Balkans and Regional Energy Market Partnership Program:
PSSE/OPF Regional Model Construction Report

Black Sea Regional Transmission Planning Project Phase III

Cooperative Agreement EEE-A-02-00054-00

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Optimal Power Flow Sensitivity and Network Analysis Report

Black Sea Regional Transmission Planning Project Phase III

Prepared for:

**United States Agency for International Development
and United States Energy Association**

Cooperative Agreement EEE-A-02-00054-00

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ABBREVIATIONS

General

TSO	- Transmission System Operator
TEN-E	- Trans-European Energy Networks
CIGRÉ	– International Council on Large Electric Systems
UCTE	- Union for the Coordination of Transmission of Electricity
ENTSO/E	– European Network of Transmission System Operators for Electricity (former UCTE)
ACER	- Agency for the Cooperation of Energy Regulators
NRA	- National Regulatory Authority or Agency
IEM	- Internal Energy Market
REM	- Regional Energy Market
LOLE	- Loss of Load Expectation
SAF	- System Adequacy Forecast
SoS	- Security of Supply
VOLL	- Value of Lost Load
ETS	- Emission Trading System
EWIS	- European Wind Integration Study
CENTREL	- Association of TSOs of Czech Republic, Hungary, Poland and Slovakia
SEE	- South East Europe
SECI	- South East European Cooperation Initiative
BSTP	- Black Sea Transmission Project
FIT	- feed-in tariff
LF	- Load flow
OPF	- Optimal power flow
FGC, UNEG	– Federal Grid Company, Unified National Electric Grid
IPS/UPS	– Interregional Power System/Unified Power System

Transmission

AC	- Alternating Current
DC	- Direct Current
HV	- High Voltage
MV	- Medium Voltage
LV	- Low Voltage
HVAC	- High Voltage AC
HVDC	- High Voltage DC
EMF	- Electromagnetic Field
ED	- Electricity Distribution
SS	– Substation
OHL	- Overhead Lines
UC	- underground cable
SC	- submarine cable
TR	- Transformer
OLTC	– On Load Tap Changer
PST	- Phase Shifting Transformer

CCT	– Critical Clearing Time
FACTS	- Flexible AC Transmission System
VSC	- Voltage Source Converter
STATCOM	– Static Synchronous Compensator
NTC	- Net Transfer Capacity
TTC	- Total Transfer Capacity
RC	- Remaining Capacity
RAC	- Reliable Available Capacity

Generation

HPP	– Hydro Power Plant
PHPP	– Pumping Hydro Power Plant
TPP	– Thermal Power Plant
NPP	- Nuclear Power Plant
CCGT	- Combined cycle gas turbine
CCS	- Carbon Capture and Storage
CHP	- Combined Heat and Power Generation
RES	- Renewable Energy Sources
NGC	- Net Generation Capacity
VAR	- Volt-Ampere-Reactive, reactive power
BTU	- British Thermal Unit = 1055J = 0.293Wh = 252cal, mBTU = 1000000BTU
tcm	- thousand cubic meter $1000m^3$
RGC	– Regional Generation Company
TGC	- Territorial Generation Company
WGC	– Wholesale Generation Company

Countries

	ISO	Country	Car
Austria	AT	AUT	A
Albania	AL	ALB	AL
Bosnia and Herzegovina	BA	BIH	BiH
Bulgaria	BG	BUL	BG
Croatia	HR	CRO	CRO
Germany	DE	GER	D
Greece	GR	GRE	GR
Hungary	HU	HUN	HU
Italy	IT	ITA	I
FYR of Macedonia	MK	FYRM	MAK
Montenegro	ME	MNE	MNE
Romania	RO	ROM	ROM
Serbia	RS	SRB	SRB
Slovenia	SI	SLO	SLO
Switzerland	CH	SUI	CH
Turkey	TR	TUR	TUR
Ukraine	UA	UKR	UKR
Armenia	AM	ARM	ARM
Georgia	GE	GEO	GEO

Moldova	MD	MLD	MLD
Russia	RU	RUS	RUS
Azerbaijan	AZ	AZB	AZB
Belorussia	BY	BLR	BLR
Iran	IR	IRN	IRN

1 INTRODUCTION

The most recent study realized through Black Sea Regional Transmission Planning Project Phase III was focused on the following two elements:

- PSSE/OPF regional model construction and OPF analyses
- Possibilities of renewables integration to transmission network.

The construction of the PSS-E/OPF regional model and the OPF analyses were oriented towards evaluating economic opportunities for trade in the Black Sea region using the OPF feature of the PSS-E software. The TSOs collected the data required to perform an OPF analysis and participated in the construction of the OPF national models and the development of generic generation cost curves. As a result of these activities, the PSS-E/OPF national and regional models for winter and summer maximum demand hours in 2015 and 2020 were constructed. Using the 2015 models, that include the developed generation cost curves representing the relationship between generator output and operating costs for every generator in the region, average production costs (AVG) and generation marginal prices (GMP) were calculated for two synchronous modes and various scenarios considering OPF optimization and transmission system constraints.

The second part of the study was focused on the updating of PSS-E/OPF transmission planning models including a more accurate simulation of the renewable energy resources to be added to the network in 2015 and 2020. The BSTP regional PSS-E/OPF model for 2015 was used to analyze balancing reserve requirements for a sudden loss of wind in different wind areas within the Black Sea region and several different balancing scenarios for covering the loss of wind.

This phase of the project focuses on performing a Sensitivity Analyses utilizing the regional OPF model to determine how sensitive the study results are to each of the model inputs. In order to understand the sensitivity of the obtained results to the input data assumptions, the Sensitivity Analysis determined which assumptions significantly impact average prices, generation marginal prices and calculated net power exchanges. In addition to the analysis, the existing OPF models were updated and validated to identify which economic factors have an influence on the model and the electricity market behavior.

Specific modeling input assumptions that are a consequence of either global or local factors can have strong influence on both production cost variation, possible power system exchanges and the addition of interconnection lines (AC or DC). To account for these elements, the following analyses were divided into two groups:

1. Production costs that imply different shapes of cost curves:
    a. Influence of ***fuel price variations***, taking into account global price forecast variations defined by the global fuel market and based on relevant published data sources.
    b. Influence of ***CO_2 cost variations*** defined by penalty factors for greenhouse gas emissions. This can impact TPPs, depending on the fuel type, and can imply different production costs and possible power exchanges. Due to this influence on the cost levels, the sensitivity analysis were conducted. Basic assumptions were based on relevant published data sources regarding this topic.

c. Influence of ***capital costs*** were modeled using two different scenarios:

   i. No capital costs (all power plants will be analyzed without any capital costs) and
   ii. Full capital costs (as if all power plants are new).

2. Different initial engagements of power plants

   a. Influence of ***different local hydrological regimes*** in certain areas in addition to wet and dry hydrological regimes were considered. The regimes were analyzed during specific load level regimes (winter peak and summer peak) and for some specific areas or power systems.
   b. Influence of ***different scenarios of RES engagement*** in certain areas including high and low penetration. The regimes were analyzed during specific load level regimes (winter and summer peak) and for some specific areas or power systems

3. Additional grid developments including ***additional interconnections*** (AC or DC) and influence of ***evolution of transfer capacities and congested locations*** which implies the calculation of transfer capacities between power systems for 2015, Winter and Summer peak period, in terms of Total and Net Transfer Capacities (TTC and NTC – as a transaction-based constraints) which is the most common capacity allocation procedure in the ENTSO - E. This activity analyzed and assessed the impact of the foreseen transmission network developments in the Black Sea region on TTC/NTC values.

The overall analysis provided an overview of how the different factors influence the power system production costs and possible power system exchanges. The region was analyzed as a coupled market and the analyses were performed for the 2015 models as previously mentioned. The scenarios for analyses were determined based on the collected data, agreed synchronous scenarios, wind engagement according to the TSOs estimation and engagement of power plants derived from OPF analysis. All of above mentioned cost variations were carried out through simple market analyses principles were the running costs are split into two parts: variable and fixed costs. Detailed analytical explanations are given in next chapter.

The study assumption is that the fuel costs are a function of the fuel price of the primary energy carrier and the efficiency. The O&M costs, referring to the energy unit in the database, must be coupled with the full-load hours. In general, one average operation time (full-load hours) is taken for each technology band. Regarding investment (capital) costs, there are three different approaches depending on the type of analyses:

1. No capital costs – only short run marginal costs. This is mainly represented in most of classical market analyses (maybe not so good for TSO planner's practice but very good for short term market planning decision makers).
2. With capital costs and assumed same payback period for all plants (e.g. 20 years) – maybe more important for analyses for IPPs (Independent Power Producers). This is applied in our previous study and it is very good for comparison between different technologies applied but more suitable from the IPPs point of view.
3. With capital costs and assumed payback period that corresponds to lifetime for each technology – maybe more suitable for planners in TSOs and selection of the technology.

In the sensitivity analyses the first and third approach were examined and then we were able to see quantitative differences between all of these approaches. In this way we covered all currently applied approaches in market and OPF analyses regarding investment costs. In the following chapters are given set of proposed levels and ranges for specific cost variations as well as level of evolution of transfer capacities and congested locations.

With the aim to assess the influence of the most important global and local factors (such as fuel prices, CO_2 emission costs, capital costs, different hydrological conditions and RES engagements as well as network reinforcement evolution) sensitivity analyses for winter and summer peak scenarios in 2015 have been carried out. The market behavior for each specified scenario within defined sensitivity analyses is presented. This is accomplished using the following parameters as the most significant indicators:

- **AVG** – average system electricity cost in $/MWh
- **GMP** – Generation marginal price in $/MWh
- **EXC** – Net power exchanges in MW.

The applied approach and important assumptions that influenced the study results are summarized as follows:

- PSS-E/OPF model developed during the previous study is used as the basic tool, updated according to the collected questionnaires provided by TSOs.
- Split constrained models of Black Sea region were used within the conducted analyses, meaning that ENTSO-E and IPS/UPS zones were analyzed separately taking into account grid limitations given through the NTC values for each border across the region.
- RES and HPPs were treated as must run units and dispatched first, disregarding production prices and merit order.
- Base Case for all sensitivity analyses was defined according to the following assumptions:
  - Starting values for fuel prices according to questionnaire
  - CO_2 emission cost was set on 12 $/ton CO_2 for each country
  - Capital costs are included
  - Average hydrology conditions
  - Average RES engagement
  - Without new transmission network reinforcements added to official BSTP models
  - With base NTC's values from previous study
  - There are no exchanges between those two synchronous areas (ENTSO-E and IPS/UPS)
- Regarding the sensitivity of these study results due to fuel price variations, the following range of values was applied:
  - Gas/Oil ±20% of Base Case values
  - Lignite/Coal ±10% of Base Case values
  - Uranium ±5% of Base Case values
- Regarding the sensitivity of these study results due to CO_2 emission cost variations, the following range of values was applied:
  - Average value of 12 $/MWh
  - Extreme value of 50 $/MWh
  - No charge for CO_2 (underdeveloped market in that sense)
- Regarding the sensitivity of these study results due to how capital costs are included in the study:
  - Case with capital costs – in Base Case CAPEX was 100% for new power plants, 45% for reconstructed both, TPPs and NPPs, as well as 30% for reconstructed HPPs. CAPEX was 0% for power plants that reached their full life time period or more
  - Case without capital costs - Short run marginal cost scenario where CAPEX for all power plants is 0% of their capital costs.
- Regarding the sensitivity of these study results due to different hydrological regimes:
  - Average year – according to average engagement of HPPs defined in BSTP models

  - Wet year – increase of HPP's production by 20% with appropriate correction of national power system balance
  - Dry year – decrease of HPP's production by 20% with appropriate correction of national power system balance
- Regarding the sensitivity of these study results due to different RES engagement assumptions:
  - Average – according to average engagement of RES defined in BSTP models
  - High RES penetration – increase of RES production by 20% with appropriate correction of national power system balance
  - Low RES penetration – decrease of RES production by 20% with appropriate correction of national power system balance
- Regarding the sensitivity of these study results due to the network reinforcement (NTC) assumptions:
  - Base Case – according to NTC's values from previous study
  - Increasing of NTCs – increase of NTC values by 500 MW on the each border (it represents the influence of the new additional interconnection projects)
  - Decreasing of NTCs – decrease of NTC values by 20% on the each border (it represents the influence of the delay of some projects defined in BSTP models)

2 METHODOLOGY

2.1 Approach and Methodology

Power system development planning requires detailed analysis of the system costs for the considered combination of existing and new generation capacities. From economic point of view, it is desirable to expend power generation portfolio by adding power plants that are cheaper to build and that produce energy at the lowest possible cost. In order to predict the future behavior of electricity market across the Black Sea region, a comprehensive sensitivity analyses regarding factors that influence generation cost of power plants are performed.

The generation costs used in market simulations are based on:

- Technical parameters for different technologies
- Capital costs for different technologies
- Corresponding O&M costs
- Forecasts of the fuel prices
- Provided power and production forecast for different plants per power systems (countries)

Input data and assumptions for these parameters are taken from previous study (Table 0.1 in Annexes) and updated from Questionnaires regarding power plant characteristics and costs provided by TSOs (Table 0.2 and Table 0.3 in Annexes).

The cost of power plant production can be defined as:

$$\boxed{C = C_{variable} + C_{fixed}}$$

Where:

- C - Electricity generation cost per MWh [$/MWh]
- C_{fixed} - Fixed cost per energy unit [$/MWh]
- $C_{variable}$ - Variable cost per energy unit [$/MWh]

Two distinct figures of merit are therefore important when discussing or comparing the economics of power generating technologies.

The fixed cost of power plant production can be defined as:

$$\boxed{C_{fixed} = C_{f\_o\&m} + C_{capital} = C_{f\_o\&m} + \frac{I \cdot CRF}{H}}$$

Where:

- $C_{f\_o\&m}$ - Fixed operation and maintenance costs per MWh [$/MWh]
- $C_{capital}$ - Capital costs per energy unit [$/MWh]
- I - Investment cost per MW [$/MW]
- CRF - Capital recovery factor $CRF = \frac{z \cdot (1+z)^n}{(1+z)^n - 1}$
- z - Interest rate
- n - Payback time of the plant [years]

- H - Full load hours electricity generation [h]

Capital costs ($C_{capital}$) represent total capital expenses (CAPEX) necessary to build a power plant and bring it into commercial operation. Capital costs are generally divided in direct and indirect costs. The direct capital costs are directly associated on an item-by-item basis with the equipment and structures that comprise the complete power plant (e.g. boiler/reactor, turbine and electric plant equipment), land, special materials, transmission plant costs and etc. The indirect capital costs are expenses of a more general nature and consist mainly of expenses for services (e.g. construction, engineering and management services), temporary facilities, and rentals. Taxes, duties and other national fees also represent indirect capital costs.

Plant capital costs are sensitive to numerous factors, including the plant site (e.g. geographical location, subsurface conditions, site meteorological conditions, and proximity to population centers), length of construction schedule, unit size, effects of escalation during construction, interest rates and regulatory requirements. Investment costs, payback life of plants and full load hours electricity generation are defined for each technology as generic data (given Table 0.4 in Annexes) and harmonized with data provided by TSOs in questionnaires.

In this study, for each power plant CAPEX is defined as following:

- CAPEX is 100% for new power plants
- CAPEX is 45% for reconstructed TPPs and NPPs and 30% for reconstructed HPPs
- CAPEX is 0% for power plants that reached their full payment time period

For reconstructed power plants as capital component cost of their reconstruction is used because we have to take into account these additional costs beside short run marginal costs when considering total plant production costs. Also, we cannot use here full capital costs since in that case those power plants would be treated as new production units which is not the case in reality.

Fixed operation and maintenance costs ($C_{f\_o\&m}$) are not dependent on operation of the power plant.

These usually include labor used to run the plant and the labor and supplies needed for maintenance. Fixed operation and maintenance cost are defined based on proportion of national GDP of each Black Sea country and EU GDP (30388$) multiplied by EU available fixed operation and maintenance costs. Value of 10% is used for interest rate for all countries across the Black Sea region.

The variable cost of power plant production can be defined as:

$$\boxed{C_{vaiable} = C_{fuel} + C_{f\_o\&m} + C_{CO_2}}$$

Where:

- C_{fuel} - Fuel cost per energy unit [$/MWh]
- $C_{f\_o\&m}$ - Variable operation and maintenance cost of production [$/MWh]
- C_{CO_2} - CO_2 emission cost per energy unit [$/MWh]

The fuel cost component (C_{fuel}) refers to those charges that must be recovered in order to meet all expenses associated with consuming and owning fuel in a power plant.

Variable operation and maintenance cost of production ($C_{f\_o\&m}$) represent costs of replacement of wear out plant equipment and materials due to production process. Variable operation and maintenance cost of production are directly correlated to power plant capacity factor.

CO_2 emission costs per energy unit [$/MWh] represents a tax paid for carbon dioxide emission as a by-product of power plant energy production. Different technologies have different level of gas emission in terms of tons of CO_2 per MWh. The largest CO_2 emitters are old lignite and coal plants with emission of more than 1 ton of CO_2/MWh. For CO_2 , emission cost value of 12$/t is used as common across the region.

Taking into account all these electricity production cost components and other characteristics of interest in Black Sea region, the following sensitivity analyses are performed to understand the future behavior of Black Sea region electricity market under different conditions:

- Fuel price variations
- Capital cost variations
- CO_2 emission cost variations
- Different hydrological regimes
- Different scenarios of RES engagement
- Evolution of transfer capacities and congested locations (TTC/NTC values)
- Russia investment cost variations

2.2 Cost Curve Toolbox

In order to generate various scenarios for sensitivity analyses, the Cost Curve Toolbox is developed. Main idea of this toolbox is to provide a user friendly tool for generating PSS/E OPF cost curves. These curves are based on production cost factors analyzed in previous section. Also, this tool allows user to analyze production cost for each power plant depending on the operating point.
Cost Curve Toolbox is developed in MS Excel, and could be described in three parts:

- Global input data & Sensitivity factors
- Production cost calculator
- PSS/E export file

2.2.1 Global Input Data & Sensitivity factors

Global input data & Sensitivity factors sheet includes:

- Global (common) variables for each country
- Different generic curves used as basis for power plant cost curves development
- Sensitivity analysis parameters

In this sheet, generic data characteristic for each power system of Black Sea region are defined. Ten different cost curve types are defined and used as generic for all conventional technologies:

- Coal 1 (300 MW)
- Coal 2 (1000 MW)
- Nuclear 1 (500 MW)
- Nuclear 2 (1000 MW)
- Gas 1 (OCGT)
- Gas 2 (CCGT)
- Gas 3 (CHP)
- Hydro 1 (Fransis)
- Hydro 2 (Caplan)
- Hydro 3 (Pelton)

For all these types, input data regarding investment capital costs, plant life cycle, fixed and variable operational and maintenance cost, fuel consumption, CO_2 emission and efficiency at different operational points are defined. Each power plant in the observed system and country is assigned to corresponding technology type (given in Table 0.4 in Annexes). Change in input data of one technology type will result in change of data for all power plants assigned to this type. Beside global input data and generic curves, sensitivity factors used for creating sensitivity analyses scenarios regarding fuel prices, CO_2 emission cost and inclusion of capital costs are defined in this sheet.

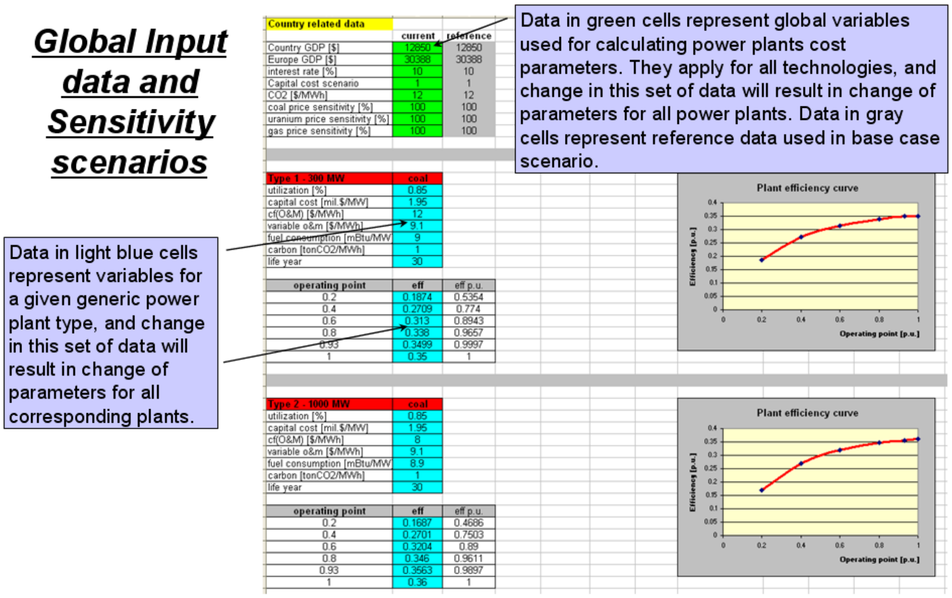


Figure 0.1 – Global input data & Sensitivity factors

2.2.2 Production Cost Calculator

Production cost calculator is the key element of the Cost Curve Toolbox. It is defined for every generator, and used for calculating production cost in function of generator loading. All power plants are clustered according to technology in 5 sheets:

- Coal
- Nuclear
- Gas
- Hydro
- RES (Renewable sources)

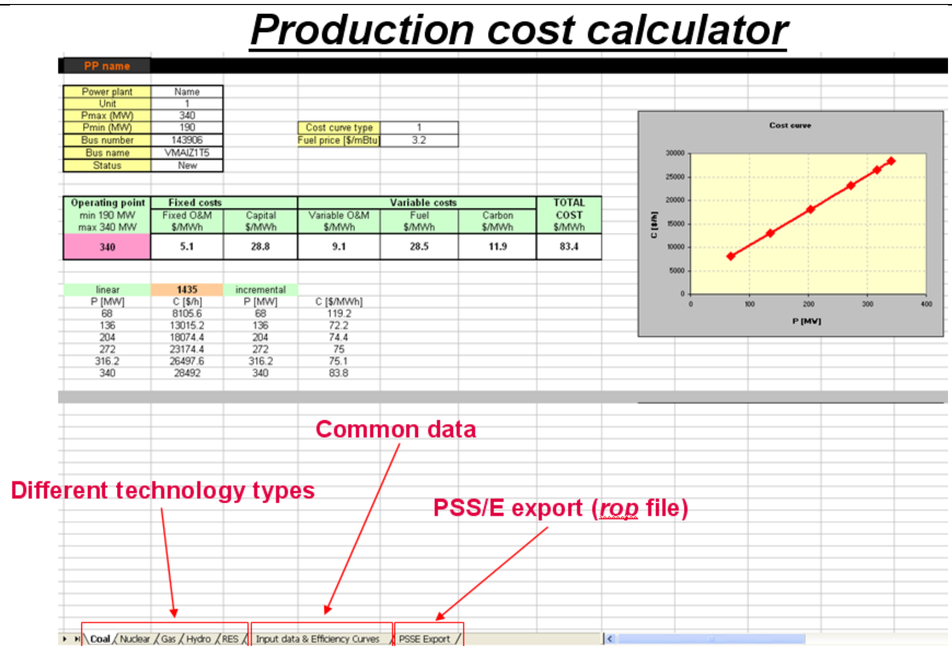


Figure 0.2 – Production cost calculator

Production cost calculator consist of three elements:

1. Power generator legend – which includes unit name and number, PSS/E bus number and name, cost curve type, maximum and minimum energy output and power plant fuel cost. Information of unit life cycle status (new, old, rehabilitated) is also given here.

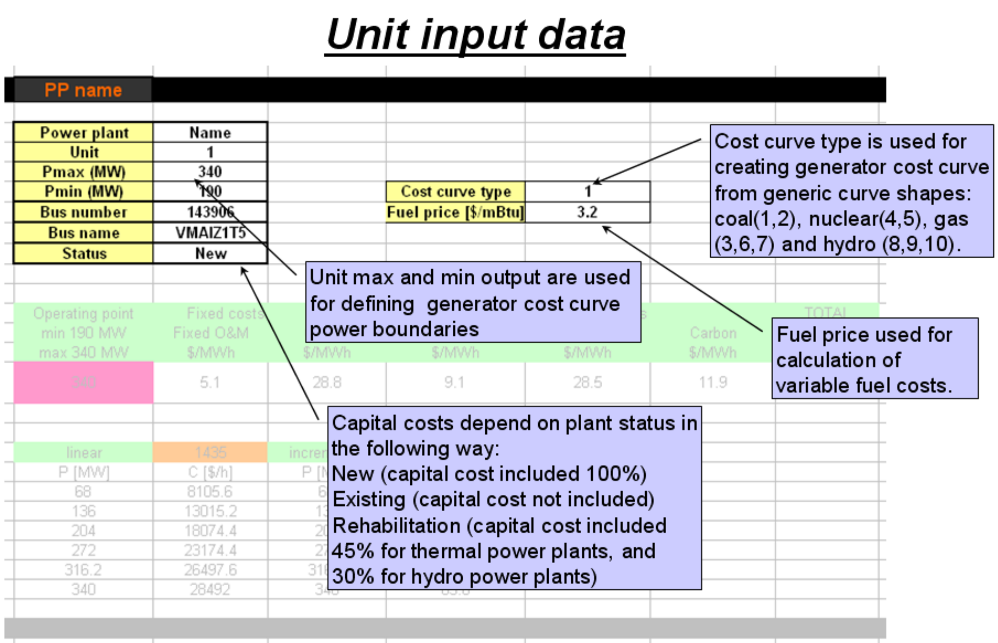


Figure 0.3 – Production cost calculator – Power generation legend

2. Calculator form – consists of:

- input data field – operating point that could be entered between defined minimum and maximum output power.
- fixed costs fields – include fixed operation and maintenance cost component taken from Global input data sheet, and capital cost component derived from Global input data sheet and information given in Power generator legend regarding unit life cycle status (new, old, rehabilitated).
- variable costs fields – include variable operation and maintenance cost, fuel cost and carbon emission cost components. Variable operation and maintenance cost component is taken from relevant information given in Global data input sheet, fuel cost and carbon emission components are calculated as a function of operating point set in input data field and unit efficiency curve corresponding to assigned generic cost curve from Global input data sheet.
- Output data field – total unit production cost in $/MWh for operating point(i.e. generator loading set in input data field)

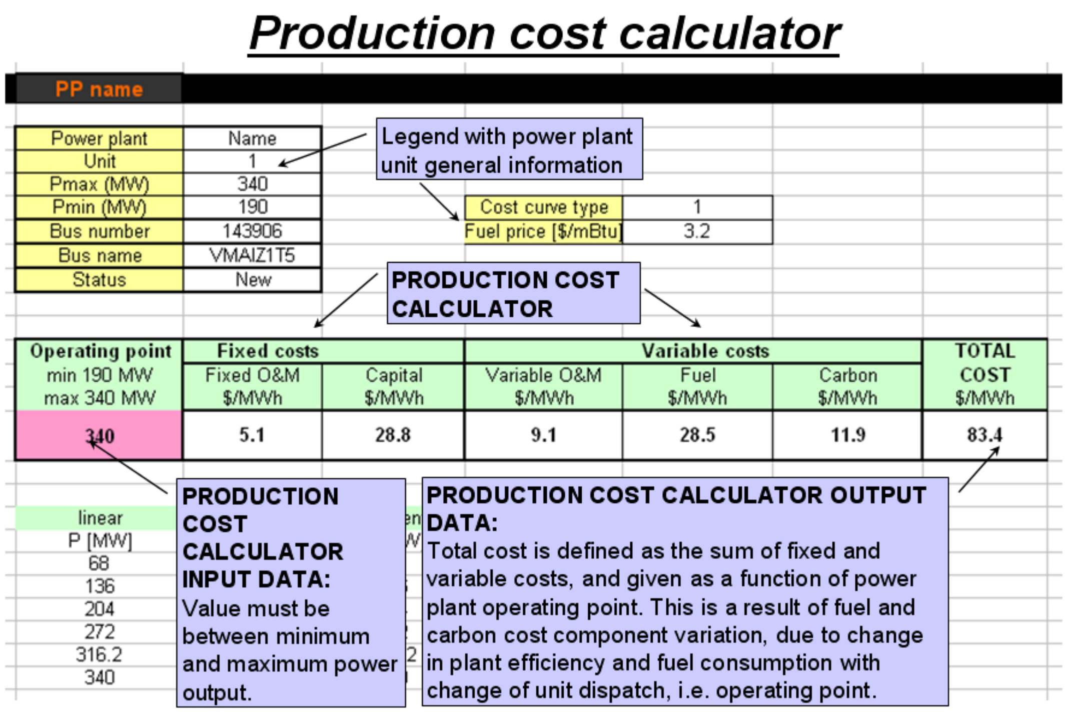


Figure 0.4 – Production cost calculator – Input and output data fields

Figure 0.5 – Production cost calculator – Production cost data fields

Production cost calculator

PP name

Power plant	Name
Unit	1
Pmax (MW)	340
Pmin (MW)	190
Bus number	143906
Bus name	VMAIZ1T5
Status	New

COSTS:
Capital, fixed and variable O&M costs are static and calculated using input data given in sheet "Input data & Efficiency Curves". Fuel and carbon costs are dynamic and calculated with production cost calculator using data given in sheet "Input data & Efficiency Curves" and operating point value (given as calculator input data).

Operating point	Fixed costs		Variable costs			TOTAL
min 190 MW max 340 MW	Fixed O&M $/MWh	Capital $/MWh	Variable O&M $/MWh	Fuel $/MWh	Carbon $/MWh	COST $/MWh
340	**5.1**	**28.8**	**9.1**	**28.5**	**11.9**	**83.4**

linear	1435	incremental	
P [MW]	C [$/h]	P [MW]	C [$/MWh]
68	8105.6	68	119.2
136	13015.2	136	72.2
204	18074.4	204	74.4
272	23174.4	272	75
316.2	26497.6	316.2	75.1
340	28492	340	83.8

Generation unit cost curves given in two forms corresponding to input data for PSS/E OPF calculation.

3. PSS/E OPF curve – which represent relevant tables given in linear and incremental forms, suitable for defining PSS/E OPF calculation unit cost curve. These tables are generated from data defined in Power generation legend unique for each power unit, and data uniform for each generic cost curve type assigned to that power unit. Tables are created for set of points (power output/linear or incremental production cost) . Also, for every unit production cost calculator, intermediate step for data processing is defined. If data assigned as uniform parameters from generic cost curve for specific unit do not correspond, unlinking calculator and Global input data sheet and predefining global variable as local is possible in this step.

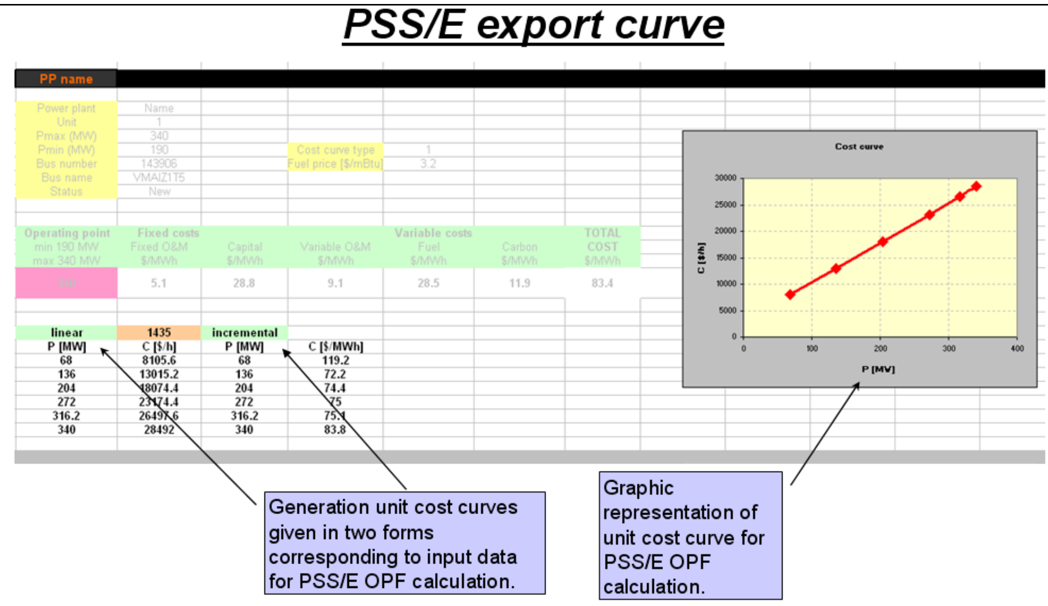


Figure 0.6 – Production cost calculator – PSS/E OPF curve

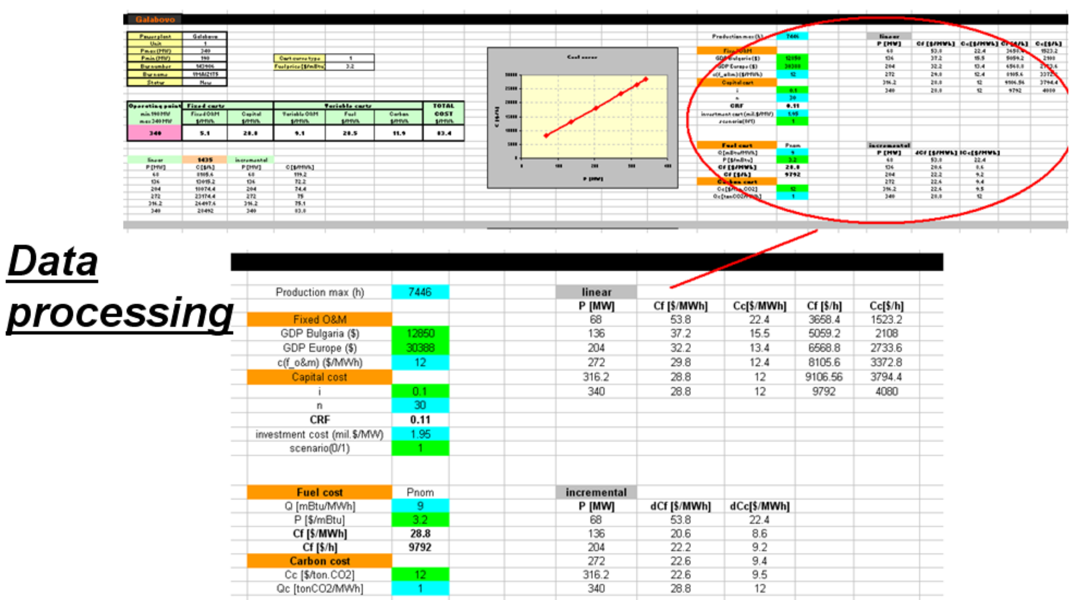


Figure 0.7 – Production cost calculator – Data processing

2.2.3 PSS/E Export Curves

Final result of input data preparation for sensitivity analyses is given by appropriate input format of cost curves adjusted to PSS/E textual file standards. Export form of cost curve toolbox is made in the manner shown in Figure 0.8.

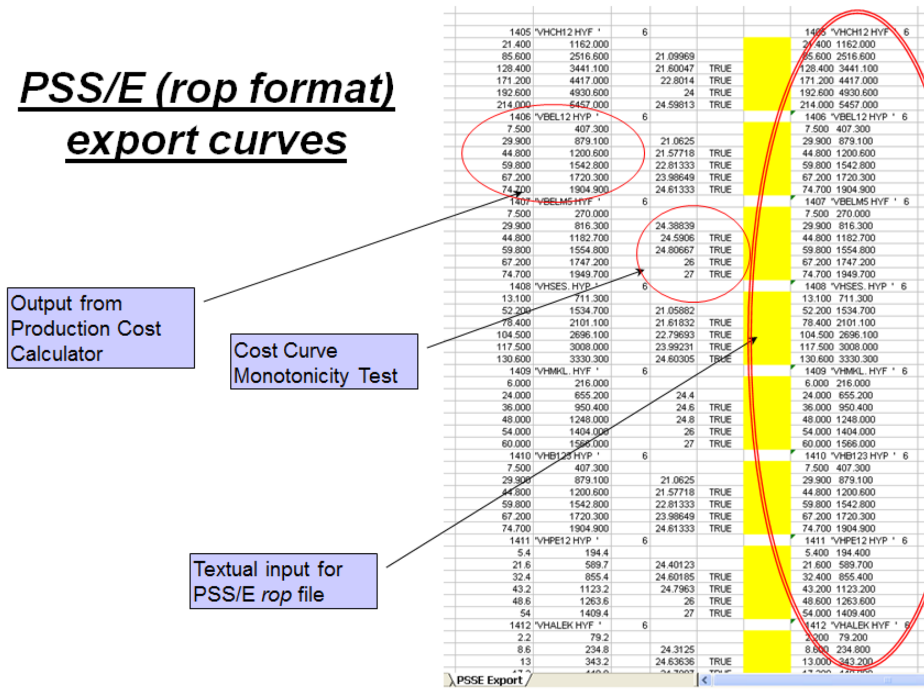


*Figure 0.8 – Cost Curve Toolbox final export to PSS/E – **rop** format*

Very important part of this cost curve toolbox export form is cost curve monotonicity test. Its significance is that only monotonous cost curves can be entered in ***rop*** textual file as well as in input window form in PSS/E. After the input data initialization, PSS/E gives report of their status.

2.3 OPF Models

PSS/E Optimal Power Flow (PSS/E OPF) module is advanced PSS/E program module and it's main purpose is advanced "constraint" analyses to derive solutions taking into consideration constraints and limitations (voltage limits, transmission line capacities…) and also economic factors for generation engagement.

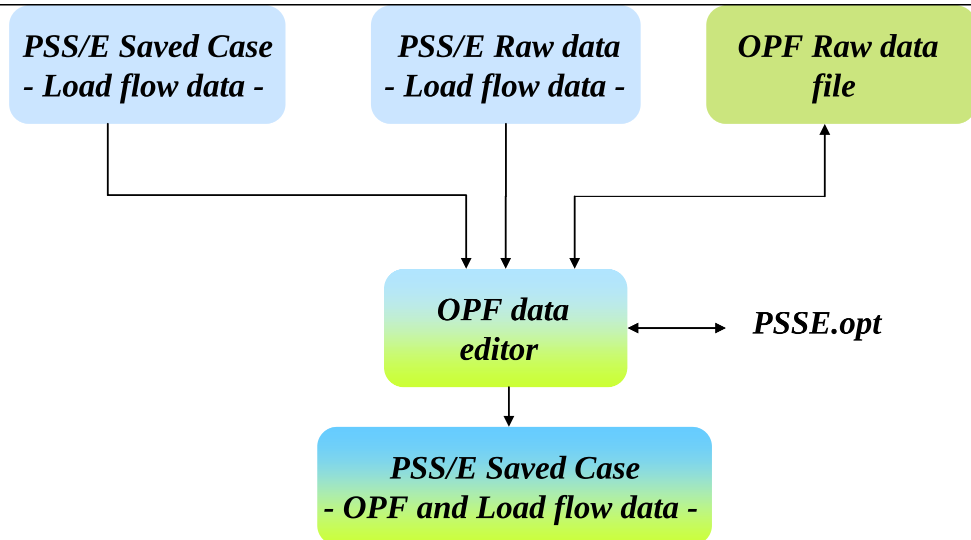


Figure 0.9 - PSS/E model – PSS/E OPF data organization

This enables you to perform so called "optimization" of network, or in more detail:

- System operation optimization
    - Reduction of system operational costs
    - Reduction of losses
    - Feasibility of regimes (technical and economic)
- Optimization of system performance (transformer tap ratios, voltage profile, reactive power plant engagement etc…)
- Series and Shunt compensation requirements
- Identification of load shed strategy to resolve system problems
- Limited economical aspect analyses
    - Marginal price calculations
    - System exchanges opportunities (export/import)
    - Congestion related costs

Objective functions are expressions of cost in terms of the power system variables (example, the fuel cost incurred to produce power is a function of the active power generation among participating machines). OPF automatically adjusts the participating machines' active power generation, within capability limits, to reduce the total fuel cost or losses or other goal. All in all optimization is achieved through minimization of objective function that can be:

- Minimize fuel costs
- Minimize Active Power Slack Generation
- Minimize Reactive Power Slack Generation
- Minimize Active Power Loss ($/pu MW)
- Minimize Reactive Power Loss ($/pu Mvar)
- Minimize Adjustable Branch Reactances
- Minimize Adjustable Bus Shunts
- Minimize Adjustable Bus Loads
- Minimize Interface Flows
- Minimize Reactive Generation Reserve

OPF data for generation units are stored in OPF module of PSS/E as Active Power Dispatch Tables which comprise:

- Generation Max
- Generation Min
- Fuel Cost scale coef, scaling of cost curve
- Cost curve type
- Cost table

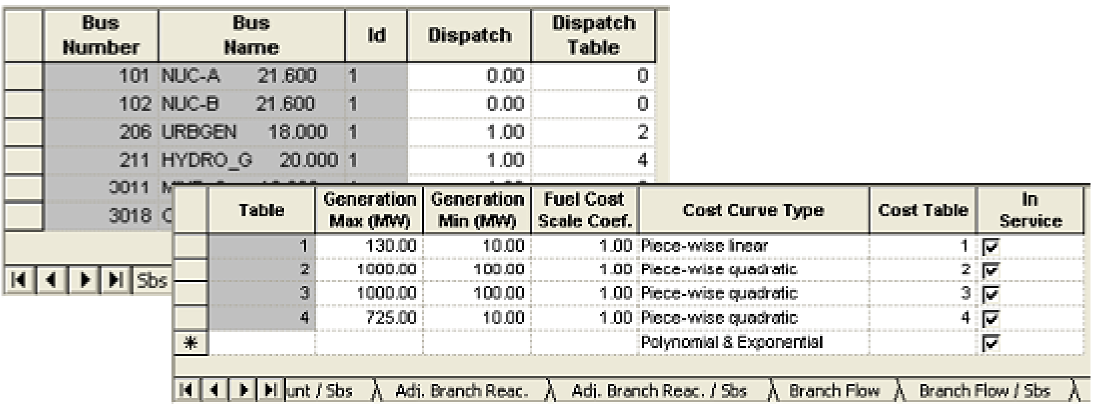


Figure 0.10 - PSS/E model – generation modeling OPF

Most important data for optimization are generation cost tables. If the cost curve table coordinate value has units of MBTU/hour, then the fuel cost scale coefficient should be entered with units of (cost units)/MBTU, and final cost tables are product between these values and the associated Fuel cost (for specific unit defined in dispatch tables) curve coordinate value produces a result that has cost units of (cost units)/hour (Figure 0.11).

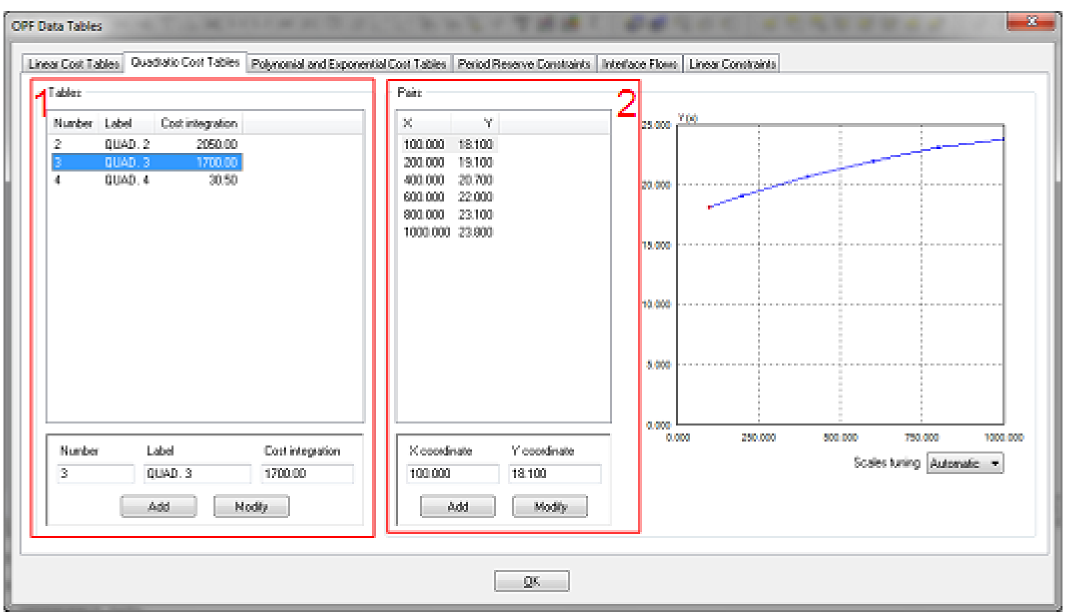


Figure 0.11 - PSS/E model – generation modeling cost curve

Biding values, as way to model market behavior (market behavior is usually different then cost curves):

- Minimum production level is usually offered at low price (just to cover expenses)

- Real market offer price is after minimum engagement is usually higher than costs, to include profits (profit based approach)

Besides all of above mentioned as one of the very important input necessary for OPF calculations is consideration of network constraints reflected through the "Interface Flows" option within PSS-S/OPF. Input window for this possibility is given in Figure 0.12 and network constraints can be involved by specifying NTC values in both directions whereby list of participating branches have to be specified.

