Project no.:

219123

Project acronym

REALISEGRID

Project title:

REseArch, methodoLogIes and technologieS for the effective development of pan-European key GRID infrastructures to support the achievement of a reliable, competitive and sustainable electricity supply

Instrument: Collaborative project
Thematic priority: ENERGY.2007.7.3.4
Analysis and scenarios of energy infrastructure evolution
Start date of project: 01 September 2008
Duration: 30 months

D3.2.2
Price, Cost and Financial Aspects of Network Expansion in the European Context

Final

Submission date: 2010-04-27

Organisation name of lead contractor for this deliverable:
Technische Universität Dresden

Dissemination Level		
PU	Public	X
PP	Restricted to other programme participants (including the Commission Services)	
RE	Restricted to a group specified by the consortium (including the Commission Services)	
CO	Confidential , only for members of the consortium (including the Commission Services)	

Deliverable number:	**D3.2.2**
Deliverable title:	Price, Cost and Financial Aspects of Network Expansion in the European Context
Work package:	WP3.2 Investments signals: a quantitative approach based on cross-border capacity allocation
Lead contractor:	Technische Universität Dresden

Quality Assurance

Status of deliverable		
Action	**By**	**Date**
Verified (WP-leader)	Gianluigi Migliavacca, ERSE	2010-04-27
Approved (Coordinator)	Gianluigi Migliavacca, ERSE	2010-04-27

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Abstract

The report deals with various techno-economic and financial aspects related to transmission network expansion. It carries out an in-depth analysis of different approaches to network expansion: a welfare optimal perspective and a traditional engineering approach based on reliability and security of supply. An integrated approach is proposed, that is tailored to the European situation: based on market prices and under security constraints, market results are simulated. These simulations enable to evaluate and recommend specific grid extension scenarios.

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ACRONYMS AND DEFINITIONS

AC: Alternating Current.
AM: Assessment Methods.
BFR: Border Flow Right.
CAISO: California ISO.
CAPM: Capital Asset Pricing Model.
CFD: Contract for Differences.
CTP: Centralized Transmission Planning.
DC: Direct Current.
EIB: European Investment Bank.
ENTSO-E: European Network of Transmission System Operators for Electricity.
ETSO: European Transmission System Operators.
FACTS: Flexible AC Transmission System.
FTR: Financial Transmission Right.
GDP: Gross Domestic Product.
HVDC: High Voltage DC.
ISO: Independent System Operator.
IRR: Internal Rate of Return.
MTI: Merchant Transmission Investment.
NPV: Net Present Value.
NUTS: Nomenclature des Unités Territoriales Statistiques.
OR: Operations Research.
PNP: Proactive Network Planning.
PTDF: Power Transfer Distribution Factor.
ROI: Return on Investment.
TCC: Transmission Congestion Contract.
TEAM: Transmission Expansion Assessment Methodology.
TEN-E: Trans-European Network – Energy.
TP: Technical Parameters.
Transco: Transmission Company.
TSO: Transmission System Operator.
TYNDP: Ten Year Network Development Plan.
UCTE: Union for the Co-ordination of Transmission of Electricity.
WACC: Weighted Average Cost of Capital.

1 EXECUTIVE SUMMARY

This document focuses on various techno-economic and financial aspects related to transmission network expansion. It shows that there are different approaches to network expansion. Academics in economics aim to answer the question which market player should carry out the investment from a welfare optimal perspective: a merchant investor or a centralized entity. The merchant investor requires a return on its investment while a centralized entity has to be regulated. For the time being it seems clear that merchant investments cannot be entirely relied upon. A merchant investor does not have the insights and often not enough interest to carry out maintenance and replacement investments. In addition, merchant investments require a well structured market place with locational marginal prices and financial derivates (e.g., financial transmission rights) that enable to incorporate the physical effect of an investment financially into the market place. Hence, even future grid investments will be most likely carried out by a centralized entity to a large extent. This leads to the question how such an entity ought to be regulated efficiently. The discussion on this point is ongoing. In the present work, the welfare maximizing approach is implemented by the ELMOD (a Model of the European Electricity Market), based on nodal pricing and able to represent the European grid towards network calculations and market solving.

A rather engineering focused approach emphasizes the aspects of reliability and security of supply. An efficient power grid is a very important target for Europe as an industrial location and represents the basic requirement not only for the future expansion and integration needs of renewable energy sources, but also for the achievement of the European climate protection goals. Over time, the targets for the development of the grid have changed and become more complex due to energy market liberalization. The present targets are: safe grid operation (reliability), security of supply often represented by the (n-1)[1] criterion, integration of renewable energy sources. To accomplish these tasks, and particularly dynamic changes in the production structure in favor of renewable energy sources, an even more comprehensive and detailed analysis of energy system planning due to energy market developments is required. Thereby, Transmission System Operators (TSOs) have to use reliable methods and to foresee the weak points and bottlenecks in the grid and react in time to secure supply and safe grid operations. These needs imply certain medium- and long-term grid expansions which are urgently required to cope with the future challenges in the energy industry. New lines are generally being built in areas where other lines are close to their (n-1) security criterion threshold and therefore need urgent reinforcements. This approach may naturally lead to different needed investments in order to ensure the reliability of the grid, the security of supply, an unconstrained European energy market, the integration of renewable energy sources and economic efficiency. The technical approach focuses on the feasibility of certain extension opportunities including technology choice (e.g., cable vs. overhead line) and technical constraints resulting from security of supply (e.g., reliability).

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[1] The (n-1) security criterion is a planning rule according to which elements remaining in operation after failure of a single network element (such as a transmission line/transformer or generating unit, or in certain instances a bus bar) must be capable of accommodating the change of flows in the network caused by that single failure while respecting all system constraints.

One purpose of this document is to connect the different approaches mentioned earlier to develop a adequate method for project evaluation. The purpose is in line with the international developments, that advocate comprehensive and sophisticated cost-benefit analyses that also take into account indirect effects of transmission expansion, such as increased system reliability or increased competition effects. According to these developments, this document presents an integrated approach that is tailored to the European situation. Based on market prices and under security constraints, market results are simulated. These simulations enable to evaluate and recommend specific grid extension scenarios.

2 INTRODUCTION

2.1 Objectives of this deliverable

Historically, national power grids were established to connect the generation centres with the centres of consumption. A public office or department in a ministry coordinated the tariffs and the operation of power plants. In most cases, a monopoly of government controlled electricity generation, transmission and distribution was in place. With the liberalisation of the European energy market this has changed. In the new situation, integrated companies were split-up while generation and the operation of the network were unbundled from each other. In addition, power marketplaces and exchanges were founded with the aim to attract traders and investors. The planning approaches described in this document account for the new situation and the interest of the different stakeholders..

The duty of a TSO (Transmission System Operator) nowadays is to operate its network in such a way that a high level of reliability is achieved. It guarantees a marketplace for customers under secure, economical, environmentally-friendly and efficient conditions. In this environment, regulators control TSOs, which are natural monopolies in most areas. However, the regulators' interests are to promote a competitive liberalized European market as well as a sustainable energy generation and therefore aim at having high capacity interconnections to guarantee free trade. Customers and politicians on the other side demand electricity prices as low as possible under socio-economic and environmentally acceptable constraints. Therefore, they demand welfare maximization while respecting all system and physical constraints.

The purpose of this deliverable is to describe methods for determining valuable network extension projects. For this goal, different methods are described such as a welfare induced approach, a security of supply induced approach and an integrated market approach to network extension, the last one being the combination of the first two. Different methods can lead to different investment projects. Therefore, a combination of the approaches leads to the identification of long run investment projects that fulfil the described multiple objectives.

Another purpose of this document is to provide a theoretical background for the above mentioned approaches and explain how the simulation tools are able to identify the necessary investment projects. There are several tools which work on the basis of the three above mentioned approaches. ELMOD (a Model of the European Electricity Market) is a bottom-up model combining electrical engineering and economics with the objective function of welfare maximization, subject to line flow, energy balance and generation constraints. The technical approach uses load flow simulation tools of the continental European grid (former UCTE grid), such as PSA (Power System Analyzer) to generate the PTDF (Power Transfer Distribution Factors) matrices, or Integral for detailed load flow calculations. The results of the above mentioned tools are the input for DrCAT (Dry-run Coordinated Auction Tool) to calculate the auction model in order to perform an investment analysis. This results in the identification of investment projects.

2.2 Expected outcome

Network extension can be approached from different directions. This deliverable starts by explaining the influences of all factors (stakeholders, frameworks and others) that affect the planning process of efficient network extension: this can be found in Chapter 3. There are several different interests that need to be considered. Politics has a big influence on the project set-up and the geographical outlay of new lines. The regulator is interested in an open market whereas the TSO tries to find the technical optimal solution with minimum costs. There is an ongoing debate among energy economists how to foster economic efficient transmission extension in liberalized electricity markets where the major concern is who should carry out the investment: a regulated entity (centralized transmission planning, or CTP), or the market (merchant transmission investment, or MTI). The objective of a standard CTP approach is to maximize (expected) social welfare, whereas under MTI an investor should be incentivized by positive return on investment (ROI). Also, the investor should participate in the effect that the investment has in the light of network externalities and the question how to deal with the risk that comes with a transmission investment for both the new investor and the existing transmission owner is still unanswered.

Chapter 4 explains the ideal welfare conditions and criteria of network extension. It reflects merchant approaches and investment criteria. The objective of the central transmission planning or regulatory approach is to maximize the social welfare within the electricity system. It involves a commercial transmission company that is regulated through price or revenue regulation to provide long-term investment incentives while avoiding congestion. The merchant approach assumes limited transmission capacity between two nodes. By increasing the capacity, a return for the investment is achieved. Furthermore the concept of an Independent System Operator (ISO) is compared to the classical Transmission System Operator. Hence Chapter 4 provides an overview of the transmission extension debate.

Chapter 5 describes the approach of welfare induced network extension. This market-based method identifies investment projects dependent on the development of the electricity price. This in return is dependent on the increase of supply and demand as well as transmission line projects which increase the overall capacity and volumes of traded electricity. The model formulation and parameterization of the used ELMOD simulation tool is presented and afterwards the extension algorithm is explained.

Chapter 6 describes the method and models used for security of supply induced network extension. This method is currently the driver for TSOs to reinforce the grid. New lines are generally being built in areas where other lines are close to their (n-1) security criterion threshold and therefore need urgent reinforcements. This approach may naturally lead to different needed investments in order ensure the reliability of the grid, the security of supply, an unconstrained European energy market, the integration of renewable energy sources and economic efficiency. The technical approach focuses on the feasibility of certain extension opportunities including technology choice (e.g., cable vs. overhead line) and technical constraints resulting from security of supply (e.g., reliability).

Both methods above reported are combined in Chapter 7 where an integrated market based approach is described. The combination of load flows and electricity prices make it possible to simulate cross-border auctions. The presented criteria are combined to identify investment signals and projects in an integrated effort. The scarcity prices for transmission capacity are not taken into account. In addition to that, a deep coordination of the network investments among TSOs based on commonly available data was neglected in the other approaches. The combination of the above two assumes a central allocation entity exists which applies a coordinated allocation based on real time network models.

Chapter 8 recaps the main outcomes of the present report and proposes the way forward.

2.3 Approach

The discussed network extension approaches are based on the analysis of literature and the experience of the authors. All three methods make use of different simulation tools. The theoretical background of these tools is described as well as the workflow of the combination of all three. This deliverable, following REALISEGRID Deliverable D3.2.1 on coordination mechanisms and cross-border transactions issues, builds the theory of the simulations which are currently being prepared but its results will be discussed in REALISEGRID Deliverable D3.2.3.

The foundation for this document is the overall discussion about how to foster efficient network extension. The central transmission planning, the merchant approach and the criteria of investment decisions build the theoretical background. They describe the approaches of decision finding while discussing the development of a coordinated central planning.

The document is significantly interrelated with other Deliverables of the REALISEGRID project, in particular:

- D1.2.1, D1.2.2, D1.4.1 for the investigation on the potentials of new technologies (like FACTS, HVDC, WAMS[2], etc.)
- D3.3.1 for the definition of a methodology able to perform a cost-benefit analysis for new reinforcements of the transmission network, especially with respect to trans-national sections
- D3.6.2 for the investigation on incentivization schemes for the TSOs
- D3.7.1 and D3.7.2 for the analysis of the authorization path of new transmission infrastructure and of the consensus problem (Not-In-My-BackYard, NIMBY syndrome).

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[2] FACTS: Flexible Alternating Current Transmission System; HVDC: High Voltage Direct Current; WAMS: Wide Area Monitoring System.

3 INFLUENCES & FRAMEWORK

3.1 Regulatory aspects

In Europe, as well as in other countries, the electricity industry is in the transformation process from a structure dominated by vertically integrated utilities to one structure dominated by competitive markets. One of the relevant consequences of market liberalization is the “unbundling” of former vertically integrated, monopolist utilities. The unbundling concerns particularly the separation of generation and transmission, the latter being still subject to regulation. The liberalization process in Europe with the resulting electricity market has led to the facilitation of international trade between the countries while the regulation is still at a national level. The challenge lies in the so-called “subsidiarity principle” that forces the European Union (EU) to concede wide autonomies to the single countries. On account of this, inter-area power exchanges in electricity networks have significantly increased and the penetration of renewable energy sources (RES) connected to the European grids has been impressive. In order to meet the increasing need of electricity and Europe’s environmental and energy targets for 2020, further grid connections and extensions are required. In the grid extension process, regulatory aspects play a key role. The reason for regulating the transmission network is the fact that the transmission part of the value chain is a natural monopoly. A natural monopoly is characterized by the fact that a single company delivers a certain commodity or service more cost-efficiently than a multiplicity of companies. Hence, the basic idea of an efficient market-based on free competition cannot be applied, due to certain framework conditions of a specific industry.

Regarding the transmission of electricity, the regulatory framework is very complex due to different existing administration levels such as European, Member States, and local authorities as well as differences from one Member State to another. Connection xcharges are investigated in the REALISEGRID Deliverable D3.1.1. The different remuneration and incentivization schemes towards the TSOs in some European countries are investigated by the Deliverable D3.6.2 of the REALISEGRID project. One of the major sources of slow transmission development are competing priorities that require guidelines with a strong influence on national and local governments in such a manner that involved stakeholders are able to unambiguously prioritize important projects. Development processes and planning are slowed down as a result of a whole range of permitting procedures stemming from a multitude of different authorities. More detailed information on the regulatory background is described in REALISEGRID Deliverables D3.7.1 and D3.7.2.

