Master's Thesis

Czech Technical University in Prague

F3

Faculty of Electrical Engineering
Department of economics, management and humanities

Congestion income distribution under Flow-Based method

Bc. Jiří Salavec

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Supervisor: Ing. Július Bemš Ph.D.

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ZADÁNÍ DIPLOMOVÉ PRÁCE

Student: Salavec Jiří

Studijní program: Elektrotechnika, energetika a management
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Název tématu: Rozdělení výnosů z řízení přetížení při použití Flow-Based metody výpočtu kapacit

Pokyny pro vypracování:

- Analyzujte způsoby výpočtu a přidělování přeshraničních kapacit
- Popište obecné metody používané pro dělení výnosů
- Proveďte rozbor důvodů, kritérií a cílů existujících a plánovaných metod rozdělení příjmů - zejména metodiky CWE
- Porovnejte dopady různých scénářů na přeshraniční profily
- Zhodnoťte CWE metodiky a návrh případných změn pro ČR

Seznam odborné literatury:

COMMISSION REGULATION (EU) 2015/1222 of 24 July 2015 establishing a guideline on capacity allocation and congestion management, July, pp. 24-72, 2015.
TRH S ELEKTŘINOU. Kolektiv autorů. AEM, 2011.

Vedoucí diplomové práce: Ing. Július Bemš, Ph.D. – ČVUT FEL, K 13116

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L.S.

Prof.Ing. Jaroslav Knápek, CSc.
vedoucí katedry

Prof.Ing. Pavel Ripka, CSc.
děkan

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Acknowledgement / Declaration

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I hereby declare that this master's thesis is the product of my own independent work and that I have clearly stated all information sources used in the thesis according to Methodological Instruction No. 1/2009 – "On maintaining ethical principles when working on a university final project, CTU in Prague".

In Prague 26. 5. 2016

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Abstrakt / Abstract

Tato diplomová práce se věnuje rozdělení příjmu z přetížení, zejména na denním trhu s elektřinou v rámci tzv. market couplingu. Nejdříve jsou popsány dva základní přístupy výpočtu a alokace přeshraničních kapacit, a to NTC metoda a detailněji také Flow-Based metoda a jejich porovnání. Dále jsou rozebrány obecné postupy dělení příjmů z přetížení, na kterých jsou analyzována data 4M Market Couplingu z roku 2015. V neposlední řade je v práci popsán způsob dělení příjmů z přetížení dle CWE metodiky a kritéria pro toto dělení. Na modelu elektrické soustavy jsou následně provedeny simulace různých scénářů a vypočteny příjmy z přetížení. Z výsledků lze porovnat rozdíl mezi v současné době používaným NTC výpočtem a budoucím FB výpočtem.

Klíčová slova: příjem z přetížení, market coupling, trh s elektřinou, denní trh, přeshraniční kapacity, flow-based metoda, NTC metoda, PTDF, metody dělení. 4M Market Coupling

This Master‘s thesis is devoted to a congestion income distribution, mainly on the Day-Ahead electricity market in terms of the so-called Market Coupling. First there are described two main capacity calculation and allocation methods: the NTC method and in more detail also the Flow-Based method and their comparison. There are also described the general principles of income allocation which are grounds for analysis of 2015 4M Market Coupling data. Last but not least there is presented the CWE congestion income allocation methodology and its criteria. Based on the electricity grid model the simulation of different scenarios and calculation of congestion income is created. According to the results there is apparently a difference between the currently used NTC method and the future FB method.

Keywords: congestion income, market coupling, electricity market, Day-Ahead market, cross-border capacity, cross-zonal capacity, flow-based method, NTC method, PTDF, allocation schemes, 4M Market Coupling

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Executive Summary

In this thesis the analysis of the congestion income distribution is conducted. First, different ways of the cross-border capacity allocation are presented. There is an option to buy the cross-border capacity in an explicit auction separately from electric power – this option is currently used in long-term auctions. The other option is to participate in an implicit auction usually in a day-ahead market and so called market coupling and not to worry about the cross-border capacities. For an effective cross-border capacity allocation the calculation of it is crucial. It can be done in two main approaches. The principle of the total transmission capacity of a cross-border line calculation is fairly similar but the treatment of commercial flows is variant. First NTC approach is little bit simpler because it treats commercial flows as physical flows which do not correspond with reality because flows in a meshed grid respect the laws of physics not the business laws. That is why it can be really inaccurate in some situations. Flow-Based approach is much better in this aspect because it is based on power flows and almost realistic impact of the commercial flow on the grid can be computed. Also according to European regulation (network code capacity allocation and congestion management) the Flow-Based approach shall be implemented in Europe.

The congestion income, which is a revenue that originates in the capacity allocation process when the cross-border capacity is not sufficient, is nowadays shared among transmission system operators of involved zones – on each side of the cross-border profile. However, there are other mechanisms which can be used, for example sharing based on absolute or relative usage of cross-border line or on shadow prices. These methods are analyzed in this thesis for 4M MC, which is a market coupling initiative of the Czech Republic, the Slovak Republic, Hungary and Romania. The total congestion income in 2015 was around 1,1 billion CZK. The most often congested cross-border profile is between the Slovak Republic and Hungary, where the congestion occurred in nearly 60 % of hours. Results show that each one of mentioned allocation methods fits the best for a different country. From the Czech TSO point of view, the method based on absolute line usage is the best and brings the highest amount of money – it has around 22 % share on the total income.

Flow-Based approach of the congestion income allocation in CWE region, which includes Belgium, France, Germany and the Netherlands, is already running. That is why this methodology is described and analyzed – there is an assumption that it will serve as a blueprint for other regions. FB as contrasted to NTC can compute flows on external borders and through external zones – external means that they are not participating in the given market coupling initiative. Also, the negative congestion income per border can occur in order to reach the maximum market welfare. Money which even up the income to the zero value have to be collected on other borders, because if this situation was not secured it would bring a disincentive to TSO. It will not be motivational to offer cross-border capacity if additional costs are connected with it.

The comparison of sharing key attitudes – currently under NTC and FB which is used in CWE shows that it treats the congestion income allocation in similar way, only with some differences presented in previous paragraph. Because of the data unavailability the computation on fictional model situations of Flow-Based approach has been done. The differences between FB and NTC are visible even on a simplified six zonal grid with about 30 nodes and 50 power lines. Also, from the results it is obvious that external zones could benefit from market coupling if they was involved in it – in some situations the congestion income associated to external zones was almost 20 %. Specific results of the computation are summarized in detail in the conclusion.

The congestion income paradox is that TSOs get money for insufficient cross-border capacity so there is no economical reason to invest in new capacities, which would cause decrement of income. Use of congestion income thus has to be monitored.

Chapter 1
Introduction

The European electricity market is currently undergoing changes - some of them are small, some of them are big. Last couple of years in Europe can be defined in one word: unification. The European Commission is trying to unify all the rules, rights and obligations of electricity market participants into one single form. Each country has nowadays its own rules which are in some cases similar and in some cases completely different. That is why the unified Network Codes under the supervision of European Network System Operators for Electricity (ENTSO-E) are created. These codes, which will be applied in all European countries, will cover all connection, operational and market rules. At the end of the path should be so-called IEM – Internal Electricity Market. But the interconnection of electricity markets brings a lot of challenges especially for Transmission System Operators (TSO). In scope of the first published network code Capacity allocation and congestion management (CACM) is also the obligation of evolution from current NTC approach to Flow-Based approach. This will have an important impact not only on the cross-border capacity calculation but it will also have some consequences on the income from congestion management.

1.1 Motivation and goals

I have chosen this topic because in my bachelor's thesis I have analyzed the interconnection of electricity markets in Europe. That gave me an oversight about market coupling initiatives in Europe and I find the idea of one single electricity market very interesting. Also thanks to a scholarship program of Czech TSO ČEPS, a. s., I have met people with work experience who suggested to me to analyze this particular topic.

The goals of this thesis are following. Obtain information regarding methods of cross-border capacity calculation and allocation with focus on Flow-Based solution used in CWE region. Discover and describe allocation methods which can be used for congestion income allocation. Next goal is to get to know the CWE congestion allocation methodology, evaluate it and describe criteria for sharing income. In the practical part to analyze different allocation methods under NTC and on a model situation to find differences between NTC and FB approach.

1.2 Thesis Outline

This thesis is divided into 6 chapters from which the first one is this Introduction and the last one is Conclusion.

In chapter no. 2 there are presented cross-border capacity calculation and allocation methods. The difference between an explicit and implicit allocation is described, also both NTC and Flow-Based approaches are analyzed and compared.

In the 3rd chapter various ways of congestion income generation are discussed and possible allocation methods based on line usage or based on shadow prices are described.

Chapter no. 4 contains information about CWE income allocation methodology and criteria for sharing income. The sharing key is presented on real-data example.

Chapter no. 5 is divided into two parts, NTC world and FB world. In NTC part there is an analysis of different income allocation schemes, which were presented in chapter 3 on real 4M Market Coupling data and their comparison. The second part – called FB world contains concept of power grid which is followed by simulation of different scenarios and computation of congestion income. The results are discussed and compared with NTC computation.

Chapter 2
Cross-border capacity calculation and allocation

In this chapter there are described the principles of the cross-border capacity allocation and calculation. The two main cross-border capacity calculation methods are explained and compared. Also historical context and recent development is mentioned.

There is no doubt about the importance of electricity for humanity. Since the 19th century people got used to using electricity in almost every possible way and I think that modern society cannot imagine world without it anymore.

At the beginning there were built only small power plants situated near electricity consumption areas. So there was no big need to transmit electricity over long distances. Then, during the electrification of cities and villages the energy system of each region was mainly developing separately and independently. Later were the interconnections with other states built only for security reasons, so in case that an outage occurred, we could use foreign help. For a long time, power grid of each state evolved on its own and that has obviously some consequences till nowadays. Although the present European grid is fully interconnected, its national parts are linked on much higher level than the cross-border connections.

These bottlenecks in the European grid reduce options of the international trading with electricity. And because of insufficient cross-border capacity, transmission system operators have to allocate the limiting capacity needed for international trading with electricity. Therefore, calculation and allocation of available transmission capacity is crucial.

We generally distinguish two types of capacity allocation.

2.0.1 Explicit allocation

The first one is an explicit allocation which means that the transmission capacity is allocated separately from the electric power. This type has some drawbacks, for example the trader can find himself in a situation where he has bought the electricity but he does not have the capacity. Or vice versa, he has the capacity but not the electricity. Both situations are unwanted.

The explicit allocation is mostly used in long-term contracts - there are yearly and monthly explicit auctions on borders in Europe. And also short-term daily explicit auctions are organized. Before August 2015 there were two main cross-border capacity allocation offices CAO and CASC.EU, which have joined together making Joint Allocation Office (JAO) [1]).

Because cross-border capacity in explicit mode is not directly connected with power delivery there are different schemes of trading with it. One is called "Right with Obligation" when the market participant which has bought the capacity has the obligation

[1]) JAO official websites - [1]

to use it [1]). The other which is more common is called “Right with Option” and purchaser of this capacity can decide whether to use it or not. Because of this uncertainty the so-called “Long Term Nomination” (LTN) has to be done. LTN is a process in which possessor of capacity from Long Term Allocation (LTA) informs TSO if and in which amount is he going to use his LTA. There are two modes of capacity bought with “Right with Option” and they are called “Use It Or Sell It” (UIOSI) and “Use It Or Lose It” (UIOLI). These modes specify what happen with the unused capacity – in UIOLI mode market participant loses his right on his allocated but not nominated capacity. On the other hand, in UIOSI he can receive some money back if he does not nominate his allocated capacity. This can happen in case that the non-nominated capacity is resold to another market participant in explicit auction or it is in the right direction of clearing price spread in implicit allocation.

2.0.2 Implicit allocation

The other type of capacity allocation is the implicit allocation which has the advantage of trading with electricity and cross-border capacity together. The trader does not have to worry about the unpleasant situations described above, because he simply makes a deal for electricity with cross-border capacity included. This allocation is mostly used in short-term markets.

The implicit allocation of cross-zonal capacity connects for example the Day Ahead market with electricity – creating so-called Market Coupling. Please note that from now on the focus of this thesis will be mainly on the congestion income of day-ahead market coupling when the implicit allocation is used.

There are two main methods that are used for cross-border capacity calculation in the Europe: the Net Transmission Capacity method [2]) and the Flow-Based method. In setting of the cross-border capacity which can be used for cross-border trade both methods work more or less in a similar way. Transmission line has its maximum power flow which it can safely handle. Simply said - from the maximum value we take off known power flows – from operational experiences and historical data. But the approach to commercial flows is markedly different.

2.1 NTC approach

The NTC method is simpler than FB and is used in most parts of Europe till nowadays and it is quite easy to understand. The whole approach is summarized in following equations (2.1), (2.2) and (2.3).

First, used terminology is presented:

NTC	Net Transmission Capacity
TTC	Total Transmission Capacity
ATC_n	Available Transmission Capacity in Base Case
PF	Parallel Flow
LF	Loop Flow
ATC	Available Transmission Capacity
AAC	Already Allocated Capacity

[1]) For TSO it is an advantage because netting on cross-border profile can be done.
[2]) Please note that in some sources “Available” instead of “Net” in the name of the method is used.

At the beginning we need to know how much power can certain line handle, which depends on many factors [2] such as:

- Current limit
- Voltage profile
- Phase angle - $\cos\varphi$
- Loading factor

This maximum flow parameter is called TTC from which the security margin TRM [1]) is subtracted making net transmission capacity.

$$NTC = TTC - TRM \tag{2.1}$$

Then the ATC_n, which is the available transmission capacity before the start of any capacity allocation timeframe, is computed– from NTC the impact of loop flows and parallel flows is subtracted. Also in this step outages of different parts of grid are modeled. That is because N-1 criterion has to be kept in any operational situation. This means that any outage of one component of the grid must not endanger the operation of the grid. From the outage modeling is therefore picked the lowest value of ATC_n which can be allocated to market participants.

$$ATC_n = NTC - PF - LF \tag{2.2}$$

Then the ATC value is continuously computed with changes of AAC in yearly, monthly or daily auctions.

$$ATC = ATC_n - AAC \tag{2.3}$$

The biggest difference from the FB method is that the approach to commercial flows is simplified. ATC calculation is based on assumption that the electrical energy flows from Country A to Country B are using only cross-border power lines between Country A and Country B. So for example if there is a 500 MW ATC from A to B and a trade of 100 MW is done from A to B then the remaining ATC will be $500 - 100 = 400[MW]$. However, this premise is far from reality, because power flows respect physical laws and electricity flows in direction of minimal resistance.

