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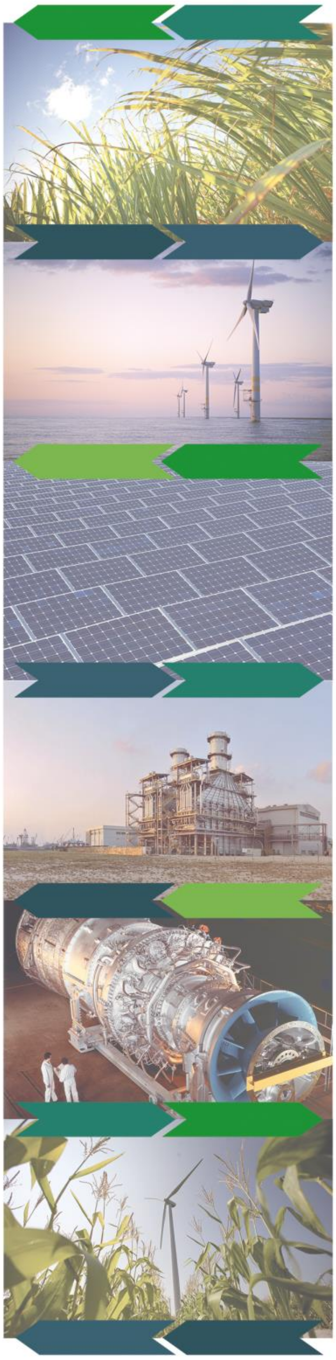
NAVIGATING THE ROADMAP FOR CLEAN, SECURE AND EFFICIENT ENERGY INNOVATION



Issue Paper on

Case study 6.2: Centralized vs. Decentralized development of the electricity sector

Impact on infrastructure

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Executive summary

The large amount of renewable generation expected in the coming decades, together with demand response and the deployment of storage, will challenge system operation and require additional infrastructure investments in the power transmission grid. The SET-Nav Project studies the implications of the different trajectories for this development in case study 6.2 “Centralized vs. Decentralized development of the electricity sector”.

In order to obtain relevant insights, ***the case study leverages on two different models, Enertile and TEPES***. Enertile is an energy-system optimization model developed at the Fraunhofer Institute for System and Innovation Research, ISI. The model focuses on the power sector, but also covers the interdependencies with other sectors, especially heating/cooling and the transport sector. It supports a high spatial and temporal resolution, incorporating also geographical correlations in renewable production. TEPES is a decision support system for defining the transmission expansion plan of a large-scale electric system at a tactical level. It was developed by Comillas. It incorporates a detailed representation of the operation of the system and the technical constraints that govern power flows.

The two scenarios consider equal amounts of installed renewable in terms of energy generated, albeit with a different focus. ***The decentralized scenario uses mostly rooftop PV that can be installed close to demand, while the centralized one leverages on offshore windfarms located in the North Seas.*** These two situations are understood as boundary conditions for the development of the system.

Our preliminary results show that ***the decentralized option has higher system costs than the centralized scenario***. This is driven by two factors: the higher cost of rooftop PV compared to other renewable technologies and an increased need for flexibility.

Although transmission grid investment is high in both alternatives, it is higher in the centralized case. This happens because this scenario allocates a considerable amount of renewable generation in Northern or Central Europe, which creates a very high need for transporting energy to meet demand.

1 Introduction and objectives of the case study

The location of a large part of the forthcoming renewable capacity will be decided based on the availability of its resource. This means that a substantial capacity will be installed in areas relatively remote from consumption areas; these remote areas tend to be weakly connected to the rest of the system at present. There will be a need for specific deep connections as well as reinforcements to bring the new renewable power from far-away production locations to consumption areas.

The large installed capacities of variable generation –wind (in particular, offshore wind) and solar- will challenge system operation. Sun and wind speed vary widely geographically. This enables reducing the overall variability for the system by integrating increasingly wide areas, which can enable a higher renewable penetration while minimising curtailment. Again, this will result in network reinforcement needs.

An increasingly complex permitting process and public opposition mean that building new transmission lines is more and more difficult. On the other hand, innovative transmission technologies (such as HVDC or FACTS) will increase the available options for grid development and usage, so they are incorporated into the analysis.

Distributed generation, power storage (both as hydro and pumped hydro and non-conventional storage) and flexible demand, in particular electric vehicles (EVs), will transform the power flows that usually traverse the system. These changes will require optimising the use of the existing transmission assets and adapting the existing grid by means of new investments.

This task aims at answering the research questions:

- ***What will be Europe's electricity infrastructure needs?***
- What are the ***main impacts of renewable energy sources and demand response***?
- What are the ***main grid architectures*** that should be considered?
- What is the impact of ***innovative transmission technologies*** on optimal grid architectures?

The case study leverages on two different models to build different consistent generation expansion pathways and consider their implications for the transmission grid. Enertile is used to create two scenarios with diverging deployment of RES, and their resulting impact on generation portfolio and electricity trading flows. These scenarios represent representative boundary conditions for centralized and decentralized systems. Centralized development will be understood as a higher share of offshore wind focused in a few target areas, while decentralized will be characterised as installing renewable in the same locations as demand, particularly using rooftop PV.These boundary conditions represent extreme (albeit sensible) situations with respect to renewable development, so that the final path taken by the system will be a combination of them two.

Then, TEPES will be used to assess the electricity infrastructure needs to expand the transmission network in order to integrate this generation at a reasonable cost. As these possible developments differ considerably in the regional location of generation, the coordination between generation and network expansion becomes particularly relevant and will be studied.

The expected output of this case study, when complete, will include:

- Insights into ***contrasting developments of the electricity sector with respect to the required infrastructure and storage investments and system costs.***

- European-wide recommendations on common and differing adaptation strategies to different evolutions of the renewable generation portfolio.
- Insights about the interaction between electricity infrastructure needs and the general policy adopted for RES and emerging generation.
- Understanding the implications of the deployment of several differing network architectures based, for example, on incremental AC reinforcements, long HVDC lines or a super-grid overlay.
- Identifying the main interactions between the general policies adopted for RES generation, the resulting RES generation deployment and the type of network architecture, including the technology solutions that are most suitable for deployment.
- Identifying the most important needs for innovation focused on emerging transmission technologies (in terms of their deployment and research triggering cost reductions of these

2 Integrating two models to provide a wide perspective on the energy system

WP6 involves the use of very different models that, together, provide a comprehensive perspective on the infrastructure side of the energy sector. In particular, network infrastructure to link supply and demand. The two models used for the analyses in case study 6.2, Enertile and TEPES, are described in this section.

2.1 Enertile: modelling generation expansion

Enertile is an energy-system optimization model developed at the Fraunhofer Institute for System and Innovation Research, ISI. The model focuses on the power sector, but also covers the interdependencies with other sectors, especially heating/cooling and the transport sector. It is used mostly for long-term scenario studies and explicitly designed to depict the challenges and opportunities of increasing shares of renewable energies. A major advantage of the model is its ***high technical and temporal resolution.***

Enertile optimizes the investments into all major infrastructures of the power sector, including conventional power generation, combined-heat-and-power (CHP), renewable power technologies, cross-border transmission grids, flexibility options, such as demand-side-management (DSM) and power-to-heat storage technologies. The model chooses the optimal portfolio of technologies while determining the utilization of these in all hours of each analyzed year. The model features a full hourly resolution: In each analyzed year, 8,760 hours are covered. Since real weather data is applied, ***the interdependencies between weather regions and renewable technologies are implicitly included.***

The potential sites for renewable energy are calculated on the basis of several hundred thousand regional data points for wind and solar technologies with consideration of distance regulations and protected areas. The hourly generation profile is based on detailed regional weather data.

Renewable electricity generation from wind and solar radiation is covered in Enertile in a high spatial resolution. A procedure to supply nodal capacities and hourly generation profiles on a nodal level for the transmission network model TEPES was developed on the basis of the highly disaggregated results of Enertile. Figure 1 below shows the regional data used in the case study, with nodes of the simplified network model represented as dots.

Figure 1.. Zonal level. Nodes indicated as dots.