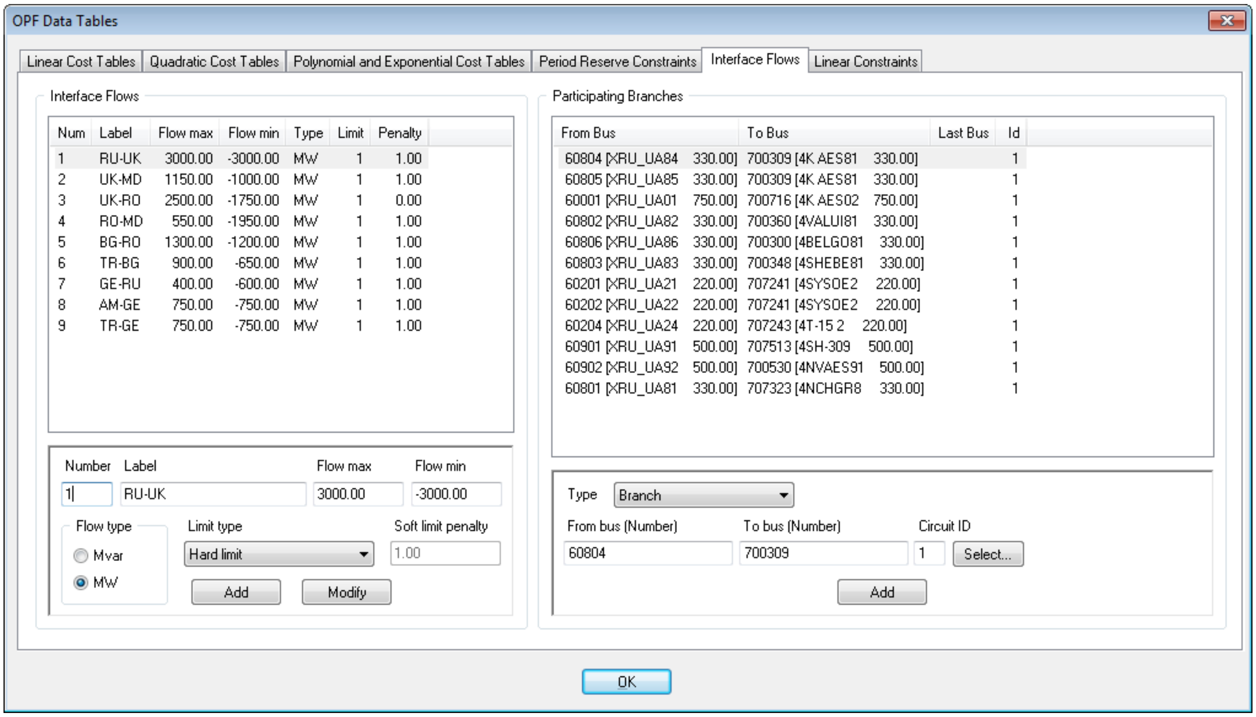


Figure 0.12 - PSS/E model – interface flows

2.4 Basic Prerequisites and Assumptions

One of the assumptions and very important starting points was related to the previous study realized within the previous phase of BSTP. The main aim of that study was to give some first results of OPF analyses conducted for Black Sea region. Precisely within this study, necessary input data for OPF models for 2015 and 2020 were collected and accordingly first OPF models for Black Sea region were formed. In the further text we will use term "Previous Study" Scenario which will correspondent with these first models, precisely with calculations related to their constrained split mode. That means that we used asynchronous operation of regional models for 2015 (winter and summer peak) taking into account NTC values as constraint in each border.

BSTP OPF models for 2015 (winter and summer peak) were updated according to collected questionnaires using the cost curve toolbox and are used as the Base Case OPF models for sensitivity analyses. Base Case for all sensitivity analyses is defined according to the following assumptions

- Starting values for fuel prices according to questionnaire
- CO_2 emission cost was set on 12 $/ton CO_2 for each country
- Capital costs are included
- Average hydrology conditions
- Average RES engagement
- Without new transmission network reinforcements added to official BSTP models
- With base NTC's values from previous study.

Within the conducted analyses, East and West part of Black Sea region are separately considered. This was done to reflect todays situation where Romania, Bulgaria and Turkey work synchronously within ENTSO-E while Moldova, Ukraine, Russia and South Caucasus countries are part of IPS/UPS interconnection. Network constraints were incorporated into the study by using NTC values for the region. The NTC values were taken from a previous study and are given in Figure 0.13 and Figure 0.14 and are implemented in previously described way.

Another important assumption is related to the RES and HPP engagements within the OPF calculations. In that sense it can be said that they participated with their fixed prices as must run and they were excluded from the optimization process. Exception was made only in case of Georgia because of its power system production structure.

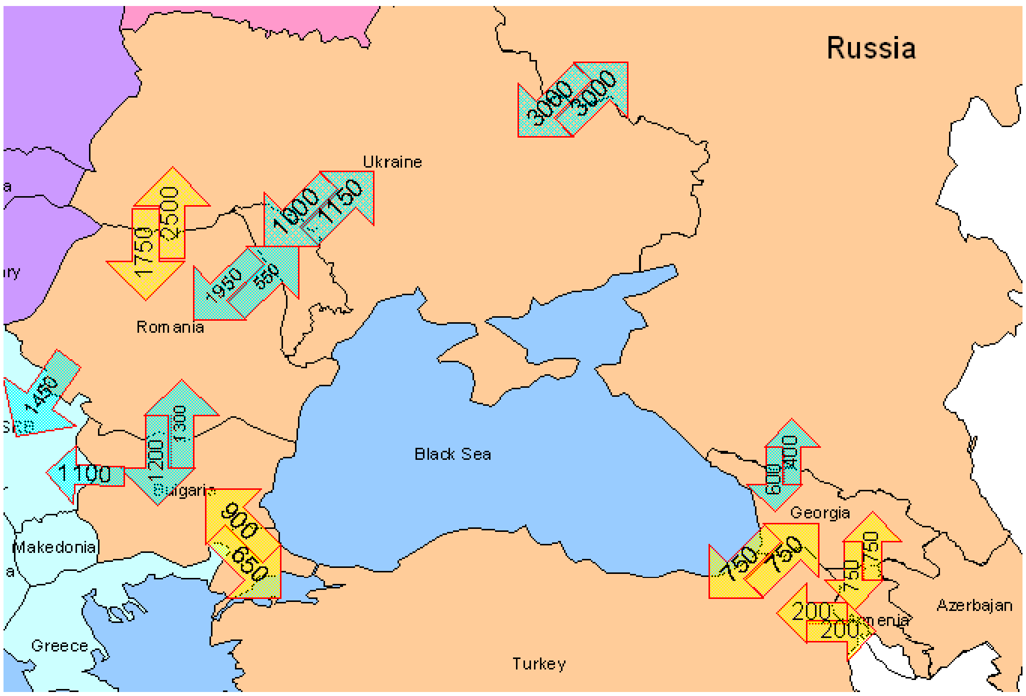


Figure 0.13 – Black Sea region – Border capacities for Winter peak

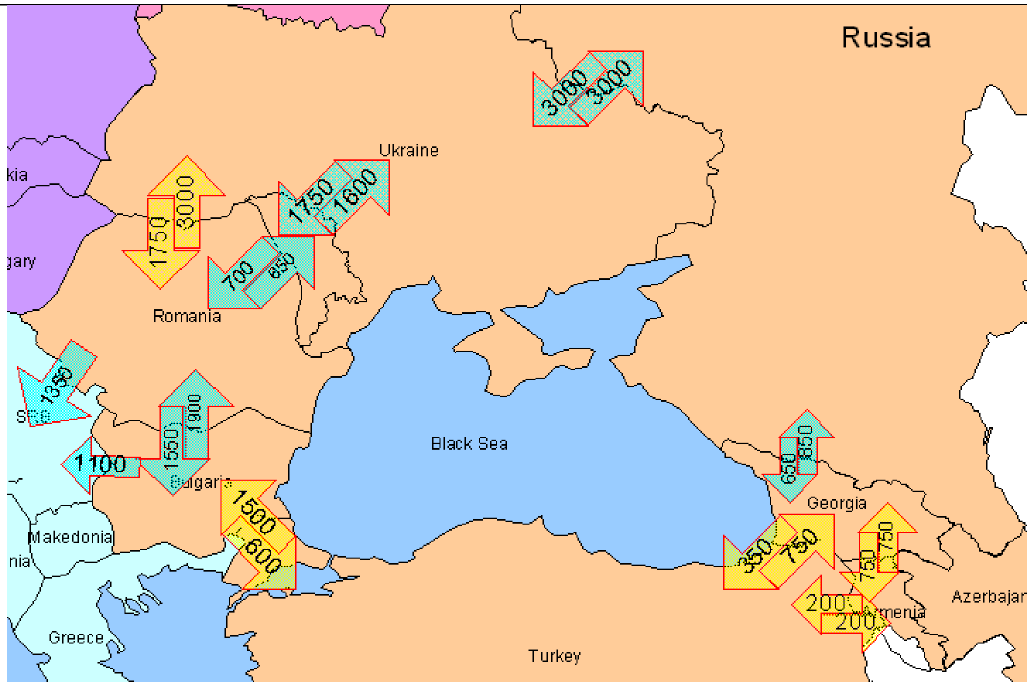


Figure 0.14 – Black Sea region – Border capacities for Summer peak

As presented in the introduction section of this report, alternative cases for sensitivity analyses are formed according to the following assumptions:

Fuel price variations:

- Gas/Oil ±20% of Base Case values
- Lignite/Coal ±10% of Base Case values
- Uranium ±5% of Base Case values

CO2 cost variations:

- Average value of 12 $/MWh
- Extreme value of 50 $/MWh
- No charge for CO_2 (underdeveloped market in that sense)

Capital costs variations:

- **Case with capital costs**: In Base Case CAPEX is 100% for new power plants, 45% for reconstructed both, TPPs and NPPs, as well as 30% for reconstructed HPPs. CAPEX is 0% for power plants that reached their full life time period or more.
- **Case without capital costs**: Short run marginal cost scenario where CAPEX for all power plants is 0% of their capital costs.

Different local hydrological regimes – this was given by specific merit order for following regimes:

- **Average**: This is Base Case according to average engagement of HPPs defined in BSTP models
- **Dry**: This was defined by decrease of HPP's production by 20% with appropriate correction of national power system balance and it would be simulate power plant engagement for specified regimes in case of dry year.

- **Wet**: This was defined by increase of HPP's production by 20% with appropriate correction of national power system balance and it would be simulate power plant engagement for specified regimes in case of wet year.

Different scenarios of RES engagement – this was given by specific merit order for following regimes:

- **Average**: This is Base Case according to average engagement of RES power plants defined in BSTP models
- **Low RES penetration**: This was defined by decrease of RES production by 20% with appropriate correction of national power system balance.
- **High RES penetration**: This was defined by increase of RES production by 20% with appropriate correction of national power system balance.

Influence of the network reinforcements:

- **Average**: This is Base Case according NTC's values from previous study
- **Decreasing of NTC**: This was defined by decrease of NTC's by 20% on the each border (it represents the influence of the delay of some projects defined in BSTP models).
- **Increasing of NTCs**: This was defined by increase of NTC values by 500 MW on the each border (it represents the influence of the new additional interconnection projects)

3 SENSITIVITY ANALISYS RESULTS

3.1 Fuel Price Variations

Fuel price variations have great impact on power plants production costs and overall electricity market behavior. Countries with dominant thermal production are most sensitive to fuel price variations on the market, especially the ones which massively depend on one type of fuel. High share of hydro production in total production or high diversity of production technologies in generation mix reduce the influence of fuel price variations on production costs. In order to evaluate in the best possible way the behavior of electricity market across the Black Sea region, two sets of assumptions are used for sensitivity analyses regarding fuel price variations:

- High fuel price case (Scenario 1)
    - Lignite/Coal: +10% of Base Case values
    - Gas/Oil: +20% of Base Case values
    - Uranium: +5% of Base Case values
- Low fuel price case (Scenario 2)
    - Lignite/Coal: -10% of Base Case values
    - Gas/Oil: -20% of Base Case values
    - Uranium: -5% of Base Case values

Aggregated results and graphs of OPF simulations for observed cases and winter and summer peak scenarios are presented in following tables and figures (Table 3.1, Table 3.2, Figure 3.1, Figure 3.2, Figure 3.3, Figure 3.4, Figure 3.5, Figure 3.6, Figure 3.7, Figure 3.8, Figure 3.9, Figure 3.10, Figure 3.11, Figure 3.12)

*Table 3.1 – Results of OPF simulations for observed cases and **winter peak scenario** (Fuel price variations)*

	Base Case			High Fuel Scenario			Low Fuel Scenario		
	AVG [$/MWh]	GMP [$/MWh]	EXC [MW]	AVG [$/MWh]	GMP [$/MWh]	EXC [MW]	AVG [$/MWh]	GMP [$/MWh]	EXC [MW]
Romania	66	94.16	1113	69.4	110.63	1071	62.7	77.78	1253
Bulgaria	50.5	140.57	773	53.2	125.75	772	47.6	87.15	643
Turkey	81.8	101.81	-672	90.1	116	-680	73.4	86.55	-682
Armenia	39.8	88.17	543	45.2	89.74	597	35	76.36	562
Georgia	23.9	59.59	340	24.2	59.53	341	23.2	67.67	281
Azerbaijan	57.4	67.28	297	63.7	77.48	240	50.6	57.08	323
Russia	50.7	68.93	2171	55.1	76.22	1697	45.9	64.4	2111
Ukraine	49.6	115.9	-634	52.7	135.71	-129	46.9	96.09	-611
Moldova	51.9	142.95	170	55.5	169.87	170	48.6	115.94	203

*Table 3.2 – Results of OPF simulations for observed cases and **summer peak scenario** (Fuel price variations)*

	Base Case			High Fuel Scenario			Low Fuel Scenario		
	AVG [$/MWh]	GMP [$/MWh]	EXC [MW]	AVG [$/MWh]	GMP [$/MWh]	EXC [MW]	AVG [$/MWh]	GMP [$/MWh]	EXC [MW]
Romania	70.1	97.44	1149	72.3	111.54	1098	67.9	84.04	1125
Bulgaria	56.3	106.46	750	58.7	125.75	747	53.8	87.17	754
Turkey	81.7	100.58	-477	89.8	114.5	-481	73.5	86.55	-469
Armenia	42.6	93.77	497	47.7	115.7	486	38.6	69.8	700
Georgia	23.9	59.54	570	24	59.52	569	23.7	59.74	569
Azerbaijan	57.2	67.28	717	63.6	77.48	779	50.7	57.08	424
Russia	50.4	68.96	1130	54.5	76.24	543	45.9	68.51	1821
Ukraine	54.6	115.91	-230	57.5	135.73	355	51.9	96.12	-847
Moldova	60.4	142.96	153	64.2	169.86	153	56.7	115.94	154

From the results of sensitivity analysis of fuel price variations it can be concluded that:

- Variation of fuel prices influence variation of average production costs across the Black Sea region for about 8% comparing to base case (increase in case of high fuel price scenario, and decrease in case of low fuel price scenario) in both winter and summer peak regime.
- Gas fired power plants are dominantly present as marginal units, and therefore dictate wider range of variation of about 15% comparing to base case (increase in case of high fuel price scenario, and decrease in case of low fuel price scenario) in both winter and summer peak regime.
- Fuel price variation has most effect on power systems with dominantly thermal production based on fossil fuels (e.g. Turkey, Azerbaijan, Armenia).
- Georgian average cost of production is most insensitive to fuel price variations as a predominantly hydropower system.
- Power exchange between Russia and Ukraine is highly sensitive to fuel price variations.
- In high fuel cost scenario, Ukraine import of electricity decreases due to assumed greater escalation of gas prices than coal prices, and more competitive position of Ukrainian coal plants on the market.
- In the West part of Black Sea region, fuel price variations have small impact on exchanges between Romania, Bulgaria and Turkey.
- In low fuel cost scenario, in the East part of Black Sea region, Azerbaijan export increases due to decrease in gas prices, while in the high fuel cost scenario Azerbaijan export decreases and Armenia import increases.

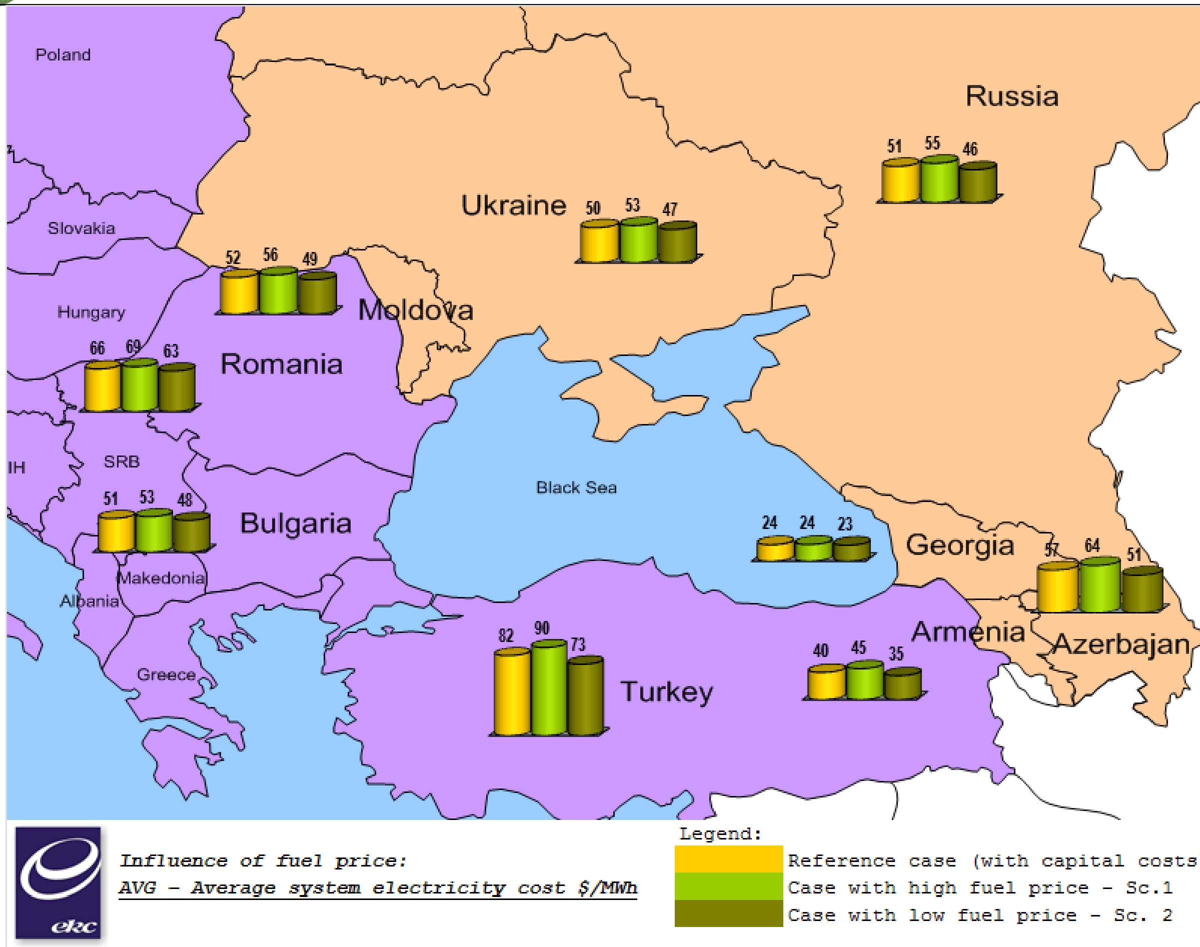
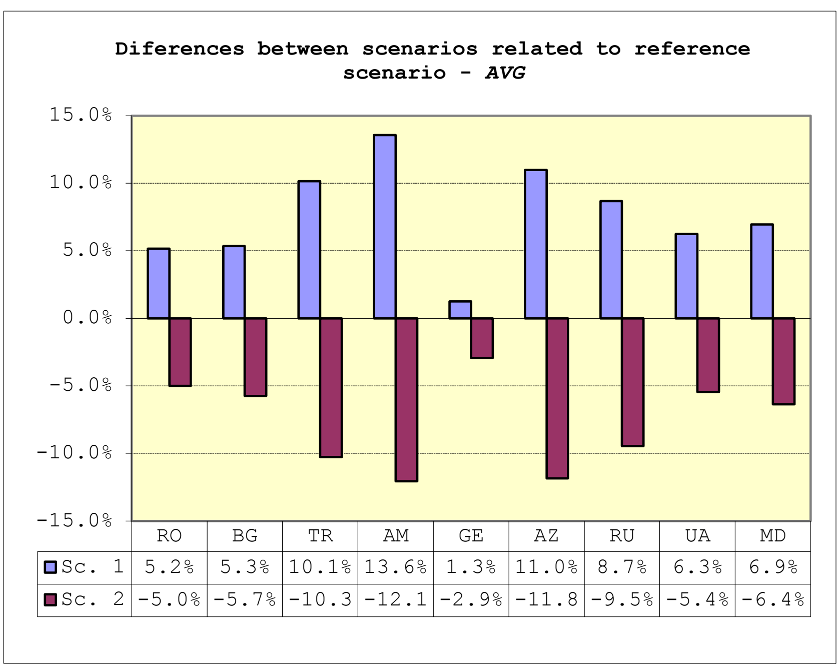


*Figure 3.1 – Black Sea region average system electricity production cost for **winter peak 2015** (Fuel price variations)*



	RO	BG	TR	AM	GE	AZ	RU	UA	MD
Sc. 1	5.2%	5.3%	10.1%	13.6%	1.3%	11.0%	8.7%	6.3%	6.9%
Sc. 2	-5.0%	-5.7%	-10.3	-12.1	-2.9%	-11.8	-9.5%	-5.4%	-6.4%

*Figure 3.2 – AVG differences between scenarios related to reference scenario for **winter peak 2015** (Fuel price variations)*

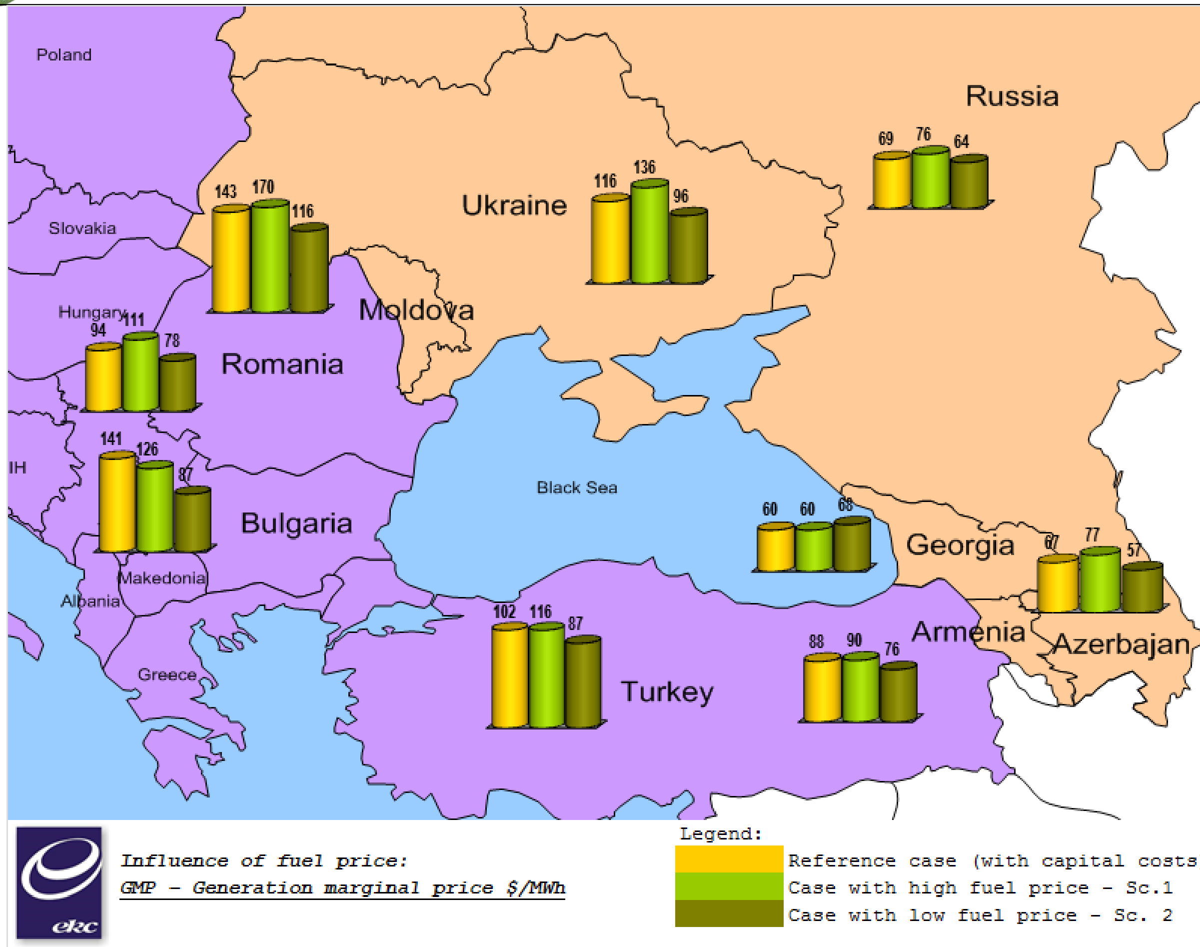
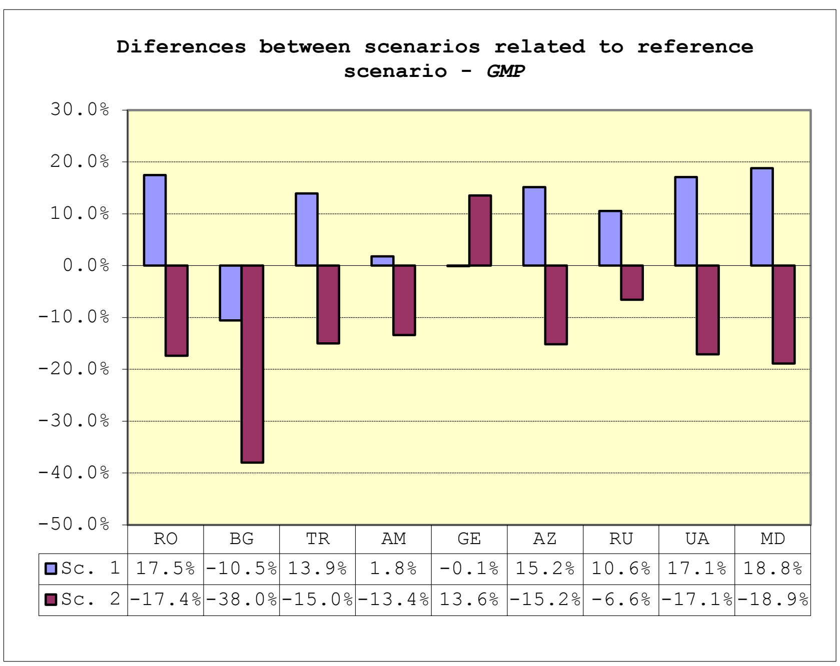


*Figure 3.3 – Black Sea region generation marginal price for **winter peak 2015** (Fuel price variations)*



	RO	BG	TR	AM	GE	AZ	RU	UA	MD
Sc. 1	17.5%	-10.5%	13.9%	1.8%	-0.1%	15.2%	10.6%	17.1%	18.8%
Sc. 2	-17.4%	-38.0%	-15.0%	-13.4%	13.6%	-15.2%	-6.6%	-17.1%	-18.9%

*Figure 3.4 – GMP differences between scenarios related to reference scenario for **winter peak 2015** (Fuel price variations)*

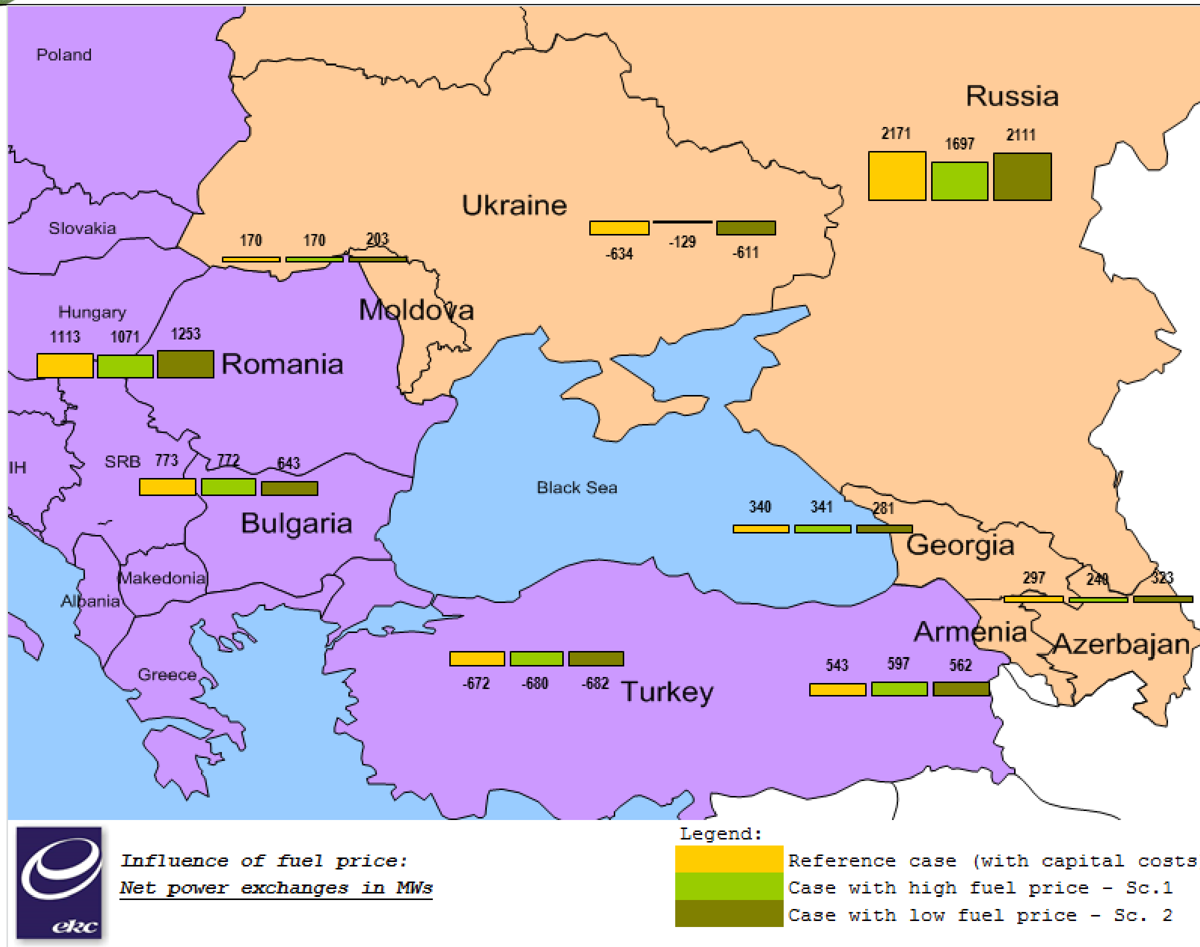


*Figure 3.5 – Black Sea region net power exchange for **winter peak 2015** (Fuel price variations)*

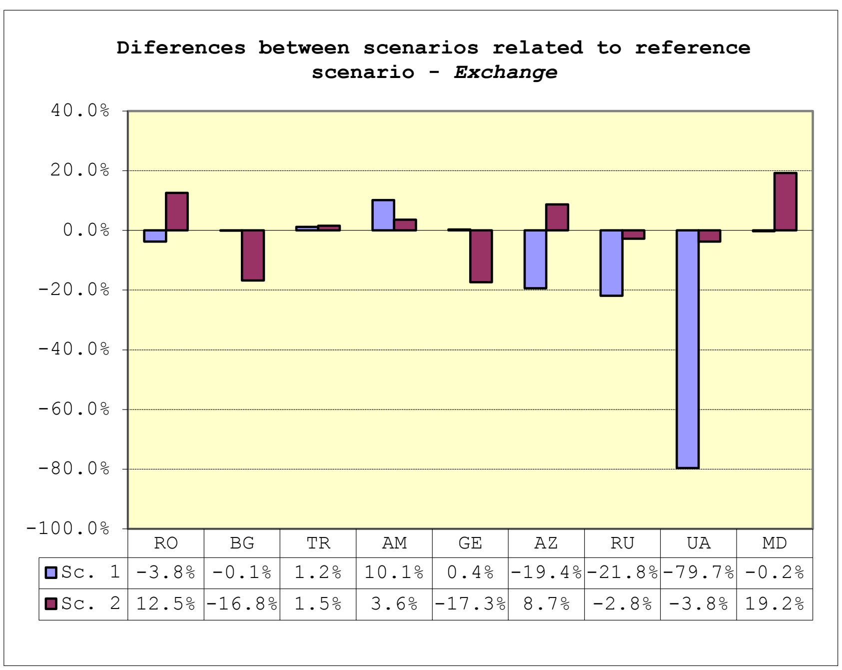


*Figure 3.6 – EXC differences between scenarios related to reference scenario for **winter peak 2015** (Fuel price variations)*

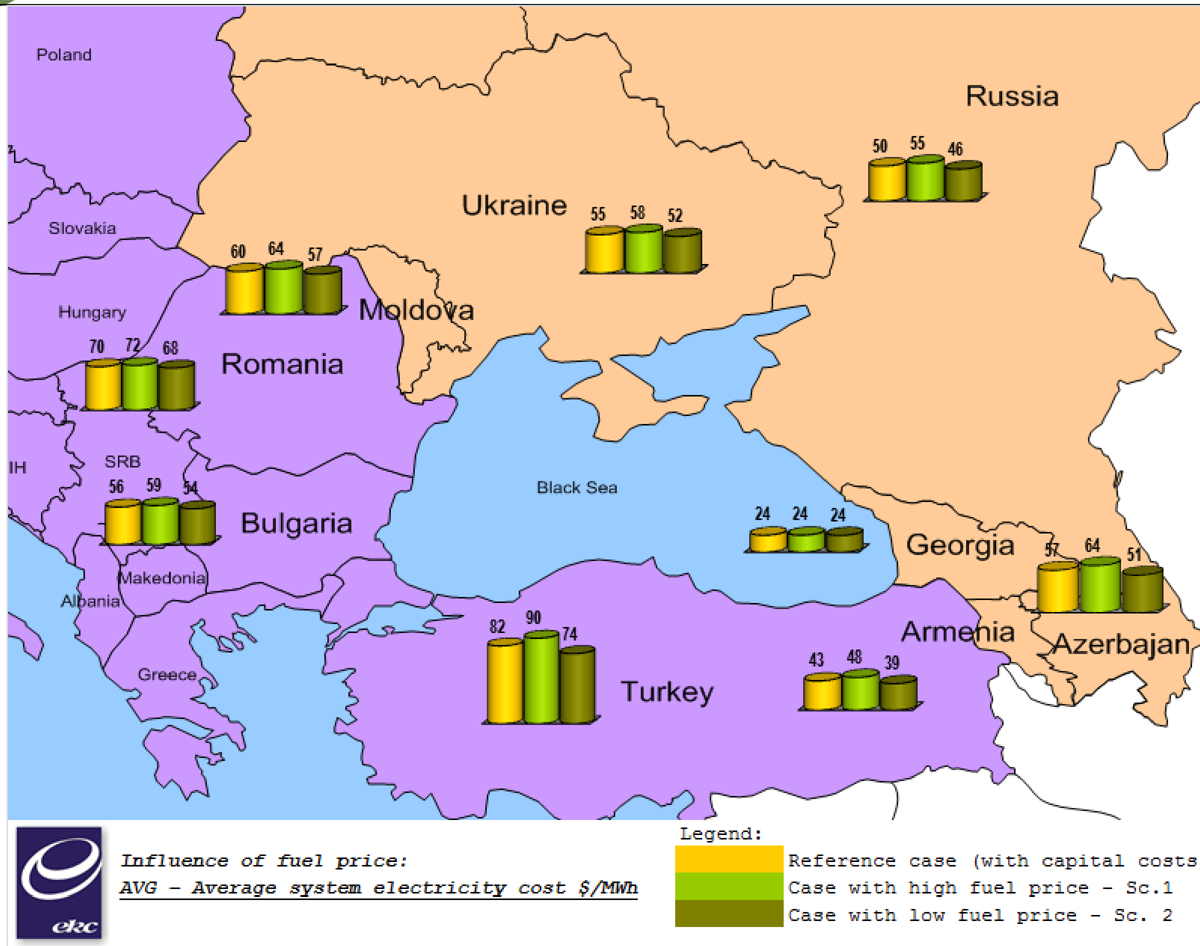
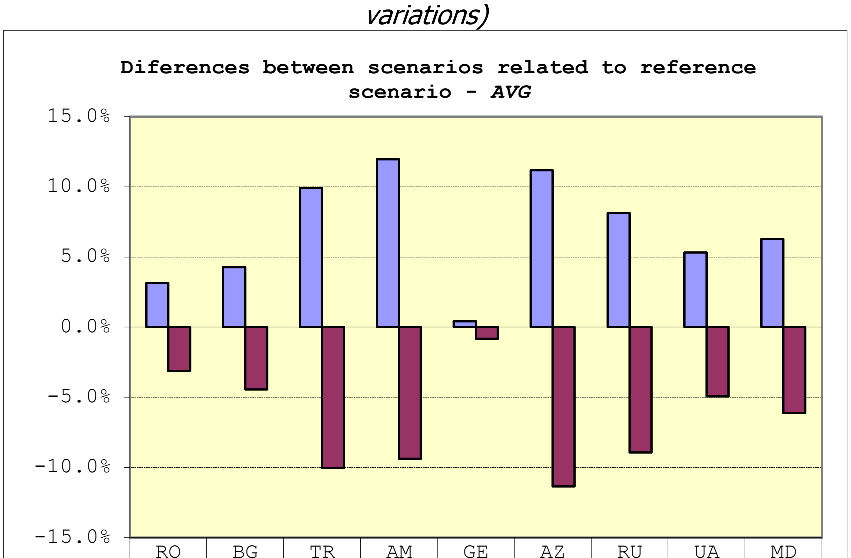


*Figure 3.7 – Black Sea region average system electricity production cost for **summer peak 2015** (Fuel price variations)*



	RO	BG	TR	AM	GE	AZ	RU	UA	MD
Sc. 1	3.1%	4.3%	9.9%	12.0%	0.4%	11.2%	8.1%	5.3%	6.3%
Sc. 2	-3.1%	-4.4%	-10.0	-9.4%	-0.8%	-11.4	-8.9%	-4.9%	-6.1%

*Figure 3.8 – AVG differences between scenarios related to reference scenario for **summer peak 2015** (Fuel price variations)*

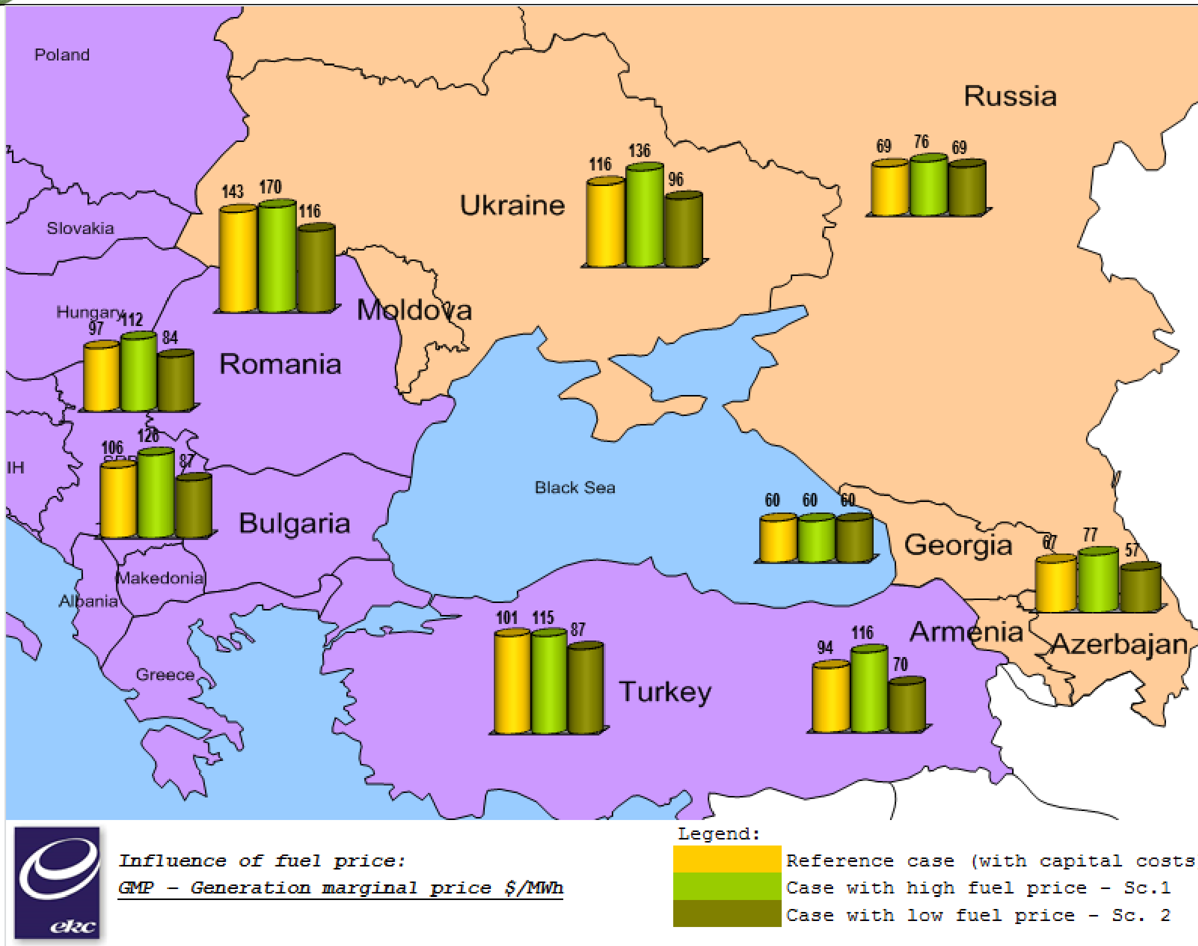


Figure 3.9 – Black Sea region generation marginal price for ***summer peak 2015*** *(Fuel price variations)*