Whole NTC calcullation process is described in detail on Czech TSO's websites [3].

2.2 CACM network code

The European Commission is now working on implementation of network codes which should unify rules, rights, and obligations of all electricity market participants. These codes are in different stages of completion, however the CACM network was the first finished network code. [4]

On the 24th of July the European Commission published Regulation 2015/1222 which is the mentioned network code on Capacity Allocation and Congestion Management. It specifies the rules and conditions for actions that will lead to the completion of a functioning internal energy market in Europe. [5]

In this regulation there is specified that FB approach should be used for day-ahead and intraday capacity calculation in Europe in order to make this process more efficient.

[1]) Please note that this margin has different label in different sources, it has for example the same meaning as FRM which is used in following sections of this thesis.

So it is a motivation for me and this thesis to analyze the impacts of FB approach on congestion income. Coordinated net transmission capacity approach should be used only when the grid is not very well interconnected and it would not bring any benefits.

Also there are mentioned bidding zones as the basics of electricity market. Bidding zones are zones with the same clearing prices which should not be the same as whole countries. That is why from now on I will use cross-zonal capacity instead of cross-border capacity because it is possible that there will be more bidding zones in one country or vice versa one bidding zone including more countries [1]).

2.3 FB approach

Flow-Based approach is more accurate than NTC because it treats power flows as a real flow of energy, respecting the Kirchhoff's laws. The main purpose of this method is to calculate the impact of commercial flow into the power system. On the other hand, this method is demanding much more data information and computer performance and it is not so easy to understand.

As it was written, there are more key inputs than in NTC method. Currently there are three main slightly different ways of calculation of the Power Transfer Distribution Factors (PTDFs), which are the key output of Flow – Based capacity calculation. One of them was developed by CWE region TSOs [2]), the second one by CEE region TSOs [3]) and the third by Nordic region TSOs [4]). I will analyze mainly the CWE approach, because it is the basis of further analyzed CWE congestion income allocation methodology described in Chapter 4.

In the next paragraphs I present the inputs of the process of FB calculation and key outputs.

2.3.1 Critical branches

At the beginning Critical Branches (CB) should be set. A critical branch is a network element, which is expected to be limiting cross-zonal trades and thus to be monitored during the FB capacity allocation. Critical branch is typically a line or a transformer which needn't be a cross-zonal element but may be an internal grid element.

The determination of CB is based on operational experience of each TSO. The key task is to assess as many CBs as needed, but in ideal case not too much because the more CBs we have the more complicated it is to be solved. On the other hand, a dismission of CB can lead to invalid results. That is why the significance of CB shall be computed and supervised.

CWE region has following rule for Critical Branch significance. If maximum value of any values in PTDF matrix [5]) for particular Critical Branch exceeds 5 % then this Critical Branch is considered as significant for FB capacity allocation. Critical Branches which are not significant are not taken into account. Of course PTDF values are continuously monitored and controlled.

[1]) This phenomenon we can now observe in single bidding zone of Germany and Austria.
[2]) Documentation to this approach is in [6]
[3]) Documentation to this approach is in [2]
[4]) Documentation to this approach is in [7]
[5]) Decription of this term is in following section 2.3.8

2.3.2 Critical outages

As it was presented earlier the safety standard operation criterion of the European power grid is called N-1. That is why critical outages during FB capacity calculation are modelled. Behavior of each Critical Branch during Critical Outage has to be included in the computation. Critical outages are determined by each TSO for its own network.

In CWE methodology the Critical Branches are specified directly with a Critical Outage scenario (CBCO).

2.3.3 Grid topology

Grid topology is not the same all the time, for example the connection of power lines changes because of some operational situations such as maintenance etc. But for precise computation it is crucial to know the parameters of the power grid. The detailed parametres of the grid in CWE had the form of the D2CF files.

The 2-Days Ahead Congestion Forecast files are the best estimate of the state of the electric system for day D. This forecast includes following estimations:

- net exchange program
- planned grid outages
- load
- renewable energy generation
- outages of generators

This output of daily procedure is crucial due to the fact that power grid is never the same. Each day is specific by its parameters. For example, production of photovoltaic power plants and wind power plants is dependent on weather. Also consumption depends on outside temperature – if it is too cold consumption of heating systems is rising, also if it is too hot consumption of cooling system is rising. Another factor is the regular maintenance of power plants, substations and lines during which the technology has to be turned off.

Forecasts of the grid situation for day D should be based on CGM which is a shortcut for Common Grid Model. CGM should be the typical state of power grid for a typical day (weekday or weekend day). The term CGM is also mentioned also in the network code CACM and it is defined as: *"Common Grid Model is a Union-wide data set agreed between various TSOs describing the main characteristic of the power system (generation, loads and grid topology) and rules for changing these characteristics during the capacity calculation process."* [5]

2.3.4 Generation shift keys

The generation shift key defines how a change in net position is mapped to the generating units in a bidding zone. Net position is the netted sum of exports and imports in one bidding zone. Generation Shift Keys are needed, because currently electricity market is based on zonal system (bidding zones – single price areas [1])) not nodal system. The Flow-Based method would be most accurate if the whole power grid was modelled (each node). But that would mean much larger data set and of course problems with transparency, also no project counts with it.

How does GSK work is demonstrated on example below.

[1]) Therefore, it does not matter where exactly in the bidding area is the generation or the load, the price is the same.

GSK example

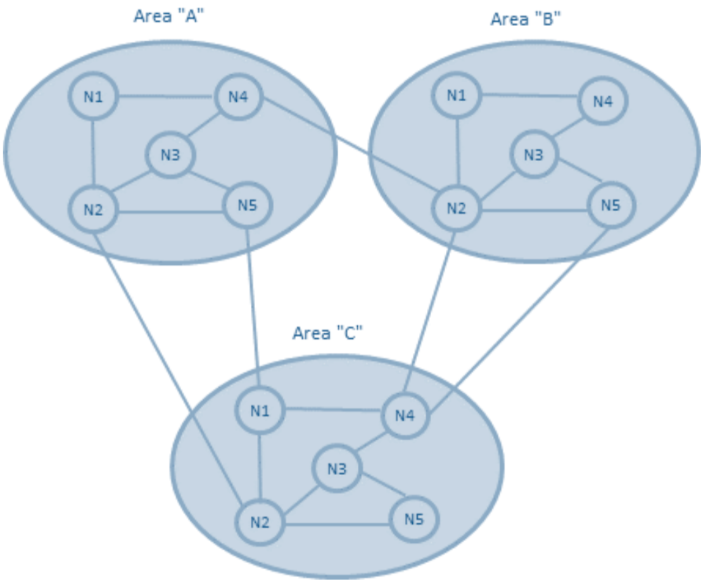


Figure 2.1. Generation shift keys - nodal vs zonal [7]

On the Figure 2.1 there is an example with 3 different bidding zones each with 5 nodes in it. GSK gives us the information in which nodes the generation will go up if we rise the generation in respective zone. In Table 2.1 there is a GSK for zone A and in next Table 2.2 there are results of increasing generation in zone A by 1 MW.

zone A	
node	value
N1	0,2
N2	0,2
N3	0
N4	0,3
N5	0,3
sum	1

Table 2.1. GSK - example

node	**before** generation [MW]	**after** generation [MW]
N1	5	5,2
N2	10	10,2
N3	3	3
N4	7	7,3
N5	5	5,3
NP	30	31

Table 2.2. GSK application

GSK setting is each TSO's business and there are different ways of achieving it. Because each region is unique (generation mix, infrastructure etc.) there is no rule how to specify the GSK. GSKs are important input of PTDF matrix calculation.

2.3.5 Maximum flow on CB

Each element of the power grid has its own maximum flow. This flow cannot be exceeded otherwise overloading and damage on the element may occur. It is the same as in NTC approach in section 2.1 the TTC value. In FB approach and in [6] is this value labeled as F_{max} and it is defined for each CBCO.

2.3.6 Reference flow

The reference flow volume is one of the volumes, which is subtracted from the maximum flow value to get the remaining available margin. It is a power flow on a critical branch under conditions specified in D2CF. It shows the best-estimated power flow on critical branch for the situation before D-A market takes place. In another words it shows how much capacity it is already used up for power grid operation and thus cannot be allocated through daily FB allocation. This value is labeled as F_{ref}.

2.3.7 Reliability margins

There are several reliability margins to secure safe operation. They are needed because of some uncertainties in FB model.

Final Adjustment Value

With this value TSO can increase or decrease remaining available margin on a critical branch based on operational experience and skills. For example for complex operational actions, which cannot be simply modelled. In further equations is this value labeled as FAV.

Flow Reliability Margin

The flow reliability margin is the same security margin as TRM in NTC approach. An analysis of forcasted and predicted values is made in order to set up the FRM right. This process is depicted on Figure 2.2. According to CWE methodology [6] following effects should be covered with this margin: unintentional flow deviations, external and internal trade, uncertainity in load and generation and application of a linear grid model.

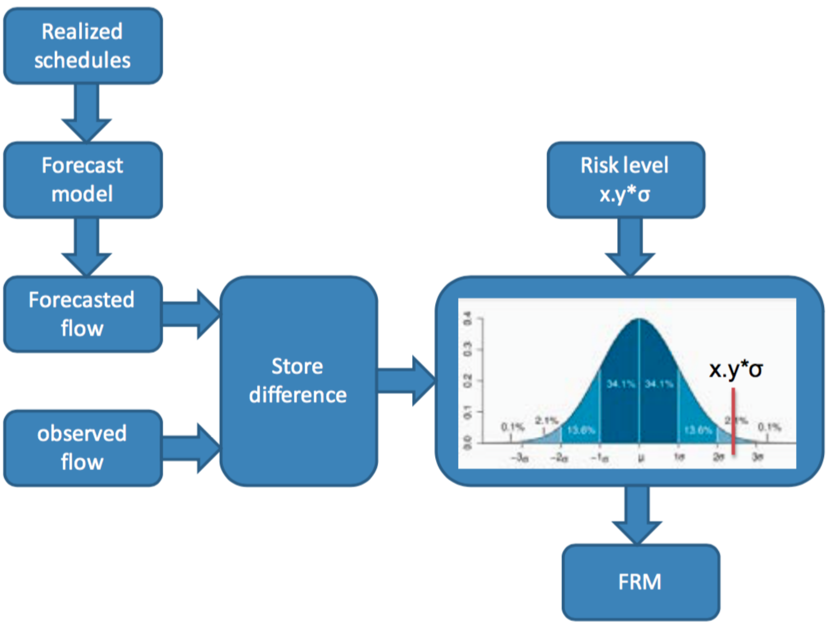


Figure 2.2. FRM principle [8]

2.3.8 Power tranfer distribution factors

The Power Transfer Distribution Factor (PTDF) matrix is a key output of FB capacity calculation. It shows what effect the additional flow has on certain critical branch. So we are able to compute effects of commercial flows. There are two types of PTDF matrices depending on the way in which they are computed. The first one is nodal PTDF and the second one is zonal PTDF and because they can be sometimes mistaken for each other I will describe both attitudes below.

Nodal PTDF

This type of PTDF matrix shows the effect of power injection in nodes of the grid on critical branches. It is set up in following way. First, the power flows on critical branches with critical outages based on D2CF are computed and then separately the increase of 1 MW in each node is made. We get two power flows for each critical branch – before and after increment. If we subtract one from the other, we get a number between 0 and 1 which expresses the change of one node on critical branch. These values now can be formed into a matrix with critical branches in rows and nodes in columns.

However, this type of PTDF matrix is not right for the FB market coupling computation, because as it was written above the European power market uses the zonal system, not the nodal system. That is why we need to get zonal PTDF which is the right output.

There are two ways how to get zonal PTDF.

Zonal PTDF

First way is to multiply the nodal PTDF with GSK which transforms nodal PTDF to zonal PTDF. Zonal PTDF matrix has CB in rows and bidding zones in columns. This seems like an easy way but even easier is to compute the zonal PTDF right away and do not waste time with nodal PTDF which is not needed.

Second way has the same beginning as computing the nodal PTDF. First power flows on critical branches with critical outages based on D2CF are computed, but then the increment of 1 MW is made for the whole zone according to GSK – so all nodes in the zone are increased with the GSK value. After this increment we compute power flows on critical branches and get the second value. Now it is the same again like with nodal PTDF – subtraction is made and effects of a change in net position of each zone on each critical branch are computed.

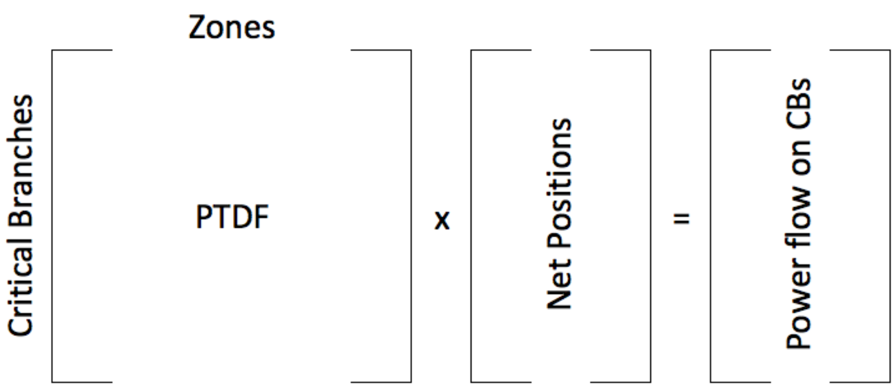


Figure 2.3. PTDF matrix principle

In the Figure 2.3 there is showed how power flows on all critical branches using PTDF matrix and net positions of each zone can be computed.

