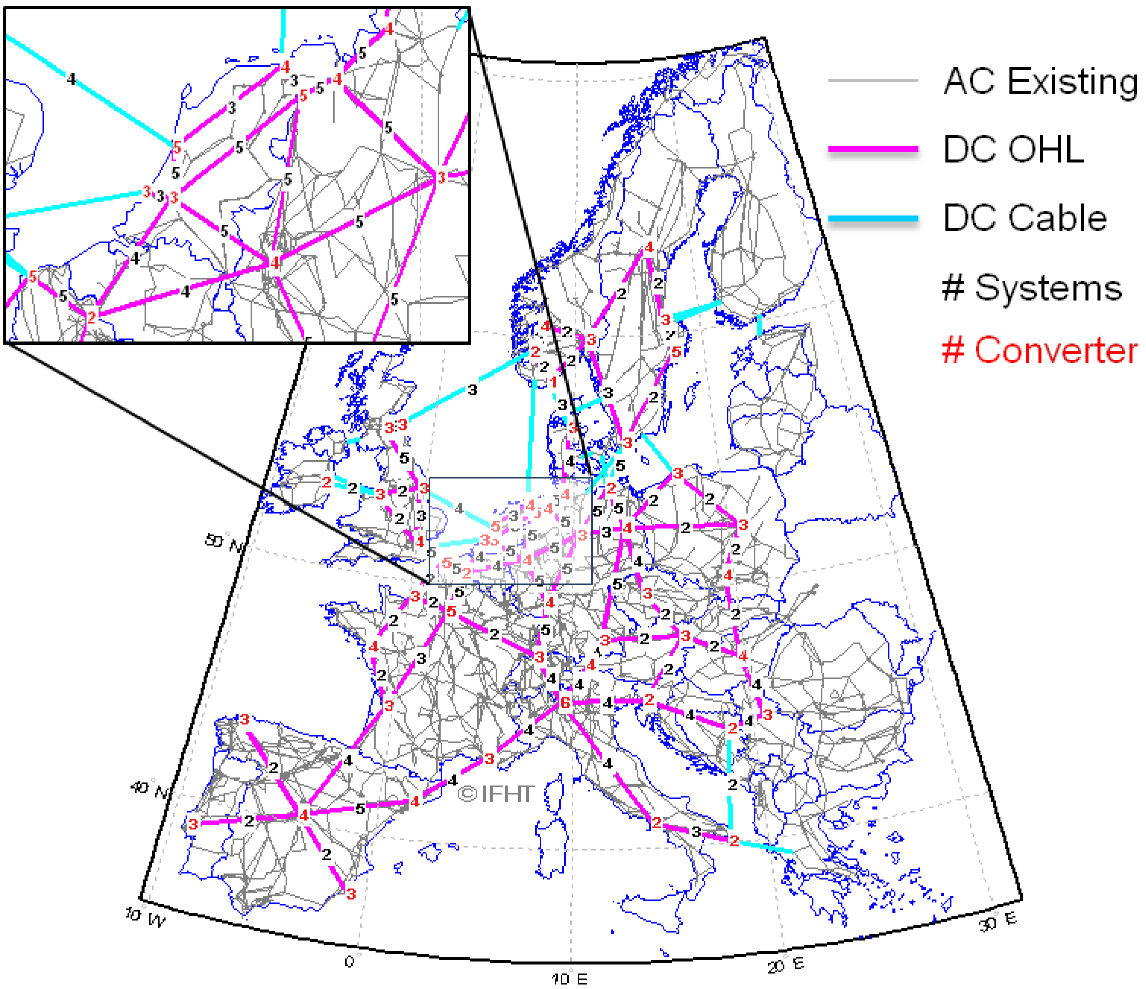


Figure 34 - HVDC network scenario - transmission system including HVDC grid overlay

[Source: Roehder *et al*. 2012]

The results suggest that most new network infrastructure in capacity terms is required in the North Sea area (mainly north-south lines), internal North-South connections within Germany, the Alpine region, and for the France-Spain interconnection.

UHVAC overlay network scenario

To further address limitations of the two previous scenarios, 67 UHVAC overhead lines have to be added as well as the concomitant phase shifting transformers (PSTs) at each substation, to allow for a certain degree of controllability of the power flows within the overlay. The substations are complemented by static VAR compensators in order to stabilize the interface points and to supply the reactive power demand with respect to line utilization.

Difficulties occur in connecting Great Britain and Scandinavia with the synchronized grid of continental Europe. Since overhead lines are no feasible solution, AC subsea cables would be needed to fulfil this task. However, to current knowledge AC cables are unlikely to become available for ultra-high operation voltages (e.g. 750 kV), and do not constitute a solution for the high reactive power compensation requirements (Chatzivasileiadis *et al*. 2012). As a consequence, an uniform, pan-European grid overlay interconnecting continental Europe with Great Britain and Scandinavia cannot reasonably expected to be established without the usage of HVDC technology at these specific interconnections. Therefore, part of the necessary connections for the establishment of a real, pan-European grid overlay are realized by means of HVDC point-to-point connections based on HVDC subsea cables instead of UHVAC technology.[29]

Furthermore, the HVAC network needs to be extended for the establishment of robust links between the UHVAC overlay network and the underlying 380 kV grid as well as further necessary reinforcements within the HVAC transmission system itself. This requires about 22,000 km of double circuits (44,000 km of circuit length) with concomitant 400/220 kV transformers and leads to additional investment needs of € 44 billion based on 2030 investment cost figures.

As in the other scenarios, cross-border transmission capacities have been upgraded with additional physical network capacity equivalent to 262 GW of network capacity available for trading purposes (NTC).

Figure 35 provides an overview of the general structure of the UHVAC grid overlay and its integration into the existing transmission system. The black numbers on the lines indicate the number of parallel transmission systems. The required HVDC connections are highlighted as well. The red numbers quote the number of parallel converter modules in the converter stations.

[29] Note that such interconnections could technically also be realized by means of GIL (or future Power Transmission Pipeline (PTP)) with impact on transmission losses (ECF, 2010).

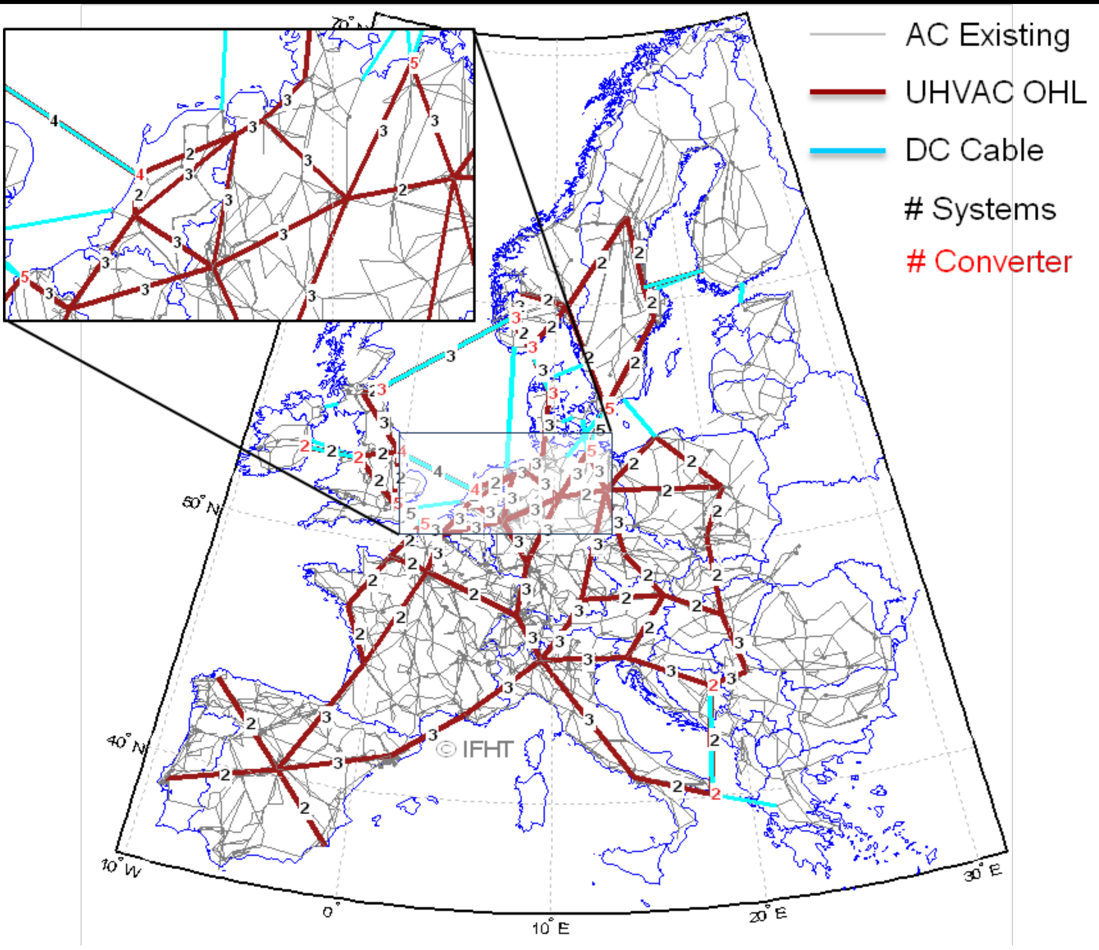


Figure 35 - UHVAC network scenario - transmission system including UHVAC grid overlay

[Source: Roehder *et al*. 2012]

3.3 SELECTION OF PREFERRED NETWORK SCENARIO

For developing a policy roadmap, emphasis will be put on the so-called preferred network technology scenario. This scenario is identified as most promising in the network analysis, provided the three policy perspectives sustainability, security of supply and affordability, and taking into account the different possible developments in electricity generation and demand, as discussed in chapter 2. The followed selection process is elaborated upon in the remainder of this section.

Sustainability and competitiveness perspectives starting point for modelling analysis
In Roehder *et al*. (2012) the starting point for the modelling analysis are two policy objectives i.e. the need for grid expansion from competitiveness and sustainability perspectives. The economic optimization results of Castro *et al*. (2012) form the basis for the identification of the need for grid expansion. Since the optimization is made including CO_2 emission costs and is supplemented with the need for grid expansion for addressing ecological weak network points the sustainability perspective is fully covered as well.

Figure 36 shows the annualized net system benefits per year of additional transmission capacity of the three network scenarios compared to the HVAC+ reference scenario. The net system benefits consist of the annualized generation cost savings minus annualized network investment costs and network losses. This figure shows all costs in euros of the separate years i.e. net benefits for 2030, 2040 and 2050 are expressed in $€_{2030}$, $€_{2040}$ and $€_{2050}$ respectively.

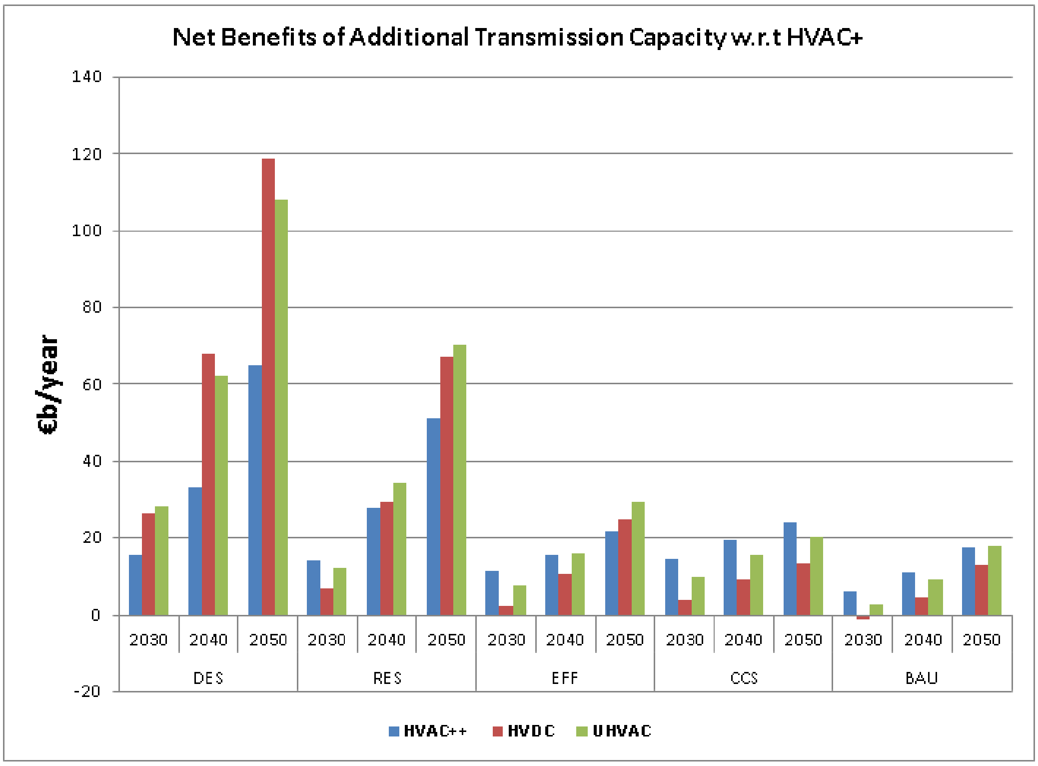


Figure 36 - Annualized net benefits of additional transmission capacity w.r.t. HVAC+ in EU-27+CH+NO

[Source: Roehder *et al*. (2012)]

For adequately comparing costs and benefits, it is common practise to calculate the net present value (NPV) of cash flows that are realized at different points of time. Most essentially, with the NPV method all costs and benefits are expressed in euros of the same year, for this analysis $€_{2010}$. Figure 37 shows the NPV of additional transmission capacity of the three network scenarios compared to the HVAC+ reference scenario.

For calculating the NPV the following assumptions are applied:

- All network investments are taking place before 2030 i.e. at the end of the year 2029 since benefits of grid expansion are realised from 2030 onwards.
- Economic lifetime of new network assets is 40 years. In order to calculate benefits and costs over commensurate periods, generation cost savings are calculated for the period 2030-2070. It is assumed that generation cost savings obtained for the years 2030, 2040 and 2050 as model

outputs (Roehder *et al*. 2012) are the yearly savings for the periods 2030-2039, 2040-2049 and 2050-2069 respectively.

- A real discount rate for network investments of 5.5% reflecting both the risk free rate of return as well as the compensation for a sector-specific risk for a regulated investor (TSO). This discount rate is used for discounting network investment costs as well as network losses costs. For generation savings a slightly higher real discount rate of 6.5% is used, since investors in electricity production operate in a more risk sensitive sector.
- In addition to the network investment costs as shown in Table 10, following Roehder *et al*. (2012) for the Desertec scenario additional network investment costs of approximately € 50 billion are assumed. This reflects the need for additional network infrastructure between Southern Europe (Italy and Spain) and Northern Africa.[30]

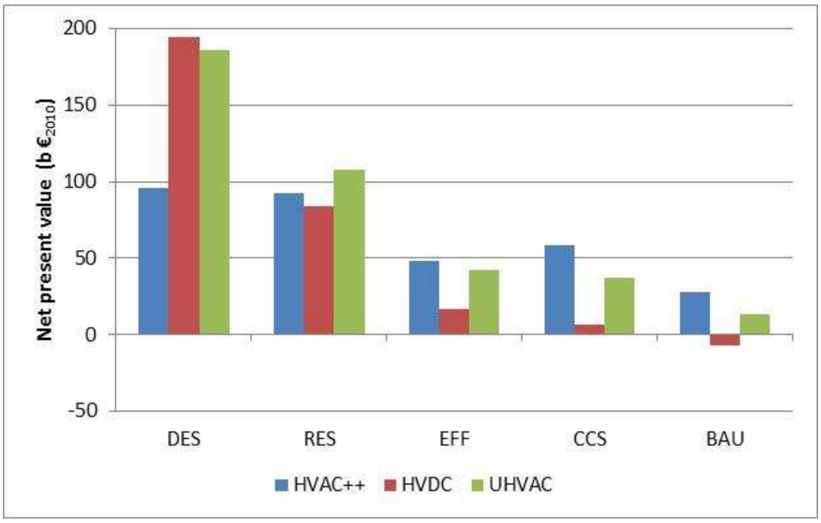


Figure 37 - Net Present Value of additional transmission capacity w.r.t. HVAC+ in EU-27+CH+NO

[Source: ECN]

Figure 37 shows that net benefits of overlay scenarios (e.g., HVDC and UHVAC) are more pronounced in the G&D scenarios where both the share of intermittent renewable energy and demand levels are high:

- The highest net benefits of the overlay scenarios (HVDC and UHVAC) are observed in the DES scenario where the net benefits are significantly higher than in the HVAC++ scenario.
- The net benefits of the RES scenario are highest when the UHVAC overlay network is rolled out. The HVAC++ and HVDC overlay deliver comparable results given the uncertainty margin around cost and benefit estimates. Figure 38 shows that operational generation cost savings of the HVDC overlay are significantly higher than the savings of the HVAC++ network, but the higher network investment costs of the former compensate for the difference.

[30] As well as the costs for additional transmission capacity between Napoli and Milan which are not included in the cost estimates of Roehder *et al*. (2012).

- In EFF, CCS and BAU scenarios which are characterized by lower shares of intermittent RES and in the case of the EFF scenario, also significantly lower electricity demand, the HVAC++ network followed by UHVAC and HVDC overlay networks shows the highest net benefits.
- Especially the CCS and BAU scenarios exhibit a lower need for overlay networks. Figure 38 shows that the differences between network scenarios mainly result from differences in network investment costs; operational generation cost savings of the three network scenarios are comparable. This result can be explained by the significant share of power generated by conventional thermal technologies closely located to the load centres in the CCS and BAU scenarios, limiting long-distance transport demand. Hence, HVDC and to a lesser extent UHVAC overlay networks do not deliver enough added value for these G&D scenarios.

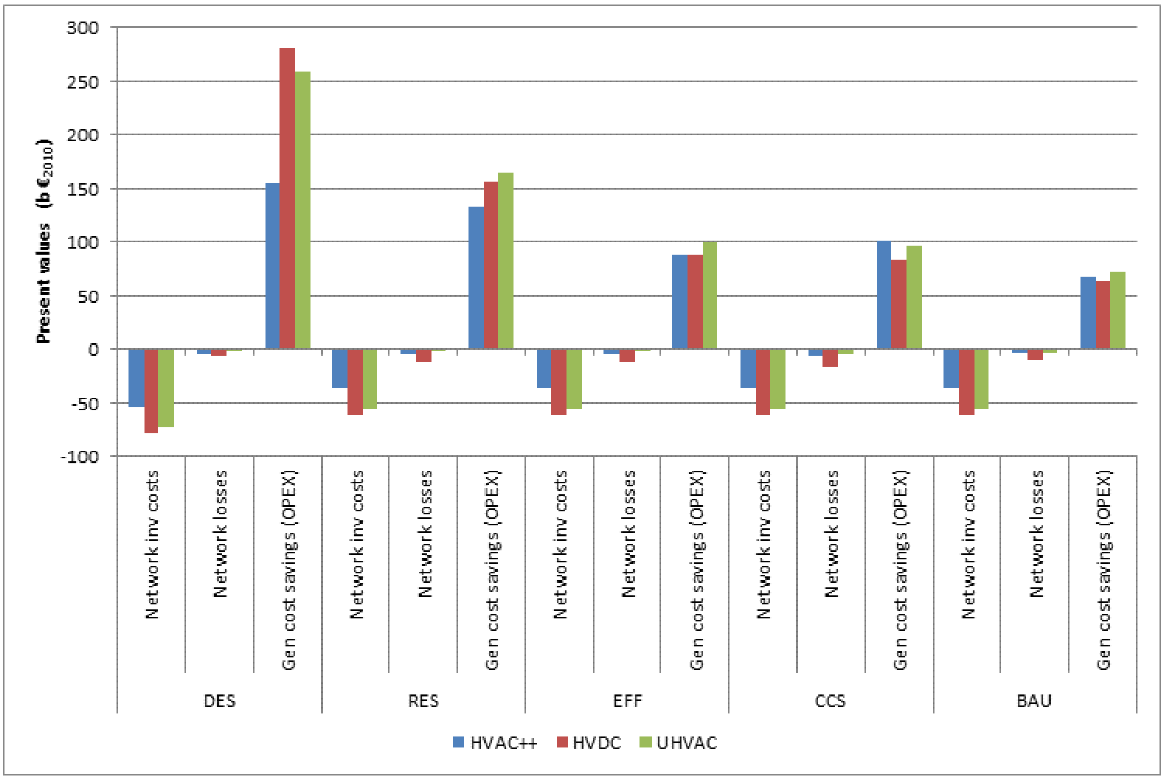


Figure 38 - Present Values of benefit and cost items of additional transmission capacity w.r.t. HVAC+ in EU-27+CH+NO

[Source: ECN]

When interpreting the results it is important to account for the following three limitations. First, the results might also be to a certain extent due to the design of network scenarios which are established based on the network expansion needs in RES and DES scenarios; not in particular for EFF, CCS, and BAU scenarios.

Second, the analysis shows the **incremental** NPV compared to the HVAC+ reference scenario. It does not provide a picture on the **overall** net system benefits for three reasons. Most importantly, since the generation investments are assumed to be exogenous to all network scenarios and equally sized in all of them, costs of generation investments in the period 2020-2050 are not included in both Figure 37 and Figure 38. However, in practise these costs are very substantial; from cost figures reported in Castro *et al*. (2012) it can be derived that the incremental generation costs range from 2389 b€ (BAU) to 5063 b€ (DES) for the period 2010-2050.[31] This implies that the higher operational generation cost savings of DES and RES scenarios are likely to be outweighed by higher generation investment costs. Furthermore, required investments in electricity distribution infrastructure, which are needed for the connection and transport of electricity from planned distributed generation (solar PV, dispersed onshore wind, small hydro, biomass and CHP plants) in the G&D scenarios are not taken into account. Finally, apart from the costs of network losses, further operational and maintenance (O&M) costs for managing the additional transmission infrastructure are not included.

Another important limitation is the implicit assumption that future G&D developments are known perfectly in advance i.e. perfect information. Obviously, the selection of the best performing network scenario will be straightforward if this is the case. However, G&D developments are uncertain; in 2030 another network technology may be required to facilitate the G&D scenario than in 2050. Hence, in 2050 it is known what would have been the best of the three network investment scenario choices per G&D scenario.

Since the average economic lifetime of network assets (an average lifetime of 40 years is standard) is certainly longer than the average lifetime of generation assets (approximately 30 years, whilst a lifetime of 20 years for renewable generation is no exception) this can easily lead to stranded network assets with associated costs for consumers. With hindsight, network planners in 2050 will sometimes regret the choice they have made. Therefore, a more robust approach is to choose a network scenario which results in the least of maximum regret under the alternative five G&D future developments.

The regret matrix in Table 11 shows the difference of net benefits in 2050 between the network scenario chosen in 2030 and the network scenario which actually gives the maximum benefits in 2050 for the corresponding G&D scenario. By definition, regret is zero if the network scenario chosen in 2030 is the one which gives the maximum net benefits in that particular G&D scenario.

Table 11 - Regret of network choice in 2050 under each G&D scenario

Network Choice before 2030	Regret under G&D scenario in 2050 (b€/year)					Maximum Regret
	DES	RES	EFF	CCS	BAU	
HVAC++	-54	-19	-8	0	0	-54
HVDC	0	-3	-5	-11	-5	-11
UHVAC	-11	0	0	-4	0	-11

[Source: Roehder et al. (2012)]

31 Note that the reported generation investment cost figures are not present values like shown in Figure 37 and Figure 38.

From the table above, the highest two maximum regret levels among all the scenarios are observed if the HVAC++ scenario is chosen in 2030 and the G&D scenario with a high share of intermittent renewables (DES and RES) is realized in 2050. For HVDC and UHVAC scenarios maximum regret is equivalent, although it is realized under different futures: if HVDC is chosen in 2030, maximum regret in 2050 is realized if CCS scenario occurs, whereas if UHVAC is chosen in 2030 maximum regret in 2050 is realized if DES scenario occurs.

In practise, network investments are distributed over time instead of fixed at one point in time. This implies that the reported regret costs are an upper bound since better information about the demand for transport capacity can be used for investments later in time, and regret costs can be partially avoided.

Overall we can conclude that HVDC and UHVAC scenarios are likely to be robust choices under all G&D scenarios since they both result in the lowest value for the maximum loss in net benefits under all G&D scenarios. In addition, in a future with a high share of intermittent renewables (i.e. in RES and DES), HVAC++ scenario would result in the highest regret of all scenarios which is significantly higher than the maximum regrets if the HVDC or UHVAC network scenarios are chosen.

Major conclusions:
1. Network investment costs are more than compensated by savings in electricity generation.
2. Europe needs a supergrid because of increasing distances between generation and demand centers in several electricity futures. The UHVAC and HVDC overlay network technology options are more suitable for long distances due to lower losses. A supergrid is characterized by a limited number of connection points with the 400 kV infrastructure and hence a so-called overlay network.

