Grid Code Development Forum

10:00-12:00

Wednesday 06th May 2020

Digital only meeting via WebEx

Please register below to receive the details to join:

WebEx Registration Link

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Agenda

1. Introductions
2. Presentation: E&R Market Suspension:
   (***Tony Johnson***, National Grid ESO)
3. Presentation: GC0117 Update
   (***Tony Johnson***, National Grid ESO)
4. Presentation: Frequency control for PPMs
   (***Nicola Barberis Negra***, Orsted)
5. Presentation: MARI
   (***Louise Trodden***, National Grid ESO)
6. Any other business
7. Close

May 2020 - Grid Code Development Forum

Emergency and Restoration Code – Grid Code Modifications to implement the Emergency and Restoration Code Market Suspension Rules – Art 35.1(b)

Antony Johnson and Susan Mwape
National Grid ESO

Summary

- Background
- The Defect
- Extract from E&R Article 35.1(b)
- Extract from Section 2.1.1 of the System Defence Plan
- Proposal
- Draft Grid Code Text
- Additional TERRE items to be included in scope of work
- Next Steps

Background

- In 2019, the ESO submitted its proposed solution to Ofgem for implementation of the European Emergency and Restoration Code
- This comprised of several submissions:-
  - Grid Code Modification GC0125 (EU Code Emergency & Restoration: Black Start testing requirements for Interconnectors) – *Approved – 5th February 2020*
  - Grid Code Modification GC0127 (EU Code Emergency & Restoration: Requirements resulting from System Defence Plan) – *Approved – 5th February 2020*
  - Grid Code Modification GC0128 (GC0128 EU Code Emergency & Restoration: Requirements resulting from System Restoration Plan) *– Approved 5th February 2020*
  - System Defence Plan *– Submitted December 2019 - Awaiting Approval*
  - System Restoration Plan *– Submitted December 2019 - Awaiting Approval*
  - Test Plan *– Submitted December 2019 - Awaiting Approval*
  - Terms and Conditions related to Emergency and Restoration EU Network Code *Submitted December 2019*
  - Market Suspension Proposals *– Submitted January 2020 Feedback Received from Ofgem – Process Mod to be raised ahead of formal decision*
- A link to the above documents are available from the attached link:-
- https://www.nationalgrideso.com/industry-information/codes/european-network-codes/other-enc-documents

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The Defect

- As part of its submission for the Market Suspension Proposals, the ESO and Elexon initially believed that the arrangements for Market suspension were adequately catered for in the GB Industry Codes through OC9.4.6 of the Grid Code and Section G3 of the BSC.
- Further the requirements for Market Suspension are summarised in section 2.1.7 of Issue 3 of the System Restoration Plan (see link on previous slide)
- The parameters under which the System is in an Emergency State are detailed in section 2.1.1 of Issue 3 of the System Defence Plan (see link on previous slide)
- In its response to the initial Submission, Ofgem advised that Article 35.1(b) of the Emergency Restoration Code was not adequately reflected in the GB Codes

Extract from E&R Article 35.1(b)

- E&R Article 35.1(b) states

- *A TSO may temporarily suspend one or more market activities laid down in paragraph 2 where:*

  - *the TSO has exhausted all options provided by the market and the continuation of market activities under the emergency state would deteriorate one or more of the conditions referred to in Article 18(3) of Regulation (EU) 2017/1485;*

  - (Note – Article 18(3) of Regulation (EU) 2017/1485 – SOGL – System Operator Guideline – Refers to the conditions under which the System is in an Emergency State)

  - The GB interpretation of this condition is covered in Section 2.1.1 Issue 3 of the System Defence Plan)

  - The current Grid Code however does not directly link the emergency conditions in section 2.1.1 of Issue 3 of the System Defence Plan to or how the market may be suspended

Extract from Section 2.1.1 of the System Defence Plan

2.1.1 *This System Defence Plan contains procedures and automatic actions available to the NGESO to prevent the occurrence of an Emergency or manage the System when it is in an Emergency state. Under, SOGL Article 18(3), a Transmission System shall be in an Emergency State when operational security analysis requires activation of one of the following measures:*

- *A situation where there is a violation of one of more criteria as defined under the National Electricity Transmission System Security and Quality of Supply Standard (NETS SQSS); or*
- *A situation when Unacceptable Frequency Conditions as defined under the National Electricity Transmission System Security and Quality of Supply Standard (NETS SQSS) have occurred; or*
- *At least one measure of the System Defence Plan is activated or*
- *There is a failure of the computing facilities used to control and operate the Transmission System or unplanned outages of Electronic Communication and Computing Facilities as provided for in BC2.9.7 or the loss of communication, computing and data facilities with other Transmission Licensees as provided for in STCP 06-4.*

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Proposal

- The proposal is to introduce a new section of the Grid Code (BC.2.9.8) introducing a set of market suspension parameters in relation to E&R Article 35.1(b)
- This would be consistent with the approach detailed in the System Defence Plan
- The new market suspension parameters are linked to the existing rules laid out in the Grid Code
  - Minimise any requirements for a BSC change.