The whole process of PTDF computation is in detail also described in [9].

2.3.9 Remaining available margin

Remaining available margin of each critical branch is the second important output of FB calculation. The computation is in the equation (2.4) below. Each component of this equation was already presented above. And the remaining available margin plays the same role as available transmission capacity in NTC approach.

$$RAM = F_{max} - F_{ref} - FRM - FAV \tag{2.4}$$

Where:

RAM	Remaining Available Margin
F_{max}	Maximum Flow on CB
F_{ref}	Reference Flow on CB
FRM	Flow Reliability Margin
FAV	Final Adjustment Value

2.4 NTC and FB domain comparison

To demonstrate differences between NTC and FB approach I have chosen an example from [7] showing it on capacity domain. Capacity domain shows which net positions of zones are acceptable without endangering grid security.

In the figure 2.4 there is an example with three biding zones connected by three cross-zonal lines which have the same impedance and remaining available margin 1000 MW. In this example only A and B zones are generation zones and zone C is a slack zone which absorbs power generated in zone A and zone B. PTDF matrix for cross-zonal lines is in this case in the Table 2.3.

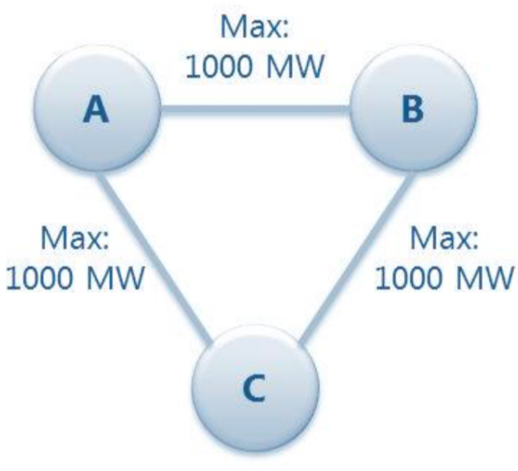


Figure 2.4. Example with 3 nodes [7]

Line	**Zone** A	B	C
A-B	33%	-33%	0%
A-C	67%	33%	0%
B-C	33%	67%	0%

Table 2.3. PTDF of NTC/FB example

In the Figure 2.5 there is a comparison between two capacity domains [1]). We can see that FB domain has bigger area and therefore is better than NTC. Below there is an explanation how we get the domains.

For NTC we get maximum net positions of A and B 1500 MW (not at the same time) because at this position the maximum flow on A-C or B-C is reached. For TSO is therefore logical to limit the capacity to 750 MW on each line which means before mentioned maximum net position of 1500 MW without endangering the grid security.

With FB calculation we obtain more solutions because we can combine net positions together. For example, NP 2000 MW in zone A, - 1000 MW in zone B and – 1000 MW in zone C is an acceptable situation [2]) because flows do not overload any line. Another situation which is in FB domain and not in NTC domain is following: NP of zone A 1000 MW, NP of zone B 1000 MW and NP of zone C -2000 MW [3]).

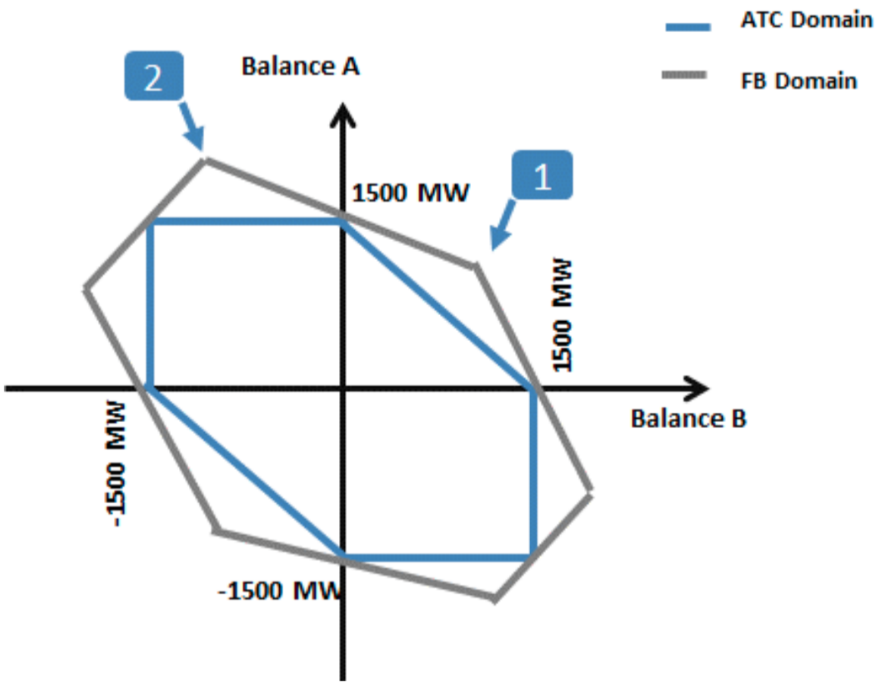


Figure 2.5. FB vs NTC domain [7]

Proof that these situations from FB domain do not endanger grid security is done below in Table 2.4 [4]) where all PFs are $\leq$ 1000 MW.

Line	Bidding zone A	B	C		NP1	NP2		PF1	PF2
A-B	33%	-33%	0%		2000	1000		1000	0
A-C	67%	33%	0%	x	-1000	1000	=	1000	1000
B-C	33%	67%	0%		-1000	-2000		0	1000

Table 2.4. FB domain proof

[1]) Please note that there is NTC domain labeled as ATC domain.
[2]) It is marked as 1 in the Figure 2.5.
[3]) It is marked as 2 in the Figure 2.5.
[4]) Using the principal shown in the Figure 2.3.

Chapter 3
General principals of income distribution

This chapter describes what a congestion income is and different situations when it is generated. There are also presented various methodologies for income distribution from congestion management.

As it happens with almost every kind of commodity, with cross-zonal capacity is that the same, there are situations when there is too much or vice versa a lack of it. If the cross-zonal capacity is sufficient it is usually allocated for free, on the other hand when it is not, from the economic point of view, the best way how to allocate the capacity is to give it to somebody, who is willing to pay the highest price.

3.1 Income generation

The definition of congestion income from CACM Network Code is following: *"congestion income are revenues received as a result of capacity allocation"*. [5]

Nowadays, there are two main attitudes regarding the allocation principle of how the income is created. The first one is in explicit allocation and the second one implicit allocation. Both situations are described in detail below.

3.1.1 Explicit capacity allocation

Available cross-zonal capacity auction process is following: market participants secretly place their bids. These bids consist of requested amount of cross-zonal capacity and unit price (EUR/MWh) they offer for it. After defined deadline these bids are analyzed and sorted from the highest price to the lowest. Then, in such order the bids are fulfilled till the cross-zonal capacity runs out. Offered price of the last satisfied bid is the final unit price for each participant.

The income from these auctions equals offered cross-zonal capacity multiplied by final unit price and timeframe for which the capacity is allocated.

In the Figure 3.1 there are demonstrated: situation with congestion - non-zero unit price which means congestion income generation and situation without congestion and zero unit price which means no congestion income.

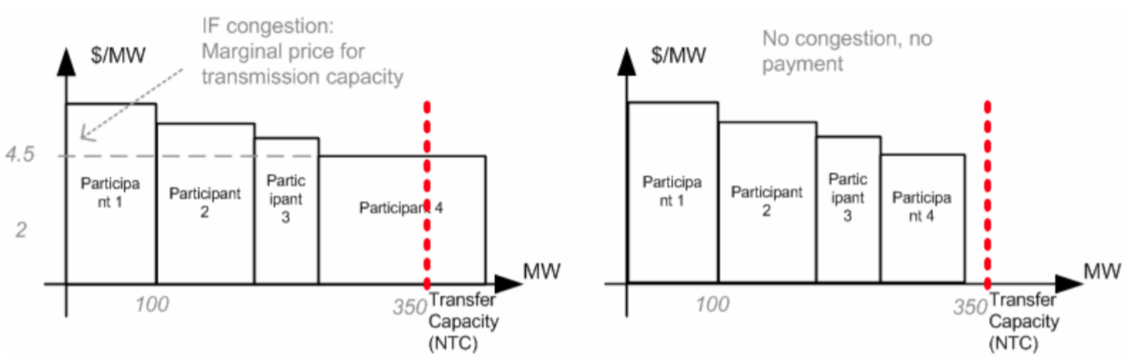


Figure 3.1. Explicit auction - congestion income [10]

3.1.2 Implicit capacity allocation

In implicit allocation scheme on cross-zonal line, traders do not need to buy electricity and cross-zonal capacity separately. Nowadays, implicit allocation works in day-ahead market in major part of Europe.

There are two main situations that can occur and in one of them no revenue is generated. This example is shown in the Figure 3.2. The price in bidding zone A is lower than the price in bidding zone B, therefore there is a push to export electricity from zone A to zone B. When the cross-zonal capacity is sufficient then prices in both areas match, creating new clearing price.

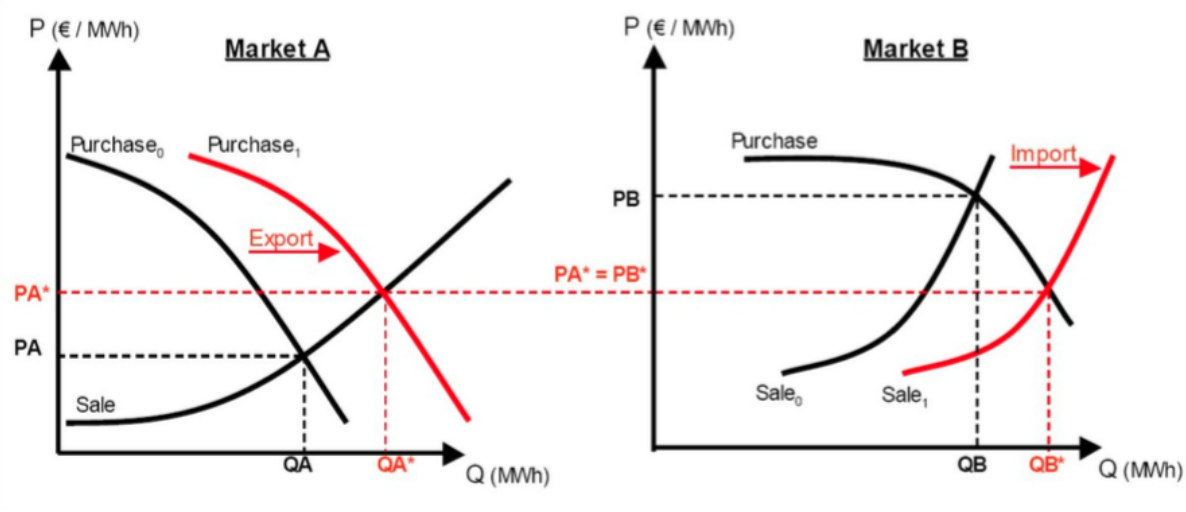


Figure 3.2. Cross border trade - no congestion [11]

The second situation is when there is a lack of cross-zonal capacity. Traders try to export cheaper electricity from zone A to zone B, but the export is limited. Then clearing price in bidding zone A rises and clearing price in bidding zone B declines, but they do not match.

This situation is shown in the Figure 3.3.

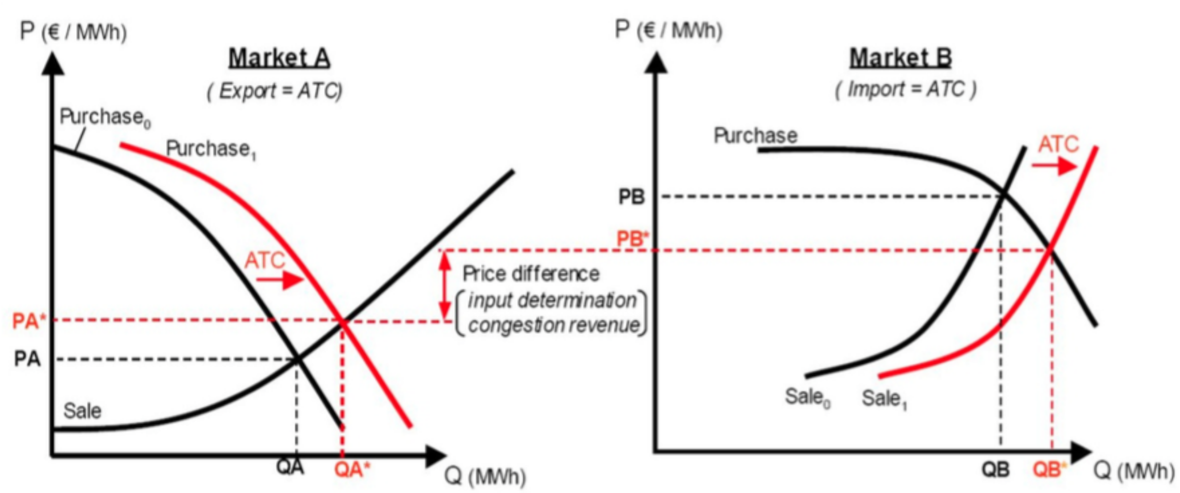


Figure 3.3. Cross border trade - congestion [11]

And in this case a congestion income occurs because there are different prices in connected areas and the cross-zonal lines are fully loaded. A seller from an area with lower clearing price (in our case bidding zone A) gets price valid in his area (PA*), but a buyer from an area with higher clearing price (bidding zone B) pays for the same electricity price valid in his area (PB*).