3.2 Environmental and social aspects

3.2.1 General view

The extension of the transmission grid or the building of new infrastructures is often characterized by a strong impact on the environment and very long authorization procedures. Some reasons for these difficulties arise from land depreciation due to the occupation of the soil and the visual impact of the transmission line. The increasing lack of social acceptance (NIMBY way of thinking) complicates the needed implementation of grid reinforcements and extensions. The resistance is carried out by affected local communities and their representatives and environmental organizations. The social opposition, often combined with long permitting procedures and the resulting delays in implementation processes, can be significant and even stop a project. Therefore,

timely completion of projects important for the infrastructure and the achievement of European policy targets are put at risk.
The need of effective communication between the TSO and the public about the motivation lying behind the projects is very important to find the most appropriate solution as a compromise between the economic, environmental and social aspects.

3.2.2 Economic view

Transmission expansion is systematically scrutinized with respect to its environmental and social consequences. In that it is not different from other infrastructures, such as highways, airports, pipelines, etc., that regularly have to be assessed with respect to indirect effects. In addition to the beneficial effects on social welfare, the construction of network infrastructures may have direct or indirect negative effects that need to be taken into account in the assessment. Transmission expansion might also have positive external effects, e.g. a lower CO_2 output if two regions with different carbon-intensive electricity generation are connected.

The "social" component of transmission investment results from the fact that such investment creates "winners" and "losers" in terms of the rents that accrue to electricity generators (producers) and payments done by consumers, respectively. Thus, in the simplest case of connecting two regions ("high price" and "low price") and perfectly competitive generation markets, the producer in the low-cost region and the consumer in the high-cost region benefit from the transmission in terms of higher producer rent and consumer rent, respectively. On the other hand, producers in the high-cost region and consumers in the low-cost region will loose rent. They will then oppose the construction of the transmission line, unless they are compensated, e.g. by side-payments.

There are different methods to assess transmission expansion, and they regularly trade-off complexity vs. comprehensibility. Static models with perfect competition are easiest to set up, but they are far from representing the complexity of a meshed network in a European context. At the other extreme, there are complex game-theoretic approaches, that model potential outcomes of cooperative and non-cooperative games, e.g. modeling competition between the producers or the interaction between neighboring transmission operators seeking a joint transmission expansion; an example from Scandinavia is provided by [33]. Game theoretic models, however, are already by themselves computationally challenging [12] and consequently too complex to be applied to real world cases regarding the physical network; in addition, they are not easily understood by decision-makers, and therefore may be of little practical value.

Within the wide literature on assessing the social effects of transmission investment, we have identified two that are most relevant in the REALISEGRID context, and that have been widely practiced:

- PJM (Pennsylvania-New Jersey-Maryland) provides a "simple" measure of the social effect of transmission expansion. It calculates cost changes by producers and consumers due to the expansion of transmission lines; this corresponds to a more economic approach, since it approximates the welfare effects of investments by the change in producer rent and in consumer rent. Thus, PJM values the economic benefit of additional transmission investment by $0.7\,\Delta PC + 0.3\,\Delta LP$, where ΔPC is the change of production costs and ΔLP is the change in load payments ([29]).
- A more comprehensive, sophisticated social cost-benefit analysis approach takes also into account indirect effects of transmission expansion, such as increased system reliability or

increased competition in one of the zones; e.g., the California ISO (CAISO) uses a comprehensive “Transmission Expansion Assessment Methodology” (TEAM) as a decision support tool for transmission planners, in which the annual benefits from an expansion include production cost benefits, competitiveness benefits, operational benefits, generation investment cost savings, reduced losses, and emission benefits ([7], summarized by [31]). An essential component of the CAISO-TEAM is that it implements a market simulation model based on dynamic supply bids and incorporating a detailed physical transmission modeling capability for a reliability region. Besides, CAISO-TEAM includes uncertainty and risks about the future which can partly be quantified. Apart from these benefits, cross-sectoral positive externalities comprise simplified rights of way for the use of other network infrastructure being built. Additionally, long-term resource cost advantages, synergies with other transmission projects, fiscal benefits from construction and taxes, and impacts on fuel markets should be taken into consideration according to [35].

Even though the CAISO-TEAM approach is more demanding in terms of data and calculation, it appears to be a feasible procedure for future transmission expansion projects in the EU as well.

3.3 Technological aspects

The present design of the transmission system is based on technical choices which were made over time such as generalized AC (Alternating Current) technology to facilitate high voltage transmission and to decrease transmission losses, the standardization of voltage levels to which users are connected, etc. These technical choices were standardized and are now difficult to change. This is also a costs issue, because transmission facilities have a long life span and are not due to be frequently renewed.

The current electricity transmission system in Europe does not generally seem adequate to reliably cope with large-scale penetration of variable power plants such as wind parks and other RES and the resulting decentralization of power generation. To address and handle the above mentioned challenges and in particular to drive the process of integrating further RES, flexible, coordinated and adequate transmission networks are necessary. These transmission networks should be designed according to modern schemes and embedding innovative technological solutions ensuring security of supply and efficiency.

Today the industry offers a wide range of possibilities to improve the transmission grid and TSOs have to select the appropriate technology for their specific case taking into account the technical, environmental, economical and social aspects (see also REALISEGRID Deliverable D1.4.1). To increase the transfer capacity of the grid, a combined application of hardware and information technologies is necessary. The hardware can consist in reinforcements of already existing lines (passive reinforcement), or in the utilization of innovative transmission technologies, like high temperature/low sag conductors, devices for routing grid power flows such as High Voltage Direct Current (HVDC) connections and Flexible AC Transmission System (FACTS) devices. REALISEGRID Deliverables D1.2.1, D1.2.2 and D1.4.1 deal in detail with these technologies and their possible support to the transmission planning activities .

3.4 Financial aspects

The fair and appropriate financial remuneration of TSO business is vital, because it is the base of long term economic growth for securing social and economic welfare across Europe.

This is amplified by the fact that a TSO as a supra-regional electricity grid operator is exposed to various, specific risks which are triggered mainly by the special properties and the volume of the necessary investments. In order to reduce possible negative consequences, we sometimes see that the proposed way of recognition is ad-hoc and not consistent with scientific economic reasoning.

Incentive regulations are very common in Europe (see REALISEGRID Deliverable D3.6.2). However, an incentive scheme is only practicable if there is sufficient potential for cost savings and efficiency gains. Benchmarks, which are a kind of starting point for incentive regulations to calculate the efficiency in comparison to the other companies in peer group, are not always fair and adequate for an industry, which has to deal with massive investments and organizational changes in the upcoming years.

It is vital for a TSO to have an appropriate interest to do the business, just to „hold the fort“. To provide that interest WACC, the weighted average cost of the invested capital, is mostly used. There are many differences in WACC values across Europe because of macro-economic environments and regulatory regimes. Therefore they can not be compared with each other. The impact of different WACC values can exemplarily be described using an undervalued WACC which will lead to shrinkage in corporate economic value for investors, even if book-entry earnings are positive. This could have negative impacts for the operational business: rising credit spreads for financing new projects, lowered attractiveness for new investors, decreasing value of the company.

Discussions with regulation authorities and investors/shareholders are an ongoing and evolutionary process. A fair remuneration for a TSO should contain at least

- transparent, consistent and fair calculation habits in the regulation regimes
- regulations that cover the costs, which a TSO has to bear to do an efficient and secure business
- systematic & appropriate risk assessment
- achieve an appropriate risk free rate, and its underlying, especially the duration of bonds leading to different yields when calculating the WACC
- adequate Debt / Equity figures in the WACC

To advocate the grid investments, a wide range of investment needs is existing which have a big influence on the cost-effectiveness on a network project.

- European investment support (for example the TEN-E framework)
- investment credits
- cooperation with distribution network providers.

4 EFFICIENT NETWORK EXTENSION

4.1 Central transmission planning

As pointed out in Chapter 2.3, the objective of the CTP or regulatory approach is to maximize the social welfare[3] (please refer to Chapter 5.2.1) within the electricity system. The regulatory approach involves a commercial transmission company (Transco) that is regulated through price or revenue regulation to provide long-term investment incentives while avoiding congestion. The crucial aspect of the CTP is that transmission investments are normally carried out by a single regulated entity. It is not intended to have a multiplicity of different investors that compete with each other. The regulator controls the decision of the monopolistic entity and tries to govern its behavior via defining a set of rules and requirements a regulated firm has to fulfill (so-called regulatory contracts). In [23] they distinguish two different families of these regulatory contracts.

The first family of contracts (so-called Bayesian regulatory approaches) can be applied if the regulator has a large knowledge of firm specific details, particularly the probability distribution concerning a company's cost. In this case, the regulator can take advantage of this knowledge to trade-off cost reduction against rent extraction. In [19] they show that the tasks of a regulator in this setting can be simply split up into two sub-tasks: 1.) reducing the transmission costs; 2.) simultaneously obtaining optimal extension quantities. In [21], a Bayesian approach is analyzed under the congestion management scheme in England and Wales. It is shown that the 'uplift' measure does in fact measure the social cost of congestion and thus a network company exposed to pay the uplift will extend the grid in a socially optimal way.[4] Since its implementation in 1996, congestion in the British transmission grid has decreased considerably.

The second family of contracts (so-called Non-Bayesian contracts) must be applied if the regulator does not know the cost function details of the regulated firm ([48]). Due to this uncertainty in the actual costs that occur, the regulator imposes a price cap. In order to still achieve the aimed outcome, adequate weights regarding price and/or quantity ([23]) within the price cap approach have to be implemented. Non-Bayesian approaches often take explicitly into account that network extension destroys congestion rents. Hence, in [30] they design a transfer mechanism providing the firm with the current congestion rent which is reduced by a rent constructed from current price levels and previous period's capacities. Another Non-Bayesian regulatory variation consists of defining a price cap made up of of two components (so-called two-part tariff cap) proposed by [47]. The first tariff component consists of the congestion rent in the system and the second part is a fixed component. By rebalancing the fixed and variable components of the tariff, the Transco can be incentivized to invest as reduced congestion revenues can be offset by increased fixed revenues. In [47] the author shows that under certain assumptions the mechanisms grant convergence to equilibrium conditions. However, the assumed cost and demand properties in [47] may actually not hold in a real electricity network context due to loop-flows. Aiming to include loop-flow

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[3] Social welfare is a measure of the total benefit a economy/society obtains from a market outcome aggregating the profit of each market participant. It can be divided in company profits (producer surplus) and the consumer surplus (see Figure 5 3). The producer surplus represents the short run profits of companies defined by the difference between the market price and the production costs. Consumer surplus represents the difference between what consumers would be willing to pay for a commodity and the market price.

[4] The uplift is defined as the sum of the difference between generation costs and the unconstrained market price for all units that are re-dispatched due to network restrictions (see [21]).

characteristics, [15] and [37] extend the mentioned two-part tariff approach. Their results are promising but not yet applicable to realistically large networks.

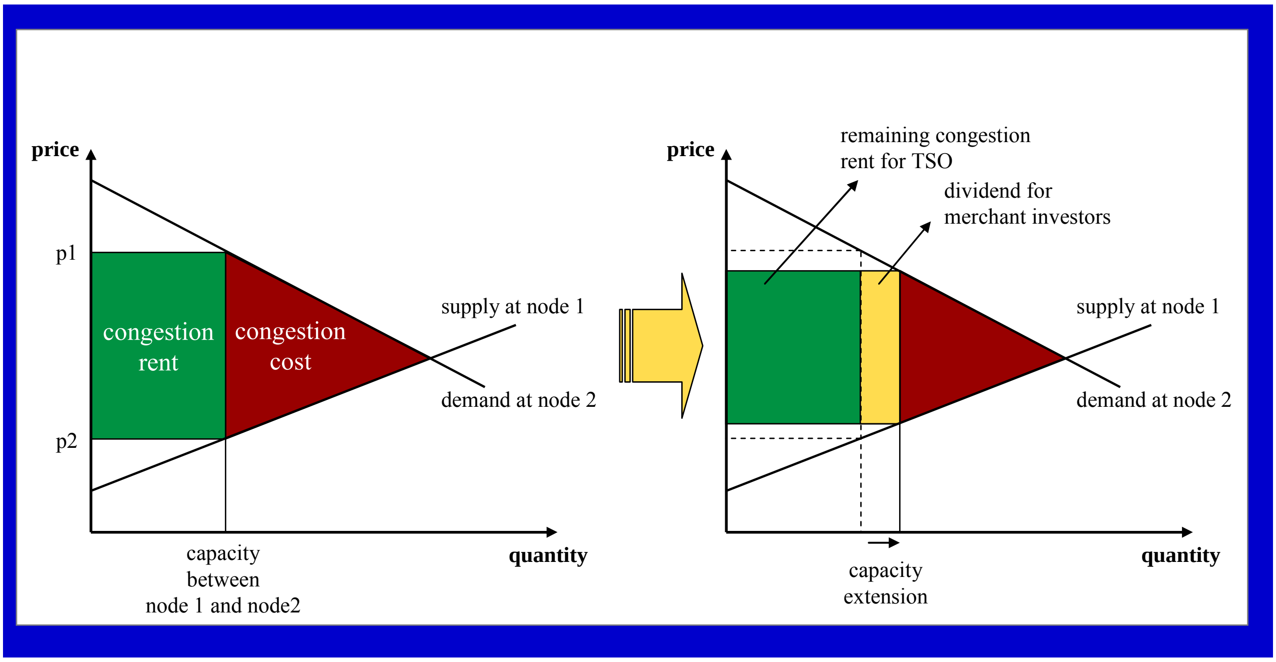
Other approaches emphasize the need to coordinate generation and transmission investment planning. As the generation investment decisions are taken in a rather decentralized way by different market actors while the network investment decisions are taken in a merely centralized fashion, a coordination of both is challenging. Existing studies look at the order of the different decisions. Due to the different realization horizons of the projects, it appears to be preferable that the network reinforcement projects are decided first in a long-term a planning process. These projects are then to be published such that marketers can take them into account for their generation investment decisions. One of the latest approaches of this type is the proactive network planning (PNP) of [40]. They compare a three-period PNP model to a combined generation-transmission operation with investment planning and to a transmission-only planning model. They conclude that PNP can correct some of the shortcomings of the transmission-only planning and claim that it is a valuable economic assessment methodology. The expected social gains by the PNP methodology should be distributed to all market players through side payments ([41]). However, as stated earlier for the two-part tariff cap, the results are promising but not yet applicable to realistically large networks or realistically large planning periods, respectively.

Last but not least, in [34] they present a design of electricity transmission charges that recover regulated network costs in a long-term perspective. These charges can be seen as uplift on the regular transmission costs due to long-term network development. The approach presented in [34] is based on the concept of average participation (compare also [3]). The latter is a method to evaluate the extent to which generation or demand at certain nodes contribute to the overall flow pattern and, thus, to which a node would be affected by a certain network extension project.

4.2 Merchant approaches

The concept of MTI is displayed in Figure 4-1. This figure includes many aspects of MTI. Under the assumption of limited transmission capacity between two nodes ($node_1$ and $node_2$), there are two different electricity prices (p_1 and p_2) for these nodes. By increasing the exchange capacity between both nodes, an investor can skim a dividend for its investment. At the same time, the electricity prices start to converge. To make this working, some framework conditions are required: 1.) one needs locational (nodal) price signals; 2.) the capacity extension should not entirely eliminate the congestion because the dividend would then fall to zero as p_1 would then equal p_2.

