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Reproducible Method for Modifying a Published Electricity Network Model for Transmission Expansion Planning

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Abstract

Transmission network-expansion planning research requires reproducibility of results and comparability of research from various sources. This paper presents a process for modifying a published electricity network model so that the model can be used for exploration of transmission expansion planning problems for different load and generation profiles. Nodal voltages and branch currents are kept within performance limits by following the applicable planning codes, with reinforcements selected based on a defined strategy to achieve compliance with the applicable standards. The process can be applied to any published model and any set of planning standards to result in a base model that is suitably up to date and realistic for transmission network-expansion planning research. A case study is presented, whereby the process is followed for the "Nordic-32"—a popular reference model based on the Swedish transmission network of the 1980s—with the result being a reproducible and updatable model suitable for exploring transmission expansion planning using 2024 generation-and-demand assumptions from Sweden and network design guidelines based on the Nordel Grid Code.

Keywords: Nordic-32; transmission network; transmission expansion; planning; power system model; electrical power; power system; grid connection; system design

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1. Introduction

1.1. Transmission Expansion Planning Issues

Transmission expansion planning is a topic that is increasingly in the public eye, as the climate crisis is demanding large-scale solutions to energy supply that are placing demands on the world's transmission grids [1]. As intergovernmental groups set targets for decarbonisation [2,3], governments develop the policies and economic frameworks to enable the transition to low-carbon energy networks. Sweden is targeting net zero by 2045 [4], and leading global companies are opting to use 100% renewable electricity to replace fossil-based sources [5]. This increase in power demand requires significant investment to increase utilisation of existing transmission network assets and to optimally plan the expansion of energy networks. The goal is to facilitate the introduction of vast quantities of new low-carbon electricity generation and new electrical demands due to direct and indirect electrification of transport, heating, and industry, including deploying alternative energy carriers such as hydrogen [6,7].

All of this development brings with it significant demands for electricity. The dominant renewable generation technologies present some well-known challenges to operation and

planning of the transmission network such as intermittency of wind and solar generation [8]. The introduction of battery energy storage systems to the grids, while being capable of helping resolve congestion and intermittency of generation, are also capable of exacerbating the same problems they claim to solve: the behaviour of storage systems in a market environment might not always be aligned with how a transmission system operator (TSO) would choose to operate them. Furthermore, application of rigid deterministic planning standards for these connections can impose cumulative worst-case assumptions that can prevent these projects from connecting ahead of the network reinforcements they are designed to obviate [9], limiting the capacity of the network to host new connections.

The requirement for new transmission circuits has grown significantly, with advanced economies forecast to build 3 million circuit km and emerging economies to build 12 million circuit km globally, by 2050 [10]. For example, the re-nationalised National Energy System Operator (NESO) in the UK has 23 planned new 400 kV routes in its 2024 Transmission Works Register [11] and Svenska Kraftnät in Sweden have 32 in their 2024 Grid Development Plan [12]. The identification of needs case and optimum design of network reinforcements requires simulation of future scenarios on a suitable model.

1.2. Transmission Expansion Planning Models

Transmission System Operators or Network Owners, collectively referred to as TSOs in this paper, do not generally publish their system models. TSOs in some countries are more restrictive than in other countries. Some TSOs publish reduced, simplified models, such as the "GB-36 bus" system [13]—designed to be realistic—while others publish reference models that are deliberately different from reality. Some TSOs publish detailed actual network data in spreadsheet format to enable model building by consultants for connecting projects and for academic research. An example of this is the technical appendices to the annual Electricity Ten Year Statement (ETYS) for the GB transmission system [14].

The Nordic-32 was developed over 30 years ago, to enable academic research into the problems of that time in lieu of actual network data being made available by the Nordic nations. The principle is to have a model that is sufficiently realistic that principles can be demonstrated on it. If a TSO were to publish an accurate model, then that would form a reliable starting point for transmission expansion planning research. If the TSO publishes sufficient data to enable creation of an accurate model, then researchers could validate such models against published network output data such as inter-regional boundary flows or eternal interconnector flows for given sets of generation-and-demand outputs. This would provide confidence that the model reflects the reality at the time of that data. Where such data is not available, the researcher requires a method of obtaining a model that, while not necessarily reflecting any specific actual network, does reflect a network that complies with a specific set of planning standards and so is appropriate for considering transmission expansion planning against that set of standards.

The Nordic-32 is loosely representative of a critical operational state of the Swedish transmission network around the early 1980s [15,16], and has demand and generation profiles that reflect the scale and spatial distribution of industrial, commercial and residential loads of that time. Generation is hydro power in the north and nuclear and some thermal plants in the central and southern regions, with interconnection from northern Sweden to Finland and Norway lumped together. It is not clear how interconnection to other networks is considered in the original Nordic-32 model; it appears that some interconnection might be lumped together with loads and generation at some peripheral nodes. Firm conclusions on this are hard to draw, though attempts have been made to do this [17].

The original Nordic-32 is not suitable for Swedish transmission expansion planning studies because it is not secure against the criteria set in the Swedish planning standards.

This is unsurprising, among other reasons because the model combines multiple circuits and nodes into single lumped representations.

In the absence of better options, the Nordic-32 has been used extensively for system studies, including power system stability [18,19] and smart grid solutions [20,21]. In many cases, the original Nordic-32 is modified in some way to make it fit the performance aspect that is being investigated. Besides academics, the International Council on Large Electric Systems, CIGRÉ, has also been involved in the model since its creation, using it for dynamic voltage stability assessment, adapting and modifying it along with other published reference models, to enable research questions to be analysed and results shared [16].

A benefit of reference models over TSOs' own models is that TSO models are constantly evolving, and this makes repeatability challenging to achieve. However, when reference models are adapted for specific research purposes, a different model is developed each time, and this makes it difficult to compare the findings of one study with those of another. Typically, different approaches are taken to modifying the circuit impedances, topology, and reactive compensation requirements in response to updated load and generation data. This indicates a need for a standardised approach to adapting published models.

1.3. Contributions

This paper is the beginning of further research in the field of transmission expansion planning (TEP) that approaches the task from the perspective of a TSO. The goals of the forthcoming research series are to improve existing practices through formal scientific exploration of improved transmission expansion planning processes based on experience and ideas formulated during the lead author's career. Figure 1 (top) shows how this paper sits within this seam of academic research and Figure 1 (bottom) shows how this research seam sits within the industry.

The examples of the forthcoming research are a formulation of methods to define the ability of a transmission network to connect new large demand and generation projects without unreasonable delay or cost (hosting capacity), using traditional approaches offering firm capacity and planning for agreed and controlled curtailment under non-firm connection agreements. The tools and techniques for specifying the terms of these arrangements is also a valuable future output, and it requires a suitable model as its foundation. Connection queues can threaten the transition through delays and deterring private investment, and so the choice of whether or not a project should need to wait for a specific large network reinforcement prior to it connecting is of high importance, as is the research to explore and improve the decisions made by a TSO on this matter.

A broad and increasingly topical trend in transmission expansion planning is stochastic methods and probabilistic planning. Having a base model that complies with the existing planning standards enables research that can demonstrate the different outcomes that can be achieved by a TSO if their planning standards are changed to incorporate stochastics.

The reference model and data that are used to demonstrate this process in Section 4 of the paper are the Nordic-32 and Swedish 2024 actual published data, and are explained in Section 4.4.3.

To summarise, the main contributions of this paper are the following:

- Fully developed methodology for adapting a published standard power system model for transmission expansion planning research.
- Insider insights into transmission expansion planning methods in use today.
- Practical, step-by-step guidance through the proposed model updating process.
- Example open-access multi-format modified Nordic-32 model suitable for 2024 Swedish transmission expansion planning studies.

- The foundations of further academic research into improved methods of transmission expansion planning.

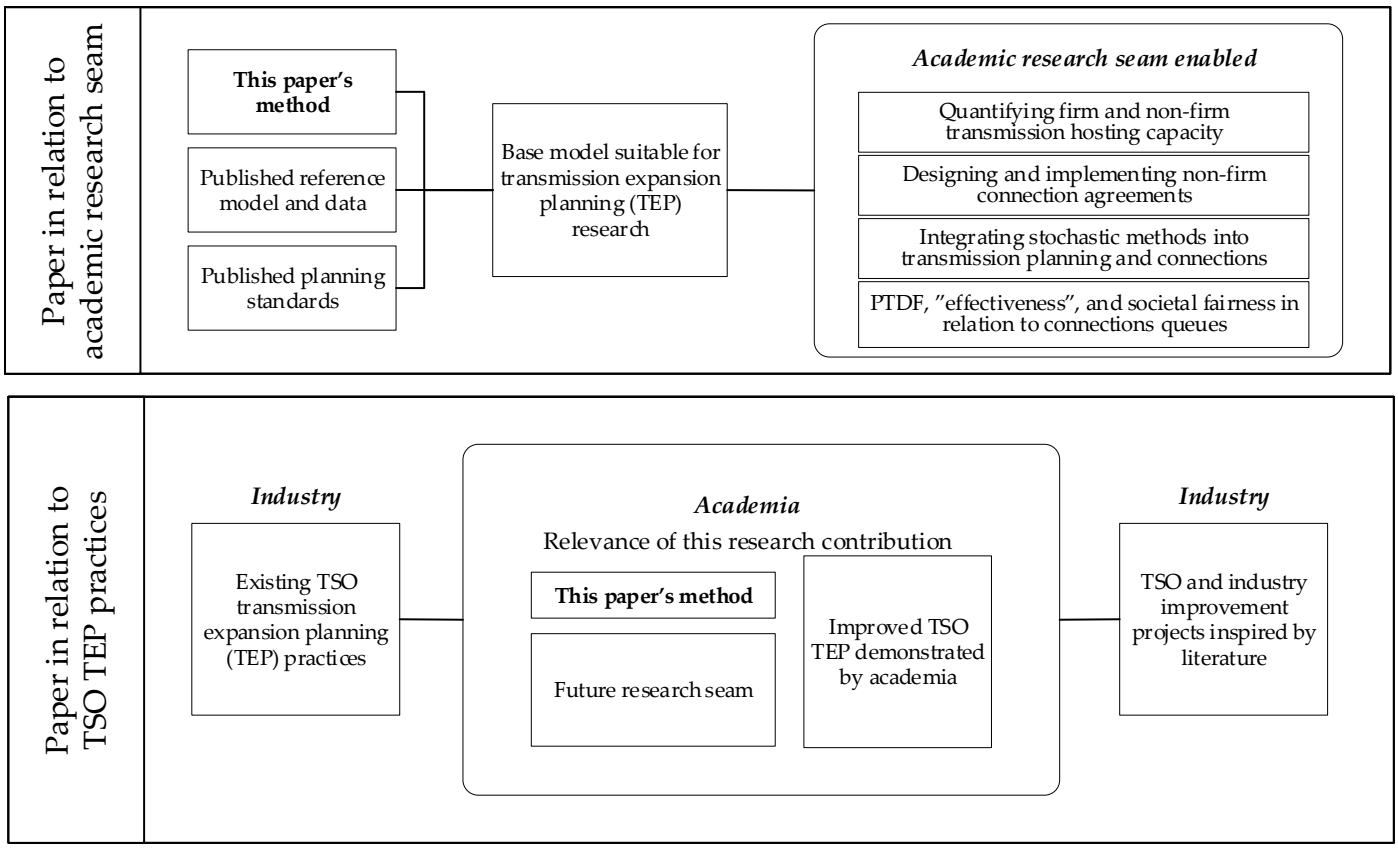


Figure 1. Visual positioning of this paper's contribution to academia (**top**) and to improved transmission system operator/owner (TSO) and industry processes for transmission expansion planning (TEP) (**bottom**).

1.4. Structure of the Paper

Section 2 of this paper presents the general principles of model modification, then Section 3 provides a generic process flow for model modification. Section 4 works through a case study example of modification of the Nordic-32 for application to transmission expansion planning studies, before Section 5 discusses the findings and Section 6 concludes the paper.

2. Transmission Expansion Modelling Principles

2.1. Purpose of Transmission Expansion Planning Models

A model is only as good as the data that informs it, and since the primary task of a transmission expansion planning model is to plan system reinforcements several years out into the future, it will always be an imperfect estimation—a forecast scenario.

The purpose of a model used for classical transmission expansion planning is to test out possible configurations of network demand and generation that reflect a situation that might be at the extreme point of required performance. In the UK, these are referred to as cardinal points and in Sweden they are called dimensioning cases. This means that rather than studying every point in time with fine resolution, a single point or a set of points along the daily demand curve are studied. For generation dispatch, different patterns and degrees of network depletion are considered. The severity of these scenarios is defined at a level that is considered to be sufficiently credible to warrant investment, should they lead

to unacceptable system technical performance. These governing documents aim to find an appropriate balance between operational risk of the future network and transmission expansion cost (investment, social and environmental). Exploration of these codes and standards presents important research questions that are outside the scope of this paper.

When updating a transmission expansion planning model for academic research, the impact of a new method or technology type or application can be tested to demonstrate its performance in a simplified controlled environment: simulation results, with and without the novel aspect, can be used to show its effect on the transmission expansion requirements. This is the intent for the series of research outcomes highlighted in Figure 1 (top), such as non-firm connection agreements and stochastic methods. For a TSO, it is more likely that the impact of a new connection application (e.g., wind farm, data centre or hydrogen production) is being assessed, but the principles are similar for, and the requirements for an appropriate model are shared by, the TSO and researchers alike.

2.2. Data Flows for Transmission Expansion Planning

The process of planning and designing the transmission network that is required in the future is about managing risk and uncertainty and involves many data and information flows between stakeholders that take place both in person, through live documents and analysis, and through pre-defined governance documents, standards and codes. Figure 2 shows these data and information flows for the transmission expansion planning process as it relates to a new customer connecting to a transmission network.

