BENCHMARKING STUDY FOR TRANSMISSION SYSTEM PLANNING METHODOLOGIES

A COMPARISON BETWEEN INDIA, EUROPE, THE NORDICS AND DENMARK

Danish Energy Agency

Ea Energy Analyses

ENERGINET

Green Strategic Partnership India-Denmark

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Credits

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Executive summary

In the wake of the findings from the Intergovernmental Panel on Climate Change (IPCC), countries around the world are joining efforts to plan and develop future power systems, where Renewable Energy Sources (RES) will be the paramount players. Denmark is leading the race at European level in the integration of RES in the power system: in 2020, the equivalent of 50% of electricity consumption was produced by variable RES, such as wind and solar. On a different scale, but the same level of ambitions, there is India. By 2040 India is projected to generate two and a half times as much electricity as today, while having ambitious targets to supply substantial amounts of this demand with RES: in 2019 the Indian government announced ambitions to reach 450 GW of installed RES by 2030.

In many cases the RES projects are developed in areas far away from consumption centres and often in areas without existing transmission network. Further ambitions regarding offshore wind are expected to challenge the traditional approach to integrate generation facilities during transmission planning. The transmission system is like the arteries of the electricity grid, and the planning of its development must be done in a manner that is both secure and economically efficient. Transmission planning is therefore a complex stochastic task which is essential to optimize value of both public and private investments in power system infrastructure.

As part of the European Network of transmission System Operators for Electricity (ENTSO-E), Denmark uses a coordinated and comprehensive transmission grid planning approach to ensure system stability, to guarantee power supply and to integrate more RES at lowest possible cost. In general, the ENTSO-E approach ensures that pan-European grid planning is optimised for the common good and addresses the different interests at stake. The main processes are based on scenario building, screening and cost-benefit analysis (CBA).

This report is a benchmarking study, comparing methodologies in Europe, India, Denmark and the Nordics, aiming at investigating and highlighting the lessons to be learned across different geographical regions and transmission planning methodologies. On this premise, the following report elaborates on the European, Indian, Danish and Nordic approaches to transmission planning, describing concepts and considerations while developing new transmission planning projects. The aim is to provide detailed information as to the contrasting methodologies in a benchmarking report, in which the comparison will shed some light on potential learnings which could benefit the Indian and European systems.

Based on the analysis performed for this benchmarking study, the authors recommend the following:

1. It is recommended to work with 3-4 scenarios for the energy futures (long-term; 15 – 20 years ahead) in the planning process.
2. India should support the further development of the wholesale markets.
3. Cost benefit calculations (e.g. cost-benefit analysis) should be used for assessing new investments
4. Stakeholder involvement in the transmission planning process is highly recommended as it, besides giving valuable input, also secures a higher degree of “buying in” and support to the final plan.
5. The authors suggest India to develop a long-term strategy for stronger interconnections to neighbours.

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Abbreviations

AP	Average Pricing
ATC	Available Transfer Capacity
CBA	Cost Benefit Analysis
CBG	Coal Before Gas
CE	Central Europe
CEA	Central Electricity Authority
CERC	Central Elecitricity Regulatory Commission
CNTC	Coordinated Net Transfer Capacity
CTU	Central Transmission Utillity
CTUIL	Central Transmission Utillity
DA	Day-Ahead
DE	Distributed Energy
DISCOM	Distribution Company
DSM	Deviation Settlement Mechanism
EC	European Commission
EENS	Expected Energy Not Served
EHV	Extra High Voltage
EHVAC	Extra High Voltage Alternating Current
EMTP	Electromagnetic Transients Program
EPS	Electric Power Survey
EU	European Union
FB	Flow Based
FRAS	Fast Response Ancillary Services
GA	Global Ambition
GBC	Gas Before Coal
GDP	Gross Domestic Product
GEC	Green Energy Corridors
GENCO	Generation Company
GNA	General Network Access
GTC	Grid Transfer Capacity
GVA	Giga Voltage Ampere
GW	Giga Watt
HV	High Voltage
HVAC	High Voltage Alternating Current
HVDC	High Voltage Direct Current
IEX	Indian Energy Exchange
IPCC	International Panel on Climate Change
ISGS	Inter State Generation Station
ISTS	Inter State Transmission System
Intra-STS	Intra State Transmission System
LDP	Long-term Development Plan
LOLE	Loss of Load Expectancy
MCP	Market Clearing Price

MNRE	Ministry of New and Renewable Energy
MP	Marginal Pricing
MVA	Mega Voltage Ampere
MVAR	Mega Voltage Ampere Reactive
MW	Mega Watt
NHPC	National Hydroelectric Power Corporation
NLC	NLC India Ltd.
NLDC	National Load Dispacth Centre
NPCIL	Nucler Power Corporation of India Ltd.
PCI	Project of Common Interest
PV	Photo Voltaic
PXIL	Power Exchange India Ltd.
RCC	Regional Coordination Centres
RE	Renewable Energy
REMC	Renewable Energy Management Centre
RES	Renewable Energy Sources
REZ	Renewable Energy Zones
RPC	Regional Power Company
RPCTP	Regional Power Committee on Transmission Planning
RR	Replacement Reserve
RRAS	Reserve Regulation Ancillary Services
RSCPSP	Regional Standing Committee on Power System
RSCT	Regional Standing Committee on Transmission
RTM	Real Time Market
SCED	Security Constrained Economic Dispatch
SJVNL	Satluj Jal Vidyut Nigam
SO	System Operator
SoS	Security of Supply
STU	State Transmission Utillity
TSO	Transmission System Operator
TTC	Total Transfer Capabillity
UHV	Ultra High Voltage
UHVDC	Ultra High Voltage Direct Current
UMSPP	Ultra Mega Solar Power Plant
US	United States

1. Introduction

Following the findings from the Intergovernmental Panel on Climate Change – 2021 [1], providing an assessment of the current evidence on the physical science of climate change, countries around the world are joining efforts to plan and develop future power systems, where Renewable Energy Sources (RES) will be the paramount players. Denmark, a Scandinavian country located in the north of Europe, is leading the race in the integration of renewable energy sources in the power system: in 2020, more than 50% of electricity was produced by variable RES, such as wind and solar [2]. On a larger scale, but with equal level of ambitions, there is India.

By 2040 India is projected to generate two and a half times as much electricity as today [3]. India has ambitions to supply substantial amounts of this demand with RES and have already made significant progress in integration of RES; the most remarkable developments have been in solar and wind. As of today RES constitute more than 20% percent of the total installed Indian capacity – in fact, the Minister for the Ministry of Power and Ministry of New and Renewable Energy, the honourable R. K. Singh, recently announced that India crossed the milestone of 100 GW renewable energy installed in its power system, excluding large hydro. In the wake of these commendable developments, the Indian government in 2019 announced ambitions to reach 450 GW of installed RES by 2030 [4].

In many cases the RES projects are developed in areas far away from consumption centres and often in areas without existing transmission network. This challenge is exemplified by the worlds' largest solar park Bhadla of 2.2 GW, which is placed approximately 100 km out of Phalodi, a city comprising of around 50,000 inhabitants. In addition to this, governmental targets for 30 GW of offshore wind by 2030 [5] highlights the geographical challenges which the integration of massive amounts of RES proposes to transmission planning.

The nature of transmission planning as long term planned public investments, compared to the volatility and unpredictability from private investors developing RES, poses challenges for the Central Electricity Authority (CEA) when dimensioning and constructing the transmission grid of tomorrows India. Just the difference in installation periods can mean difficulties in the transmission planning – where solar power parks e.g. takes months to install, the transmission line needed for the connection usually have a timeframe of years. Developers' commitment to projects is thus a key for a smooth and effective build out of the Indian transmission grid.

Denmark has a long term experience with high level transmission planning, both inside its borders and in cooperation with neighbouring countries. For instance, the Skagerrak connection between Denmark and Norway went into service already in 1977, by then it was the world longest HVDC underwater cable. The build out of the Danish fleet of RES, including not only the world first offshore wind power parks but also the world first offshore wind farm connecting to a neighbouring country, have all contributed to the accumulation of expert knowledge on transmission planning within Danish Transmission System Operator (TSO) Energinet. Energinet has also benefitted from being part of the European cooperation in the ENTSO-E. These forums have accelerated the cooperation and knowledge sharing with various European TSOs, hence allowing a contextualization and use of national challenges within other national grids.

As part of ENTSO-E, Denmark thus uses a coordinated and comprehensive transmission grid planning approach (e.g. sharing of data, development of scenarios, coordinated market modelling and grid stability modelling, combined cost benefit analysis, stakeholder engagement) to ensure system stability, guarantee power supply and integrate more RES at lowest possible cost. In general, the ENTSO-E approach ensures that pan-European grid planning is optimised for the common good and addresses the different interests at stake. The main processes are based on scenario building, screening and cost-benefit analysis (CBA).

The Danish experience, used to assess and validate decisions regarding new transmission lines, can be replicated in other contexts for assessing similar queries. On these premises, the following report aims to elaborate on the European, Indian, Danish and Nordic approaches to transmission planning, describing concepts, methodologies and considerations while developing new transmission planning projects. The aim is to provide detailed information as to the contrasting methodologies in a benchmarking report, in which the comparison will shed some light on potential learnings which could benefit the Indian and European systems.

Following the introduction in **Chapter 1**, **Chapter 2** unfolds the topic of the current approach to transmission system planning in Europe. **Chapter 3** elaborates on the approach to transmission planning in India, providing an overview of Indian power system, while **Chapter 4** focuses on Denmark and the Nordics. Last, **Chapter 0** provides an overall comparisons of transmission planning approach among India, Europe, the Nordics and Denmark. **Chapter 0** concludes providing recommendations for replicating Danish, Nordic and European experience in the Indian context

2. Transmission system planning in Europe

ENTSO-E is the European Network of Transmission System Operators for Electricity. It was established in 2009 with its basis in the third liberation package which had cross border transport of electricity and the creation of the internal energy (electricity and gas) market in Europe as important targets.

Formally, ENTSO-E was founded according to a European Commission Regulation (EU2019/943), with the objective to ensure optimal management of the electricity transmission network and to allow trading and supplying electricity across borders in Europe.

With the establishment of ENTSO-E, the European TSOs have been given important tasks and thereby substantial influence on the development of the European power market and transmission system. Key figures for ENTSO-E are shown in Figure 1.

One of the tasks of ENTSO-E is to carry out a non-binding community-wide 10 Year Network Development Plan (TYNDP) each second year. Grid development is a vital instrument in achieving European energy objectives, such as the security of electricity supply across Europe, sustainable development of the energy system with RES-integration, and affordable energy for European consumers through market integration. As a community-wide report, the TYNDP contributes to these goals and provides the central reference point for European electricity grid development.

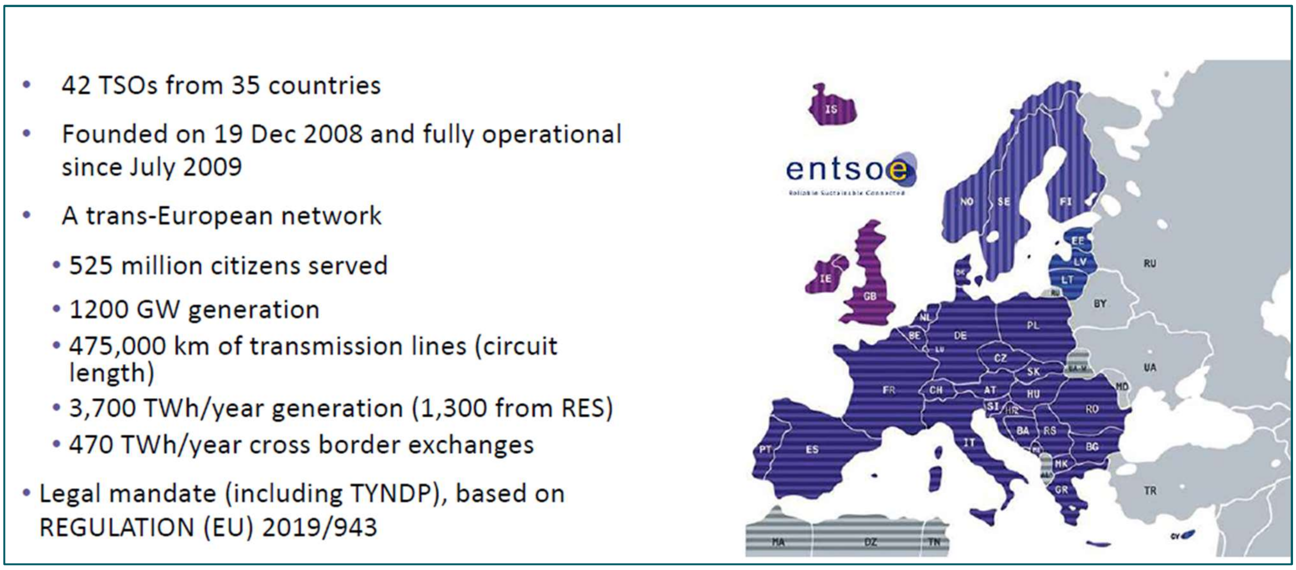


Figure 1: ENTSO-E: key figures. Source: [6]

Besides proposing an EU-wide TYNDP (each second year) ENTSO-E has the mandate to:

- Propose network codes
- Ensure market integration EU-wide
- Support Research and Development
- Analyse the European Generation Adequacy Outlook (5/15 years horizon)
- Provide an integrated network modelling framework at the European level

2.1. ENTSO-E TYNDP – overview

As mentioned, the main product of the TSOs planning is the TYNDP which is carried out under EU regulation EU2019/943. Although the plan is non-binding, the TYNDP is an important pan-European planning tool, which is published every two years. The latest plan, TYNDP 2020, consisted of a package of deliverables, among others (https://tyndp.entsoe.eu/).

Figure 2: Main report highlights and project sheets. Source: [7]

The TYNDP 2020 main report [7], reported in Figure 2, has its focus on transmission development through socio-economic cost benefit analyses of a number of concrete projects. Most projects have been nominated by the TSOs based on the national and regional planning and the work carried out in the "power system needs" process [8].

In addition to the TSOs' proposals for projects, third-party projects (typically commercial investor projects) are also handled in TYNDP. Third party projects must meet the same criteria for inclusion in the TYNDP as TSOs' projects.

Figure 3: Power System Needs. Source: [8]

The pan-European *system needs*- report [8], in Figure 3, describes the future power system needs with focus on new or reinforced transmission capacity in the main European transport corridors. The results are based on pan-European market- and grid- analyses for the years 2030 and 2040.

Figure 4: TYNDP 2020 scenarios for 2030 and 2040. Source: [9]

The Scenario report [9] describing future European scenarios (Figure 4) forms the basis for the TYNDP. The scenario story lines were developed in cooperation with European stakeholders including regulators. Besides, the same scenarios are used for both power and gas (ENTSO-G is the corresponding cooperation for gas-TSOs, who do a parallel TYNDP for European gas transmission). That means that TYNDP- electricity and TYNDP- gas use the same data describing the future energy systems for 2025, 2030 and 2040.

- Regional investment plans addressing system- and transmission- needs on regional level. For planning purposes Europe has been divided into 6 regions.
- A number of insight reports with specific focus on key regional or European subjects important for the future development of the power system (e.g., transition of the power system into a green system and sector integration).

2.2. TYNDP results – overview

The TYNDP 2020 project portfolio contains 154 transmission projects, representing 323 investments overall, in 37 countries with planned commission before 2035. Total investment cost is estimated at 118 billion Euro. [10]. For each project, cost-benefit evaluations were conducted in 3 European scenarios.

54 % of investments are overhead line development, with underground and subsea cables making 26 % of the portfolio. Other investments include substations, reactive compensation devices, phase shifting transformer or converter stations. In total, the TYNDP 2020 portfolio represents over 46,000 km of potential additional cables and lines, of which 19,000 km (41 %) are AC and 27,000 km (59 %) are DC [10]

Some important main results from TYNDP 2020 are shown in Figure 5.

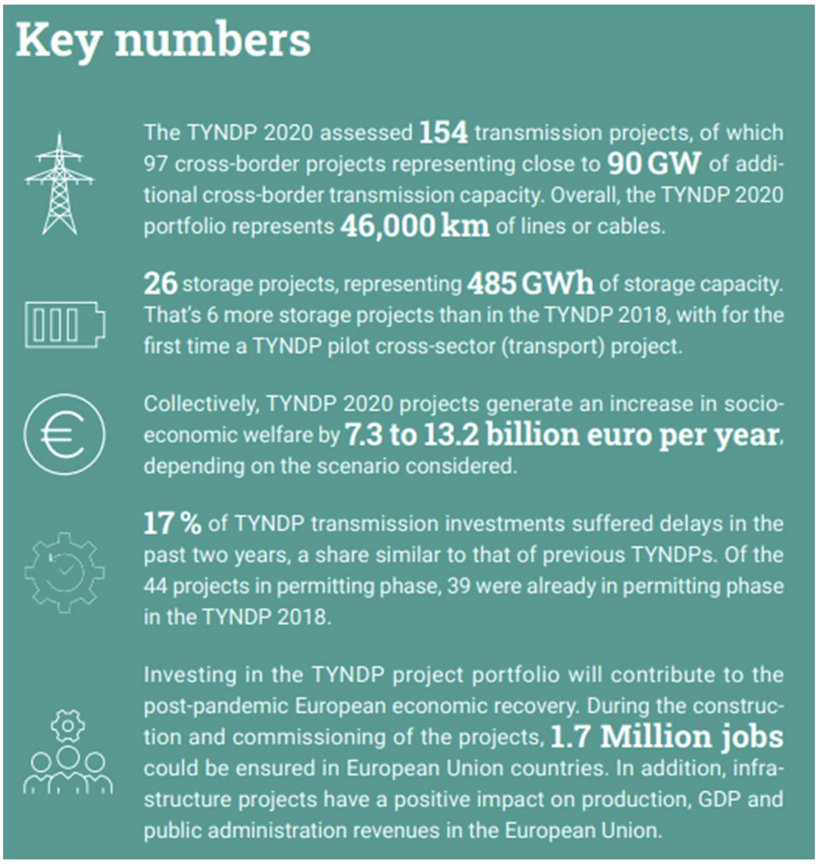


Figure 5: Key numbers in TYNDP 2020 (total investment is 118 billion euro). Source: [7]

2.3. Projects of Common Interest (PCI)

Regulation (EC) 714/2009 and Regulation (EU) 347/2013 specify that the TYNDP should help identify those infrastructure projects that are key to the EU achieving its climate and energy objectives. Such projects, known as European projects of common interest (PCI), are selected among the TYNDP overall list of transmission and storage projects. TYNDP 2020 contains 58 PCI projects (4th PCI list).

Every two years, the European Commission utilises the information in the latest TYNDP as part of its selection and adoption of a new biannual list of PCIs. PCI projects (see Figure 6) must comply with certain rules with regard to transparency and involvement of stakeholders. However, the PCI projects in return can achieve a more swiftly permitting as well as obtain financial support from EU's Connecting Europe Facility (CEF) funding, which is an important way in which the European Regulation can support the concrete delivery of infrastructure required for decarbonising the energy system.

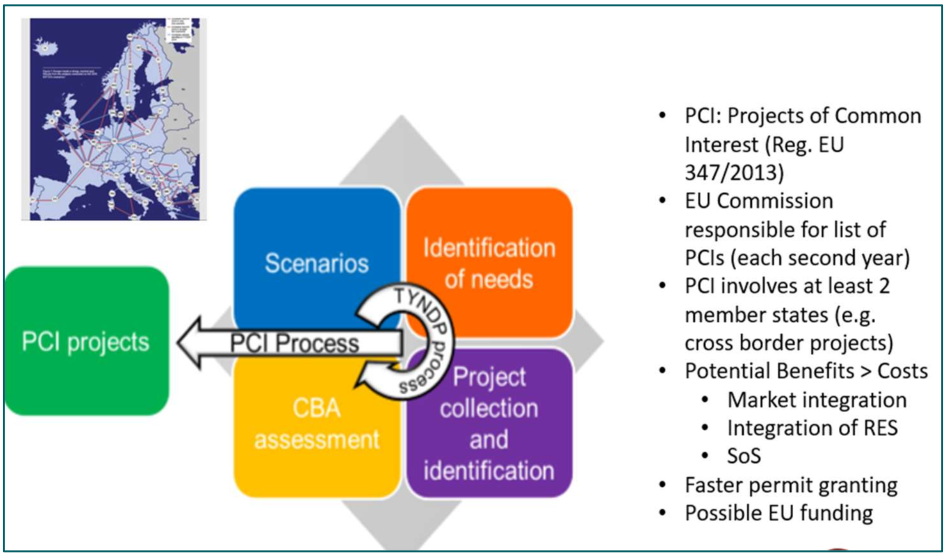


Figure 6: Process for PCI projects. Source: [11]

In case a PCI project encounters significant implementation difficulties, in agreement with the Member States concerned, the European Commission may designate a European coordinator to assist in stakeholder involvement, support permitting processes, amongst other benefits that would facilitate the implementation.

2.4. ENTSO-E planning process

General

ENTSO-E uses a coordinated and comprehensive transmission grid planning approach, which includes sharing of data, development of scenarios, coordinated market modelling and grid stability modelling, combined cost benefit analysis, stakeholder engagement, etc. The aim is to ensure system stability, guarantee power supply and integrate more RES at lowest possible cost.