Figure 4-1: The concept of MTI



Source: [18].

Merchant investments are carried out by a multiplicity of different investors. These investors do not necessarily have to stem from the electricity sector. They are rather large investment funds or financial institutions. These investors do normally not operate the grid. They invest into a line or some network element and receive the financial benefits from this investment via financial constructs. Hence, a merchant investor decides based on profit opportunities.

However, the debate is still ongoing which financial constructs are fully able to reflect the physical realities while simultaneously incorporating certain financial properties, e.g., in terms of liquidity, tradability, and hedging. In [6] the authors distinguish contracts for differences (CFD) to hedge temporal price risks and transmission congestion contracts (TCC) that pay the owner by the locational price difference between the two nodes specified in the contract. Bushnell and Stoft base their analysis on a contract network regime as proposed by [14] – nodal pricing – and find that in this case TCCs provide the correct incentives for network investments. In [8] they use the nodal pricing methodology and design tradable transmission capacity rights that are able to combine a competitive market for transmission services and a competitive spot market for electricity. They suggest a trading rule for these transmission capacity rights that combines a property right approach to transmission congestion and to account for network externalities. In [16], however, they distinguish two types of tradable rights: financial transmission rights (FTRs)[5] and physical transmission rights. FTRs are financial instruments that entitle or oblige the holder to receive or make payments in case of congestion. Physical rights give the holder the right to transmit electricity even in congestion scenarios. The two authors find that in instances of loop flow effects physical rights can be withheld and thus are likely to be misused in order to exert market power. Thus, they

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[5] According to [18], the terms TCC and FTR are interchangeable.

favor FTRs where physical withholding is not possible.[6] On the other hand, in [1] the author introduces border flow rights (BFRs) to make FTRs dispensable. He states that with FTRs, there is a property-rights issue for existing transmission capacity if new transmission capacity is brought online as in this case the number and values of FTRs in circulation changes. BFRs are supposed to resolve this problem. However, the problem of BFRs is that – in contrast to FTRs – they do not have a generally acknowledged definition and on their usefulness is still debated.

Other existing studies focus on specific implementation requirements for MTI. For example, in [5] they focus on the welfare effects of a must-offer provision of line capacity. They conclude that the regulatory instrument of a must-offer provision has positive short-term welfare effects but may lead to underinvestment in network assets. They do not recommend applying must-offer provisions. Other authors look at the risk associated with a MTI decision under uncertainty (e.g., [38]; [39]).

Additionally, in [18] they conduct an in-depth analysis of merchant investment under different market imperfections. They distinguish two types of network extensions: deepening investments (reinforcement of existing equipment) and extension investments (construction of separate new lines). The former are considered to be only possible by the incumbents due to incentive problems with decentralized ownership and information asymmetries. Thus only independent network extension can be subject to merchant approaches. They show that market power, lumpy investments, FTR allocation, and the actual definition of transmission capacity all impact the outcome and conclude that the merchant model ignores important restrictions of electricity markets which a regulatory approach can cope with and thus a sole reliance on merchant investment seems unlikely.

4.3 Investment analyzing and decision finding

4.3.1 Introduction

Talking about network extension leads to the question how to analyze the different technical possibilities. The objective of this section is to describe different methods of analyzing alternative technical investment possibilities and the decision finding process. Due to the existence of different alternatives, the most beneficial one has to be selected.

The next sections provide an overview of the different investment analysis methodologies, useful to evaluate the most beneficial investment scenarios. The preferable methods are described here.
In order to select the right method, it has to be checked that the input data fulfil the pre-conditions or framework conditions (so-called axioms) for the different criteria. An axiom is a precondition that has to be fulfilled so that a specific method can be used. If the axiom is not fulfilled the specific method might give wrong results.

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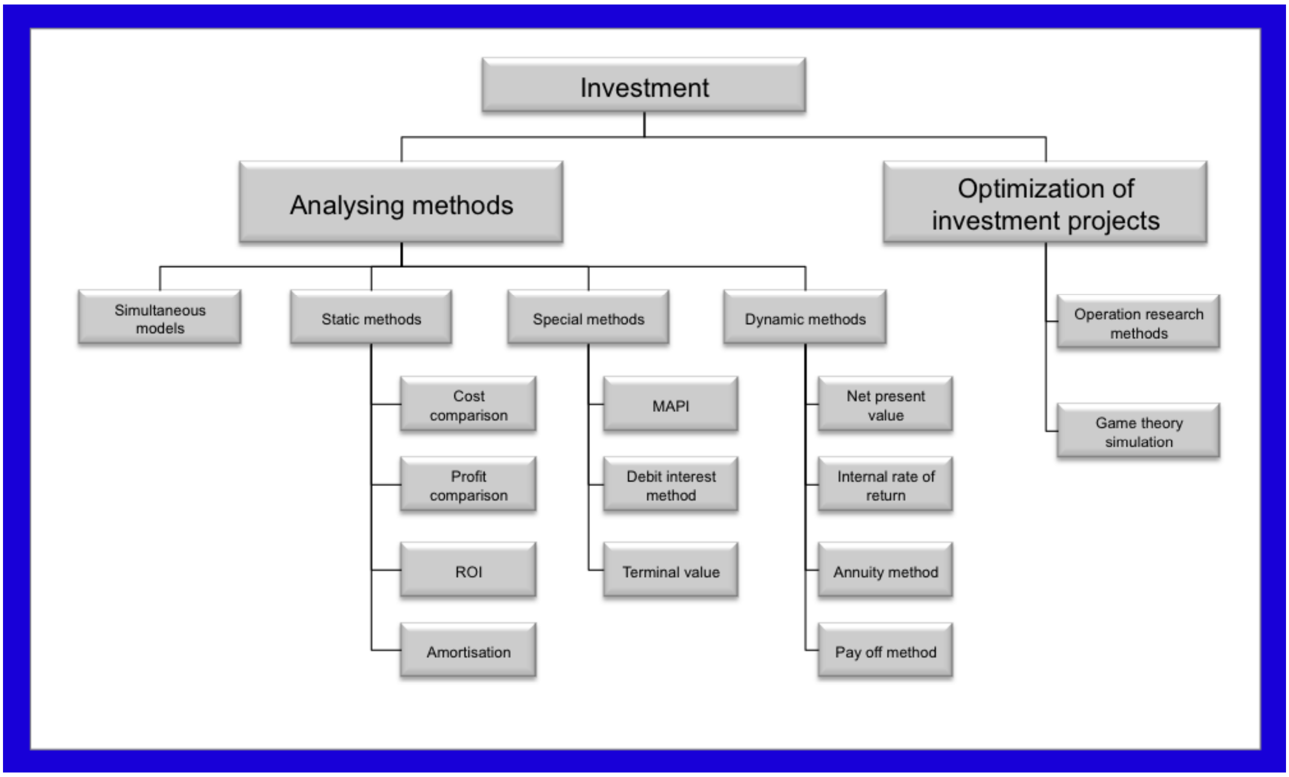
[6] The interaction between imperfect markets and investment decisions is also addressed by [4] and [22].

4.3.2 Overview to investment analyzing methods

In investment decisions, many evaluation criteria exist. These methods can be partitioned into two major groups. The first is the group of static criteria, taking into account only money flow. No time differentiation is considered. The second group is that of dynamic methods ([45]), incorporating also the time “axis” ([2]).

Investment projects in the power industry and power network operation are always characterized by a long time horizon and so the static methods will, in general, provide no help in analyzing different investment alternatives. Only the dynamical methods appear to be suitable for this evaluation. Depending on the concrete data of the investment projects (network extensions projects) the suitable methods have to be selected. In the following, an overview of the most important methods will be given.

Figure 4-2: Methods of investment analysis

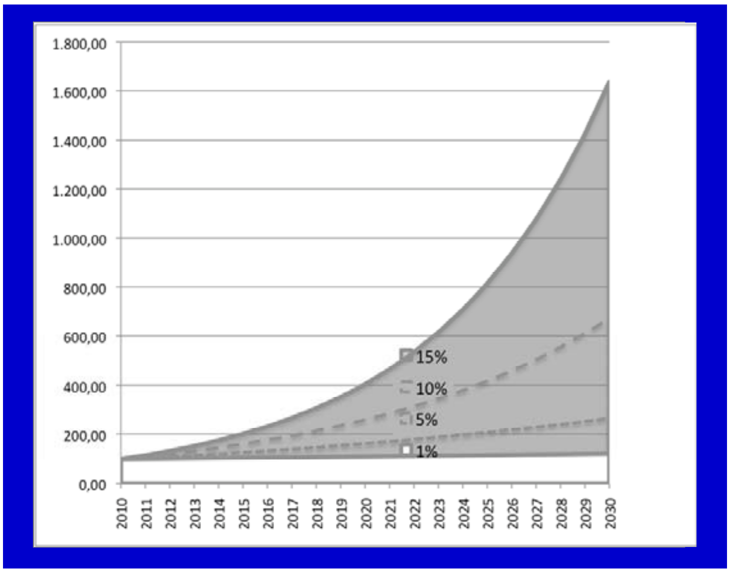


Depending on the investment problem, many methods are used. The most common ones are the Net Present Value (NPV), the Internal Rate of Return (IRR) and the amortisation. The first two belong to the group of dynamic methods, whereas the third belong to the static methods.

Dynamic and static methods are all part of the analysing methods. All methods of the analysing group look only at the given cost-benefit structure and deliver a comparison of the different possibilities. If several projects are given, the overall problem can also be defined in terms of an optimization algorithm by using Operations Research (OR) or game theory methods. This approach is not considered in our investigation. Advised for long term investments with uncertainty and fuzziness, the OR methods are difficult to implement in a model. In macro economic problems, also the game theory methods seem to be not so beneficial, as game theory assumes to be able to define clear strategies for all players, that in the case of macro economic problems is not so easily done.

In our investigation, the dynamic methods will be preferably used. The following diagram shows why the static methods seem not useful in this case.

Figure 4-3: Dynamic influence of discount factor



In the example shown in Figure 4-3, the considered time horizon is 20 years. Depending on the chosen discounted interest rate, the error of not considering the time axis and actualize the payments can amount to up to over 1500 in the case of a 15% discount rate. This simple evaluation shows very clearly that the static methods are not useful for such a long-term problem (source: own calculations, [13]).

Simultaneous models optimize internal factors like production and value chain (macro economic problem, not relevant to our case).

The relevant parameters for investment decisions are: social welfare, investment costs and time horizon. Different investment scenarios should be compared. For this case the Net Present Value out of the dynamic methods seems to provide the best approach.

4.3.2.1 Net Present Value (NPV)

The net present value ([45]) is the sum of discounted values of all earnings and efforts relating to the time in which they take place.

$$NPV = \sum (EA_t - EF_t) / (1 + i)^t \qquad (4.1)$$

where

EA_t	earnings out of the investment project in the time period t
EF_t	efforts for the investment project in the time period t
t	time period
i	interest rate (discount factor)

In investment calculation and especially in long-term investments, the time points are defined on a yearly basis. The interest rate i (discount factor) is compared to the interest rate of alternative investments, so that a “normalized” NPV results, that is positive only if the considered investment profits more than the benchmark one. For investments in a macro economic environment, the allowed internal rate of return on equity (IRR, see below) calculated by means of the weighted average cost of capital (WACC, compare Chapter 5.3) can be used too.

If the normalized NPV is greater than zero, then the investment is more favorable than the alternative investment which is represented by the normalized discount rate (e.g., the interest rate of a state bond). In the macro economic view, the earnings are the social welfare and the present value is the difference between the social welfare and the cost in each year.

If more than one investment project is compared, the investment project with the highest NPV is the most favorable. The highest NPV brings the highest welfare to the society.

4.3.2.2 Internal rate of return (IRR)

The internal rate of return ([45]) is the interest rate where the NPV becomes zero and will be compared to the minimum interest rate expectations of the investor.

$$0 = \sum (EA_t - EF_t) / (1 + j)^t \qquad (4.2)$$

where

j internal rate of return

This method is used in companies to evaluate if investments bring a given minimum IRR on equity. The problem of the method is the calculation of the n^{th} root, which is not unique and can be solved only approximately by numerous methods. In the case of equal financing structure (similar investment volume) and if we use the same discounting factor for all investments, the IRR provides the same information as at the NPV value method. In the case of a wide range of investment volumes for the different investment scenarios (alternatives), the question about the financing structure comes up. If there is a different financing structure this leads to different discounting factors of the NPV method, then the IIR method can be an alternative to rank the different investments.

4.3.2.3 Amortization

The amortization method ([45]) calculates the year where the NPV for given earnings, efforts and interest rate becomes zero. The amortization gives information about the financial benefit of an investment. It can be used only to compare investment projects based on their risk level. Under the assumption that the prediction of payments is affected by high uncertainty, then the investment project with the shorter amortization time has less risk. This is used, if the NPVs of two investment projects are closer together as additional information for the decision.

4.3.3 Method of comparing transmission network investment decisions for the decision finding process

Investment analysis is usually based on a comparison between alternative investments, or in some cases between a given investment and doing nothing. Investment analysis always implies a cost – benefit comparison. Therefore, it is necessary that an investor can define costs and benefits for each investment project. The alternatives must be comparable and there exist preferences for the investor. The wording “comparable” means, e.g. for the NPV methodology, that the interest rate is the same for all the investments given by similar investment volumes, and the time horizon is equal.

Also a preference criterion must be given between the different investment alternatives. E.g. if the outcomes of two investment project evaluation methods deliver the values A and B, a preference-relation like “A $\succ$ B”must subsist. That means the outcome A from the first investment alternative (I_A) is as good or better than the outcome B of the second investment alternative (I_B). This is the so-called first axiom of completeness of a given problem.

Investment analyses are only comparable if the assumptions mentioned above, about interest rate and duration, are fulfilled. Then the conclusion from the preference-relations “A $\succ$ B” and “B $\succ$ C” to “A $\succ$ C” is possible and the problem is transitive. Transitivity is the second axiom that a problem has to fulfil.

Based on the existing UCTE network model, different investments can be done within the evaluated time slices. Different investment decisions may have different influence on technical parameters (and therefore on Security of Supply issues) as well as on welfare (see Chapter 5.2.1) aspects from a socio-economic perspective. The relevant time slices are summer, winter, spring and autumn, day, night and peak for each of the years considered by the project REALISEGRID, i.e. 2010, 2015, 2020 and 2030.