Draft Grid Code Text

BC2.9.8 Market Suspension

BC2.9.8.1 Within the **GB Synchronous Area**, the **Transmission System** shall be considered to be in an emergency state when operational security analysis requires activation of one of the following measures:

A situation where there is (or could be) a violation of one of more criteria as defined under the **National Electricity Transmission System Security and Quality of Supply Standard** (NETS SQSS); or

A situation when Unacceptable Frequency Conditions as defined under the **National Electricity Transmission System Security and Quality of Supply Standard** (NETS SQSS) have occurred; or

At least one measure of the **System Defence Plan** is activated; or

There is a failure of the computing facilities used to control and operate the **Transmission System** or unplanned outages of Electronic Communication and Computing Facilities as provided for in BC2.9.7 or the loss of communication, computing and data facilities with other **Transmission Licensees** as provided for in STCP 06-4.

BC2.9.8.2 While the **Transmission System** is still in an emergency state if after issuing system warnings and emergency instructions in accordance with (but not limited to) the requirements under OC7.4 and BC2.9, and the situation deteriorates to such an extent that it results in:-

a) a **Total Shutdown**, **The Company** will suspend the market in accordance with the provisions of OC9.4.6; or

b) a **Partial Shutdown**, **The Company** will also suspend the market but only where the **Market Suspension Threshold** has been met in accordance with OC9.4.6.

Additional TERRE Items to be included in scope of Work

- BC4.9 allows for TERRE market suspension but a Grid Code mod is also required to ensure NGESO notifies Users (through Elexon) that the TERRE market is suspended.
- The BSCCo must be notified if TERRE market tools are on outage so that no data will be transferred from NGESO regarding RR bids, RR auction result data or RR flagged acceptance data.
- BC4.9 will need to be updated to clarify that TERRE will be suspended when the BM is suspended.

Next Steps

- Establish Workgroup or proceed to Code Administrator Consultation
- Present to May GCRP
- Discuss Proposal
- Both Ofgem and Elexon are comfortable with this approach
- The ESO ideally would like to proceed to Code Administrator Consultation rather than holding a Workgroup

May 2020 - Grid Code Development Forum

GC0117: Improving transparency and consistency of access arrangements across GB by the creation of a pan-GB commonality of PGM requirements

Presented by Antony Johnson (NGESO) on behalf of Garth Graham (SEE)

Summary

- The Defect
- Background
- Purpose of this Presentation
- What are the implications of Regional Differences
- When is a Generator caught by the requirements of the Grid Code
- What Type of Connection Agreements apply
- What other requirements apply
- How is consistency best achieved across GB
- Options
- What are the Implications and what needs to be considered

The Defect

- The Concept of Large, Medium and Small Power Stations was introduced at Vesting (Privatisation in 1990) being a cornerstone of the industry codes
- They defined:-
  - The Connection Process
  - Charging Arrangements
  - Technical Requirements
- Regional differences exist in the definition of Small, Medium and Large Power Stations between each Transmission Area in GB.
- RfG has removed the difference in technical requirements across GB for New Generators but fundamental differences remain in the connection process, data requirements and the industry codes that apply.
- The implication of this is that a Large Embedded Power Station in the North of Scotland (10MW) will have to sign the CUSC and meet the requirements of the Grid Code (in addition to that of the DCUSA and Distribution Code), whereas the same size Power Station (10MW) in the South of Scotland or in England and Wales would only be required to sign the DCUSA and satisfy the requirements of the Distribution Code without having to meet the requirements of the CUSC or Grid Code.
- This issue was brought into sharper focus via the implementation of EU Network Codes in particular SOGL.