In general, the ENTSO-E approach ensures that pan-European grid planning is optimised for the common good and addresses the different interests at stake. A key aspect of the ENTSO-E methodology is the recognition from the transmission grid planning perspective that the market will determine the use of the grid. The main processes (steps) in the ENTSO-E approach are:

1. Scenario development,
2. Screening
3. CBA

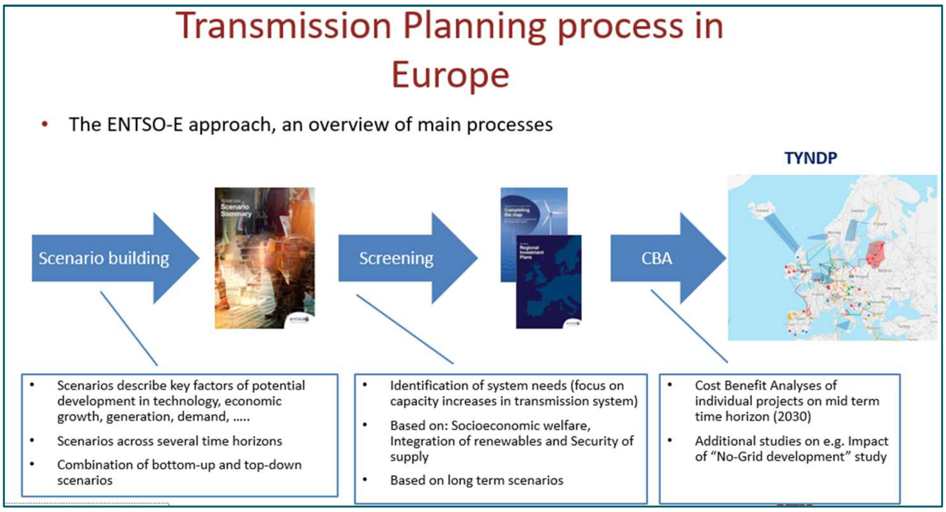


Figure 7: ENTSO-E TYNDP planning process. Source: [12]

Step 1- develop scenarios for the future

- **Scenarios**:
  To identify what Europe needs in terms of electricity transmission infrastructure, one needs to first analyse how the energy landscape will evolve. Some political objectives are set until 2030/2040 but many uncertainties exist about generation investments, demand evolution, and market developments to name a few. The TYNDP scenario development is about framing uncertainties, it is not about predicting the future. All interested stakeholders are invited to participate to the scenario building.
  As an example, Figure 8 shows the scenarios in the 2020 TYNDP.

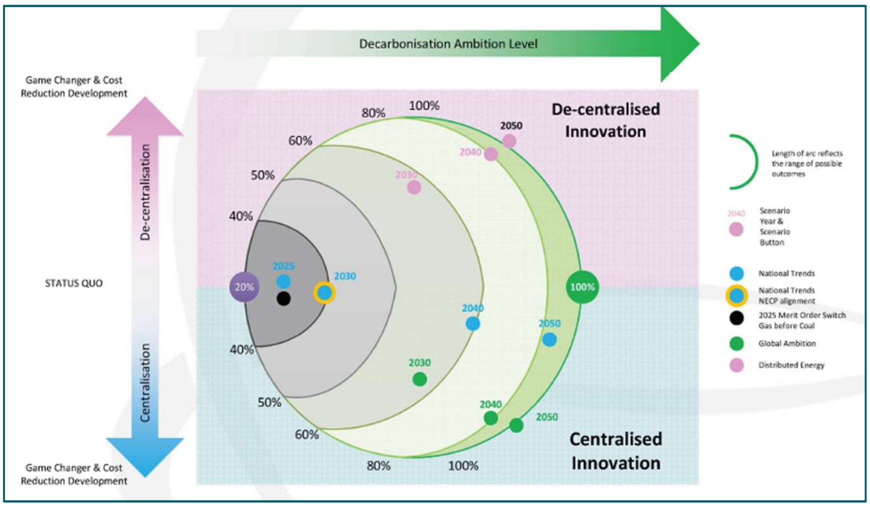


Figure 8: 2020 TYNDP scenarios. Source: [9].

- **Storyline drivers**:
  ENTSO-G and ENTSO-E identified two main drivers to develop their scenario storylines: Decarbonisation and centralisation/decentralisation. Decarbonisation refers to the decline in total GHG emissions while centralisation/decentralisation refers to the spatial set-up of the energy system, such as the share of large/small scale electricity generation (offshore wind vs. solar PV) or the share of indigenous renewable gases (biomethane and Power2Gas (P2G)) vs. share of decarbonised gas imports (either pre- or post-combustive).

  Figure 8 illustrates the relation of the two key drivers for all three scenarios. For the short- and medium-term, the scenarios include a *Best Estimate*-scenario (bottom-up data including a merit order sensitivity between coal and gas in 2025). For the longer term, they include three different storylines to reflect increasing uncertainties.

  For 2020 and 2025, all scenarios are based on bottom-up data from the TSOs called the *Best Estimate*-Scenario and reflects current national and European regulations. A sensitivity analysis regarding the merit order of coal and gas in the power sector is included for 2025 following stakeholder input regarding the uncertainty on prices, even in the short term. These are described as 2025 Coal Before Gas (CBG) and 2025 Gas Before Coal (GBC).

  National Trends keeps its bottom-up characteristics, taking into account TSOs' best knowledge of the gas and electricity sectors in compliance with the NECPs (National Energy and Climate Plans). Country-specific data was collected for 2030 and 2040 (when available for electricity) in compliance with the TYNDP timeframe. For gas, further assumptions have been made to compute the demand for 2050 on an EU28-level.

Distributed Energy and Global Ambition are built as full energy scenarios (all sectors, all fuels) with top-down methodologies. Both scenarios aim at reaching the 1.5°C target of the Paris Agreement following the carbon budget approach. They are developed on a country-level until 2040 and on an EU28-level until 2050.

- **Building scenarios – Generation capacities**:
  A key component of developing scenarios is converting storylines into placement of installed capacities for generation. The generation capacities are calculated by a power market investment model.

  The approach differs between bottom-up and top-down scenarios. The bottom-up process is based on data collected by TSOs, whereas the top-down scenarios use bottom-up data along with power system market tools to optimize the total cost of the system based on CAPEX and OPEX for generation technologies.

  A fundamental feature of TYNDP power market scenarios is the aim to closely reflect country specific details. TYNDP2020 has introduced an interim step in the distribution of generation by collecting generation and demand trajectory files for each country. This process was implemented in order to set country specific boundary conditions for the models.

  The trajectory files provide low, medium, and high trajectories for power sector supply technologies (nuclear, fossil, renewables) and demand technologies for the future.

  Once the electricity demand time series has been determined, and the nuclear, coal and lignite production capacity has been calibrated, the investment model determines the optimal development of the renewable energy capacity and interconnection capacity under given economic conditions such as fuel prices, CAPEX and OPEX prices of the new resources.
  Grid expansion is a necessary component in transitioning towards full decarbonisation. By neglecting this option, there would be high risk for inefficient RES generation placement and therefore this would lead to irrational scenarios due to market effects, such as price collapse and an exaggerated increase of the overall system costs. The grid expansion within the scenario building phase uses a simple linear expansion approach. This provides a signal that cross border congestion is an issue, but since the problem is linearised it does not consider the blocky nature of interconnection projects. The grid expansion problem is simplified, but the intention is to ensure rational generation placement and not network needs identification. The costs of interconnection are standard costs based on experience.

  It should be clearly stated that the expansion of interconnection capacity within the scenario building phase, does not signify a particular transmission need or indeed the identification of a project for a future time horizon. The *system need* process is where European needs are identified, investigated and presented. Thus, at the start of the system need process the transmission expansions found during the scenario building process are removed, thereby defining the reference grid as basis for screening for new transmission.

- **Storylines**:
  The storylines for 2030 and 2040/2050 are:

National Trends (NT) is the central bottom-up scenario in line with the NECPs in accordance with the governance of the energy union and climate action rules, as well as on further national policies and climate targets already stated by the EU member states. Following its fundamental principles, NT is compliant with the EU's 2030 Climate and Energy Framework (32 % renewables, 32.5 % energy efficiency) and EC 2050 Long-Term Strategy with an agreed climate target of 80–95 % CO_2 reduction compared to 1990 levels. National Trends relies on data provided by the latest submissions of country specific NECPs for 2030 at the freeze date of the data. Where, in particular for 2040, NECPs do not provide sufficient information or necessary granularity, National Trends is based on TSOs' best knowledge in compliance with national long-term climate and energy strategies.

Global Ambition (GA) is a scenario compliant with the 1.5°C target of the Paris Agreement also considering the EU's climate targets for 2030. It looks at a future that is led by development in centralised generation. Economies of scale lead to significant cost reductions in emerging technologies such as offshore wind, but also imports of energy from competitive sources are considered as a viable option.

Distributed Energy (DE) is a scenario compliant with the 1.5°C target of the Paris Agreement also considering the EU's climate targets for 2030. It embraces a de-centralised approach to the energy transition. A key feature of the scenario is the role of the energy consumer (prosumer), who actively participates in the energy market and helps to drive the system's decarbonisation by investing in small-scale solutions and circular approaches. Based on stakeholders' feedback on the Draft Scenario Report, a part of biomass usages has been transferred to both power to liquid (P2L) and direct electricity consumption. The updated scenario comes very close to the 1.5 TECH/LIFE scenario of the European Commission for most of the parameters.

Step 2 – Screening of needs for infrastructure expansion

- **Screening**:
  The TYNDP has normally three to four scenarios for the development of the power system. Some have high targets in terms of renewables, some envisage a more decentralized power system, and some envisage a strong European framework. Based on these scenarios, experts of 42 TSOs in 35 European countries carry out common planning studies.

Using common methodologies and tools, the experts look at how power will flow in Europe in 2030/2040 taking into account the different scenarios. This allows them to see where bottlenecks will be, and how much transmission capacity is needed at borders to manage these flows.
The results of the screening studies are a series of infrastructure projects. These are only one part of the whole set of TYNDP projects. The other part is constituted of projects that are coming from third party investors (non-ENTSO-E members) and that meet the criteria for inclusion in the TYNDP set by the European Commission.

As for the scenarios, the list of projects is open to public consultation before being finalised.

Figure 9 (from TYNDP 2018) illustrates part of the screening process. The process is based on market modelling for Europe as whole system. The market model emulates the European spot market in the future scenarios. In an iterative process, the capacities at the borders between market areas are successively increased, and borders with highest socio-economic benefits compared to investment costs of expansion the capacities at borders are selected for further assessment.

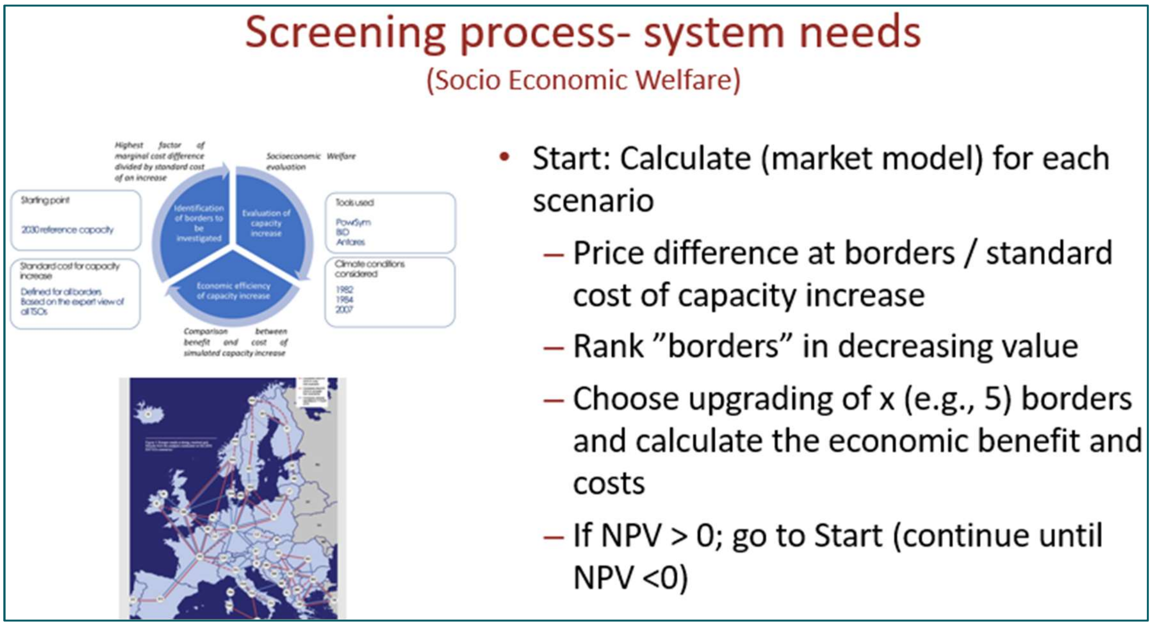


Figure 9: Screening process (socio economic welfare is indicator). Source: [11]

Last, Figure 10 shows the European transmission barriers and the TYNDP 2020 transmission projects. The projects are based on the ENTSO-E screening studies, or they may have been put forward by third party investors.

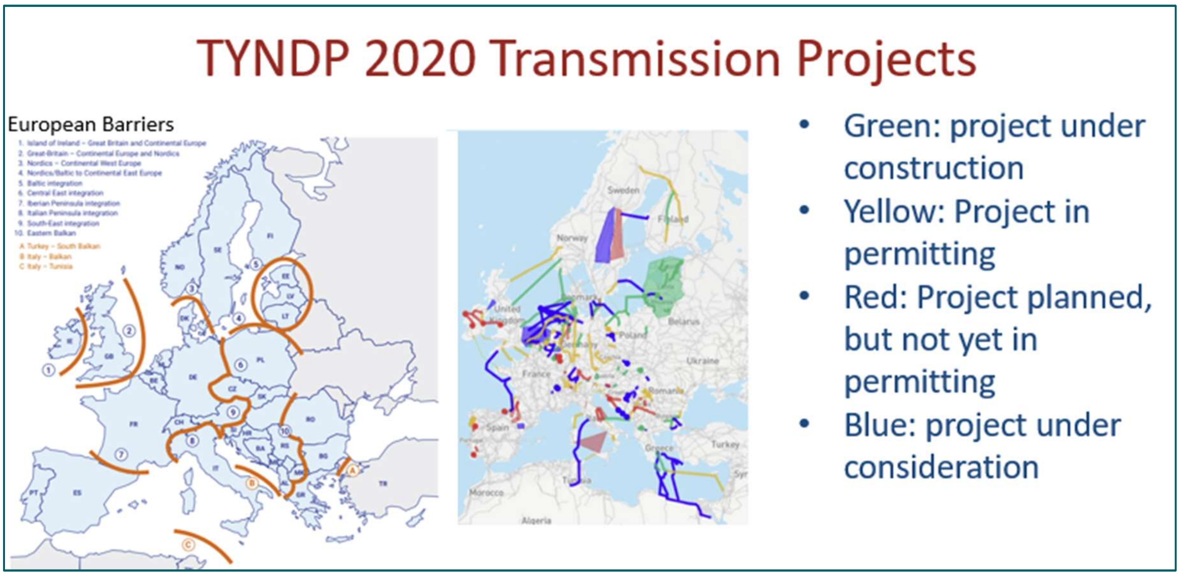


Figure 10: TYNDP 2020 transmission projects and European transmission barriers. Source [11]:

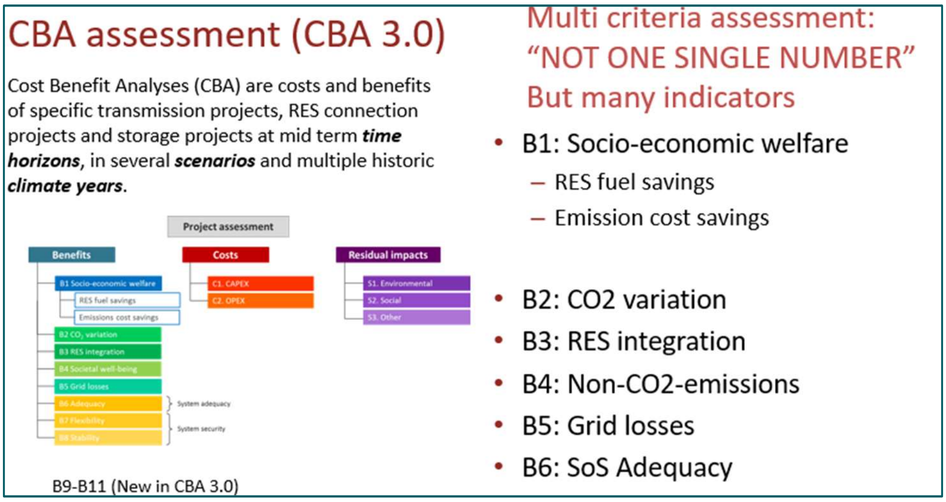
Step 3 – Project assessment

- **Cost Benefit Analysis**:
  The last phase of the planning process in the TYNDP is the assessment of projects. This is done using a European approved methodology to assess the costs and benefits of projects [13]. This assessment is not just a purely economic assessment. It takes into account also how projects support the environment, the welfare in Europe, the security of supply among others. The results of such costs and benefits assessment of projects form the core of the TYNDP report.
  By reading the TYNDP report, everyone shoud be able to see the value of each infrastructure project. The TYNDP thus provides decision-makers with a robust and detailed analysis of transmission infrastructure projects, on which to base their decisions. One illustration of this is the fact that TYNDP projects and their assessment are used in a European Commission-led process for updating the PCI list of projects.

2.5. ENTSO-E system wide cost benefit analysis-method

General

All new transmission project candidates in the TYNDP planning process are assessed according to the same system wide cost-benefit analysis [13]. The methodology is based on a multi-criteria assessment including the categories outlined in Figure 11.



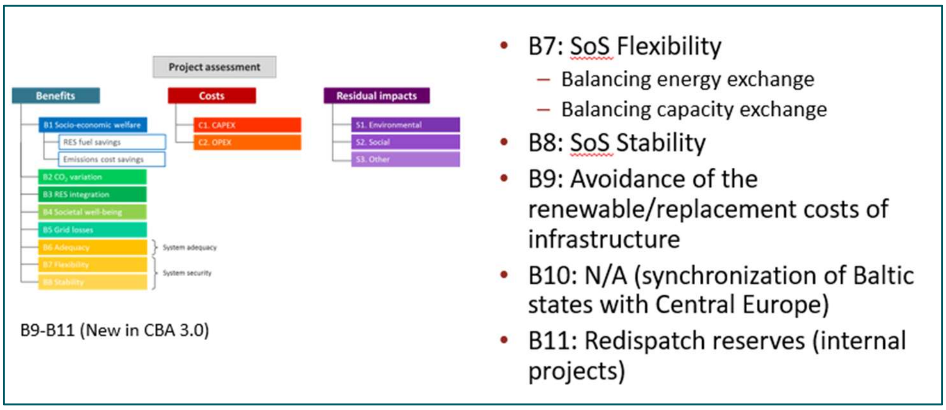


Figure 11: TYNDP Categories of cost benefit assessment. Source: [14]

The elements of the CBA are:

- Grid Transfer Capacity (GTC) in MW. It is estimated by grid analysis.
- Security of supply is Expected Energy Not Served (EENS) or Loss of Load Expectancy (LOLE)
- Socio economic welfare (SEW) is defined as the sum of producer surplus, consumer surplus and congestion rents. SEW includes implicitly monetized values for CO_2 and RES integration (e.g. improved value of RES generation by reducing curtailment of wind).
- Transmission losses (change in losses for the whole system)
- Costs are project costs and changes in other costs incurred by the project (except for losses)
- Technical resilience/system safety is the ability of the system to withstand increasingly extreme system conditions (exceptional contingencies). Semi-quantitative estimation based on KPI (key performance indices) scores.
- Flexibility/robustness is the ability of the proposed reinforcement to be adequate in different possible future development paths or scenarios.
- Semi-quantitative estimation based on key performance indices (KPI) scores.

Normally, for a transmission project to be proposed, the total system benefits must be bigger than the costs, e.g., by a certain percentage amount.

The assessment framework is shown in Figure 12 with market and network indicators resulting from market and network modelling, respectively.

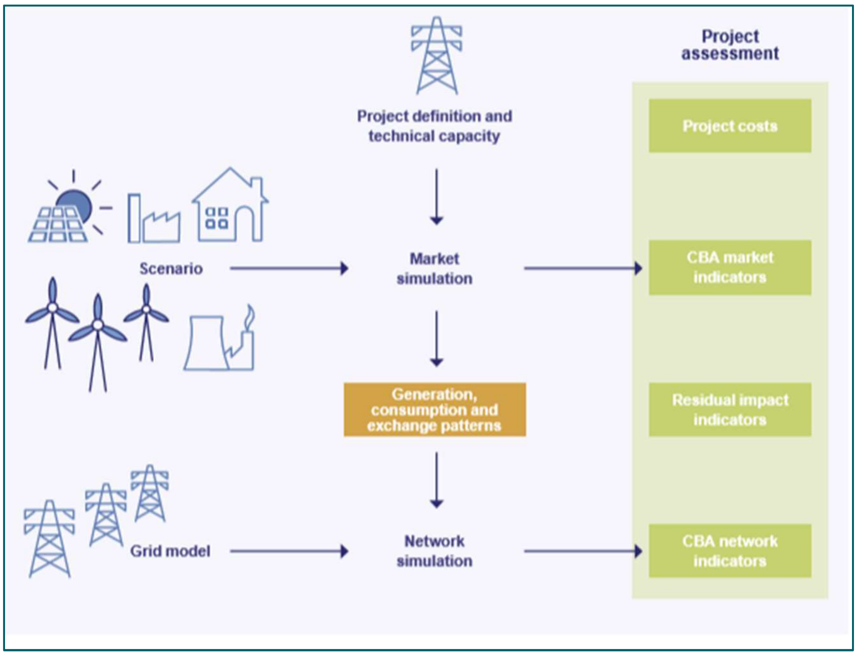


Figure 12: "CBA market" and "CBA network indicators" are a direct outcome of market and network studies, respectively; "project costs" and "residual impacts" are obtained without the use of modelling. Source: [13]

Reference grid

Project benefits are calculated as the difference between a simulation including the project and a simulation which does not include the project. The two proposed methods for project assessment are as follows (see Figure 13):

- *Take Out One at the Time* (TOOT) method, where the reference case reflects a future target grid situation in which all additional network capacity is presumed to be realised (compared to the starting situation) and projects under assessment are removed from the forecasted network structure (one at a time) to evaluate the changes to the load flow and other indicators.
- *Put IN one at the Time* (PINT) method, where the reference case reflects an initial state of the grid without the projects under assessment, and projects under assessment are added to this reference case (one at a time) to evaluate the changes to the load flow and other indicators.