Taking the dynamic perpective into account, the NPV of the difference between the cost and benefits can be calculated as follows:

$$totBIs_n = NPV\,(\,CIs_t\,;\,Swf_t\,;\,I\,) \tag{7.1}$$

where:

$totBIs_n$	total benefit of an investment scenario n
CIs_t	costs of a Investment scenario at the timeframe t
Swf_t	social welfare at the timeframe t
i	discounting factor / internal discount rate (alternative investment)

In the case of a wide range of investment volumes the Axioms of transitivity and completeness might not be fulfilled. As discussed above the IRR can be used in this case, calculated by a different numerical methods.

$$IRRIs_n = f\,(\,CIs_t\,;\,Swf_t\,) \tag{7.2}$$

where:

$IRRIs_n$	*internal rate of return for the investment scenario n*

The objective is to find the most beneficial investment scenario out of a range of scenarios. Depending of the problem the Objective function is:

$$Max(\,totBIs_n) \qquad or \qquad Max(IRRIs_n) \tag{7.3}$$

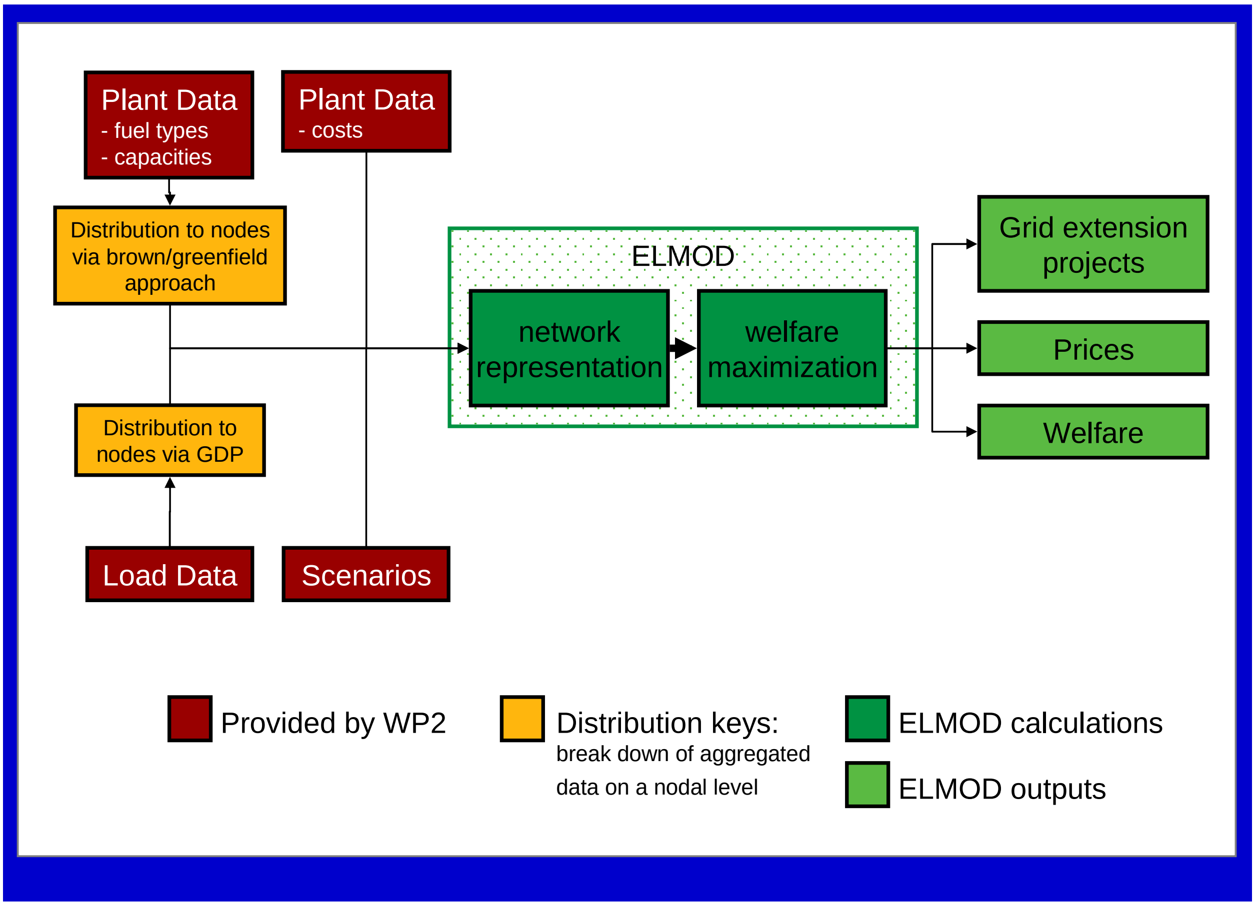
5 WELFARE INDUCED NETWORK EXTENSION

5.1 Procedure

As pointed out in Chapter 2, the present chapter highlights the welfare perspective of grid upgrades. Starting from a welfare benchmark, different extension approaches can be supplemented. Following, the general procedure of the proposed welfare approach will be presented. In the subsequent section, the model formulation and parameterization is presented and afterwards the extension algorithm is explained.

To derive a welfare optimal network extension the welfare gain due to an extension measure needs to be compared to the necessary costs for the extension. Figure 5-1 interlinks the ELMOD model and the data set from the long term scenario analysis performed by the WP2 of REALISEGRID as well as the output generated by ELMOD that will be used further within the project.

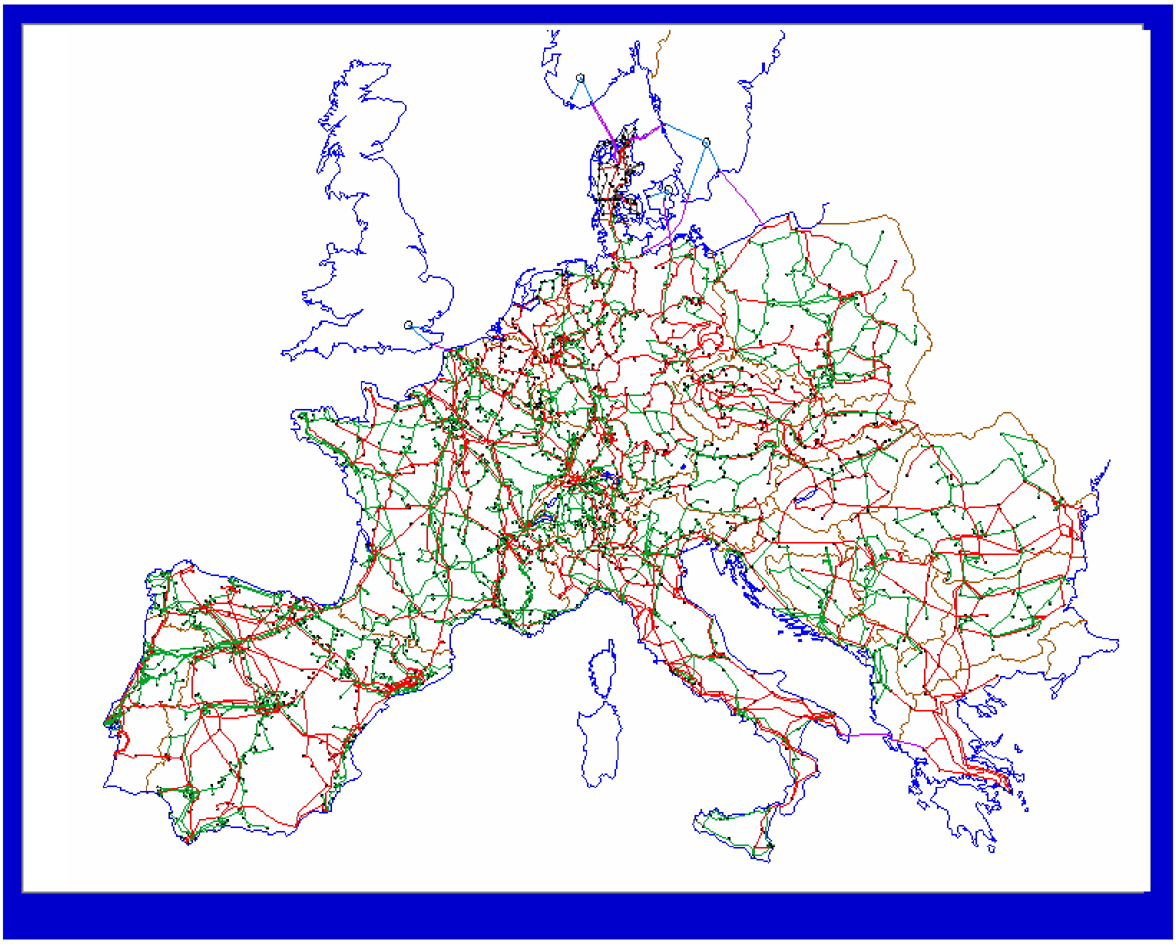
Figure 5-1 ELMOD within the project framework



5.2 ELMOD adjustments

To calculate the scenarios we apply the software ELMOD to model of the European electricity market (see [24]). ELMOD covers the whole continental European electricity transmission network of ENTSO-E as well as the DC connections to the UK and Scandinavia (Figure 5-2). Following we provide an overview of the basic formulation of the model ELMOD, applications to energy policy analyses, and the data adjustments required within the REALISEGRID framework. The extension algorithm is presented in detail in the next section.

Figure 5-2: Network representation in ELMOD



5.2.1 ELMOD: Basic formulation

In its basic formulation, ELMOD can be classified as a large non-linear optimization model maximizing social welfare under the assumption of perfect competition taking into account technical constraints. It is solved using GAMS.[7]

The optimization is based on maximizing social welfare W (Figure 5-3), that is defined as the unweighted sum of consumer and producer surplus. We assume a linear inverse demand function $p_n(q_n)$ for each node where p_n is the nodal price at node n and q_n is the demand quantity at node n.

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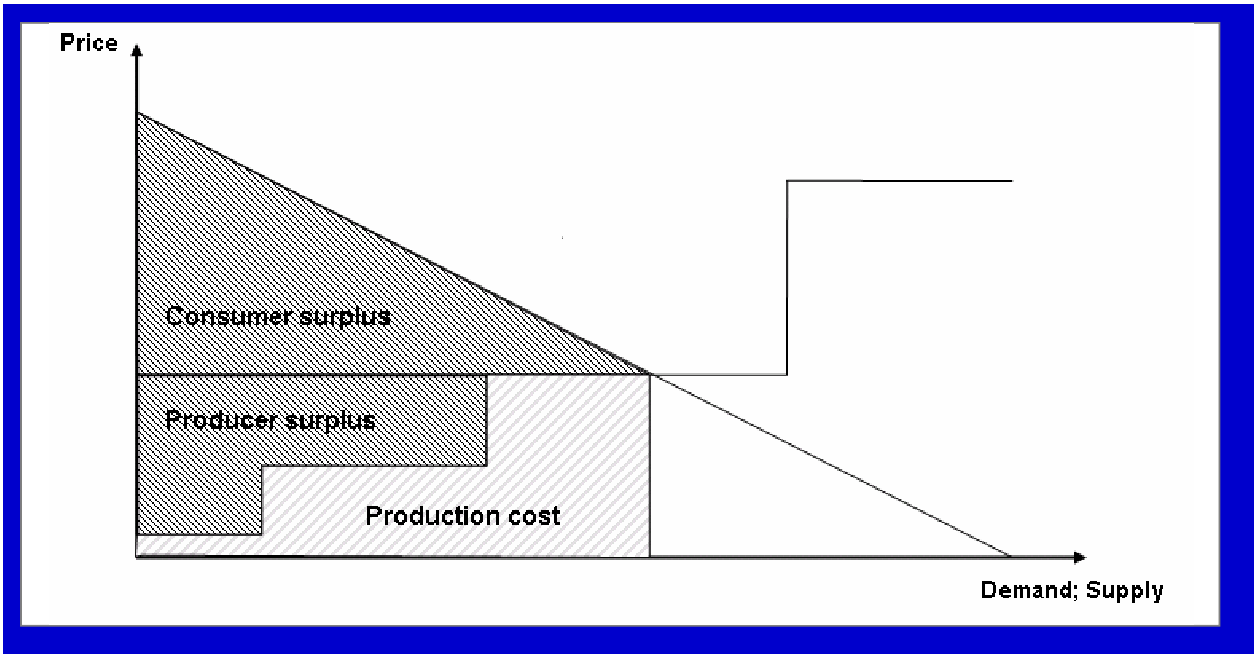
[7] The General Algebraic Modeling System (GAMS) is a commercial software which is particularly suited for large scale optimization and mathematical complementarity problems. The mathematical problems are coded up in GAMS which then compiles the data and executes standard solvers (e.g., CPLEX for linear programs or PATH for complementarity problems) to solve the problem. Compare: www.gams.com.

At each node reference demand, reference price and elasticity (see Chapter 5.2.3) are estimated to derive the linear demand function. The assumption of linearity is based on the mathematical nature of ELMOD. The linear demand function is a good approximation of a price sensitive demand and does not complicate the solving of the large scale model due to its linear and continuous properties.

Figure 5-3 Representation of the social welfare



The optimal dispatch maximizing social welfare (equation 5.1) is determined respecting physical laws and technical conditions, namely energy balance (equation 5.2), line capacity (equation 5.3) and maximum generation capacity (equation 5.4) constraints:

$$\max_{q,g} \quad W = \sum_N \left(\int_0^{q_n} p_n(q_n) dq_n - \sum_T c_{nt} g_{nt} \right) \quad \text{objective function} \qquad (5.1)$$

s.t.

$$\sum_T g_{nt} - q_n - i_n = 0 \quad \forall n \qquad \text{energy balance equations} \qquad (5.2)$$

$$|P_l| \leq P_l^{\max} \quad \forall l \qquad \text{line flow constraints} \qquad (5.3)$$

$$g_{nt} \leq g_{nt}^{\max} \quad \forall n,t \qquad \text{maximum generation constraints} \qquad (5.4)$$

We assume constant marginal costs c_{nt} for each generation g_{nt} at a node n depending on plant type t. Additional costs, such as those arising from network operation and maintenance as well as start-up costs and ramping conditions are not considered. The energy balance (equation 5.2) states that at a node n the difference between total generation and demand has to be balanced by injections into or withdrawals from the grid *i*. The price at a node can then be derived by applying the linear demand function *p(q)* and the resulting demand level *q* at this node.[8]

Power flows P_l and transmission losses are obtained using the DC Load Flow network model (DCLF) described by [42] and [44]. From the standard π -equivalent circuit of a transmission line, the active (P) and reactive (Q) power flows between two nodes k and m can be calculated taking into account the voltage levels U at the nodes, the voltage angle difference Θ between the nodes, and the resistance and reactance of a line (via the series conductance g and the series susceptance b):

$$P_{km} = g_{km}|U_k|^2 - g_{km}|U_k||U_m|\cos\Theta_{km} + b_{km}|U_k||U_m|\sin\Theta_{km}$$

active power flow (5.5)

$$Q_{km} = b_{km}|U_k|^2 - g_{km}|U_k||U_m|\sin\Theta_{km} + b_{km}|U_k||U_m|\cos\Theta_{km} - \frac{1}{2}b_{km}^{sh}|U_k|^2$$

reactive power flow (5.6)

The DCLF focuses on the real power flows P. In order to derive a linear representation of the power flow applicable for modelling purposes the calculation is carried out as per unit calculation normalizing the voltage level U to approximately 1, the voltage angle difference is assumed to be small making $\cos\Theta_{km}$ about 1 and $\sin\Theta_{km}$ about Θ_{km}. Furthermore, the node to node setting is transferred into a line setting in which a line l connects two nodes n and m. This yields a linear equation for the lossless line flows:

$$P_l = b_l\Theta_l \quad \forall l$$

power flow equations (5.7)

In addition, losses are important as they increase the amount of generated energy that is needed to supply a certain demand and represent additional cost impacts if energy has to be transported over large distances. The losses correspond to the sum of the loadflows along both transmission directions:

$$L_{km} = P_{km} + P_{mk}$$

power loss equation (5.8)

Applying the same simplifications as for the active power flow calculation and transferring the node to node formulation into a line bases formulation, losses can be reformulated as:

$$L_l = g_l\Theta_l^2 = \frac{r_l\left(r_l^2 + x_l^2\right)}{x_l^2}P_l^2$$

power loss equation (5.9)

Assuming that the series resistance r is significant smaller than the series reactance x yields the following equation for losses on a line:

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[8] The price obtained by applying the demand function is equal to the shadow price on the energy balance.

$$L_l = r_l P_l^2 \quad \forall l \qquad \text{power loss equations} \qquad (5.10)$$

Transmission losses are included by splitting them between the start and end nodes of a line *l* as presented by Todem [45]. Hence, losses are represented within the net input i_n that defines the amount of energy that is injected or withdrawn from the network at node *n*. To account for the (n-1) constraint, we use a transmission reliability margin of 20%; thus the P^{max} of each line *l* is 80% of the full thermal limit.

