Azerbaijan-Georgia-Turkey (AGT) Power Bridge Project: BUSINESS PROCESS MANUAL FOR MONTHLY NETWORK MODELLING AND NTC CALCULATION

Energy Technology and Governance Program:
Cooperative Agreement: AID-OAA-A-12-00036

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Energy Technology and Governance Program

Azerbaijan-Georgia-Turkey (AGT) Power Bridge Project

DRAFT BUSINESS PROCESS MANUAL FOR MONTHLY NETWORK MODELLING AND NTC CALCULATION

Prepared for:

United States Agency for International Development and United States Energy Association

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ABBREVIATIONS

ATC	Available Transfer Capacity
AZ	Azerbaijan
BCE	Base Case Exchange
BPM	Business Process Manual
C.E.	Continental Europe (synchronous area, formerly UCTE)
EC	European Commission
EHV	Extra High Voltage
ENTSO-e	European Network of Transmission System Operators for Electricity
EU	European Union
GW/GWh	Gigawatt / Gigawatt-hour
GE	Georgia
GSE	Georgian TSO
HV	High voltage
IPS/UPS	Interconnection of Russia / former USSR
kV	Kilovolt
MVA	MegaVoltAmper
MW/MWh	Megawatt /Mewgawatt-hour
NTC	Net Transfer Capacity
OHL	Over-head lines
PP	Power plant
SS	Substation
Tr	Transformer
TR	Turkey
TRM	Transmission Reliability Margin
TTC	Total Transfer Capacity
TEIAS	Turkish TSO
TSO	Transmission System Operator

1. INTRODUCTION

This document Business Process manual (BPM) describes the procedures for exchanging data and producing the common grid models (CGM) for monthly level in the scope of AGT project, and the procedures of transmission network Net Transfer Capacity (NTC) calculation and harmonization between participating TSOs from Azerbaijan, Georgia, Turkey (AGT region, see Figure 1).

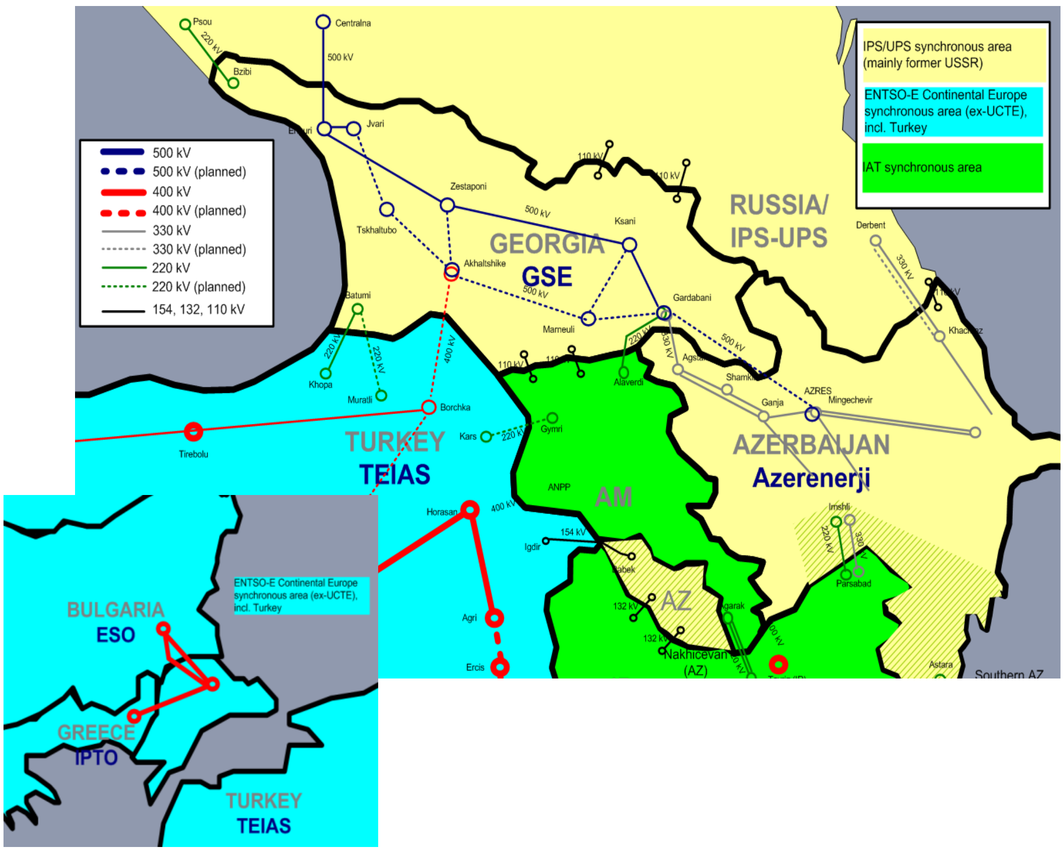

Figure 1. AGT region.

The BPM will harmonize the following procedures among the TSOs:

- Processes and timeframes for exchanging data and exchanging and merging models, needed by each party to calculate and verify NTCs in both bilateral and composite manner.
- Technical assumptions to be adopted in load flow and dynamic models to be used in the calculation of the NTCs.
- Time intervals upon which NTCs will be calculated.
- Process by which NTCs are agreed to by each TSO and how NTCs are adopted when calculations of the TSOs differ.

This BPM will constantly be revised during the AGP Project Phase 3 until it covers all aspects of data exchanging and merging procedures in the scope of NTC calculations for the AGT countries.

2. DATA EXCHANGE AND MERGING

The Common Grid Model of Azerbaijan, Georgia, Turkey and relevant neighboring countries equivalents is produced during an exchange and merging procedure.

1.1 Main Terms

Data format and software:

Network models will be exchanged in the latest commonly agreed version of PSS/E format (initial format version is PSS/E V33.3.0), which includes:

- data for load flow (RAW file or SAV file format) and
- dynamic data (DYR file format)
- it is recommended also to provide the corresponding Single Line Diagram file (sld format)

In future, any other software and data format can be agreed among the AGT TSOs, if appears as needed.

Exchange procedure:

- All data related to the common network model of the AGT region has to be sent by e-mail or via common web-based data exchange platform.
- The data are provided to all parties in TSOs of Azerbaijan, Georgia and Turkey on the basis of reciprocity and confidentiality.
- List of corresponding persons needs to be agreed among the TSOs.

CGM-coordinator:

The function of CGM-coordinator for monthly common grid model is to perform validation of received data and merging of national models into a regional monthly model, suitable for TTC/NTC calculations, including load flow and dynamic stability checking.

All organizational activities regarding common grid monthly model should be performed by CGM-coordinator. The function of CGM-coordinator may have:

- Participating TSOs on the rotational principle (Participating TSOs should agree on time-schedule of providing the role of CGM-coordinator among them), or
- One participating TSO on behalf of all, for a longer time period
- External model processing partly, if defined so by the AGT TSOs

1.2 National network models

- The national model representative for the monthly calculation in month M is 3rd Wednesday in month M, morning “characteristic” hour.
- Timing should be universal, i.e. all models from AGT TSOs should correspond to the same moment, regardless of the time zone.

E.g. if there is 1-hour time difference, TEIAS provides model for 10:30h local TR time, which corresponds to the GSE and Azerenerji models for 11:30h local GE and AZ time.

- In future, AZ, GE AND TR will analyze the followings to define the best simultaneous representative hours, suitable for all:
    - Time zone differences (make table), and
    - Historical hourly load curves, (TSOs should send the hourly data of own load)
- Any other representative model can be additionally provided and used, if appeared as necessary and agreed among the AGT TSOs.
- All TSOs should send representative model of their power system. "Representative" means that the model has to reflect all necessary technical characteristics of the relevant real power system.
- National network models represents internal EHV grid of the system, at voltage levels 500 kV, 330 kV, 220 kV, 154 kV, and where considered necessary, 110 kV, as well as all tie-lines to the neighboring systems.
- National network models have to:
    - contain the expected network topology (lines, transformers bus-bar coupler statuses...) for the considered time sample.
    - contain the best nodal forecasts of generation and consumption in the considered time sample. Non-modeled lower voltage networks can be modeled as equivalent sources or sinks (fixed injections) in modeled nodes.
    - considering the best forecast of the total country power exchange (export or import), by modeling the expected physical flows at the virtual X-nodes on the tie-lines.
    - Coordinating the expected statuses (on/off) of the tie-lines with neighbors

1.3 X-nodes

Expected physical exchanges with neighbors have to be modeled at the virtual nodes, so-called „X-nodes".

- The X-nodes modeled at the tie-line, with the electrical parameters related to the country border line. Therefore, when merged, two parts of the tie-line (country 1 – to X-node, and X-node – to country 2); again represent the whole physical line.
- TSO define the list of X-nodes, and all the time uses the same names and node numbers for them, in order to enable smooth and accurate merging of national models. List of X-nodes is provided in Table 1 below. All X-nodes have to have unique node numbers and names.
- Expected physical exchanges at the modeled time stamp have to be modeled as positive or negative injections (loads) at the X-nodes.
- TSOs send the models with all the tie lines included, whether these are in operation or not (line always included, and the status on/off to be adjusted according to the expected topology status).
- Harmonization of initial X-node injection values:
    - At the DC connections (such as one Akhaltsikhe), it is mandatory that two „guesses" of an X-node injections are the same in two neighboring models (see Figure 2).
    - At the island AC connections, it is mandatory that two „guesses" of an X-node injections are the same in two neighboring models.

- At the meshed AC connections, it is not mandatory that two "guesses" of an X-node injections are the same in two neighboring models. Real power exchange will anyhow flow naturally over the tie-line after the merging.

- Sum of all X-node injections of one country mandatorily has to correspond to the expected total exchange of a country.
- Recommended tie-lines and x-nodes codes are given in Table 1.

Table 1. Tie-lines and x-nodes

Full name	Areas	Base kV	Bus Number	Bus Name
Agstapha-Gardabani "Gardabani"	AZ-GE	330	62811	XGE_AZ81
Samukh-Gardabani "Mukhrani Velley"	AZ-GE	500	62911	XGE_AZ91
Akhaltsikhe-Borcka	GE-TR	400	62111	XGE_TR11
Babaeski/Hamitabat (TR)-Maritsa (BG) [1]	TR-BG	400	14141	XMI_BA11
Hamitabat (TR)-Maritsa (BG) [2]	TR-BG	400	14142	XMI_HA12
Babaeski (TR)-N.Santa (GR)	TR-GR	400	30121	XNS_BA11
Enguri(GE)-Centralna (RU)	GE-RU	500	62901	XGE_RU91
Derbent(AZ) - (RU) [1]	AZ-RU	330	69801	XRU_AZ81
Derbent(AZ) - (RU) [2]	AZ-RU	330	69802	XRU_AZ82

Comment 1: Each X-node should have unique bus number and bus name!