As the selection of the reference case has a significant impact on the outcome of an individual project assessment, a clear explanation of it must be given. This should include an explanation of the initial state of the grid, in which none of the projects under assessment in the relevant study is included. The reference network is then built up of including the most mature projects that are: a) in the construction phase or b) in the 'permitting' or 'planned but not yet permitting' phase where their timely realization is most likely e.g. when the country specific legal requirements have stated the need of the projects to being realized.

Projects in the 'under consideration' phase are seen as non-mature and have therefore generally to be excluded from the reference grid leading to an assessment using the PINT method.

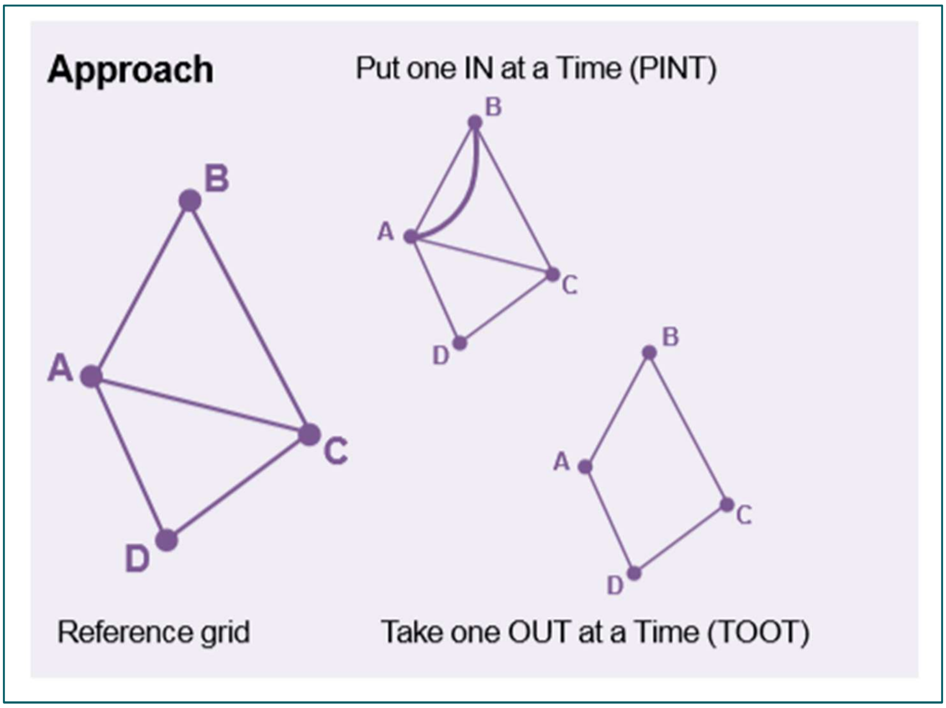


Figure 13: Reference grid and definitions of TOOT and PINT. Source: [13].

Figure 14 illustrates the assessment of a capacity investment at a boundary with decreasing marginal expansion benefit. It follows that TOOT and PINT will result in different results.

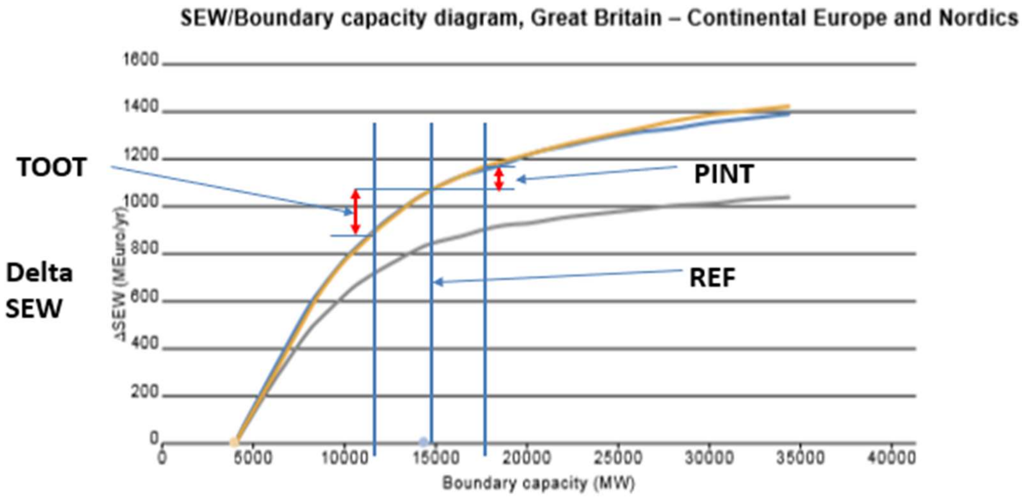


Figure 14: Illustration of economic assessment of capacity expansion according to TOOT and PINT. Source: [11]

Specific description of CBA parameters, overview

Benefit categories are defined as follows [13]:

- **B1**
  SEW from wholesale energy market integration is characterised providing increase in power exchanges including the ability to reduce (economic or physical) congestion. It thus provides an increase in transmission capacity that makes it possible to increase commercial exchanges, so that electricity markets can trade power in a more economically efficient manner.
- **B2**
  Additional societal benefit due to CO_2 variation represents the change in CO_2 emissions in the power system due to the project. It is a consequence of changes in generation dispatch and unlocking renewable potential. The EU has defined their climate policy goals by reducing the greenhouse gas emissions by at least 40% until 2030 compared to the 1990 levels. As CO_2 emission is the main greenhouse gas coming from the electricity sector, they are displayed as a separate indicator. This indicator takes into account the additionally societal costs of CO_2 emissions.
- **B3**
  The contribution to *RES integration* is defined as the ability of the system to allow the connection of new RES generation, unlock existing and future “renewable” generation, and minimising curtailment of electricity produced from RES. RES integration is one of the EU 2030 goals which set the target of increasing the share of RES to 32% with respect to the overall energy consumption.

- **B4**

  Non-direct greenhouse emissions represent the change in non-CO_2 emissions (e.g., CO_x, NO_x, SOx, PM 2, 5, 10) in the power system due to the project. It is a consequence of changes in generation dispatch and unlocking renewable potential.
- **B5**

  Grid losses in the transmission grid is the cost of compensating for thermal losses in the power system due to the project. It is an indicator of energy efficiency and expressed as a cost in euros per year.
- **B6**

  Security of supply, characterises the project's impact on the ability of a power system to provide an adequate supply of electricity to meet demand over an extended period of time. Variability of climatic effects on demand and RES production is taken into account.
- **B7**

  Security of supply, where flexibility characterises the impact of the project on the ability of exchanging balancing energy in the context of high penetration levels of non-dispatchable electricity generation. Balancing energy refers to products such as Replacement Reserve (RR), manual Frequency Regulation Reserve (mFRR) and automatic Frequency Regulation Reserve (aFRR). The reduction of congestions is an indicator of social and economic welfare assuming equitable distribution of benefits under the goal of the European Union to develop an integrated market (perfect market assumption).
- **B8**

  Security of supply, where stability characterises the project's impact on the ability of a power system to provide a secure supply of electricity as per the technical criteria.
- **B9**

  Avoidance of the Renewal / Replacement Costs of Infrastructure characterises the benefit a project can bring by avoiding or deferring replacing or upgrading already existing infrastructure.
- **B10**

  Synchronization with Continental Europe (CE) (for Baltic States) is understood as safeguarding operational security, preventing the propagation or deterioration of an incident to avoid a widespread disturbance and the blackout state as well to allow for the efficient and rapid restoration of the electricity system from emergency or blackout states.
- **B11**

  Redispatch Reserves or Reduction of Necessary Reserves for Redispatch Power Plants characterises the project's impact on needed contracted redispatch reserve power plants by assessing the maximum power of redispatch with and without the project.

Costs are defined as follows:

- **C1**
  CAPEX as an indicator reports the capital expenditure of a project, which includes elements such as the cost of obtaining permits, conducting feasibility studies, obtaining rights-of-way, ground, preparatory work, designing, dismantling, equipment purchases and installation. CAPEX is expressed in euros.
- **C2**
  OPEX expenses are based on project operating and maintenance costs. OPEX of all projects must be given on the actual basis of the cost level with regard to the respective study year (e.g., for TYNDP 20 the costs should be given related to 2020) and expressed in euro per year.

Residual impact is defined as follows:

- **S1**
  Residual Environmental impact characterises the (residual) project impact as assessed through preliminary studies and aims at giving a measure of the environmental sensitivity associated with the project.
- **S2**
  Residual Social impact characterises the (residual) project impact on the (local) population affected by the project as assessed through preliminary studies and aims at giving a measure of the social sensitivity associated with the project.
- **S3**
  Other impacts provide an indicator to capture all other impacts of a project.

In the following:

- Box 1 illustrates principles of calculating the key parameter SEW
- Box 2 is an example from TYNDP 2018, showing results for changes in SEW, RES integration and CO_2 due to a 1400 MW interconnector between Norway and Great Britain.

BOX1 - Socio Economic Welfare

Principles of calculation of B1 – socio economic welfare

A central parameter in most European projects is B1: Socio economic welfare. In European TYNDP this parameter is often the most important for providing evidence for a proposed infrastructure expansion. The calculation of B1 is conducted via market modelling of the European system in two cases: with and without the project in question. In the model the European day-ahead market is emulated in each hour over the year in each scenario.

The principle is illustrated in Figure 15 showing the gain in B1 when connecting two bidding areas (zonal price design) by a transmission line with capacity "C". The optimal scheduling is to transport the amount "C" from the low-price area to the high price area. Thereby the price will increase in the low-price area and decrease in the high price area as shown in the figure. The prices in the two zones will in this case end up being different due to congestion constraint on the interconnector.

The figure shows the change in consumer and producer surplus in the two price areas. The net increase in surpluses is indicated by the dark purple triangles. The light purple area is the congestion rent.

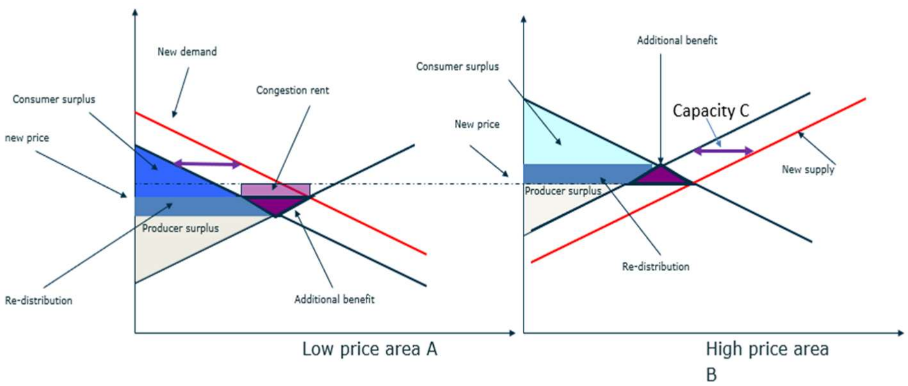


Figure 15: Optimal flow between to market zones (source: [11])

The situation is further illustrated in Figure 16. Here is shown the prices in area A and area B when the capacity between areas increases, together with congestion rent and gains in B1 in the two areas (left part of figure).

Also is shown the variation in congestion rent (lower red curve in right part of figure) and total trading benefit (=SEW) (the upper yellow curve in right part of figure).

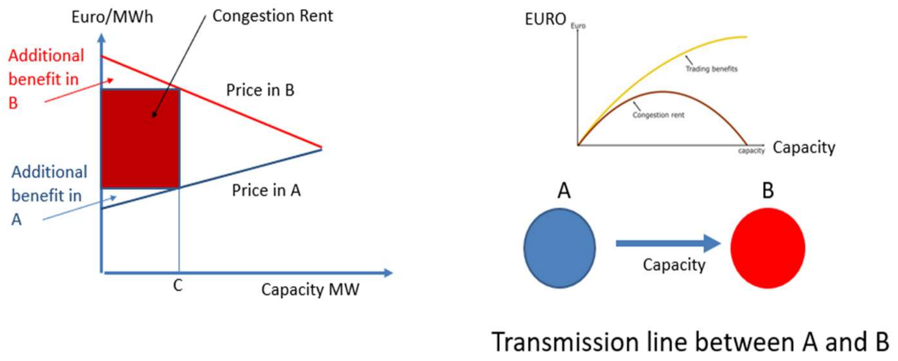


Figure 16: Congestion rent and SEW as a function of transmission capacity Source: [11]

In the market model, the total gains in SEW are calculated for all price areas including total net increase in all congestion rents for the whole European system, when adding a given project. This is done for each hour over the year in all scenarios.

In addition to the changes in SEW, also the changes in CO_2-emissions and the changes in curtailment of renewables (wind and solar), see above B3 (RES integration), come out of the market modelling.

Figure 17 illustrates the principle of optimal expansion of transmission between the two areas A and B from Figure 16. The optimum is where marginal cost of expansion equals marginal socio-economic benefit. If however a commercial company is investor the optimum capacity would be less as the marginal company benefit is equal to the marginal congestion rent.

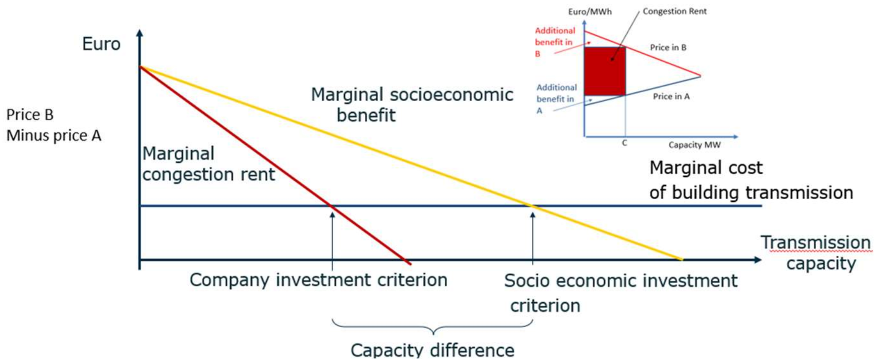
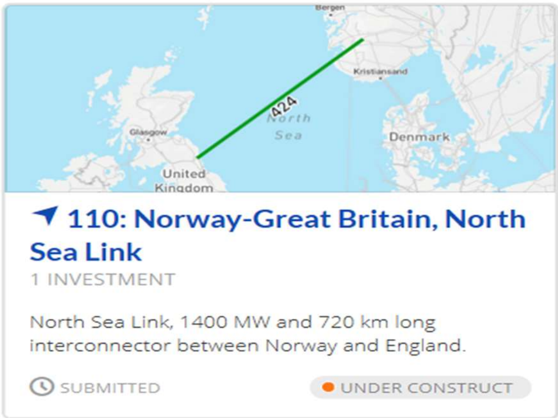
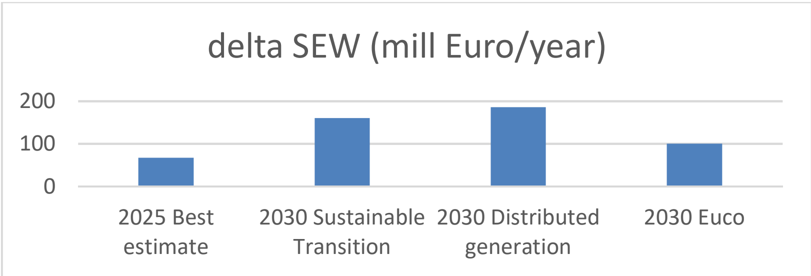


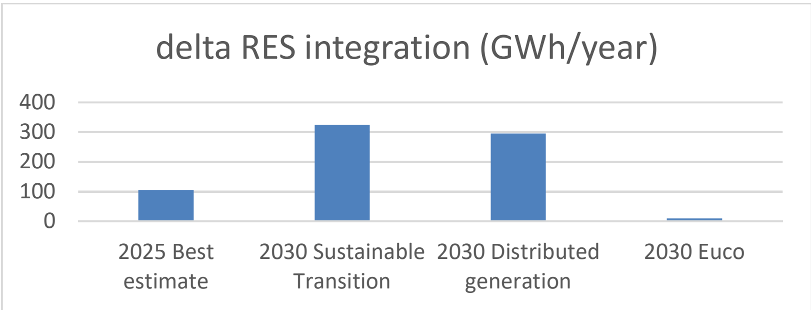
Figure 17: Optimal expansion of transmission Source: [11]

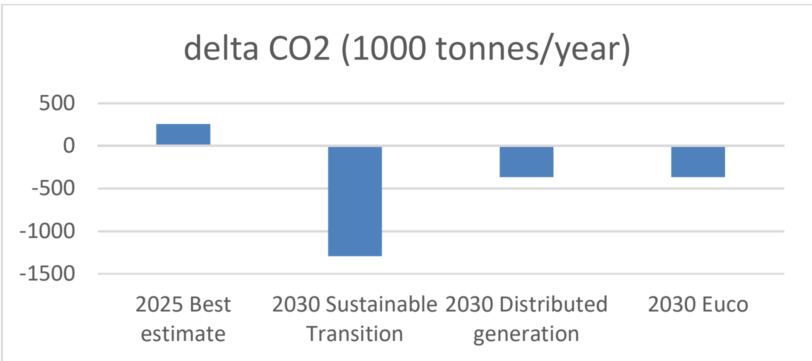
BOX 2 – Example of TYNDP CBA result

TYNDP 2018 results for Norway – Great Britain interconnector









3. India- Transmission planning

3.1. Overview of Indian power system

3.1.1 Introduction

Spanning across India, with HV (400kV), EHV (765kV) and UHV (1200kV) transmission lines, the Indian transmission grid is one of the largest operational synchronous grids in the world, with over: 452,400 circuit kilometre (ckm) [15], transmission substations (220kV and above) of 1080 GVA capacity, inter-regional power transfer capacity at 112,250 MW (which is expected to be enhanced to about 118,740 MW by 2022) and an installed generation capacity of approximately 393 GW pan-India (Dec, 2021). The Indian power grid is hence a gigantic and complex piece of machinery.

With projected electricity demand almost doubling every ten years, ambitious climate goals and an aim for energy independence along with delivering on the Paris agreement, the Indian power sector faces a two-sided challenge. On one hand, security of supply is to be maintained on par with highest standards, and on the other hand the system is tackling the shift from mainly conventional based generation sources to intermittent RES of concern.

In the past decade, the RES based penetration in the Indian power system has increased many folds, i.e. from 15,521 MW in 2010 to 151,400 MW (38% approx. of installed capacity) up to Dec. 2021 and at the same time, transmission network has matchingly been strengthened, thanks to a well-coordinated planning across States and Centre owned institutions. Such transmission planning / system studies were started in year 2012 with assessment of potential Renewable Energy Zones (REZs) and transmission requirements along with generation additions vs. demand forecasting up to year 2022. A similar long term approach is now being taken-up for development of Indian power sector by year 2030. Recently, the Govt. of India has committed to have 500 GW of installed capacity based on non-fossil fuel, which includes large integration of wind- and solar based generation projects with or without Energy Storage Systems.

3.1.2 Structure of power sector

Electricity is a concurrent subject under the seventh Schedule of the Constitution of India. The Ministry of Power at Centre level is primarily responsible for the development of electrical energy in the country. The State Governments are responsible for development of electrical energy in the respective States. The Ministry of Power, have established a number of institutions for development of efficient, seamless, coordinated, well-planned, technical and economical Indian power sector, see Figure 18.

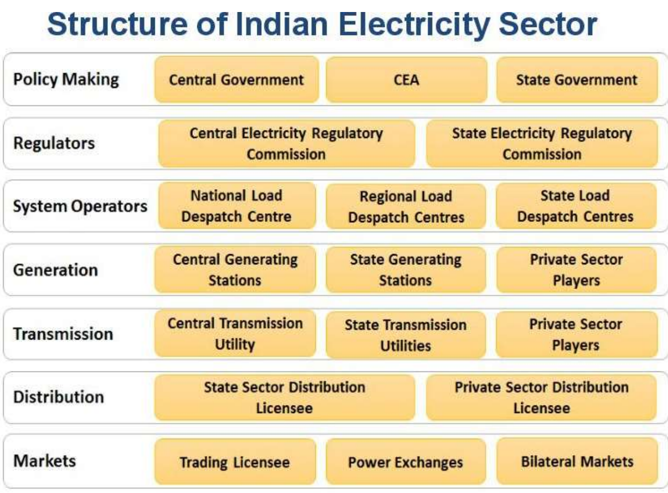


Figure 18: Structure of Indian Electricity Sector Source: [16]

Of special importance for Transmission System planning are e.g., Central Electricity Authority (CEA), Central Transmission Utility (CTU), State Transmission Utilities (STUs) and Central Electricity Regulatory Commission (CERC).