Background

- Raised by SSE at the GCRP in June 2018
- A workgroup was established with meetings held in October 2018, March 2019 and April 2019
- A presentation on the issues was also presented to the Open Networks Workstream in June 2019.
- The GC0117 workgroup was then placed on hold as a result of the urgent need to develop solutions for implementation of the Emergency Restoration Code in GB (Grid Code Modifications GC0125, GC0127 and GC0128)
- Details of the work completed by the Workgroup prior to its delay are available from the following link.
- https://www.nationalgrideso.com/codes/grid-code/modifications/gc0117-improving-transparency-and-consistency-access-arrangements

Purpose of this Presentation

- Describe the issue and defect
- Briefly outline the work completed to date and options going forward
- Make industry aware of the intention to re-start the Workgroup
- Seek new nominations for the workgroup – in particular Trade Associations and smaller parties who could be affected by any Grid Code change
- Re-Present the issue at the May GCRP with the aim of holding the first workgroup in May 2020.

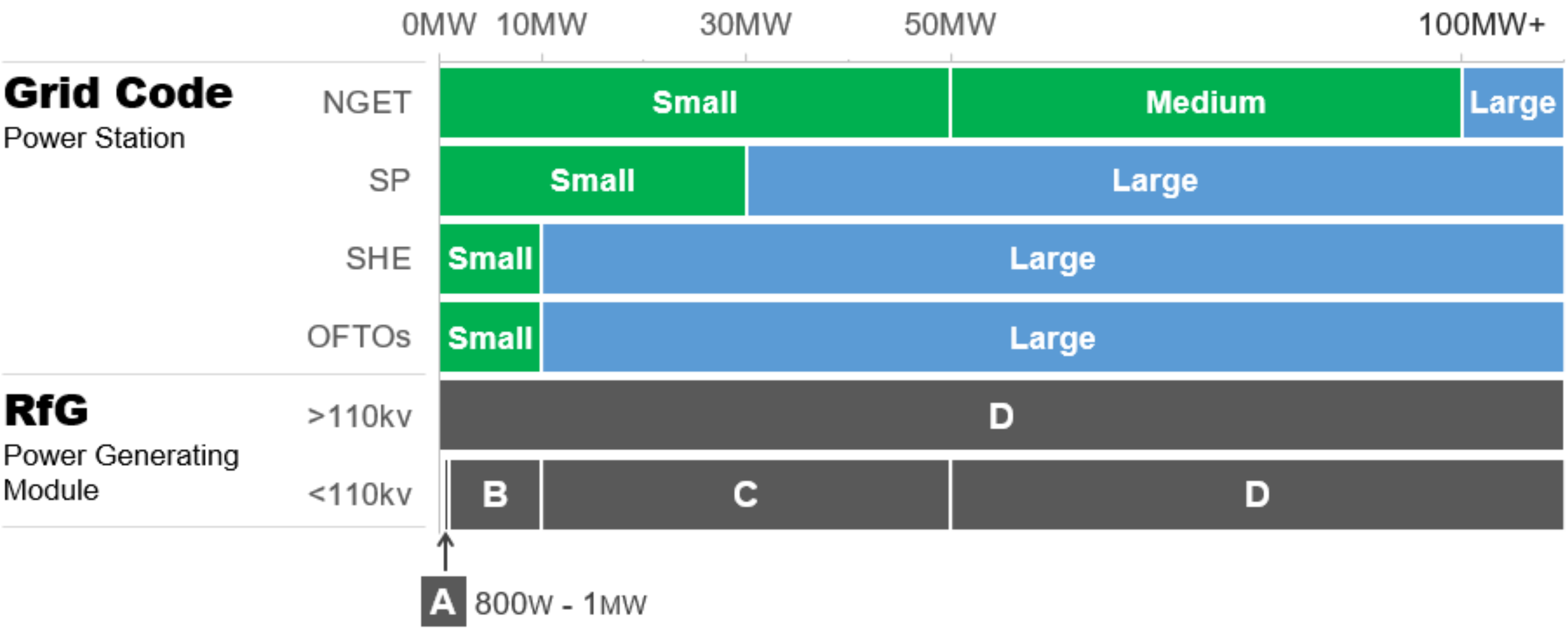
What are the implications of Regional Differences