This basic model formulation of ELMOD is time static with a reference period of one hour. Due to the welfare maximization the model becomes a non-linear program (NLP). Due to the large size of the represented network neither consecutive time steps (e.g., a 24 hour day) nor a fully unit commitment including start-up and minimum running restrictions are incorporated. Furthermore, the welfare maximization reproduces market results similar to a perfect competitive equilibrium neglecting the impact of strategic company behaviour on market prices.

5.2.2 ELMOD: Existing applications

ELMOD has been applied to several policy related questions. The analyses can roughly be clustered in three research areas:

- Congestion management in a German context
- Wind energy integration in Europe
- Spatial aspects of generation investments in congested networks

One of the first uses of ELMOD was to study different congestion management schemes for the German electricity market, particularly the problem of integrating large scale offshore wind projects as presented in [9]. In [26] the authors demonstrated that nodal pricing is superior to uniform pricing in welfare terms given the German market environment. In [49], the model is extended to include a time-frame of 24 hours in order to simulate variable demand and wind input as well as unit commitment, start-up and pump storage issues. He shows that while the average price during off-peak times is on an equal level under uniform and nodal pricing, prices greatly diverge during peak times. Moreover, although specific nodes face higher prices under nodal pricing than under the current uniform system the average price level is much lower during peak hours resulting in a welfare gain of about 100 million € per year.

Regarding the second research field, [50] continued the extension of ELMOD by including France, Benelux, Western Denmark, Austria and Switzerland in order to examine cross-border issues. They point out that even under status quo conditions, the price situation in Benelux is affected by high wind input in Germany. This situation is bound to aggravate if the planned wind capacity extension will be realized without proper grid adjustments. In [27], the authors build on the aforementioned works in order to recommend nodal pricing for electricity market analysis particularly in a European context. In [51], the authors analyzed the possibility of integrating large scale off-shore capacities using high voltage direct current (HVDC) lines in order to transport the energy to demand centers in the South and West of Germany. They showed that not only Germany benefits from the HVDC approach due to less congestion and lower prices, particularly in the South, but also the Benelux benefit from the reduction in cross-border flows leading to congestion in their markets.

Finally, [25] focused on large-scale wind integration in a European context with a particular focus on efficient grid extension measurements. They estimate the impact of additional wind energy by analyzing price situations and develop an extension algorithm to extend the grid incrementally until an economically optimal system status is identified that is capable of carrying the additional wind. The approach applied in the REALISEGRID framework is an extension of [25] (see Chapter 5.3). In [25] they showed that developing the network at existing bottlenecks - mainly cross-border connections - should be encouraged by regulatory authorities.

Regarding the spatial aspects of generation investments, [10] modelled investment location decisions for power plants in the German market up to the year 2012 based on realistic data of planned generation projects. They analyzed where in the current scheme new investment in generation is most likely to take place and compare these results to an optimal investment pattern taking into account network constraints. They applied nodal pricing to identify local price changes and resulting congestion. The results indicate that new generation capacities are not needed in Germany but in the Benelux area and a significant welfare surplus could be obtained by the reallocation. The developed model by [10] will be utilized to distribute green field generation provided by Work package 2 within ELMOD (see next section).

5.2.3 ELMOD Scenario adjustments for REALISEGRID

The basic dataset of ELMOD covers the continental European electricity market on the transmission level with about 2400 nodes, 1500 power plants, and 3800 lines. For REALISEGRID the basic dataset is extended to include South-East Europe and connection to the UK and Scandinavia (Figure 5-2). The basic dataset for the model runs is provided by the long term scenario analyses carried out within the REALISEGRID project (see D2.1 and D2.2).

As the approach is time static; we calculate different scenarios to account for the seasonal and daily variations in the electricity market. An average year is approximated using four seasonal (winter, spring, summer, fall) and three time of day (night, day, peak) periods. Each period is weighted according to their occurrence during a year. For each scenario a reference demand is provided which is divided by the number of hours in the period to obtain an hourly load value. The aggregated demand levels per country are distributed to the nodal scale of ELMOD using the GDP within a region as key assuming a positive correlation between economic income and total electricity demand. The GDP is available at Euro NUTS2[9] level for larger countries and Euro NUTS2 for smaller countries. Each district is assigned to a node. In case there are different nodes in one district, the entire gross value is divided by the number of nodes. In case there is no node in the district, the gross value added is distributed to all neighboring districts with nodes. The share of a node of the whole gross value added is calculated and applied to the load level with the same share.

Generation information is also provided by the long term scenario analysis. Generation is clustered into different technologies defined by operation costs, efficiency, and emission levels. Fuel prices are differentiated for countries and the different time slices (2005, 2015, 2020, 2030). Marginal generation costs are then derived for each power plant type. The aggregated installed capacities

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[9] Nomenclature of Territorial Units for Statistics (NTUS) is the geographical division system of the European Union. The NUTS2 level corresponds to larger regions, provinces, and governmental regions.

again have to be distributed to the nodal scale of ELMOD. Existing capacities are distributed based on the current power plant location. Newly installed capacities in the different time slices will then be distributed using two methods. First, replacement of decommissioned units will be sited at the same nodes as the pre-existing capacities (brown field approach). Second, remaining capacities are distributed to nodes with similar field plants (brown field) and potential new nodes (green field), e.g. close to resources or harbors, by making a pre-run with ELMOD to determine the optimal locations. We adjust the basic model formulation to allow for a flexible plant location. We assume a benevolent planner approach in which the projected plants are located in order to maximize social welfare. The generation location becomes an endogenous variable and is incorporated into the model formulation. The methodology is described in [10].

The dataset is the feed into ELMOD to derive a welfare optimal dispatch for each scenario (Figure 5-1). The aggregated yearly welfare is then calculated by summing the scenario welfare values accounting for the scenario weights.

5.3 Extension algorithm

We apply an extension heuristic developed by [25] and presented by [16] and in an adjusted version by [24], respectively. The objective of the extension algorithm is to estimate the welfare optimal amount of necessary grid extensions to cope with congestion occurring due to changes in the demand and generation structure in the coming years. The algorithm gradually extends the existing grid (upgrading lines). In a first step the model calculates the weighted average nodal prices for each node out of the seasonal reference days (compare Chapter 5.2). Next, the model identifies the most severe congestion (identifying the line between the two nodes with the highest price difference). This line is then extended by adding another circuit of the same kind at the same link, simulating a line extension in the form of adding one additional parallel line to an existing connection. We assume that this type of extension measure is possible on each circuit of the model. However, our model does not allow for more than four parallel circuits on one connection. If this constraint becomes binding, the line with the second highest price difference is extended and so on. After each extension step it, the model performs a new run and determines the new welfare value and the welfare change $\Delta W^{it} = W^{it} - W^{it-1}$. The model then compares the welfare change to the investment effort required to implement the respective grid extension. If the costs are higher than the change of welfare, the line is not considered for further extensions. The model automatically stops if no welfare gain is obtained for 50 different extension steps (compare also Figure 5-4 for a simplified illustration).

- **Step 1: Initialization.** ELMOD is run with the basic dataset obtaining the welfare optimal dispatch and nodal prices.
- **Step 2: Identify most severe congestion.** Determine the highest price differences Δp between all interconnected nodes.
- **Step 3: Upgrading.** The line with the highest price difference is upgraded by adding a further line of the same voltage level to the system (e.g., in case of a double circuit 380kV line a third circuit is added). This can be done up to a maximum of four circuits on an interconnection.
- **Step 4: New model run.** ELMOD is run with the adjusted dataset and the new optimal dispatch is obtained.

- **Step 5: Comparison**. The welfare of the new model run is compared with the previous model run welfare result. In case the welfare gain due to the line upgrade exceeds the investment costs (W^{it} - $W^{it-1} \geq Icost$) the upgrade is kept and the iteration restarts with step 2 identifying the next highest price difference. In case the welfare gain is lower than the costs (W^{it} - $W^{it-1} \leq Icost$) the upgrade is undone and the line is neglected for further upgrades. The iteration restarts at step 2 with the second highest price differential.

Investment costs (*Icost*) for a line upgrade are based on the discounted value of the annual depreciation of the investment costs for the particular extension measure. The discounted annual depreciation value is calculated by multiplying the initial costs for the particular extension measure with the annuity factor *ANF*:

$$ANF = \frac{r \cdot (1+r)^k}{(1+r)^k - 1} \tag{4.5}$$

where r represents the weighted average capital costs (WACC) and k the given period. The WACC is calculated as:

$$r = \left(\frac{E}{TC}\right) \cdot r_E + \left(\frac{DC}{TC}\right) \cdot r_{DC}(1-s) \tag{4.6}$$

with E for equity, TC for total capital, r_E for equity yield rate, DC for debt capital, r_{DC} for interest on debt capital and s for tax rate. The rate r_E is determined using the Capital Asset Pricing Model (CAPM):[10]

$$r_E = r_f + (\mu_m - r_f) \cdot \beta \tag{4.7}$$

with r_f for the risk-free rate of return, μ_m the market rate of return and β the risk factor. We choose a given period (k) of 12 years, 25% equity ratio (E/TC), 6% interest on debt capital (r_{DC}), 40% tax rate (s), 3.5% risk-free rate of return (r_f), 13% market rate of return (μ_m) and 0.9 as risk factor (β). Based on these assumptions, the annuity factor *ANF* is 11.75%. The capital expenditure for upgrades to be compared with the welfare increase is calculated by multiplying the specific price per km with the length of the upgraded line.

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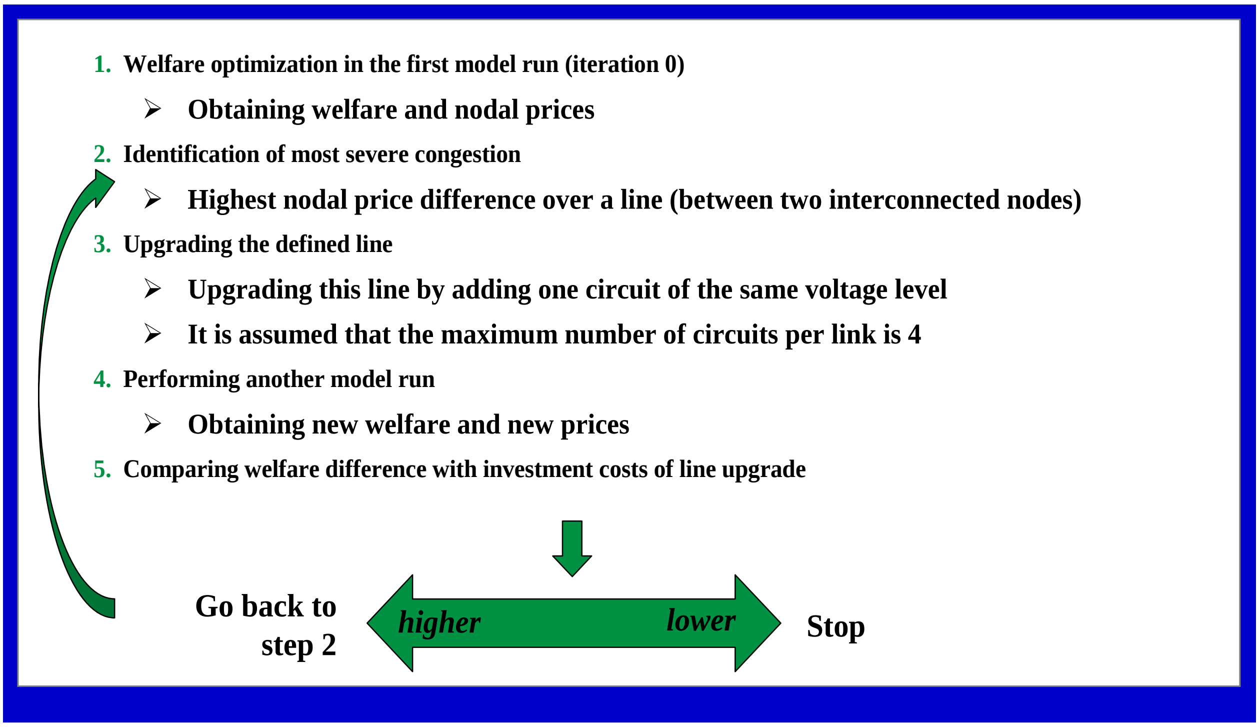
[10] The Capital Asset Pricing Model (CAPM) is an evaluation method for assets subject to risk. According to the CAPM the expected return of an asset can be derived by adding a risk premium on top of the risk free reference return (e.g. state bonds).