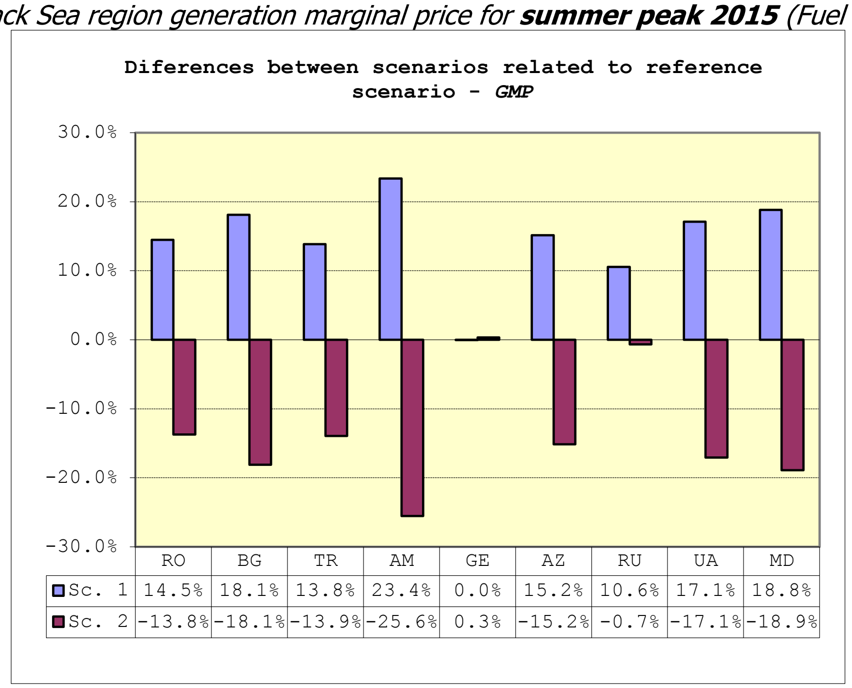


Figure 3.10 – GMP differences between scenarios related to reference scenario for ***summer peak 2015*** *(Fuel price variations)*

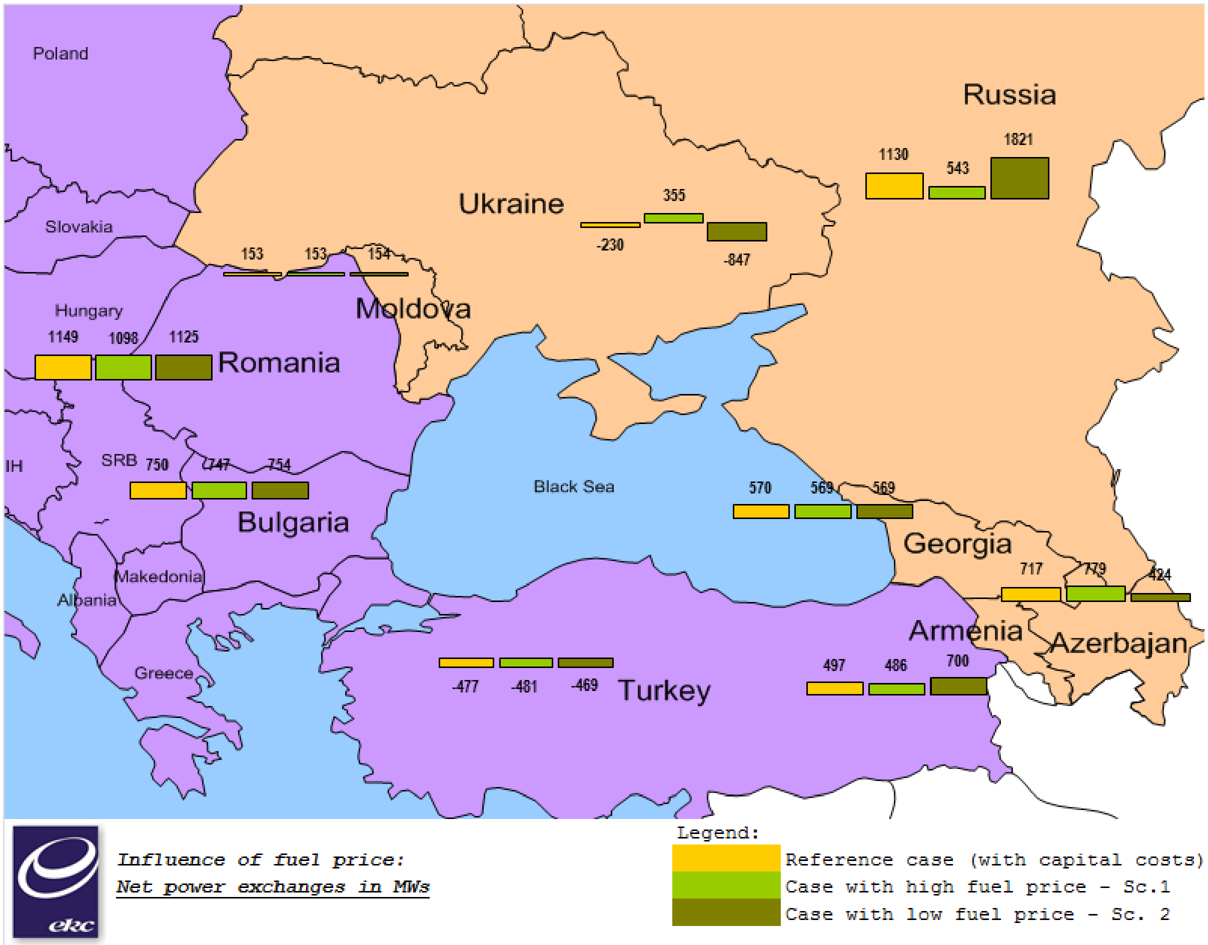
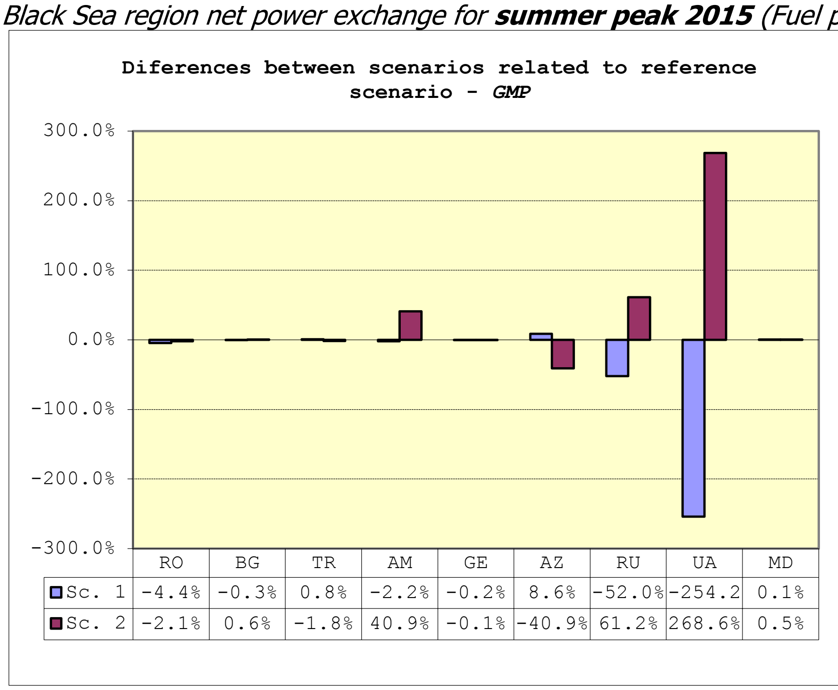


Figure 3.11 – Black Sea region net power exchange for ***summer peak 2015*** *(Fuel price variations)*



	RO	BG	TR	AM	GE	AZ	RU	UA	MD
Sc. 1	-4.4%	-0.3%	0.8%	-2.2%	-0.2%	8.6%	-52.0%	-254.2	0.1%
Sc. 2	-2.1%	0.6%	-1.8%	40.9%	-0.1%	-40.9%	61.2%	268.6%	0.5%

Figure 3.12 – EXC differences between scenarios related to reference scenario for ***summer peak 2015*** *(Fuel price variations)*

3.2 Capital Cost Variations

Capital costs represent a significant component in power plant's life cycle overall costs. In order to return investment and make profit, revenue gained in electricity market from produced energy must cover both operational and capital costs of power plants. Different technologies have different ratio of operational and capital costs. For some technologies, large starting investments are required (e.g. nuclear power plants), but operational costs are rather low and plant is almost always competitive on the market. Other technologies require relatively small starting investments (e.g. gas power plants), but operational costs are rather high and plant position on the market is less competitive. These factors affect plant investors and owners. In order for them to make best possible decisions, various scenarios of electricity market behavior and bidding strategies must be analyzed.
To analyze the impact of different levels of capital cost inclusion in plant bids to electricity market behavior, three scenarios are analyzed:

- Case with long run marginal cost bidding (LRMC) - Study Base Case: capital expenses (CAPEX) are 100% included in plant bids for new power plants, 45% for reconstructed TPPs and NPPs and 30% for reconstructed HPPs. CAPEX is 0% for power plants that reached their full life time period or more.
- Case with short run marginal cost bidding (SRMC): CAPEX is 0% for all power plants (therefore capital costs are not included in plants market bids).
- Case from previous study.

Aggregated results and graphs of OPF simulations for observed cases and both winter and summer peak regimes are presented below (Table 3.3, Table 3.4, Figure 3.13, Figure 3.14, Figure 3.15, Figure 3.16, Figure

3.17, Figure 3.18, Figure 3.19, Figure 3.20,

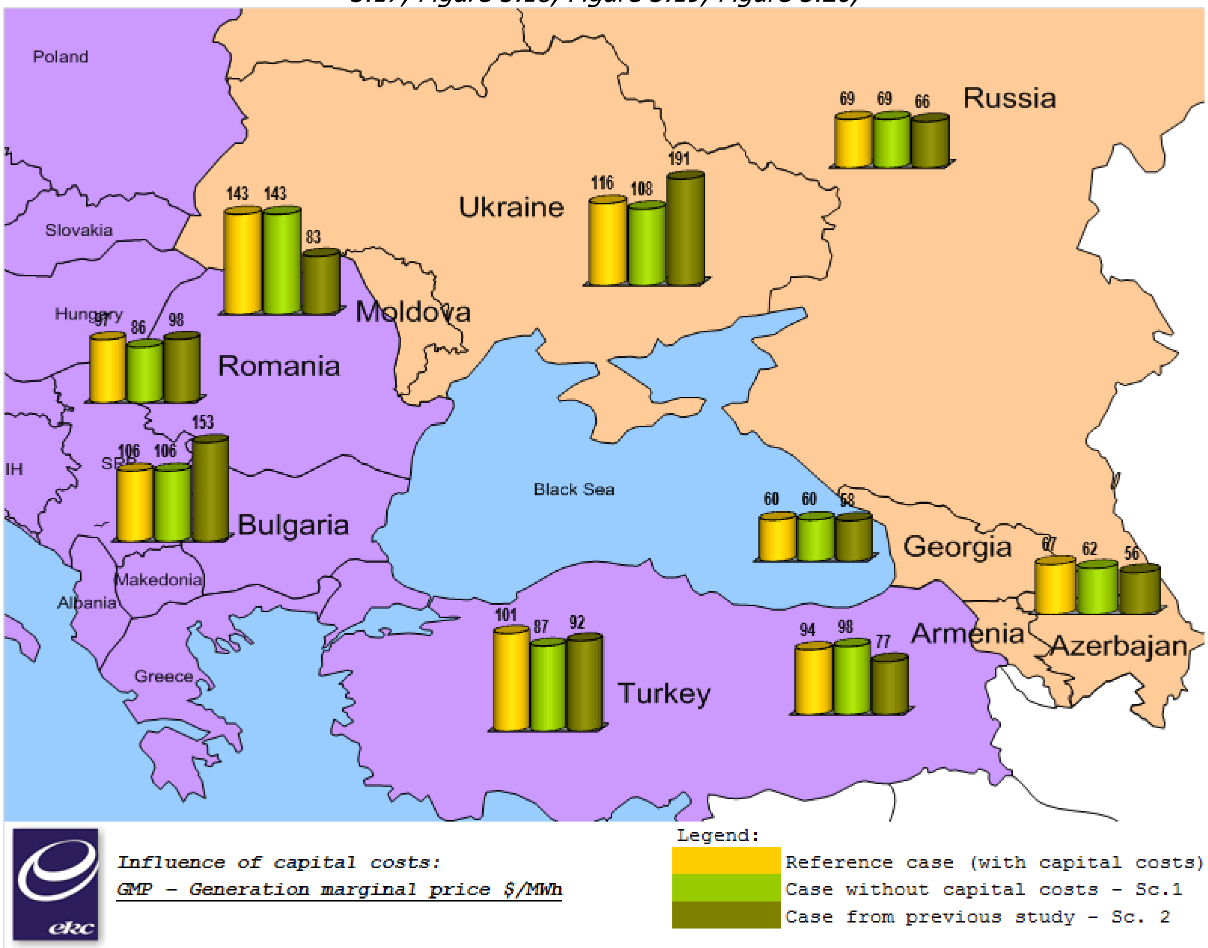


Figure 3.21, Figure 3.22, Figure 3.23 and Figure 3.24).

*Table 3.3 – Results of OPF simulations for observed cases and **winter peak scenario** (Capital cost variations)*

	Base Case (LRMC)			SRMC Scenario			Case from previous study		
	AVG [$/MWh]	GMP [$/MWh]	EXC [MW]	AVG [$/MWh]	GMP [$/MWh]	EXC [MW]	AVG [$/MWh]	GMP [$/MWh]	EXC [MW]
Romania	66	94.16	1113	52.2	85.94	1341	65.2	97.97	1446
Bulgaria	50.5	140.57	773	43.3	106.44	616	60.6	152.81	362
Turkey	81.8	101.81	-672	64.8	87.15	-660	75.5	92.32	-669
Armenia	39.8	88.17	543	36.6	51.03	718	35.4	77.31	581
Georgia	23.9	59.59	340	11.9	74.5	261	27.9	67.45	308
Azerbaijan	57.4	67.28	297	45.8	61.97	171	47.1	56.14	257
Russia	50.7	68.93	2171	50.6	68.94	1715	44	61.88	1585
Ukraine	49.6	115.9	-634	45.9	107.95	-176	41.4	131.86	-138
Moldova	51.9	142.95	170	51.9	142.96	169	50.8	73.14	241

*Table 3.4 – Results of OPF simulations for observed cases and **summer peak scenario** (Capital cost variations)*

	Base Case (LRMC)			SRMC Scenario			Case from previous study		
	AVG [$/MWh]	GMP [$/MWh]	EXC [MW]	AVG [$/MWh]	GMP [$/MWh]	EXC [MW]	AVG [$/MWh]	GMP [$/MWh]	EXC [MW]
Romania	70.1	97.44	1149	58.2	86.05	1120	69.6	97.99	866
Bulgaria	56.3	106.46	750	51.2	106.45	813	61.6	152.85	576
Turkey	81.7	100.58	-477	65.2	87.15	-435	75.5	92.32	-493
Armenia	42.6	93.77	497	40.6	98.42	582	36.5	77.14	477
Georgia	23.9	59.54	570	12.5	59.58	566	26.4	58.41	716
Azerbaijan	57.2	67.28	717	46.9	61.97	759	48	56.08	410
Russia	50.4	68.96	1130	50.2	68.97	403	43.9	65.73	1349
Ukraine	54.6	115.91	-230	51.8	107.95	398	45.9	190.58	-323
Moldova	60.4	142.96	153	60.5	142.97	153	58.6	82.59	164

From the results of sensitivity analysis for winter and summer peak scenario it can be concluded that:

- Deviation in generation marginal price of base case from reference case in previous study is less than 10% in both winter and summer peak regimes and within expected limits due to new data and changes made according to provided Questionnaires from TSOs.
- In scenario without capital costs attached to generators bids (i.e. economic dispatch based on short run marginal costs), average cost of production decreases across the Black Sea region for about 14% in both observed regimes.
- Capital cost variations has no impact on prices in Russia and Moldova due to no planned entries of new conventional power plants.
- Only modest changes of generation marginal prices are observed comparing scenario with and without capital costs, due to small share of capital cost component in overall production cost of gas fired power plants, which represent marginal units in most countries.
- In scenario without capital costs, the greatest impact on countries net exchanges comparing to reference case, will happen on Russian - Ukrainian border, where export from Russia to Ukraine will decrease as a result of more competitive position of new Ukrainian coal plants on the market and short run marginal cost generator biding.

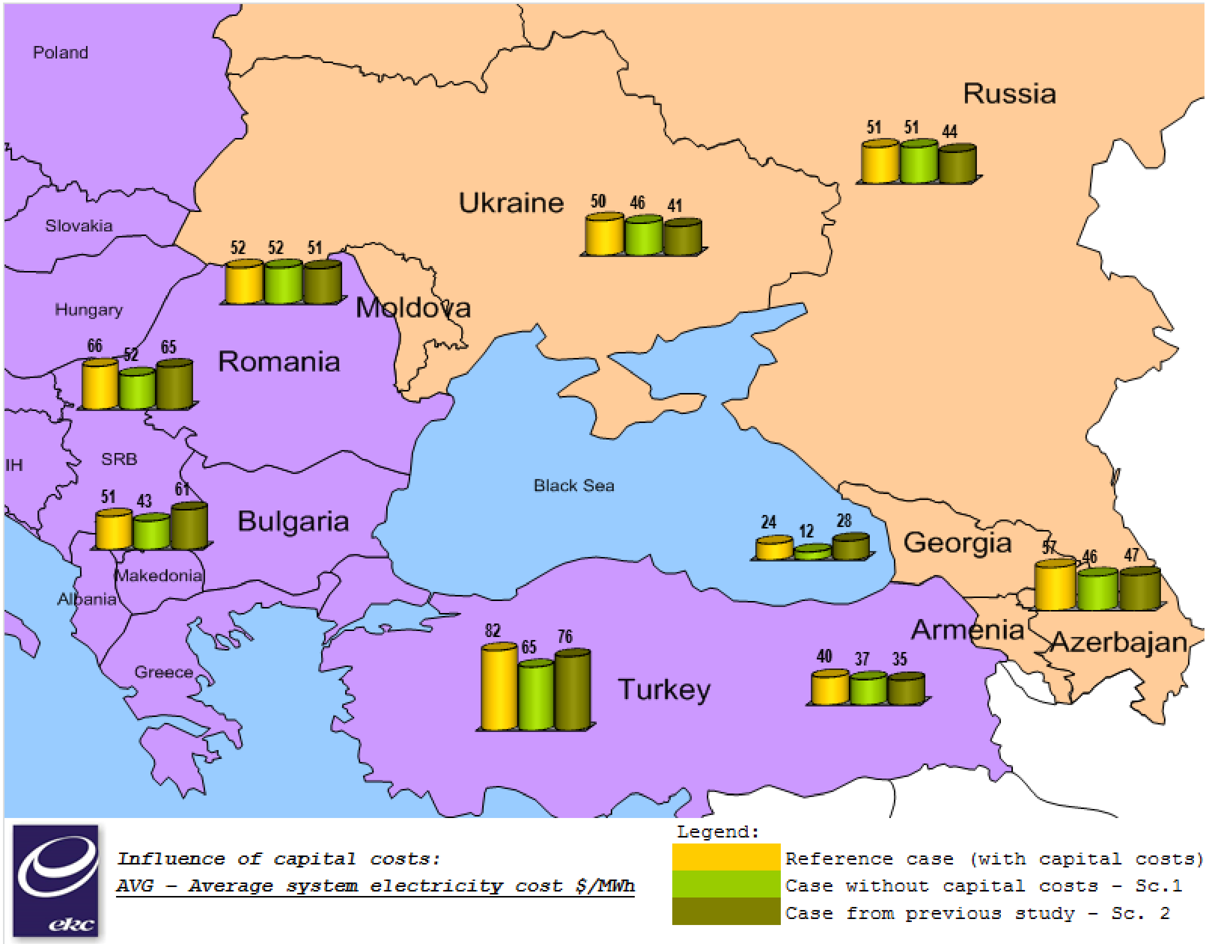
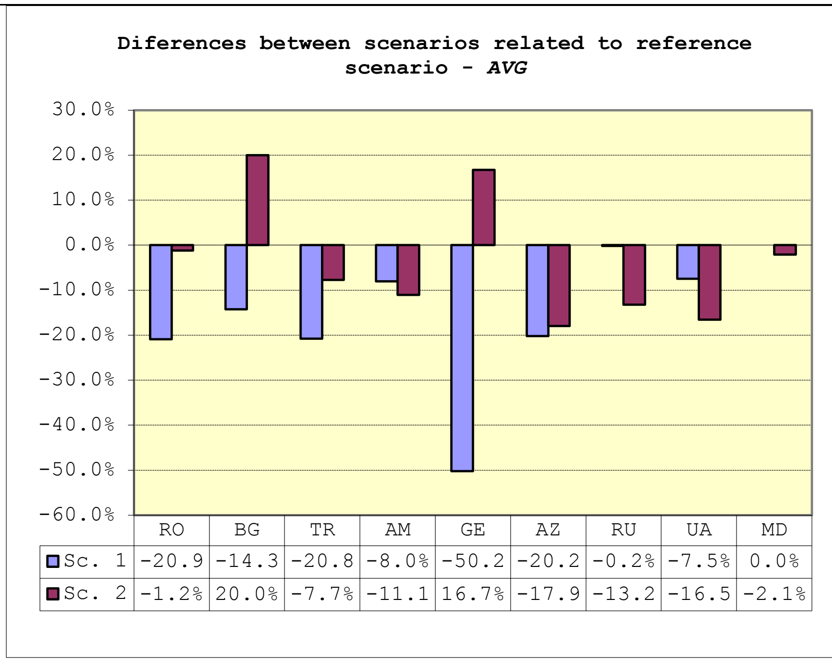


*Figure 3.13 – Black Sea region average system electricity production cost for **winter peak 2015** (Capital cost variations)*



	RO	BG	TR	AM	GE	AZ	RU	UA	MD
Sc. 1	-20.9	-14.3	-20.8	-8.0%	-50.2	-20.2	-0.2%	-7.5%	0.0%
Sc. 2	-1.2%	20.0%	-7.7%	-11.1	16.7%	-17.9	-13.2	-16.5	-2.1%

*Figure 3.14 – AVG differences between scenarios related to reference scenario for **winter peak 2015** (Capital cost variations)*

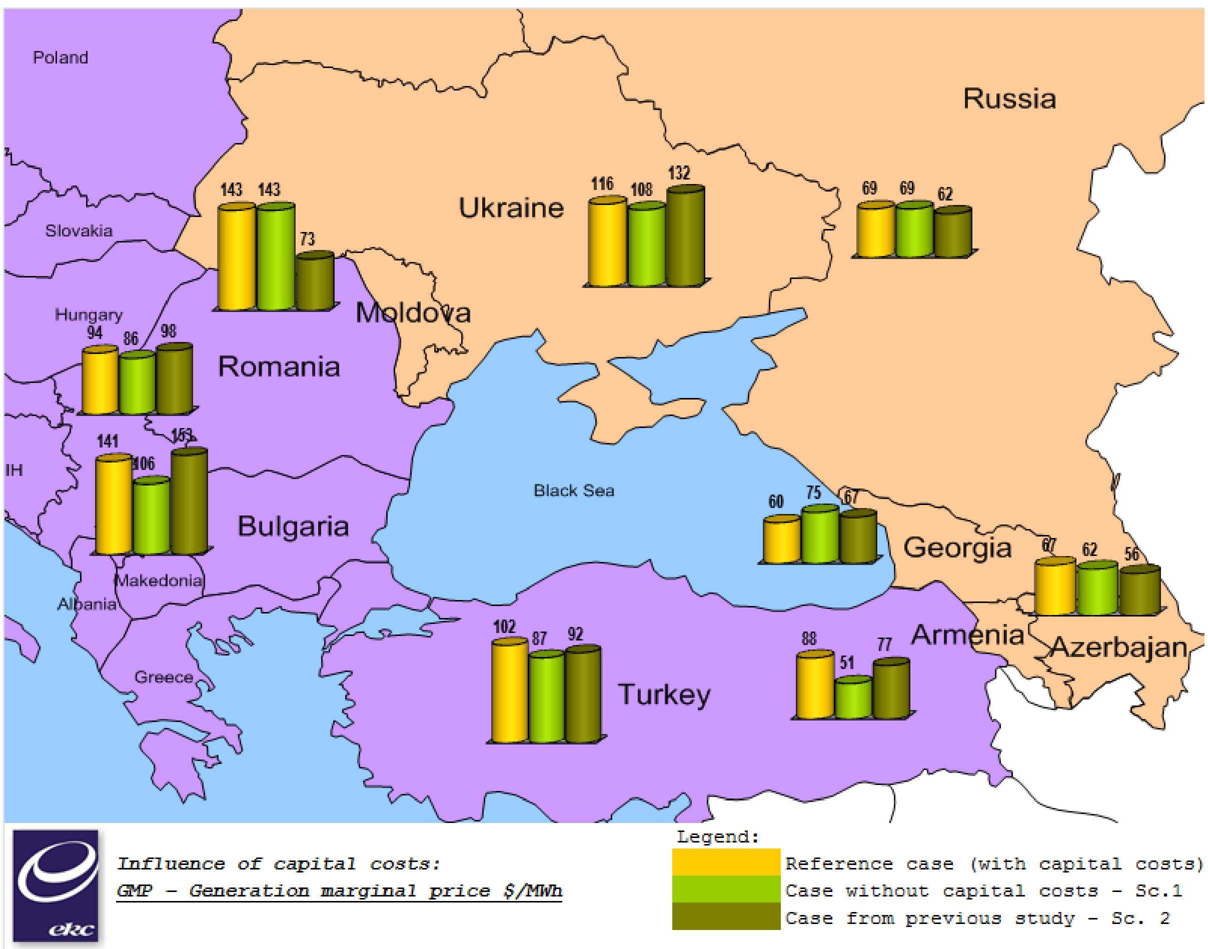
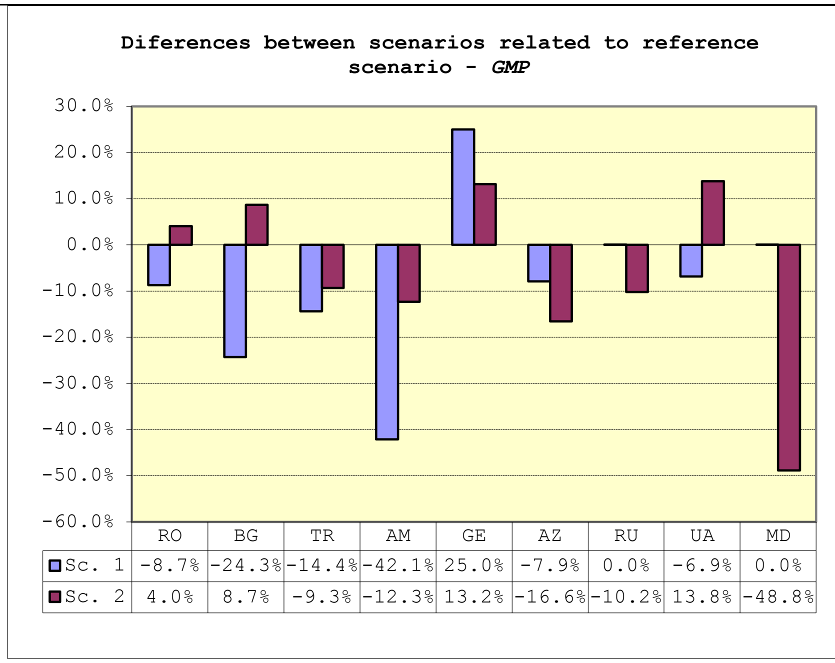


*Figure 3.15 – Black Sea region generation marginal price for **winter peak 2015** (Capital cost variations)*



	RO	BG	TR	AM	GE	AZ	RU	UA	MD
Sc. 1	-8.7%	-24.3%	-14.4%	-42.1%	25.0%	-7.9%	0.0%	-6.9%	0.0%
Sc. 2	4.0%	8.7%	-9.3%	-12.3%	13.2%	-16.6%	-10.2%	13.8%	-48.8%

*Figure 3.16 – GMP differences between scenarios related to reference scenario for **winter peak 2015** (Capital cost variations)*

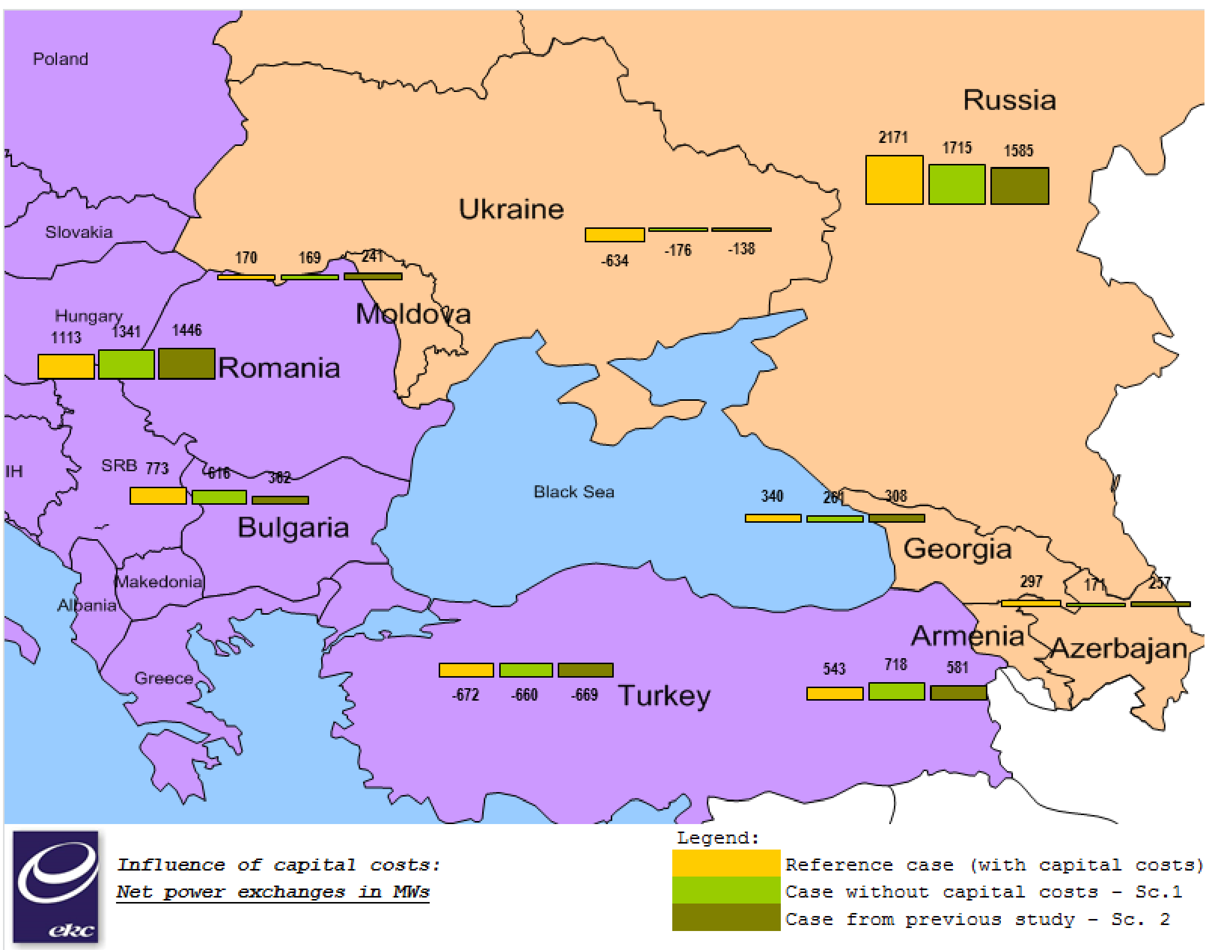
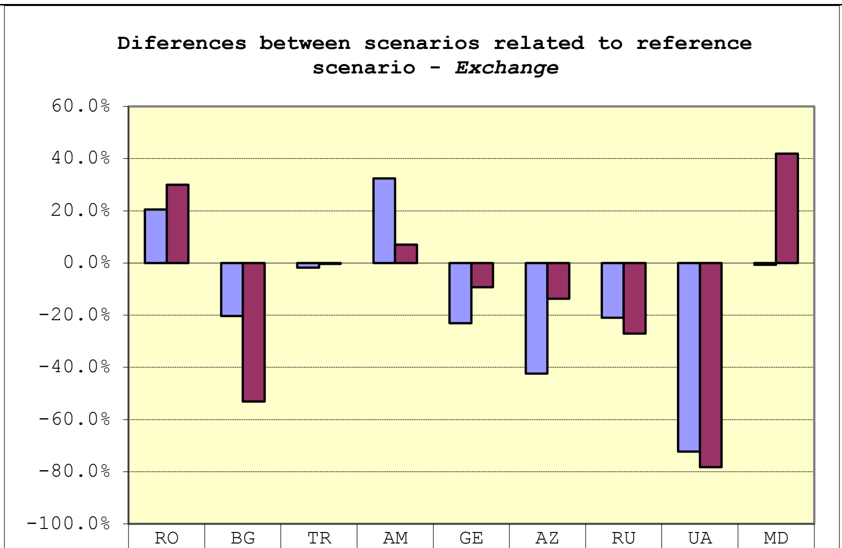


*Figure 3.17 – Black Sea region net power exchange for **winter peak 2015** (Capital cost variations)*



	RO	BG	TR	AM	GE	AZ	RU	UA	MD
Sc. 1	20.5%	-20.3%	-1.8%	32.4%	-23.1%	-42.4%	-21.0%	-72.3%	-0.6%
Sc. 2	29.9%	-53.1%	-0.4%	7.0%	-9.3%	-13.7%	-27.0%	-78.2%	41.9%

Figure 3.18 – EXC differences between scenarios related to reference scenario for ***winter peak 2015*** *(Capital cost variations)*

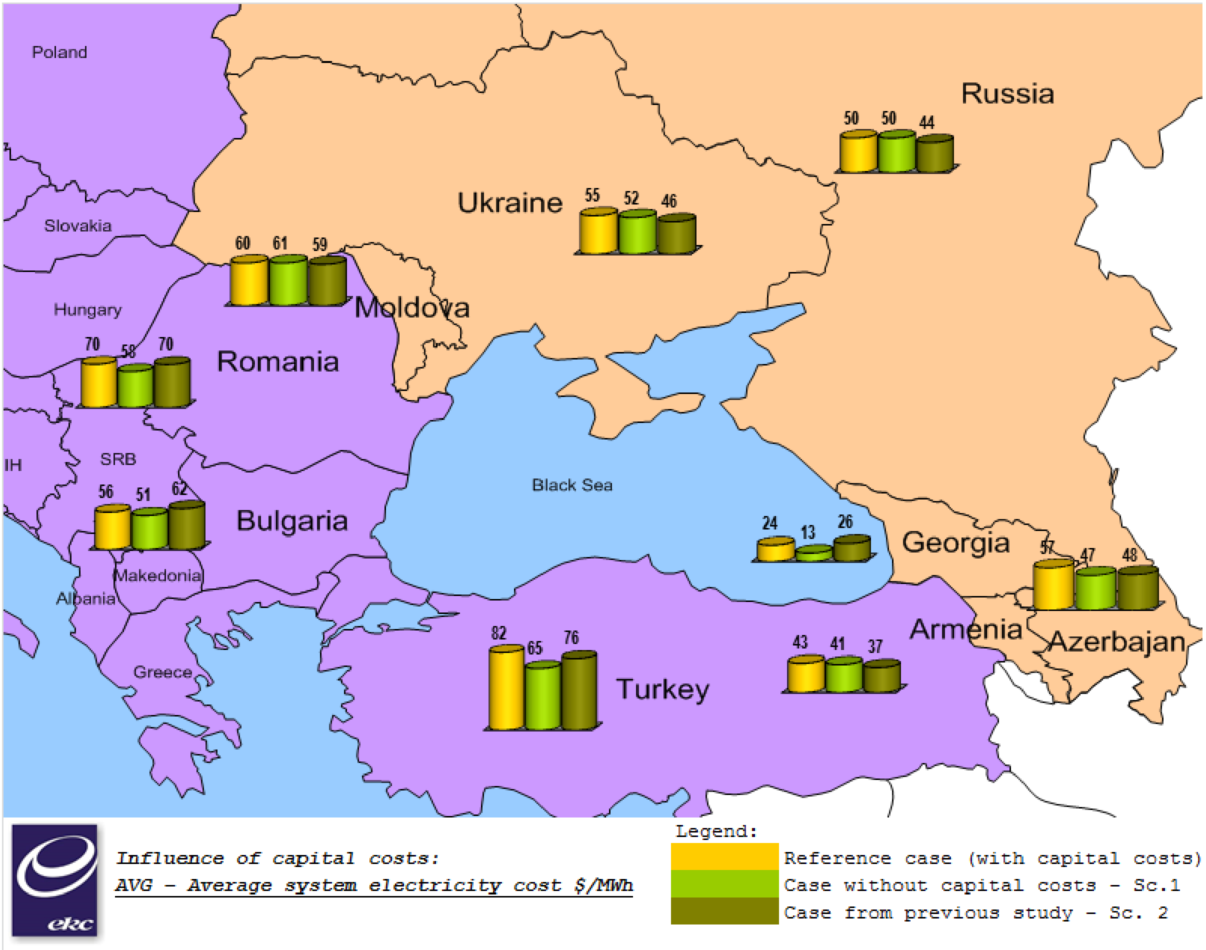


Figure 3.19 – Black Sea region average system electricity production cost for ***summer peak 2015*** *(Capital cost variations)*

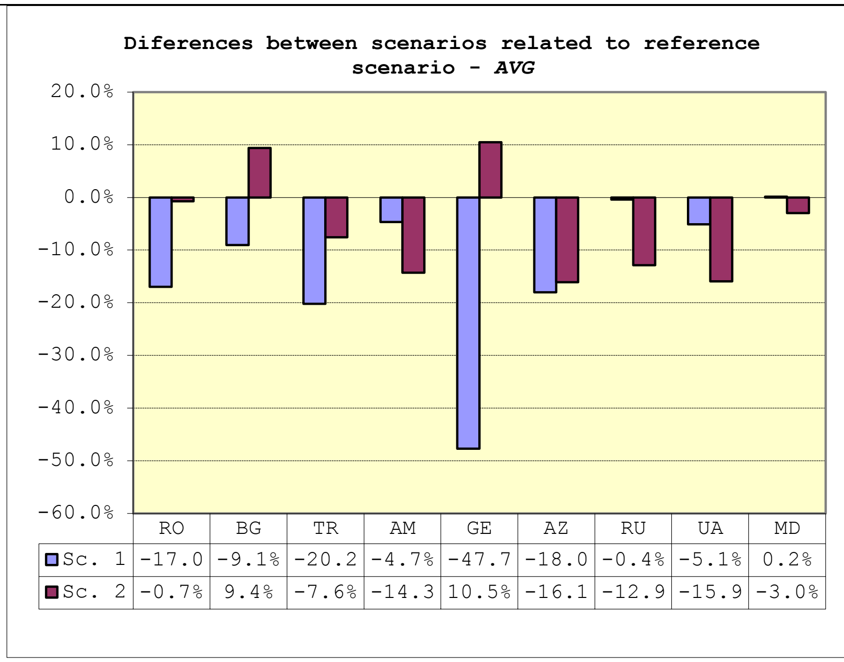


*Figure 3.20 – AVG differences between scenarios related to reference scenario for **summer peak 2015** (Capital cost variations)*

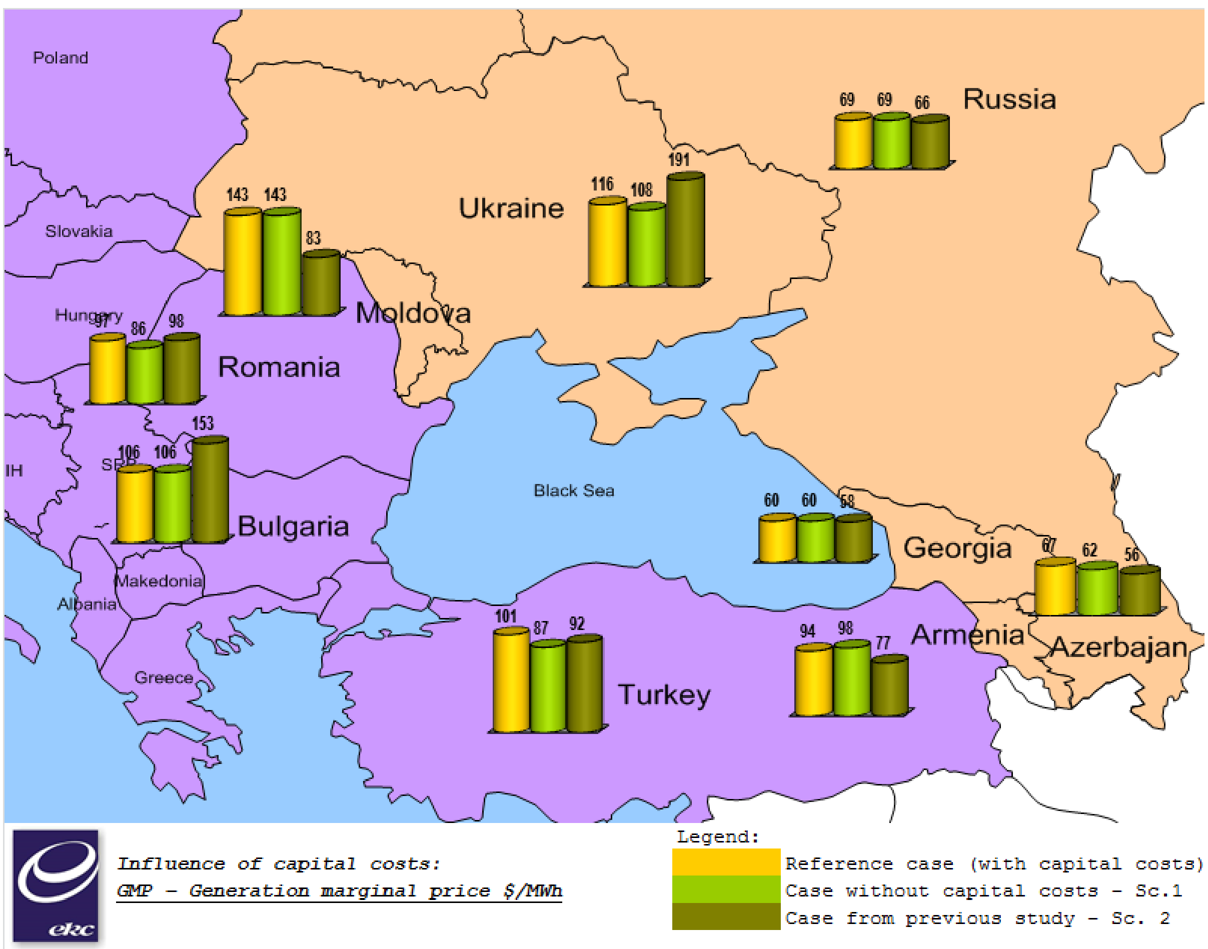


*Figure 3.21 – Black Sea region generation marginal price for **summer peak 2015** (Capital cost variations)*

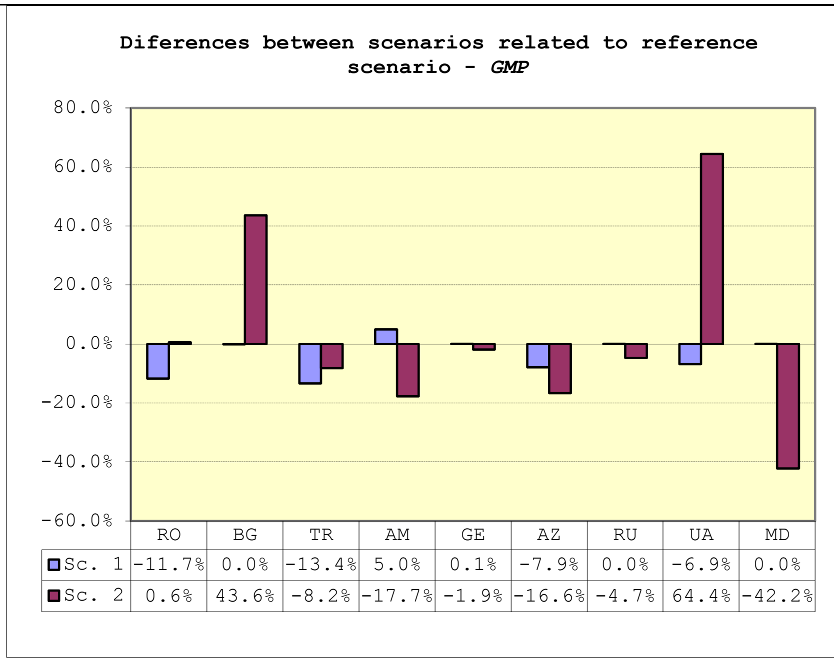


Figure 3.22 – GMP differences between scenarios related to reference scenario for ***summer peak 2015*** *(Capital cost variations)*