Comment 2: Name of a node should correspond to the UCTE format also (8 characters, starting with "X"…). 7th character in the node name could correspond to the voltage level, to comply with UCTE format also: ("0" for 750, "1" for 380/400, "2" for 220, "3" for 150, "4" for 120, "5" for 110, "6" for 70, "7" for 27, "8" for 330)

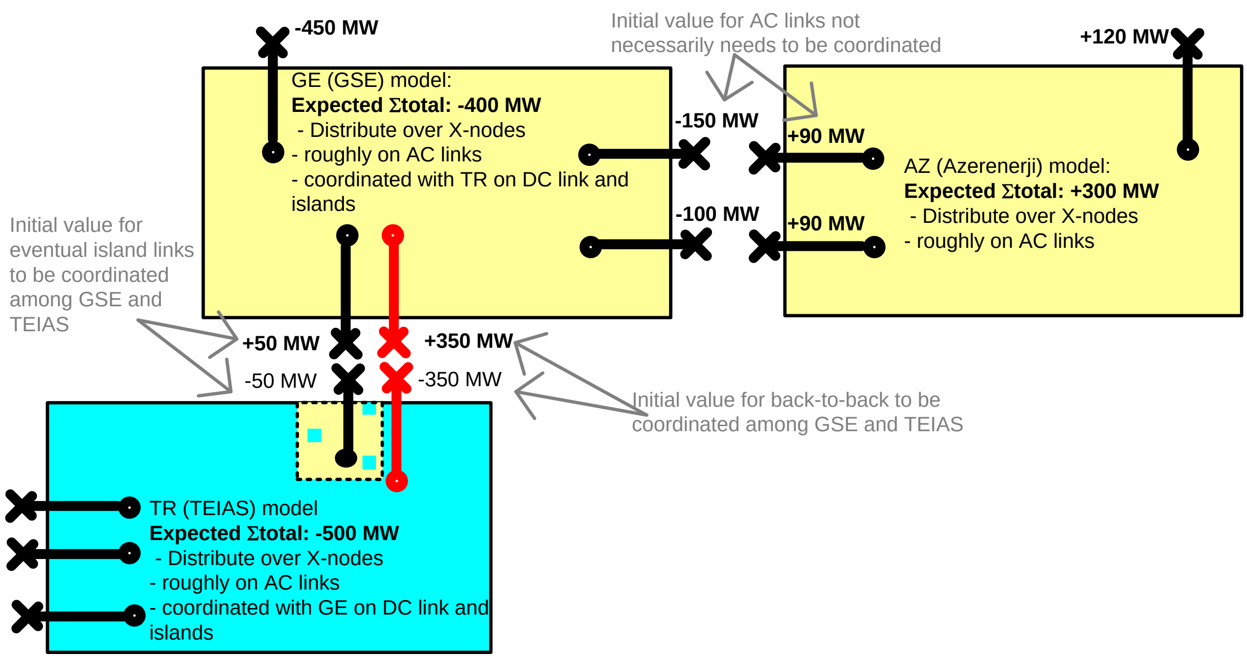

Figure 2. X-node initial injections – example

1.4 Filename structure

The name of the forecast load flow data set file is:

<yyyymmdd>_<HHMM>_FO<w>_<cc><v>.type,

yyyymmdd:	year, month and day of the forecasted time,
HHMM:	hour and minute of the forecasted time,
w:	day of the week, starting with 1 for Monday,
cc:	the country-code (AZ, GE, TR)
v:	version number starting with 0.
type:	File type (RAW, SAV, DYR, SLD)

Example 1: *Turkish Forecast model in RAW format for 17th of January, 10h30, version 0:*
20130117_1030_FO3_TR0.RAW

Example 2: *Azeri Forecast dynamic model for 17th of January, 10h30, version 0:*
20130117_1030_FO3_AZ0.DYR

Node and area naming conventions:

Area and Node numbers to be used, according to the previous practices are given in Table 2.

Table 2. Area and Node numbers to be used.

Country	Bus Code Range	Area/Zone
AZ	90000-99999	9 / 9
GE	20000-29999	2 / 1
TR	540000-549999	6 / 6
ENTSO/E Equivalent	100000-399999	96 / 1403-1404
IPS-UPS Equivalent	700000-799999	97 / 7004
OTHERS	-	* / 11
X - nodes	-	** / 99

Convergence:

TSOs should check and obtain the convergence of their load flow model before sending it with the following load flow solution parameters:

- Solution method – Full Newton-Raphson
- Initial conditions - Flat start
- VAR limits – Apply automatically
- Switched shunt and transformer tap adjustments optionally according to information from TSOs.

Area slack bus engagement:

All TSOs should send the model with area slack bus engagement as it is after running the load flow (load flow file with resulting engagement), i.e. the swing bus engagement have to correspond to the actual balance of the model

(Pslack = Pload – Pexchange – Ploss - Prest.gen).

Engagement of the generator connected to area swing bus must be within specified active/reactive power minimum and maximum limits.

Islands:

Any islands in separate models connected to the x-nodes should be self-balanced, so the original total of the TSO would not be changed after merging.

Example: TR island on 220 kV link with GE has expected load of 50 MW. Then the corresponding X-node in TR model has to have the injection of -50 MW. Also, GSE and TEIAS should coordinate that the same X-node in GE model has injection of 50 MW.

Plant limits:

All TSOs should send models with power plant's active/reactive power production between their specified minimum and maximum limits. These minimum and maximum limits should correspond to the real forecasted possibilities of the generators for the observed reference regime.

Equipment rating:

Rating of network equipment in the model should correspond to thermal limits, current protection settings and allowed voltage limits in normal operation:

- Bus voltage – Voltage limits in normal operation for different voltage levels
- Branches – First step of overcurrent protection or thermal limit in case of no overcurrent protection (I as MVA)
- Transformer – Rated apparent power in MVA

Remedial actions:

Each TSO should send list of eventually existing remedial actions (topology changes, special protection schemes – SPS, interruptible generation or load…) for resolving overloaded elements or voltage violations in the system according to its operational practice.

Limits:

All TSOs should send models without any overloaded branch or out of limit bus voltage.

National Dynamic models:

Initial reference dynamic model should not be updated on the monthly basis. Dynamic data should be exchanged once initially and then TSOs should send only updates after changes such as new generator unit commissioning, regulators replacement, etc.

1.5 External network equivalents

AGT region connects two synchronous zones (see Figure 3):

- Azerbaijan and Georgia are within Russia/IPS-UPS synchronous zone, directly connected to Russia.
- Turkey is within ENTSO-e Continental Europe (C.E.) synchronous zone, directly connected to Bulgaria and Greece.

To properly model the network interactions of modeled and the influence of external systems, it is needed either to model the entire synchronous zones (which is considered not necessary and time and effort-demanding), or to build the proper equivalents of IPS/UPS and ENTSO-e C.E.

- AGT TSOs can agree to jointly develop and update the network equivalents of IPS/UPS and ENTSO-E C.E., or to split the activities (e.g. TEIAS can be responsible for the ENTSO-E equivalent development, and GSE or Azerenerji for IPS/UPS equivalent).
- The formatting and data conventions should be applied for the equivalents, in order to enable smooth and accurate merging process.

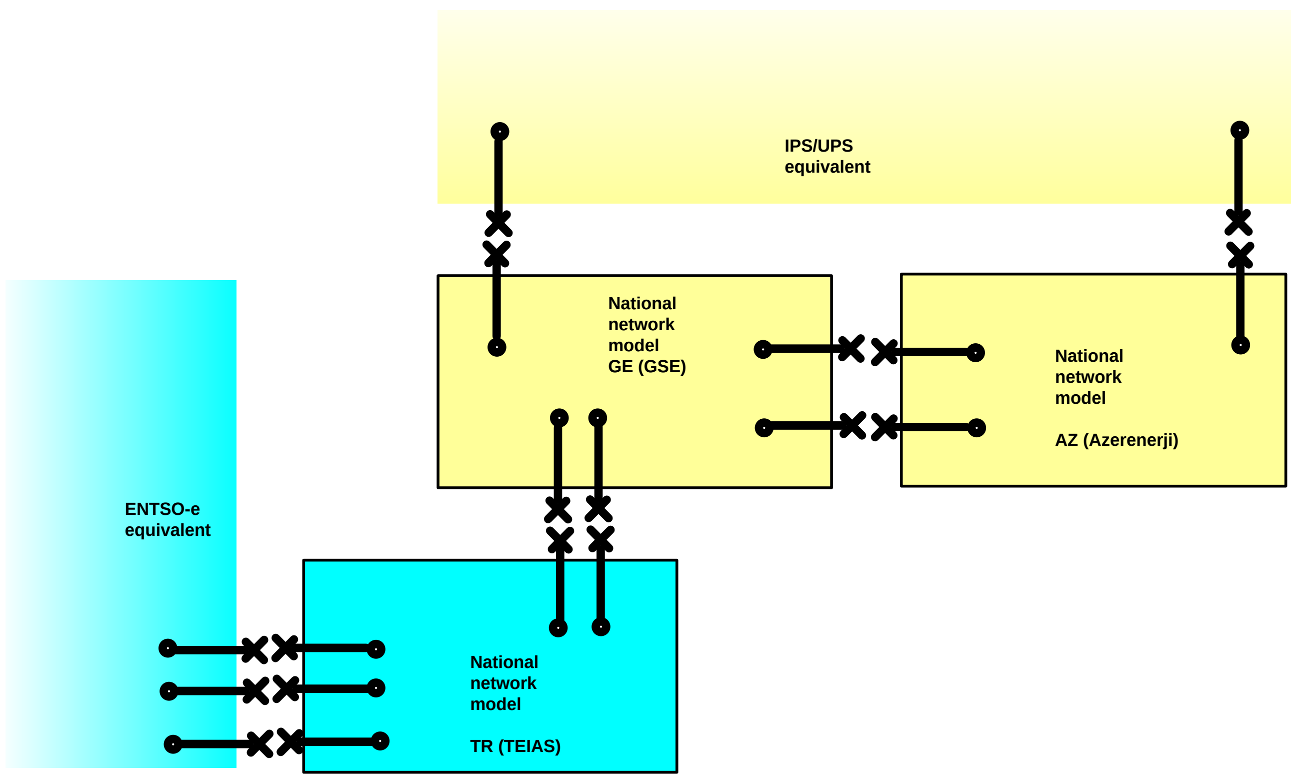

Figure 3. AGT region: National network models and external equivalents.

1.6 Preliminary data harmonization

Before the models provision, AGT TSOs should preliminary coordinate the certain data, in order to properly produce the initial network models.

- Expected statuses of tie-lines (on-off)
  - TEIAS and GSE at common border
  - GSE and Azerenerji at common border
- Expected special network configurations
  - such as forming of islands, statuses of links to Russia, etc.
- Expected initial injections at back-to-back link, or at network islands
  - TEIAS and GSE for Akhaltsikhe back-to-back link
  - TEIAS and GSE for eventual islands on 220 kV link
- Recommended: expected total balances of countries
  - All TSOs: TEIAS, GSE, Azerenerji

In order to simplify this preliminary data harmonization phase, TSOs can agree on some default rules, to be applied automatically, e.g.:

- For Akhaltsikhe – Borchka link, initial value of e.g. 350 MW can be fixed, for national network models of GSE and TEIAS (this value would later be shifted upwards, within the NTC calculated).
- For the islands, one TSO (e.g. TEIAS) provides the expected size of island, and informs the other one (GSE).

The proposed form for preliminary data harmonization is given in Figure 4.

