1st DSA Stakeholder Workshop
Brussels | 23 May 2018

23 May 2018

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Part 1: Welcome & Introduction
10:00-10:30

Knud Johansen /
Remigiusz Warzywoda

23 May 2018

Welcome! Let’s present ourselves!

Hans	Abildgaard	Energinet	Denmark
Pieter	Tielens	Tractebel (Engie)	Belgium
Karstein	Brekke	Hydro Energi AS	Norway
Mitja	Paaker	ELES	Slovenia
Harri	Kuisti	Fingrid	Finland
Athanasios	Krontiris	ABB	Germany
Rafal	Kuczynski	PSE	Poland
Bieshoy	Awad	National Grid	United Kingdom
Eric	Dekinderen	VGB	Belgium
Susan	Mwape	National grid	United Kingdom
Luca	Guenzi	Solar turbines - Euturbine	Switzerland
Uros	Gabrijel	ACER	Slovenia
Ilari	Ristolainen	Wärtsilä Finland	Finland
Eckard	Quitmann	ENERCON GmbH	Germany
Mustafizur	Rahman	Wartsila Finland Oy	Finland
Ivan	Dudurych	Eirgrid	Ireland
Ton	Geraerds	RWE Generation	Netherlands
knud	johansen	Energinet	Denmark
Ralph	Pfeiffer	Amprion GmbH	Germany
Stein	Øvstebø	Hydro	Norway
olivier	bronckart	ELIA	Belgium
Manuel	Jäkel	innogy SE	Germany
Remigiusz	Warzywoda	PSE	Poland
Marios	Zarifakis	VGB	Ireland

1ST DSA Stakeholder Workshop - AGENDA

1. Welcome & introduction (10:00-10:30)
2. Brief presentation of the SO GL requirements & planned activities for fulfilment (10:30-11:00)
3. Coffee & Tea break (11:00-11:15)
4. Current practice in RG CE (11:15-12:00)
5. Current practice in RG Nordic(12:00-12:30)
6. Lunch (12:30-13:30)
7. Current practice in RG GB / IE / NI(13:30-14:15)
8. Presentation of current practice in RG Baltic (14:15-14:45)
9. Coffee & Tea break (14:45-15:00)
10. Question and answer session on DSA and Minimum Inertia in general (15:00-15:45)
11. Conclusions and wrap up of workshop (15:45-16:00)

Workshop Expectations

- Familiarization with SO GL requirements on dynamic stability monitoring and assessment
  - art. 38 Dynamic stability monitoring and assessment (DSA)
  - art. 39 Dynamic stability management (MI - minimum inertia)
- Explanation the needs for performing DSA
- Presentation of current practices on DSA and minimum inertia in different synchronous areas
- Exchange of views.
- Gather feedback and expectations.

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Part 2: SO GL requirements & planned activities
10:30-11:00

Knud Johansen /
Remigiusz Warzywoda

23 May 2018

SO GL art. 38 Dynamic stability monitoring and assessment

1. *Each TSO shall monitor the dynamic stability of the transmission system by studies conducted offline in accordance with paragraph 6. Each TSO shall exchange the relevant data for monitoring the dynamic stability of the transmission system with the other TSOs of its synchronous area.*
2. *Each TSO shall perform a dynamic stability assessment at least once a year to identify the stability limits and possible stability problems in its transmission system. All TSOs of each synchronous area shall coordinate the dynamic stability assessments, which shall cover all or parts of the synchronous area.*
3. *When performing coordinated dynamic stability assessments, concerned TSOs shall determine:*
   a) *the scope of the coordinated dynamic stability assessment, at least in terms of a common grid model;*
   b) *the set of data to be exchanged between concerned TSOs in order to perform the coordinated dynamic stability assessment;*
   c) *a list of commonly agreed scenarios concerning the coordinated dynamic stability assessment; and*
   d) *a list of commonly agreed contingencies or disturbances whose impact shall be assessed through the coordinated dynamic stability assessment.*
4. *In case of stability problems due to poorly damped inter-area oscillations affecting several TSOs within a synchronous area, each TSO shall participate in a coordinated dynamic stability assessment at the synchronous area level as soon as practicable and provide the data necessary for that assessment. Such assessment shall be initiated and conducted by the concerned TSOs or by ENTSO for Electricity.*
5. *When a TSO identifies a potential influence on voltage, rotor angle or frequency stability in relation with other interconnected transmission systems, the TSOs concerned shall coordinate the methods used in the dynamic stability assessment, providing the necessary data, planning of joint remedial actions aiming at improving the stability, including the cooperation procedures between the TSOs.*
6. *In deciding the methods used in the dynamic stability assessment, each TSO shall apply the following rules:*
   a) *if, with respect to the contingency list, steady-state limits are reached before stability limits, the TSO shall base the dynamic stability assessment only on the offline stability studies carried out in the longer term operational planning phase;*
   b) *if, under planned outage conditions, with respect to the contingency list, steady-state limits and stability limits are close to each other or stability limits are reached before steady-state limits, the TSO shall perform a dynamic stability assessment in the day-ahead operational planning phase while those conditions remain. The TSO shall plan remedial actions to be used in real-time operation if necessary; and*
   c) *if the transmission system is in the N-situation with respect to the contingency list and stability limits are reached before steady-state limits, the TSO shall perform a dynamic stability assessment in all phases of operational planning and re-assess the stability limits as soon as possible after a significant change in the N-situation is detected.*

SO GL art. 39 Dynamic stability management

1. *Where the dynamic stability assessment indicates that there is a violation of stability limits, the TSOs in whose control area the violation has appeared shall design, prepare and activate remedial actions to keep the transmission system stable. Those remedial actions may involve SGUs.*
2. *Each TSO shall ensure that the fault clearing times for faults that may lead to wide area state transmission system instability are shorter than the critical fault clearing time calculated by the TSO in its dynamic stability assessment carried out in accordance with Article 38.*
3. *In relation to the requirements on minimum inertia which are relevant for frequency stability at the synchronous area level:*
   a. *all TSOs of that synchronous area shall conduct, not later than 2 years after entry into force of this Regulation, a common study per synchronous area to identify whether the minimum required inertia needs to be established, taking into account the costs and benefits as well as potential alternatives. All TSOs shall notify their studies to their regulatory authorities. All TSOs shall conduct a periodic review and shall update those studies every 2 years;*
   b. *where the studies referred to in point (a) demonstrate the need to define minimum required inertia, all TSOs from the concerned synchronous area shall jointly develop a methodology for the definition of minimum inertia required to maintain operational security and to prevent violation of stability limits. That methodology shall respect the principles of efficiency and proportionality, be developed within 6 months after the completion of the studies referred to in point (a) and shall be updated within 6 months after the studies are updated and become available; and*
   c. *each TSO shall deploy in real-time operation the minimum inertia in its own control area, according to the methodology defined and the results obtained in accordance with paragraph (b).*

Activities within ENTSO-E

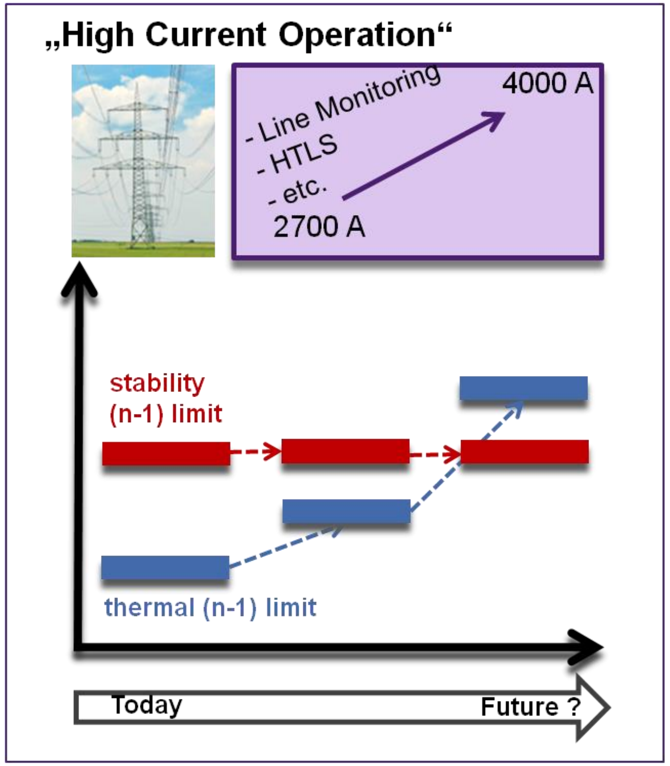
- In May 2017 the DSA Project was established. It's main task is to coordinate the works (on fulfilment SO GL requirements) that is already lead by respective expert teams in different regions.
- Coordination is mainly done through the internal ENTSO-E workshops
- Two ENTSO-E workshops have been organized. 1st in Autumn 2017. 2nd in April 2018. Goals of the workshops:
  - familiarize TSO experts with the SO GL requirements
  - gather and exchange information on current practices
  - discuss the solutions
- 3rd internal workshop will be probably organized in Summer/Autumn 2018

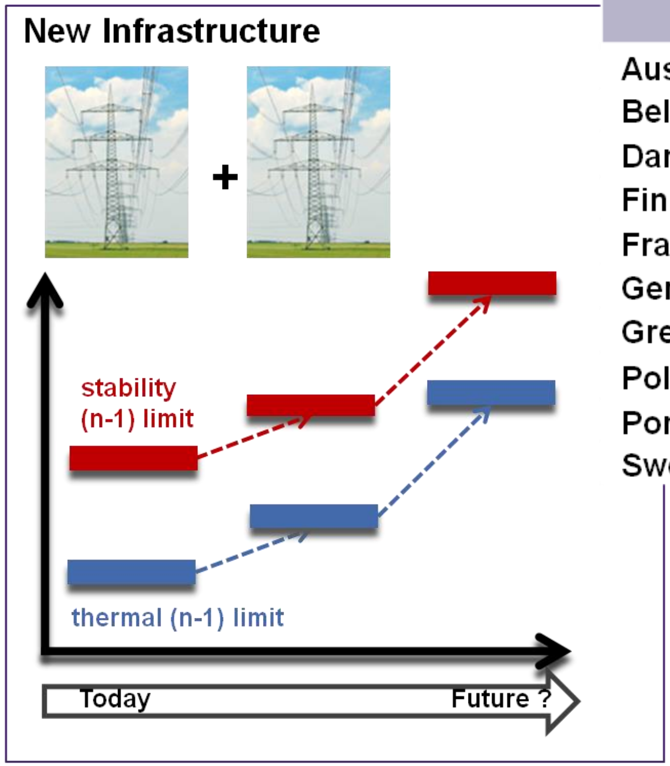
DSA Introduction

SG System Protection and Dynamics
Hans Abildgaard, Energinet

DSA WS May 23nd 2018

Why DSA

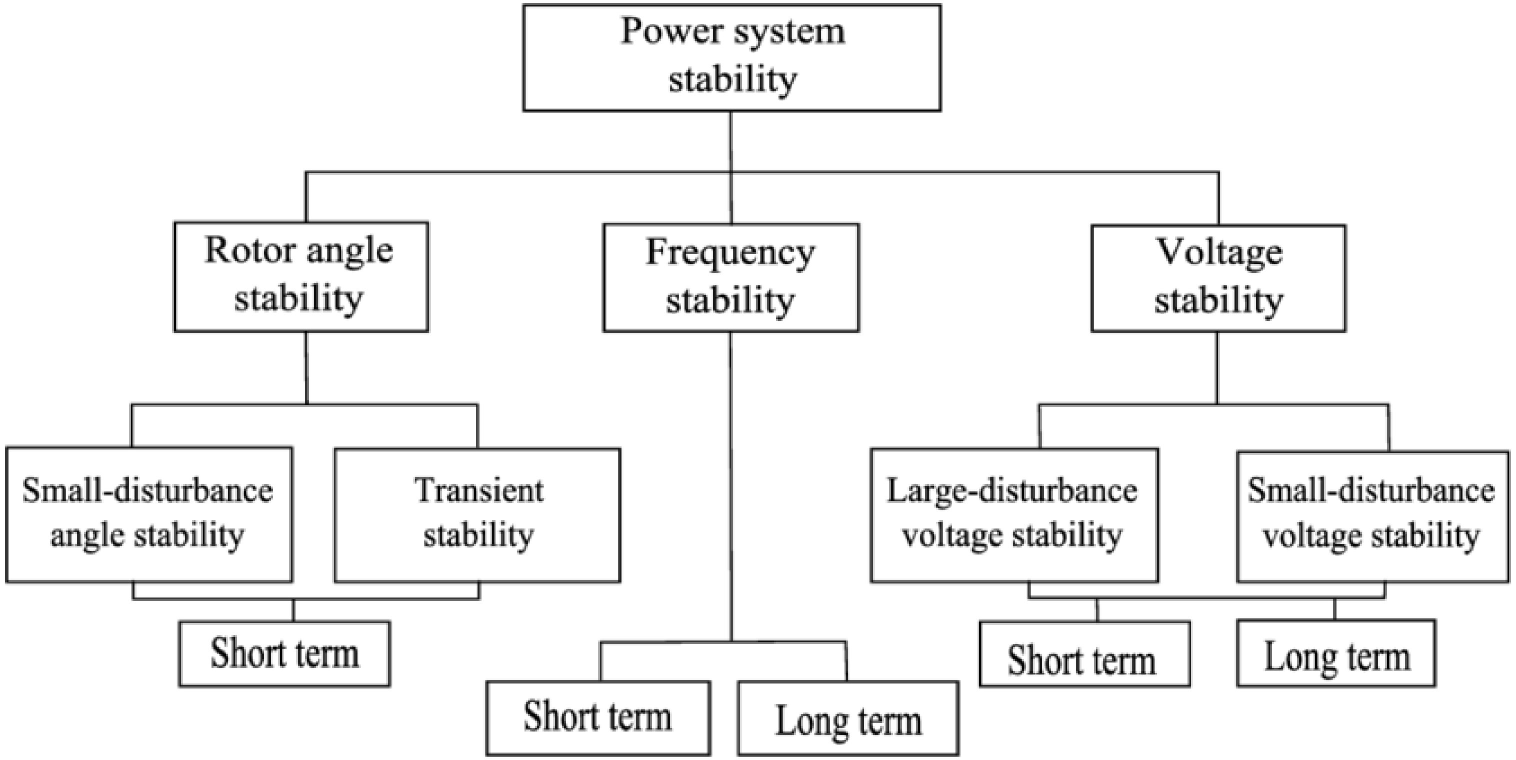




Country	Mean duration to build new lines
Austria	3
Belgium	5
Danmark	2,5
Finland	5
France	6,5
Germany	10
Greece	6
Poland	4
Portugal	2
Sweden	7

- (n-1) contingency analysis is not enough!
- Additional calculations are required

Source SPD WS 10. Nov. 2010, Brussels



Definition and classification of power system stability IEEE/CIGRE joint task force on stability terms and definitions, IEEE Transactions on Power Systems, Aug. 2004

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RG CE activities

SG System Protection and Dynamics
Hans Abildgaard, Energinet

23 May 2018

Article 38 Dynamic stability monitoring and assessment

Analysis for Continental Europe

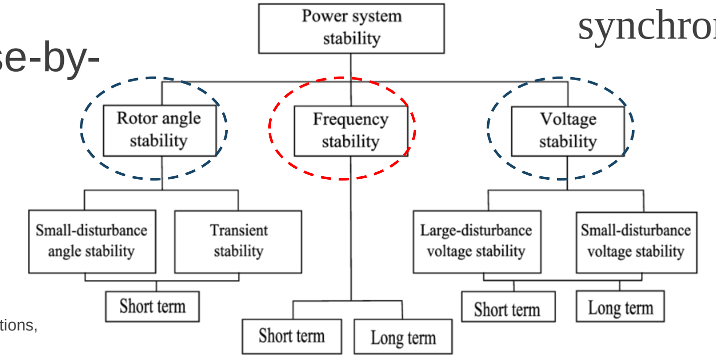
- SO GL addresses issues relevant for normal and alert state
- In the CE system frequency stability assessment is covered by the 3 GW FCR provision
- Beyond normal and alert state frequency stability is relevant for the defense plan which is addressed in NC ER
- DSA is required only for rotor-angle and voltage stability monitoring and assessment

Implementation proposal

- Each TSO develops an individual DSA concept for his control area and involves neighboring TSOs if necessary
- DSA can be limited to transient rotor-angle stability and voltage stability
- Small-disturbance angle stability addressed by expert group for the synchronous area (SPD) on a case-by-case basis and for relevant TSOs
    - Accurate damping requires accurate load models

Article 38
Each TSO is obliged to implement a Dynamic Stability Assessment (DSA) in his control zone and to perform it at least once a year

- Minimum as an offline application
- Dynamic stability includes rotor-angle stability, frequency stability and voltage stability
- All TSOs of a synchronous area shall coordinate DSA concerning models, scenarios and contingencies
- DSA shall cover all or parts of the synchronous area.