Including the security of supply perspective

The analysis outlined above includes the sustainability and competitiveness perspectives but excludes the security of supply perspective. For an overall system or socio-economic assessment it is required to take into account security of supply aspects such as the cost of security. In order to ensure security, power system operation should always fulfil the N-1 criterion. According to ENTSO-E definition of N-1 criterion (ENTSO-E, 2009), a loss of an element in either production or network within the TSO's responsibility area must not endanger the security of interconnected operation and "must not lead to the triggering of an uncontrollable cascading outage propagating across the borders or having an impact outside the borders [of the TSO responsibility area]". Most power systems in practice, not only in ENTSO-E, are bound to operate in an N-1 secure state.

Common formulations of Optimal Power Flow (OPF) problems usually do not consider the N-1 security criterion. An optimization problem which explicitly takes into account outage events is often termed Security-Constrained Optimal Power Flow (or SC-OPF). The objective is to find a least-cost generation dispatch such that an outage of an arbitrary line or generator will not lead to overloads at any point in the system. It is evident that the dispatch costs determined from SC-OPF calculations will be at least equal or higher than the costs determined through a "standard" OPF.

The difference in the generation dispatch costs between a "standard" OPF and an SC-OPF is what we term the 'Cost of N-1 Security' (CoS, see *Eq*. 1). Essentially, the CoS reflects the additional costs that are incurred to the system, so that N-1 security is ensured (Chatzivasileiadis *et al*. 2011).

$$CoS = C_{SCOPF} - C_{OPF} \qquad Eq.\ 1$$

The CoS provides a quantitative index when comparing the effects of different network reinforcements on the electricity system with respect to power system security. The solution that results in the least 'cost of security' guarantees, on the one hand, the secure operation of the power system, and, at the same time, it has the maximum positive effect from a societal viewpoint, as it incurs the least additional costs.

For the analysis of the costs of security, two assumptions are made by Chatzivasileiadis *et al*. (2012). First, different line ratings are assumed for different network technologies (HVAC and HVDC: 3,000 MVA; UHVAC: 3,900 MVA). Second, for the identification of critical contingencies it is assumed that lines cannot be loaded for more than 85% of their capacity provided the N-1 criterion. Cost of security for the year 2050 expressed in billion euros per year are shown in Figure 39.

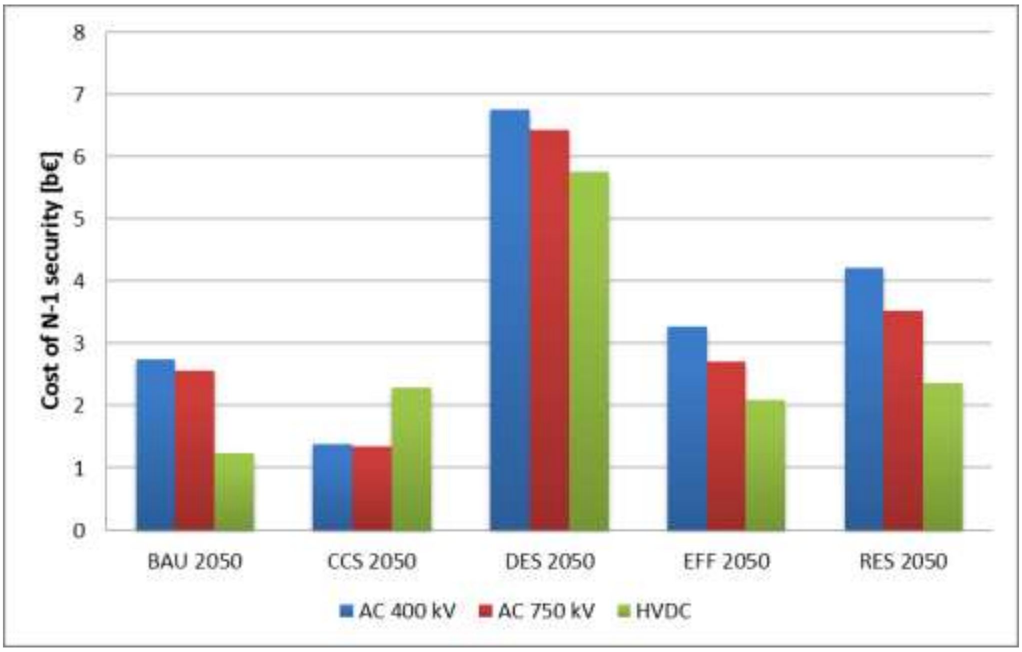


Figure 39 - Cost of N-1 Security

[Source: Chatzivasileiadis *et al*. (2012)]

Since Roehder *et al*. (2012) and Chatzivasileiadis *et al*. (2012) analyse the same network technologies for different EU network representations, cost of security results of the latter have been made comparable to the results of the former.[32] Figure 40 shows that the magnitudes of cost savings for guaranteeing N-1 security of overlay networks are comparable to their higher network investment costs for the DES scenario. Most importantly, the lower cost of N-1 security of the HVDC overlay network compensates for the higher network investment cost of the RES scenario in the year 2050.[33] This supports the case for grid expansion with HVDC or UHVAC overlay networks.

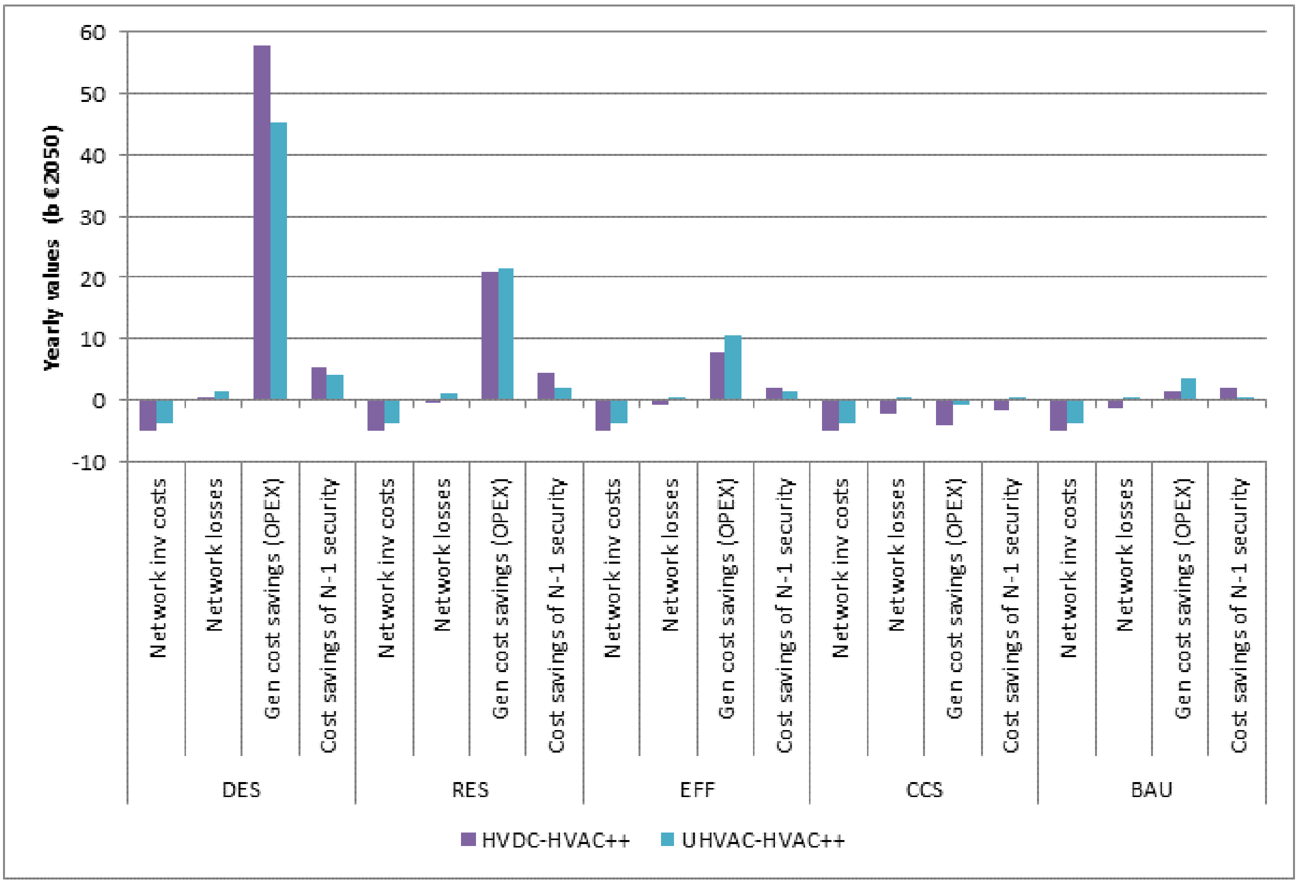


Figure 40 - Benefits and costs for the year 2050 compared to the HVAC++ network scenario[34]

[Source: ECN]

Besides, N-1 security also other network security aspects are important. For HVDC and UHVAC overlay networks, the same level of network controllability has been assumed.[35] However, in reality HVDC networks offer additional network controllability advantages for various security aspects

32 Therefore, a two-step procedure is applied; as a first step, the fraction of cost of security of total OPF costs of Chatzivasileiadis *et al*. (2012) is calculated. Subsequently, this fraction is multiplied with the total OPF costs of Roehder *et al*. (2012).

33 N-1 security cost savings are probably lower before 2050 when the system is loaded to a lower extent.

34 Since the analysis of Chatzivasileiadis *et al*. (2012) does not contain the same type of HVAC+ reference scenario as the analysis of Roehder *et al*. (2012), benefits and costs of HVDC and UHVAC overlay scenarios are compared to the HVAC++ network scenario.

35 Whilst for the HVAC++ scenario implicitly a lower level of network controllability has been assumed.

related to dynamic security as well as steady-state security, although these are difficult to quantify. In most cases a UHVAC network equipped with PSTs and Static Var Compensators (SVCs) would not be able to react fast enough, since the reaction of a PST would be too slow.

Thus, when network security considerations are included in the overall system perspective an overlay grid topology based on VSC-HVDC technology is selected to become the preferred network technology scenario for the roadmap.

Major conclusion: HVDC is the most robust backbone technology. 400 kV AC network technology scenario shows higher socio-economic costs than 750 kV UHVAC and 500 kV HVDC network technology scenarios. Inherent control possibilities of HVDC technology are larger than control provided by FACTS devices in UHVAC network scenario. Hence, HVDC is the preferred network technology scenario for the roadmap.

4 NEED FOR TRANSMISSION INVESTMENT

4.1 BACKGROUND AND NECESSITY ON TRANSMISSION INVESTMENT

On 4th November 2006, an EU wide blackout occured which affected 15 million consumers in Europe due to a disturbance in Germany. One of the main reasons of this blackout incident was insufficient investment both at the level of reliability and the operation of the grid. The European Commission therefore urged the TSOs to improve their investments in particular to alleviate bottlenecks [ERUP07]. The investigation on the 2003 blackout event in Northern America showed that transmission network has been the weakest link in the U.S. power industry after reformation, and strengthening the transmission network is one of the major measures [HML04].

Currently, there is a global trend to a market-driven power industry. The unbundling of the power sector has resulted in the separation of the sector into generation, transmission and supply entities [XDW06]. In the restructured environment, the functions of the transmission system have expanded beyond the roles of linking generation to load and ensuring system reliability. Interconnection enables more generators to compete in the market to serve the combined load. On the other hand inadequate transmission capability leading to bottlenecks enables generators at specific locations in the network to exercise market power in the local market. Investing in transmission system, therefore, can enhance competition and mitigate market power in a restructured market environment. This chapter surveys the issues and the approaches to transmission investment and transmission planning in a restructured market environment, especially in Europe.

4.1.1 Challenges under the deregulated environment

In the electricity industry, deregulation towards competitive markets brings new challenges to the power transmission process. In the last century since the electricity industry deregulation was implemented, challenges were brought to transmission owners, system operators and investors to define new planning objectives, re-examine conventional principles and develop new means to meet these objectives if necessary [CFS99]. Moreover, the fundamental change towards an unbundled electricity system has already taken place recently, especially in some European countries and will be gradually implemented in Europe [DIR09]. Incentives are required and developed to encourage the network investment and to coordinate the interaction between regulated and commercial parts of the power system.

Uncertainties for the future generation capacity and location add difficulties on the transmission investment/expansion plan under the unbundling environment.

Finally, there is a higher demand on the network flexibility and robustness under the competitive environment. Scheduling based on auctions results in a more frequent occurrence of unconventional operation mode. This is because power scheduling of generation companies is dependent on power prices which are sometimes strategic, and varying and varying more than the underlying generation costs. In addition, in some electricity markets, large users are allowed to buy electricity directly from generation companies. Furthermore, generation and load patterns are likely to change more frequently due to competition and the incorporation of RES. Subsequently, the power flow patterns will also change more frequently, following the market activities [CMG00]. U.S. Electric Power Research Institute (EPRI) made an assessment in its report that the deregulation results in significantly increasing in the trade of electricity, and the transmission distance increase. Last but not least, there will be an urgent need to alleviate transmission congestion by adding new transmission equipment [ZFL05]. Overall, the market environment will require a greater demand for transmission capacity.

4.1.2 Worldwide network investment situation

Electrical technology and the power system structure have faced grossly accelerating changes in the past fifteen years. Almost all countries in the world have performed changes in their electricity industry especially in the last eight years with a general trend to deregulation, releasing generation and supply sections and making competition opportunities in these sections. The worldwide investment situation is complicated under the unbundling environment. Different countries have different organisational structures, thus resulting in different investment modes. Here we provide a survey on market structure/ investment situation of countries around the world.

4.1.2.1 Market structure in different countries

Germany

Germany has Europea's largest installed capacity and power generation, and European largest electricity market. The increase of renewable energy sources brings new challenges for the transmission system, and in Germany, the decrease of generation capacity in the central and southern regions combined to the placement of new conventional and renewable power plants in the north necessitates investments in the transmission grid [OSRR11].

Germany centrally locates within the European electricity market, having a variety of interconnections with its neighboring countries. Over the past few years, four generating companies RWE Power AG, E.ON Energie AG, Vattenfall Europe AG and EnBW AG formed an oligopoly with RWE and E.ON being in dominant market positions. German electricity market was characterised by vertically integrated utilities until it was liberalised in 1998 [IE05]. Currently, for three of the four German TSOs, the ownership is unbundled from commercial businesses; the grid of E.ON has been sold to the Dutch TSO--TenneT, the grid of RWE is called Amprion and owned by financial investors, and the grid of Vattenfall is called 50 Hertz and owned by Elia.

Some changes can be observed with the opening of German electricity market since 1998. According with the EU guidelines of open electricity markets, the German market was gradually opening up. In April 1998, Germany launched the power industry law and started its market liberalisation[WSI06], which won the consent of all those generation companies who would like to take part in the competition; however no regulatory regime existed at that time. A similar situation also occurred in the natural gas network market, where most of the transmission right was controlled by large cross-region companies. In April 2003, the Germany government announced that a regulatory authority would be set up in 2004. This body—Bundesnetzagentur, which has already existed for a long time until now, determines the grid connection and use conditions and is responsible for the regulation.

Until 2004, four network energy supply companies took up 95.6% of the power generation with RWE (38.7%), E.ON (26.5%), EnBW (13.8%) and Vattenfall Europe (16.2%); others accounted 4.4% including regional producers and local producers. Power transmission was 100% shared by the four network energy supply companies [VSI06]

The U.S.

In the U.S., there are several independent electricity markets. Some transmission systems are publicly-owned and some are owned by investors. Most regions have multiple transmission owners. The system operation and transmission ownership in these regions are separated. Taking California for example, California Independent System Operator (AISO) is responsible for conducting the transmission and ancillary service markets and manages the spot market [CC99]. There is a difference between the U.S. and Europe with regard to the way the transmission network is managed. In the U.S., ISOs and Regional Transmission Operators (RTOs) are created when a group of transmission owners transfer some or all operating control (not ownership) of the the transmission facilities to an independent organisation. The primary difference between an ISO and a RTO is that a RTO controls the operation of the transmission system over a wider area across state borders. Transmission owners own and maintain the transmission assets, develop network and manage the asset replacement and investment to ensure the long-term reliability of the network. In Europe, the transmission grid are mostly owned and operated by the same company (TSO mode), of which the operating borders coincide with the border of a certain country after the unbundling of the vertically integrated companies. E.g. The Dutch TSO TenneT is fully state-owned. These TSOs in Europe combine the tasks of the ISOs/RTOs and transmission owners in the U.S..

UK

In UK the transmission grid in England and Wales is owned and controlled by the National Grid (NG) and the transmission grid is operated at 400 and 275 kV, while 132 and 66 kV levels in England and Wales are run by several DSOs. In Scotland, the transmission grid is owned by SHETL and SPTL and the operation of the Scottish grid is done by NG (ISO mode which is different from most European TSO modes) which covers the 400, 275 and 132 kV lines [BDB08].

NG is almost in a monopolised position which is also the system operator, responsible for the operation of the whole transmission system and system investment/expansion. NG carries out a regular research on the usage of transmission system. The research report is titled “Seven Year Statement”, providing generation and load forecasts and transmission planning. The related transmission investment fund is from the NG regulated transmission tariffs. The transmission price is supervised by the regulatory agency.

Australia

In Australia, each zone has one or more state-owned transmission companies. In addition, there are also some non-state-owned cross-transmission assets. Every state-owned transmission company takes the responsibility of the transmission planning. Any economic entities, including the companies which do not own transmission assets, can make transmission investment. Generation companies and transmission companies can work together to raise funds in order to avoid or eliminate the transmission congestion. There are no clear investment incentives for regulated transmission assets; for non-regulated transmission assets (merchant transmission assets), the investment incentives are provided by the income from transmission service.

Spain

In Spain, the private-owned transmission company REE is responsible for the system operation. OMEL is the operator for the power market. It is responsible for the technical management of the power system, i.e. guaranteeing supply continuity and security, and offers daily trading [RSM08]. The transmission system planning is undertaken by the government and supervised by the Ministry of Economy (ME). Transmission planning is mandatory and centralised. The government makes the transmission expansion planning based on the suggestion put forward by REE, and ME evaluates the annual investment planning provided by REE. Transmission expansion planning is divided into interim study (6-10 years) and long-term study (15-30 years), with which the interim study is updated every four years.

Norway

In Norway, Statnett is a state-owned company that owns about 85% of the transmission assets. The remaining 15% of the transmission assets is owned by 20 other entities. Stattnet is responsible for a five-year forecast on the transmission expansion projects which will be examined and approved by the regulatory agency. The cost-recovering of transmission investment is from the transmission service fees.

Others

In Argentina, Chile, Brazil, Colombia and some other countries, institutions for system operation are separated from system owners. In Argentina, there are seven privately owned transmission companies. TRANSENER is an extra high voltage transmission service company, with a national transmission franchise. The other six companies own regional transmission systems. In Chile, TRANSELEC is the largest transmission company, and owns most of the high voltage transmission systems. The rest of the transmission assets are owned by generation companies and large industrial users. In Brazil and Colombia, there are multiple transmission owners.

4.1.2.2 Electricity stakeholders in Europe

Liberalisation, deregulation (reregulation) and privatisation are in all progress under the general label of market reforms. Competition is fundamental to most market reforms and it is introduced in order to reduce costs and increase efficiency [PSRD01]. Under this new environment, what criteria should guide transmission expansion decision-making amid parties with diverse interests is a critical issue. Should the criteria be based on benefit? Firstly, key stakeholders in the new deregulated power utilities are identified:

- The European Commission

- Power plant owners
- Transmission operators and owners, and network planners
- Regulators, policy makers
- Consumers
- Manufacturers

The European Commission/Policy makers:
The objectives of the transmission expansion under the deregulated electricity market according to the European Commission's expectation is: 1) to maintain system reliability and security standards; 2) to keep the environmental impact of expansion at proper levels; 3) to improve the economic performance of the electricity market. This is also the IRENE-40 project's expectation: Future network expansion should develop towards a sustainable, secure and cost efficient future power grid.

Regulators and network planners:
Generally for a given network in the restructured electricity market, the network planner would like to implement the transmission expansion that maximises social welfare, minimises the local market power of the agents, maximises the consumer surplus and maximises the producer surplus [SO07]. Regulator's role is to supervise and control during the transmission expansion and is always seeking to maximise a social welfare function which reflects the goal of limiting the rents which are transferred from consumers or taxpayers to the firm's owners and managers subject to a firm participation [PLJ06]. The processes related the transmission assets can be divided into three parts: planning, approval and pricing. Each regulatory procedure will have a significant impact on transmission investment and expansion. Price regulation is mostly concerned, which is further discussed in section .4.5.

Producers (power plant owners) and consumers:
The competition forces market participants (producers and consumers) concerning more about their benefits if they would participate in the transmission investment, which can be described as revenues and costs. From the suppliers' point of view, increasing profit can be achieved by decreasing costs or increasing revenues. For example, a decrease in costs is possible when a supplier can achieve a higher efficiency and an economic dispatch. An increase in revenues is possible when a supplier can expand its consumer basis. From the consumers' point of view, an increase in profits is directly related to finding a supplier who can offer the same quality goods at lower prices.

This pursuit of profits provides strong economic incentives in such a competitive environment to improve and maintain the quality of consumers' service and invest in productivity-enhancing technologies. These incentives are not obvious by state ownership.

There are a number of advantages related to competition in electricity generation, such as innovation. Competition not only leads firms to be more responsive to consumers' demands and compete on the basis of price, but also provides an incentive to be innovative. Developing a new service, a better method of reducing costs or a faster way of dealing with problems keeps the innovator at a competitive edge.

What is more, market will provide an array of service standards that more closely match consumers' preferences. Consumers could be offered with priority service which contains a schedule of electricity rates increasing with the reliability level. A competitive market in electricity generation could offer a much broader array of services than state monopolies or regulated generators [HR87] [PSRD01].

Transmission system operators and owners:
Deregulation often involves "unbundling", i.e. generation, transmission and distribution could be separated and be offered as discrete services. The transmission system thus becomes the focus of attention in facilitating competition and the rules for managing access by all participants that must be transparent and non-discriminatory. In an operational environment, it is also vitally important to maintain the system reliability; an important reliable measurement is system security. System security refers to a system's ability to withstand possible disturbances. As the power industry evolves into a competitive environment, system security continues to be a crucial function. The primary responsible parties are the TSOs/ISOs or similar entities, to ensure the system reliability while seeking the economic benefit [PSRD01].

Private investors:
From the private investors' side, network expansion planning should consider not only the investment level but also the market prospects. It is especially important for private investors who tend to have market oriented objectives through increasing the benefit of expansion projects. Merchant transmission investment scheme that is presented in section 5.3 is totally driven by profits.

Manufacturers:
The manufacturers' interests are referring to the requirements of transmission infrastructures ranging from short to long term planing horizons. Such requirements include the expected network infrastructure sach as additional HVAC, HVDC overhead lines/underground cables, transformers, converters, etc.

4.2 CONTROL-BASED EXPANSION

The chapter analyzes and assesses the role of so-called control-based grid expansion for mitigating operational challenges in power systems that are connected to the deployment of variable or fluctuating RES generation units, e.g. wind turbines as well as solar, PV and concentrating solar power (CSP) units and the increasing trading activity on European power markets and hence an intensification of cross-border physical energy flows.

These challenges manifest themselves mainly in the form of difficulties of keeping the power balance in light of strong wind and/or PV power in-feed conditions as well as in the form of large cross-border physical energy flows. The recent rise of "inflexibility" events in power system operation can largely be attributed to an on-going paradigm change in power system operation, which can, in simple words, be described as a shift from "generation follows load" to "load follows generation". The importance of the operational flexibility for power system operation and grid expansion planning has been addressed in several recent publications, e.g. ENTSO-E's Ten-Year Network Development Plan (TYNDP).

In order to assess the grid operation challenges arising from the on-going deployment of variable RES generation as well as the beneficial role that storage capacity, be it directly in the form of hydro-based bulk energy storage units or indirectly in the form of demand-side participation, or the expansion of available power transfer capacities between countries, i.e. the net transfer capacity (NTC) values, a sophisticated simulation platform is needed.

Within WP4, a simulator platform has been created that allows to model the properties of the different power system unit types (e.g. generator ramp-rates, storage power and energy rating, full or partial dispatchability and curtailability/sheddability) with high fidelity as well as to simulate power dispatch processes, based on marginal or levelized generation costs, taking into account technical constraints such as generator ramp-rates, shut-down times, storage saturation, line limits and the forecast accuracy of load demand as well as wind and PV in-feed. The modeling is accomplished using the recently developed Power Nodes modeling framework. Dispatch processes are simulated using a predictive power dispatch scheme that uses an optimization formulation based on so-called model predictive control (MPC).

The currently existing Power Nodes simulator platform, depicted in Fig. 1, allows to perform predictive power dispatch optimizations for a portfolio of power system units consisting of very diverse generation, load and storage units. The specific properties of energy storage units, i.e. there inherent energy constraints, are explicitly considered. The platform can model, simulate and analyze the behavior of the existing European power system (29 country node model) as well as its possible evolution over the next decades as defined by the ECN scenario family.