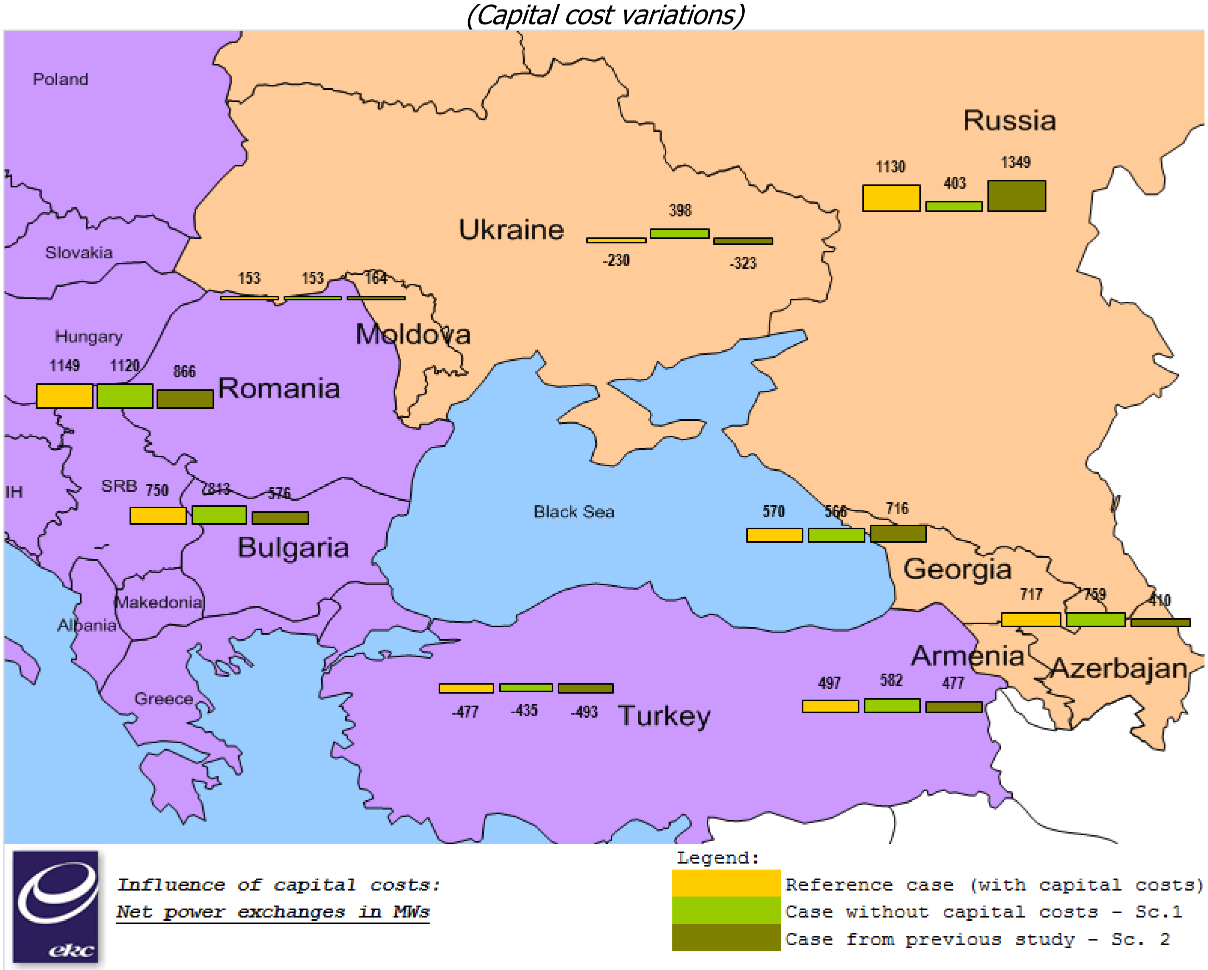


Figure 3.23 – Black Sea region net power exchange for ***summer peak 2015*** *(Capital cost variations)*

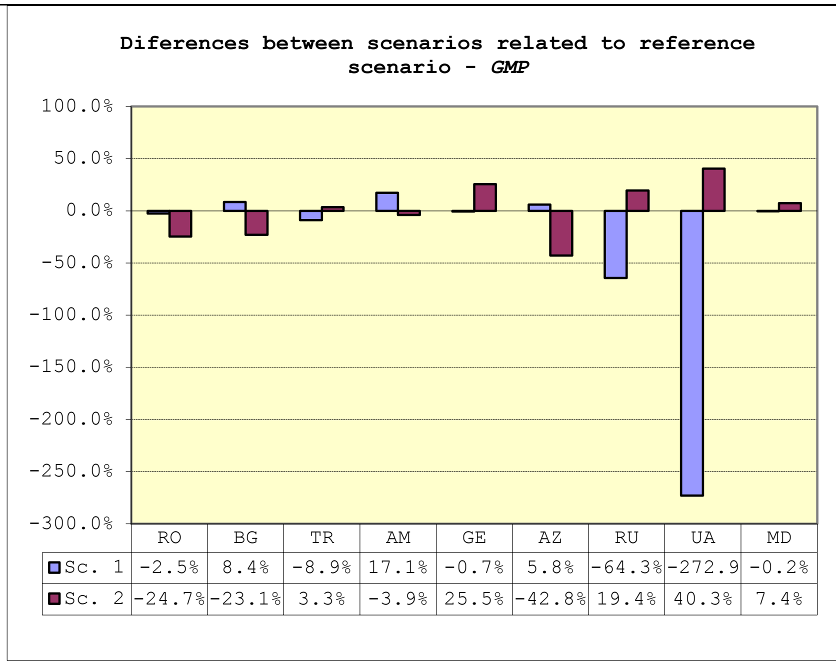


Figure 3.24 – EXC differences between scenarios related to reference scenario for ***summer peak 2015*** *(Capital cost variations)*

3.2.1 Russia Investment Cost Variations

As one additional exercise in terms of influence of capital cost variations especially in part of reconstruction and revitalization costs, Russia investment cost variation was conducted. Russian power production system is the largest in the Black Sea region and therefore has great impact on behavior of electricity market in the region. For that reason an alternative scenario for sensitivity analysis is created where impact of level of investment (and therefore addition to capital costs) in Russian power plants rehabilitation was examined. In this alternative scenario 20% of capital costs foreseen as rehabilitation expenditures are included in power plants bids on electricity market.

Aggregated results and graphs of OPF simulations for observed cases, winter and summer peak scenarios are presented below (Table 3.5,

Table 3.6, Figure 3.25, Figure 3.26, Figure 3.27, Figure 3.28, Figure 3.29, Figure 3.30, Figure 3.31, Figure 3.32,

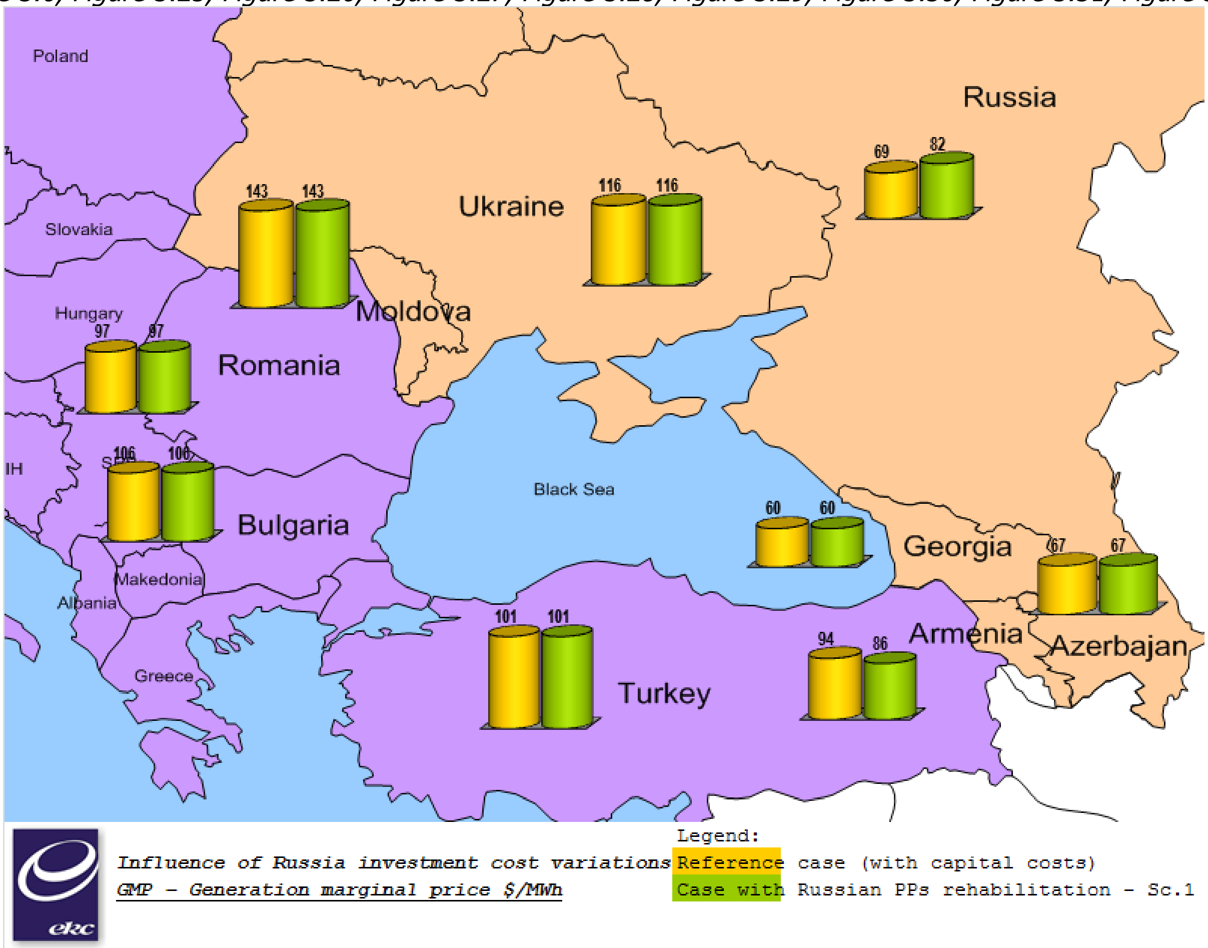


Figure 3.33, Figure 3.34, Figure 3.35 and Figure 3.36).

*Table 3.5 – Results of OPF simulations for observed cases and **winter peak scenario** (Russia investment cost variations)*

	Base Case			Russia - alternative scenario		
	AVG [$/MWh]	GMP [$/MWh]	EXC [MW]	AVG [$/MWh]	GMP [$/MWh]	EXC [MW]
Romania	66.0	94.2	1113	66.0	94.2	1113
Bulgaria	50.5	140.6	773	50.5	140.6	773
Turkey	81.8	101.8	-672	81.8	101.8	-672
Armenia	39.8	88.2	543	39.7	89.2	538
Georgia	23.9	59.6	340	23.9	59.6	338
Azerbaijan	57.4	67.3	297	57.4	67.3	312
Russia	50.7	68.9	2171	64.6	82.0	1423
Ukraine	49.6	115.9	-634	49.3	115.9	-34
Moldova	51.9	143.0	170	52.4	142.9	201

*Table 3.6 – Results of OPF simulations for observed cases and **summer peak scenario** (Russia investment cost variations)*

	Base Case			Russia - alternative scenario		
	AVG [$/MWh]	GMP [$/MWh]	EXC [MW]	AVG [$/MWh]	GMP [$/MWh]	EXC [MW]
Romania	70.1	97.4	1149	70.1	97.4	1149
Bulgaria	56.3	106.5	750	56.3	106.5	750
Turkey	81.7	100.6	-477	81.7	100.6	-477
Armenia	42.6	93.8	497	42.9	86.0	531
Georgia	23.9	59.5	570	23.9	59.5	566
Azerbaijan	57.2	67.3	717	57.2	67.3	784
Russia	50.4	69.0	1130	64.5	82.1	177
Ukraine	54.6	115.9	-230	54.6	115.9	546
Moldova	60.4	143.0	153	60.4	143.0	154

From the results of sensitivity analysis for both scenarios it can be concluded that:

- In case of higher plants rehabilitation investments in Russia, looking in short term horizon, electricity cost in Russia will increase, and export from Russia will decrease.
- Most affected would be neighboring countries, with notable decrease of Ukraine import as a result of more competitive position in electricity market of Ukrainian plants as compared to Russian plants. This change would be from about 100% in winter peak and more than 300% in summer peak regime.
- In long term perspective, the electricity market of Black Sea region would benefit from these new investments which would extend a life cycle of plants in Russia and therefore prevent possible shortages of energy and ensure a competitive market.

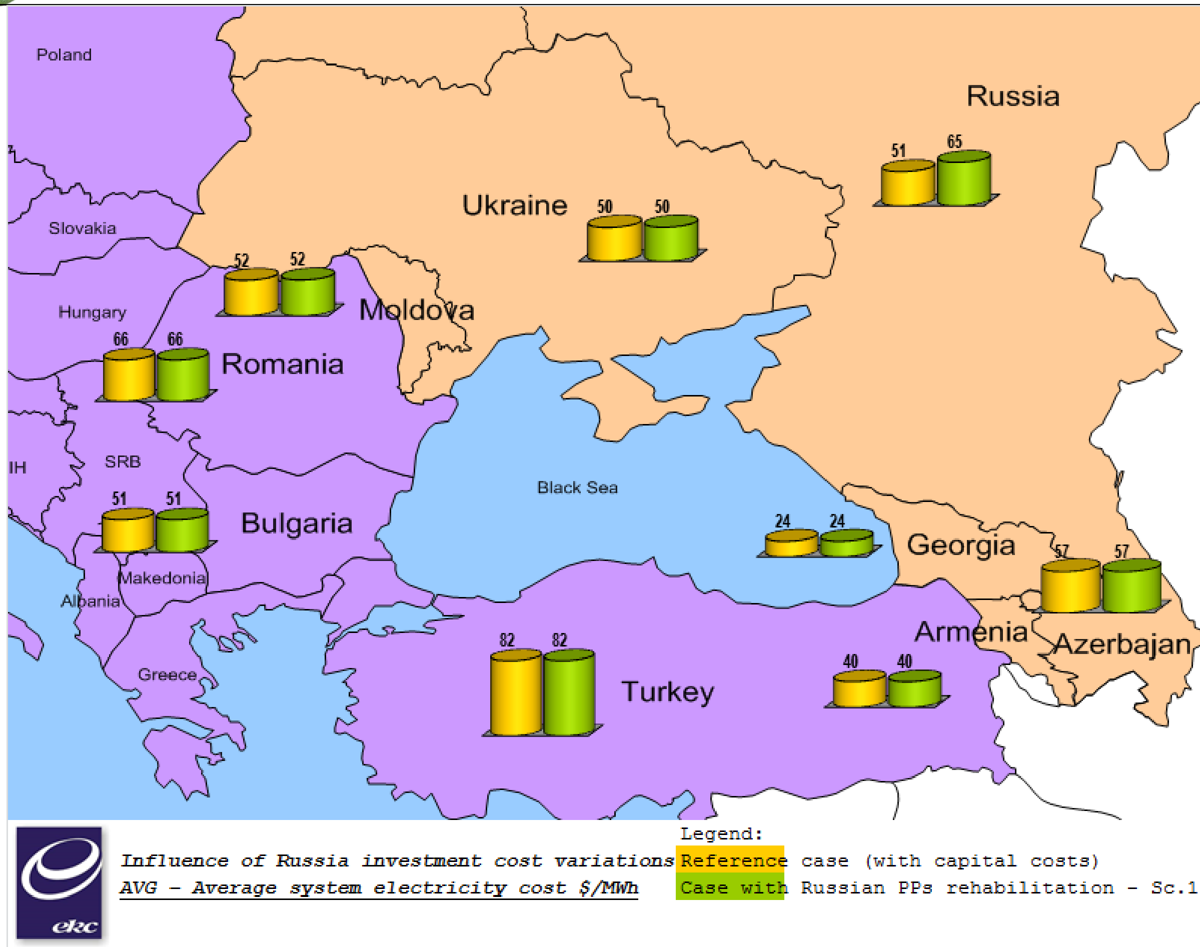


*Figure 3.25 – Black Sea region average system electricity production cost for **winter peak 2015** (Russia investment cost variations)*

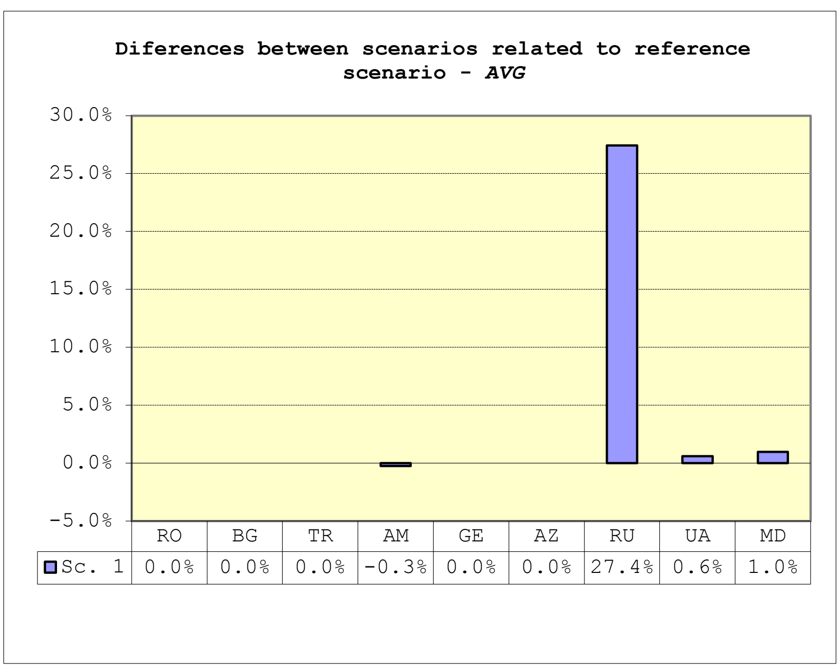


*Figure 3.26 – AVG differences between scenarios related to reference scenario for **winter peak 2015** (Russia investment cost variations)*

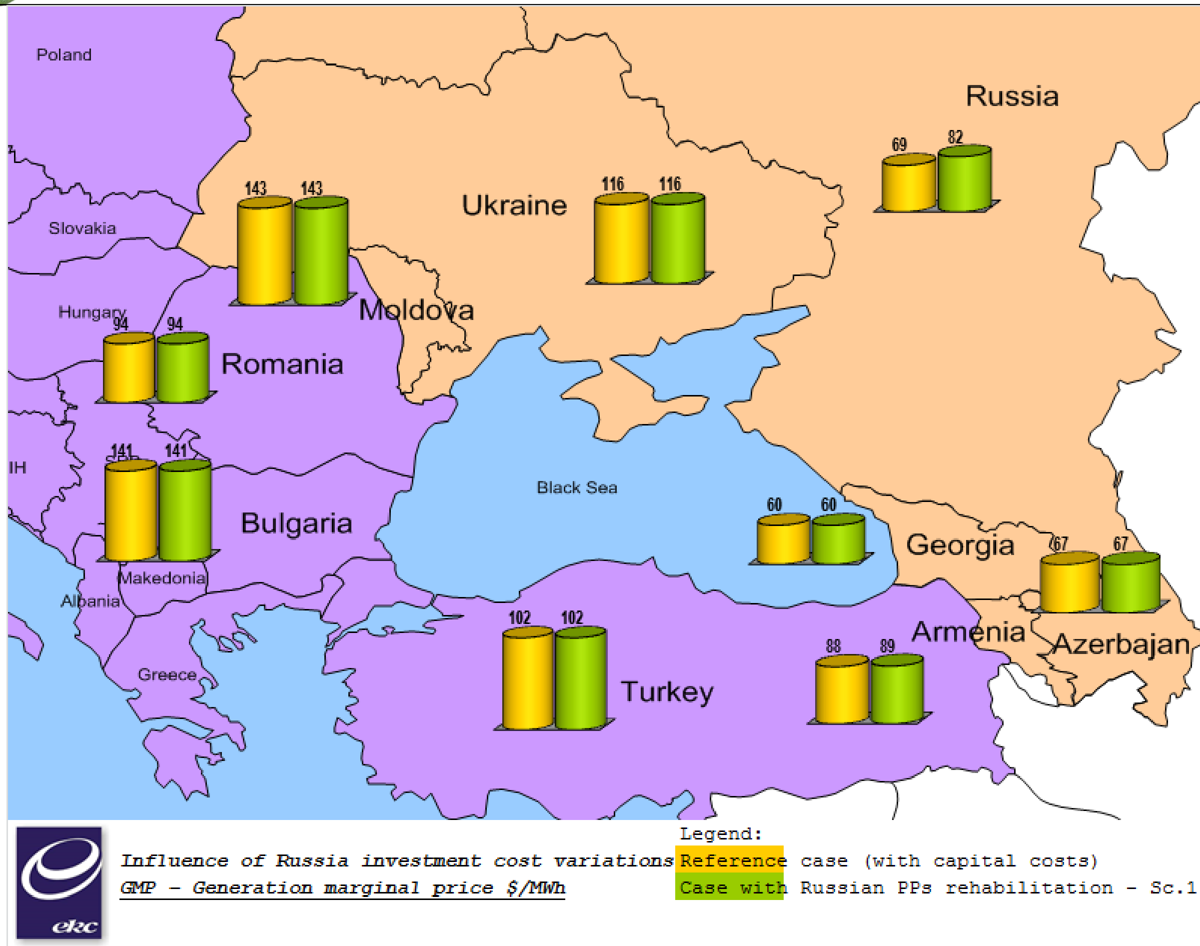


*Figure 3.27 – Black Sea region generation marginal price for **winter peak 2015** (Russia investment cost variations)*

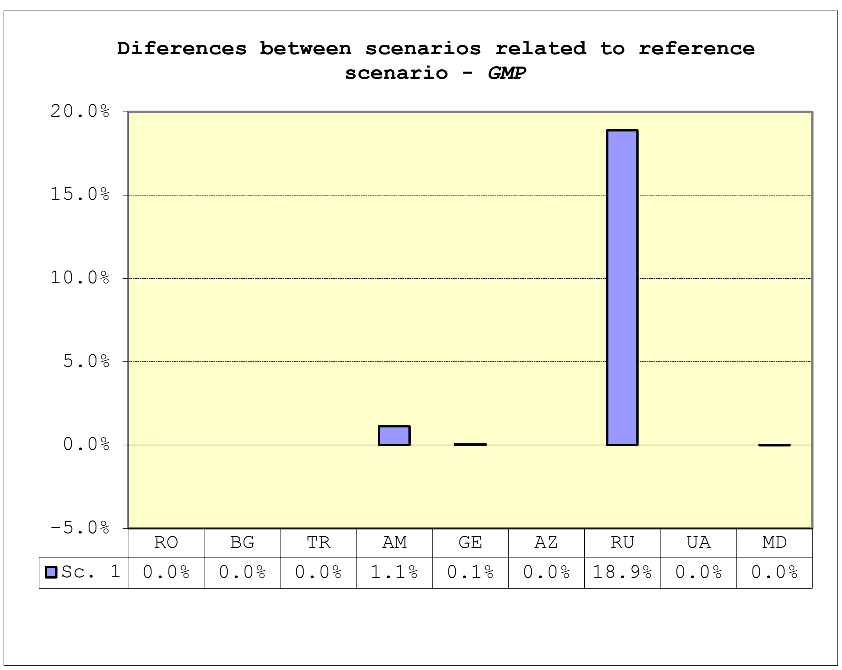


*Figure 3.28 – GMP differences between scenarios related to reference scenario for **winter peak 2015** (Russia investment cost variations)*

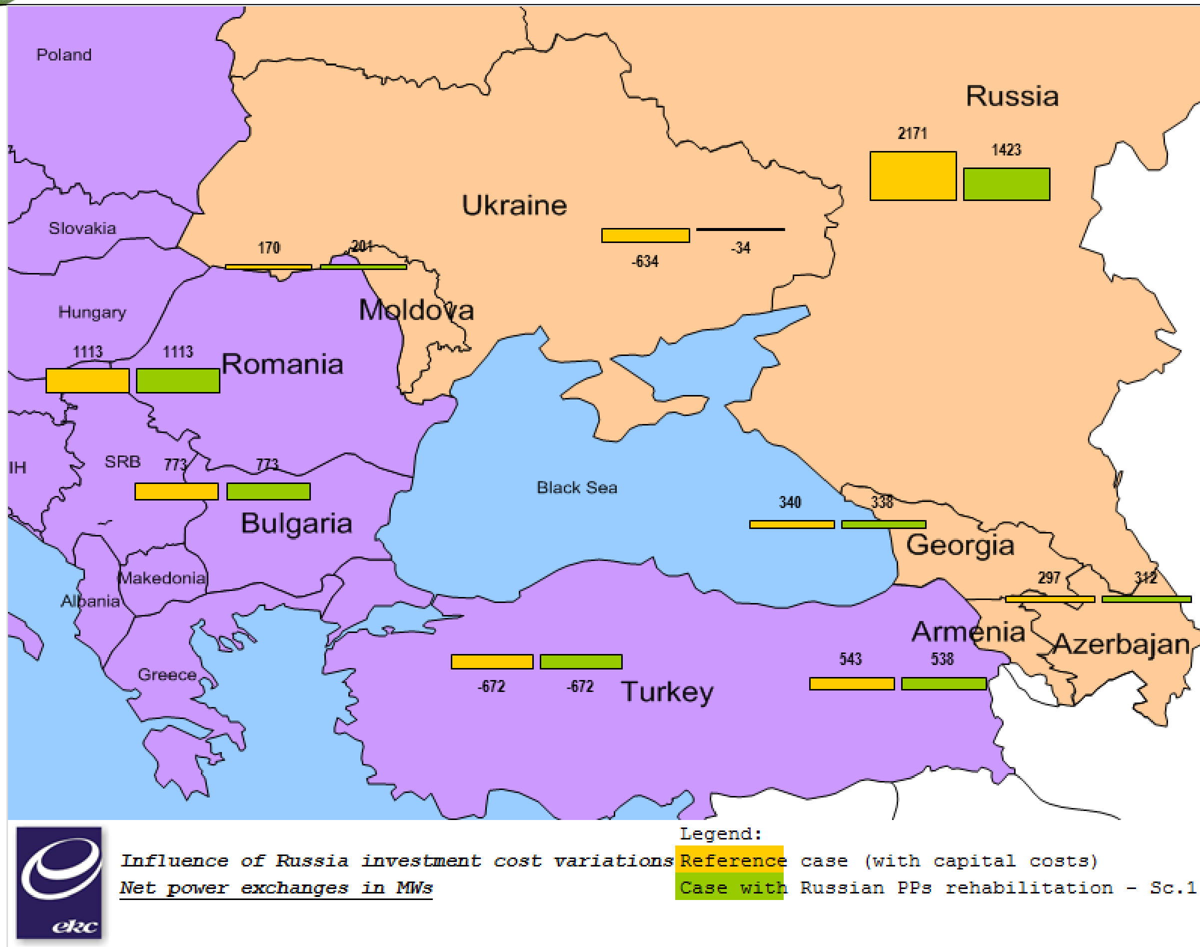


*Figure 3.29 – Black Sea region net power exchange for **winter peak 2015** (Russia investment cost variations)*

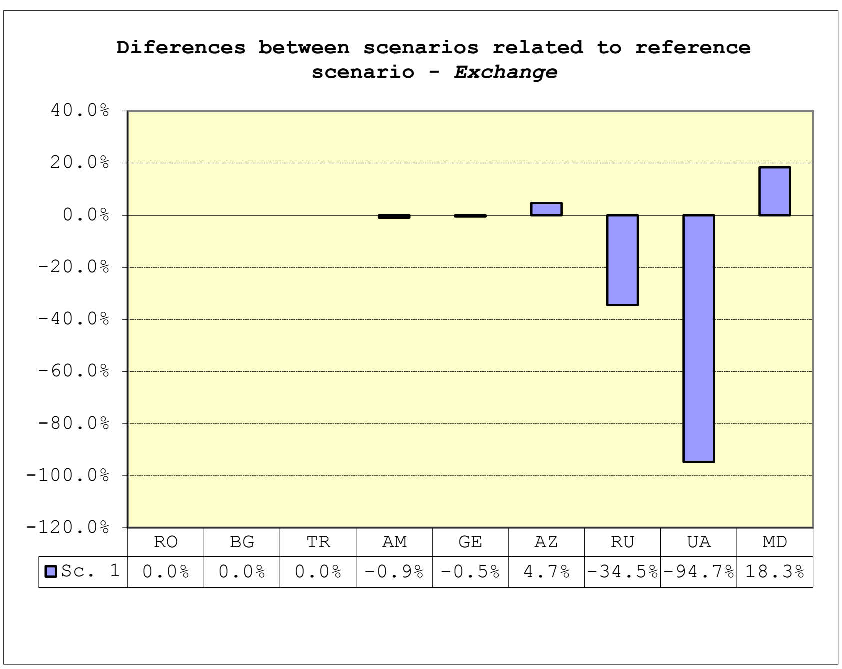


*Figure 3.30 – EXC differences between scenarios related to reference scenario for **winter peak 2015** (Russia investment cost variations)*

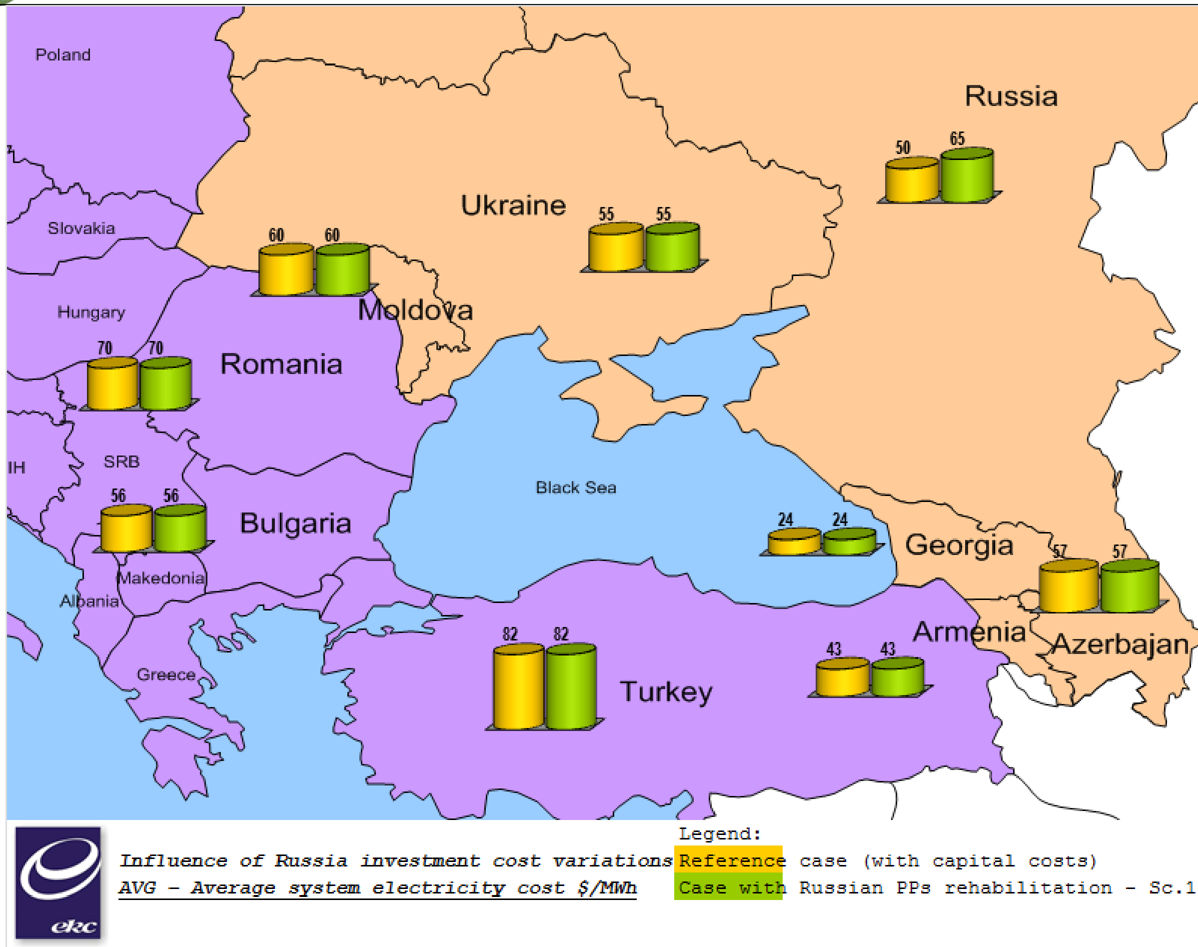


*Figure 3.31 – Black Sea region average system electricity production cost for **summer peak 2015** (Russia investment cost variations)*

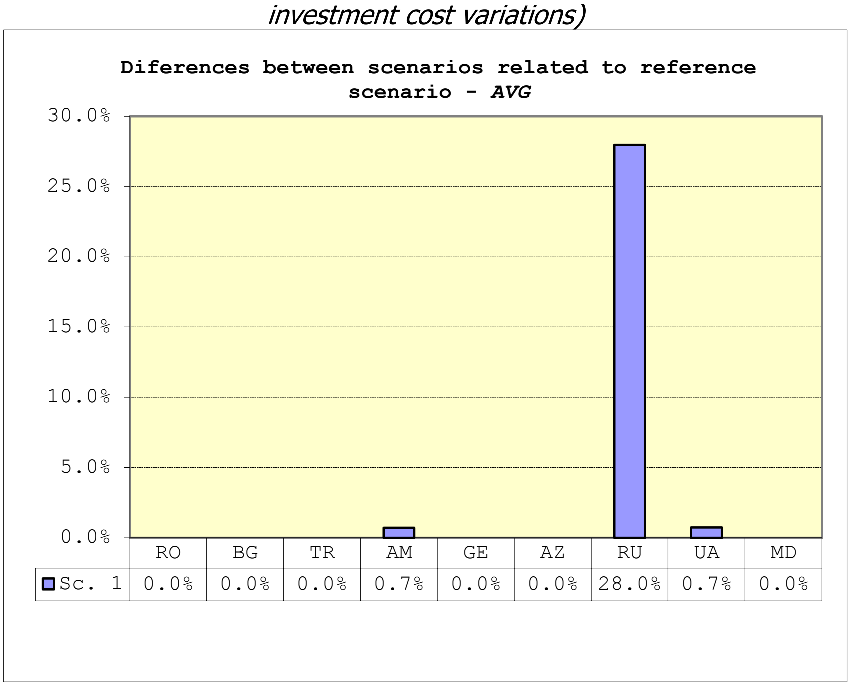


*Figure 3.32 – AVG differences between scenarios related to reference scenario for **summer peak 2015** (Russia investment cost variations)*

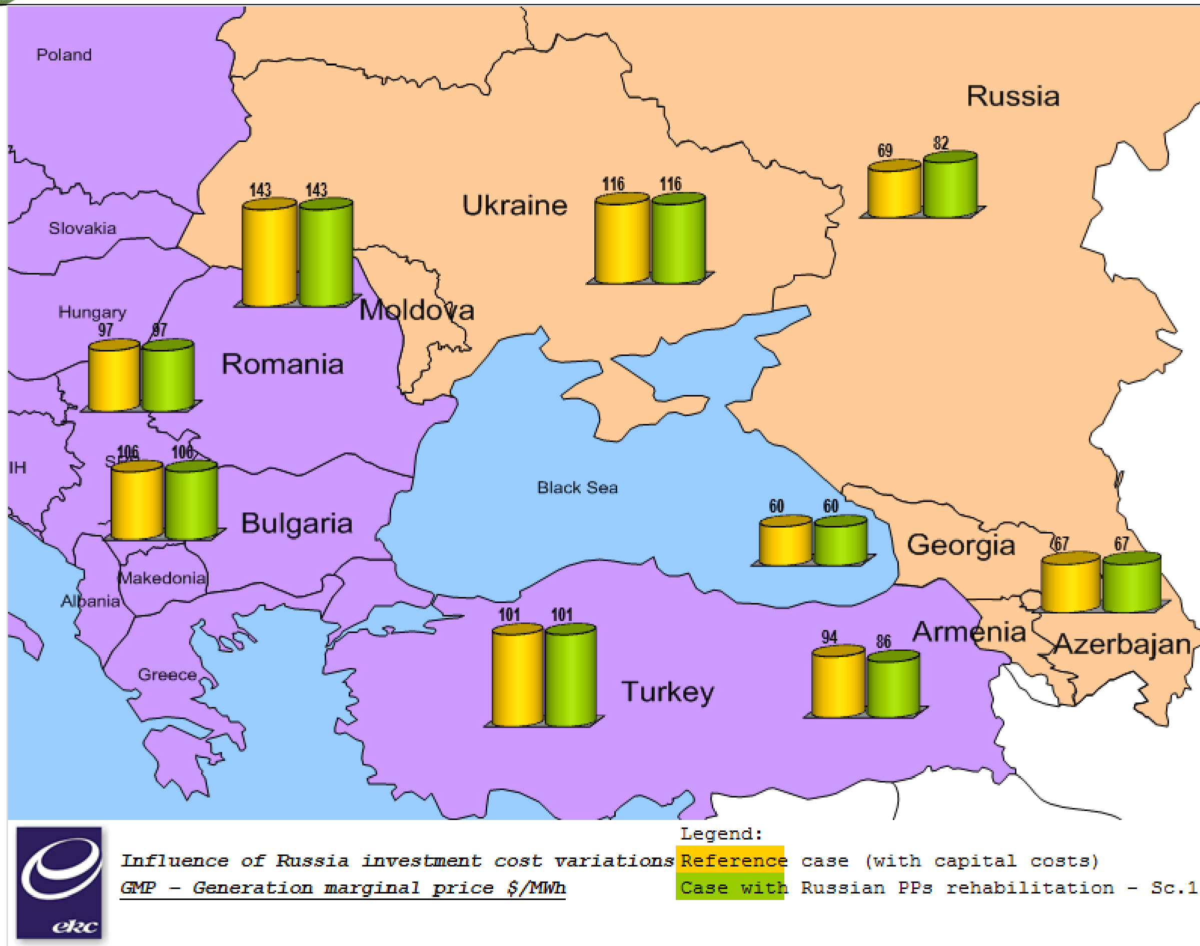


*Figure 3.33 – Black Sea region generation marginal price for **summer peak 2015** (Russia investment cost variations)*

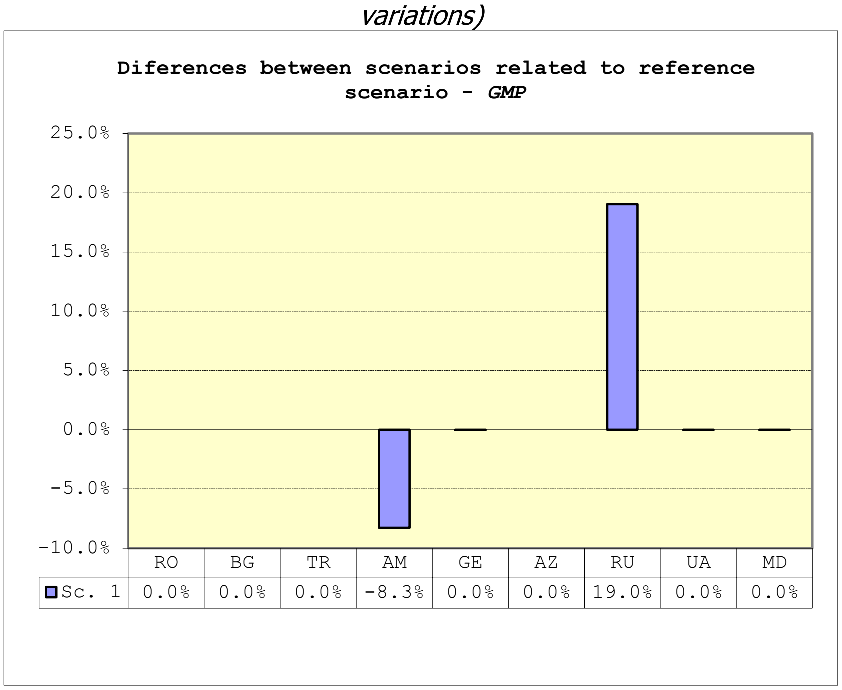


*Figure 3.34 – GMP differences between scenarios related to reference scenario for **summer peak 2015** (Russia investment cost variations)*

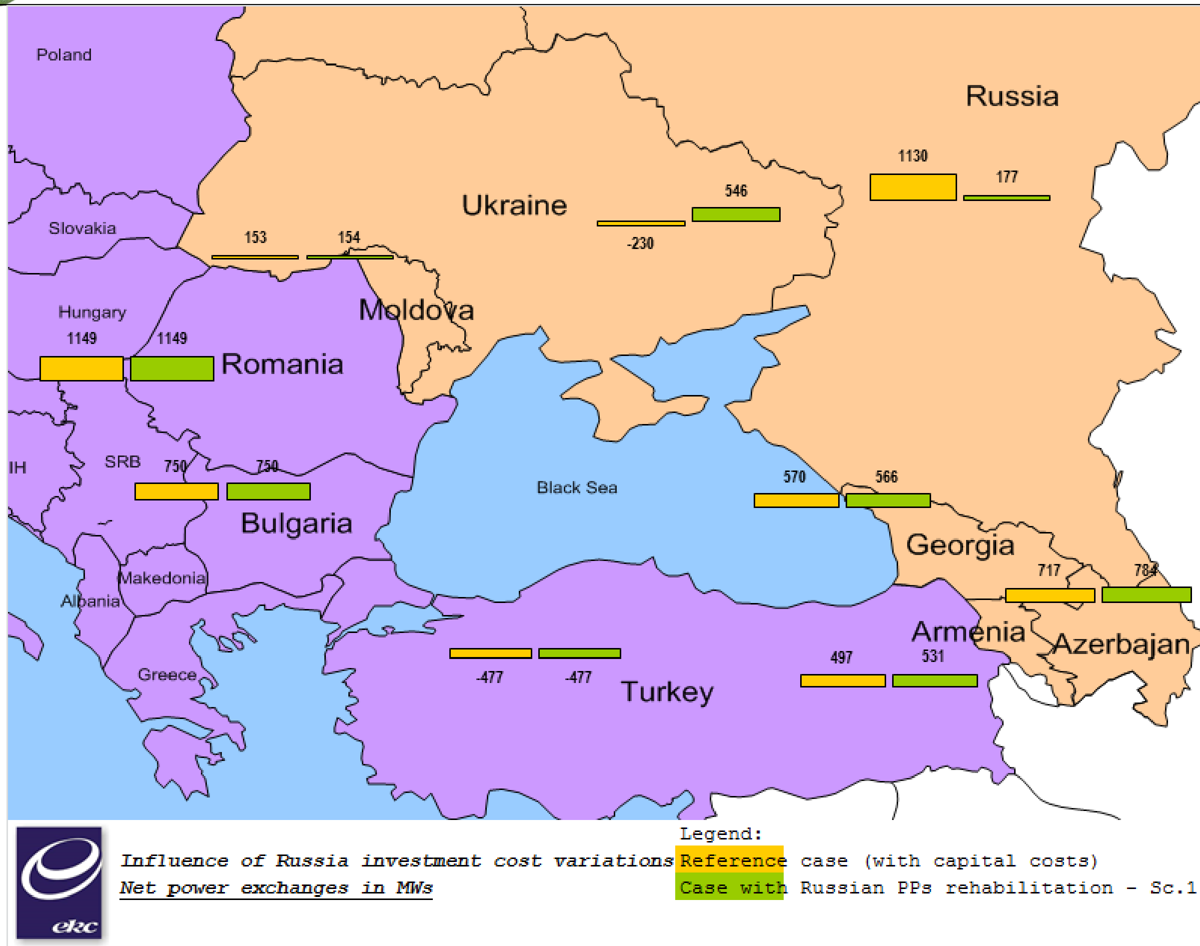


*Figure 3.35 – Black Sea region net power exchange for **summer peak 2015** (Russia investment cost variations)*

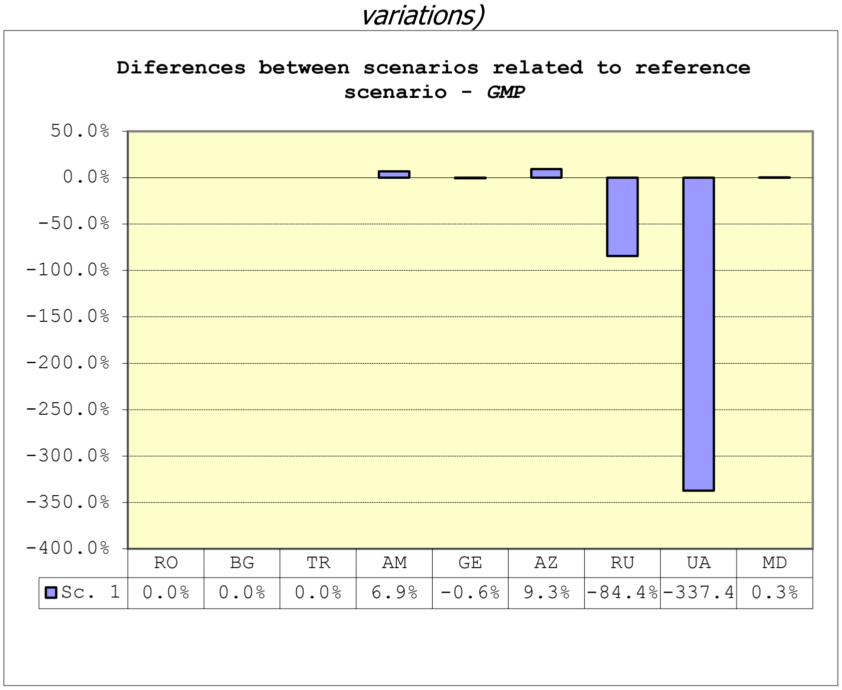


*Figure 3.36 – EXC differences between scenarios related to reference scenario for **summer peak 2015** (Russia investment cost variations)*

3.3 CO_2 Emission Cost Variations

CO_2 emission cost variations are defined as penalty factors for CO_2 emission, and have various impacts on power plants production costs depending on the fuel type and production technology. Production cost of hard coal and lignite power plants will be the most affected in the high environmental awareness scenarios, with less competitive position on the market.