Definition and classification of power system stability
IEEE/CIGRE joint task force on stability terms and definitions,
IEEE Transactions on Power Systems, Aug. 2004

Article 39 Minimum inertia requirements

Analysis for Continental Europe

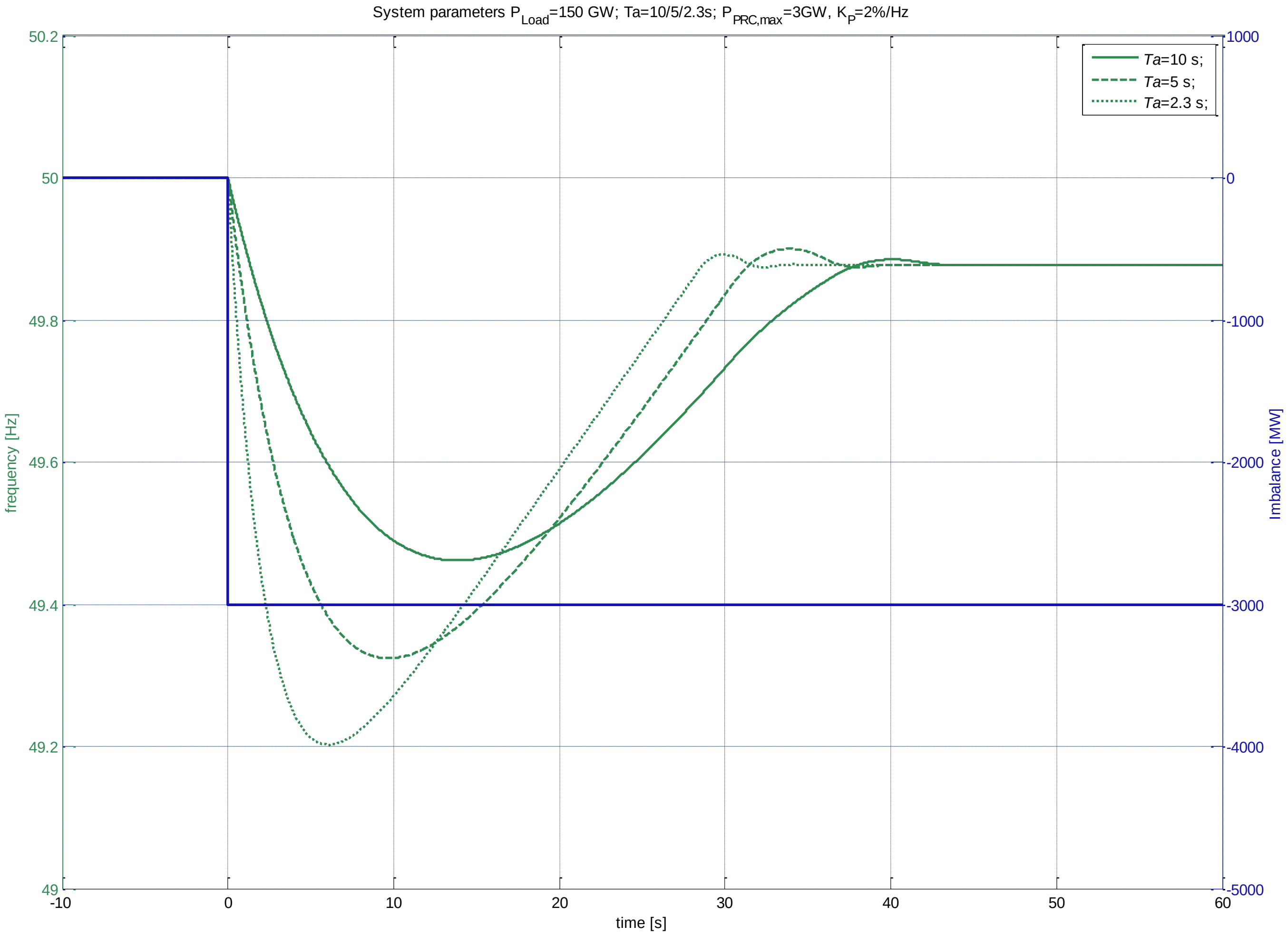
- In the CE system inertia challenge is only relevant in case of a system split which is covered by NC ER

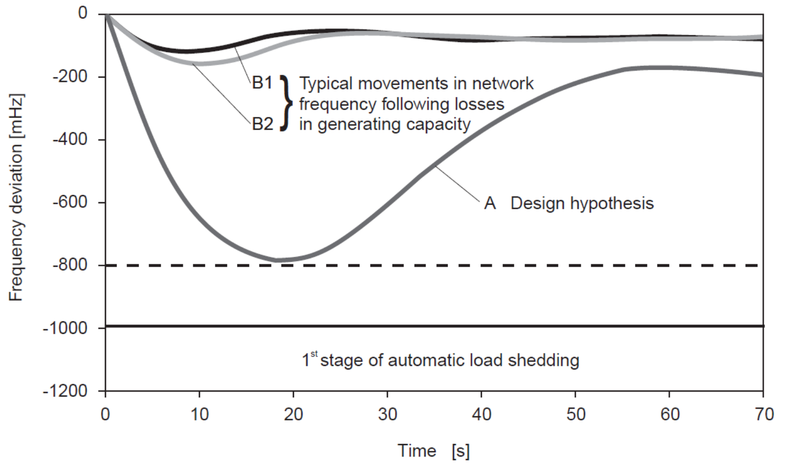
Implementation proposal

- The required study to identify the need of a minimum inertia will be prepared by SG SPD.
- Existing SPD studies can be used to prove, that a minimum inertia is not required for ordinary and exceptional contingencies in CE.
- This study will also point out, that requirements on minimum inertia have to be discussed as part of the defense plan (NC Emergency and Restoration)

Article 39
All TSOs of a synchronous area shall conduct a common study to identify whether a minimum required inertia needs to be established, taking into account costs and benefits and potential alternatives.
If this study determines that a minimum inertia requirement is needed, the TSOs shall develop a methodology how to determine a minimum required inertia.

A39 CE inertia in low load case/normative incident





A Loss in generating capacity: P = 3000 MW, $P_{network}$ = 150 GW, self-regulating effect of load: 1% / Hz
B1 Loss in generating capacity: P = 1300 MW, $P_{network}$ = 200 GW, self-regulating effect of load: 2 % / Hz
B2 Loss in generating capacity: P = 1300 MW, $P_{network}$ = 200 GW, self-regulating effect of load: 1% / Hz

https://www.entsoe.eu/Documents/SOC%20documents/RGCE_SPD_frequency_stability_criteria_v10.pdf

Alignment of dynamic models takes time!

- Implementation of 167 CGMES standard models is progressing slowly

Status December 15 2014

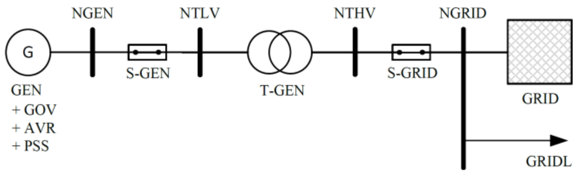
Implementation completed and results exported in xls available					
Vendor A	Vendor B	Vendor C	Vendor D	Vendor E	Vendor F
64	49	41	65	55	62

Status December 20 2017

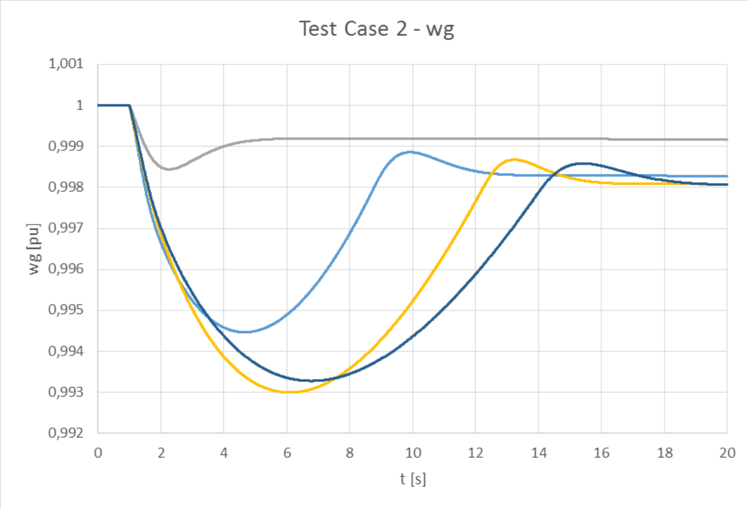
Implementation completed and results exported in xls available					
Vendor A	Vendor B	Vendor C	Vendor D	Vendor E	Vendor F
106	75	58	146	102	88

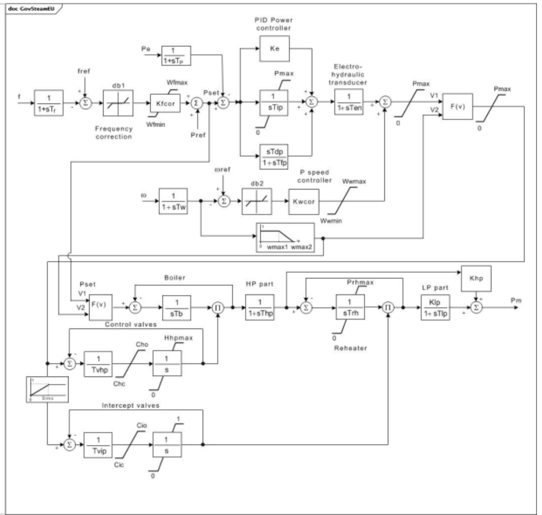
- Comparison for the one generic dataset is no guarantee for success
  - Treatment of zero time constants
  - Interpretation of deadbands
  - Different per unit system, etc.

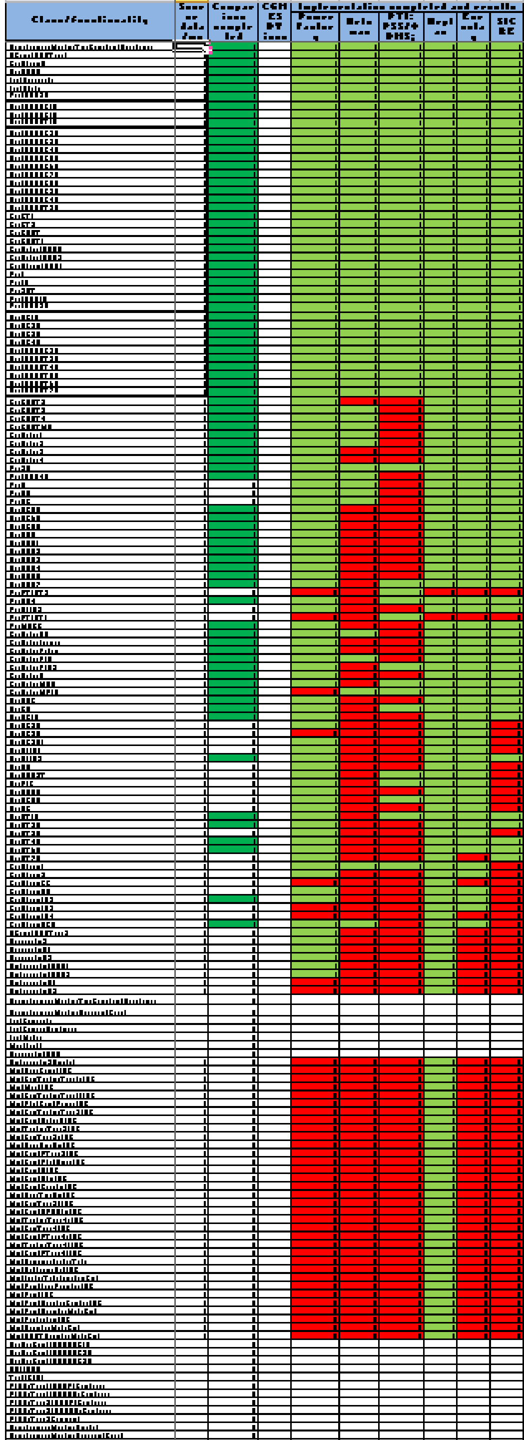
- Example comparing first simulated response from 4 simulation tools for a single governor model!



https://www.entsoe.eu/fileadmin/user_upload/_library/publications/entsoe/RG_SOC_CE/131127_Controller_Test_Report.pdf







SG SPD deliverables – messages to public workshop

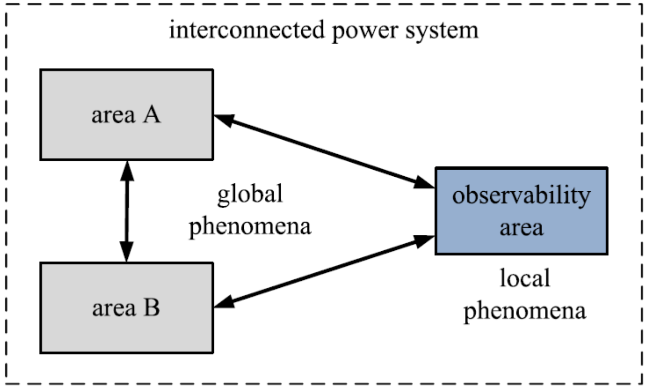
Article 38 (No deadline in SO GL but "*..some feedback on yearly DSA and coordination should arrive in the beginning of 2019*")

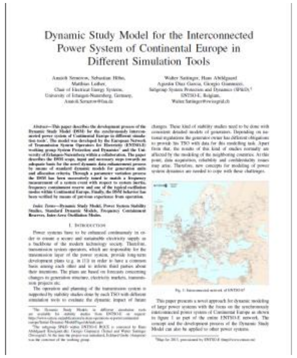
- Dynamic models will be available for TSOs to execute DSA studies

Article 39 (Deadline SO GL EIF 14/9/2017+2 years)

- Ready for Continental Europe
- Short report consolidating existing results ~ Q2 2019

SG SPD will continuously monitor system disturbances, propose mitigation measures and validate dynamic system models




Dynamic Study Model for the Interconnected Power System of Continental Europe in Different Simulation Tools

Dynamic Study Model for the Interconnected Power System of Continental Europe in Different Simulation Tools. PowerTech 2015 EES, SPD.