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Form for **Preliminary Data Harmonization**

FIELDS TO BE FILLED BY:	AZ	GE	TR	W

General information:

Data exchange for:	2013	April			
		Date	Local time		
			AZ	GE	TR
Representative model:		2013-04-17	11:30	11:30	10:30
			AZ	GE	TR
Data format:		PSS/E	v33.3.0	v33.3.0	v33.3.0
area / зона:			9	2	6
nodes/узлы:			90000 - 99999	20000 - 29999	540000 - 549999

Supplied Data:

	AZ	GE	TR
Load Flow Model	✓	✓	✓
Dynamic Model	✗	✗	✓
Visualization Info (sld file/geographic info)	✓	✓	✓
Generation Shift Info	✗	✗	✗
Remedial Actions List	✗	✗	✗

Line information:

Полное название	Базовая kV	Номер шины	Название шины	ON/OFF		
Full name	Base kV	Bus Number	Bus Name	AZ	GE	TR
Agstapha-Gardabani "Gardabani"	330	62811	XGE_AZ81	On	On	
Samukh-Gardabani "Mukhrani Velley"	500	62911	XGE_AZ91	Off	Off	
Akhaltsikhe-Borcka	400	62111	XGE_TR11		On	On
Batumi-Hopa "Adjara"	220	62211	XGE_TR21		Off	Off
Hamitabat (TR)-Maritsa (BG) [1]	400	14141	XMI_HA11			On
Hamitabat (TR)-Maritsa (BG) [2]	400	14142	XMI_HA12			On
Babaeski (TR)-N.Santa (GR)	400	30121	XNS_BA11			On
Enguri(GE)-Centralna (RU)	500	62901	XGE_RU91		Off	
Derbent(AZ) - (RU) 1	330	69801	XRU_AZ81	On		
Derbent(AZ) - (RU) 2	330	69802	XRU_AZ82	Off		

Expected Power Exchange information:

(+ export, - import)	Total AGT:	AZ	GE	TR	ENTSO/E	IPS-UPS
AZ/IPS-UPS (330 kV)		3.6			-	-3.6
AZ/GE (500+330 kV)		90	-90		-	-
GE/IPS-UPS (500 kV)			0		-	0
TR/GE: back-to-back			200	-200	-	-
TR/GE: 220			0	0	-	-
TR/ENTSO-e				-120	120	0
Expected total exchange:	-116.4	93.6	110	-320	120	-3.6

Comments:

AZ	GE	TR

Figure 4. Proposed Form for Preliminary Data Harmonization

1.7 Data validation

LF models:

Before merging, CGM-coordinator has to perform the following checks in order to guarantee a high level of data quality for the initial reference and monthly merged model:

- Errors of file naming and inconsistencies between naming and content
- Conventions on area and node naming and numbering
- Conventions on X-nodes completeness, naming, statuses and numbering
- SAV or RAW format errors – In the process of reading RAW file PSS/E will perform basic format checks upon the related network model.
- Non-convergence of load-flow calculation (single national network model files). A load-flow calculation is defined non-convergent if the total active and reactive power mismatch per node exceeds a defined threshold value, e.g. 0,01 MW (convergence criterion). CGM coordinator will perform convergence checking with the following load flow solution parameters:
    - Solution method – Full Newton-Raphson
    - Initial conditions - Flat start
    - VAR limits – Apply automatically
    - Switched shunt and transformer tap adjustments optionally according to information from TSOs
- Incompliance between the control area balance, X-node initial injections at the DC or island links, and the corresponding values from the preliminary coordinated data sets (prior to models provision).

CGM-coordinator has obligation to check each model and in the case of any mistake and convergence problem to ask responsible TSOs to resend correct model.

If at least one of the above conditions is not fulfilled, or not repairable by the CGM-coordinator with basic interventions, the data set is rejected.

In the case of LF model non-convergence, checking of power flow data should be performed in PSS/E. It considers the following:

- Branch parameters checking which indicates the potential for difficulties in obtaining a power flow solution
- Island checking
- Checking/Changing Controlled Bus Scheduled Voltage
- Checking/Changing Transformer Adjustment Data

As long as the TSOs do not deliver a functioning data, there will be prompt requests for valid datasets, until a given deadline. Only after the deadline, monthly model will be replaced according to the Replacement Strategy.

Dynamic models:

CGM coordinator also has to perform validation of the dynamic data:

- Errors of file naming and inconsistencies between naming and content
- DYR format errors
- Any machine which is online in the load flow case must have at least generator model
- Generator bus numbers and IDs from .dyr file must correspond to related load flow file
- Unsaturated subtransient reactance for conventional generation units from .dyr file must be set equal to the machine reactance value from the load flow model (X source [pu])
- Standard excitation and turbine test requirements must be fulfilled for all conventional generator units
- Initializing Model for State-Space Simulation - Activity STRT – During the model initialization process, any model variable must not be initialized beyond its prescribed limits. The absence of suspect initial conditions generally (though not always) indicates a valid steady state. Conversely, the presence of initial condition alarms usually indicates some error in dynamic modeling
- Performing State-Space Simulation in Time Steps – After execution of RUN activity for simulation time of 50 seconds, without applying any disturbances, all monitored variables should keep original values from the initialization process. It is good practice to use this test to reveal time constants which are too small in relation to the simulation time step, or other modeling errors

If at least one of the above conditions is not fulfilled, not repairable by the CGM-coordinator with basic interventions, the data set is rejected.

CGM-coordinator has obligation to check each dynamic model and in the case of any mistake and convergence problem to ask responsible TSOs to resend correct model.

As long as the TSOs do not deliver a functioning data, there will be prompt requests for valid datasets, until a given deadline. Only after the deadline, monthly model will be replaced according to the Replacement Strategy.

1.8 Replacement strategy and informing about mistakes

In case of missing, or bad, non-repairable models, the last available valid monthly model or national model from initial reference model will be used for calculation, adjusted in sense of balance and topology for this purpose.

All TSOs should be notified about the used backup models and performed changes.

1.9 Models merging

CGM-coordinator will merge the individual models in the regional AGT model, and after the harmonization and consistency checking, this model will be used for the further calculations.

If the monthly national models satisfy criteria regarding convergence, but merging model doesn't converge with VAR limits, in that case CGM-coordinator will try to solve model with ignoring VAR limits option.

The CGM-coordinator has to check the consistency of the merged model and has to perform the following analyses: maximum permissible thermal load overloads in base case and maximum and minimum voltage levels.

CGM-coordinator should send merged model without overloads element in base case. If the results of analysis show overloads, CGM-coordinator should communicate with TSOs in order to determine whether the violation is related to modeling error or it is realistic network condition.

For the reason of simple and efficient models merging, suited for PSS/E modeling and merging principles, it is recommended that CGM-coordinator:

- use the initially merged model of AZ+GE+TR+equivalents (e.g. the one from the previous month), and creates the new merged model (see Figure 5).
- by regular (monthly) replacing the AGT TSOs parts in the initially merged model, with updated national models (PSS/E option “add to working case”), and
- with occasional updates of equivalents, when and where necessary.

The merging procedure by CGM-coordinator includes the following activities:

1. Prepare and maintain the initially merged model
2. Check “fresh” national models of Azerbaijan, Georgia and Turkey - the files send by TSOs. In case of problems, to ask the corresponding TSO for an update. In case of no update, to perform Replacement.
3. Add national monthly models to working case
4. Update power exchanges of equivalents according to new total balances from national monthly models from participating TSOs
5. Load reference dynamic model

Global slack:

Since the two synchronous zones are present in the merged model, the two global slack nodes should be selected, one for each.

It is proposed to select the global slack nodes as far as possible from the AGT region - one in IPS/UPS-Russian equivalent and another one in ENTSO-E equivalent.

Solving imbalance due to changes of losses:

After merging, it is expectable that the totals of the systems are additionally slightly changed because of the changes in losses. In order to restore the totals of all systems, the generation of local slack nodes have to be adjusted, by using the LF option “tie lines and loads“.

Load flow: Before distributing the merged model it has to be solved by the CGM-coordinator (load flow and dynamic calculation has to be performed) using PSS/E software.

Provision of final merged model:

After the merging process, CGM-coordinator provides to all AGT TSOs the merged model, along with all information related to data quality and merging process. The merged regional network model is to be used for all network analyses within the regular monthly NTC calculation.

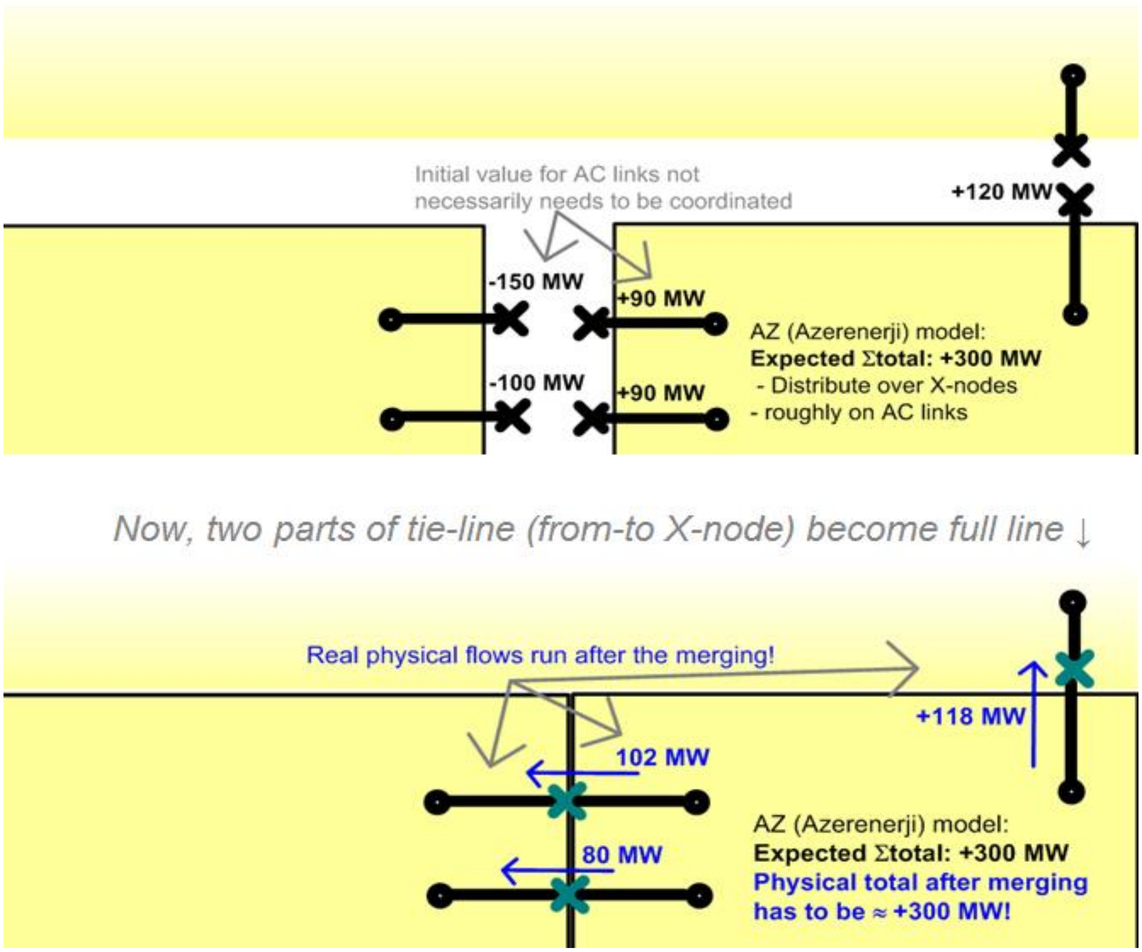


Figure 5. Merging illustration.

1.10 Time table for building network model for month M

The procedure of monthly network model creation for month M, during the second half of month M-2 is roughly scheduled in Table 3. Flowchart of the models provision and merging time table is illustrated in Figure 6

Table 3. Procedure of monthly network model creation.