An optimization setup is formulated over a prediction horizon (usually 1-10 days ahead), which allows to incorporate load demand and RES power in-feed forecast time-series. The quality of the prediction information can range from being perfectly accurate to being significantly inaccurate, for example given by *a priori* defined forecast error bounds.

In order to allow large scale simulations of different scenario setups and for exploring the effects of parameter variations of the power unit portfolio or the optimisation setup itself, the possibility to perform parallel calculation of 10s...1000s of different scenarios has been included in the simulator platform. Furthermore, extensive aggregation and plot routines were added in order to facilitate the analysis and visualization of simulation results.

The previously described five different ECN scenario families (BAU, CSS, EFF, RES, DES) for the five reference years 2010, 2020, 2030, 2040 and 2050 have been used for assembling each countries unit portfolio including the varying yearly load demand and RES in-feed time-series. This leads to altogether 25 different setups for full-year simulations (with a sampling time of 60 min).

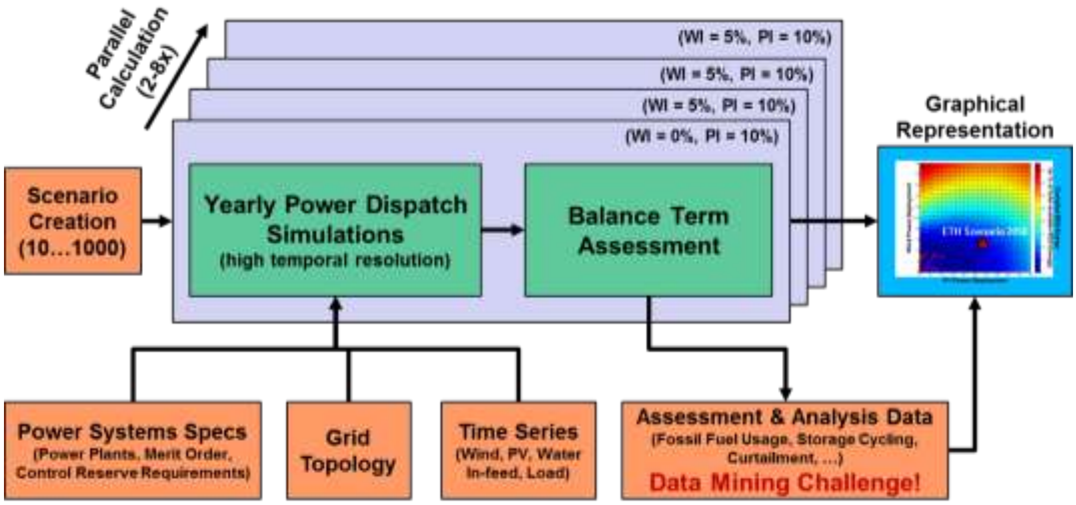


Figure 41 - Principal Schemata of the Power Nodes simulator platform.

In addition to this, a parameter study has been performed to analysis the qualitative and quantitative effects that flexibility measures (= control-based grid expansion measures) such as

- increasing the share of DSM,
- making the conventional generator fleet more flexible,
- increasing storage capacity (power and energy rating) and
- allowing for PV/wind curtailment

have for the operation of the European power system. This is measured here as the capability to effectively integrate of fluctuating RES power in-feed into the power system. For comparison, the effect of increasing the net transfer capacities (NTC) of the power system, the traditional hardware-based grid expansion measure, for RES integration has also been simulated and analyzed.

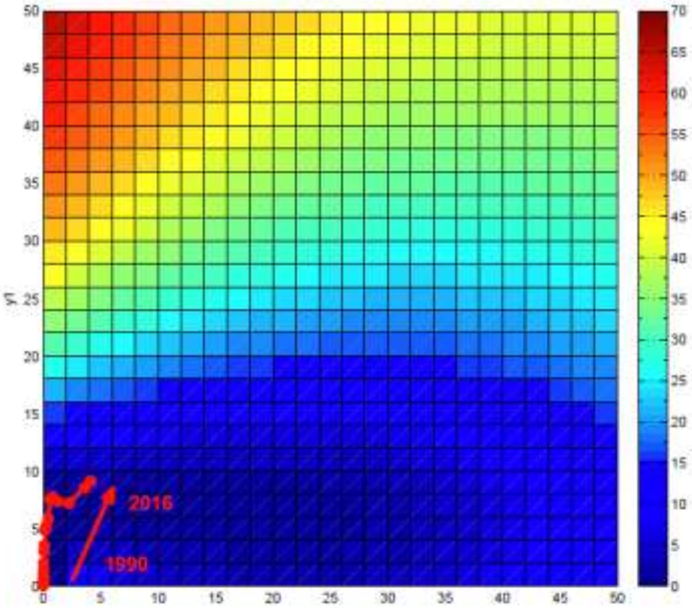


Figure 42 - Curtailed RES in-feed as function of RES deployment (% of yearly load demand, x-axis: PV, y-axis: Wind). Curtailment shown in % of available RES energy within Germany's power system (40 GWh).
(Red line: RES deployment path for 1990-2016.)

One assessment result, showing the impact that rising energy shares from wind and or solar PV units would have on forced curtailment of RES in-feed for the German power system is given below for illustration purposes.

5 MERCHANT TRANSMISSION INVESTMENT (MTI)

5.1 INTRODUCTION OF MTI AND OVERVIEW IN EUROPE

Although in the liberalised market most of the transmission investments have been made on a regulated basis, the transmission investment is no longer the exclusive right of TSOs with merchant investment taking place in, for instance, the USA, Australia, Latin-America and Europe [GB05]. The main reason for opening transmission investment to profit-motivated investors is that this may address the problem of under-investment in transmission [JKH06]. Regulators attempt to stimulate transmission investment by allowing third parties to invest in the transmission network, primarily funded by trading between differently priced markets.

The European Union has implemented competition in the power sector and meanwhile a more sustainable and secure energy future is aimed at. More than 10 years after liberalisation, there is however a lack of investment especially in interconnectors, at least partly, explained by failing of regulatory framework, taking away incentives to invest in interconnectors. Under this circumstance, EU policy is becoming more favorable towards merchant investment as an alternative for lacking regulated investment. Until recently, several merchant projects exist in Europe: the interconnector Estlink between the Baltic and Nordic electricity markets, BritNed between UK and the Netherlands, the two East West Cables between Norway and Germany and a merchant line connecting Italy and Austria [HR11].

5.1.1 Advantages of MTI [BMB07]

Currently in most member states, legally (not fully) unbundled TSOs have few incentives to invest in market opening by increasing cross-border capacity or adding new interconnected lines. As long as generation is involved in transmission, investment decisions will be biased against market opening. Although some countries already have implemented ownership unbundling scheme, the majority is unlikely to fully perform ownership unbundling in the short term. The lack of unbundling is the main reason for the lack of cross-border transmission investment. Under this circumstance, MTI is a powerful tool to tackle the lack of investment in interconnectors. Investors are attracted by congestion revenues and also by priority access, which allows an investor to earn revenues in an early stage of the projects, thereby decreasing the payback period and the project risk.

In the European MTI model, investors are incentivised by congestion revenues and by the long-term contracts and granting priority access. When only relying on congestion revenues a merchant investor receives revenues through the yearly, monthly and daily allocation of scarce cross-border capacity, which results in a long payback period. When priority access and long-term contracts are allowed, long-term (e.g. 20 years) allocation of the interconnector capacity is possible. By selling long-term contracts, investors could have more revenues in an early stage of the project, thus reduce the payback period and decreases the project risk and the capital cost.

Under the MTI scheme, investors are attracted by the protection against regulatory risk. Usually, an investment is always done within a certain regulatory context, which does however not necessarily remain constant throughout the entire project lifetime. Regulatory authorities can change the rules and thereby change the viability of the project.

5.1.2 Problems and solutions [BMB07]

On one hand, the MTI scheme might indeed help to address a perceived problem of under-investment as discussed above. On the other hand, it leads to a partial unregulated monopolisation of the network, which increases the risk of anti-competitiveness effects, especially when the MTI investor is a dominant generator in one of the related markets. As mentioned, the "protection against regulatory risk" and "priority access" can benefit the investors but disrupt the non-discriminative access objective.

The Third Energy Package brought three main changes: 1) strengthening unbundling of transmission assets from generation/supply activities, 2) enhancing the national regulators' power and creating an Agency for the Cooperation for Energy Regulators (ACER) with limited competences on MTI, 3) increasing market transparency by a set of measures on disclosure of post-trade data and records. The Third Energy Package starts to unify energy regulatory oversight at the European level, and as a consequence, it may open new opportunities for a smarter EU energy policy on MTI.

5.2 MTI SIMULATION IN IRENE-40 SCENARIOS

This section deals with the investment strategies of different stakeholders in a competitive electricity market environment. It focusses on the installation of HVDC lines, and takes advantage of the controllability they offer. Two different objectives are studied: maximization of the social welfare and maximization of the revenues of the HVDC line owners.

By maximizing the social welfare, the objective is to place the HVDC line so that it can relieve congestions and minimize generation costs. An analytical method has been developed, which determines the most effective line placement for congestion relief. Based on some basic optimization theory, it can be demonstrated that for N congested lines, there are exactly N+1 marginal generators[36]. For example, if there is one congested line, then there exist exactly two marginal generators: one "cheap generator" with costs equal or below the system marginal cost without congestion, and one "expensive generator", with costs above the system marginal cost. Then the most effective DC line placement is a line connecting a cheap with an expensive marginal generator. This placement also serves as an upper bound for the prospective costs of the line

[36] Assuming linear generation costs. Marginal generators are the generators which produce neither at their minimum nor at their maximum limit

installation, which means that we can identify what is the maximum cost of a new line installation in order to relieve congestion. At the same time, this implies that we should focus our search for the optimal HVDC placement to these options, which have installation costs lower than this “upper bound”. A further remark here is that although placing a new DC line in parallel with the congested line can often relieve the bottleneck; the “performance” of such a placement usually cannot exceed the “performance” of a new line directly connecting a cheap with an expensive marginal generator.

The second objective examined is the optimal HVDC placement in order to maximize the revenues of the HVDC owner. Here, we are focussing on the so-called merchant transmission investments. An agent-based framework was developed. Each agent can decide the line capacity and between which nodes to place its line but is not allowed to manipulate the line, i.e., to create virtual congestions, in order to increase its profits. In total, for our optimization framework, 20 individual agents could select from 50 possible locations and 3 capacity limits in order to maximize their profits.

The results of our studies, as illustrated in Figure 43 and Figure 44, show that certain interconnection paths have a high need for transmission capacity; the agents find it more profitable to install several parallel transmission lines on these paths, rather than select a transmission path where they can be the sole investor. Such paths are the FR-UK, DE-SE, and PL-SE – for all generation scenarios. Furthermore, the interconnections FR-ES, FR-UK and PL-SE seem to have a high potential to generate substantial revenues in all scenarios, while for the DES scenario, the corridors GR-IT and DE-PL are also quite profitable. Nevertheless, the most profitable single investment in our studies is the HVDC line between IE and UK in the DES and RES scenarios, which is expected to generate up to 750 million Euros per year. Indeed, our results seem to reflect reality quite well, as the need for line reinforcement between Ireland and the UK, as well as the potentially profitable operation of a merchant line has already been identified by stakeholders. A regulated 500 MW HVDC interconnector between Ireland and the UK was inaugurated in September 2012 (Eirgrid East-West Interconnector), while two additional merchant DC transmission lines of 350-500 MW each are planned to be commissioned until 2019.

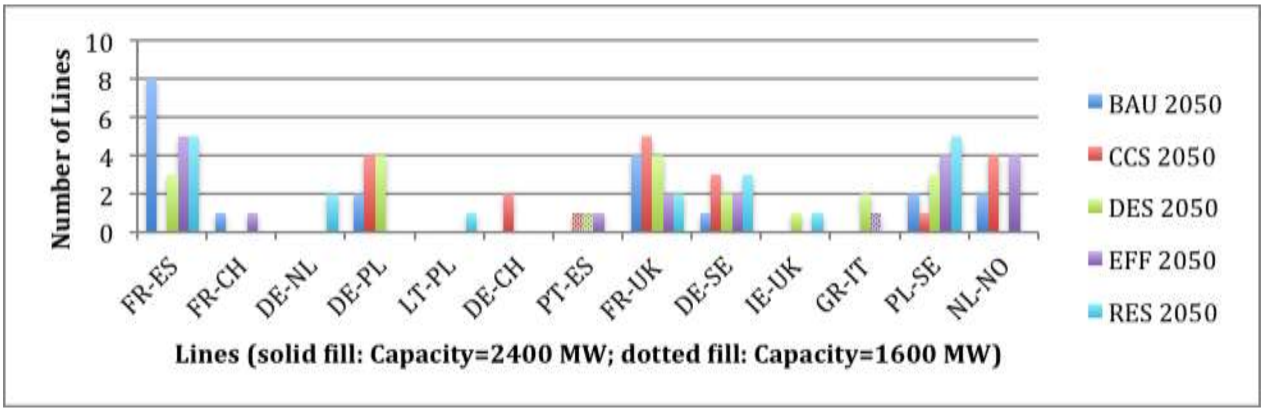


Figure 43 - Number of Lines installed at each location and each generation scenario (dotted fill in case of PT-ES CCS+DES and GR-IT EFF capacity =1600 MW)

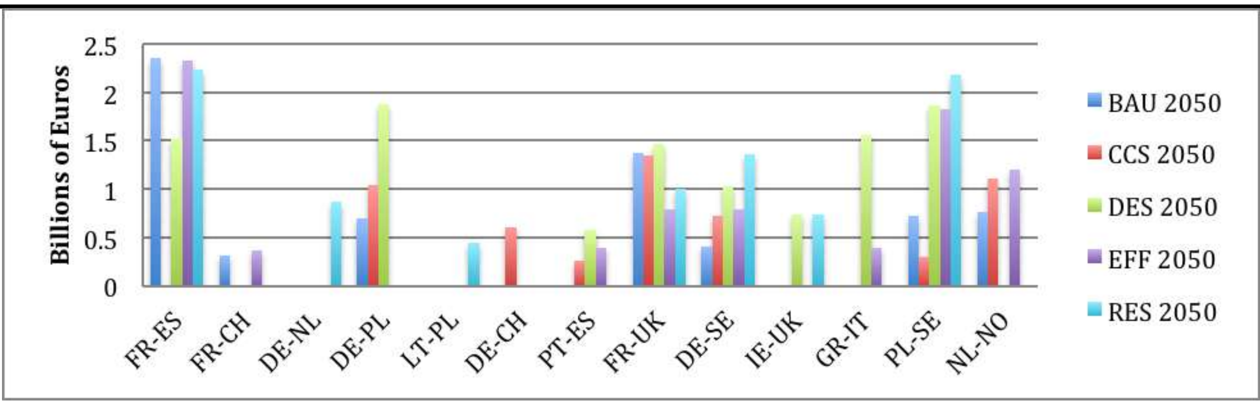


Figure 44 - Comparison of MTI Yearly Revenues per each interconnection (sum of the revenues of all parallel MTI lines installed at each interconnection) and for each generation scenario

Concluding, it seems that there is enough room for profitable merchant transmission investments in all possible future generation scenarios. Our results especially show that the higher are the shares of variable generation, the higher is the potential for profitable MTI lines. Specifically for the DES scenario, it is shown in Figure 43 and Figure 44, that it results not only in low total generation costs (i.e., leading to a higher social welfare), but also provides the best environment for merchant transmission line investments. The cumulative revenues that MTI lines are expected to generate in the DES scenario exceed 10 billion Euros per year.

6 FACTORS THAT INFLUENCE THE TRANSMISSION SYSTEM INVESTMENT STRATEGY

6.1 TRANSMISSION TARIFF

6.1.1 Introduction

One of the outstanding issues in the liberalisation of the electricity market is the way in which transmission costs are translated into tariffs. The transmission grid is seen as a natural monopoly, and thus the transmission tariffs should be regulated. Ideally, the tariff structure should lead to economic efficiency, and it should enable the grid owners to cover their costs.

From the market perspective, reasonable transmission tariffs can ensure the open and fair competition in the market, thus improving the market stability, guaranteeing the sustainable development of the power grid. For transmission system investors, the transmission pricing method is related to whether they can recover the investment and how to get the payment back, thereby affecting their operation mode. In other words, if the use of the pricing methodology is not enough to recover the cost, investors do not have the incentives to invest and expand the transmission grids and the power grid is probably faced with the risk of under-investment; in the contrary, if the pricing methodology allows investors to get excessive return, investors are encouraged to invest on the transmission lines in advance, then the power grid will face the risk of over investment and ahead of construction.

Usually, transmission tariffs cover all the energy transmission charges; they include not only components connected to TSO activities but also other regulatory charges not directly related to transmission costs. The components taken into account are [ETSO08]:

- Infrastructure charges (operation and capital)
- Loss compensation costs
- Internal congestion costs
- Costs of supply of system services
- Costs of system balancing

6.1.1.1 Transmission tariff schemes and the influence on investment strategy

In December 1996, the European Council of Ministers adopted the European Directive concerning common rules for the internal market for electricity and the general guidelines for transmission tariffs. Whatever system is chosen, the tariffs should attain as well as possible some general objectives as follows [RCBD99]:

- A good pricing system has to give correct incentives to the market participants and encourage an efficient use of the existing network, efficient location of new generation units and new customers, and encourage investments in the existing network and network expansion.

- The price should be non-discriminating, transparent and helpful in congestion avoidance.
- The charges should reflect the cost of the assets or services provided or acquired by the system operator, and allow a fair return on investment.

Some important tariff systems are the postage stamp, the distance related and the nodal pricing system [RCBD99].

Postage Stamp

The postage stamp system is the simplest method from all pricing system available and it is a uniform tariff expected to recover project investments, operation and maintenance costs. While transporting a given amount of electrical energy over the grid, a fixed price per energy unit is charged, independent of the distance or the voltage level, regardless of the congestion and power losses. This fixed charge allows the ISO to recover its costs. The postage tariff is independent of the place the energy supplied to or taken from the grid.

This tariff system is extremely simple to implement regarding the billing of the charges and only the exchanged energy has to be measured. The costs are divided among all users independent of the actual costs they are causing. The regional postage stamp method is beset with problems of averaging the transmission charges, which deters economy trade across regions and prevents competition and efficient use of resources [NYDN11]. In general, the postage stamp pricing system does not give the incentives to suppliers or users for future investments or for an efficient use of the grid in the short term. The system operator does not get any incentive from such pricing system either [RCBD99].

Postage stamp method is more suitable when the geographical area in consideration is relatively small; flows are simple and do not cause large externalities for electrically contiguous regions [NYDN11].

Distance related tariff

Distance related tariff looks at the distance between generators and customers. Flow-Mile method rates explicitly reflect the fact that the cost of transmission depends on the distance and how much power is transmitted. The characteristic associated with the distance related method is that the geographically distant loads are burdened with large usage costs when compared with postage stamp allocations [NYDN11].

The distance related tariff has no incentives to ISO, or provisions for investment [RCBD99].

Nodal pricing method

The nodal method is based on locational marginal price (LMP) difference and is currently developed internationally [MGRG10]. In this method, the network revenues are equal to the transmission rent (TR), which is defined as the difference between what the consumers pay and what the producers are paid. The LMP method provides correct economic signals to consumers, producers and system operators towards efficient use of the transmission network and consequently, it has the desirable long-term impact on reducing the need for network expansion.

The main problem of this method is that the TR cannot recover the total transmission network costs. If the network is lossless with no congestion, LMPs at all nodes are equal, so TR is zero. Even for a network under congestion, there is no guarantee that TR could recover the transmission network costs. Reports show that in several systems around the world (Argentina, Central America, Chile, England, Wales and Spain), the maximum TR is only 25% of the total network investment cost.

Situation in England & Wales

The electricity service in England & Wales is provided by the privately independent electrical company—the National Grid company (NG). The regulated relationship between power plants and power grid allows not only to recover the investment in grid construction, operation and maintenance costs ensuring a reasonable return on the transmission investment, but also to guarantee the recovery of the loan on the construction of transmission projects by financial institutions due to the establishment of the normal power grid investment recovery mechanisms.
The transmission tariffs in England & Wales include the transmission connection charges, transmission use of system charges.

The policy of transmission connection charges in England and Wales is that generators and loads pay shallow costs. NG levies site-specific connection charges for assets installed solely for the use of a single user or a specified group of users. New users pay a rental charge to the existing user of the shared asset.

The Transmission Use of System Charges (TUoS) is mainly targeted to generation companies, local electrical companies and large consumers. For generation companies, the fee is charged according to the maximum generating capacities. For local electrical companies and large customers, the TUoS is levied depending on the power demand in peak load period. Generators and loads pay for TNUoS with a 27/73 split respectively [ETSR04]. Charges to both generation and suppliers vary on a zonal basis. TNUoS charges are considered to contain two elements. The first one reflects the long-run marginal cost of a change in demand or generation at a particular point on the network. The second one reflects the overall cost of providing a secure network. Only the marginal cost varies with location.

Situation in Nordic countires

The principles of Nordic transmission pricing methodology include [SERC12][CER04]:

- Being beneficial for the market transparency
- Being helpful for high efficiency in using of current power system
- No disturbance on the market competition
- Ensuring recovering of network investment

The deregulation of the electricity market in the Nordic countries incurred a unified market for electricity and coordinated rules for the exchanges between the countries; but each system has its own transmission operator and its own transmission pricing method. Sweden, East Denmark, West Denmark and Finland belong to Nordpool. The market price can differ among these countries because of cross-border transmission constraints. However, no transmission border fee exists between the countries [VP06]. So each exporter or importer will only pay the tariff corresponding to its national system. Thus, the network tariff for a producer in Finland should be the same when it produces for a Finish or a Swedish consumer.

Transmission tariffs in the Nordic grid are point-of-connection tariffs [CER04]. Point-of-connection (POC) scheme of transmission pricing in decentralized markets charges the participants a single rate per MW depending on their point-of-connection. Use of grossly aggregated postage stamp rates as POC charges fails to provide appropriate price signals. Point-of-connection tariffs apply throughout today's unified Nordic power system. Different prices apply to feeding power into the grid and drawing power from the grid.

The principle of the point-of-connection tariff is that payment in the point of connection, gives access to the whole network system, and thus the whole electricity market place. This means consumers/producers connected to a local network pay network fees only to the owner of that network. Similarly, the local network owner will pay network fees to the appropriate regional network owner and the regional network owner will pay fees to the main grid (national transmission network) [VP01]. (See Figure 45)

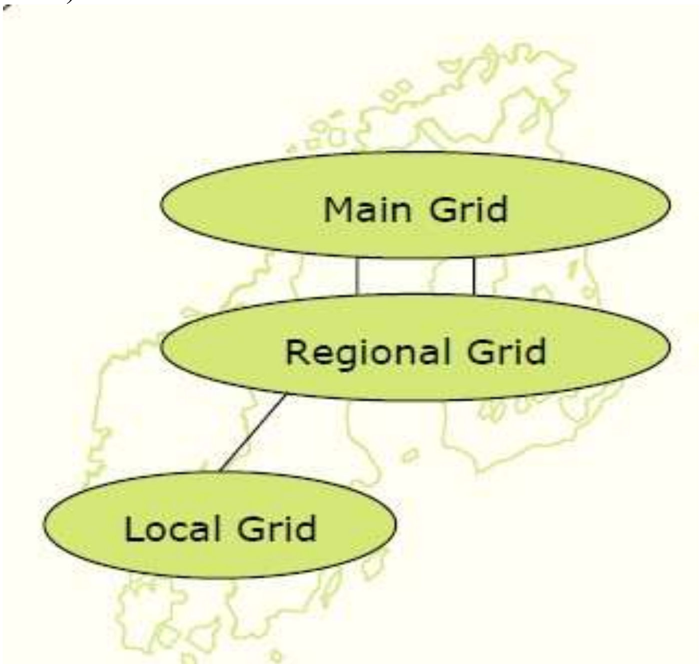


Figure 45 - The structure of the Nordic grid tariff methodology

The key principles in the transmission tariffs are:

- Main-grid tariffs must reflect the main grid's total costs.
- Regional-grid tariffs must reflect total regional-grid costs plus usage of the main grid.
- Local-grid tariffs must reflect local-grid costs plus usage of the regional grid.

Situation in other European countries

In Germany, generators and consumers pay deep connection charges (including maintenance, renewal or operating costs arising in conjunction with the direct system connection). For the transmission use of system charges, only consumers pay this part. Consumers with a direct connection to the grid pay a metering charge (in euro/month) and Use of System (UoS) charges with 2 alternative ways: annual charges or monthly demand charges

In Greece, generators and demand customers pay shallow connection costs and new users pay a rental charge to the existing user of the shared asset (like in the UK), cogeneration plants and renewable also pay a shadow connection costs. For the UoS charges, generators and demand customers pay a use of system fee per MW. Cogeneration plants and renewables do not pay that fee. However, the annual use of system fees corresponding to cogeneration and renewable plants are calculated and are debited to a separate account, named as "surcharges account" and final consumers are charged by these costs.