Further reading

System Dynamic Issues for the synchronous zone of Continental Europe

- https://docstore.entsoe.eu/Documents/SOC%20documents/Regional_Groups_Continental_Europe/2017/170926_RG_CE_TOP_08_1_D_1_SPD_Codes_TF_v5_System_Dynamic_Issues_for_CE.pdf

Frequency stability evaluation criteria (Inertia Report)

- https://www.entsoe.eu/Documents/SOC%20documents/RGCE_SPD_frequency_stability_criteria_v10.pdf

Overfrequency Control Scheme Report

- https://www.entsoe.eu/Documents/SOC%20documents/Regional_Groups_Continental_Europe/2017/170926_RG_CE_TOP_08.1_D.2_SPD_Codes_TF_v6_Overfrequency_Control_Schemes.pdf

Critical Fault Clearing Time Report

- https://www.entsoe.eu/Documents/SOC%20documents/Regional_Groups_Continental_Europe/2017/SPD_FCT-BestPractices_website.pdf

Dynamic Security Analysis Report

- https://www.entsoe.eu/Documents/SOC%20documents/Regional_Groups_Continental_Europe/2017/DSA_REPORT_Public.pdf

Initial Dynamic Model

- https://www.entsoe.eu/publications/system-operations-reports/continental-europe/Initial-Dynamic-Model/Pages/default.aspx

Frequency measurement requirements and usage

- https://docstore.entsoe.eu/Documents/SOC%20documents/Regional_Groups_Continental_Europe/2018/TF_Freq_Meas_v7.pdf

Requirements for UFLS settings

- https://www.entsoe.eu/Documents/Publications/SOC/Continental_Europe/141215_Technical_background_for_LFDD.pdf

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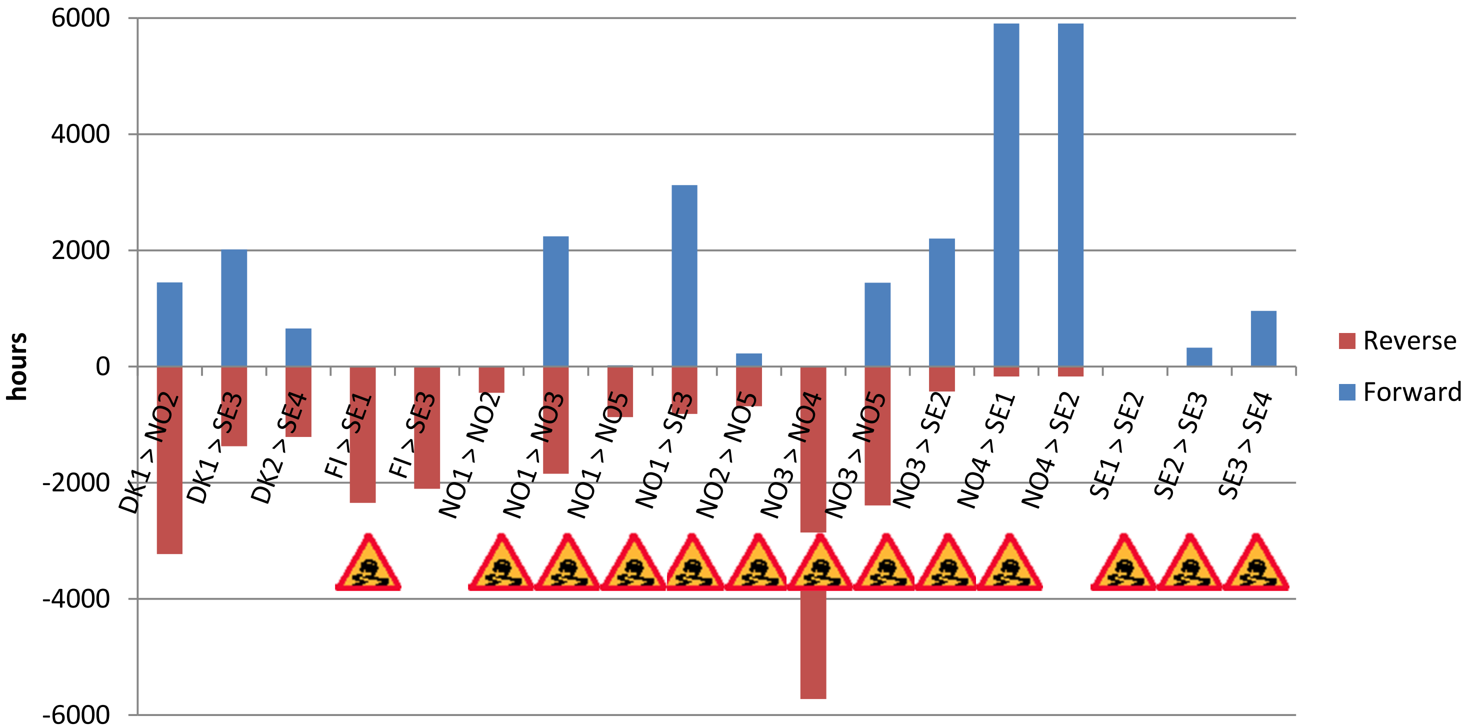
RG Nordic activities

Harri Kuisti, FinGrid

23 May 2018

Market limitations on Nordic internal borders



Compared to Continental Europe the dynamic issues are more dominant in the Nordic region

DSA and SO GL

Most relevant for Nordics is Art. 38.6:

(b) if, under planned outage conditions, with respect to the contingency list, **steady-state limits and stability limits are close to each other** or stability limits are reached before steady-state limits, the **TSO shall perform a dynamic stability assessment in the day-ahead operational planning phase** while those conditions remain. The TSO shall plan remedial actions to be used in real-time operation if necessary; and

(c) if the transmission system is in the N-situation with respect to the contingency list and **stability limits are reached before steady-state limits**, the **TSO shall perform a dynamic stability assessment in all phases of operational planning** and re-assess the stability limits as soon as possible after a significant change in the N-situation is detected.

DSA and SO GL

- DSA is already a part of transmission capacity calculation and operational planning

- A coordinated methodology will be gradually introduced and included Nordic System Operation Agreement

Performing DSA

Off-line studies already possible:

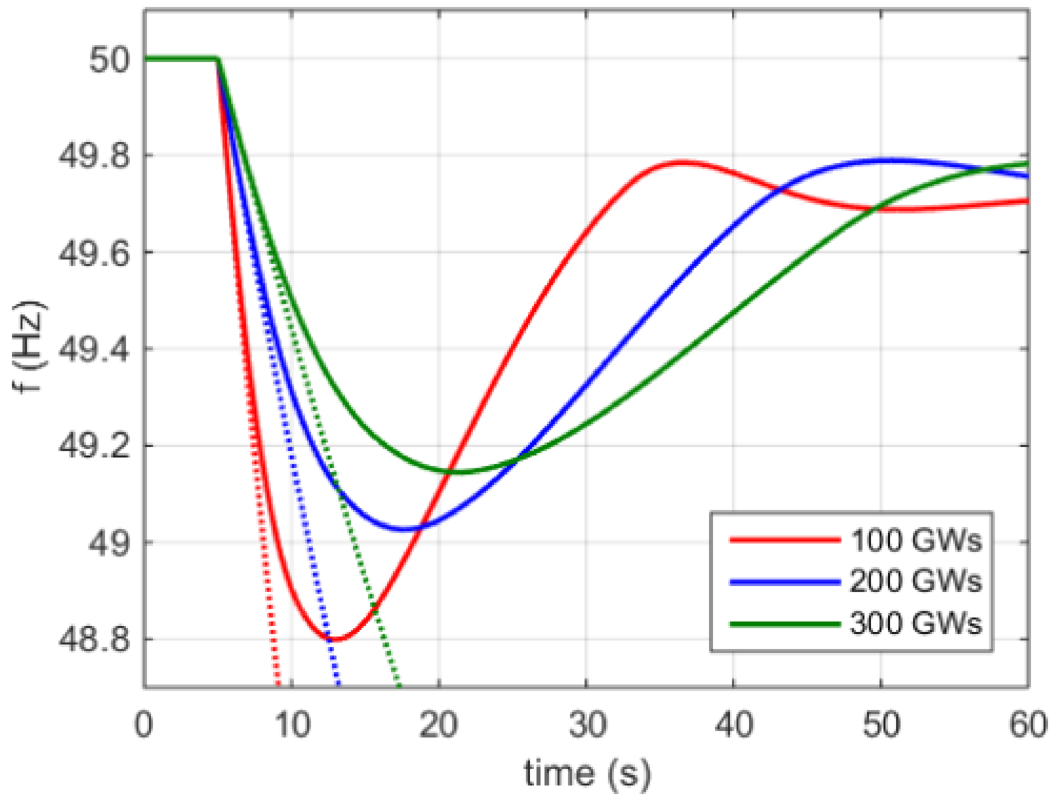
- **Nordic planning model (PSS/E)**
- **Svk and SN use also Aristo**

In future nearly real-time DSA becomes possible:

- **Common grid model will include dynamic models**
- **Many of dynamic models in Nordic planning model will need to be recreated in order to suit CGMES-standard**

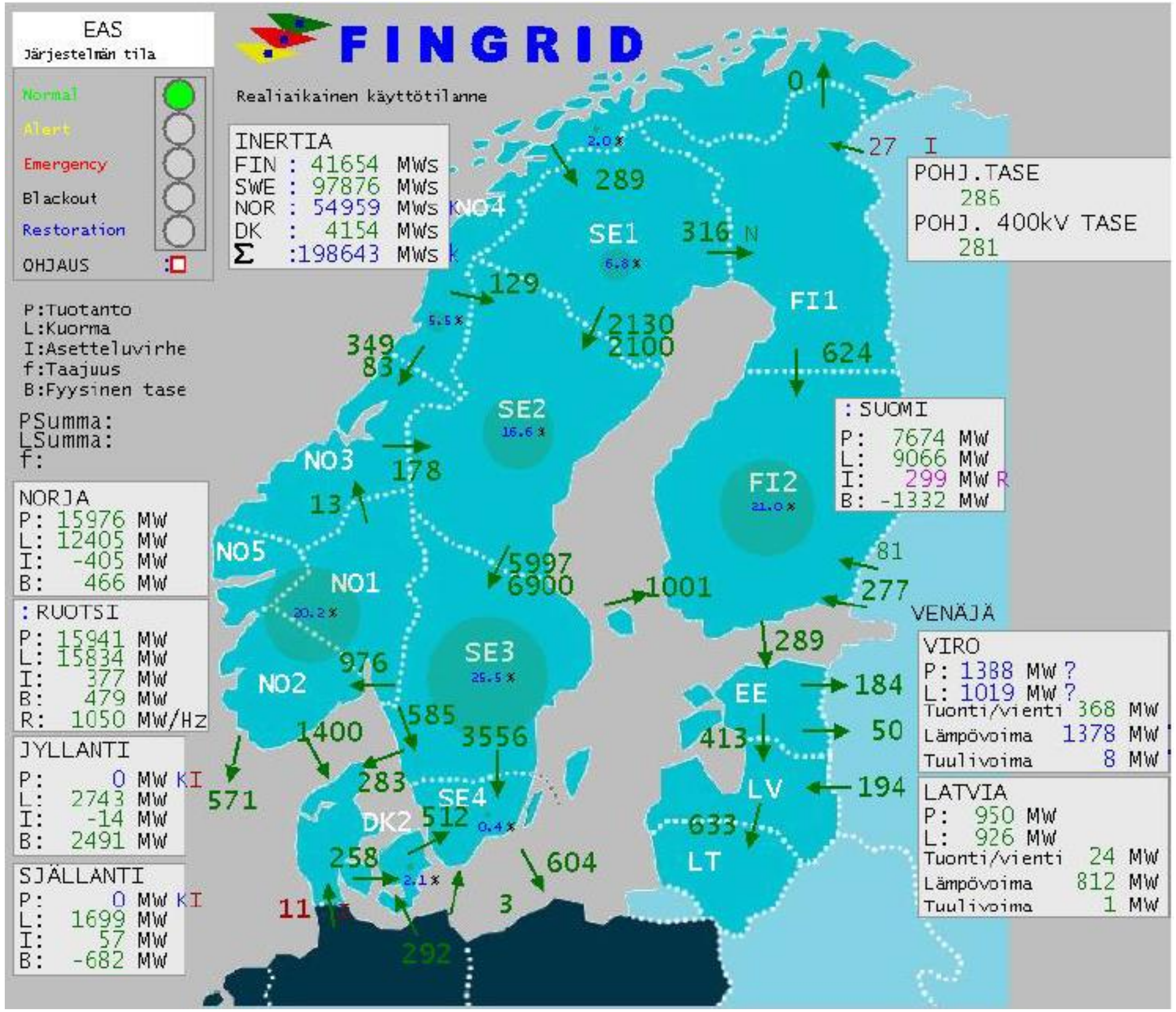
Inertia in the Nordic synchronous area

System reserves designed for loss of largest unit (1450MW: FCR-D 1250MW + load self regulation)



Inertia monitoring

- Tool developed to monitor the inertia real time level in the Nordic region
- Bottom-up approach
  - Based on breaker state and power measurements
- Visualized in each Nordic control room
- Further reading [Nordic report Future system inertia]



Inertia variation

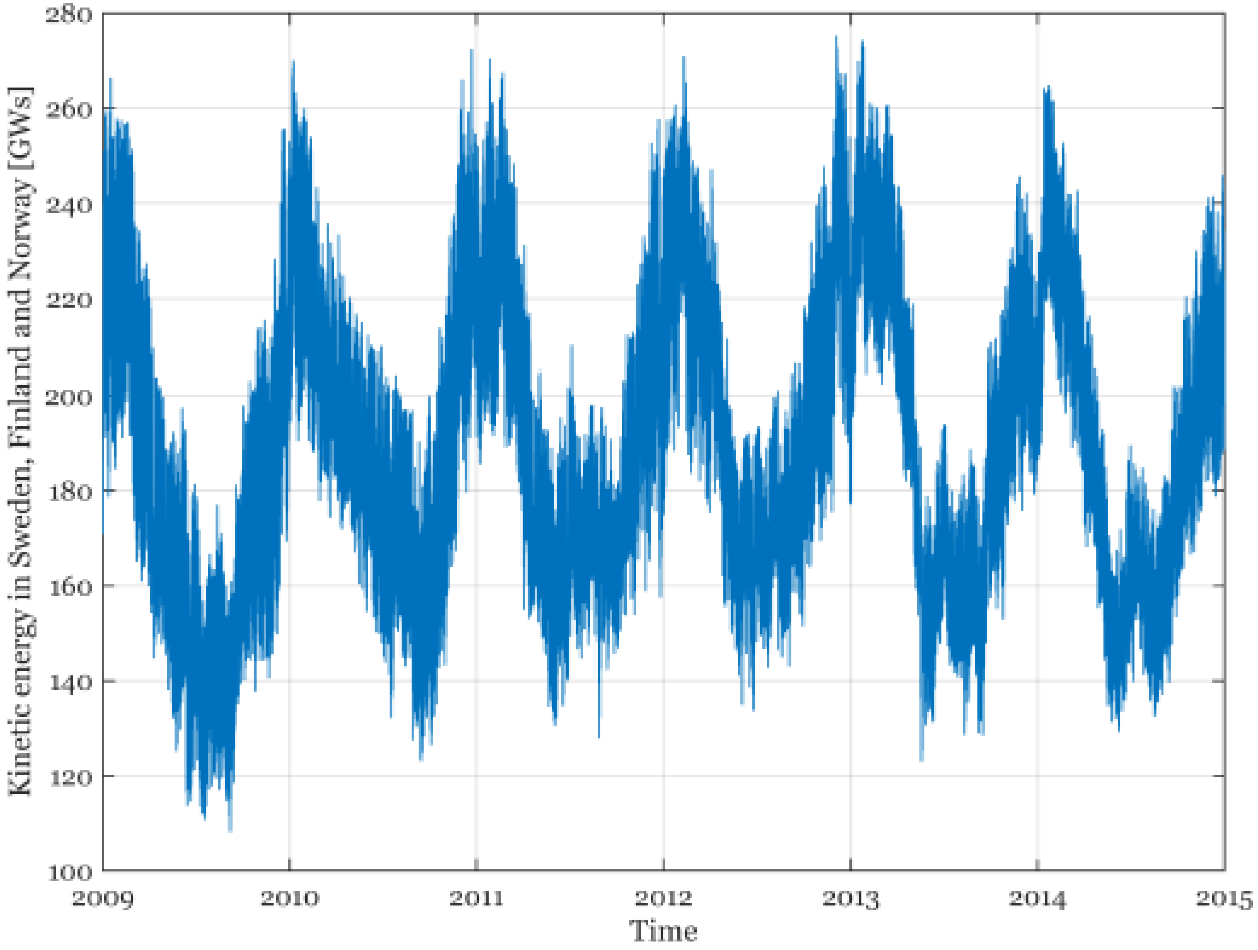
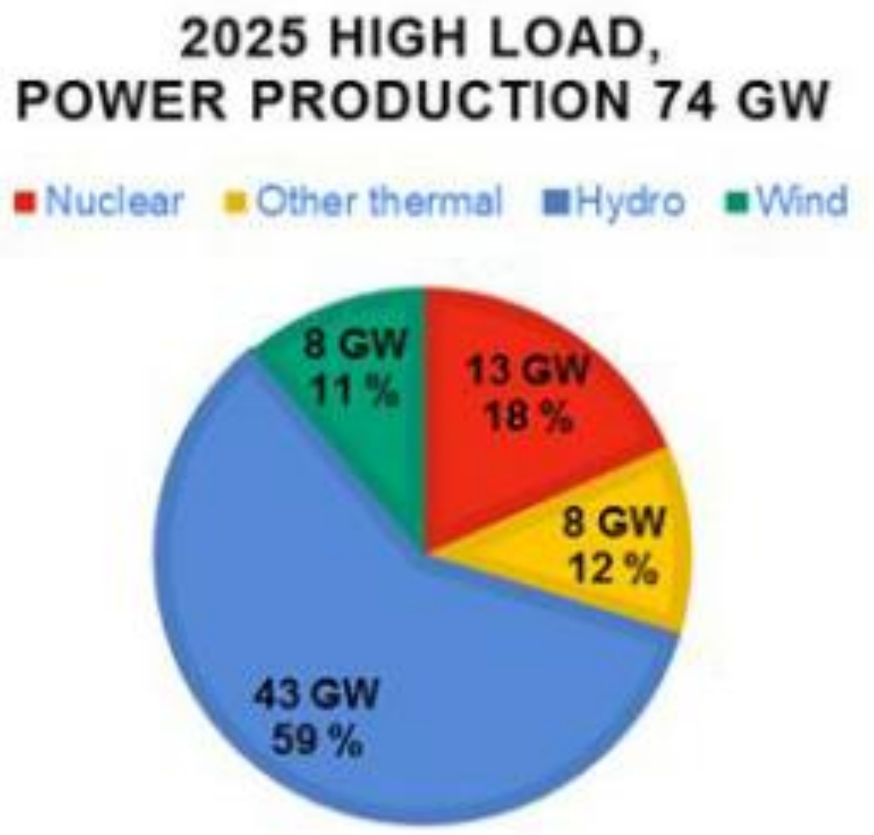
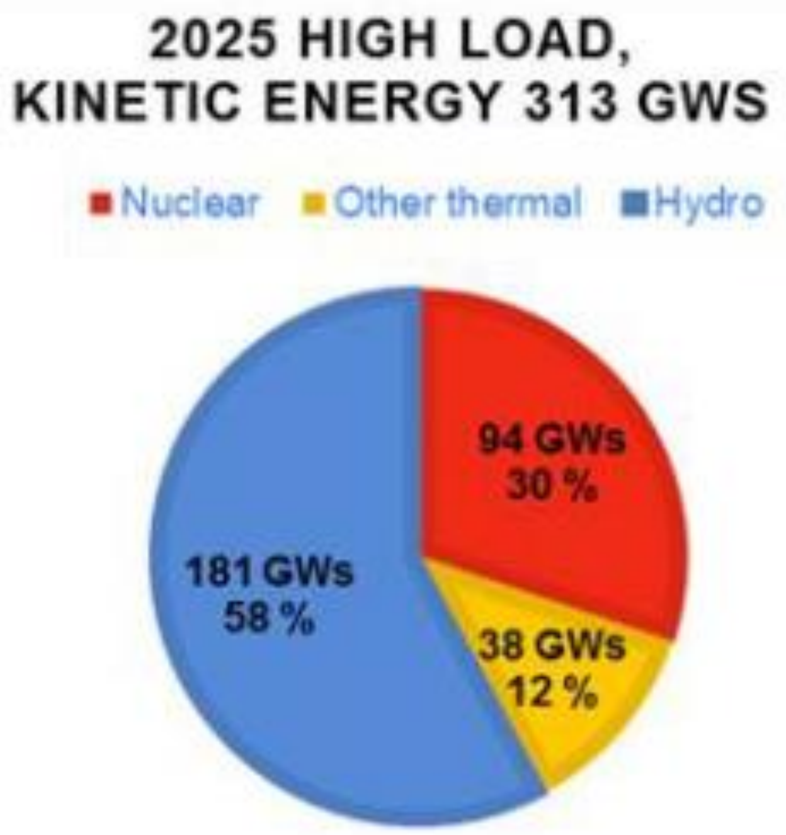