Influence of CO_2 cost variations are observed by the level of environmental awareness, and therefore divided in three categories:

- Average value of 12 \$/tonCO_2 (applied in Base Case)
- Extreme value of 50 \$/tonCO_2
- No charge for CO_2 emission (underdeveloped market in that sense)

Aggregated results and graphs of OPF simulations for observed cases winter and summer peak scenarios are presented below (Table 3.7, Table 3.8, Figure 3.37, Figure 3.38, Figure 3.39, Figure 3.40, Figure 3.41, Figure 3.42, Figure 3.43, Figure 3.44, Figure 3.45, Figure 3.46, Figure 3.47 and Figure 3.48).

*Table 3.7 – Results of OPF simulations for observed cases and **winter peak scenario** (CO_2 emission cost variations)*

	Base Case			High CO_2 emission costs			Low CO_2 emission costs		
	AVG [\$/MWh]	GMP [\$/MWh]	EXC [MW]	AVG [\$/MWh]	GMP [\$/MWh]	EXC [MW]	AVG [\$/MWh]	GMP [\$/MWh]	EXC [MW]
Romania	66	94.16	1113	83.9	119.75	1448	60.2	93.15	1094
Bulgaria	50.5	140.57	773	68.6	118.03	625	44.6	102.76	775
Turkey	81.8	101.81	-672	100.3	129.72	-657	75.9	98.35	-678
Armenia	39.8	88.17	543	44.2	100.8	506	38.3	83.66	541
Georgia	23.9	59.59	340	24.3	61.07	318	23.7	59.85	336
Azerbaijan	57.4	67.28	297	57.3	67.28	382	54.5	62.28	304
Russia	50.7	68.93	2171	55.1	107.14	2654	49.3	62.19	1745
Ukraine	49.6	115.9	-634	65.5	130.37	-1058	44.5	112.1	-251
Moldova	51.9	142.95	170	87.5	155.05	205	40.6	139.16	170

*Table 3.8 – Results of OPF simulations for observed cases and **summer peak scenario** (CO_2 emission cost variations)*

	Base Case			High CO2 emission costs			Low CO2 emission costs		
	AVG [$/MWh]	GMP [$/MWh]	EXC [MW]	AVG [$/MWh]	GMP [$/MWh]	EXC [MW]	AVG [$/MWh]	GMP [$/MWh]	EXC [MW]
Romania	70.1	97.44	1149	84.3	126.24	1260	65.2	126.99	1205
Bulgaria	56.3	106.46	750	76.1	118.05	629	50	102.75	780
Turkey	81.7	100.58	-477	99.7	128.03	-456	75.9	98.31	-480
Armenia	42.6	93.77	497	47.6	99.87	523	41.1	92.67	488
Georgia	23.9	59.54	570	24.1	59.51	567	23.8	59.58	571
Azerbaijan	57.2	67.28	717	57.2	67.27	791	54.3	62.28	673
Russia	50.4	68.96	1130	54.9	113.69	2577	49	65.41	421
Ukraine	54.6	115.91	-230	69.4	133.39	-1653	49.7	112.11	494
Moldova	60.4	142.96	153	92.6	155.03	184	50.2	139.16	153

From the results of sensitivity analysis for both scenario it can be concluded that:

- Variation in CO_2 emission costs has greatest impact on production cost of coal fired power plants.
- In case of high CO_2 emission cost scenario (50$/ton CO_2) most affected would be Moldova with increase of 69% in winter and 53% in summer regime of average production cost, followed by Ukraine and Bulgaria with increase in range of 30% - 35% in average production cost.
- On the other hand, the least affected would be Georgia, due to CO_2 emission free production from hydro power plants.
- Coal fired power plants are dominantly present as marginal units in case of high CO_2 emission cost scenario, unlike in the base case and case with no CO_2 emission cost, due to about 35 $/MWh higher production cost penalization comparing to gas fired plants.
- Power exchange between Russia and Ukraine is highly sensitive to CO_2 emission cost variations with increase of Russia export and Ukraine import due to more competitive position of power plants in Russia than in Ukraine in high CO_2 emission cost scenario, and vice versa in no CO_2 emission cost scenario.
- For other countries beside Russia and Ukraine, net exchanges would stay relatively the same in scenario without CO_2 emission cost.
- In case of high CO_2 emission cost scenario, in the West part of Black Sea region, notable is increase of electricity export from Romania, and decrease of electricity export from Bulgaria to Turkey, due to less competitive position of Bulgaria coal plants.

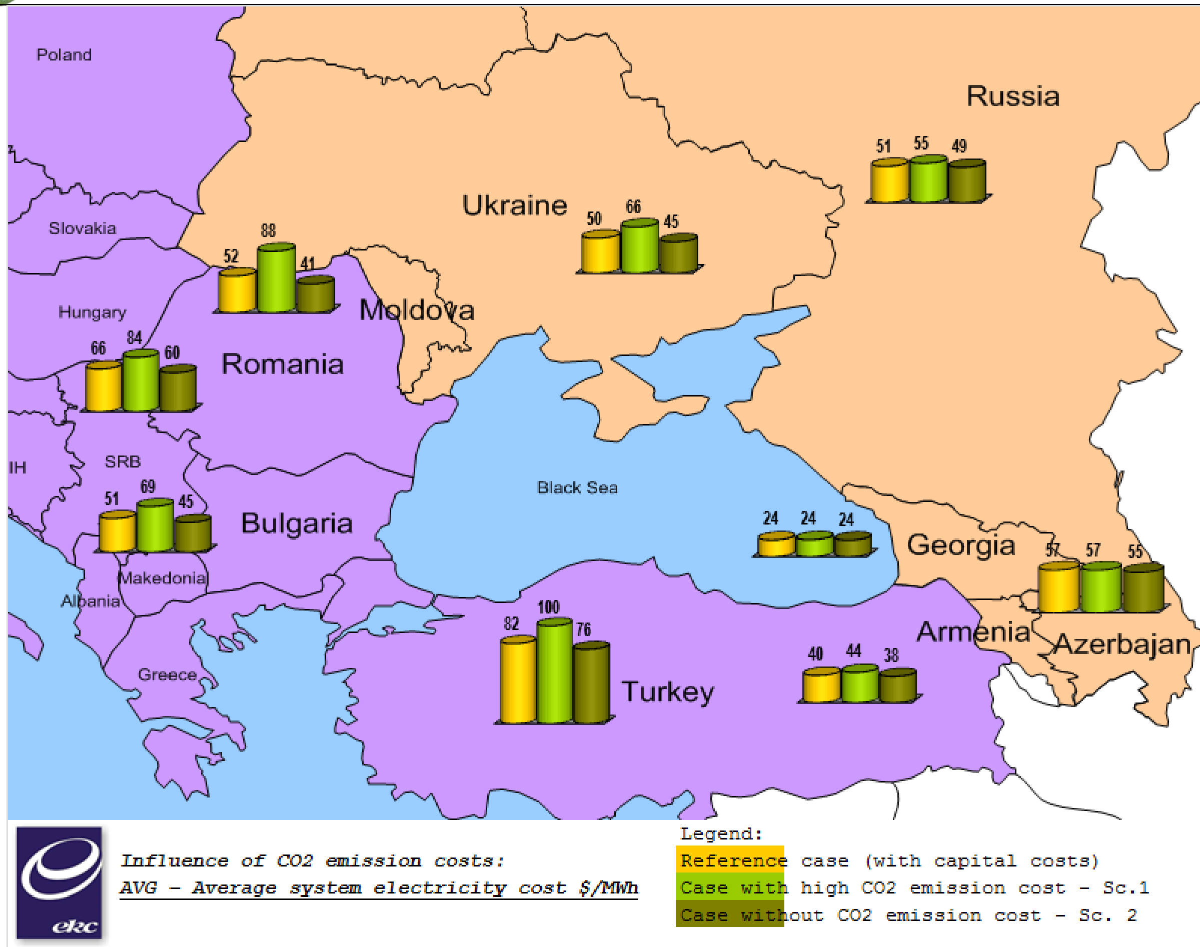
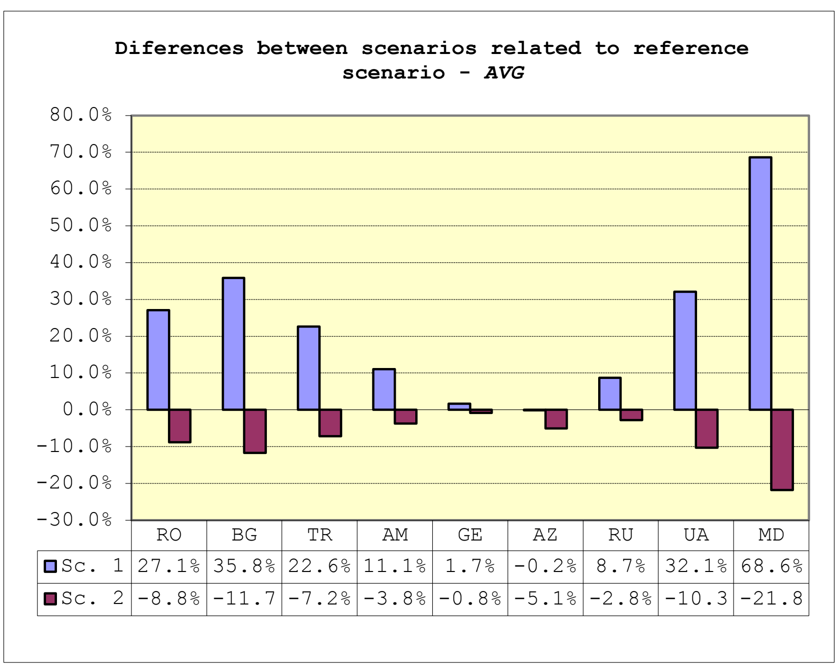


*Figure 3.37 – Black Sea region average system electricity production cost for **winter peak 2015** (CO_2 emission cost variations)*



	RO	BG	TR	AM	GE	AZ	RU	UA	MD
Sc. 1	27.1%	35.8%	22.6%	11.1%	1.7%	-0.2%	8.7%	32.1%	68.6%
Sc. 2	-8.8%	-11.7	-7.2%	-3.8%	-0.8%	-5.1%	-2.8%	-10.3	-21.8

*Figure 3.38 – AVG differences between scenarios related to reference scenario for **winter peak 2015** (CO_2 emission cost variations)*

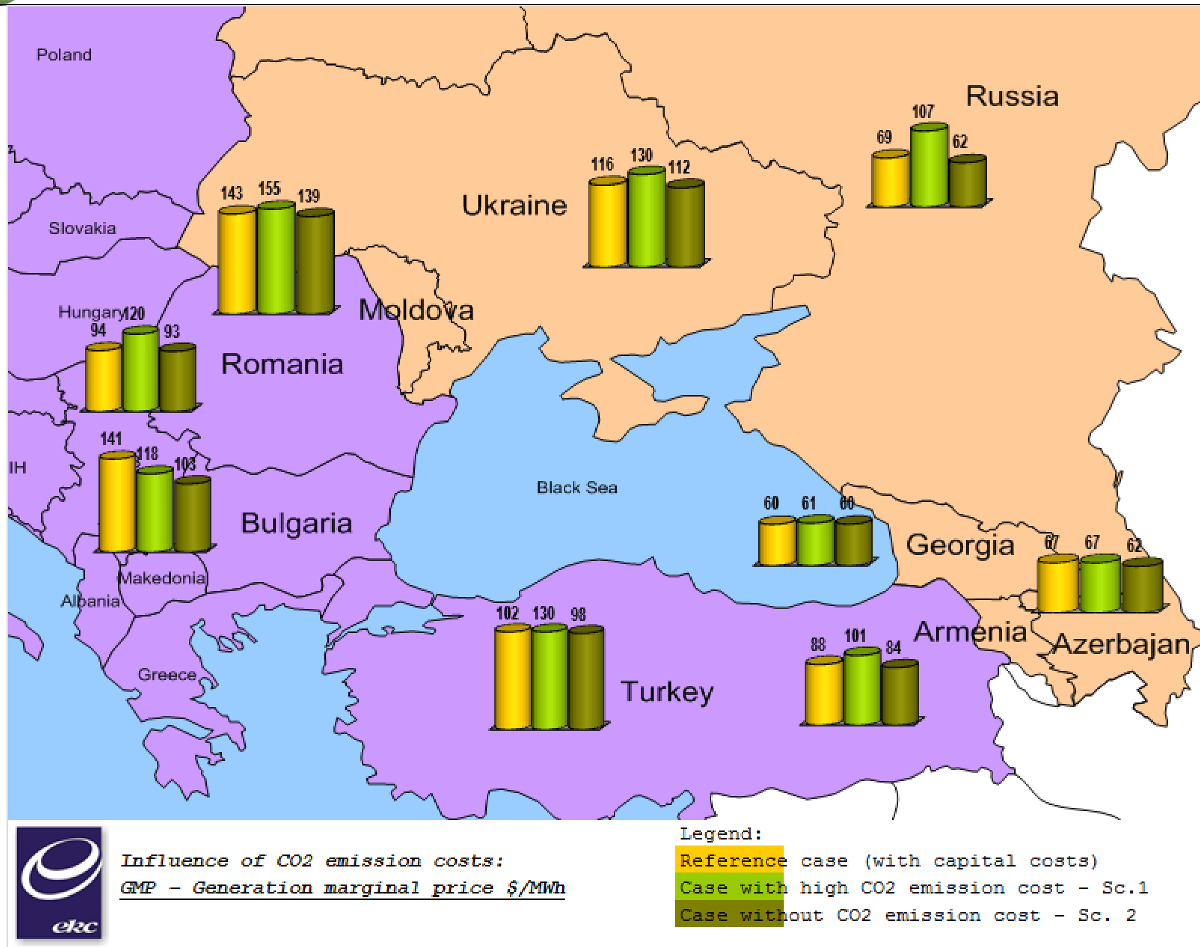
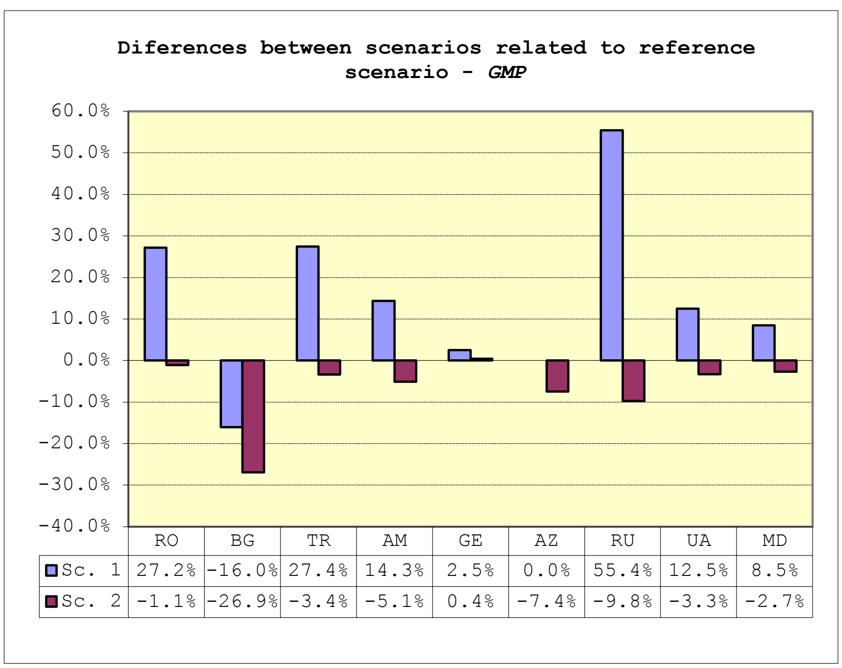


*Figure 3.39 – Black Sea region generation marginal price for **winter peak 2015** (CO_2 emission cost variations)*



	RO	BG	TR	AM	GE	AZ	RU	UA	MD
Sc. 1	27.2%	-16.0%	27.4%	14.3%	2.5%	0.0%	55.4%	12.5%	8.5%
Sc. 2	-1.1%	-26.9%	-3.4%	-5.1%	0.4%	-7.4%	-9.8%	-3.3%	-2.7%

*Figure 3.40 – GMP differences between scenarios related to reference scenario for **winter peak 2015** (CO_2 emission cost variations)*

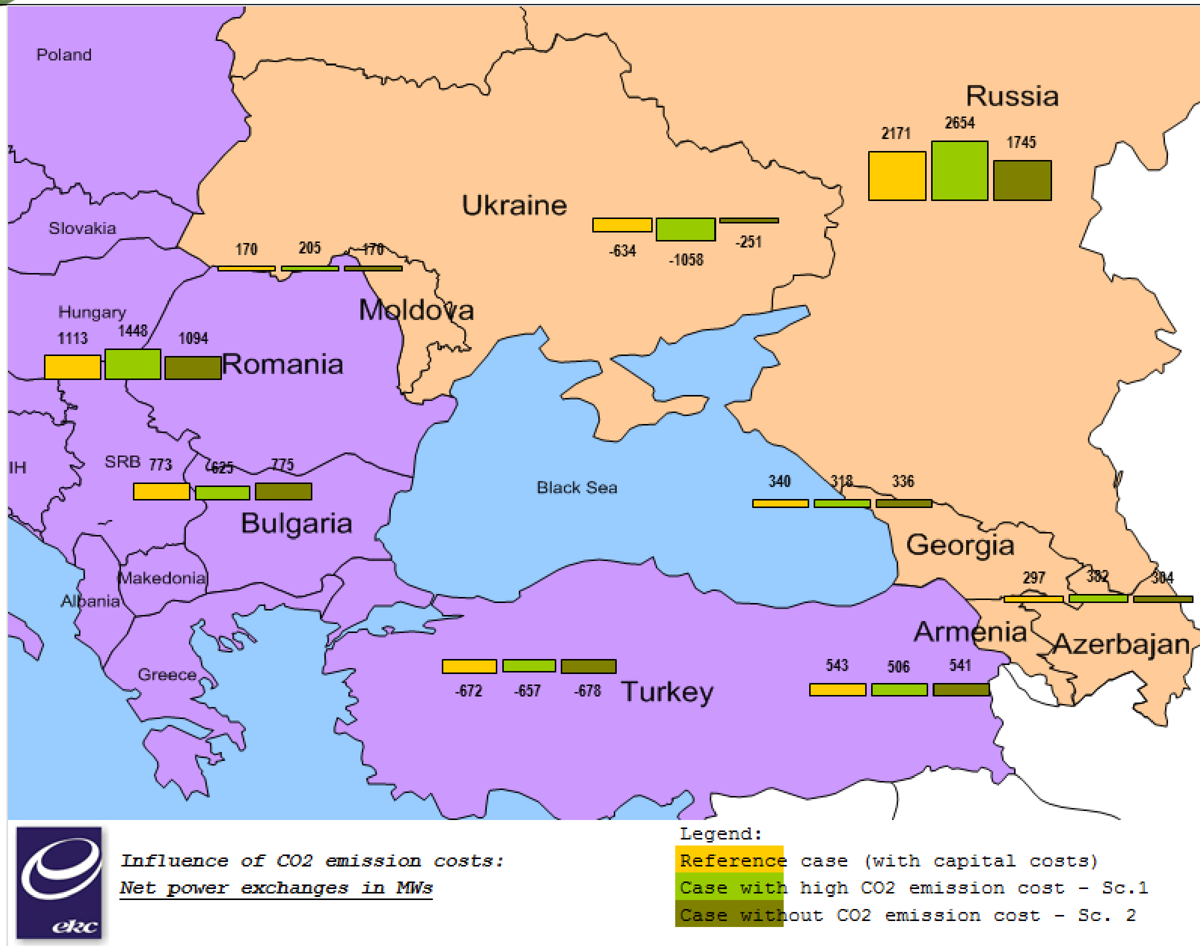
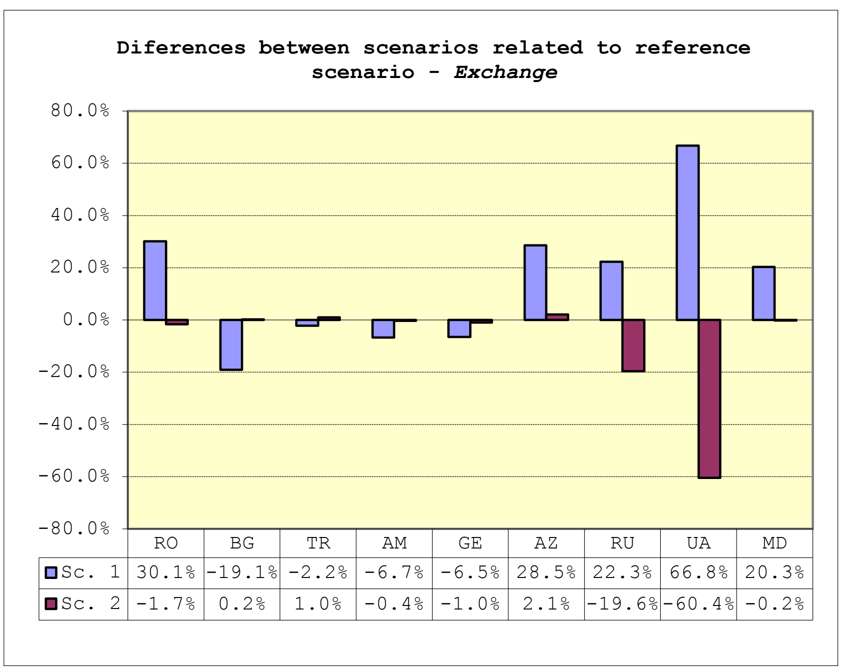


*Figure 3.41 – Black Sea region net power exchange for **winter peak 2015** (CO_2 emission cost variations)*



	RO	BG	TR	AM	GE	AZ	RU	UA	MD
Sc. 1	30.1%	-19.1%	-2.2%	-6.7%	-6.5%	28.5%	22.3%	66.8%	20.3%
Sc. 2	-1.7%	0.2%	1.0%	-0.4%	-1.0%	2.1%	-19.6%	-60.4%	-0.2%

*Figure 3.42 – EXC differences between scenarios related to reference scenario for **winter peak 2015** (CO_2 emission cost variations)*

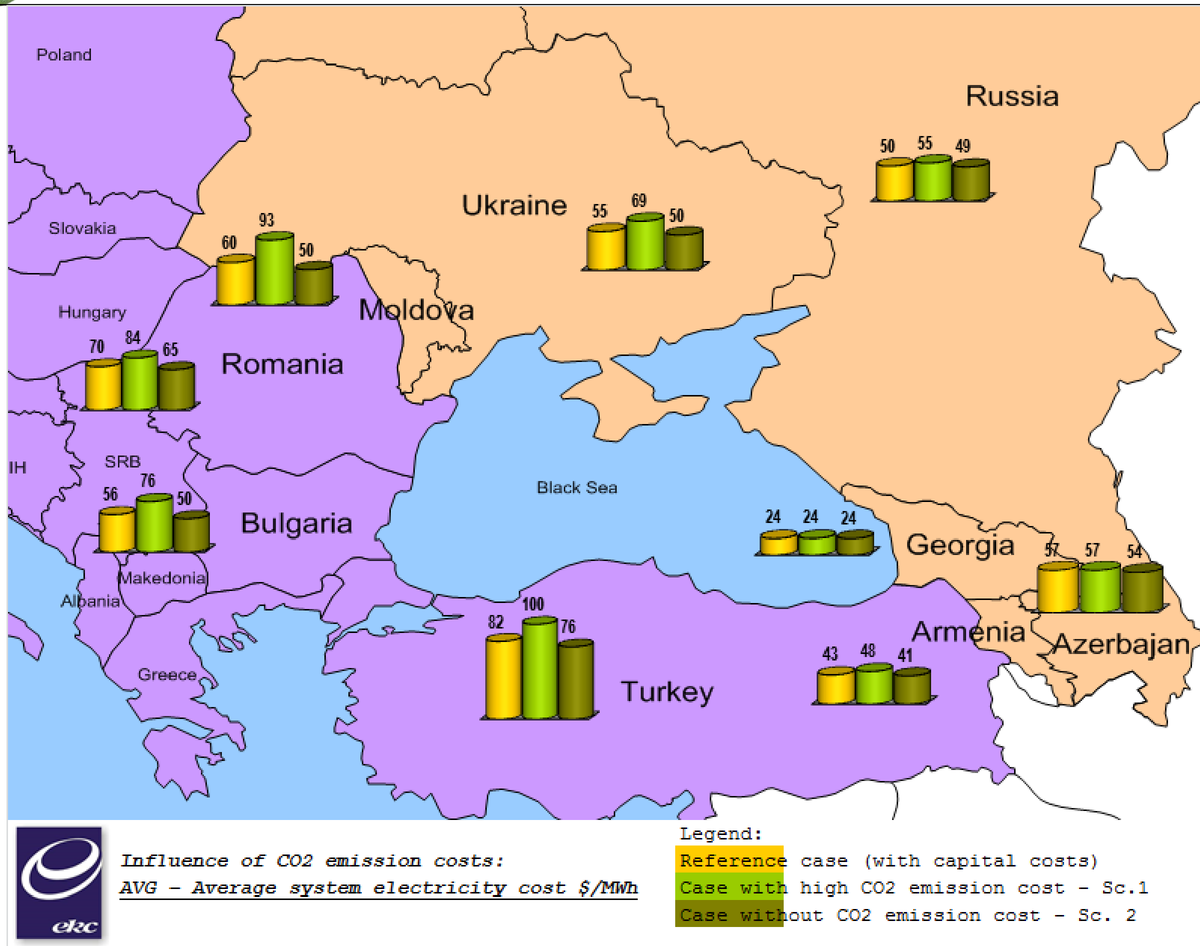


*Figure 3.43 – Black Sea region average system electricity production cost for **summer peak 2015** (CO_2 emission cost variations)*

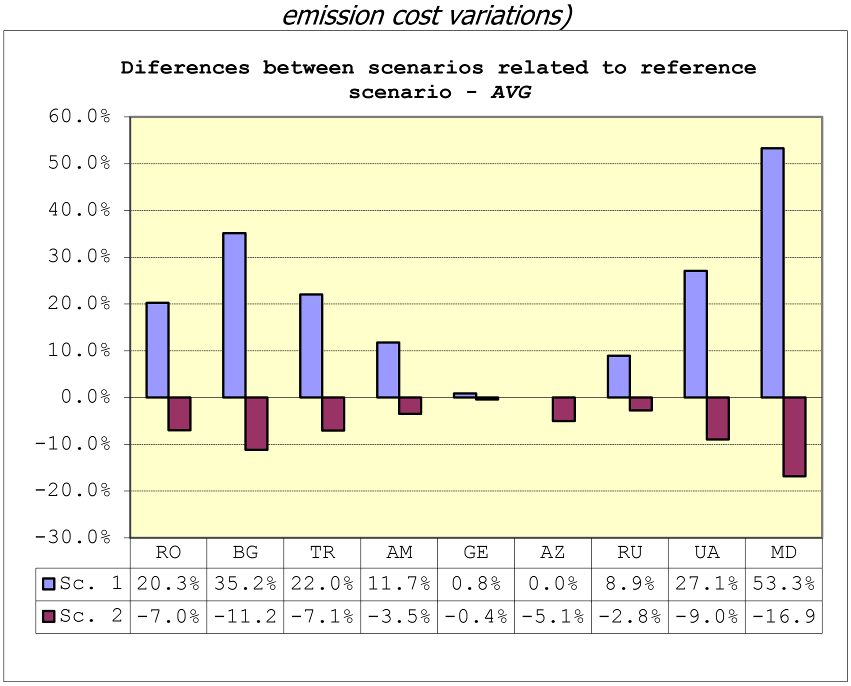


*Figure 3.44 – AVG differences between scenarios related to reference scenario for **summer peak 2015** (CO_2 emission cost variations)*

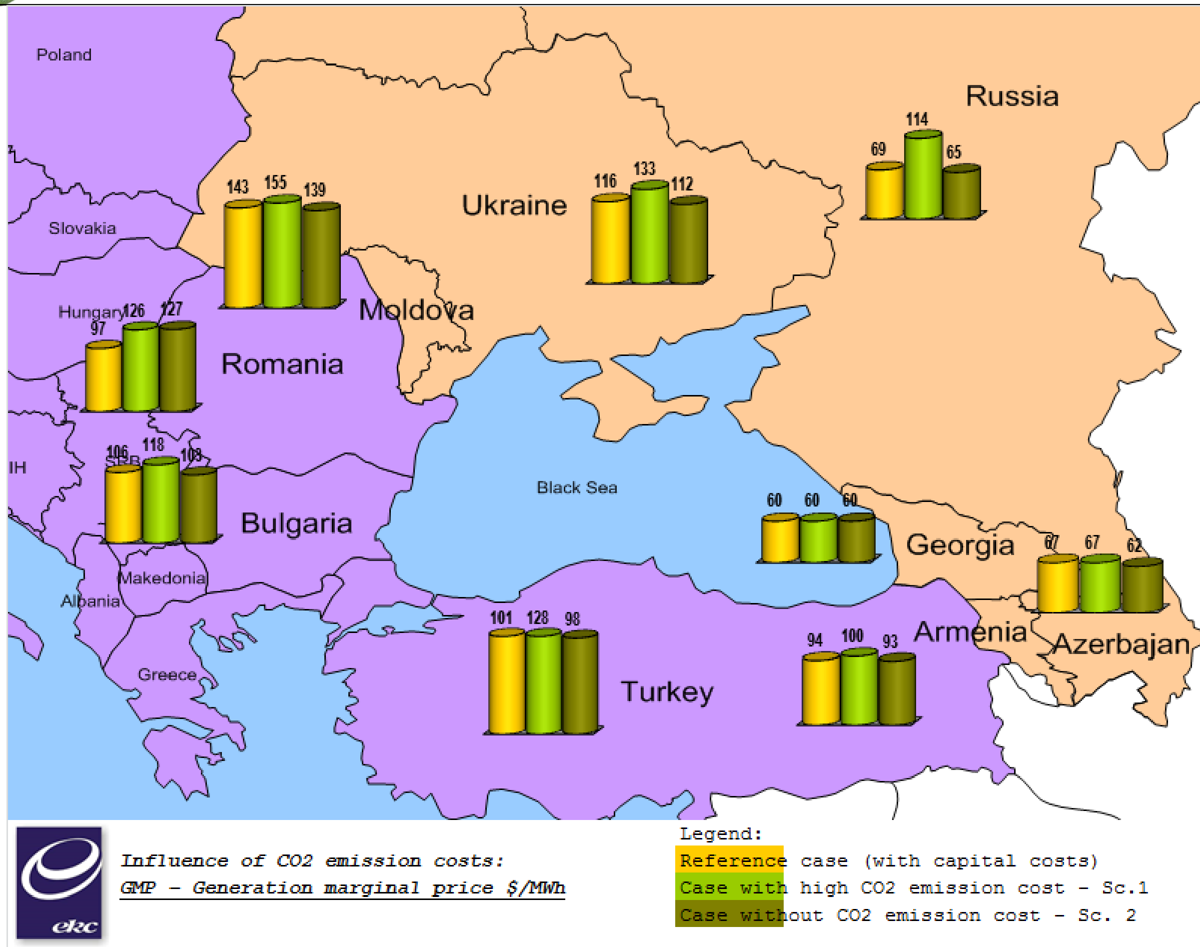


*Figure 3.45 – Black Sea region generation marginal price for **summer peak 2015** (CO_2 emission cost variations)*

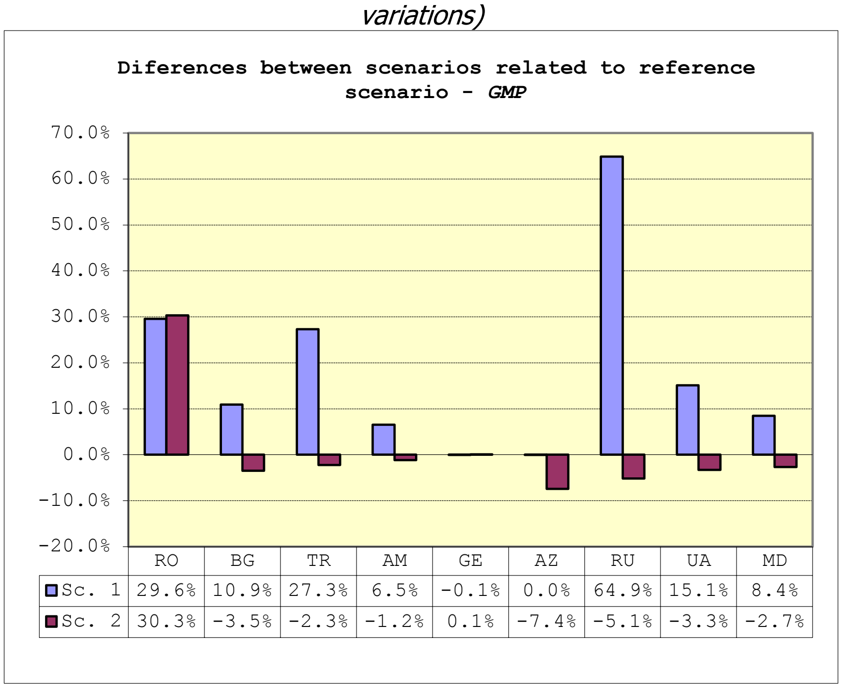


*Figure 3.46 – GMP differences between scenarios related to reference scenario for **summer peak 2015** (CO_2 emission cost variations)*

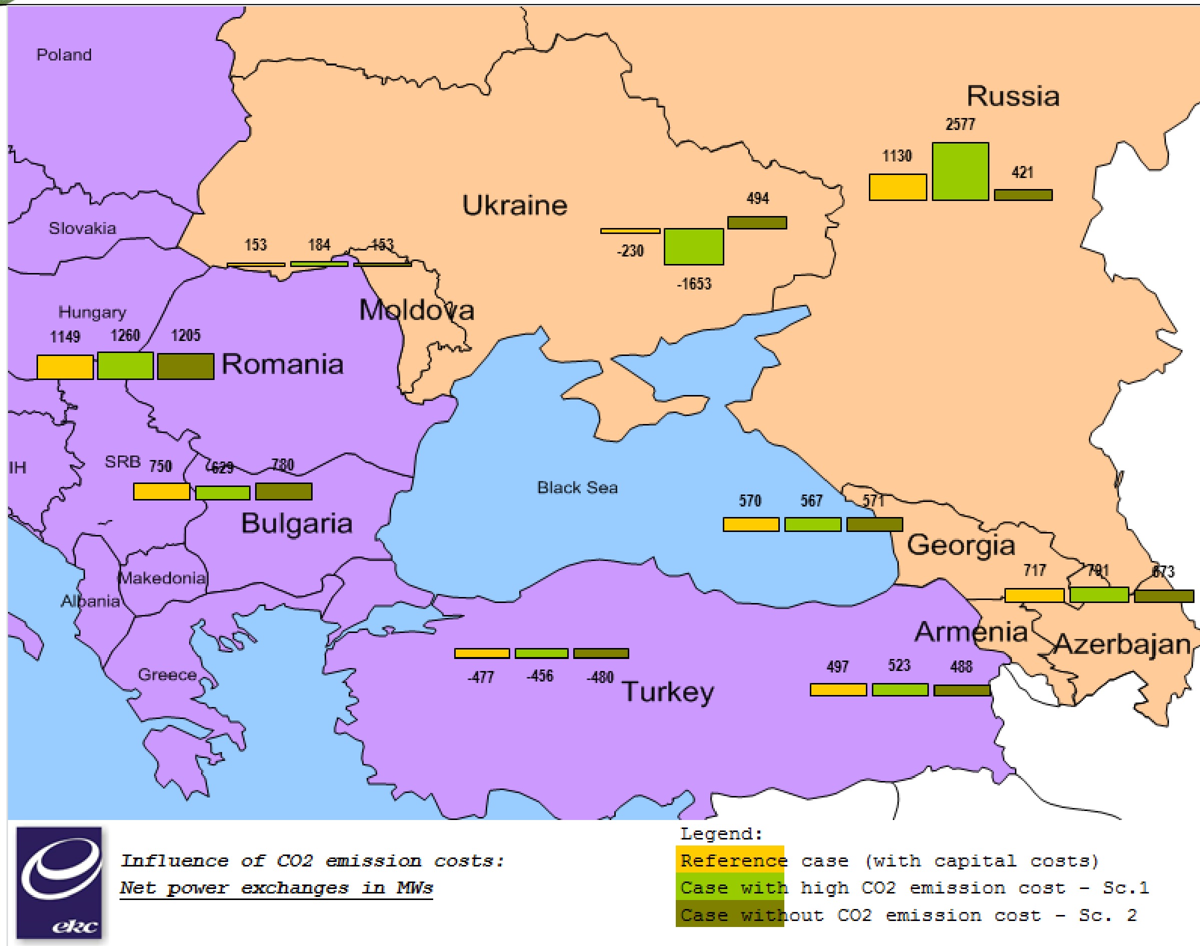
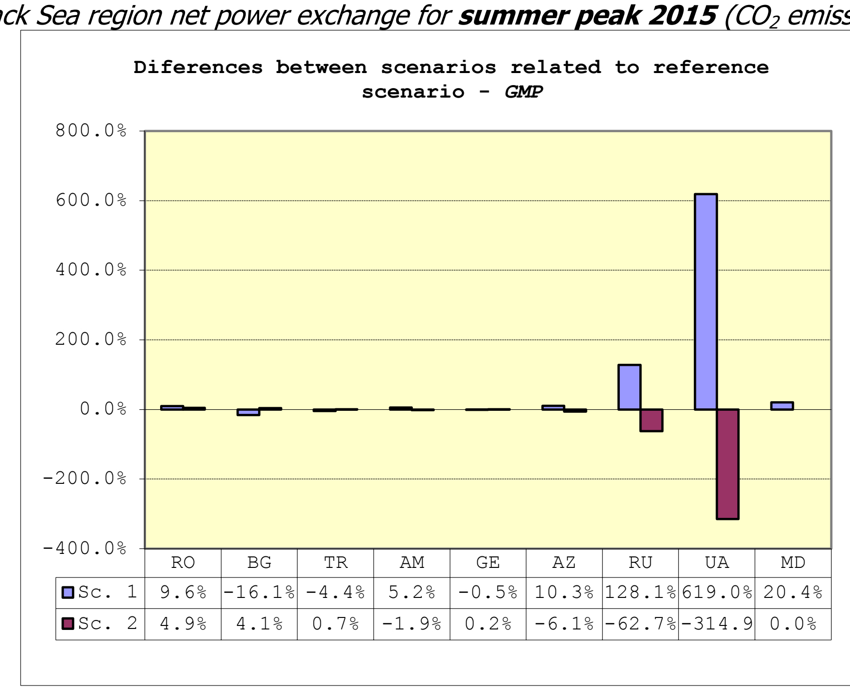


*Figure 3.47 – Black Sea region net power exchange for **summer peak 2015** (CO_2 emission cost variations)*



	RO	BG	TR	AM	GE	AZ	RU	UA	MD
Sc. 1	9.6%	-16.1%	-4.4%	5.2%	-0.5%	10.3%	128.1%	619.0%	20.4%
Sc. 2	4.9%	4.1%	0.7%	-1.9%	0.2%	-6.1%	-62.7%	-314.9	0.0%

*Figure 3.48 – EXC differences between scenarios related to reference scenario for **summer peak 2015** (CO_2 emission cost variations)*

3.4 Different Hydrological Regimes

Hydrological conditions have a great impact on the electricity market affecting expectations for import, export and market price developments. Decrease of hydro power plants energy production due to dry hydrological conditions will result in shortage of low cost energy and increase of electricity prices across the region. In case of wet hydrological conditions, higher production from hydro power plants will happen, which will lead to more competitive electricity market and decrease of electricity prices in the region.

In order to evaluate in the best possible way the impact of different hydrological regimes on behavior of electricity market across the Black Sea region, three sets of conditions are analyzed for sensitivity analyses regarding the impact of different hydrology:

- Average year (Base case) - According to average engagement of HPPs defined in BSTP models
- Dry year - Decrease of HPP's production by 20% with appropriate correction of national power system balance
- Wet year - Increase of HPP's production by 20% with appropriate correction of national power system balance

Aggregated results and graphs of OPF simulations for observed cases. winter and summer peak regimes are presented below (Table 3.9, Table 3.10, Figure 3.49, Figure 3.50, Figure 3.51, Figure 3.52, Figure 3.53, Figure 3.54, Figure 3.55, Figure 3.56, Figure 3.57, Figure 3.58, Figure 3.59 and Figure 3.60).