In Spain, producers and demand users make up-front payments for the capital cost of connection, including the costs of the required network reinforcements. For UoS charges, only loads pay for transmission usage.

6.1.2 Inter-TSO compensation

6.1.2.1 Introduction

Transmission system operators shall receive compensation for costs incurred as a result of hosting cross-border flows of electricity on their network on the basis of the guidelines set out by EU [CR09].

Commission Regulation (EU) No 774/2010 [COT10] of 2nd September, 2010 lay guidelines related to inter-transmission system operator compensation that established a mechanism for the compensation of TSOs for the cost of operating cross-border flows. However, this regulation expired on 2nd March 2011 [CR09].

Commission Regulation (EU) No 838/2010 of 23 September 2010 set new guideline related to the inter-transmission system operator compensation mechanism. Here some rules are abstracted from literature [CR09].

- The Inter-Transmission System Operator Compensation (ITC) mechanism shall provide compensation costs for hosting cross-border flows including providing cross-border access to the interconnected system.
- TSOs should be compensated for energy losses due to hosting cross-border flows of electricity. This kind of compensation should be based on an estimate of what losses would have been incurred during the transmission process.
- A fund should be established by the European Network of Transmission System Operator for

Electricity (ENTSO for Electricity) to compensate TSOs for the costs of hosting cross-border flows of electricity.

- The Inter-Transmission System Operator Compensation fund shall provide compensation for:
  - ✓ The costs of losses incurred on national transmission systems due to hosting cross-border flows of electricity. The amount of losses incurred on a national transmission system shall be established by calculating the difference between the amount of losses actually incurred on the transmission system during the relevant period and the estimated amount of system losses on the transmission system, which would have been incurred during the relevant period if no transits of electricity, had occurred.
  - ✓ The costs of making infrastructure available to host cross-border flows of electricity. The Commission shall determine the annual cross-border infrastructure compensation sum which shall be apportioned among TSOs as compensation for the costs incurred as a result of making infrastructure available for hosting cross-border flows of electricity. The annual cross-border infrastructure compensation sum shall be apportioned amongst TSOs responsible for national transmission systems in proportion to
    1) a transit factor which refers to transits on that national transmission system as a proportion of total transits on all national transmission systems;
    2) a load factor which refers to the square of transits of electricity, in proportion to load plus transits on that national transmission system relative to the square of transits of electricity in proportion to load plus transit for all national transmission systems.
- The exact value of the compensation fund should be based on Union-wide assessment of the long run average incremental costs in making infrastructure available to host cross-border flows. TSOs shall contribute to the ITC fund in proportion to the absolute value of net flows from their national transmission system as a share of the sum of the absolute value of net flows from all national transmission systems.
- The Union-wide assessment of electricity transmission infrastructure related to facilitating cross-border flows of electricity should be carried out by the Agency for the Cooperation of Energy Regulators (ACER) as the entity is responsible for coordinating the activities of regulatory authorities that must carry out a similar function at a national level
- ACER should supervise the implementation of the Inter-Transmission system operator Compensation (ITC) and report to the European Commission each year on the implementation of ITC and the management of the ITC fund.
- ENTSO-E shall cooperate with the European Commission and with ACER in this task and shall provide ACER with all information necessary for this purpose. Also, each TSO shall provide ENTSO-E and ACER with all information necessary for the implementation of the ITC mechanism.

6.1.2.2 The influence on the investment strategy

ITC is an incentive to encourage investment in the trans-national infrastructures at European level and to stimulate cross-border exchanges, by a set of mechanisms mentioned above able to allocate the costs of transmission infrastructures used for cross-border trade to the countries responsible for those transactions. Uaually TSOs get incentives to invest within their national regulatory framework. However, inter-national transmission investment in European transmission backbones is insufficient due to lack of incentives and uncertainties after liberalisation [SEV10]. Since 2002, ITC has been in place. The compensation is paid by the operators of national systems from which the cross-border flows originate and it received by TSOs for hosting cross-border flows [MPHB06]. For detailed discussion of the compensation system, see section 5.4.2.1. The aim of the ITC mechanism is to create a real internal electricity market, and to establish principles for setting fair rules for cross-border exchanges in electricity.

6.1.3 TSO funding schemes

6.1.3.1 Introduction

It is required to make efforts to strengthen and expand Europe's energy infrastructure and to interconnect networks across borders to meet EU's core energy policy objectives of competitiveness, sustainability and security of supply [EC11]. Due to this, there is a demand for a new EU energy infrastructure policy to coordinate and optimise network development on a continental scale, even though the existing policy of the Commission's Communication on energy infrastructure priorities for 2020 and beyond adopted from 17th November 2010 confirmed in particular the necessity to overhaul the existing Trans-European Network for Energy (TEN-E) policy and financing framework.

On 29th June 2011, the European Commission adopted the Communication "A Budget for Europe 2020" on the next multi-annual financial framework (2014-2020). This communication proposed the creation of a Connecting Europe Facility to develop the completion of priority energy, transport as well as digital infrastructures with a fund of €40 billion, among which €9.1 billion are dedicated to energy. Following this communication, on 19th September 2011, the European Commission issued the proposal for establishing the Connecting Europe Facility (CEF) by the European Parliament and the Council [EC 2011b]. Only projects which qualify as project of common interest (PCI) and are not commercially viable but are economically viable, can apply for the CEF.

Literature [EC11] gives four financing options with regard to infrastructure development. The four options are: use of risk sharing (including project bonds and guarantees); use of risk capital (including equity participations); use of grant support for project studies and construction; and a combination of grants, risk sharing and risk capital.

6.1.3.2 The influence on the investment strategies

Risk sharing is a kind of risk management in which the cost of the consequences of a risk is distributed among several participants in an investment behavior. Risk sharing is likely to be suitable for large project-financed investments, such as big gas import pipelines involving numerous shareholders.

Risk capital refers to funds used for high-risk, high-reward investment. Such capital can either earn large amount of returns over a period of time, or may dwindle to a fraction of the initial amount invested if such a project proves unsuccessful. In risk capital cases, funds are made available for startup firms and small business with exceptional growth potential. Managerial and technical expertises are often also provided.

Grant support refers to non-repayable funds disbursed by one party, often a government department, corporation, foundation to a recipient, such recipient is often (not always) a nonprofit entity, such as a non-profit transmission network grant supported by European Union to increase the whole system's reliability and security. The European Commission provides financing through numerous project proposals. E.g. the Seventh Framework Programme is currently in progress.

The last option-- a combination of grants, risk sharing and risk capital instruments, is the most recommended as it cumulates the positive impact of the individual options and provides a flexible toolbox of market-based instruments and direct financial support. This option is taken as basis for the Connection Europe Facility.

6.1.4 Congestion management

6.1.4.1 Necessity of congestion management

Transmission congestion occurs when there is insufficient transmission capacity for a transmission line to accommodate the power requests for transmission services. Historically, vertically integrated utilities managed this condition by economic dispatch of generators with the goal of ensuring security and reliability of their own or neighboring systems. With the reformation of electrical industry, generation and power supply have been unbundled with transmission and moved into the competitive market, thus leaving transmission as a natural monopolised source in the regulated environment. This mixing of competitive generation/supply and regulated transmission make congestion management difficult [KD02].

6.1.4.2 The influence on the investment strategies

In the wholesale electricity market, the transmission operator dispatches power, such that demand is met by the least-cost set of power plants. However, in the presence of transmission line congestion, higher-cost power plants closer to demand centers must be dispatched. So transmission congestion forces the transmission operator to dispatch a sub-optimal set of power plants resulting in higher electricity prices and potentially higher levels of emissions.

Congestion occurs when demand from generators to use a specific transmission line exceeds the transmission line capacity. Not all generators are able to use transfer capacity to transmit their electricity to the load center. Congestion thus leads to higher local marginal electricity prices in the load center, since more electricity must be supplied by local generators rather than less expensive but more distant generators. Investment of an additional transmission line to ease congestion would lead the electricity production from local expensive generators to decrease and generation from distant generators to increase, resulting in a price reduction at the load certer. An additional benefit would be a reduction in air pollution given that conventional fossil fuel generators are typically located closer to the load centers than renewable energy generators, such as wind power plants.

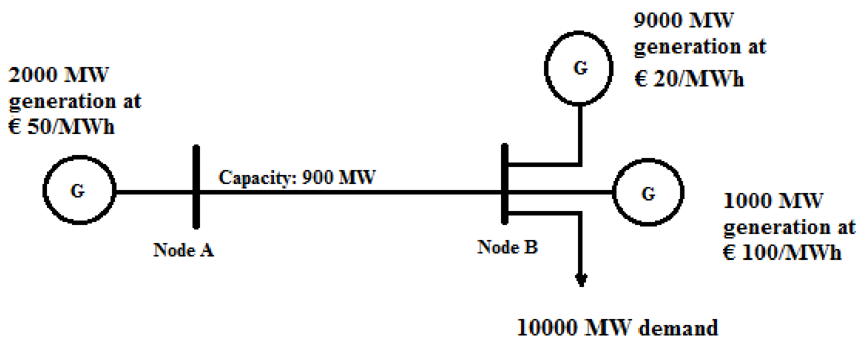


Figure 46 - A two-node network model [BBBW07]

An example to describe how congestion rents can influence a transmission project (see Figure 46):

Assuming that the added transmission capacity between Node A and B were only 900 MW and that wholesale price is based on locational marginal prices (LMPs). Because some of the expensive generation would be needed at Node B, the LMPs at Node B would be €100/MWh, while the LMP at Node A would be €50/MWh. So there is a net injection of 900 MW at €50/MWh into Node A and a net withdrawal of 900 MW at €100/MWh at Node B. In this case, the congestion rents equal the flow of power (900 MW) from Node A to Node B times the price difference between the two nodes (€50/MWh). So the congestion rents are €45000 per hour. If another additional 100 MW of transmission capacity is added, then the congestion rent would be eliminated. In other words the transmission expansion by another 100 MW would save €45000 an hour in congestion rents. On generation side, the additional 100 MW would reduce the generation costs by €5000 an hour. From the TSO's point of view, this additional 100 MW transmission project is not economic beneficial due to the loss of congestion rent. However, the "benefits" of this kind transmission projects are measured at least partly in terms of their impacts on the welfare by lowering marginal electricity prices and also increasing the reliability in this area.

6.1.5 Regulatory influence

Even though the electricity market is gradually deregulated and becoming more competitive, it is still necessary to regulate the transmission system in order to create a place for fair competition. The market-oriented operation of the power industry will gradually break the existing monopoly. Some of the new generation and transmission entities, such as regional transmission organizations, independent generation companies, etc. will emerge, moving towards a decentralised trend on the grid investment. Anyone can participate in the transmission investment. However, in the market-driven investment process, regulatory agencies still play significant roles.

The reality is that we are facing insufficient investment in the transmission network, resulting in binding capacity constraints and network congestion. The regulatory system seems somehow to have failed in coping with the need for new transmission investment in a timely fashion [NSE11]. Particularly in Europe, there is a huge demand for new transmission investment in interconnectors between countries to facilitate competition and market integration into a common European electricity market, and for realizing the EU policy targets with regard to increased renewable energy in the power system.

Regulatory processes related to transmission assets can be divided into three parts: planning, approval and pricing. Each regulatory procedure has a significant impact on transmission investment and expansion. Among the three procedures, price regulation is mostly concerned because it directly influences the profit and benefits of the market participants and investors, alters the decision of both generators and consumers, affects the development of the electricity over time, and provides various incentives.

"Incentive regulation" is an important way for regulated firms to reduce costs, improve service quality in a cost effective way, stimulate the introduction of new products and services, and stimulate efficient investment in and pricing of access to regulated network infrastructure service.

Regulator is always seeking to maximise a social welfare function, which reflects the goal of limiting the rents that are transferred from consumers or taxpayers to the firm's owners and managers subject to a firm participation [PLJ06]. However, the transmission assets owners especially for the privately-owned stakeholders or investors prefer to maximise the general profit. There is always a conflict between regulatory agents' will and investors or stakeholders' expectation. In general, regulatory behaviour on one hand provides incentives to stimulate transmission expansion and improve efficiency, and on the other hand regulates the pricing methodology in order to protect consumers' benefits.

Case study on regulation in EU and obstacles to meet the collective goal (up to 2020)

New policy context points out substantial needs for new energy infrastructure investment in EU, which is estimated more than €200 billion up to 2020, in order to reach EU's 20-20-20 goals [EIP10]. Specifically identified investment needs include [EIIN11]: a) About €140 billion for high voltage electricity transmission systems of European significance with onshore (€70 billion) and offshore (€30 billion), another €40 billion for the storage and smart grid applications; b) About €70 billion for high pressure gas pressure transmission pipelines, storage, liquefied natural gas terminal and reverse flow infrastructure. The assessment took significantly account of the future demand, especially in the transport sector, interdependencies between the electricity and gas system of all member states and the remaining infrastructure bottlenecks to obtain a fully integrated European network (Annex2 in [EIIN11]).

Competitiveness, sustainability and security of supply are three Europe's energy challenges that need to be taken into account through all stages (short term, middle term and long term). A real internal energy market is essential to meet the three challenges.

In EU, electricity transmission is a regulated business at a national level and the cost allocation to final beneficiaries is difficult for large trans-European infrastructures. The goal for tariff regulation is to keep transmission tariffs as low as possible. In most member states, tariff regulation is based on the principle of cost-efficiency that allows recovery of cost only for projects based on the real market needs or cheapest available solutions.

However, some kinds of projects are difficult in the realisation through this approach.

- Projects with higher regional benefit: For higher regional benefit of a project, more member states will be involved and it will probably become more complex concerning different regulatory regimes, rates of return or investment amortisation periods and different permitting procedures. Also, cross-border coordination is more difficult if the costs and benefits of the project are shared asymmetrically.
- Projects using innovative technologies: innovative technologies involve high risks as their industrial-scale applicability and business case are not fully proven yet. Market players do often not ask for and regulators do not approve a higher rate of return. Thus, using new technologies for generation (e.g. carbon capture and storage) or transmission (e.g. DC VSC offshore grid technology, storage, smart grid applications), which are necessary for achieving the EU energy and climate objectives, will not be implemented within a short time.

Long and uncertain permitting procedures were indicated as one of the main reasons for delay in the implementation of infrastructure projects, especially in electricity. It puts a major additional risk on investment in power generation and transmission and has slowed down or even stopped new projects. Usually, the time between start of planning and final commission of a transmission line is more than 10 years especially for a domestic or a cross-border project and projects can even take up to 20 years to be completed. Cross-border projects often face additional opposition, as they are always perceived as mere “transit lines” without local benefits.

Aforementioned issues are EU regulatory interests/expectations and conflicts occurred in achieving EU energy and climate objectives. These conflicts and obstacles need more coordination among states members in order to make a more suitable regulatory framework in achieving the long-term collective goals.

7 ELECTRICITY INFRASTRUCTURE ROADMAP TOWARDS 2050

The electricity system is an important part of the overall energy system. It is expected that it will become more and more important towards 2050 when the energy sector needs to strongly decrease its CO_2 emissions. The electricity infrastructure is the backbone of the electricity system and needs to facilitate future energy transition. However, a range of uncertain factors may over time affect the requirements for future electricity infrastructure systems, so that different electricity system trajectories can be envisaged.

The IRENE-40 project has extensively studied the impact of different electricity system trajectories towards a more sustainable energy system in 2050 thereby making due allowance for different sets of uncertain factors. This chapter aims to synthesize overall results into a (qualitative) road map for electricity infrastructure into 2050 on five dimensions:
(1) Network investment strategies
(2) Cost allocation
(3) RD&D policy
(4) Public acceptance
(5) Electricity market design.

The key question is: how do stakeholders, predominantly TSOs and regulatory authorities need to deal with uncertain developments in the electricity system towards 2050? What are the key issues for different futures? Which network technologies need to be considered? And how will they know which choice to make in certain situations?

7.1 FACILITATING BETTER NETWORK INVESTMENT STRATEGIES IN AN UNCERTAIN FUTURE

The power system is characterised by at least three large uncertainties which impact the transmission planning by European TSOs as well as policy makers and regulators that steer and monitor the planning process, and system actors which are confronted with benefits and costs of new infrastructure (producers and consumers). These are uncertainties concerning:

- Future generation mix
- Technology development and commercialisation of new network technologies
- Policy developments.

Uncertainty about the future generation mix

A first important uncertainty is which future generation mix is most likely to occur; will the future generation mix consist mainly of large scale onshore and offshore wind parks, solar CSP in Northern African countries, fossil fuelled generation deployed with CCS, or distributed generation (solar PV and dispersed wind turbines)?[37] A different generation mix requires different network

[37] Note that this not only depends on technological development but also strongly depends on developments of fuel and CO_2 prices as well as policies regarding RES-E stimulation.

investments; both different network investment levels and at different geographical locations. Since the economic lifetime of network assets is long, typically more than 40 years, while the economic lifetime of generation assets is shorter (this holds especially for renewable generation), there is a high risk of stranded assets when the generation mix develops inconsistently over time. A large diversity of locations of generation assets in time diminishes the chance of 'recycling' of network assets.

The IRENE-40 analysis provides indications for the risks for stranded assets in different ways. First, it shows that network investment costs differ significantly for different G&D scenarios. According to Castro *et al*. (2012) network investment costs range from 10 billion euro for the CCS scenario up to 194 billion euro for the DES scenario for the period 2010-2050.[38] Additionally, Roehder *et al*. (2012) show that there can be high regret costs involved with network investments when EU member states move from one generation scenario to another over decades. Among others, these costs constitute the cost of stranded network assets i.e. network assets which can be marginally used (if at all) in case of another generation scenario.

IRENE-40 network scenarios illustrate the uncertainty related to different G&D scenarios also on the individual interconnection level (see Figure 47 below). For instance, investments in interconnectors ES-FR and UK-NO are only required in case of the DES, EFF and RES scenarios. Furthermore, demand for grid expansion shows a high variability for several interconnectors including amongst others ES-FR, FR-BE, IT-AT, DE-DK, BA-SI, NL-DE and NL-BE. This implies that there are high costs associated with changing preferences of commercial electricity generators for the size of the network costs. At the same time, the picture also indicates a number of robust choices; for the interconnections FR-UK, NO-DE, FR-IT, HU-AT, RO-BG, CH-AT, NL-NO, SE-DE, SE-FI, LU-DE, LT-SE either no or a very comparable amount of network investments is required for the different G&D scenarios.

Furthermore, it has to be realised that in practise investment decisions are not made at one point in time but in several steps over the 40 years planning horizon. When part of the decisions can be made later in time, uncertainty will be partially reduced and hence the diversity in network requirements of different G&D scenarios. However, although the uncertainty bandwidths are somewhat smaller than indicated by Figure 47 the uncertainty about the future generation mix remains a key issue for TSOs in determining their investment strategies.

[38] Figure 38 shows that incremental network investment costs for the high resolution model range from 36 bn $€_{2010}$ to 79 bn $€_{2010}$. This smaller bandwidth is likely to be due to the selection of the RES G&D scenario as basis for the selection of network reinforcements.

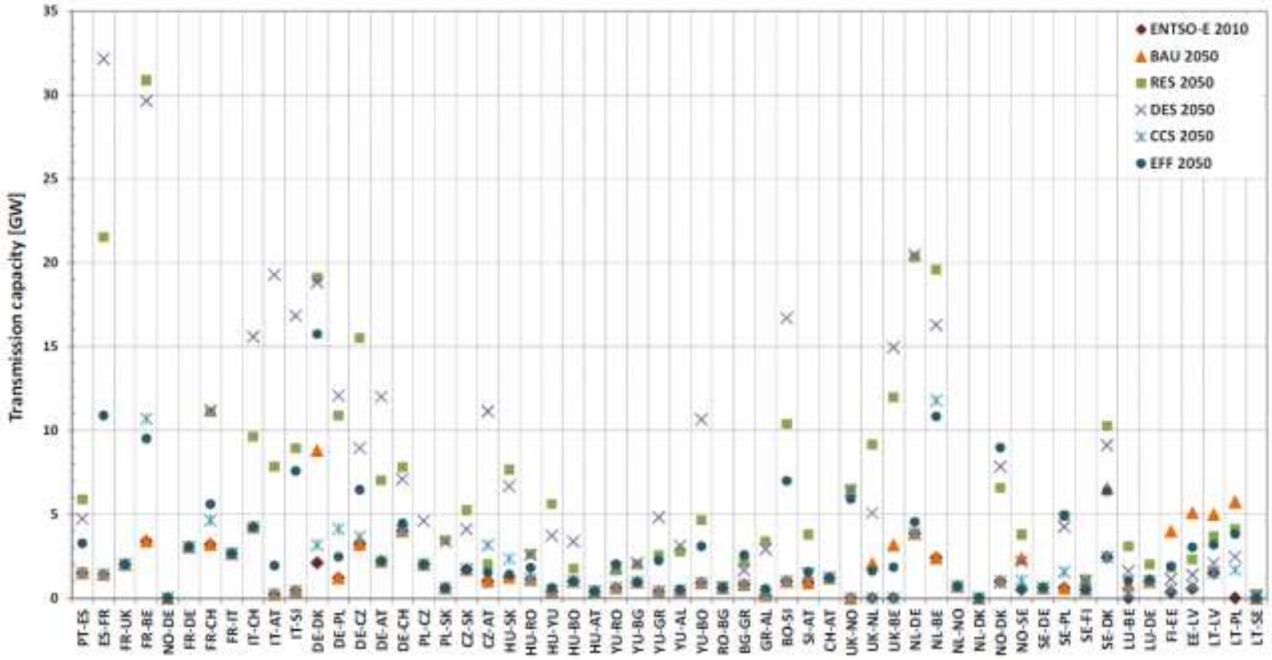


Figure 47 - Interconnector capacity requirements of the five generation and demand scenarios

[Source: Castro *et al*. 2012]

Uncertainty about the technology development and commercialisation of new network technologies

The second uncertainty is when new network technologies (transmission, conversion and storage components) will become available for cost-efficient mass deployment. Especially, HVDC is considered to be an important technology for the realization of generation scenarios with high levels of electricity production from renewables. The large scale deployment of HVDC technology depends on the realization of learning effects; since foresight of cost reductions is imperfect, deployment of new technologies is potentially more risky for TSOs, especially if the regulatory framework assumes low risk investments only.

Uncertainty about policy developments

The third uncertainty relates to policy developments; which role is the EU allowed to play in energy policy and which issues will remain national competences? Uncertainties over the profitability of network investments most fundamentally relate to the current lack of coordination between generation and network investments. With the unbundling of the commercial entities such as electricity generation from the regulated networks, economic incentives are needed for coordination between both system segments. However, current economic incentives are not unambiguous; European integration in the energy sector is limited to electricity markets and networks, but policy related to sustainable and conventional electricity production is the responsibility of individual member states. Lack of coordination between national policies (e.g. nuclear phase out in Germany while in the UK incentives for nuclear energy are planned) increases uncertainty over the demand for network capacity over time. Larger uncertainty over the demand for network capacity induces larger uncertainty over the profits of new network investments and increases the probability of stranded network assets if investments are realized.

For policy makers and regulators it is important to limit the probability of high system costs due to stranded network assets as far as possible. Hence, they incentivise TSOs to operate as cost efficiently given environmental and security of supply constraints. Their common question is 'How to hedge against future uncertainties related to technological and policy developments and associated risk for stranded assets while at the same time accommodating the transition to a sustainable electricity sector?'.

For answering this question, a closer look to the current policy and regulatory framework for network investment strategies is needed. Suboptimal regulation prevents efficient hedging within these strategies against future uncertainties. Barriers include:

- Lack of coordination of investments in generation and network capacity
- Long permitting procedures for grid expansion
- Limited role for demand response and storage

In the following we will discuss these barriers and highlight promising policy options to overcome them. The description of policy options is not intended to provide detailed policy recommendations as this would require assessment of additional political criterions as well as stakeholder consultation. The aim is rather to signal directions for resolving barriers for sound and efficient network investment strategies.

7.1.1 Coordinating investments in generation and network capacity

European TSOs are often obliged to accommodate grid connection requests by expanding the grid without possibilities to structurally manage the demand for network capacity at certain locations. This obligation is based on the copper plate paradigm, which assumes that national electricity networks have infinite capacity and the locations of production and consumption are unimportant. Therefore all links in national electricity networks need to have infinite capacity and all generation units are equally effective at meeting demand at any location in the transmission network (Baldick *et al*. 2011). This paradigm became standard in the early days of market integration when congestion was limited. The facilitating role of networks is reflected in the current network planning philosophy within the EU where grid expansion has to follow generation expansion i.e. 'transmission follows generation'. Hence, TSOs are obliged to connect new generation facilities whatever their location. Furthermore, as soon as their local connection is ready generators need to be able to transport their full generation and have to be compensated if this is not the case ('connect-and-manage').