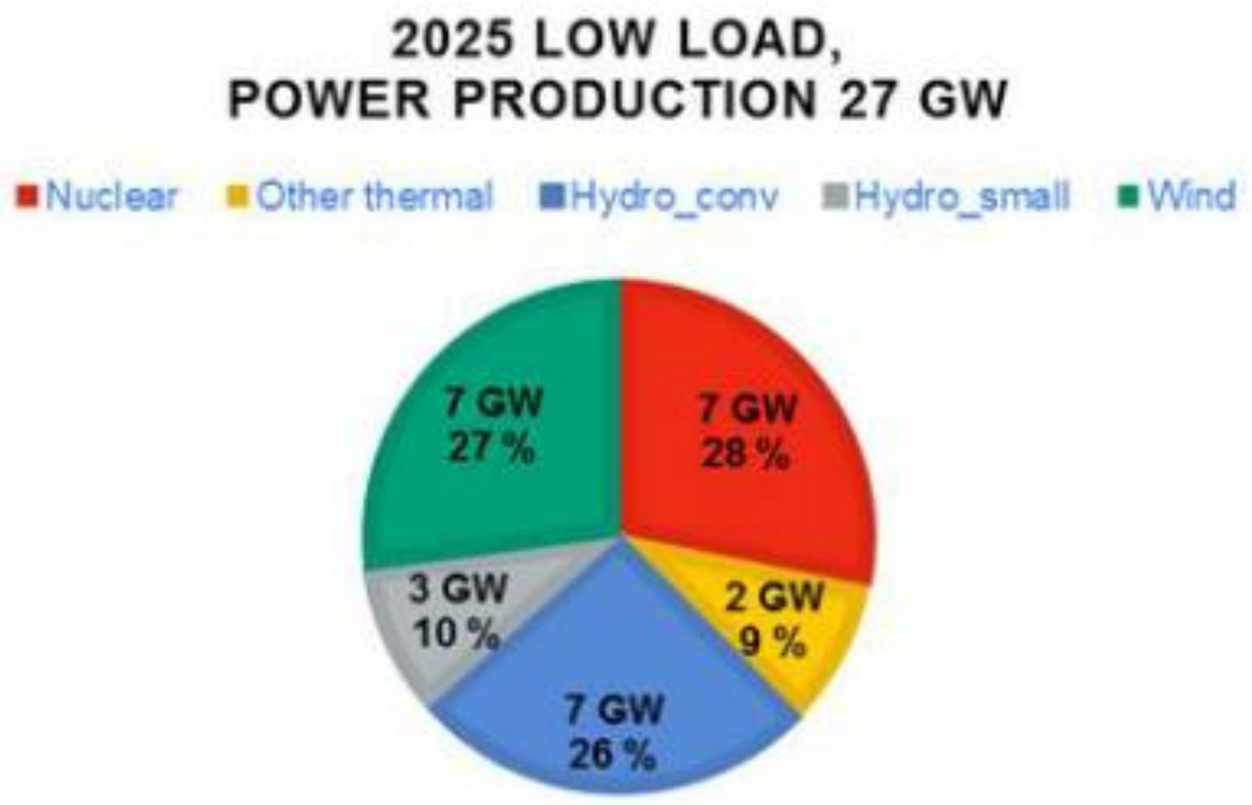
FIGURE 4.8: ESTIMATED KINETIC ENERGY IN SWEDEN, FINLAND AND NORWAY

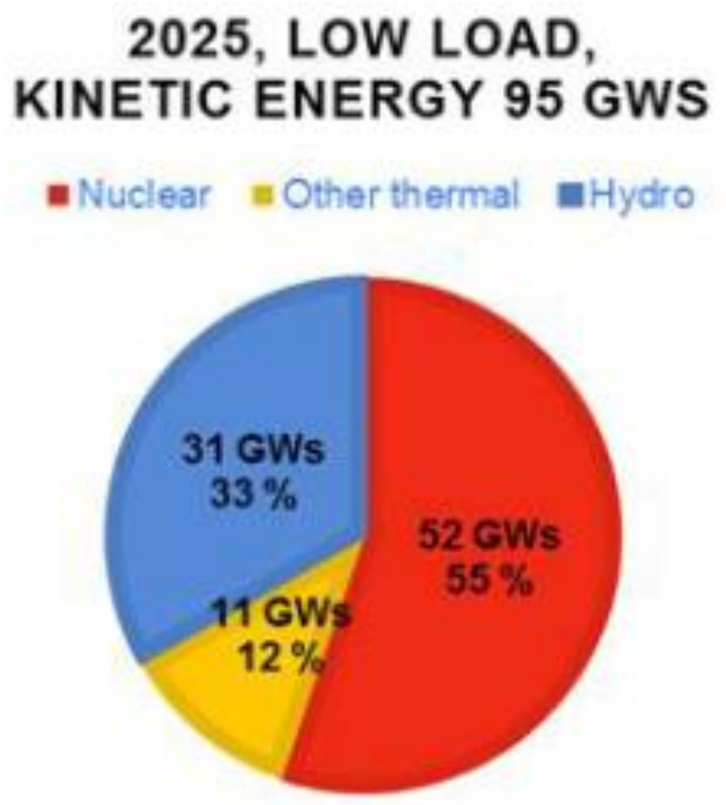
Future inertia during high load





Future inertia during low load





Handling low inertia situations

Several measures for handling low inertia cases have been identified to be further investigated:

- synthetic inertia
- hydro power plants running on minimum active power or as synchronous compensators
- reducing the size of the dimensioning incident
- adjustable FCR parameters for FCR contributing power plants

Suitable measures will be agreed on in Nordic System Operation Agreement

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RG GB activities

Susan Mwape, National Grid

23 May 2018

Dynamic stability monitoring and assessment requirements (Art.38)

- A suite of programs are used for offline studies from long term to day ahead
- Online studies to determine post-fault transient and dynamic stability issues in real time
- Studies are driven by: circuit availability, large synchronous plant availability, HVDC flows, voltage issues, thermal limits, outage patterns
- Remedial actions include bids and offers, generation load reduction, interconnector trades, emergency instructions, raising system voltage
- NGET does not currently exchange dynamic stability studies with other TSOs

System operational security standards

For the following faults…

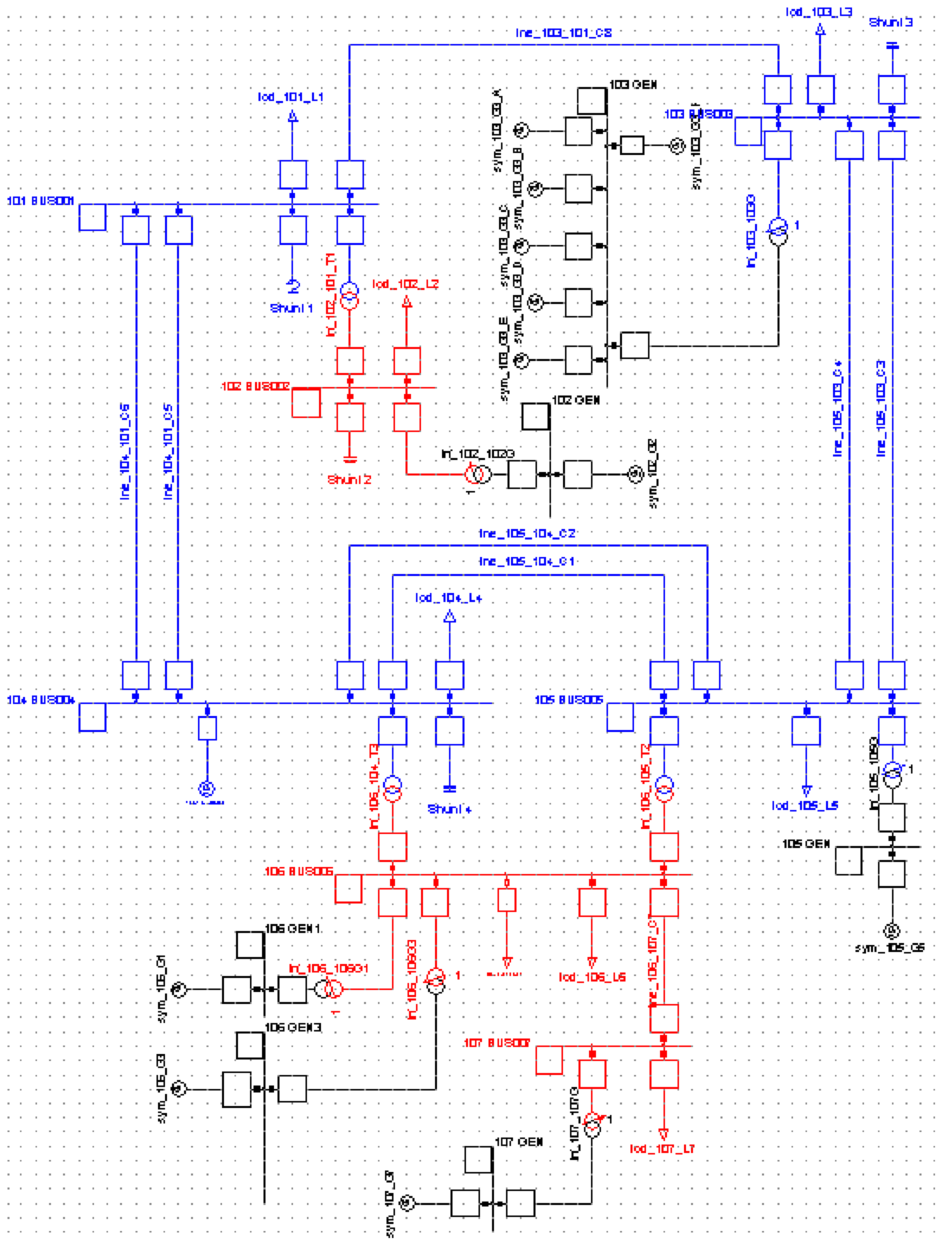
- Single circuit cable or overhead line
- Double circuit overhead line
- Busbar or mesh corner
- Supergrid transformer
- Reactive compensator
- The most onerous single system infeed

There shall not be:

- A loss of supply
- Permanent change in frequency below 49.5Hz or above 50.5Hz
- Unacceptable overloading of transmission apparatus
- Unacceptable high or low voltage conditions
- System instability

Network stability studies

- Simplified GB system representation
- Post fault transient angular and dynamic stability is assessed for most credible contingencies
- Tool flags credible contingencies as insecure if transient stability criteria is not met



Remedial actions

Action	Voltage impact	Downward margin	Inertia	Response
Synch Additional Machines	Helps	Worsens	Helps	Helps
Desyn Machines	Worsens	Helps	Worsens	Worsens
Reduce Interconnector Imports		Helps	Helps	Worsens
Position plant for response		Worsens		Helps

Dynamic stability monitoring and assessment (Art.38)

SOGL Article number	Current approach in GB
38.1 and 38.2	Dynamic assessment is already carried out
38.3 and 38.4	NGET is sole entity with SO responsibility for coordinated dynamic stability in GB synchronous area
38.5	Not relevant for GB synchronous area as transmission system is not AC-interconnected
38.6	Dynamic assessment rules specific to GB synchronous area

Dynamic stability management requirements (Art 39)

- To date studies are based on energy balancing and power factory scenarios
- In both cases it's clear that inertia has a significant effect on the rate of change of system frequency and the minimum frequency achieved.
- Reducing the largest credible loss reduces the maximum potential RoCoF following a loss
  - Increasing system inertia is less effective than reducing the largest loss
- Frequency Response requirements are driven by:
  - Synchronous demand, system inertia, Rate of change of frequency, largest loss, frequency limits

Dynamic stability management (Art.39)

Article number	NGET compliance
39.1	In the case of violation of stability limits, NGET has a process to carry out remedial actions
39.2	Process for clearing faults in time is calculated through dynamic system assessment
39.3	Current studies are based on reduction of largest loss, there is no set minimum inertia. - Minimum inertia study?