Figure 5-4: Grid extension algorithm



1. Welfare optimization in the first model run (iteration 0)
    - Obtaining welfare and nodal prices
2. Identification of most severe congestion
    - Highest nodal price difference over a line (between two interconnected nodes)
3. Upgrading the defined line
    - Upgrading this line by adding one circuit of the same voltage level
    - It is assumed that the maximum number of circuits per link is 4
4. Performing another model run
    - Obtaining new welfare and new prices
5. Comparing welfare difference with investment costs of line upgrade

6 SECURITY OF SUPPLY INDUCED NETWORK EXTENSION

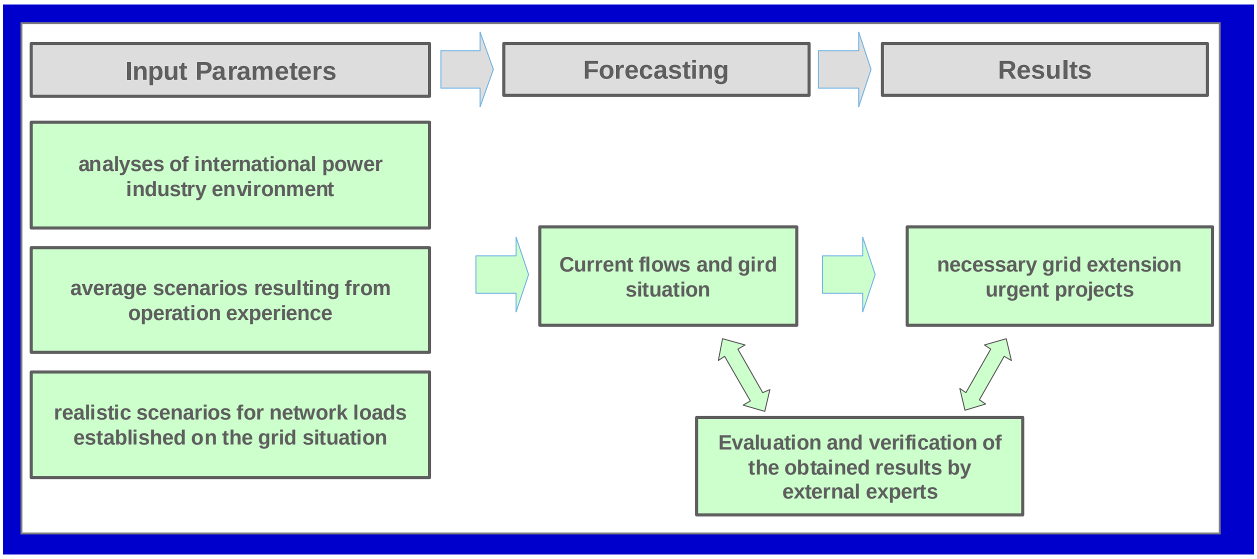
6.1 Procedure and input parameters

An efficient power grid is a very important asset for Europe and represents the basic requirement not only for the future expansion of renewable energy sources, but also for the achievement of the European climate protection goals. Being an infrastructure operator, a TSO is committed to long-term planning and well functioning of the grid. Over time the targets for the development of the grid have changed and become more complex due to energy market liberalization. Presently, the most important targets can be summarized as being:

- safe grid operation (reliability),
- security of supply ((n-1) criterion),
- unconstrained European energy market,
- integration of renewable energy sources,
- economic efficiency.

To accomplish the above mentioned tasks and, particularly, to cope with the increasing penetration of renewable energy sources, an even more comprehensive and detailed energy system planning is required. The method explained in this chapter offers a possibility for a TSO to foresee the weak point and bottlenecks in the grid and react in time to secure supply and safe grid operations. Another aspect of this method is the ranking of the needed projects in order of ugency. The method shows the medium- and long-term grid expansions which are urgently needed to cope with the future challenges in the energy industry. The method here illustrated for medium- and long-term grid extension planning to ensure safe grid operation, high security of supply, and unconstrained European energy market is based on researched input parameters and detailed forecast calculations. The applied process is shown in Figure 6-1.

Figure 6-1: Methodology



The in the following explained steps are necessary for the definition of network extension projects.

Step 1: Evaluation of the current situation of electricity consumption, installed power and current flows on a national and international basis. For this purpose the data is collected from a variety of sources and also Import and Export rates of the TSOs control area need to be taken into account. Out of these data, the weak points and the bottlenecks in the control area of the TSO can be located and therefore can be better taken into account.

Step 2: In this step, the development over the years of electricity consumption, power installation and import/export rates are examined on a national and international basis. The starting year of the examination is determined according to existing data and interest. Also the grid building strategies of the different countries which have an influence on the import/export rates should be shown. The analysis in detail covers the development of the European energy consumption taking into account an increase in energy efficiency, possible influences due to climate protection targets and target cut in overall energy consumption as well as the development of national power plant facilities and production structure.

Step 3: Analysis of the collected data and formulation of hypotheses of the future development of the energy consumption, power installation import/export rates.. The evolution of the installed generation park is based on one hand on the announced projects (known to the TSO) and on the other hand on assumptions.

Step 4: Creation of scenarios according to the results obtained in step 3. The network expansions surrounding the TSO's control area are also taken into account. Also national and international targets such as the EUs"20-20-20-targets", other targets such as for example increasing wind energy production or the extending hydroelectric power production are taken into account as well. For the Trend Forecast also possible influences and impacts of new trends and technologies for the transmission grid such as electric mobility can be taken into account. The scenarios should be robust, which means that current influences and their impact on the economy along with the economic development in the individual countries have no major influence on the definition of the required projects. Therefore the derived projects present a robust solution which can balance possible negative effects on the security by future developments such as the energy market, load flow situations etc.

Step5: Based on these input parameters, detailed forecast calculations are performed and the respective network loads are calculated and analyzed for different years. The framework of the forecast calculations is shortly explained in the following. For this forecast, a calculation tool is used modeling the whole integrated UCTE network. This network model simulates the 380kV and the 220kV networks, the lower voltage networks are included as loads. Power plants that are directly feeding the 380kV/220kV network are included with their technical data whereas power plants who are connected to the 110kV network are considered as operational nodes. The achieved results are the foundation for medium- and long-term grid extension planning to ensure the above mentioned targets of the development of the grid. It is advised to model realistic network load situations which correspond to likely situations. In this way, it can be avoided that low probability situation affect the network planning.

Step 6: The needed grid extensions and renewals can be derived form the obtained results of the calculations made in step 5. The results can be visualized for example with a traffic light design (see 6.2.2). Based on the calculated load flows for the different years projects can be very easily defined and the TSO knows which projects have to be realized to assure security of supply and safe grid operations.

Step 7: For the verification of the results, new calculations and analyses are required for the defined projects, in order to be sure of the positive impact of the projects on the safer grid operation and security of supply. .

6.2 Model description on the basis of APG-Masterplan 2009 – 2020

This section provides an overview on the implementation of the method introduced in Chapter 6.1. This method is used for example in the APG Master Plan 2009-2020 for mid- and long-term network planning and therefore the example is based on the applications and results in the Master Plan.

6.2.1 Defined input parameters and forecasting

Network loads 2009- 2020
For the evaluation of future challenges realistic scenarios have been developed for the grid calculations. Referring to the explained method the scenarios are input parameters based on the analysis of the power industry environment.
Findings and forecasts form international working groups (UCTE, ETSO → ENTSO-E) are included as well.

For the forecast calculation precise assumptions were made for the future developments of consumption, production and development of the grid. In general a so called 95%-approached was used therefore the received results of the network loads correspond to regularly appearing values.

Network scenarios for the assessment of development planning /Master Plan
For the evaluation of development planning a reference data set of load flows in the examined grid is needed. For this purpose the following two scenarios import and export scenario have been selected and a representative data set has been elected.

Import scenario
The Import scenario is very important for the future assessments of the North/South Connection within the APG-grid. The essential parameters in this scenario are high wind generation in Austria and Europe, low consumption at night, low current price and reduced use of thermal power plants.

Export scenario
The export scenario is very important for the load of wires to other countries. The essential Criteria for a typical export situation are low wind generation in Austria and Europe, high consumption in the evening, high current price and thermal power plants are full load.

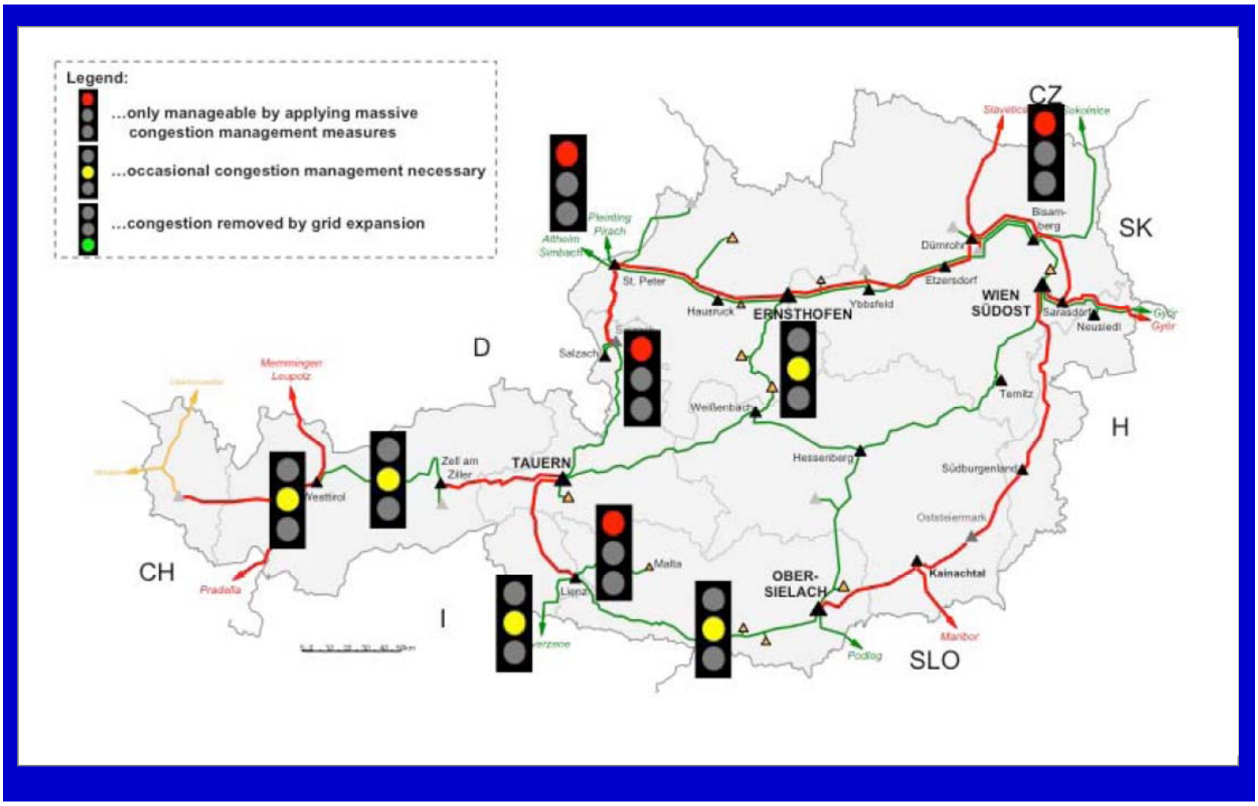
Methodology of the network loads forecasting
The network load forecasting was conducted with a network model of the UCTE (in future ENTSO-E). Planed network extensions in Austria and also in the European environment were consider in the UCTE- network model according to their start of operation.

The node load in the APG- transmission was calculated with a energy economic model, which shows the changes in the 110-kV networks in the node loads of the transmission grid. The power plant projects which are reported to the APG were considered as well in the energy economic model. The import and export rates to Germany were taken into account whereas the import and export rates to, from and between other countries were frozen in place for the different scenarios. The other assumptions which were taken ware already mentioned in Chapter 6.1.The results of the calculations are shown and explained in the Chapter 6.2.2.

6.2.2 Obtained Results

This step is equivalent to step 6 introduced in a general manner in Chapter 6.1. Figure 6-2 shows the obtained results for a specific year (here 2017) of the forecasting with today's network (no extensions). For better clarity of the results of calculations the traffic light design is used.

Figure 6-2: Grid load 2017 with the present network



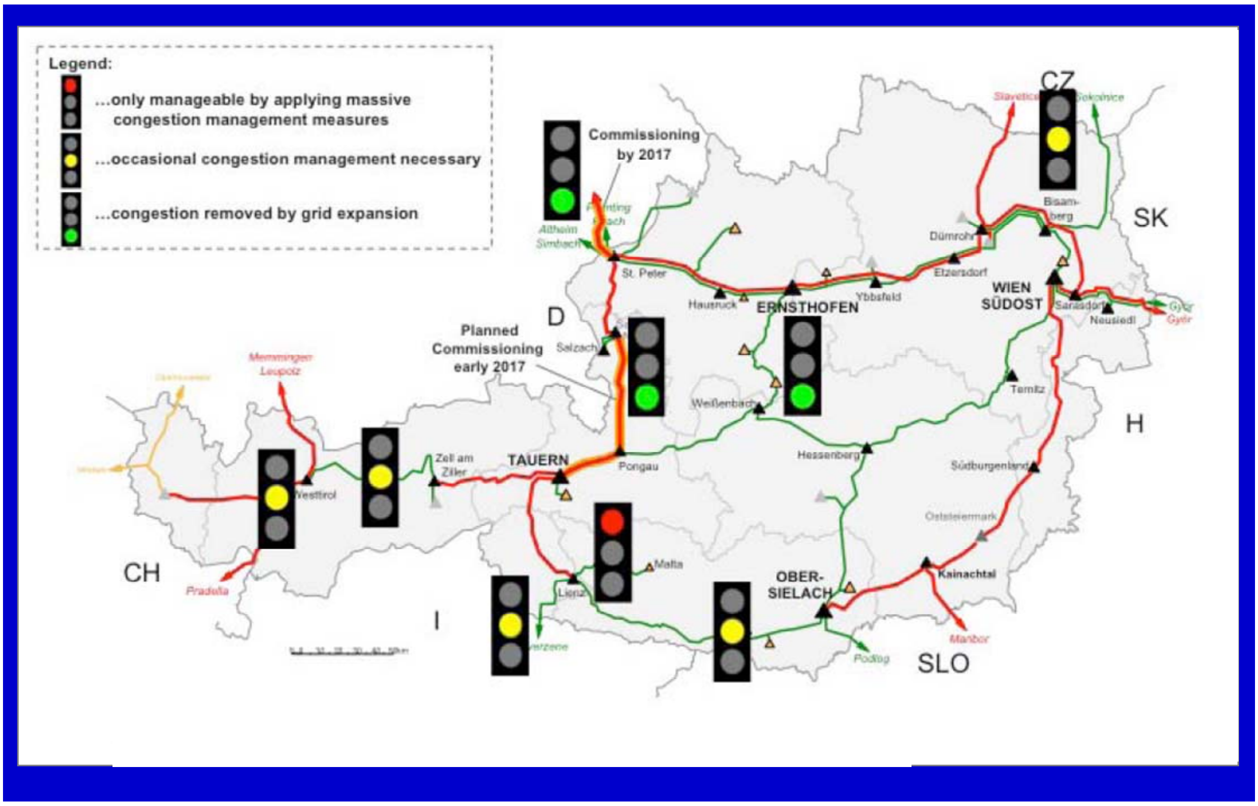
As can bee seen in the figure large network extensions by the year 2017 will be necessary to assure security of supply. Due to the missing Salzburg line 2 and the missing reinforcement to Germany, massive restrictions to the operation manner of most of the power plants that were expanded in the period by 2017 will be required, especially for the pumped storage plants in the Central Alps. In addition, massive congestion management is required for the lines to the Czech Republic, to Germany. Temporary congestion on the lines where the signal light is yellow will be needed.
With this mehtode it is very easy to make out the required projects to accomplish the mentioned targets in 6.1.