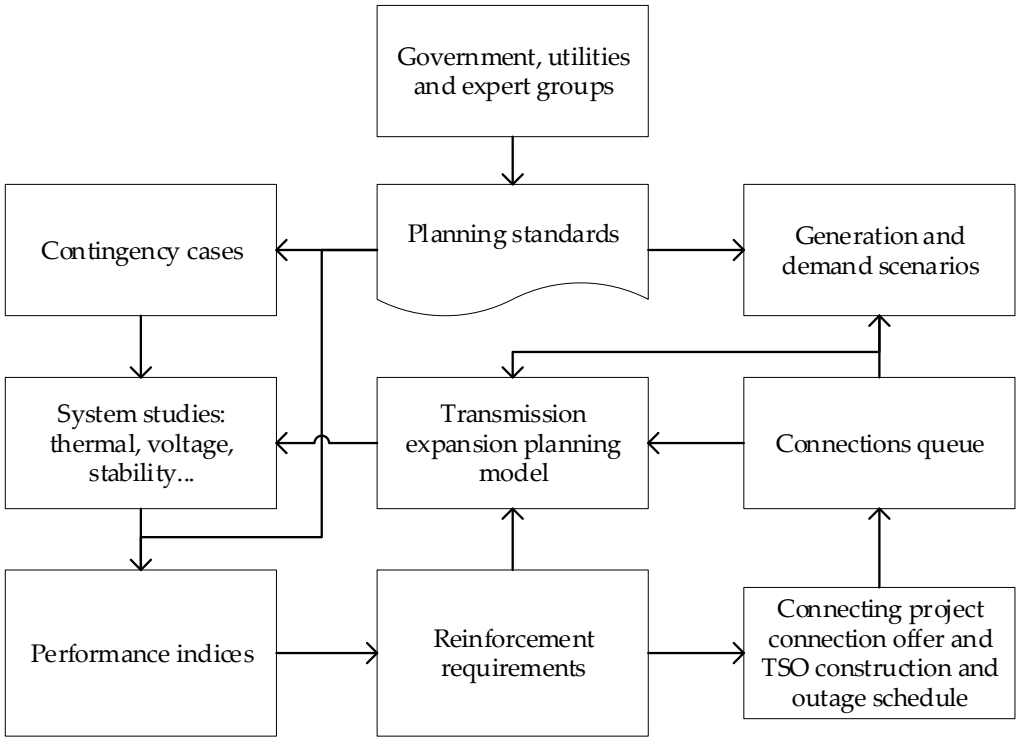


Figure 2. Data flows for transmission expansion planning.

A notable feature of Figure 2 is the centrality of the transmission expansion planning model and the system studies made on it to the outcome of individual projects and to the expansion of the transmission network. The model inputs and the selected scope for the studies are also pivotal to the evolution of the energy network in the region that the model relates to. These decisions shape the landscape—visually, environmentally and socioeconomically—and it is choices made by engineers on the selection of data and the interpretation and application (or otherwise) of sometimes outdated planning standards

that determine these decisions. A case study of this effect is the UK, where connection volumes drove a departure from studying the full planning standards (National Electricity Transmission System Security and Quality of Supply Standard, NETS SQSS) [22] for connections, to only applying pre-fault criteria and then to stopping carrying out connection studies that had no local implications [9,23] related to fault level and substation layout. This increased the risk of incorrect or insufficient transmission network reinforcements being specified. A greater degree of centralised locational and technology-specific strategic planning is now proposed under connection reform [9,24], and is an example of responding to connection volumes and the challenges of the energy transition by moving transmission system design back from private control (National Grid Electricity Transmission, NGET) to a central government entity (National Energy System Operator, NESO).

Policymakers traditionally have input to the higher-level structure of the industry and its financing mechanisms and to the planning rules via grid codes and planning codes. They do not, however, have direct input to the decisions made by the TSO on network reinforcements or project connection dates. Control of the small details of the processes is retained by the experts, and these details can and do determine the resulting design of the transmission network. Model input data is central to these decisions.

Assumptions on what set of network conditions (contingency cases) should be included are defined by the relevant planning codes, which are designed to balance the costs and risks of network reinforcement options, including making no reinforcement. Through strict application of these planning codes, the ability of a TSO to connect a defined quantity of a specific technology type at a specific substation at a specific time can be determined, and is sometimes known as the firm hosting capacity.

Generation-and-demand patterns are usually defined by pre-agreed, though sometimes vague, scenarios specified in planning codes (for example, "credible worst-case conditions of wind and PV"), and should take account of the other connections that are contracted ahead of the connection under study (the connections queue). It is common to study winter peak demand, summer minimum demand, and maximum demand during the maintenance period, along with any other conditions that might be expected to form the limiting conditions for the performance indices. This can be highly network-specific, and is usually informed by operational experience and/or large datasets and analysis and documented in TSO internal procedures rather than planning codes, although some codes are more prescriptive than others. In the literature, the definition of contingency cases is also considered, but is often done through selection of a specific approach rather than by reference to planning standards [25–27].

Different TSOs and networks have different levels of availability of key model input data. The planning standard for the Nordic synchronous grid, Nordel Grid Code, for example, specifies fault groups but then provides loose definitions such as "local consequences", where local is undefined, and "minor grid breakdowns", with no criteria to judge what is a minor breakdown or what becomes a "major national disturbance." It does not specify the generation or demand patterns to use, stating that "economically reasonable generation situations shall be assumed," [28]. In addition, it is not clear, post-2015, whether the Nordel Grid Code still applies, as it is no longer updated, and the replacement harmonised European legislation from the European Network of Transmission System Operators for Electricity (ENTSO-E)—requirements for generators [29] and demand connection code [30]—do not provide any detail at all on how the network is to be dimensioned/what the rules or processes are for transmission expansion planning in Sweden.

The planning standard in the UK, the NETS SQSS [22], is more specific. The NETS SQSS reads in a legalistic way and uses tightly defined terms such as "The *transmission*

capacity for the connection of a *power station* shall be planned such that, for the background conditions described in Section 2.8, prior to any fault there shall not be any of the following: 2.9.1 equipment loadings exceeding the *pre-fault rating*; 2.9.2 voltages outside the *pre-fault planning voltage limits* or *insufficient voltage performance margins*" (original italics, denoting a defined term). This way of formulating achieves precision, with less scope for (re)interpretation by a TSO. This is not, however, a complete picture or a fully transparent process either, because many finer modelling and study-setup assumptions are needed for transmission expansion planning. More scenarios, including minimum demand scenarios, reactive power scenarios, and consideration of generation technology performance like wind profiles and solar irradiance assumptions, are also used to dimension the UK network. Further details to guide the engineering decisions are then provided in internal governance documents. These are not always kept up to date, and processes followed may deviate from governance documents, may vary between TSOs, and may also vary within a TSO as a function of internal and external politics, workload/capability and regulatory incentives [23,31]. In the literature, it is common for decisions on which set of generation-and-demand scenarios to study to be made without reference to TSO or industry guidelines: the definition of scenarios in the literature is somewhat arbitrary. Often, the resulting choices will align broadly with those typically made by TSOs, but without the auditable reference to such an authority [26,27,32].

The connections queue is not always published or kept updated by a TSO, but is an input into transmission expansion planning studies. Academics can look to large projects' own publications and news stories for information on their ambitions and can use published development statements, connections registers, or any other published data on network options assessments from the relevant TSOs, to inform about major project timelines and identified future reinforcements. Or they can use assumed data. For example, the UK aims to publish a register of all large generation applications that sign a connection agreement for transmission entry capacity (TEC register) [33], but Svenska Kraftnät, the TSO in Sweden, do not, although some information about their expansion plans made in response to selected larger connections is offered in their annual Grid Development Plan [12].

2.3. The Need for Modified or Updated Models

The key question to consider when updating a model remains the following: what is the model to be used for? Whether or not actual data or best-estimate data is needed, depends on the answer to this question. Sometimes highly uncertain estimated data is sufficient.

There can be different times and purposes for initiating transmission expansion planning studies. For the TSO:

- In response to a connection application for a new connecting project above a certain size; or
- Through a regular (typically annual) process of assessing system requirements in general.

For the academic researcher:

- When seeking to prove a new concept or technology in application to a transmission network, since full-scale experimentation is not possible; and
- To find and to share improved processes and approaches to solving transmission expansion planning problems.

In all these cases, it is usually necessary to position the study, at least partly, in the present or in the future. Published models for academic use, however, are always somewhat out of date by time of publication, and highly used models such as standard test models

published in books or international standards are likely to be a few years old by the time of publication, and older still when used.

In addition to the lag time between the authors collating data to inform a model and readers deciding to use it, one must also consider that there is no requirement for published models to reflect actual generation-or-demand assumptions for the region that they are deemed to be representing. Furthermore, in some cases, a decision is made by a TSO to release a model that reflects something different from reality, as we discussed in Section 1. The academic research community requires only that a model is capable of demonstrating a new approach, process, or technology, to enable proof of concept. The model must conform to the planning standards of the case study or to some defined set of typical planning rules. It is then for a specific TSO to prove the application of the new concept to an accurate, detailed, and up-to-date model of their network.

An example of the need to update a published model in order to conclude meaningful transmission expansion planning studies comes from the Nordic-32 network. The Nordic-32 does not include any wind power, since such projects did not exist at scale when the model was produced. Northern Sweden, however, at Markbygden, has what is planned to become the largest windfarm in Europe, with 2 GW of a planned 4 GW of capacity already installed. It is necessary to include this technology change, as well as the additional generation capacity to the generation mix for transmission expansion planning studies in the Nordic region, because the change to the dispatchability and predictability of the region's generation on different timescales can be important for identifying transmission reinforcement requirements. This is particularly pertinent when looking at the effects of voltage or angular stability on transmission expansion because, as conventional generation is replaced by inverter-based resources, there is a resulting reduction in stored kinetic energy both locally and in the wider synchronous region (inertia), a trend that is well-documented [21,34–36].

3. Transmission Expansion Model Modification Process

3.1. Key Inputs to the Process

Figure 2 shows the flows of data and information that are required. We can use these to identify which data sources are needed to enable the model modification:

- Original model.
- Target-region planning standards, to inform:
  - Contingency cases to include;
  - Generation mix;
  - Which demand scenarios (cardinal points of load curve) to include;
  - Study scope (performance indices (PIs) of interest, e.g., circuit loading, voltage, angular stability…); and
  - Performance limits for each PI.
- Statistics/publications from, or about, the target region, to infer information on planning standards where there is no published information.
- Demand data for the target region of interest.
- Reinforcement options and history in the target network.

The above are all system study inputs, but might not all be readily available. Assumptions may be needed. These parameters may themselves be a focus of the research, or perhaps sensitivity parameters within the study. Planning codes do not always provide clear guidance on which cardinal points of demand to study.

Where there is either vague or no information from official sources made available publicly, inferences can be drawn by searching publications by the TSO or regulatory bodies

such as [12]. The most important thing is that results are reproducible and updatable by following a defined and repeatable process.

How to select and prioritise reinforcement options is important where standardisation of the model update process is the goal. It is logical to limit the set of options to those that have already been deployed—on the assumption that these are the most likely to be used again—but one must always consider what technologies existed in the time lag between the published model and the year for which it is being updated. Furthermore, there could be innovative smart-grid solutions that are being proposed for comparison against existing options. For example, smart-grid technologies such as power flow control devices [37] and operational control options such as global or local supervision schemes for soft or hard curtailment [38] or dynamic-line-rating [39–41] reliability analysis and stochastic approaches [40] and operational risk assessment [40,41] can be compared against conventional approaches [42]. To ignore options such as these could limit the scope of application of the research being carried out on the model and indirectly discourage a TSO from embracing technological and process change.

As technology evolves, it is desirable that the model used to demonstrate the performance of new technology also evolves to more appropriately reflect the key technical performance aspects of the network(s) expected to host the new technology.

3.2. Process Flowchart

In Section 4, we present a detailed case study that demonstrates the application of each step of the process presented here to an example network. The present subsection concerns the general process flow for the model updating process.

The general process for updating the model is based on the same principles as transmission expansion planning itself: the difference is that underlying data in the model is changed. Whether a researcher is modifying a published model to fit the latest data or the TSO is modifying the contracted future network model to assess the connection of the next GW of hydrogen production, the requirements for updating the model to reflect the new future condition under test conditions and to then assess the system technical performance are broadly the same. An important difference is that whereas a TSO will typically maintain a model that can implement each new connection of generation, demand or system reinforcement incrementally, ensuring compliance with the planning codes at each increment, researchers updating a model are, in our case, attempting to jump from the model state at publication to a model that is compliant with the planning codes at the time of the latest data we have available. This can be decades ago and, in the case of the Nordic-32, can involve increases in demand that dictate significant changes to the network (in the Nordic-32 example, the original peak demand is 2.34 times lower than 2024 Swedish peak demand). Figure 3 breaks the process for updating the model down into a few key stages, and shows how the general method for transmission expansion planning as is typically performed by a TSO, which is a main contribution of this paper, compares to the method deployed for preparing a model for transmission expansion planning, which is another main contribution of this paper. The main stages of the method are then described in further detail.

3.3. Gathering All the Required Data

The box with ~1 in Figure 3 (right) includes the scope of the studies (thermal, voltage, angular stability…), generation capacities and dispatch assumptions (e.g., time series or cardinal points of each generator or lumped by technology with a method of allocation to specific nodes), demand profiles (time series or cardinal points, including a method of allocation to specific load elements), network contingency cases (e.g., N-1 of series- or

shunt-connected elements), limits on performance (e.g., thermal ratings of circuits, voltage limits, boundary/cross-cut flow transfer limits) and reinforcement options that have been previously specified in the target region, to inform the choice of least-cost reinforcement.