However, in practice siting of generation plants and load pockets plays a large role in the demand for network capacity. Network costs for transporting electricity from generation units sited far away from demand are significantly higher than the network costs of generation units at locations nearby demand. Again, IRENE-40 estimates of network costs confirm this; network costs for meeting the same electricity demand levels for the period 2010-2050 are substantially lower for CCS and BAU scenarios (€ 10-23 bn) where generation is closer located to demand than for DES and RES scenarios (€ 154-194 bn) (Castro *et al*. 2012).[39] [40]

Alternative "generation follows transmission" methodology
Instead of the 'transmission follows generation' philosophy, an alternative philosophy applied in the US is 'generation follows transmission'. Turning the network planning philosophy around may seem strange, but can help both to reduce costs of stranded network assets as well as to minimize overall system costs (i.e. generation and network costs).

This requires a two-step approach. The first step is that network investments precede generation investments i.e. anticipatory investments are performed. The second step is discouraging the connection of generators at locations which is expected to result in prohibitively high overall system costs.

First step: Introduce possibility for anticipatory investments
Following Ofgem (2010), anticipatory investments are 'capital expenditures based on anticipated future requirements, rather than prevailing contracted requirements'. Anticipatory investments enable more cost efficient long term network developments by realizing economies of scale; because of the lumpiness of network investments line reinforcement costs decrease substantially with larger network capacities. Hence, it is advantageous to realize larger network capacity additions at once instead of several incremental reinforcements over time. Furthermore, anticipatory investments prevent or reduce the time lag between realization of network and generation investments and therefore may help the timely realization of the 20/20/20 EC energy targets.

Anticipatory investments may also offer advantages for several stakeholders. TSOs may profit from a growth of investment projects in the short term which increases their regulatory asset base. Furthermore, they are allowed to pursue a more long term network planning and realize economies of scale in network reinforcements. Therefore they need to adapt their procedures for project selection and need to follow a more forward looking approach instead of waiting for connection requests. Network technology providers may profit as well from the growth of network investments in the short term and the larger possibilities for innovative network technologies such as HVDC with benefits over longer time periods. Producers may obtain possibilities for faster connection. Effects for consumers seem negative, in the short term they will have to pay higher network tariffs to allow for TSO cost recovery. In the long term, this effect may be somewhat dampened by the realization of economies of scale in network reinforcement.

In fact, anticipatory investments have already been assumed in the IRENE-40 analysis of Roehder *et al*. (2012); all network investments are planned before 2030 assuming planned generation investments will be realized in 2030, 2040 and 2050 respectively. However, currently anticipatory investments are only allowed in a few countries including the UK (Ofgem, 2010). Furthermore, this

[39] The EFF scenario has a lower electricity demand and is therefore not mentioned.
[40] Additional interconnection capacity varies from 11-15 TW/km (BAU and CCS) to 131-156 TW/km (RES and DES) for the period 2010-2050. For the EFF scenario 57 TW/km of additional interconnection capacity is required during this period.

type of investments is also considered as possible policy instrument for advancing Projects of Common Interest (PCIs) of the EU (EC, 2013).[41]

In order to guarantee that investment projects are selected which increase social welfare, instead of investments that are profitable for TSOs but have no clear advantage from societal perspective, anticipatory investments like any other network investments should be identified using an assessment whether the investment will be used and useful from a welfare perspective. For such assessments social cost-benefit analysis is most appropriate since this type of analysis provides a consistent, objective picture of the expected impacts of network investments on both individual stakeholders as well as social welfare. Hence, the UK requires a cost benefit analysis (Ofgem, 2010) and the EC prescribes its use for the selection of PCI investment projects (EC, 2013).

Recommendation: Regulators/ policy makers: introduce possibility for anticipatory investments in the regulatory framework of TSOs. Investments should be based on an used-and-useful assessment of the network investment for the overall society. For this assessment a social cost benefit analysis is preferred.

However, financing and construction of grid expansion before generation investments take place does not resolve risks for stranded assets without concomitant measures. If TSOs do not have the possibility to transfer network costs to those who caused those costs (‘cost causality’ principle), siting and production decisions of generators cannot be influenced resulting in higher uncertainty for grid planning and higher risks for stranded assets. This relates to the fact that generators do not receive an incentive to take into account the required network investments costs resulting from their decision to locate either remote or nearby demand since they do not pay or only pay a very small share of the costs they cause to the electricity system.

Second step: Introduce locational incentives for generators

Therefore it is worthwhile to consider the second step of the network planning philosophy. This step consists of a locational incentive for generators to minimize overall expected costs of the electricity system (i.e. production, trading, networks and supply) given environmental and security constraints (Baldick *et al*. 2011). There are at least two possibilities to do so.

The first possibility is restricting the obligation of TSOs to expand the grid in such a way that generators are incentivised to locate only at favourable locations from system costs perspective. Requests for connections that are close to the main grid infrastructure (‘backbones’) are likely to induce relatively low system costs and will be connected like before. However, requests for connections in remote areas that incur prohibitively high system costs and hence do not contribute to lowest overall expected system-wide cost of generation and transmission, will be treated differently. In this case, the deep network reinforcements will not be performed by TSOs. This means that investors in generation at remote locations face congestion which lowers the profitability

41 See Article 14(3) of EC (2013). This draft regulation is planned to become in force by January 2013.

of their investments or have to organise the reinforcement of the network branch to which they seek connection themselves and pay for these deep connection costs.[42]

The second possibility is to oblige generators to pay for locational specific network costs by allocating them the network costs they cause to the electricity system. Therefore first the costs and benefits of network investments need to be assessed. Subsequently, the beneficiary pays principle prescribes that network costs should be allocated based on the net benefits each stakeholder obtains from the investment.[43] These network costs can be levied to the network users by both congestion management[44] and locational network tariffs. If generators following application of the beneficiary pays principle should pay a larger part of the network costs, they will take into account these costs in their *production* decisions. For providing most efficient incentives, network costs may also be differentiated among producers according to locations, since the production location drives the network costs to a high extent. If producers experience such locational incentives they will also take into account the network costs they induce to the system in their *siting* decisions. Hence, they will site nearby one of the transmission backbones instead of at remote branches.

Both possibilities have important advantages for the electricity system. Notably electricity consumers profit from relatively lower network tariffs since inefficient deep network investments are avoided, the regulatory asset base of TSOs increases less rapidly, and hence network tariffs rise to a lower extent. Also generators that want to replace existing power plants or build new power plants nearby transmission backbones may profit substantially. On the other hand, generators with sites at remote network branches, for instance investors in wind turbines, will face higher network costs and oppose any approach based upon locational incentives. Likewise, TSOs might oppose these policies as they decrease the regulatory asset base and hence profit opportunities, whilst increasing administrative efforts. However, this practise is optimal from an overall social welfare perspective since network users have to pay charges which reflect actual costs incurred and transparency of network costs increases. At the same time it should be realised that part of the benefit may be lost because at least in the short term higher subsidies for support of renewable energy maybe needed to achieve the 20/20/20 and 2050 EU energy goals.

At the moment, the first possibility is not applicable to EU countries since all generators need to be connected by TSOs whatever their location (‘non-discrimination’ principle). Directive 2009/72/EC states that ‘each transmission system operator shall be responsible for … ensuring the long-term ability of the system to meet reasonable demands for the transmission of electricity’. Therefore, current legislation makes it difficult for TSOs to refuse any connection request, because if they do so they have to prove that the particular connection request is unreasonable.

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42 In fact the generation facility is connected, but the required network reinforcements behind the grid connection point are not performed and the TSO deploys congestion management to keep the demand for network capacity within security limits.

43 The application of this principle is further explained in Section 7.2.

44 It concerns cross-border congestion management in the day-ahead market which takes place by regional (implicit) auctions. Following the EU target model for the day-ahead market (EC, 2009b), the EC and stakeholders strive for one implicit EU auction across Europe.

However, the second possibility seems in line with current EU policy developments for two reasons. First, for congestion management within Europe an increasing number of bidding zones is foreseen, including the split of current zones consisting of one country in several zones, see Figure 48 which shows the example EC officer M. Supponen provided in 2010.

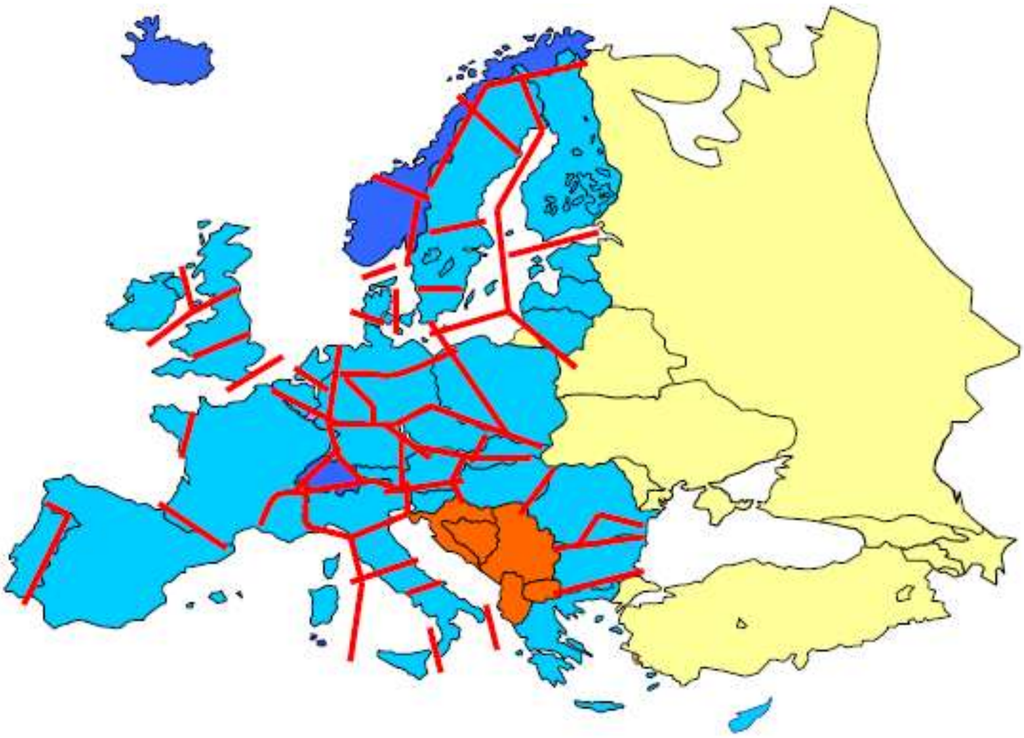


Figure 48 - Pedagogical example by M. Supponen concerning price zones in Europe (EC, 2010)

Hence, if current plans materialize substantial internal congestion will be priced and producers will face lower electricity prices in zones with excess electricity and higher prices in zones with shortage of electricity. This provides locational incentives for siting of new generation units.

Second, all remaining network costs that are not levied by congestion management are covered by network tariffs. The preamble of EU Regulation 714/2009 states that 'A proper system of long-term locational signals is necessary …' and the regulation itself states 'Where appropriate the level of the tariffs applied to producers and/or consumers shall provide locational signals at Community level …'.[45] Furthermore, the regulation offers explicitly the possibility for the EC to issue guidance for the introduction of locational signals in network tariffs of member states.[46]

45 See Article 14(2) of Regulation 714/2009.
46 See Article 18(2) of Regulation 714/2009.

Recommendation: Policy makers and regulators are advised to consider also the second step of the 'generation follows transmission' network planning philosophy that allows for steering the siting of new generation units to those locations that have the lowest overall costs for society. This requires introduction of locational incentives for producers but will limit probabilities for and costs of stranded network assets considerably.

7.1.2 Faster permitting procedures for grid expansion

Delays in realization of network reinforcements are not taken into account within IRENE-40 network scenarios, but in practise play an important role since they may impede construction and implementation of sound network investment strategies. Given the current 'transmission follows generation' philosophy, in Europe the process for network reinforcements starts usually only when the application for connection of the new generation investment is firm (Lapuerta *et al*. 2007). Since the construction of new overhead lines often takes 10 years or even more (EC, 2011b), while new production facilities like gas and coal power plants are often realized within 3-4 years, there is a substantial time lag between the realisation of production and network investments. The construction of new network capacity is often finished when the production capacity is already available for years.

Both at member state level (e.g. Germany, the Netherlands) as well as at European level, initiatives exist for reducing the lead time for grid expansion by faster permitting procedures and enabling better public participation in infrastructure extension processes. At EU level, among others an one-stop shop for permits for Project of Common Interest (PCIs) is foreseen. Although this is considered as the most controversial part of regulation (EC, 2013) by stakeholders, faster permitting procedures are key for the timely realisation of grid expansion.

Recommendation: Policy makers are advised to reduce the lead time for grid expansion by striving for faster permitting procedures as timely realisation of grid expansion enables realisation of sound network investment strategies.

7.1.3 Larger role for flexibility of demand response and storage

Currently the focus of TSOs is on meeting the demand for network capacity by grid expansion with increasing risks of stranded network assets. An important alternative studied in the IRENE-40 project is managing the demand for network capacity by allowing a larger role for demand response and storage. Strbac *et al*. (2011) and Castro *et al*. (2012) indicate that the system level benefits of using demand side potential can be substantial, among others by limiting system peak demand and hence by reducing or deferring network investments required to accommodate future demand growth and to facilitate the integration of renewable energy resources. Associated costs have not been analysed. It can be seen in Figure 49 below that the presence of demand side flexibility (10%

of daily total net generation capacity and 10% of daily energy)[47] in IRENE-40 scenarios leads to transmission investment savings of 30b€, 18 b€ and 6b€ in RES, EFF and DES scenarios respectively for the year 2050.

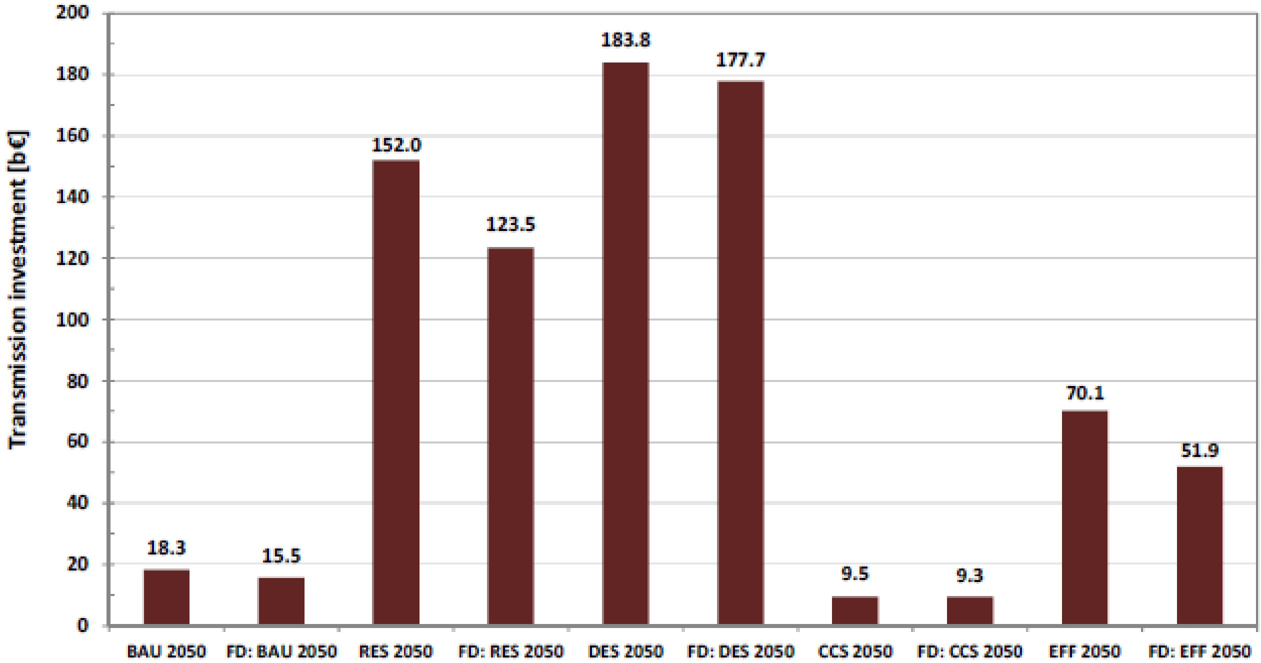


Figure 49 - Avoided transmission investments by deployment of demand response

[Source: Castro *et al*. (2012)]

Managing the demand for network investments with demand response and storage thus prevents stranded network assets. Hence, it may be optimal to postpone network investments which are not robust for several G&D scenarios and resolve potential congestion with these other sources of flexibility.

Another manner to get insight in potential savings is by simulating the value of postponement of network investments. For instance, assume that network investments scheduled for before 2030 are postponed until the year 2040 or 2050. On the one hand this implies that network investment costs are realized later in time and hence costs are lower when discounted to present values, on the other hand it means that generation savings are realized later in time and discounted benefits are lower as well. Figure 50 shows the results of this imaginary situation.

[47] Efficiency losses for the shifting process are taken into account.

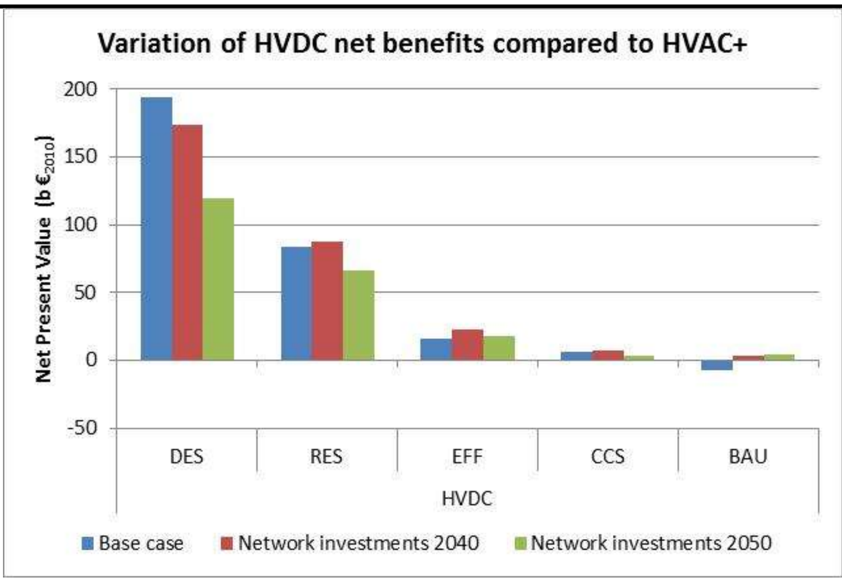


Figure 50 - Variation of HVDC net benefits compared to HVAC+

[Source: ECN]

Postponement of network investments to 2050 lowers the net benefits for the DES scenario and to a lesser extent for the RES scenario. This relates to the generation cost savings which stronger decrease than the network costs. The negative value of extension for the DES and RES scenarios is in contrast with expectations. Since the network investments consist largely/partially of cross-border investments identified by Castro *et al*. (2012) for the year 2050, one would expect that postponing network investments until 2050 would be more profitable for network investors. The EFF, CCS, BAU scenarios are not significantly affected, probably because they need less network investments due to a lower need for long distance electricity transport than the other scenarios.

The same story holds for the postponement of network investments to 2040 in the DES scenario. The RES, EFF, CCS, and BAU scenarios do not show a significant change of net results in this case.

These results seem to contradict the results of Strbac *et al*. (2011) and Castro *et al*. (2012). However, in reality where uncertainty plays an important role there is likely to be a positive value of extension of grid expansion and therefore a role for managing the demand for network capacity by deployment of flexible demand or storage facilities. This is supported by the regret analysis in the context of the high resolution models, which showed that the network costs of uncertainty are substantial (see Table 11).

Recommendation: In case of large uncertainty about the robustness of grid expansion for different G&D scenarios and hence large risks for stranded assets, TSOs should be incented to consider alternative solutions like deployment of flexibility made available by demand response and storage facilities.

7.2 IMPROVING COST ALLOCATION SUPPORTS REALISATION OF NETWORK STRATEGIES

7.2.1 Effects of transmission infrastructure investments on stakeholders

Transmission infrastructure investments have different economic impacts on different market participants. This is usually evaluated within a social welfare framework which enables the analysis of impacts upon market participants like producers, consumers and TSOs. Impacts are determined using notions as consumer surplus, producer surplus and congestion rents. The process to identify these notions can be illustrated using Figure 51 below, which assumes a perfectly competitive electricity market but limited interconnection capacity.

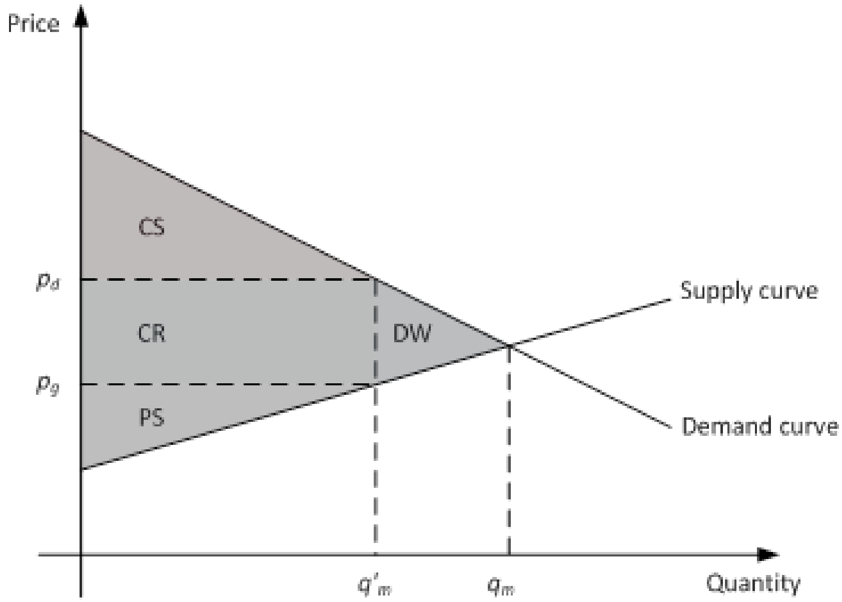


Figure 51 - Social welfare components and interconnection

[Source: Imperial College]

The intersection of the supply and demand curves determines the competitive equilibrium point, characterised by the market clearing quantity (q_m). It can be observed that when the system has limited interconnection capacity, the original equilibrium point (q_m) cannot be reached. Although there is still one market clearing quantity (q'_m), in the quasi-equilibrium point there exists two distinct prices: (i) one related to the consumers' willingness to pay (p_d); and (ii) one given by the marginal cost of production (p_g).

The supply curve represents the aggregate marginal cost curves of the producers. It can be observed that there are producers in the market able to supply at lower cost than the highest marginal costs at the quantity consumed (p_g). These producers sell at a profit as they offer their production at a lower price, but subsequently are paid the average price which is related to the highest marginal generation costs. The triangular area enclosed by the aggregated marginal cost curve (supply curve) and the highest marginal generation costs at the quantity consumed (p_g) is known as producers' surplus (PS). Producers' surplus measures the difference between the revenues that the producer receives for its clearing quantity at the highest marginal generation costs and the costs that the producer incurs for its clearing quantity at its offer price. Similarly, on the demand side, some consumers in the market are willing to pay more than the actual market clearing price (p_d). These consumers also derive a benefit from this situation resulting in the consumer surplus (CS). The latter corresponds to the triangular area enclosed by the demand curve and the market clearing price (p_d). Consumers' surplus measures the difference between the value of the energy purchased at the consumers' bid prices and that at the market clearing price (p_d).

From the market operator viewpoint, the operator would buy electricity at the price (p_g) and would sell it to the consumer at the price (p_d), as this reflects the willingness to pay at the demand side. Hence, the market operator collects a rent known as the congestion rent (CR) or surplus. The triangular area on the right hand side of the congestion rent represents the deadweight loss (DW). The deadweight loss is incurred by the fact that less energy can be traded leading to a loss on the overall welfare.

Up to now, energy trade within a bidding zone was assumed. Energy trade between two adjacent market zones occurs when the price differences are relevant and interconnection capacity is sufficient to allow price arbitrage. Price arbitrage means moving power from load in the low price zones (the exporting zone) to the high price zones (the importing zone). Figure 52 shows the effects of arbitrage trades between adjacent markets on producers' surplus, consumers' surplus and congestion rents.

