Project no.:
608540

Project acronym:
GARPUR

Project full title:
Generally Accepted Reliability Principle with Uncertainty modelling and through probabilistic Risk assessment

Collaborative project

FP7-ENERGY-2013-1

Start date of project: 2013-09-01
Duration: 4 years

D3.1
Quantification method in the absence of market response and with market response taken into account

Due delivery date: 2016-02-29
Actual delivery date: 2016-01-19

Organisation name of lead beneficiary for this deliverable:
KU Leuven

Project co-funded by the European Commission within the Seventh Framework Programme (2007-2013)		
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:	D3.1
Deliverable short title:	Quantification method in the absence of market response and with market response taken into account
Deliverable title:	Quantification method in the absence of market response and with market response taken into account
Work package:	WP3 Socio-economic assessment of reliability criteria
Lead participant:	KU Leuven

Revision Control			
Date	**Revision**	**Author(s)**	**Comments**

Quality Assurance, status of deliverable		
Action	**Performed by**	**Date**
Verified (WP leader)	Fridrik Mar Baldursson (RU)	2016-01-19
Reviewed (Sc. Advisor)	Louis Wehenkel (ULG)	2016-02-10
Approved (EB)	EB (by email)	2016-03-07
Approved (Coordinator)	Oddbjørn Gjerde (SINTEF)	2016-03-07

Submitted		
Author(s) Name	**Organisation**	**E-mail**
Marten Ovaere	KUL	Marten.Ovaere@kuleuven.be
Julia Bellenbaum	UDE	Julia.Bellenbaum@uni-due.de
Fridrik Mar Baldursson	RU	FMB@ru.is
Stef Proost	KUL	Stef.Proost@kuleuven.be
Christoph Weber	UDE	Christoph.Weber@uni-due.de
Gerd Kjølle	SINTEF	Gerd.Kjolle@sintef.no
Ewa Lazarczyk	RU	Ewalazarczyk@ru.is

The research leading to these results has received funding from the European Union Seventh Framework Programme under Grant Agreement No 608540.

Table of Contents

Page

EXECUTIVE SUMMARY **10**

1 INTRODUCTION **11**

2 TERMS AND DEFINITIONS **14**

3 SOCIO-ECONOMIC IMPACT ASSESSMENT **16**

3.1 Introduction 16
3.2 Value of served load $\boldsymbol{v}$ and value of lost load $\boldsymbol{V}$ 18
3.3 System costs and benefits 19
3.3.1 Consumer benefit 19
3.3.2 Interruption costs 20
3.3.3 TSO costs 25
3.3.4 Producer costs 26
3.3.5 Congestion cost 26
3.3.6 Environmental costs 27
3.4 Simplified formulation of surplus of stakeholder groups 28
3.4.1 Socio-economic surplus 28
3.4.2 Consumer surplus 28
3.4.3 Producer surplus 28
3.4.4 TSO surplus 29
3.4.5 Government surplus 29
3.5 General formulation 30

4 APPLICATION OF THE QUANTIFICATION METHOD IN THE DIFFERENT TIME FRAMES **31**

4.1 Introduction to the illustration 31
4.2 Operational planning and system operation 33
4.2.1 TSO actions 33
4.2.2 Formulation 34
4.2.3 Illustration 35
4.3 Asset management 39
4.3.1 TSO actions 39
4.3.2 Formulation 39
4.3.3 Illustration 40
4.4 System development 41
4.4.1 TSO actions 41
4.4.2 Illustration 42

5 MARKET RESPONSE **45**

5.1 Consumers 45
5.1.1 Demand 45
5.1.2 Value of served load $\boldsymbol{v}$ and value of lost load $\boldsymbol{V}$ 47
5.1.3 Mitigation measures 47

The research leading to these results has received funding from the European Union
Seventh Framework Programme under Grant Agreement No 608540.

5.1.4 Effect of consumer response on surplus 48
5.2 Producers 49
5.2.1 Competitive response 49
5.2.2 Strategic response 51
5.3 TSO 52
5.4 The effect of market response on the SEIA 53
6 MULTI-ACTOR ASPECTS 54
6.1 Multiple TSOs 54
6.2 Multiple countries 55
6.2.1 Distributional aspects 56
6.2.2 Strategic behaviour 57
6.3 Multiple consumers 58
6.3.1 Distributional aspects and fairness 58
6.3.2 Different consumer locations 58
6.3.3 Different consumer types 61
7 FINDINGS 63
8 REFERENCES 66
APPENDIX A METHODS FOR ESTIMATING INTERRUPTION COSTS 68
APPENDIX B THE TSO PROFIT FUNCTION UNDER EFFICIENCY AND QUALITY INCENTIVES 69
APPENDIX C CROSS-BORDER BALANCING 70

The research leading to these results has received funding from the European Union
Seventh Framework Programme under Grant Agreement No 608540.

Table of Figures

Page

Figure 1.1 Total costs (solid line), interruption costs (dotted line) and all other electricity market costs (dashed line) as a function of the reliability level. 12

Figure 3.1 System costs and benefits, and transfer payments between stakeholder groups. 18

Figure 3.2 Net consumer and producer surplus; change of producer surplus; change of consumer surplus........20

Figure 3.3 Interruption cost as a function of interruption duration........23

Figure 4.1 Five-node simplified version of the Roy Billinton Test System [2] 31

Figure 4.2 Generation cost, interruption cost and total costs for different TSO candidate decisions at 10 AM (on a weekday in winter)........37

Figure 4.3 Socio-economic surplus for different candidate decisions on NTC availability and different times of the day. 38

Figure 5.1 Decrease of electricity cost (light grey area) and the additional consumer surplus due to elastic demand (dark grey area). 46

Figure 5.2 Set-up of the competitive generation response illustration 49

Figure 5.3 Baseload ($\boldsymbol{K1}$) and peakload capacity ($\boldsymbol{K2}$) as a function of transmission capacity. The dotted line is a numerical simulation based on the real Elia 2013 load-duration curve (LDC); the solid line is a theoretical result from a linear approximation of the real LDC. 50

Figure 6.1 Relative cost (compared to autarky) with reserves exchange and reserves sharing, as a function of the cost asymmetry and the correlation ρ between the reserve needs........55

Figure 6.2 Producer and consumer surplus after an investment in transmission capacity [40]. 56

Figure 6.3 The optimal reliability level $\boldsymbol{\rho i} *$ in North and South, determined from reliability costs $\boldsymbol{Ci}$ and interruption costs $\boldsymbol{CINT} = \boldsymbol{\rho V}$........59

Figure 6.4 SAIDI (2005-2012) for different regions in Norway [43]........61

Figure 0.1 Cost minimization under reserves exchange between two TSO zones........72

Table of Tables

Page

Table 3.1 System costs and benefits of consumers, producers and TSO (Above). Payments between consumers, producers and TSO (below). ... 17

Table 3.2 Value of lost load Vic [€/kWh] (2007) for some German states and some consumer types [15]. ... 21

Table 3.3 Multipliers for the interruption cost in Norway at reference time for various interruption characteristics and for residential, industrial, commercial and public consumers [14]. ... 22

Table 3.4 Interruption cost for different duration and for various consumer types, cost level 2014, exchange rate 0.115 €/NOK, based on Norwegian survey [14]. ... 24

Table 3.5 VOLL $Vicd$ (with respect to duration)[€/kWh] for various consumer types at reference interruption durations, cost level 2014, exchange rate 0.115 €/NOK, based on Norwegian survey [14]. ... 24

Table 3.6 Examples of TSO costs in the different decision making contexts ... 25

Table 4.1 Load data. Load scenarios and their probability of occurrence ... 32

Table 4.2 Bus data. Share of a sector in total load of a node ... 32

Table 4.3 Generation data; rated capacity and variable cost of generation ... 32

Table 4.4 Network data ... 32

Table 4.5 Additional values ... 33

Table 4.6 Socio-economic assessment for the candidate decision of 70 % NTC given to the market at 10 AM (on a weekday in winter). All values in €. ... 36

Table 4.7 Difference in surpluses between candidate decisions of 60 % and 70 % NTC given to the market at 10 AM (on a weekday in winter). All values in €. ... 36

Table 4.8 Summer [€/h] ... 40

Table 4.9 Winter [€/h] ... 41

Table 4.10 Socio-economic assessment: Case with an additional line – base case. All values in E[€/h] ... 43

Table 5.1 Residential, industrial and commercial short- and long-run price elasticity of demand for different countries ... 45

Table 5.2 Numerical values for the illustration of generator response ... 50

Table 5.3 Summary of results from an illustration [35] on the RBTS [2]. ... 53

Table 5.4 Summary of market responses ... 53

Table 6.1 Illustrative comparison of costs for two regions i (North and South) for five reliability criteria: (1) N-1, (2) probabilistic, (3) probabilistic with Pareto in costs, (4) probabilistic with Pareto in reliability level, and (5) probabilistic with a minimum reliability level ρmin= 0.999. Ci= reliability cost in region i, TT=transmission tariff=average TSO cost, $CINT$, i=interruption cost, TCi=total cost for a consumer in zone i, ATC=average total cost [€/MWh]. ... 60

Table 6.2 Difference in average total cost [€/MWh] and distribution of costs between random load-shedding and perfect load-shedding. ... 62

Table 0.1 Reserves and costs in TSO zone 1 and 2: *RR* = relative reserves; *TC* = total cost; *RC* = relative cost ... 75

The research leading to these results has received funding from the European Union Seventh Framework Programme under Grant Agreement No 608540.

List of symbols

Sets

$i \in 1, \dots, I$	Node: TSO zones, regions, countries, areas, substations, etc.[1]
$t \in 0, \dots, T$	Time
$g \in 1, \dots, G$	Generation technologies
$c \in 1, \dots, C$	Consumer types: households + types categorized according to NACE codes
$\mathrm{d} \in 1, \dots, \mathrm{D}$	Interruption duration: 1 minute, 1 hour, 4 hours, 8 hours, 24 hours
$\mathrm{m} \in 1, \dots, \mathrm{M}$	Interruption moment: summer weekday 10 am, winter weekend 8pm
$\mathrm{p} \in 1, \dots, \mathrm{P}$	Pollutants: SO_x, NO_x, CO_2, noise, etc.

Variables

p_{it}	Electricity price at node i, at time t [€/MWh]
S_s	Surplus for stakeholder group s: consumers, producers, TSO, government [€/h]
u_{cdit}	Interrupted load in node i, of consumer type c, of duration d, at time t [MW]
$c_{gen,git}$	Variable generation costs for generation technology g, at time t [€/MWh]
$C_{gen,git}$	Generation investment costs for generation technology g, at time t [€/h]
$c_{TSO,it}$	Variable TSO costs, at time t[€/h]
$C_{TSO,it}$	Fixed TSO costs, at time t [€/h]
$c_{ENV,git}$	Environmental cost of generating 1 MWh using technology g, in node i , at time t [€/MWh]
c_{INT}	Interruption cost [€/h]

Parameters

Consumers

D_{cit}	Price-inelastic demand of consumer type c [MW]
V_{cdit}	Marginal interruption cost of consumer type c, of duration d [€/MWh]
v_{cit}	Value of served load of consumer type c [€/MWh]
f_{cit}^{m}	Multiplier accounting for the moment m of interruption [/]
f_{cit}^{n}	Considering advance notification of interruptions [/]

General

DF_t	Discount factor at time t [%]
TS	Time step [h]
r	Annual discount rate [%]

Environment

d_{pt}	Environmental damage of pollutant p [€/ton]
$e_{p,git}$	Emissions of pollutant p for generation technology g [ton/MWh]
t_{pit}	Tax on emission of pollutant p, in node i, at time t [€/ton]

Transfers

TT_{it}	Transmission tariff in node i, at time t [€/MWh]
f_{it}	TSO fee to producers in node i, at time t [€/h]
x_{it}	Value added tax in node i, at time t [%]
t_{pit}	Tax on emissions of pollutant p [€/MWh]
${R^{u,TSO}}_{cit}$	Compensatory payment by the TSO for unserved load in node i, at time t [€/h]

[1] There is a mapping of $\{N\} \mapsto \{I\}$ from these economic definition of nodes ($i \in I$) to the physical model of the transmission system, where the nodes are substations ($n \in N$). The demand and generation is tied to the physical system, and therefore described as loads and generation at specific nodes but aggregated in the economic nodes.

The research leading to these results has received funding from the European Union
Seventh Framework Programme under Grant Agreement No 608540.

EXECUTIVE SUMMARY

This report formulates and illustrates the socio-economic impact assessment (SEIA) methodology with and without market response. The SEIA methodology is based on social welfare analysis of the electricity market and allows to quantify the costs, benefits, and surplus of all market stakeholder groups: electricity consumers, electricity producers, the TSO, the government surplus from taxes on electricity and environmental surplus from electricity-related externalities. The methodology details how to calculate interruption costs, TSO costs, producer costs, environmental costs and congestion costs on different time horizons.

Socio-economic surplus is defined as the sum of consumer surplus, producer surplus, TSO surplus and government surplus.

- Consumer surplus is defined as consumer benefit less interruption costs, environmental costs, electricity payment – a transfer to producers – and transmission tariff payments – a transfer to the TSO – plus the net sum of other transfers such as interruption compensation, demand-response payments, value-added taxes (VAT), DSO tariffs etc.. The report specifies and illustrates how to assess interruption costs – depending on data availability – as a function of consumer type, location, time and duration of interruption, (whether or not the interruption was notified in advance) and weather conditions.
- Producer surplus is defined as electricity payments less costs of fuel, investment, operation and maintenance and the net sum of costs/benefits related to the environment plus other transfers such as environmental taxes and congestion payments.
- TSO surplus is defined as transmission tariff payments less monetized electricity losses, costs of operation, maintenance and investment plus the net sum of other transfers such as congestion payments.
- Government surplus is defined as revenues from taxes on electricity consumption, such as the value-added tax.

A general mathematical formulation of these surpluses is given for different nodes, generation technologies, consumer types, time of occurrence and duration of interruptions, interruption moments and pollutants. The report also illustrates how to apply the SEIA to a numerical test case. To illustrate multi-country aspects, the test case is adapted to a two-country setting. The illustration is done in each GARPUR time frame.

The SEIA allows for evaluation of benefits, costs and surpluses of all electricity market stakeholders and can be used to compare socio-economic surplus between different reliability criteria. The methodology implicitly assumes that behaviour of market stakeholders is constant. However, the report extends the SEIA by providing an analysis of possible responses of electricity market stakeholders to changing market variables such as the reliability level, electricity prices and taxes.

Finally, the report considers multi-actor aspects and analyses the interaction of multiple TSOs and multiple countries, and the effects on welfare. Three types of interactions are distinguished: between multiple TSOs, multiple countries and the distributional effect on different consumers. Multiple TSOs through cross-border cooperation on reserves can increase the reliability of the grid and decrease costs related to reliability issues as compared to the situation when TSOs in the neighbouring countries do not cooperate on reserves. In case of multiple countries, changes to reliability criteria may have an impact on available interconnector transmission capacity and therefore the distributional aspects are of primary importance as they create different incentives. Furthermore, we assess distributional welfare effects on different consumer types and different consumer locations and discuss fairness of distributional transfers.

The research leading to these results has received funding from the European Union
Seventh Framework Programme under Grant Agreement No 608540.

1 INTRODUCTION

This document is the first deliverable of work package 3 (WP3) of the GARPUR[2] project. The GARPUR project designs, develops and assesses new probabilistic reliability criteria for the electricity transmission network and evaluates their practical use while maximising social welfare. WP3 of the GARPUR project develops a sound methodology for the quantitative evaluation of the socio-economic impact of different reliability management approaches. This deliverable combines the contributions of the tasks T3.1, T3.2 and T3.3. The objectives of these tasks are [1]:

- T3.1: Definition of terms and classification of concepts
- T3.2: Quantification of costs, benefits and social welfare
    - Develops a methodology to evaluate the costs and benefits of the different actors (end-users, producers, TSOs, environment and net changes in tax revenues) in the absence of an anticipated behavioural adaptation of these actors to economic incentives.
    - Focuses on the post-processing of technical quantities (power, voltage, voltage angle and frequency, durations of interruptions etc.).
- T3.3: Prediction of costs, benefits, and social welfare with market response
    - Analyses how these actors adapt their behaviour in reaction to the reliability management strategy.
    - Looks at situations of growing complexity, finishing with a system composed of multiple TSOs, multiple markets, and multiple regulations.

This deliverable is divided into two main parts. The first part, consisting of chapters 3 and 4, focuses on the quantification of costs and benefits of the different market actors, assuming exogenous behaviour, i.e. without market response. The second part, consisting of chapters 5 and 6, focuses on the response of the different market actors, distributional issues and multi-actor interactions.

Chapter 3 proposes the socio-economic impact assessment (SEIA) methodology. The SEIA methodology is based on social welfare analysis and allows to quantify the costs and benefits of all market stakeholder groups: electricity consumers, electricity producers, the TSO, the government surplus from taxes on electricity consumption and generation, and environmental surplus from electricity-related externalities.

First, in sections 3.1 and 3.2 the methodology explains in detail the costs of the different market stakeholder groups: interruption costs, TSO costs, congestion costs, producer costs and environmental costs. Next – using these quantified costs and benefits and making assumptions on prices, taxes, payments and fees – sections 3.4 and 3.5 propose the social welfare analysis methodology to calculate the surplus[3] of the different market stakeholders.

The objective of reliability management is then to maximize the sum of all market stakeholders' surplus. However, often the TSO still uses cost minimization as a proxy for surplus maximization[4]. Figure 1.1 summarizes this cost minimization. This figure plots expected total costs (solid line) of the electricity market as a function of the reliability level ρ. The dotted line represents expected interruption costs, decreasing

[2] http://www.garpur-project.eu/

[3] Socio-economic surplus is a good proxy of socio-economic welfare if all societal and environmental costs are taken into account, and under reasonable assumptions: changes in the electricity market do not significantly affect other markets and consumers' utility is assumed to be quasi-linear in the good at focus, i.e. no income effects in the demand of that good.

[4] Cost minimization is only equal to surplus maximization under the assumption of "no market response", see below.

The research leading to these results has received funding from the European Union Seventh Framework Programme under Grant Agreement No 608540.

with the reliability level, while the dashed line represents the net sum of all other expected electricity market costs[5], increasing with the reliability level.

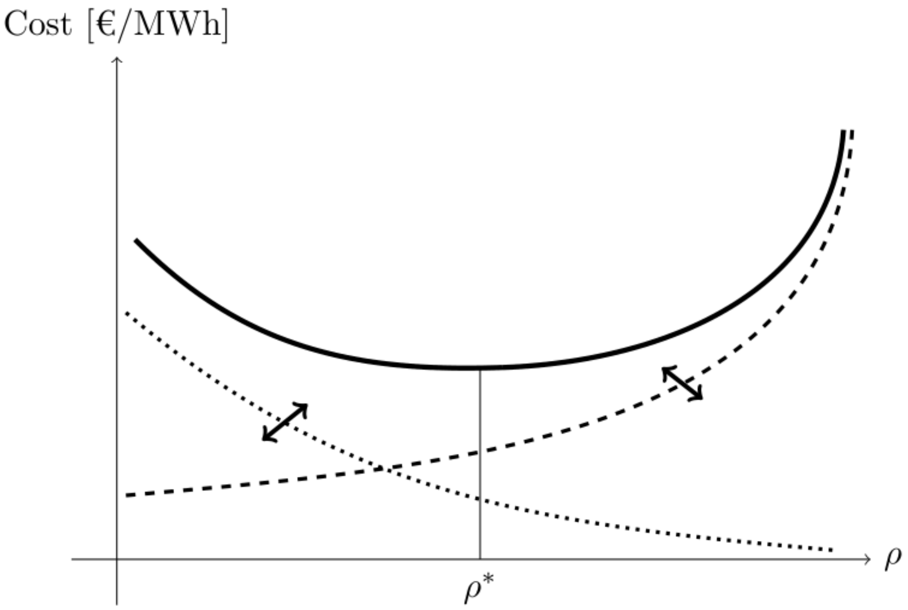

Figure 1.1 Total costs (solid line), interruption costs (dotted line) and all other electricity market costs (dashed line) as a function of the reliability level.

The reliability level ρ^* that minimizes expected socio-economic costs is at the point where the marginal decrease (with respect to ρ) of interruption costs equals the marginal increase of all other electricity market costs (with respect to ρ). That is, when the slopes of the two lines are equal in absolute value.

The TSO takes in all time frames, the decisions that minimize its costs of reliability management. The objective of effective regulation is to ensure that the TSO incorporates all socio-economic costs into its decision making, so that it is incentivized to minimize all electricity market socio-economic costs, not only its own costs.

Chapter 4 illustrates the proposed SEIA methodology of chapter 3 in a five-node reliability test system [2]. We apply the SEIA methodology to the three different time frames considered in the GARPUR project: operational planning and system operation, asset management and system development. In order to facilitate comparisons between different situations, the illustration focuses on differences in costs, benefits and surpluses rather than on absolute values.

Cost minimization and surplus maximization are only equal under the assumption of no market response by electricity market actors. **Chapter 5** lists and explains possible responses of electricity market stakeholders to changing market variables such as the reliability level, electricity prices and taxes. This chapter also shows how these market responses could be integrated in the SEIA, in which behaviour of all market stakeholders is assumed to be constant. Examples of market response are:

- Consumer demand can change with price and reliability levels: $D(p, \rho)$. Therefore, the surplus in the market can increase or decrease with changing price or reliability. This is not reflected in the cost minimization approach. On the contrary, a decreased consumer demand could decrease costs but does not increase consumer surplus!

[5] TSO costs, congestion costs, environmental costs and producer costs.

The research leading to these results has received funding from the European Union
Seventh Framework Programme under Grant Agreement No 608540.

- If agents adapt their behaviour in response to changes in the electricity market, the cost functions of Figure 1.1 shift, as shown by the black arrows in the figure. Examples are:
    - **Consumers** may react to a lower reliability level by taking themselves mitigating measures such as installing back up devices. This shifts the interruption cost function downwards.
    - **Producers** may react to changing reliability criteria and management approaches – and thus changed transmission margins – by increasing or decreasing installed generation capacity, by adopting different bidding behaviour or new maintenance policies, etc.
    - **TSO** cost functions may also change with the introduction of a new reliability criterion and management approach: faster reaction to line failures, optimized preventive actions, more efficient congestion management, increased demand response participation, etc.
- Likewise, these functions can change with interacting actors (e.g. interacting TSOs or countries). This is discussed in chapter 6.

All these examples of market response could change the cost functions and could thus lead to different optimal reliability levels and different optimal decisions.

Lastly, **chapter 6** elaborates more on multi-actor aspects. This chapter analyses the interaction of multiple TSOs and multiple countries, and the effects on welfare. Furthermore, a cost minimization conceals distributional effects of socio-economic surplus between different stakeholder groups and between different regions. Therefore we assess distributional welfare effects of introducing new reliability criteria and discuss fairness of distributional transfers.

The research leading to these results has received funding from the European Union
Seventh Framework Programme under Grant Agreement No 608540.

2 TERMS AND DEFINITIONS

Asset management
Systematic and coordinated activities and practices through which an organization optimally manages its physical assets and their associated performance, risks and expenditures over their lifecycles for the purpose of achieving its organizational strategic plan. In the GARPUR context asset management encompasses system development activities undertaken by a TSO in the mid-term planning horizon. [3]

Congestion cost
Congestion costs are the additional generation costs when transmission constraints are present in the transmission grid. That is, the difference in generation costs between a system of infinite capacity and an actual system. In order to alleviate congestion, cheap generation in an export-constrained node should decrease, while more expensive generation in an import-constrained node should increase.

Contingency
A contingency is the unexpected failure or outage of a system component, such as a generator, transmission line, circuit breaker, switch, or other electrical element. A contingency may also include multiple components, which are related by situations leading to simultaneous component outages [4].

Energy not supplied
Energy not supplied is the estimated energy which would have been supplied to end-users if no interruption had occurred.

Expected value
The expected value of a random variable is the long-run average value, calculated as the probability-weighted average of all possible values.

N-1 criterion
The N-1 criterion is a principle according to which the system should be able to withstand at all times a credible contingency – i.e., unexpected failure or outage of a system component (such as a line, transformer, or generator) – in such a way that the system is capable of accommodating the new operational situation without violating operational security limits. (The definition is partly based on ENTSO-E documents [4] and [5]).

Operational planning
Operational planning is the group of reliability management activities linked to system optimization occurring ahead of real-time operation, within the short-term and mid-term horizons. [3]

Power system reliability
Power system reliability is the probability that an electric power system can perform a required function under given conditions for a given time interval. Reliability quantifies the ability of an electric power system to supply adequate electric service on a nearly continuous basis with few interruptions over an extended period of time. ([7], IEV ref 617-01-01).

Real-time operation
Real-time operation is exercised within recurring time intervals, beginning with a regular update on the system operating conditions. The duration of these intervals (typically in the range of 15–60 minutes) is such that the system operating conditions can be assumed to be relatively predictable, unless a contingency happens. Real-time operation includes preventive, corrective and emergency operation. [3]

The research leading to these results has received funding from the European Union
Seventh Framework Programme under Grant Agreement No 608540.

Reliability criterion

A reliability criterion is a principle imposing a basis to determine whether or not the reliability level of a power system is acceptable. Such a principle can be expressed as a set of constraints that must be satisfied by the decisions taken by a TSO.

Reliability management

Power system reliability management means to take a sequence of decisions under uncertainty. It aims at meeting a reliability criterion, while minimising the socio-economic costs of doing so.

Socio-economic surplus

Socio-economic surplus is the sum of surplus or utility of all stakeholders, including external costs and benefits (e.g. environmental costs).