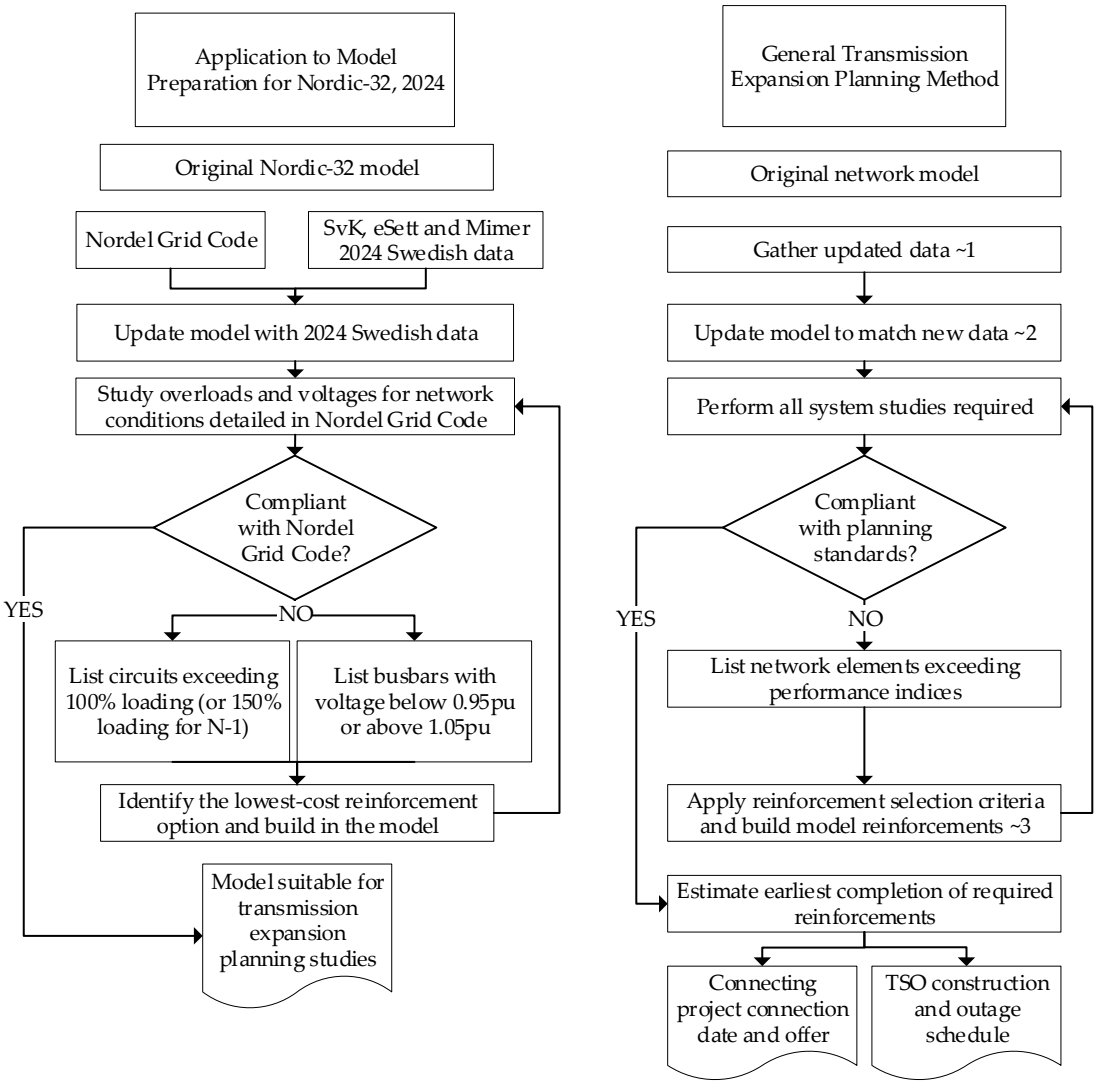


Figure 3. Process flow for model updating and transmission expansion planning with the general method (**right**) and how it can be applied to the 2024 Swedish case (**left**) to produce a model that is suitable for transmission expansion planning from any generic published model.

3.4. Updating the Model

The box with ~2 in Figure 3 (right) is where the new data is loaded into the model. This includes the decision to either update the model in a single pass or to split the updates into several incremental steps. Incremental steps can make the model easier to handle, reducing the likelihood of non-converging loadflows, which are to be expected if the data change is large. In these cases, increasing total demand in multiples of around 10% will improve the chances of convergence.

3.5. Dealing with Non-Convergence of Loadflow

While it can be tempting to declare that a non-converging loadflow means the network is in breach of its performance limits, there could be other factors at play, particularly in a complex model and with complex software. Controllers might be incorrectly configured or network topology might be in an unintended state. Only by obtaining converged loadflow solutions is it possible to draw conclusions on the performance of the network.

In the case of non-convergence, a DC loadflow can be used to identify circuit-rating breaches. Consider that some of the capacity will be used up by reactive power flows, and so it is appropriate to not allow the full overload capability for DC loadflow. Alleviating these overloads and attempting an AC loadflow will leave voltage breaches. If an AC loadflow still does not converge, relax voltage limits in network elements (e.g., busbars) and consider changing loadflow settings to prevent reactive power limits from affecting reactive power output of elements (e.g., generators or HVDC). If a loadflow now converges, then inspect reactive power flows in the model to see which locations are most in need of reactive compensation. If a loadflow still does not converge, then use DC loadflow results to identify the receiving end of large flows on long lines; these may well be the weakest points. Now, add sources of infinite reactive power with a voltage setpoint equal to the busbar target voltage at these nodes and to other nodes if needed, until an AC loadflow will converge. These are, of course, temporary, and are used to enable loadflow results that will enable specification of appropriate reinforcements to resolve the voltage issues in the network in a more realistic manner.

3.6. Identifying Performance-Limit Breaches for All Secured Events

On the face of it, identifying performance-limit breaches is a case of simply running a set of loadflows. However, the choice of the set of system conditions against which we require the performance indices to be within their limits is a highly important factor that can drive the design of the network and the extent of reinforcements required.

The applicable planning standards can be used to select a set of contingency cases that are appropriate to consider when dimensioning the network. The Nordic synchronous network has what is called the "N-1" criteria for dimensioning contingencies. This is more nuanced than a simple application of N-1 of all network elements. For example, the Nordic N-1 criteria defines four fault groups that apply for different pre-fault conditions to give a set of acceptable consequence levels from local through regional to system breakdown. System restoration within 15 min is also highlighted and used in the first of three alert $\rightarrow$ disturbed $\rightarrow$ emergency states, during which there are blurred divisions between categories of regional and national consequence. There is significant ambiguity and space for TSO (re)interpretation of these standards. In these cases, it may be necessary to simplify the planning standards for the purposes of model modification.

For the Nordic-32 example, we assume that N-1 means a set of single-circuit outages for consideration of circuit loadings and nodal voltage limits, and consider that reinforcements are needed before the connection can be accepted if one or more of these limits are breached for one or more of the studied cases.

Transfer capacities between areas can also be included and can act as simplified proxies for stability limits, which, in operational practise, are managed through limits of flow across critical cross-cuts/boundaries. These are identified through RMS simulation studies in planning timescales to ensure that the likelihood of system instability due to inter-area oscillation and the risk of system splitting do not exceed a defined level.

Stability is studied by TSOs in planning timescales using detailed generator dynamic models for automatic voltage regulation and power system stabilisers on models that include dynamics of the transmission system. Operationally, however, flow limits from one part of the network to another are defined typically one week and/or day ahead, and these are followed by the control room operators. These inter-area transfer limits can be used as a proxy in planning timescales by researchers to enable consideration of stability when preparing a model for transmission expansion planning.

When appraising the performance limits for circuits, nodes and regional transfers, it is necessary that all performance limits are satisfied for all network conditions studied, and so we document all non-compliances against the required performance level.

3.7. Identifying Appropriate Network Reinforcements

The box with the ~3 in Figure 3, the specification of network reinforcements, is not a simple and universal routine operation—it depends on the appropriate planning standards and consenting environment of the target region and the history and proposed future development direction of the network. The task of collapsing this into a simple process for modifying an existing standard model is not straightforward, but there are principles that can be applied to enable recommendations for a defensible and repeatable approach.

Grid development plans, network development option statements or other such TSO publications can show the tendency that the TSO in that region has for selection of network reinforcement. Of course, this is difficult to define or predict, as TSO behaviour varies as a function of many things, including time and regulatory environment, but terms such as "economic and efficient", "least-regret investments" and "most appropriate balance of cost, risk and performance" give subjective indicators of how TSOs approach this task. The principle that is applied in this paper's approach is to find the lowest-cost and best-performing network upgrades to tackle the immediate breaches of simulated network performance, with an eye on expected future requirements. When updating a model incrementally, it is important to consider whether, once loads are fully updated, the reinforcement being proposed for an incremental step is likely to remain suitable for the full load increase. For example, if 2024 loading is triple that of the original model, then reconductoring to gain an extra 50% capacity is not likely to be sufficient if the line is already close to a performance limit. In this case, a new circuit is highly likely to be required, and introducing it in an early iteration will help develop the voltage performance and stability of the model.

It is important to recognise that one network reinforcement will affect the other performance indices at different locations in the network, and so an iterative process is needed until all performance indices are satisfied for all cases studied.

Circuit-loading breaches can be resolved by the following:

- A new circuit;
- Upgrading voltage level, e.g., 130 kV or 220 kV to 400 kV;
- Reconductoring an existing circuit;
- Series capacitive compensation; and
- Reducing reactive power (Mvar) flows.

Nodal-voltage breaches can be resolved by control changes and/or new assets:

- Shunt static compensation;
- Shunt dynamic compensation;
- Revised generator reactive performance charts and limits;
- Revised busbar voltage targets and limits; and
- Revised transformer tap-changer limits.

Inter-area transfer breaches can be resolved by the following:

- Reconductoring an existing circuit;
- Power flow control devices, including series capacitive compensation; and
- New circuits across cross-cuts/boundaries.

3.7.1. Reinforcing to Resolve Circuit Loadings

One solution to resolve circuit loading issues is to build new circuits. The simplest approach to this is to maintain the existing topology of the network and to install parallel circuits. This method is appropriate if single circuits are used, such as is the case in the Nordic-32. Where double-circuit construction is standard, such as in the UK, it is more likely that a new circuit will be subject to extensive design studies and optimised for minimum cost and environmental impact, considering the maximum benefit to system transfer capacity/boundary capability. In these cases, comparing different options for new circuit connections is recommended.

Reconductoring is the replacement of the current-carrying components of the circuit to enable larger flows. If the same transmission towers/pylons can be used, or modified without requiring new planning consent, then the cost and timescales are many times less than that of the construction of a new overhead line circuit. The limit for current flow on an overhead line circuit is set with consideration for the sag in the conductor due to the heating effect of the metals in the conductor. Conductor technology moves on, and replacing the original conductor type in old overhead line circuits can increase the current-carrying capacity significantly [43]. In the UK, NGET typically look to deploy the triple Araucaria 700 mm^2 conductor, 30.5 nΩ.m rated at 75 °C, for 400 kV lines. For a circuit previously strung with twin Rubus 500 mm^2 (as is common), this reconductoring will roughly double the MVA capacity, delivering pre-fault continuous rating of 4.63 kA [31,44]. In most cases, reconductoring is the best first option for significant increase in capacity, and TSO development plans may reflect this strategy. For example, NESO Holistic Network Design (HND) has 20 reconductoring projects identified out of 98 total reinforcements [45] and Svenska Kraftnät (SvK) Grid Development Plan 2024 shows 18 reconductoring projects in construction or preparation phase and 14 more under consideration [12]. Reconductoring works best when carried out along all circuits that span congested transmission boundaries (cross-cuts), so that the loss of one reconductored circuit is covered by another reconductored circuit.

Where a single circuit is in place already, there is the option to replace the towers and create a double-circuit route. This can provide more future-proofing than reconductoring, and has less of a problem with permitting than new circuits, as the route is an existing one. Changes to visual and environmental risk will still need to be considered by the host network and society, and may have an associated delay. However, these projects are more likely to pass through planning regimes smoothly than new lines are, and can be delivered in only a few years.

3.7.2. Reinforcing to Resolve Nodal Voltages

The voltage performance varies, according to model parameters such as how the lines are modelled, how reactive power demand of loads is scaled, and how generator reactive power is dispatched, controlled and limited. Reactive compensation requirements will differ, according to the modelling approach taken for long lines. Simple models like the Nordic-32 might not include line capacitance, in which case distributed parameters (recommended for long lines [46]) cannot be used. This poses a limitation on the suitability of the model for electromechanical and electromagnetic transient studies. However, for steady-state loading and nodal voltages, a lumped impedance representation for circuits is suitable.

For steady-state voltage performance studies, the choice of reactive compensation can be informed by the history of the development of the target region, as published by the TSO. What have they previously deployed to support voltage? What technology options have the TSO recently published that they are considering? While large dynamic reactive

compensation solutions will be effective, the principle of least-cost reinforcement should apply, and incremental build in stages of standard sizes as previously deployed by the TSO is more realistic. For example, 225 Mvar shunt capacitor banks at 400 kV.

Section 3.5 showed how an infinite source of reactive power at a problematic busbar can achieve a converging loadflow. Once you have a set of contingency results, you can then use this source to size the reactive compensation requirements at that busbar by adjusting the amount of reactive compensation to obtain acceptable voltage performance across all the required system contingency conditions. The temporary source of reactive power can remain in place, alongside the new reinforcements, which can be added until the temporary source is no longer contributing significantly and can be removed. The transferred impact that a new source of Mvars at one busbar has on adjacent busbars should be considered (do not try to solve the whole network with one large source at one node) and repeat the studies iteratively, until you find the minimum build solution for the affected region. It is likely that a new shunt capacitor at one busbar will support voltage within a region around that busbar, so adding shunts at every busbar that has undervoltage is unlikely to be required.