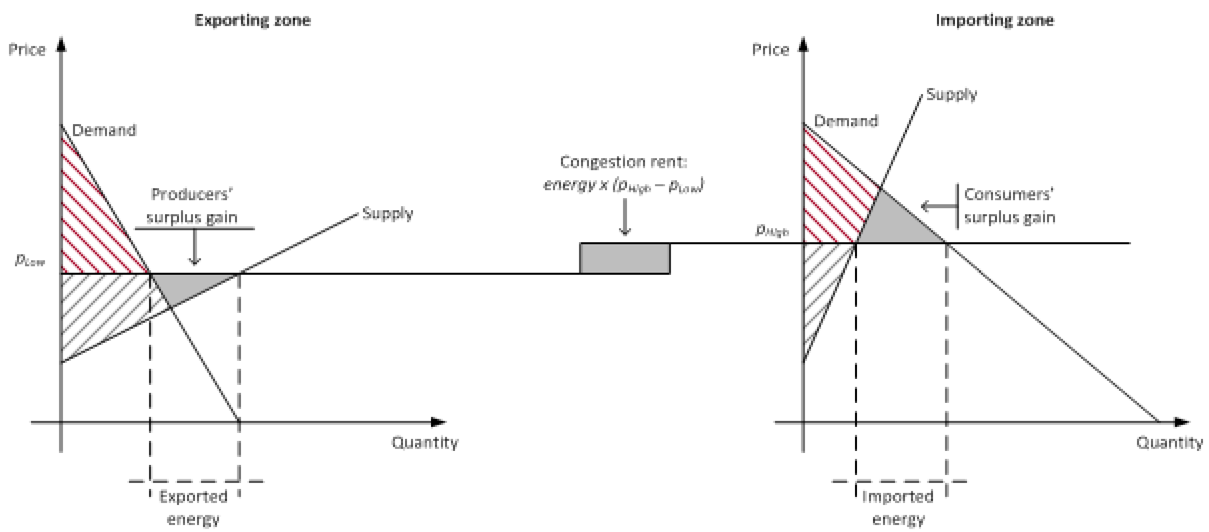


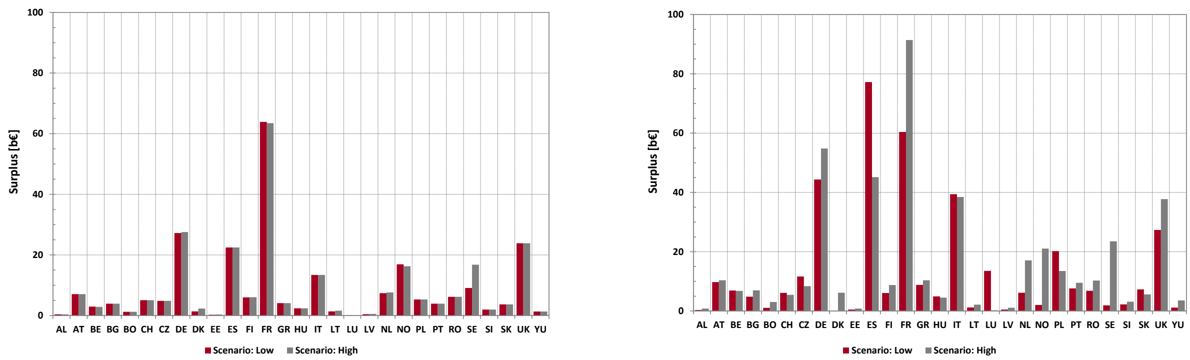
Figure 52 – Main economic effects of electricity trading between countries

It can be observed that effects on producers and consumers depend on whether the country at hand exports or imports:

- Producers located in importing zones experience lower energy prices and a potential decrease in energy production for higher marginal cost plants (i.e. mid-merit and peak plants) which in turn leads to reduced revenues and surplus.
- Producers located in exporting zones potentially produce higher volumes of energy from lower marginal cost plants (i.e. renewable energy sources, base load and mid-peak plants) which are sold at higher prices permitting them to secure further producer surplus.
- Consumers located in importing zones have access to competitive offers from producers located in adjacent zones. The local market price decreases resulting in a further gain in consumer surplus as higher volumes are consumed against lower prices.
- Consumers located in exporting zones observe higher energy prices resulting to an increase of the payments incurred for the consumption of electricity.

Based upon the outlined economic theory, the effects of identified cross-border transmission infrastructure investments by Castro et al. (2012) upon market participants like producers, consumers and TSOs can be shown.

The first observation is that cross-border interconnection not only in theory but also in practise causes asymmetrical impacts (i.e. costs and benefits) to producers and consumers in export and import situations. For producers this is illustrated by Figure 53 below. Spain shows a significant decrease of producers' surplus due to the additional import allowed by the additional interconnection capacity, while France shows a significant increase of producers' surplus due to additional export following the grid expansion.

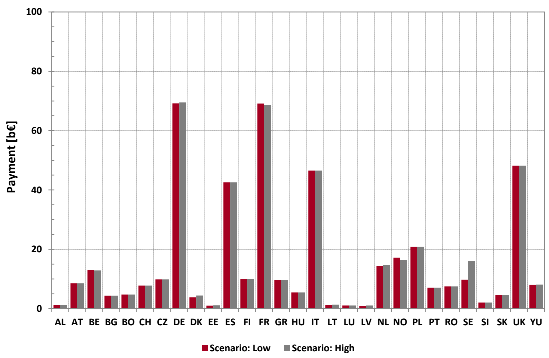


(a) Year 2030 **(b) Year 2050**

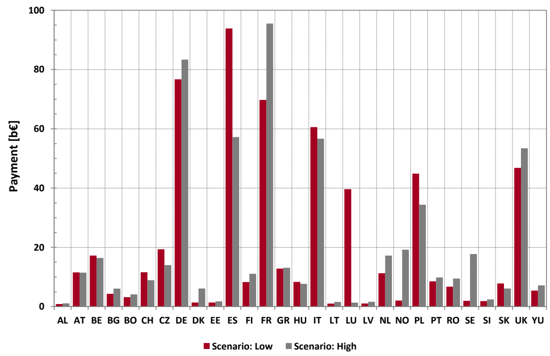
Figure 53 - RES scenario – Producers' surplus per country

[Source: Imperial College]

Consumers are effected in the opposite way. Figure 54 shows the situations for consumers located in importing zones (e.g. Spain) and exporting zones (e.g. France) respectively. Consumers' surplus in Spain increases with additional import, while the consumers' surplus in France decreases with additional exports.



(a) Year 2030



(b) Year 2050

Figure 54 - RES scenario – Consumers' payment per country

[Source: Imperial College]

Furthermore, the overall net benefit of the market sales and purchases as a result of trade has been calculated. Within the IRENE-40 project, social welfare is defined as the sum of total producer surplus, consumer surplus and congestion rents. Figure 55 and Figure 56 show the effects of cross-border transmission infrastructure investments upon market participants compared to the case of no grid expansion after 2010, for the periods 2010-2030 and 2010-2050 respectively.

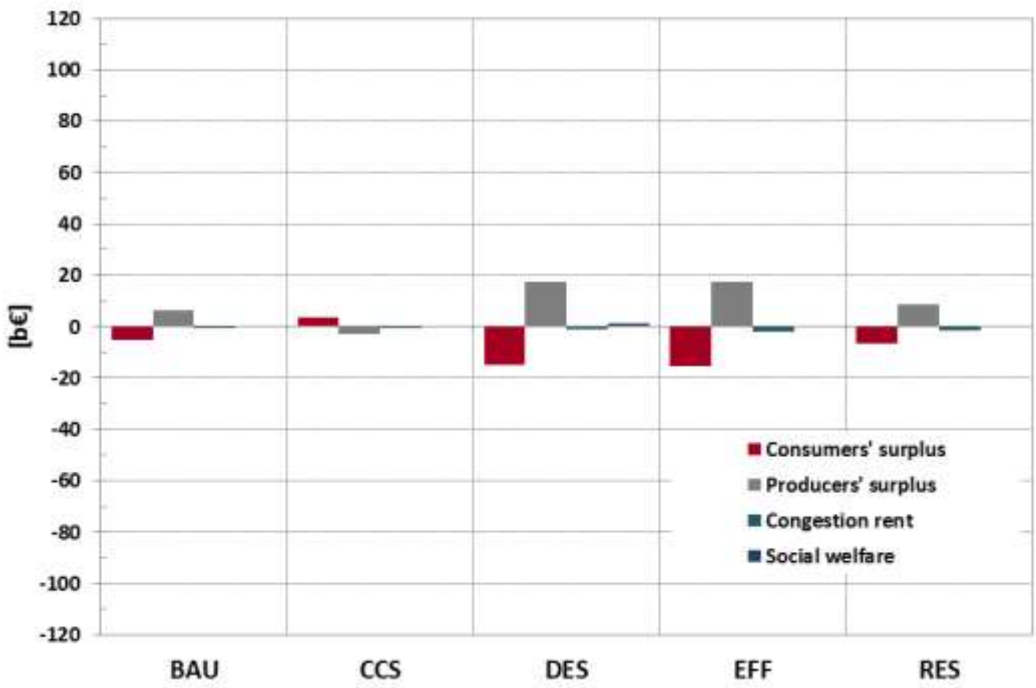


Figure 55 - Effects of cross-border investments on stakeholders for the period 2010-2030

[Source: Imperial College]

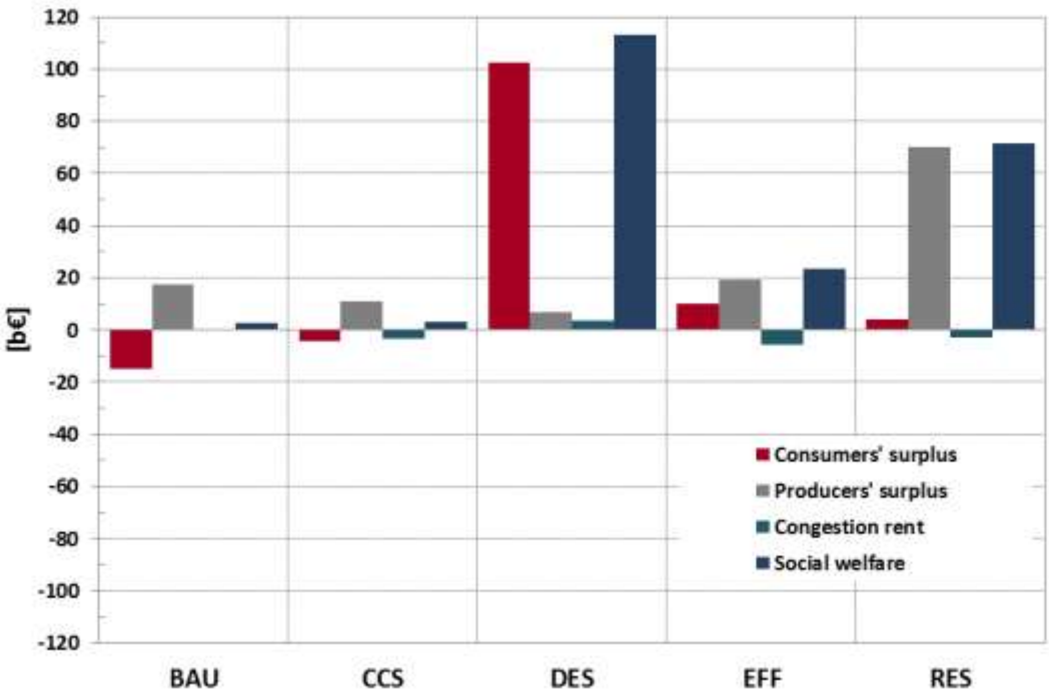


Figure 56 - Effects of cross-border investments on stakeholders for the period 2010-2050

[Source: Imperial College]

It is clearly visible that cross-border interconnection causes dissimilar impacts for different decarbonisation pathways and for different years.

For the year 2030, impacts on social welfare are generally slightly positive. Gains of producer surplus are lower than losses in consumer surplus for all scenarios, except for the CCS scenario where a loss of producer surplus is compensated by a small increase of consumer surplus. The increase of producer surplus is due to the increased possibilities for better utilisation of low marginal cost generation, but payments of consumers show a modest increase. For the CCS scenario the marginal increase in interconnection capacity permits a more efficient use of the resources, while producers are confronted with more competition and a small decrease of revenues. The congestion rents are slightly negative compared to the reference ('low') scenario due to the limited grid expansion.

For the year 2050, the highest impacts on social welfare are shown by the DES and RES scenarios, followed by EFF, CCS and BAU scenarios. For all scenarios the net incremental impacts are positive. Cross-border interconnection causes asymmetrical impacts (i.e. costs and benefits) to different market players, such as producers, consumers and network investors.

It can be observed that investments in additional interconnection capacity increase the revenues and surplus collected by producers from energy sales and reduce the cost that producers incur for producing electricity, especially in the RES scenario. In particular, low marginal producers such as wind power producers see an increase in revenues and surplus whilst producers with higher marginal cost plants such as gas face a decrease in revenues and surplus.

In the analysis, electricity demand is assumed to be perfectly inelastic resulting in an infinite consumer surplus. Perfectly inelastic demand means that customers do not respond to changes in price, i.e. the quantity demanded remains the same irrespective of its price. In this respect, the analysis addresses the consumers' payments as opposed to consumers' surplus. Consumers' payment represents the payment that the consumer incurs for consuming electricity. In the DES scenario, overall consumer payments are lowest of all scenarios for the year 2050. Energy trading across borders combined with access for customers located in Europe to the solar energy resources concentrated in North Africa results in lowest average electricity prices in Europe of the G&D scenarios surveyed.

The congestion rents for the TSO decrease in relative terms in EFF, CCS and RES scenarios, since - due to the higher interconnection capacity compared to the reference scenario without grid expansion- price differences between adjacent markets and hence congestion rents decrease. Congestion rents in DES and BAU (slightly) increase since the decrease of congestion rents is compensated for by higher trading volumes. In absolute terms, in all scenarios congestion surplus grows significantly in time due to higher trading volumes.[48]

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[48] For more details on the effects of investments in interconnection capacity on amongst others electricity prices, electricity price differences in time and the utilisation of the generation mix is referred to Chapter 6 of Liu *et al*. (2012).

It has to be noted that the analysis above does not include the costs of investments in interconnection capacity. When these costs are included, it has been shown that absolute net profits decrease with € 1 - 18 billion (CCS vs DES) over the period 2010-2050 and are very close to zero for the period 2010-2030.

Conclusion: The shown asymmetrical impacts of grid expansion on both producers and consumers in different countries can potentially delay the development of cross-border interconnectors as it may feed resistance of stakeholder groups against network reinforcements. In the EU, the stakeholder who benefits is not always the one who pays, and the stakeholder who incurs costs does not always benefit.

Existing cost allocation practices as well as possible improvements are evaluated in more detail in the remainder of this section. Section 7.2.2 starts by evaluating the consequences for TSOs, while Section 7.2.3 proceeds with consequences for producers and consumers. Finally, Section 7.2.4 addresses the necessity of sufficient coordination of network investments in AC networks because of the occurrence of parallel flows.

7.2.2 Decreasing congestion rents require increase of other sources of income for investors / TSOs

TSOs dispose of several sources of financing of grid expansion. First of all, TSOs obtain congestion rents by auctioning of transmission rights in electricity markets with different time frames (forward, day-ahead, intraday). Producers buy transmission rights for export of electricity either through an explicit auction (network capacity only) or implicit auction (network capacity is sold bundled with electricity). In principle, refraining from market imperfections, prices of transmission rights are in the case of implicit auctions[49] by definition equal to the difference between electricity prices between two countries. Hence, congestion rents as product of the price difference and the electricity traded over the interconnection are fully paid by producers. They constitute the income for the two involved TSOs, who usually share the revenues on a 50/50 basis (CWE, 2008). Congestion rents are a main source of income for financing cross-border investments of TSOs but as shown before decrease with the planned grid expansion.

In the absence of additional TSO incentives, in the current liberalized and restructured power system without vertical integration TSOs are primarily incented to maximize their own profits, rather than taking into account the wider consequences of their investments decisions on overall system costs or providing additional welfare. Hence, regulatory incentives need to guarantee that sufficient network investments take place by compensating a decrease of congestion rents by other sources of revenues.

This also links to the fact that congestion rents are insufficient for full cost recovery of TSOs because congestion revenues compensate only for short term marginal costs, while TSOs face the higher long term marginal costs for transportation of each kWh. Long term marginal costs are

49 Preferred option according to the target model for day-ahead market integration.

higher due to reliability constraints like N-1 requirements which require additional network investments compared to the economic optimal network investments (Peréz-Arriaga, 1995).

TSOs usually dispose of other sources of revenues for financing the residual or complementary network costs. All EU member states allow for TSO cost recovery by national grid tariffs, while in some EU member states also the inter TSO compensation (ITC) mechanism[50] can compensate part of the costs.[51] [52]

Recommendation: TSOs need to compensate decreasing congestion rents by other funding sources. Hence, regulators need to enable TSOs to pass through grid expansion costs increasingly by network tarification, through national grid tariffs and/or the EU ITC mechanism.

7.2.3 Increasing importance of network tarification effects producers and consumers

A larger role for national grid tariffs and / or the ITC mechanism effects the net benefits of grid expansion that producers and consumers obtain.

National grid tariffs

As already known, the residual network costs are incurred by network tariffs which in most EU countries are (nearly) entirely paid for by consumer (see ENTSO-E, 2012). An increase of network costs due to grid expansion and decreasing congestion rents will mean that consumers have to pay relatively more and producers relatively less. On the other hand, new interconnections may also change the distribution of benefits over producers and consumers. Network costs should therefore be allocated based on the net benefits each stakeholder obtains (‘beneficiary pays principle’) instead of cost socialization to consumers. The asymmetrical benefits and costs of interconnectors on different electricity market participants signals that costs may need to be allocated in accordance with the benefit that each market participant obtains of the use of the interconnection. This so-called beneficiary pays principle is tested in different ways in some U.S. market areas (e.g. MISO and CAISO, see Hogan, 2011) however not yet implemented in EU member states. One difficulty in applying this principle is that realized network flows provide insufficient insight in the costs of network restrictions and cannot be allocated to individual network users. Hence, the beneficiary pays principle is usually applied with cost allocation based upon expected benefits (‘ex-ante perspective’). However, when uncertainty over benefits is high (e.g. in highly meshed grids) it is difficult to fully allocate costs on this basis and part of the costs have to be socialized. At the same time, the principle can be applied to allocate costs related to indisputable benefits in meshed grids as well as a larger part of the costs in less meshed grids.

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50 The ITC mechanism is further elaborated upon below.

51 This holds only for those countries that obtain net receipts from the ITC mechanism. Countries that face net payments have to incur all residual costs by national grid tariffs (or other national mechanisms).

52 Section 6.1.3 mentions some additional sources for funding of TSO investments in projects with overall socio-economic viability, but lacking financial viability (‘TSO funding schemes’).

As seen before, a cost benefit analysis (CBA) of (portfolios of)[53] intended grid expansion project(s) can provide more clarity over the distribution of net benefits over stakeholders. If CBA results indicate that the distribution of benefits is not in line with the distribution of network costs, it is advised to adapt the distribution of network costs according to the beneficiary pays principle in order to improve the long term efficiency of the power system.

Since producers often pay no or a small share of network costs in EU countries, it seems likely that producers will have to pay (a larger) part of the network costs than currently is the case.

Recommendations: Found network tarification as far as possible on the beneficiary pays principle instead of cost socialization. Utilize cost benefit analysis to get insights on the distribution of costs and benefits over stakeholders.

ITC mechanism

The ITC mechanism compensates TSOs for hosting of cross-border flows and concomitant network losses on their networks (see also Section 6.1.2). Nowadays, the mechanisms plays a marginal role in investment decisions due to limitation of the fund for transactions between TSOs to 100 million euro per year. The fund is limited to this amount of money as the current mechanism will be revisited by ACER (EC Regulation 838/2010). This is related to the suboptimal design of the current ITC mechanism (Welle *et al*. 2011a). Among others, it is an ex-post mechanism that does not take into account expected costs and benefits of new grid infrastructure as it is based on an analysis of past transit flows (Welle *et al*. 2011b, Hirschhausen *et al*. 2012).

Since costs of existing infrastructure as well as expected costs of planned grid expansion exceed the current size of the fund by far, a larger role for the ITC mechanism is necessary in order to provide adequate investment incentives and not to disturb the level playing field between system actors in different member states (Welle *et al*. 2011b, Hirschhausen *et al*. 2012).

Recommendation: Transform the ITC mechanism in an ex-ante mechanism that takes into account expected benefits and costs of new infrastructure and increase the fund size accordingly.

7.2.4 Coordination in grid expansion may overcome one cost allocation issue

An additional issue is the lack of coordination in grid expansion agreements. Network expansion agreements are often bilateral. However, due to network effects ('parallel or loop flows') of AC lines, costs and benefits of reinforcements of interconnections as well as important national reinforcements will partly fall in third countries that are outside those bilateral agreements

[53] Assessing portfolios of grid expansion projects has at least two advantages. First, the sequence of network investments no longer influences the net benefits of projects. Second, if the negative effects of project A on a stakeholder are compensated by project B, a portfolio of projects may be acceptable while separately project A may not take place.

('externalities').[54] As long as these costs and benefits are not taken into account in the congestion rents distribution, this will lead to suboptimal decisions about investments in new interconnections.

In case the investment results in additional costs to a third country, ideally the investment should be smaller or in the extreme case (if additional costs turn the business case negative) even not taking place. Otherwise free riding of the project promotor(s) at the expense of the third country takes place.

In case the investment results in additional benefits to a third country, the size of the planned investment should be larger or in the extreme case such an investment is profitable instead of detrimental from social welfare point of view. Without coordination free riding of the third country or countries happens.

Therefore, multilateral agreements over grid infrastructures are required to overcome these free riding effects. Such multilateral agreements are foreseen for grid infrastructures labelled as PCIs by EC (2013).[55] However, there are some concerns over the legal feasibility of the new approach, especially there are doubts whether ACER can be provided these responsibilities (Hirschhausen *et al*. 2012).

Recommendation: Policy makers should carry through regulation aimed at multilateral agreements over grid infrastructure with a significant effect on third countries.

7.3 STIMULATING THE UPTAKE OF INNOVATIVE NETWORK TECHNOLOGY

7.3.1 Mix of innovative technologies warranted for successful energy transition

The future electricity system will need to deal with an increasing level of variability in electricity supply and a decreasing predictability of supply brought about by notably the increasing penetration of intermittent electricity production technologies. In addition, the distance between electricity production locations and load centres will further increase as electricity supply developments will increasingly be determined by the uneven potential for renewable-based production across Europe. These generation developments are robust, as demonstrated by modelling analyses reported on in Section 2.2 although the magnitude of network impacts varies significantly across future energy

[54] This was not shown in the IRENE-40 project due to the complexity of modelling parallel or loop flows in long-term economic optimization models.

[55] Article 13(3) postulates that national regulators being part of regional groups consisting of TSOs and other project promotors, policy makers and regulators (all both on EU level and national level) should decide on the cross border allocation of projects with significant cross-border effects i.e. PCIs within 6 months of the application. If national regulators do not reach agreement within 6 months, ACER has to decide (article 13(5) and (6)). The six months period seems fairly ambitious.

scenarios (see Section 7.1).[56] A mix of new, innovative network technologies will be needed over time in order to arrive at a future sustainable energy system with an acceptable, lower level of system infrastructure costs.

Further technology developments are required for a mix of different transmission network technologies: ranging from transmission, conversion and storage technologies to smart grid technologies involving demand response and generation flexibility at notably distribution network levels. In the context of this project, the focus has been on technologies mostly relevant at the transmission level of the energy system. Whereas smart grid technologies undoubtedly need to be part of the future solution, they will always need to be accompanied with the large-scale implementation of transmission, conversion and storage technologies.

Transmission technologies basically consist of lines which can be used in transmission planning and can provide solutions for interconnection between the various system nodes. Those lines can be either overhead lines or underground/submarine cables. Also serving different purposes there can be either AC lines in various voltage levels or DC lines. Furthermore transmission technologies include the newly developed Gas Insulated Lines (GIL), the cables used for High Voltage Direct Current (HVDC) electric power transmission and the innovative Superconducting Cables (High temperature Superconductors) which promise to revolutionize power distribution by providing lossless transmission of electrical power.

Conversion technologies consists of technologies used to control the power flow in the transmission networks. Those technologies can be either established large scale conversion technologies such as substations, transformers, converters etc., or newer conversion technologies such as FACTS and PST or small scale components such as switches and current limiters, used for specific control purposes.

Storage technologies consists of technologies used either exclusively or potentially for energy storage. Those technologies can be Pumped Hydro, batteries (including PHEVs modelled as batteries), CAES and hydrogen.

Within the IRENE-40 project a network technology database has been constructed covering these three classes of innovative and conventional technologies, see Figure 57.[57]

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56 Analyses show that the intermittent renewables share varies from around 20% (BAU and CCS scenarios) to 30-40% (EFF, DES, and RES scenarios) in 2050 (see Section 2.2), while additional interconnection capacity in a low resolution network model vary from 11-15 TW/km (BAU and CCS) to 131-156 TW/km (RES and DES) for the period 2010-2050 (see Section 7.1).