Preliminary data harmonization: *Azerenerji, GSE, TEIAS*	Month M-2: 15th -20th
Sending models by each TSO: *Azerenerji, GSE, TEIAS*	Month M-2: 20th-23rd
Merging models by CGM-coordinator:	Month M-2: 23rd-25th
NTC calculation:	Month M-2: 25th-30th
NTC allocation:	Month M-1: 1st-10th
Usage of capacities:	Month M

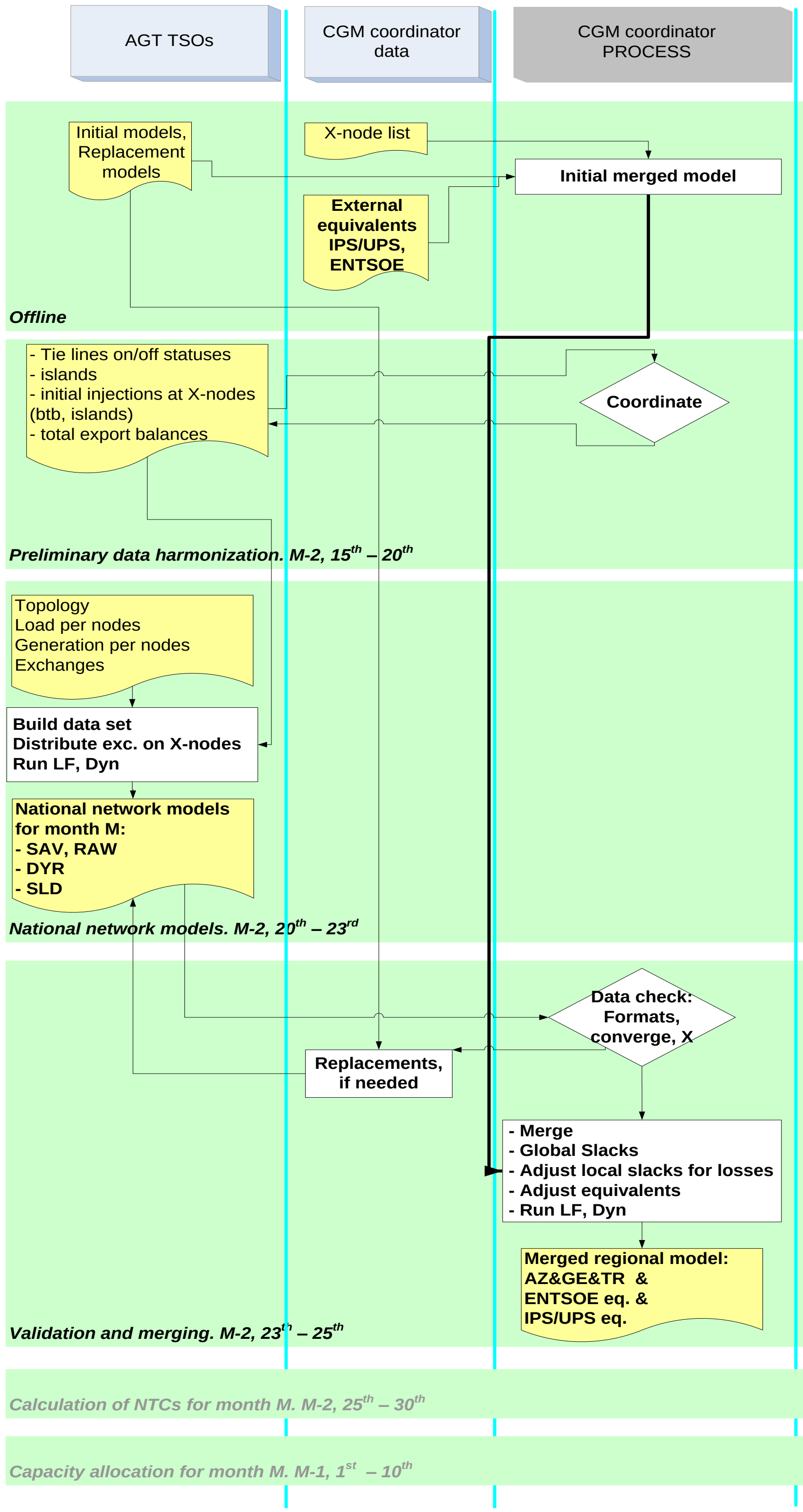


Figure 6. Flowchart of the models provision and merging time table.

3. NTC CALCULATION AND HARMONIZATION

1.11 General

Transfer capacities (TTC, NTC) are important indicators for market participants to anticipate and plan their cross-border transactions and for the TSOs to manage these international exchanges of electricity. Also they can give indications about weak points of the transmission network and can be used to evaluate the influence of network development plans and new planed network reinforcements.

General definitions of transfer capacities and the procedures for their calculation are given by ENTSO-E, which is the basis for present document, while here also some practical issues and experiences are included and refined in detail.

These cross-border transmission capacities are used as constraints in the transaction-based (or ”ATC-based”, or “NTC-based”) allocation procedures, explicit and implicit auctions, market-splitting and market coupling, based on the transactions reported at the respective borders.

1.12 Definitions of calculated values

According to ENTSO-e, the definitions that refer to program values are presented below. As explained in the Introduction, these definitions are related to the classical calculation of transfer capacities – between neighboring systems/areas, linked with the tie-lines.

Also, it is important to note that the TTC, NTC, BCE, AAC, ATC are the EXCHANGE PROGRAM values; these are not the physical flows, and generally differ from the physical flows at the interconnection lines (except in particular cases of radial operation[1]).

Capacity calculation is always related to a given power system scenario, i.e.: generation schedule and pattern, consumption pattern and available network state. These constitute the data allowing building up a mathematical model of the power system (load flow equations). The solution of this model leads to the knowledge of the voltages at the network nodes and the power flows in the network elements which are the parameters being monitored by a TSO to assess system security. The solution of this model is the so-called “**Base Case”** and is the starting point for the computation. This Base Case can already contain exchange programs between TSOs and control areas. These are the various transactions likely to exist in the forecasted situation according to what has been observed in the past.

In the Base Case model, for a given pair of neighboring control areas, A and B, for which capacities are to be computed, a global cross-border exchange program called **Base Case Exchange (BCE)** can exist, as a starting point for the NTC calculation.

Sometimes it is hard to determine the Base Case Exchanges for a given base case network model, even for the classical calculation of transfer capacities (between the neighboring areas). It is easy to determine the load-flows at the tie-lines by running the load-flow on the base case model and recording the active power flows at the tie-lines (this value is called the Notified Transmission Flow - NTF). However, BCEs are the program (contractual) values related to the base case model, therefore, theoretically there can be an infinite number of sets of BCEs which give the same exchange totals of all modeled systems. That is why the BCE should be agreed by the consensus among the calculation parties. Since the final TTC values highly depend on the agreed value of BCE, it is recommended that

[1] Actually, radial and island modes of operation are exceptional in Continental Europe, but quite often in Southern Caucasus region. Therefore, at most of the borders in Southern Caucasus, exchange programs and physical flows would not differ.

realistic BCEs are agreed (base case load flows on interconnection lines ≈ NTFs, can give some indication of the BCEs which are resulted from).

As the result of the calculation procedure, TTC equals the maximum exchange program between the two areas being considered, if the generation and load pattern in these areas and in other areas strongly interconnected to these two would exactly correspond to the assumptions made in the evaluation steps, namely the ones implicit in the base case.

The maximum additional program exchange (over the BCE) that meets the security standards is marked with **ΔEmax**.

The Total Transfer Capacity (TTC) is the maximum exchange program between two areas, compatible with operational security standards* applicable at each system**, if future network conditions, generation and load patterns were perfectly known in advance***.

TTC = BCE + ΔEmax

* *the most important and often checked is the n-1 security criterion*

** *in highly meshed networks, usually not only the two systems are observed, but also the "third" systems, if they are significantly influenced by the transfers between the two systems*

*** *the last part of the sentence indicates that no model and/or forecasting imperfections are taken into account within TTC (they are evaluated within the TRM, as explained below)*

The evaluation of TTC between two electrical areas requires:

- Choice of local power system scenario
- Definition of a base case, which involves the sharing of full information amongst TSOs to build up the global (merged) load flow model
- Application of an agreed procedure for carrying out the calculations

The uncertainties associated with the forecast of the power system state, for a given time period in the future, may decrease according to the selected time frame. Therefore the TTC value may vary (i.e. increase or decrease) when approaching the time of program execution as a result of a more accurate knowledge of generating unit schedules, load pattern, network topology and tie-lines availability.

Transmission Reliability Margin (TRM) is a security margin that deals with uncertainties on the computed TTC values arising from:

- Unintended deviations of physical flows during operation due to the physical functioning of load-frequency control (LFC)
- Emergency exchanges between TSOs to deal with unexpected unbalanced situations in real time
- Inaccuracies, e. g. in data collection and measurements

TRM is associated with the real-time operation and its value is determined by each TSO, in order to guarantee the operation security of its own power system. TRM may vary seasonally or may be updated according to possible modifications occurred in the power system.

Net Transfer Capacity (NTC) is defined as:

NTC = TTC-TRM

NTC is the maximum exchange program between two areas compatible with security standards applicable in both areas, taking into account the technical uncertainties on future network conditions.

Figure below gives the graphical explanation of defined program values, using an example of transfer capacities calculation between areas A and B, with already existing Base Case Exchange from A towards B.

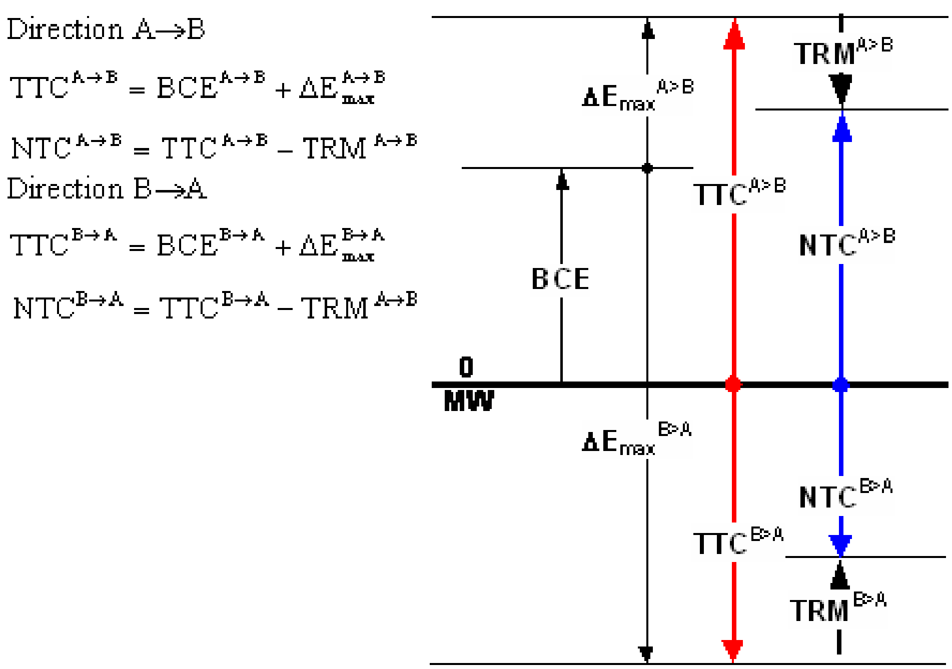


Figure 7. Graphical presentation of transfer capacities and their analytical relations

NTC may be allocated in different time frames to meet the need for securing longer term trading and provide room for shorter term trading. One may distinguish, as the result of the allocation procedures in each allocation time frame, two notions:

Already Allocated Capacity (AAC), is the total amount of already allocated transmission rights, committed at the eventual previous allocation rounds.