The urgently needed projects which can be defined according to this result are the installation ot the Salzburgline 2, reinforcement to Germany.

To make sure that the defined projects will live up to the expectaions/targets such as security of supply and safe grid operatios more calculations have to be made with the defined projects included as mentioned in step 7.

The results of step 7 are illustrated in Figure 6-3. As can be seen the installation of the defined projects would upgrade the grid situation and from a current point of view, no power plant limitations worth mentioning can be expected especially in the Central Alps.

Figure 6-3: Grid load 2017 with mentioned grid extensions (Salzburgline 2,reinforcement to Germany)



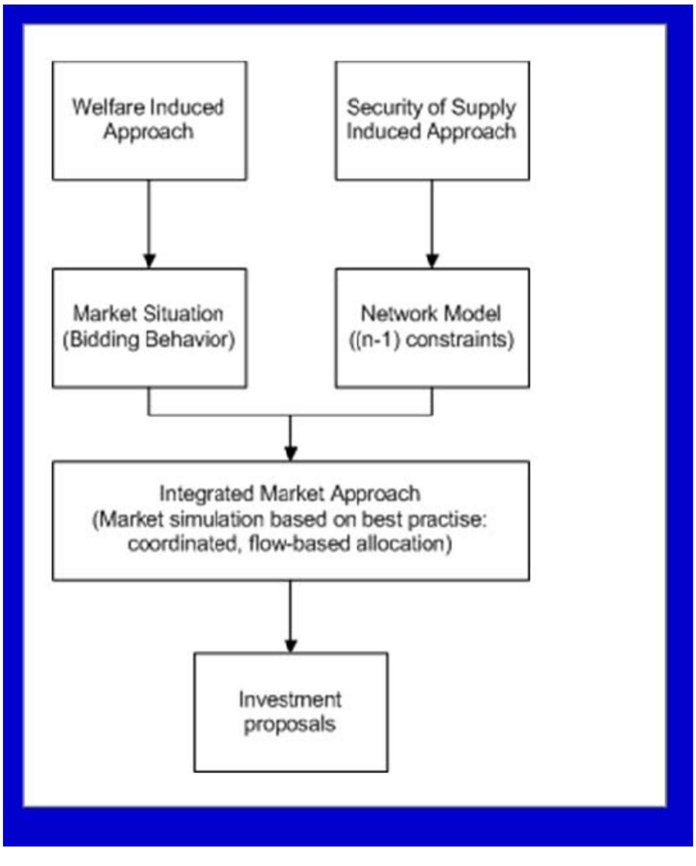
The method introduced in this chapter focuses on the best doable mid- and long-term network planning and shows the urgently needed projects in the future. Although realistic results are achieved the energy market is implemented in this method as a market study and not as a market model which would improve the results. The difference between a market study and a market model is that a market study is based on collected, reported (power plant facilities) and experienced data. Unexpected developments such as an electric car revolution might not be sufficiently taken into account. Due to this the influence of the market on the grid development is based on experiences and its interpretation and is in this chapter not based on a separate functioning energy market model.

7 AN INTEGRATED MARKET APPROACH TO NETWORK EXTENSION

In the previous sections, different methodologies and methods for investment planning were presented. The proposed social welfare induced network planning (see Chapter 5) originates from rather theoretical economic concepts whereas the European TSOs apply a load-flow based approach emphasizing security of supply (see Chapter 6). The latter is focused on the technical side, hence the scarcity prices for transmission capacity resulting from market based allocations are not taken into account. In addition to that, a deep coordination of the network investments among TSOs based on commonly available data was neglected up to now.

The purpose of this section is to connect the previously mentioned approaches and their overall objectives to recent methods of project evaluation. On the one hand-side, the welfare induced network planning approach yields an estimation for future market power prices. These findings are the basis for modelling the capacity market side (bidding behaviour) of the integrated market simulation. On the other hand side, the safe and reliable operation of the network as well as security of supply are taken into account as well. This is achieved by considering all network elements like (n-1) constraints in the integrated market simulation. Thus, a coordinated, flow-based allocation as a simulation instrument offers to identify those network investments that are optimal on a regional level and hence facilitates a harmonization of the European network planning process. Thereby, the present document illustrates an integrated approach that is tailored to the European situation.

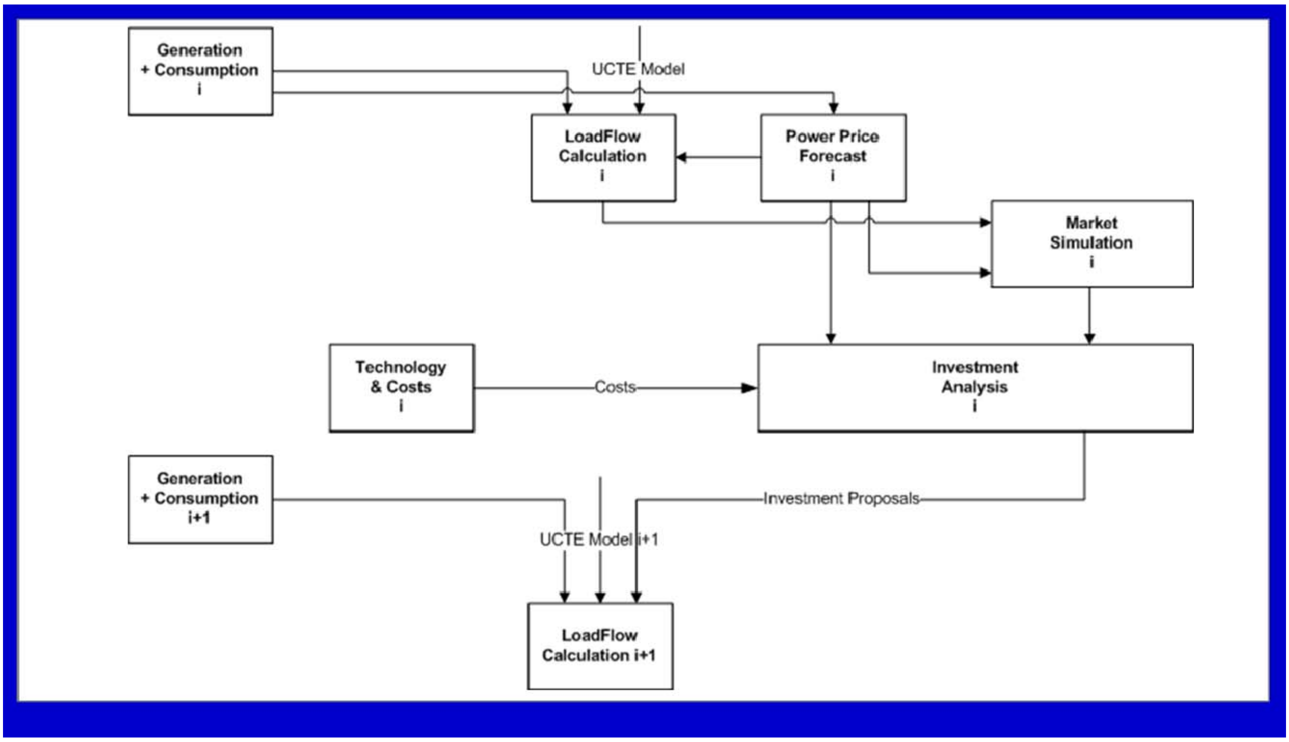
Figure 7-1: Integrated market approach



7.1 Methodology and interrelation of models

As stated in the introduction, our integrated method – where integration has to be seen in terms of bringing together market information and technical data – tries to combine two approaches (social welfare induced and security constrained) and supposes the existence of a central allocation entity which applies a coordinated allocation based on real time network models submitted by TSOs. The allocation mechanism can be a either explicit or implicit, flow-based auctioning. The result is the optimal market based allocation of bids of the day ahead market taking into account network constraints of the entire UCTE grid. Investment signals are provided in the form of network flows and congestion. This section will replicate the outlined procedure in detail on a typical application. An overview of one iteration of the main work flow of the illustrated investment planning methodology is shown in Figure 7-2.

Figure 7-2: Work flow



The analysis is done for any future time frame. A time frame is composed of the annual four seasons (spring, summer, autumn, winter). Each of the season is further subdivided into the three time slices (day, night, peak). A season is represented by a daily explicit auction with three products: daily band, nightly band and peak. An investment analysis cycle for a given time frame (e.g., for REALISEGRID the time frames 2015, 2020 and 2030 are investigated) begins with a forecast of the generation and consumption patterns for the different countries[11] for all

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[11] For REALISEGRID, these data are provided as a result of the long-term models developed within the WP2 and illustrated within the deliverables: D2.1, D2.2, D2.3.1 and D2.3.2.

characteristic time slices (e.g., base during day, base during night and daily peak in spring) in the respective time frame.

For a certain time frame, the welfare maximizing approach yields the power price forecast which is used as a calibration for the market simulation and is based on the nodal pricing model (ELMOD, see Chapter 5.2). As an input, this forecast calculation requires first the assessment of generation and consumption for each time slice (e.g., daily peak in spring) independently. The results (prices, flows, etc) are calculated for each market area.

Next, a load flow calculation follows which will lead to ensure the target of a safe grid operation and security of supply represented by the (n-1) criterion. As input data, the procedure also requires the projected patterns of generation and consumption as well as an accurate representation of the network for each of the investigated characteristic time slices. The load flow calculation was presented in Chapter 6. In a first step, all models provided by the TSOs of the region are merged into a common grid model[12]. In the second step, an A/C load flow calculation[13] is carried out, which yields for all network elements the available maximum flows (constraint) as well as the PTDF matrix. This matrix represents the physical flows induced by any energy transport from a particular source market area to a particular sink market area of the region (also referred to as commercial exchange).

Having an estimation for the power prices of the first time frame (here in 2015) as well as the respective network constraints, the market simulation described in detail in Chapter 7.2.1 can be conducted. The market simulation reflects the currently applied practice of an explicit or implicit coordinated allocation. Specifically the approach presented in this section will be based on explicit auctioning for the CEE region in which requests for transmission capacity are allocated in the best way optimizing the security-constrained social welfare and taking into account the physical reality. The results of the allocation are accepted volumes and market clearing prices, network flows caused by the commercial exchanges between the different countries, the social welfare and the total auction income for the participating transmission system operators.

The investment in a second step interprets the results of the market simulation. Provided with clear and transparent investment signals such as network flows and shadow prices, locations for network investment projects can be proposed. When also taking into account the projected technology developments and its costs as well as the auction revenues as return on investments, investment projects can be derived and the contribution on the entire social welfare can be analysed.

For the next iteration, the grid model is updated with proposed investment projects. The above elaborated steps are repeated for the year 2020 and 2030 in this application.

7.1.1 Market simulation

Figure 7-3 shows the process of market simulation and investment analysis.

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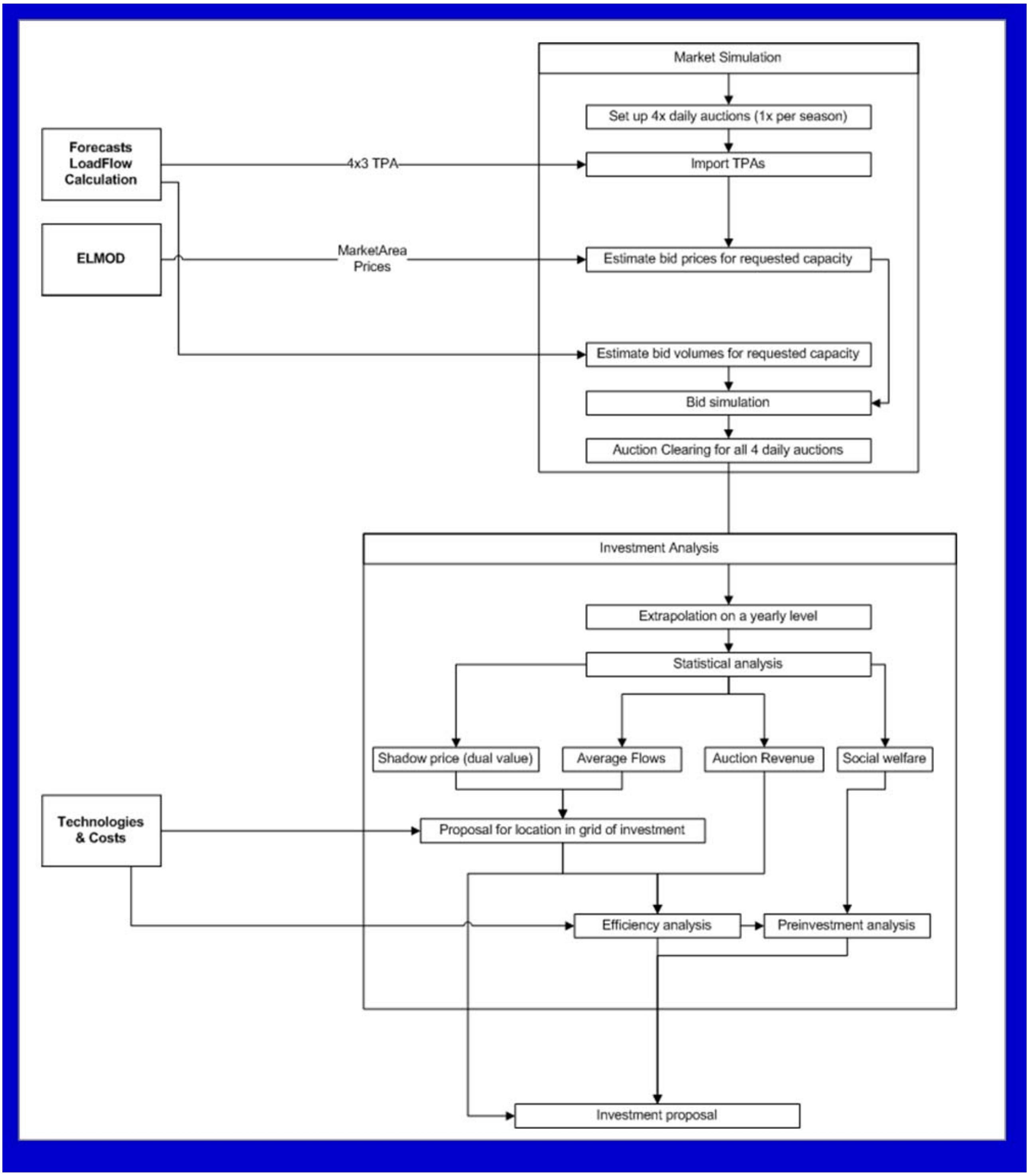
[12] This is accomplished using the software Merlin.
[13] This is done using the PSA tool.