57 The IRENE-40 network technology database is publicly available at http://irene40.e-umbrella.eu/.

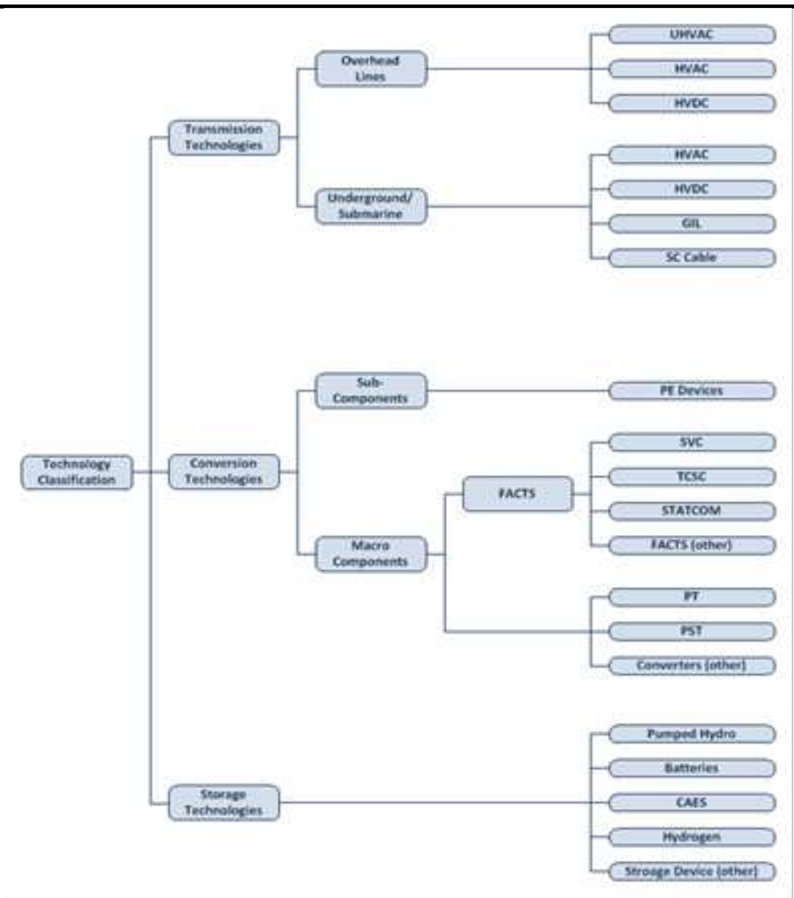


Figure 57 - Technology structure of the technology database

[Source: NTUA]

Which *specific* technologies need to be adopted in the future if we, as a society, want to restrict overall system cost given future system developments related to energy transition? In order to address this issue technology assessments have been performed for many of these technologies. This assessment, performed by ABB, Alstom and Siemens, resulted in unit cost estimates for technology adoption in future decades. A technological development forecast methodology which accounts for continuous learning effects was part of this assessment (see Winter *et al*. 2010 for more details).

Based on the future cost of technology assessments a range of model simulations have been performed to explore the required uptake of specific technologies in different future demand, generation, and network scenarios. Table 11 of Section 3.1 illustrates the required implementation of specifically transmission and conversion technologies for a range of different network scenarios. Based on this table it can be deduced that from the total required network investments, about three-quarter involves transmission technology components and about one-quarter involves conversion technology components.

7.3.2 The maturity gap on the intake of innovative network technology matters

The relevant transmission, conversion and storage technologies are in different stages in the innovation cycle, Figure 58 provides a rough indication thereof.

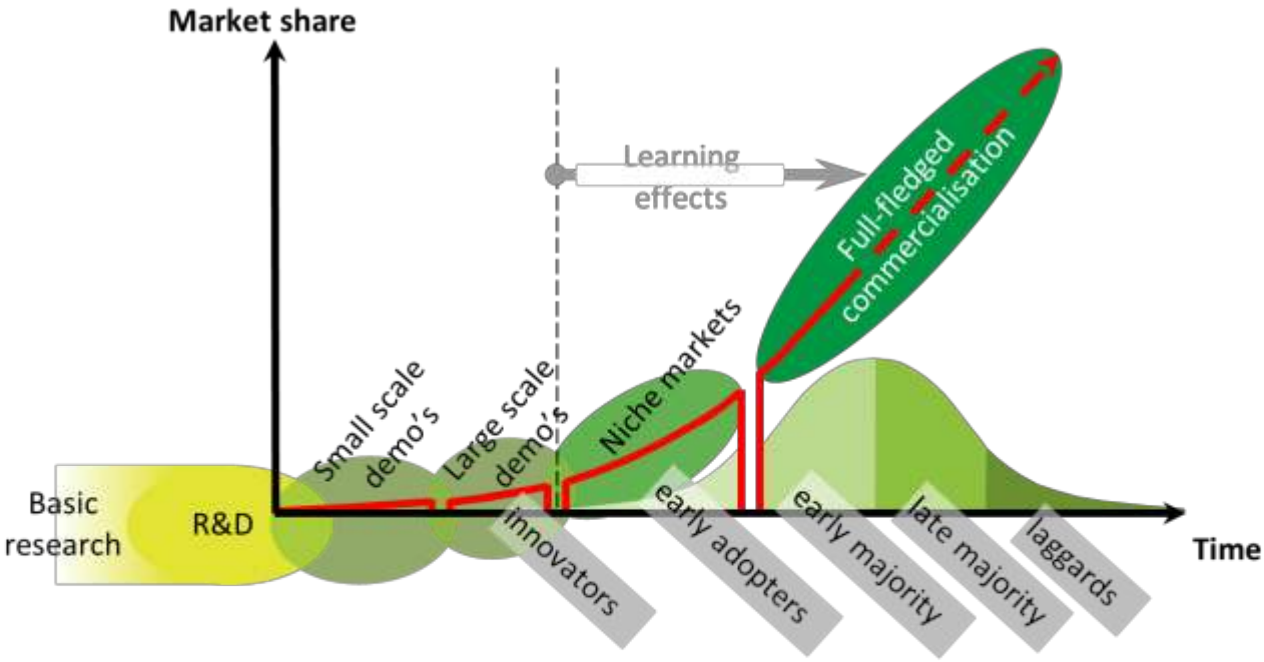


Figure 58 - Different phases in the innovation cycle of a technology

[Source: Schoots *et al*. (2010)]

When considering the process of technology development right from the first conceptualization to outright commercial maturity the following stages can be discerned (Schoots *et al*. 2010; IEA , 2010b; Eurelectric, 2011):

1. **Basic research**. Successful experimentation in public or private laboratories leads to proof of principle.

2. **Research and development**. In this phase research seeks to improve the technology primarily towards technical maturity. Typically private industry is leading. In the power network industry this might be network technology providers such as ABB, Siemens, and Alstom. (Semi-)public or industry-financed knowledge centres may assist in these efforts.

3. **Small-scale demonstration projects.** In this phase experience is gained with the performance of the technology from a user perspective with a view to mitigation of technical implementation problems, improvement of user convenience, standardization resulting in reduction of production cost, and production up-scaling. The design and construction are tested and associated costs are assessed. In this phase the network companies play an overriding role,

which makes that network regulation has a major impact on the realization of small-scale demo-projects.

4. **Large-scale (commercial-scale) demonstration projects.** Projects aiming to demonstrate that the technology can be adopted by the market once price competitiveness has been reached. New/adapted supply infrastructure and regulations to use it and/or new technology/product standards might need to be put in place to level the technology playing field. Quite a few potential technologies do not scale this 'valley of death' hurdle. Underlying reasons may be that not enough financial resources can be mobilised or because the lobby by incumbent technology providers forecloses the adoption of aforementioned level-playing field adjustments. Again in this phase the network companies play an overriding role. Hence, network regulation has a major impact on the realization of large-scale demo-projects as well.

5. **Fledgling take-off in niche markets.** The technology starts to be embraced by early adopters'. This stage is key for successful marketing, descending the learning curve, and growing commercial interests in mainstreaming the technology concerned. As early adopters have to take high risks, network regulation has to allow for adequate rewards when they are successful and for limitation of down-side impact.

6. **Full-fledged commercialization.** The technology makes major inroads upon conventional technology in high-turnover markets and is becoming mainstream.

Network technology providers, like ABB, Alstom and Siemens, typically take the lead in the full innovation cycle for developing network components and related ICT technology. The role of TSOs is often the one of adopter of smart components produced by network technology providers (innovation phases 3-6).

Regarding transmission technology TSOs are still hesitant in applying HVDC technology as compared to the conventional HVAC technology. This relates both to costs (HVDC is more capital-intensive than HVAC technology) as well as technology aspects (e.g. DC breakers to handle DC faults in more complex grids are components that are not yet technologically mature). Hence, HVDC is currently in phase 5 of the innovation cycle, while DC breakers are still in phase 2.

Since HVDC technology is identified as most promising technology for grid expansion in the coming decades, Figure 21 exhibits the foreseen HVAC and HVDC grid expansion in the HVDC network scenario.

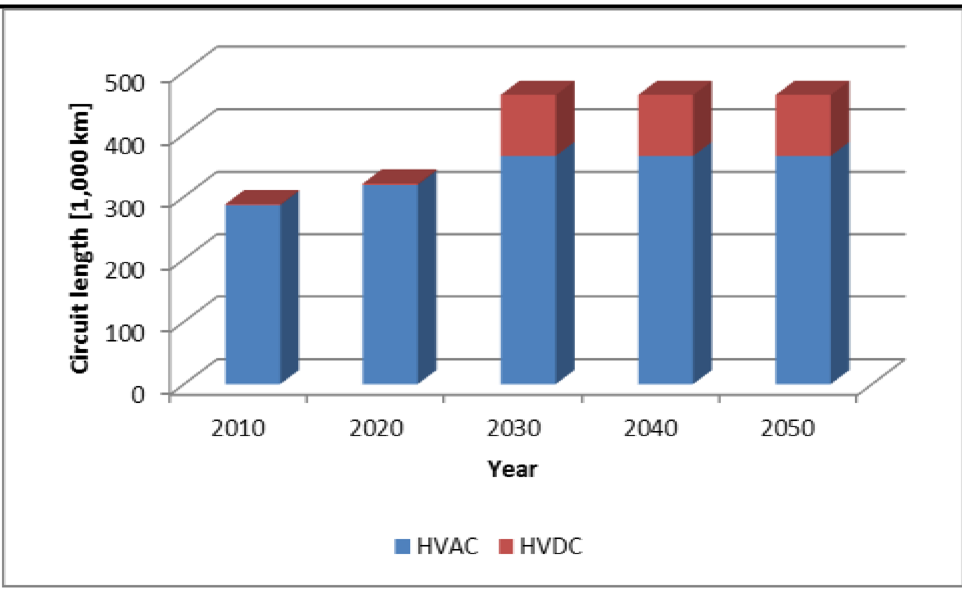


Figure 59 - Development of circuit length of HVAC and HVDC network technologies for period 2010-2050 in the HVDC network scenario

[Source: Data: RWTH (2020-2050) and ENTSO-E (2011c). Presentation: ECN.]

It can be observed that the current share of HVDC in total circuit length is rather limited, but significantly increases in the period 2020-2030. In the high resolution model of RWTH it is assumed that all network investments after 2020 take place before the year 2030. In reality, network investments will be distributed over time since it is uncertain to which extent future generation and demand developments will be realized and hence to which extent grid expansion in the future will be needed.

The associated network investment costs are shown in Figure 22 below. The realisation of an HVDC overlay network accounts for more than 70% of network investment costs in the period 2020-2030 i.e. nearly € 150 billion given two assumptions. First, network cost figures are based upon network unit costs for 2010; hence no cost degradation is assumed. Second, network investment costs realized after 2010 are not discounted for the time value of money.

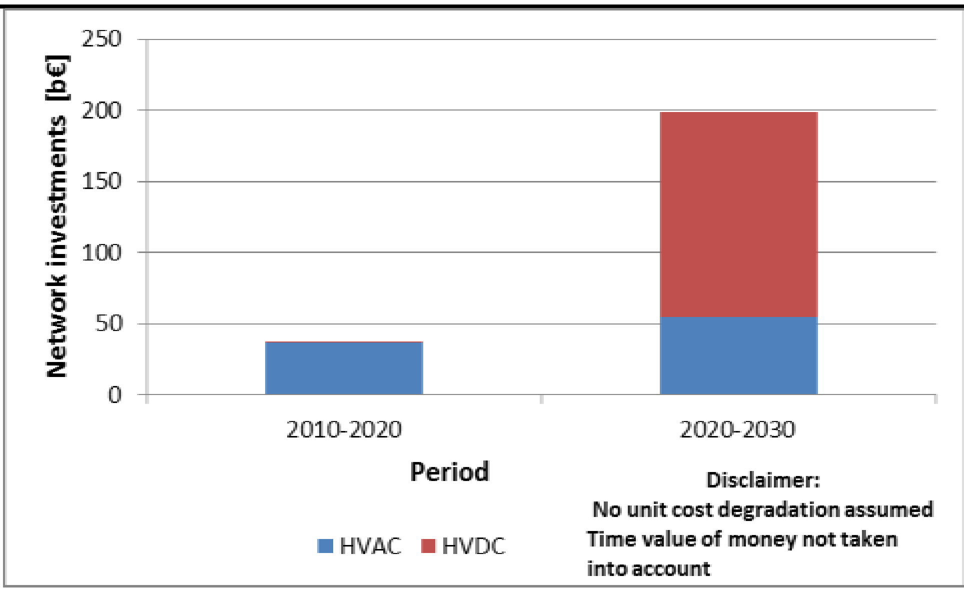


Figure 60 - HVAC and HVDC network investment costs for period 2010-2050

[Source: Data: RWTH. Presentation: ECN.]

Further development of HVDC network technology is required for realisation of the HVDC network scenario. Technology development towards phase 6 may follow the steps depicted in Figure 61 below. The network operators that plan a grid will start by ordering point-to-point systems that should be grid-enabled for a future extension to a three- or multi-terminal system. Starting as from 2020 there will be a few first regional multi-terminal projects. After 2030, the point-to-point connections and the regional multi-terminal projects will be connected with each other to more extensive grids. The timing of these steps is summarized in Table 12 below.

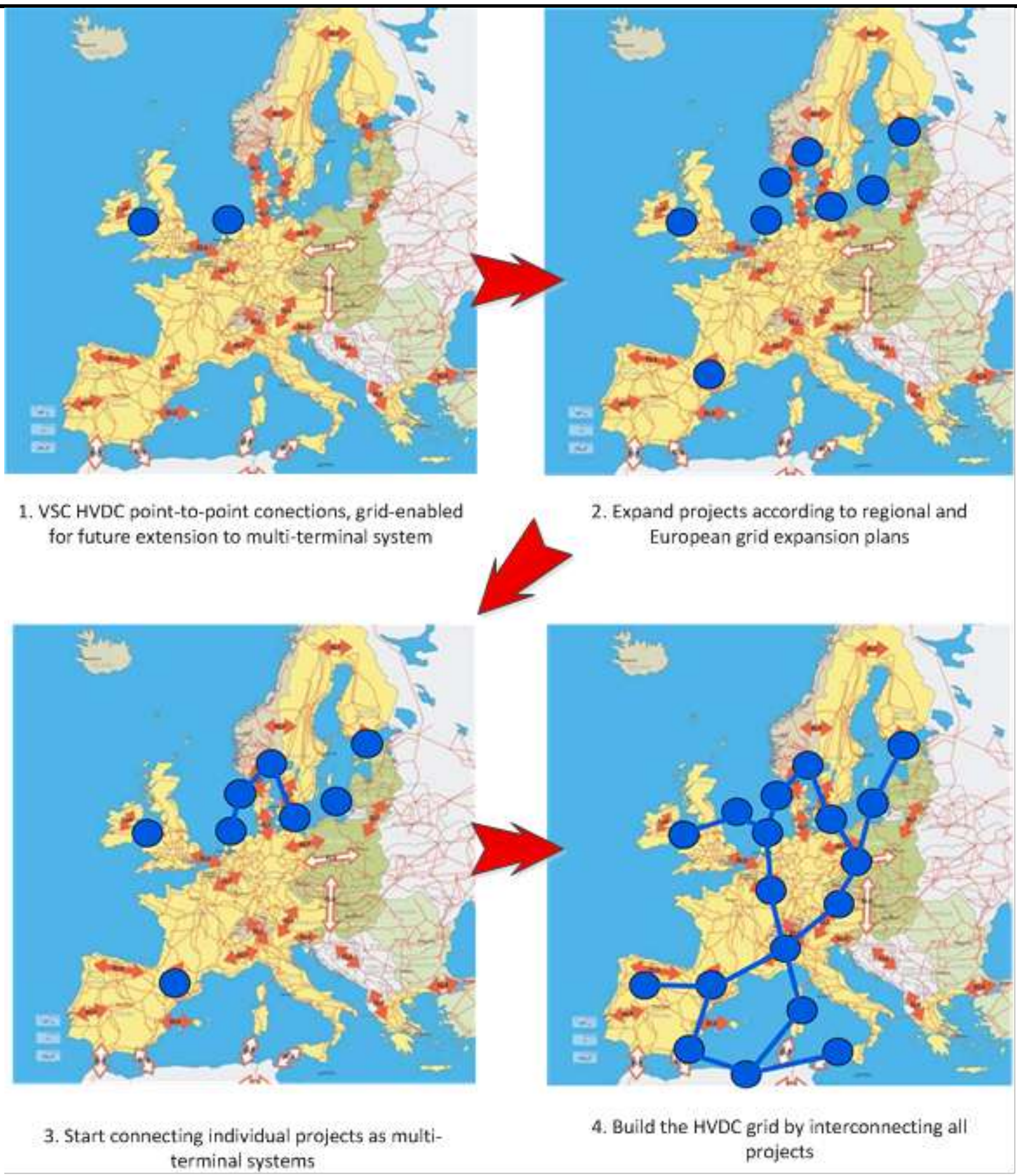


Figure 61 - Building a European HVDC Supergrid

[Source: ABB]

Table 12 - Time steps in HVDC overlay network development

Time steps	HVDC network developments	Decisions needed on
Point-to-point connections 2012-2020	Business as usual: Point-to-point connections (subsea) not yet prepared for HVDC overlay grid	• DC-breakers • Power flow control • Network restoration • Standards and regulations **Final GO/NO GO for HVDC overlay network: 2020**
Regional multi-terminal networks 2020-2030	All new HVDC with VSCs. First primarily point-to-point, later integration into regional multi-terminal HVDC networks (first sections of overlay grid)	
Full overlay network 2030-2050	Construction of HVDC overlay network: Connecting regional multi-terminal networks	

[Source: IRENE-40 consortium, presentation: ECN.]

It also needs the further development of technical standards and associated regulation, involving technology companies, national regulating agencies and European umbrella organizations such as CEER, ERGEG, ACER (innovation phases 3-5).

Recommendation: Develop technical standards and associated regulation for, amongst others, power flow control and network restoration in HVDC network technologies (e.g. DC grid code) and strive for EU wide harmonisation.

7.3.3 Regulatory reform needed

The deployment of innovative network technologies by TSOs is closely related to prevailing network regulation. Given that network operators conduct a regulated activity, network regulation plays a key role in shaping their business behaviour, including their attitudes towards innovation and new network technologies.

The current regulatory environment governing present-day European TSOs tends to imply biases against the application of innovative network concepts to the advantage of conventional grid solutions. Deployment of innovative network technologies such as HVDC and UHVAC carry higher risks for TSOs and therefore need prospects for higher remuneration than conventional network technologies like HVAC. However, network regulation generally offers compensation for investments based upon a risk profile assuming investments in conventional network technologies. This results from the focus of applied incentive regulation at short-term efficiency gains and quality of supply to the detriment of long-term, dynamic efficiency benefits. Hence, TSOs are reluctant to increase investment costs as efficiency mechanisms in incentive regulation tends to reduce allowable revenues or tariffs over time (see also ENTSO-E, 2011a). As a result there exist severe lock-in risks to currently applied network technologies.

Furthermore, current regulation does probably not sufficiently take into account the hold-up problem as well as spill-over effects of innovative investments in regulatory frameworks. The hold-up problem refers to two economic actors where one party is deferring an investment decision that might be favorable from a social perspective, because the other party is capable of changing ex-post the pay-off of the investment to the latter's advantage. Applying this to a network operator gauging the private return on investment in innovation, he may be reluctant to invest because of uncertainty regarding ex-post decisions by the regulator. If the regulator is able to claw-back too high profits of the TSO due to successful but risky network innovations, the TSO may feel forced to refrain from risky network innovation.

Concerning the spill-over effect, TSOs risk that the potential benefits of innovative network investment will spill over to other network operators and network users before they have been able to recover their investment. Since regulatory periods last 3-5 years on average, innovative network operators may profit for too short period from successful implementation of innovative technologies to compensate for the increase of their costs, implying bad efficiency scores in regular efficiency benchmarking by regulators. Hence, 'lazy' operators may await the successful outcomes of their experimenting counterparts. To the extent that technology implementing system operators can patent successful technologies, they will be in a position to mitigate spill-over effects. However, patenting specific forms of implementation of innovative network technologies by TSOs may well turn out to be much more cumbersome than patenting innovative network products by technology providers. See Roehder *et al*. (2012) for more details on these three biases against network innovation. For all reasons, TSOs may be not able to provide sufficient funding for application of innovative and promising network concepts.

Recommendations:
In introducing an enabling, smart regulatory framework and general framework conditions for (potential) stakeholders in essential new network technology such as HVDC, due allowance for the gap of a fledgling technology under consideration towards maturity is key. New technologies at earlier development stages bear higher risks for developers and adopters i.e. TSOs and merchant investors should be remunerated accordingly.

There are a range of actions that could be taken in the short and medium term to enable a level playing field for innovative and conventional network technologies:

- Include explicit mechanisms that allow for sufficient funding of RD&D activities by TSOs, outside of the efficiency improvement requirements set periodically, for example by applying a higher weighted average cost of capital for RD&D investments or including a special allowance for RD&D expenditures (recently applied by UK, Italy, Denmark and Finland; ENTSO-E, 2011b);
- Increase the potential for TSOs to capture benefits due to adoption of innovative approaches and technologies by increasing the length of the regulatory period and other forward looking approaches;

- Include the adoption of new technologies in the regulatory framework when assessing future performance requirements.

7.3.4 EU-wide cooperation in network technology R&D

Additionally, provided competition law aspects, the increasing interconnectedness of national transmission networks, and economies of scale, European collaboration and coordination in sector-specific public support and development of technical standard has to be considered in all public interventions at member-state level. ENTSO-E[58] and ACER in association with related EU-wide initiatives (such as the SET Plan, framework research programme Horizon 2020 and the Intelligent Energy Europe research programme of the European Commission) will have a key role to play in coordinating RD&D activities undertaken with respect to the development and implementation of innovative technology in European transmission networks and accommodating regulatory changes by the member states.[59] This should ensure improved static and dynamic efficiency benefits accruing ultimately to European electricity users, whilst enabling the transition towards a low carbon, resource-efficient European power sector.

Recommendation: For the speedy development and EU-wide adoption of essential new HVDC network technology EU-wide RD&D cooperation is indispensable. There is an urgent need to intensify the use of effective platforms for exchanging regulatory experiences among Member States, including ENTSO-E, ERGEG and ACER, to accelerate the realisation of essential smart regulatory practices and learning from the successes and failures of front running Member States.

7.4 PUBLIC ACCEPTANCE OF NETWORK TECHNOLOGIES

Permitting procedures for new infrastructure last on average about 10 years in many EU member states and therefore impede efficient network planning. Lengthy permitting procedures are largely due to lack of public acceptance of new grid infrastructure.

The main reason for public resistance seems to be the lack of effective stakeholder engagement in the decision making process. It is important that stakeholders perceive themselves as co-owners of grid expansion decisions. Therefore, the social, political, economic and cultural context of the project as well as characteristics of the used technologies are important for stakeholder engagement and should be taken into account (Welle *et al*. 2011b).

The IRENE-40 project touches upon one of these factors important for stakeholder engagement; the characteristics of used network technologies. Public resistance partly reflects perceived impacts of

[58] See e.g. the ENTSO-E R&D Plan (ENTSO-E, 2011b).

[59] Examples are the network codes being designed by ENTSO-E, consistent with framework guidelines from ACER and the EC Mandate 490 on the interoperability of smart grids.

increased deployment of network technologies on environment (visibility, land usage) and health (electromagnetic fields (EMF)).

Concerning the environmental impacts of network technologies some conclusions can be derived from the developed network technology scenarios. First, Table 10 above showed that all network technology scenarios assume the deployment of overhead lines (OHL) for onshore grid expansion, while for offshore grid expansion they all assume the same amount of HVDC subsea cables. Although realization of subsea cables is often opposed for competing spatial planning purposes (fisheries, shipping), generally the public opposition against onshore grid expansion seems even more intense.

Second, the corridor length of UHVAC and HVDC overlay network scenarios is comparable (about 30,000 km) but the corridor surface of OHLs is not. Assuming that it is feasible to put two 500 kV HVDC systems on one tower, based upon the corridor width the corridor surface of OHLs can be determined. Corridor width is here defined as the actual width of the tower plus isolation, not containing any protection area due to EMF. Given a corridor length of 30,000 km, the corridor surface of a single transmission line with a corridor width of 40-60 meters amounts to about 1,900-2,900 km^2 for the HVDC overlay and 2,600-3,900 km^2 for the UHVAC overlay respectively.[60] Hence, the land usage of the 500 kV HVDC scenario is smaller than for the 800 kV UHVAC network technology scenario. This is illustrated below with an artistic impression (see Figure 62).