If the balance of dynamic and static compensation is of concern to ensure sufficient voltage performance for a range of power flows (avoiding system brittleness), then consider converting some of the static shunt reactive compensation units to dynamic units such as Static Var Compensators (SVCs) or Statcoms of equivalent maximum range. Allow the history of the natural development of the network to inform this selection, where such data is available. The UK TSO, for example, recommends a balance of 60:40 between static and dynamic reactive compensation, and has deployed Statcoms of 225 Mvar capacitive range and SVCs typically of 150 Mvar capacitive, 75 Mvar inductive, both with continuous adjustability throughout that range, and deploys static shunt reactive compensation at 400 kV in blocks of 225 Mvar capacitive or 150 Mvar inductive [47]. If planning standards do not specify otherwise, consider that loss of a reactive power unit should be considered in the N-1 criteria, and also that dynamic reactive compensation is designed to sit close to zero output pre-fault to enable post-fault support.

It is advisable to adjust the reactive compensation values at each bus to minimise Mvar flows around the network, as these use up capacity of the network. Transformer tap changers can be used to reduce Mvar flows, but should not normally sit on minimum or maximum tap, as some of the range is typically reserved for post-fault response. If more-accurate data for transformer tap-changer range and generator reactive capabilities is available, then this may be used if it helps with voltage profiling and can be made publicly available for others to also use.

In general, to obtain repeatability of results and comparability of research, it is important that all model parameters used are either part of an original published model or are defined by a published process, such as is provided by this paper, or are made publicly available along with the research that uses them.

3.7.3. Reinforcing to Resolve Inter-Area Transfers

Consider the transfer capacity of the boundary/cross-cut in the original model. This can be used to inform the percentage loading of all of the circuits across the boundary combined. This boundary transfer limit reflects the stability limit. For example, if four circuits, each of 1 GVA capacity, span a critical boundary for stability that is rated at 3 GW transfer capacity, then, as the model is reinforced, the performance limit for total transfer across the boundary/cross-cut should be equal to ¾ of the sum total capacity of the lines.

Inter-area transfer limits will be increased by the addition of new circuits across the boundary/cross-cut. In addition, power flow control devices such as quadrature boosting

transformers or power electronic series-connected flow control devices, including series capacitors of varying fixed or controllable degrees of compensation can change the effective impedances of circuits to better balance flows or to divert flows under post-fault conditions, to avoid breaching transfer limits as well as circuit overloads. Look to TSO publications to see what has been done in the past with these devices, but note that the impact of moving power flows is highly dependent on topology and impedances, and may not free up significant capacity compared with new circuit build or reconductoring.

3.7.4. Cost Estimates for Reinforcement Options

Typical network reinforcements can be ordered according to cost, using historical data from the network under study. The relative costs can vary a lot, both between networks and at different sites within the same network, based on urban or rural location and geography, among other factors. Publicly available data was found for the UK case. Estimation using global data might be required. The important thing is to follow a defined and documented process for selecting reinforcement technologies. In the case study of Section 4, we choose the lowest-cost reinforcement to resolve a performance index breach. The cost estimates are the result of literature searching for primary authoritative sources on actual project costs, and are used to rank the reinforcements in cost order. Costs for the UK, USA, and Europe are expected to be similar, and the data found supports this, to some degree.

1. Upgrade voltage level in urban region, e.g., 220 kV to 400 kV, including tower replacement and some cabling: forecast cost GBP 142 m for 23 km Hackney to Waltham Cross 275 kV upgrade to 400 kV, so GBP 6.2 m per km [48]. (This may be considerably cheaper in rural areas if the same towers can be used and there are no cable sections along the route.)
2. New 400 kV circuit: cost GBP 4 m per km [49].
3. Reconductoring existing circuit, 232 circuit km Harker to Quernmore Tee 400 kV estimated GBP 100 m, so GBP 0.43 m per km [44].
4. New series compensation on circuit: GBP 40 m per circuit [44].
5. New power flow control devices on circuit: UK experience is of roughly GBP 7 m per circuit with latest technology, and earlier estimation from the USA suggests USD 100–160k per Mvar [50]. It heavily depends on the ratings required and technology deployed.
6. Shunt dynamic reactive compensation: USD 40–80k per Mvar for a static var compensator (current source device) or USD 60–120k per Mvar for a Statcom (voltage source device) [50]. UK experience broadly aligns with [50], with typical 150 Mvar or 225 Mvar applications in the region of GBP 10 m.
7. Shunt passive (static) reactive compensation cost: USD 20–40k per Mvar, based on the fixed-series capacitor costs from [50], which can be expected to be similar. UK experience is in the region of GBP 3 m for a 225 Mvar 400 kV bank.

3.8. Estimating Connection Dates

Once the system studies show that no further reinforcements are needed to obtain results across all of the cases within the scope of the studies (known as dimensioning contingencies in Sweden) which have no performance indices breached, then the customer connection date can be defined. This is the date at which all of the works identified as necessary for completion prior to connection will be completed. This needs to consider deliverability in terms of funding, resources and system outage availability—it is not always possible to work on several parts of the system at once. Indeed, the N-1 criteria suggests that it might be one circuit at a time, though it is more likely to have a zonal

bias, whereby circuits that are remote from each other might be able to be on outage for upgrading or other works at the same time, whereas circuits close to each other might not.

4. Case Study: Modifying the Nordic-32 for Swedish Transmission Expansion Planning Studies

In this paper, we use DIgSILENT PowerFactory 2024 for simulations, but the principles apply to the Nordic-32 in other software [51] and to any other published model. The method is versatile, but the specific models produced belong in the context of the nations whose transmission networks they represent, and are dependent upon the datasets used and the planning standards or approaches considered.

All supporting documents are shared with the goal of enabling extension of the research in a fully open manner. The modified Nordic-32 in a reduced spreadsheet format containing all information for recreating a branch-and-node network representation is provided in the academic data-sharing repository at [52], along with the exported model in PowerFactory 2022 and 2024 formats.

This section works through a case study of how to modify the Nordic-32 to use 2024 data on generation and demand from Sweden, to enable transmission expansion planning studies. The process could be applied to any model using any generation-and-demand data. The resulting model is suitable for the first phase of need-case identification, which is typical of TSO annual grid-development studies and studies made in response to connection requests by large connecting projects. It does not consider dynamics, and so is not a complete assessment of all network reinforcement requirements, only those related to overloading of circuits and voltage compliance for contingencies.

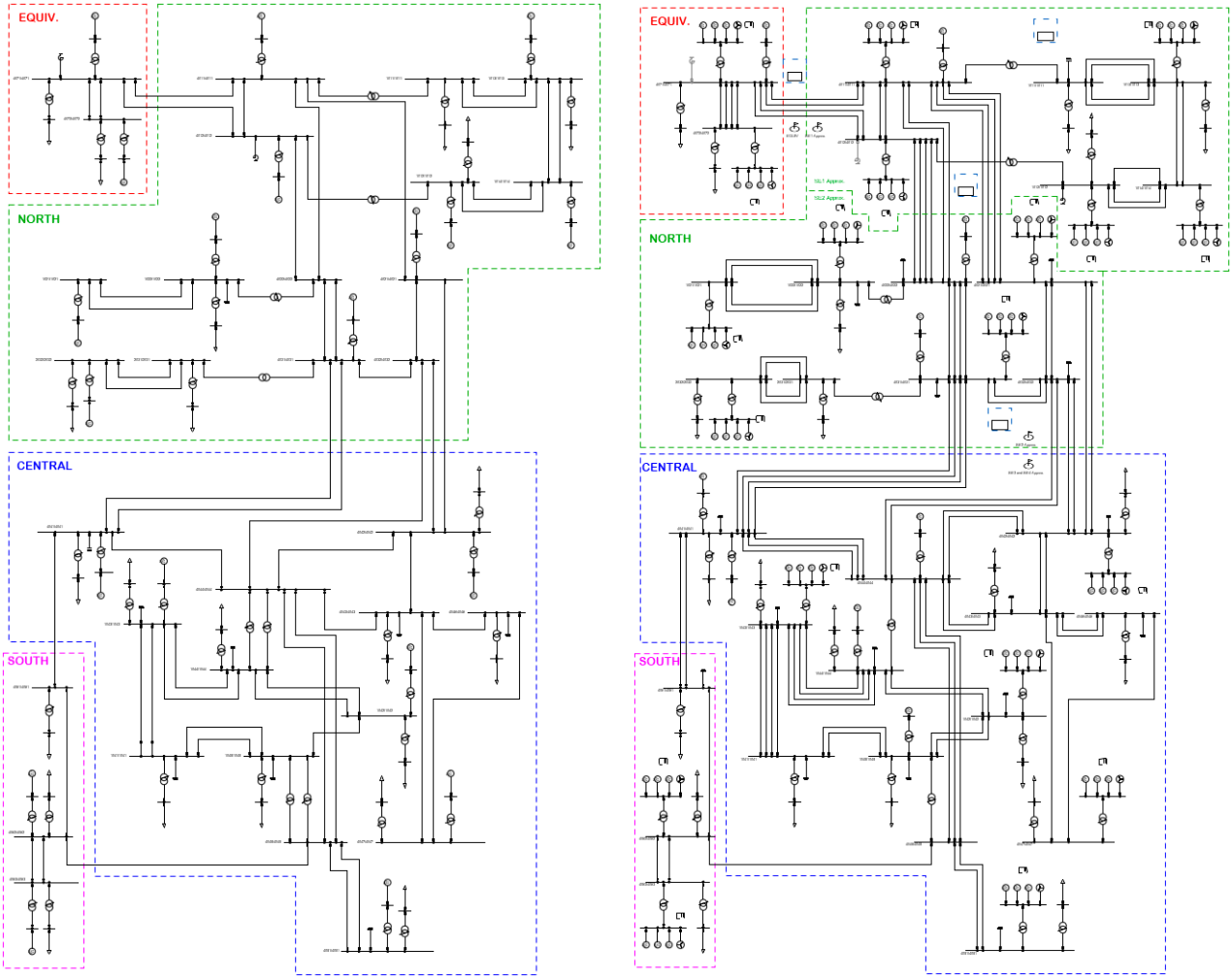
Figure 4a shows the original Nordic-32 model and Figure 4b shows the modified Nordic-32. This section shows how we transition from one to the other by following a fully defined and repeatable process using recent generation-and-demand data from Sweden. The extent of the reinforcements needed is evident from the figures. The Swedish network is split into NORTH, CENTRAL and SOUTH, with EQUIV. denoting external interconnection of northern Sweden to Norway and Finland, lumped together. The nomenclature in the Nordic-32 model (replicated here) is for busbars to have a four-digit name, where the first digit is the number of hundreds of kilovolts in the voltage level; for example, 4011 is a 400 kV busbar. Circuits connecting two busbars have an L, to denote “line”, followed by the two busbar names separated by a hyphen; for example, L4011–4021 is a circuit connecting busbars 4011 and 4021.

4.1. Scale of Changes from Circa 1990 to 2024

The first step, as presented in Figure 3, is to collate all the data needed. This example focuses on the Nordic region, so the applicable planning standards are the Nordel Grid Code and ENTSO-E requirements for generation-and-demand connection code [28–30].

The demand data in this example comes from the TSO [53], and it is the total power for the peak load hour that is focused on for dimensioning the network for peak studies. Other demand points such as minimum demand and peak demand during maintenance period could also be relevant, and may be dimensioning (to use the Swedish terminology).

Notable in Table 1 is the fact that we have chosen not to scale the reactive power (Mvar) demands. This reflects the assumption that the reactive power consumption of each lumped load is defined mostly by the nature of the fixed impedance of the downstream network, rather than reactive power consumption of connected parties, which could scale with active power. Published reactive power demand is not available for the actual network.



(**a**) (**b**)

Figure 4. Comparison of original and modified Nordic-32 networks; (**a**) original Nordic-32 network; (**b**) Nordic-32 with least-cost modifications to accommodate the Swedish 2024 generation-and-demand data, while complying with the Nordel Grid Code N-1 criteria.

Table 1. Nordic-32 original and Swedish 2024 peak demand data [53].

Year	MW Total	Mvar Total
Original	10,687	2836
2024	≈25,000	2836

4.2. Assessing Compliance of the Network Against Nordic Planning Standards

The Nordic-32 was designed for dynamic voltage studies, primarily [51], and it represents a particularly vulnerable system state. It was not intended for transmission expansion planning and thus not intended to meet the requirements of the Nordic planning codes.

Applying our process for network modification to the original Nordic-32 network identifies breaches of PIs presented in Table 2. This was a simple application of N-1 of all unique circuits for the original (assumed winter peak) load and generation values, and asserts a simple 0.05 pu deviation from steady-state nominal or 5% step change as a voltage breach.

Table 2. Nordic-32 original performance-index breaches summarised.

Voltage Level of Substation	Number of Nodes with at Least One PI Breach Across Contingencies, and Highest Value of that Breach			
	Vpu <0.95	**Vpu >1.05**	**Vstep >5%**	**Circuit Loading > 100%**
400 kV	11 of 19, 0.550 pu	9 of 19, 1.066 pu	16 of 19, 49%	3 of 33, 157%
220 kV, 130 kV	7 of 13, 0.480 pu	6 of 13, 1.070 pu	11 of 13, 55%	4 of 19, 122%

With voltage step change of 55%, way beyond the 5% planning limit, it can be concluded that the original published model is not suitable for assessing the impact of circuit loss. This is due to the lumped nature of the circuits, whereby one circuit in the Nordic-32 can represent multiple circuits in the real Swedish network. The question of what the model is going to be used for again comes to the fore. To modify the network to enable such a study would require the replacement of many of the 400 kV lines with multiple lines to better capture the network performance at 400 kV and the building out of the 130 kV network, along with the addition of parallel transformers. There is a general rule of thumb that to study voltage effects meaningfully at a desired voltage level, for example 400 kV, you must have an accurate representation of the network topology at least one voltage level below that being studied. This would require that the 130 kV and 400 kV networks and all transformers between the two be modelled in sufficient detail. The Nordic-32 does not meet this criterion. It has been designed for voltage and angular stability studies, however, so the 400 kV steady-state nodal voltages for the intact network should be suitable for use in transmission expansion planning studies.