In detail, the market simulation comprises the full operation of an auction clearing process. Based on the input data provided, daily auction models for each season (e.g., spring, summer, fall and winter) are created for each projected year. The agreed time slices "day", "night" and "peak" are assigned as products to each auction, hence enabling a separate allocation for each interval.

Figure 7-3: Market simulation and investment analysis



Now, the above mentioned technical constraints given by the load flow calculation can be imported and the bid simulation can be conducted for each time slice.

The bid simulation is necessary to predict the future bidding behaviour of the market participants. For all pairs of market areas, where the power price of the source market area is lower than the power price of the sink market area (commercial path), it is assumed that market participants will try to acquire rights for transmission capacity to make a profit out of the power price differences. The bidding behaviour itself has a big impact upon the auction results. There is strong competition among all bids for transmission capacity based upon the bid prices, the high priced bid replacing low price bids where capacity is short. Hence, it is important to apply the same assumptions made in the simulation. For the bid simulation, there are two approaches.

The first approach generates merit order curves (a series of bids from a particular source to sink market area sorted price descending) with the majority of requests scattered closely around the market areas price difference. Each simulated bid consists of a requested capacity [MW] and a capacity price [in €/MWh]. The transmission capacity bid prices are simulated using a normal distribution. The mean value (M, see formula) is assumed to be the market area price difference between any two market areas. The deviation is set to 1/3 of the mean. Hence, 68.27% of the generated bids are within the range [M+1/3M; M-1/3M] and 31.72% are outlier.

$M = P_{Sink} - P_{Source}$, where P …. Price

The requested capacities are derived from the maximum feasible capacity of the commercial path based on the network model. Independently of the price, there is a maximum feasible capacity for each commercial path, which is implicitly contained in the list of technical parameters.

The second approach is based fully on the results given by the nodal pricing model (ELMOD, see Chapter 5.2). Outcome of the nodal price calculation are the nodal prices (prices for electric energy for each node of the network model), actual generation costs and generation volumes. A relation between nodes and control areas is also available.
For each production unit, it is now possible to derive a bidding strategy assuming that the facility would offer its generation in any market area with a price higher than the "domestic" price and hence would need to request transmission capacity.

$\Pr ice(Bid) = P_{SinkMarketArea} - P_{SourceNode}$, where P …. Price

With all input data available, the auction model can be calculated using the Dry-run Capacity Auction Tool (DrCAT, compare www.drcat.at).

In particular, outcomes of the market simulation are the market clearing prices, accepted and rejected bids, the social welfare, the shadow prices, the flows on each network element and the auction income distribution among the participating TSOs. The social welfare is the sum of the value of all accepted bids. The bids value is understood as the requested capacity multiplied with the bid price. All allocated capacities will cause flows on the networks elements. Where the available maximum flow of a network element is exceeded, it becomes congested and has a shadow price. The shadow price represents the value of an additional marginal unit of transmission capacity of the congested network element in terms of increase in social welfare. The market clearing price is the price for transmission capacity on a commercial path that has to be paid by the winning market participant. It is calculated as the impact of the commercial path on the congested element.

7.1.2 Investment analysis

Aim of the investment analysis is to interpret the results obtained from the market simulation and give proposals where to invest within the regional network using what technology (investment project). This sub process begins with an extrapolation of bid prices, auction revenues and the auction income distribution to an annual level in order to make the monetary results comparable with the accounting (project financing). E.g., the auction revenue of each seasonal daily auction is multiplied with the number of days per season providing the auction revenue per season. The yearly auction revenue is constituted of the four seasonal revenues.
The extrapolation leads to difficulties when it comes to the load flows. A simple average would distort the results when nullifying adverse flows. Hence, a relative element loading is introduced. Regarding the social welfare and the shadow prices, an absolute assessment seems sufficient, hence a projection to a yearly level does not have any additional benefits.

The examination of investments will be done in two steps. First, an investment location within the network or a certain network element to be upgraded has to be identified. After the clearing of a time frame (e.g. year 2015), among other there will be 12 (for each time slice, four seasons times three products) load flow results. The load flow results represent those flows which originate from price differences based on the flow based explicit allocation.

As a software-based decision support to identify any investment projects based upon the load flow results, the following two indicators are proposed:

- Indicator AF represents the value of the network element's loading (in percent of the thermal maximum flow).
- Indicator SP is given by the sum of the network element's shadow prices (in €/MW).

The two indicators are combined to a weighted assessment method (AM) of network elements with the following weights:

$$AM = 0.8AF + 0.2SP$$

The justification of the weight applied to the two indicators depends from a macro economic view. From a national economic perspective, the security of supply is of greater significance, since the costs of a system wide breakdown outnumber the congestion costs. The combination of the two interests presented here seems sufficient from a TSO experience.

All assessed network elements (technical parameters (TP)) will be sorted descending according to the above described assessment method. Per time frame, two investment programmes will be proposed:

- The first investment programme comprises all investment projects with a TP assessment above a defined quantile (in percentage).
- The second investment programme comprises a number (definable) investment projects having the highest assessment.

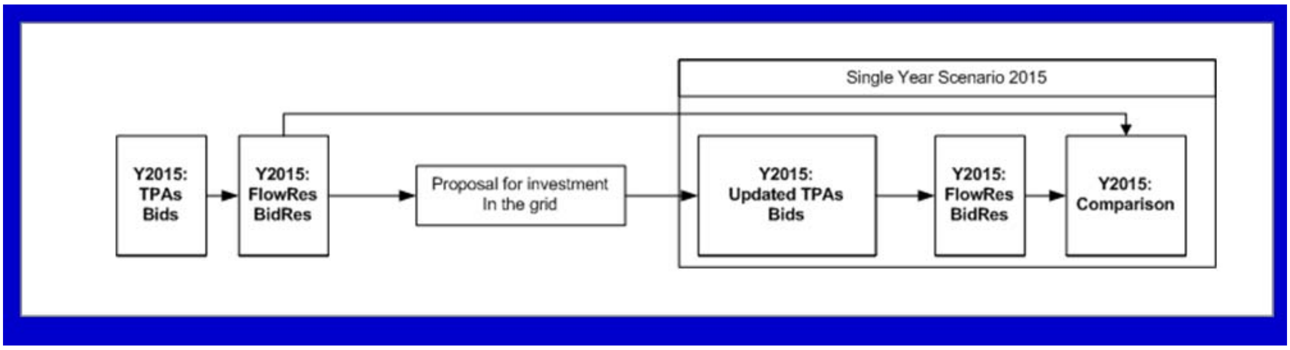
In a second step, a suitable technology and its costs will be proposed.
For each of the associated investment projects, a technology is chosen based on the forecasted available technologies and costs as well as framework conditions, such as terrain. The choice of

technology has a significant impact on the future load flow behaviour and therefore on the security of supply. The project costs are derived from the technology's costs and the size (length) of the network element. The total costs of the investment programme are the sum of all project costs. The costs are an integral part of the application of any finance based investment decision instrument and are compared with the expected return on investment.

The results of the second examination (P2) are two investment alternatives (e.g. Y2015.A1 and Y2015.A2, see Figure 7-5).

For both alternatives, the network models as well as the load flow calculation are updated. The updated technical constraints yielded by the load flow calculation will be used to recalculate the social welfare, which in return highly depends on the technical constraints. The results of both investment alternatives and the alternative without investments can be compared in the next step (see Figure 7-4).

Figure 7-4: Scenario

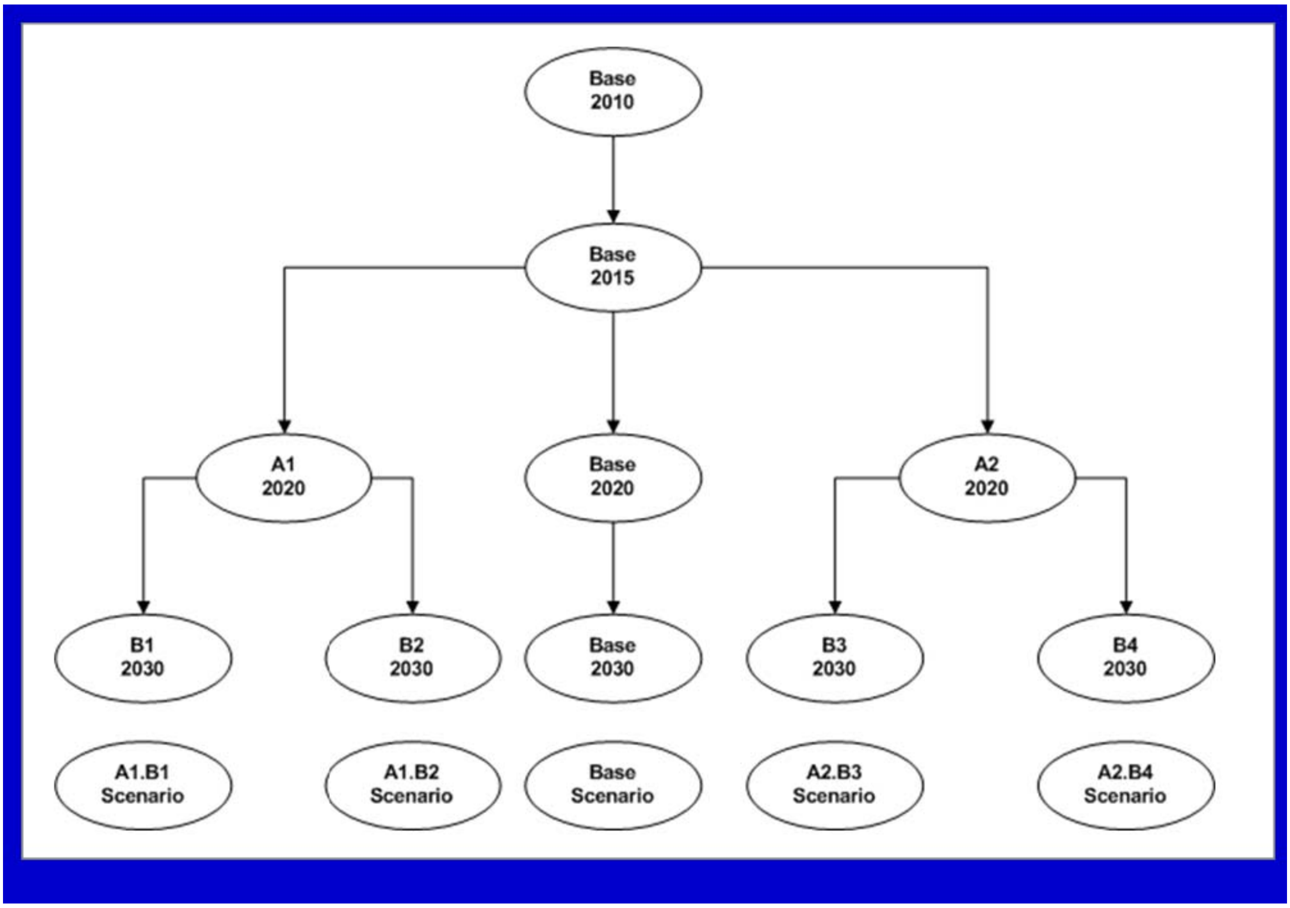


7.2 Derivation of investment scenarios

The investment planning will benchmark possible network investment projects with a base scenario and compare the projects among another regarding the identified aims.

The base scenario assumes no additional investments up to the year 2030 other than those contained in the TYNDP. For the future scenarios, a number of investments in 2015 and 2020 will be proposed. Here, the focus is on the presentation of the approach and not on the results, that will be illustrated in D3.2.3.

Figure 7-5: Investment tree



In 2015, two alternative investment programmes will be proposed. The calculation of the time frames 2020 has to incorporate the investment decisions in 2015. An investment tree is developed (see Figure 7-5). A scenario comprises all investment decisions taken. starting from present, hence, a scenario of the approach presented in this section consists of two investment decisions (investment programmes in 2015 and 2020), e.g. scenario A1.B2.

A financial investment decision is based on the costs of the investment programmes and compares these with the revenues in the form of increase of social welfare. The investment analysis will be done for an entire branch of the “investment tree” (e.g. scenario A1.B2).

The purpose of the presented scenarios will be the comparison of different technologies for upgrading a given part of the network model (e.g. upgrade line A_B with technology X or with technology Y) and the comparison of different line upgrade locations (e.g. upgrade line A_B with technology X or line C_D with technology X).

8 CONCLUSIONS

This document shows that there are different approaches to the network expansion. Academics in economics aim to answer the question which market player should carry out the investment from a welfare optimal perspective: a merchant investor or a centralized entity. A merchant investor requires a return on its investment while a centralized entity has to be regulated. For the time being it appears to be clear that one can not rely entirely on merchant investments. A merchant investor does not have the insights and often not enough interest to carry out maintenance and replacement investments. In addition, merchant investments require a well structured market place with locational marginal prices and financial derivates (e.g., financial transmission rights) that enable to incorporate the physical effect of an investment financially into the market place. Hence, even future grid investments will be most likely carried out by a centralized to a large extent. This leads to the question how such an entity ought to be regulated efficiently. The discussion on this point is ongoing. In the illustrated methodology, the welfare maximizing approach is represented by the calculations of the model ELMOD, that is able to model a nodal pricing approach for the European grid.

An engineering focused approach emphasizes the aspects of reliability and security of supply. An efficient power grid is a very important criterion for Europe as an industrial location and represents the basic requirement not only for the future expansion of renewable energy sources, but also for the achievement of the European climate protection goals. Over time, the targets for the development of the grid have changed and become more complex due to energy market liberalization. The recent targets are: safe grid operation (reliability), security of supply, often represented by the (n-1) criterion, integration of renewable energy sources. To accomplish these tasks and cope with the on-going increasing penetration of renewable energy sources, an even more comprehensive and detailed analyses of energy system planning due to energy market developments is required. Thereby, TSO have to use reliable methods and to foresee the weak points and bottlenecks in the grid and react in time to secure supply and safe grid operations. These needs imply certain medium- and long-term grid expansions which are urgently needed to cope with the future challenges in the energy industry.

The purpose of the last part of this document is to connect the mentioned approaches and their overall objectives with recent methods of project evaluation. In the international context, a comprehensive and sophisticated social cost-benefit analysis approach is proposed, that also takes into account indirect effects of transmission expansion, such as increased system reliability or increased competition in one of the zones; e.g., the California ISO (CAISO) uses a comprehensive “Transmission Expansion Assessment Methodology” (TEAM) as a decision support tool for transmission planners, in which the annual benefits from an expansion include production cost benefits, competitivity benefits, operational benefits, generation investment cost savings, reduced losses, and emission benefits. The present document illustrates an integrated approach that is tailored to the European situation. Based on market prices and security constraints, market results are simulated. These simulations enable to evaluate and recommend possible grid extension scenarios.

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