*Table 3.9 – Results of OPF simulations for observed cases and **winter peak scenario** (Different hydrological regimes)*

	Base Case			Wet Hydrology Scenario			Dry Hydrology Scenario		
	AVG [$/MWh]	GMP [$/MWh]	EXC [MW]	AVG [$/MWh]	GMP [$/MWh]	EXC [MW]	AVG [$/MWh]	GMP [$/MWh]	EXC [MW]
Romania	66	94.16	1113	64.6	97.43	1191	67.2	89.33	807
Bulgaria	50.5	140.57	773	48.9	106.46	960	51.2	128.79	1033
Turkey	81.8	101.81	-672	80.3	102.05	-689	83.7	102.04	-639
Armenia	39.8	88.17	600	38.1	87.29	628	43.6	79.32	694
Georgia	23.9	59.59	-53	26.5	59.57	47	22.2	59.52	-84
Azerbaijan	57.4	67.28	699	57.5	67.28	350	57.1	67.28	707
Russia	50.7	68.93	2155	50.7	68.94	1985	50.7	68.91	2212
Ukraine	49.6	115.9	-688	49	115.92	-310	50.3	115.9	-793
Moldova	51.9	142.95	170	51.6	142.94	177	52	142.93	164

*Table 3.10 – Results of OPF simulations for observed cases and **summer peak scenario** (Different hydrological regimes)*

	Base Case			Wet Hydrology Scenario			Dry Hydrology Scenario		
	AVG [$/MWh]	GMP [$/MWh]	EXC [MW]	AVG [$/MWh]	GMP [$/MWh]	EXC [MW]	AVG [$/MWh]	GMP [$/MWh]	EXC [MW]
Romania	70.1	97.44	1149	69.1	97.49	1126	71	97.37	981
Bulgaria	56.3	106.46	750	56	106.84	847	56.6	67.67	683
Turkey	81.7	100.58	-477	80.1	102.05	-473	83.4	102.03	-477
Armenia	43.9	79.7	638	41.8	91.69	589	45.6	79.41	638
Georgia	24.9	59.53	-13	26	59.54	119	22.2	59.52	-42
Azerbaijan	57.2	67.27	792	57.2	67.28	816	57.2	67.28	689
Russia	50.5	68.95	1448	50.4	68.96	1228	50.7	68.95	1698
Ukraine	54.6	115.92	-181	54.1	115.91	-68	55.2	115.91	-300
Moldova	60.4	142.96	153	60.3	142.96	155	60.5	142.96	151

From the results of sensitivity analysis for both scenarios it can be concluded that:

- Different scenarios for hydrological regimes (20% increase/decrease) influence the variation of average production costs across the Black Sea region less than 2% compared to base case.
- Observing the market behavior, wet hydrological conditions benefit market competition, decrease prices and increase system reserve. Dry hydrological conditions produce less competitive market, increase prices and decrease system reserve.
- Georgia is most sensitive to different hydrological regimes due to dominantly hydro production system with variation in average production cost in range of 10%
- Different hydrological regimes have almost no impact on Russia and Moldova due to low share (in case of Moldova) or almost no share (in case of Russia) of hydro power plants.
- In East part of Black Sea region, for wet hydrology, Ukraine will decrease import of energy from Russia to 45% share of base case.
- In Caucasus, in wet hydrological regimes, Georgia would become exporter of electricity compared to average and dry hydrological regimes.
- In West part of Black Sea region, with about 31% share of hydro production in overall production mix, different hydrological regimes would most influence Romania, decreasing Romania export for about 15% in summer peak scenario and 27% in winter peak scenario.

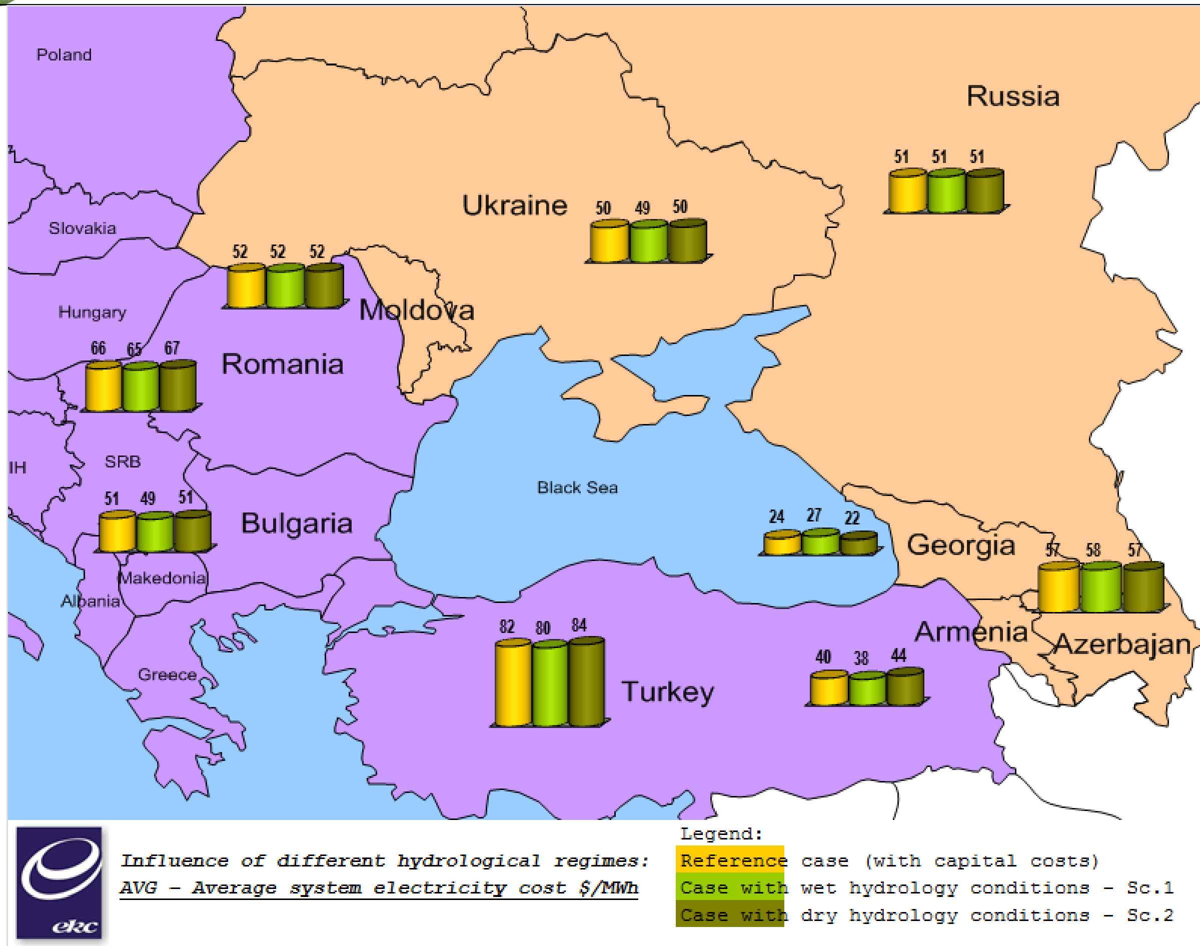
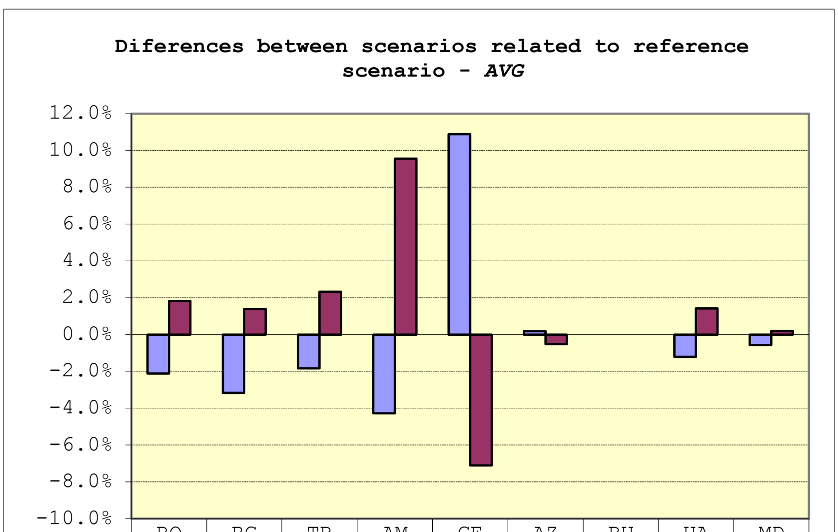


*Figure 3.49 – Black Sea region average system electricity production cost for **winter peak 2015** (Different hydrological regimes)*



	RO	BG	TR	AM	GE	AZ	RU	UA	MD
Sc. 1	-2.1%	-3.2%	-1.8%	-4.3%	10.9%	0.2%	0.0%	-1.2%	-0.6%
Sc. 2	1.8%	1.4%	2.3%	9.5%	-7.1%	-0.5%	0.0%	1.4%	0.2%

*Figure 3.50 – AVG differences between scenarios related to reference scenario for **winter peak 2015** (Different hydrological regimes)*

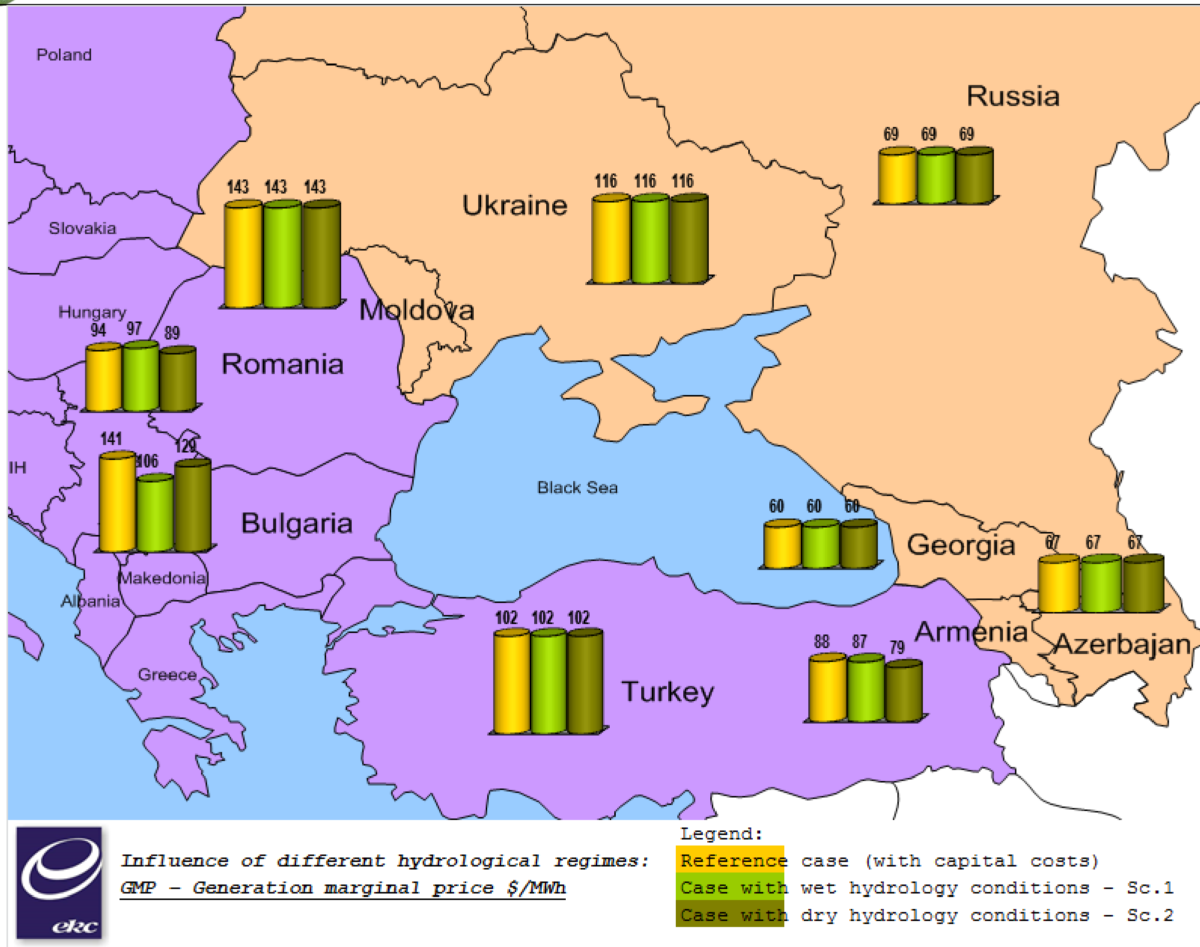
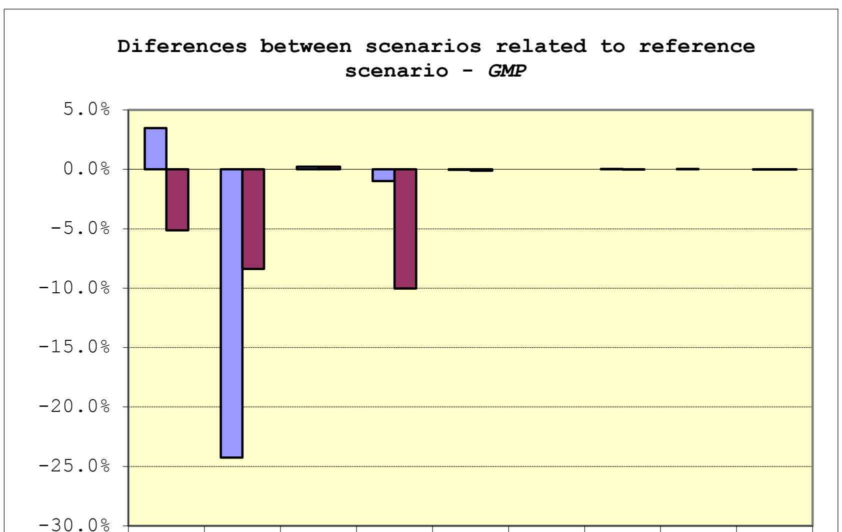


*Figure 3.51 – Black Sea region generation marginal price for **winter peak 2015** (Different hydrological regimes)*



	RO	BG	TR	AM	GE	AZ	RU	UA	MD
Sc. 1	3.5%	-24.3%	0.2%	-1.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Sc. 2	-5.1%	-8.4%	0.2%	-10.0%	-0.1%	0.0%	0.0%	0.0%	0.0%

*Figure 3.52 – GMP differences between scenarios related to reference scenario for **winter peak 2015** (Different hydrological regimes)*

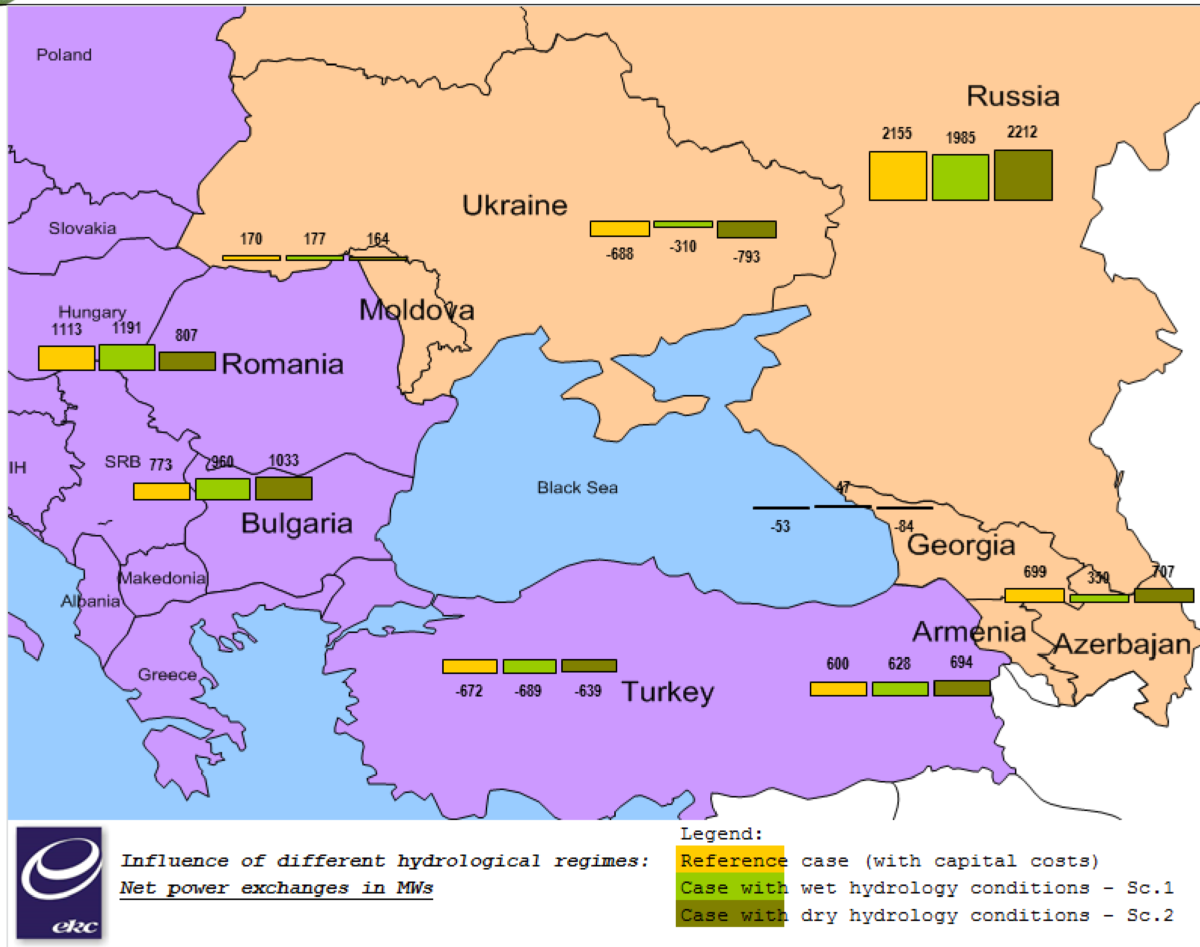
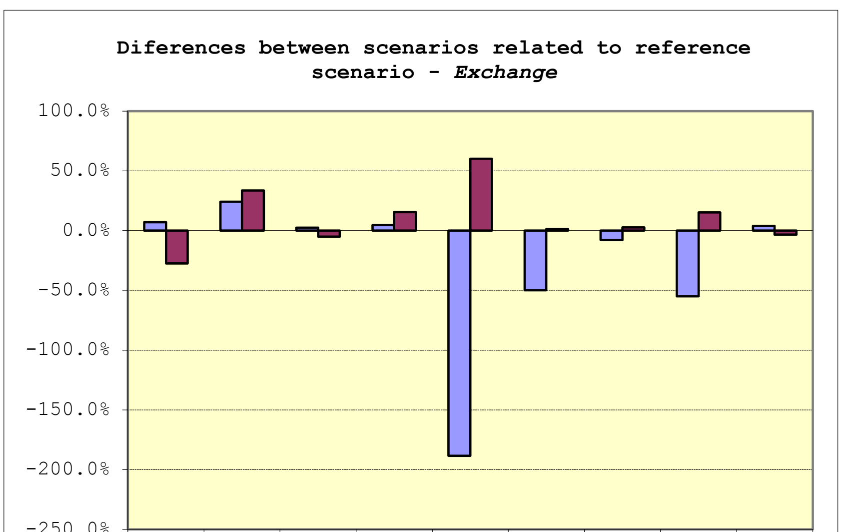


*Figure 3.53 – Black Sea region net power exchange for **winter peak 2015** (Different hydrological regimes)*



	RO	BG	TR	AM	GE	AZ	RU	UA	MD
Sc. 1	7.0%	24.2%	2.5%	4.6%	-188.4	-49.9%	-7.9%	-54.9%	4.0%
Sc. 2	-27.5%	33.7%	-4.9%	15.6%	60.1%	1.2%	2.6%	15.2%	-3.4%

*Figure 3.54 – EXC differences between scenarios related to reference scenario for **winter peak 2015** (Different hydrological regimes)*

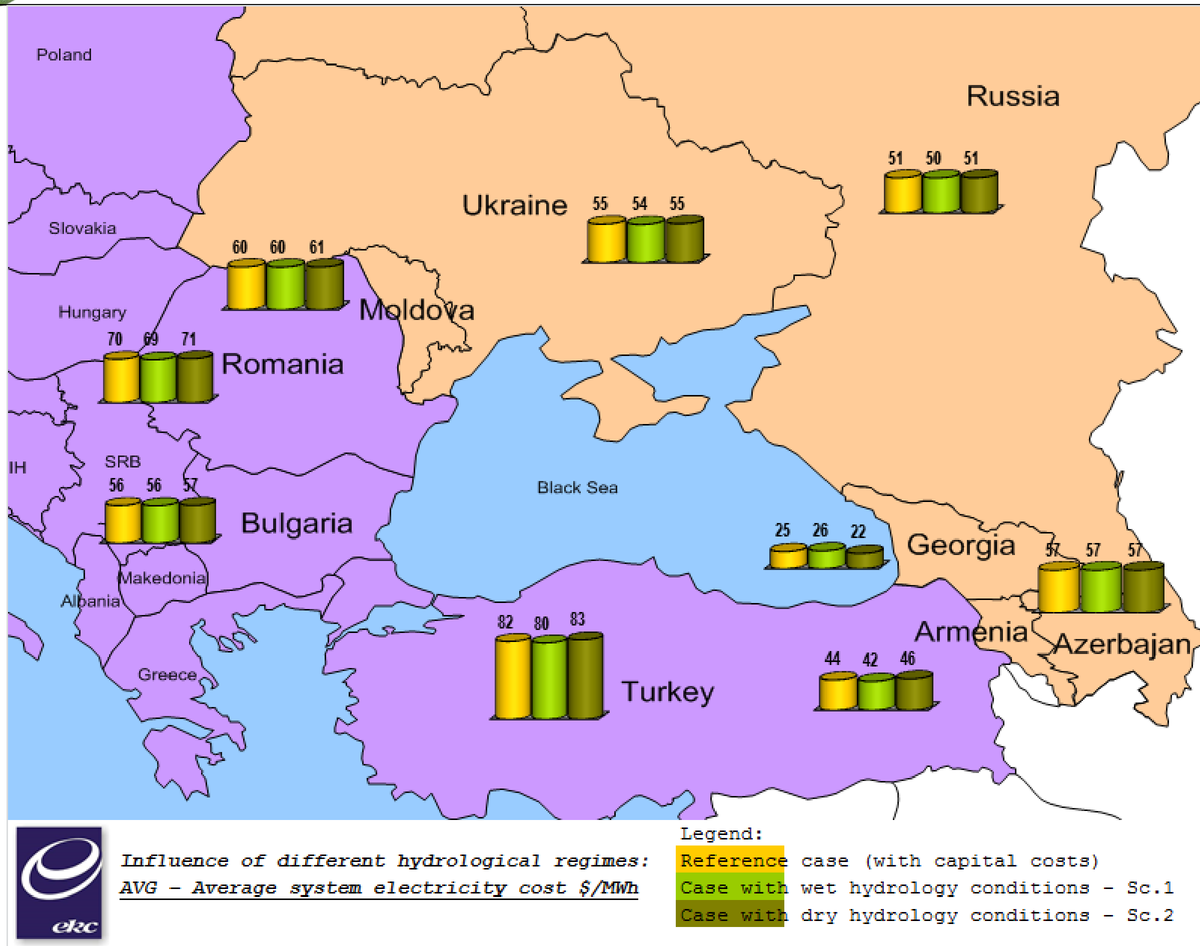


*Figure 3.55 – Black Sea region average system electricity production cost for **summer peak 2015** (Different hydrological regimes)*

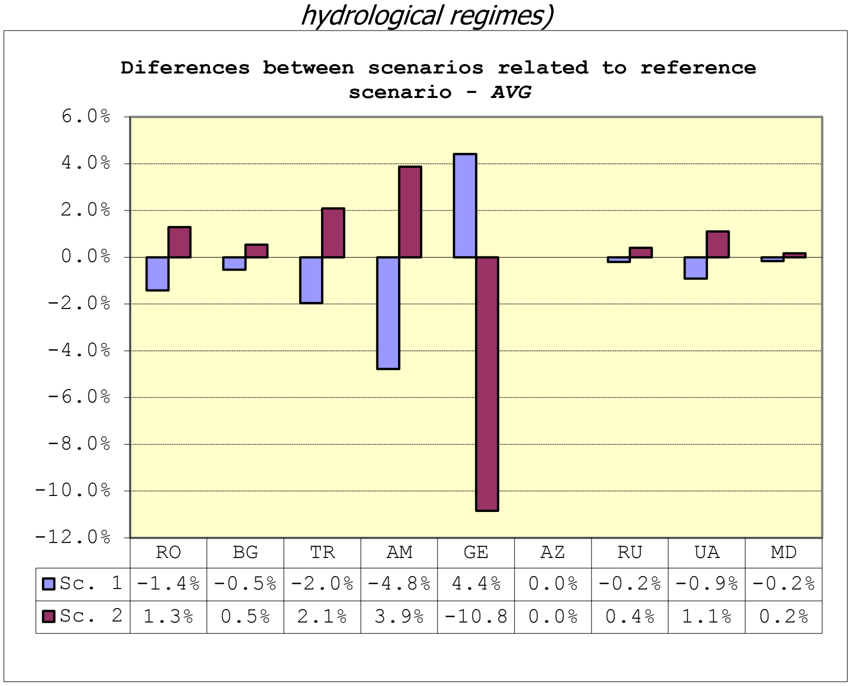


*Figure 3.56 – AVG differences between scenarios related to reference scenario for **summer peak 2015** (Different hydrological regimes)*

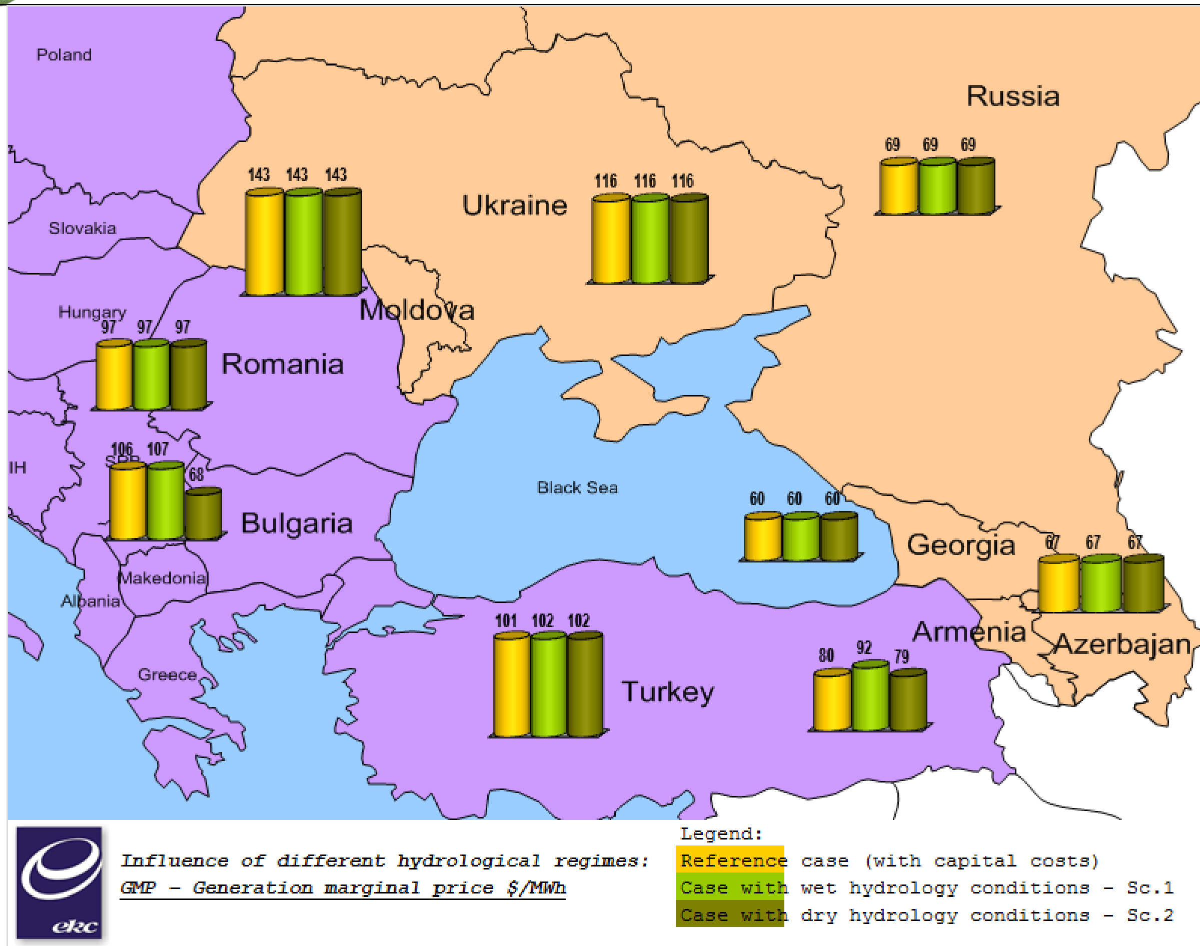
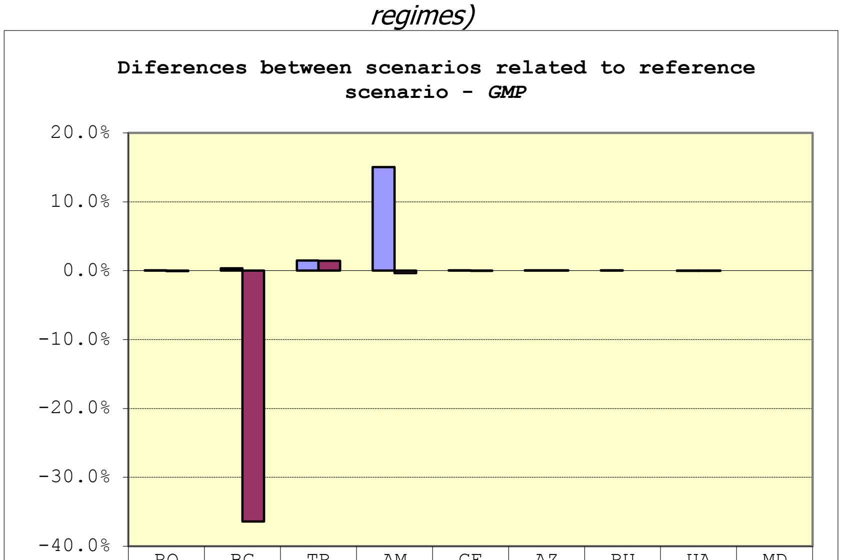


*Figure 3.57 – Black Sea region generation marginal price for **summer peak 2015** (Different hydrological regimes)*



	RO	BG	TR	AM	GE	AZ	RU	UA	MD
Sc. 1	0.1%	0.4%	1.5%	15.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Sc. 2	-0.1%	-36.4%	1.4%	-0.4%	0.0%	0.0%	0.0%	0.0%	0.0%

*Figure 3.58 – GMP differences between scenarios related to reference scenario for **summer peak 2015** (Different hydrological regimes)*

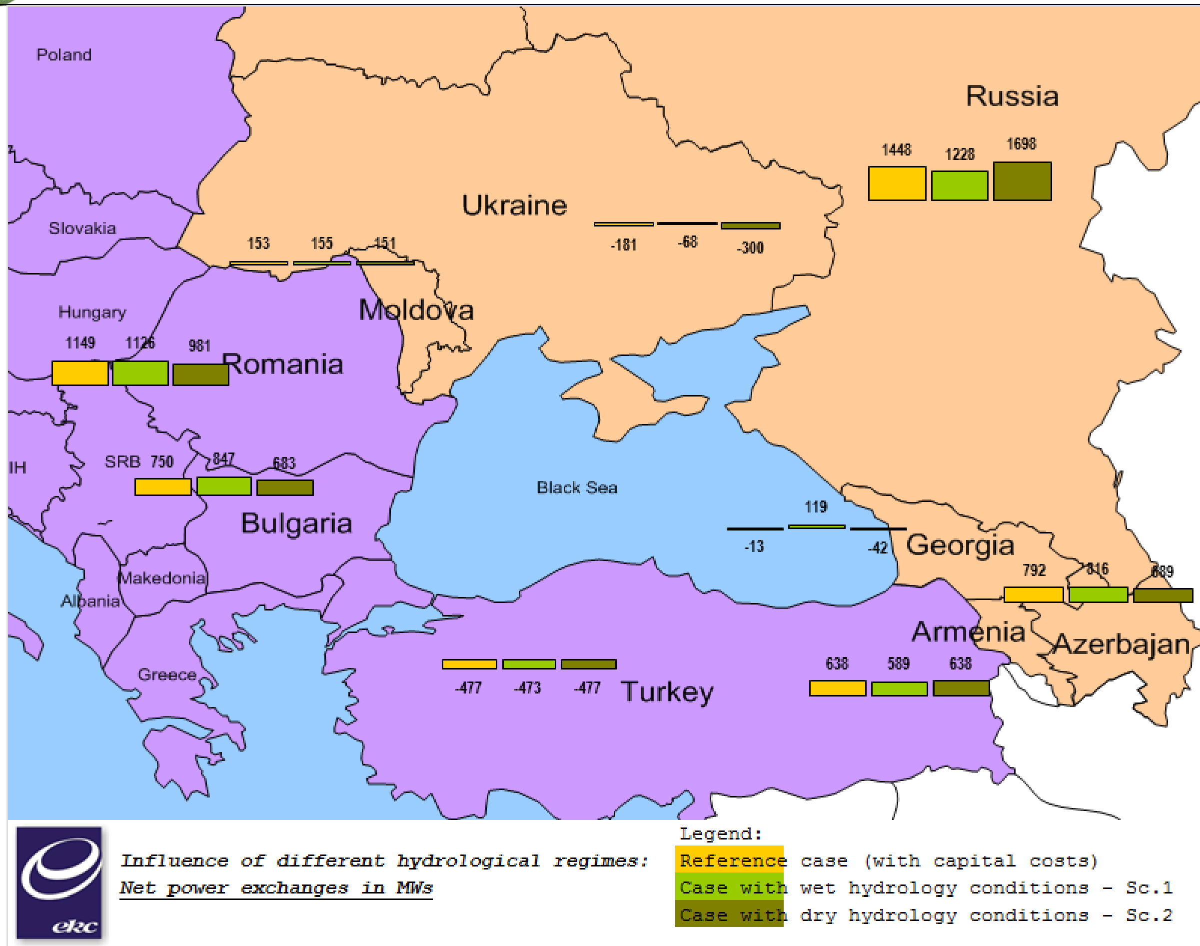
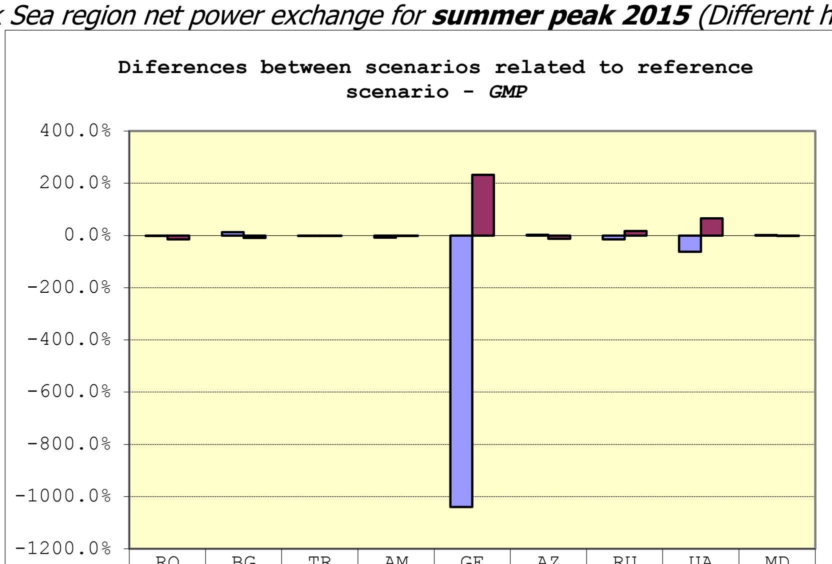


*Figure 3.59 – Black Sea region net power exchange for **summer peak 2015** (Different hydrological regimes)*



	RO	BG	TR	AM	GE	AZ	RU	UA	MD
Sc. 1	-2.0%	13.0%	-0.8%	-7.7%	-1040.	2.9%	-15.2%	-62.3%	1.4%
Sc. 2	-14.6%	-8.9%	-0.1%	-0.1%	232.3%	-13.0%	17.3%	65.7%	-1.5%

*Figure 3.60 – EXC differences between scenarios related to reference scenario for **summer peak 2015** (Different hydrological regimes)*

3.5 Different RES Engagement

The penetration of renewable energy into the electricity supply mix is becoming more and more present in the region, according to the plans for increasing the share of production of sustainable and environmentally clean energy. Since RES are treated as must run units and dispatched first, disregarding production prices and merit order, variation of RES engagement can have significant influence on market behavior. In cases of higher RES penetration, we would have more available conventional capacities for dispatch and therefore a more competitive game on the market, and in case of lower RES penetration we would have less available conventional capacities for dispatch and therefore a less competitive game on the market

In order to evaluate in the best possible way the impact of different RES engagement on behavior of electricity market across the Black Sea region, three sets of assumptions are used for sensitivity analyses:

- Base case - According to average engagement of RES defined in BSTP models
- High RES penetration - Increase of RES production by 20% with appropriate correction of national power system balance
- Low RES penetration - Decrease of RES production by 20% with appropriate correction of national power system balance

Aggregated results and graphs of OPF simulations for observed cases winter and summer peak scenario are presented below (Table 3.11, Table 3.12, Figure 3.61, Figure 3.62, Figure 3.63, Figure 3.64, Figure 3.65, Figure 3.66, Figure 3.67, Figure 3.68, Figure 3.69, Figure 3.70, Figure 3.71 and Figure 3.72).

*Table 3.11 – Results of OPF simulations for observed cases and **winter peak scenario** (Different RES engagement)*

	Base Case			High RES engagement			Low RES engagement		
	AVG [$/MWh]	GMP [$/MWh]	EXC [MW]	AVG [$/MWh]	GMP [$/MWh]	EXC [MW]	AVG [$/MWh]	GMP [$/MWh]	EXC [MW]
Romania	66	94.16	1113	66	97.38	1216	66.2	89.34	1107
Bulgaria	50.5	140.57	773	50.2	106.59	692	50.7	129.15	780
Turkey	81.8	101.81	-672	81.7	102.03	-675	81.8	100.78	-677
Armenia	39.8	88.17	543	39.8	88.16	548	39.8	88.16	537
Georgia	23.9	59.59	340	23.9	59.59	340	23.9	59.59	340
Azerbaijan	57.4	67.28	297	57.4	67.28	291	57.4	67.28	305
Russia	50.7	68.93	2171	50.7	68.93	2150	50.7	68.92	2206
Ukraine	49.6	115.9	-634	49.6	115.9	-626	49.6	115.91	-657
Moldova	51.9	142.95	170	51.9	142.95	181	51.9	142.96	159

*Table 3.12 – Results of OPF simulations for observed cases and **summer peak scenario** (Different RES engagement)*

	Base Case			High RES engagement			Low RES engagement		
	AVG [$/MWh]	GMP [$/MWh]	EXC [MW]	AVG [$/MWh]	GMP [$/MWh]	EXC [MW]	AVG [$/MWh]	GMP [$/MWh]	EXC [MW]
Romania	70.1	97.44	1149	70.3	97.45	1117	69.2	97.4	1162
Bulgaria	56.3	106.46	750	56	106.59	797	56		704
Turkey	81.7	100.58	-477	81.6	101.52	-463	81.7	100.56	-492
Armenia	42.6	93.77	497	42.6	95.41	501	42.6	91.95	496
Georgia	23.9	59.54	570	23.9	59.54	572	23.8	59.54	570
Azerbaijan	57.2	67.28	717	57.2	67.28	714	57.2	67.28	721
Russia	50.4	68.96	1130	50.4	68.96	1083	50.4	68.96	1171
Ukraine	54.6	115.91	-230	55.2	115.91	-200	54	115.91	-264
Moldova	60.4	142.96	153	61.1	142.95	164	59.6	142.96	142

From the results of sensitivity analysis for both scenarios it can be concluded that:

- Different scenarios of RES engagement (20% increase/decrease) influence variation of average production costs across the Black Sea region for less than 1% comparing to base case.
- Small influence of different scenarios of RES engagement is a result of modest share of RES in Black Sea region in overall production mix, and 20% variation of RES engagement means about 900 MWh/h, which represents only 0.75% change of overall produced energy.
- In East part of Black Sea region, 94% of RES production is in Ukraine and Moldova, so the impact of different RES engagement is noted in terms of increase of Moldova export and decrease of Ukraine import from/to Russia.
- In Caucasus, small influence of net exchange is observed due to small share of production of RES in overall produced energy.
- About one third of energy produced from RES in whole Black Sea region is in Romania, and increase of Romania export increases in high RES penetration scenario for about 10% in winter peak regime.