NG proposes maintaining dynamic stability requirements at a synchronous level in accordance with the existing approach

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RG IE / NI activities

Ivan Dudurych, EirGrid

23 May 2018

Power Systems of Ireland and Northern Ireland

9500 MW of conventional plant

4500 MW of windfarms

Peak Demand of 6500 MW

Valley Demand 2500 MW

Northern Ireland – Scotland

  500 MW HVDC (LCC)

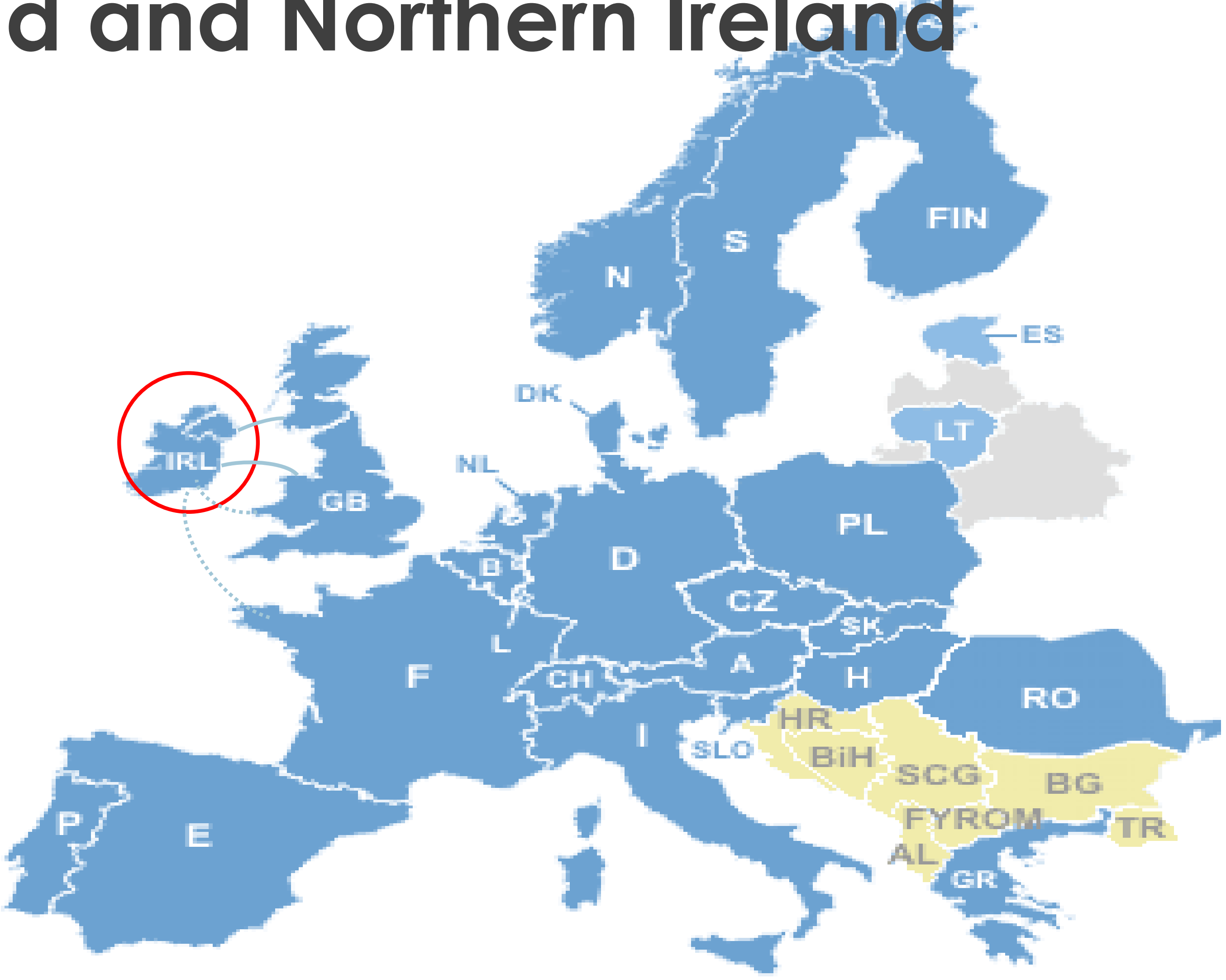
Ireland – Wales

  500 MW HVDC (VSC)

In consideration:

  700 MW HVDC Ireland-France: “Celtic Interconnector”

  500 MW HVDC Ireland-Wales: “Greenlink Interconnector”



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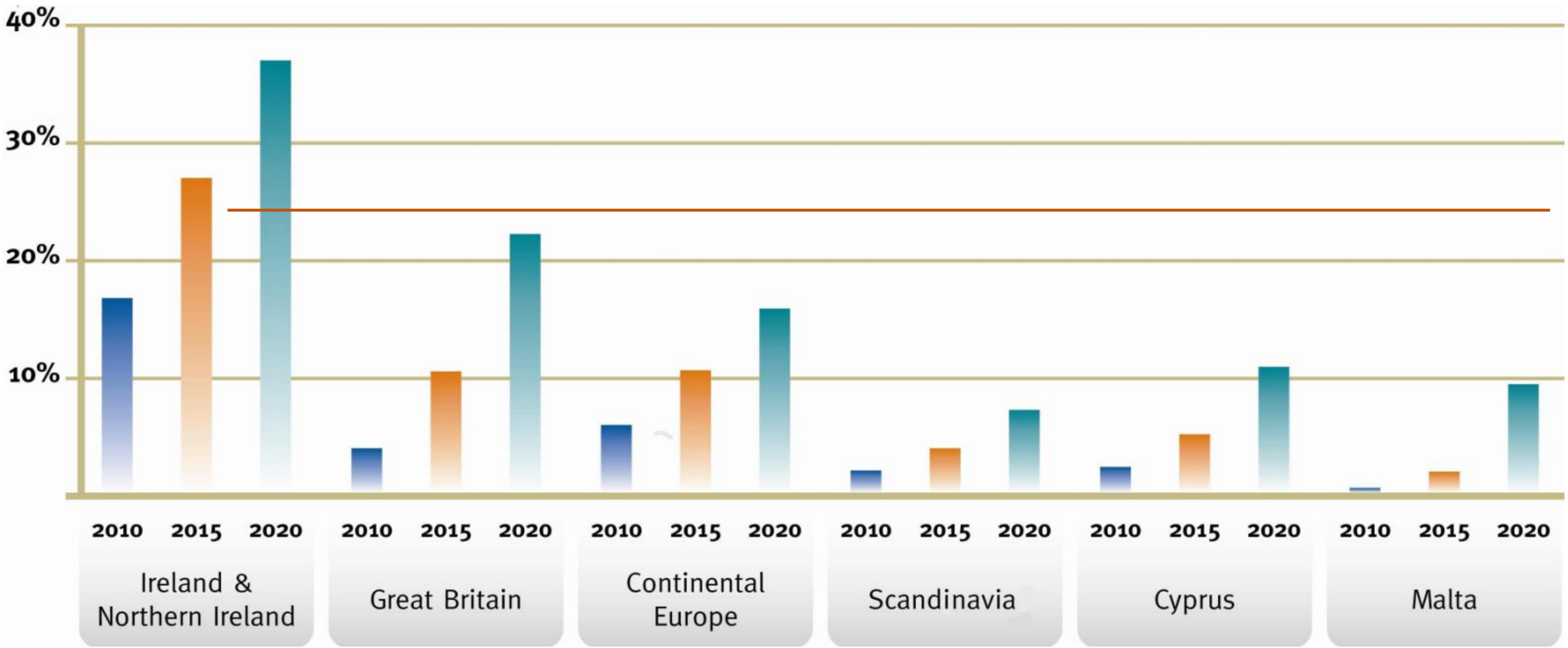
2020 Wind Targets



* Based on analysis of National Renewable Action Plans (NREAPs) as submitted by Member States

Implementation of Article 38 (Dynamic Stability Monitoring and Assessment)

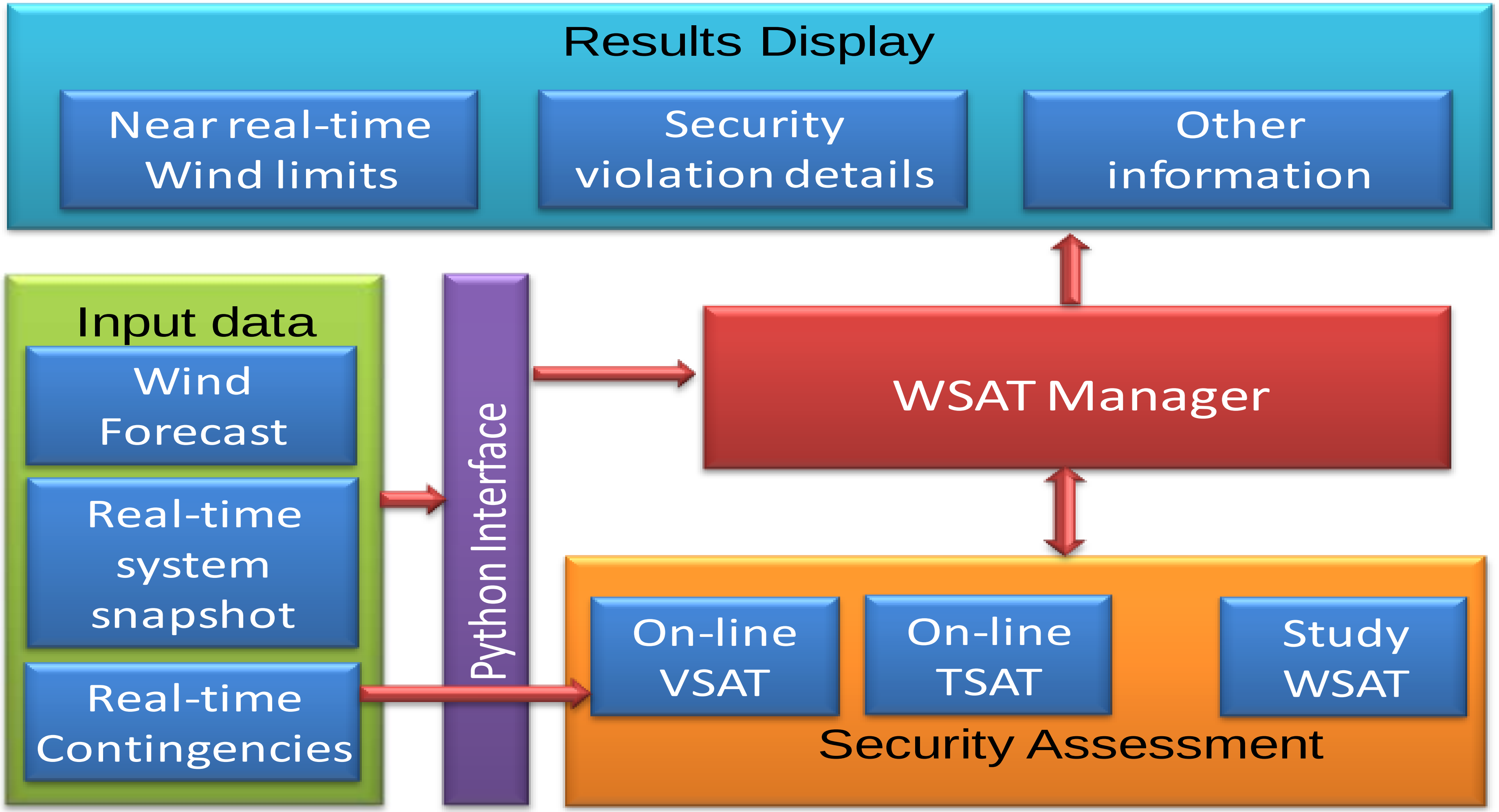
Wind Dynamic Security Assessment Tool (WSAT) automatically runs every 5 minutes (24/7 – 365) in both Ireland (IE) and Northern Ireland (NE) Electricity Control Centers

WSAT provides Grid Controllers with a real-time information and advice on operational security of the Grid

This exceeds the most strict requirement of Article 38 – paragraph 38(6)(c)

Conlcusion: for RG IE/NI the requirements of Article 38 are fully fulfilled

WSAT – Software Structure



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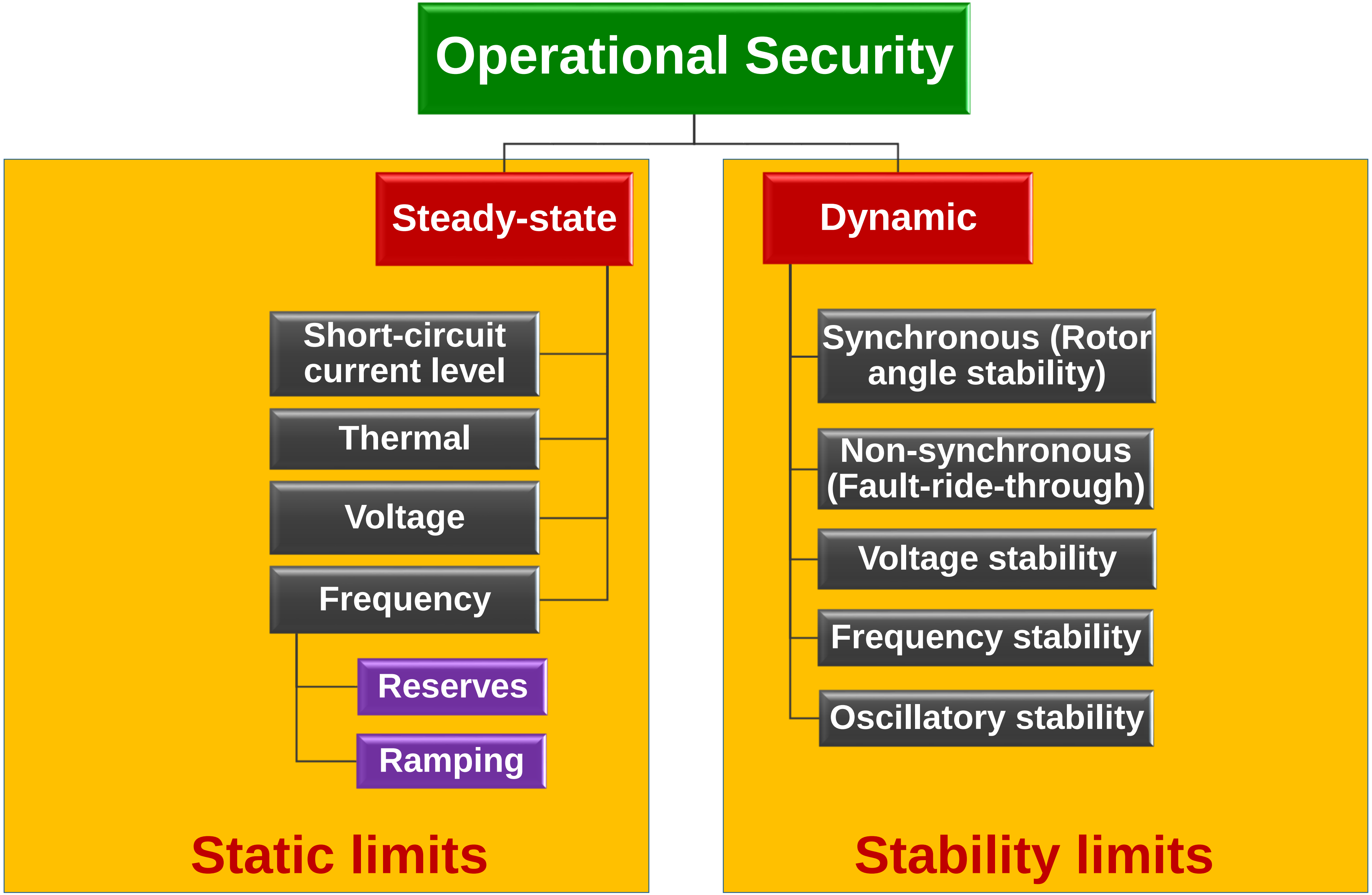
Operational Security
Steady-state
Short-circuit current level
Thermal
Voltage
Frequency
Reserves
Ramping
Static limits
Dynamic
Synchronous (Rotor angle stability)
Non-synchronous (Fault-ride-through)
Voltage stability
Frequency stability
Oscillatory stability
Stability limits