2.2 TEPES: analyzing detailed grid costs

The intermittent nature of the output of most renewable energy resources (RES), its non-homogeneous distribution and the deployment of a large share of this generation is expected to result in a significant increase in the power flows among areas in large-scale systems. As a result of this, the development of the transmission network should be planned in an integrated way spanning all the areas in the relevant market (the Internal Electricity Market, IEM, of the EU in our case). Besides, the number of operation snapshots to consider in the planning process should probably be high. The TEPES model identifies the main optimal transmission network corridors to reinforce, and determines the extent of the reinforcements needed in them. TEPES also computes the value of the main investment and operation variables affected by the existence of the grid, like the investment cost of grid additions, the network losses incurred, the CO2 emissions produced, the overall production by technology, and the fuel production costs. Computing the optimal expansion of the electricity transmission grid is a major challenge for large-scale systems.

TEPES is a decision support system for defining the transmission expansion plan of a large-scale electric system at a tactical level. A transmission expansion plan is defined as a set of network investment decisions for future years. The candidate lines are pre-defined by the user, so the model determines the optimal decisions among those specified by the user, or identified automatically by the model. Candidate lines can be HVDC or HVAC circuits.

The TEPES model is stochastic. It considers stochastic scenarios related to operation. The operation scenarios are associated with renewable energy sources, electricity demand, hydro inflows, and fuel costs. It can use a DC load flow model for a sufficiently accurate description of the technical constraints of the system, a Transportation model, or a combination of both, depending on the features of transmission assets and modelling needs in the analysis at hand. Transmission ohmic losses are included in any of the previous options. In addition, TEPES has been extended to include innovative transmission technologies as options for expansion, including Phase-Shifting Transformers (PSTs) and Flexible Alternating Current Transmission Systems (FACTS).

The results of the TEPES model include detailed grid expansion costs and decisions, and detailed operation data, including operation costs, RES generation and curtailment, line flows, emissions or short-run marginal costs that can be an indication of nodal prices. TEPES has been used in several research projects and appears in over 20 academic publications.

The TEPES model jointly minimizes the system operation and transmission network expansion costs. The network reinforcements computed by the model are, thus, aimed at minimizing the system costs. In other words, investment decisions are purely cost based. There is no relevant constraint imposed on the system functioning driving the development of the grid. Reliability requirements are considered by the TEPES model through the cost of not achieving a sufficient reliability level. Thus, a cost is set for each MWh of non-supplied load. Different cost levels may be assigned to the non-supplied load of different types (domestic, commercial, industrial, etc.).

When computing the expansion of the transmission grid, TEPES needs to consider a sufficiently large number of operation snapshots, which should be representative of all the operation situations that may occur in the system in the target horizon. Advanced clustering techniques (medoids method) are employed to determine the set of snapshots to consider in Transmission Expansion Planning (TEP) analyses. The main clustering variables taken into account are based on the net demand (demand net of intermittent generation) existing in each area within a set of them that the system is divided into. The areas to be considered should be defined so that grid congestion does not affect the trade of electricity within each area, but only that among areas.

2.3 Methodology applied: discussing the interaction between Enertile and TEPES in our case study

The different possible future clean technology strategies considered in different scenarios may largely influence the transmission network development. This includes the choice between focusing on the deployment of centralized RES generation in specific areas of the system and putting the focus on the deployment of decentralized RES generation that is relatively closer to load centers. Both the investment and the variable power production costs in the system would be affected by this choice. Investment and variable operation costs are being jointly minimized by Enertile, though considering only a high-level representation of the transmission grid. On the other hand, TEPES is considering a low-level, detailed, model of the transmission grid in Europe, but is taking the development of generation and storage in the system as given. While the generation and storage investment costs are not considered in the analyses conducted with TEPES, the variable operation costs are. TEPES is not able to compute the optimal management of storage facilities either, since it is not considering the intertemporal constraints making the operation of the system in the several snapshots this model considers interdependent. However, it is able to precisely compute the cost for the system of building the transmission capacity required to transfer a certain amount of power between any two areas considered in the representation made of the system within the Enertile analyses. The network reinforcements are undertaken to enable the replacement of power generation whose costs are high with other generation whose costs are lower. Hence, TEPES is computing the optimal tradeoff between network investment and variable generation costs, given the development of generation and storage.

Thus, the TEPES model is used here to provide Enertile, a higher-level model, with information on the costs to be incurred per unit of additional transmission capacity built in each corridor. Using this information, Enertile jointly computes the expansion of generation, transmission and storage in the system (though at an aggregate level) to determine the appropriate balance between the costs of expanding the transmission grid, the generation, and the storage in the system, and the system variable operation costs corresponding to the system conditions and the resulting infrastructure in place.

Given that only Enertile is able to compute the expansion of generation and storage considering the interactions among this, the network developments, and the operation of the system, both the generation and storage expansion results and the final main system operation results are provided by this model. On the other hand, TEPES is providing the final results on the required network expansion, its associated costs, and those system operation variables directly related to the existence of the grid, namely the transmission network losses. Figure 2 depicts the interaction between both models within the analyses in this case study.

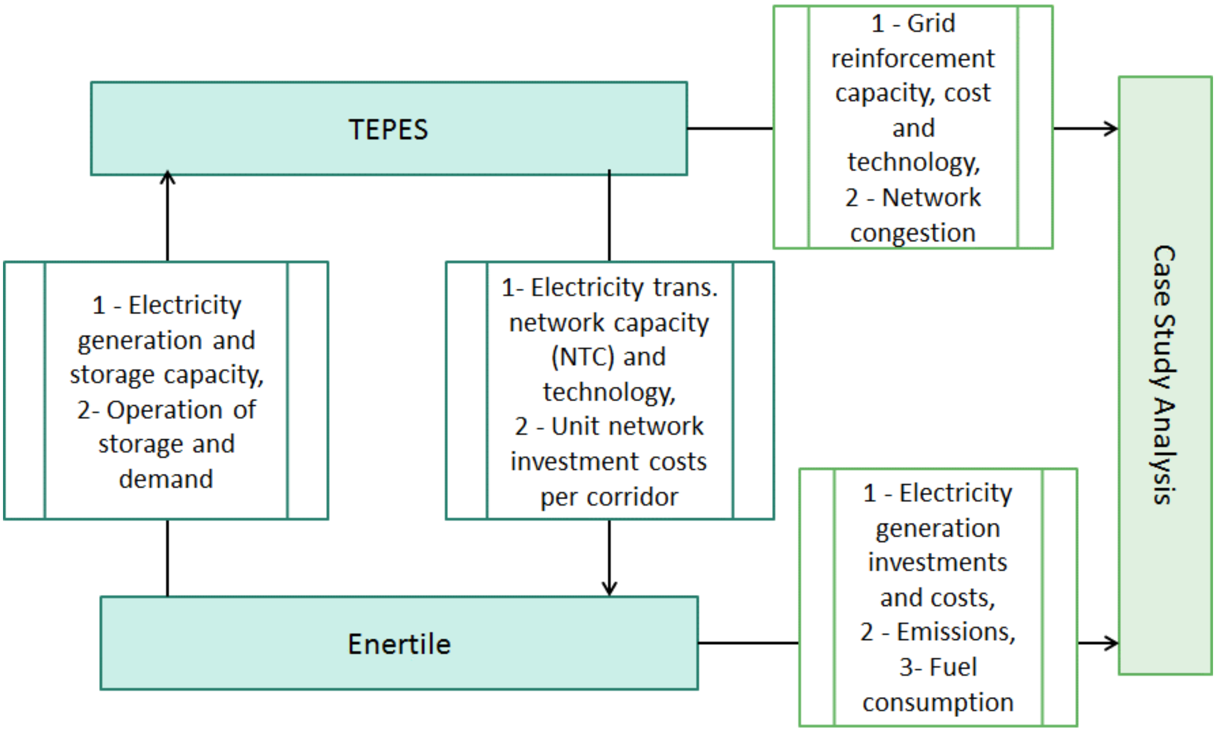

Figure 2: Model interactions within case study 6.2

3 Defining the scenarios: boundary conditions for renewable development

The central goal of this case study is to analyse the impact of centralized and decentralized electricity supply on the electricity grid. The case study is carried out by computational ***optimization of the electricity sector in the year 2050***. Instead of leaving the system to plan the system entirely, two different situations are imposed:

- The decentralized case study imposes a certain share of demand to be served with decentralized renewable.