- For example, at the monthly auctions, the value allocated previously on yearly auctions would be taken into account as AAC at the monthly auctions. Both yearly and monthly allocated (and nominated) transmission rights are considered as AAC at daily auctions, etc.
- Also, some specific cases like long term contracts or reserved portion of technical capacity at certain profile (e.g. private share of capacity, not subject to third party access), can formally be considered as AAC. *Note: long-term contracts and reserved cross-border capacities are not considered as market-based solutions at the European capacity market.*

The Available Transmission Capacity (ATC), is the part of NTC that remains available, after each phase of the allocation procedure, for further commercial activity. ATC is given by the following equation:

ATC = NTC- AAC

Therefore, AAC and ATC are results of each stage of the allocation procedure.

In definitions of transfer capacities, a clear distinction is made between the program (contractual, scheduled) values, and the physical active power flows related to these program values, i.e. originated by them, and recorded in AC load flow model.

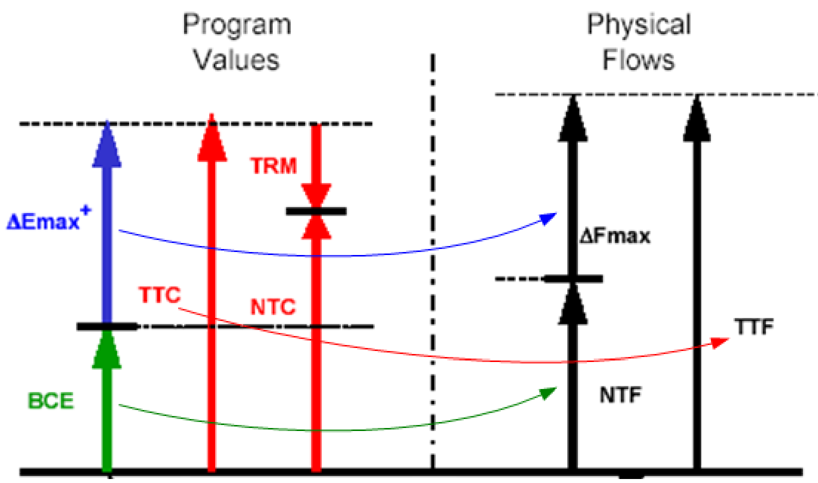


Figure 8. Corresponding program (commercial) values and physical values

Since the definitions of the program values are related to the border between the two TSOs, the definitions of physical values are also related to the sum of the individual tie-line flows at the observed border.

Notified Transmission Flow (NTF) is the physical flow over the tie-lines between the considered areas observed in the base case model prior to any generation shift between the areas. It results from the Base Case Exchanges (BCE).

The additional physical flow ΔFmax is the physical flow over the tie lines between the two areas, induced by the maximum generation shift **ΔEmax**.

Total transfer Flow (TTF) is the net physical flow across the border associated with an exchange program of magnitude TTC, provided that no other exchanges have been modified from the base case (except the one between the two areas between which the TTC is calculated).

TTF = NTF + ΔFmax

Difference in commercial and physical cross border flows is not expected as major effect in Southern Caucasus, since network is not highly meshed.

But there are certain profiles where this effect could take place: In case of “triangle” synchronous connection among Azerbaijan, Georgia and Russia (see figure) it is possible that part of commercial programmed exchange from AZ to GE could make a loop flow over RU network.

This effect is bearable, as long as the network security is maintained, and the corresponding TSOs should accommodate it within the advanced Rules of synchronous operation. Of course, it should be followed with multilateral mechanism of accounting of exchanges, compensation of unintentional deviations, and a compensation of losses.

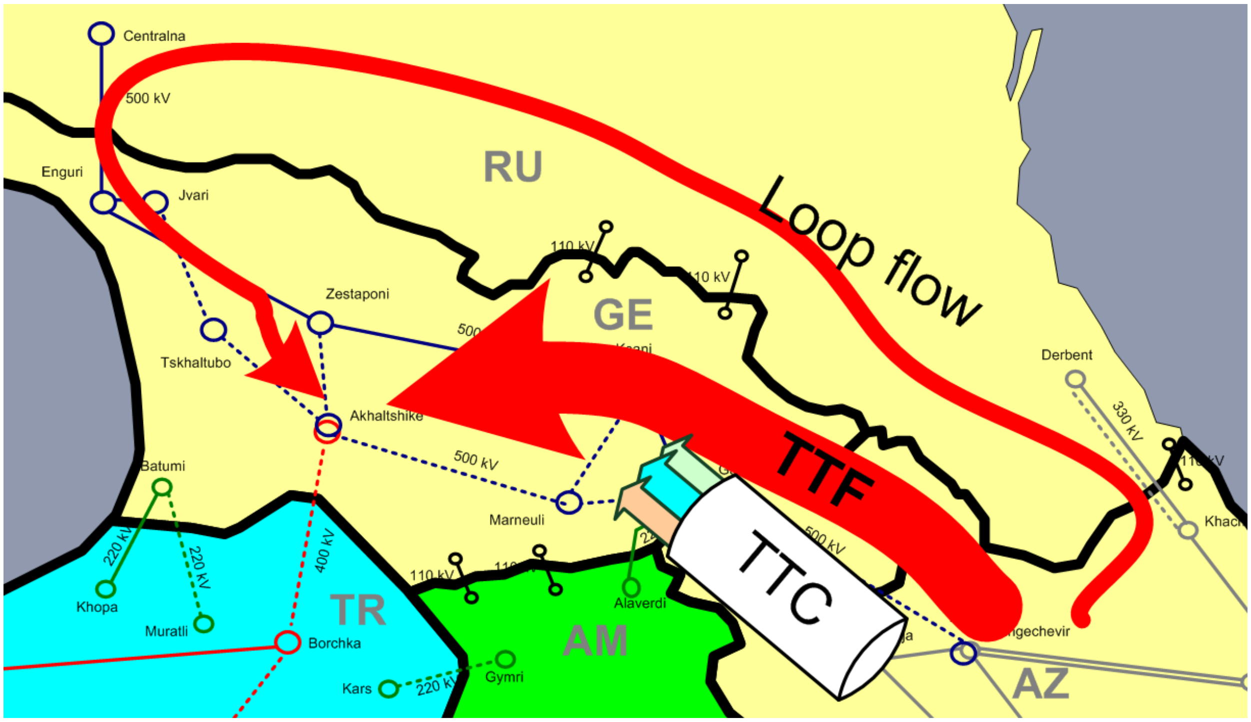


Figure 9. Loop flows (power wheeling)

1.13 Calculation of TTC/NTC

The general concept of TTC calculation based on ENTSO-e documents is explained with an example of TTCs calculation between areas A and B, where BCE from A towards B already exists in base case.

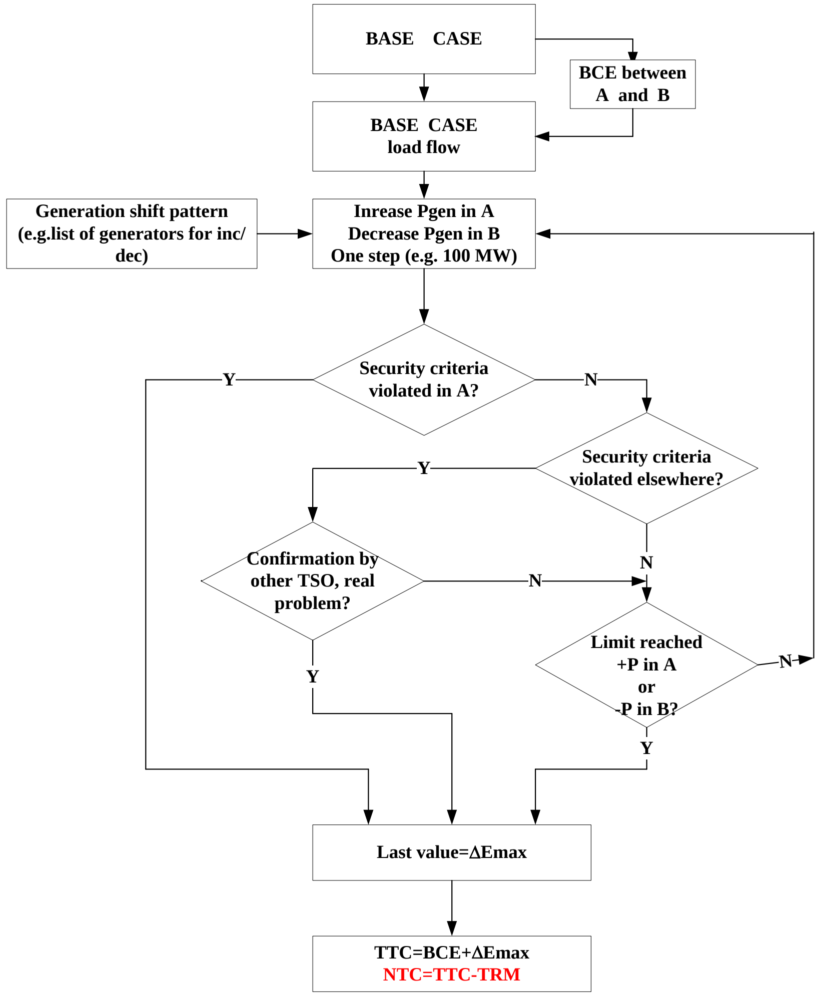


Figure 10. Process of TTC calculation

<u>When computing TTC</u> from area A to area B, generation is increased stepwise in control area A and decreased in control area B giving rise to power flow from area A to area B. The shifts of generation are named as ΔE^+ and ΔE^- for increase and decrease respectively. This process is carried out up to the point where security rules are violated (in systems A, B, or in some of the neighbouring systems highly dependent on the transaction among A and B) resulting to values $\Delta Emax^+$ and $\Delta Emax^-$. The maximum exchange from A to B, compatible with security rules, without taking into account uncertainties and inaccuracies, is actually the TTC from A to B, and it is calculated as:

$$\mathbf{TTC = BCE + \Delta Emax^+}$$

This procedure is reversed (decrease of generation in system A and increase of generation in system B) when computing TTC from area B to area A leading to a maximum increase of generation of $\Delta Emax^-$ and thus to a maximum exchange from B to A of $\Delta Emax^-$ - BCE.

For planning purposes (evaluation of development plans) and for long-term transfer capabilities evaluation, after reaching the exchange in which first critical contingency occurs, calculations should be continued, to confirm this identified bottleneck, till the next critical contingency is identified.

The bi-directional capacity calculation should be done at AGT borders in order to determine the capacity in both directions. However, regular calculation of NTC should be done only in the directions that are expected to be congested in certain periods (years, months…). It can happen that in certain time frames both directions at the same borders can be (commercially) congested – in such case NTCs for both directions have to be calculated.

1.14 Network modeling

For the calculation of the transaction-based cross-border capacities, such as TTC, the common practice is to use the merged Interconnection or regional network models with common "usual" base case exchanges among the TSOs, representing the forecasted situation as it would be after the allocation[2]. For such purpose, prior to the TTC calculation the matrix (table) with Base Case Exchanges is usually harmonized among the TSOs.