This congestion income can be intuitively computed as:

$$CI_{ij} = PF_{i\to j} \times \Delta CP_{i\to j} \tag{3.1}$$

Where:

CI_{ij}	Congestion income associated to i/j cross-zonal profile
$PF_{i\to j}$	Planned power flow on profile between zone i and zone j
$\Delta CP_{i\to j}$	Clearing price difference between zone i and zone j

In most market coupling initiatives there is more than one cross-zonal profile. The total congestion income is then sum of all congestion incomes on cross-zonal profiles.

$$CI = \sum_{j=1}^{NZ} \sum_{j>i}^{NZ} CI_{ij} \tag{3.2}$$

Where:

CI	Total congestion income
CI_{ij}	Congestion income associated to i/j cross-zonal profile
NZ	Number of zones

Nowadays, the congestion income is allocated in the following way. Each profile gets the congestion income associated to it and each TSO operating this profile gets half of it. [1])

$$CI_i = \frac{1}{2} \times \sum_{j=1}^{NZ} CI_{ij} \tag{3.3}$$

Where:

CI_i	Congestion income for TSO operating in zone i
CI_{ij}	Congestion income associated to i/j cross-zonal profile

Using equations (3.1), (3.2) and (3.3) we can write down the following equation (3.4) with overall congestion income so it can be compared with following methods in easier way.

$$CI_i = \frac{1}{2} \times CI \times \frac{\sum_{j=1}^{NZ} PF_{i\to j} \times \Delta CP_{i\to j}}{\sum_{j=1}^{NZ} \sum_{j>i}^{NZ} PF_{i\to j} \times \Delta CP_{i\to j}} \tag{3.4}$$

This congestion income allocation method awards each cross-zonal profile with income the profile generated, so it seems to be the fairest. On the other hand, in situations with a big clearing price difference between two zones but with really low capacity of cross-zonal profile, this profile which needs investments does not get much money. Also each TSO has no certainty that it will get a part of congestion income at all.

[1]) This statement is based on assumption that each bidding zone is operated by one TSO – it is valid for 4M MC but not for all market coupling initiatives.

In next two sections below, more different ways of income allocation are presented, these attitudes were described in [12] and [13]. The number of different attitudes is countless, but because income allocation scheme should be transparent and easy to understand [1]) I have chosen allocation schemes that in my opinion fulfill these criteria.

3.2 Allocation methods based on usage

An allocation based on line usage means that the total congestion income is distributed according to the use of cross-zonal lines. At this point it is important to highlight that the power flow [2]) is the input of computation, not the real physical flow [3]).

3.2.1 Absolute usage

This method allocates income according to the power line usage and TSO is rewarded for absolute transmitted electricity. This brings money to cross-zonal profile regardless it is congested or not - TSO has certainty that it will get a part of total congestion income if there is a flow on its cross-zonal profile. Cross-zonal profiles with big capacity and big power flows are awarded despite the fact that investments are needed for profiles with low capacity.

Absolute usage method is mathematically expressed in following equation:

$$CI_{ij} = CI \times \frac{|Q_{ij}|}{\sum_{j=1}^{NZ} \sum_{j>i}^{NZ} |Q_{ij}|} \tag{3.5}$$

Where:

CI_{ij}	Congestion income associated to i/j cross-zonal profile
CI	Total congestion income
Q_{ij}	Planned power flow on cross-zonal profile i/j
NZ	Number of zones

3.2.2 Relative usage

The method based on relative usage of power lines rewards TSO according to the relative usage of its cross-zonal capacity. It also brings certainty to TSO that it will get part of congestion income and because of using relative share it brings investments to the most loaded profiles. On the other hand, TSOs may have interest in lowering its cross-zonal capacity, which is not wanted, in order to get more money.

Computation is following:

$$CI_{ij} = CI \times \frac{Q_{ij}/TBC_{ij}}{\sum_{j=1}^{NZ} \sum_{j>i}^{NZ} Q_{ij}/TBC_{ij}} \tag{3.6}$$

Where:

CI_{ij}	Congestion income associated to i/j cross-zonal profile
CI	Total congestion income
Q_{ij}	Planned power flow on cross-zonal profile i/j
NZ	Number of zones
TBC_{ij}	Total capacity of i/j cross-zonal profile

[1]) These are discussed in Section 4.2.
[2]) Computed either with NTC or FB method.
[3]) Division and equations are based on what is described in [12] but the label “based on real line usage” is in my opinion misleading, so the word “real” was omitted. Also equations were turned into unified style used in this thesis without any changes in results.

3.3 Allocation method based on shadow price

An allocation based on shadow price has its own section in this chapter because it is quite different from the others. So far I have described methods which award cross-zonal profile, but as it was described earlier in the Chapter 2 not only cross-zonal lines can be congested.

We can use this method for FB allocation because it can work with critical branches. But first I explain what shadow price means. In this case shadow price is a value which represents economic surplus of increasing capacity of critical branch for example of 1 MW. This implies that shadow price of a not congested critical branch equals to zero, because nobody is willing to pay for increased capacity when the critical branch is not fully loaded. And on the other hand, congested branch always has shadow price ≥ 0.

This method is expressed by following equation:

$$CI_j = CI \times \frac{SP_j}{\sum_{i=0}^{m} SP_i} \tag{3.7}$$

Where:

CI_j	Congestion income associated to critical branch j
CI	Total congestion income
SP_j	Shadow price of critical branch j
m	Number of critical branches

We can also use this allocation scheme in NTC world using some assumptions. First assumption is that cross-zonal profile is considered as one critical branch and the second one is that the increment of capacity has no influence on clearing prices in affected zones. Then we can get the shadow price of cross-zonal profile as a clearing price difference between respective zones.

All presented income allocation methods are used in the Chapter 5 where there is an educational example of the computation. They are used for day-ahead market coupling congestion income allocation, which means for implicit allocation, but they can be used accordingly for explicit allocation.

Chapter 4
Analysis of CWE methodology of income allocation

In this chapter there is described the current methodology of income allocation in CWE region, which is described in official paper [8]. CWE region includes Belgium, France, Germany and Netherlands and forms market coupling which is the only one European initiative that is based on Flow-Based approach. Criteria for income allocation are also presented.

First the general definitions are introduced. Used terminology is clarified at each equation [1]).

4.1 General definitions

The total congestion income can be computed in two different ways, with the same result, of course. The first way is using net positions of all zones and clearing prices in all zones which is in my opinion simpler and easier to understand. This method is mathematically expressed by following equation:

$$CI = -\sum_{i}^{NZ} NP_i \times CP_i \tag{4.1}$$

Where:

CI	Total congestion income
NP_i	Net position of zone i
CP_i	Clearing price of zone i
NZ	Total number of zones

The other calculation method is based on shadow prices [2]) and flows on critical branches. The equation (4.2) shows the computation of the total congestion income using shadow prices. On the equation (4.3) the computation of additional aggregated flow, which is also used later in this chapter, is presented.

$$CI = \sum_{i}^{NC} AAF_i \times SP_i \tag{4.2}$$

$$AAF_i = \sum_{i}^{NZ} PTDF_{i,j} \times NP_j \tag{4.3}$$

[1]) Please note that terminology used in this thesis is slightly different to that in [6] to fit already used terminology. For example use of "zone" instead "hub" - which has the same meaning.
[2]) The meaning of shadow price was already explained in Chapter 3 in Section 3.3.

Where:

CI	Congestion income
NC	Total number of critical branches
AAF_i	Additional aggregated flow associated to critical branch i
SP_i	Shadow price associated to critical branch i
$PTDF_{i,j}$	Power transfer distribution factor of zone j on critical branch i
NP_i	Net position of zone i

4.2 Criteria for allocation mechanism

There are some criteria which the congestion income methodology has to fulfil. First there are criteria set by CACM network code [5]:

- *facilitate the efficient long-term operation and development of the electricity transmission system and the efficient operation of the electricity market of the Union*
- *comply with the general principles of congestion management provided for in Article 16 of Regulation (EC) No 714/2009*
- *allow for reasonable financial planning*
- *be compatible across time-frames*
- *establish arrangements to share congestion income deriving from transmission assets owned by parties other than TSOs*

In my opinion the most important requirement is that the methodology should be transparent and easy to understand. It should give signals to TSOs where the investment is needed. Then the methodology should not provide disincentives for TSOs to optimize the offered capacity and be resistant to gaming on data manipulation. However reasonable financial planning is very hard with the congestion income because its occurrence has random character. Obviously all involved parties should be part of the methodology – for example other than TSO owners of HVDC lines. On the other hand, under Flow-Based approach the negative congestion income may occur [1]) and in these situations TSO should not pay this negative price but other TSOs should help to make the congestion income for each TSO non-negative.

All criteria which the methodology in this chapter complies are described in [8].

According to Regulation 714/2009 [14] the congestion income shall be used for guaranteeing the availability of allocated capacity and maintaining or increasing capacities through new investments. And if this cannot be achieved the income shall be placed on special account and spared for future investments. Or if the regulatory authority allows it can be taken into account (up to a maximum amount) when calculating the network tariffs.

4.3 Allocation mechanism

Presented allocation mechanism is described on the Flow-Based Market Coupling results from the 3th January, 2013, 9:00 – 10:00 – the same as in [8]

First, in the Table 4.1 there are values of net positions and clearing prices in CWE region.

[1]) When flow against clearing price difference makes an optimal solution.

Zone	Net Position [MW]	Clearing Price [EUR/MWh]
BE	-1317,6	49,29
FR	-1331,9	45,59
DE	5434,8	39,96
NL	-2784,9	51,15

Table 4.1. CWE example NP and CP

The total congestion income resulting from this situation can be computed using the equation (4.1). This equation with particular values from the Table 4.1 is following:

$$CI = 1317,6 \times 49,29 + 1331,9 \times 45,59 - 5434,8 \times 39,96 + 2784,9 \times 51,15 = 50939 \quad (4.4)$$

The total congestion income equals to 50 939 EUR.

4.3.1 Long term capacity rights

There is a little difficulty with long-term capacity rights. Because there is usually a difference between long-term allocated and nominated capacity [1]) this methodology uses a sharing key that is "nomination proof". And in this step the net positions are modified with long term nominations.

Updated net positions are in table 4.2.

Zone	Net Position [MW]	Clearing Price [EUR/MWh]
BE	-1912,6	49,29
FR	-756,9	45,59
DE	5754,4	39,96
NL	-3084,9	51,15

Table 4.2. CWE example updated NP and CP

Now we can compute the aggregated additional flows which are the inputs of the sharing key using the equation (4.5).

Results of this computation are introduced in the Table 4.3 and illustrated on the Figure 4.1.

$$AAF_i = \sum_{j=1}^{NZ} PTDF_{i,j} \times NP(FBMC + LTN)_j \quad (4.5)$$

Where:

AAF_i	Additional aggregated flow associated to network constraint i
NZ	Number of zones
$PTDF_{i,j}$	Power transfer distribution factor of zone j on critical branch i
NP_j	Net position of zone j
$FBMC$	Part of NP from DA MC (including resold LTA)
LTN	Correction of NP due to LTN

[1]) More about this phenomenon in Chapter 2 in Section 2.0.1.

Border	Type	AAF_{ij} [MW]	$\Delta\|CP\|$ [EUR/MWh]	share
DE-FR	int	-1299,6	3,7	16,95%
FR-DE	int	-1049,4	5,63	13,69%
DE-NL	int	3697,9	11,19	48,23%
NL-BE	int	613	1,86	8,00%
FR-DE	ext	-1007,1	5,63	13,14%
sum		7667		

Table 4.3. CWE example AAFs

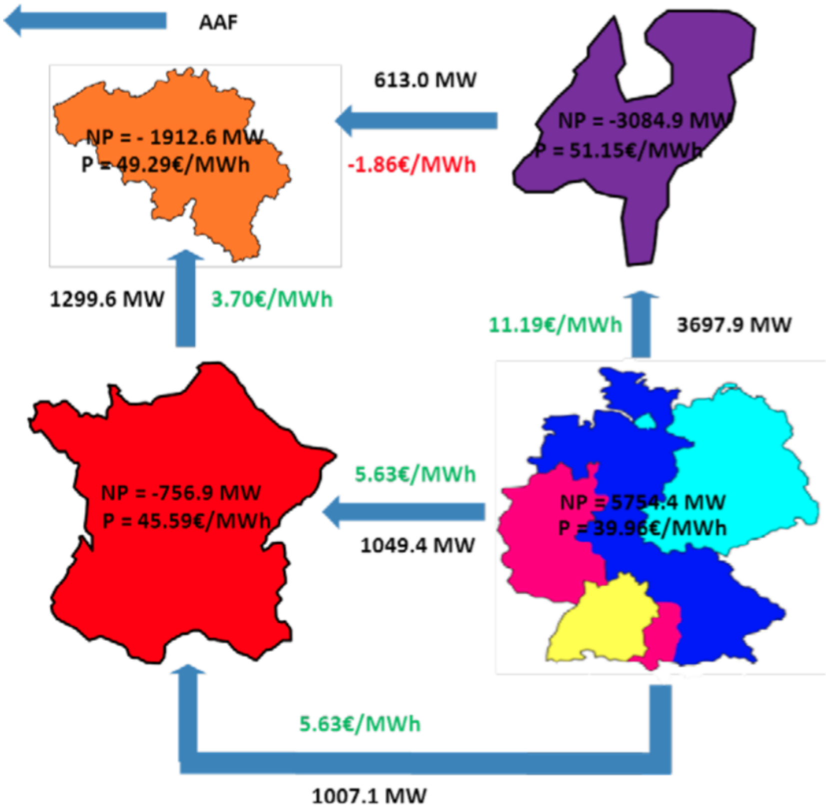


Figure 4.1. CWE - example [8]

4.3.2 Border value computation

This congestion allocation mechanism is very similar to currently used mechanism under NTC [1]). The grounds are the same – computation of the border value by multiplying AAFs by the price difference. But then the absolute border value is taken into account because as I have mentioned before, negative border value may occur under FB. Computation is done according to following equation:

$$CI\_Zone_i^{CBCPMABS} = \frac{1}{2} \times CI \times \frac{\sum_{j=1}^{NZ} |AAF_{zone\ i \to j} \times \Delta CP_{zone\ i \to j}|}{\sum_{j=1}^{NZ} \sum_{j>i}^{NZ} |AAF_{zone\ i \to j} \times \Delta CP_{zone\ i \to j}|} \tag{4.6}$$

[1]) This sharing key can be found in Chapter 3 in Section 3.1.2 equation (3.4).