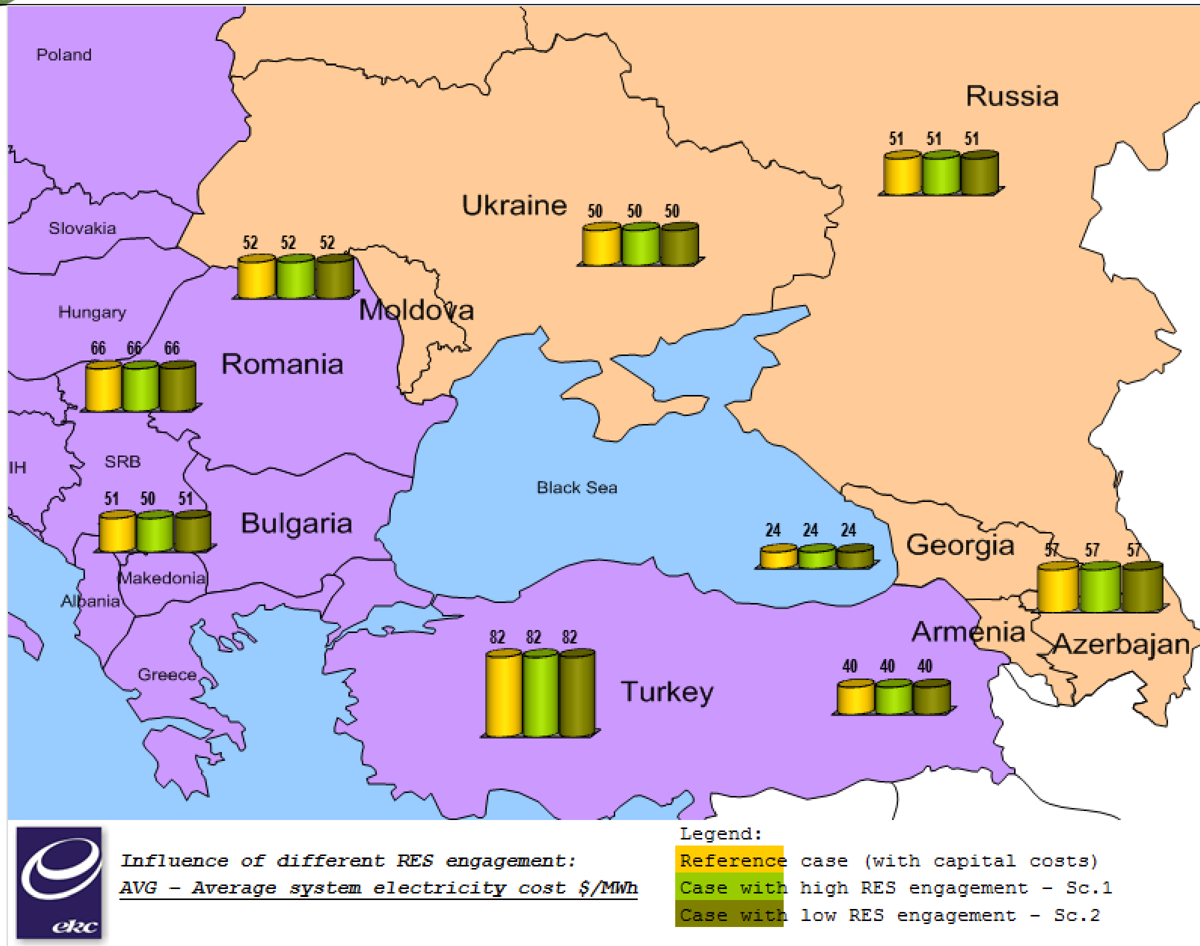


Figure 3.61 – Black Sea region average system electricity production cost for ***winter peak 2015*** *(Different RES engagement)*

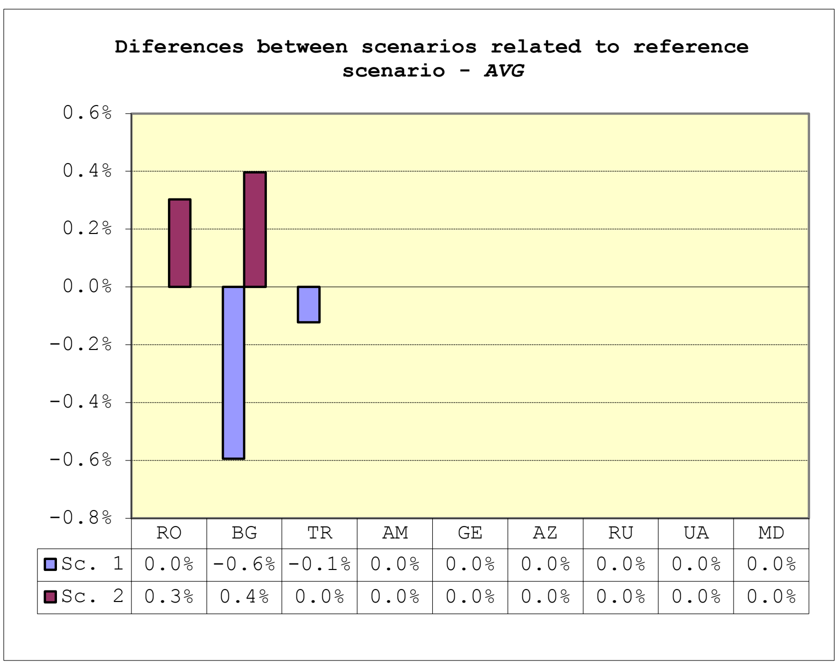


Figure 3.62 – AVG differences between scenarios related to reference scenario for ***winter peak 2015*** *(Different RES engagement)*

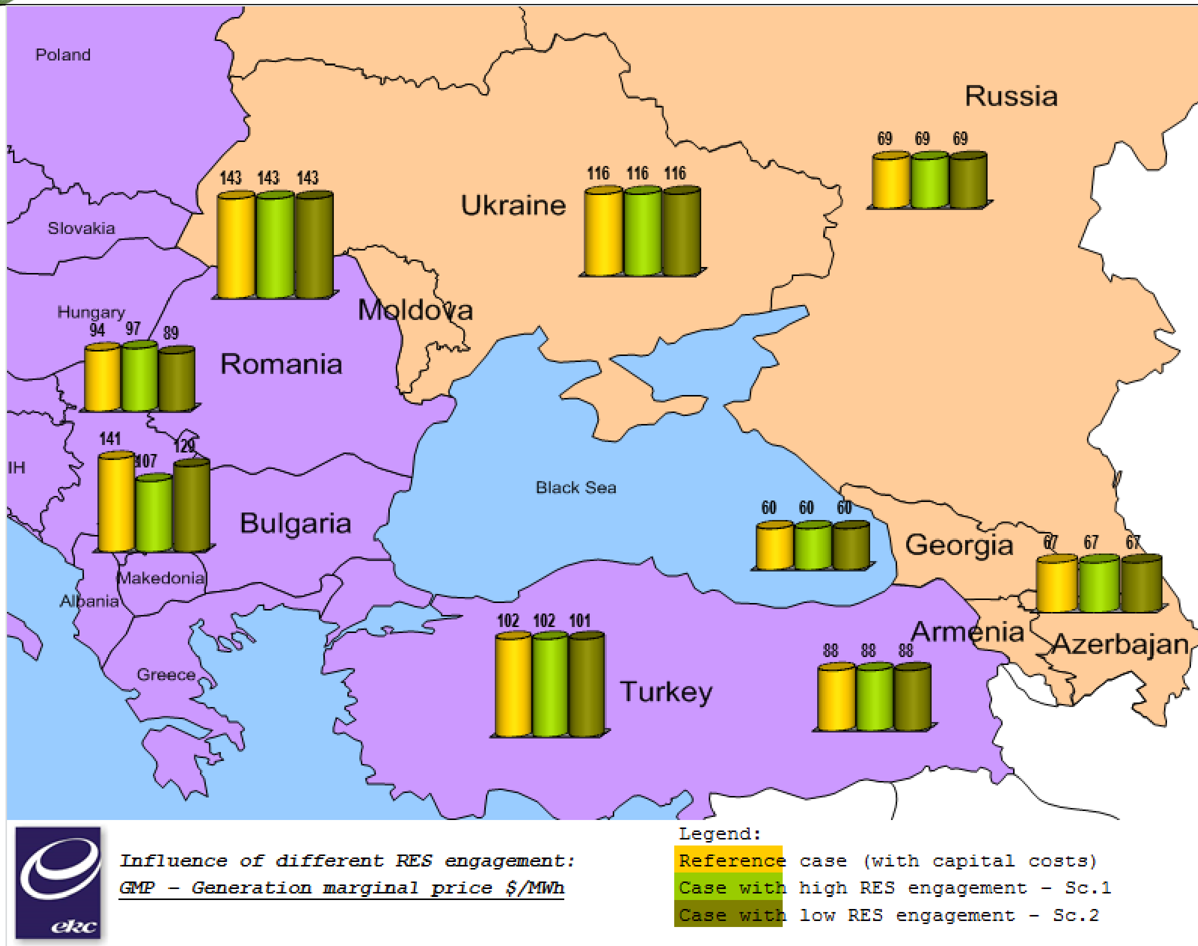
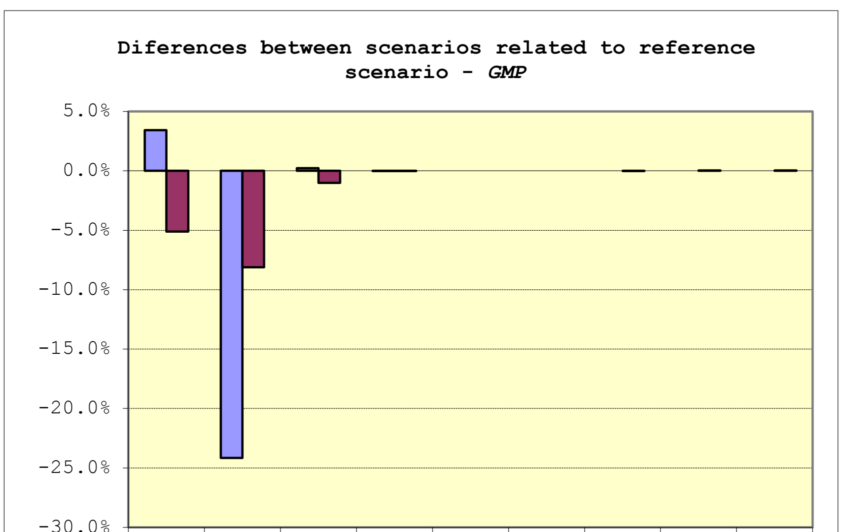


*Figure 3.63 – Black Sea region generation marginal price for **winter peak 2015** (Different RES engagement)*



	RO	BG	TR	AM	GE	AZ	RU	UA	MD
Sc. 1	3.4%	-24.2%	0.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Sc. 2	-5.1%	-8.1%	-1.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

*Figure 3.64 – GMP differences between scenarios related to reference scenario for **winter peak 2015** (Different RES engagement)*

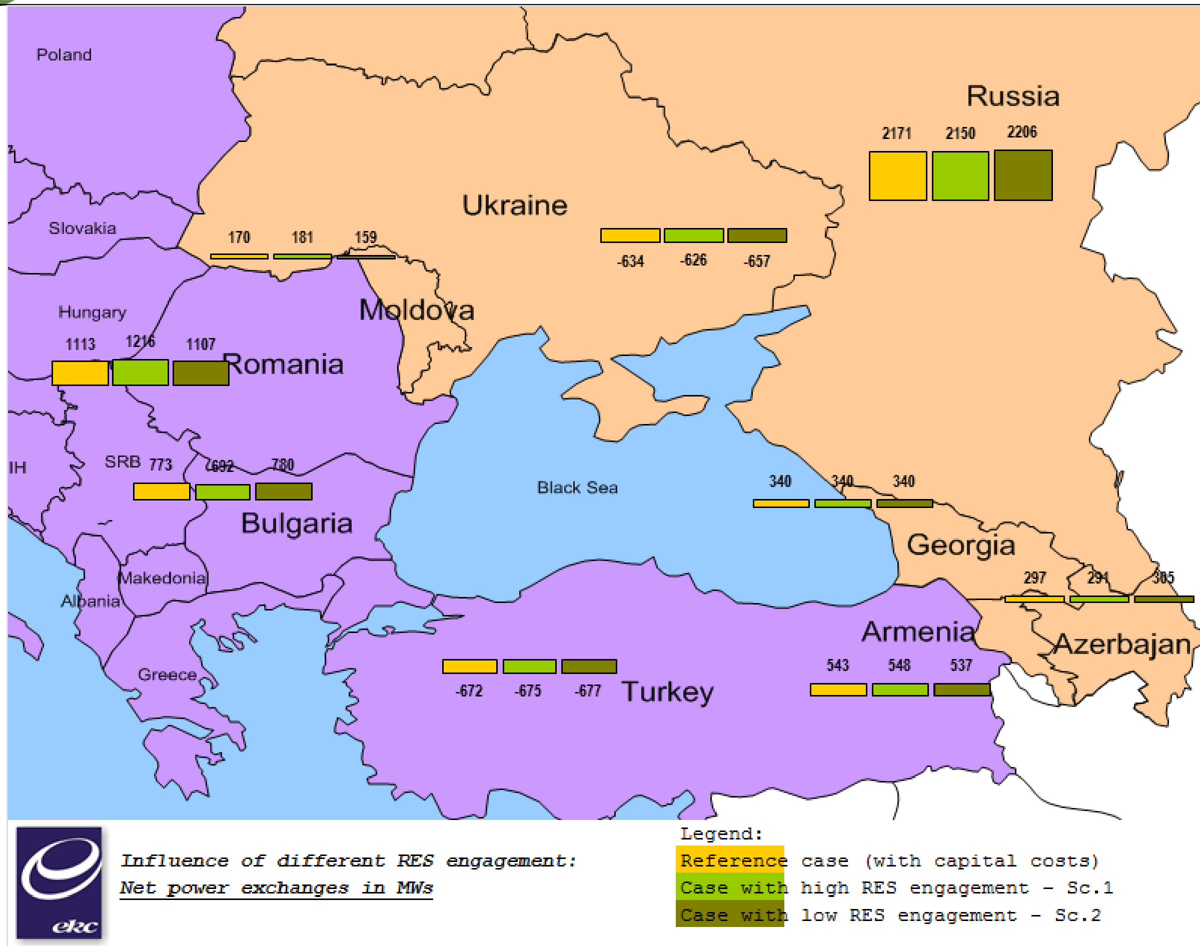
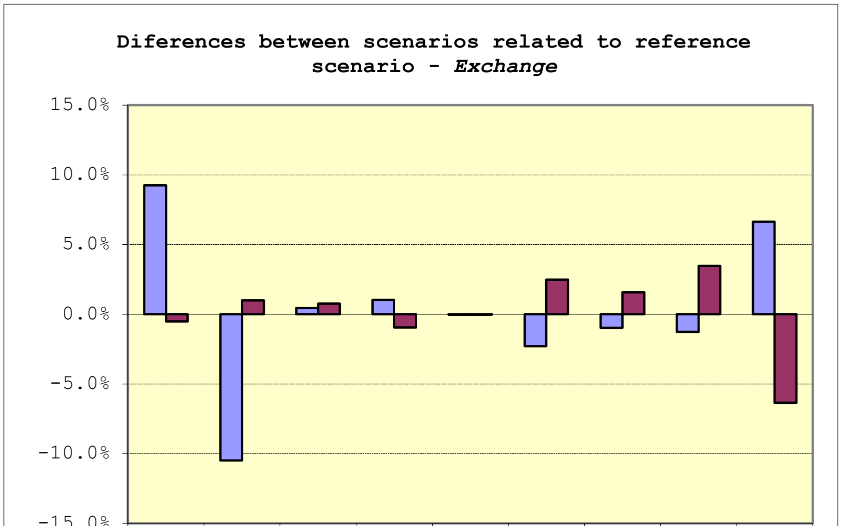


*Figure 3.65 – Black Sea region net power exchange for **winter peak 2015** (Different RES engagement)*



	RO	BG	TR	AM	GE	AZ	RU	UA	MD
Sc. 1	9.2%	-10.5%	0.4%	1.0%	0.0%	-2.3%	-1.0%	-1.3%	6.6%
Sc. 2	-0.5%	1.0%	0.8%	-1.0%	0.0%	2.5%	1.6%	3.5%	-6.3%

Figure 3.66 – EXC differences between scenarios related to reference scenario for winter peak 2015 (Different RES engagement)

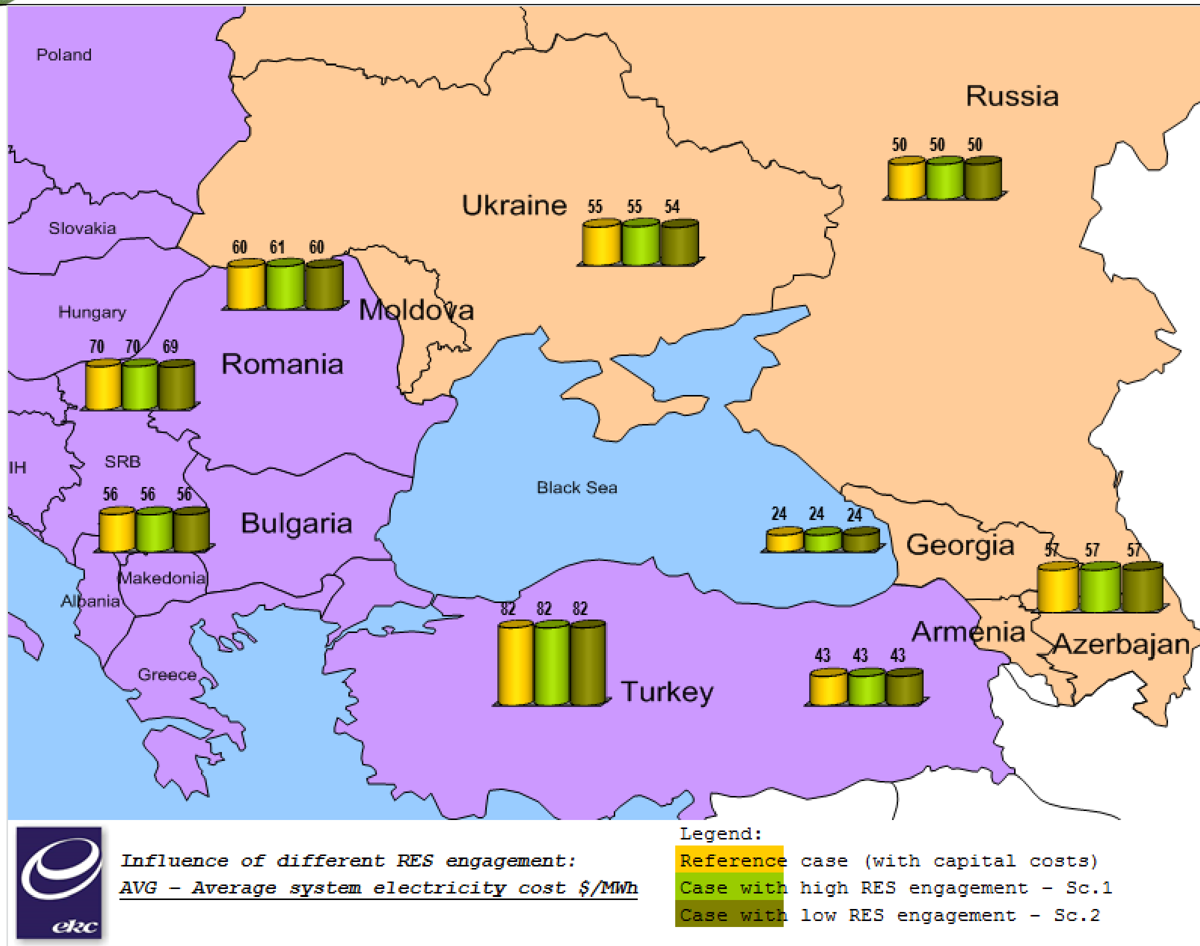
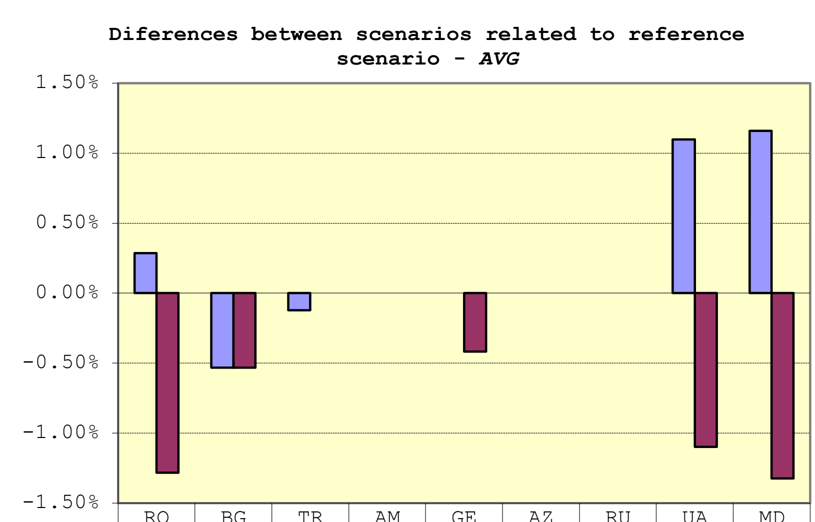


*Figure 3.67 – Black Sea region average system electricity production cost for **summer peak 2015** (Different RES engagement)*



	RO	BG	TR	AM	GE	AZ	RU	UA	MD
Sc. 1	0.29%	-0.53	-0.12	0.00%	0.00%	0.00%	0.00%	1.10%	1.16%
Sc. 2	-1.28	-0.53	0.00%	0.00%	-0.42	0.00%	0.00%	-1.10	-1.32

*Figure 3.68 – AVG differences between scenarios related to reference scenario for **summer peak 2015** (Different RES engagement)*

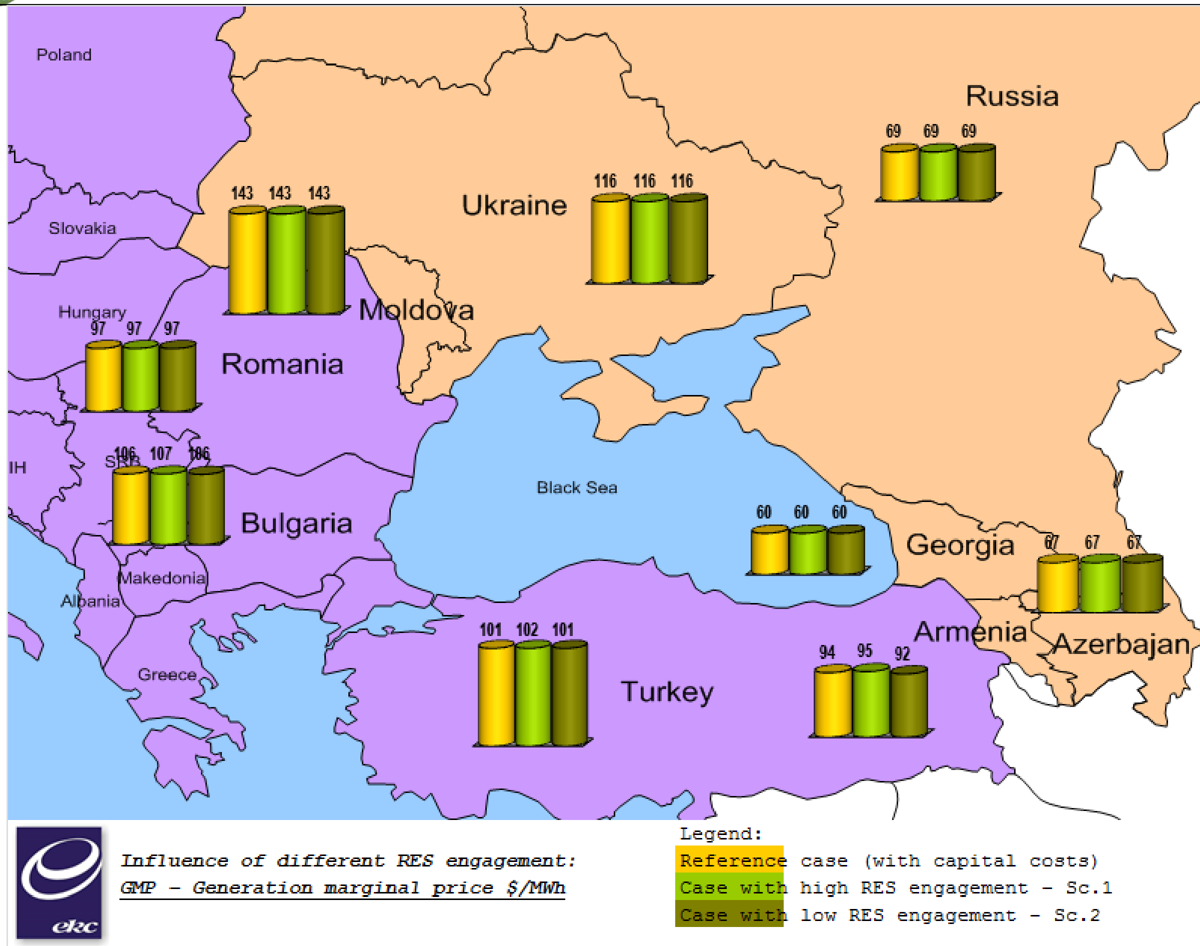
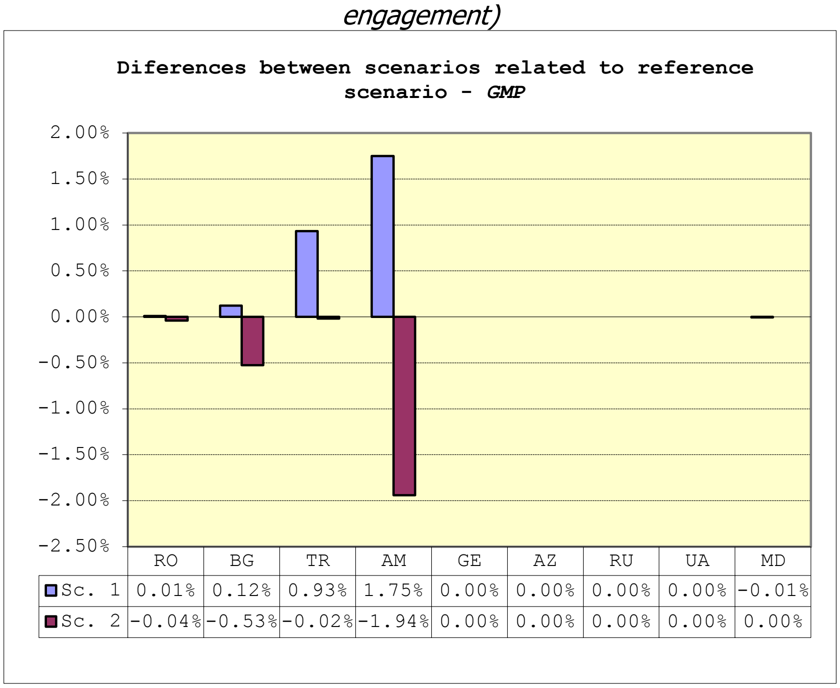


*Figure 3.69 – Black Sea region generation marginal price for **summer peak 2015** (Different RES engagement)*



	RO	BG	TR	AM	GE	AZ	RU	UA	MD
Sc. 1	0.01%	0.12%	0.93%	1.75%	0.00%	0.00%	0.00%	0.00%	-0.01%
Sc. 2	-0.04%	-0.53%	-0.02%	-1.94%	0.00%	0.00%	0.00%	0.00%	0.00%

*Figure 3.70 – GMP differences between scenarios related to reference scenario for **summer peak 2015** (Different RES engagement)*

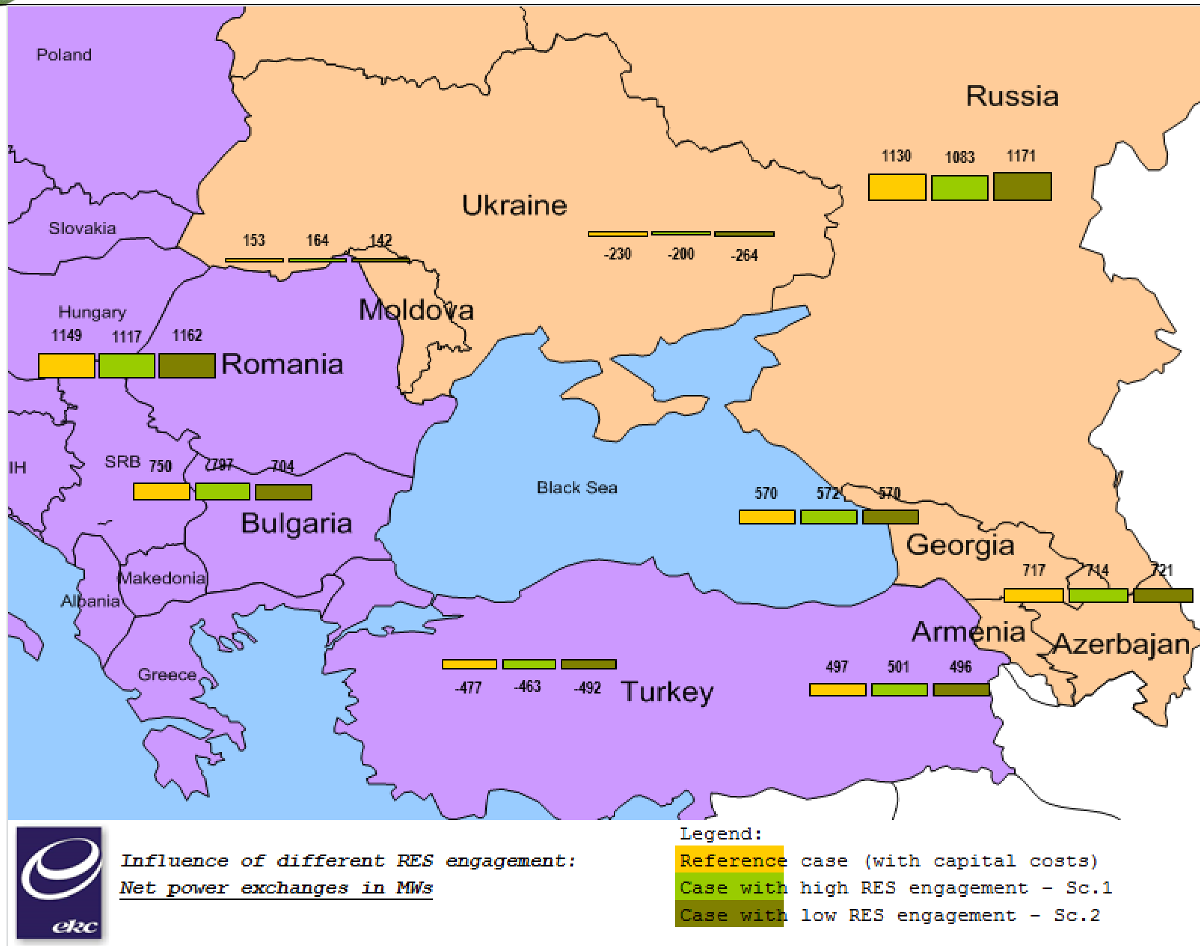
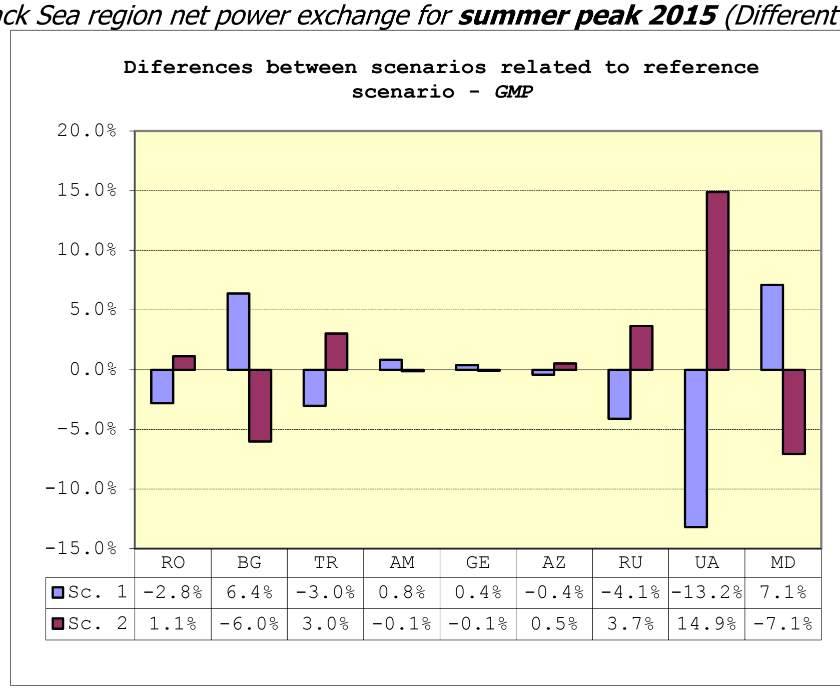


*Figure 3.71 – Black Sea region net power exchange for **summer peak 2015** (Different RES engagement)*



	RO	BG	TR	AM	GE	AZ	RU	UA	MD
Sc. 1	-2.8%	6.4%	-3.0%	0.8%	0.4%	-0.4%	-4.1%	-13.2%	7.1%
Sc. 2	1.1%	-6.0%	3.0%	-0.1%	-0.1%	0.5%	3.7%	14.9%	-7.1%

*Figure 3.72 – EXC differences between scenarios related to reference scenario for **summer peak 2015** (Different RES engagement)*

3.6 Influence of the Network Reinforcements

Development of cross-border electricity trade in the region requires that the development of the transmission infrastructure takes place through the extension and strengthening of the interconnection of power systems with the purpose of sales and exchanges of electricity. The new network reinforcements reduce the total cost of electricity supply. Therefore, a transmission project can increase economic welfare.

In order to evaluate in the best possible way the impact of the entrance of new network reinforcements on behavior of electricity market across the Black Sea region, three sets of assumptions regarding transfer capacities are analyzed for sensitivity analyses:

- Base case - According to NTCs from previous study
- Increased NTCs - Increase of NTC values by 500 MW on the each border (it represents the influence of the new additional interconnection projects)
- Decreased NTCs - Decrease of NTC's by 20% on the each border (it represents the influence of the delay of some projects defined in BSTP models)

Aggregated results and graphs of OPF simulations for observed cases winter and summer peak scenario are presented below (Table 3.13, Table 3.14, Figure 3.73, Figure 3.74, Figure 3.75, Figure 3.76, Figure 3.77, Figure 3.78, Figure 3.79, Figure 3.80, Figure 3.81, Figure 3.82, Figure 3.83 and Figure 3.84).

*Table 3.13 – Results of OPF simulations for observed cases and **winter peak scenario** (Influence of the network reinforcements)*

	Base Case			High NTC values Scenario			Low NTC values Scenario		
	AVG [$/MWh]	GMP [$/MWh]	EXC [MW]	AVG [$/MWh]	GMP [$/MWh]	EXC [MW]	AVG [$/MWh]	GMP [$/MWh]	EXC [MW]
Romania	66	94.16	1113	66.3	89.03	1417	66	97.33	1038
Bulgaria	50.5	140.57	773	51	127.82	1061	50.3	106.45	680
Turkey	81.8	101.81	-672	81.6	102.04	-1326	81.8	100.61	-500
Armenia	39.8	88.17	543	40.4	86.68	606	39.7	88.78	539
Georgia	23.9	59.59	340	23.9	59.53	327	23.9	59.6	341
Azerbaijan	57.4	67.28	297	57.1	67.28	790	57.5	67.28	167
Russia	50.7	68.93	2171	50.6	68.95	1848	50.7	68.9	2226
Ukraine	49.6	115.9	-634	49.6	115.92	-864	49.6	115.91	-554
Moldova	51.9	142.95	170	51.9	142.95	170	51.9	142.96	170

*Table 3.14 – Results of OPF simulations for observed cases and **summer peak scenario** (Influence of the network reinforcements)*

	Base Case			High NTC values Scenario			Low NTC values Scenario		
	AVG [$/MWh]	GMP [$/MWh]	EXC [MW]	AVG [$/MWh]	GMP [$/MWh]	EXC [MW]	AVG [$/MWh]	GMP [$/MWh]	EXC [MW]
Romania	70.1	97.44	1149	70	97.35	1593	69.1	97.44	1048
Bulgaria	56.3	106.46	750	56.4	106.46	802	55.8	106.46	749
Turkey	81.7	100.58	-477	81.4	102.04	-1255	81.7	100.56	-362
Armenia	42.6	93.77	497	42.6	93.66	497	42.3	98.45	451
Georgia	23.9	59.54	570	23.9	59.54	570	23.9	59.61	587
Azerbaijan	57.2	67.28	717	57.2	67.28	717	57.8	67.28	-43
Russia	50.4	68.96	1130	50.4	68.96	1129	50.7	68.94	1836
Ukraine	54.6	115.91	-230	54.8	115.91	-230	54.7	115.92	-144
Moldova	60.4	142.96	153	60.4	142.96	153	60.4	142.96	153

From the results of sensitivity analysis for both scenarios it can be concluded that:

- Influence of the network reinforcements, quantified through increase or decrease of NTC values, according to entrance of new power lines or delay of entrance of new power lines, has small impact on electricity prices across Black Sea region.
- Observing the overall market behavior, entrances of new reinforcements contribute to higher NTC values and therefore better market interaction with decrease of production costs.
- Unlike to the rather modest impact on cost indicators, this sensitivity analysis shows a great impact on net exchanges, with exchange increase of 40% in winter regime and 23% in summer regime in the high NTCs scenario compared to base case, and decrease of 11% in winter regime and 13% in summer regime in the low NTCs scenario compared to base case.
- In West part of the Black Sea region, the most sensitive to NTC change is border between Bulgaria and Turkey, and in East part of the Black Sea region, the most sensitive are the borders between Russia and Caucasus countries.
- In high NTCs scenarios, Turkey will more than double energy import from the west, with Romania supplying most of this increased import of Turkey in summer regimes. In winter regimes this increased energy import to Turkey is supplied almost equally from Romania and Bulgaria.
- In winter regimes, in case of high NTC values, export from Caucasus region to northwest is increased, mainly from cheaper Azerbaijan plants that suppress marginal gas units in Russia and Ukraine.
- In summer regimes and lower NTCs scenarios, due to network restrictions, export from Caucasus region to northwest is lower than in base case, with most significant change of Azerbaijan net exchange between neighboring countries.

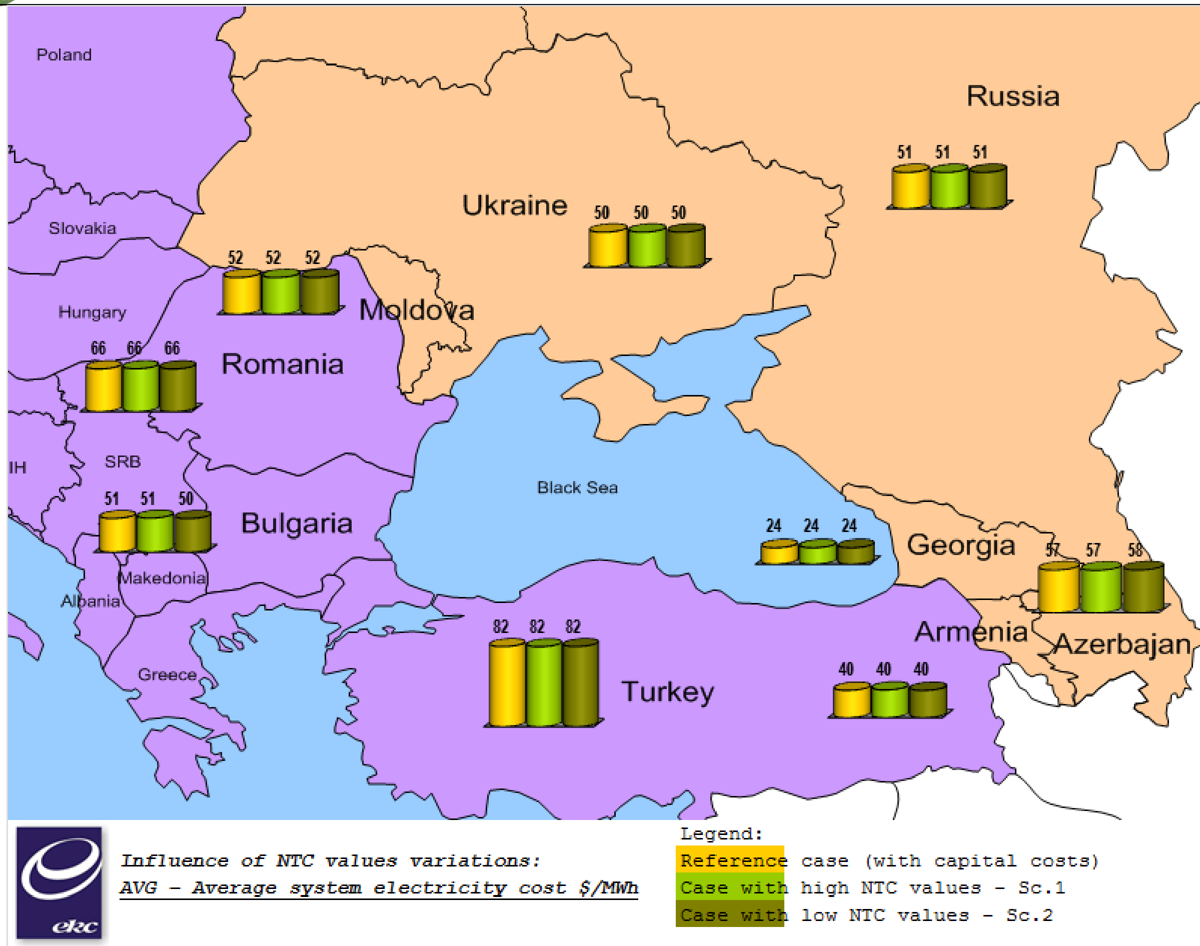
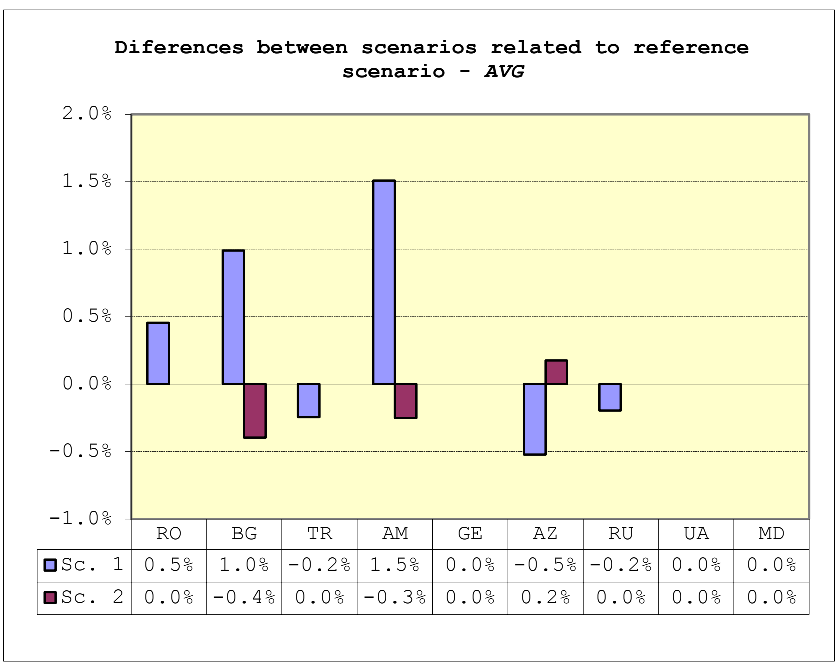


*Figure 3.73 – Black Sea region average system electricity production cost for **winter peak 2015** (Influence of the network reinforcements)*



	RO	BG	TR	AM	GE	AZ	RU	UA	MD
Sc. 1	0.5%	1.0%	-0.2%	1.5%	0.0%	-0.5%	-0.2%	0.0%	0.0%
Sc. 2	0.0%	-0.4%	0.0%	-0.3%	0.0%	0.2%	0.0%	0.0%	0.0%

*Figure 3.74 – AVG differences between scenarios related to reference scenario for **winter peak 2015** (Influence of the network reinforcements)*

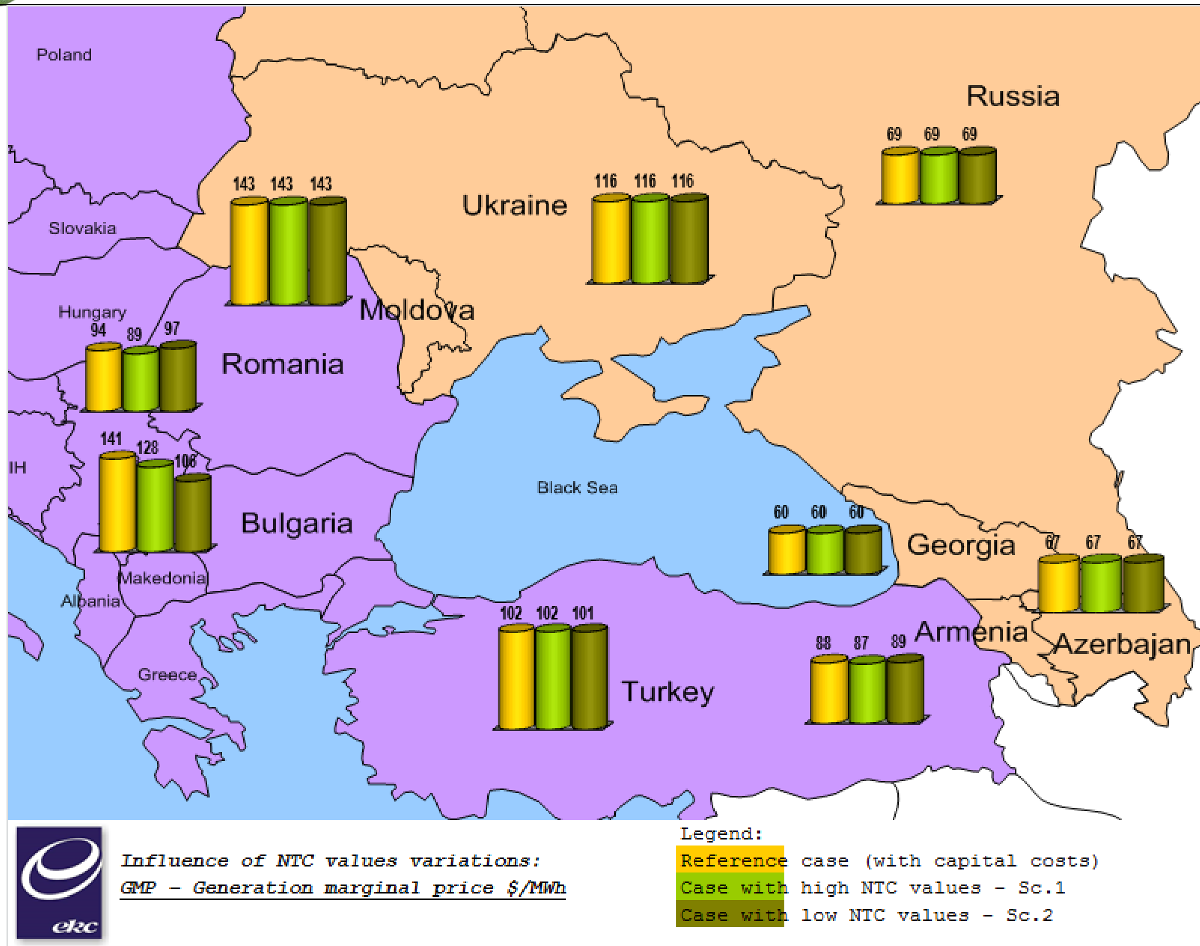
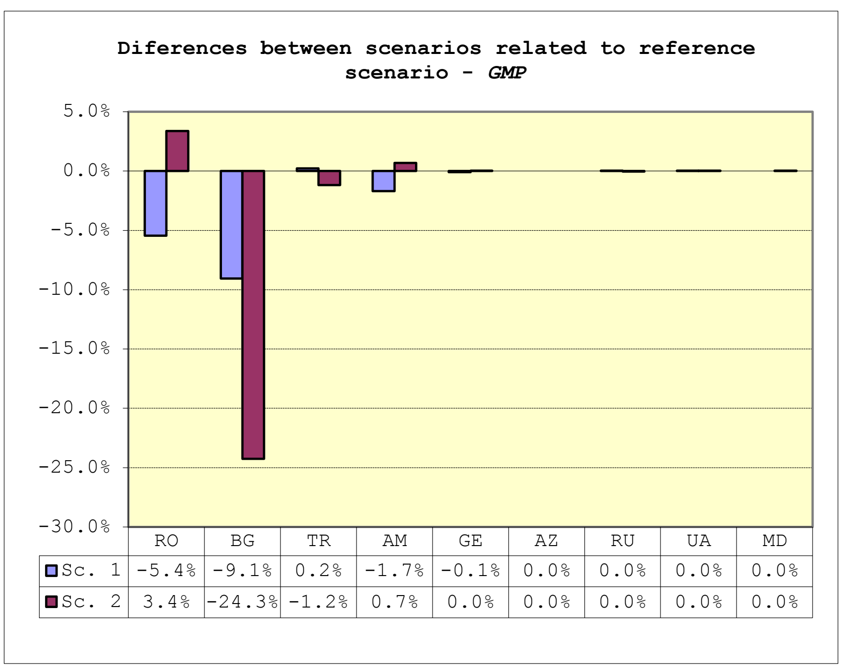