This initial test also shows us that there are many breaches of the performance indices that seem credible and of lower severity; for example, voltages between 1.05 pu and 1.1 pu and loadings between 100% and 157% of the nominal rated loading.

4.3. Identifying Appropriate Network Reinforcements

In our example, we will resolve the circuit overload and steady-state voltage breaches by modifying the network.

The model converges in all cases studied using contingency analysis in PowerFactory but some PI breaches are present, so we focus on identifying a set of reinforcement options that resolve these conditions at the lowest cost. For the reinforcements made in this example (working on the original Nordic-32 loading), we will not consider any future changes to required demand and generation, and instead simply apply the lowest-cost means to resolve PI breaches.

4.3.1. Reinforcement to Resolve Circuit Loadings

Following Figure 3 and the guidance in Section 3, the circuit overloads are resolved first. The Nordel Grid Code provides guidance on overloading, and suggests that nothing should be tripped for overloads after a contingency event. This can reasonably be interpreted as the following: for the base case, there can be no overloading, but for contingency cases we can assume overload capability (and time-inverse overcurrent protection), since there will not be maintenance work carried out close to the time of peak load. Such decisions create space for a TSO to interpret the planning standards and tune the network design according to time-varying factors such as investment and operational risk strategy. For our purposes, what matters is that we clearly define and document the approach taken, so that it is repeatable and consistent.

The 60% pre-fault loading 15 min overload capability of triple Araucaria 400 kV 3×700 mm^2 at 75 °C is 5010 MVA, compared to pre-fault continuous rating of 3210 MVA. A simple ratio of 150% post-fault overload capability is assumed in substitution of these

values. We are left with one 400 kV circuit, L4031–4032, with current rating of 2.02 kA, which exceeds even the 150% overload rating during at least one dimensioning contingency.

We must work methodically from lowest-cost to higher-cost solutions for this, and to do this we need to look at where the power is flowing.

L4031–4032 is a relatively short line, with reactance of 16 Ω. The problematic contingency is that of L4011–4021, which is a very long line in the Nordic-32, with second-highest reactance of all lines in the model at 96 Ω. Switching it out is unsurprisingly problematic for the network, and when doing this manually on the original Nordic-32 the AC loadflow will not converge, despite the contingency analysis converging. The reason for this is that the contingency analysis tool in PowerFactory makes use of the existing Jacobian matrix from the base case. This is all handled automatically by the contingency analysis function [54]. If the contingency analysis function is set to always use the standard method then it too fails to complete this problematic case. To resolve this overload, we need to understand what happens to the power flows.

The role that L4031–4032 plays in the loadflow results of the original Nordic-32 is to move power to busbar 4032, where it is exported from the NORTH region to CENTRAL region, as can be seen by inspecting the model and reproducing this case. If more power were to flow from 4031 to 4041 and less from 4032, then the flow on L4031–4032 would, intuitively, be reduced. This can be enacted either with power flow control devices on L4031–4032 or series compensation on the double circuit L4041–4031a,b. Series compensation reduces the effective impedance of a circuit, which helps with post-fault stability. Power flow control devices on L4031–4032 (modelled as increase in reactance to reduce flow) would not offer this benefit, and both have a similar cost. Series compensation is known to be deployed on several of the long North-to-South circuits in Sweden, and so we consider it the most appropriate option. Selecting this option and going for a low degree of compensation to reduce the size and cost of the installation while still choosing a standard size (as deployed in the UK), we assume 35% degree of compensation. The reactance of each circuit of the L4041–4031 double circuit reduces from 64 Ω to 41.6 Ω. The AC loadflow now shows loading of all circuits less than 150% for all dimensioning contingencies, so we can move on to resolve voltage breaches. Note that once the reactive power flows are included, from the AC loadflow results, then we may need to revisit this reinforcement option, as loading is in MVA and capacity is used up by reactive power flows which, while they can be optimised, will still be present in the lines.

4.3.2. Reinforcement to Resolve Nodal Voltages

A first run of the contingency analysis tool shows that there are many voltage excursions in the original Nordic-32, with Tables 3 and 4 showing several busbar voltages above 1.05 pu or below 0.95 pu, with undervoltage being a particular problem and likely to be close to voltage collapse, which is not surprising if we recall that the model was initially developed to study voltage stability.

Inspection of Table 4 shows that the worst-case contingency is the loss of L4011–4021. There could be a case for building a parallel circuit to cover this loss. If we remove this contingency, then only busbars 4022 and 4061 have low voltage breaches, and all are above 0.94 pu, so a parallel circuit would be an effective solution. However, for this first task of improving the Nordic-32 to achieve a network that is compliant with the planning standards using least-cost reinforcements, if we can avoid requiring a new circuit, then we will. As loading is increased towards 2024 values, then it will become necessary to build this new circuit. For now, it is possible that simply adjusting some control parameters within the existing network could resolve these breaches, so we explore these options and cheaper reinforcements aiming at reactive power provision, first.

Table 3. Nordic-32 original overvoltage breaches.

Busbar	Cont. Max. Vpu	Base Max. Vpu	Worst-Case Cont.
4041	1.066	1.051	L4041–4044
4051	1.066	1.066	Base Case
4072	1.059	1.059	L4046–4047
4047	1.059	1.059	Base Case
4062	1.056	1.056	L4043–4046
4063	1.054	1.054	L4043–4046
4045	1.053	1.053	Base Case
4021	1.053	1.049	L4061–4062
4032	1.051	1.049	L4031–4032
2032	1.070	1.069	L4045–4051a
1012	1.065	1.063	L4045–4062
1011	1.064	1.062	L4046–4047
1014	1.062	1.061	L4046–4047
1013	1.056	1.055	L4046–4047
1022	1.055	1.051	L4041–4044

Table 4. Nordic-32 original undervoltage breaches.

Busbar	Cont. Min. Vpu	Base Min. Vpu	Worst-Case Cont.
4031	0.540	1.037	L4011–4021
4022	0.602	0.995	L4011–4021
4032	0.631	1.049	L4011–4021
4041	0.689	1.051	L4011–4021
4021	0.812	1.049	L4011–4021
4044	0.824	1.039	L4011–4021
4042	0.835	1.043	L4011–4021
4043	0.865	1.037	L4011–4021
4061	0.870	1.039	L4011–4021
4045	0.880	1.053	L4011–4021
4046	0.894	1.036	L4011–4021
4012	0.936	1.024	L4011–4021
4011	0.936	1.022	L4011–4021
2031	0.551	1.028	L4011–4021
2032	0.819	1.069	L4011–4021
1022	0.672	1.051	L4011–4021
1044	0.806	1.007	L4011–4021
1041	0.840	1.012	L4011–4021
1045	0.845	1.011	L4011–4021
1043	0.862	1.027	L4011–4021
1021	0.948	1.031	L4011–4021

Overvoltage can be addressed by control options if they are available, or by specifying new shunt compensation at the problematic busbars. Automatic switching can be implemented so that the contingency analysis tool's loadflows can mimic control room reactive-switching actions. This requires changes to the elements and enabling the switching of shunts and automatic tap-changer action in loadflow settings. Control changes (e.g., switchable shunts) are implemented first, then generator setpoint changes are implemented, starting with the most severe breach, before specification of an additional plant is considered to resolve any remaining breaches. The studies are re-run after each change, because the voltage effects will propagate, to some extent, through the network.

Shunts are made switchable (a single step, reflecting circuit-breaker operation) and automatic tap-changing is enabled in loadflow settings and transformer elements, with

transformers starting at neutral tap and set to change tap position where voltage is outside of the planning limits (0.95–1.05 pu, in this case) to save taps for post-fault restoration, as is typical control practise. We now have almost no voltage breaches, but there is one contingency, L4011–4021, for which the loadflow struggles to converge. The power flow in circuits for DC loadflow and for all other AC contingency cases remains compliant, and the 35% compensation on L4041–4031a,b is still required with the new Mvar flows, due to the control changes. Revisiting the previous findings when significant changes are made to the model is necessary to ensure that the need case for the reinforcement (e.g., 35% compensation on L4041–4031a,b) is not met by the other reinforcements or changes (e.g., automated reactive switching and taps).

To resolve the non-converging case, we try to prop up the voltage at the receiving end of the new flows. Looking at the DC loadflow, with L4011–4021 out, the flow from 4021 to 4011 instead goes to 4022 from 4011 and 4012. This will drop the voltage at 4022, so this is where we place a static-generator element. Setting its voltage to 0.95, we see that 677 Mvar are delivered to 4022. Increasing the voltage profile pre-fault can sometimes be sufficient to ensure that post-fault voltages are within limits. Increases to generator voltage targets and use of transformer tapping (changing starting tap position) are employed to raise voltages, starting at the sending end of the flow and including the receiving end busbar. Voltage targets for G9, G10, G19, and G20 are set to 1.05 pu, shunt reactors at 4071 and 4012 are switched out, and transformers tr1011–4011, tr1012–4012, tr1022–4022, tr4011-g9, and tr4012-g10 are set to target voltage of 1.049 pu at the 400 kV side. The static generator is now delivering 370 Mvar to 4022 to enable a bus voltage of 0.95 pu. Looking at the original model to inform selection of typical shunt capacitor-bank capacity, we try two switchable steps of 200 Mvar each, and remove the static generator. The model fails to converge. Increasing to three steps of 200 Mvar converges with voltages dropping towards the lower 0.95 pu limit at 1022. Three steps of the standard capacitor-bank size of 200 Mvar is therefore deployed, and the contingency cases now all converge to give us the results for remaining breaches, shown in Table 3.

With converging AC loadflow results for all N-1 contingencies, we can resolve the remaining voltage breaches. There are no 400 kV, 220 kV or 130 kV overvoltage breaches, but some under-voltages are present, indicating a need for some reactive compensation. These are detailed, along with their resolutions, in Table 5. The "static generator method" of sizing reactive compensation requirements is used with steps of 200 Mvar for 400 kV and, for 130 kV, creation of additional steps equal to the magnitude of the original Mvar provided at that node in the original model. We start at the worst breaches, specify reinforcement, then see if further reinforcements are needed. It could be that a spread of capacitors around the 1041-to-1045 loop would offer better resilience and lower Mvar flows in circuits than the two larger reinforcements made at 1041 and 1044, but completing works at more sites would increase the cost and so we follow the defined process and its reinforcement selection priorities.

Table 5. Nordic-32 N-1-compliant undervoltage reinforcements.

Busbar	Cont. Min. Vpu	Base Min. Vpu	Worst-Case Cont.	Resolved by Which Reinforcement, New Cont. Min. Busbar Vpu
4061	0.859	0.980	L4061–4062	2 × 200 Mvar, 0.989
4046	0.937	0.979	L4046–4047	4046-Cap up to 2 × 200 Mvar, 0.977
1044	0.912	0.940	L4041–4044	1044-Cap up to 3 × 200 Mvar, 0.959
1041	0.920	0.954	L4041–4044	1041-Cap up to 2 × 250 Mvar, 0.964
1045	0.921	0.954	L4041–4044	1041-Cap and 1044-Cap ups, 0.960
1022	0.938	1.010	L4011–4021	1022-Cap up to 4 × 50 Mvar, 0.962
1043	0.946	0.973	L4041–4044	1041-Cap and 1044-Cap ups, 0.982

We now have a Nordic-32 that is compliant against a defined planning standard, based on network reinforcements that have been specified by following a defined least-cost approach. This model is reproducible by following the method presented herein, and is also made available at [52] for continuation or extension or adaptation of this research. The next task of interest is to increase the loading in the network and adjust the generation total and technology mix, to represent publicly available 2024 data.

4.4. Reinforcing the Nordic-32 to Meet Planning Standards with 2024 Data

This section works through an example of modifying the original Nordic-32 to meet a simplified and fully transparent interpretation of the Nordel Grid Code planning standards for 2024 data, documenting the key decisions to ensure reproducibility of the process. Our model is to be used for studies into new connections of demand at the 400 kV nodes in the NORTH region, so flows into and out of this region are important, as they will influence the trigger point for new circuits.

4.4.1. Single Pass or Incremental Increase in Demand

In Section 3.4, we recommended using steps of around 10% to increase loading towards a new total. To bring the peak demand up from 11.06 GW to 25 GW, we start in increments of 1 GW to 15 GW, then 2 GW to 25 GW. There is no rule here: it is a trade-off between number of increments and likelihood of overcoming convergence problems. Prior to increasing the generation and demand, there are some other decisions to make.

4.4.2. Transformer Capacity Expansion

The Nordic-32 lumps generation and demand behind a single transformer for each lumped element at a substation. In reality, standard-sized transformers are used in parallel to enable redundancy and maintenance and incremental expansion over time. As demand increases, new grid supply-point transformers would be added in a similar manner. What to do about these, as flows increase, depends on what the model is to be used for.

If the focus of the transmission expansion planning study is the need for new circuits, then questions of redundancy and reliability of transformer provision are not important. By lumping various-sized generation and demand behind single transformers of sufficient capacity to supply them, the original Nordic-32 does not enable consideration of redundancy or security of supply for transformer maintenance or fault outages. If this is needed, then it is recommended to define standard transformer types based on published data from the TSO or transformer manufacturers, and replace existing transformers with these standard blocks. In addition, when increasing demand significantly, it is likely that some of this new demand will arrive at locations that justify new substations to connect to the transmission network, and this too will affect the topology and performance of the network. In our example, we assume that the purpose of the model is to provide a base model on which to vary a few parameters of the transmission expansion planning process to explore the need for new circuits in response to new connections. As such, we do not need to change the approach from the original Nordic-32 for transformer provision. Instead, we will ensure that there is sufficient capacity in each transformer to deliver the full rated active and reactive power of the transformer and the loads and generators connected to it, without oversizing the assets.