Socio-economic welfare

While surplus is the additional aggregate utility from the existence of one market (e.g. the electricity market), welfare has a broader scope, namely the aggregate utility from all existent markets.

A change in surplus resulting from a policy change in one market is an approximation of the aggregate gain in welfare. A change in surplus in a particular market is only equivalent to a change in overall welfare under the following conditions: policy changes do mainly affect one market and consumers' utility is assumed to be quasi-linear in the good at focus (no income effects in the demand of that good). Since all markets are at least slightly interdependent, a surplus calculation in a particular market is only an approximation of a full social welfare analysis.

System development

System development deals with taking decisions that change the system's power transfer capability through construction, upgrading, replacement, retrofitting or decommissioning of assets.

Transmission system

Transmission system means the electric power network used to transmit electric power over long distances within and between member states. The transmission system is usually operated at the 220 kV and above for AC or HVDC, but may also include lower voltages ([8], p. 252).

Transmission system operator

A transmission system operator (TSO) is a natural or legal person responsible for operating, ensuring the maintenance of and, if necessary, developing the transmission system in a given area and, where applicable, its interconnections with other systems, and for ensuring the long-term ability of the system to meet reasonable demands for the transmission of electricity. [3]

Value of lost load

Value of lost load (VOLL) is defined as a measure of the cost of unserved energy (the energy that would have been supplied if there had been no outage) for consumers. It is generally normalised in €/kWh ([9], p. 55).

The research leading to these results has received funding from the European Union
Seventh Framework Programme under Grant Agreement No 608540.

3 SOCIO-ECONOMIC IMPACT ASSESSMENT

3.1 Introduction

The Socio-Economic Impact Assessment (SEIA) explained in this chapter quantifies surplus as the difference between benefits and costs for all economic agents or stakeholders. Within the GARPUR project, the objective is to study the surplus for different reliability-related TSO decisions in multiple decision making contexts.

In order to carry out the Socio-Economic Impact Assessment (SEIA), one has to define the system under assessment and its boundaries. A system is defined by four attributes:

1. The **assessed market**. In this case we only study the electricity market. The implicit assumption of this partial equilibrium approach is that changes in the assessed market, i.e. the electricity market, do not have a significant effect on other markets.

2. The **included stakeholder groups**. In the remainder of this document we only assess the socio-economic surplus of electricity consumers, electricity producers, the TSO, the government surplus from taxes on electricity and the environmental surplus from electricity-related externalities. Surpluses of other electricity market stakeholders, e.g. DSOs and market operators, are not assessed under the assumption that these do not change significantly with the TSO decisions studied in this document and within the GARPUR framework.

3. The **geographical scope**. TSO decisions within a certain area can influence surpluses of stakeholders in other areas. Therefore, in order to assess total surplus from a TSO decision, all areas which are significantly affected should be included in the SEIA.

4. The **temporal scope**. Costs and benefits are calculated for a defined period and time step. The choice of the underlying period and time step should be aligned with the object of investigation and the time horizon for which the SEIA is conducted. For example, an analysis of a system-operation action suggests the SEIA for a couple of hours with a small time step (1 hour, 30 minutes, 15 minutes depending on the specific decision) while the SEIA of a long-term investment should be dimensioned for years.

Table 3.1 is an extensive – but not exhaustive – list of the costs and benefits of electricity consumers, producers and the TSO. Each economic actor's surplus is the difference of his benefits and costs. These can be categorized into:

(1) System costs: upper part of the table. The difference between all system benefits and costs constitute the socio-economic surplus of the electricity market, as shown in the first column and in equations (3.10) and (3.15) below. System costs thus decrease socio-economic surplus.

(2) Cost transfers: lower part of the table. Cost transfers appear as costs to a certain stakeholder but are payments, and thus benefits, to other stakeholders, and thus net out in the aggregate and do not affect the socio-economic surplus. For example, the TSO pays a congestion payment to producers that are rescheduled for congestion management purposes. Rescheduling generation capacity entails an increase of producer costs (c_{gen} and C_{gen})[6], and thus decreases welfare.

[6] This increase of generation costs could also increase environmental costs (c_{ENV}), depending on which generation plants are substituted, e.g. gas for coal.

The research leading to these results has received funding from the European Union
Seventh Framework Programme under Grant Agreement No 608540.

However, the reimbursement by the TSO of these increased producer costs is a transfer payment and has zero net effect on socio-economic surplus.

The details of transfer payments, and the accompanying transfer of services, depend on the regulation in place in the TSO zone. For example:

- Managing transmission constraints could be done after the energy auction clearing by redispatch or counter trading in uniform-price zones, or during the energy auction clearing by congestion rent in nodal pricing or market splitting. Different congestion management methods can lead to different physical and financial flows.
- In some European countries[7], individual consumers receive a compensation payment after a long interruption or after many interruptions in a certain period. In Norway, the TSO is penalized financially for interruptions but individual consumers are not compensated. These regulatory details affects the surplus of (individual) consumers and the TSO, but not aggregate socio-economic surplus.

Note that the definition of system costs and benefits depends on the four attributes above. For example, fuel costs (gas, coal, oil) are a net cost for electricity producers, but are transfer payments to fuel producers, which are not included in the SEIA as stakeholder groups.[8]

Table 3.1 System costs and benefits of consumers, producers and TSO (Above). Payments between consumers, producers and TSO (below).

System balance	Stakeholders' balances		
	Consumer balance	**Producer balance**	**TSO balance**
+ Consumer benefit - Interruption costs - Variable producer costs - Fixed producer cost - Environmental costs - Variable TSO costs - Fixed TSO costs	+ Consumer benefit v - Interruption costs c_{int}	- Variable costs c_{gen} - Fixed costs C_{gen} - Environmental costs c_{ENV}	- Variable costs c_{TSO} - Fixed costs C_{TSO}
	+Interruption compensation + Demand response payment - Transmission tariff TT - Electricity payment p_i	+ Electricity payment p_i - Capacity fee + Reserve payment + Congestion payment f	- Interruption compensation - Demand response payment + Transmission tariff TT + Congestion rent + Capacity fee - Reserve payment - Congestion payment f
= Socio-economic surplus	**= Consumer surplus**	**= Producer surplus**	**= TSO surplus**

Only the system costs and cost transfer payments with a symbol alongside in Table 3.1 are explicitly included in the formulas in sections 3.4 and 3.5. Other transfer payments could be included – see for example section 4.2 on operational planning and system operation which adds congestion rent and interruption compensations to the formulas.

[7] For examples see page 51 of [9].

[8] To make the implicit assumption of the second attribute "included stakeholder groups" more explicit: the SEIA assumes that changes in fuel use do not change the surplus of fuel producers. This is the case if prices equal marginal cost – a valid assumption for gas and coal, but less for oil.

The research leading to these results has received funding from the European Union Seventh Framework Programme under Grant Agreement No 608540.

Figure 3.1 shows all the cost and benefit terms of Table 3.1 (system costs and benefits + cost transfer payments) graphically. This figure introduces the government as an additional stakeholder. The government earns a surplus in the electricity market by levying taxes on electricity consumption, such as a value-added tax (VAT) x, excise taxes, public service taxes, contributions for the national regulatory authority, etc. All of these taxes entail a transfer between electricity market stakeholders. For example, the government could use the revenues from VAT to subsidize renewable energy generation: a transfer from consumers, through the government to (a subgroup of) producers. For simplification, we only introduce VAT as a tax levied by the government. However, other taxes could be integrated into the SEIA in the same way.

Section 3.3 explains all the different costs and benefits of Table 3.1 and Figure 3.1 in more detail. But first section 3.2 explains two important concepts to calculate consumer benefit and interruption costs: value of served load and value of lost load.

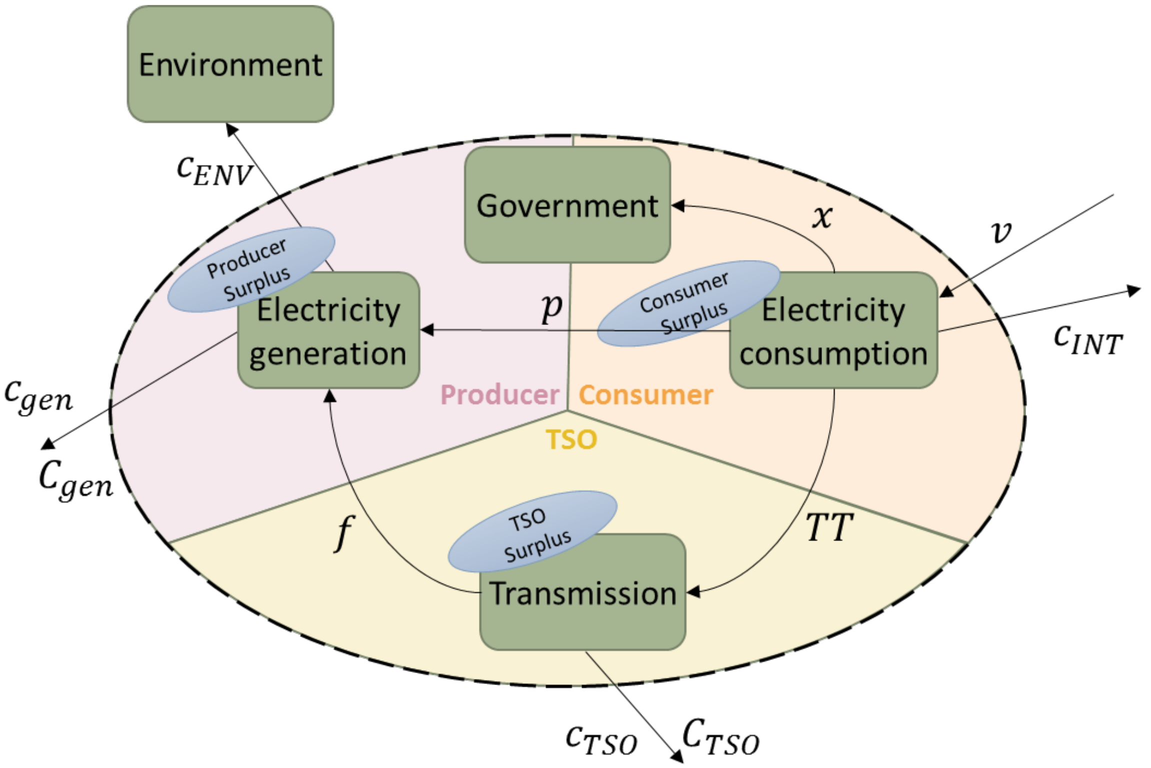

Figure 3.1 System costs and benefits, and transfer payments between stakeholder groups.

3.2 Value of served load v and value of lost load V

Value of served load (VOSL) v is defined as the consumer benefit, or utility, from electricity **consumption**. This benefit depends on the type of consumer c, the time of consumption t and the location of consumption i: v_{itc}. In contrast, value of lost load (VOLL) V is defined as the cost of unserved energy (the energy that would have been supplied if there had been no outage) in case of an electricity **interruption**. Also VOLL depends on many characteristics. This is treated in more detail in section 3.3.2. In this deliverable we normalise both measures in €/MWh or €/kWh, as is general practice ([9], p. 55).

The research leading to these results has received funding from the European Union
Seventh Framework Programme under Grant Agreement No 608540.

To explain the difference between VOSL and VOLL, consider a manufacturer that makes a car component. The total cost of his production process, excluding electricity (material, personnel, machinery, building, etc.) is 40 € per component. If the manufacturer sells his components at a price of 50 €, his consumer benefit is 10 € per component or 2,000 €/hour if he producers 200 components per hour. Suppose that he consumes 1 MWh of electricity per batch and that this hourly batch of 200 components is lost in case of an interruption of 3 minutes or longer. This means that an interruption longer than 3 minutes costs him 10,000 €. That is, the value of his production: his hourly profit of 2,000 € and the hourly cost of his lost components of 8,000 €. The manufacturer will thus be willing to pay up to 10,000 € per hour in order not to be interrupted. However, he will not be willing to pay this every hour, since this would cost him more than his gross profit (i.e. excluding the cost of electricity) of 2,000 €/hour. Therefore, his long-run maximum willingness-to pay (WTP) for electricity is 2,000 €/MWh. To summarize this example:

$$VOLL \ = consumption\ benefit + interruption\ damage$$
$$V = v + damage = 2{,}000\ €/MWh + 8{,}000\ €/MWh$$

Note that in this example a 2 minute interruption only has an interruption cost of 2,000*2/60 = 67 €, or VOLL=2,000 €/MWh, under the assumption that the manufacturing plant is at full capacity.

In reality this manufacturer's long-run WTP for electricity is lower than 2,000 €/MWh due to the existence of substitutes such as gas or coal. If the long-run electricity price would rise a lot, e.g. above 200 €/MWh, it could become cheaper (taken into account the difference in reliability between different energies) for the manufacturer to use gas or coal instead of electricity.

The distinction between VOSL and VOLL is important for two reasons. First, consumer benefit is the product of served load and value of served load (see section 3.2). When served load is multiplied by a value higher than VOSL, consumer surplus is overestimated. For example, Belgian's electricity consumption is about 80 TWh/year. Multiplying this value with a VOLL of 5,000 €/MWh, yields a yearly electricity consumption benefit of 400 billion €, which is about 75% of Belgian's GDP.

Second, the VOSL is important to determine the optimal long-run reliability level ρ^*. In the long-run consumers change their demand in response to the price or reliability level of electricity, which has an effect on total surplus. Section 5.1.4 explains in detail how the value of served load v has an effect on total surplus.

3.3 System costs and benefits

Following the principle of social welfare analysis, net surplus of a stakeholder is defined as the difference between the benefits and the costs of this stakeholder. From a system perspective, socio-economic surplus is obtained as the difference between benefits and costs exceeding the system borders. This section describes different relevant benefits and costs of the stakeholders under consideration.

3.3.1 Consumer benefit

Adam Smith famously wrote that "Consumption is the sole end and purpose of all production" [11]. Unfortunately, measuring the benefit, or utility, arising from electricity consumption is a difficult task since it depends on many factors such as the type of consumer c, the time of consumption t and the location of consumption i. To represent this value of consumption, we introduce the value of served load v_{itc},

The research leading to these results has received funding from the European Union
Seventh Framework Programme under Grant Agreement No 608540.

expressed in $[€/MWh]$. At each time step of our socio-economic assessment the total consumer benefit is the product of electricity demand D_{ic}[9] and the value of served load v_{ic}[10]:

$$\sum_{i=1}^{I}\sum_{c=1}^{C} D_{ic}v_{ic} \tag{3.1}$$

In the remainder of this document, we use a time step of 1 hour. That is, all benefits and costs are expressed in $€/h$. Of course, other time steps (15 minutes, 2 hours, 1 year, etc.) are possible.

Because of the difficulty of empirically estimating v_{itc}, its value is uncertain. Therefore, interpretation of the absolute consumer benefit must be done with utmost care. However, when applying socio-economic assessment to compare the consumer benefit of different regimes in the short term, this consumer benefit will cancel out. This is illustrated in Figure 3.2. The left-hand panel shows total net consumer surplus, i.e. the area between the demand curve and the price. The central and right-hand panel show the change of producer (PS) and consumer (CS) surplus resulting from a TSO decision. The shift of the supply curve from S_1 to S_2 could for example be caused by a change in the TSO's congestion or reliability policy. The central panel shows that the increase of the supply curve leads to higher generation costs (PS-) but also to a higher price and thus to a higher producer surplus (PS+). The right-hand panel shows that the decrease of consumer surplus (CS-) is equal to $(P_2 - P_1)Q$, which does not depend on v_{ic}.[11]

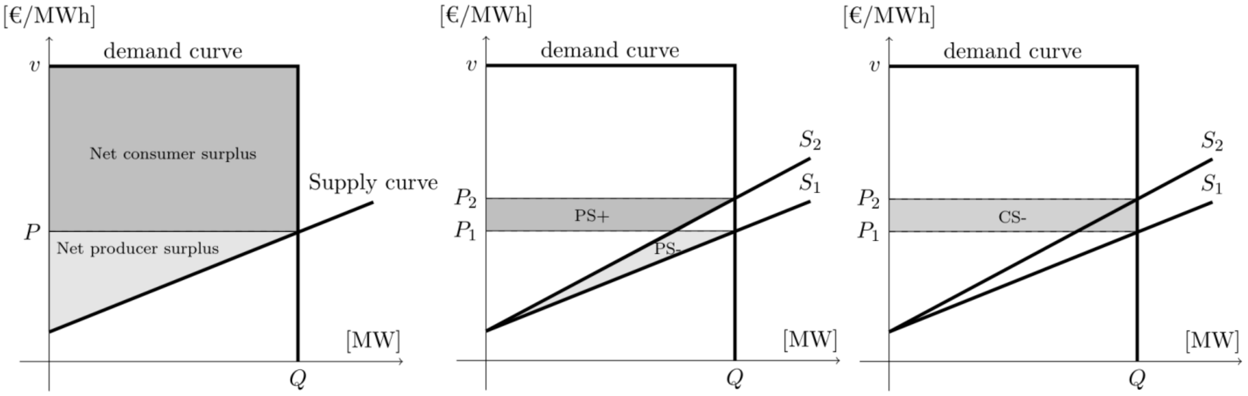

Figure 3.2 Net consumer and producer surplus; change of producer surplus; change of consumer surplus.

3.3.2 Interruption costs

An electricity interruption has a negative economic impact on electricity consumers: it causes a loss of consumer benefit as well as costs such as broken appliances, spoiled food, failed manufacturing, etc. [12]. Interruption costs are calculated as the product of energy not supplied (ENS)[12] [MWh] – represented by symbol u – and VOLL [€/MWh] – represented by symbol V. The VOLL is the marginal interruption cost with respect to energy not supplied [MWh], i.e. the interruption cost of an additional 1 MWh interruption.

$$c_{INT} = uV \tag{3.2}$$

[9] The demand D_{ic} is assumed to be price-inelastic up to a choke-price v_{ic}.
[10] The value of served load v_{ic} is assumed to be constant in chapters 3 and 4. Section 5.1.2 relaxes this assumption.
[11] This is only true under the assumption of inelastic demand. Section 5.1.1 relaxes this assumption.
[12] Energy not supplied is the estimated energy which would have been supplied to end-users if no interruption had occurred.

The research leading to these results has received funding from the European Union Seventh Framework Programme under Grant Agreement No 608540.

As an example, assume a five-hour interruption of 3 MW and a VOLL of 5000 €/MWh:

$$c_{INT} = uV = 15\,MWh\,.\,5{,}000\,€/MWh = 75{,}000\,€$$

In the previous example, the VOLL of the manufacturer is 50,000 €/MWh.

The VOLL is not a constant value, it depends on several characteristics, such as:

- consumer type
- location of the consumer
- time of interruption
- duration of interruption
- advance notification of interruption
- weather at the time of interruption
- urban area vs rural area
- previous quality of supply

In the remainder of this section and in the illustration of chapter 4, we will incorporate the above characteristics in the calculation of interruption costs. Equation (3.2) is the most basic formulation of interruption costs. In the following, we gradually introduce more differentiation.

a) Region of interruption and type of consumer

First we calculate interruption costs that take into account different regions i and different consumer categories c:

$$c_{INT} = \sum_{i=1}^{I}\sum_{c=1}^{C} u_{ic}V_{ic} \quad (3.3)$$

V_{ic} is the VOLL $[€/MWh]$ for region i and consumer type c. Consumers can be divided into different categories according to, among others, their size, their electricity consumption and their availability of backup supply. In general, consumers are divided according to their NACE code [12]. As an illustration, Table 3.2 shows the estimated VOLL for some German states i and some consumer types c [13].

Table 3.2 Value of lost load V_{ic} [€/kWh] (2007) for some German states and some consumer types [14].

	Households	Chemical and petrochemical	Food and beverages	Machinery and equipment	Rubber and plastics
Bavaria	13.77	1.11	2.58	7.26	1.90
Bremen	11.96	2.43	2.04	16.99	5.21
Hamburg	11.70	2.94	2.43	13.12	1.78
Saarland	13.00	0.28	2.01	5.01	1.06
Hesse	14.96	2.27	2.61	9.96	1.99

It is important to note here that these data are not comparable to the data given in Table 3.4 and Table 3.5 below, for two reasons:

1) The method used to estimate the numerator in euros is completely different. Here, it is based on the gross value added while in Table 3.4 it is based on contingent consumer evaluation, i.e., direct costs of interruptions and/or willingness to pay to avoid an interruption.

The research leading to these results has received funding from the European Union
Seventh Framework Programme under Grant Agreement No 608540.

2) The denominator (i.e., the normalization factor used) is here the electricity consumption. In Table 3.4, the normalization factor is the interrupted power.

The data of Tables 3.2-3.5 are for illustrative purposes should thus be used with utmost care, because of the differences in the normalization factors in particular. A national regulator should determine these values himself. For more information on methods for estimating interruption costs and VOLL, see Appendix A.

The VOLL of a specific region and consumer type (V_{ic}) is defined as the average interruption cost of a 1 MWh interruption for consumers with type c in region i.

b) <u>Time of occurrence and advance notification</u>

If we also incorporate the time of occurrence and advance notification of interruptions, expression (3.3) becomes:

$$c_{INT} = \sum_{i=1}^{I} \sum_{c=1}^{C} u_{ic} V_{ic} f_{ic}^{m} f_{ic}^{n} \tag{3.4}$$

Where f_{ic}^{m} is the multiplier accounting for the moment of interruption and f_{ic}^{n} the multiplier considering advance notification of interruptions (cf. Table 3.3).

The multiplier accounting for the moment of interruption f_{ic}^{m} depends on the hour of the day h, the day of the week w and the season of the year s.[13]

$$f_{ic}^{m} = f_{ic}^{h} f_{ic}^{w} f_{ic}^{s} \tag{3.5}$$

As an illustration, Table 3.3 shows the f_{ic}^{h}, f_{ic}^{w}, f_{ic}^{s} and f_{ic}^{n} multipliers for Norway [13].

Table 3.3 Multipliers for the interruption cost in Norway at reference time for various interruption characteristics and for residential, industrial, commercial and public consumers [13].

Characteristics		Residential	Industry	Commercial	Public
Time of day f_{ic}^{h} [14]	10:00 AM	0.69	1	1	1
	5:00 PM	1	0.14	0.29	0.31
	2:00 AM	0.4	0.12	0.11	0.43
Weekday f_{ic}^{w}	Working day	1	1	1	1
	Saturday	1.07	0.13	0.45	0.3
	Sunday	1.07	0.14	0.11	0.29
Season f_{ic}^{s}	Spring	0.57	0.87	1	0.67
	Summer	0.44	0.86	1.02	0.51
	Autumn	0.75	0.88	1.06	0.58
	Winter	1	1	1	1
Advance notification f_{ic}^{n}	24 hours	0.55	0.55	0.83	0.91
	3 days	0.52	0.5	0.7	0.82
	7 days	0.51	0.49	0.66	0.8

[13] In case the costs of data collection outweigh the benefits, the temporal multiplier could be 'months' instead of 'seasons'.

[14] 10 AM, 5 PM and 2 AM respectively represent daytime, afternoon and night.

The research leading to these results has received funding from the European Union Seventh Framework Programme under Grant Agreement No 608540.

The exemplary Norwegian data presented in Table 3.3 can be interpreted as follows. These multipliers are within the interval between 0 and 1 or slightly above and related to a reference. For industrial consumers the reference is an interruption at 10 AM on a winter working day without any advance notification [12]. For residential consumers the reference time is 5 PM on a winter working day without any advance notification. If the moment of interruption differs from the reference, the interruption costs are multiplied by the corresponding multiplier. Advance notification is analogously accounted for.

c) <u>Duration of interruption</u>

To take into account the effect of the interruption duration on the interruption cost, we allow the VOLL to change with interruption duration d: V_{icd}. Figure 3-3 compares the interruption costs for a VOLL that is constant with respect to interruption duration (dotted line) and a VOLL that changes with interruption duration (solid line). In this figure, the VOLL (which is given in €/MWh) is the slope (with respect to duration) of the interruption cost curve (which is given in€/MW interrupted power). A VOLL that is constant with respect to interruption duration is an approximation of a duration-differentiated VOLL.

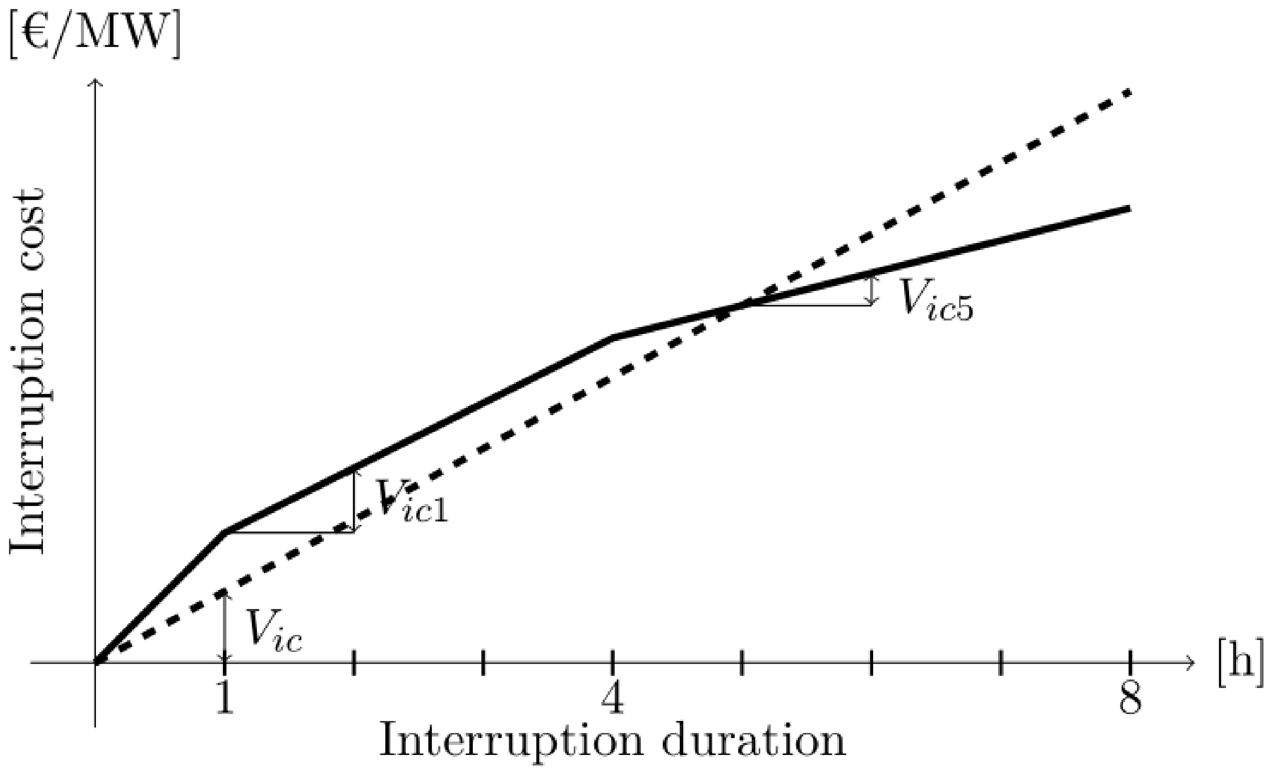

Figure 3.3 Interruption cost as a function of interruption duration.