*Figure 3.75 – Black Sea region generation marginal price for **winter peak 2015** (Influence of the network reinforcements)*



	RO	BG	TR	AM	GE	AZ	RU	UA	MD
Sc. 1	-5.4%	-9.1%	0.2%	-1.7%	-0.1%	0.0%	0.0%	0.0%	0.0%
Sc. 2	3.4%	-24.3%	-1.2%	0.7%	0.0%	0.0%	0.0%	0.0%	0.0%

*Figure 3.76 – GMP differences between scenarios related to reference scenario for **winter peak 2015** (Influence of the network reinforcements)*

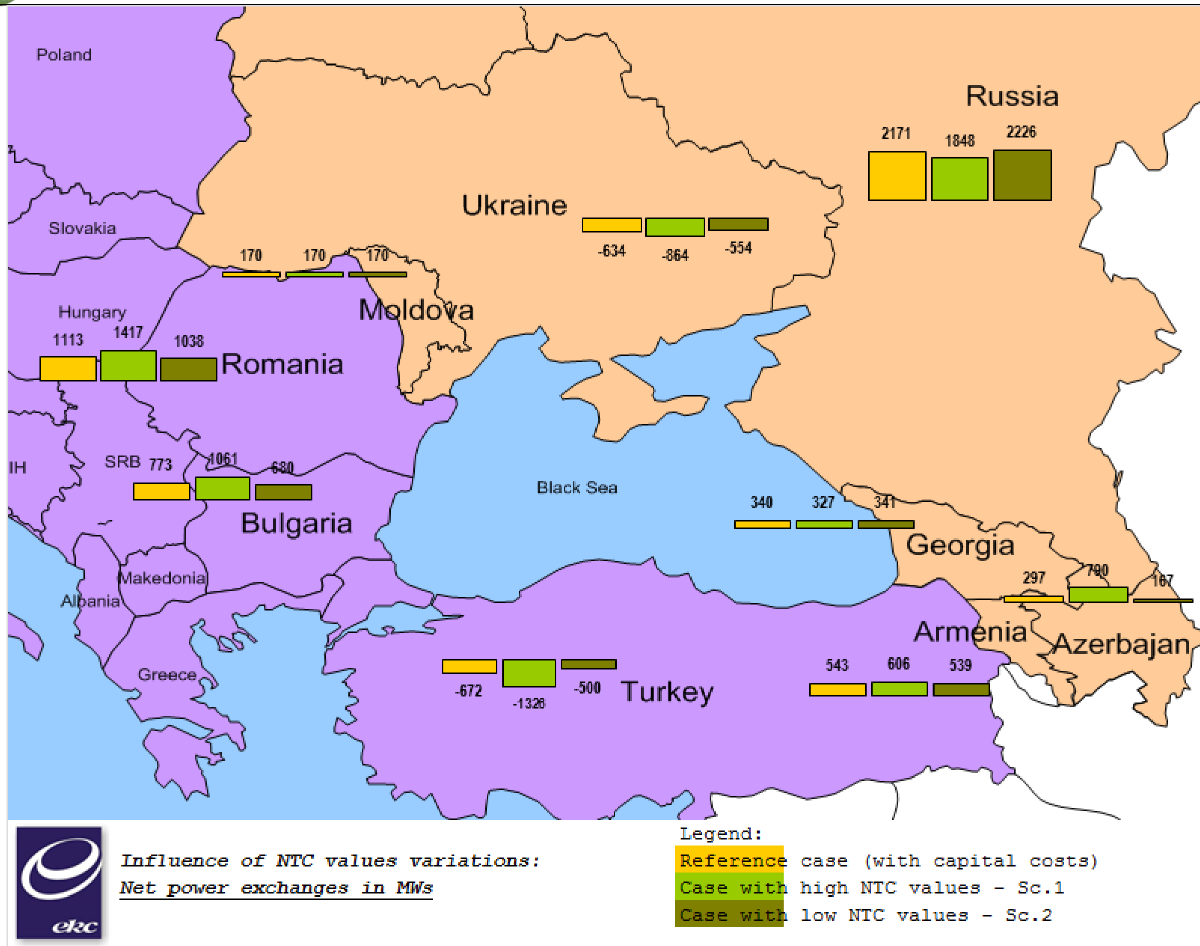
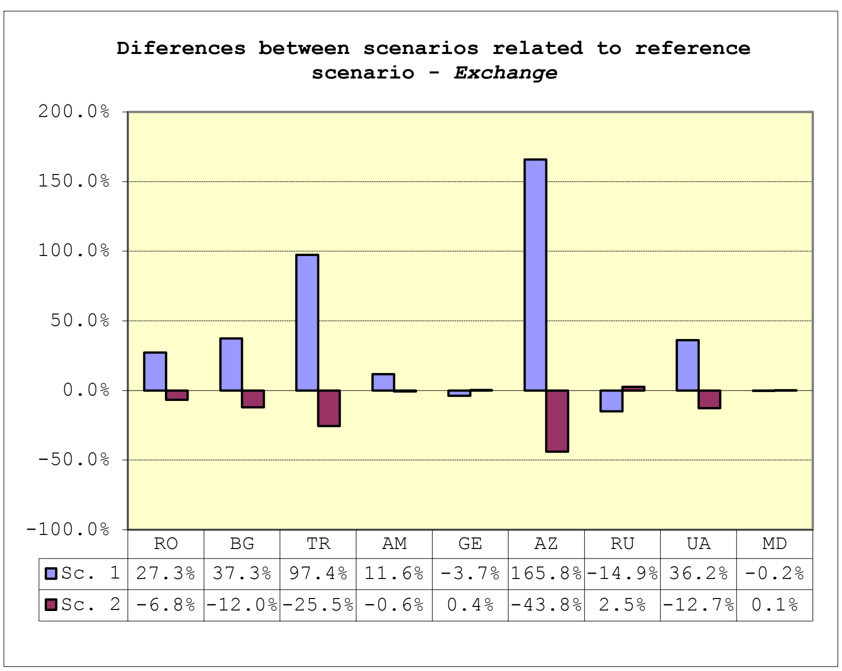


*Figure 3.77 – Black Sea region net power exchange for **winter peak 2015** (Influence of the network reinforcements)*



	RO	BG	TR	AM	GE	AZ	RU	UA	MD
Sc. 1	27.3%	37.3%	97.4%	11.6%	-3.7%	165.8%	-14.9%	36.2%	-0.2%
Sc. 2	-6.8%	-12.0%	-25.5%	-0.6%	0.4%	-43.8%	2.5%	-12.7%	0.1%

*Figure 3.78 – EXC differences between scenarios related to reference scenario for **winter peak 2015** (Influence of the network reinforcements)*

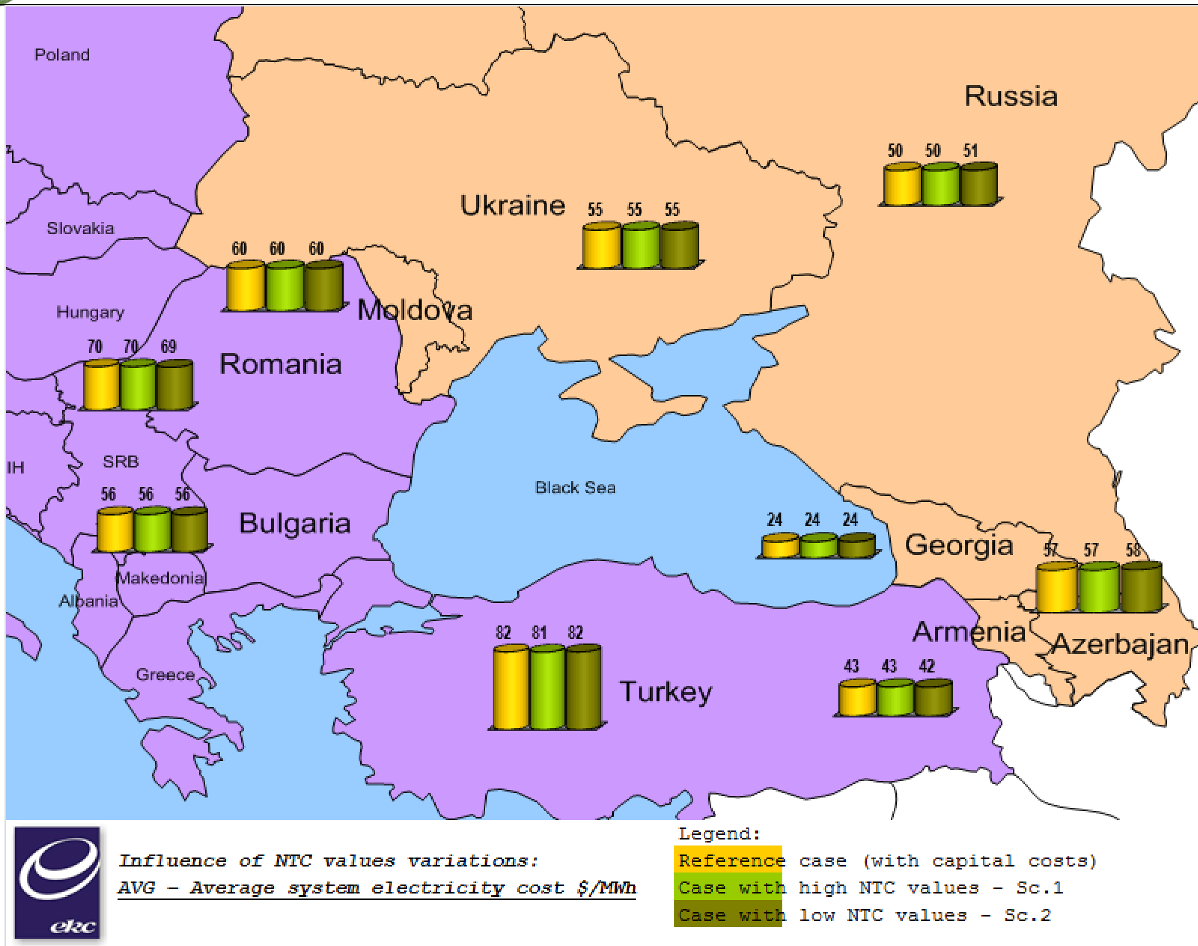
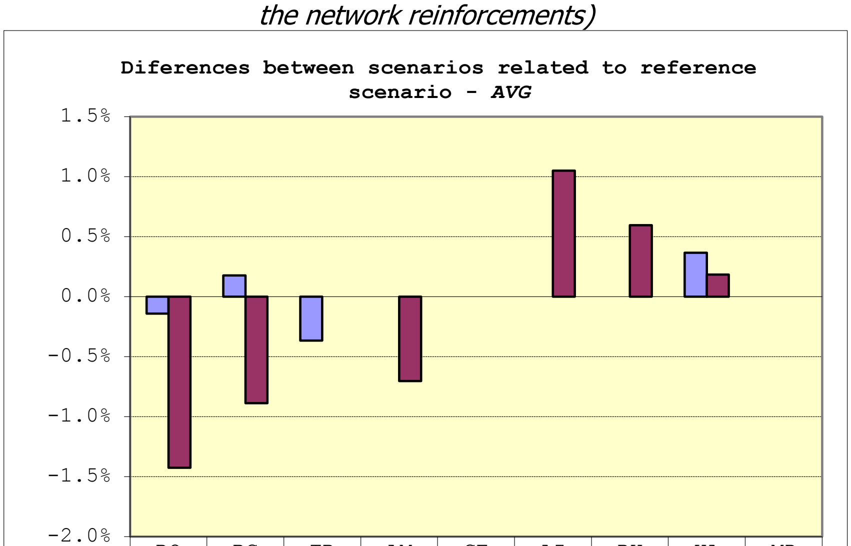


*Figure 3.79 – Black Sea region average system electricity production cost for **summer peak 2015** (Influence of the network reinforcements)*



	RO	BG	TR	AM	GE	AZ	RU	UA	MD
Sc. 1	-0.1%	0.2%	-0.4%	0.0%	0.0%	0.0%	0.0%	0.4%	0.0%
Sc. 2	-1.4%	-0.9%	0.0%	-0.7%	0.0%	1.0%	0.6%	0.2%	0.0%

*Figure 3.80 – AVG differences between scenarios related to reference scenario for **summer peak 2015** (Influence of the network reinforcements)*

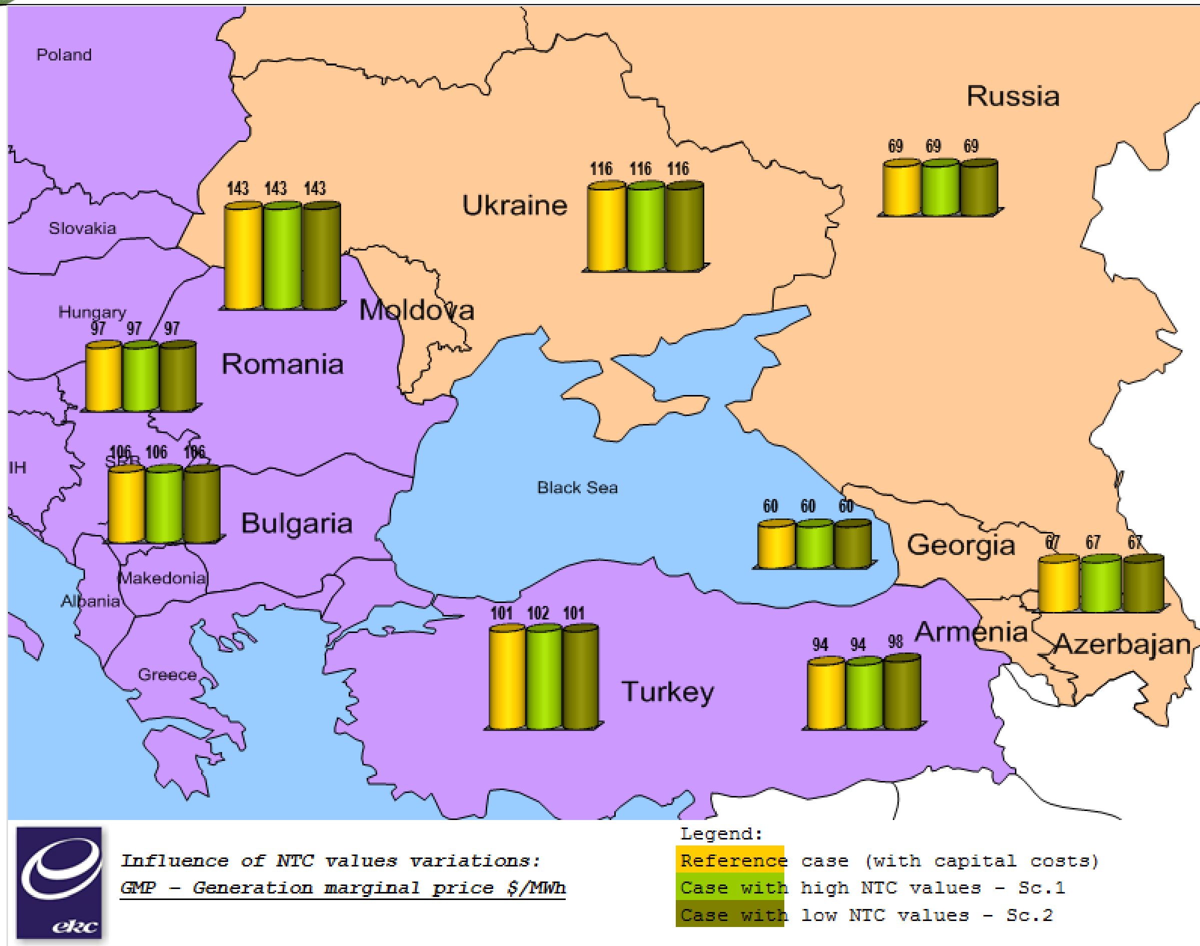
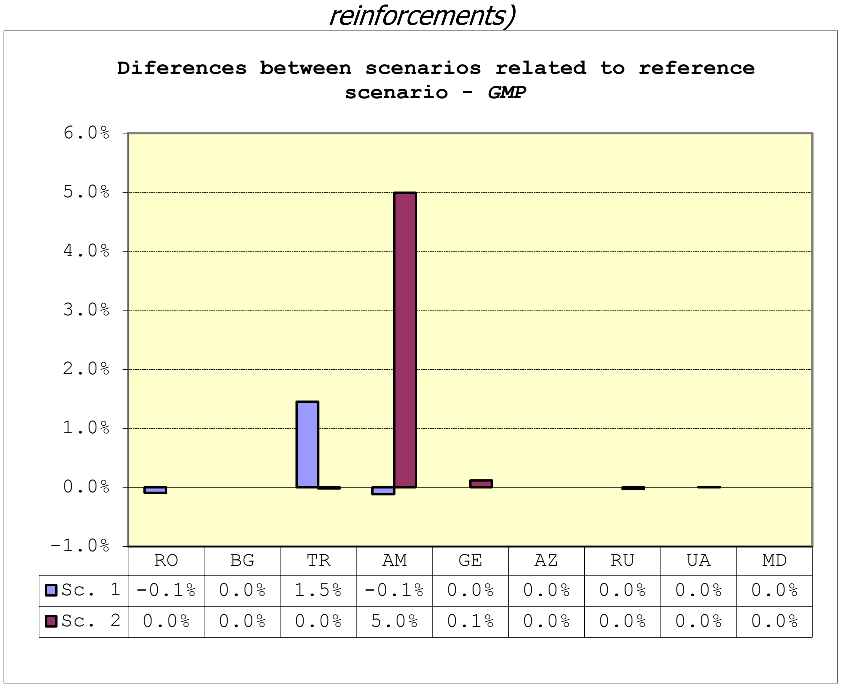


*Figure 3.81 – Black Sea region generation marginal price for **summer peak 2015** (Influence of the network reinforcements)*



	RO	BG	TR	AM	GE	AZ	RU	UA	MD
Sc. 1	-0.1%	0.0%	1.5%	-0.1%	0.0%	0.0%	0.0%	0.0%	0.0%
Sc. 2	0.0%	0.0%	0.0%	5.0%	0.1%	0.0%	0.0%	0.0%	0.0%

*Figure 3.82 – GMP differences between scenarios related to reference scenario for **summer peak 2015** (Influence of the network reinforcements)*

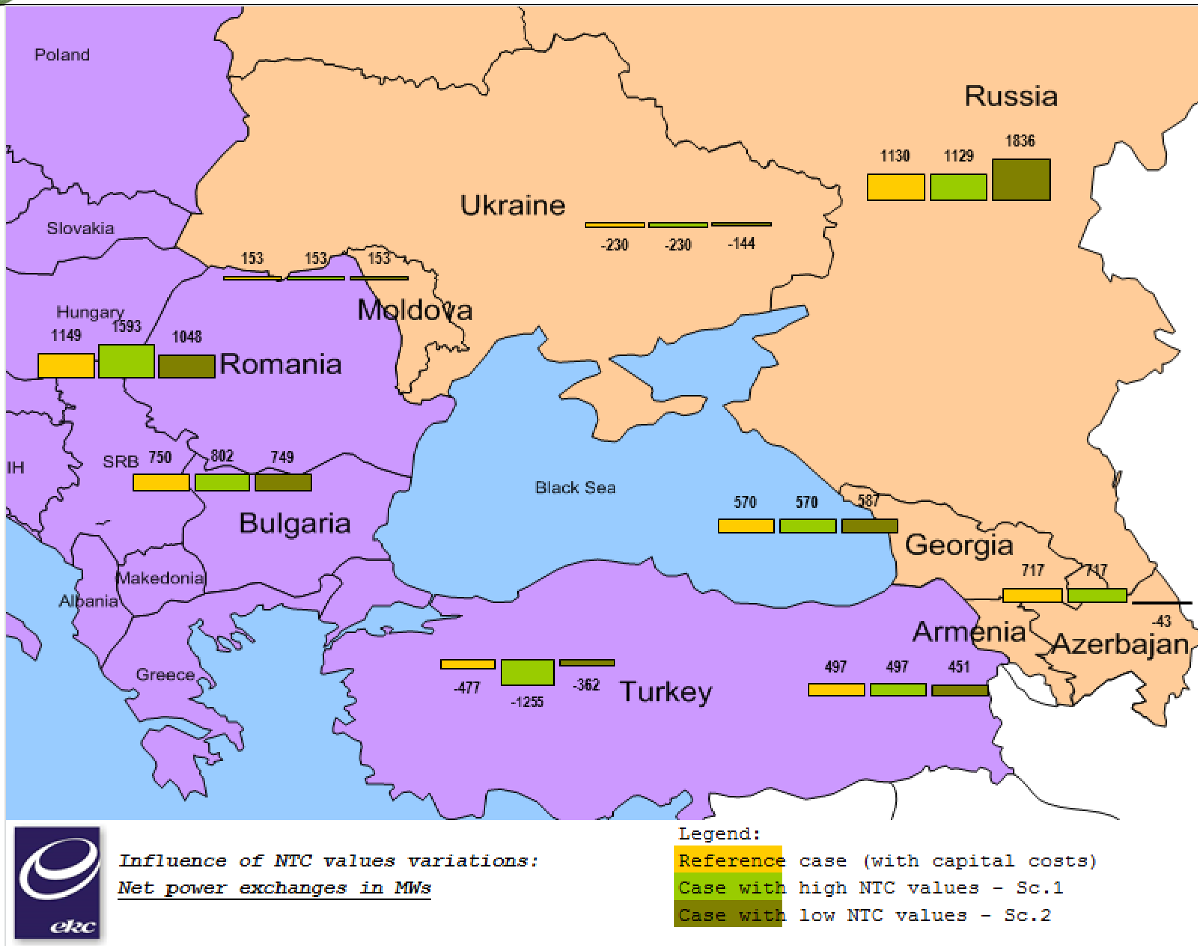
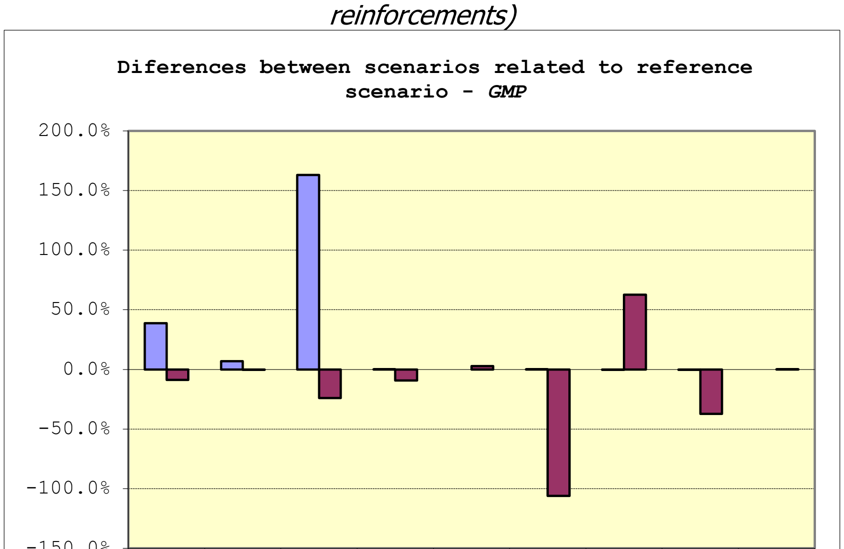


*Figure 3.83 – Black Sea region net power exchange for **summer peak 2015** (Influence of the network reinforcements)*



	RO	BG	TR	AM	GE	AZ	RU	UA	MD
Sc. 1	38.6%	7.0%	163.2%	0.1%	0.0%	0.0%	-0.1%	-0.2%	0.0%
Sc. 2	-8.8%	-0.1%	-24.0%	-9.2%	2.9%	-106.0	62.5%	-37.4%	0.1%

*Figure 3.84 – EXC differences between scenarios related to reference scenario for **summer peak 2015** (Influence of the network reinforcements)*

4 CONCLUSIONS

With the aim to assess the influence of the most important global and local factors (such as fuel prices, CO_2 emission costs, capital costs, different hydrological conditions and RES engagements as well as network reinforcement evolution) sensitivity analyses for winter and summer peak scenarios in 2015 have been carried out. The market behavior for each specified scenario within defined sensitivity analyses is presented. This is accomplished using the following parameters as the most significant indicators:

AVG – average system electricity cost in $/MWh
GMP – Generation marginal price in $/MWh
EXC – Net power exchanges in MW.

The applied approach and important assumptions that influenced the study results are summarized as follows:

- PSS-E/OPF model developed during the previous study is used as the basic tool, updated according to the collected questionnaires provided by TSOs.
- Split constrained models of Black Sea region were used within the conducted analyses, meaning that ENTSO-E and IPS/UPS zones were analyzed separately taking into account grid limitations given through the NTC values for each border across the region.
- RES and HPPs were treated as must run units and dispatched first, disregarding production prices and merit order.
- Base Case for all sensitivity analyses was defined according to the following assumptions:
    - Starting values for fuel prices according to questionnaire
    - CO_2 emission cost was set on 12 $/ton CO_2 for each country
    - Capital costs are included
    - Average hydrology conditions
    - Average RES engagement
    - Without new transmission network reinforcements added to official BSTP models
    - With base NTC's values from previous study
    - There are no exchanges between those two synchronous areas (ENTSO-E and IPS/UPS)
- Regarding the sensitivity of these study results due to fuel price variations, the following range of values was applied:
    - Gas/Oil ±20% of Base Case values
    - Lignite/Coal ±10% of Base Case values
    - Uranium ±5% of Base Case values
- Regarding the sensitivity of these study results due to CO_2 emission cost variations, the following range of values was applied:
    - Average value of 12 $/MWh
    - Extreme value of 50 $/MWh
    - No charge for CO_2 (underdeveloped market in that sense)
- Regarding the sensitivity of these study results due to how capital costs are included in the study:
    - Case with capital costs – in Base Case CAPEX was 100% for new power plants, 45% for reconstructed both, TPPs and NPPs, as well as 30% for reconstructed HPPs. CAPEX was 0% for power plants that reached their full life time period or more

  - Case without capital costs - Short run marginal cost scenario where CAPEX for all power plants is 0% of their capital costs.
- Regarding the sensitivity of these study results due to different hydrological regimes:
  - Average year – according to average engagement of HPPs defined in BSTP models
  - Wet year – increase of HPP's production by 20% with appropriate correction of national power system balance
  - Dry year – decrease of HPP's production by 20% with appropriate correction of national power system balance
- Regarding the sensitivity of these study results due to different RES engagement assumptions:
  - Average – according to average engagement of RES defined in BSTP models
  - High RES penetration – increase of RES production by 20% with appropriate correction of national power system balance
  - Low RES penetration – decrease of RES production by 20% with appropriate correction of national power system balance
- Regarding the sensitivity of these study results due to the network reinforcement (NTC) assumptions:
  - Base Case – according to NTC's values from previous study
  - Increasing of NTCs – increase of NTC values by 500 MW on the each border (it represents the influence of the new additional interconnection projects)
  - Decreasing of NTCs – decrease of NTC values by 20% on the each border (it represents the influence of the delay of some projects defined in BSTP models)

The analyses gave the results in wide range, showing stronger influence of some factors comparing to others on the market behavior of the Black Sea region in 2015 winter peak and summer peak scenarios:

- Base case models with above mentioned assumptions are formed as upgrade of models from previous study according to new data from Questionnaires provided by TSOs.
- Deviation of base case from reference case in previous study is less than 10% and in expected limits, due to new data and changes made according to Questionnaires.
- The largest influence on the average system electricity cost (AVG) is calculated to be in fuel price variations, capital cost assumptions and high CO_2 emission cost scenarios.
- Gas fired power plants are dominantly present as marginal units, setting the GMP value across the Black Sea region in most scenarios with exception of high CO_2 emission cost. This is consequence of higher production cost penalization of coal fired power plants compared to gas fired power plants.
- Only a small influence of different hydrology conditions and RES engagements is observed on production cost due to their modest share in overall production mix, except in case of Georgia.
- The greatest impact on net power exchanges is identified in the analyses concerning the influence of the network reinforcements, due to the variation of transfer capacities.
- Power exchange between Russia and Ukraine is most sensitive to variations of all indicators used in sensitivity analyses.
- In Caucasus region, power systems of Azerbaijan and Armenia with dominantly thermal production based on fossil fuel are highly sensitive to fuel price variations and CO_2 emission cost variations. In the case of Georgia, as predominantly hydropower system, hydrological conditions have most influence on production costs.
- For Moldova, because of the structure of its power production system, CO_2 emission cost is calculated to be the most sensitive variable.
- For Romania, as the country with largest share of RES production in the Black Sea region and great hydro potential, scenarios with increase of RES engagement will benefit Romania position on the market and increase of export to the southeast.

- Exchange on border of Turkey and Bulgaria is very sensitive to variations of NTC values, due to Turkey being import-dependent country and this border being congested in base case.
- In case of higher plants rehabilitation investments in Russia, looking in short term horizon, electricity cost in Russia will increase and export from Russia will decrease. However, looking in long term perspective, the electricity market of Black Sea region would benefit from these new investments which would extend the life cycle of plants in Russia and therefore prevent possible shortages of energy and ensure a competitive market.

Generally, variations of all sensitivity factors are in reasonable limits which makes our base case model a good planning foundation for the Black Sea region.
These sensitivity analyses show that fuel price variations have most significant impact on market behavior suggesting that special attention in transmission planning process and market analysis should be paid to fuel price values assumptions and available pricing data.
Also, in order to accurately evaluate market behavior, it is important to correctly calculate and define NTC values on each border across the region.

For further investigation of this subject, as a follow up it is proposed:

- The provided analyses are performed with available limited data sets especially in terms of market fuel prices in Black Sea region countries, in sense of prices at a define time. In other words it is very important for planning practice to have coincident starting fuel price values and the same fuel price forecast methodology.
- Permanent update of NTC values as network constraints is very important in planning process in order to give more realistic picture of power system model regarding each kind of market analyses.
- In addition, the conducted analyses are done only for two typical hours (winter and summer peak). A full Black Sea market analysis on the basis of typical weeks with modeling the interdependence among the hourly regimes is proposed. Such an analysis would provide more in-depth insight in the potentials and economic indicators of behavior in the electricity markets across the region.
- Taking into account above mentioned necessary PSS-E/OPF model improvements, further development has to be directed to resolving of appropriate modeling of:
    - different hydrology conditions adequately considering hydro power plant accumulation as well as the influence of pump storages
    - influence of availability of the plants (forced and maintenance outage rates (FOR and MOR)) for thermal power plant units
    - different number of different time series (several time series for only one year) for RES whereby demand side management (DSM) would be considered in parallel
- All of above mentioned implies further careful development of appropriate planning models that can cover most of these issues.
- For all of this sensitivity analyses, the cost curve toolbox was developed. Detailed explanation and its importance is described in appropriate chapter. Using this tool and knowledge from this study, one of the very important further steps should be constant improvement of PSS-E/OPF planning models and their permanent updating.

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ANNEXES

Table 0.1 – Electricity production costs by source

	CAPACITY	HEAT RATE	EFF	UTIL	LIFE	ENERGY	OVER NIGHT	CAPITAL	O&M			OVER HEAD	DECOMMISSION	TRANSMISSION	CO2 EMIS.	LEVELIZED COST	PRODUCTION COST
									FIXED	VARIABLE	FUEL						
TYPE	MW	mBTU/MWh	%	%	year	GWh	Ml$/MW	$/MWh	$/MWh	$/MWh	$/MWh	$/MWh	$/MWh	$/MWh	$/MWh	$/MWh	$/MWh
1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18
CONVENTIONAL																	
NUCLEAR	1000	10.4	40	90	40	7884.0	2.75	40.40	12.00	8.24	7.49	4.00	7.80	3.00	0.00	75.44	32.04
NUCLEAR	500	10.4	40	90	40	3942.0	2.75	40.40	20.00	8.24	7.49	4.00	5.20	3.00	0.00	80.84	37.44
COAL	1000	8.9	45	85	30	7446.0	1.70	26.40	8.00	39.34	30.26	4.00		3.60	12.00	93.34	63.34
COAL ADV	600	8.9	45	85	30	4467.6	2.00	31.10	11.00	34.80	30.26	3.50		3.60	10.50	94.50	59.80
COAL ADV CCS	1000	8.9	45	85	30	7446.0	2.30	35.80	12.00	36.31	30.26	3.50		3.60	5.00	96.21	56.81
HYDRO DAM	500			50	30	2190.0	2.20	58.20	3.50	7.10				5.70	0.00	74.50	10.60
HYDRO PENSTOCK	150			50	30	657.0	2.00	52.90	3.50	7.10				5.70	0.00	69.20	10.60
HYDRO RUN	150			50	30	657.0	1.20	31.70	3.10	7.10				5.70	0.00	47.60	10.20
GAS CCGT	786	7	58	85	25	5852.6	0.90	14.00	5.04	51.23	48.79	2.70		3.60	5.40	81.97	64.37
GAS CCGT NEW	786	6.75	58	85	25	5852.6	0.95	14.80	4.70	49.40	47.05	2.70		3.60	5.40	80.60	62.20
GAS CONV	160	10.8	40	85	25	1191.4	0.60	9.30	6.85	79.04	75.28	1.50		3.60	8.10	108.39	95.49
GAS CONV CHP	500	10.8	40	85	25	3723.0	0.93	14.50	5.51	79.04	75.28	1.50		3.60	8.10	112.25	94.15
GAS CONV CHP	50	10.8	40	85	25	372.3	1.20	18.70	7.25	79.04	75.28	1.50		3.60	8.10	118.19	95.89
GAS CONV CHP	10	10.8	40	85	25	74.5	1.25	19.40	8.33	79.04	75.28	1.50		3.60	8.10	119.97	96.97
RENEWABLES																	
SOLAR PV	5		45	21.7	20	9.5	6.00	365.50	6.40					13.00		384.90	6.40
SOLAR TH	100		45	31.2	20	273.3	5.00	211.90	21.80					10.40		244.10	21.80
GEOTHERMAL	50	34.6		85	30	372.3	1.70	26.40	22.90			3.50		4.80		57.60	26.40
BIOMASS	10	9.6		85	30	74.5	2.76	42.90	19.00	12.60		29.40		3.80		107.70	61.00
SMALL HYD. BASE	2	9.05		65	30	11.4	1.40	28.50	2.80	7.10				6.00		44.40	9.90
SMALL HYD. PEAK	1	10.07		65	30	5.7	1.65	33.60	2.80	7.10				6.00		49.50	9.90
WIND	50			30	20	131.4	2.00	75.50	11.70			6.10		8.40		101.70	17.80
WIND OFFSHORE	100			35	20	306.6	2.40	79.30	24.40			5.70		9.00		118.40	30.10

1 - Type of power plant
2 - Capacity
3 - Heat rate (nominal)
4 - Efficiency
5 - Utilization
6 - Life time
7 - Yearly Energy production
8 - Overnight costs
9 - Capital costs (20year loan, 10% discount rate)
10 - Fixed O&M costs
11 - Variable O&M costs (includes fuel costs)
12 - Fuel costs
13 - Overhead costs
14 - Decommissioning
15 - Transmission costs
16 - CO_2 emissions (rate 20$/ton CO_2)
17 - Levelized costs = 9+10+11+13+14+15+16
18 - Production costs (related only to production) =10+11+13+14+16

Table 0.2 – Questionnaire structure, National data – part I

Data preparation and questionnaire structure - Plant identification and age data

Plant type and fuel

Power plant	Plant type	Fuel	Commissioning Year	Reconstruction Year	Decommissioning Year	Hydro - RoR or RES	Turbine	Heat rate (mBTU/MWh)	Bus Num	Bus Name	Id
Moldovska GRES	TPP	Coal					Steam	10.8	630102	5MGREST2	C
	TPP	Coal					Steam	10.8	630103	5MGREST3	C
	TPP	Coal					Steam	10.8	630104	5MGREST4	C
	TPP	Coal					Steam	10.8	630105	5MGREST5	C
	TPP	Coal					Steam	10.8	630106	5MGREST6	C
	TPP	Coal					Steam	10.8	630107	5MGREST7	C
	TPP	Gas					Steam	10.8	630108	5MGREST8	G
	TPP	Gas					Steam	10.8	630109	5MGREST9	G
	TPP	Gas					Steam	10.8	630111	5MGRESTA	G
	TPP	Gas					Steam	10.8	630140	5MGRESTB	G
	TPP	Gas					Steam	10.8	630141	5MGRESTC	G
	TPP	Coal					Steam	10.8	630150	5MGREST1	C
	CHP	Gas					Steam	10.8	630197	5MGRE3G2	GH
Kishinev CHP	CHP	Gas					Steam	10.8	638001	5KSPP2G1	GH
	CHP	Gas					Steam	10.8	638002	5KSPP2G2	GH
	CHP	Gas					Steam	10.8	638003	5KSPP2G3	GH
Wind Power	WPP	Wind							638045	5PAHOAW	W
	WPP	Wind							638046	5KALARW	W
	WPP	Wind							638047	5NISPOW	W
	WPP	Wind							638048	5BOLDUW	W
	WPP	Wind							638049	5SIPOTW	W
	WPP	Wind							638050	5KARPIW	W

Age data

Plant identification data

Table 0.3 – Questionnaire structure, National data – part II

Data preparation and questionnaire structure - operating characteristic data

Mbase (MVA)	Pmax (MW)	Pmin (MW)	Nominal cost ($/MWh)	Curve	Average annual production (GWh)	O&M (fixed) costs ($/MWh)	Capital costs ($/MWh)	Variable costs ($/MWh)
235.3	200	100	49.2	6301		8	26.4	9.08
235.3	200	100	49.2	6301		8	26.4	9.08
235.3	200	100	49.2	6301		8	26.4	9.08
235.3	200	100	49.2	6301		8	26.4	9.08
235.3	200	100	49.2	6301		8	26.4	9.08
235.3	200	100	49.2	6301		8	26.4	9.08
247	210	100	75.42	6301		6.85	9.3	3.76
247	210	100	75.42	6301		6.85	9.3	3.76
247	210	100	75.42	6301		6.85	9.3	3.76
247	210	100	75.42	6301		6.85	9.3	3.76
247	210	100	75.42	6301		6.85	9.3	3.76
235.3	200	100	49.2	6301		8	26.4	9.08
75	60	12	75.42	6304		6.85	9.3	3.76
125	100	25	75.42	6303		6.85	9.3	3.76
125	100	25	75.42	6303		6.85	9.3	3.76
125	100	25	75.42	6303		6.85	9.3	3.76
88.5	84	0	8.88	6386		11.7	75.5	0
34.2	32.5	0	8.88	6386		11.7	75.5	0
36.8	35	0	8.88	6386		11.7	75.5	0
36.8	35	0	8.88	6386		11.7	75.5	0
39.5	37.5	0	8.88	6386		11.7	75.5	0
44.2	42	0	8.88	6386		11.7	75.5	0

Operating data

Specific cost data

Table 0.4 – Generic data for investment costs, payback life of plants and full load hours

Type 1 - 300 MW	coal
utilization [%]	0.85
capital cost [mil.$/MW]	1.95
cf(O&M) [$/MWh]	12
variable o&m [$/MWh]	9.1
fuel consumption [mBtu/MW]	9
carbon [tonCO2/MWh]	1
life year	30

Type 6 - 300 MW CCGT	gas
utilization [%]	0.85
capital cost [mil.$/MW]	1.5
cf(O&M) [$/MWh]	4.7
variable o&m [$/MWh]	2.35
fuel consumption [mBtu/MW]	6.75
carbon [tonCO2/MWh]	0.3
life year	25

Type 2 - 1000 MW	coal
utilization [%]	0.85
capital cost [mil.$/MW]	1.95
cf(O&M) [$/MWh]	8
variable o&m [$/MWh]	9.1
fuel consumption [mBtu/MW]	8.9
carbon [tonCO2/MWh]	1
life year	30

Type 7 - 300 MW CHP	gas
utilization [%]	0.85
capital cost [mil.$/MW]	1.2
cf(O&M) [$/MWh]	5.8
variable o&m [$/MWh]	3.76
fuel consumption [mBtu/MW]	10.4
carbon [tonCO2/MWh]	0.3
life year	25

Type 3 - 300 MW OCGT	gas
utilization [%]	0.85
capital cost [mil.$/MW]	0.8
cf(O&M) [$/MWh]	6.5
variable o&m [$/MWh]	3.76
fuel consumption [mBtu/MW]	10.4
carbon [tonCO2/MWh]	0.3
life year	25

Type 8 - 500 MW Fransis	hydro
utilization [%]	0.5
capital cost [mil.$/MW]	2.3
cf(O&M) [$/MWh]	3.7
variable o&m [$/MWh]	7.2
life year	30

Type 4 - 500MW	nuclear
utilization [%]	0.9
capital cost [mil.$/MW]	3.3
cf(O&M) [$/MWh]	20
variable o&m [$/MWh]	9
fuel consumption [mBtu/MW]	10.4
carbon [tonCO2/MWh]	0
life year	40

Type 9 - 150 MW Caplan	hydro
utilization [%]	0.5
capital cost [mil.$/MW]	1.25
cf(O&M) [$/MWh]	3.7
variable o&m [$/MWh]	7.2
life year	30

Type 5 - 1000MW	nuclear
utilization [%]	0.9
capital cost [mil.$/MW]	3.3
cf(O&M) [$/MWh]	12
variable o&m [$/MWh]	12
fuel consumption [mBtu/MW]	10.4
carbon [tonCO2/MWh]	0
life year	40

Type 10 - 150 MW Pelton	hydro
utilization [%]	0.5
capital cost [mil.$/MW]	2.1
cf(O&M) [$/MWh]	6
variable o&m [$/MWh]	7.2
life year	30