- The centralized case imposes a certain share of demand to be served with centralized renewable.

For each of these two situations, the rest of the system is optimized: that is, the condition is imposed on only one technology, and the rest of the technologies are expanded according to te model.

The technology of PV on buildings is a good example for decentralized electricity supply as it is close to electricity demand. Therefore, we decided to create a decentralized scenario by enforcing a share of 25-30% electricity supply generated by rooftop PV in those countries with enough potential. An overview of the spatial distribution is given in the following maps. Since Enertile allows for a very high spatial resolution for the modelling of renewables, the big cities with high demand and high concentration of PV can be identified. This adds up to 961GW of rooftop PV installed in Europe.

Region	Minimum capacity in GW	Region	Minimum capacity in GW
AL_ZN	1.7	HU_ZN	12.0
AT_ZN	13.2	IE_ZN	9.4
BE_ZN	30.2	IT_N_ZN	53.0
BG_ZN	7.1	IT_S_ZN	28.4
BI_ZN	3.3	LT_ZN	2.8
CH_ZN	15.1	LU_ZN	1.0
CY_ZN	1.4	LV_ZN	2.5
CZ_ZN	21.9	ME_ZN	1.2
DE_N_ZN	121.4	MK_ZN	2.6
DE_S_ZN	42.3	MT_ZN	0.0
DK_ZN	11.4	NL_ZN	36.0
EE_ZN	2.9	NO_ZN	45.2
ES_ZN	58.2	PL_ZN	57.8
FI_ZN	28.0	PT_ZN	10.2
FR_N_ZN	98.7	RO_ZN	12.5
FR_S_ZN	18.4	RS_ZN	12.1
GB_N_ZN	11.1	SE_N_ZN	3.8
GB_S_ZN	115.2	SE_S_ZN	40.0
GR_ZN	11.3	SI_ZN	4.4
HR_ZN	4.2	SK_ZN	9.4

Table 1 Minimum capacity enforced for rooftop PV in the centralized scenario

In the scenario with centralized electricity supply, ca. 117 GW of offshore wind capacity is enforced in Central Northern Europe, which leads to serving around 25% of demand using this technology. As the cost-optimization procedure tends to build considerable amounts of onshore wind generation facitilies close to the coastlines, the combination with the enforced offshore wind capacities leads to a high concentration of wind generation capacities in Central Northern Europe. An overview of the enforced offshore windcapacities is given in the following map.

Region	Minimum capacity in GW	Region	Minimum capacity in GW
AL_ZN	0	HU_ZN	0
AT_ZN	0	IE_ZN	2.1
BE_ZN	1	IT_N_ZN	0
BG_ZN	0	IT_S_ZN	0
BI_ZN	0	LT_ZN	0.7
CH_ZN	0	LU_ZN	0
CY_ZN	0	LV_ZN	0.6
CZ_ZN	0	ME_ZN	0
DE_N_ZN	30	MK_ZN	0
DE_S_ZN	0	MT_ZN	0
DK_ZN	2.8	NL_ZN	8
EE_ZN	0.6	NO_ZN	9.25
ES_ZN	0	PL_ZN	5
FI_ZN	0	PT_ZN	0
FR_N_ZN	20	RO_ZN	0
FR_S_ZN	0	RS_ZN	0
GB_N_ZN	2.3	SE_N_ZN	0
GB_S_ZN	25	SE_S_ZN	9.5
GR_ZN	0	SI_ZN	0
HR_ZN	0	SK_ZN	0

Table 2 Enforced offshore capacity in the centralized scenario

These situations have been considered sufficiently diverse to constitute two boundary conditions, but sensible enough so that their results were not affected by any foreseeable distortion. The real path taken by the expansion should be expected to fall between these two situations.

4 Preliminary results

Within this section, we first provide preliminary results on the expansion and operation of the European power system in the Centralized and Decentralized RES deployment scenarios that have been described in section 3. Afterwards, based on this, we draw some conclusions on the impact that the strategy adopted for the development and deployment of RES generation may have on the required investments within the European power system and the associated operation costs. The following table shows the results for the calculated electricity system in Enertile. Grey values are part of the scenario definition and therefore enforced results of the model. Blue values are results of the optimization process.

	Centralized scenario in GW		Decentralized scenario in GW	
	Capacity (GW)	Generation (TWh)	Capacity (GW)	Generation (TWh)
Gas	108	33.4	98	53.4
Hardcoal	0.3	2.0	0.3	2.0
Nuclear	61	372	61	344

Biomass	58	252	58	252
CSP	65	244	54	207
Rooftop PV	8	11.5	961	1003
Utility scale PV	335	442	5	8.7
Wind offshore	117	512	0	0
Wind onshore	380	1516	398	1585
Storages	69	-14.5	121	-43.7

Table 3 Installed capacities and generation in the electricity system based on Enertile calculations (fully optimized values (blue), enforced result (grey)

The decentralized scenario leads to higher investments in storages. The installed capacity reaches 121 GW in the decentralized scenario and 69 GW in the centralized scenario. The difference in storage losses 14.5 TWh (centralized) and 43.7 TWh (decentralized) is even higher as the load profile of large amounts of PV leads to high utilisation of storages. Another major difference between both scenarios is the investment in utility scale PV. Because the decentralized scenario is already characterized by a high level of rooftop PV only 5 GW of utility scale PV are built. In the centralized scenario 335 GW of utility scale PV are built since it is cheaper than rooftop PV. In contrast to PV the installed capacity of wind onshore is relatively constant reaching 380 GW in the centralized scenario and 398 GW in the decentralized scenario. In both scenarios it is the dominant generation technology reaching more than 1500 TWh of generation. In terms of system cost excluding electricity grids the centralized scenario reaches ca. 248 billion € of annual cost while the decentralized scenario leads to annual cost of 273 billion €. This comparison shows that the centralized scenario is ca. 25 billion € cheaper than the decentralized scenario, if only cost of the electricity generation are taken into account.

As mentioned above, the expansion of the system is computed in the 2050-time horizon. First of all, the overall transmission network investment and variable operation costs computed in both scenarios are provided in Table 4 and graphically represented in Figure 3. Costs are expressed in million €. In the case of variable operation costs, these are annual figures. Network transmission and distribution investment costs are annualized figures, i.e. those corresponding to the fraction of the overall investment costs allocated, for accounting purposes, to each year throughout the useful life of these assets. In the case of distribution, we are not providing an estimate of the overall network investment costs. These result from the joint development of generation and demand at distribution level, while here we are only providing an estimate of the costs associated with generation. The cost of the investments in the distribution network necessary to integrate distributed generation has been estimated making use of the results of previous projects[1].

[1] The DG-driven cost estimated that has been used in this issue paper was calculated from the amount of rooftop PV generation installed in each scenario as a proxy for distributed generation, multiplied by a median cost of 10 €/kW. We have based our estimate of the average per unit distribution network cost of integration of DG on the results, in this regard, produced in several previous research projects and studies. These include the IMPROGRES project (Cossent et al. 2010; Cossent et al 2011), the MIT Future of Solar project (MIT 2015), and OFGEM's Electricity Distribution Price Control Reviews (DPCR) (OFGEM 2004, 2009). According to the analyses within the IMPROGRES project, the annualized DG driven distribution costs are within the range [-5, 70] €/kW. Researchers within the Future of Solar project concluded that annualized incremental distribution costs caused by DG could range between few euros and 27€/kW. Lastly, the average capital expenditure needed to connect DG to the grid, according to the DCPR conducted by OFGEM, was 6.4€/kW. Considering all these estimates, one may assume that typical DG-driven

Table 4: Overall estimation of costs per scenario

Annualized Costs [MEUR]	Transmission investment	Distribution investment (estimated)	Operation	Total
Centralized	8.805,19	60,78	9.740,78	18.606,75
Decentralized	5.633,20	4.763,62	10.459,97	20.856,79

Detailed quantitative information on the required developments of the European transmission network in each scenario is only provided in Annex 1, due to the size of the corresponding tables. Table 3 shows the amount of installed capacity per technology. The capacity installed per technology and per country has not been included due to size constraints. Table 4 and **Error! Reference source not found.** provide, for a scenario and each transmission corridor defined in it, the unit investment cost, in M€ per MW of capacity built; the initial capacity, the final capacity, and the increase in capacity, in MW; and the total investment cost, and annualized investment cost, in M€. Table 6 shows transmission losses in each scenario, in TWh. Figures 6 and 7 show the incremental transmission investments on the European map. For ease of inspection, Figures 8 and 9 show the largest-capacity corridors only.