If we incorporate this duration of interruptions, expression (3.5) becomes:

$$c_{INT} = \sum_{i=1}^{I} \sum_{c=1}^{C} \sum_{d=1}^{D} u_{icd} V_{icd} \cdot f_{ic}^{m} \cdot f_{ic}^{n} \tag{3.6}$$

where V_{icd} is the VOLL of an "additional 1 hour" interruption of 1 MW for an interruption that already lasts for d hours. That is, d is the duration up to now of an ongoing interruption. D is the set of all ongoing interruptions at the time step of study.

It is important to note that c_{INT} is the interruption cost at a particular time step. For example, the interruption cost at 6-7 PM on 13 January 2016 is the sum of the hourly cost of all ongoing interruptions

The research leading to these results has received funding from the European Union
Seventh Framework Programme under Grant Agreement No 608540.

during that hour. This means that only a part of the interruption cost of a longer interruption is allocated to this specific hour. Which part of the cost of this x-hour interruption is allocated to a specific hour depends on V_{icd}, i.e. the VOLL differentiation with respect to duration d.

Figure 3.3 illustrates the VOLL V_{icd} for an interruption that already lasts for 1 hour (V_{ic1}) and one that already lasts for 5 hours (V_{ic5}): $D = \{1,5\}$.

As an illustration, Table 3.4 shows interruption cost data [€/kW] from a Norwegian survey [13] for 6 different consumer types and for 5 different durations. This data shows for example that a 4-hour interruption of 1kW to an average residential consumer is estimated to cost 4.62 euros. Of course, the interruption cost differs between different residential consumers, just like different industrial or commercial consumers can have different interruption costs. The data on interruption costs presented in this table are piecewise linear but interruption costs could as well be represented by smooth functions.

Table 3.4 Interruption cost for different duration and for various consumer types, cost level 2014, exchange rate 0.115 €/NOK, based on Norwegian survey [13].

Interruption costs [€/kW]		Residential	Industry	Commercial	Public	Large industry	Agriculture
Duration	1 minute	0.13	3.92	3.23	6.69	5.65	0.58
	1 hour	1.27	13.62	22.62	19.96	6.00	2.19
	4 hours	4.62	42.12	54.12	29.66	11.77	7.62
	8 hours	9.23	67.86	119.32	53.55	13.04	14.19
	24 hours	27.24	135.25	308.35	86.09	18.23	40.62

Table 3.5 shows the marginal (with respect to duration) interruption costs for the same data. This is the slope of the interruption cost curve of Figure 3.3. For example, the interruption cost of an additional hour of interruption to an average commercial consumer, when that consumer has already been interrupted for 4 hours, is 16.30 €/kW.

Table 3.5 VOLL V_{icd} (with respect to duration)[€/kWh] for various consumer types at reference interruption durations, cost level 2014, exchange rate 0.115 €/NOK, based on Norwegian survey [13].

Marginal interruption costs V_{icd} [€/kWh]		Residen-tial	Industry	Commercial	Public	Large industry	Agriculture
Duration interval	0 – 1 minute	7.80	235.2	193.8	401.40	339	34.80
	1 minute - 1 hour	1.16	9.86	19.72	13.49	0.36	1.64
	0 hour - 1 hour	1.27	13.62	22.62	19.96	6.00	2.19
	1 hour - 4 hours	1.12	9.50	10.50	3.23	1.92	1.81
	4 hours - 8 hours	1.15	6.44	16.30	5.97	0.32	1.64
	8 hours - 24 hours	1.12	4.21	11.81	2.04	0.32	1.65

From the above data we construct a small example to illustrate the interruption cost calculation. Suppose that at the time of the SEIA (spring weekday at 6pm) the following two interruptions are happening in Norway:

- 1: 3 MW of residential consumers, already interrupted for 5 hours, unnotified;
- 2: 2 MW of industry, already interrupted for 1 hour, notified 7 days in advance.

The research leading to these results has received funding from the European Union Seventh Framework Programme under Grant Agreement No 608540.

Assuming that the two interruptions continue during the next hour and that no new interruptions happen during this hour, the interruption cost for this additional hour of interruptions is, combining Table 3.5 and Table 3.3:

$$c_{INT,Norway} = 3{,}000*1.15*1*0.57*1+2{,}000*9.50*0.14*0.87*0.49 = 3{,}100 \text{ [€/h]}$$

Where $D = \{1,5\}$; $u_{icd} = u_{Norway,residential,5} = 3MW$ and $u_{icd} = u_{Norway,industry,1} = 2\ MW$; $V_{icd} = V_{Norway,residential,5} = 1{,}150$ €$/MWh$ and $V_{Norway,industry,1} = 9{,}500$ €$/MWh$.

However, the cumulative cost of the two interruptions up to now is:

$$c_{INT,Norway} = 3{,}000*\mathbf{(1.27+3*1.12+2*1.15)}*1*0.57*1+2{,}000*\mathbf{(13.62+1*9.50)}*0.14*0.87*0.49 = 14{,}610\text{ €}$$

That is, only €3,100 of the interruption cost of €14,610 is attributable to the last hour of interruption. In other words, clearing the two interruptions at this moment (after 5 and 1 hours respectively), saves €3,100.

In comparison, the same two interruptions but on a winter weekday at 8am yields the following interruption cost for this additional hour:

$$c_{INT,Norway} = 3000*1.15*0.69*1*1+2000*9.50*1*1*0.49 = 11{,}6901 \text{ [€/h]}$$

d) <u>Weather at the time of interruption</u>

Many papers study the influence of weather (wind speed, temperature, rainfall, etc.) on failure probabilities and restoration time [15]. However, to our knowledge the effect of weather on consumer interruption costs has not yet been quantified. Currently, the closest available data on the effect of temperature on VOLL is the seasonal effect multiplier f_{ic}^{s}, which is correlated with temperature. In case of (future) data availability this effect can be directly taken into account in the form of multipliers.

e) <u>Extent of the interruption</u>

The extent of the interruption (local vs. widespread) could also be incorporated using multipliers. The multiplier takes into account the increase of interruption costs in case of a widespread interruption or blackout.[15]

3.3.3 TSO costs

The TSO incurs different costs while managing the reliability of the transmission system. Some of these costs are incurred in real-time operation, while others are incurred well before real time. Table 3.6 lists a non-exhaustive sample of TSO costs in the different decision making contexts.

Table 3.6 Examples of TSO costs in the different decision making contexts.

Real-time operation	Operational planning	Asset management	System expansion
Losses	Preventive actions	Replacement inspection	Materials and assembly
Corrective actions	Scheduling	Repair	Dismantling
Preventive actions	Reserve contracting	Maintaining stock	Consenting
Congestion management	Congestion management	Planned outage	Research and planning

[15] This can e.g. accommodate a "maximum" interruption cost in case of a full blackout.

The research leading to these results has received funding from the European Union Seventh Framework Programme under Grant Agreement No 608540.

The TSO costs of this table are system costs, as well as cost transfers. For example, repair of transmission components is a system cost, while congestion management is a cost transfer to producers. Load shedding entails a compensation transfer to consumers that are shed voluntarily or involuntarily (depending on the regulation, as explained in section 3.1).

The actual cost functions are TSO specific, and depend on the system characteristics
Load shedding the operations and maintenance (O&M) policy, regulation, the reliability criterion, etc. These are further described in GARPUR D4.1 [3], D5.1 [16] and D6.1 [17]. Moreover, Chapter 4 discusses the TSO costs in the different decision making contexts in more detail.

As already introduced in section 3.1, we split TSO costs into costs c_{TSO} [€/h] that can be directly attributed to a time step (e.g. of 1 hour) like losses, reserve usage and congestion management; and costs like reserve procurement, maintenance and investment costs, that are fixed in the short term, but vary in the medium and long term. These have gains that extend beyond the specific time step in which the expense is incurred. These types of expenditures are to be compared with the short term costs that can be saved via these expenditures. One needs in this case to make a SEIA to include also the expected result of effects in the longer term.

Another issue is that many decisions have a current and a future cost. That is, parts of the costs are uncertain since they depend on uncertain factors and future decisions. Expected value of future costs are commonly used to calculate socio-economic costs.

3.3.4 Producer costs

Generating electricity is a costly business: building power plants, burning fuel, payroll expenses, maintenance, consenting, etc. In the current restructured electricity market, private generating companies invest in generation capacity with the aim of earning a rate of return on their investment by selling electricity to consumers.

Economics divides producer costs into variable costs c_{gen} [€/MWh] like fuel costs, that vary with output; and fixed costs like investment costs, that are independent of output. Producer costs are highly heterogeneous – they differ in generation technology, age of the generation plant and its equipment, location, etc. – and exact estimation of variable and fixed cost of specific power plants is difficult. However, this is not critical for the SEIA methodology, since only those costs that change with different reliability decisions need to be considered.

Additional producer costs from reliability-related TSO decisions are damage to equipment[16], increased generation costs (start-up costs or lower efficiency) and a lost opportunity to sell electricity. This could be a non-negligible cost but should be considered on a case-by-case basis.

3.3.5 Congestion cost

Congestion costs $\boldsymbol{c_{cong}}$ [€/h] are the additional generation costs[17] when transmission constraints are present in the transmission grid. That is, the difference in generation costs between a system of infinite transmission capacity and an actual system. In order to alleviate congestion, cheap generation in an export-

[16] Interruptions could lead to generation unit tripping and depending on the generation technology this could lead to physical damages which require increased maintenance and repair costs.
[17] Under the assumption of inelastic demand, see section 5.1. In case of elastic demand, which is more important in the longer term, there is an additional deadweight loss.

The research leading to these results has received funding from the European Union
Seventh Framework Programme under Grant Agreement No 608540.

constrained node should decrease, while more expensive generation in an import-constrained node should increase.

Congestion management is the responsibility of the TSO and is done using redispatch or counter trading in uniform-price zones. In that case, the TSO pays a congestion payment to producers that are rescheduled for congestion management purposes. Thus, TSO congestion management costs are taken into account in the calculation of stakeholder surpluses. The net effect of this transfer payment on socio-economic surplus is, however, zero, but rescheduling generation capacity entails an increase of producer costs (c_{gen} and C_{gen}), which is reimbursed by the TSO. Note that congestion costs are taken into account in the calculation of generation costs; counting TSO congestion management costs as social costs would lead to double counting.[18]

3.3.6 Environmental costs

In order to assess the full socio-economic impact of different TSO decisions, one also has to include external costs. These are costs that are not directly borne by producers or consumers, of electricity in this case. The most important external costs in the electricity market are environmental costs like SO_x, NO_x and CO_2 emissions from electricity generation.

The costs from emission e_p of a pollutant p is the product of total emissions and emission damage d_p:

$$c_p = e_p d_p \tag{3.7}$$

With $p = SO_x, NO_x, CO_2$, etc. In general emissions are expressed as [ton/MWh] and damage as [€/ton]. It is important to note that, in order to avoid double-counting, for costs that are already internalised in the generation costs only the remaining societal damage should be included here.

$$c_p = e_p(d_p - t_p) \tag{3.8}$$

Ideally the price or tax on emissions t_p [€/ton] equals the societal cost d_p of emissions in order to give correct incentives.

For example: in Europe the damage of CO_2 emissions is already internalized – albeit only partly and imperfectly – in the generation cost through the EU Emissions Trading Scheme. Likewise, NO_x emissions are already taxed in France and Sweden, and SO_x emissions are taxed in the USA.

Additional environmental costs from the electricity market are biodiversity costs, noise and visual pollution costs. In principle, these can also be monetized and included in the assessment of environmental costs.

The environmental costs [€/MWh] are:

$$\mathrm{c_{ENV}} = \sum_p e_p(d_p - t_p) \tag{3.9}$$

[18] A parallel is provided by costs of unemployment: unemployment benefits, which are transfers from the government to the unemployed, certainly indicate the existence of social costs of unemployment. Those costs are, however, given by forgone surplus and other social damage of unemployment, not the transfers as such.

The research leading to these results has received funding from the European Union
Seventh Framework Programme under Grant Agreement No 608540.

3.4 Simplified formulation of surplus of stakeholder groups

The simplified formulation of this section shows the surplus of different electricity market stakeholder groups and the transfers between them. A more elaborate formulation, taking into account different nodes, generation technologies, consumer categories, interruption durations, interruption moments and time, is presented in section 3.5.

3.4.1 Socio-economic surplus

Socio-economic surplus [€/h] in the electricity market is given by consumer benefit Dv less all costs:

$$S = Dv - \left[\mathrm{c}_{\mathrm{INT}} + c_{TSO} + C_{TSO} + C_{gen} + (\mathrm{D} - \mathrm{u})(c_{gen} + c_{ENV})\right] \tag{3.10}$$

Socio-economic surplus is independent of electricity prices, and any payments, tariffs or taxes, due to the assumption of no market response[19] and assuming that surplus to all market participants is valued equally[20].

3.4.2 Consumer surplus

$$S_{cons} = Dv - c_{INT} - (D - u)[(p + TT)(1 + x) + c_{ENV}] \tag{3.11}$$

Where p is the price that consumers pay for electricity, TT a transmission tariff and x a value added tax on the total end-consumer (retail) price. This shows that a price increase entails a monetary transfer from consumers to producers and the government. In addition, environmental costs[21] are subtracted from consumer surplus, since consumers, i.e. society, bear the consequences of pollution. For global pollutants like CO_2 the damage is felt outside of the geographical scope of the SEIA, which causes some policy makers to only consider part of the global damages. However, these “Tragedy of the Commons” issues are outside of the scope of this analysis and we thus make the assumption of a benevolent (i.e. accounting for the global damage) decision maker for global pollutants.

3.4.3 Producer surplus

$$S_{prod} = (D - u)\left(p - c_{gen} - t\right) - C_{gen} + f \tag{3.12}$$

Producers receive a price p [€/MWh] for each MWh of electricity sold. The contribution margin earned by selling electricity at a price above marginal costs are called inframarginal rents or quasi-rents to indicate that this profit is not a profit in the strict economic sense. That is, producers need these quasi-rents in order to repay for the incurred fixed costs like investment costs.[22] Under the assumption of perfect competition in the wholesale market and perfect entry possibilities for new generation capacity investment, producer surplus S_{prod} equals a positive value close to zero[23], since producers will only enter the market as long as

[19] Demand is inelastic (short-term & long-term price elasticity of demand is zero) and no demand shifting to other times in case of interruptions (elasticity of intertemporal substitution is zero), see section 5.1.

[20] For example, a transfer from consumers to producers, through a higher price, is not disliked. In reality one would suppose that consumer surplus is strictly preferred by policy makers to rent to producers and TSOs, as in [18].

[21] But only the part that is not yet internalized into electricity generation costs, as shown in equation (3.9).

[22] Assuming average prices are equal to long-run marginal costs, these quasi-rents exactly repay investment costs. However, there could be rents due to imperfect competition, investment constraints, imperfect foresight, risk-aversion, etc. See section 5.2.

[23] In a market with perfect competition, free entry, perfect foresight and rationality, no risk-aversion and constant returns to scale producer surplus would be zero, but these conditions are not exactly met in reality.

The research leading to these results has received funding from the European Union Seventh Framework Programme under Grant Agreement No 608540.

expected profits are above a certain rate of return (e.g. the long term nominal rate of government bonds + a risk premium). The long-term expected value of price p is thus endogenously determined by generation capacity investment. Similarly, producers invest in generation capacity based on their prediction of the expected price p and its distribution.

When congestion is present between two uniform-price zones, this is alleviated using counter trading or redispatch, which entails a transfer f between the TSO and producers. When congestion is present between two zones that are allowed to have different prices, this is managed using the price signal. In that case there is no transfer between the TSO and producers, but the price p will differ, which is a transfer from consumers to producers.

If emissions from generation are taxed (t), this is an additional cost transfer from producers to the government.

3.4.4 TSO surplus

$$S_{TSO} = (D - u)\mathrm{TT} - c_{TSO} - C_{TSO} - f \tag{3.13}$$

TSOs are financed through a transmission tariff TT, which is levied on the consumption of electricity [€/MWh]. Other means of revenue collection exist, e.g. capacity fees, congestion rent on interconnectors from the auctioning of transmission rights, imbalance tariffs, etc. The tariffs are chosen such that each tariff period the revenue collected is just sufficient to pay the TSO's costs and allow a fair rate of return.[24] This implies that if the TSO's costs c_{TSO} and C_{TSO} change, the transmission tariffs should change accordingly (with a lag). Section 5.3 elaborates more on the change of TSO profit as a reaction to a change of reliability criterion.

3.4.5 Government surplus

$$S_{gov} = (D - u)(p + TT)x + (D - u)t \tag{3.14}$$

The government levies a value-added tax (VAT) on electricity consumption. This VAT is between 5% and 25% in countries of the European Union [20]. In addition, we assume that the government receives the gains from environmental taxes t.

[24] Since tariffs are decided at the start of a tariff period (e.g. a year), the collected revenues may differ from the allowed revenues, due to uncertainty on factors such as total electricity consumption, the number of connections, etc. The excess/deficit revenues are subtracted from/added to next years allowed revenue. The excess/deficit revenue balance is to be adjusted towards zero over time, through tariff changes.

The research leading to these results has received funding from the European Union
Seventh Framework Programme under Grant Agreement No 608540.

3.5 General formulation

This section extends the surplus formulations of the previous section to different nodes i, generation technologies g, consumer types c, interruption durations d, interruption moments m, time t and pollutants p.

Socio-economic surplus

$$\begin{aligned} S = \sum_{t=0}^{T} DF_t \Bigg[TS \sum_{i=1}^{I} \Bigg(\sum_{c=1}^{C} \Bigg(D_{cit} v_{cit} - \sum_{d=1}^{D} u_{cdit} \mathrm{V}_{\mathrm{cdit}}\, f_{cit}^{m}\, f_{cit}^{n} \Bigg) - (D_{it} - u_{it}) \mathrm{c}_{\mathrm{TSO,it}} \\ - \mathrm{C}_{TSO,it} - \sum_{g=1}^{G} \big(c_{gen,git} y_{git} + C_{gen,git} \big) \\ - \sum_{g=1}^{G} y_{git} \sum_{p=1}^{P} e_{p,git} (d_{pt} - t_{pit}) \Bigg) \Bigg] \end{aligned} \tag{3.15}$$

Consumer surplus

$$\begin{aligned} S_{cons} = \sum_{t=0}^{T} DF_t \Bigg[TS \sum_{i=1}^{I} \Bigg(\sum_{c=1}^{C} \Bigg(D_{cit} v_{cit} - \sum_{d=1}^{D} u_{cdit} \tilde{V}_{cdit}\, f_{cit}^{m}\, f_{cit}^{n} \Bigg) - (D_{it} - u_{it})(p_{it} \\ + TT_{it})(1 + x_{it}) - \sum_{g=1}^{G} y_{git} \sum_{p=1}^{P} e_{p,git} (d_{pt} - t_{pit}) \Bigg) \Bigg] \end{aligned} \tag{3.16}$$

with

$$DF_t = \frac{1}{(1+r)^{\frac{t*TS}{8760}}}$$

Producer surplus

$$S_{prod} = \sum_{t=0}^{T} DF_t \Bigg[TS \sum_{i=1}^{I} \Bigg(\sum_{g=1}^{G} \Big(\big(p_{it} - (c_{gen,git} + t_{\mathrm{pit}})\big) y_{git} - C_{gen,git} \Big) + f_{it} \Bigg) \Bigg] \tag{3.17}$$

TSO surplus

$$S_{TSO} = \sum_{t=0}^{T} DF_t \left[TS \sum_{i=1}^{I} \Big((D_{it} - u_{it}) TT_{it} - \mathrm{c}_{\mathrm{TSO,it}} - \mathrm{C}_{TSO,it} - f_{it} \Big) \right] \tag{3.18}$$

Government surplus

$$S_{gov} = \sum_{t=0}^{T} DF_t \left[TS \sum_{i=1}^{I} \big((D_{it} - u_{it}) ((p_{it} + TT_{it}) x_{it} + t_i) \big) \right] \tag{3.19}$$

The research leading to these results has received funding from the European Union Seventh Framework Programme under Grant Agreement No 608540.

4 APPLICATION OF THE QUANTIFICATION METHOD IN THE DIFFERENT TIME FRAMES

4.1 Introduction to the illustration

In this chapter, the quantification framework developed above is applied to a numerical test system, based on the Roy Billinton Test System [2]. The illustration for the short-term horizon provides both an application to illustrate the socio-economic assessment of TSO behaviour induced by the reliability criterion in the short term and builds the basis for the longer time horizons discussed in the subsequent sub-chapters. It does not depict the complete set of TSO actions nor exhaustively apply the differentiation of dimensions influencing interruption costs or respectively the VOLL since this work is done in other WPs of the GARPUR Project. This illustration applies the method of socio-economic assessment developed in WP3 to an illustrative test system in order to illustrate the basic principles and concepts.

The illustration comprises a simplified depiction of the European electricity market and grid operation with sequential decision making. This simplification provides the input data necessary to conduct the socio-economic impact assessment.

The RBTS is slightly adapted in its layout and parameterization. In order to depict the multi-country aspect, it is divided into two zones, East and West, where East consists of nodes 2 and 4 and West of 1, 3 and 5. Consequently, there are three cross-border transmission lines connecting the two zones.

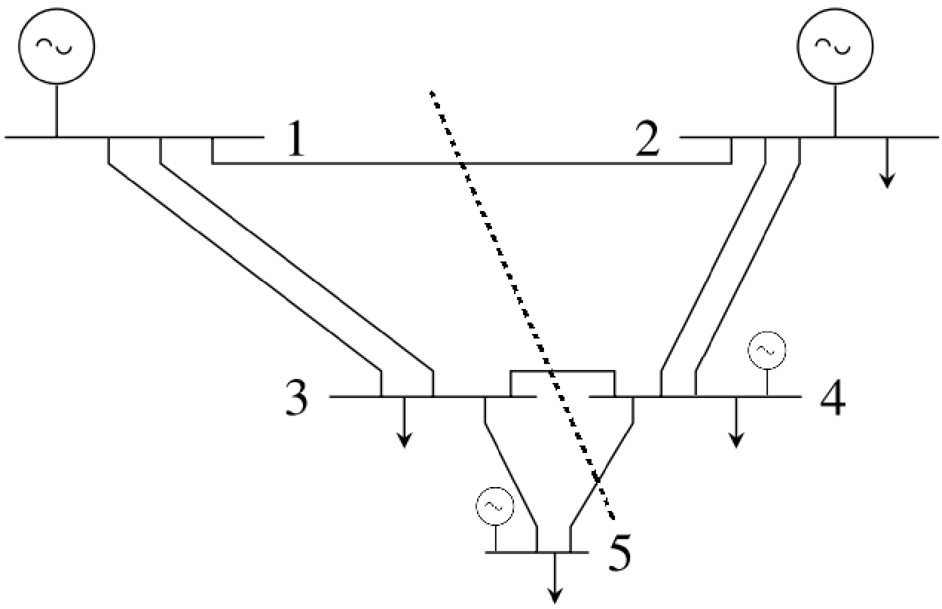

Figure 4.1 Five-node simplified version of the Roy Billinton Test System [2]

Table 4.1 to Table 4.5 summarize all the necessary data for this illustration. Load is given in seven different levels with respective probabilities of occurrence. It is divided to nodes 2 to 5 within the system by constant percentage shares (Table 4.2, column 2) of the absolute load levels given in Table 4.1 and further differentiated to different sectors as indicated in Table 4.2.

Table 4.3 contains information on generation capacity characterised by its location, variable cost and emissions while Table 4.4 informs about network characteristics.

The research leading to these results has received funding from the European Union
Seventh Framework Programme under Grant Agreement No 608540.