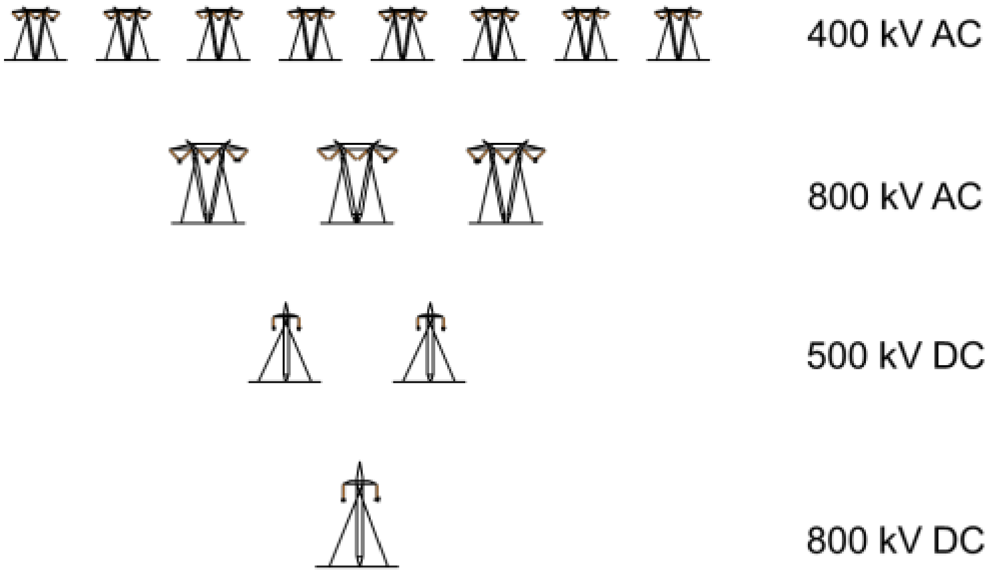


Figure 62 - Artistic impression of number of parallel overhead lines to transmit 7,000 MW for different (U)HVAC and HVDC technologies[61]

[Source: ABB]

60 Information provided by RWTH.

61 This figure is artistic as TSOs will not place 8 single circuit 400 kV HVAC lines next to each other, but instead will use double circuit systems. Furthermore, VSC HVDC technology is not yet available for 800 kV DC OHLs.

In addition to using HVDC technology, heavy public opposition against grid expansion could be further lowered by undergrounding new, critical onshore connections. Provided the unproven reliability of high voltage AC cables, HVDC cable technology with VSC converters is currently the preferred technology for undergrounding.

Recommendations:
Visibility and land usage impacts of electricity networks on local communities can be reduced through deployment of HVDC network technology, thereby limiting the likelihood of public opposition. Furthermore, the (perceived) advantages of undergrounding and preferences of consumers have to be balanced against the higher costs of innovative network technologies.

Commercialisation of network components such as DC breakers as well as bringing down costs (costs degradation) of new components by further development efforts of network technology providers can contribute to lower public opposition.

7.5 MARKET DESIGN AND THE ROLE FOR CAPACITY MARKETS

7.5.1 Energy-only markets and the need for capacity markets

The expected developments in the electricity generation mix in the future pose a challenge to European energy-only markets in their ability to maintain security and reliability of supply.

An increasing amount of in particular intermittent renewable energy sources will increasingly contribute to the amount of energy supplied, but may not be able to contribute in a situation with very high energy demand. This implies that electricity generation units that mainly produce during peak hours may over time experience that the number of operating hours (i.e. load hours) is reduced. It makes it harder for investors in these units to recover the total ex ante cost of investment. In other words, the increasing amount of intermittent renewable electricity production is likely to worsen the business case for base-load units in the generation mix, which may deter investment in new generation capacity. This creates the risk that future electricity generation capacity may be inadequate in accommodating electricity demand during peak hours.

For electricity systems with only low levels of intermittent renewable electricity the problem may be solved by the balancing reserve markets operated by system operators (or transmission system operators). These are effectively capable of triggering additional electricity production in times of scarcity and provide additional payments for the units deployed for this purpose. However, the size of this market is relatively small when compared with the overall size of the electricity market. As the amount of renewable intermittent electricity production capacity grows, and volatility in production increases, it becomes more unlikely that current balancing reserve markets will be able to cope with these fluctuations. In the future, a capacity market may be needed to guarantee sufficient peaking capacity in the electricity system.

Although the increase in renewables exacerbates the problem of so-called 'missing money' (from the perspective of the investor), the origin of the problem lies in a key characteristic of electricity markets, namely demand inelasticity. The difficulty of storing electricity in an economic and efficient manner in combination with a lack of time-dependent price signals for electricity consumers gives rise to a general lack of demand-side response. This implies that the missing money problem and associated need for capacity markets may be relieved by increasing demand response.

There are several options to increase response on the demand side. Firstly, implementation of smart electricity meters and the use of time and / or location varying signals could increase demand response. Currently, most electricity consumers in the EU pay uniform tariffs or dual-tariffs with peak and off-peak distinction. This implies that they are not able to respond to changes in hourly electricity prices as observed on wholesale markets. Secondly, different forms of interruptible contracts could enhance demand response with particularly large electricity consumers. Against negotiated payments and in pre-specified circumstances, large electricity consumers can reduce their consumption and relieve capacity problems.

Summarising: in energy-only markets, a lack of demand response (and unavailability of cost-effective energy storage options) may lead to low incentives for investment in peaking units. In systems with low levels of intermittent electricity production this may be solved by designing balancing reserve markets, but as the share of intermittent electricity production in the system increases, the problem increases and implementation of some form of capacity market may be required. Improving the flexibility on the demand side (i.e. demand response) may relieve the problem somewhat, but will not solve it.

7.5.2 The impact of increasing renewables and market integration

Liu *et al*. (2011) have analysed the magnitude of the problem of 'missing money' for peaking units (based on gas and oil input) in different future scenarios and show that the need for capacity markets depends on developments in the electricity generation mix as well as the level of integration between EU member states.

A larger share of renewables increases need for capacity market
Projects results show that when there is a higher share of intermittent renewable electricity production capacity in the capacity mix, peak electricity production units – typically oil and gas based – require a higher level of financial support in order for investment incentives and generation capacity adequacy to be maintained (see Figure 63). The need for financial support for these type of units is the highest in scenario's where large-scale solar PV (such as the Desertec project) and wind projects materialise. Future scenario's with a continuing large share of fossil-based electricity production units (for example in combination with CCS) are relatively more favourable for the economics of peak units.

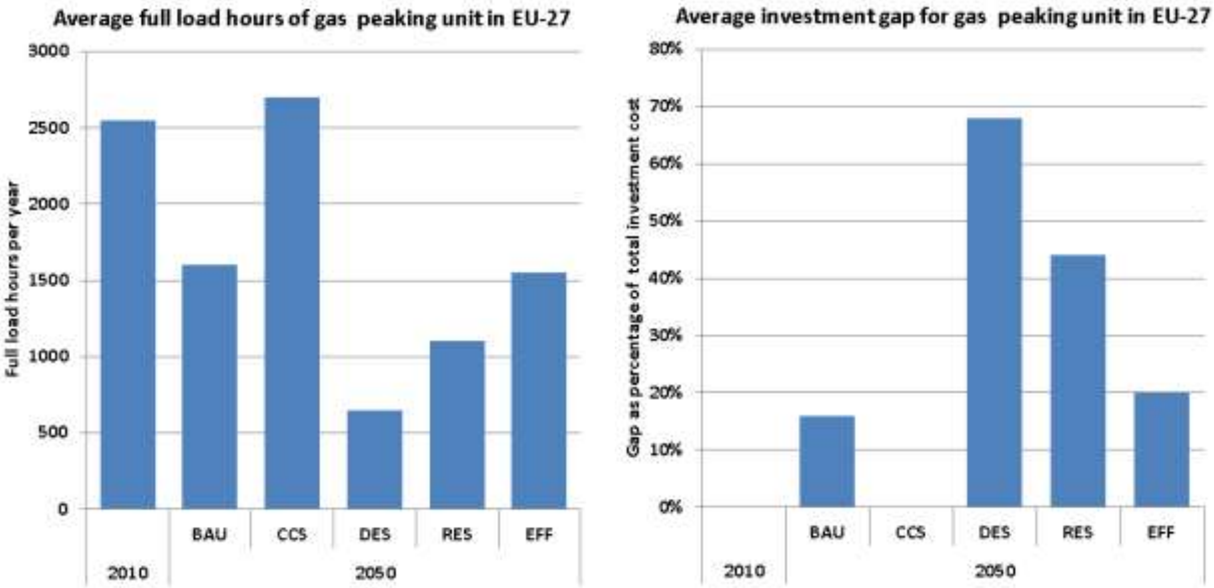


Figure 63 - Estimation of average full load hours and average investment gap for gas peaking units in EU-27 in different scenarios

[Source: Liu et al. 2011, variant 4 estimation]

When the installed capacity of renewable sources increase over time, utilisation ratio (full load hours) and hence economic viability of peak generators without capacity market become worse: this is mainly due to the fact that RES will contribute to the overall supplied energy but not to effective system safety margin—thus more peak generators need to be installed to meet increasing load peaks, while their full load hours are becoming lower over time due to the 'lost demand' that are supplied by RES units.

More demand response and a higher level of integration could reduce the need for capacity markets

Designing large-scale capacity markets that allow for more investment in peaking facilities may not be the most cost-efficient option to increase flexibility. Increasing demand response, for example via smart meters, interruptible contracts and various smart grid concepts, could relieve the problem of insufficient investment in peaking capacity. At the same time these options increase overall efficiency of the electricity system.

Project results also show that a higher level of market integration in the EU – for example measured by the level of cross-border interconnection capacity – could reduce the need for capacity markets. If national markets are not (sufficiently) connected, then each market will needs to ensure capacity adequacy individually, which will come at a cost for society. Market integration may be improved by either improving the usage of existing capacity, or by expanding existing capacity bottlenecks. As markets get better interconnected, the amount of reserve capacity that is required as a back-up in times of low electricity production from wind and solar PV can be shared across regions. However, this does assume that investors in electricity production capacity are sufficiently capable of deriving the long-term implications of increased interconnection for the need for flexibility and thus the need for particularly peaking units. Investment in electricity production may be characterised by boom-bust cycles with periods of overinvestment and underinvestment in capacity. In a situation of overinvestment, increasing interconnection will in fact worsen the business case for existing peaking units, and may lead to their owners calling for an increasingly large role for capacity markets.

Recommendation: Policy makers should consider alternatives to capacity markets. These should include demand response and stronger European network integration.

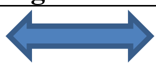
7.5.3 Harmonisation of capacity market approaches

Even with demand response and strong European network integration, a strong case for the adoption of some kind of capacity market approach over time remains, as the amount of intermittently producing renewable electricity increases. Only when low carbon options such as coal and gas in combination with CCS or nuclear are adopted on a large scale instead of wind and solar PV will the need for capacity markets be negligible. When capacity markets are adopted across the EU, their implementation should be coordinated and harmonized in order to minimize distortions for the internal energy market. The implementation of 27 different capacity markets in 27 different EU countries will most likely be the end of the internal energy market as there will no longer be a level playing field in electricity generation across Europe. Naturally, given the different starting conditions of the electricity markets across Europe, the call for capacity markets will be unevenly spread. It is important that the implementation of a capacity market in the 'early adopting countries' is coordinated with neighbouring countries, because the impact of capacity market mechanisms exceeds national borders and because decisions on the design of the capacity market may affect future decision-making on the design of a capacity market in other countries.

Recommendation: The introduction of capacity markets in EU member states should be coordinated and the approaches should be harmonised.

7.6 ACTION PLAN AND TIMING OF ACTIONS

Table 13 - Action plan with responsibilities and timing of actions

Recommendation	Responsibility	Timing		
		2012-2020	2020-2030	2030-2050
Network investment strategies				
Introduce possibility for anticipatory investments in regulatory framework and adapt network planning accordingly	Policy makers/ regulators, TSOs			

Recommendation	**Responsibility**	**Timing**		
		2012-2020	2020-2030	2030-2050
Assess potential investments with social cost benefit analysis in European perspective	Policy makers/ regulators	↔		
Allow for steering of new generation facilities to locations with lowest overall costs for society to prevent stranded network assets	Policy makers/ regulators	↔	↔	↔
Allow for wider application of demand response and storage	TSOs, policy makers/ regulators	↔	↔	↔
Reduce lead time for grid expansion by faster permitting procedures	Policy makers	↔		
Cost allocation				
Enable TSOs to pass through grid expansion costs increasingly by network tarification	Regulators	↔		
Align network tarification with the beneficiary pays principle instead of cost socialization	Policy makers / regulators	↔	↔	
Transform the ITC mechanism in an ex-ante mechanism that takes into account expected benefits and costs of new infrastructure and increase the fund size accordingly	Policy makers / regulators	↔	↔	
Pursue multilateral agreements over grid infrastructure with a significant effect on third countries	Policy makers	↔		
RD&D policy				
Develop and harmonize technical standards and associated regulation for HVDC network technologies	TSOs, regulators	↔	↔	
Enable a level playing field for innovative and conventional network technologies by introducing innovation incentives in the TSO regulatory framework	Policy makers/ regulators	↔		
Improve EU-wide cooperation in RD&D by intensifying the use of effective platforms for exchanging regulatory experiences among Member States	Policy makers (EU)	↔	↔	
Public acceptance				

Recommendation	Responsibility	Timing		
		2012-2020	2020-2030	2030-2050
Stimulate network innovation to reduce impacts of grid expansion on local communities	Policy makers	↔	↔	↔
Further development efforts of innovative network components that allow for undergrounding	Network technology manufacturers	↔	↔	↔
Capacity markets				
Improve possibilities for demand response and strengthening of European network integration to reduce the need for capacity markets	Policy makers	↔	↔	↔
Harmonize national capacity market designs for level playing field in electricity generation	Policy makers	↔		

Table 13 shows the actions of the preceding sections of this Chapter as well as the stakeholders responsible for taking these actions. The last column indicates the optimal timing of the each action.

The action plan provides a range of actions to be taken by stakeholders like national and European policy makers, network technology manufacturers and TSOs in order to enable the realisation of the preferred HVDC network scenario. Many actions concern policy actions that enable changes in TSO investment strategies, more innovation by network technology manufacturers, and higher public acceptance of grid expansion. They also contribute to a more efficient power system in the long run from social welfare perspective.

Like the discussion of the RD&D policy for stimulating the uptake of HVDC network technology, three time periods are distinguished: until 2020 (short term), until 2030 (medium term) and after 2030 (long term).

For many policy actions holds the earlier the better, since it removes socio-economic and institutional barriers for achieving a higher social welfare level in general and the uptake of HVDC network technology in particular. Furthermore, these actions facilitate achievement of EU policy targets against lower costs. Hence, all actions can qualify as short-term actions and should preferably be performed before the year 2020. Some actions such as the assessment of potential investments with social cost benefit analysis in European perspective, the reduction of lead times for grid expansion by **faster permitting procedures**, and the pursuance of multilateral agreements over grid infrastructure with a significant effect on third countries are already foreseen in EU legislation (EC, 2013).

At the same time, some actions may be more complex and/or costly than others and are likely to be partially realized after 2020 for three reasons.

First, some actions are heavily dependent of the maturity of technologies such as HVDC, electricity storage and demand response technologies. Harmonisation and standardisation of rules and regulation for HVDC technology can only be achieved when multi-terminal VSC HVDC technology is fully available (including DC breakers) and regional multi-terminal HVDC networks start to evolve. Likewise, investments in realisation of a full overlay HVDC network have to be distributed over time to limit financial risks and achieve technology learning effects.

Second, some actions require the active involvement of electricity consumers which is not granted beforehand. For instance, larger involvement of consumers in permitting procedures may prevent faster permitting procedures. Besides, more demand response requires the active involvement of electricity consumers and sufficient attention for their preferences and requirements.

Third, some actions require drastic changes of policy and regulation and therefore require a step-by-step approach over longer time periods. These actions include:

- Full implementation of beneficiary pays principle. Full implementation is difficult as long as network flows cannot be attributed to individual network users and there is a large diversity of benefits of potential investments due to lack of locational pricing.
- Introduction of locational incentives. Current generation facilities cannot change their location without high costs and probably need to be compensated for any substantial locational incentive. Furthermore, as long as renewable energy policy remains a national competence, steering towards realisation of EU-wide RES potential with lowest overall system costs seems unlikely. Probably locational incentives can only have their full effect in the medium term.
- Changes to and larger role for ITC mechanism. This action may only be implemented over a longer time period due to its controversial nature.
- Harmonised EU approach in design of national capacity markets. This requires at least some European coordination of electricity generation, which is currently considered as a national competence by many member states.
- Larger role for demand response and storage requires new business models which are heavily dependent on changes in policy and regulation. Promoting demand response requires time-dependent electricity prices and network charges, while advancing electricity storage necessitates clearer conditions for usage of storage facilities by commercial stakeholders like producers and traders as well as regulated TSOs.

For all actions hold that they should be as robust as possible for different G&D scenarios. This holds for all less complex actions, hence there are no regret costs involved with these actions. However, concerning the more complex actions the situation is somewhat different. First, policy actions aimed at increasing network innovation may not deliver the expected results, but offer important chances for the realization of a more efficient EU wide electricity network. These RD&D actions are primarily focussed on shaping preconditions for successful innovations, hence if regret costs occur they are relatively limited. Second, several actions require more detailed investigation of regional and national conditions which is outside the scope of this project. Finally, it should be kept in mind that all actions are more urgent when policy makers strive for realization of generation and demand scenarios with a high share of renewable electricity and a higher demand for transport (EFF, RES, DES).

8 FUTURE RESEARCH AND DEVELOPMENT

8.1 FUTURE NETWORK TECHNOLOGY

It is widely accepted that the renewable energy sources in European network system will increase substantially to reach a high percentage in the future. That requires network expansion, reinforcement, increase of network flexibility to allow for the "renewable revolution". Under this circumstance, investment network expansion and further innovation regarding in transmission, conversion and storage technology is inevitable. Several technological solutions are brought out that is probably applied in the near future, and may facilitate the request of the transmission system development. These technological options are HVAC, HVDC, and UHVAC, based electricity transmission system, which are applied in corresponding network scenarios.

In order to meet the increasingly growing demand, modification of the existing network is required; voltage upgrading or even grid restructuring should be considered. So there is arising need for increased controllability in especially in AC network scenarios due to integration of intermittent renewable energy sources. The controllability can be handled by Flexible AC Transmission Systems (FACTS) devices and/or Voltage Source Converter (VSC) based converter technologies. Upgrading the voltage level to UHVAC (>=750 kV) is an AC alternative for the network expansion, which will represent a multiregional grid able to carry high power capacities and lead to beneficial results to the system reliability and decreased transmission losses as well. UHVAC also allows greater permitted range of transmission, so longer distance transmission would be more efficient with higher voltages.

For DC technology, the main driver to develop HVDC appears to harvest off-shore wind resources. HVDC is an obvious candidate choice as it facilitates subsea power transmission and VSC based converter technologies which are particularly suitable for connection to off-shore wind farms. However, starting the step from point-to-point HVDC links to DC grids will face some challenges, one of which is how to handle DC faults without the risk of bringing down the whole DC grid. This needs further R&D in the near future. VSC (Voltage Sourced Converter)-HVDC technology has a better performance on system dynamic security as well as steady-state security and a higher controllability compared with classic HVDC. It has a number of potential advantages: short circuit current reduction; rapid and independent control of the active and reactive power, etc. With such advantages VSC-HVDC will likely be the backbone of future transmission infrastructure scenario for the roadmap development. However, VSC transmission has some disadvantages including potentially high losses and costs. A number of possible applications and advancements in VSC technology are required by further assess the potential and limitation of VSC transmission for industrial power system on the aspects of control system, faults and its protection, system design, etc.[CD03]. Continuous R&D is necessary for this newly developed but promising technology.

Controllability in the future transmission network is a key requirement. FACTS mentioned above is one of the most convenient ways to tackle this in an AC network by use of dynamic shunt compensation, controlled series compensation and phase-shifting transformer.

Each technology can be technically feasible in a future network scenario. The application in large scale can be challenging. The resulting network scenarios and technologies to be used will depend closely on the assumptions made for the future and the forecast on cost and technology development. The common goal of these technologies is to ensure a secure, sustainable and cost-efficient network and be able to handle the needs of the future transmission network.

8.2 RECOMMENDATIONS FROM CONSORTIUM PARTNERS

Contribution from ECN

Several partners contributed to the scenario analysis with low-resolution models which optimize hourly generator dispatch with a given transmission infrastructure and a given set of electricity generators. Only a single partner (Imperial) contributed with a tool in which cross-border transmission capacity could be optimized, starting with a given set of generators. A next logical step would be to optimize also installed generation capacities. This would be a tool, which would be especially beneficial for long-term scenarios (2030 and after).

Contribution from ETH Zurich

Our studies within IRENE-40 have shown that the future European grid will need a significant degree of controllability, in order to utilize effectively network assets, ensure power system security, and allow a smooth integration of renewable sources, coping with their variability. Several solutions for increasing the power system controllability have already been developed, most notably FACTS devices or HVDC lines. Nevertheless, increased controllability usually comes along with increased complexity in the operation of the grid. Therefore, significant research efforts are now necessary in order to identify how such devices can be operated in order to facilitate long-distance power flows, minimize RES curtailment and react rapidly in case of contingencies. Would a pan-European coordination scheme between the devices be necessary, or distributed schemes could also be as effective? What should the role of merchant transmission lines be, when considering power system security?

Contribution from Alstom

In reviewing future networks it is important to learn from previous disasters and incidents. Possible future R&D studies on transmission networks should include a comprehensive review of and focus on previous system grid incidents (both European and worldwide) and the lessons learnt and emanating from them. For instance when a bombing incident occurs, a thorough investigation is always carried out and procedures changed and adopted to avoid a repetition in the future. Transmission grids have had similar incidents and investigations carried out and "lessons learnt". A comparison between different technological solutions can be carried out referring to network incidents ensuring that planners are made aware of the risks that could occur with each transmission technology. In addition to equipment related causes, specific lessons learnt as a result of utility restructuring and liberalisation of markets needs to be highlighted in order to avoid possible repetition elsewhere. An example to consider for instance would be the "California Energy Crisis" of 2000 and 2001, and possibly recent events in India. Power failure incidents often have an equipment failure trigger but most often have an underlying cause of inappropriate procedure, controls or system management that is a real determinant for system security. The sharing of "lessons learnt" following incidents incurred up till now, by mainly national and regional utilities can only benefit neighbouring utilities and can provide greater impetus and progress towards the development of more European grid cooperation and interconnection.

Contribution from ABB

In IRENE-40 the European electricity transmission network was investigated using a number of future generation and demand scenarios and network models. A comprehensive assessment based on various factors, such as technical feasibility, environmental impact, security and competitiveness, has come up with a suggested scenario for the future network, in order to fulfil the needs for increased demand and generation and also integration of renewables. This future network will most probably be a mixture of the current HVAC grid and a pan-European overlay grid topology with enhanced controllability. As stated in the final deliverable D3.2, "the overlay grid will enable substantial economic and ecological benefits in particular in the context of possible future developments involving a high utilization of RES, while being robust towards other development paths. The increased controllability can either result from an HVDC overlay network or from a UHVAC overlay network with a substantial amount of FACTS devices..." However, due to the "overall better performance of VSC-HVDC for various security aspects both for dynamic security as well as for steady-state security, ... an overlay grid topology based on VSC-HVDC technology is selected to become the backbone transmission infrastructure scenario for the roadmap development.."

Implementing the above scenario, a number of new network technologies have to be developed. These new technologies should enhance power flow control in such an HVDC overlay grid and facilitate seamless power exchange in various voltage levels. The power capability should be increased, achieving maximum efficiency. Reduced losses will be the key in all systems, such as HVDC stations, cables, various types of new converters, etc. A number of technical challenges for the future HVDC grid have to be solved, as well, such as fault handling and dynamic stability. Coordinated control schemes will have to be developed, as well as increased communication (eg. WAMS). Finally, the HVAC grid should also be strengthened with enhanced reactive compensation, by fully exploiting the STATCOM capabilities and also with better active power flow control. All the above technologies should be in the forefront of future R&D activities in the EU.

Of course, in order to implement the above technologies as soon as possible to facilitate the future network scenario, large investments are needed. In order to bring investment strategies in line with the general objectives of the roadmap, a number of actions need to be planned in the framework of the European Union. First of all, the EU could facilitate seed money in order to push forward technology demonstration projects. In that way the TSOs and the rest of the investors involved in the network development, can more easily start to adopt the new technologies. New regulatory schemes will define how this money will be distributed among the involved parties and will set the rules for prioritization of funding. Moreover, important changes regarding regulatory issues, such as scheduling, pricing and operating of such an overlay grid, are necessary. Even if the technologies are demonstrably working, a new regulatory framework must be set to define how to operate the system, who will be responsible for specific actions, who will be benefiting. etc. Only then can the future network become a reality, when all the stakeholders, for example TSOs, know the exact benefits and have a way to operate it effectively.

Contribution formulated after presenting preliminary findings in Brussels on October 30th 2012

A relevant electricity network characteristic to illustrate long term developments of an increase in long-distance and cross border flow would be the average distance travelled via the transmission network between generation and load. Due to modelling issues this was not done in the framework of the IRENE-40 project. However, we recommended that this is included in future projects with a relevant scope.

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