It should be noted that the example presented in this paper considers only a few aspects of transmission expansion planning. Its limitations include not considering lower voltage-level representations and their associated transformers. It does not include identification of transmission expansion requirements for provision of grid supply points to distribution networks (through, for example, additional 400/130 kV transformers and detailed MV representation). These aspects of transmission expansion planning may be important to

some researchers, and so the important question to ask is always "what is the model going to be used for?" This answer should inform the selection of the appropriate level of detail for different aspects of the model.

4.4.3. Generation Technology Mix

If the only modification is to scale demand, then the technology types of generation could be left, as they are in the original model, and only the ratings scaled.

In our example model, the generators are modified to enable exploration of the impact of dispatchability. To enact this, we consider four generator types at each generator bus, rather than the single generator in the original model. Each generator bus hosts a mix of wind, hydro, nuclear and thermal. The sources for generation mix come from Svenska Kraftnät for the Swedish bidding zones [55], the Swedish Energy Agency, Energimyndigheten, data on wind farm capacity and distribution [56] and the ENTSO-E transparency platform for generation data from Finland and Norway [57]. All data is for 2024 capacity, and is made available in the data share for model data for this paper [52]. In the real Nordic synchronous grid, there is significant interconnection with the synchronous grid of continental Europe; this is assumed to be lumped in with generation or demand in some edge nodes of the Nordic-32. Our model does not add in additional interconnection, and instead assumes these nodes to be generator nodes, in line with the original Nordic-32.

Knowing that we are aiming towards 25 GW peak demand, and having data for the mix of generation capacity corresponding to that figure, we can build out the generator types rated to their final 25 GW values and scale their output according to the demand scenario. Transformer types are scaled in rating at each increment in load and generation, to avoid having unreasonably large transformer impedances in the model for the incremental steps in demand.

The Swedish network is split into four bidding zones, with SE1 northernmost and SE4 southernmost. The area marked NORTH in the original Nordic-32 roughly corresponds to bidding zones SE1 and SE2 in Sweden, and data from these zones is used to inform generation mix in this region [17]. In CENTRAL and SOUTH regions, the generation-capacity values come from SE3 and SE4 data.

EQUIV corresponds to the interconnection with Finland and Norway, and comes from published data for NO3, NO4 and FI bidding zones, with a scaling factor to determine the proportion of the generation capacity that could lead to transfers with the NORTH region, rather than with other bidding zones. This factor is defined by the ratio of the amount of published transfer capacities out from NO3, NO4 and FI that connect to SE1 or SE2 to the amount that do not. From NO3 and NO4, 54% (1550 MW of 2850 MW) of transfer capacity relates to the connection with SE1 and SE2. From FI to SE1 and SE2, the proportion is 33%, and from CENTRAL and SE3 and SE4 to SE1 and SE2, the proportion is 46% [57]. These factors are used to determine the total capacity of each generation type in each bidding zone, for which we have TSO published data, to give totals for each generation type in the Nordic-32 regions, EQUIV, NORTH, and CENTRAL and SOUTH. (CENTRAL and SOUTH are grouped together, because our model is to be used for demand at NORTH, and SOUTH does not have a direct connection to NORTH.)

The total generation capacity (based on 2024 data) in each region of the Nordic-32 is defined using the process above to give the values shown in Table 6, which are then distributed to nodes as shown in Table 7, based on the proportion of the total generation that was at each node in the original Nordic-32 region for the previously dominant technology type (hydro in NORTH and EQUIV, otherwise nuclear). New generation types are given an even distribution across all generator nodes in that region. In our example, this means that wind and thermal totals for each region are allocated evenly between all nodes. This

could, of course, be the subject of the study, and varied to inform optimal location from the perspective of minimum transmission reinforcement. This kind of analysis is important, but beyond the scope of this work.

Table 6. Nordic-32 generation capacity by technology type and region, 2024 data.

Generation Type	Total Capacity = 50,295 MW		
	NORTH MW	EQUIV MW	CENTRAL + SOUTH MW
Hydro	13,360	6668	1353
Nuclear	0	1440	3202
Wind	10,483	3955	3134
Thermal	276	2855	3569
TOTAL	24,119	14,918	11,258

Table 7. Nordic-32 generation capacity by technology type and node, 2024 data.

Node	Region	% Regional Share	Hydro MW	Nuclear MW	Wind MW	Thermal MW
4071	EQ	10.0%	667	720	1978	1427
4072 [a]	EQ	90.0%	6001	720	1978	1427
4011	N	16.0%	2138	0	1048	276
4012	N	12.8%	1710	0	1048	0
4021	N	4.8%	641	0	1048	0
4031	N	5.6%	748	0	1048	0
2032	N	13.6%	1817	0	1048	0
1012	N	12.8%	1710	0	1048	0
1013	N	9.6%	1283	0	1048	0
1014	N	11.2%	1496	0	1048	0
1021	N	9.6%	1283	0	1048	0
1022	N	4.0%	534	0	1048	0
4042	C+S	20%	193	640	448	510
4047	C+S	20%	193	640	448	510
4051	C+S	20%	193	640	448	510
4062	C+S	20%	193	640	448	510
4063	C+S	20%	193	640	448	510
1042	C+S	0% [b]	193	0	448	510
1043	C+S	0% [b]	193	0	448	510

[a] Generator G20, located at node 4072 in the EQUIV region, is used as the slack bus and represents the external interconnection of the network to Finland [17]. [b] The original Nordic-32 distribution of nuclear generators of rating 400 MW and 200 MW for G6 and G7, respectively, is departed from, and the nuclear part of these generator buses is set to zero, and the capacity is shared between the region's 400 kV substations.

Nuclear is identified in the original Nordic-32 by inspection of the inertia constant values. The ratings of nuclear unit types are modified from the original Nordic-32 to define standard units of credible size for each region (720 MW in EQUIV and 640 MW in CENTRAL + SOUTH). These are distributed across nodes that already had nuclear generation in CENTRAL + SOUTH and to one unit at each generator node in EQUIV, to achieve the 2024 quantity of nuclear generation capacity in each region. The original Nordic-32 had two 130 kV nodes, 1042 and 1043, which have generators with the same parameters (e.g., subtransient reactance, Xd″ and inertia constant, H) as the 400 kV connected nuclear generators. These small (and unrealistic, with only 130 kV grid connection) nuclear generators are removed from the model, to enable the abovementioned pattern of nuclear generator specification to be consistently applied across the model.

Generally, where existing technology in a region (e.g., hydro in NORTH) is to be scaled, this is done using the original distribution, such that the nodes that previously had the highest proportion of the generation still have the same proportion of the total

for that technology type in that region. These decisions can have a significant impact on the resulting flows and study outcomes. Consideration should be given to sensitivities, particularly in the siting of new generation.

A type is created at each node for each of the generators, with ratings informed by Table 7. Figure 5 shows the generator elements modelled at the generator busbars.

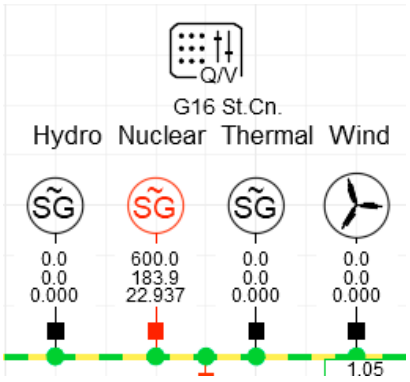


Figure 5. Generator busbar model modification with four generation types, to enable consideration of dispatchability in transmission expansion planning studies.

The planning standards and connection codes can be used to inform details on generator performance such as reactive power-capability curves. In this example, an assumption of 0.95 leading and lagging capability is made. Original generator target voltages are preserved, but are implemented using a station controller. The station controller distributes the reactive power output of all synchronous generators and synchronous dynamic reactive compensation, and also controls the generator transformer tap-changer behaviour to maximise reactive reserves, as is realistic. The initial setting for busbar target voltage is preserved in the station controller, and is equal to the generator output voltage in the original model. Synchronous generators that have zero active power are assumed to be disconnected. Wind generators will typically remain synchronised, even when at zero output, so they are available for reactive power support at all nodes that have wind farms.

A validation of the success of this step of model build is made by repeating the contingency analysis with unchanged generation-and-demand values, to ensure that no erroneous changes have been made.

4.4.4. Load Scaling

The load is scaled retaining the original proportion of total load at each bus from the original model and scaling up by the ratio of previous-to-new total demand. This does not have to be done this way; it could be a sensitivity or key parameter of interest in a model. It depends on what the model is to be used for. The assumption here is that demand grows in areas of existing demand: cities grow and industry grows in existing industrial and mining regions. Additional large-demand impact and siting, such as hydrogen production connection capacity and optimal siting, can be explored once the base model is established.

4.4.5. Generation Dispatch

Generation is dispatched according to the following priority list, based on technology limitations (e.g., nuclear start-up) and fuel cost assumptions:

1. Wind is considered to be non-dispatchable, and is either fully on or fully off, and is energised even with P = 0 MW;
2. Nuclear is must-run;
3. Hydro (all assumed to be reservoir-based); then

4. Thermal (represents a mix of gas, oil, and interconnection).

This change could lead to a revised set of reinforcements for the N-1 case, without demand change. In our example, since we have such a large increase in demand to implement, this is not a concern, as the risk of specifying unneeded reinforcements from this change is negligible.

4.5. Full Walkthrough of First Increment

For this paper, to enable reproducibility and clarity of the methods, the first increment in load growth is reported in full detail. Subsequent increments are reported in summary.

4.5.1. Load Scaling

The first step is from the original demand, 10,687 MW to 12,000 MW. This is implemented first in the loads by scaling the active power component of each load by 12,000/10,687.

4.5.2. Generation Dispatch

The generation is satisfied by using a priority list/ranking-order approach based on the merit order as defined in Section 4.4.5. Wind is not added, because there is so much of it that it will not be possible to accommodate it until the total demand is close to 20 GW. For this reason, the full wind scenario is created once the network is dimensioned for 25 GW load and no wind. Scenarios of lower than full load with full wind output are, of course, still possible, and transmission expansion planning studies should consider this scenario: low load, full wind, for example, as post-fault stability and inertia could become limiting factors.

Allocation of total hydro in NORTH is made according to the original distribution of rated capacity of each plant in that region, and the split between regions (NORTH and EQUIV for hydro) is made in the same way, giving us 5 GVA in EQUIV and 6.25 GVA in NORTH, so 44% in EQUIV and 56% in NORTH.

Nuclear units are deployed at full output. Reserve requirements are not considered in the base model, though the selected merit order will result in some hydro being dispatched for loads beyond 4600 MW plus losses. There is 6360 MW hydro power to distribute, 56% in NORTH and 44% in EQUIV.

Dispatch for 12 GW load scenario is provided in Table 8. The slack at 4072 picks up the mismatch between generation and demand plus losses.

4.5.3. Reinforcement to Resolve Circuit Loadings

The AC loadflow for the network, with the new load and generation patterns, does not converge. A DC contingency analysis is run to identify those circuits that will require reinforcing. Knowing that we are due to double the total load and generation, where a circuit is overloaded, a parallel circuit is built. As we approach the later increments of demand, we will stop building new circuits and again look for lower-cost incremental build. This is because it is obvious from the 12 GW loadflow that key circuits, when demand reaches 25 GW, will need more capacity than can be released by flow control, series compensation, or even reconductoring.

The reinforcements in Table 9 are built in the model (v2.3 of the PowerFactory model: post-reinforcement, compliant with planning standards for 12 GW demand). Generator transformers are set to the sum of the MVA capacity of all the generation connected. Load transformers are scaled to be slightly higher than the highest MVA loading experienced across the contingency cases. In reality, it is more likely that additional units will be added

in parallel, and when the model will be being used to plan transformer capacity provision for loads or generation, the size of individual transformers will need to be considered.

Table 8. Nordic-32 12 GW no-wind scenario, generation dispatch.

Node	Region	% Regional Share	Hydro MW	Nuclear MW	Wind MW	Thermal MW
4071	EQ	10.0%	280	720	0	0
4072	EQ	90.0%	2965	720	0	0
4011	N	16.0%	570	0	0	0
4012	N	12.8%	456	0	0	0
4021	N	4.8%	171	0	0	0
4031	N	5.6%	199	0	0	0
2032	N	13.6%	484	0	0	0
1012	N	12.8%	456	0	0	0
1013	N	9.6%	342	0	0	0
1014	N	11.2%	399	0	0	0
1021	N	9.6%	342	0	0	0
1022	N	4.0%	142	0	0	0
4042	C+S	20.0%	0	640	0	0
4047	C+S	20.0%	0	640	0	0
4051	C+S	20.0%	0	640	0	0
4062	C+S	20.0%	0	640	0	0
4063	C+S	20.0%	0	640	0	0
1042	C+S	0.0%	0	0	0	0
1043	C+S	0.0%	0	0	0	0

Table 9. Nordic-32 12 GW reinforcements to resolve circuit loadings.