The usage of the network model with "usual" BCEs is especially justified for the calculation of the TTCs in commercially significant directions, usually corresponding to the base case flows directions.

On the other hand, for the calculation of TTCs in the opposite directions, "No realistic Limit" can be imposed if the calculation in such direction would provide the unrealistic result, due to the base case not suited for such exchange.

The details on the procedures for network modelling are provided in the first part of the document.

1.15 Simultaneous feasibility: border-wise and composite capacities

The TTC values are currently the basis for applied mechanisms for allocation of the transmission capacity at all European borders. Nevertheless, the strong interdependence between some of the borders within the highly meshed European grid can seriously compromise the usage of classically calculated TTCs as bilaterally agreed values.

The effect of parallel flows, i.e. the physical flows containing the natural flows and the loop flows originated by the scheduled transactions at some "third" borders, often endanger the operational security of the transmission grid, even if all the calculated NTCs are respected.

A simple example can show the main side of this problem:
If TTC (or NTC) is calculated for the export of system A towards system C, the generation is increased in A and decreased in C until the security limits are violated. Thus the value TTC A→C is obtained. In this case the generation in system B remains as in the base case. If then the TTC (B→C) is calculated, the base case model is again the starting point, and the generation is increased in B and decreased in C, while the generation in B is as in the base case.

The situation where "parallel composite" NTC calculation would be needed is not expected in Southern Caucasus, due to the weakly meshed interconnected network in the region.

[2] This is called a "chicken and egg" problem even in ENTSO-e documents: In order to set up the network model for the NTC calculation, TSOs have to predict the behaviour of generation and consumption as it will be after the allocation of the very NTCs that still have to be calculated. It can happen that some of market generators will not "pass" the NTC auction, while they are considered either in the base case or later in the shift during the NTC calculation. There is no formal solution for this; TSOs have to bear the risk of imperfect forecasting of the market behaviour.

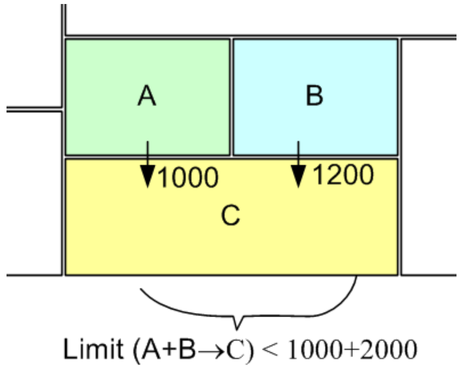


Figure 11: TTC for simultaneous transfers

If the two bilaterally agreed values TTC (A→C) and TTC (B→C) are offered to the market, the final operational regime can be dangerous from the security point of view (although both TTCs are "correctly" calculated), since the borders A→C and B→C are interdependent.

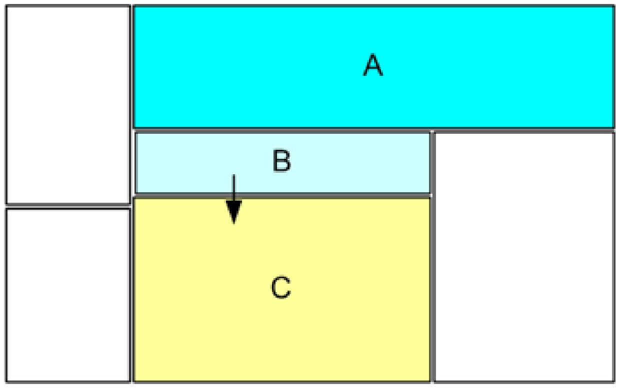
The values TTC (A→C) and TTC (B→C) are not cumulative, i.e. the value TTC (A→C) + TTC (B→C) cannot be offered to the market.

One of the possible ways to mitigate this problem is the calculation of the so-called "composite" or "bundled" TTC, which can be treated as simultaneously feasible. First the highly interdependent borders or regional cross-sections should be detected (can comprise two or more bilateral borders).
In the above example, the composite TTC can be calculated by the simultaneous generation increase in systems A+B (according to the predefined generation shift scenario) and decrease in system C. Thus the composite TTC for the border (A+B)→C is calculated, taking into account the impact of both systems (A and B) export programs to system C. If necessary, it can be allocated per border (A→C and B→C) e.g. proportionally to the physical power flows, "TTFs", at these borders, based on sensitivity factors).

The principle of simultaneous generation shift in more than one exporting (or importing) areas can also be used in case of calculating the TTCs over third, transit systems. If system B (figure 5) is the transit system for the electricity exchanges between A and C, the calculation of TTC by increasing the generation only in B would lead to unrealistically small capacity. Therefore the generation can be increased in (A+B) simultaneously and leads to more accurate transfer capabilities results.

This situation where "serial composite" NTC would be needed, can appear in Southern Caucasus region: e.g. calculation of NTC toward Turkey can be done as GE+AZ → TR, or even as GE+RU→TR. Thus, even in the regimes when there is no sufficient internal Georgian generation for exports, the transit over Georgia can be simulated.

For example, in calculation of e.g. NTC GE->TR, and if all generation reserve in GE would be used in calculation (for instance, in low hydro periods), and still no critical contingencies appear, the calculation could be continued with increasing generation in Azerbaijan, etc.



B – transiter system

Calculate (A+)B $\rightarrow$ C instead of B $\rightarrow$ C

Figure 12: TTC calculation in the presence of a transit system

This is analogue also to the calculation of NTC (A-B), where generation decrease is more realistic to be done upon the systems B and C jointly.

1.16 Assessment of Transmission Reliability Margin (TRM)

TRM is particularly related to the:

- unintended deviations due to primary control: $P_{TRM\,1}$
- unintended deviations due to power-frequency (secondary) control: $P_{TRM\,2}$
- common reserve and emergency exchanges to cope with unbalanced situations: $P_{TRM\,e}$
- inaccuracies in data collection and measurements: $P_{TRM\,i}$

Overall value of TRM

The inclusion $P_{TRM\,2}$ is not necessary since if $P_{TRM\,1}$ is included, the secondary control deviations evaluated through the $P_{TRM\,2}$ are typically much lower than those originated by the primary control, so they are covered with the value of $P_{TRM\,1}$. If $P_{TRM\,1}$ is not included (i.e. if generator outages are observed during TTC calculation), $P_{TRM\,2}$ is again lower, and covered with $P_{TRM\,1}$ (in TTC calculation).

The TRM fractions described in previous chapter can be combined in different ways, from “pessimistic” to “optimistic”. The most pessimistic combination would be the adding all of those:

$$\mathbf{TRM_{pessimistic} = P_{TRM\,1} + P_{TRM\,e} + P_{TRM\,i}}$$

The optimistic combination would comprise not expecting the simultaneous appearing the regulation deviations with the need for the emergency exchanges.

$$TRM_{optimistic} = \max(P_{TRM\,1}, P_{TRM\,e}) + P_{TRM\,i}$$

In despite of comprehensive theory in behind of TRM, in European practice it is typical that TRM is agreed among the TSOs and fixed for longer time period, on the basis of simple calculation rules.

Usually it is defined as fixed figure (50, 100, 150 MW), or as a percentage of TTC.

For the special case of having back-to-back connection at GE-TR border, there is no uncertainty of the power flows, or primary control flows. Therefore, for that portion of TRM, the value of zero can be considered.

For the effect of inaccuracies in modelling and calculation, the virtual calculation of TTC over the back-to-back capacity can be performed, to check the capacity of the AC parts of the networks in AZ, GE and TR.

E.g. if the capacity of back-to-back is 350 MW, TSOs can simulate the virtual exchange even above that (400, 450…) to check the rest of the network.

Upon that calculation, the TRM can be defined and subtracted from TTC (e.g. 50 MW).

1.17 Generation Shift Keys

In order to determine the cross-border transmission limit between two neighbouring countries or zones, cross-border exchanges are gradually increased while maintaining the loads in the whole system unchanged until security limits are reached.

Starting from the common Base Case Exchanges, the additional exchange is performed through an increase of generation on the exporting side and an equivalent decrease of generation on the importing side. This generation shift is to be made stepwise until a network constraint is violated.

The generation increase/decrease has to be performed according to some predefined criteria. The most common methods of generation increase/decrease distribution in some area over the different generating sets are:

1.17.1 Proportionally to the base case generation of generator units

This is a widely used generation shift method, suitable for fast calculations, because it does not require any additional information except the base case Load flow model. Commonly used principle is that the factor which distributes the generation increase/decrease in a given area over the different generators in this area is the ratio of base case engagement of each generator to the total of internal generation scheduled and involved in the shift.

$$P_{new}^{inc} = P_i + \Delta E \cdot \frac{P_i}{\sum_n (P_i)}; \quad P_{new}^{dec} = P_i - \Delta E \cdot \frac{P_i}{\sum_n (P_i)}$$

P_i - active power generation of respective production unit

P_{new}^{inc} - new increased generation

P_{new}^{dec} - new decreased generation

ΔE - step of the generation shift

This method of generation shift can lead to non-feasible generation patterns, because of the fact that the generators already highly engaged in base case are favoured during the shift, often above their real capability. On the other hand, some generators which are not engaged in the base case, will not be engaged in the generation shift process too.

PSS/E software supports such generation shift principle in semi-automatic mode, through the SCAL function. Generation can be scaled in PSS/E on the basis of base case level.

In order not to breach the Pmin/Pmax limits of respective generators, option "Enforce machine power limits" should be checked.

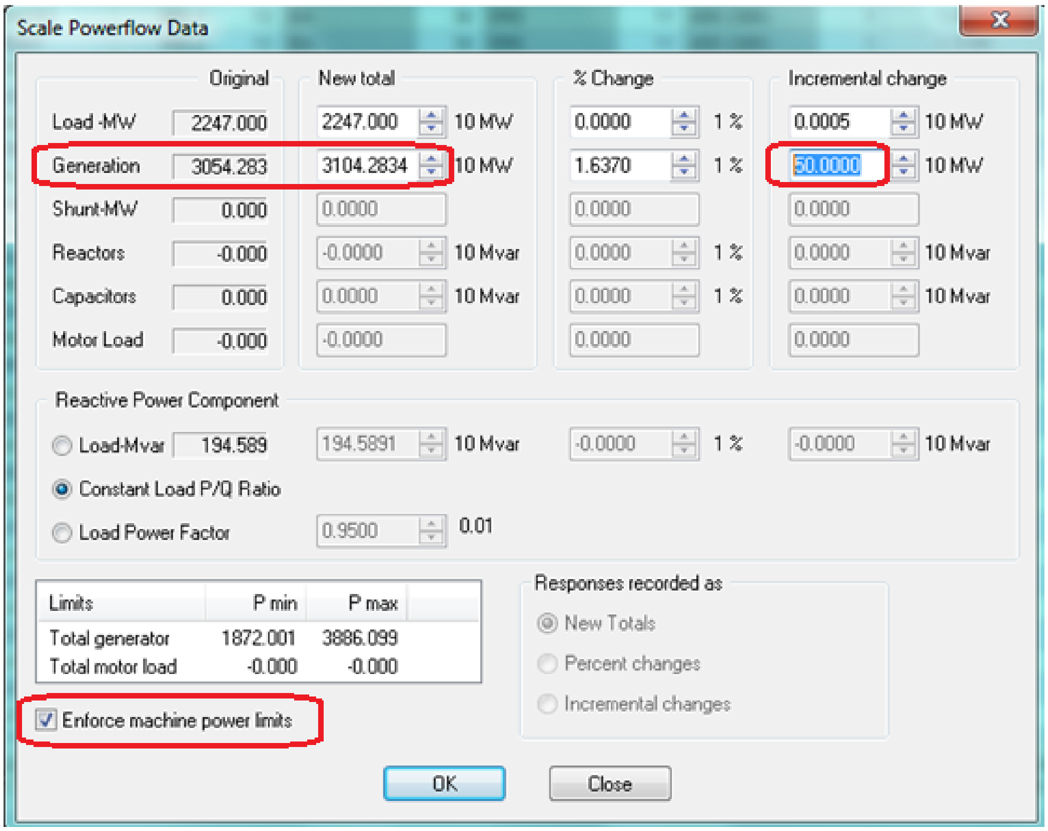


Figure 13: SCAL function in PSS/E

1.17.2 According to the priority list of the production units (order & generation shift)

Within this method, the priority lists of the generators for the participation in generation shift are known, with an order of the engagement and the active power for the increase/decrease. Then, generation is shifted simultaneously increased/decreased according to the shifting lists. This list corresponds to the common operational practice of increasing the amount of the power exchanges, and thus corresponds to the realistic scenarios. Alternatively, the priority list can be made according to the economic dispatch, or even market prices.