Central Electricity Authority (CEA)

CEA is the apex body in the power sector and assumes the following main roles in the Indian Electricity sector:

- Advising the Central Government on National Electricity policy in short and long term perspectives.
- Specify technical and, safety grid standards for construction and operation of various electrical infrastructure – Generation, Transmission, Distribution
- Specifying metering conditions for Electricity Supply
- Collecting, recording and carrying out investigations and publishing such data/reports concerning Generation, Transmission, Distribution, competitiveness, cost etc.
- Promote and assist timely completion of projects through actively promoting R&D in the field of Power Sector
- Advise State Governments, private entities, regarding technical matters in order to maintain the electricity system under their control in an improved manner in coordination with other Governments, entities

Central Transmission Utility (CTU)

The Central Transmission Utility of India Ltd (CTUIL), 100% subsidiary of Power Grid Corporation of India Limited, is notified as the Central Transmission Utility under Section 38 of the Electricity Act 2003. Its functions as per Electricity Act, 2003 under Section 38 are as below:

- to undertake transmission of electricity through inter-State transmission system;
- to discharge all functions of planning and co-ordination relating to inter-state transmission system with - (i) State Transmission Utilities; (ii) Central Government; (iii) State Governments; (iv) generating companies; (v) Regional Power Committees; (vi) Authority; (vii) licensees; (viii) any other person notified by the Central Government in this behalf;
- to ensure development of an efficient, co-ordinated and economical system of inter-State transmission lines for smooth flow of electricity from generating stations to the load centres;
- to provide non-discriminatory open access to its transmission system for use by - (i) any licensee or generating company on payment of the transmission charges; or (ii) any consumer as and when such open access is provided by the State Commission under sub-section (2) of section 42, on payment of the transmission charges and a surcharge thereon, as may be specified by the Central Commission:

Power Grid Corporation of India Limited (PGCIL), a 'Maharatna' Public Sector Enterprise of Govt. of India was incorporated in Oct 1989. It is engaged in bulk transmission of power through its EHVAC (up to 1200 kV level) and +800/+500kV HVDC transmission network. As of today (31st Dec 2021), PGCIL, owns and operates 172,190 ckm (circuit km) of HVAC, EHVAC, HVDC and UHVDC transmission lines, 264 Substations and a total transformation capacity of 469,600 MVA. The transmission system availability of its system is consistently maintained above 99% which is at par with international utilities, by deploying best operation and maintenance practices.

Central Electricity Regulatory Commission (CERC)

As entrusted by the Electricity Act 2003, the Commission discharges the following main roles:

- To Regulate the tariffs of generating companies owned or controlled by Central Government or those who sell power in more than one state
- To regulate and determine tariffs of Inter-State Transmission of Electricity
- To issue licenses to persons (transmission licensee) and electricity trader for inter-state operations. At the same time to ensure quality, continuity and reliability of services from such licenses.
- To adjudicate all disputes between generating companies and transmission licensee
- To specify Grid Code having regard to Grid Standards
- To fix the inter-state trading margin of electricity, if considered necessary
- Promote competition, efficiency and economy in electricity industry
- Promotion of investment in electricity industry

3.1.3 Generation

Present and expected future generation capacity of India are shown in Figure 19 to Figure 22. Generation can be divided according to ownership as follows:

Central sector generation (e.g. NTPC, NHPC, NPCIL, NLC, SJVNL etc.)

The despatching of central sector generating units lies mainly with the RLDCs. NTPC is the largest owner of generation capacity in India. The total number of power plants owned by NTPC stand at 33 coal based, 11 gas based. Its total thermal based (coal and gas) installed capacity is approximately 74.5 GW (which is approximately 32% of 235 GW of installed thermal capacity in India). Moreover, NTPC has also installed 1 Hydro, 1 wind, 12 solar, and 12 other renewable energy based plants, totalling to approximately 5.5 MW.

State Generation (GENCOs)

Each of the Indian states has also established state level Generation companies. Out of the 393 GW of installed capacity, the state generation companies account for almost 26% of capacity i.e., 104 GW of which 72% is fossil-based thermal and 26% is hydropower.

Private generation Companies

There are multiple private power generation companies in India. Approximately 48% or 190 GW out of 393 GW is under private sector.

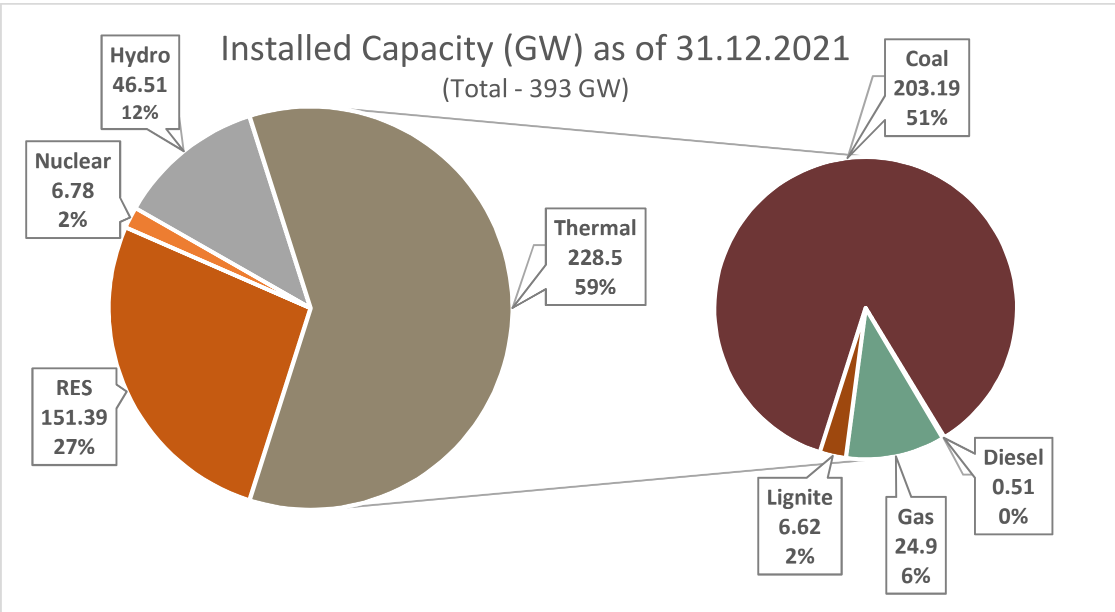


Figure 19: Installed Capacity in India per 31.12.2021. Source: [17]

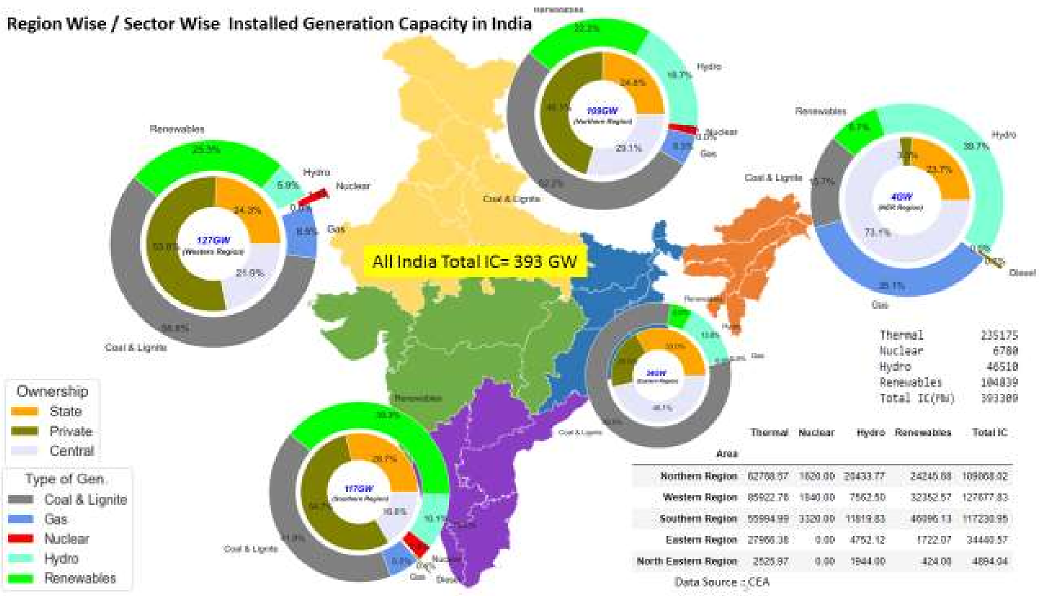


Figure 20: Regional Installed Generation Capacity 2021 - Resource wise and Sector wise [18]

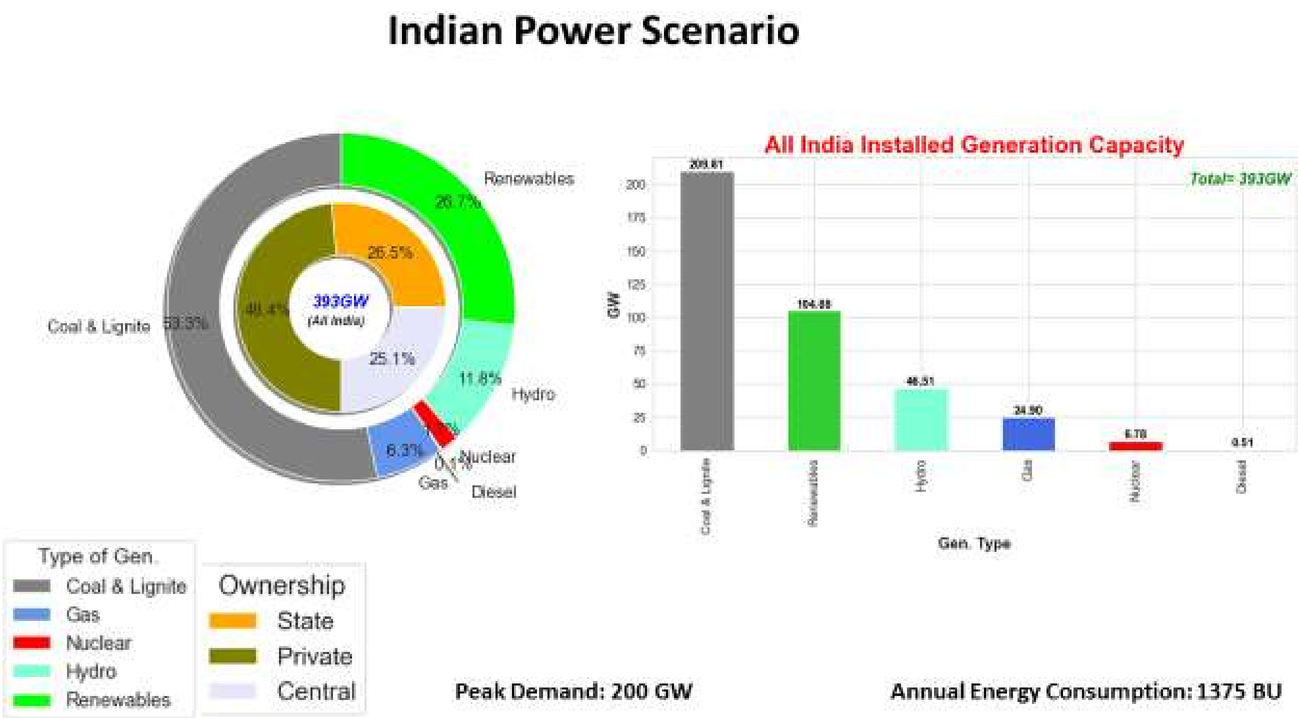


Figure 21: Indian Installed capacity as of December. 2021 [18]

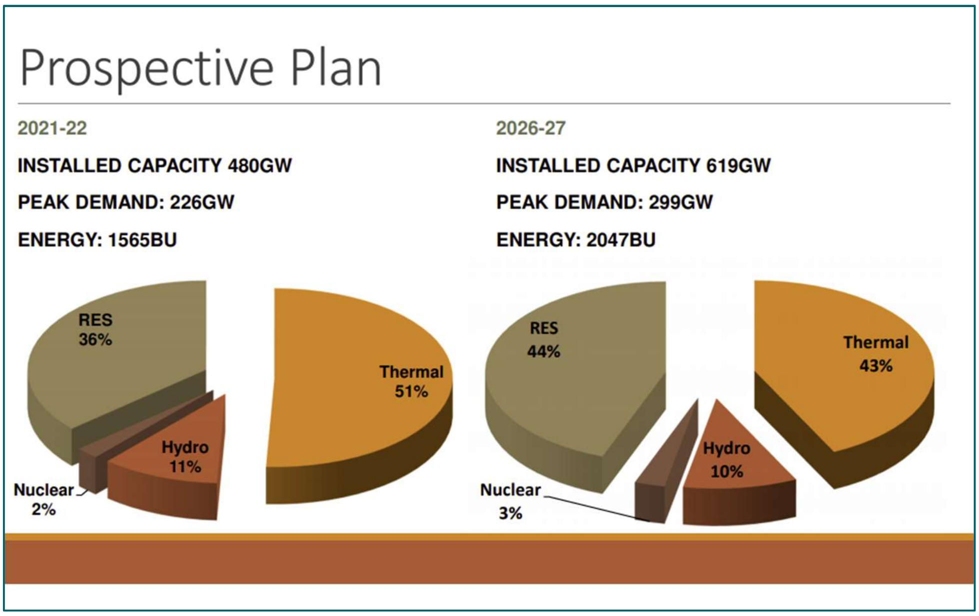


Figure 22: Indian Prospective plan for installed capacity: 2021-22 and 2026-27 [18]

3.1.4 Transmission system

The following figures (Figure 23 - Figure 27) describes the development of the Indian power transmission system including development of inter-regional national capacity, synchronisation of 5 independent regional grids, transmission system as of end of 2020, growth of transmission sector, a map of the Inter State Transmission System (ISTS) of today and finally an overview of cross border interconnections.

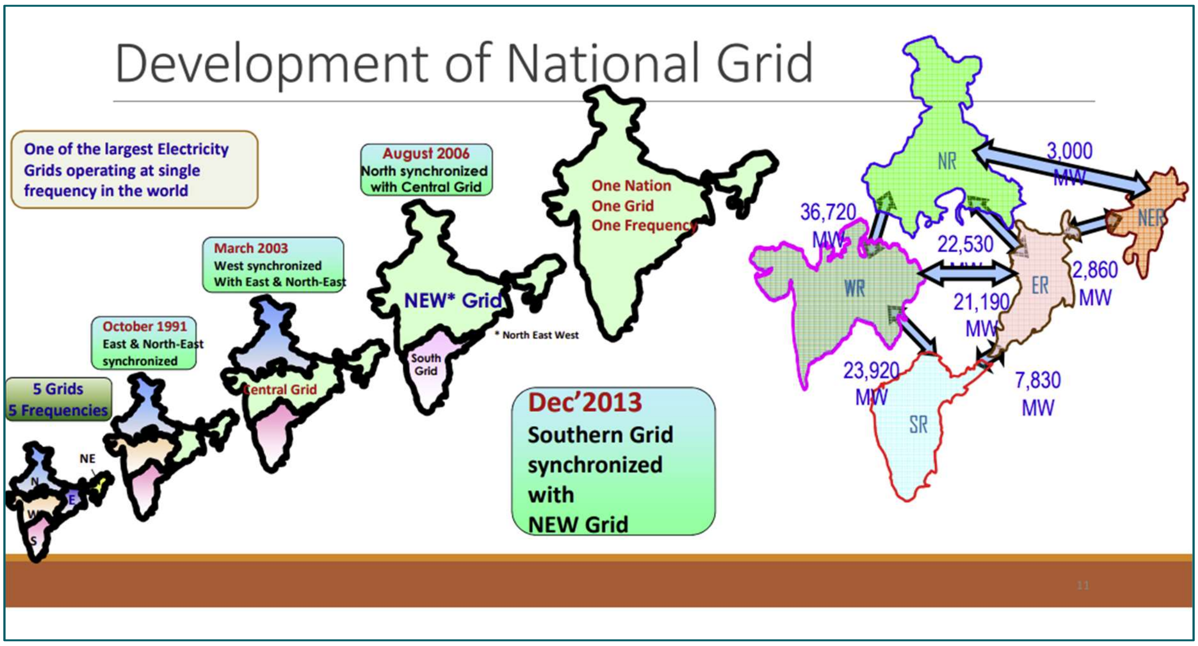


Figure 23 : Development of synchronization into one national grid. Source: [18]

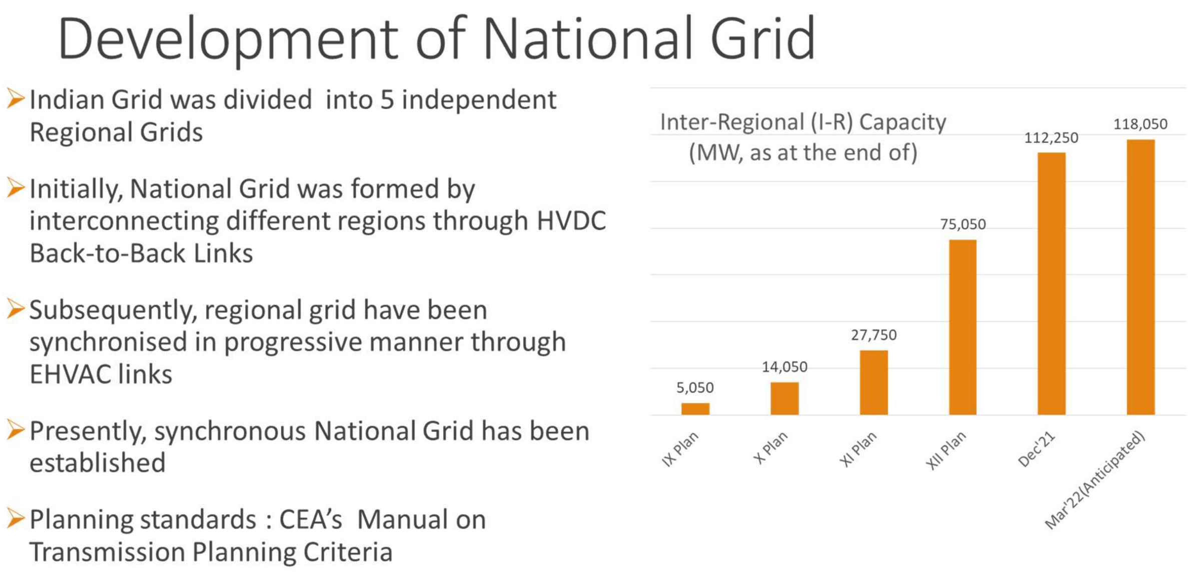


Figure 24: Development of Indian National grid. Source: [18]

Figure 25: Indian transmission system. Source: [18]

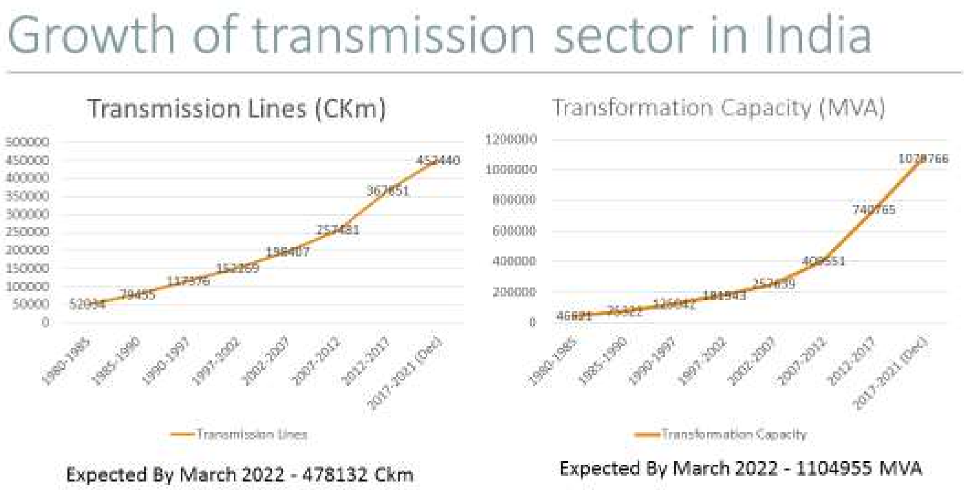
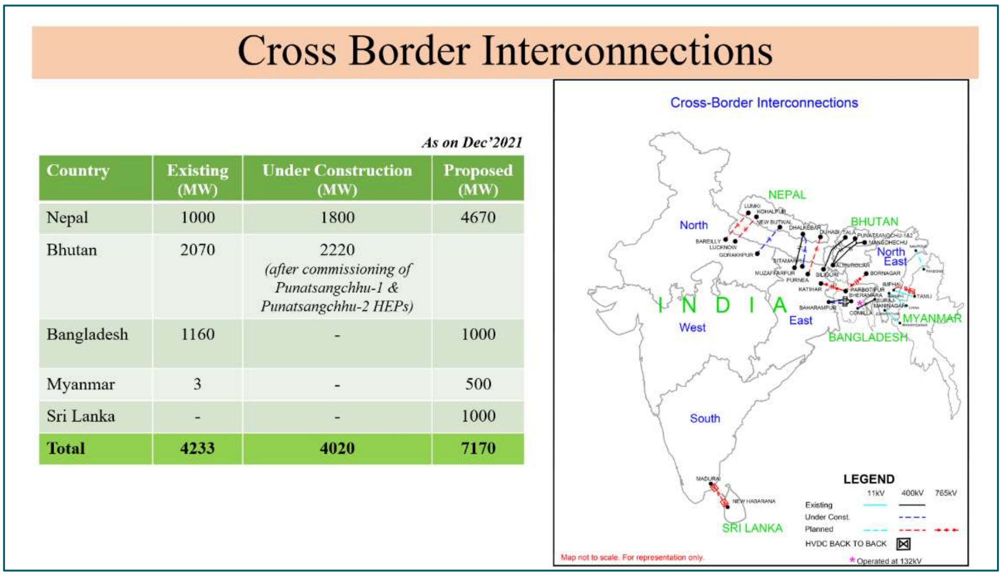


Figure 26: Indian growth of transmission assets Source: [18]



As on Dec'2021

Country	Existing (MW)	Under Construction (MW)	Proposed (MW)
Nepal	1000	1800	4670
Bhutan	2070	2220 *(after commissioning of Punatsangchhu-1 & Punatsangchhu-2 HEPs)*	
Bangladesh	1160	-	1000
Myanmar	3	-	500
Sri Lanka	-	-	1000
Total	**4233**	**4020**	**7170**

Figure 27: Cross border interconnections. Source: [18]

3.1.5 Power Market

At present, there are two energy exchanges in India namely Indian Energy Exchange (IEX) and Power Exchange of India Limited (PXIL). These two organizations came into being in 2008, when Indian electricity markets were opened for entities to buy and sell power. A third energy exchange is also being established at the time of writing.