Where:

CI	Congestion income
$AAF_{zone\ i \to j}$	Additional aggregated flow associated from zone i to zone j
$\Delta CP_{zone\ i \to j}$	Clearing price difference between zone i and zone j
NZ	Number of zones

Because of the absolute border value and updated net position, the sum of single congestion incomes per zone can be higher than the total congestion income. That is why the rescaling has to be done. It is a really simple procedure – the unscaled congestion income is multiplied by k factor. k factor is the value of total congestion income divided by the sum of unscaled congestion incomes, computation is in our example following:

$$k = \frac{CI}{CI_n} = \frac{50939}{58906} = 0,865 \tag{4.7}$$

Where:

k	Scaling factor
CI	Total congestion income
CI_n	Sum of unscaled congestion incomes

In CWE region there are 4 internal borders and 1 external border which are taken into account. Unscaled and scaled congestion income values per border are presented in the Table 4.4.

Border	Type	Congestion Income [EUR] unscaled	scaled
BE-FR	int	4808,52	4158,14
FR-DE	int	5908,12	5109,01
DE-NL	int	41379,50	35782,67
NL-BE	int	1140,18	985,96
FR-DE	ext	5669,97	4903,07

Table 4.4. CWE example - border values

4.3.3 Resale Cost

The difference between long-term allocation and long-term nomination has been already presented. Also the principle UIOSI which gives the market participant opportunity to earn some money for not nominated capacity has been described. The resale cost value is therefore computed to evaluate the payment for participants which have not nominated their allocated capacity in the right direction of clearing price difference on cross-zonal profile. The resale cost can be computed by following way:

$$Resale\ Cost = \sum_{i,j} (LTA_{i \to j} - LTN_{i \to j}) \times max(0, \Delta CP_{zone\ i \to j}) \tag{4.8}$$

Where:

$LTA_{i \to j}$	LTA capacity on the border in direction from i to j
$LTN_{i \to j}$	LTN capacity on the border in direction from i to j
$\Delta CP_{zone\ i \to j}$	Clearing price difference between zone i and zone j

Results of resale cost computation are in the Table 4.5. More details about resale cost computation are in [8]. Important point is that in case of negative income per border it is set to zero and other borders contribute to the difference on pro rata basis.

Zone	Resale Costs [EUR]	CI after RC [EUR]
BE	2518,34	53,71
FR	3483,23	1150,34
DE	5802,26	14643,58
NL	5352,21	13032,10
external	2591,4	2311,67

Table 4.5. CWE example - resale costs

4.3.4 External border sharing

Another difference between NTC and FB approach is that we can compute flows through external borders/zones. As follows from previous computation there is a congestion income associated with external borders. Under CWE methodology is this income shared in following way.

50 % of the external border income goes to a "special package" and the remaining 50 % of the external border income goes to the internal zone TSO. This is not new, halving of border income and associating it to involved zones is common case. But in this situation the methodology behaves like there is no other partner on external border. That is why all internal borders/zones get its share on the money which are in the "special package" and the division is based on share of AAF_i on sum of all $AAFs$ [1]). Please note that there is only one external border showed in Tables 4.3 and 4.4 but this external border (FR)-(DE) consist of two external borders: (FR)-(External zone) and (External zone)-(DE).

4.3.5 Total net congestion income

The total net congestion income per zone is computed according to the presented mechanism in following Table 4.6.

Zone	Congestion Income [EUR]		
	internal	external	total
BE	53,71	144,17	197,88
FR	1150,34	830,89	1981,24
DE	14643,58	1011,67	15655,25
NL	13032,10	324,94	13357,05

Table 4.6. CWE example - internal + external CI

From what was described above is apparent that the sharing key is very similar to the one which is currently used. Differences are in the possibility of the occurrence of the negative congestion income, which is resolved, and the inclusion of external borders to the computation. In my opinion it is not sure whether the treatment to external borders is fair. But, on the other hand, in the final form of the electricity market there will only be internal borders so it is only a temporary question.

[1]) Values of this share are in the Table 4.3.

Chapter 5
Analysis of different scenarios on cross border lines

This chapter is divided into two sections according to the capacity calculation method. Firstly, there is a NTC world analysis in which I analyze different congestion allocation schemes on real data. Unfortunately, there are no real data available for FB world analysis which is the second part of this chapter. That is the reason I had to make a model grid and analyze some model situations. I need to point out that this whole chapter is devoted to Day-Ahead electricity market.

5.1 NTC world analysis

I have labelled this section as "NTC world" because data set resulting from NTC capacity calculation is used throughout this section. In this section I show which situations can occur in 4M MC. 4M MC is a Market coupling initiative which includes day-ahead markets of the Czech Republic, the Slovak Republic, Hungary and Romania.

4M MC region is quite specific by the location of each country. As we can see in the Figure 5.1 this region resembles a snake. There are 4 countries, which are lined up one after another and that means there are only 3 cross-zonal borders – CZ/SK, SK/HU and HU/RO.

In this initiative the Czech Republic and Romania are operating 1 border each, whereas the Slovak Republic and Hungary are operating 2 borders each. This fact has an impact on the congestion income from market coupling – we can expect higher income for countries operating more involved borders.

Figure 5.1. 4M Market Coupling [15]

5.1.1 Input data

As an input data set served the annual report for electricity from Czech market operator OTE, a. s., which is available on their website [16]. For analysis in this thesis I have chosen year 2015 and its 8760 hour-values, provided in a .xls file.

5.1.2 Basic information and congestion occurrence

For a better picture of 4M MC in the Table 5.1 below there is a basic statistic of 4M MC operation in 2015.

	CZ	SK	HU	RO
Average Price [EUR/MWh]	32	34	41	36
Minimum Price [EUR/MWh]	-11	-11	0	0
Maximum Price [EUR/MWh]	99	121	150	68
Average Net Position [MW]	186	160	-12	-333

Table 5.1. 4M MC - countries

As it was written above, there are only 3 cross-zonal borders involved in 4M MC. In the Table 5.2 below there are some more pieces of information concerning each border. We can observe that the occurrence of congestion is the most common on SK/HU. Contrarily, it is the least common on CZ/SK border. This has simple explanation – the Czech and Slovakian grid are very well interconnected because in the past it was a grid of one state.

	CZ/SK	SK/HU	HU/RO
Number of Congestions	846	5 318	2 694
Average Price Spread [EUR/MWh]	13	12	14
Congestion Income [thousads EUR]	12 668	26 596	1 267
Total Congestion Income [EUR]		40 530 980	

Table 5.2. 4M MC - borders

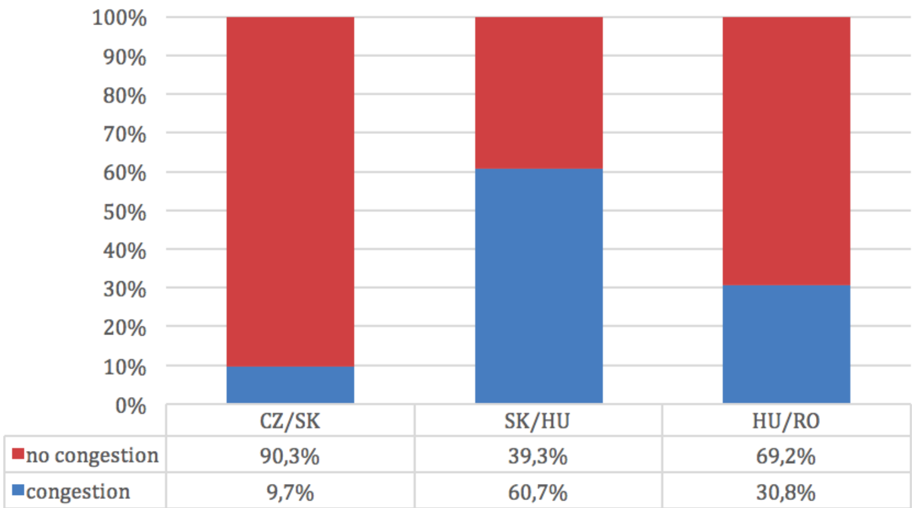


Figure 5.2. 4M MC - relative share of congestion

5.1.3 Possible situations

For the purpose of this analysis I created a VBA macro in MS excel in order to sort out different situations which occur in 4M MC. These situations are specified by the direction of the flow on each border. There are 8 (or 9) different possible options, the ninth option is when a situation with zero flow on border occurs. List of them is in the Table 5.3. Each situation is specified by a double-number code.

Situation no.	Power flow direction			Occurrence	
	CZ - SK	SK - HU	HU - RO	total	congestion
11	→	→	→	3190	2689
22	→	→	←	894	887
33	→	←	→	58	26
44	→	←	←	103	103
55	←	→	→	2511	1752
66	←	→	←	782	771
77	←	←	→	357	6
88	←	←	←	325	317
00	zero on one of borders			540	539

Table 5.3. List of situations.

From the Table 5.3 it is obvious that the most common situations are 11 – in this case the power flows “from west to the east” and 55 – same as 11, but with opposite flow on CZ/SK border.

5.1.4 Congestion income allocation methods

General principles of the income allocation were described in the Chapter 3. For my analysis I have chosen 4 methods and compared the amount of congestion income for each country. The summary of chosen methods is in the Table 5.4.

Method name	Label	Described in section
Commonly used	CI1	3.1.2
Absolute usage	CI2	3.2.1
Relative usage	CI3	3.2.2
Shadow price	CI4	3.3

Table 5.4. CI methodologies overview.

There is a simple example described below on which I demonstrate principals of each method which were used on input data.

Educational situation

Data used for this example correspond with 22nd hour on the 8th of January 2015. Data necessary for this computation are in the Table 5.5 below and in graphical representation in the Figure 5.3.

	CZ	SK	HU	RO
Clearing Price [EUR/MWh]	23,62	43,6	53,07	53,07
Net Position [MW]	1700	-1340	-77	-283
	CZ/SK	SK/HU	HU/RO	sum
Power Flow [MW]	1700,0	360,0	283,4	2343,4
Cross-border capacity [MW]	1700	360	1010	-
Relative Usage [%]	100 %	100 %	28 %	228 %
Clearing Price spread [EUR/MWh]	20,0	9,5	0,0	29,5
Total Congestion Income [EUR]	37375,2			

Table 5.5. Educational example data

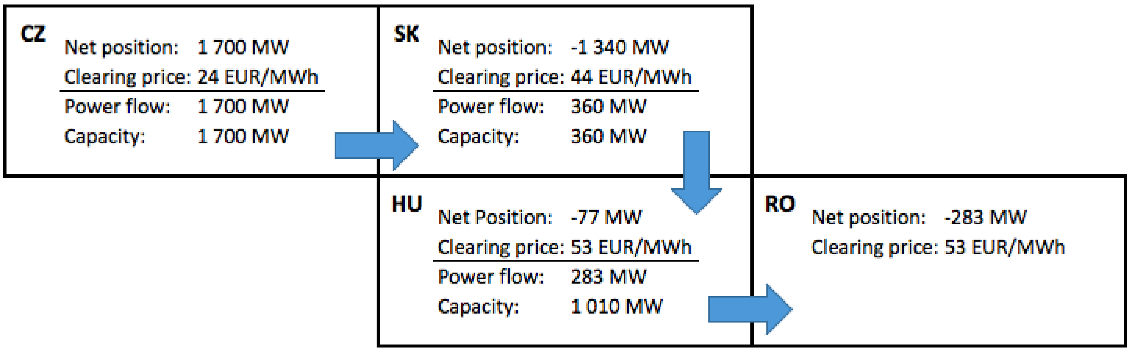


Figure 5.3. Educational example

Below there is in detail described the calculation procedure for each allocation method. All calculations are made only for CZ/SK border. In all allocation methods there is a border congestion income computed, this amount is then shared among TSOs operating the border equally.

Used shortcuts in following equations are:

- CI Total congestion income, with index cz/sk congestion income that belongs to cz/sk border
- PF Power flow on border marked in index, $\sum$ PF is sum of all PF
- ΔCP Clearing price spread on border marked in index, $\sum \Delta$ CP is sum of all Δ CP
- RU Relative usage of border marked in index, it is quotient of PF and Cross border capacity, $\sum$ RU is sum of all RU

All values used in following computations can be found in the Table 5.5.

CI1

This income allocation method is commonly used for example in 4M MC. It awards only the border on which the congestion occurs. So the congestion income stays where it is generated.

$$CI_{cz/sk} = PF_{cz/sk} \times \Delta CP_{cz/sk} = 1700 \times 19,98 = 33966 EUR \tag{5.1}$$

- **CI2**

  This income allocation method distributes the total congestion income by share of the power flow on sum of all power flows in market coupling. Which means that all borders get a part of the congestion income. The value depends on the power flow on the border, not on the fact if it was congested or not.

$$CI_{cz/sk} = CI \times \frac{PF_{cz/sk}}{\sum PF} = 37375 \times \frac{1700}{2343,4} = 27113EUR \tag{5.2}$$

- **CI3**

  This income allocation method distributes the total congestion income by share of the relative usage of one border on sum of all relative usages in market coupling. This method also allocates the congestion income to all borders and the share depends on a relative usage of the border.

$$CI_{cz/sk} = CI \times \frac{RU_{cz/sk}}{\sum RU} = 37375 \times \frac{1}{2,28} = 16393EUR \tag{5.3}$$

- **CI4**

  This allocation method distributes the total congestion income by share of the clearing price spread of the border on the sum of all clearing price spreads. So only congested borders get part of congestion income.

$$CI_{cz/sk} = CI \times \frac{\Delta CP_{cz/sk}}{\sum \Delta CP} = 37375 \times \frac{19,98}{29,45} = 25357EUR \tag{5.4}$$

5.1.5 Results

Using a model in MS Excel I was able to compute the congestion income per border using different allocation methods for all 8760 hours of year 2015. I think it is needed to point out that the total congestion income is fixed and it does not matter which congestion allocation method is used. In 2015 it was circa 40,5 million EUR (around 1,1 billion CZK). What actually changes is the relative share of each border. The volumes of congestion income per border are showed in graph in the Figure 5.4.