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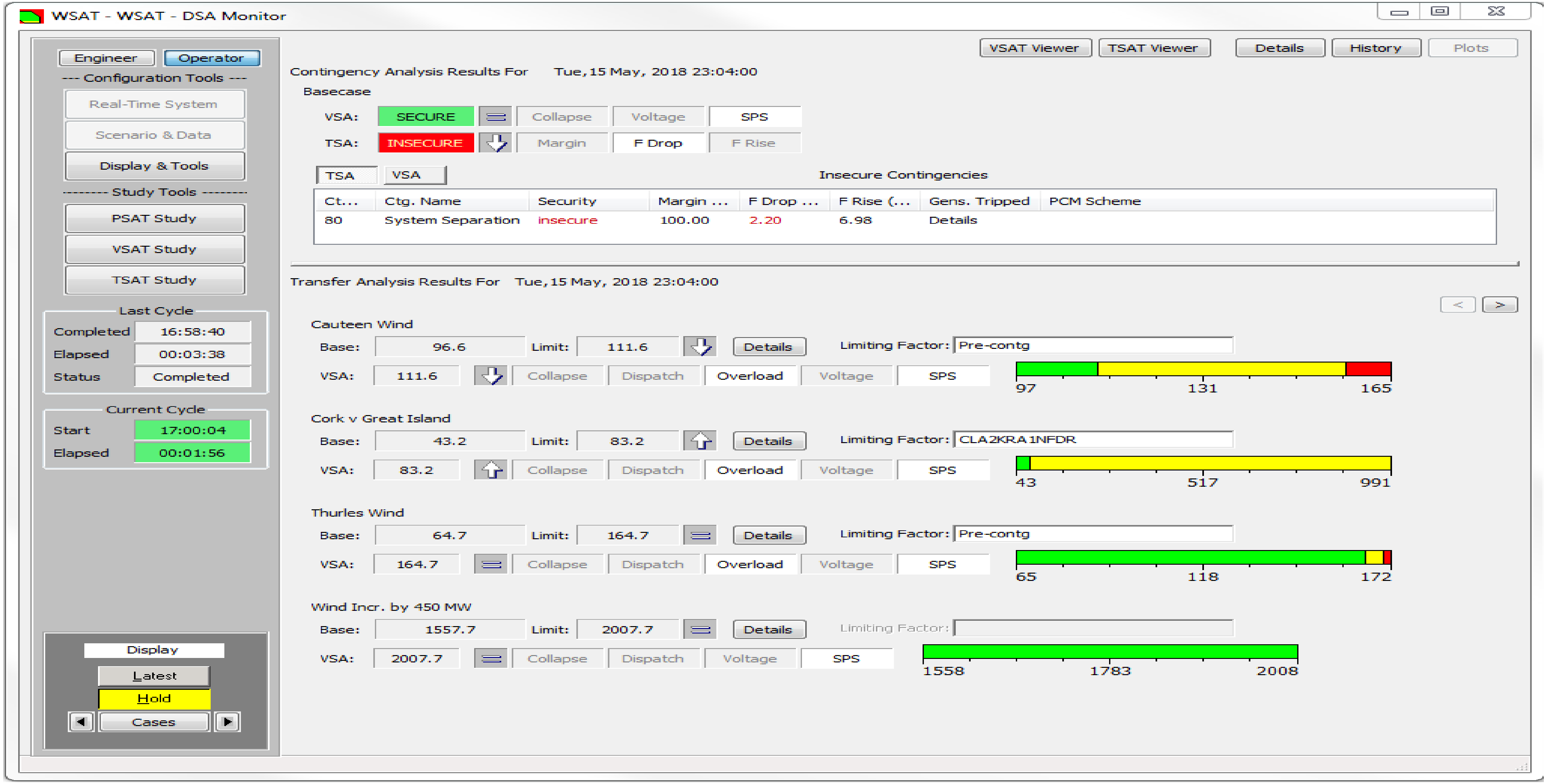
WSAT Monitor User Interface



Implementation of Article 39 (Dynamic Stability Management - paragraphs 1 and 2)

When WSAT indicates violation of stability limits, it also suggests remedial actions. These are performed by Grid Controllers using approved steps:

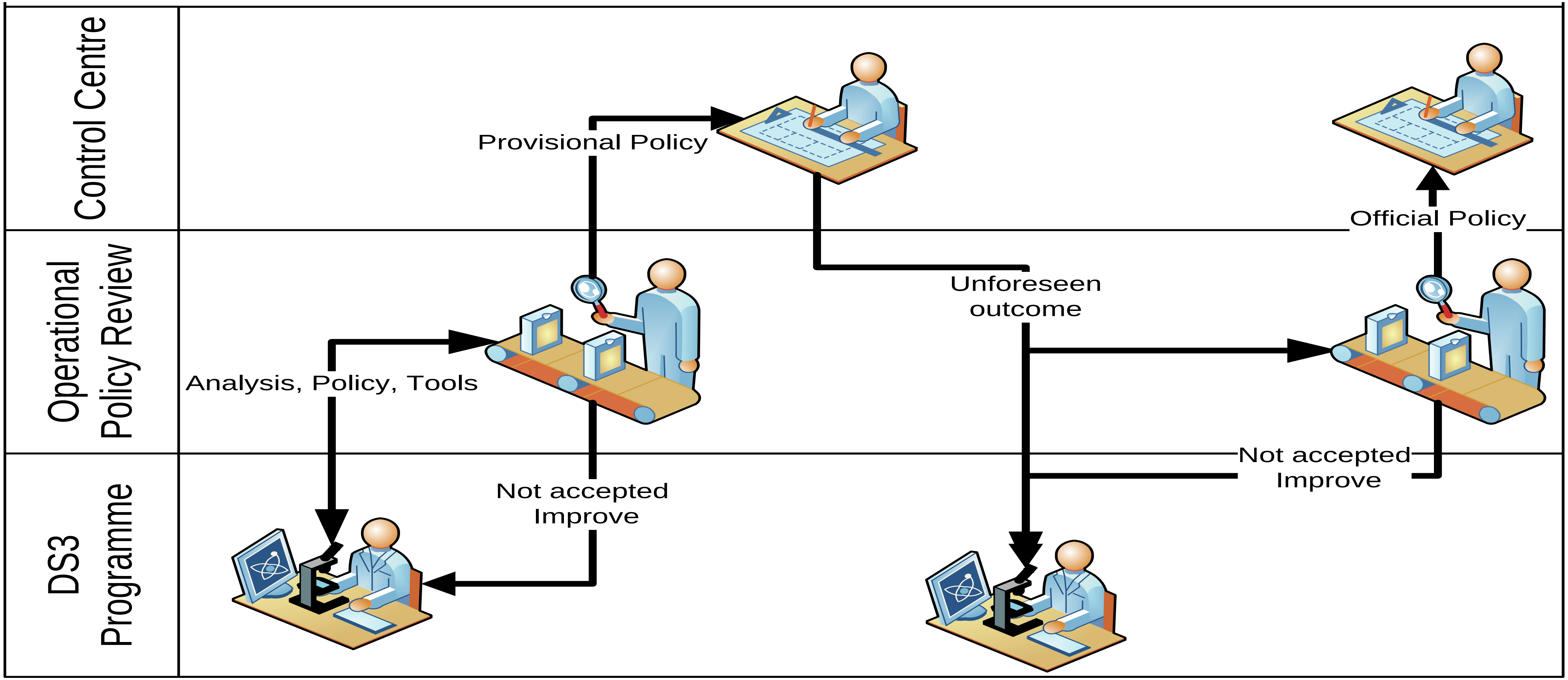
- Likelihood of the insecure scenario
- Severity of possible consequences
- Other factors (e.g. weather warnings, existence of substantial outages etc.)
- Action (as recommended by WSAT or/and from previous experience)

Critical Fault Clearance Time (CCT) and Fault-Ride-Through (FRT) requirements are indirect criteria of transient stability. These are to be met at planning stage before generator can be connected to the grid.

WSAT assesses transient stability directly – by running time-domain analysis of system every 5 minutes for the current system state.

Conclusion: for RG IE/NI the requirements of Article 39(1) and Article 39(2) are fully fulfilled

DS3: Operational Control Process



Implementation of Article 39 (Dynamic Stability Management - paragraph 3 - Inertia)

System Inertia is monitored in Control Centres in Ireland and Northern Ireland

System Inertia (SI) is a sum of inertias of all conventional generators on the system

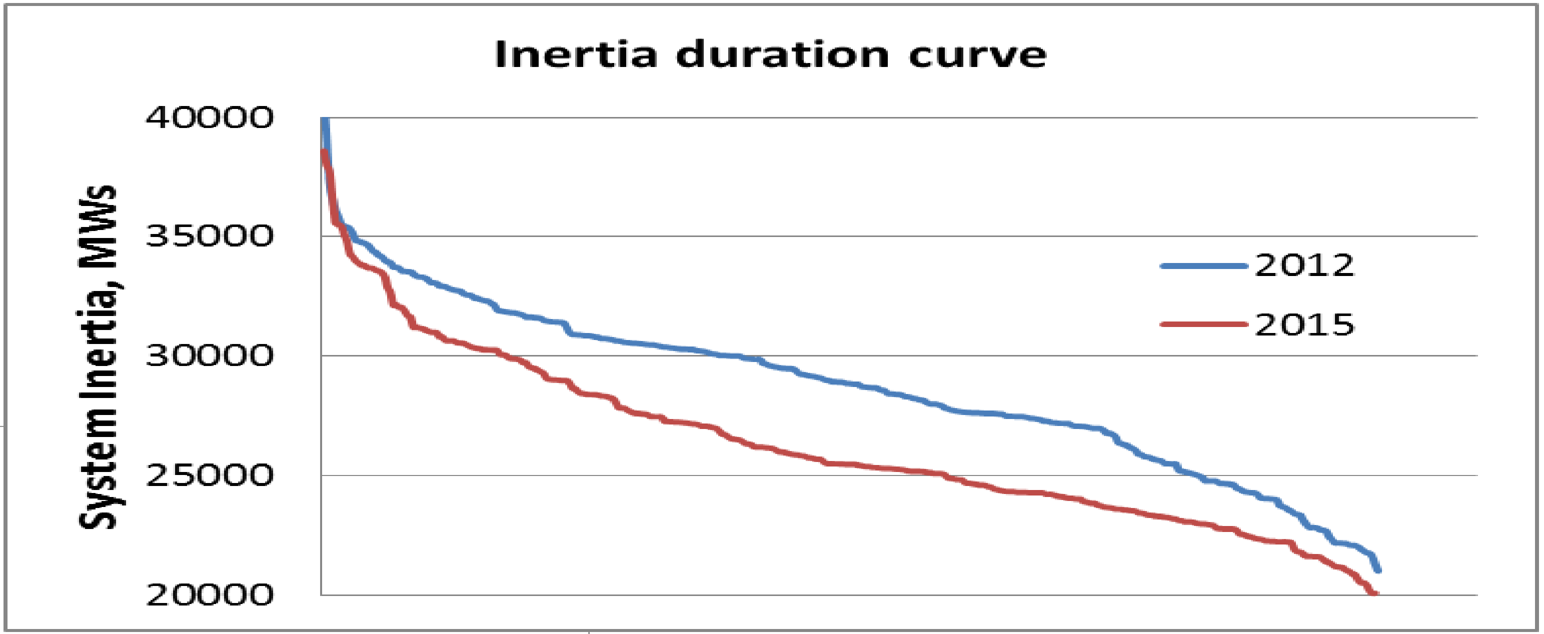
SI is calculated on-line in EMS based on the status of the generator's CBs

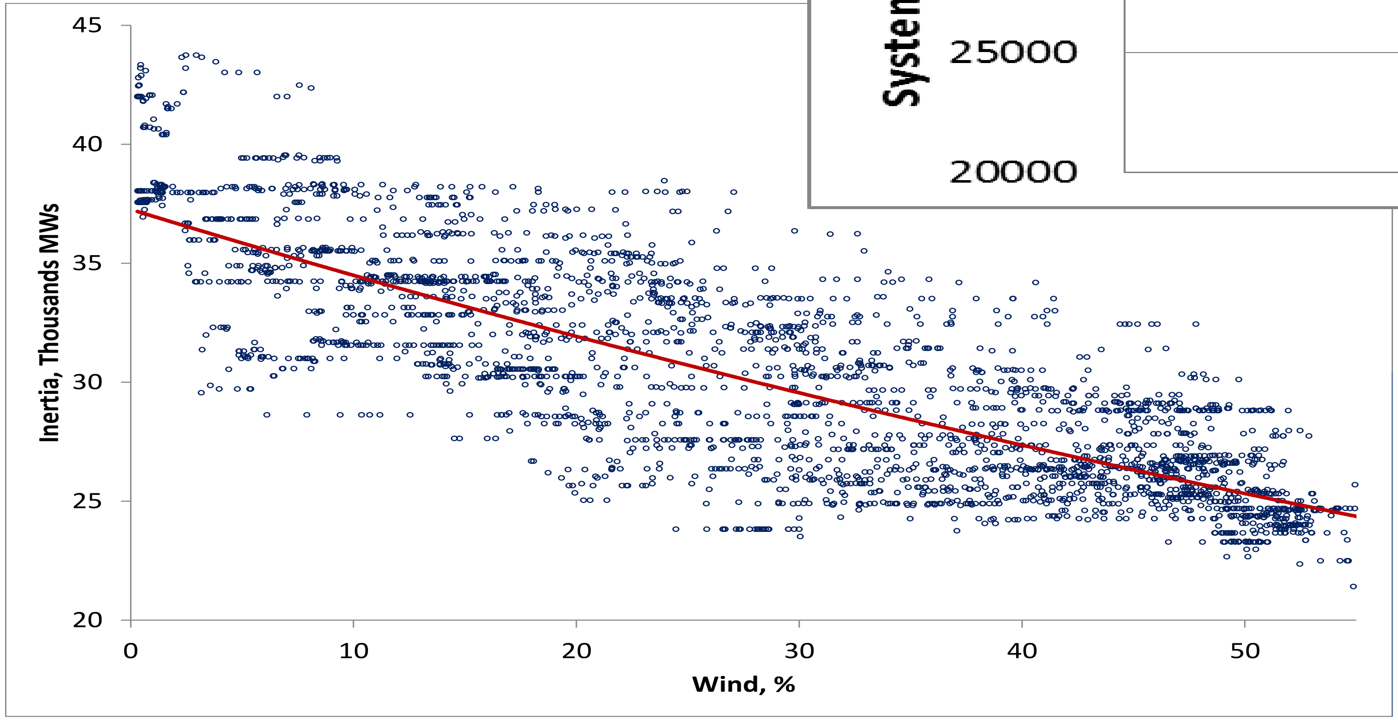
INERTIA

	SONI	EGRD	TOTAL
Inertia	5524	27718 M	33242
SYS INERTIA		ROCOF(+)	ROCOF(-)
33242		0.00	0.35

- **Conclusion:** For RG IE/NI currently there is no further need for establishing calculations. We will re-evaluate if current operational practices fulfil the requirements in article 39(3)(b)

Depletion of Inertia





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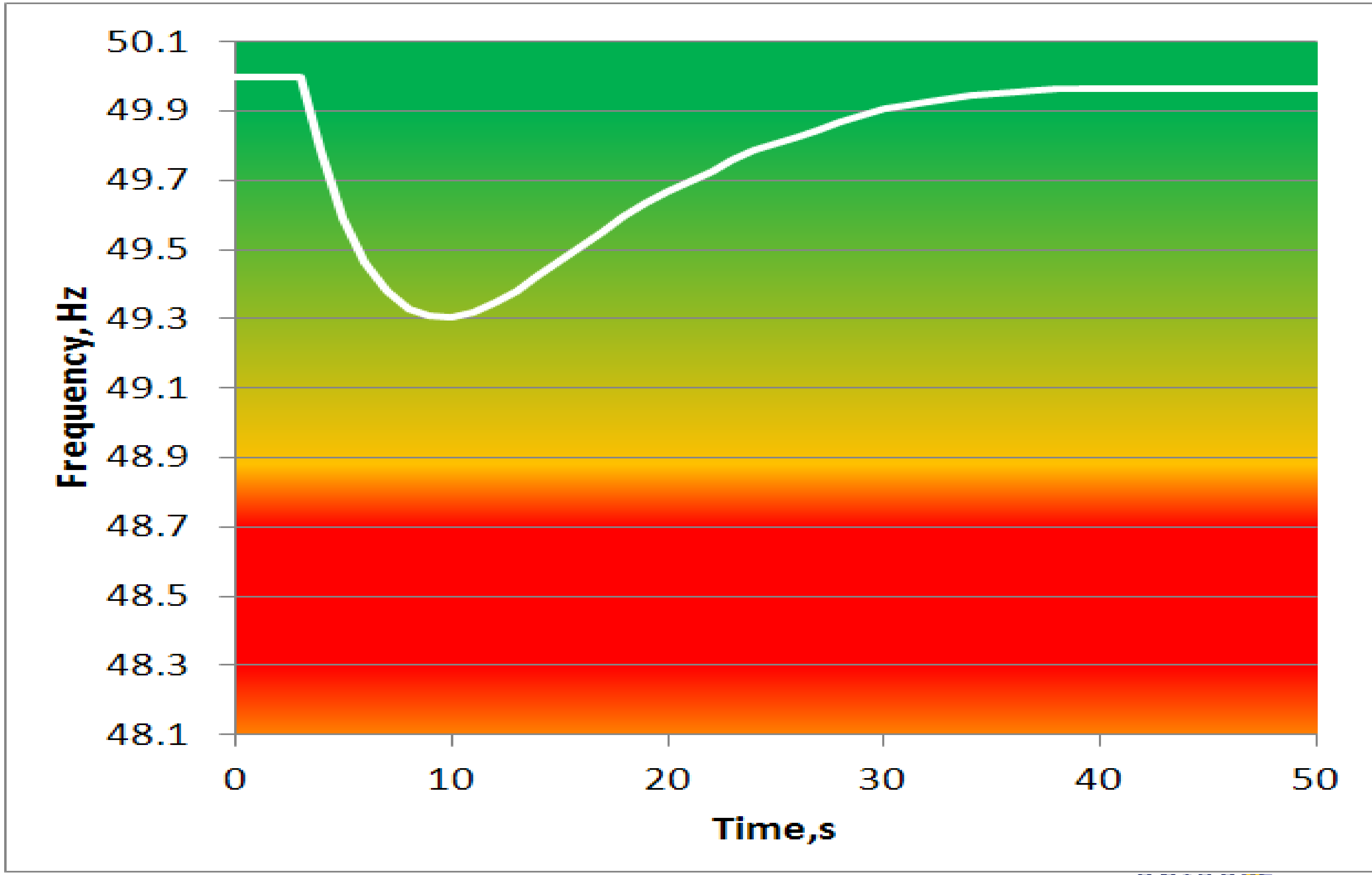
Frequency Stability