This pattern of generation shift provides more accurate representation of network conditions in respective calculation steps, but requires additional information in a form of generation shift list.

In case of using the generation shift according to the priority list, additional data should be exchanged along with the base case model, comprising the information of the shifting order (1,2,3…) and the available amount of generation shift.

Example: Priority list for increase within one system containing three modelled power plants can be:

Node	Order	$Pgen_{basecase}$	ΔP+	STEP		STEP 1		STEP 2		STEP 3	
						Pshift	$Pgen_{new}$	Pshift	$Pgen_{new}$	Pshift	$Pgen_{new}$
		[MW]	[MW]	[MW]	⇒	[MW]	[MW]	[MW]		[MW]	
ENGURI	**1**	440	**70**	50		50	**490**	20	**510**	/	
GARDABANI	**2**	230	**65**			/	230	30	**260**	35	**295**
ABCDE	**3**	200	**15**			/	200	/	200	15	**215**
		sum:	**150**			**50**		**50**		**50**	

Figure 14: Example of priority list

Thus, if the generation shift step is e.g. 50 MW:

- In first step the ENGURI will be increased by 50 MW, and its engagement will be 440+50=490 MW.
- In second step ENGURI will be increased by 20 MW more (reaching the limit defined in the priority list herein) and its engagement will be 510 MW. Additionally, GARDABANI will be increased by 30 MW in this step, etc.

1.17.3 Proportionally to the active power reserve in respective production units

This method respects the real production capability of the generators, and requires additional information about the Pmin and Pmax of the generators that will participate in generation shift. Then, in each step, the amount of the shift will be shared among the engaged generators according to their remaining production “reserve” (UCTE method A).

$$P_{new}^{inc} = P_i + \Delta E \cdot \frac{P_i^{\max} - P_i}{\sum_n (P_i^{\max} - P_i)} \; ; \quad P_{new}^{dec} = P_i - \Delta E \cdot \frac{P_i^{\min} - P_i}{\sum_n (P_i^{\min} - P_i)}$$

P_i - active power generation of respective production unit

P_{new}^{inc} - new increased generation

P_{new}^{dec} - new decreased generation

ΔE - step of the generation shift

$P_i^{\min}$ - minimum permissible generation (for the generators participating in decreasing)

$P_i^{\max}$ - maximum permissible generation (for the generators participating in increasing)

In case of using the generation shift proportionally to the reserve, the information about actual Pmin [MW] and Pmax [MW] for modelled power plants should be comprised in the corresponding format for the network model. Pmin and Pmax should not be related to the theoretical minimum and maximum generation of the respective power-plant, but to its available limits, which correspond to the observed values.

Thus, the power reserve for some power plant can be calculated:

$\Delta P_{increase} = P_{max} - P_{base\ case}$

$\Delta P_{decrease} = P_{base\ case} - P_{min}$

1.18 Static security calculations and criteria

As shown, the recursive procedure of the cross-border calculation is terminated if:

1) Maximum export capability in exporting system is reached, or maximum import capability in importing system is reached. In cases of reaching the Pmax of export or import, the last ΔE is considered as ΔEmax.
2) Critical contingencies are discovered. If the critical contingency is reached, the calculation is stopped, and the generation shift ΔE from the previous step is considered as ΔEmax.

TTC is calculated as: **TTC = BCE + ΔEmax**

The **base case model is checked** with respect to the security criteria. If some contingencies are determined in base case, their relevancy concerning the transfer capacity which is to be calculated should be evaluated and the calculation could be continued depending on the conclusion (i.e. some contingencies from the base case can be irrelevant for the observed transfer, and in such case the calculation can be performed).

Security assessment comprises the exhaustive analysis of system behaviour under disturbances (usually single or double). Single contingencies could typically include:

- HV and EHV overhead line outages
- Transformers 500/x, 400/x
- Where necessary, transformer 330/x, 220/x outages
- Where necessary, selected double-line outages
- Where necessary, selected generation outages

Bus-bar outages are usually not considered, since such an outage may lead to major disturbances that are out of the scope of TTC calculation.

The violation of security rules may occur internally in any of the involved systems or on the tie lines between them. The upper acceptable limits for the loading of the network elements are typically:

- Imax for transmission lines (in Amps)
- the nominal apparent power Snom for the transformers (in MVA)

The above values (Imax and Snom) should be defined in the base case model. Imax should comprise the typical operational current limit for the transmission lines known by the system operators (thermal limit, or protection setting).

Due to the uncertainty of reactive power forecast, **voltage violations** are considered only for each internal network by the corresponding system operator. Usually this is done in order to check that corrective measures are available.

If during the contingency analyses **divergence** of a model occurs, such cases should be carefully explored (for instance, with ”manual” outage simulation and corresponding model setup), since they are the consequence of:

- modelling errors and model numerical instability,
- serious network conditions related to the analysed outage

Also, some critical contingencies can be detected in TTC calculation, but can be neglected in the following cases:

- if the reason for the detected critical contingency is not the real critical operational regime, but the **imperfection of the used network model** (for example not modelled lower voltage network in one area, which actually mitigates the effect of the observed outage).
- if reasonable **preventive & fast post-event measures (remedial actions)** can be made by the system operator of the network affected by the considered contingency (meshing of lower voltage network, generation restrictions and re-dispatching). The list of such remedial actions should be communicated among the TSOs, and possibly be available prior to the TTC calculation.

  Remedial actions that could be taken into account are, among others:
    - Network topology changes (connection/disconnection of network elements, busbar splitting etc.)
    - Cancelling planned disconnection of network elements or maintenances that are already in progress
    - Generation redispatch
    - Changes (cancellation or reduction) in cross-border exchanges
    - Special Protection Schemes (SPS) in case of emergency designed to detect particular system condition that is known to cause unusual stress to the power system and to take predetermined action to counteract in a controlled manner. The predetermined action may require opening of one or more lines, tripping of generators, ramping of HVDC back-to-back power transfer, intentional load shedding, or other measures that will solve the problem (e.g. SPS applied in Georgia and Turkey).

  Such calculation assumptions:
    - Should correspond to the electricity market organization, taking into account eventual commercial consequences of such actions in the real operation (power purchase obligations, security of supply issues, where applicable).
    - Should be communicated among the TSOs in the AGT region, as potential remedial actions considered in the calculation time, as well as in real operation time, when applied.

- if a critical contingency is caused by the outage of an element with low **failure probability according to existing experience** (for example an element operating for a few years without any unplanned outage):
    - Its failure probability should be assessed and evaluated on the basis of historical data (fault frequency and fault duration) with the reliability assessment function in PSS/E.
    - Market actors should be aware of (low) failure probabilities of certain contingencies and their consequent small effect in the calculation of NTC and should be advised through the capacity contract, that in certain periods their deliveries would be curtailed with no remuneration (e.g. 2 hours per month at monthly auctions etc.), if such contingency occurs in real time.

1.19 Dynamic stability calculations and criteria

Power system stability can be defined as the ability of an electric power system, for a given initial operating condition, to regain a state of operating equilibrium after being subjected to a physical disturbance, with most system variables bounded so that practically the entire system remains intact.
Power systems are subjected to a wide range of disturbances, small or large. Small load, generation or topology changes without any faults occur continually and the system must be able to adjust to these changing conditions and operate satisfactorily. It must also be able to survive numerous disturbances of severe nature, such as short-circuit on a transmission line or loss of a large amount of generators even if the large disturbance may lead to structural changes due to cascading events and the isolation of the faulted elements.
The analyses of dynamic stability issues and the design of effective countermeasures can be highly assisted by an appropriate definition and classification of power system stability problems. Classification scheme of power system stability problems is depicted in the following Figure:

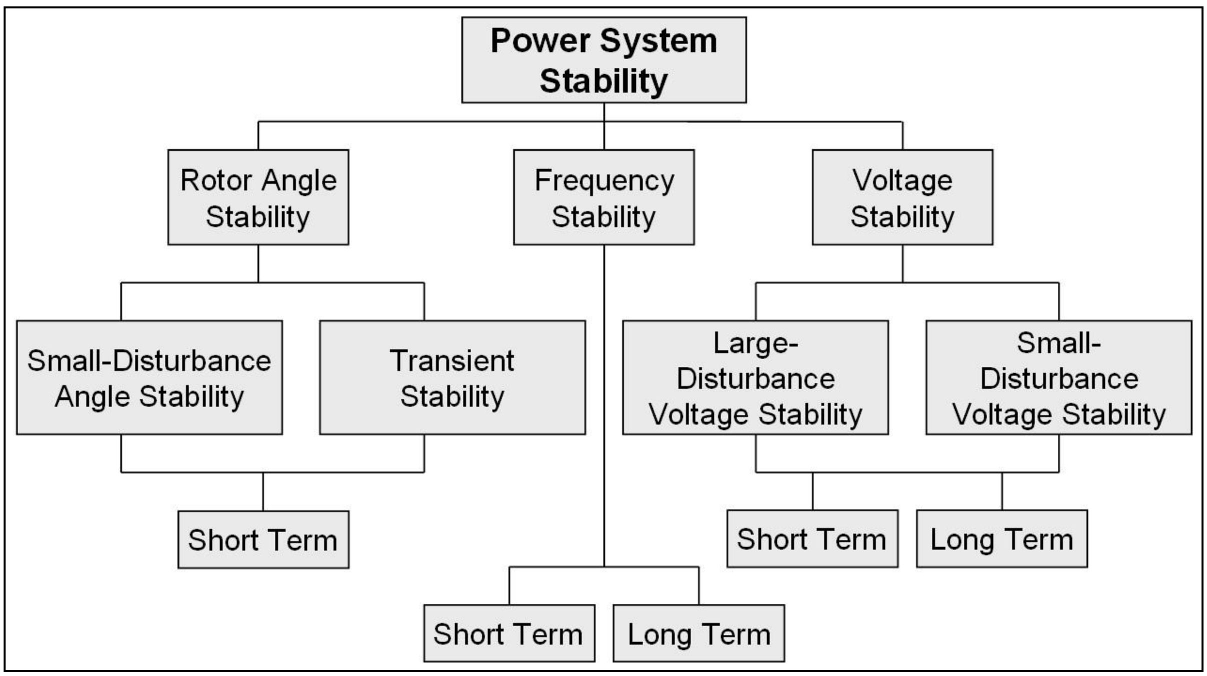


Figure 15: Classification of power system stability

Taking into account classification scheme the objectives of dynamic stability analysis are **rotor angle stability, frequency stability, voltage stability** in case of normal contingencies i.e. incidents which are specifically foreseen in the planning and operation of the system. A normal contingency is loss of one of the following elements:

- Generator
- Transmission circuit (overhead, underground or mixed)
- Transformer between two voltage levels of the transmission system
- Shunt device (capacitors, reactors)
- Single DC line
- Equipment for load flow control (phase shifter, FACTS, HVDC back-to-back station…)
- A line with two or more circuits on the same towers if a TSO considers this appropriate and includes this contingency in its normal contingency list

Stability analysis, oriented to identify possible instability problems, should be performed only in cases where problems with stability can be expected, based on TSO knowledge. For the assessment of normal contingencies in dynamic stability, a successful fault clearing by the primary protection system should be implied, i.e. first step of distance protection, so fault duration should not overreach 150 ms.