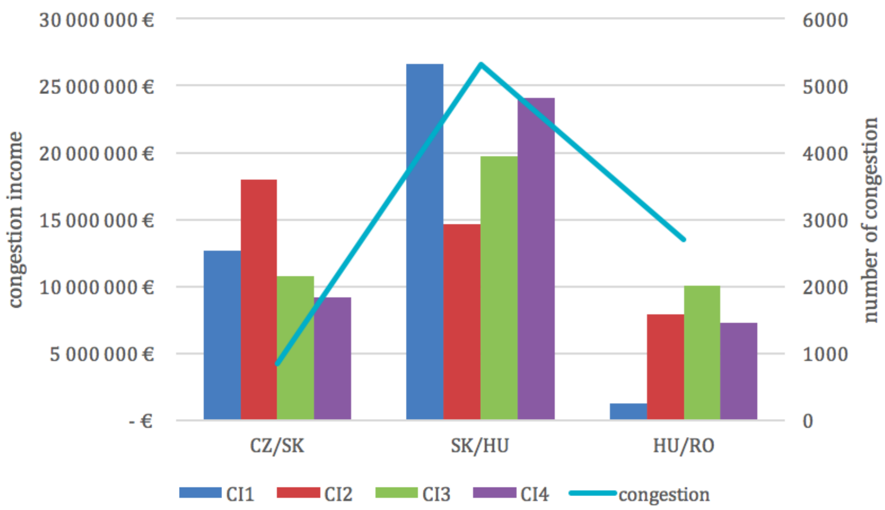


Figure 5.4. Graph - CI volume per border

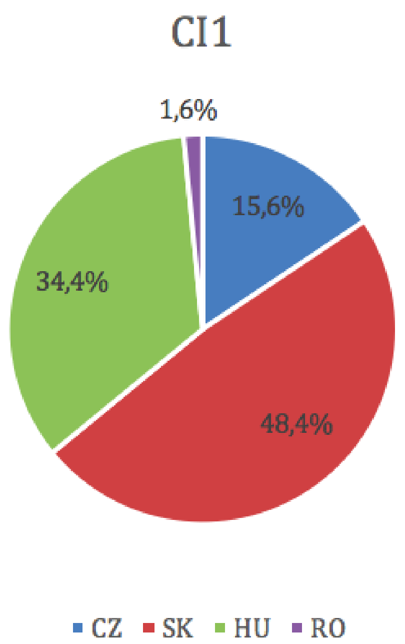


Figure 5.5. CI1 relative shares

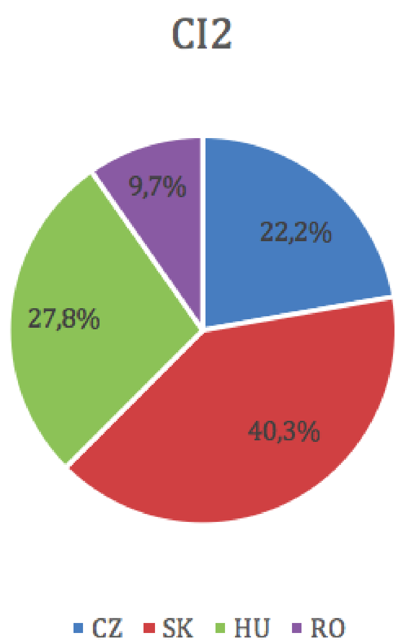


Figure 5.6. CI2 relative shares

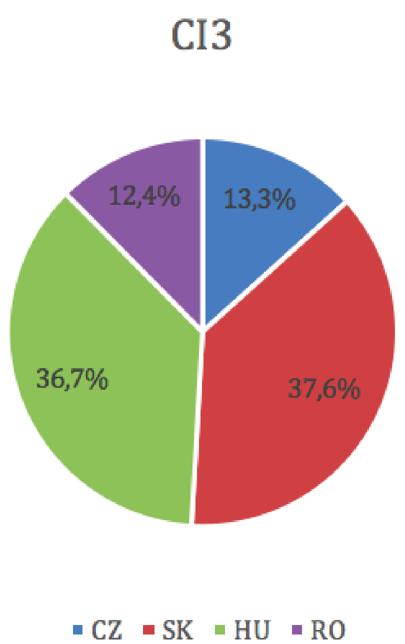


Figure 5.7. CI3 relative shares

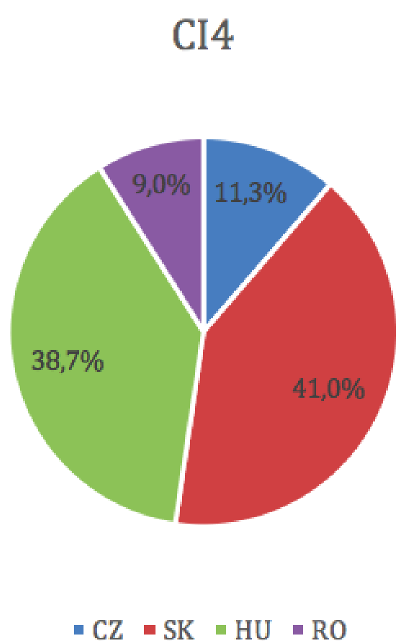


Figure 5.8. CI4 relative shares

From the Figure 5.5 to the Figure 5.8 there are the relative shares of each country on the congestion income. We can see quite interesting result - each country reaches maximum share of the congestion income using different method. From the Czech Republic's point of view, we can say that CI2 is the best because it gives the highest amount of money. This phenomenon is caused by large volumes of energy flowing on CZ/SK border which has, compared to other borders, much bigger capacity. For the

Slovak Republic the currently used method CI1 is supreme as the Slovak Republic gets almost one half of the total congestion income collected in 4M MC. Despite the variance in computation of CI3 and CI4 relative shares of all zones are comparable. There are some slight differences though, so the CI3 method is better for Romania and the CI4 for Hungary.

5.2 FB world analysis

This second section is named "FB world" because here I analyze a model situation, which is specified by Flow-Based parameters. Initially I intended to analyze real data in the same way as in the first section, but there is a big problem with FB data availability. Countries in CEE region are only in the first stages of implementing Flow-Based procedure and for me it was impossible to obtain data I needed. That is why I came up with an alternative solution: a simulation based on fictional power grid. The whole computation was made in MS Excel using VBA macros.

5.2.1 Power flow computation

For FB capacity parameters computation, the power flow equations are crucial, because as I have mentioned in the Section 2.3.8, PTDF matrices are formed by the change in power flows in different situations. In this section I present equations I used in my model and assumptions which are needed to be accepted. Everything is described in more details in [17] and [18].

Used terminology in this section is as follows:

P_k	Active power flow of node k
P_{kj}	Active power flow between node k and node j
V_k	Voltage magnitude in node k
G_{kj}	Real part of Admittance matrix - k^{th} row and j^{th} column
B_{kj}	Imaginary part of Admittance matrix - k^{th} row and j^{th} column
N	Number of nodes
θ_k	Phase angle of node k

The real power flow equation (5.5) is showed below. Next, there are some assumptions which are taken into account to simplify the computation. According to the first assumption only the real power equation is needed and the reactive power equation is not relevant in this computation.

$$P_k = \sum_{j=1}^{N} |V_k||V_j|(G_{kj} \times \cos(\theta_k - \theta_j) + B_{kj} \times \sin(\theta_k - \theta_j)) \tag{5.5}$$

Assumptions

- Real power $\gg$ Reactive power
$$P_{kj} \gg Q_{kj}$$
- Resistance $\ll$ Reactance
$$G = 0$$
- Angle difference of voltage phasors between two nodes connected with a line is small
$$\sin(\theta_k - \theta_j) = (\theta_k - \theta_j)$$

- Voltage magnitude in per unit system is close to 1

$$|V_k| = |V_j| = 1$$

Equation (5.5) modified according to presented assumptions is below:

$$P_k = \sum_{j=1,k\neq j}^{N} B_{kj} \times (\theta_k - \theta_j) \tag{5.6}$$

Equation (5.5) can be written down for each node of the grid and from these equations we are able to obtain a matrix form which can be expressed as following:

$$P_k = B_{kk} \times \theta_k \tag{5.7}$$

Now we can express θ_k as:

$$\theta_k = B_{kk}^{-1} \times P_k \tag{5.8}$$

Because B_{kk} matrix is singular we cannot make an inverse matrix to it. There is a dependency in equations, so we need to choose one node as a reference with $\theta_l = 0$ and eliminate corresponding l^{th} row and l^{th} column. Choosing a reference does not have any impact on the results of our computation. Then there is no obstacle in the computation of θ matrix.

Knowing all θ we can now calculate the power flow on line between node k and node j using following equation, which represent one part of equation (5.6).

$$P_{kj} = B_{kj} \times (\theta_k - \theta_j) \tag{5.9}$$

5.2.2 Input model

The input model used in this part is completely fictional and consists of 6 zones (countries), 33 nodes and 50 lines. I have taken inspiration from CEE part of power grid so with a large amount of imagination in can be liken to Poland (A), the Czech (B) and the Slovak (C) Republic, Austria (D), Hungary (E) and Romania (F). That is also why there are 4 internal zones (such as in 4M MC) and 2 external zones, which do not participate in market coupling initiative. Below I describe the simulation step by step with actions which are relevant during Flow-Based computation and are in direct relation to congestion income allocation.

STEP 1

First, each TSO sends a model of its grid to a merging entity, because for proper computation the whole grid has to be modelled. Grid model contains an estimation of crucial values, such as: generation, load, exchange program and grid topology. The grid model is made for each hour of the day, usually 2 days before day D – because at this time TSOs have quite precise estimations of upcoming situation.

Furthermore, TSO has to set Generation Shift Keys and Critical Branches with Critical Outages.

For illustration there is the Figure 5.9, where we can see 6 nodes (bold lines, marked with bold number) and 14 lines (marked with letter) and information about generation (green cell) and load (red cell) in MW in each node. These information we can observe also in the Table 5.6 with extra information about each node balance. Other information, such as lines parameters (starting and ending node, length), used during computation, can be found in Annex B.7 and B.8.

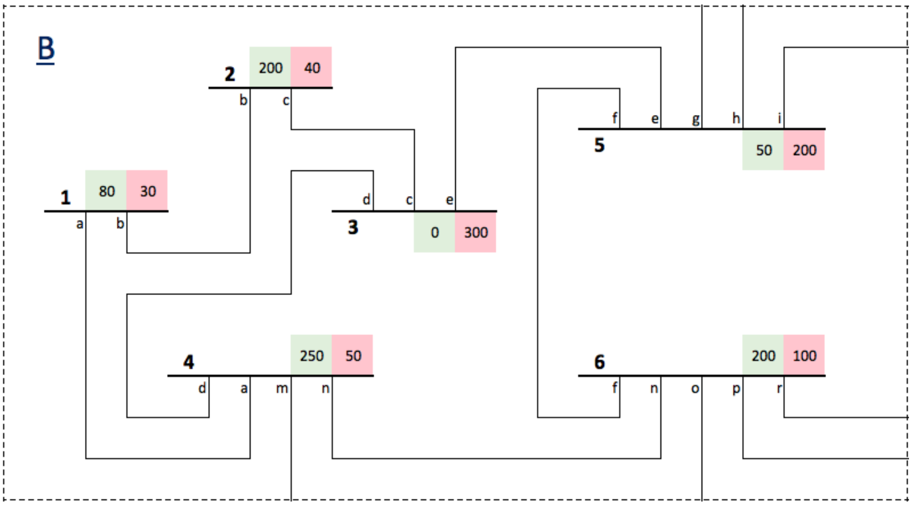


Figure 5.9. Grid of zone B

node	generation [MW]	load [MW]	balance [MW]	zone
1	80	30	50	B
2	200	40	160	B
3	0	300	-300	B
4	250	50	200	B
5	50	200	-150	B
6	200	100	100	B

Table 5.6. Information about nodes in zone B

STEP 2

The merging entity collects individual models from each TSO and merge them into a whole power grid model. The merged model of my power grid is in the Figure 5.10. The Table 5.7 contains information about net position of each zone. In this model situation I assume that external zones A and D do not have any commercial exchanges with other zones.

To make my model little bit more realistic I have approximately set the generation and load values as hourly average values for year 2015 in above mentioned countries divided by 10 to make lower and more synoptic numbers. Generation and Load data can be found in ENTSO-E Transparency platform [19]. These data cover not only the Day-Ahead electricity market, but all electricity market time-frames.

zone	generation [MW]	load [MW]	net position [MW]
A	1600	1600	0
B	780	720	60
C	300	320	-20
D	600	600	0
E	310	470	-160
F	770	650	120