Power Exchanges Market Share and Congestion Related Curtailments

From 2.77 BU in 2008-09 to 79.70 BU in 2020-21 (of total approx. 1270 TWh), the volume of electricity traded on exchanges has risen. However, compared to the total energy consumed, it is still very low. Figure 28 shows the share of supplied electricity in the India electricity market [19]. During 2020-2021, about 6.27% of electricity was traded on the Electricity exchange markets (i.e., IEX and PXIL), 4.17% through bilateral transactions and a small fraction of 1.80% was traded through deviation settlement mechanism (DSM).

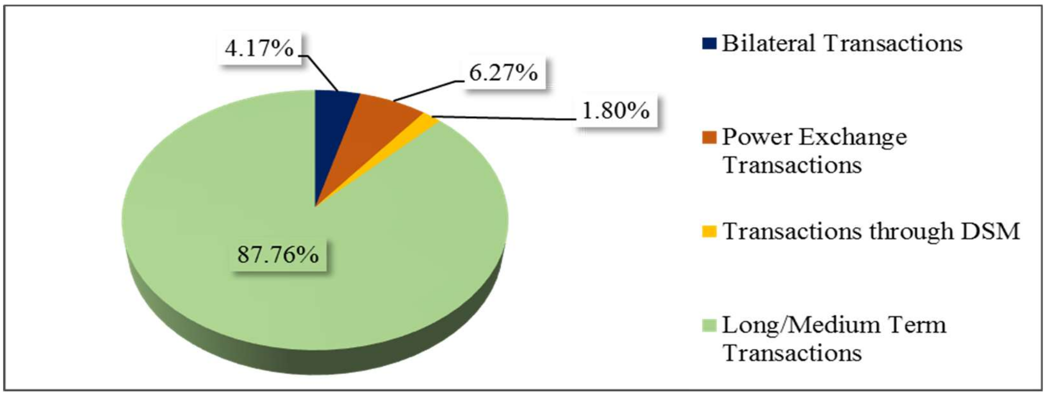


Figure 28: Share of Market Segments in Total Electricity Generation. Source: [19]

Month wise breakdown of transacted power in 2020-2021 as per monthly reports of CEA [15] is shown in Figure 29.

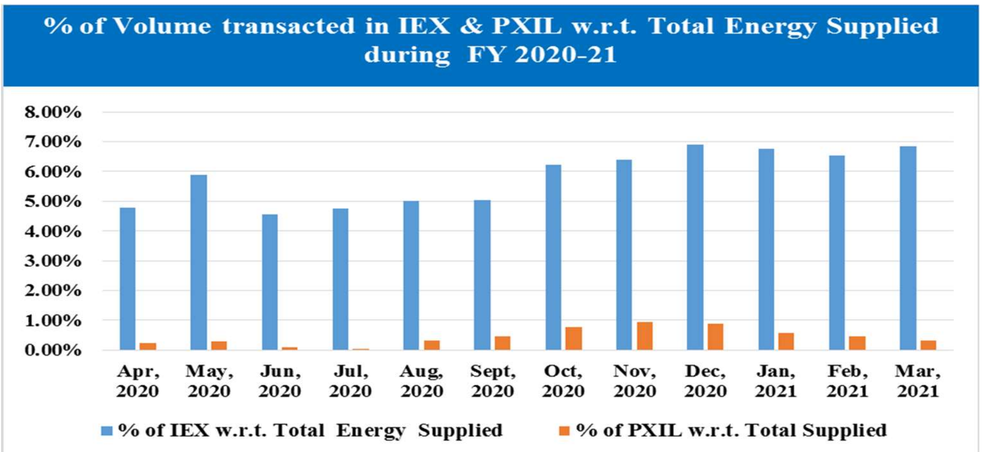


Figure 29: Percentage of volume transacted through IEX and PXIL in 2020-2021 Source: [15]

Market functioning

Since the founding principle of any market is optimisation of costs for the stakeholders, the resulting Market Clearing Price (MCP) is dynamic which generates price signals according to the grid conditions and various technical constraints.

The pricing of electricity done in India has been quite mature and has applied both the concepts of Average Pricing (AP) and Marginal Pricing (MP), as well as a Hybrid method employing both AP and MP according to CERC regulations and discussions with various stakeholders from time to time. The detailed method is described in [20].

The Electrical market bidding zones (present and potential future) in India are shown in Figure 30. The division into present zones reflect the traditional spread of conventional power generation locations and the load centres. E.g., W1, W3, N1, N3, S2, E1 and A2 are generation pockets while N2, W2, S1, E2 are load centres. As per RES growth trajectory however, there are some very large solar based power plants expected in N1, N2, S2, and W2 which will necessarily change the load flow scenario in a big way and hence there is a need for defining new market zones in the Indian electricity sector similar to findings in CEA expert review of Indian electricity grid code [21].

Since the creation of the exchanges, trades have increased consistently, with market clearing prices in decline and trading volumes on the rise. However, system operators (SLDCs or the DISCOMs) still schedule generators based on long-term contracts and not on the basis of the merit or least-cost dispatch order [22].

Thus, India´s Day-Ahead Market is still in the nascent stage, each year increasing the optimised dispatch of power plants across the country. However, CERC has directed a pilot for Security-Constrained Economic Dispatch (SCED) with POSOCO and the Inter State Generating Stations (ISGS), which has shown significant savings in dispatching the thermal generators with the lowest marginal cost.

With future market development encompassing a growing share of generation and demand across India market prices in the established price-zones can be basis for a secure and least cost operation of the power system as known from e.g., Europe and the US. Thus, market prices will likely govern the power flows in the daily operation. Besides, the market will provide economic incentives for new investments in generation and transmission e.g., the price difference in a specific hour between two zones is the marginal benefit of adding an additional transmission capacity.

By recognising this interlinkage between planning and market, a future developed market in India will provide improved basis for future effective grid planning. Modelling future market prices obtained through market modelling of future scenarios for the power system would be central to cost benefit analyses of new transmission assets in India.

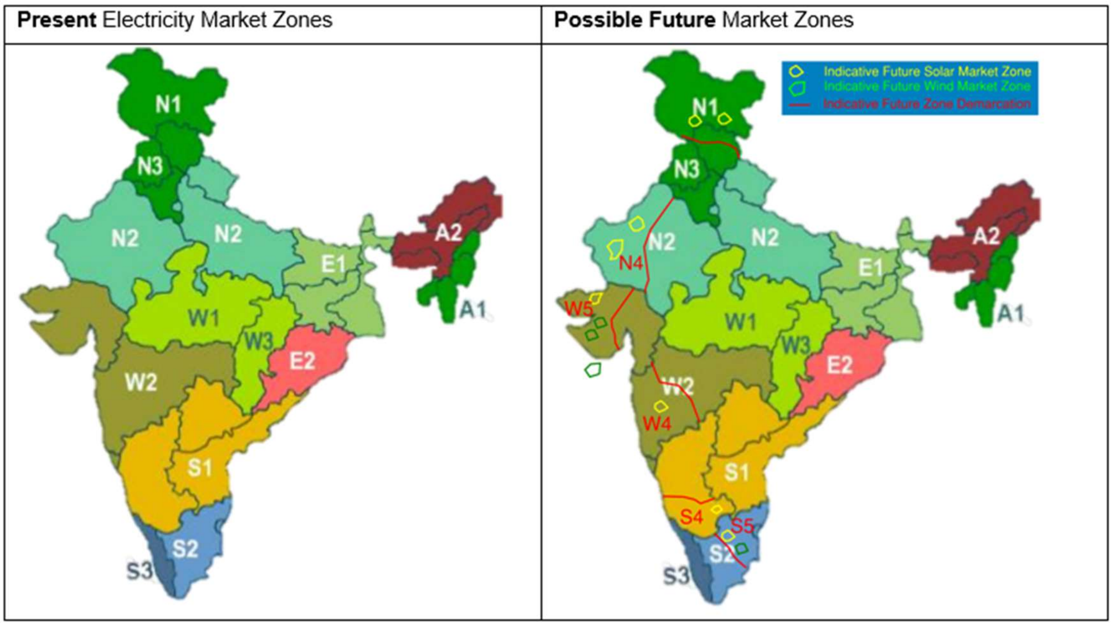


Figure 30: Present and Future Market Zone Scenario. Source: [15].

Optimization of Utilisation of Transmission Capacity

The existing practice in India for approving the Day-Ahead (DA) market trade capacity depends upon the practice of Available Transfer Capacity (ATC) as released by NLDC between various regions. This is much like European practice where the National TSOs along with Regional Coordination Centres (RCCs) calculate the Coordinated Net Transmission Capacity (CNTC) which in Indian context is equivalent to Inter-regional TTC and ATC margins. However, the Nordic countries in Europe, will adopt a new method for clearing the capacity available for DA electricity trade, the so-called Flow Based (FBs) approach [23].

3.2. Transmission system planning

3.2.1 Overview

The information presented here on transmission planning is based on interactions between Danish and Indian Partners CEA, CTU & POSOCO [18], the National Electricity Plan 2017 by Central Electricity Authority which describes the transmission planning approach [24], and various orders/notifications/rules/regulations of Government of India and its agencies.

The objectives of transmission planning in India are:

- Evacuation of power from generating stations
- To meet projected growth in load / demand
- Optimum utilisation of unevenly distributed generation resources in different regionsAdditionally, the expansion of the transmission system depends on:
- Generation addition in a particular time frame- (Input from Generation Planning, long term adequacy (LTA)…)
- Projected Peak demand during the same time frame – (Input from Electric Power Survey, …)
- Operational feedback – (input from RLDCs)
- Requirement of state transmission augmentation

Transmission planning in India has evolved over the last few decades keeping pace with developments and needs of the electricity sector. The transmission planning has been aligned with the Electricity Act 2003, National Electricity Policy, Tariff Policy, Regulations, and market orientation of the electricity sector. The objectives, approach, and criteria for transmission planning, which evolved over a time period, takes care of uncertainties in load growth and generation capacity addition while optimizing investment in transmission on long term basis.

These objectives, approach and criteria are kept in view while planning transmission addition requirements to meet targets for adequacy, security, and reliability. The transmission plan is firmed up through system studies/analysis considering various technological options. The transmission system in India is planned considering the guidelines given in "*Manual on Transmission Planning Criteria*" of January, 2013 by Central Electricity Authority. [25]

3.2.2 Transmission planning - Coordination and consultation

Optimum development of transmission system growth plan requires coordinated planning of the inter-State and intra-State grid systems. The Central Transmission Utility (CTU) is responsible for the inter-State transmission system and the State Transmission Utility (STU) is responsible for the intra-State transmission system (intra-STS). In respect of development of intra-STS, the focus mainly is the interface of intra-STS and State grid at evacuation points of the State and the ability of intra-STS to deliver States allocated power and provide additional reliability to the State grid.

In respect of development of Intra-STS, the focus is to enhance the ability of State grid to transmit power drawn from intra-STS and its own generating stations up to its load centres. The process of integrated planning is coordinated by the CEA. The transmission system is being planned through a coordinated planning process, involving the Regional Standing Committee on Power System Planning (RSCPSP) / Regional Standing Committee(s) on Transmission (RSCT) / Regional Power Committee (Transmission Planning) (RPCTP) involving CEA, CTU, POSOCO or Operators, STUs, RPCs and RLDCs. This regional coordination function has recently (October 2021) been entrusted to Regional Power Committees (RPCs).

National Committee on Transmission (NCT) assess the trend of growth in demand and generation in different regions; identify the constraints, if any, in the inter-State, inter-Region transfer of power and recommends / approves construction of transmission lines, grid stations and other infrastructures in order to meet the requirements, which are likely to arise in the near term/ medium term, so that transmission does not constrain growth.

The transmission planning process is further illustrated in Figure 31.

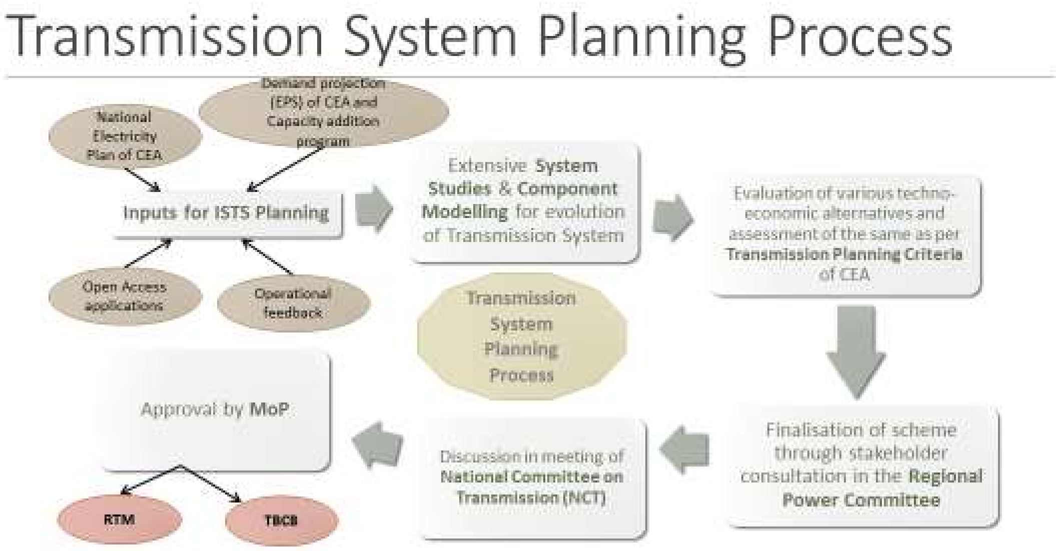


Figure 31: Indian transmission planning process. Source: [18].

Planning of the transmission system for a particular timeframe considers the plans formulated by CEA and the generation projects being taken up for execution in that timeframe. The transmission system requirement covers the power evacuation system from the generation projects and system strengthening of the network for meeting the projected load growth up to that time frame. The transmission system is evolved keeping in view the overall optimisation on national level. In this process the total investment in transmission including the inter-state as well as intra-state system is optimised.

The intra-STS is to be developed by the State utilities. Their network planning, scheme formulation and the program of intra-state transmission development must take into account the transmission system requirements for evacuation of power from state sector and private sector generation projects for intra-state benefit, absorption of power made available through ISTS, meeting the load growth in different areas of the State and improve the reliability of their system. For a coordinated development process aiming at perspective optimisation in meeting the growth targets, it would be appropriate that the State Transmission Utilities prepare their State Electricity Plans taking advantage of development plans for regional grid system and focusing on the specific requirements of the concerned State.

With regards to transmission planning some of the most important CERC regulations include, but are not limited to [18]:

1. Indian Electricity Grid Code Regulations, 2010 as amended from time to time
2. Grant of Connectivity, Long-term Access and Medium-term Open Access in inter-State Transmission and related matters Regulations, 2009 as amended from time to time
3. Cross Border Trade of Electricity Regulations, 2019
4. Planning, Coordination & Development of Economic and efficient ISTS by CTU and other related matters 2018 as amended from time to time
5. Regulatory Approval Regulations, 2010
6. Tariff Regulations, 2019 as amended from time to time
7. Sharing of Inter-State Transmission Charges and Losses Regulations, 2020

Furthermore, there are three types of open access to the Inter-State Grid, which are described in Figure 32. These types are long-term access (LTA), medium term open access (MTOA) and short-term open access (STOA). LTA refers to the right to use the inter-state transmission system (ISTS) for a period exceeding seven years. MTOA refers to the right to use the ISTS for a period equal to or exceeding 3 months but not exceeding 5 years. Under STOA surplus transmission capacity available in ISTS after use by the long-term & medium-term customers is utilised. Thus, during scheduling LTA customers are given priority, followed by MTOA and then STOA customers. However, these are being under consideration to be replaced with the Connectivity and General Network Access (GNA).

Furthermore, the Transmission System Planning & Approval process has undergone tremendous changes for expeditious planning and approval so that it is made available in the matching timeframe of the envisaged large scale RES integration in the Indian National Grid. The details are provided in the subsequent paragraph 3.2.3 Transmission Planning – Regulatory and approval mechanism

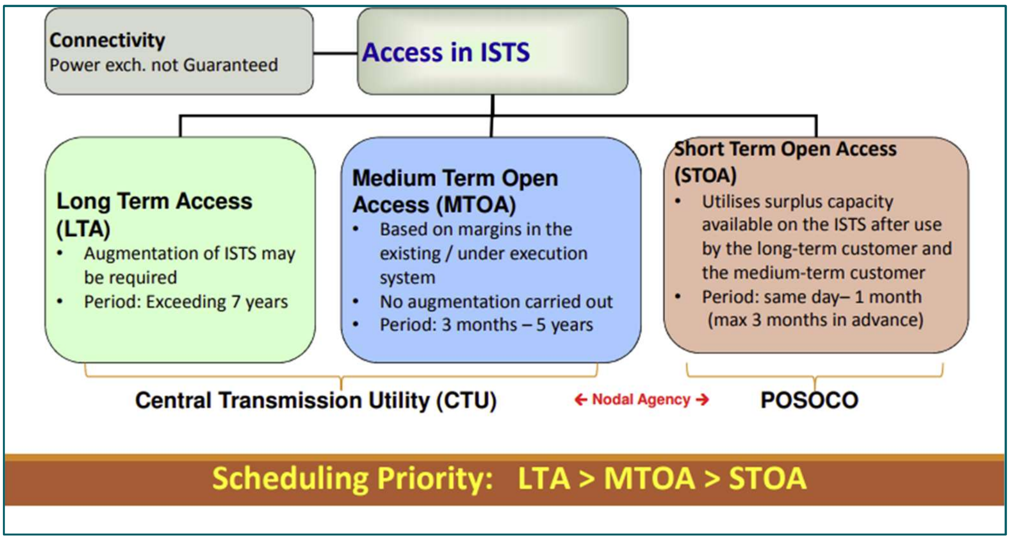


Figure 32: Open access to Inter-State transmission system. Source: [18].

3.2.3 Transmission Planning – Regulatory and approval mechanism

Transmission system is the vital linkage in the power sector value chain connecting the generation and the demand. The regulatory and approval framework for transmission planning are mainly governed by rules and regulations of Ministry of Power and CERC. Regulations of CERC have been mentioned in paragraph 3.2.2 Transmission planning - Coordination and consultation

In view of the short gestation period of RES generation projects, to expedite the planning and approval process, Ministry of Power, Govt. of India has recently (October 2021) reconstituted National Committee on Transmission which inter-alia includes approval jurisdictions for ISTS schemes. In another associated order (also in October 2021), the RPC-TPs have been dissolved and instead the regional coordination for the purpose of transmission planning has been entrusted to Regional Power Committees (RPCs). In view of these recent developments, it becomes important to know and enumerate the terms of reference to NCT viz:

a) The NCT shall evaluate the functioning of the National Grid on a quarterly basis.

b) The Central Transmission Utility (CTU), as mandated under the Electricity Act, 2003, is to carry out periodic assessment of transmission requirement under Inter-State Transmission System (ISTS). The CTU shall also make a comprehensive presentation before the NCT every quarter for ensuring development of an efficient, coordinated and economical ISTS for smooth flow of electricity. The CTU, in the process, may also take inputs from the markets to identify constraints and congestion in the transmission System.

c) The CTU after consulting Regional Power Committee(s) [RPC(s)] shall submit the proposal for expansion of ISTS to the NCT for their consideration. For proposal up to Rs. 500 crores, prior consultation with RPC would not be required.

d) As per provision of Electricity (Planning, Development and Recovery of ISTS charges) Rules 2021, the CTU shall also prepare a five-year rolling plan for ISTS capacity addition every year. The Annual

Plan shall be put up to the NCT six months in advance, e.g. The Annual Plan for FY 2023-24 will be put up before the NCT by 30th September 2022.

e) After considering the recommendations of the CTU and views of the RPCs, the NCT shall propose expansion of ISTS after assessing the trend of growth in demand and generation in various regions, constraints, if any, in the inter- State, inter- Region transfer of power, which are likely to arise in the near term/ medium term, so that transmission does not constrain the growth.

f) The NCT shall formulate the packages for the proposed transmission schemes for their implementation.

g) The NCT shall estimate the cost of transmission packages and may constitute a cost committee for this purpose.

h) The NCT shall recommend to Ministry of Power (MoP) for implementation of the ISTS for projects with cost more than Rs 500 crore, along with their mode of implementation i.e. Tariff Based Competitive Bidding (TBCB) / Regulated Tariff Mechanism (RTM), as per the existing Tariff Policy. However, the NCT shall approve the ISTS costing between Rs. 100 crore to Rs.500 crore or such limit as prescribed by MoP from time to time, along with their mode of implementation under intimation to MoP. The ISTS costing less than or equal to Rs. 100 crores, or such limit as prescribed by MoP from time to time, will be approved by the CTU along with their mode of implementation under intimation to the NCT and MoP. After approval of the ISTS by the NCT or the CTU (as the case may be), the TBCB project shall be allocated to Bid Process Coordinators through Gazette Notification, while the RTM project shall be allocated to CTU.

i) The NCT shall allocate the task of carrying out survey amongst the CTU and Bid Process Coordinators by maintaining a roster.

Another important development in process of transmission planning is the notification of Electricity (Transmission System Planning, Development and Recovery of Inter-State Transmission Charges) Rules, 2021.
These rules pave the way for overhauling of transmission system planning, towards giving power sector utilities easier access to the electricity transmission network across the country. The Central Government has notified these rules with a view to streamline the process of planning, development and recovery of investment in the transmission system. The rules are aimed at encouraging investments in the generation and transmission sectors. The rules will enable the country to develop deeper markets.

At present, generating companies apply for long-term access (LTA) based on their supply tie-ups, while medium-term and short-term transmission access is acquired within the available margins. Based on LTA application, incremental transmission capacity is added. A number of sector developments, such as the increasing focus on renewable energy, and the development of the market mechanism, necessitated a review of the existing transmission planning framework which is primarily based on LTA.