Circuit	Cont. Max. Load %	Base Load %	Reinforcement
L4011–4071	191.0	103.8	L4011–4071b
L4012–4071	191.0	87.3	L4012–4071b
L4022–4031a	181.4	104.3	L4022–4031c
L4022–4031b	181.4	104.3	L4022–4031c
L4012–4022	171.9	108.3	L4012–4022b
L4011–4022	167.2	87.1	L4011–4022b
L4031–4032	162.8	79.8	L4031–4032b
L4071–4072a	143.2	71.6	L4071–4072c
L4071–4072b	143.2	71.6	L4071–4072c
L4011–4021	136.5	108.2	L4011–4021b
L4011–4012	132.5	38.3	L4011–4012b
L4031–4041a	129.9	77.3	L4031–4041c
L4031–4041b	129.9	77.3	L4031–4041c
L1043–1044a	128.8	81.7	L1043–1044c
L1043–1044b	128.8	81.7	L1043–1044c
L4041–4044	124.0	77.7	L4041–4044
L4042–4043	123.4	82.4	L4042–4043
L4042–4044	120.3	61.1	L4042–4044

AC loadflow convergence is achieved by using static-generator elements as sources of infinite reactive power to identify the need for voltage reinforcements. Some transformers needed higher ratings to enable the reactive power flows, due to the generator reactive power outputs, and increasing these resolved non-convergence in some cases. The DC loadflow neglects losses and reactive power flows; consequently, some circuit and transformer reinforcements were only identified once some voltage reinforcements had been

implemented. The circuit reinforcements resulting from this stage are reported alongside the voltage reinforcements in Table 10.

Table 10. Nordic-32 12 GW voltage-driven reinforcements.

Busbar or Circuit	Resolved by Reinforcement
4031	4031-Cap, 4 × 200 Mvar
4021	4021-Cap, 4 × 200 Mvar
4022	4022 SC, addition of 500 MVA synchronous compensator
L4022–4031	L4022–4031d (reactive flows trigger fourth circuit)
4071	4071 SC, addition of 500 MVA synchronous compensator
L4071–4072	L4071–4072d (reactive flows trigger fourth circuit)
1042	1042-Cap, 4 × 50 Mvar
1044	1044 SC, addition of 500 MVA synchronous compensator
1045	1045 SC, addition of 500 MVA synchronous compensator
4042	4042-Cap, 2 × 200 Mvar

4.5.4. Reinforcement to Resolve Nodal Voltages

The principle of 60:40 static-to-dynamic reactive compensation is applied, with the approach of adding dynamic reactive compensation where static reactive compensation has already been installed. This 60:40 balance and the siting of both static and dynamic reactive compensation at the most critical locations is typical of NGET (UK TSO), to avoid transmission voltage brittleness and to encourage elasticity (stable steady-state voltage profile across large range of power flows). The voltage reinforcements shown in Table 10 result from this process, and broadly follow the 60:40 principle.

Besides specification of an additional plant to assist with the voltage stability of a transmission network, control parameters and operation regimes are used by the TSO to maintain voltage within the performance limits ($0.95 \leq V \leq 1.05$ pu, in this case). Coordination between generator reactive power output and transformer tap-changer operation is achieved with station controller elements set to maximise reactive reserves of the generators and using tap changers that refer to the transformer's HV node for target voltage [58].

Target voltages at the 400 kV, 220 kV and 130 kV nodes are set according to the following strategy, to provide robustness against contingencies and a replicable consistent approach across the model:

1. Generator busbars are set at the upper limit in the planning standard (1.05 pu, in this case).
2. Load busbars are set to 1 pu.
3. Busbars at substations that are at the receiving end of large flows are set at 60% between 1 pu and the upper voltage limit in the planning standard (1.03 pu).
4. Busbars at the sending end of large flows are set to the upper limit (1.05 pu).

In some cases, setting a busbar to the upper limit results in some contingencies giving an overvoltage breach. At those nodes where overvoltages occur, the busbar targets are lowered until compliance is achieved. In our example, 1.046 pu was enough in every case (busbars 1021, 1022, 2031, 2032, 4012, 4022, 4031, 4071), but this could be customised at each node. Investing time in voltage profiling a model and setting controllers up consistently and effectively helps avoid non-convergence for contingency cases and moves the model close to a realistic pre-fault condition.

The settings for all model elements for this stage of the modification can be inspected by copying the model from [52] and rolling back the copy to version "v2.4".

4.6. Subsequent Increments in Brief

The subsequent increments applied are the following: 13 GW, 14 GW, 15 GW, 17 GW, 19 GW, 21 GW, 23 GW, 25 GW, and a final case of "25 GW Windy" (100% output from all wind generation). Minimum demand cases involving wind output could also result in network reinforcement requirements, as could inter-area transfer limits and dynamic stability requirements, but are beyond the scope of the example in this paper.

For reasons of brevity, this section only reports the reinforcements, and not the process undertaken to identify them, except where the method deviates from the standard process detailed in the paper so far or where something of particular interest becomes apparent that is not covered elsewhere in the paper. In most cases, the standard process was followed, which is, in summary:

1. Use DC contingency analysis to achieve convergence and identify new circuit requirements.
2. Use static generators to identify approximate reactive power requirements for converging AC loadflows.
3. Use AC contingency analysis to identify final network-reinforcement requirements.

The stages of incrementally increased demand and generation shown in Table 11 result in the need for network reinforcements in accordance with the principle of least-cost reinforcement to achieve compliance with the planning standard. The generation-and-demand profiles are stored in scenario data in the DIgSILENT PowerFactory model and the subsequent reinforcements are stored in expansion stages. These are shown in Figure 6.

Table 11. Nordic-32 13 GW to 25 GW demand reinforcements.

GW	Location(s)	Breach, Reinforcement
13	4021, 4022, 1022, 1013, 1014, 4011	Overvoltage, reduce target voltage (1.04 pu)
14	L1021–1022c	Circuit overloading for AC Contingency Cases (AC Cont.), new circuit
14	4042	Non-convergence persisting due to voltage at 4042. L4021–4042 over 100% (though less than 150%) but new line will be needed soon, so triggering L4021–4042b now
15	1041, 4031, 4061	Overvoltage, reduce deltaVmax to 3% to prevent stepping up of 1041-Cap, 4031-Cap, 4061-Cap for overvoltage cases
17	L1011–1013c	Circuit overloading for DC loadflow
17	L4031–4041d	Circuit overloading for DC contingencies
17	L4011–4012a,b L2031–2032a,b	Circuit overloading for DC contingencies, 50% series compensation as X × 0.5 to avoid new circuits
17	L1013–1011d	Circuit overloading for DC contingencies
17	L1043–1044d	Circuit overloading for DC contingencies
17	L1041–1043c	Circuit overloading for DC contingencies
17	L4012–4022c	Circuit overloading for DC contingencies
17	L4041–4044c	Circuit overloading for DC contingencies
17	4022	Undervoltage, extra 3 × 200 Mvar on 4022-Cap
17	4042	Undervoltage, extra 3 × 200 Mvar on 4041-Cap
17	4041	Undervoltage, extra 3 × 200 Mvar on 4041-Cap
17	4041	Undervoltage, addition of 1 000 MVA synchronous compensator, 4041-SC
17	1011	Undervoltage, 2 × 200 Mvar, 1011-Cap
17	L2031–2032c	Circuit overloading AC Cont. causing undervoltage, future-proof with circuit
17	L1021–1022d	Circuit overloading AC Cont. causing undervoltage, future-proof with circuit
17	4021	Undervoltage, extra 3 × 200 Mvar on 4021-Cap
17	L4044–4045c	Circuit overloading AC Cont. and causing undervoltage, future-proof with circuit
17	L4011–4021c	Circuit overloading AC Cont. and causing undervoltage, future-proof with circuit
17	L4022–4031a,b,c,d	Circuit overloading AC Cont., already four circuits, reconductoring with 4.63 kA
17	L4012–4022d	Circuit overloading AC Cont. causing undervoltage, future-proof with circuit
17	4031	Undervoltage, addition of 1000 MVA synchronous compensator, 4031-SC
17	1012	Overvoltage, addition of 2 × 150 Mvar shunt reactor, 1012-Ind

Table 11. *Cont.*

GW	Location(s)	Breach, Reinforcement
17	4011	Undervoltage, addition of 1 000 MVA synchronous compensator, 4031-SC
19	L1014–1012c	Circuit overloading for DC Cont.
19	L4021–4042a,b	Circuit overloading for DC Cont., reconductoring to avoid third circuit, 4.63 kA
19	L4031–4041a,b,c,d	Circuit overloading for DC Cont., already four circuits, reconductoring with 4.63 kA
19	L4042–4043a,b	Circuit overloading for DC Cont., reconductoring to avoid third circuit, 4.63 kA
19	L4032–4044b	Circuit overloading AC Cont. causing undervoltage, future-proof with circuit
19	L4032–4032	Circuit overloading AC Cont., reconductoring to avoid third circuit, 4.63 kA
19	L4031–4032a,b	Circuit overloading AC Cont., reconductoring to avoid third circuit, 4.63 kA
19	L4011–4071	Circuit overloading for AC Cont., already four circuits, reconductoring with 4.63 kA
19	L4011–4021d	Circuit overloading for AC Cont., new circuit
19	L4021–4032b	Circuit overloading for AC Cont., new circuit
19	L4041–4061b	Convergence issue for outage, new circuit
21	L2031–2032d	Circuit overloading for DC Cont.
21	L1013–1011a,b,c,d	Circuit overloading (within 150% of rating) but causing undervoltage, series compensation (50%) [a]
21	4032	Undervoltage, 8 × 100 Mvar, 4032-Cap
21	4031–4041a,b,c,d	Undervoltage convergency, increase degree of series compensation to 50%
21	4044	Undervoltage, addition of 1 000 MVA synchronous compensator, 4044-SC
21	L4032–4044b	Convergence issue for outage, new circuit [b]
21	1042	Undervoltage, replant 1011-Cap to 5 × 100 Mvar
21	L4043–4044b	Convergence issue for outage, new circuit [b]
21	1022	Undervoltage, replant 1022-Cap to 2 × 200 Mvar
21	L4022–4031a,b,c,d	Undervoltage, 50% series compensation to reduce voltage drop
21	L4011–4021	Undervoltage, 50% series compensation to reduce voltage drop
21	L4011–4022	Undervoltage, 50% series compensation to reduce voltage drop
21	L1042–1045b	Undervoltage at other nodes for outage, new circuit [b]
21	1043	Undervoltage, upgrade 1043-Cap to 3 × 200 Mvar
23	L4021–4042	Undervoltage, 50% series compensation to reduce voltage drop
23	L4032–4042	Undervoltage, 50% series compensation to reduce voltage drop
23	L4032–4044	Undervoltage, 50% series compensation to reduce voltage drop
23	L4043–4046b	Convergence issue for outage, new circuit [b]
23	4043	Undervoltage, upgrade 4043-Cap to 3 × 200 Mvar
23	L1041–1043d	Circuit overloading AC Cont. causing undervoltage, future-proof with circuit
25	L1013–1011	Circuit overloading beyond 150% in DC cont. Already four circuits, so redispatching generation (hydro 50% for thermal at G16 (500 MW) and G17 (141.3 MW)) [c]
25	L1013–1014	Circuit overloading beyond 150% in DC cont. and feeding overloads in L1011–1013a,b,c,d, so redispatching generation (hydro 50%, 748.15 MW for thermal at G17 (368.5 MW) and G7 (379.65 MW)) [c]
25	1022	Undervoltage, upgrade 1022-Cap to 5 × 100 Mvar instead of 2 × 200 Mvar
25 [d] Wind	L1011–1013a,b,c,d	Circuits overloaded >100% in base case, redispatch 180.9 MW hydro from G2 to G7

[a] Reconductoring not possible for the 130 kV lines in the model because the existing current rating in the Nordic-32 is very high already and there is no available conductor system at this voltage that can credibly increase the rating. [b] The circuit is not overloaded (or not beyond 150%), but is critical for the compliance of other circuits/nodes, such that its outage prevents AC loadflow convergence. Converting the single circuit to a double circuit provides N-1 security, in this case. [c] Selection of how to redispatch is made by considering where they will alleviate overloads the most. This is done using DC contingency results to back off the largest flows, where generators are available that are effective at achieving this. Trial and error enables optimum selection. [d] This scenario has the export from all wind generation set to its rated value and is dispatched first, along with nuclear, then hydro, then thermal.

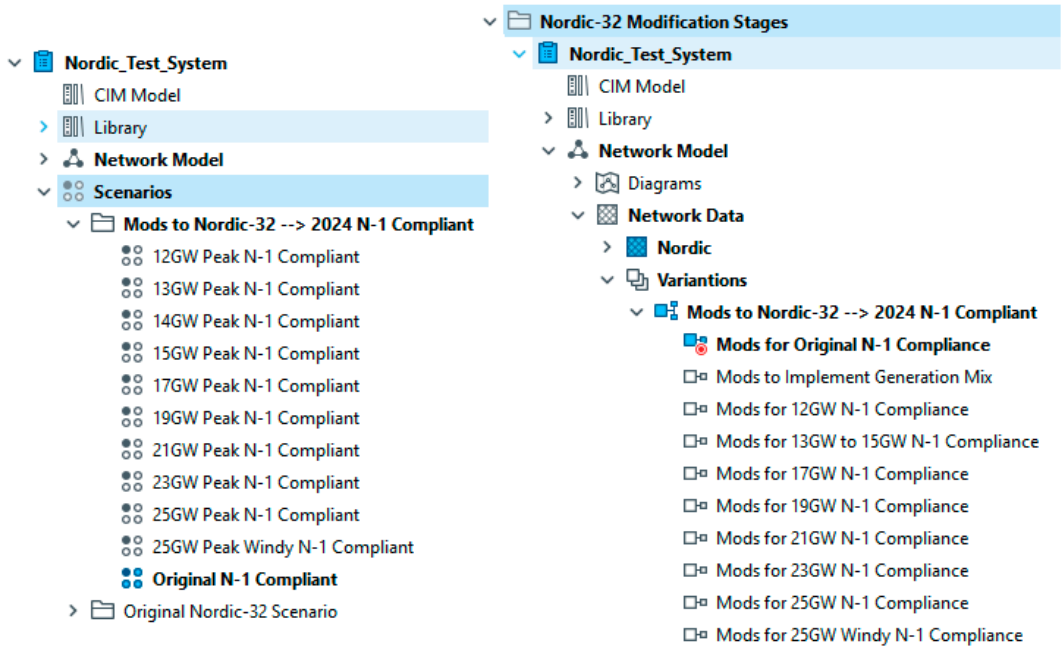


Figure 6. Screenshots from the model showing scenarios of generation and demand for each stage of the model development (**left**) and expansion stages for network reinforcements (**right**).