Table 4.1 Load data. Load scenarios and their probability of occurrence

Load scenario	Total load [MW]	Probability [%]
1	162,8	0,006
2	170,2	0,061
3	177,6	0,242
4	185	0,382
5	192,4	0,242
6	199,8	0,061
7	207,2	0,006

Table 4.2 Bus data. Share of a sector in total load of a node

Node	Load [%]	Residential [%]	Industry [%]	Commercial [%]	Public [%]	Large industry [%]	Agriculture [%]
2	10.8	0	40	20	0	30	10
3	46.0	40	0	40	20	0	0
4	21.6	30	40	10	10	10	0
5	21.6	80	0	10	0	0	10

Table 4.3 Generation data; rated capacity and variable cost of generation

Node	Rated Capacity [MW]	Variable cost [€/MWh]	Emissions [ton/MWh]
1	110	40	0.05
2	130	10	0.65
4	20	55	0.05
5	20	60	0.90

Table 4.4 Network data

from bus	to bus	r [p.u.]	x [p.u.]	b [p.u.][25]	Rating [MWA]	Failure rate [/y]	Repair time [h]	Line length [km]	Cost [€/MWy] [26]
1	2	0.0912	0.48	0.0212	33.725	4	8	200	10,000
1	3	0.0342	0.18	0.0212	85	1.5	4	75	3,750
1	3	0.0342	0.18	0.0212	85	1.5	4	75	3,750
2	4	0.114	0.6	0.0704	71	5	8	250	12,500
2	4	0.114	0.6	0.0704	71	5	8	250	12,500
3	4	0.0228	0.12	0.0142	33.725	1	8	50	2,500
3	5	0.0228	0.12	0.0142	71	1	8	50	2,500
4	5	0.0228	0.12	0.0142	33.725	1	24	50	2,500

Nodes 1, 3 and 5 are part of the country West, while East comprises of nodes 2 and 4. CO_2 emissions have a price (equal to the social damage, d_{CO_2}) of 25 €/tCO_2. Consumers pay a transmission tariff (TT) of 10

[25] r, x and b define the technical characteristics of the transmission line: r = resistance, x = reactance, b = susceptance.
[26] Assuming a that the transmission lines are 150 kV and thus have a line cost of 100 €/MW.km.year, according to [19].

The research leading to these results has received funding from the European Union
Seventh Framework Programme under Grant Agreement No 608540.

€/MWh in both countries, and a value-added tax of 6% and 21% in the East (x_E) and the West (x_W), respectively. The value of served load v is 500 €/MWh, representing a typical average willingness-to-pay by consumers. Note that while this impacts the aggregate surplus estimates (Table 4.6(4.6), is has no impact on the comparison of different scenarios (Table 4.7) since demand is assumed to be inelastic.

Table 4.5 Additional values

$x_W = 0.21$ [-]	$TT = 10$ [€/MWh]	$r = 4$ [%]	v = 500 €/MWh
$x_E = 0.06$ [-]	$d_{CO_2} = 25$ [€/tCO₂]	TS $= 1$ [h]	

4.2 Operational planning and system operation

In this section, the system sketched in the previous section is applied with a special focus on short-term planning and system operation. The next subsection discusses TSO decisions relevant for the short-term horizon while section 4.2.2 reshapes the equations to quantify surpluses for the relevant actors. This is followed by the numerical illustration in section 4.2.3.

4.2.1 TSO actions

In the short term, decision making is either linked with preventive or corrective measures as a reaction to events threatening system security or adequacy. Relevant decisions made by the TSOs in the short-term horizon are:

- Balancing and procurement of balancing services;
- Reserves scheduling and management;
- Congestion management: countertrading and re-dispatch under zonal and uniform pricing, congestion rent under nodal pricing;
- Maintaining voltage quality, frequency quality and commercial quality (harmonics, transients, variations);
- Network capacity scheduling: decisions about grid capacities made available to markets (net transfer capacities, Remaining available margins, etc.);
- Outage scheduling.

A more detailed technical description of these tasks can be found in deliverable D6.1 of the GARPUR Project [17]. Network capacity scheduling, reserve management, congestion management and outage scheduling are identified as being directly influenced by reliability criteria.

The tasks related to network capacities provide input for the operation of the power markets. The capacities are defined and loading limits for connections within the transmission system are identified and communicated. These are used for the market settlement. Costs arise only through subsequent activities. Costs and benefits to actors involved further depend on the prices formed on the two interconnected markets. These could be calculated in comparison to the reference situation without congestion, yet this is a hypothetical situation and will therefore not be considered further here.

By way of illustration, the numerical application of section 4.2.3 focuses on the TSO decision on cross-border grid transmission capacities that are made available to the market.

The research leading to these results has received funding from the European Union
Seventh Framework Programme under Grant Agreement No 608540.

4.2.2 Formulation

Socio-economic surplus

$$
\begin{aligned}
S = \sum_{t=0}^{T} DF_t \Bigg[TS \sum_{i=1}^{I} \Bigg(\sum_{c=1}^{C} \Bigg(D_{cit} v_{cit} - \sum_{d=1}^{D} u_{cdit} \mathrm{V}_{\mathrm{cdit}} \, f_{cit}^{m} \, f_{cit}^{n} \Bigg) - (D_{it} - u_{it}) \mathrm{c}_{\mathrm{TSO,it}} - \mathrm{C}_{TSO,it} \\
- \sum_{g=1}^{G} \left(c_{gen,git} y_{git} + C_{gen,git} \right) - \sum_{g=1}^{G} y_{git} \sum_{p=1}^{P} e_{p,git} (d_{pt} - t_{pit}) \Bigg) \Bigg]
\end{aligned}
\tag{4.1}
$$

Consumer surplus

$$
\begin{aligned}
S_{cons} = \sum_{t=0}^{T} DF_t \Bigg[TS \sum_{i=1}^{I} \Bigg(\sum_{c=1}^{C} \Bigg(D_{cit} v_{cit} - \sum_{d=1}^{D} u_{cdit} \mathrm{V}_{\mathrm{cdit}} \, f_{cit}^{m} \, f_{cit}^{n} + R^{u,TSO}{}_{cit} \Bigg) \\
- D_{it} p_{it} (1 + x_{it}) - (D_{it} - u_{it}) TT_{it} (1 + x_{it}) \\
- \sum_{g=1}^{G} y_{git} \sum_{p=1}^{P} e_{p,git} (d_{pt} - t_{pit}) \Bigg) \Bigg]
\end{aligned}
\tag{4.2}
$$

with

$$DF_t = 1$$

and a compensatory payment for unserved load paid by the TSO $R^{u,TSO}{}_{cit}$. The existence and exact design of this compensatory payment is subject to regulatory decisions. It is likely to depend on the amount of energy not served and may be differentiated among consumer groups analogously to their differentiation of the value of lost load. Transmission tariffs, however, are assumed to be charged only for the amount of energy served.

Producer surplus

$$
S_{prod} = \sum_{t=0}^{T} DF_t \Bigg[TS \sum_{i=1}^{I} \Bigg(\sum_{g=1}^{G} \Big(\big(p_{it} - (c_{gen,git} + t_{\mathrm{pit}})\big) y_{git} - C_{gen,git} \Big) + f_{it} \Bigg) \Bigg]
\tag{4.3}
$$

TSO surplus

$$
\begin{aligned}
S_{TSO} = \sum_{t=0}^{T} DF_t \Bigg[TS \sum_{i=1}^{I} \Big((D_{it} - u_{it}) TT_{it} - \mathrm{c}_{\mathrm{TSO,it}} + \left(p_{it} - p_{jt}\right) * (D_{it} - y_{it}) - R^{u,TSO}{}_{cit} \\
- \mathrm{C}_{TSO,it} - f_{it} \Big) \Bigg]
\end{aligned}
\tag{4.4}
$$

Government surplus

$$
S_{gov} = \sum_{t=0}^{T} DF_t \left[TS \sum_{i=1}^{I} \left(D_{it} p_{it} x_{it} + (D_{it} - u_{it})(TT_{it}) x_{it} \right) \right]
\tag{4.5}
$$

If the government levies taxes that are not spent within the system, they add to the aggregate socio-economic surplus at the cost of consumer surplus.

The research leading to these results has received funding from the European Union
Seventh Framework Programme under Grant Agreement No 608540.

4.2.3 Illustration

In the short term, both transmission and generation capacity installed are fixed and maintenance decisions are known in advance. The TSO action chosen to be modelled for the illustration is the decision on how much cross-border transmission capacity to give to the market. This decision is usually made before producers' final decision on generation and market clearing. Hence, the sequential decision-making process specific for the European electricity market is explicitly considered. In the short term, we assume that demand is known (185 MW), so that the only source of uncertainty is component failures.

As presented above, the numerical illustrations for the time horizons are based on a modified RBTS. Five nodes are divided into two zones or countries, West and East. With a zonal pricing approach, which is prevalent in the European power system, the internal transmission lines do not influence market clearing. In practice, the uniform price within a zone is ensured by congestion management, e.g. in form of re-dispatch, while component failures are treated with reserves. Neither of these mechanisms are depicted in this illustration. Instead, the three lines connecting West and East are of major interest. The TSO decision on the share of cross-border transmission capacity made available to the market is influenced by reliability requirements imposed by the reliability criterion. These influence the choice of the transmission reliability margin which is selected in order to prevent service interruptions resulting from contingencies. For the illustration, instead of an optimization, a set of candidate decisions is modelled and assessed. This set includes different shares of the installed cross-border transmission capacity or, in other words, different shares of the reliability margin.

The setup of the numerical illustration mirrors the sequential decision process of the European Power System. For given long- and mid-term decisions, the TSO decides on the transmission capacity, which implies a restriction for the subsequent market clearing. Depending on whether or not the chosen transmission capacity constraint is binding, market clearing results either in a uniform price for the system or in different prices for each zone. After market clearing, there is no uncertainty left, i.e. potential line outages become visible. After realization, the TSO calculates the optimal power flows (OPF) with the only available (corrective) action being load shedding and generation redispatch. At this point the TSO can apply the transmission capacity reserved for its reliability policy. The resulting outcomes are assessed with the help of the socio-economic assessment framework.

Uncertainty is considered by investigating a set of contingencies with their respective probabilities. Consequently, the resulting values serving as input for the assessment are probability weighted expectations instead of values resulting from a single contingency. In addition to input data described in section 4.1, the socio-economic impact assessment makes use of data from Table 3.3 and Table 3.4. According to the input data on interruption costs, the value of lost load is time dependent, i.e. depends on time of the day, weekdays and seasons. In this example, only the time of the day is changed with 10 AM on a weekday in winter as the reference time. The hourly value is multiplied with the respective multiplier for the moment in which the service interruption occurs.

Table 4.6 depicts exemplary surpluses for the actors of the electric power system at 10 AM (on a weekday in winter) for a candidate decision of 70 % network transmission capacity (NTC) given to the market. This situation corresponds to 30 % transmission reliability margin. The high share of consumer surplus in relation to other surpluses stems from a high evaluation of electricity consumption by the consumers reflected in the value of served load (cf. Table 4.5) relative to other monetary values such as prices or tariffs. The distribution of consumer surplus between the two zones corresponds to their shares of demand. In contrast, producer surplus almost exclusively arises in the eastern zone due to its cheaper generation technology. External costs and government revenues arise where electricity is generated and consumed, respectively.

The research leading to these results has received funding from the European Union
Seventh Framework Programme under Grant Agreement No 608540.

Table 4.6 Socio-economic assessment for the candidate decision of 70 % NTC given to the market at 10 AM (on a weekday in winter). All values in €.

	Total socio-economic surplus	Consumer surplus	Producer surplus	TSO surplus	External costs	Government revenues
Aggregate	85,535	80,468	3,904	1,846	2,175	1,492
East	29,390	26,812	3,904	1,246	2,106	180
West	56,145	53,656	0	600	69	1,312

In order to compare different candidate decisions, Table 4.7 presents the impact of changing the transmission capacity given to the market from 70 % to 60 %. Compared to the previous case, this implies an increased transmission reliability margin adding up to 40 % of the installed transmission capacity. As can be seen from the positive change of aggregate socio-economic surplus, the candidate decision of 60 % transmission capacity is preferable to 70 % from a welfare perspective. A zone-wise evaluation reveals that the socio-economic surplus decreases in the East while increasing in the West as a result of this change of the TSO decision. When it comes to distributional effects, consumers in both countries as well as the TSO itself benefit from its decision on a higher transmission reliability margin. Producers in the East, on the other hand, suffer losses. External costs increase whereas government revenues decrease.

Table 4.7 Difference in surpluses between candidate decisions of 60 % and 70 % NTC given to the market at 10 AM (on a weekday in winter). All values in €.

	Δ Total socio-economic surplus	Δ Consumer surplus	Δ Producer surplus	Δ TSO surplus	Δ External costs	Δ Government revenues
Aggregate	411.83	2461.71	-3901.72	1822.89	136.58	-107.63
East	-1041.02	1910.03	-3901.75	910.58	148.20	-108.00
West	1452.85	551.68	0.03	912.32	-11.62	0.37

The difference between the two exemplary TSO candidate decisions is also shown in Figure 4.2 where total costs are higher for the lower choice of transmission reliability margin. Figure 4.2 depicts generation costs, interruption costs as well as total costs for a range of TSO candidate decisions between 100 % and 0 % transmission capacity given to the market or 0 % and 100 % reliability margin, respectively, with interruption costs valid for service interruptions starting at 10 AM on a weekday in winter. Total costs are

The research leading to these results has received funding from the European Union
Seventh Framework Programme under Grant Agreement No 608540.

lowest for NTC at 40% but is almost constant between 60 and 40% NTC since the increase of generation costs due to less transmission capacity is compensated by the decrease of interruption costs.

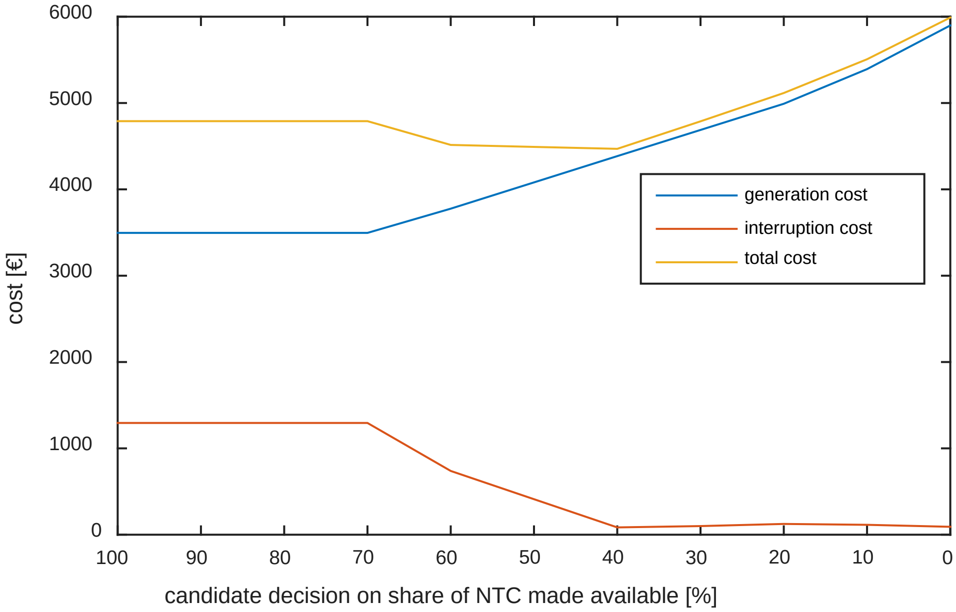

Figure 4.2 Generation cost, interruption cost and total costs for different TSO candidate decisions at 10 AM (on a weekday in winter).

For the further numerical analysis, three situations each reflecting one hour of operation of the electric power system are investigated. These reflect three different moments in time with regard to the potential service interruptions. Figure 4.3 shows socio-economic surplus for a variety of candidate decisions at three different times of the day.[27] As explained above and shown in Table 3.3, the value of lost load varies with time (here: time of the day) and between the different consumer sectors. These influence at which node load is shed in case contingencies require load-shedding. The graph shows that socio-economic surplus within each time period of the day is almost equal for a range of candidate decisions between 100 % and 70 % cross-border transmission capacity given to the market. A minimum reliability margin is necessary to compensate a contingency of one of the three cross-border transmission lines. Before this threshold, interruption costs are constant. Similarly, for any share between 0 % and 40 % available NTC, the socio-economic surplus curves are parallel and at a similar level for the different times of the day. This can be explained by the fact that between 0 and 40 % NTC, increasing generation costs are more relevant than avoided interruption costs. The lower the scheduled cross-border transmission capacity choice, the more electricity has to be procured from the more expensive generation units in zone West, resulting in rising generation costs. At the same time, interruption costs decrease and are no longer dependent on the chosen cross-border capacity. As shown in Figure 4.2, interruption costs are roughly constant for lower NTC values because line failures from certain contingencies cannot be compensated by withholding cross-border transmission capacity.

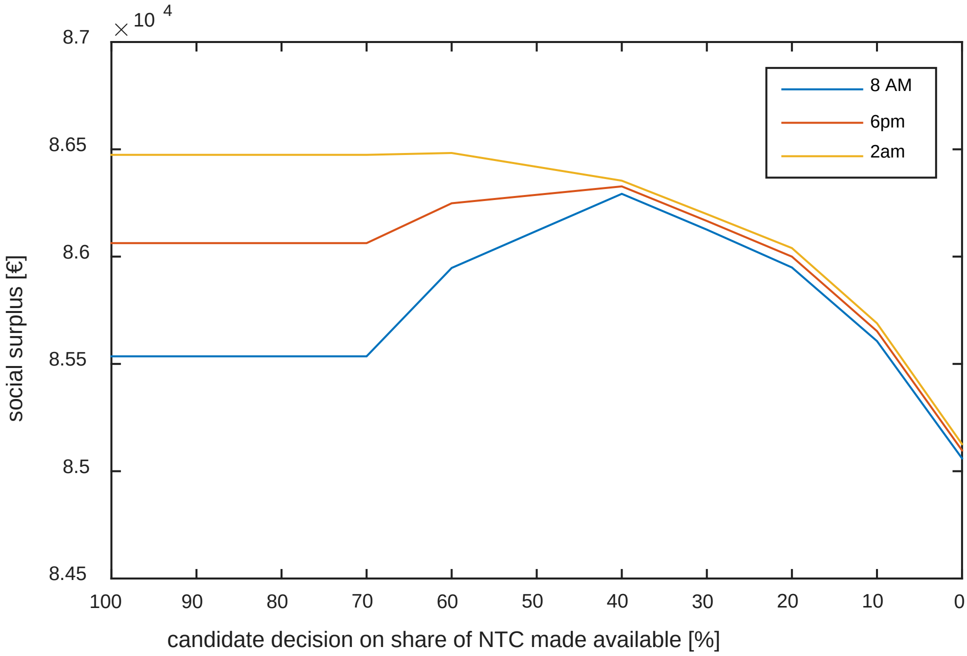

Figure 4.3 Socio-economic surplus for different candidate decisions on NTC availability and different times of the day.

More interesting is the shape of the socio-economic surplus curves within the interval between 70 % and 40 % cross-border transmission capacity given to the market. It is different for the different times of the day and leads to different optimal candidate decisions for each time. While a higher NTC value is optimal for a situation of the electricity market at night, in the morning and in the afternoon a lower NTC is given to the market to allow a higher reliability margin, since interruption costs are higher during the day than the night.

[27] Again, surplus is a probability weighted expectation of the surpluses for all contingencies considered.

The research leading to these results has received funding from the European Union
Seventh Framework Programme under Grant Agreement No 608540.

4.3 Asset management

In the GARPUR context (cf. Chapter 1 of D5.1 [16]) the mid-term interval lies within the interval beginning with (approximately) one month and ending (approximately) two years ahead. On the mid-term horizon the available decisions are those in the asset management category. GARPUR D5.1 ([16]) provides an extensive analysis of asset management activities, but in broad terms, one can say that asset management is about maintaining and enhancing the capacity of the existing transmission system to render transmission services.

4.3.1 TSO actions

In this section, we sketch an outline of TSO decisions in the mid-term, which mainly deals with the scheduling of outages for maintenance for the work we consider in GARPUR. A more detailed description of mid-term decisions can be found in D5.1 [16], which gives a detailed account of the functional workflow for the asset management decision-making processes within TSOs.

There are two main types of asset management decisions:

1. Decisions on *what* to do, i.e. what maintenance and replacement actions to undertake within the mid-term planning horizon.
2. Decisions on *when* to act, i.e. at what time asset management actions are to be undertaken within the planning horizon.

The reason for this division into "what" and "when" is important since maintenance often involves planned outages: the line or system component to be repaired or replaced must usually be taken out of service during the maintenance work. In such cases, the system therefore becomes less reliable during maintenance.

In current practice, asset management involves preparing a plan for maintenance and replacement operations for the next years (cf. D5.1 [16]), which is then elaborated into short-term (covering weeks to months) maintenance schedules. An inventory of components that will need to be taken out of service during these maintenance operations and an outage plan are also prepared.

The outage plan must be prepared for the mid-term time horizon, but the precise timing of action needs to be flexible: when it comes to outage scheduling in operational planning it may be found that a maintenance action needs to be postponed, depending on the present state of the system and the short-term outlook. On the other hand, if circumstances are opportune the action may be brought forward. Maintenance plans for power plants are also taken into consideration in outage planning.

4.3.2 Formulation

There are two main categories of costs connected to asset management. One is the direct cost of the actions involved, e.g. the material and labour cost of replacing a component, as well as provisions for maintenance such as availability of spare parts. The other is the cost resulting from the temporary reduction in system capacity when a planned outage occurs as a result of undertaking maintenance. This may lead to increased system losses, may increase the severity of any unexpected outage, and may even require costly load shedding. As a consequence, expected interruption costs will be higher. Congestion incidence and related costs (accruing to TSO's and other market participants) may also increase when system components are taken out of service for the duration of a maintenance operation. Environmental cost – in particular, costs of CO2 emissions – may also rise for the same reason, for example if generation

The research leading to these results has received funding from the European Union
Seventh Framework Programme under Grant Agreement No 608540.

from wind farms cannot be supplied to the system due to an outage of a power line, provided the set of measures can capture the related cost.

For modelling purposes three main categories of asset management operations may be identified:

1. Asset management operations related to maintaining particular system components – these involve planned outages.
2. Asset management operations related to failures of system components – these involve unplanned outages
3. Day-to-day asset management operations

A more detailed technical description of these tasks can be found in deliverable D5.1 of the GARPUR Project [16].

4.3.3 Illustration

Timing outages for repair or maintenance is one of the most common asset management decisions. As an illustration of such a decision we compare a day in summer and winter to see during which day the loss of socio-economic surplus [€/h] is the lowest if the line between node 3 and node 4 (a cross-border line) is taken out of service for maintenance. The analysis assumes that the TSO takes the optimal short-term decision, i.e. schedules the optimal available transmission capacity at each operational time step. As in the short-term illustration in the previous section, the only difference between summer and winter is the value of lost load and the demand level; other parameters are held fixed. Note that since the comparison is between a day in summer and a day in winter, with the assumption of no other difference between the two outage decisions, the surplus calculations are based on exactly the same formulas as in section 4.2.2.

The results of the exercise are shown in Table 4.8 and Table 4.9. Both tables show the change in surplus in the test system as a result of the (planned) outage. The expected drop in socio-economic surplus during a summer day is 746 €/h while the corresponding number for a winter day is 800 €/h. The expected cost of this action is therefore somewhat higher during winter than in summer. Expected socio-economic surplus will therefore be higher if the outage is planned for summer rather than for winter.

Lost consumer surplus – mostly due to interruption costs – are the largest cost item for both summer and winter. Consumer surplus decreases mainly in West because cheaper Eastern generation is substituted for more expensive Western generation. This increased generation cost is partly offset by a lower external cost of the generation in node 1. TSO surplus decreases due to the more price converge between East and West. While the outage has consequences for other stakeholders, the timing matters far less for them.

Note that in many European countries, load and failure probabilities may be expected to be higher in winter than summer and the duration of maintenance operations may be expected to be longer. More realistic assumptions on these factors would contribute to making the decision to schedule an outage in summer more attractive.

Table 4.8 Summer [€/h]

	ΔSocio-economic surplus	ΔConsumer surplus	ΔProducer surplus	ΔTSO surplus	ΔExternal costs	ΔGovernment revenues
Aggregate	-746	-597	2	-306	154	0
West	-756	-590	1	-154	-13	0
East	10	-7	1	-152	167	0

The research leading to these results has received funding from the European Union Seventh Framework Programme under Grant Agreement No 608540.

Table 4.9 Winter [€/h]

	ΔTotal socio-economic surplus	ΔConsumer surplus	ΔProducer surplus	ΔTSO surplus	ΔExternal costs	ΔGovernment revenues
Aggregate	-800	-651	3	-306	154	0
West	-797	-630	1	-154	-13	0
East	-3	-21	2	-152	167	0

4.4 System development

In the long-term timeframe, i.e. from a few years to more than 10 years, a TSO focuses on system development. The main difference of the long-term planning of system development activities compared to shorter planning horizons is that new assets can be taken into operation and thus supplement the existing asset base. In general, system development deals with taking decisions that change transmission capacities. Commonly used time horizons for long-term planning are:

- 5–10 years or more: Detect grid reinforcement needs and identify development paths to deal with these needs;
- 2–3 years: Optimize the timing of grid reinforcements expected in the development paths.

According to GARPUR D4.1 [3] , the main objective of long-term planning is "to ensure that sufficient facilities are installed on the system to enable it to be operated in accordance with appropriate system operation rules and standards. In particular, the system development planner should ensure that the system's capability to transfer power from producer to consumer is sufficient." This shows that system development is closely linked to all subsequent time steps and that it is only a first step towards the ultimate goal of reliable and economically efficient system operation.

4.4.1 TSO actions

System development deals with taking decisions that change transmission capacities either within a TSO's own system or towards other TSOs systems, such as [3]:

Construction, upgrading, replacement, retrofitting or decommissioning of assets, like:

- o AC or DC high-voltage lines
- o substations
- o phase-shifting transformers
- o shunt reactors
- o capacitor banks
- o synchronous condensers
- o flexible AC transmission systems (FACTS)
- o static VAR compensators (SVC)
- o series compensation devices
- o communication or measurement systems
- o etc.