The rules underpin a system of transmission access which is termed as a General Network Access (GNA) in the inter-state transmission system. This provides flexibility to the States as well as the generating stations to acquire, hold and transfer transmission capacity as per their requirements. Thus, the rules will bring in rationality, responsibility and fairness in the process of transmission planning as well as its costs. In a major change from the present system of taking transmission access, power plants will not have to specify their target beneficiaries. The rules will also empower state power distribution and transmission companies to determine their transmission requirements and build them. Also, states will be able to purchase electricity from short term and medium term contracts and optimize their power purchase costs.

Apart from introducing GNA, the rules also specify clear roles of various agencies involved in the transmission planning process. The Central Electricity Authority shall prepare a short-term plan every year on rolling basis for next 5 years and perspective plan every alternative year on rolling basis for next 10 years. The Central Transmission Utility shall prepare an implementation plan for inter-State transmission system every year on rolling basis for up to next 5 years which will take in to account aspects such as right –of-way and progress of the generation and demand in various parts of the country. The rules specify how the existing LTA would be transitioned into General Network Access. The rules also outline the recovery of GNA charges from the users of transmission network and assign the responsibility of billing, collection and disbursement of inter-state transmission charges to the Central Transmission Utility.

> The rules have enabled, for the first time that the transmission capacity can be sold, shared or purchased by the States and generators. The rules prescribe that excess withdrawal or injection over the GNA capacity sanctioned shall be charged at rates which are at least 25% higher and this will ensure that the entities do not under-declare their GNA capacity. The Central Electricity Regulatory Commission (CERC) has been empowered to bring out detailed regulations on GNA in inter-state transmission system. The Rules also underpin that *“electricity transmission planning shall be made in such way that the lack of availability of the transmission system does not act as a brake on the growth of different regions and the transmission system shall, as far as possible, be planned and developed matching with growth of generation and load and while doing the planning, care shall be taken that there is no wasteful investment”*.

Ministry of Power, Govt. of India through resolution (December 2021) has also reconstituted Regional Power Committees (RPCs) and revised the functions to be discharged by the Committee. The Committees shall meet at least once in a month and shall facilitate all functions of planning relating to inter-state/ intra-state transmission system with CTU/STU.

Due to these recent developments, the practice and procedures for implementation of these new rules are under discussion and at formative stage at present.

3.2.4 Transmission planning – presumptions for analyses

In the Indian context, the transmission system has been broadly categorized as ISTS and Intra-STS. The ISTS is the top layer of national grid below which lies the Intra-STS. The criteria prescribed here are intended to be followed for planning of both ISTS and Intra-STS.

The long-term applicants seeking transmission service are expected to pose their end-to-end requirements well in advance to the CTU/STUs so as to make-available the requisite transmission capacity and minimize situations of congestion and stranded assets.

The transmission customers as well as utilities need to give their transmission requirement well in advance considering time required for implementation of the transmission assets. The transmission customers are also required to provide a reasonable basis for their transmission requirement such as - size and completion schedule of their generation facility, demand based on Electric Power Survey (EPS) and their commitment to bear transmission service charges.

STU (State Transmission Utility) acts as the nodal agency for Intra-STS planning in coordination with distribution licensees and intra-state generators connected/to be connected in the State Transmission Utility grid. The STU is the single point contact for the purpose of ISTS planning and is responsible on behalf of all the intra-State entities, for evacuation of power from their state's generating stations, meeting requirements of DISCOMS and drawing power from ISTS commensurate with the ISTS plan. STUs coordinate with urban planning agencies, industrial developers etc. to keep adequate provision for transmission corridor and land for new substations for their long-term requirements.

The system parameters and loading of system elements shall remain within prescribed limits. The adequacy of the transmission system should be tested for different feasible load-generation scenarios as prescribed in the Planning criteria Manual.

The system is planned to operate within permissible limits both under normal as well as after more probable credible contingencies as detailed in subsequent paragraphs of this manual. However, the system may experience extreme contingencies which are rare, and the system may not be planned for such rare contingencies. To ensure security of the grid, the extreme/rare but credible contingencies are identified from time to time and suitable defence mechanism, such as - load shedding, generation rescheduling, islanding, system protection schemes, etc. may be worked out to mitigate their adverse impact.

Critical loads such as - railways, metro rail, airports, refineries, underground mines, steel plants, smelter plants, etc. shall plan their interconnection with the grid, with full redundancy and as far as possible from two different sources of supply, in coordination with the concerned STU.

3.2.5 Technical modelling - overview

The system shall be planned to operate within permissible limits both under normal as well as after more probable credible contingencies (N-1, N-1-1). To ensure security of the grid, the extreme/rare but credible contingencies should be identified from time to time and suitable defence mechanism, such as - load shedding, generation rescheduling, islanding, system protection schemes, etc. may be worked out to mitigate their adverse impact.

Normal thermal ratings and normal voltage ratings voltage limits represent equipment limits that can be sustained on continuous basis and Emergency thermal ratings and emergency voltage limits represent equipment limits that can be tolerated for a relatively short time (one hour to two hours depending on design of the equipment).

In the planning phase, transmission requirements for generation projects and system reinforcement needs are evolved, based on detailed system studies and analysis keeping in view various technological options, planning criteria and regulations. These studies/analyses are problem-specific, that is, in a particular exercise, only a sub-set of the analysis/studies may be necessary. The system is being planned on the basis of, among others, the following power system studies:

I. Power Flow Studies
II. Short Circuit Studies
III. Stability Studies (including transient stability and voltage stability)
IV. EMTP studies (for switching / dynamic over-voltages, insulation coordination, etc.)

Time Horizons for transmission planning

Going from concept to commissioning of transmission elements generally takes three to five years; about three years for augmentation of capacitors, reactors, transformers etc., and about four to five years for new transmission lines or substations. Therefore, system studies for firming up the transmission plans may be carried out with 3-5 year time horizon.

Load - generation scenarios

The load-generation scenarios shall be worked out in ways reflecting in a pragmatic manner the typical daily and seasonal variation in load demand and generation availability.

Load demands

The system peak demands (state-wise, regional, and national) are based on the latest EPS report of CEA. However, the same may be moderated based on actual load growth of past three years.

The load demands at other periods (seasonal variations and minimum loads) are derived based on the annual peak demand and past pattern of load variations. In the absence of such data, the season-wise variation in the load demand may be taken as given in manual.

While doing the simulation, if the peak load figures are more than the peaking availability of generation, the loads may be suitably adjusted substation-wise to match with the availability. Similarly, while doing the simulation, if the peaking availability is more than the peak load, the generation dispatches may be suitably reduced, to the extent possible.

From practical considerations the load variations over the year shall be considered as under:

I. Annual Peak Load
II. Seasonal variation in Peak Loads for Winter, Summer and Monsoon
III. Seasonal Light Load (for Light Load scenario, motor load of pumped storage plants shall be considered)

3.2.6 Integration of RES projects

India is planning a massive transition of the power system with a significantly higher integration of renewable based generation as a part of the energy mix. This transition is reflected in the key numbers presented in Figure 33 and Figure 34. These figures show the generation system in 2020 and the expected generation mix by 2025. Installed capacity of renewables (excl. hydro) is expected to reach 39% (240 GW) of the generation fleet (619 GW) in 2025 compared to presently 23.6 % of a total generation capacity of 375 GW.

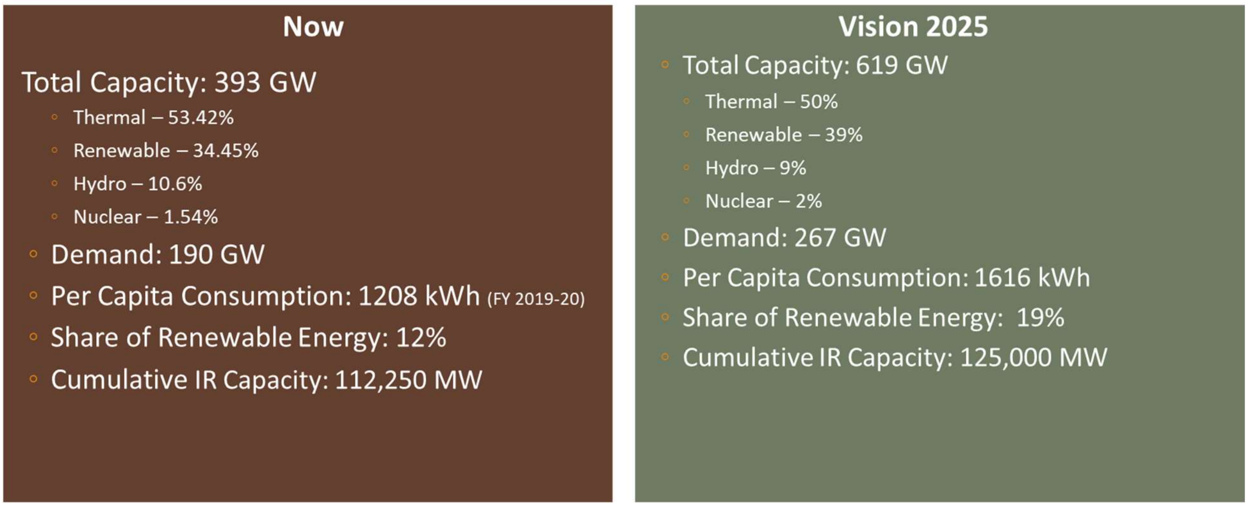


Figure 33: The planned development of the Indian power generating system towards 2025: [18]

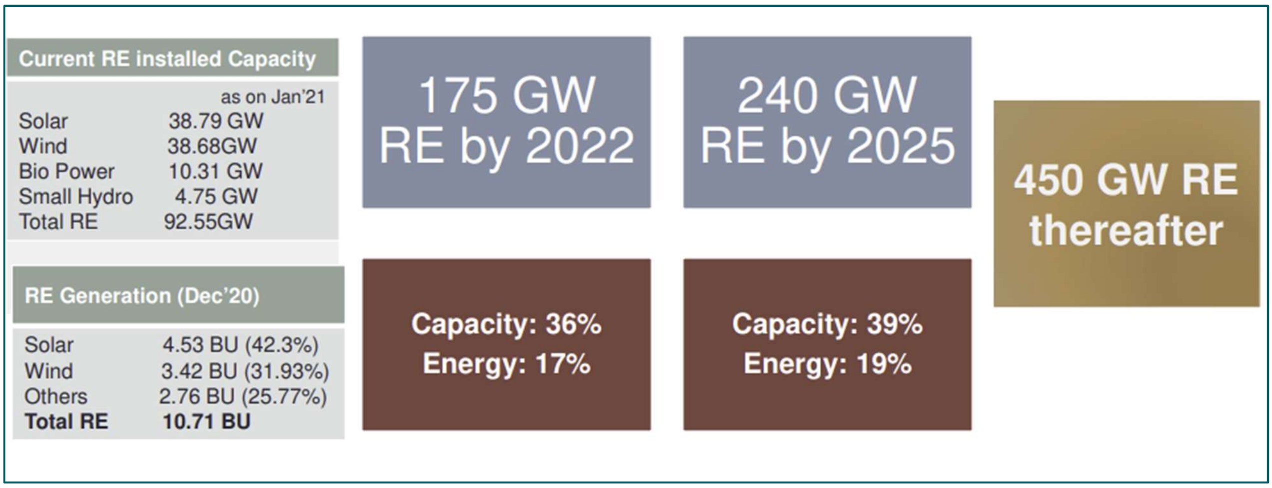


Figure 34: The Indian renewable energy expansion program. Source: [18].

The renewable energy target needs to be taken in context with the increase of per capita consumption from 1181 kWh in 2020 to 1616 kWh by 2025. With such significant increase in demand along with increased RES integration, the security of supply needs to be considered. Some key issues with increased renewable integration are:

- Short gestation period
- Intermittency and variability of resources
- Uncertainty in generation
- Grid balancing to counter over or under supply from RES

Some of the mitigation measures being considered to counter these issues are:

- Integration planning accounting for potential
- Flexibility in generation/transmission and on demand side
- Forecasting and scheduling
- Energy storage systems

India is already taking actions to facilitate smoother integration of large amounts of RES. The initiatives for this include (non-exhaustive list):

- Comprehensive Green Energy Corridors (GEC)
- Integration of Ultra Mega Solar Power Parks (UMSPP)
- Renewable Energy Management Centres (REMC)
- Dynamic Compensation (>13,000 MVAR)
- Integration planning based on potential RES Zones

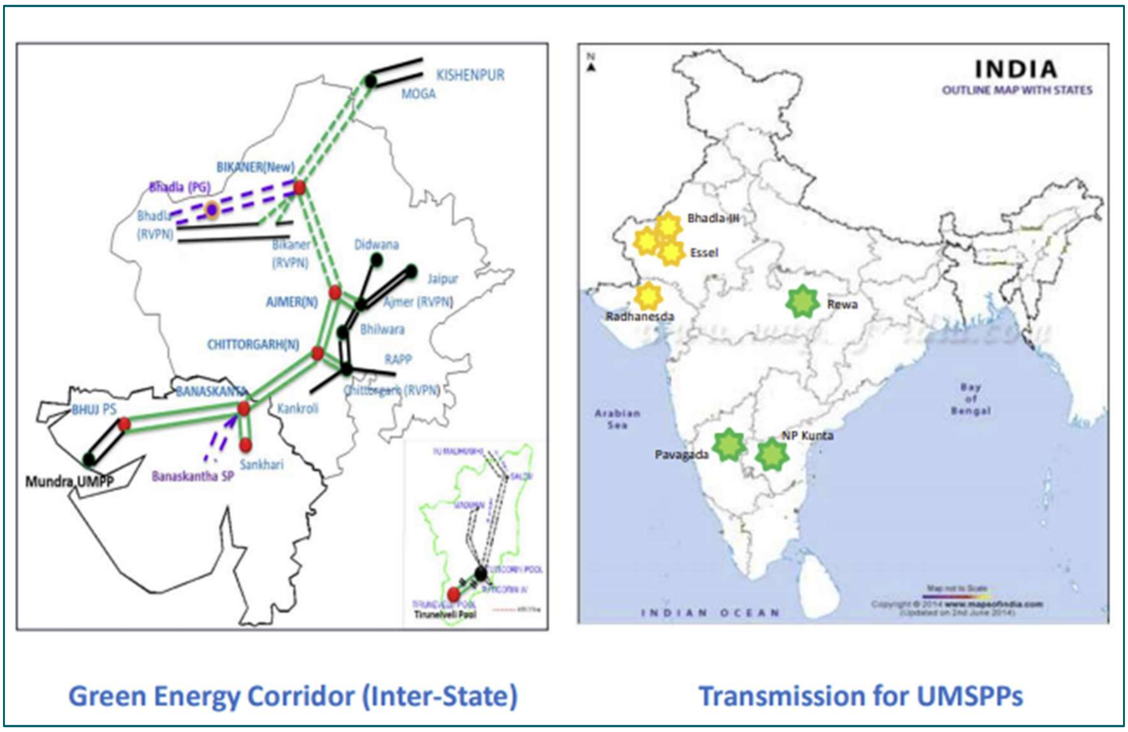


Figure 35: Green energy corridors and ultra-mega solar power parks (UMSPP) Source: [18]

Green Energy Corridors (GEC)

The Green Energy Corridor Project, in Figure 35, aims at synchronizing electricity produced from renewable sources, with conventional power stations in the grid. For evacuation of large-scale renewable energy, Intra-STS project was sanctioned in 2015-16. It is being implemented by eight renewable-rich states of Tamil Nadu, Rajasthan, Karnataka, Andhra Pradesh, Maharashtra, Gujarat, Himachal Pradesh, and Madhya Pradesh. The project is being implemented in these states by the respective STUs.

The project includes approximately 9,400 ckm transmission lines and substations of a total capacity of 19,000 MVA. The purpose is to evacuate 20,000 MW of large-scale renewable power and improvement of the grid in the implementing states. The total project cost is Rs. 10141 crores. The project is being implemented by respective STUs allocating the work through a competitive bidding process. As of 31. December 2019, 6258 ckm, out of 9767ckm, for intra-state transmission was completed. Furthermore, inter-state transmission of 3068 ckm has also been completed [26].

Ultra-Mega Solar Power Projects (UMSPP)

Scattering of solar power projects leads to higher project cost per MW and higher transmission losses. Individual projects of smaller capacity incur significant expenses. It also takes a long time for project. To overcome these challenges, the scheme for “Development of Solar Parks and Ultra-Mega Solar Power Projects” was rolled out in December 2014 with an objective to facilitate the solar project developers to set up projects in a plug-and-play model.

It was planned to set up at least 25 solar parks, each with a capacity of 500 MW and above; thereby targeting around 20,000 MW of solar power installed capacity. Due to excellent response from the states, 34 solar parks of aggregate capacity 20,000 MW have already been approved in 21 states. [26].

Renewable Energy Management Centres

The establishment of Renewable Energy Management Centres (REMC) equipped with advanced forecasting tools, smart dispatching solutions, and real time monitoring of RES generation, closely coordinating with SLDCs/RLDCs has been envisaged as a primary requirement for grid integration of large scale RES (Figure 36). REMCs are being rolled out in renewable energy-rich states to facilitate VRE integration along the Green Energy Corridors. The REMCs are co-located with the State Load Dispatch Centres (SLDCs) in Tamil Nadu, Karnataka, Andhra Pradesh, Maharashtra, Madhya Pradesh, Gujarat and Rajasthan; and in Regional Load Dispatch Centres (RLDCs) at Bengaluru, Mumbai and New Delhi; and at the National Load Dispatch Centre (NLDC). 55 GW of renewable power (solar and wind) are currently monitored through the eleven REMCs.

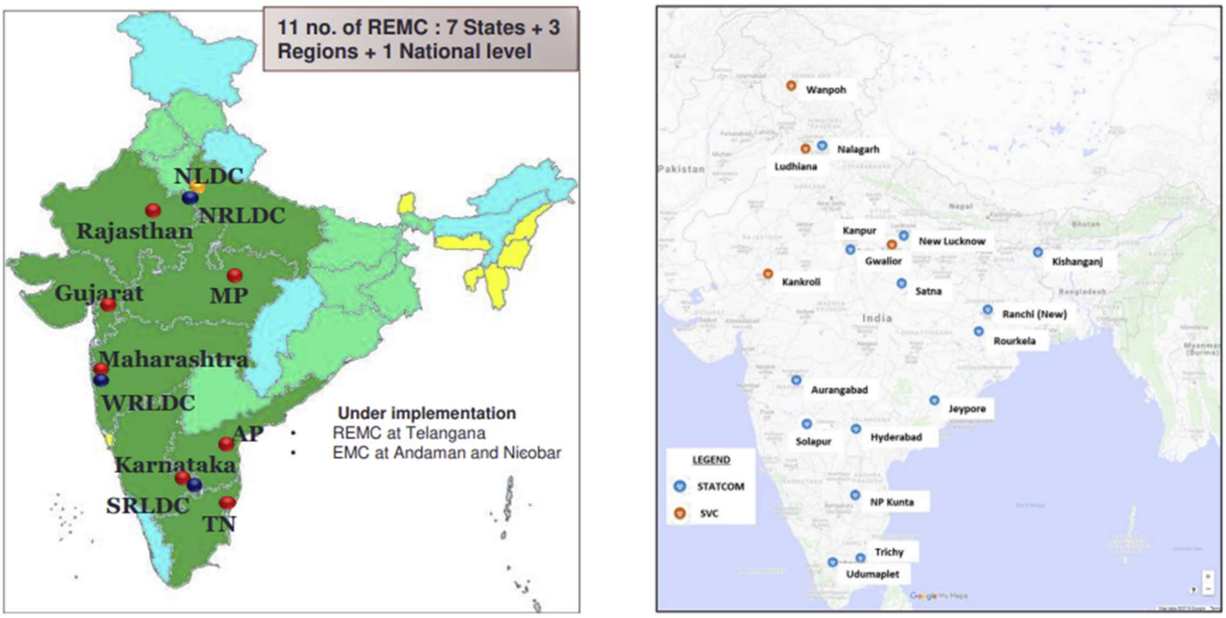


Figure 36: Renewable energy management centres in VRE rich states and dynamic compensation assets. Source: [18]

Renewable Energy Zones

As an additional integration measure, the Ministry of New and Renewable Energy (MNRE) has identified potential zones for solar and wind in RES rich states, namely: Tamil Nadu, Andhra Pradesh, Karnataka, Gujarat, Maharashtra, Rajasthan & Madhya Pradesh. Altogether 66.5 GW of zones have been pointed out. The details can be seen below, Figure 37.

State	Total	
	Wind	Solar
Gujarat	6	10
Maharashtra	2	5
Madhya Pradesh		5
Total WR	8	20
		20
Total NR		20
Karnataka	2.5	5
Andhra Pradesh	3	5
Tamil Nadu	3	
Total SR	8.5	10
Total	16.5	50
	66.5	

Figure 37: Identification REZ Source: [18]

Regulatory Framework

On the regulation side India has established various supporting regulatory framework for integration of RES. Some of the framework included are:

- Separate Connectivity Regulations for RES
- Waiver of interstate transmission charges & losses for solar and wind projects: solar and wind projects commissioned till Jun 2023
- All transmission system for RES as National Component for calculation of Inter State Transmission Charges
- Technical Standards for Connectivity of the Distributed Generation Resources, Regulations
- Incentivizing Flexibility: Technical Minimum of 55% in Conventional Thermal Generators
- Reserve Regulation Ancillary Services (RRAS)
- Real Time Power Market (RTM)

Way Forward

Some of the most important steps in the way forward of transmission planning in India from a CEA/CTU perspective include [18]:

- Matching Transmission Infrastructure with RES Development
- Flexibility & Control in Generation / Transmission / Loads
- Ancillary Services Market
- Energy Storage
- Awareness & Capacity Building

3.2.7 Cross border interconnections

At present India is connected with Nepal, Bhutan and Bangladesh. The capacity of transmission with Nepal and Bhutan are adequate considering grid size of these two countries.

Interconnections with Bhutan are mainly for evacuation of power from various hydro projects in Bhutan. About 2000 MW is being imported from Bhutan and another 2000 MW is under implementation.