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annualized distribution costs lie within the range [0, 20] €/kW. Then, within our analysis, we have decided to take a value of 10 €/kW as representative of this cost interval.

Table 2: Rooftop PV capacity installed in both scenarios

	Rooftop PV [MW]
Centralized	6078
Decentralized	476362

It should be noted, however, that depending on the characteristics of the specific zone the cost can vary from needing virtually no investment to a very high cost of up to 80€/kW. In order to refine the cost estimation carried out in this issue paper, extensive work would be needed to identify the factors that underlie this cost at a European level and apply this to the whole European network. This would demand a level of effort equivalent of a whole new project.

Therefore, the cost estimate provided should be taken as an indicative figure only, emphasizing the high level of uncertainty associated with it.

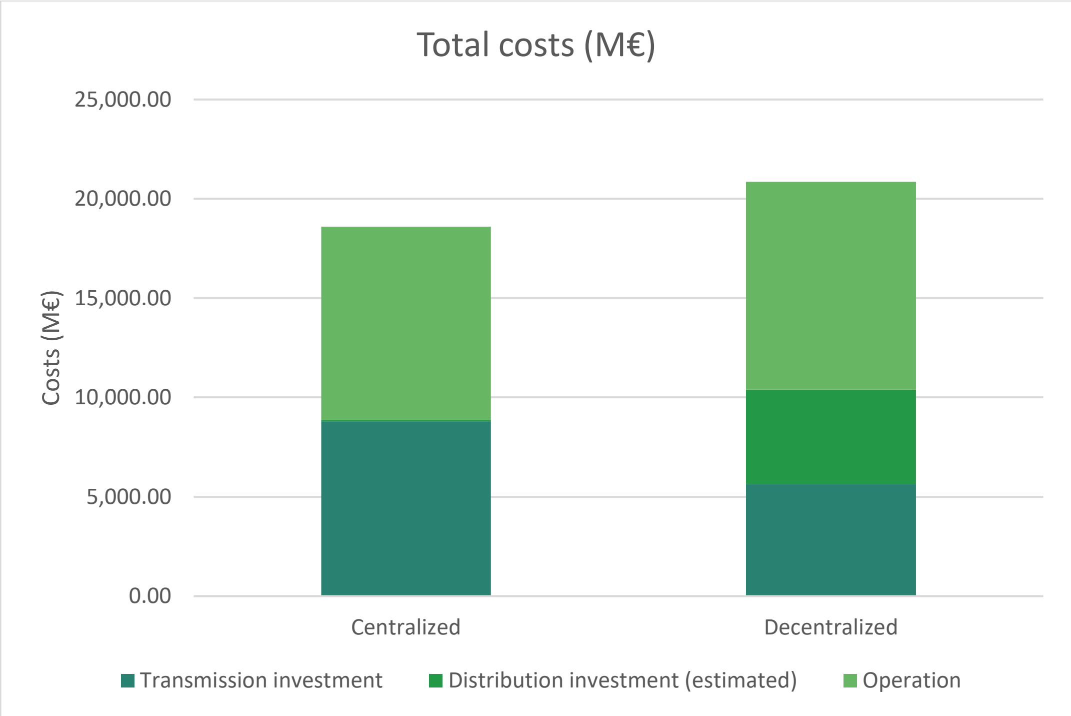

Figure 3. Network development and operation costs per scenario

The main results are discussed below.

The decentralized scenario has higher total system costs than the centralized scenario. This is driven by two factors. The first aspect is that the generation mix for renewables in the decentralized scenario is suboptimal with regard to cost. Rooftop PV has higher generation cost than utility-scale solar power. The allocation of considerable amounts of PV in northern Europe is also more expensive than wind generation in these regions. The second aspect is the need for flexibility. The decentralized case requires far more flexibility in the electricity system to match supply and demand. This can be achieved by demand-side flexibility or by the utilisation of costly storage.

The centralized scenario requires a stronger expansion of the electricity transmission grid. Due to the fact that in the centralized scenario a considerable amount of renewable generation capacity is installed in Northern or Central Europe, considerable amounts of electricity need to be transported across Europe to match supply and demand. This requires more transmission lines within Europe. Most of the investment happens around the *blue banana* region in central Europe (the axis Milan-Manchester), given that it is a region where large cross-area flows happen. In addition, large North-to-South corridors are built in order to integrate the large renewable investments that take place in the periphery of Europe. These corridors are consistent with the findings of other European projects such as e-Highway. A larger proportion of transmission losses (around 30% higher) appear in this scenario as a result of the larger cross-area flows.

Both scenarios require a strong expansion of the transmission grid (albeit lower in the decentralized case). This is caused by the fact that, according to the assumptions we are making on the evolution of the cost of the several generation, storage and network technologies in the time horizon of the study, electricity transmission is a cheap flexibility option compared to other technologies such as additional generation capacities or storage. Then, a higher system integration across Europe emerges as the most cost-efficient alternative in terms of flexibility.

Distribution grid upgrades have a considerable cost in the decentralized case. In the decentralized case, the upgrades to the distribution network needed to integrate the new distributed generation are comparable to the needs of the transmission network. The cost of distribution network upgrades is subject to considerable uncertainty and varies depending on local characteristics. Any cost estimates should be treated with extreme caution.

Public acceptance is the main currency of the energy transition. In both scenarios, substantial infrastructures in terms of generation and transmission –also in distribution in the decentralized case- need to be built. This requires sizeable financial resources and public acceptance. The cost of the electricity system is one important aspect, but the required acceptance for grid lines or generation technologies is also crucial for the sustainable long-term development of the sector.

International cooperation is beneficial. In both scenarios substantial electricity trades between regions and common optimization of the supply infrastructure is part of the calculation procedure. International cooperation reduces costs and requires less resources in terms of generation infrastructure.

5 Takeaway message

Transmission grids are the backbone for the decarbonisation of the electricity sector in Europe, as they allow for the efficient decarbonisation of the electricity sector. This is true for a decentralized model just as well as for a decentralized development of energy resources. A more centralized approach requires even larger transmission developments, but less flexibility in the system with a lower use of storage.

The need for transmission should be considered when planning the expansion of the system, as their effect is considerable. It is not enough to plan for the expansion of generation: ***network investments must be taken into account.***

6 Annex 1: Detailed results

Table 3: Generation expansion capacity results in each scenario

Technology	Generation capacity in Centralized scenario [GW]	Generation capacity in Decentralized scenario [GW]
Gas CCGT	0,2	19,8
Gas GT	107,3	78,3
Hardcoal	0,3	0,3
Lignite	0,0	0,0
Nuclear	60,6	60,6
Biomass	43,2	43,2
Hydro	34,9	34,9
SoPV	267,1	674,0
SostDirectGeneration	73,9	63,5
Wind Offshore	120,4	0,0
Wind Onshore	410,2	427,7

Table 4: Detailed network expansion results for the Centralized scenario

Zone Origin	Zone Destination	Unit Investment Cost [M€/MW]	Initial Capacity [MW]	Final Capacity [MW]	Increase in Capacity [MW]	Investment Cost [M€]	Annualized Investment Cost [M€]
AL	GR	0.199	750	1722	972	193.6	14.31
AL	IT-S	0.353	500	1500	1000	353.4	26.12
AL	ME	0.125	750	1750	1000	125.3	9.26
AL	MK	0.254	458	660	202	51.4	3.80
AL	RS	0.259	300	300	0	0.0	0.00
AT	CH	0.261	1042	1962	920	240.3	17.76
AT	CZ	0.274	744	744	0	0.0	0.00
AT	DE-S	0.248	1508	4449	2941	728.4	53.83
AT	DE-N	0.332	0	8166	8166	2712.5	200.46
AT	FR-N	0.399	0	4000	4000	1594.9	117.86
AT	HU	0.364	673	1915	1242	452.3	33.43
AT	IT-N	0.465	306	1133	827	384.1	28.39
AT	PL	0.410	0	4000	4000	1639.7	121.17