Additionally, decisions have to be made on the specific type of technology for each of these assets, e.g. a conventional vs. superconductive cable. Likewise, decisions on the timing, location and size of the asset are needed. Furthermore, in the long term, a TSO makes strategic decisions like replacement, maintenance and operational policies, including decisions on reliability management.

The research leading to these results has received funding from the European Union
Seventh Framework Programme under Grant Agreement No 608540.

4.4.2 Illustration

As an illustration of system development we calculate and compare expected socio-economic surplus [€/h] between the base case of section 4.1 and a case with an additional cross-border line built between node 1 and node 2.

To calculate this, we assume that the TSO always makes the optimal short-term operational planning and system operation decision about how much NTC to schedule between the two regions – as in section 4.2. That is, at every system operation time step of the system development decision, each with a particular demand and VOLL for different consumer groups, the TSO makes the decision that maximizes short-term socio-economic surplus [€/h]. Given this NTC, supply is determined in the Eastern and Western region. Since the regions are uniform-price zones, redispatch is needed if supply violates internal limits.

We represent the probability distribution function of demand by a normal distribution with seven different demand levels in a year, each with a different probability of occurrence, as in Table 4.1. In addition, we take into account three different times-of-day and four seasons. Using Table 3.3 the VOLL of different consumer types is altered with the hour and the season. For example, Table 3.3 shows that at afternoon time (5 PM) VOLL of industrial consumers is only 14% of their VOLL during the work day, while VOLL of residential users is at its highest at 5 PM. Therefore, at a winter evening at 5 PM, it makes more sense to interrupt industrial consumers than residential consumers.[28]

To summarize, we calculate the difference in expected surplus between the base topology of section 4.2 and a topology with an additional line between node 1 and node 2. The expectation is taken over seven different demand levels, three different times-of-day and four seasons, each with a different VOLL:

$$E[\Delta S|TSO\ makes\ opt.ST\ decision] = \sum_{s} S_S^*(V_S, D_S, base\ case)\, f(s) - \sum_{s} S_S^*(V_S, D_S, add.line\ 12)\, f(s)$$

Where s is the state of the world determined by the demand, time-of-day and season and $f(s)$ the discrete probability distribution of the state of the world. S_S^* is the optimal surplus in each state of the world s.

Table 4.10 shows the result of the comparison between the case with an additional line between node 1 and 2 and the base case of section 4.1. This table shows that building the additional line increases expected[29] socio-economic surplus with 451 €/h. The expected socio-economic surplus[30] at a specific time step varies between 474 €/h and 401 €/h, for high and low demand respectively.

Compared to the base case, more transmission capacity will be scheduled when the additional line is built. This causes prices to converge. In this illustration, prices converge to 40 €/MWh for most demand levels. That is, prices increase. But, the additional transmission line (which can also fail) also decreases expected interruption costs for all demand levels, due to a higher transmission reliability margin. Since the average price increases in East, consumer surplus decreases, but less than the producer surplus increase, due to the decreased interruption costs. Expected TSO surplus decreases (due to decreased congestion rent). Furthermore, since with more transmission capacity available between East and West, low-$C0_2$ generation in node 1 is substituted for high-$C0_2$ generation in node 2, external costs increase. We attribute this external cost to East, but in case of a global pollutant like CO_2, the actual external costs are divided over all countries.

[28] We assume that the share of consumption by each consumer type and at each node is constant over time.
[29] The expected level over all demand levels and contingencies.
[30] The expected level over all contingencies.

The research leading to these results has received funding from the European Union
Seventh Framework Programme under Grant Agreement No 608540.

Lastly, government revenues increase in West since VAT is defined as a percentage over the electricity price, which increases in East.

Table 4.10 Socio-economic assessment: Case with an additional line – base case. All values in E[€/h].

	Δsocio-economic surplus	ΔConsumer surplus	ΔProducer surplus	ΔTSO surplus	ΔExternal costs	ΔGovernment revenues
Aggregate	451	-1314	2695	-588	-417	76
West	-227	32	0	-294	35	0
East	678	-1346	2695	-294	-452	76

Table 4.10 also shows distributional issues between stakeholder groups and between zones. That is, since West's socio-economic surplus decreases, its inhabitants could oppose this investment, unless a sufficient side-payment is made. Likewise, Eastern consumers, environmentalists and the TSO[31] could also oppose this investment since their surplus decreases.

The above assessment only calculates the immediate change of socio-economic surplus between the initial reference state and the alternative state with an additional line. However, a large part of the costs are upfront investment costs of the transmission line, but the economic lifetime of the investment extends far into the future.

To determine if a project, such as a line investment, increases socio-economic surplus, all costs and benefits over the period of study, e.g. the economic lifetime, have to be calculated. In doing this, the modeller has to make assumptions on the evolution of the system over the economic lifetime.

First, our analysis does not endogenise long-term response by producers and consumers but assumes that both increase at a certain exogenous rate of 1 per year. Section 5.1 relaxes the assumption of exogenous demand by developing a model that shows demand response as a reaction to price changes and reliability changes. Section 5.2 develops a model that shows the generation response as a reaction to net transmission capacity.

Second, future costs and benefits should be discounted with a certain factor, e.g. 4%[32] on a yearly basis. The discount rate r reflects the time value of money. A discount rate is used to convert future monetary benefits and costs into their present value. The discount rate can be calculated as a real or a nominal rate. The nominal rate is expressed in monetary terms, while the real rate is an adjustment from the nominal to incorporate (expected) inflation of the general price level.

$$DF_t = \frac{1}{(1+r)^{\frac{t*TS}{8760}}} \tag{4.6}$$

Since we assume both generation and demand to increase at 1% per year (all generation plants and demands proportionally), the yearly benefits from the line investment of 33.725 MW between node 1 and

[31] This depends on the specificities of the regulation in the TSO zone. If congestion rents are excluded from TSO revenues or if a decrease of congestion rent is compensated by an increased transmission tariff, the TSO supports this investment. This is treated in more detail in section 5.3 on TSO regulation.

[32] Selected to be between the lower bound of the risk free rate and the higher bound of the Weighted Average Capital Cost (WACC), as proposed by [21].

The research leading to these results has received funding from the European Union
Seventh Framework Programme under Grant Agreement No 608540.

2 increase in the future. However, these benefits are discounted at 4% on a yearly basis. The net present value of these benefits over a lifetime of 50 years amount to €88 million. This has to be compared with the investment costs. The last column of Table 4.4 gives a yearly cost (annuity) of 20,000 €/MW for this 33.725 MW line of 200km. This amounts to an annuity of 675,000 €/year, or a net investment cost of €14.5 million at a yearly discount rate of 4%. The line investment is thus welfare-improving under the above assumptions.

The research leading to these results has received funding from the European Union
Seventh Framework Programme under Grant Agreement No 608540.

5 MARKET RESPONSE

The SEIA methodology proposed in chapter 3 allows to evaluate the costs and surplus of all electricity market stakeholders. This methodology is used to compare socio-economic surplus for different TSO decisions. However, the methodology implicitly assumes that behaviour of all market stakeholders is inelastic, i.e. it does not alter with changing market variables such as the reliability level, electricity prices and taxes.

This chapter lists and explains possible responses of electricity market stakeholders (consumers, producers, TSO and government) to changing market variables. Subsequently, we give an indication of how these market responses could be integrated in the SEIA and in the precursory electricity market simulation.

5.1 Consumers

When the reliability (ρ) or price (p) level of a transmission network changes – for example through a change of operational, maintenance or system development policy – consumers will react. Consumers could change their demand $D(p,\rho)$, their value of served load $v(p,\rho)$, and their value of lost load $V(p,\rho)$.

5.1.1 Demand

The effect of a price change on consumer demand is well studied in literature [22],[23]. The ability of demand to respond to price is measured by the price elasticity of demand, i.e. the percentage change in quantity demanded (D) over the percentage change in price (p), other things equal:

$$\epsilon_p = \frac{dD/D}{dp/p} < 0 \tag{5.1}$$

The price elasticity of demand represents the marginal change and could thus be only valid around the current equilibrium (D,p). Estimates of price elasticity of demand exist for different regions i, different consumer types c and for different periods of study. Furthermore, these studies estimate the price elasticity of demand for different response times: very short term (real time), short term (<1 year) and long term (>1 year). Table 5.1 gives estimates for the residential, industrial and commercial short- and long-run price elasticity of demand for different countries, different periods of study and different estimation methods. These values differ significantly but are negative and smaller than 1 in absolute value.

Table 5.1 Residential, industrial and commercial short- and long-run price elasticity of demand for different countries

Residential	USA [22]	Israel [24]	Taiwan [25]	Greece [26]
Short-run elasticity	-0.24	-0.125	-0.15	/
Long-run elasticity	-0.32	-0.579	-0.16	/
Industrial				
Short-run elasticity	/	-0.123	/	-0.51
Long-run elasticity	/	-0.311	/	-0.77
Commercial				
Short-run elasticity	-0.21	/	/	/
Long-run elasticity	-0.97	/	/	/

Long-run elasticity of electricity is always larger than short-term elasticity since consumers have more time to adapt to new prices. A consumer has different possible responses to an increase of the electricity price:

(1) decrease the use of his electricity-using appliances;
(2) purchase a more efficient appliance;
(3) switch to another energy source such as natural gas or heating oil;
(4) start producing your own electricity e.g. by solar PV.

Options (2) to (4) require buying relatively expensive appliances or equipment and thus considerable adjustment time is needed.

To illustrate the concept of price elasticity of demand, assume a TSO zone with an average electricity price p of 50 €/MWh, an average electricity demand D of 10,000 MW and an average (long-term) price elasticity of demand ϵ of 0.5. Suppose that by introducing a new reliability criterion the average cost of electricity provision decreases with 5 €/MWh, and that, assuming perfect competition, this translates in a price decrease of 5 €/MWh. To calculate demand after the price decrease, use equation (5.1):

$$-0.5 = \frac{dD/10{,}000}{5/50} \qquad (5.2)$$

This increases demand by 500 MW. Figure 5.1 shows the decrease of electricity cost (light grey area) and the additional consumer surplus due to elastic demand (dark grey area). In case inelastic demand is assumed, this area would be zero.

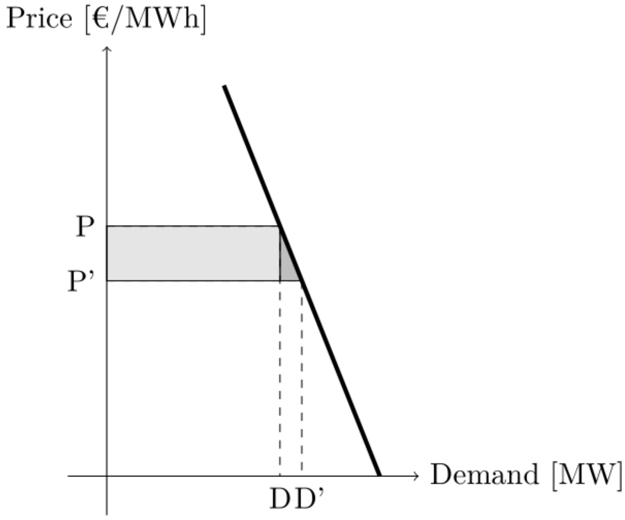

Figure 5.1 Decrease of electricity cost (light grey area) and the additional consumer surplus due to elastic demand (dark grey area).

The decrease of electricity cost yields a consumer surplus increase of 10,000*5 = 50,000 €/h and the additional consumer surplus due to inelastic demand is 500*5/2 = 1,250 €/h. This additional surplus of 1,250 €/h is neglected under the assumption of inelastic demand.

Price elasticity of demand could differ substantially by region. Reference [22] divides the USA into 9 regions and estimates that short-term residential elasticity is between -0.05 and -0.3, while long-term elasticity is between -0.05 and -0.6.

Price elasticity of demand in the very short-term, i.e. demand response in real time, is less widely studied. Reference [27] estimates a value between −0.0014 and −0.0043 for total demand, while reference [28] estimates values between virtually zero and -0.05 for four industrial sectors. However, for one industrial sector, the water supply industry, reference [28] finds a price elasticity of demand of about -0.2. This shows

The research leading to these results has received funding from the European Union
Seventh Framework Programme under Grant Agreement No 608540.

that very short-term price elasticity of demand is almost zero for total demand but that demand can be price-responsive for specific industries and specific consumers.

It should be noted that demand response is expected to increase in the future by the introduction of smart meters and smart appliances.[33] However, this mainly shifts demand to other hours and so increases the very-short term price elasticity of demand, not the short- or long-term elasticity.

Demand for network capacity could also change with the reliability level because consumers may start to produce themselves or give up their own production. The price elasticity of reliability is:

$$\epsilon_\rho = \frac{dD/D}{d\rho/\rho} > 0 \tag{5.3}$$

However, this is less straight-forward to estimate and there are few references available on this topic in literature. Elasticity of demand with respect to reliability level seems less smooth than price elasticity of demand. This highly depends on the specific consumer and his reliability level. Non-residential consumers can have different preferences for reliability: some industries like food processing plants can be interrupted for several hours, while aluminium smelter facilities have major damage after four hours of interruption and industries like manufacturing and IT require a very high reliability level and power quality. They could move their production outside of the TSO zone in case reliability is too low.

5.1.2 Value of served load v and value of lost load V

Less obvious but equally important for the SEIA is that value of served load v and value of lost load V can also change with the price or reliability level. When demand increases or decreases in response to a changing price or reliability level, the remaining demand will have a different value of load. Examples:

- Low electricity prices lead to increased use of electricity for heating, which is supposed to have a relatively high V in winter.
- High electricity prices lead to a higher electricity efficiency, i.e. less electricity consumption.
- Low reliability could cause certain industries, with high V, to relocate, thus lowering aggregate industrial V. Likewise, low reliability could induce consumers to install backup equipment, thus lowering V.
- High reliability could attract industries with a high V.
- Increased electricity prices increase the marginal v which also causes v to increase.

The direction of these changes is uncertain but the above examples seem to indicate that v and V increase with ρ. To our knowledge, literature provides no estimations of the relationship between the reliability level ρ and V.

5.1.3 Mitigation measures

Consumers could also take mitigation measures in response to a decreasing reliability level. For example buy an uninterruptible power supply or install a small-scale diesel generator. If consumers are perfectly rational and have perfect foresight, they will implement those measures in the long term that have a lower

[33] The introduction of demand response has an effect on reliability. It provides more options to the TSO to manage the transmission system.

The research leading to these results has received funding from the European Union
Seventh Framework Programme under Grant Agreement No 608540.

marginal cost than the marginal benefit of prevented interruptions. This lowers the interruption cost by lowering the VOLL[34].

5.1.4 Effect of consumer response on surplus

To show the effect of price or reliability elasticity of demand and the value of VOSL on total surplus, we introduce a small model. Suppose a continuum consumers. All have the same VOSL v and the same VOLL V, however they have a different potential for changing their electricity intensity and a different preference for relocating their plant to other countries. Their aggregate demand for electricity is $D(\rho, p)$, which increases with the reliability level ρ and decreases with the electricity price p:

$$\frac{\partial D(\rho,p)}{\partial \rho} > 0 \; and \; \frac{\partial D(\rho,p)}{\partial p} < 0 \tag{5.4}$$

The cost of reliability $c(\rho)$ is passed on to the consumers (the manufacturers), all other electricity costs are neglected. The demand curve then becomes $D\big(\rho, p(\rho)\big) = D(\rho)$. Its slope is uncertain

$$\frac{dD(\rho,p(\rho))}{d\rho} < or > 0 \tag{5.5}$$

And depends on the reliability level. It makes sense to assume that demand first increases with the reliability level and then decreases again when the demand decrease caused by the price increase overtakes the demand increase caused by the reliability increase. The optimal reliability level is found by maximizing the following sum

$$\max_{\rho} D(\rho)[v - c(\rho) - (1-\rho)V] \tag{5.6}$$

Which is the product of demand and net consumer benefit, i.e. consumer benefit minus reliability costs and expected interruption cost. The optimal reliability level is found by the following first-order condition:

$$c'(\rho) = V + \frac{D'(\rho)}{D(\rho)}[v - c(\rho) - (1-\rho)V] \tag{5.7}$$

That is, the optimal reliability level depends on the price and reliability elasticity of demand (5.4), the value of served load v and the value of lost load V.

Note that neglecting the fact that demand is reliability-dependent, and thus only minimizing the sum of reliability and expected interruption costs, yields the following first-order condition: $c'(\rho) = V$. Depending on the sign of $D'(\rho)$, this yields a reliability level that his higher or lower than the optimal one. Likewise, when demand is indeed independent of the reliability level and the price, for example in the short-term, when the consumers don't have the time to react to a changing reliability level or price, the optimal reliability level is also found by the same first-order condition $c'(\rho) = V$, which does not depend on VOSL v.

To summarize, the VOSL v plays no role in reliability decisions in the short term - when $D'(\rho)$ is zero - but determines the long-run effect of reliability decisions. This means that cost minimization is a correct short-run objective of a TSO is cost minimization, but that in the long run, the objective should be surplus maximization, not cost minimization.

5.2 Producers

5.2.1 Competitive response

The previous section explained that consumer demand changes in the short and long run when prices change. Likewise, when prices change, producers´ behaviour will also change.

Generation capacity is an asset with a long construction time, a long technical life time and large upfront investment costs. Therefore, investments in generation capacity are only made when producers expect a sufficient return on investment over the lifetime of the generation unit. That is, only if they expect prices to be sufficiently above variable costs (e.g. fuel costs, operations and maintenance costs, etc.), will they install new generation capacity.

At the end of the technical lifetime of a generation plant, new investments (e.g. retrofitting, increased maintenance, replacement of components) aimed to extend the lifespan are made only if the expected rents (prices minus variable costs) are sufficient to remunerate the costs of these investments. If not, the plant is mothballed or dismantled. Furthermore, if prices fall permanently below a plant's variable costs, it is also mothballed or dismantled. Among power plants of the same technology, price decrease especially affects older power plants as they have usually higher variable costs.

In addition to the average price, also the distribution of the price over the year matters for generation investment. Different generation technologies react differently to changes in the price distribution. For example, for peak plants a few price spikes could be sufficient to repay fixed costs, while base load plants need a sufficiently high average price. A case in point is the increased penetration of renewables in Europe that pushes gas-fired power plants "out of the money" and causes them to be mothballed – but not dismantled, so one expects prices to go up again during the technical lifetime of the plants.

In summary, a change of prices changes the shape of the supply curve in the longer run. We use the set-up of Figure 5.2 to illustrate this point.

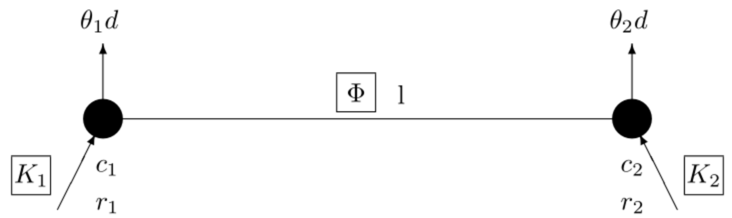

Figure 5.2 Set-up of the competitive[35] generation response illustration

Suppose two regions are connected by a transmission capacity of Φ MW. We assume that a baseload technology can be installed in region 1 and a peakload technology in region 2. That is, variable cost $c_1 < c_2$ [€/MWh] and capital cost $r_1 > r_2$ [€/MWh]. The installed baseload and peakload generation capacity are denoted by K_1 and K_2 respectively and are perfectly reliable. Total installed capacity is $K = K_1 + K_2$

[35] A market is perfectly competitive when every participant is a price taker, i.e. no participant thinks he is able to influence the price of the product he/she buys or sells.

The research leading to these results has received funding from the European Union
Seventh Framework Programme under Grant Agreement No 608540.

[MW]. It is assumed that all decisions (investment, retrofitting, mothballing, closure, etc.) are decentralized and made by individual profit maximizing producers who take the prices and transmission capacity as given.[36] Demand d for electricity is assumed to be inelastic and stochastic with a probability distribution function $f(d)$. A fraction $\theta_i \in (0,1)$ of demand is located in node i. Demand in both markets is perfectly correlated. Lastly, consumers have a maximal willingness-to-pay for electricity V. This means that demand equals zero if the price is above this value. The value of served load is assumed to be above c_2, but its value is of no importance here. Table 5.2 shows the numerical values for this illustration:

Table 5.2 Numerical values for the illustration of generator response

$\theta_1 = 0.6$	$V = 500$ €$/MWh$	$d_{max} = 13{,}119\ MW$	$c_1 = 10$ €$/MWh$	$r_1 = 40$ €$/MWh$
$\theta_2 = 0.4$	$f(d) = Elia2013$	$d_{min} = 6{,}016\ MW$	$c_2 = 50$ €$/MWh$	$r_2 = 10$ €$/MWh$

That is, demand in region 1 is 60% of total load. The probability density function of load is hourly 2013 load data of Elia [29]. Maximum load is 13,119 MW, while minimum load is 6,016 MW. The baseload technology in region 1 has a variable cost of 10 and a capital cost of 40 €/MWh; the peak load technology in region 2 has a variable cost of 50 and a capital cost of 10 €/MWh.

Figure 5.3 shows how generation capacity in regions 1 and 2 changes with the perfectly reliable transmission capacity Φ between the two regions. The transmission capacity could change in response to the introduction of a new reliability criterion, either in the short term (a change of the transmission margins) or the long term (building new transmission lines).

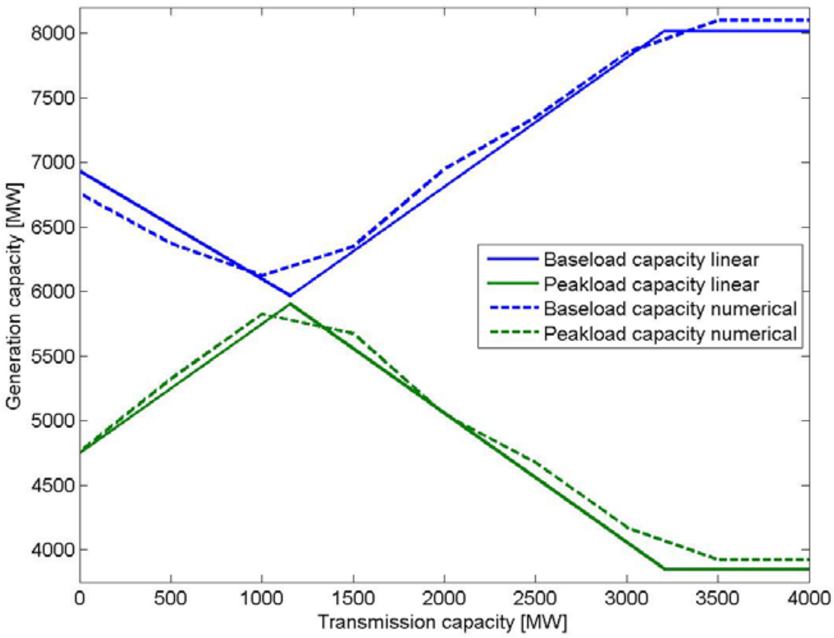

Figure 5.3 Baseload (K_1) and peakload capacity (K_2) as a function of transmission capacity. The dotted line is a numerical simulation based on the real Elia 2013 load-duration curve (LDC); the solid line is a theoretical result from a linear approximation of the real LDC.

The dotted line is a numerical simulation based on the real Elia 2013 load-duration curve (LDC), while the solid line is a theoretical result from a linear approximation of the real LDC. This figure shows that installed

[36] With the current assumption of perfect competition the equilibrium equals the equilibrium attained by a centralized surplus-maximizing decision maker.

The research leading to these results has received funding from the European Union
Seventh Framework Programme under Grant Agreement No 608540.

baseload generation capacity first decreases and then raises with increasing transmission capacity. The reason is that with low transmission capacity the transmission capacity is congested in both directions – from region 1 to 2 for low load levels and from region 2 to 1 for high load levels – while with a higher transmission capacity, the transmission line is only congested from region 1 to region 2 – for low load levels. With a different set-up – e.g. more nodes, more generation technologies or imperfectly correlated demand – the exact shape of generation response will change but generation capacity will still change in the long term in response to changing transmission capacity.

A second result of this illustration is that total socio-economic surplus changes in the long run. The relative? Surplus in the short run [€/h] is always lower than surplus in the long term [€/h]. The reason is that in the long run producers have an additional decision variable to react to a changing transmission capacity. Since the short run is a constrained version of the long run, surplus always increases in the long run. [37]

As already explained in section 3.3.5, the extent of installed and available transmission capacity determines short-run generation costs. Congestion costs represent the increase of generation costs with congested transmission capacity, compared to an uncongested transmission capacity. This section shows that in addition, more transmission capacity allows cheaper electricity production capacity cost in the long run.

To summarize[38], more available transmission capacity increases surplus (excluding transmission investment costs), by allowing:

a) In the short run: cheaper generation cost (less congestion costs)
b) In the long run: cheaper electricity production capacity cost

5.2.2 Strategic response

In reality, producers are not necessarily perfectly competitive. Electricity is generated by a finite – and in some markets, small – number of producers. Therefore, these producers are able to influence somewhat the price of electricity. Possible ways that producers are able to influence the price are:

a) In the short run: bidding above variable cost, withholding generation capacity, collusion, etc.
b) In the long run: postponing new generation investment, mothballing generation capacity, increased schedule outage of certain generation units, raise barriers to entry, etc.

This degree of competitiveness depends on the transmission capacity [30] [31]. For example, if the new probabilistic reliability criterion is less strict than the N-1 reliability criterion, more flow is allowed on transmission lines, which causes regions to converge and thus decrease the number of producers in a geographical market. Similarly, if the new probabilistic reliability criterion is stricter than the N-1 reliability criterion, transmission expansion could be needed to comply with this rule, which also leads to more flow on transmission lines.