The interconnection with Nepal, traditionally, was at low voltage to meet requirement of load centres in Nepal. In November 2020, a high capacity interconnection with Nepal of 400kV was established and implementation of another two such interconnections are in progress. Considering hydrology and demand pattern in Nepal these will be used for two-way exchange of electricity.

The interconnection with Bangladesh is also an Extra High Voltage, high capacity link including a HVDC back to back system. Thus, the India - Bangladesh is an asynchronous inter-connection, whereas, the India - Nepal and India - Bhutan are synchronous interconnections. Another 1000 MW high capacity link between India and Bangladesh has been agreed in principle. Establishment of high capacity links between India - Sri Lanka and India - Myanmar are under planning /discussion stage.

4. Denmark and Nordics – Transmission planning

4.1. General introduction

Energinet is the Danish electricity and gas system operator and a state-owned company. According to the Danish Electricity Supply Act the purpose of Energinet is to own, operate and develop the overall energy infrastructure and handle task relations to it and thereby contribute to the development of a carbon neutral energy supply. Energinet will consider security of supply, climate and environmental factors, and secure a transparent approach for all consumers of the grids. According to the law of electricity supply act Energinet is required to connect RES-plants to the transmission grid.

Energinet works to ensure that the green transition is carried out in an economically responsible way without compromising on Denmark's already high security of supply.

Progress towards the policy objectives means achieving a balance between three dimensions as shown in Figure 38 – something called the energy trilemma: A robust energy system must be 1) secure and reliable, 2) environmentally sustainable and 3) affordable and accessible.

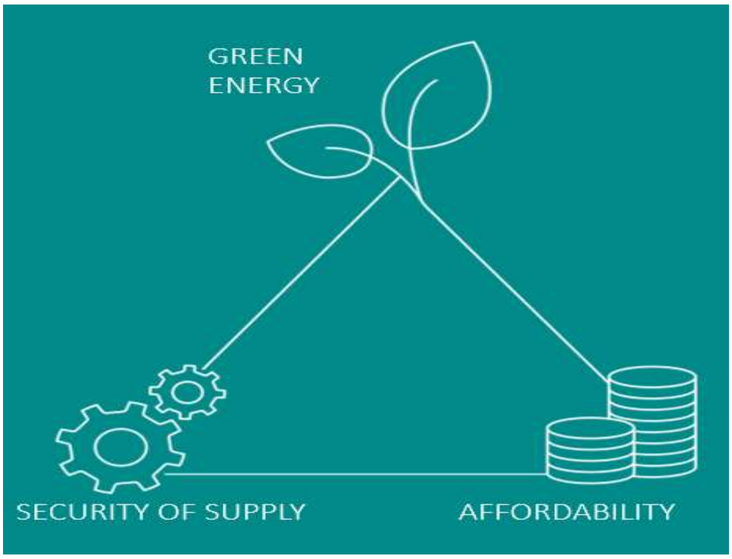


Figure 38: Energy trilemma. Source: [12]

In short that means that Energinet strives towards the agreed political objective of transforming the energy system to be based on 100% renewable energy, without compromising on security of supply while considering affordability for society and individual consumers.

The Danish electricity system consumes annually 34 TWh; the generation capacity consists of approx. 6 GW wind, 1 GW solar, and 6 GW thermal. Eastern Denmark is part of Nordic synchronous areas and Western Denmark is part of European continental synchronous area. Denmark is well connected to neighboring countries Norway, Sweden, Germany and Holland with more than 7 GW interconnector capacity. In 2020 wind and solar produced more than 17 TWh of electricity and around 50% of the Danish electricity consumption.

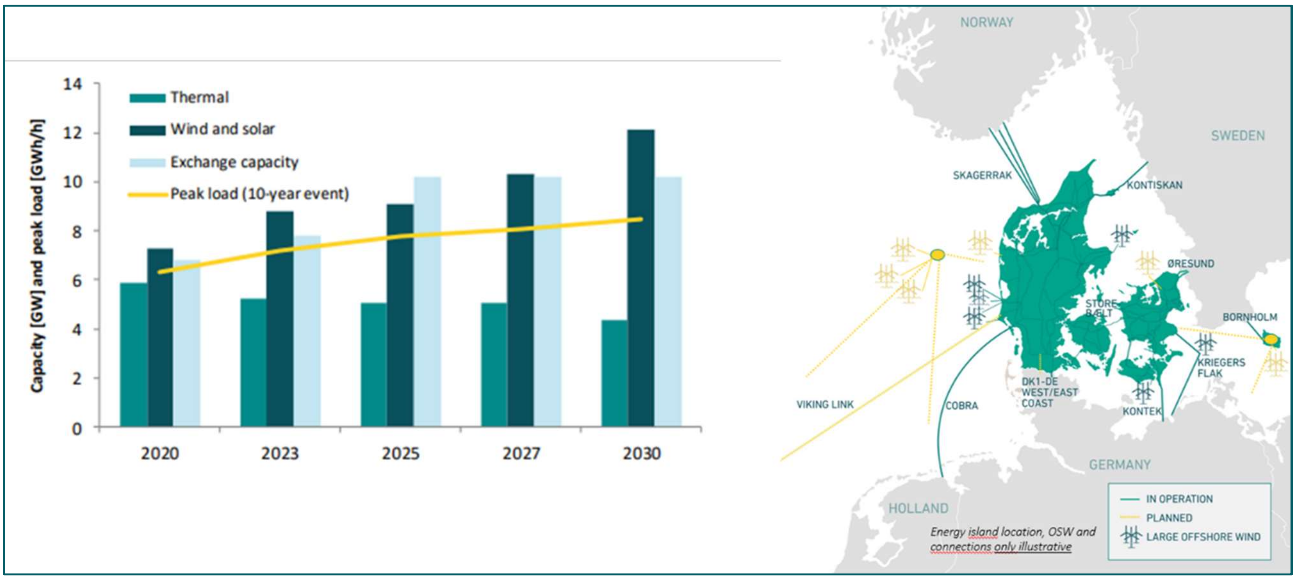


Figure 39: Overview of Danish electricity transmission grid and expected generation capacity development. Source: [12].

Towards 2030 a large increase in VRE generation and consumption is expected (see

Figure 39). The VRE generation is driven by market based investments and with high uncertainty for actual realization and timing for commissioning. Up to 15 GW new capacity of onshore wind and solar is expected towards 2030 but with currently almost 30 GW of potential projects already announced by developers. Up to 7 GW of offshore wind is based on political agreed tenders by Danish Energy Agency with Energinet involvement in the planning. Consumption is expected to increase 50% before 2030 driven by electrification and system integration of heat, transport and PtX, but the timing of new investments is uncertain.

The development towards 2030 changes the framework for long term grid planning and the increased uncertainty and acceleration of VRE investments and electrification are handled in the grid planning process through continuous system planning and grid investment plans, coordination with neighbouring countries and regions, close dialogue with Distribution System Operators (DSOs), developers and municipalities on expected VRE investments. The handling is also made through updates of investment and business case processes focusing on sensitivities and consequences of alternative developments. This approach is further described in the next chapter.

4.2. Grid planning approach

Energinet continuosly works with a variety of solutions to meet the development needs in the power grid and the uncertainty in the needs. Solutions include; market solutions, operational solutions and adjustments to the regulatory frameworks etc. This is done in close cooperation with sector authorities, market participants and other stakeholders. The solutions will often be general requirements or rules, disseminated across the entire power grid and not just at local sites. New rules and frameworks are incorporated into the planning process as they are developed and approved, and they can affect the development needs and thus the long-term grid structure. Table 1 gives an overview of the short and long term solutions Energinet are currently pursuing and implementing.

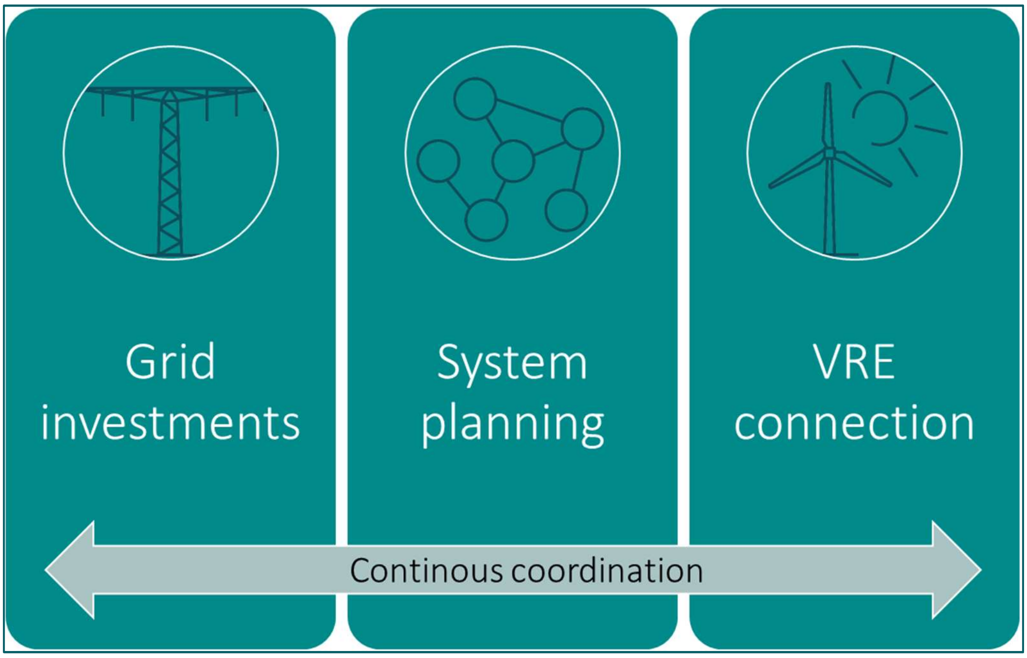


Figure 40: Overall approach to system planning with continuous stakeholder coordination and updates of grid and system plans. Source: [12]

Managing uncertainty in grid planning	
Long term	• Unbundling and separate long term grid and production planning • Regional/European coordination • Long term development (LDP) plan with scenarios • Public involvement (knowledge on technology development and investment plans) • Continuous bi-annual process
Medium term	• Low investment market and operational solutions as temporary alternative to grid investment • Business case based on more alternative investments, probability, sensitivities and dependencies (criteria: socio economic net present value, security of supply/energy flow, climate effect and public acceptance) • Public involvement (status and plans for new production and consumption projects) • Continuous annual process
Short term	• Execution of grid extensions dependent on consent and approval of new production/consumption • Development of Digital capacity map with municipalities and DSO with status on projects and consents of new production and consumption • Continuous process

Table 1 Energinet actions to manage uncertainty in grid planning

4.2.1 Long term development plan (LDP)

One of the most important new solutions is a new long term planning process with change in the political approval of Energinet investments to ensure assessment of non-grid alternatives and an earlier stakeholder involvement. After the latest review of the law of electricity supply act in 2020, Energinet is required to create and publish a long-term development plan (LDP). The first LDP will be published in 2022 and will provide an overview over the needs and possible solutions for the transmission grids from both an immediate and long-term perspective. In the process of the long-term development plan Energinet is required to involve and engage the public. Energinet will publish and submit the long-term development plan to the minister of climate, energy- and supply to orientation.

LDP is a 2-year iterative process divided into four subprojects: Scope, Need, Solutions and Plan.

The primary objectives of the LDP are:

1. Provide an overview over trends, obstacles and solutions for the development of the power and gas systems.
2. Include stakeholders and the public in Energinet's planning process and create transparency and awareness.
3. Secure coordination and optimized development of the transmission systems.

4. Create a path for general acceptance of solutions regarding new infrastructure related to green transition.

Core messages of LDP needs in the power grid:

1. Production and consumption of renewable energy will increase significantly towards 2040
2. The green transition will result in the existing power grid being overloaded.
3. Power grid overloading will result in a need for measures that can relieve the load on or increase the capacity of the power grid.
4. The green transition will result in the need to expand the power grid, but when and how much is
5. The need to expand the power grid can be reduced by solutions that create better simultaneity or geographic balance between production and consumption

4.3. Planning methodology

Figure 41 shows the overall planning methodology in Energinet. The planning is based on grid modelling and future scenarios using the assumptions from the Danish Energy Agency to ensure arm's length between assumptions and planning. The decision process is based on business cases and internal Energinet and external DEA approval depending on size of investments. The grid solutions must always include a comparison with alternative market or operational solutions.

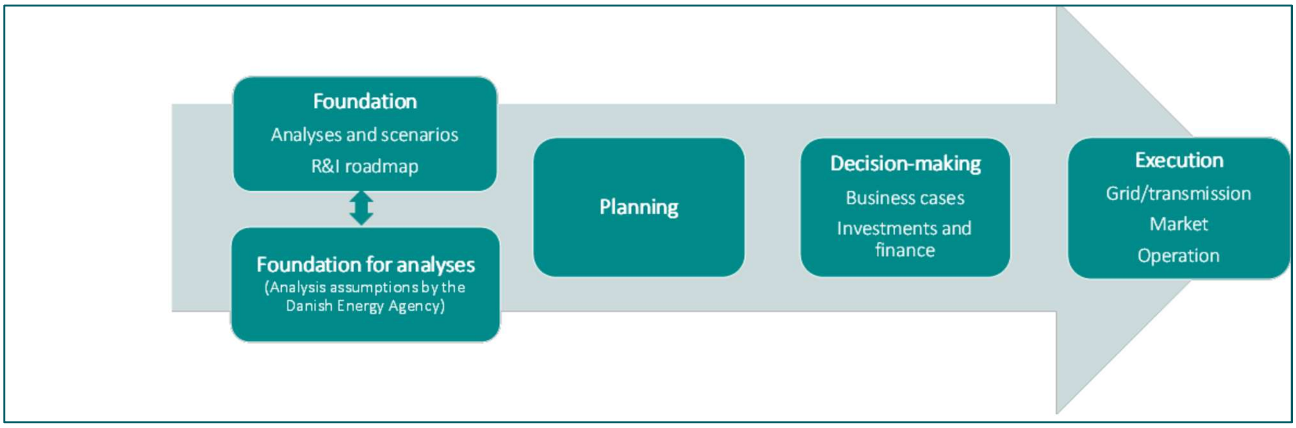


Figure 41: Overview Energinet grid planning process. Source: [12]

4.3.1 The Danish Energy System Base Case Scenario – The Analysis Assumptions

When modelling the Danish energy system with the purpose of developing its infrastructure, the Analysis Assumptions provided to Energinet by the Danish Energy Agency must be utilised.

The Analysis Assumptions contain all the data necessary to model the Danish energy system. Both the consumption- and generation side is handled. For consumption special emphasis is on electricity- and gas, whereas electricity- and district heating is the focus for generation. Examples of provided input data is yearly electricity- and gas consumption amounts, fuel- and CO_2-quota costs, capacities of interconnectors, PtX-units, renewable energy source production capacities and average full load hours, thermal power plant capacities, fuel sources and efficiencies, heat pump and electrical boiler capacities etc.

What the Analysis Assumptions from the Danish Energy agency do not provide is profiles. The electricity- and heat demand time-series and renewable energy source production profiles are constructed internally in Energinet. The scenario should be viewed as the best estimate for the system´s future developments. The most recent iteration provides data from 2020 to 2040. An overview of the data contained in the scenario is apparent from the Danish Energy Agency webpage[1].

4.3.2 The Pan-European Energy System Base Case Scenario – National Trends

When modelling the pan-European energy system, for example when performing market simulations for use in interconnector business cases, a reliable best estimate energy system scenario is vital. For this purpose, Energinet utilizes in its pan-European market model, BID3, the National Trends scenario made available through the ENTSO-E. The National Trends scenario is bottom-up. This means that it is created as a collection of individual scenarios reported by each TSO. The scenario is described in greater detail in Section 4.3.3 Building Market Models using the Analysis Assumptions and National Trends Scenario. The Energinet contribution to the National Trends scenario is the reporting of the newest addition of the Analysis Assumptions dataset at the time of data collection. The data received through the National Trends scenario includes all energy system data needed to construct pan-European market models. Essentially the provided data categories are the same as for the Danish Analysis Assumptions, though the scope is European. Additionally, the ENTSO-E makes the following available; demand time-series, RES production profiles and hydrological profiles for 36 climate years ranging from 1981 to 2016.

4.3.3 Building Market Models using the Analysis Assumptions and National Trends Scenario

Figure 42 illustrates the scenario implementation loop carried out yearly in Energinet.

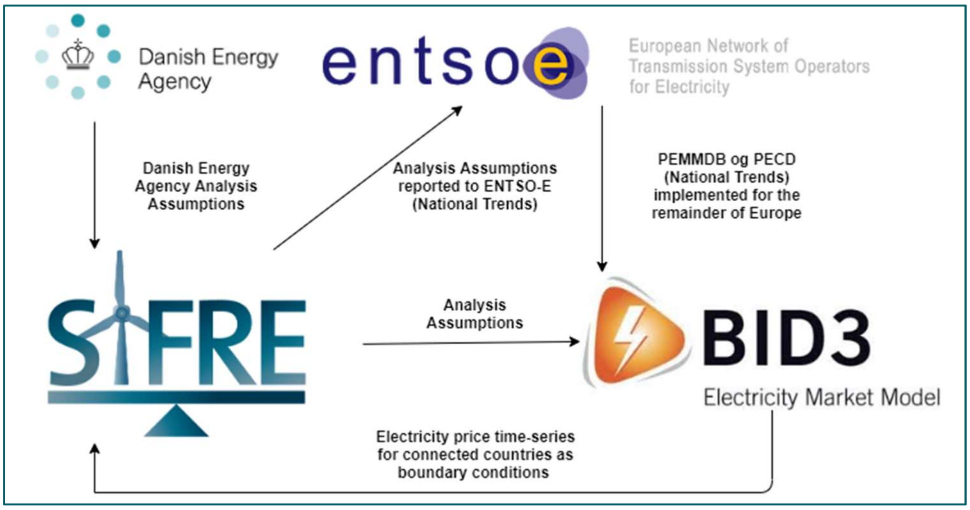


Figure 42: Implementation of the Analysis Assumptions in SIFRE and BID3 in Energinet. Source: [27]

[1] Analysis Assumptions for Energinet by the Danish Energy Agency (link only in Danish): https://ens.dk/service/fremskrivninger-analyser-modeller/analyseforudsaetninger-til-energinet

Figure 42 highlights that the Analysis Assumptions are implemented in the simulation software BID3 and SIFRE each year, whereas the National Trends scenario is implemented in BID3 only. The model building process culminates in electricity price time-series being fed back to SIFRE from BID3 as boundary conditions for the domestic model in order to reach the highest possible convergence of electricity prices and parameters depending on these given the geographical scope difference between the two models.

The BID3 implementation of the Analysis assumptions is done as closely as possible to the SIFRE implementation given the inherent differences between the two models. Such differences include that heat as an energy carrier cannot be modelled as realistically in BID3 as it can in SIFRE. The heat constraints of combined heat and power plants is therefore implemented as must-run conditions instead. Additionally, electricity usage of heat pumps and electric boilers are not outputs of BID3 as they are of SIFRE but are rather modelled as electricity consumptions based on the SIFRE optimization. BID3 is chosen as the pan-European model due to its high-quality hydro optimisation, which is essential in modelling especially the Nordic countries but the rest of Europe as well.

When the scenario implementation is finalised each year, Energinet is equipped to deliver high quality market model results to various studies, projects, business cases and transmission planning studies – whether the scope is Danish or pan-European.

The connection between SIFRE results and the grid planning models is illustrated in Figure 43.

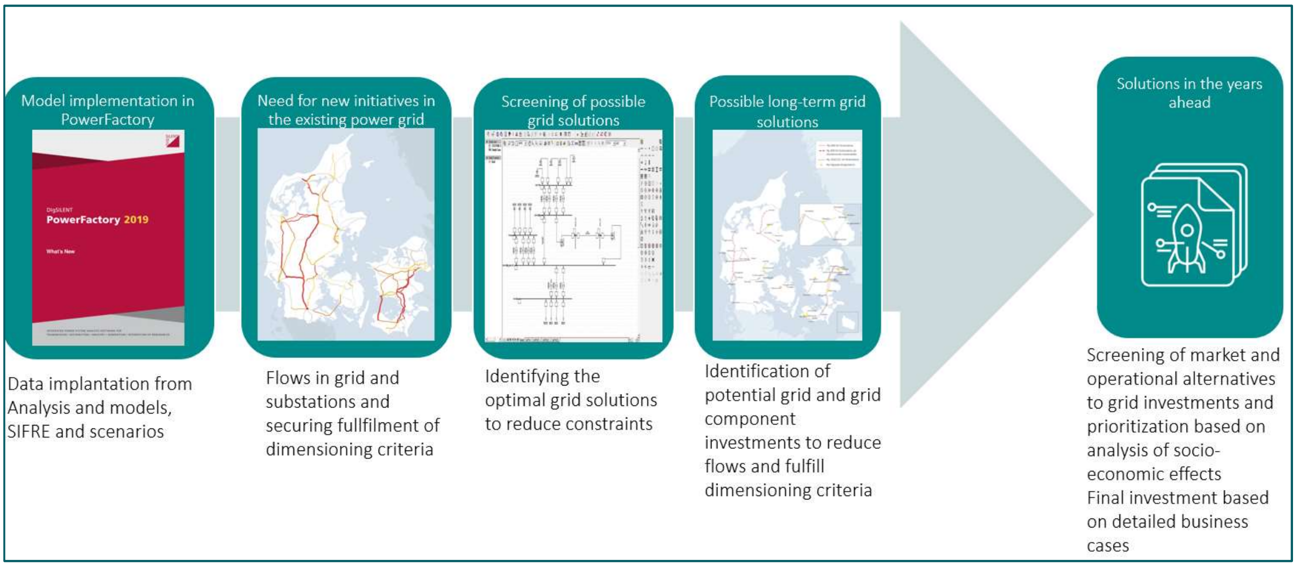


Figure 43: Modelling and analysis as input to grid planning process and investment assessments. Source: *[27]*

4.4. Identifying new transmission projects

New transmission projects are identified based on the needs in the Danish power grid [27]; they can be classified according to three categories:

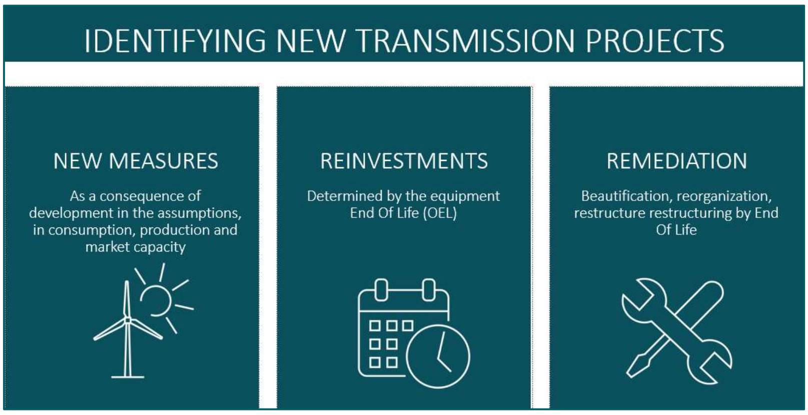


Figure 44: Identification of new transmission projects Source: [27]

Depending on the complexity, the identified projects will be separated into different processes, known as *'Tracks'* and are categorized as*:*

- *Track 1: relatively simple projects with typically one solution. Almost all reinvestments are categorized as such and also VRE and new large demand connections applications fills the majority of the portfolio for these projects.*
- *Track 2: Project with enhanced complexity and politically awareness, and this is mainly new measures, and the electrify market may have a larger role in the solution.*

New interconnectors have their own investment process and with larger involvement from ministries and Danish Energy Agency and in the end dependent on political decision.