Table 5.7. Zonal generation, load and net position

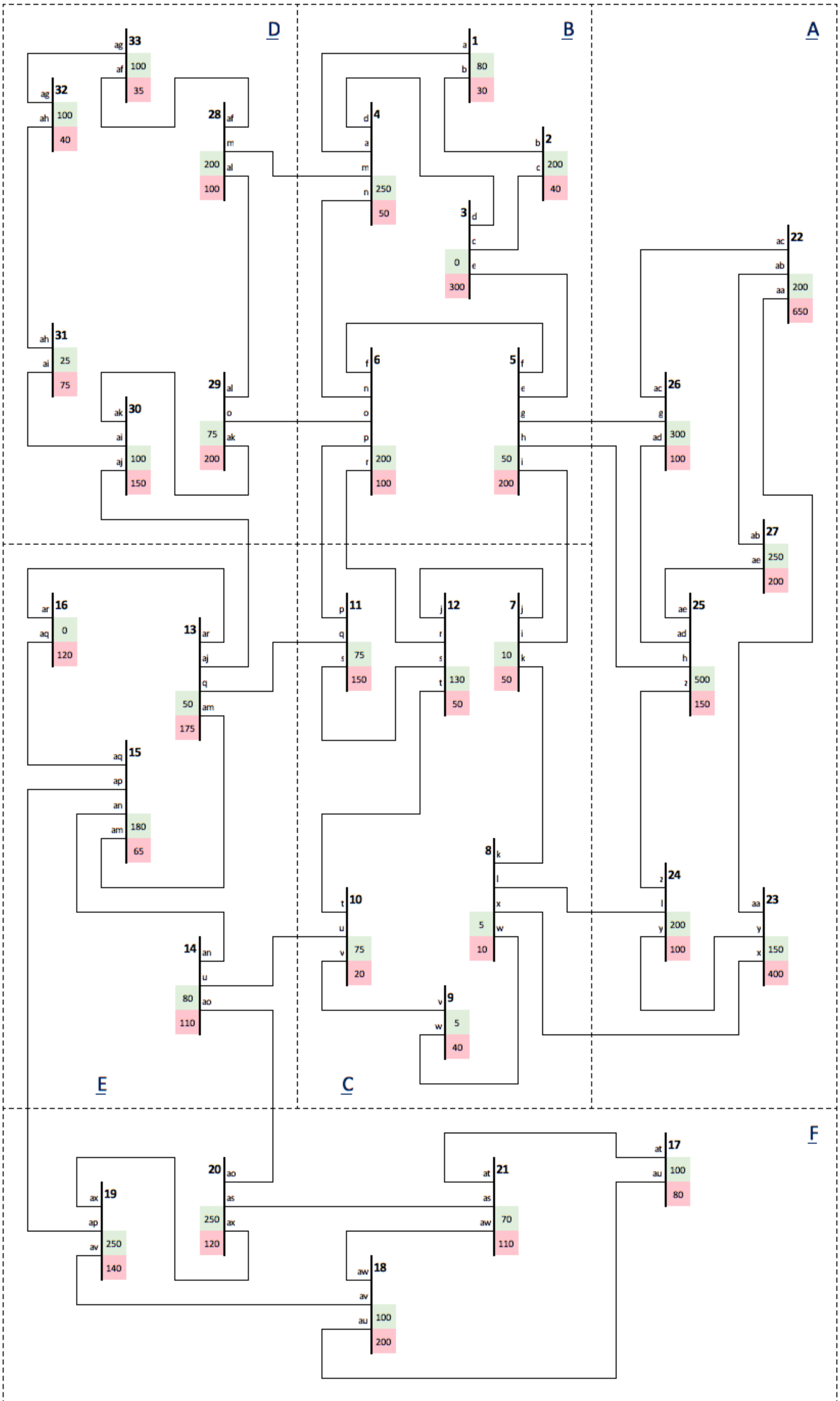


Figure 5.10. Model of the whole grid

5.2.3 Output

One of the reasons of modelling a fictional grid was to get the PTDF matrix. More information is presented below.

PTDF matrix is one of the most important components for the congestion income allocation as it was described in the Section 4.3. It contains information how each critical branch is affected by a change in net position of each zone. Based on the grid model and generation shift keys, which can be found in the Annex B.1 I have computed PTDF matrix which is in the Table 5.8 using procedures described in the Sections 5.2.1 and 2.3.8. Another educational example is described in [9].

Assumptions used during computation are following:

- Critical branches are all cross-zonal power lines only.
- All parameters are valid for given grid model and no critical outages are taken into account.
- Long term allocations are 100% nominated.

Please note that also the remaining available margin is, in the real world, important output, because with PTDF matrix these are key inputs for computation of flow-based market coupling results. However, it would make computations in this section more complicated and more assumptions or estimations would be required due to the real data unavailability. Later I will simulate final market results, therefore RAM is not needed for congestion income allocation computation in this case.

CB	zone A	zone B	zone C	zone D	zone E	zone F
G	-21,3%	1,8%	-4,2%	-0,3%	-2,7%	-3,0%
H	-37,9%	3,1%	-7,1%	-0,5%	-4,6%	-5,2%
I	-5,5%	7,5%	-14,1%	-1,0%	-8,1%	-8,8%
L	-16,3%	-1,9%	4,3%	0,3%	2,8%	3,1%
M	50,2%	59,4%	45,1%	8,2%	36,2%	37,3%
O	28,1%	24,2%	27,2%	-1,5%	17,7%	18,8%
P	0,6%	5,2%	-20,3%	-3,1%	-19,6%	-18,3%
Q	8,7%	8,9%	12,2%	-4,1%	-21,0%	-17,8%
R	-14,2%	-1,2%	-26,6%	-1,7%	-18,8%	-20,8%
U	13,0%	7,5%	15,5%	-2,7%	-32,9%	-38,3%
X	-24,5%	-3,1%	7,1%	0,5%	4,6%	5,1%
AJ	21,7%	16,4%	27,8%	-6,7%	46,1%	43,9%
AO	4,3%	2,5%	5,1%	-0,9%	5,7%	-44,0%
AP	-4,3%	-2,5%	-5,1%	0,9%	-5,7%	-56,0%

Table 5.8. PTDF matrix

As we can see from the Table 5.8 all critical branches fulfil the $> 5\%$ condition presented in the Section 2.3.1 and that is why they are significant in cross-zonal electricity market.

5.2.4 Model situations

Besides the PTDF matrix we need to know the electricity market results, which are provided by the power exchange. These are calculation results of market coupling algorithm.

Needful market results are as follows:

- Clearing price of each zone [EUR/MWh]
- Net position of each zone [MW]

For this computation I had to set these values by myself. I have taken inspiration in 4M MC in the same way as I did to set up the grid model. Used data set is in the Table 5.9 where there are 9 different situations as in this Chapter in the Section 5.1.3 with average values of net positions for Day-Ahead market only. Net positions of external zones are set to zero – they are not included in market coupling. In the same manner there are values of clearing prices in Table 5.10.

	Net Position [MW]					
	zone A	zone B	zone C	zone D	zone E	zone F
11	0	58	-11	0	1,5	-48,5
22	0	85	-46	0	-40,5	1,5
33	0	130	-170	0	70	-30
44	0	108	-140	0	30	2
55	0	-21,5	68,5	0	3,5	-50,5
66	0	-27	65	0	-40	2
77	0	-52	42	0	100	-90
88	0	-62	30	0	30	2
00	0	29	-4	0	-27	2

Table 5.9. FB model situations - net positions

	Clearing Price [EUR/MWh]					
	zone A	zone B	zone C	zone D	zone E	zone F
11	0	31,8	33,8	0	42,1	42,1
22	0	40	41	0	51	37,6
33	0	46	51,5	0	51,5	51,6
44	0	49,9	60,5	0	60,5	39,2
55	0	28,3	28,3	0	38,4	38,6
66	0	34,8	34,8	0	42,7	30,3
77	0	21,5	21,5	0	21,5	26,4
88	0	34,3	34,3	0	34,3	29,1
00	0	39	40,8	0	52,6	34,1

Table 5.10. FB model situations - clearing prices

Through the knowledge of data in the Table 5.8, in the Table 5.9 and in the Table 5.10 I have been able to compute the congestion income for each zone as it is described in the Section 4.3.

First, I have computed the power flow through all critical branches resulting from different net positions of zones in D-A market. These flows are in the Table 5.11, flows with negative sign mean, that the power flow has direction from end node to start node.

Because the congestion income distribution is based on cross-zonal border it is needed to aggregate flows to each border. Knowing the real power flow on each CB from data in the Table 5.11 we are able to sum flows on critical branches belonging to correspondent borders. The relation between CB and cross-zonal border is apparent from the model of the grid in the Figure 5.10 or from the Table B.8 in the Annex B.3. There are three internal borders and 2 external borders, results and the overview of the aggregation is described in the next section.

CB	Power Flow [MW]								
	11	22	33	44	55	66	77	88	00
G	2,9	4,5	8,5	6,9	-1,8	-2,2	-2,7	-3,3	1,4
H	5,0	7,7	14,5	11,9	-3,1	-3,7	-4,6	-5,6	2,3
I	10,1	16,0	30,7	25,2	-7,1	-8,1	-10,0	-11,5	4,7
L	-3,0	-4,6	-8,6	-7,1	1,9	2,2	2,7	3,3	-1,4
M	11,9	15,6	14,7	12,6	0,5	-0,5	-9,3	-11,7	6,4
O	2,2	1,2	-8,0	-6,2	4,5	4,4	-0,4	-1,2	1,5
P	13,8	21,4	33,0	27,7	-6,4	-7,1	-14,4	-15,6	7,3
Q	12,2	10,2	-18,5	-14,1	14,7	13,6	-4,5	-8,5	7,4
R	12,0	18,5	36,6	29,8	-8,1	-9,8	-10,6	-13,3	5,4
U	20,7	12,0	-28,2	-24,3	27,2	20,5	4,2	-10,6	9,7
X	-5,0	-7,7	-14,3	-11,7	3,1	3,7	4,5	5,5	-2,3
AJ	-14,1	-16,8	-6,7	-6,4	-5,1	-4,0	9,7	12,9	-7,9
AO	22,3	-3,2	11,6	-3,7	25,4	-0,5	46,1	0,8	-1,9
AP	26,2	1,7	18,4	1,7	25,1	-1,5	43,9	-2,8	-0,1

Table 5.11. Computed power flows in different situations

5.2.5 Results

The difference between NTC and FB world is that when using FB, we can compute flows on external borders and avoid the non-realistic assumption of NTC that the commercial flow is equal to the physical flow [1]) . In the Table 5.12 and 5.13 we can compare both commercial and physical flows on each border. There are no commercial flows on external borders [2]), but as you can see that it does not mean that they are not involved in the physical transmission of energy.

Border		Commercial flow [MW]								
start/end	type	11	22	33	44	55	66	77	88	00
B/C	int	58,0	85,0	130,0	108,0	-21,5	-27,0	-52,0	-62,0	29,0
C/E	int	47,0	39,0	-40,0	-32,0	47,0	38,0	-10,0	-32,0	25,0
E/F	int	48,5	-1,5	30,0	-2,0	50,5	-2,0	90,0	-2,0	-2,0
B/C	ext	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0
B/E	ext	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0

Table 5.12. FB commercial flows

Border		Physical flow [MW]								
start/end	type	11	22	33	44	55	66	77	88	00
B/C	int	35,9	55,9	100,3	82,8	-21,6	-25,0	-35,0	-40,3	17,4
C/E	int	32,9	22,2	-46,7	-38,4	41,9	34,0	-0,3	-19,1	17,1
E/F	int	48,5	-1,5	30,0	-2,0	50,5	-2,0	90,0	-2,0	-2,0
B/C	ext	8,0	12,3	23,0	18,8	-4,9	-5,9	-7,3	-8,8	3,7
B/E	ext	14,1	16,8	6,7	6,4	5,1	4,0	-9,7	-12,9	7,9

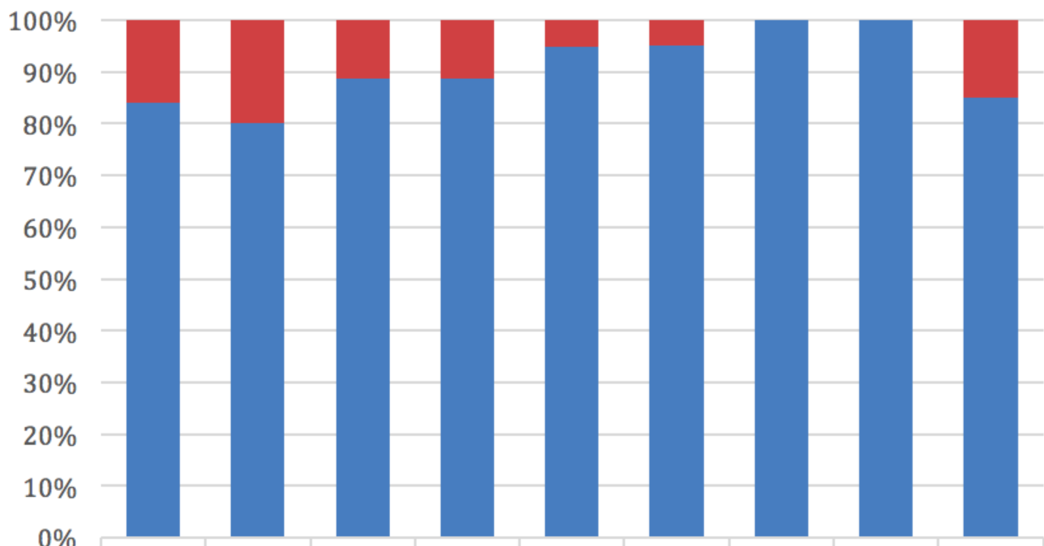
Table 5.13. FB physical flows

[1]) Please note that this assumption can be correct in some grid topologies, but in a highly meshed grid it causes inaccuracies.
[2]) Because they are not participating in the presented market coupling.

There is one border for which commercial and physical flows are the same and that is E/F border. The explanation is simple, there are no parallel ways to this border so the assumption that the commercial flow is equal to the physical flow is fulfilled. The other borders have their parallel way so we can compare the differences. The biggest absolute difference occurs on B/C border in model situation 33 – where there is a 130 MW commercial flow but only a 100,3 MW physical flow which makes a difference of nearly 30 MW. The biggest relative difference is on border C/E in model situation 77 – where there is a -10 MW commercial flow but only a -0,3 MW physical flow which makes circa 98% difference.

Knowing the described differences, we can be sure that there will be a difference in congestion income allocation. That is caused by different inputs of NTC and FB congestion income allocation - NTC is using commercial flows while FB is using physical flows. I have implemented both computation below.

What I have described above implies that the congestion income allocation for external borders under NTC is not possible [1]), but in FB world this can be done. Using the model input data and FB methodology presented in the Section 4.3 the congestion income allocation can be computed for each model situation. The first, in my opinion quite interesting, observation is relative share of the congestion income for internal and external borders. The CWE methodology uses terms internal and external pot and the explanation of them is following. In the internal pot belong all congestion incomes on internal borders plus one half of congestion incomes on external borders. In the external pot there is the remaining half of the congestion income on external borders [2]). Relative shares of the internal and external pot are depicted in the Figure 5.11 with data table.



	11	22	33	44	55	66	77	88	00
external pot	16,0%	19,9%	11,4%	11,3%	5,3%	4,8%	0,0%	0,0%	14,9%
internal pot	84,0%	80,1%	88,6%	88,7%	94,7%	95,2%	100,0%	100,0%	85,1%

Figure 5.11. Overview - external and internal pot

[1]) Congestion income for all external zones is zero.
[2]) Reasons of this sharing are also described in the Section 4.3.