$$E = \frac{1}{2} \mathbf{J} \ \omega_{0m}^{2}$$



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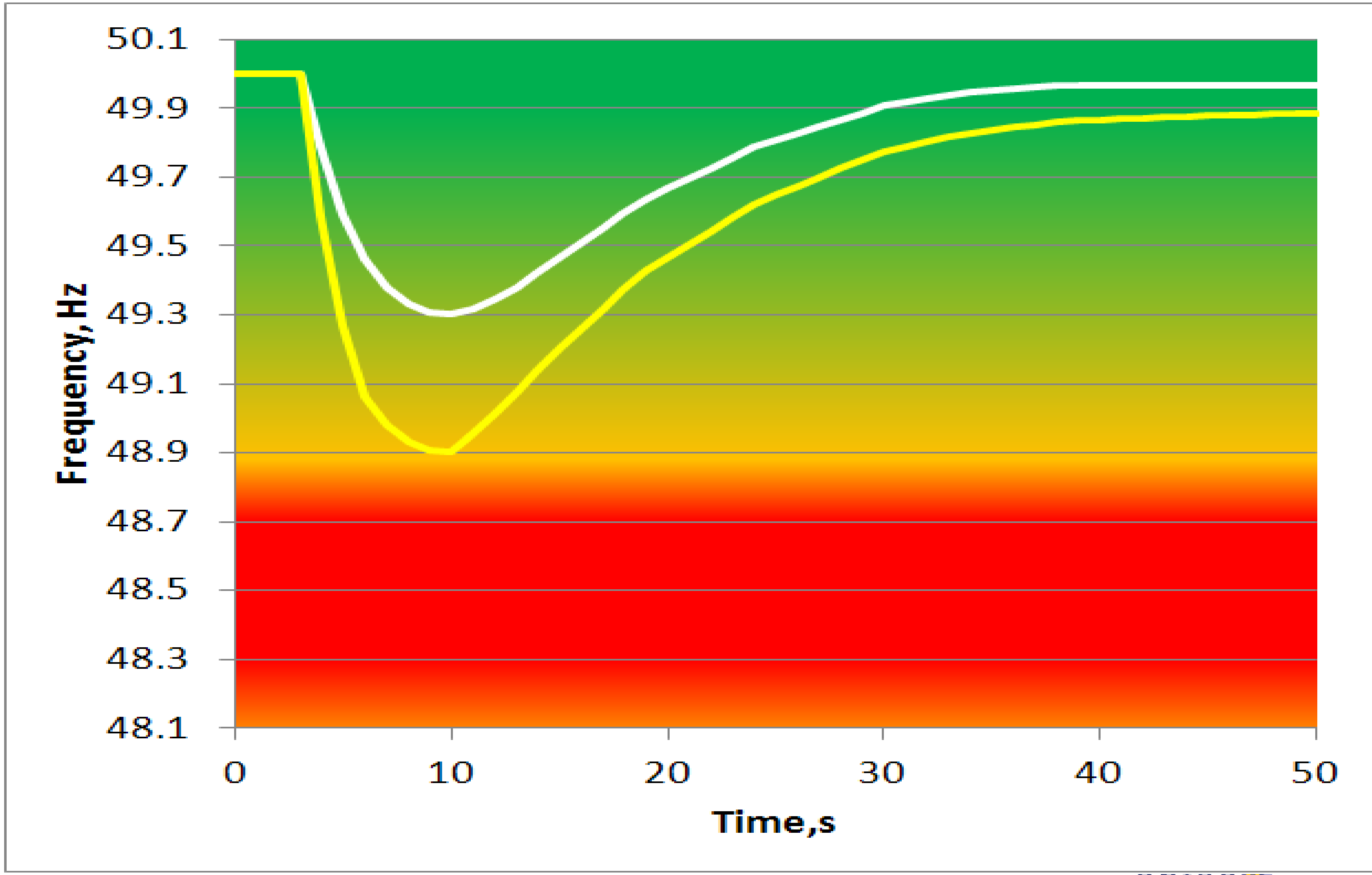
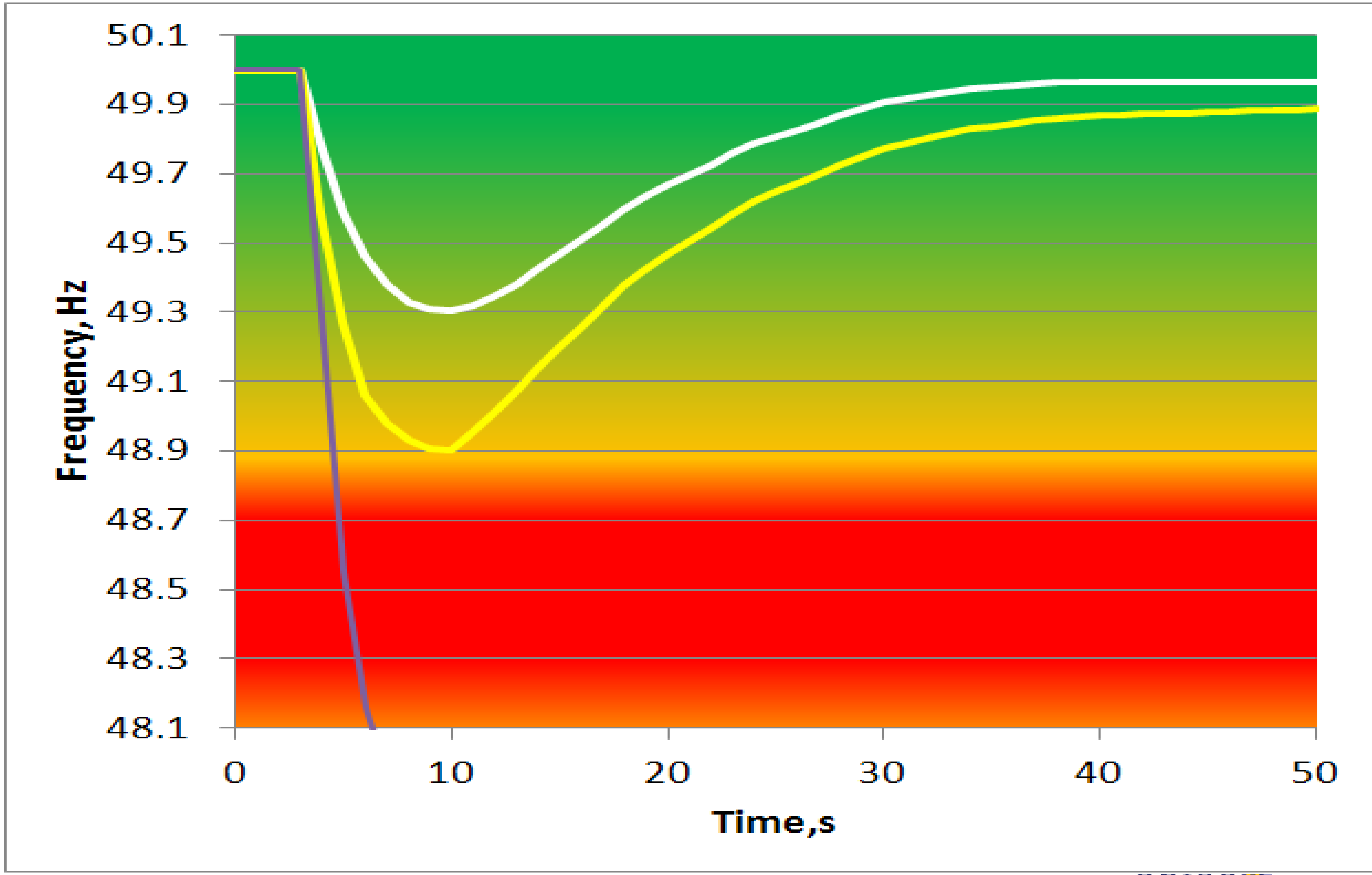
Frequency Stability

$$E = \frac{1}{2} J \ \omega_{0m}^{2}$$



Frequency Stability

$$E = \frac{1}{2} \, J \, \omega_{0m}^{2}$$



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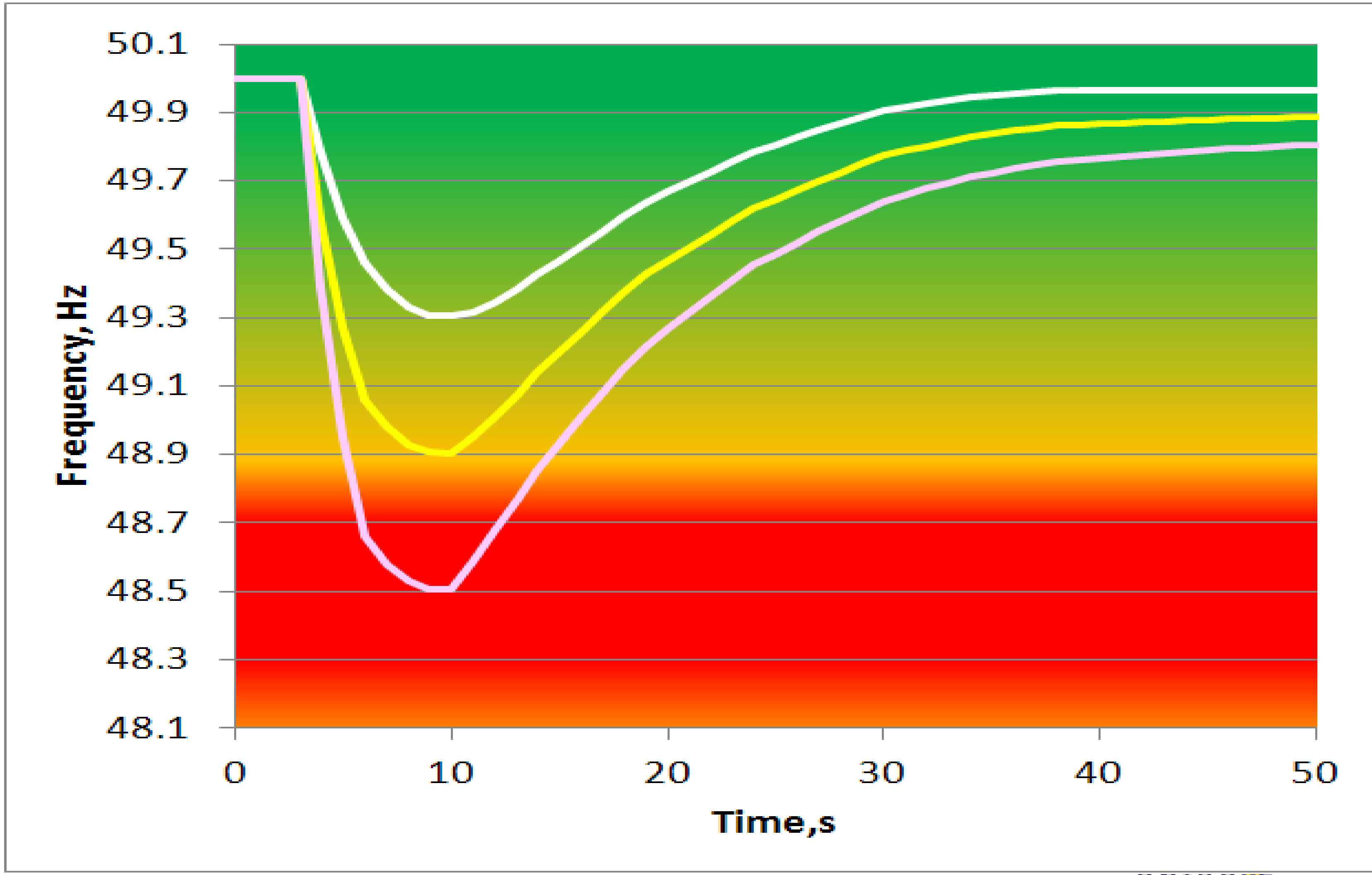
Frequency Stability

$$E = \frac{1}{2} \, J \, \omega_{0m}^2$$



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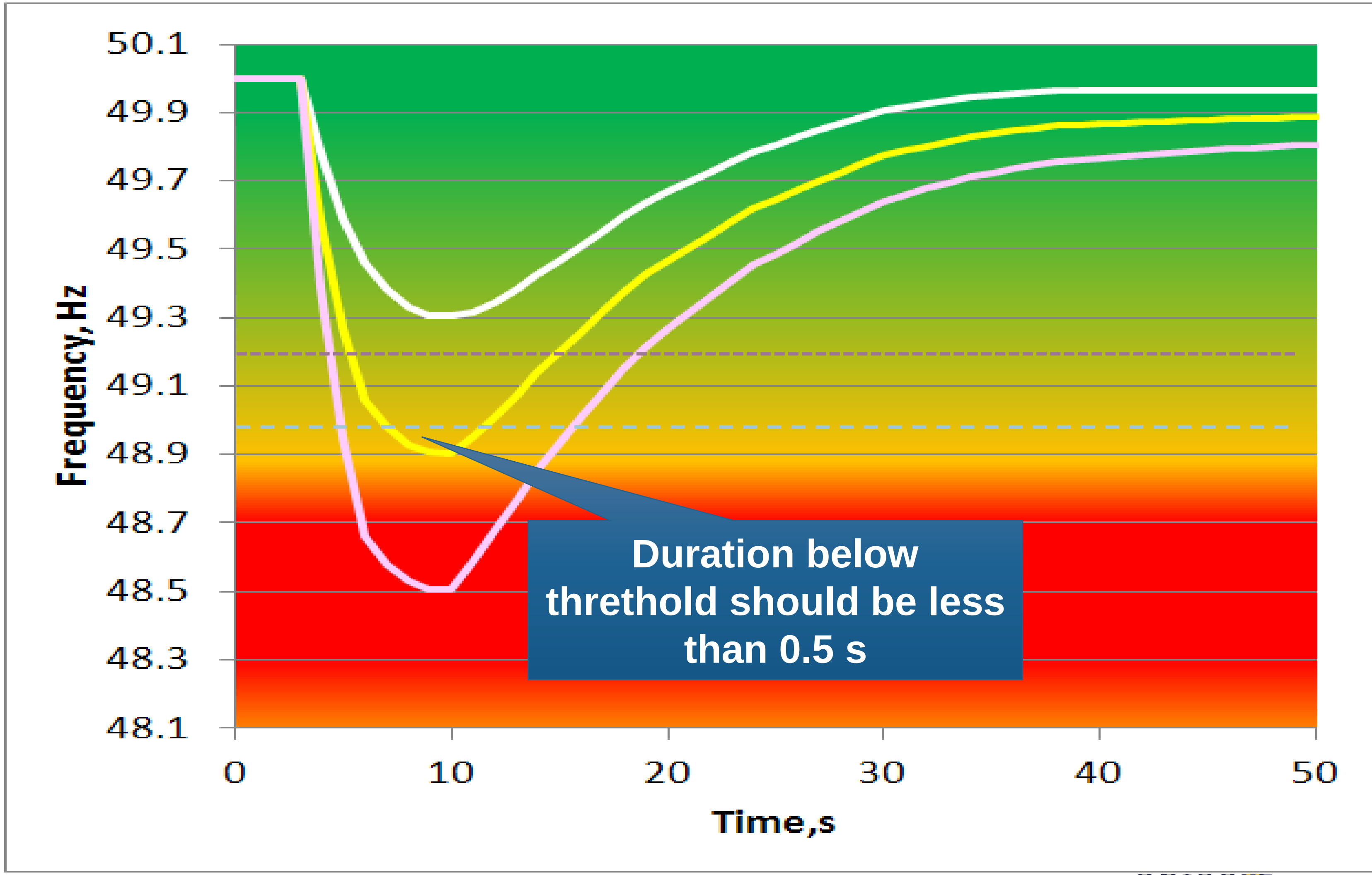
Frequency Stability