All stability analyses should be performed at least for the network model with the last value of additional exchange that does not involve any static security problem (ΔEmax) in order to check its feasibility from dynamic stability point of view. If TSO assumes, based on their experience, that during stepwise generation shift procedure, there might be some dynamic stability issues although static security is satisfied, analyses should be performed for each step of generation shift.

1.19.1 Rotor angle stability

Rotor angle stability refers to the ability of synchronous generators of an interconnected power system to remain in synchronism after a disturbance. It depends on the ability to maintain/restore equilibrium between electromagnetic torque and mechanical torque of each synchronous machine in the system and depends on the initial operating state of the system. Instability that may result occurs in the form of increasing angular swings of some generators leading to their loss of synchronism with other generators or aperiodical divergence of the angle between the machine (or the cluster) and the rest of the system.
Rotor angle stability problems can be divided in small-disturbance and transient stability sub-categories:

- Small-disturbance (or small-signal) rotor angle stability - ability of power system to maintain synchronism under small disturbances. Small disturbance rotor angle stability problems may be either local or global.
    - Local problems concern a small part of the power system and are usually associated with rotor oscillations of a single power plant against the rest of the power system [0.8 - 2 Hz]. Such oscillations are called local plant mode oscillations.
    - Global problems are caused by the interaction among large groups of generators and have widespread effects. They involve oscillations of a group of generators in one area against a group of generators in another area. These oscillations are called inter-area mode oscillations [0.1 - 0.8 Hz]

- Large-disturbance rotor angle stability or transient stability - ability of the generators to maintain in synchronism after a severe disturbance (such as a short circuit on a transmission line or bus). The time frame of interest in transient stability studies is usually 3 to 5 seconds following the disturbance and the resulting system response involves large excursions of generator angles and is influenced by the non-linear power-angle relationship.

Small signal stability criteria - Oscillatory stability of the power system should be analysed by linearizing the power and control system equations and calculation of relevant frequency modes damping factors.
Transient stability criteria - Any 3-phase short circuit simulated and successfully cleared with primary protection system in the observed network model should not result in the loss of rotor angle stability and disconnection of the generating unit.

1.19.2 Frequency stability

Frequency stability is related to the ability of a power system to reach and maintain a stable operating point (sustainable from generators) following a severe disturbance (resulting in a significant imbalance between production and consumption). Instability that may result occurs in the form of sustained frequency swings leading to tripping of generating units and/or loads or in an aperiodic transient.
During frequency excursions, the time constants of the processes and devices participating in the network model will range from fraction of seconds (corresponding to the response of devices such as under-frequency relays and generator controls and protections) to several minutes, corresponding to the response of devices such as prime mover energy supply systems and load voltage regulators. In this sense, frequency stability should be analysed as a short-term or long-term phenomenon.

1.19.3 Voltage stability

Voltage stability refers to the ability of a power system to maintain acceptable voltages at all buses in the analysed network under normal conditions and after a disturbance and depends on the ability of the analysed power system to supply the active and reactive load through the operating grid.
Instability that may result occurs in the form of a progressive fall or rise of voltages at some buses. A possible result of voltage instability is the loss of load in an area, or tripping of transmission lines and other elements by their protection systems leading to cascading outages.
Time frame of interest for voltage stability problems may vary from a few seconds up to tens of minutes due to the fact that the dynamic of instability depends on high dynamic elements such as induction motors, electronically controlled loads, SVC, HVDC converters, voltage controller and limitations of generators so much as slower acting equipment as On Load Tap Changers, generator current limiters, thermostatically controlled loads or secondary voltage control.

1.20 NTC calculation in case of back-to-back or HVDC ties

Currently two interconnections, IPS/UPS (GE, AZ, RU…) and ENTSO-E (TR, BG, GR…), are asynchronously connected via HVDC back-to-back station in Akhaltsikhe and AC transmission line Akhaltsikhe - Borchka.

Transfer capacity of HVDC back-to-back station is known in advance, with constant value depending on the size of converter station and it is not an issue for NTC calculation between countries, but stability issues of surrounding grids should be checked through static and dynamic security calculations as integral parts of NTC calculation.

NTC value on the borders with HVDC back-to-back station should be calculated in “serial” way. Total power exchange should be stepwise increased in exporting country together with transfer capacity on HVDC back-to-back station in the same amount, while power exchange in importing country should be decreased accordingly.

Feasibility of such regimes should be checked with static and dynamic security analyses, as it is explained in chapters 1.18 and 1.19.

Maximal possible value for transfer capacity between asynchronously connected countries is the capacity of HVDC back-to-back station.
If full capacity of HVDC back-to-back station is not reached, then minimum value among the two calculated values of NTC (from both bordering countries) should be adopted as harmonized NTC value.

Outage of HVDC back-to-back station itself should be checked in n-1 security assessment and static and dynamic stability should be monitored due to large disturbances that might occur in both bordering areas.

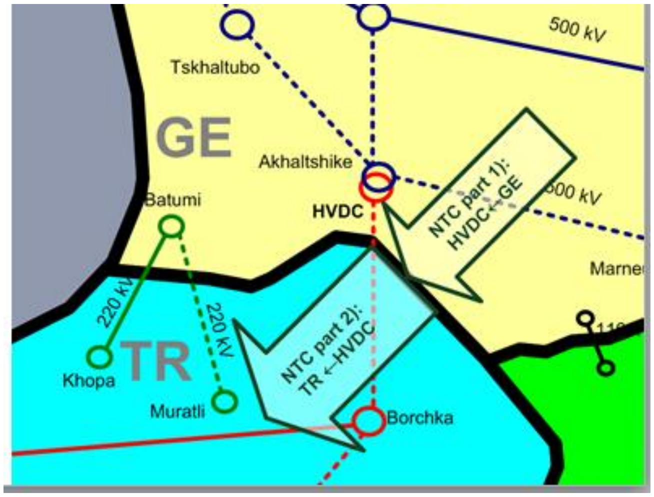


Figure 16: NTC calculation on asynchronous border

1.21 NTC results harmonization

Two neighboring TSOs typically should both calculate the NTCs for the same border/direction. The best practice for harmonization of the results is checking of the capacity limitations issues, especially for problems encountered in other TSO's area.
As a rule, if no agreement for harmonized value of NTC can be achieved between two neighboring TSOs, than lower of the two values should be taken as common NTC.
The example of NTC calculation report, suitable for harmonization process is given in the following Figure.

Calculated by: GSE	NTC calculation							Source/sink information				Static stability calculation results (For AcceptedStep + 1)			Dynamic stability calculation (For AcceptedStep + 1)		Technical description
	STE	50	MW														
Period: April 2013	NTF	BCE	DEmax	TTC	TTF	TRM	NTC	Source area	Shift method	Sink areas	Shift method	CAUSE: Outage of element	RESULT: Overloading of element	I/Imax %, or S/Snom	CAUSE: Analyzed disturbance	RESULT: Dynamic instability description	Comments
GE -> TR *	0	0	350	350	352	0	350	GE 50%, AZ 50%	Generation shift list	TR	Prop To Reserve	500 kV OHL Imereti (Enguri-Zestafoni) (GE)	TR 500/220 Enguri (GE) 220 kV OHL Vardnili-Zugdidi 220 kV OHL Menji-Qutairi	142% 105% 148%			Special Protection Schemes (SPS) are used for tripping part of generation in Enguri HPP and part of load in East GE in order to remain the post-contingency load flow values on 220 kV backbone in permitted ranges
TR -> GE				0			0	TR		GE							
AZ -> GE	94	100	250	350	348.2	50	300	AZ		GE							
GE -> AZ	-94	-100		-100			-100	GE		AZ							

Additional info*:
- 350 MW unit of back-to-back considered in service.
- N-1 static analysis: Single 500 kV elements outages in GE
- Dynamic analysis: 3-phase faults on single 500 kV line in GE, cleared after 0.1sec with tripping of the faulted line
- Shift: Increase in HPP Enguri (GE), and AZTPP (AZ), each step 50:50. Increase power transfer on HVDC back-to-back.

Notified Transmission Flow (NTF) is the **physical** flow over the tie-lines between the considered areas observed in the base case model prior to any generation shift between the areas. It results from the Base Case Exchanges (BCE).

Base Case Exchange (BCE) - assumption about "exchange programs" between TSOs

The maximum exchange ΔEmax - maximum additional program exchange (over the BCE) that meets the security standards

The Total Transfer Capacity (TTC) is the maximum exchange program between two areas compatible with operational security standards applicable at each system, if future network conditions, generation and load patterns were perfectly known in advance
TTC = BCE + ΔEmax

The additional physical flow ΔFmax is the physical flow over the tie lines between the two areas, induced by the maximum generation shift **ΔEmax**.

Total transfer Flow (TTF) is the net **physical** flow across the border associated with an exchange program of magnitude TTC, provided that no other exchanges have been modified from the base case (except the one between the two areas between which the TTC is calculated).
TTF = NTF + ΔFmax

Transmission Reliability Margin (TRM) is a security margin that deals with different uncertainties on the computed TTC values

Net Transfer Capacity (NTC) is the maximum exchange program between two areas compatible with security standards applicable in both areas, taking into account the technical uncertainties on future network conditions.
NTC = TTC-TRM

Figure 17: NTC calculation report

Time table for NTC calculation for month M

The procedure of NTC calculation for month M, at the end of month M-2, is roughly scheduled in Table 3.

Table 4. Time table for NTC calculation for month M

Static stability calculations: *Azerenerji, GSE, TEIAS*	Month M-2: 25^{th} -26^{th}
Dynamic stability calculations: *Azerenerji, GSE, TEIAS*	Month M-2: 27^{th}-28^{th}
Harmonization of NTC values: *Azerenerji, GSE, TEIAS*	Month M-2: 28^{th}-29^{th}
Publishing of NTC values: *Azerenerji, GSE, TEIAS*	Month M-2: 30^{th}
NTC allocation:	Month M-1: 1^{st}-10^{th}
Usage of capacities:	Month M

4. References

[1] Definitions of Transfer Capacities in liberalized Electricity Markets, Final Report, ETSO, April 2001

[2] Procedures for cross-border transmission capacity assessments, ETSO, October 2001

[3] UCTE Operational Handbook, Policy 4

[4] Network Code on Capacity Allocation and Congestion Management, ENTSO-E, September 2012