Zone Origin	Zone Destination	Unit Investment Cost [M€/MW]	Initial Capacity [MW]	Final Capacity [MW]	Increase in Capacity [MW]	Investment Cost [M€]	Annualized Investment Cost [M€]
AT	SI	0.350	779	1892	1113	389.4	28.77
AT	SK	0.235	254	254	0	0.0	0.00
BA	DE-N	0.462	608	1581	973	449.8	33.24
BA	DK	0.583	600	1600	1000	583.0	43.08
BE	DE-N	0.279	385	385	0	0.0	0.00
BE	FR-N	0.549	3872	5860	1988	1092.1	80.71
BE	LU	0.333	320	980	660	317.7	23.48
BE	NL	0.320	1099	5712	4613	1474.1	108.94
BE	NO	0.873	660	5660	5000	4364.1	322.50
BE	GB-S	0.435	1000	6000	5000	2173.3	160.61
BE	GB-N	0.527	0	6000	6000	3161.0	233.60
BG	GR	0.303	602	1602	1000	303.0	22.39
BG	MK	0.297	183	183	0	0.0	0.00
BG	RO	0.147	918	1486	569	83.7	6.18
BG	RS	0.150	750	1750	1000	150.0	11.09
BG	TR	0.312	894	981	87	53.5	3.95
BI	HR	0.148	728	2095	1367	202.0	14.93
BI	ME	0.107	1285	2419	1134	121.6	8.99
BI	RS	0.163	750	1750	1000	162.6	12.02
CH	DE-S	0.233	2511	4211	1699	395.5	29.23
CH	DE-N	0.347	0	12000	12000	4165.0	307.79
CH	FR-N	0.270	2844	19128	16284	4400.5	325.19
CH	IT-N	0.437	1608	2608	1000	436.6	32.26
CH	LU	0.243	0	4000	4000	972.5	71.86
CY	GR	1.125	0	0	0	0.0	0.00
CZ	DE-S	0.237	977	977	0	0.0	0.00
CZ	DE-N	0.273	1200	5076	3876	1059.7	78.31
CZ	PL	0.261	1629	1629	0	0.0	0.00
CZ	SK	0.257	1108	1767	659	169.6	12.53
DE-S	FR-N	0.337	2423	7423	5000	1685.9	124.59
DE-S	LU	0.202	0	3000	3000	606.9	44.85

Zone Origin	Zone Destination	Unit Investment Cost [M€/MW]	Initial Capacity [MW]	Final Capacity [MW]	Increase in Capacity [MW]	Investment Cost [M€]	Annualized Investment Cost [M€]
DE-N	DE-S	0.266	5354	14518	9164	2437.8	180.16
DE-N	DK	0.271	1434	10434	9000	2443.3	180.56
DE-N	FR-N	0.454	577	1577	1000	454.3	33.57
DE-N	IT-N	0.567	0	4000	4000	2269.2	167.69
DE-N	LU	0.311	730	1837	1108	344.1	25.43
DE-N	NL	0.231	2188	9523	7335	1690.9	124.96
DE-N	NO	0.757	1400	2400	1000	756.7	55.92
DE-N	NORTH	0.462	0	21	21	9.5	0.71
DE-N	PL	0.384	2327	7327	5000	1922.3	142.06
DE-N	SE-S	0.702	600	1600	1000	702.4	51.91
DK	NL	0.401	600	1600	1000	400.7	29.62
DK	NO	0.723	1600	3600	2000	1445.7	106.84
DK	PL	0.649	660	660	0	0.0	0.00
DK	SE-S	0.658	2400	4400	2000	1316.3	97.28
EE	FI	0.488	1000	3000	2000	975.6	72.10
EE	LV	0.274	1766	3035	1270	347.2	25.66
EE	SE-S	0.622	660	660	0	0.0	0.00
ES	FR-S	0.635	3901	4592	691	621.5	45.93
ES	FR-N	0.924	0	8000	8000	8057.1	595.42
ES	IE	1.433	660	3660	3000	4299.1	317.71
ES	MA	0.380	0	0	0	0.0	0.00
ES	PT	0.641	2246	2377	131	84.2	6.22
FI	NO	0.637	900	1846	946	602.6	44.53
FI	SE-N	0.363	843	6816	5973	2169.1	160.30
FI	SE-S	0.534	1294	1896	602	321.6	23.76
FR-N	FR-S	0.333	5115	12893	7778	2593.3	191.65
FR-N	IE	0.758	700	4700	4000	3033.5	224.17
FR-N	IT-N	0.449	3098	24081	20983	9411.6	695.52
FR-N	LU	0.359	506	1563	1056	379.1	28.02
FR-N	GB-S	0.678	2988	6000	3012	2041.7	150.88
GR	IT-S	0.444	500	1500	1000	443.6	32.78

Zone Origin	Zone Destination	Unit Investment Cost [M€/MW]	Initial Capacity [MW]	Final Capacity [MW]	Increase in Capacity [MW]	Investment Cost [M€]	Annualized Investment Cost [M€]
GR	MK	0.184	1000	2000	1000	184.3	13.62
GR	TR	0.634	900	1635	735	465.9	34.43
HR	HU	0.121	832	1738	905	109.5	8.09
HR	IT-N	0.459	986	2000	1014	465.4	34.40
HR	RS	0.261	750	750	0	0.0	0.00
HR	SI	0.109	1151	1810	659	72.1	5.33
HU	PL	0.423	0	1000	1000	422.9	31.25
HU	RO	0.254	764	4259	3495	888.9	65.69
HU	RS	0.166	750	1750	1000	165.9	12.26
HU	SI	0.090	1429	3429	2000	180.3	13.33
HU	SK	0.176	1956	3118	1162	204.8	15.13
IE	NI	0.377	506	1300	794	712.8	52.67
GB-N	IE	0.431	0	3000	3000	1292.2	95.49
IT-S	ME	0.627	1000	1000	0	0.0	0.00
IT-S	MK	0.491	0	3000	3000	1474.3	108.95
IT-N	IT-S	0.442	4691	8457	3766	1666.2	123.13
IT-N	SI	0.420	719	1719	1000	419.7	31.02
LT	LV	0.295	1484	3484	2000	589.9	43.60
LT	PL	0.415	983	6983	6000	2491.8	184.14
LT	SE-S	0.722	700	2700	2000	1444.1	106.72
LV	SE-S	0.711	660	660	0	0.0	0.00
ME	RS	0.168	634	1450	815	137.1	10.13
MK	RS	0.259	1165	1165	0	0.0	0.00
NL	NO	0.761	1400	3400	2000	1521.1	112.41
NO	SE-N	0.573	1000	2000	1000	605.0	44.71
NO	SE-S	0.288	3920	12033	8113	2335.5	172.59
PL	RO	0.493	0	3000	3000	1479.5	109.34
PL	SE-S	0.806	600	1600	1000	806.2	59.58
PL	SK	0.339	600	1600	1000	338.9	25.05
RO	RS	0.159	2099	3099	1000	159.1	11.76
RO	TR	0.574	691	700	9	5.3	0.39

Zone Origin	Zone Destination	Unit Investment Cost [M€/MW]	Initial Capacity [MW]	Final Capacity [MW]	Increase in Capacity [MW]	Investment Cost [M€]	Annualized Investment Cost [M€]
SE-N	SE-S	0.523	1564	1949	385	201.2	14.87
GB-S	IE	0.564	900	2900	2000	1127.4	83.31
GB-S	NL	0.628	1000	2000	1000	627.8	46.40
GB-S	NO	1.156	1400	2400	1000	1155.9	85.42
GB-N	NI	0.495	500	1324	824	676.0	49.95
GB-N	GB-S	0.344	4956	9615	4659	1602.5	118.43