From the Figure 5.11 we can see that in some model situations (77 and 88) there is no income in external pot, which is caused by the fact that in these situations the clearing price spread occurred only on E/F border, which has no parallel external border. In other situations, the relative shares of external pot were circa from 5 % to 20 %.

The final results of the FB congestion income allocation for each presented situation are in the Table 5.14 below.

zone	Congestion income [EUR]								
	11	22	33	44	55	66	77	88	00
B	96,3	118,2	344,2	556,8	16,7	12,1	0,0	0,0	63,7
C	197,5	178,6	340,7	549,7	218,8	141,3	0,0	0,0	138,1
E	200,2	187,7	26,4	58,9	239,4	158,9	220,5	5,2	162,9
F	12,1	10,6	6,7	22,1	9,9	12,6	220,5	5,2	19,5

Table 5.14. CI per zone in different situations

Relative shares of each zone on total congestion income is in the Figure 5.12 for FB method and in the Figure 5.13 for NTC method. [1]) We can see that there is a difference in relative share [2]). The shares of B and C zones changed whereas shares of zone E and F remained about the same. The difference of B and C may be caused by the B/E external border which is in a way parallel to B/C and C/E internal borders. The exclusion of zone C by the flow through the external border means a decrease of the congestion income for C and rise of the congestion income for B. So from zone's B point of view the FB allocation is better because it recieves more money.

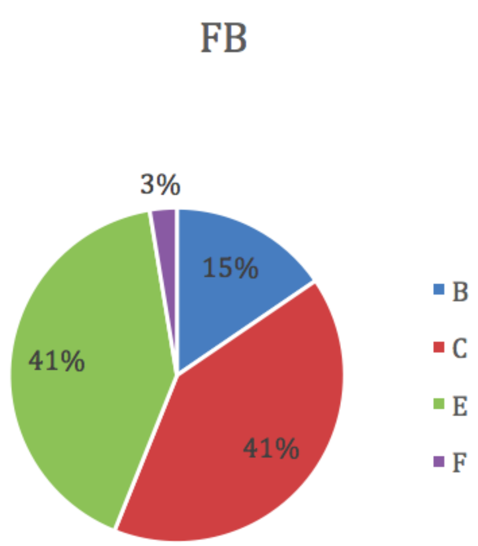


Figure 5.12. CI - FB relative shares

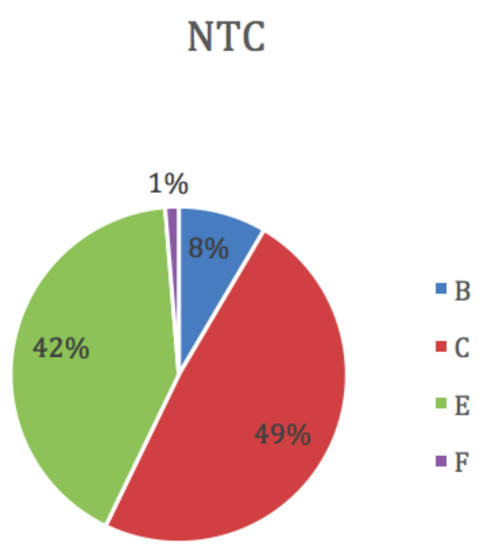


Figure 5.13. CI - NTC relative shares

[1]) Please note that because of the approximation to reality the occurrence of each model situation was taken into account. There is a number of occurrences of congestions in the Table 5.3 in the Section 5.1.3 for each situation. Results of model situations in this section were multiplied by these values in order to take probability of model situations into consideration.

[2]) The total amount of congestion income is the same.

As you can see in the Figure 5.12 there is no congestion income for external zones A and D even though we are able to compute power flows through these zones. This is caused by the allocation mechanism which divides the external pot between all internal borders by the relative share of flows through these borders. Below in the Figure 5.14 there is a model situation in which the external pot is not divided among internal borders but among respective external borders.

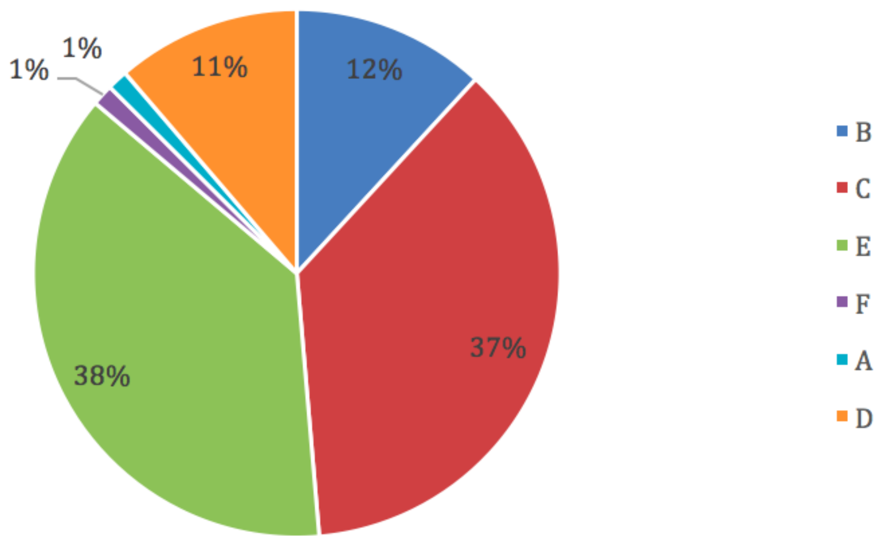


Figure 5.14. CI - FB relative shares with external zones

From the Figure 5.14 it is obvious that especially for zone D it would be beneficial if the congestion income would be shared not only among internal zones but among external zones as well.

Chapter 6
Conclusion

There are two main approaches to cross-zonal capacity calculation and allocation. Currently there is one market coupling initiative which uses Flow-Based method of cross-zonal capacity calculation for Day-Ahead electricity market and it is CWE region. Mainly based on their documents I have discovered and described principals of Flow-Based method. FB approach is the target solution of CACM network code so the evolution to FB from currently used NTC approach should be mandatory for all European countries. That is why new methodologies are analyzed and presented.

In this thesis I mainly focused on the congestion income allocation, so there are described different income allocation methods. Concretely under NTC the currently used method (CI1), then two methods based on line usage – one on absolute line usage (CI2) and second on relative line usage (CI3) and last method based on shadow prices (CI4). The last one has an advantage that it can be used for critical branches and thus for nodal system, not only for cross-zonal borders in zonal system.

Based on market results of 4M market coupling initiative in which the Czech Republic has its place, I have analyzed four earlier mentioned congestion income allocation schemes. The total congestion income of 4M MC in 2015 was around 40,5 million Euro (circa 1,1 billion Czech crowns). The most congested border in this initiative was SK/HU border where the congestion occurred more than in 60 % of hours. Results show that each one of the income allocation methods is the best for a different country. In CI1 the Slovak Republic has the maximum share – nearly 50 %, whereas the Czech Republic has the biggest share in CI2 – around 22 % of total congestion income. Shares of all countries in CI3 and CI4 are very similar, but in CI3 Romania has the biggest share of 12,4 % and in CI4 Hungary reaches the maximum share of nearly 40 % on total congestion income. For Czech TSO, based on this computation, it would be best if CI2 was used, because it gives it highest amount of money.

The second part of my analysis was devoted to FB world and CWE methodology of income allocation. The main difference between NTC and FB approach is that in FB a negative congestion income may occur, when there is a flow against the clearing price difference spread. This illogical flow can be a part of optimal solution, with maximum welfare, of Flow-Based market coupling. Because of that, assuring of non-negative congestion income for TSO is crucial, because it would be a disincentive for TSO to pay for offering cross-zonal capacity. Another difference is that in FB approach the congestion income can be associated not only with internal borders but also external borders. The fact is that external TSOs do not get any part of the congestion income on their borders but their share is distributed among internal TSOs. This a little bit unfair situation will be solved in the future because with single electricity market there will be no external borders.

Originally, I wanted to simulate different scenarios on real Flow-Based data but due to their unavailability I had to create a simplified power grid model which served as a base for my computation. I have modeled a power grid with 4 internal and 2 external zones including 33 nodes and 50 powerlines from which 14 were considered as critical branches. Based on situations from NTC analysis I simulated different cases which could occur. To demonstrate the difference between NTC and FB congestion income approach I had computed both of them and compared. In one model situation (marked as 22) the congestion income share of external zones was nearly 20 %. I also demonstrated a non-negligible difference between the commercial and physical flow, which can cause unwanted situations in the power grid. For two modeled zones different approaches resulted in very similar shares on the congestion income, nevertheless the other two zones indicated a difference. FB approach was better for zone B, with a 15% share and NTC for zone C with almost a 50% share. And lastly I have simulated a case when external zones get “their” congestion income share. For zone A was the share only a little – 1 %, but for zone D as the share was 11 % which is far more than internal zone F and almost the same as share of internal zone B. From this we can come to a conclusion that external zone D is burden while trading in internal zones and it would be beneficial for it to be part of market coupling initiative.

I would like to end with an idea and a paradox connected with the congestion income. The idea is the definition of the congestion income as a bad income, because it shows that constraints exist in the grid which is not ideal for the internal market. You get money for not being perfect.

And the paradox is in relation to what I have already written. TSOs get money because their grid elements are congested, in order to invest into the rising capacity of their elements, which will have a consequence: getting less money. That is why the use of congestion income has to be monitored – TSOs has no economical initiative to invest heavily into cross-zonal constraints.

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Appendix A
Glossary

AAC	Already Allocated Capacity
ATC	Available Transmission Capacity
BC	Base Case
BE	Belgium
CB	Critical Branch
CGM	Common Grid Model
CI	Congestion Income
CNE	Critical Network Element
CO	Critical Outage
CP	Clearing Price
CZ	Czech Republic
DE	Germany
D2CF	2 Days Ahead Congestion Forecast
ENTSO-E	European Network of Transmission System Operators for Electricity
FAV	Final Adjustment Value
FR	France
FRM	Flow Reliability Margin
GSK	Generation Shift Key
HU	Hungary
LF	Loop Flow
LTA	Long-Term Allocation
LTN	Long-Term Nomination
MM	Market Margin
NL	Netherlands
NP	Net Position
NTC	Net Transmission Capacity
PF	Power Flow (or Parallel Flow)
PTDF	Power Transfer Distribution Factor
RA	Remedial Actions
RAM	Remaining Available Margin
RC	Resale Cost
RO	Romania
SK	Slovak Republic
TRM	Transmission Reliability Margin
TSO	Transmission System Operator
TTC	Total Transmission Capacity
UIOLI	Use It Or Lose It
UIOSI	Use It Or Sell It
4M MC	4M Market Coupling

Appendix B
Input data

B.1 GSK

zone A	
node	value
22	0,1
23	0,2
24	0,2
25	0,2
26	0,2
27	0,1
sum	1

Table B.1. GSK for zone A

zone B	
node	value
1	0,4
2	0,4
3	0
4	0
5	0,2
6	0
sum	1

Table B.2. GSK for zone B

zone C	
node	value
7	0,1
8	0,1
9	0
10	0,3
11	0,3
12	0,2
sum	1

Table B.3. GSK for zone C

zone D	
node	value
28	0,2
29	0,1
30	0,2
31	0,2
32	0,2
33	0,1
sum	1

Table B.4. GSK for zone D

zone E	
node	value
13	0,4
14	0,5
15	0,1
16	0
sum	1

Table B.5. GSK for zone E

zone F	
node	value
17	0,05
18	0,5
19	0,2
20	0,2
21	0,05
sum	1

Table B.6. GSK for zone F

B.2 Nodes overview

node	generation [MW]	load [MW]	balance [MW]	zone
1	80	30	50	B
2	200	40	160	B
3	0	300	-300	B
4	250	50	200	B
5	50	200	-150	B
6	200	100	100	B
7	10	50	-40	C
8	5	10	-5	C
9	5	40	-35	C
10	75	20	55	C
11	75	150	-75	C
12	130	50	80	C
13	50	175	-125	E
14	80	110	-30	E
15	180	65	115	E
16	0	120	-120	E
17	100	80	20	F
18	100	200	-100	F
19	250	140	110	F
20	250	120	130	F
21	70	110	-40	F
22	200	650	-450	A
23	150	400	-250	A
24	200	100	100	A
25	500	150	350	A
26	300	100	200	A
27	250	200	50	A
28	200	100	100	D
29	75	200	-125	D
30	100	150	-50	D
31	25	75	-50	D
32	100	40	60	D
33	100	35	65	D

Table B.7. Nodes overview

B.3 Lines overview

line	start hub	end hub	B	CB	length [km]
A	1	4	52	0	130
B	1	2	28	0	70
C	2	3	36	0	90
D	3	4	40	0	100
E	3	5	100	0	250
F	5	6	52	0	130
G	5	26	20	1	50
H	5	25	40	1	100
I	5	7	40	1	100
J	7	12	40	0	100
K	7	8	48	0	120
L	8	24	40	1	100
M	4	28	48	1	120
N	4	6	60	0	150
O	6	29	32	1	80
P	6	11	48	1	120
Q	11	13	28	1	70
R	6	12	52	1	130
S	11	12	28	0	70
T	10	12	40	0	100
U	10	14	40	1	100
V	9	10	28	0	70
W	8	9	40	0	100
X	8	23	60	1	150
Y	23	24	48	0	120
Z	24	25	30	0	75
AA	22	23	160	0	400
AB	22	27	80	0	200
AC	22	26	140	0	350
AD	25	26	24	0	60
AE	25	27	88	0	220
AF	28	33	80	0	200
AG	32	33	80	0	200
AH	31	32	40	0	100
AI	30	31	32	0	80
AJ	13	30	40	1	100
AK	29	30	30	0	75
AL	28	29	60	0	150
AM	13	15	48	0	120
AN	14	15	60	0	150
AO	14	20	80	1	200
AP	15	19	88	1	220
AQ	15	16	40	0	100
AR	13	16	40	0	100

line	start hub	end hub	B	CB	length [km]
AS	20	21	80	0	200
AT	17	21	80	0	200
AU	17	18	88	0	220
AV	18	19	80	0	200
AW	18	21	92	0	230
AX	19	20	72	0	180

Table B.8. Lines overview