[37] Assuming that all environmental costs (see section 3.2.6) are internalized in the generation costs of the producers. That is, profit-maximizing decisions of producers are perfectly aligned with surplus maximization. Producers' profit-increasing reaction to changes in the electricity market then also increase socio-economic surplus.

[38] Apart from these effects there are more channels through which reliability management affect producers' behaviour, mostly depending on the regulation. E.g. participation in reserve markets, participation in capacity markets, whether or not price spikes are allowed.

The research leading to these results has received funding from the European Union Seventh Framework Programme under Grant Agreement No 608540.

5.3 TSO

A TSO is responsible for operating, maintaining and expanding the transmission system. Since an electricity transmission system is a natural monopoly and an unregulated monopolist would be in a position[39] to charge consumers a higher price, wrong quality levels, higher costs and insufficient innovation compared to the economic efficient equilibrium, some form of regulation is required to ensure efficiency.

The regulator is the independent body that represents needs of society, like low prices, right level of quality, cost efficiency and innovation. That is, society wants the monopolistic firm to be efficient in the short- and long-term. [40] On the other hand, the regulator should ensure sufficient remuneration such that the firm is able to perform its task. This is called the long-run financial viability or budget-balance constraint. Reference [33] summarizes this fundamental problem of a regulator to induce a regulated firm to efficient behaviour, while satisfying its long-run financial viability, the “Efficiency-Rent Trade-off”.

The regulation should allow the TSO to collect sufficient revenues to earn a fair rate of return on his investments and that all his costs are remunerated. In general, this is complemented with some form of efficiency and quality regulation in order to incentivize the TSO to carry out its tasks in a cost-efficient way and to maintain a correct reliability level. A TSO regulated in this way has the following profit function:

$$\pi_t = b\left((c_t^* - c_t) + (c_{INT,t}^* - \mathrm{c_{INT,t}})\right) \tag{5.8}$$

Where π_t is the TSO profit in year t, b a measure of the incentive power of the efficiency regulation[41], c_t^* is the justified-cost norm[42], c_t the actual TSO costs in year t, $c_{INT,t}^*$ the norm for interruption costs, and $\mathrm{c_{INT,t}}$ the actual interruption costs in the TSO zone in year t. Appendix B explains in detail how this expression is derived. The justified-cost norms c_t^* and interruption costs norms $c_{INT,t}^*$ are calculated from historical costs of the TSO, a fair rate-of-return, detailed assessment of the cost structure and benchmarking with other TSOs that share similar characteristics.

Equation (5.8) shows that the TSO earns a profit in year t if his network or system costs are lower than the norm, or when the interruption costs are lower than the interruption-cost norm. This section argues that when a new probabilistic reliability criterion and management approach is introduced, the network and system costs c_t and the interruption costs c_{INT} will change, and therefore – since the justified-cost norms are calculated from historical costs, which were incurred under the old deterministic N-1 criterion – the TSO profit will also change. The TSO profit function can thus be written as follows:

$$\pi = b\left((c_{N-1}^* - c_{prob}) + (c_{INT,N-1} - \mathrm{c_{INT,prob}})\right) \tag{5.9}$$

Therefore, when changing to a probabilistic reliability criterion – and with unchanged regulation of TSO remuneration – the TSO’s profit change. In order to get an idea of the order of magnitude of this change,

[39] Consumers have no possibility to choose another firm that supplies the good at a better value-for-money. The leeway is bigger when the firm produces a necessity good like electricity.

[40] In the absence of a natural monopoly (and other imperfect market structures), workable competition will ensure that the social welfare optimum is attained while each individual firm is maximizing its own profit. Competition (the “invisible hand“) drives firms to align their actions with the socially desirable optimum.

[41] Cost-efficiency incentives increase with b: $b \in [0,1]$. The TSO can keep a share b of cost reductions.

[42] Only costs that are subject to efficiency incentives are included in this term. Some costs are considered uncontrollable and are fully remunerated without efficiency incentives e.g. employee benefit costs, transport grid fees for distribution companies, primary control, countertrade costs, etc. [32].

The research leading to these results has received funding from the European Union Seventh Framework Programme under Grant Agreement No 608540.

we used values from an illustration [34] based on a five-node version of the Roy Billinton reliability test system (RBTS). This illustration compares the operational costs and the interruption costs for an N-1 and a probabilistic reliability criterion. The probabilistic criterion minimizes the dispatch costs, the expected corrective redispatch and interruption costs in a first stage (day ahead). In a second stage (real time), the criterion minimizes corrective redispatch and interruption costs. VOLL is 10,200 €/MWh and average load is 165.5 MWh. Results are summarized in Table 5.3.

Table 5.3 Summary of results from an illustration [34] on the RBTS [2].

	Expected redispatch cost	Expected interruption cost
N-1	347.9 €/h	313.4 €/h
Probabilistic	346.2 €/h	264.9 €/h

That is, in this particular illustration expected redispatch costs stay approximately the same but expected interruption costs decrease significantly when changing to a probabilistic reliability criterion. Assuming an incentive power of 0.6 (as in Norway), the resulting TSO profit, expressed in [€/MWh] is:

$$\pi = \frac{0.6}{165.5}\big((347.9 - 346.2) + (313.4 - 264.9)\big) = 0.182\ €/MWh \tag{5.10}$$

That is, under the assumption that the TSO remuneration regulation and interruption probabilities do not change[43], the TSO earns a profit by changing from a deterministic to a probabilistic reliability criterion. The reason is that due to the efficiency and a reliability incentives, a TSO that is able to decrease the sum of TSO costs and interruptions costs – in this case by introducing a new reliability criteria – will be partly rewarded with the gains. Note that this is only an illustration of a five-node test system and thus the exact changes of expected redispatch cost and expected interruption cost, and the resultant profit under the assumed regulation are uncertain.

5.4 The effect of market response on the SEIA

Table 5.4 summarizes the market response of consumers, producers and the TSO to a change of reliability criterion. The third column indicates the consequences of the different market responses.

Table 5.4 Summary of market responses

	Response	Consequence
Consumers	Change of demand or VOSL	Use the price or reliability elasticity of demand or VOSL to incorporate additional consumer surplus due to elastic demand.
	Change of VOLL	Has an effect on interruption costs.
Producers	Competitive response	1) Short-term effect: change of generation costs. 2) Long-term effect: additional change of generation capacity costs.
	Strategic response	Regulation should be transparent so that strategic behaviour is limited.
TSO	Change of TSO revenues and profit	Regulator should ensure sufficient TSO revenues to guarantee correct transmission system operation but should limit excessive TSO profits.

[43] With a growing share of renewables, interruption probabilities may rise. The increase of interruption costs could exceed the efficiency gains from new probabilistic criteria. In that case, the TSO profit is negative and the TSO should be remunerated to satisfy the TSO budget balance.

The research leading to these results has received funding from the European Union
Seventh Framework Programme under Grant Agreement No 608540.

6 MULTI-ACTOR ASPECTS

6.1 Multiple TSOs

In addition to managing transmission system contingencies, the TSO has to deal with imbalances[44] in real time using upward and downward reserves. An important aspect of short-term TSO reliability management is to schedule and procure generation reserves at least cost, while providing sufficient reserves to maintain a high reliability level. Reserves are needed to react to real-time imbalances due to a combination of forecast errors of demand and intermittent supply, and failures of generation capacity or transmission components. This section shows that cooperation between adjacent TSOs on reserves dispatch and procurement reduces this cost.[45]

TSO cooperation can decrease costs of reserves management in at least two ways:

(A) Cost arbitrage: if the reserve market is enlarged, expensive reserves can be substituted for cheaper procurement and dispatch of reserves.
(B) Pooling of reserve needs: less reserve capacity is needed if idle reserve capacity can be used in neighboring TSO zones in need of capacity.

This section employs a probabilistic approach by explicitly incorporating costs and benefits of cross-border reserve procurement. Such an approach is increasingly used to assess the gains and the complexities of probabilistic criteria for transmission reliability management.

Although the topic of integrated balancing markets is present in the literature [35] [36], to the best of our knowledge, there is still a lack of understanding, whether and to what extent TSO reliability management actions and interactions of generation reserves scheduling, as imposed by reliability criteria in network codes, are economically efficient for two TSO zones as a whole. Furthermore, these reliability criteria impose the levels of required reserves and thus determine a certain reliability level, without any reference to balancing the costs of reserves and interruptions.

The probabilistic model, which is explained in appendix C, analytically derives the optimal reliability level and procurement of reserves for different degrees of TSO cross-border cooperation. The optimal level depends on the value of lost load, the probability distribution of reserve needs and the procurement cost. The model shows that each step in the integration of TSO zones results in progressively lower expected reserves and balancing costs, and that the cost reduction from TSO cooperation depends on the asymmetry of procurement costs between TSOs and the degree of correlation of reserve needs.

In compliance with the network codes [37] and [38], we distinguish two degrees of TSO reserves cooperation:

- Exchange of reserves makes it possible to procure part of the required level of reserves in adjacent Load Frequency Control (LFC) blocks. These reserves are exclusively for one TSO, meaning that they cannot contribute to meeting another TSO's required level of reserves. This is an exchange of contractual obligations between TSOs. That is, the reserve capacity remains in the reserve-

[44] Since demand has to equal supply at all times but a perfect forecast of demand and supply is not possible.
[45] There are many other aspects of multi-TSO interaction that could be taken up in further research, e.g. capacity allocation and the implied coordination/arbitration mecanisms.

The research leading to these results has received funding from the European Union Seventh Framework Programme under Grant Agreement No 608540.

providing TSO zone, however, if needs arise the exchange results in physical delivery of power to the reserves-receiving TSO.

- Reserves sharing allows multiple TSOs to take into account the same reserves to meet their reserve requirements resulting from reserve dimensioning.

Exchange of reserves only allows cost arbitrage (A), while reserves sharing allows both cost arbitrage and variance-reducing pooling of reserve needs (A)&(B).

Figure 6.1 summarizes the results of our model. The probability density functions of reserve needs are assumed to be jointly normal with correlation ρ, each with a mean of 10 MW and a variance of 5 MW: N(10,5). The cost of reserve procurement in TSO zone 1 is $\gamma_1(R_1) = c_1 R_1^2$, with $c_1 = 2$. The details of the calculations can be found in appendix C. The x-axis is the ratio of the cost values c_1 and c_2. In the middle of this figure, the cost values are equal and reserve procurement costs are fully symmetric in both zones.

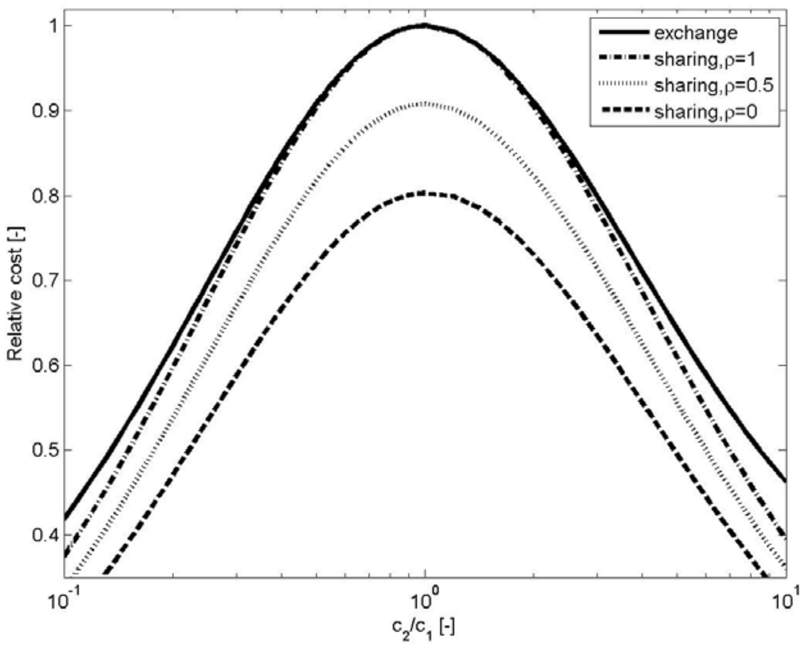

Figure 6.1 Relative cost (compared to autarky) with reserves exchange and reserves sharing, as a function of the cost asymmetry and the correlation ρ between the reserve needs.

This figure shows that the cost reduction increases when the reserve procurement costs become more asymmetric (x-axis) and the reserve needs are less correlated. With high cost asymmetry and low correlation, cross-border cooperation yields a large cost reduction. With low cost asymmetry and low correlation, reserves sharing yields the major part of the cost reduction, while with high cost asymmetry and a high correlation, reserves exchange yields the major part of the cost reduction. With symmetric costs and high correlation, cross-border cooperation in reserves yields very little cost reduction.

6.2 Multiple countries

This section considers the interaction of countries as it relates to reliability. Section 6.2.1 highlights the distributional aspects of reliability already mentioned in Section 6.1. Section 6.2.2 discusses the incentives this creates for countries and possible policy interventions.

The research leading to these results has received funding from the European Union Seventh Framework Programme under Grant Agreement No 608540.

6.2.1 Distributional aspects

This section first revisits the distributional consequences of an interconnector. We consider a simple example where a low-cost country and a high-cost country – previously unconnected – are connected by an interconnector. Demand and supply in the low-cost country and the high-cost country prior to connection are illustrated by the curves in the left-hand and right-hand panel of Figure 6.2, respectively (prices/costs are on the vertical axes and quantities on the horizontal axes). When the two countries are connected, export demand will shift the demand curve in the low-cost country up (i.e. to the right). Conversely, demand in the high-cost country shifts down by the corresponding imports. The market price of electricity – determined by the intersection of demand and supply – rises in the low-cost country, but falls in the high-cost country.

In the low-cost exporting node (left-hand panel) producer surplus increases by A+B+C and consumer surplus decreases by A+B. In the high-cost importing node (right-hand panel) consumer surplus increases with D+E+F and producer surplus decreases by D. There is a net gain of producer surplus of C and consumer surplus of E+F. Since there is still congestion and a difference in market prices between the two countries, there is also an economic gain for the owners of the transmission capacity equal to the traded volume times the difference in prices after the interconnector is installed.

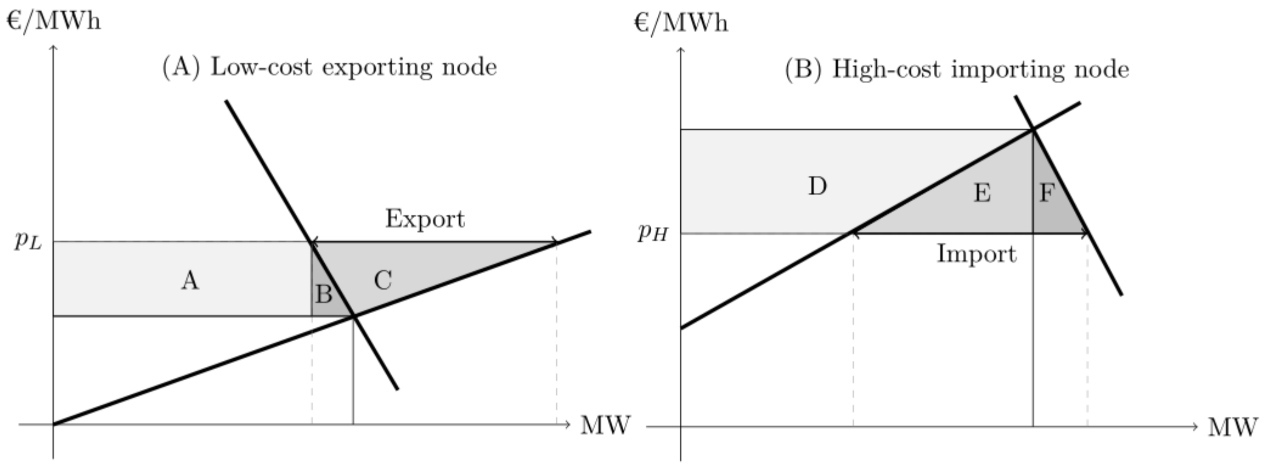

Figure 6.2 Producer and consumer surplus after an investment in transmission capacity [39].

Given that the investment cost of the interconnector does not exceed the combined increase in surplus the overall effects of the interconnector are positive. There are, however, distributional effects: in the low cost country producers gain and consumers lose while in the high-cost country the opposite distributional effects are obtained.

This example shows the effects of a new interconnector. Changes in reliability criteria, which allow for more trade between regions on average – e.g. by relaxing the N-1 criterion – may have qualitatively similar effects on prices, surplus and congestion costs as a new interconnector. Such changes may have corresponding distributional implications as outlined for the interconnector example.

Interconnection of countries will, in general, have implications for TSO operations within each country. One implication, pointed out by [40] is that an increase in transmission capacity between countries may increase congestion within price zones in the individual countries. For example, in the low-cost country of Figure 6.2, if substantial production is located in an area with limited transmission capacity to the border, then higher cross-border transmission capacity will create or exacerbate congestion within that country. This may necessitate counter-trading and operational costs for the TSO. A lower capacity on transmission capacity across the border, on the other hand, may lead to increased profits for the TSO, since the price

The research leading to these results has received funding from the European Union
Seventh Framework Programme under Grant Agreement No 608540.

difference between the two countries will increase. It may be noted here that typically each TSO suggests what cross-border capacity is available and it is the lower value which prevails.

Interconnection of countries also allows for cooperation as regards reliability. An example is provided by cooperation on reserves procurement discussed in Section 6.1. As shown there, reserves exchange, with unchanged reliability criteria in each country, will yield lower costs of procuring reserves overall as long as the two countries are asymmetric in terms of reserves procurement technology. This gain arises in the same way as increased net producer surplus in the example above. Analogously, the gain will be distributed in an asymmetric way : producers in the low-cost country will gain while those in the high-cost country will lose. Since – according to network codes – reliability criteria are unaffected by cooperation on reserves procurement, consumers are not affected by that measure. There may, however, be spill-over effects on other electricity markets within the two countries leading to asymmetric impacts for consumers (this is not modelled in Section 6.1).

Progressive steps towards increased cooperation/integration of countries in terms of reserves procurement lead to higher gains. Full cooperation, where the two countries are effectively treated as one zone – pooling reserve needs and procuring reserves jointly – will yield the largest overall gains. Apart from the implications for producers, the relative reliability levels in each country may then also change, the low-cost country decreasing, and the high-cost country increasing, the reliability level. Pooling reserve needs, however, reduces overall reserve needs –the lower the correlation in demand between the two countries, the larger will be the gain. This in itself may in the end suffice to improve reliability in both countries. It may be conjectured that these results can be extended to other aspects of cooperation on reliability.

6.2.2 Strategic behaviour

As noted in the previous section, changes to reliability criteria may have an impact on available interconnector transmission capacity. This may in turn lead to distributional effects where the various stakeholders win or lose. This generates different incentives:

- Producers in low-cost countries and consumers in high-cost countries have an incentive to increase exports while producers in high-cost countries and consumers in low-cost countries have the opposite incentives. Consumers will typically follow these incentives by exerting domestic political pressure and producers will lobby for a favorable decision. With sufficiently strong political pressure, e.g. by organized interests, such pressure may suffice to prevent expansion of cross-border transmission capacity.
- Similar incentives are created by cooperation on reliability management. For example, while reserves exchange with unchanged reliability criteria will – at least in the first instance – only affect producers, reliability may be negatively affected for consumers in a country with a high degree of reliability by reserves sharing as reserve needs are pooled. If reserve needs in the countries are weakly correlated the gains from lower reserve needs may, however, be sufficiently large to improve reliability for both countries. These incentives are therefore likely to be less important than those relating to the direct price effects of increased cross-border capacity.
- When there is potential for inter-country congestion, TSO's may have an incentive to reduce announced cross-border transmission capacity, effectively moving congestion to the border [40]. If TSO's are penalized for service interruptions within their countries, they may have similar incentives as regards reliability, i.e. to reduce announced cross-border capacity to prevent reliability from falling within their country.

It should be stressed here that these are economic incentives, not predictions of actual behaviour. At the domestic level inefficient behaviour can be checked by improved regulation and/or redistribution between parties (e.g. from winning producers to losing consumers) so that the main stakeholder groups are not worse off than before. At the European level this can be done by agreements and network codes. It is,

The research leading to these results has received funding from the European Union
Seventh Framework Programme under Grant Agreement No 608540.

however, unlikely that a stable consensus can be achieved on any arrangement that makes one country worse off. It is therefore important to design agreements and network codes in such a way that they are *incentive compatible*. This will typically involve side payments in some form from countries that gain to countries that lose.

6.3 Multiple consumers

6.3.1 Distributional aspects and fairness

Introducing new reliability criteria could change prices and reliability levels (e.g. look at Table 5.3). The previous section showed that this has a distributional effect on a national level. This section discusses the distributional effects on different consumer types and different consumer locations.

A reliability criterion that explicitly incorporates total socio-economic surplus, as compared to the deterministic N-1 reliability criterion which does not, and strives for economic efficiency, could clash with universal reliability of electricity supply. First, for consumers in less densely populated and remote areas, if costs to maintain a high reliability level are very high, it may make economic sense to provide a low level of reliability. Second, it is economically efficient to disconnect consumers with the lowest VOLL first, in case of interruptions or load-shedding.

The consideration of "economic efficiency vs. universal reliability" is a normative one and at the heart of many economic and political discussions: should society oblige everyone to pay his own social cost of production?; do we allow for distributional transfers?; do we provide a minimum reliability level to all consumers?; do we address socio-economic inequality within the electricity system ("energy poverty") or do we leave this to other instruments like the income tax or a two part electricity tariff ?[46]

Assuming that a new reliability criterion increases socio-economic surplus, we have some leeway in addressing the distributional effects resulting from this new criterion. The following two sections explain the distributional effects in more detail, and show how to address them in reliability management.

6.3.2 Different consumer locations

Suppose a country has two distinct regions (North and South) for which costs differ substantially. For example, assume the following two cost functions[47] C_i, that represent the cost to provide a certain reliability level ρ_i in region i:

$$C_N = \frac{0.02}{1-\rho_N} \quad \& \quad C_S = \frac{0.005}{1-\rho_S} \tag{6.1}$$

[46] In economic theory, it has been shown that addressing income inequality can be addressed more efficiently via progressive income taxes than by distorting the prices of consumption products [42].There is one exception: when the distortion of the consumer price of a good increases or decreases labour supply. The same principle holds for the pricing of electricity supply to different regions. Pricing electricity at a lower rate than the marginal cost is a second best strategy because the interpersonally inequality is usually much larger than the interregional inequality. So it is better to help the poor via income taxes than to help the poor and the rich in the region with lower average income.

[47] This specific functional form is chosen for illustrative purposes. The cost functions only allow qualitative conclusions. However, they are a good example of what you would expect such a curve to look like: costs are increasing convex and reaching infinity for a 100% reliability system.

The research leading to these results has received funding from the European Union Seventh Framework Programme under Grant Agreement No 608540.

That is, costs are four times higher in the Northern region. These cost functions include all costs, net of congestion rent, to reach a certain reliability level: building lines, maintenance, personnel, vegetation management, reliability margins, corrective and preventive actions, congestion costs, etc.

The reliability level ρ_i is $\in [0,1]$ and defined as:

$$\rho_i = \frac{total\ demand_i - expected\ energy\ not\ supplied_i}{total\ demand_i}\rho_i \tag{6.2}$$

If $VOLL$ (V) is the same in both regions and equal to 5000 €/MWh, the optimal reliability level is:[48]

$$\rho_N^* = 1 - \left(\frac{0.02}{V}\right)^{0.5} = 0.998 \quad \& \quad \rho_S^* = 1 - \left(\frac{0.005}{V}\right)^{0.5} = 0.999 \tag{6.3}$$

That is, due to the higher cost in the North, optimally one should provide a lower reliability level. Figure 6.3 shows these reliability cost curves and the resulting optimal reliability levels. The interruption cost is ρV.

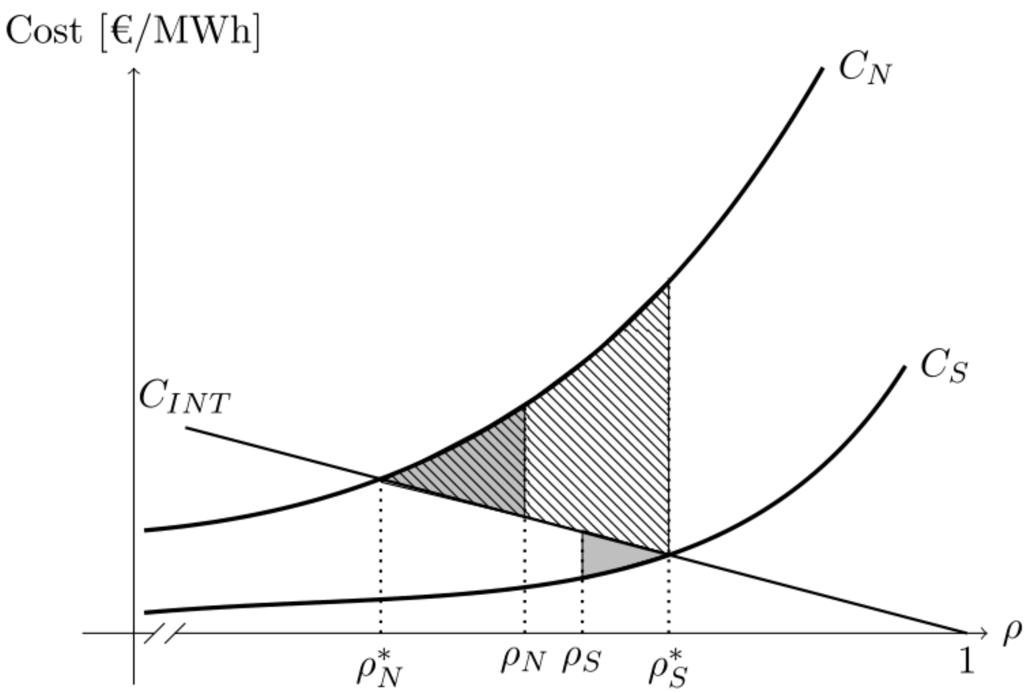

Figure 6.3 The optimal reliability level ρ_i^* in North and South, determined from reliability costs C_i and interruption costs $C_{INT} = \rho V$.