Table 5: Detailed network expansion results for the Decentralized scenario

Zone Origin	Zone Destination	Unit Investment Cost [M€/MW]	Initial Capacity [MW]	Final Capacity [MW]	Increase in Capacity [MW]	Investment Cost [M€]	Annualized Investment Cost [M€]
AL	GR	0.145	750	1583	833	120.9	8.94
AL	IT-S	0.346	500	1500	1000	345.6	25.54
AL	ME	0.108	750	1684	934	101.1	7.47
AL	MK	0.143	553	1407	854	122.0	9.01
AL	RS	0.259	300	300	0	0.0	0.00
AT	CH	0.209	1053	1958	905	188.9	13.96
AT	CZ	0.240	744	3744	3000	720.4	53.24
AT	DE-S	0.168	1506	8505	6999	1176.0	86.91
AT	FR-N	0.371	0	4000	4000	1483.3	109.61
AT	HU	0.365	893	1636	743	271.3	20.05
AT	IT-N	0.416	307	1104	797	331.4	24.49
AT	PL	0.365	0	5000	5000	1823.9	134.79
AT	SI	0.323	770	1443	673	217.5	16.07
AT	SK	0.235	254	254	0	0.0	0.00
BA	DE-N	0.282	608	608	0	0.0	0.00
BA	DK	0.307	600	600	0	0.0	0.00
BE	DE-N	0.428	385	385	0	0.0	0.00
BE	FR-N	0.478	3754	5367	1613	770.2	56.92
BE	LU	0.333	320	980	660	245.3	18.13
BE	NL	0.306	1148	2844	1696	518.9	38.35
BE	NO	0.858	660	4660	4000	3431.8	253.61
BE	GB-S	0.534	1000	2000	1000	533.8	39.45
BG	GR	0.515	564	564	0	0.0	0.00
BG	MK	0.297	148	148	0	0.0	0.00

BG	RO	0.247	761	761	0	0.0	0.00
BG	RS	0.347	750	750	0	0.0	0.00
BG	TR	0.156	852	852	0	0.0	0.00
BI	HR	0.192	1000	1000	0	0.0	0.00
BI	ME	0.153	1016	1683	667	102.0	7.53
BI	RS	0.158	750	1750	1000	158.0	11.68
CH	DE-S	0.149	2469	6731	4262	634.2	46.87
CH	FR-N	0.263	2839	14145	11306	2972.9	219.70
CH	IT-N	0.266	1608	1608	0	0.0	0.00
CY	GR	1.125	0	0	0	0.0	0.00
CZ	DE-S	0.237	977	977	0	0.0	0.00
CZ	DE-N	0.258	1200	2358	1158	298.9	22.09
CZ	HU	0.277	0	3000	3000	830.4	61.37
CZ	PL	0.276	1404	5125	3721	1027.7	75.95
CZ	SK	0.244	1108	1108	0	0.0	0.00
DE-N	DE-S	0.234	5397	8959	3562	832.8	61.54
DE-S	FR-N	0.368	2423	2423	0	0.0	0.00
DE-S	IT-N	0.370	0	3000	3000	1110.6	82.07
DE-N	DK	0.307	1434	14434	13000	3995.9	295.30
DE-N	FR-N	0.418	577	1577	1000	418.1	30.89
DE-N	LU	0.329	812	2586	1774	583.2	43.10
DE-N	NL	0.273	2325	4446	2121	578.5	42.75
DE-N	NO	0.960	1400	1400	0	0.0	0.00
DE-N	NORTH	0.774	0	21	21	16.7	1.23
DE-N	PL	0.330	2327	3987	1659	547.9	40.49
DE-N	SE-S	0.664	600	1600	1000	664.0	49.07
DK	NL	0.383	600	4600	4000	1533.2	113.30
DK	NO	0.761	1600	3600	2000	1522.9	112.54
DK	PL	0.649	660	660	0	0.0	0.00
DK	SE-S	0.640	2400	4400	2000	1279.5	94.56
EE	FI	0.440	1000	2000	1000	439.6	32.49
EE	LV	0.253	2035	3035	1000	253.0	18.70
EE	SE-S	0.622	660	660	0	0.0	0.00
ES	FR-S	0.542	3728	8033	4305	2333.9	172.48
ES	FR-N	0.667	0	8000	8000	5339.8	394.61
ES	IE	1.199	660	1660	1000	1199.2	88.62
ES	MA	0.380	0	0	0	0.0	0.00
ES	PT	0.369	2339	5050	2711	1000.7	73.95
FI	NO	0.666	900	1900	1000	666.2	49.23
FI	SE-N	0.607	843	1843	1000	607.2	44.88
FI	SE-S	0.565	1195	1225	30	16.8	1.24
FR-N	FR-S	0.300	4989	6152	1163	349.1	25.80

FR-S	IT-N	0.534	0	4000	4000	2134.5	157.74
FR-N	IE	0.938	700	700	0	0.0	0.00
FR-N	IT-N	0.393	3098	22472	19374	7621.4	563.22
FR-N	LU	0.315	539	4263	3724	1174.2	86.77
FR-N	GB-S	0.559	2988	6000	3012	1683.2	124.39
GR	IT-S	0.396	500	1500	1000	396.1	29.27
GR	MK	0.184	1000	1992	992	182.9	13.51
GR	TR	0.581	900	900	0	0.0	0.00
HR	HU	0.201	755	1832	1078	216.1	15.97
HR	IT-N	0.396	986	2000	1014	401.1	29.64
HR	RS	0.261	750	750	0	0.0	0.00
HR	SI	0.147	1151	1151	0	0.0	0.00
HU	PL	0.357	0	3000	3000	1071.6	79.19
HU	RO	0.222	611	1451	840	186.2	13.76
HU	RS	0.227	750	1750	1000	227.2	16.79
HU	SI	0.288	1429	1429	0	0.0	0.00
HU	SK	0.188	2293	2293	0	0.0	0.00
IE	NI	0.377	506	1300	794	1021.3	75.47
IT-S	ME	0.627	1000	1000	0	0.0	0.00
IT-N	IT-S	0.367	4081	8148	4068	1494.8	110.47
IT-N	SI	0.371	719	1719	1000	370.9	27.41
LT	LV	0.245	1484	3484	2000	489.6	36.18
LT	PL	0.500	983	2983	2000	999.8	73.89
LT	SE-S	0.700	700	700	0	0.0	0.00
LV	SE-S	0.711	660	660	0	0.0	0.00
ME	RS	0.198	561	561	0	0.0	0.00
MK	RS	0.259	1165	1165	0	0.0	0.00
NL	NO	0.778	1400	3400	2000	1555.3	114.94
NO	SE-N	0.553	1000	3611	2611	1443.2	106.65
NO	SE-S	0.329	3729	8920	5191	1709.5	126.33
PL	SE-S	0.732	600	600	0	0.0	0.00
PL	SK	0.283	600	1467	867	245.7	18.16
RO	RS	0.126	2099	2099	0	0.0	0.00
RO	TR	0.305	691	691	0	0.0	0.00
SE-N	SE-S	0.605	1459	2721	1262	764.1	56.47
GB-S	IE	0.529	900	2900	2000	1058.8	78.24
GB-S	NL	0.595	1000	2000	1000	595.3	43.99
GB-S	NO	1.370	1400	1400	0	0.0	0.00
GB-N	NI	0.495	500	1324	824	1016.7	75.13
GB-N	GB-S	0.346	4956	10275	5319	1842.1	136.13

Table 6: Line losses in each scenario

	Line losses in Centralized scenario [TWh]	Line losses in Decentralized scenario [TWh]
Line losses	85,8	68,8