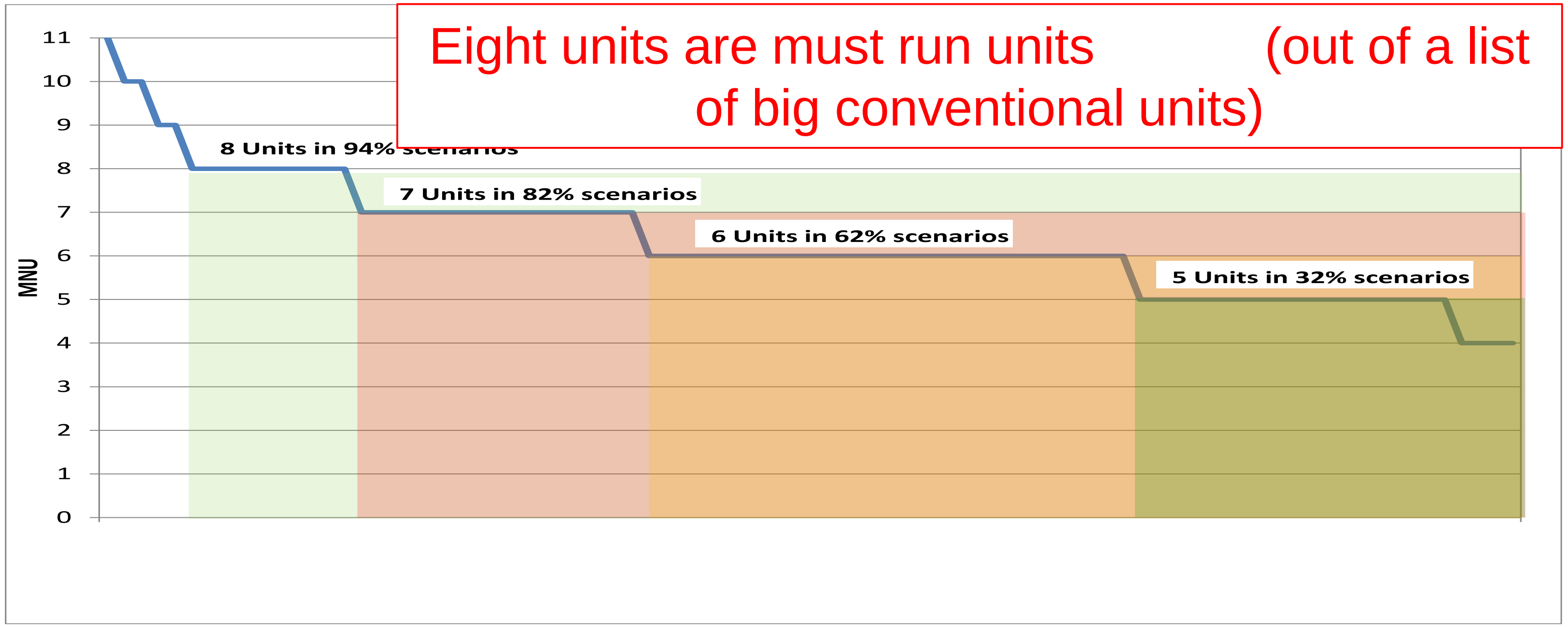
$$E_{min}\Xi = \frac{1}{2} J_{min} \quad \omega_{0m}^2$$



Approaches for Defining the Minimum System Inertia (SI)

Approach 1: Identify a Minimum Number of conventional generators sufficient to maintain Frequency Security of the system. The sum of inertias of these generator will be the minimum SI required

2013 EirGrid Study identified eight such must-run units with total inertia E_o = 20,000 to 23,000 MW·s



Approaches for Defining the Minimum System Inertia (SI)

Approach 2: Define minimum SI as a *Design Parameter*

Assuming that only inertial response is available to counteract a sudden power imbalance on the system during the initial short period immediately after the event, three main design parameters can be established:

- The maximum (or "normative") imbalance ΔP_{max}(MW) on the system
- The maximum duration time of "pure" inertial response ΔT_{max}(s). It should be as short as possible, but not shorter than a time needed for reliable assessment of system frequency, and
- The maximum allowed frequency excursion $\Delta \omega_{max}$(Hz) during this period. Such frequency excursion should be less than dead band of the devices providing "fast" frequency response

Approach 2 for Defining the Minimum System Inertia (SI)

$$E_0 = \frac{J\omega_0{}^2}{2} \rightarrow E_0 - \Delta E = \frac{J(\omega_0 - \Delta\omega_{max})^2}{2}$$

$$\Delta E = \Delta P_{max} \times \Delta T_{max} \rightarrow E_0 = \frac{\omega_0 \times \Delta P_{max} \times \Delta T_{max}}{2 \times \Delta\omega_{max}}$$

Note: As minimum inertia is based on 3 main design parameters (ΔP_{max}, ΔT_{max}, and $\Delta\omega_{max}$), the actual value will be different for different system designs and system evolutional stages. These, in turn are dependant upon existing and evolving technical characteristics of the system (including design and implementation of such products as "synthetic inertia," fast frequency response, and FCR)

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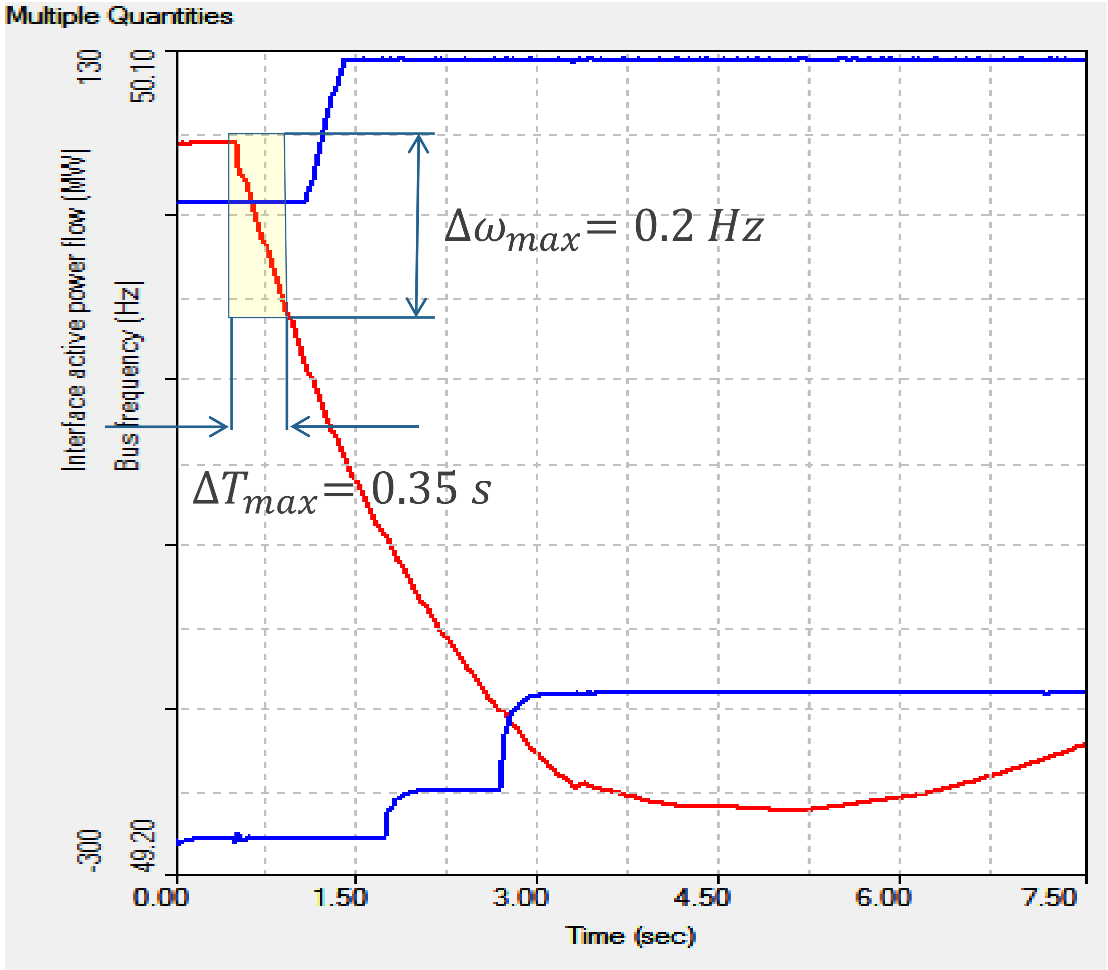
Example: Trip of 500 MW in Ireland



$$E_0 = \frac{\omega_0 \times \Delta P_{max} \times \Delta T_{max}}{2 \times \Delta\omega_{max}}$$

$$E_0 = \frac{50 \times 500 \times 0.35}{2 \times 0.2} = 21{,}875 \text{ MWs}$$

At present IE/NI Minimum SI is set as

23,000 MW·s

Key Operational Milestones

	2017	2018	2019	2020
SNSP	60% -> 65%	65% -> 70%	70% -> 75%	75%
RoCoF	0.5 Hz/s	0.5 -> 1 Hz/s	1 Hz/s	1 Hz/s
Inertia	23,000 MW.s	20,000 MW.s	17,500 MW.s	17,500 MW.s
Min Sets	8	8	7	7
Exports	300 -> 500 MW (interim)	500 MW (interim)	500 MW (interim -> enduring)	500 MW (enduring)
System Services	Current providers, 11 Services			New providers, 14 Services, increased volumes to operate at high RES

1st DSA Stakeholder Workshop
Brussels | 23 May 2018

RG Baltic activities

Kaur Krusell, Elering

23 May 2018

Baltic DSA and MI – current practice

Brell system

Baltic system is part of BRELL synchronous area (Russia, Belarus, Estonia, Lithuania, Latvia).

FCR is assured by Russia. Other countries have to assure their own area FRR reserves to fulfill hourly power balance. Baltic area has common balance regulation.Each party of BRELL has to share 100 MW mFRR for each other.

For frequency security there is common load shedding requirements for full BRELL system.

Brell system

Operational security

Because of strong connections with Russia dynamic security assesment isn’t actual.

Currently there has not been detected any issues with minimium inertia criteria (normal operation).

Main operational security assesments:

- N-1 calculations day ahead and real time.
- Transmission capacity monitoring
- Ensuring baltic area hourly power balance
- FRR activation

Preparedness

Each Baltic country has its own system restoration plan.

There is done several separation tests.

- Estonian separation tests 1995, 1997, 2001, 2006, 2009
- Baltic separation test 2002
  - 2019 is planned another Baltic system separation test.

Preparedness

- Baltics common dynamic model.
  - Needs validation
    - Power plants tests before separation test
    - Re-validation after separation test
- CGMES model exchange
- Comprehensive grid acceptance tests (also real FRT)
- Many common studies have been done on the capability of the desynchronization from Russia
- Each baltic country have installed lot of PMU-s
  - Lithuania and Estonia have their own WAMS system with interarea oscillation detection

1st DSA Stakeholder Workshop
Brussels | 23 May 2018

Q&A session on DSA and MI in general

Knud Johansen /
Remigiusz Warzywoda

23 May 2018

Q & A session

Q: to RG CE: margin for the inertia seems to be large, thus if there is a need for the synthetic inertia. What with inter-area oscillation. Are there studies

A: Hans responded: for the minimum inertia for the short term the need for synthetic inertia is not foreseen. With regard to inter-area oscillation this is closely monitored (most close was in December – there will be a monitor describing it, the previous also for December 2016 and affected Iberian – this is already recorded). Analyses have been extended for the WAMS. For the modelling and forecasting – this is slightly difficult due to modelling: damping is very hard for modelling (on load side). Any problems affecting particular areas should be covered by the studies of the respective TSOs.

Q: Uros to RG CE: coordination among the TSOs on the system split scenarios – I would expect the coordination not only on the results but also on the assumptions. Also what with the transparency: if the stakeholders would have impact on this coordination (like for workshops). Load component is less and less unpredictable – suggestion to start gather information from PMUs

A: Hans responded: as for the system split – this should be addressed through the NC ER, but the largest threat is 50.2Hz (over frequency) that can lead to the under frequency load shedding. As for the load modelling – there are PMUs on place, but we also having hybrid (industrial and domestic) loads – the pattern is extremely difficult. As for the stakeholders involvement this needs to be examined, but its worth pointing that large stake of materials were published.

Note: As for the frequency there is not enough information. There is a need for clear definitions on the frequencies and minimum requirements for the timeframe below 1s (synthetic inertia, fast response). It would be very good for the industry to have more and clear information on that.

Note: Suggestion to address the vendors for the modelling.

Q: The quality of the models may threat the results. How to make sure that within the calculations more detailed models would be taken into account.

A: Hans responded: in practice it is impossible to model everything in detail – it is not feasible. Also in CGM requirements it is requested to separate the auxiliary load from generation.

There is a dimensioning requirement on determining the sequence of faults.

Q: Ralf Pfeiffer: the assumptions in the studies on the system split are working assumptions – studies would benefit if the reference ranges would be defined – to say to each extend we could survive. Common agreement on the range of the reference contingencies??? Something has to be given from the TSOs. There are reference cases(fx 6 scenarios) that could be used – were done by EirGrid.

A: Hans responded: on out of range incidents – it is very difficult to address this. There were cases when low parameters were investigated. When we go it has to be decided whether this is deterministic criteria or likehood. Also extremely contingencies might be address by the on line systems that are working like in Ireland or Italy.

Q: Uros. Special protection schemes could also be considered for those scenarios.

A: Hans responded: there are special protection schemes used.

1st DSA Stakeholder Workshop
Brussels | 23 May 2018

Conclusions and wrap up of workshop

Knud Johansen /
Remigiusz Warzywoda

23 May 2018

DSA stakeholder WS 2018.05.23 – summary & conclusions

1. Participants acknowledged the need for monitoring the system inertia in all synchronous areas for normal and alert operation.
2. Stakeholders suggestion to extend the DSA coordination on agreeing among TSOs on the assumptions on the system split scenarios, including stakeholder’s participation.
3. Stakeholders expectation on exchanging information on DSA assessment and management. Workshop concept seems to be an efficient solution.
4. Expectations form stakeholder on establishing a set of clear definitions/requirements on the algorithms/assumptions related to frequency stability aspects (synthetic inertia, fast frequency response functions) in order to enable industry/vendors to provide services.
5. The participants agreed that quality of models used for calculations is a key element for obtaining proper quality of results.
6. Suggestion from stakeholder for the TSOs to take the lead on the RoCoF studies / requirements.
7. Distinction between „network design“ and “system design“ were proposed as essential in the system stability discussions. The terms could be defined as follows:
   a. “Network design” shall define the dimensioning of the transmission (and distribution) grid infrastructure. One relevant criterion for network design is robustness/resilience against normal and a number of exceptional contingencies (e.g. common mode failures).
   b. “System design” shall define the robustness/resilience of the transmission (and distribution) system against more severe contingencies, which are beyond network design, e.g. exceptional contingencies without a common cause or out-of-range contingencies like system splits. These incidents shall be mitigated by system defense plans, to which all system users shall contribute through their system-supportive behavior, e.g. by contributing to system inertia.
8. ACER requested a pan-European harmonization on scenario assumption and boundary condition for the DSA studies. Eventually a set of reference scenarios as used by EirGrid – link to reference scenarios:
9. Special Protection Schemes is considered in the scenarios simulated and presented at the workshop.
10. Investigation of the catalogue of “normative incidents” needs to be reviewed and whether we can prepare a set reference incidents will be discussed on the ENTSO-E level. A more detailed look on the definitions on what is normal and what is abnormal must be included in the review.