Let us now compare this optimal probabilistic criterion, which correctly trades off all costs and benefits, with a deterministic N-1 reliability criterion. Suppose that the N-1 criterion yields a reliability level of 0.9985 in North and a slightly higher reliability level of 0.9987 in South. Using reliability cost functions (6.1) and the interruption cost function $(1-\rho)V$, we can calculate the reliability cost C_i, the interruption cost, the total cost per region, as well as the uniform transmission tariff TT needed to remunerate all reliability costs. Suppose that 10% of the country's electricity consumption is located in the expensive Northern region. The first two rows of Table 6.1 show the values for the N-1 and the probabilistic criterion.

[48] The optimal reliability level minimizes the sum of interruption costs $(1-\rho)$V and the cost of providing the reliability $C(\rho)$: $\min_{\rho}\ \{(1-\rho)V + C(\rho)\}$ -> $\rho_N V = \frac{0.02}{(1-\rho_N)^2}$.

The research leading to these results has received funding from the European Union
Seventh Framework Programme under Grant Agreement No 608540.

Table 6.1 Illustrative comparison of costs for two regions i (North and South) for five reliability criteria: (1) N-1, (2) probabilistic, (3) probabilistic with Pareto in costs, (4) probabilistic with Pareto in reliability level, and (5) probabilistic with a minimum reliability level ρ_{min}= 0.999. C_i= reliability cost in region i, TT=transmission tariff=average TSO cost, $C_{INT,i}$=interruption cost, TC_i=total cost for a consumer in zone i, ATC=average total cost [€/MWh].

		ρ_N	ρ_S	C_N	C_S	TT	$C_{INT,N}$	$C_{INT,S}$	TC_N	TC_S	ATC
(1)	N-1	0.9985	0.9987	13.3	3.85	4.8	7.5	6.5	12.3	11.3	**11.4**
(2)	Prob.	0.998	0.999	10	5	5.5	10	5	15.5	10.5	**11**
(3)	Pareto C	0.998	0.999	10	5	2.3/5.9	10	5	12.3	10.9	**11**
(4)	Pareto ρ	0.9985	0.999	13.3	5	5.8	7.5	5	13.3	10.8	**11.1**
(5)	ρ_{min}	0.999	0.999	20	5	6.5	5	5	11.5	11.5	**11.5**

(1) and (2): These rows shows that the average total cost (ATC), including reliability costs and interruption costs, is lower for the probabilistic reliability criterion (11 compared to 11.4 €/MWh). However, total cost for Northern consumers increases steeply, due to an increased transmission tariff (which we assume to be equal throughout the country) and increased interruption costs, while total cost for Southern consumers decreases. Therefore, Northern consumers will dislike the change to this probabilistic reliability criterion. The increased cost of the deterministic criterion compared to the probabilistic criterion is represented by the two grey triangles in Figure 6.3.

(3) To make the change of reliability criterion acceptable for both regions, i.e. to make it a Pareto improvement by ensuring that no single consumer's cost increases, the transmission tariff for Northern consumers should decrease to 2.3 €/MWh. In response, the transmission tariff for Southern consumers should increase to 5.9 €/MWh. This makes the change Pareto optimal without increasing average total cost. However, this could raise opposition from Southern consumers since Northern consumers with higher costs now pay lower transmission tariffs.

(4) Another option is to make the change Pareto in terms of the reliability level. That is, explicitly imposing the restriction that no single consumer's (or consumer group's) reliability level decreases. However, this constraint comes with an additional rise in average total cost (11.1 €/MWh compared to 11 €/MWh).

(5) A last option is to provide a minimum reliability level to all consumers. As an example, suppose that this minimum level is ρ=0.999. However, this minimum level increases reliability costs and thus the uniform transmission tariff. In addition, the option is neither a Pareto improvement, nor a welfare improvement in this illustration. The additional cost to provide a high, and costly, reliability level to the Northern consumers is represented by the hatched area in Figure 6.3.

All five options entail a large transfer from Southern consumers to expensive Northern consumers. Expensive Northern consumers don't pay the full cost of their electricity provision, but are subsidized by the less expensive Southern consumers. This is, of course, an issue regardless of the change of reliability criterion and should be decided by the regulator based on a nation's preferences.

Figure 6.4 shows the System Average Interruption Duration Index (SAIDI)[49] for different Norwegian regions. This figure shows that the reliability level is not equal throughout the country. The reliability level differs in

[49] This is the average duration of interruption at the consumer location. This measure combines outages stemming from outages in all voltage levels, not only the high-voltage transmission system.

The research leading to these results has received funding from the European Union Seventh Framework Programme under Grant Agreement No 608540.

function of geography (e.g. soil type, number of trees in the vicinity), weather (e.g. lightning), population density (the number of lines), etc.

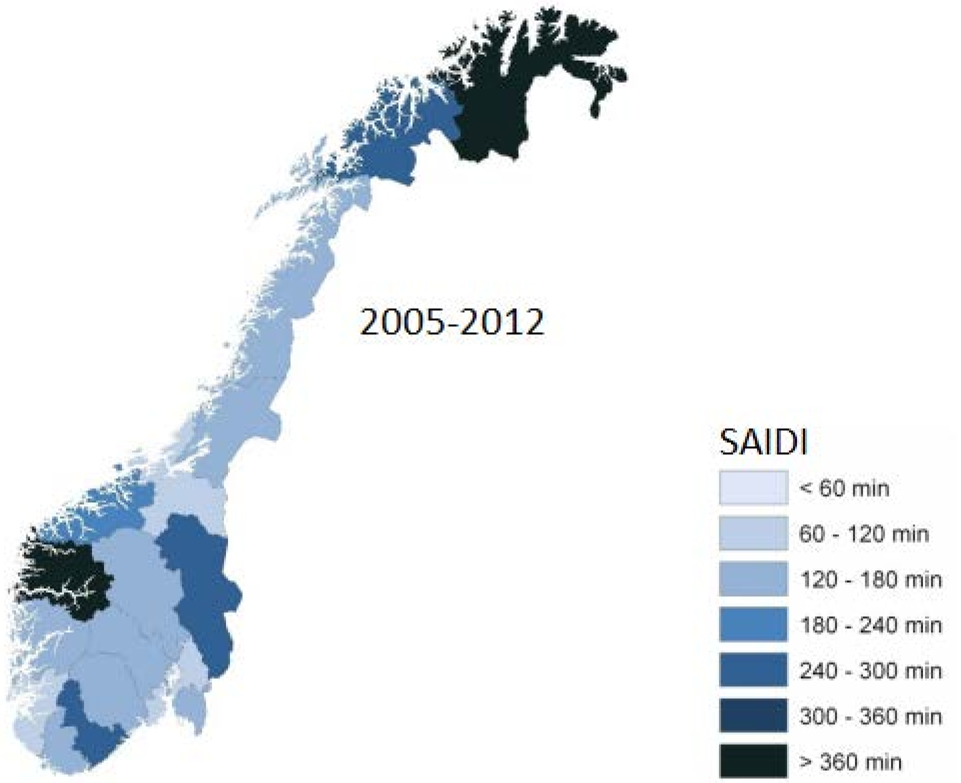

Figure 6.4 SAIDI (2005-2012) for different regions in Norway [42].

6.3.3 Different consumer types

The effects discussed in the above section are also present in the context of different consumer types. As an illustration, assume that a country consists of residential consumers and industrial consumers. Table 3.4 shows that their VOLL is:[50]

$$V_R = 1160\ €/MWh \qquad \& \qquad V_I = 9860\ €/MWh$$

That is, interruptions are costlier for industrial than for residential consumers. Suppose that the reliability cost C equals $\frac{0.005}{1-\rho}$ for all consumers in the country, as in the illustration above. Similar to (6.3), the optimal reliability level for residential and industrial consumers is:

$$\rho_R^* = 1 - \left(\frac{0.005}{1160}\right)^{0.5} = 0.9979 \quad \& \quad \rho_I^* = 1 - \left(\frac{0.005}{9860}\right)^{0.5} = 0.9993 \qquad (6.4)$$

Assuming that the share of residential consumers is 55.9% and the share of industrial consumers is 44.1%, the average VOLL is 5000 €/MWh. Suppose the regulator imposes an average required reliability level of 0.999[51] and compare two cases: random load-shedding and perfect load-shedding (both costless). With random load-shedding the TSO is unable to choose which consumers to interrupt or does not know the

[50] Assuming no differentiation according to duration, moment of interruption or advance notification, as in Table 3.3.
[51] Note that this is not the optimal reliability level in this illustration

$VOLL$ of different consumers, while with perfect load-shedding the TSO is able to interrupt those consumers with the lowest $VOLL$ first.

Table 6.2 shows the difference in average total cost between random and perfect rationing. This table shows that average total cost is lower with perfect rationing. That is, the TSO can reduce cost of interruptions if he is able to interrupt low VOLL residential consumers instead of high VOLL industrial consumers. However, this strategy causes interruption costs to increase for residential consumers. A solution, as explained earlier, is to decrease transmission tariffs for this consumer group.

Table 6.2 Difference in average total cost [€/MWh] and distribution of costs between random load-shedding and perfect load-shedding.

	ρ_R	ρ_I	IC_R	IC_I	TT	TC_R	TC_I	ATC
Random	0.999	0.999	1.16	9.86	5	6.16	14.86	10
Perfect	0.9982	1	2.1	0	5	7.1	5	6.2

The research leading to these results has received funding from the European Union
Seventh Framework Programme under Grant Agreement No 608540.

7 FINDINGS

The aim of this report is to formulate and illustrate the socio-economic impact assessment (SEIA) methodology with and without market response. The SEIA methodology is based on social welfare analysis of the electricity market and allows to quantify the costs, benefits, and surplus of all market stakeholder groups: electricity consumers, electricity producers, the TSO, the government surplus from taxes on electricity and environmental surplus from electricity-related externalities. The methodology details how to calculate interruption costs, TSO costs, producer costs, environmental costs, and congestion costs on different time horizons. TSO decisions within a certain area can influence surpluses of stakeholders in other areas so geographical scope also needs to be taken into consideration; all areas significantly affected should be included in the SEIA.

In the surplus analysis, it is important to distinguish costs borne by the entire analysed system (e.g. fuel costs and investment costs) from transfers between stakeholders (e.g. transmission tariffs and compensation for interruptions). While such transfers will affect the surplus or balance of different stakeholders, if aggregated they cancel out and do not affect net socio-economic surplus. The details of transfer payments and the accompanying transfer of services depend on the regulation in place in the TSO zone.

Socio-economic surplus or system surplus is defined as the sum of consumer surplus (or balance), producer surplus, TSO surplus and government surplus.

- Consumer surplus is defined as consumer benefit less interruption costs, electricity payment – a transfer to producers – and transmission tariff payments – a transfer to the TSO – plus other transfers. The report specifies and illustrates how to assess interruption costs – depending on data availability – as a function of consumer type, location, time and duration of interruption and whether or not the interruption was notified in advance.
- Producer surplus is defined as electricity payments less costs of fuel, investment, operation and maintenance and costs related to the environment plus other transfers.
- TSO surplus is defined as transmission tariff payments less monetized electricity losses, costs of operation, maintenance and investment plus other transfers.
- Government surplus is defined as revenues from value-added tax on electricity consumption.

In a general mathematical formulation, these definitions are given for different nodes, generation technologies, consumer types, time and duration of interruptions, and pollutants. The report also illustrates how to apply the SEIA to a numerical test system, based on the Roy Billinton Test System (RBTS). To illustrate multi-country aspects, the RBTS is adapted to a two-country setting. The illustration is done in each GARPUR time frame:

1. The short-term time frame of operational planning and system operation, with the illustrative decision of how much cross-border transmission capacity to give to the market.
2. The medium-term time frame of asset management, with the illustrative decision of whether to schedule an outage in winter or summer.
3. The long-term time frame of system development, with the illustrative decision of whether to build an additional cross-border line.

The SEIA allows for evaluation of benefits, costs and surplus of all electricity market stakeholders and can be used to compare socio-economic surplus between different reliability criteria. The methodology implicitly assumes that behaviour of market stakeholders is constant, i.e. does not change with changing market variables such as the reliability level, electricity prices and taxes. However, the report extends the

The research leading to these results has received funding from the European Union
Seventh Framework Programme under Grant Agreement No 608540.

SEIA by providing an analysis of possible responses of electricity market stakeholders to changing such market variables. It is shown how these market responses could be integrated in the SEIA, in which behaviour of all market stakeholders is assumed to be constant. When considering possible responses of electricity market stakeholders (consumers, producers, TSO and government) to changing market variables we have concluded the following:

- The response time matters: in the short time it is more difficult to change behavior, in the long time market participants can adjust their behavior to changed market conditions.
- The demand response is expected to increase in the future due to the introduction of smart meters and smart appliances. This mainly shifts demand to other hours and so increases the real-time term price elasticity of demand, not the short- or long-term elasticity.
- Value of served load v and value of lost load V can also change with the price or reliability level. When demand increases or decreases in response to a changing price or reliability level, the remaining demand will have a different value of load.
- When prices change, producers' behavior changes too and both average prices and distribution of prices will affect investment.
- The total socio-economic surplus changes in the long run, compared to the short run, as producers need to react to a new variable – changing transmission capacity.
- Available transmission capacity increases interconnection surplus in the short run as there is less congestion therefore generation costs are lower., but at the expense of a higher expected redispatch and interruption cost.
- More available transmission capacity reduces congestion costs even more in the long run through cheaper electricity production capacity cost.
- TSO profits will change when the new reliability criteria are implemented.

Finally, the report considers multi-actor aspects and analyses the interaction of multiple TSOs and multiple countries, and the effects on welfare. Furthermore, we assess distributional welfare effects of introducing new reliability criteria and discuss fairness of distributional transfers. Three types of interactions are distinguished: between multiple TSOs, multiple countries and the distributional effect on different consumers. Multiple TSOs through cross-border cooperation on reserves can increase the reliability of the grid and decrease costs related to reliability issues as compared to the situation when TSOs in the neighbouring countries do not cooperate on reserves. In case of multiple countries, changes to reliability criteria may have an impact on available interconnector transmission capacity and therefore the distributional aspects are of primary importance as they create different incentives.

- Producers in low-cost countries and consumers in high-cost countries have an incentive to increase exports while producers in high-cost countries and consumers in low-cost countries have the opposite incentives.
- Similar incentives are created by cooperation on reliability management. For example, while reserves exchange with unchanged reliability criteria will – at least in the first instance – only affect producers, reliability may be negatively affected for consumers in a country with a high degree of reliability by reserves sharing as reserve needs are pooled. If the countries are not too correlated the gains from lower reserve needs may, however, be sufficiently large to improve reliability for both countries. These incentives are therefore likely to be less important than those relating to the direct price effects of increased cross-border capacity.
- When there is potential for inter-country congestion, TSO's may have an incentive to reduce announced cross-border transmission capacity, effectively moving congestion to the border. If TSO's are penalized for service interruptions within their countries, they may have similar

The research leading to these results has received funding from the European Union
Seventh Framework Programme under Grant Agreement No 608540.

incentives as regards reliability, i.e. to reduce announced cross-border capacity to prevent reliability from falling within their country.

Introduction of new reliability criteria may change prices and reliability levels and could have distributional effects on different consumer types and different consumer locations, depending on the implementation chosen.

- Reliability levels of the power grid and thus also its cost vary according to geographical location, weather, population density etc.
- Change of the reliability criterion will come at a cost for some consumers and as an advantage for others. Therefore, its acceptability will differ in the regions.
- Limits on the reliability level, e.g. a minimum reliability level for different consumer locations and different consumer types, increase fairness but at the expense of efficiency.

The research leading to these results has received funding from the European Union
Seventh Framework Programme under Grant Agreement No 608540.

8 REFERENCES

[1] GARPUR Consortium, GARPUR – Generally Accepted Reliability Principle with Uncertainty modelling and through probabilistic Risk assessment 2013, EU Commission.

[2] R. Billinton, S. Kumar, N. Chowdhury, K. Chu, K. Debnath, L. Goel, E. Khan, P. Kos, G. Nourbakhsh, and J. Oteng-Adjei, "A reliability test system for educational purposes-basic data," Power Systems, IEEE Transactions on, vol. 4, no. 3, pp. 1238–1244, 1989.

[3] BSI British Standard Institution. PAS 55-1: Asset Management. Part 1: Specification for the optimized management of physical infrastructure assets, The Institute of Asset Management, British Standards Institution.

[4] ENTSO-E. Continental Europe Operational Handbook G Glossary. Originally a UCTE document but now available at: https://www.entsoe.eu/publications/system- operations-reports/operation-handbook/

[5] ENTSO-E. Network Code on Operational Planning and Scheduling. 24 September 2013. Available at: https://www.entsoe.eu/major-projects/network-code-development/operational-planning-scheduling/

[6] GARPUR, "D4.1 A functional analysis of the System Development decision making process," 7th Framework Programme, EU Commission Grant Agreement 608540, 2015.

[7] IEC International Electrotechnical Commission. Electropedia: The World's Online Electrotechnical Vocabulary. Available at: http://www.electropedia.org/.

[8] ENTSO-E. Supporting Document for the Network Code on Operational Security. Available at: https://www.entsoe.eu/fileadmin/user_upload/_library/resources/OS_NC/130924- AS-NC_OS_Supporting_Document_2nd_Edition_final.pdf.

[9] ENTSO-E. Guideline for Cost Benefit Analysis of Grid Development projects. 14 November 2013. Available at: https://www.entsoe.eu/Documents/SDC%20documents/TYNDP/ENTSO-E%20cost%20 benefit%20analysis%20approved%20by%20the%20European%20Commission%20on%204%20February%202015.pdf

[10] CEER, 5th Benchmarking Report on the Quality of Electricity Supply, 2011.

[11] A. Smith, "An Inquiry into the Nature and Causes of the Wealth of Nations," in Library of Economics and Liberty, vol. 5th edition, Edwin Cannan, ed., 1776.

[12] M. Hofmann, H. Seljeseth, G. H. Volden and G. H. Kjølle, Study on Estimation of Costs due to Electricity Interruptions and Voltage Disturbances, 2010.

[13] L. Bjørk, E. Bowitz, C. Seem, U. Møller, G. Kjølle, M. Hofmann and H. Seljeseth, "Socio-economic costs of interruptions and voltage disturbances. Implications for regulation," Energy Norway, 2012.

[14] C. Growitsch, R. Malischek, S. Nick, H. Wetzel, „The Costs of Power Interruptions in Germany: an Assessment in the Light of the Energiewende," EWI Working Papers No. 13/07, 2013.

[15] P. Wang, and R. Billinton. "Reliability cost/worth assessment of distribution systems incorporating time-varying weather conditions and restoration resources." IEEE Transactions on Power Delivery, Vol. 17, No. 1, 2002.

[16] GARPUR, "D5.1 Functional analysis of Asset Management processes," 7th Framework Programme, EU Commission Grant Agreement 608540, 2015.

[17] GARPUR, "D6.1 Functional analysis of System Operation processes," 7th Framework Programme, EU Commission Grant Agreement 608540, 2015.

[18] D.P. Baron, and R.B. Myerson, "Regulating a Monopolist with Unknown Costs." Econometrica 50 (4): 911–930,1982.

[19] P. Buijs, D. Bekaert, D. Van Hertem, R. Belmans, "Needed investments in the power system to bring wind energy to shore in Belgium," PowerTech, 2009 IEEE Bucharest. IEEE, 2009.

[20] European Commission, "VAT Rates Applied in the Member States of the European Union." Taxud.c.1(2015)

[21] ENTSO-E, "TSO Cooperation and the Internal Energy Market," 2013. [Online]. Available: https://www.entsoe.eu/Documents/Publications/ENTSO-

The research leading to these results has received funding from the European Union Seventh Framework Programme under Grant Agreement No 608540.

E%20general%20publications/140415_ENTSO-E_Annual_Report_2013_Final.pdf. [Accessed 18 November 2015].
[22] M.A. Bernstein, and J.M. Griffin, “Regional differences in the price-elasticity of demand for energy,” National Renewable Energy Laboratory, 2006.
[23] C. Dahl, “A Survey of Energy Demand Elasticities in Support of the Development of the NEMS,” Paper prepared for United States Department of Energy, Contract De-AP01-93EI23499, 1993
[24] M. Beenstock, E. Goldin, D. Nabot, “The demand for electricity in Israel,” Energy Economics 21, 168–183. 1999
[25] P. Holtedahl, F.J. Loutz, “Residential electricity demand in Taiwan,” Energy Economics 26, 201–224, 2004
[26] Y.D. Caloghirou, A.G. Mourelatos, H. Thompson, “Industrial energy substitution during the 1980s in the Greek economy,” Energy Economics 19, 476–491, 1997.
[27] M.G. Lijesen, “The real-time price elasticity of electricity,” Energy economics, 29.2: 249-258, 2007.
[28] R.H. Patrick, and F. A. Wolak, “Estimating the customer-level demand for electricity under real-time market prices,” No. w8213. National Bureau of Economic Research, 2001.
[29] http://www.elia.be/nl/grid-data/data-download
[30] J.B. Cardell, C.C. Hitt, and W.W. Hogan, “Market power and strategic interaction in electricity networks, “ Resource and Energy Economics, 19(1-2), 109–137, 1997.
[31] B. Willems, “Modeling Cournot Competition in an Electricity Market with Transmission Constraints,” The Energy Journal, 23(3), 95–125, 2002.
[32] NordREG, “Economic Regulation of TSOs in the Nordic Countries,” 2012.
[33] J.J. Laffont, J. Tirole, “A theory of incentives in procurement and regulation,” MIT press, 1993.
[34] E. Heylen, G. Deconinck, and D. Van Hertem,“Impact of Value of Lost Load on Performance of Reliability Criteria and Reliability Management,” 2015
[35] L. Vandezande, M. Saguan, L. Meeus, J.M. Glachant and R. Belmans, ”Assessment of the implementation of cross-border balancing trade between Belgium and the Netherlands”, 6th International Conference on the European Energy Market, EEM 2009, 2009.
[36] A.F. van der Weijde, and B.F. Hobbs, ”Locational-based coupling of electricity markets: benefits from coordinating unit commitment and balancing markets”, Journal of Regulatory Economics, 39(3), 2011.
[37] ENTSO-E, ”Network Code on Electricity Balancing”, 2013.
[38] ENTSO-E, ”Network Code on Load-Frequency Control and Reserves”, 2013.
[39] R. Turvey, ”Interconnector economics”, Energy Policy, 34(13), 1457–1472, 2006.
[40] J.M. Glachant, and V. Pignon, ”Nordic congestion’s arrangement as a model for Europe? Physical constraints vs. economic incentives”, Utilities Policy, 13(2 SPEC. ISS.), 153–162, 2005.
[41] B. Jacobs, and R. Boadway. "Optimal linear commodity taxation under optimal non-linear income taxation," *Journal of Public Economics* 117: 201-210, 2014.
[42] NVE, Avbrotsstatistikk 2013, NVE Rapport nr 74, 2014. (in Norwegian)
[43] R. Billinton, “Methods to Consider Customer Interruption Costs”, task force 38.06.01 Cigré, 2001.
[44] GARPUR, “D1.1 State of the art on reliability assessment in power systems,” 7th Framework Programme, EU Commission Grant Agreement 608540, 2014.
[45] G. H. Kjølle, K. Samdal, B. Singh and O. A. Kvitastein, “Customer Costs Related to Interruptions and Voltage Problems: Methodology and Results,” Power Systems, IEEE Transactions on, vol. 23, no. 3, pp. 1030-1038, 2008.
[46] London Economics, “The Value of Lost Load (VoLL) for Electricity in Great Britain,” July 2013. [Online]. Available: https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/224028/value_lost_load_electricty_gb.pdf.
[47] CEER, “Guidelines of Good Practice on Estimation of Costs due to Electricity Interruptions and Voltage Disturbances”, 2010.
[48] EY, “Mapping Power and Utilities Regulation in Europe,” 2013.

The research leading to these results has received funding from the European Union
Seventh Framework Programme under Grant Agreement No 608540.

APPENDIX A METHODS FOR ESTIMATING INTERRUPTION COSTS

A variety of methods have been utilized to obtain empirical estimates of costs due to electricity interruptions. These methods can be grouped into three broad categories [43], see also D1.1 [44]:

- Indirect analytical evaluations
- Case studies of blackouts
- Customer surveys (Direct worth and stated preference).

Among these, customer survey methods are the most common approaches to estimate costs of interruptions. The state of the art on survey methodologies is presented in [12],[45] and advantages and disadvantages of the different methods are discussed. An overview of recent surveys is also given, showing the methods applied. The direct worth (DW) method is the dominating method used for Industry and Commercial services, whereas the stated preference methods "contingent valuation" and "conjoint analysis" are the dominating methods for Households. In the direct worth methods, the customers are asked to estimate their cost of hypothetical interruption scenarios of different duration, seasons, days of the week and times of the day, etc. The costs are estimated in terms of lost production, costs for making up production, damage to equipment and raw material, etc. Stated preference methods measure the willingness to pay (WTP) to avoid, or willingness to accept (WTA) a compensation for, hypothetical interruption scenarios. WTA estimates are typically quite close to the DW estimates but significantly larger than WTP estimates, see e.g. [45], [46]. For example, the ratio of DW/WTP cost estimates varied in the order of 2-12, depending on customer group in the study reported in [45].