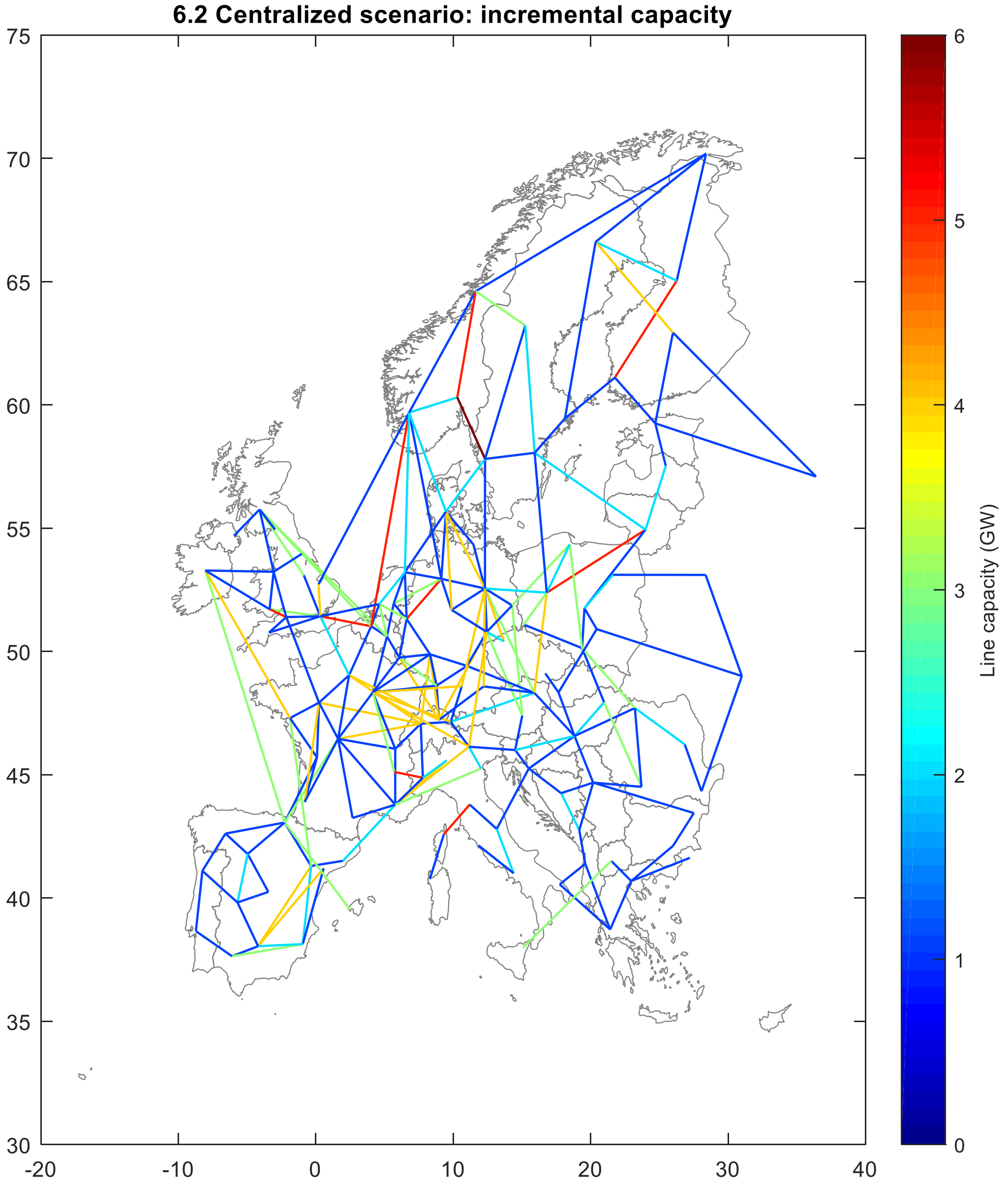

Figure 6. Incremental transmission capacity in the Centralized scenario

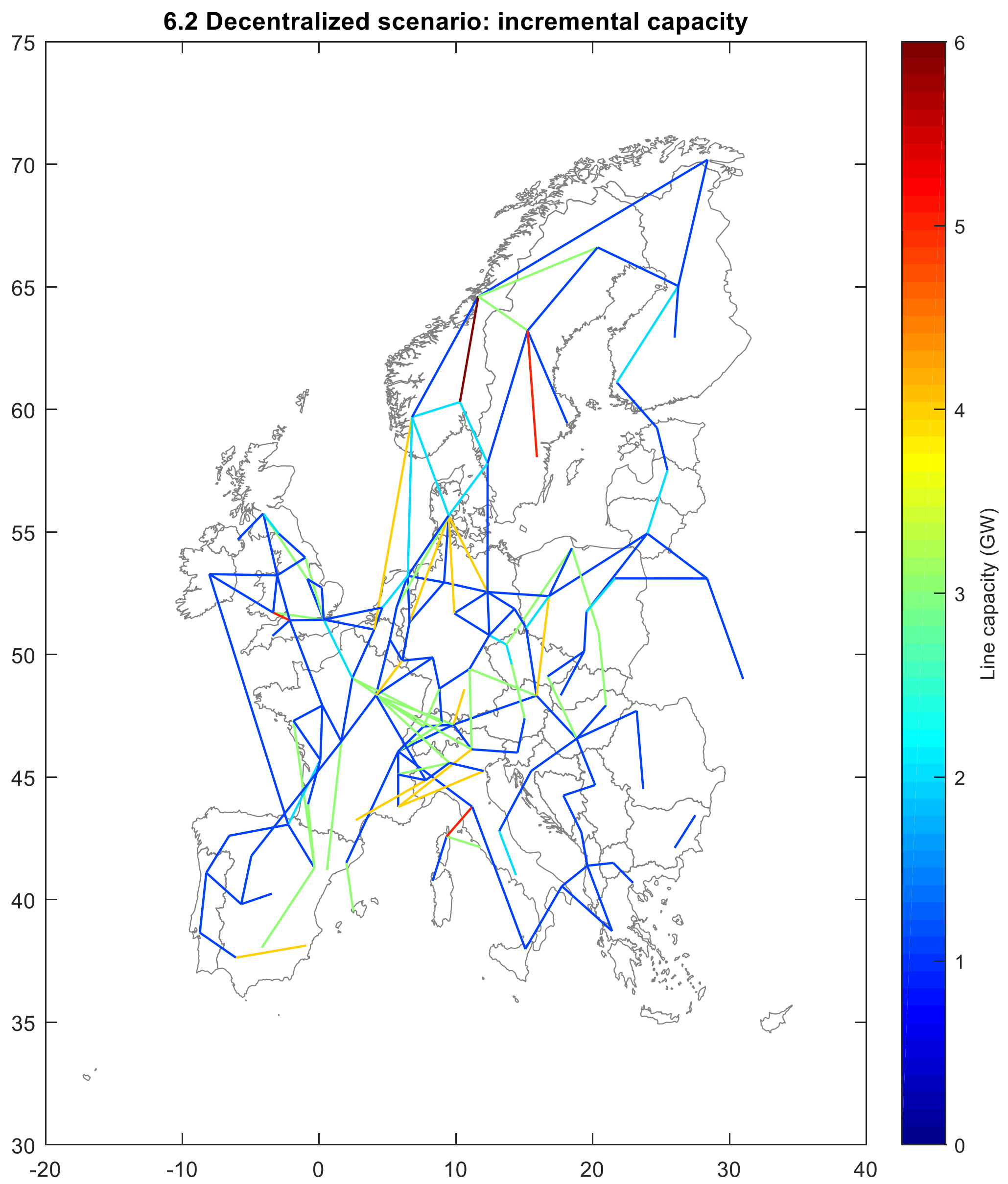

Figure 7. Incremental transmission capacity in the Decentralized scenario

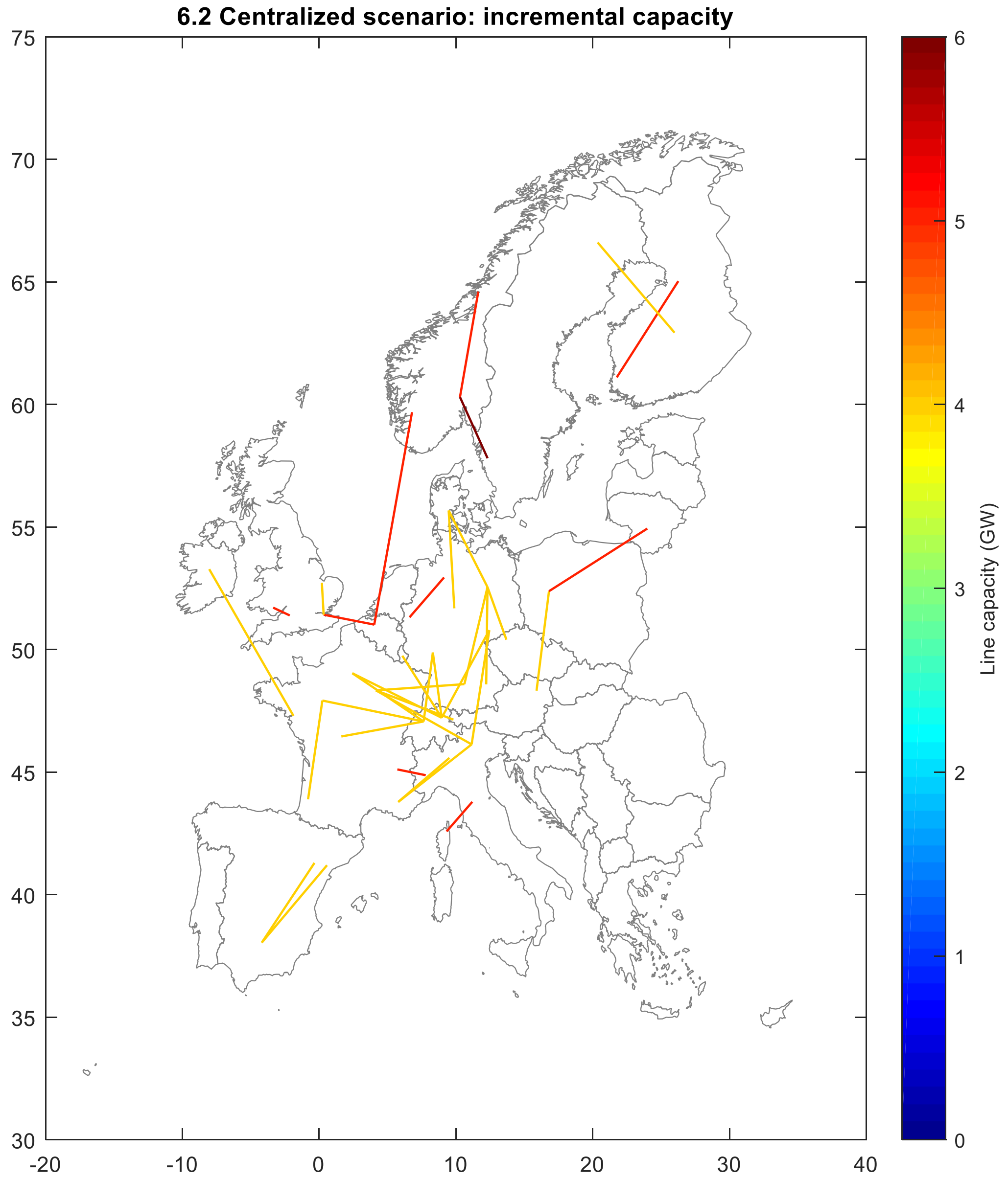

Figure 8. Incremental transmission capacity in the Centralized scenario (largest-capacity corridors)

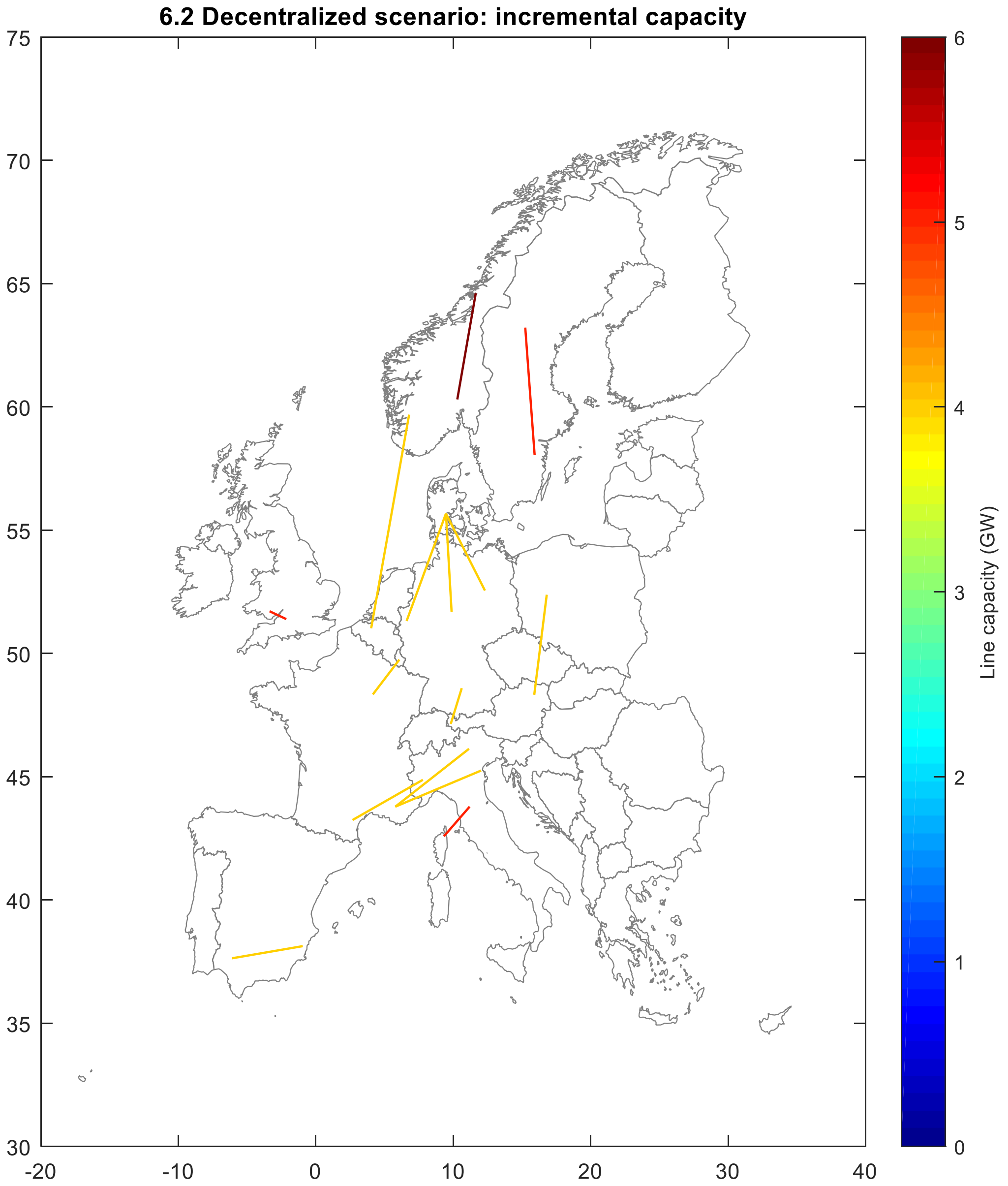

Figure 9. Incremental transmission capacity in the Decentralized scenario (largest-capacity corridors)

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SET-Nav
Strategic Energy Roadmap

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About the project

SET-Nav aims for supporting strategic decision making in Europe's energy sector, enhancing innovation towards a clean, secure and efficient energy system. Our research will enable the European Commission, national governments and regulators to facilitate the development of optimal technology portfolios by market actors. We will comprehensively address critical uncertainties facing technology developers and investors, and derive appropriate policy and market responses. Our findings will support the further development of the SET-Plan and its implementation by continuous stakeholder engagement.

These contributions of the SET-Nav project rest on three pillars: modelling, policy and pathway analysis, and dissemination. The call for proposals sets out a wide range of objectives and analytical challenges that can only be met by developing a broad and technically-advanced modelling portfolio. Advancing this portfolio is our first pillar. The EU's energy, innovation and climate challenges define the direction of a future EU energy system, but the specific technology pathways are policy sensitive and need careful comparative evaluation. This is our second pillar. Ensuring our research is policy-relevant while meeting the needs of diverse actors with their particular perspectives requires continuous engagement with stakeholder community. This is our third pillar.

Who we are?

The project is coordinated by Technische Universität Wien (TU Wien) and being implemented by a multinational consortium of European organisations, with partners from Austria, Germany, Norway, Greece, France, Switzerland, the United Kingdom, France, Hungary, Spain and Belgium.

The project partners come from both the research and the industrial sectors. They represent the wide range of expertise necessary for the implementation of the project: policy research, energy technology, systems modelling, and simulation.

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