5. Discussion

5.1. Reflections on the Modification Process

The process was a success, and followed the methodology provided in Section 3. There are a few details of implementation of the process, whose importance became apparent as the model was modified, and which will have significant impact on model topology as it is updated.

5.1.1. The Role of the Planning Standards

How the planning standards are interpreted is important to the outcome of the studies and the reinforced network model that emerges in response. A requirement to secure the network against deeper levels of system depletion (e.g., N-2 rather than N-1) will lead to greater reinforcement. If a planning standard specifies types of system event that must be secured against then these, too, will affect the resulting network reinforcements. For example, if a maintenance outage is to be secured rather than fault outage, then short-term ratings will not be available, since the maintenance outage is an enduring condition. The system technical performance limits also drive reinforcements, for example limits of $0.95 \leq V \leq 1.05$ pu on steady-state voltage drive more reinforcement than would $0.9 \leq V \leq 1.1$ pu. Asset ratings, including short-term overload capability and the safety margins built into these values affect reinforcement requirements; for example, allowing 150% nominal loading for contingencies or considering dynamic line rating based on weather or asset condition monitoring.

The choice of how many dispatch scenarios to consider can lead to finding more reasons to reinforce the network. Exploring short-time-step time series (e.g., 15 min or 1 h) of wind output and of loading for each unit (lumped-load or generator) individually, will lead to the discovery of more possible local worst-case combinations of loading and voltage than would be identified from a single point deemed to be representative of an overall worst case. Exploring the impact of these decisions is important future work, beyond the scope of this paper.

5.1.2. The Role of Specific TSO Reinforcement Strategies

The reinforcement strategy has a direct impact on the resulting network changes. In this example, we deployed the lowest-cost reinforcements to resolve the performance breaches, but other approaches exist. Decisions such as building parallel circuits reduces substation build, but might introduce problems such as protection design and point-on-bar loading within a substation. The model developed here did not include these considerations. However, such design criteria could be added to the approach and lead to a different network topology.

The historical preferences for reinforcement strategy or, indeed, any published present or future strategy will be different from one TSO to another, and will affect the choice of reinforcement and resulting topology of the model. For example, if one TSO is under political pressure to minimise capital investment costs but another is trying to stimulate economic growth by investing in major infrastructure projects, then it might be that small overloads are more likely to lead to new 400-kV circuits for the keen-to-invest TSO, whereas the cash-strapped TSO might review the short-term ratings of their conductor types, consider accepting greater operational risk, or opt for dynamic line rating.

Future-proofing with anticipatory investment could be considered. In this approach, reinforcements are targeted to increase capability to enable future connections, rather than to respond to them. A TSO can present specified capacity for target technology types at strategic areas of the network to assist with grid stability or to help with other societal goals, such as economic stimulus or collocation with other industries as part of a circular economy. There may be a decision to uprate lower-voltage sections of the network, rather than build parallel circuits, as part of a vision to have a larger transmission backbone, or a more heavily meshed transmission network. The choice of reinforcement strategy brings in political, economic, environmental, and other societal aspects to transmission expansion planning.

5.1.3. The Role of Land Planning

The existence of constraints on network development from planning can be important to shape the topology of a transmission network as it expands. In this example, we assumed that four parallel circuits is the maximum that would be permitted. More than two double circuits may be considered to be creating a “wirescape”, which is in breach of the old Central Electricity Generating Board (CEGB) “Holford Rules” [59], which still guide the visual design of transmission expansion in the UK.

5.1.4. The Role of System Operational Strategy

When it comes to voltage performance, the balance between post-fault and pre-fault performance is important. In our example, we maximised the reactive reserves. This meant that the station controller would adjust generator reactive-power output to stay as close to the centre of their reactive range as possible, and transformers would sit close to nominal tap position. Switchable shunts would be first to provide voltage support and dynamic sources are held back for post-fault. The requirements for reactive power compensation will be affected by this. In addition, allowing busbar target voltages that are outside of the planning limits can reduce the costs of infrastructure build, but might bring performance issues for connected parties downstream in the network. In our example, generator busbars were allowed to be higher than 1.05 pu, as long as substation busbars that could host connections stayed below 1.05 pu. In many planning standards, there are more relaxed limits (or no limits) for customer busbars or generator busbars at lower voltages, and the strict limits apply at points of common coupling such as transmission substation busbars.

5.2. Reflections on the Network That Resulted from This Process

The various decisions made as part of this process inevitably lead to different possible outcomes for the model. The goal of the process is to deliver something repeatable and that is achieved; however, changes to the aspects covered in Section 4.1 will lead to variations in the resulting network. As such, it is important to document and to publish the assumptions made when using this method, to create a transmission expansion planning model.

It is of interest to consider how "realistic" the resulting model is. There are a few characteristics of the model that stand out as being unrealistic, but each one is the result of a documented decision made based on the purpose of the model. For example, there are no parallel transformers for load or generation, and there are synchronous compensators that are larger than would be delivered in a single unit. Likewise, some static reactive compensation is larger than would be expected at a single site. The example model in this paper is designed to enable studies looking at steady-state voltage and circuit loading. Substation configuration, transformer outages, and reactive compensation outages were excluded from the studies that led to the specification of network reinforcements. Had this not been the case, then the network would feature multiple parallel transformers and would be likely to have substations running split (as two independent nodes) and additional substations to account for maximum loss of infeed and loss of demand fed from a single site. The decisions as what is the subject of the study, and what is not relevant to the research outcome that the model is to be used for, affect the resulting topology of the model and, in this case, make it less realistic. But it is no less useful for its intended purpose.

If we consider the model to be Sweden then we can look at the approximate location of the Aurora line, a new 400 kV circuit connecting in 2026 between northern Sweden and Finland. This is roughly like adding a line between substations 4072 and 4022. Adding this to the model is highly effective at overcoming overloads for the maximum demand scenarios where power comes from EQUIV. and goes towards CENTRAL and SOUTH and is also effective in minimum demand, maximum wind scenarios where wind power from NORTH and CENTRAL regions needs to find its way out of Sweden. To enable a more clear and simple elucidation of the modification process, the example used in this paper did not include identification of optimum routes for new circuits. If this had been considered, then it is likely that the topology would be quite different. For example, the Aurora line route from 4072 to 4022 is likely to contain a double circuit, and there might not be so many quadruple circuits in the model.

Another aspect of the model that is not realistic is that during the timespan between the model's inception in the 1980s and 2024, transmission networks will likely have grown in terms of number of substations. This happens in response to new generation and demand, both at low voltages and, more recently, in directly connected GW-scale projects. This changes the topology, and can create new routes for power flows through a greater degree of meshing of the network. By adding additional generation and demand to existing generation-and-demand nodes only, we are stressing the existing transmission routes and so this, too, leads to a greater number of parallel circuits than would be expected in reality. Further work could be to consider how the resulting topology would differ if an optimal transmission circuit-routing task were performed to address an overload condition. It is possible that increased meshing from new circuit routes would offer greater flexibility to changes in flow patterns than adding more parallel lines.

5.3. Reflections on the Classic Transmission Expansion Planning Problem

Finally, there is the very important question of whether it is more appropriate to spend money on transmission expansion or on generation constraints, i.e., build another circuit to always enable the power to flow from every generator, or save that money to pay for

redispatch and compensation payments to generators. If the example case study here were extended for a minimum-demand maximum-wind scenario, then it is very likely that there would be a choice to be made between significant network reinforcement and curtailing wind, to redispatch other generation. A study that quantifies the costs of congestion in terms of redispatch is highlighted as future work to inform TSO decision-making on network investment.

The balance between network and operational costs will be different for each network and its market environment, but the principle of balancing investment costs in network infrastructure against operational costs of running a congested transmission system is as important now as it has ever been. The basic principle of this trade-off for transmission planning for new connections is illustrated by Figure 7.

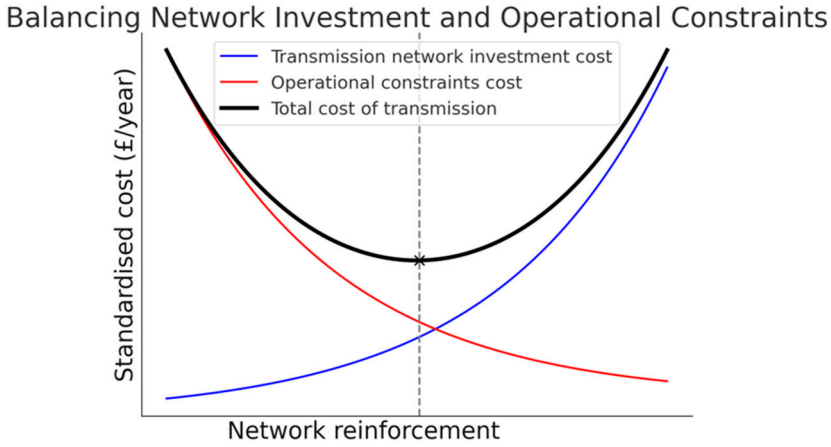


Figure 7. Illustration of balance between network investment and transmission-system operational costs. The dashed line indicates the optimum level of network reinforcement.

5.4. Further Work

The creation of a model suitable for transmission expansion-planning research naturally leads to the task of carrying out transmission expansion-planning research on such a model. Some ideas for directions of research, which are identified in the research seam that is enabled by this paper, are presented in Figure 1. The different stages in the process shown in Figure 3 can each be the subject of research. Transmission expansion planning can be researched for novel transmission-network assets such as battery storage, including storage as power flow control; dynamic line rating apparatus, as well as TSO process-based innovation such as conditional grid connection agreements and re-interpretation of planning standards, can all be studied with a base model established to enable comparison of reinforcement requirements, with and without the new technology or new approach, and this is identified as valuable further work to shed light on TSO processes and their impact on investment requirements. Future works to explore aspects of transmission expansion and network design such as hosting capacity for firm connections, non-firm capacity, and curtailment mechanisms are planned, and will apply the methods described in this paper to obtain a suitable model.

Within the model modification itself, there is work to be done to explore the suitability of the process for other types of study: would the same method hold if a model is needed for angular stability? Furthermore, the application of this model modification method to other published reference models would help to build confidence in the method. In addition, applying generation and demand from future scenarios, such as net zero 2045 or TSO forecasts for generation-and-demand change would enable some comparison of TSO planned reinforcements with those suggested by the method presented in this paper.

6. Conclusions

A methodology is defined for modifying a published model to comply with defined planning standards for published data on demand and generation. In lieu of actual transmission-network models for expansion planning, this process results in a model that represents the desired starting point from which to explore phenomena of interest to the transmission expansion-planning problem.

The case study application of this process to the Nordic-32 gave a model (fully shared in multiple formats) that represents the least-cost set of network modifications required for a modified Nordic-32 that is capable of supplying 2024 Swedish electricity demand with 2024 Swedish generation capacity (dispatched following a merit-order approach for windy and not-windy scenarios) against a contingency security level of N-1 (a simplified interpretation of the Nordic Grid Code planning standard). This model begins with the published Nordic-32, but the modification process could be applied to any model and any demand-and-generation datasets and planning standards.

The modification process as presented in this paper is important to the energy industry, because it enables academia to produce research into transmission expansion planning from a similar starting point and perspective as a TSO. This enhances the usability of the research and increases the likelihood of the research being adopted by industry. Figure 1 shows this graphically.

The status quo for transmission expansion-planning research is to either directly use an unchanged published reference model (e.g., Nordic-32 or IEEE 24-bus models) or to make bespoke changes to these models in order to demonstrate a particular research outcome. This paper has presented an improvement to this approach by putting planning standards at the centre of the model. This ensures that the resulting base model is realistic from a system security perspective and, in doing so, enables data from any given year or network to be applied to the model to inform network reinforcement of that model. This results in creation of a base model that is not only realistic, but is also reproducible and adaptable.

To summarise, performing transmission expansion-planning research on a model that is created by following the method in this paper has the following advantages over the traditional approach of using bespoke one-off models:

- Demonstrable compliance with planning standards, resulting in a model that is realistic to a specific region and its transmission design principles.
- Applicable to any published transmission-system test model.
- Applicable to any system study type for which planning standards define performance indices.
- Adaptable to different types of network reinforcement or national investment strategy.
- Repeatable, such that a series of research studies can follow the same method, and models can, for example, be updated with different years' data or for different future scenarios.
- Auditable, such that there is no opportunity to strategically select model parameters that are not realistic, but which produce results that back up a hypothesis.
- Ethical, due to auditability and repeatability.

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Abbreviations

The following abbreviations are used in this manuscript:

CEGB	Central Electricity Generating Board
ETYS	Electricity Ten-Year Statement
HND	Holistic Network Design
NESO	National Energy System Operator
NGET	National Grid Electricity Transmission
FACTS	Flexible AC Transmission
PI	Performance Index/Indices
SVC	Static Var Compensator
TEC	Transmission Entry Capacity
MW	Megawatt
GW	Gigawatt
MVA	Megavolt-ampere
Mvar	Megavolt-ampere Reactive
RMS	Root Mean Square
NETS	National Electricity Transmission System
SQSS	Security and Quality of Supply Standard
SvK	Svenska Kraftnät
TSO	Transmission System Owner/Operator
TEP	Transmission Expansion Planning
PTDF	Power Transfer Distribution Factor

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