To carry out the grid planning and to take investment decisions, Energinet is also in close corporation with the individual DSO's throughout the country, as the DSO's have local insight and knowledge for future supply and demand criteria, and by close coordination with Energinet effective planning is carried out.

Once the DSO and TSO has decided whether the applicant should be connected to the DSO of TSO grid, the procedure shown in Figure 45 below is carried out, to ensure a stable process and effective portfolio control.

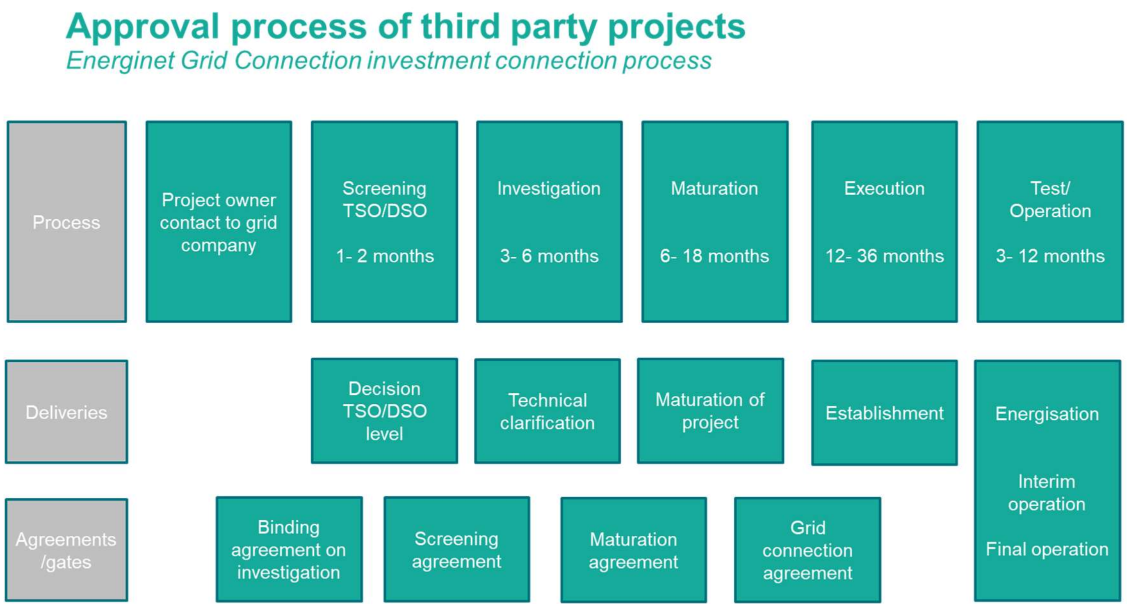


Figure 45 Approval process of 3rd party projects. Source: [27]

Energinet does not start any establishment before there is grid connection agreement based on a bank approval and confirmation of the connecting project.

4.5. Business case and investment decision for transmission projects

To fulfil the objective in the Electricity Supply Act, Energinet measures the profitability of a grid project based on socioeconomic welfare as opposed to corporate profits. This means that not only costs and benefits related to the financial performance of Energinet must be considered but also security of supply, environmental effects and those effects related to the financial performance of other agents in the economy, in particular electricity consumers and producers. Indirect effects on e.g. occupation and GDP growth are not considered.

Before making any sizeable investments Energinet makes a business case highlighting costs, benefits, and risks related to the project. The business case goes through an internal approval process before the project itself is started. For investments that do not exceed 150m. DKK the Danish Energy Agency audits the analysis while the relevant ministry (The Danish Ministry of Climate, Utilities- and Energy) audits projects exceeding 150m. DKK in value.

To calculate market effects Energinet uses an hourly-based market simulation tool. The BID (Better Investment Decisions) model is used to simulate electricity spot markets in the main part of Europe using assumptions about production capacities, consumption, wind profiles and interconnectors. Hence electricity prices and market effects for all the countries in the model are simulated. CAPEX is measured through a detailed assessment of potential establishment of a plant and the cost of it. OPEX is measured through access of components and average prices for maintenance.

Most projects involve costs and benefits that have different timing. Typically, most costs are incurred early in a project while benefits are spread over a long time period, in some cases more than 30 years. Energinet uses a NPV criterion to determine if a project is profitable. When calculating the NPV of a project Energinet uses the official discount rate as set by the Danish Ministry of Finance. The current discount rate is a 4 % real interest rate for the first 35 years and 3 % for the next 35 years. When evaluating the profitability of a project it is important to compare results with the correct alternative. The correct alternative is the situation that would have occurred if the given project would not have been commenced. For example, the state of the electricity system might be such that certain investments are needed to keep it functional at an acceptable level.

Type of investment	Criteria	Financing	Decision maker
Cross border investments (Interconnectors)	Optimization of investment.	Energinet owned interconnectors financed by loans from Danish National Bank and depreciated based on technical life-time (30/40 years)	Political process
Re-investments	Overall positive socio economic.	Re-investment of infrastructure is financed by the tariff	Energinet
General development of infrastructure	Subject to Board approval.	Development of infrastructure is financed by the tariff	Energinet
Connections of RES-assets on transmission system	The developer is required to provide financial assurance.	Pre-tender site assessment financed by DEA/developer	Energinet

Table 2 Four different types of investment in the Danish transmission system

Cross border investment or interconnectors are made in a partnership with another TSO. (These projects are primarily listed in TYNDP). Traditionally, the process of identifying a cross border investment is decided based on political ambitions and strategies as well as socioeconomic benefits for Denmark and the partnering country. Once both TSO's have formally indicated interest in the project, feasible studies are conducted. There are several criteria to be considered in cross border investments: (technology choice, capacity, timing, onshore connection, routing, internal grid investments).

Reinvestments in transmission infrastructure are identified in Energinet's annually publish Grid Plan. The Grid Plan identifies needs for the transmission system. Before deciding a reinvestment in the transmission infrastructure, a business case is conducted to determine the overall socioeconomic benefits.

General development of the infrastructure is analysed in Energinet's LDP. The LDP incorporates dialogue with stakeholders to identify possible alternatives to development of infrastructure. Before imitating a project, a socioeconomic analysis is conducted in a business case in order to determine the economic impact of the project. The business cases are subject to board approval. Depending on the cost of the project, the process for initiation and approval is different. More information is provided in the memo "*Responsibilities of the Danish Energy Agency related to investment in the national power grid*" by the DEA. [28]

Table 3 below reports an example of Energinet's economic investment analysis. Underlying any analysis is a set of basic assumptions. Energinet publishes its assumptions yearly to make transparent what is expected to happen in the future. Some information is confidential and cannot be made public because it can affect electricity markets. For this reason, Energinet also maintains an internal set of assumptions. However, the differences between the external and the internal set of assumptions concern only a few details.

Investment criteria (third party connection)		Alternative x	Alternative y	Alternative z
Energinet	+NPV investments	200 mil. DKK	220 mil. DKK	150 mil. DKK
	+NPV operations	20 mil. DKK	20 mil. DKK	50 mil. DKK
	=NPV	220 mil. DKK	240 mil. DKK	200 mil. DKK
Integration of VRE	Potential for integration of VRE	local	regional	local
Security of supply	Change in expected non-delivered energy	No impact	No impact	X GWh from 2030
Risks	Number of identified risks	3	3	5
Impact on environment	Pollution, impact on landscape/nature, CO_2 effects	SF6 gas	SF6 gas Impact on local forest	Limited impact
Safety	Impact on Lost Time incident frequency	limited	limited	limited
Image	Impact on image	limited	limited	some
Plans	Included in current long-mid-term plans	yes	yes	yes

Table 3 Example of business case overview for track 2 project

When evaluating the profitability of a project it is important to compare results with the correct alternative. The correct alternative is the situation that would have occurred if the given project would not have been commenced. For example, the state of the electricity system might be such that certain investments are needed to keep it functional at an acceptable level.

Beside the economic and criteria, there can in some projects also be other criteria involved as use of cables instead of overhead lines due to other environmental effects and according to environmental protection.

4.6. Financing and cost distribution of investment projects

Energinet's grid investments are financed by the grid tariff. The socialized tariff is based on the consumption of electricity with approximately 0.06 DKK/kWh ≈ 0.7 INR/kWh. The operation of the electricity system is financed by the system tariff and is also approximately 0.06 DKK/kWh ≈ 0.7 INR/kWh.

The grid and system tariff have been increasing over the last 5 years and is expected to increase with 10-20% pr. year toward 2023. This is due to grid extensions and increased system operation costs to ancillary services and it-systems. The increased interconnector capacity is expected to give positive earnings from congestion income between connecting electricity market prices areas.

A change in tariff is being discussed with stakeholders and DEA and with suggestion to change from energy based tariff to a combined capacity and energy based tariff. This should result in more cost based tariff, where large generators and consumers covers a fairer share of the costs from their use of the grid. Further a suggestion for possible geographical grid connection tariff are being investigated to give incentive to locate new generation and consumption in areas with excess grid capacity and reduce new connections in areas with limited transmission capacity.

4.7. Nordic transmission planning

Energinet, Fingrid, Statnett and Affärsverket Svenska kraftnät publish a common Nordic Grid Development Plan (NGDP) every second year by request of the Nordic Council of Ministers. The purpose is to communicate a common Nordic view on the overall development of the future power system, the status of ongoing and planned investments of Nordic significance and how these investments contribute to Nordic socioeconomic welfare.

The NGDP is intended to function as a complementary bridge between the national planning processes and the ENTSO-E Ten Year Network Development Plan. This is especially true for the analysis of the selected corridors, where the ambition is to present a comprehensive overview of the net benefits of increasing the transmission capacity, describe the main drivers and provide an assessment of the uncertainty of possible future investments.

An important part of the work has been to prepare a common Nordic reference scenario with data sets for use in each of the TSO's market models. The data sets are used as a point of departure for the bilateral analyses and includes one common scenario for 2030 and 2040.

A significant part of the Nordic cooperation on grid development is about sharing knowledge and data on the overall future system and market development, both in the Nordic area and in Europe as a whole. As the European power system is becoming increasingly interconnected, each TSO needs to have a good understanding of the main features of European development since changes to one power system affects the others more and more. The increased understanding is additionally relevant in national grid development and associated plans. In addition, this sharing of data and knowledge is a prerequisite for making consistent and sufficiently coordinated Nordic grid development plans. Thus, a closer cooperation on relevant scenarios, methods and data sets, provides efficiency and increased quality both on the national and the Nordic levels. Finally, a closer Nordic cooperation makes it easier to have an impact on the long-term analysis and grid planning within the ENTSO-E. It is the ambition of the Nordic TSOs to further improve the cooperation on grid planning, studies and the joint effort within the ENTSO-E.

As mentioned above, the Nordic Grid Development Plan will be updated every second year as part of the larger cooperation described in the report "*The way forward – Solutions for a changing Nordic power system*" [29]. Updated scenarios for market development, the overall need for more grid capacity in the north-south direction, more capacity in the whole Nordic region and more interconnector capacity are all relevant topics in the next plan.

Overall comparisons of transmission planning approach

Table 4 proposes a comparison of transmission planning approaches in India, Denmark, Nordics and Europe (ENTSO-E) is shown in condensed form. The comparison is made for the parameters: “Use of scenarios”, “Use of Cost Benefit Analysis (CBA), societal or production cost”, “Stakeholder involvement”, “Use of Non-Transmission Alternatives (NTA)”, “Planning Horizon” and “Focus on interconnectedness with neighbours in the planning process”. The table is thought to be to a high degree self-explanatory and is to a high degree the basis for the described recommendations in Chapter 0.

	India	Energinet- TSO	Nordic TSO cooperation	ENTSO-E
Use of scenarios	India uses combinations of drivers (fuel price projections, demand projections, hydro years) as planning assumptions for the future generation addition plan/scenarios. These generation addition scenarios then go as input to transmission planning.	Uses Analysis Assumptions (AA) from DEA for the future. Latest AA is for 2021. AA 21 is building on ENTSO-E National Trend scenario from TYNDP 2020. European scenarios "Distributed Energy" and "Global Ambition may be used in sensitivity analyses.	Common Nordic reference scenario developed in co-operation among the Nordic TSOs (Denmark, Norway, Sweden, Finland).	In 2020 the ENTSO-E TYNDP included three scenarios. They all are on track by 2030 to meet the climate targets set out by the EU. Each scenario represents an overall coherent future across the society with focus on energy sectors. The scenario application is about framing uncertainties in the future.
Use of CBA (societal or production cost)	Uses reductions in costs of generation and energy not supplied as measure for benefit, as part of building generation addition plan/scenarios.	CBA is used to evaluate societal costs and benefits of projects (e.g., new interconnectors). Benefits are unfolded into consumer surplus, producer surplus and congestion rent. Least cost planning approach in obligatory projects (e.g., connections of RES)	CBA is used to evaluate societal costs and benefits of interconnector projects. Benefits are unfolded into consumer surplus, producer surplus and congestion rent.	CBA is used to evaluate societal costs and benefits of projects. Benefits are unfolded into consumer surplus, producer surplus and congestion rent.
Stakeholder involvement	Stakeholder involvement is handled at all the three levels i.e. during formation of generation addition plan, long term demand forecasting and transmission addition plans.	Stakeholders are actively involved throughout the planning process. Requirement In Energy act of engaging and including the public	Stakeholders are primarily involved through national TSOs	Stakeholder involvement in ENTSO-E takes place at many levels including during scenario building, screening for system needs, when formulating guidelines and through public consultation of the TYNDP and the review of decisions by an advisory board.
Use of non-transmission alternatives (NTA)	Not explicitly applied in planning at present.	Is considered when setting up the scenarios for the future. The grid solutions must always include a comparison with alternative market or operational solutions.	Is considered when setting up the scenarios	NTA solutions (energy efficiency, demand response, distributed generation, and storage) are evaluated/addressed in the pre-processing when setting up the scenarios.
Transmission plans and planning horizons	Every 5 year a new plan (National Electricity Plan consisting generation and transmission) is published. The planning horizon is 5-10 years. However, through the regional/national coordinated planning process, the transmission strengthening is identified about 6-7 times in a year.	Planning is done for short, medium (5-10 years?) and long term (20 years ahead). New LDP (Long term Development Plan) including needs and solutions each second year.	Planning horizon is 20 years. New Nordic Plan every second year. Latest from 2019. Plan is a complement "bridge" between National and ENTSO-E planning.	The main focus is on 10-15 years horizon. Some evaluations are on short term horizon (~5 years ahead) and some on extra-long term (~20 years ahead) horizon.
Degree of interconnectedness with adjacent areas and focus on this theme in planning process	Modest degree of interconnectedness with neighbours at present. With the implementation of new Guidelines on cross border trade of electricity 2018, interconnection with neighbouring countries has gained momentum and new interconnections are under discussion with Nepal, Bhutan, Sri Lanka and Myanmar.	High degree of interconnection to adjacent areas.	High degree of interconnection to adjacent areas. High focus on this issue in Nordic planning.	Europe (ENTSO-E) consists of national transmission grids which are highly interconnected. In the TYNDP planning process new interconnections between countries have a high priority.

Table 4 Comparison of transmission planning approaches in India, Denmark, Nordics and Europe.

5. Recommendations for replicating Danish, Nordic and European experience in the Indian context

The Danish experience, used to assess and validate decisions regarding new transmission lines, can be replicated in other contexts for assessing similar queries. Throughout the report, the analysis performed has compared the European, Indian, Danish and Nordic approaches to transmission planning, describing concepts, methodologies and considerations while developing new transmission planning projects. The initial aim was to provide detailed information as to the contrasting methodologies in a benchmarking report, where a comparison can shed some light on potential learnings which could benefit the Indian and European systems.

Based on the assessment performed, the authors suggest five main recommendations. Today, the planning process in India considers one basic forecast (about e.g. fuel price projections, demand projections, hydro years?) as planning assumption for the future development.

1. **<u>The recommendation is to work with maybe 3-4 scenarios for the energy futures (5-15 years ahead) in the transmission planning process.</u>**

   Scenarios are characterised by:

   - Scenarios are not forecasts; they set out a range of possible futures.
   - Each future/scenario has a story line with some determining drivers, e.g., integration of RES (renewables) or CO_2 emission targets.
   - Each scenario represents an overall coherent future across the society with focus on energy sectors.

   For each scenario it is possible to do supplementary evaluations/sensitivity analyses by varying relevant parameter values.

   The authors believe that scenario techniques are the best approach to illustrate the uncertainty about the future in coherent and consistent narratives taking into account interlinkages across energy sectors. Further, a scenario-approach enables a robust method for comparison to both previous and future plans, allowing to track progression in technology development, future trends, and key drivers.
   The scenarios should be transparent and include input from stakeholders in the energy sector.
   In ENTSO-E's TYNDP (Ten Year Network Development Plan) scenarios are very fundamental for the planning process and results. The scenario development is about framing uncertainties. Inspiration on how to develop scenarios can be found in e.g., ENTSO-E's approach [9].

   Scenarios are also used by Energinet. It is important that the transmission and generation adequacy plans are based on transparent and clear assumptions and preferably the same assumptions. Analysis assumptions are prepared by DEA to be used in Energinet's scenarios and modelling in transmission planning. This is similar to the process for Energinet's generation adequacy planning, where both analysis assumptions and technology catalogues from DEA are used as input data.

2. **<u>Transmission planning should support the further development of the wholesale markets.</u>**

   A big challenge is the lack of an efficient day-ahead market and a governing market based dispatch of power plants and transmission lines between the states/bidding zones. A market based supply would allow India to minimise the costs of electricity supply, making the best use of all existing assets, including transmission and new variable renewable resources. Market price discovery on state and bidding zone level would also be of great value for cost benefit calculations of new transmission line investments (see next bullet)

3. **<u>Cost-Benefit Analysis of an investment in generation and transmission should be the deciding factor for a new investment.</u>**

   Benefit evaluations could be unfolded and thereby be more informing by applying welfare theoretical concepts as used in both Denmark, Nordics and Europe [13].

   This is done by emulating the day-ahead market with supply and demand curves in each transmission region (or node). By this method the integration and correlation between planning and market environment is ensured in the modelling of the system.
   Outputs from the model are benefits distributed on producers (producer surplus), consumers (consumer surplus) and grid owners (congestion rents).

   Also, the benefits in each transmission region can be assessed: E.g., by increasing the capacity between a low-price region and a high price region the producers in the low-price region and the consumers in the high price region will gain and vice versa.

   So, by using welfare theory concepts it can be assessed how benefits are distributed among stakeholders and across the country. This kind of information is valuable in general and specifically when discussing/deciding on cost allocation schemes of new investments.

4. **<u>Stakeholder involvement in the transmission planning process is highly recommended as it, besides giving valuable input, also secures a higher degree of “buying in” and support to the final plan.</u>**

   Stakeholder involvement is regarded as very important in Denmark and European/ENTSO-E transmission planning process.

   In ENTSO-E involvement takes place in

   - Scenario building (workshops and webinars)
   - Screening for system needs (webinar with stakeholders to explain results)
   - TYNDP project collection (transparency regarding third party projects from developers)
   - CBA guidelines (consultations with organizations and stakeholders when updating guidelines)
   - TYNDP (public consultation of draft TYNDP: ten years network development plan)
   - “Advisory stakeholder network group” reviews ENTSO-E decisions (e.g., rejection of an investor project in the TYNDP)

Today the cooperation and involvement with stakeholders in India is taken care of in the present practices. However, the recommendation is that Indian institutions may re-evaluate their relation to stakeholders in a broad perspective and consider if some further targeted stakeholder involvement could be beneficial for the planning process. Practices from Europe and Denmark could be a good way of starting.

5. **The authors suggest India to develop a long-term strategy for stronger interconnections to neighbours.**

There could be additional future benefits in power exchanging with neighbours regarding e.g., integration of increasing amounts of variable renewables as seen in Europe, where energy import/export between countries (facilitated by the European electricity market) are ensuring a high level of renewable integration. Interconnections can also generate economic benefits in sharing of reserves. When building new interconnectors, it would be of utmost relevance for India to assess the distribution of benefits between India and neighbours, see recommendation above regarding benefit assessment. The distribution of benefits would often be used as basis for distributing the costs.

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