The different methods cover different parts of the total socio-economic costs of interruptions, and the appropriateness of the methods vary by customer category. For instance, the Direct worth method measures the monetary part of the Private customer costs. The Contingent valuation and Conjoint analysis methods on the other hand, measure in principle the total private costs (both monetary and non-monetary). In general, the survey methods do not cover the net costs to the rest of society (with a few exceptions where third party costs are covered to some extent). Often in customer surveys, different methods are utilized for cross-check, reducing disadvantageous effects such as strategic response, etc., but also due to the suitability of the methods to cover different aspects. Another advantage is that the use of different methods gives a possible range of the private customer costs, if it is hard to come up with a single cost. Cost estimates revealed based on different methods are often presented together, or they may be combined to obtain single cost estimates. For instance, the Norwegian survey in 2002, provided cost data as a function of both DW and WTP for all categories [45]. In the Norwegian survey in 2010, only DW or WTP was used, depending on customer category. The new regulation from 2015 uses the cost data from the latest survey [13].

In a recent study in UK, the term VOLL is used instead of interruption costs [46]. Here, a stated preference choice experiment (Conjoint analysis method) is used to estimate VOLL in terms of WTA and WTP depending on customer category and type of interruption. This study also used a variety of methods, depending on customer category and for purposes such as mentioned above.

The study reported in [12] provided the basis for the Council of European Energy regulators' Guidelines of Good Practice on Estimation of Costs [48].

The research leading to these results has received funding from the European Union
Seventh Framework Programme under Grant Agreement No 608540.

APPENDIX B THE TSO PROFIT FUNCTION UNDER EFFICIENCY AND QUALITY INCENTIVES

At the two extremes of the regulatory spectrum we have “cost-plus” and “revenue cap” regulation. Historically, the dominant method of regulating TSOs has been cost-plus regulation. Regulators allowed full remuneration of all costs of the (then vertically-integrated) utilities, plus a fair rate of return, by use of regulated transmission tariffs. Currently, most regulators have switched or are in the process of switching to regulation without a full cost pass-through. This means that part of the remuneration is decoupled from actual costs. For this part, the regulator determines the justified costs, i.e. the cost that an efficient TSO needs to manage its grid, pay for transmission services, asset remuneration, depreciation, etc. The justified cost norm is based on historical costs of the TSO, a fair rate-of-return, detailed assessment of the cost structure and benchmarking with other TSOs that share similar characteristics. The general formulation of a TSO’s allowed revenue under incentive regulation is summarized as:

$$R_t = (1 - b)C_t + bC_t^* \tag{0.1}$$

where R_t is the TSO’s allowed revenue for year t, C_t are the actual costs of the TSO, C_t^* is the justified cost norm and b is the power of the incentive scheme. A regulatory scheme with $b = 1$ amounts to a **revenue cap**. Under such a high-powered scheme, the allowed revenue is fixed and therefore the TSO, being the residual claimant of his efficiency gains, has an incentive to reduce its costs. Generally, the revenue cap is allowed to increase during the regulatory period at the growth rate of the retail price index minus the anticipated rate of technological progress (RPI-X). A regulatory scheme with $b = 0$ amounts to a **cost-plus**. Under such a low-powered scheme, all costs of the TSO are passed-through to transmission tariffs, i.e. to consumers, and the TSO thus has no incentive to decrease its costs. Under cost-plus regulation, the TSO runs no risk of long-run financial unviability. Furthermore, he has an incentive to honestly reveal all its costs but has no incentive to reduce its costs.

In Europe today, most TSOs are regulated somewhere in between the two extremes of cost-plus and revenue cap regulation. For example in Norway, b equals 0.6. That is, only 40% of all costs are directly remunerated. In other countries like Finland, Sweden and Germany, b officially equals 1, but practically the regulator excludes part of the costs from the revenue cap. These costs are called non-controllable or non-influenceable costs and may include employee benefit costs, transport grid fees for distribution companies, primary control, countertrade costs, etc. In countries like Belgium, Switzerland and Denmark, b is officially 0, but the regulator only remunerates costs considered as necessary at efficient operation [48] [10], so practically there is no full cost pass-through.

Some national regulators introduce a quality regulation into the hybrid price/revenue cap regulation (0.1). This quality regulation rewards TSOs with a fraction b of interruption cost $\mathrm{c_{INT,t}}$ below the norm $c_{INT,t}^*$, and a symmetric penalty for interruption costs above this norm. Expression (0.1) now becomes:

$$R_t = (1 - b)C_t + bC_t^* + b(c_{INT,t}^* - \mathrm{c_{INT,t}}) \tag{0.2}$$

Subtracting all TSO costs c_t:

$$\begin{aligned} R_t &= (1 - b)c_t + bc_t^* + b\big(c_{INT,t}^* - \mathrm{c_{INT,t}}\big) - c_t \\ &= b\left((c_t^* - c_t) + (c_{INT,t}^* - \mathrm{c_{INT,t}})\right) \end{aligned} \tag{0.3}$$

The research leading to these results has received funding from the European Union Seventh Framework Programme under Grant Agreement No 608540.

APPENDIX C CROSS-BORDER BALANCING

Here we develop a general model that analyses four degrees of TSO cooperation in reserves provision. First, we examine autarkic TSO reserve provision - a non-cooperative TSO equilibrium. Then we study reserves exchange when a TSO can acquire reserve capacity in the adjacent TSO area. The last case investigates reserves sharing. Reserves sharing amounts to maximising the surplus of the two nodes jointly and it allows both a cost arbitrage and pooling of reserve needs. We show why reserves sharing is economically superior to reserves exchange. We also present a numerical example in order to provide an illustration of the four scenarios.

TSO cooperation can increase efficiency in reserves management in at least two ways:

(C) Cost arbitrage: if the reserve market is enlarged, expensive reserves can be substituted for cheaper procurement and dispatch of reserves.
(D) Pooling of reserve needs: less reserve capacity is needed if idle reserve capacity can be used in neighboring TSO zones in need of capacity.

According to the network codes, TSOs can cooperate in three ways:

- **Exchange of reserves** makes it possible to procure part of the required level of reserves in adjacent LFC blocks. These reserves are exclusively for one TSO, meaning that they cannot contribute to meeting another TSO's required level of reserves. This is an exchange of contractual obligations between TSOs. That is, the reserve capacity remains in the reserve-providing TSO zone, however, if needs arise the exchange results in physical delivery of power to the reserves-receiving TSO.
- **Reserves sharing** allows multiple TSOs to take into account the same reserves to meet their reserve requirements resulting from reserve dimensioning.
- **Imbalance netting** avoids counteracting activation of balancing energy in adjacent TSO zones.

Exchange of reserves only allows cost arbitrage (A), while reserves sharing allows both cost arbitrage and variance-reducing pooling of reserve needs (A)&(B).

The model

Our model studies reserves sharing and exchange between two TSO zones $i = 1,2$. The need for reserves in TSO zone i at a certain instant is r_i [MW]. This is the imbalance in real time due to a combination of forecast errors of demand and intermittent supply, and failures of generation capacity or transmission components. We denote the joint probability density function of the reserve needs r_i by $f(r_1, r_2)$; r_1 and r_2 are assumed to be non-negatively correlated and jointly normal with known parameters. The TSO's variable of choice is R_i [MW], the quantity of reserves procured.

We are interested in efficiency gains from exchange or sharing of reserve procurement, not efficient dispatch as such. Hence, as noted earlier, we abstract from generation dispatch and take marginal generation costs to be equal to zero. Costs of procuring R_i MW of reserve capacity in TSO zone i, however, are not zero and are given by $\gamma_i(R_i)$, with γ_i increasing, smooth and convex.

We only model reserve needs in the first quadrant of the two-dimensional space of reserve needs (r_1, r_2). Reserve needs in the second and fourth quadrant, i.e. when the reserve needs have a different sign (imbalance netting), are irrelevant when marginal generation costs are zero. The analysis for reserve needs in the third quadrant, i.e. for negative reserve procurement, is similar to the analysis of positive reserve procurement.

The research leading to these results has received funding from the European Union
Seventh Framework Programme under Grant Agreement No 608540.

Order of Events
The order of events in the model is as follows:

Ex ante (before uncertainty is realised):
1. The TSO at node i chooses how much reserve capacity R_i to procure.

Ex post (after uncertainty is realised):
2. In real time the actual need for reserves r_i is observed in each i.
3. The procured reserves will be used to accommodate the reserve needs. In case local reserves are insufficient, TSOs will use exchanged or shared reserves, or carry out load shedding.
4. Settlement payments are made.

Note that the choice of reserve capacity could be for different time horizons, e.g. for an hour, a week, a month, or a year. The probability density function $f(r_1, r_2)$ will in general depend on the procurement interval and the time to real time operation. In case of exchange or sharing of reserves, the procurement entails payments between TSOs.

Autarkic TSO reserve provision
We first consider the case where there is no trade or exchange of reserves between zones. Thus, each TSO zone operates as an isolated "island". The dimensioning rules define what quantity of reserves each LFC area is required to procure. The dimensioning incident is defined as one component failure for FRR and RR, and a joint failure of two components for FCR. Here we pursue an alternative approach by assuming that TSO i procures a quantity of reserves R_i such that expected socio-economic surplus in zone i is maximized. That is, he selects R_i to maximize $E[S_i]$ with respect to R_i, where

$$E[S_i] = v\left\{D_i - \int_{R_i}^{\infty} (r_i - R_i) f(r_i)\, dr_i\right\} - \gamma_i(R_i) \tag{0.1}$$

and v is the value of lost load (VOLL) [€/MWh], assumed to be equal in the two nodes. Gross surplus from electricity consumption is the product of VOLL and electricity demand D_i. Interruption cost is the product of VOLL and the quantity of unserved demand (given by the integral in (1)). Net consumer surplus is the difference of these two terms. Socio-economic surplus in zone i, S_i, is given by consumer surplus less the cost of procuring reserves.

The optimal reserve capacity in autarky, $R_{i,a}^*$, is determined from the following first-order condition:

$$vP\{r_i > R_i\} = \gamma'_i(R_i), \tag{0.2}$$

which is obtained by differentiating (0.1). The intuition of this condition is that reserves are procured up to the point where the marginal cost of interruptions - given by VOLL times the loss of load probability - equals the marginal cost of providing that level of reserves.

It is easily seen that the second-order condition for maximum of $E[S_i]$ is satisfied.

Reserves Exchange
As explained earlier, reserves exchange makes it possible to procure part of the required level of reserves in adjacent TSO zones. We assume that sufficient transmission capacity is available to always accommodate the flows arising from use of reserve capacity in adjacent TSO zones. That is, there is only load-shedding if $r_i > R_i$, irrespective of where the reserve capacity is procured. Exchange of reserves only allows cost arbitrage, not pooling of reserve needs. Here we assume, compliant with the network codes, that the

The research leading to these results has received funding from the European Union
Seventh Framework Programme under Grant Agreement No 608540.

required level of reserves in each TSO zone is the same as in autarky, i.e. $R^*_{i,a}$. We also assume that the two TSOs jointly minimise total costs of procurement, subject to the constraint on reserves. That is, the cheapest reserve capacity in the two TSO zones is procured first. This amounts to the following constrained cost minimization:[52]

$$\min_{R_1,R_2}\{\gamma_1(R_1)+\gamma_2(R_2)\} \text{ s.t. } R_1+R_2=R^*_{1,a}+R^*_{2,a}. \tag{0.3}$$

This leads to the following set of equations:

$$\begin{cases} \gamma'_1(R_1)=\gamma'_2(R_2) \\ R_1+R_2=R^*_{1,a}+R^*_{2,a}. \end{cases} \tag{0.4}$$

That is, costs are lowest when marginal costs of reserve procurement are equal in the TSO zones. Figure 0.1 shows this cost minimization graphically. The axis runs from left to right for TSO zone 1 and from right to left for TSO zone 2. Clearly, if costs are symmetrical in the two zones, then there is no reason to exchange reserves and the optimal solution is for each TSO to procure reserves within his own zone. If costs are asymmetrical, then there is a rationale for exchange. The grey area in the figure is this reduction of procurement costs under a pay-as-bid system. The costs of the reserves-providing TSO (Zone 1 in the figure) will clearly rise so, to make this arrangement incentive compatible, the reserves-receiving TSO needs to pay the reserves-providing TSO an amount that at least covers the latter TSO's costs.[53]

It is convenient to define a cost function for procuring a combined amount of reserves in both nodes as follows

$$c(R)=\min_{R_1}\{\gamma_1(R_1)+\gamma_2(R-R_1)\} \tag{0.5}$$

Where R is the total reserve need in both nodes.
The total cost of procuring (the autarkic) reserves with reserves exchange is then given by $c\left(R^*_{1,a}+R^*_{2,a}\right)$.

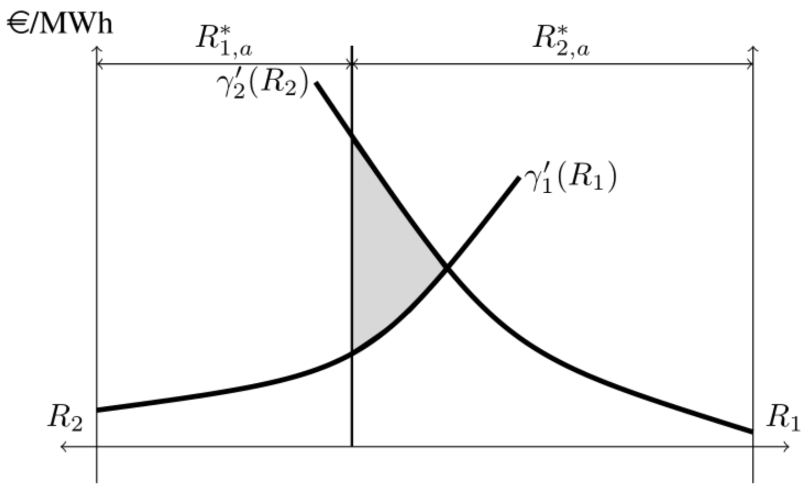

Figure 0.1 Cost minimization under reserves exchange between two TSO zones

[52] As a simplification, we neglect any limits on reserves exchange.
[53] The behaviour of the two TSOs and the contract needed for cooperation is not studied in detail in this section. TSOs could have an incentive to act strategically while cooperating with adjacent TSOs. For example, by distorting the congestion signal in cross-border congestion management \cite{Glachant2005} or by spending too little on network maintenance \cite{Tangeras2012}.

The research leading to these results has received funding from the European Union Seventh Framework Programme under Grant Agreement No 608540.

Reserves exchange allows the reserves-receiving TSO to procure reserves more cheaply than under autarky. However, the cost-minimization does not incorporate the VOLL and does not allow to change the quantity of reserves, i.e. it does not maximize expected surplus. Likewise, reserves exchange does not exploit the possibility of pooling reserve needs with adjacent TSOs.

Locally optimal reserves procurement with reserves exchange

When reserves exchange is introduced, TSO's face different reserve procurement cost functions from those prevailing in autarky. In the absence of further cooperation between TSO's, TSO 1, say takes zone 2 reserves procurement as given. Hence, procurement costs at zone 1 are given by $g(R_1|R_{2,a}^*) = c(R_1 + R_{2,a}^*)$. Analogously, zone 2 faces the procurement cost function $g(R_2|R_{1,a}^*) = c(R_{1,a}^* + R_2)$. This implies, in general, that marginal costs of procurement and interruptions are no longer equal in each zone separately as was the case in autarky (cf. (0.2)). Hence, TSO's now have incentives to adapt the reliability level to the new reserves exchange cost function. Assuming that regulation adapts to the economic conditions created by exchange, each TSO will procure reserves for his zone optimally, given procurement of reserves in the other zone.

In the resulting equilibrium, which we denote by $(R_{1,l}^*, R_{2,l}^*)$, $R_{1,l}^*$ is the optimal choice of reserves in zone 1 given that zone 2 procures $R_{2,l}^*$ and *vice versa*.[54] Each TSO thus equates marginal costs of interruptions and reserves procurement, taking the other zone's procurement as given. The first-order conditions are as follows:

$$\begin{cases} vP\{r_1 > R_{1,l}^*\} = g'(R_{1,l}^*|R_{2,l}^*), \\ vP\{r_2 > R_{2,l}^*\} = g'(R_{2,l}^*|R_{1,l}^*). \end{cases} \tag{0.6}$$

This equilibrium, which involves locally optimal reserves procurement with reserves exchange, does not involve pooling of reserve needs. It is not difficult to show, however, that the minimisation of combined costs of interruptions and reserves procurement (with exchange) in the two zones, i.e. choosing R_1 and R_2 to minimise

$$v\{E[r_1 - R_1]^+ + E[r_2 - R_2]^+\} + c(R_1 + R_2), \tag{0.7}$$

results in the same outcome as locally optimal reserves procurement with reserves exchange. Since demand is inelastic this also results in maximisation of overall socio-economic surplus in the two zones.

Reserves Sharing

Reserves sharing allows multiple TSOs to draw on the same reserves resources to meet their required level of reserves when it comes to operation. It allows both cost arbitrage and pooling of reserve needs, including sharing of interruptions if necessary. As before, we assume that transmission capacity is always sufficient to accommodate the flows arising from use of reserve capacity in adjacent TSO zones. That is, there is only load-shedding if $r_1 + r_2 > R_1 + R_2$. In our model, reserves sharing amounts to maximizing the surplus of the two nodes jointly, i.e. maximizing $E[S_1 + S_2]$. Expected socio-economic surplus in the two zones together may be written as

[54] The resulting equilibrium is thus a *Nash equilibrium*.

The research leading to these results has received funding from the European Union
Seventh Framework Programme under Grant Agreement No 608540.

$$E[S_1+S_2] = v\left\{D_1+D_2-\int_0^\infty\int_{R_1}^\infty (r_1+r_2-R_1+R_2)f(r_1,r_2)\,dr_1dr_2\right\}\left\{D_1+D_2 - \int_0^\infty\int_{R_1+R_2}^\infty (r_1+r_2-(R_1+R_2)f(r_1,r_2)\,dr_1dr_2\right\} - \gamma_1(R_1)-\gamma_2(R_2). \tag{0.8}$$

The optimal reserve capacities when reserves sharing is allowed, $R_{1,s}^*$ and $R_{21,s}^*$, are determined from the following first-order conditions:

$$\begin{aligned} vP\{r_1+r_2>R_1+R_2\} &= \gamma'_1(R_1),\\ vP\{r_1+r_2>R_1+R_2\} &= \gamma'_2(R_2), \end{aligned} \tag{0.9}$$

which are derived by differentiation of (0.8) with respect to R_1 and R_2, respectively. The intuition for this set of first order conditions is to procure reserves in each TSO zone up to the point where the total marginal cost of interruptions, i.e. the product of VOLL and the loss of load probability (LOLP) in the two zones jointly, equals the marginal cost of providing that level of reserves.

Clearly, this implies that marginal costs of procurement are equal at the optimal levels of procurement. Hence, the costs of reserves procurement are minimized as in reserves exchange, but for different levels of reserves and, hence, also reliability. This leads to an alternative formulation of the reserves sharing problem, *viz.* choose R to minimise the expected combined costs of interruptions and reserves procurement

$$vE[r-R]^+ + c(R), \tag{0.10}$$

where $r = r_1 + r_2$ and c is given by (0.5), and then choose R_1 and R_2 such that $R = R_1 + R_2$ and marginal costs of procuring reserves are equal across the two zones.

Comparing the four cases

It is not difficult to see that the overall expected socio-economic surplus with reserves sharing is equal or larger than with locally optimal reserves procurement and reserves exchange; this follows directly from the alternative formulations of locally optimal reserves procurement and reserves sharing, cf. (0.7) and (0.10) respectively, and the inequality $[x+y]^+ \leq x^+ + y^+$. This relation will be strict unless the zones are perfectly correlated.

Moreover, the overall expected socio-economic surplus with locally optimal reserves procurement and reserves exchange is no smaller than that with reserves exchange and autarkic reserve procurement levels; this is a consequence of the alternative formulation of the former, cf. (0.7). Finally, overall expected socio-economic surplus with locally optimal reserves procurement and reserves exchange is no smaller than that in autarky, since costs of reserves procurement are lower and interruption costs are the same. These two last comparisons will be strict, unless the zones are perfectly symmetric, in which case exchange as such offers no advantage – pooling of reserve needs is then necessary to improve on autarky.

Thus, each step in the integration of zones results in progressively higher expected socio-economic surplus.

Another important issue to note is that when the zones are asymmetric, there will be distributional consequences of reserves exchange. Reserves costs will fall in one zone and rise in the other. There is a minimal payment that will suffice to make exchange incentive compatible. There will still be a surplus that may be split in some way between the two zones, e.g. by Nash bargaining. However, we do not consider this issue here. A similar issue arises with locally optimal reserves procurement and reserves exchange.

The research leading to these results has received funding from the European Union
Seventh Framework Programme under Grant Agreement No 608540.

With reserves sharing, there may also be distributional consequences that make one zone better off and the other worse off, both as regards reserves costs and expected interruptions. Similar to reserves exchange, for incentive compatibility of sharing there will be a minimal side payment from the better off zone to the one that is worse off.

Illustration

In this section we present a numerical example to illustrate the comparison of the four regimes (autarky, reserves exchange, locally optimal reserves procurement and reserves exchange and reserves sharing).

The base case for the illustration is that the probability density functions of reserve needs are jointly normal with correlation ρ, each with a mean of 10 MW and a variance of 5 MW: N(10,5). The cost of reserve procurement is $\gamma_i(R_i) = c_i R_i$. Table 0.1 shows the results of this numerical illustration.

The first three columns of the table show procured reserves in each of the TSO zones and the sum of all procured reserves, for each degree of cooperation. The fourth column expresses total procured reserves relative to the procured reserves in autarky. The fifth column shows the total cost, which is the sum of expected interruption costs and procurement costs in both TSO zones. The last column expresses the total cost relative to the autarky cost.

The first part of the table shows the results of a symmetric case, i.e. marginal procurement costs are equal in the two TSO zones. The correlation coefficient is zero. In the second part of the table, procurement cost is twice as high in TSO zone 1, while the correlation coefficient increases from zero to one.

Table 0.1 Reserves and costs in TSO zone 1 and 2: *RR* = relative reserves; *TC* = total cost; *RC* = relative cost

$c_1 = c_2 = 2$	R_1	R_2	$R_1 + R_2$	RR	TC	RC
Autarky	15.05	15.05	30.10	100%	998.4	100%
Exchange	15.05	15.05	30.10	100%	998.4	100%
Sharing, $\rho = 0$	13.63	13.63	27.26	90.5%	801.7	80.3
$c_1 = 4$, $c_2 = 2$						
Autarky	14.46	15.05	29.50	100%	1431.9	100%
Exchange	9.83	19.67	29.50	100%	1303.7	91.0%
Sharing, $\rho = 0$	8.97	17.95	26.92	91.3%	1046.1	73.1%
Sharing, $\rho = 0.5$	9.46	18.93	28.39	96.2%	1178.8	82.3%
Sharing, $\rho = 1$	9.87	19.74	29.61	100.4%	1295.3	90.5%

This illustrates several important issues. In the first case, when the two TSO zones are identical, no cost arbitrage is possible and exchange of reserve does not yield any cost reduction. However, reserves sharing leads to a lower reserve need and thus a lower cost. In the second case, when the cost of reserve procurement is higher in TSO zone 1, reserves exchange does yield a cost reduction. TSO 1 procures part of its reserve obligation with reserve capacity providers in TSO zone 2. The resulting cost reduction, between autarky and exchange, of 128.2 €/h can be a gain for TSO 1, TSO 2 or distributed between both (e.g. through Nash bargaining). In reserves sharing, costs are evidently even lower. Again, how this cost reduction is distributed over the two TSOs depends on the details of the inter-TSO contract. The table shows that the cost reduction decreases when the reserve needs in the two TSO zones are more correlated. When the reserve needs are fully correlated, reserves sharing yields almost no additional cost reduction compared to reserves exchange.

The research leading to these results has received funding from the European Union Seventh Framework Programme under Grant Agreement No 608540.

Lastly, the total procured reserves do not always decrease with reserves sharing. When costs are asymmetric but reserve needs are highly correlated, the decreased procurement cost due to cooperation could entail more reserves to be procured optimally, i.e. a higher reliability level.

Conclusions

This section compares four degrees of TSO cooperation in generation reserves provision: autarky, reserves exchange, locally optimal reserves procurement and reserves exchange and reserves sharing. We derive analytically the optimal procurement of reserves in each of the four cases and show that costs, which are expected to rise with increasing penetration of renewable generation, decrease with cooperation. The benefits of reserves exchange and reserves sharing depends on cost asymmetry and correlation of reserve needs between the TSO zones. That is, when TSO zones have highly asymmetric reserve procurement costs but highly correlated reserve needs, reserves exchange already yields a high cost reduction. When TSO zones have fairly equal reserve procurement costs but a low degree of reserve needs correlation, reserves sharing is needed to reap the full benefits of TSO reserves cooperation.

National electricity markets are increasingly interconnected in Europe, spurred by European Regulations, Directives and network codes. In the day-ahead market there has been considerable progress in coupling national markets at the regional level, however, cooperation in balancing and reserves has been minimal and limited to a few voluntary agreements. The Network Code on Electricity Balancing discusses how TSOs ought to cooperate. This paper shows analytically the cost reduction for different degrees of cooperation.

The research leading to these results has received funding from the European Union
Seventh Framework Programme under Grant Agreement No 608540.