- With the introduction of RfG in 2018 the technical requirements are now based on whether the Power Generating Module is of Type, A, B, C or D not Power Station Size. This is common across the whole of GB.
  - Type A – 800W – 1MW, Type B 1MW – 10MW, Type C 10MW – 50MW (all connected below 110kV)
  - Type D – 50MW and above or connected at or above 110kV
- The Connection Process and Charging arrangements are based on TEC and Large, Medium and Small criteria for which in the latter case, regional differences exist
- Charging is a separate issue which is outside the scope of this workgroup.
- A Large Power Station in SHE Transmission Area is classified as 10MW or above. A Large Power Station in England and Wales is classified as 100MW or above. These classifications apply irrespective of weather the Power Station is Embedded or directly connected.
- As the CUSC and Grid Code apply to Large Power Stations it means a 10MW Embedded Power Station in SHE Transmission Area or Offshore will have to meet the applicable requirements of the Grid Code (including BC1 and BC2), the CUSC and have an agreement with the ESO whereas a 10MW Embedded Power Station in Scottish Power's Transmission Area or in England and Wales will only require a connection with the DNO and have to meet the Distribution Code.

Power Station Size – Definitions

- Defined under the Grid Code
- Based on Registered Capacity not CEC / TEC or any other Commercial Product
- Large
  - England and Wales – 100MW or Greater
  - SPT's - Transmission Area – 30 MW or greater
  - SHETL – Transmission Area – 10MW or greater
  - Offshore – Transmission Area – 10MW or greater
- Medium
  - Apply only in England and Wales – 50 MW or greater but less than 100MW
- Small
  - England and Wales – Less than 50MW
  - SPT's - Transmission Area – Less than 30MW
  - SHETL – Transmission Area – Less than 10MW
  - Offshore – Transmission Area – Less than 10MW

Interaction between RfG and GB Requirements



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When is a Generator caught by the requirements of the Grid Code

- This is defined under section 6.3 of the CUSC but in summary the following rules apply:-

- The Generator is directly connected (irrespective of being Small, Medium or Large)
- The Generator is Large (either Embedded or Directly connected)
- The Generator is Embedded Medium or Small and applies for TEC

What Type of Connection Agreements apply

- Bilateral Connection Agreement (BCA) – A CUSC Contract which applies between the ESO and any directly connected party irrespective of being Demand or Generation
- Bilateral Embedded Generation Agreement (BEGA) – A CUSC Contract which applies between the ESO and any Embedded Generator who has applied for TEC. All Large Embedded Power Stations greater than 100MW ***must*** have a BEGA.
- Any Embedded Generator under 100MW can apply for TEC if they so wish. In this case a BEGA would still be used.
- Bilateral Exemptable Large Licence Exempt Generator Agreement (BELLA) apply only in Scotland and applicable to Large Power Stations under 100MW.
- BELLA's do not have TEC
- They have to meet the requirements of the Grid Code applicable to Large Power Stations
- In general they will need to meet the requirements of BC1 and BC2 (a requirement of the Bilateral Agreement) but are classed as Generating Units and not BM Parties for which the requirements are different.
- LEEMPS – specific agreements do not exist in respect of LEEMPS – this is achieved through the BCA between National Grid and the DNO (Appendix E)

What other Requirements Apply

- Any Generator who owns a Power Station (irrespective of size) which is directly connected must be in the Wholesale Market (ie in the BM).
- Any Generator who owns a Large Embedded Power Station of 100MW or greater must also be in the Wholesale Market (ie in the BM).
- Any Generator who owns an Embedded Power Station and less than 100MW can choose to be in the BM – this would mean they apply for TEC.
- LEEMPS are not required to be in the BM (England and Wales only – 50 – 100MW)
- BELLA’s as a condition of their Connection Agreement are required to meet the requirements of BC1 and BC2 but they are treated as Generating Units not BM Parties and therefore a form of BM subset.

How is consistency best achieved across GB

- To adopt a consistent set of thresholds for Large, (Medium and) Small across GB.
- One approach is to define two new thresholds between Large and Small with Medium being removed? – Several options are under consideration – see next slide
- This would apply across the whole of GB
- LEEMPS would/could be removed.
- Code changes are believed to be minimal as most changes are made to the definitions between Large, (Medium) and Small
- Other options could be considered

Options

Option	Small	Medium	Large
Option 1	Less than 10MW	N/A	10MW and greater
Option 2	Less than 30MW	N/A	30MW and greater
Option 3	Less than 50MW	N/A	50MW and greater
Option 4	Less than 100MW	N/A	100MW and greater

Option 1 Increases visibility to the ESO, and could reduce Balancing Costs whilst and enabling greater use of services from Smaller Players in a more holistic way. It will increase costs for the ESO, DNO's and Generators with respect to agreements and metering issues

Option 4 Reduces visibility to the ESO and could increase Balancing Costs whilst reducing the ability to utilise services from Smaller Players unless they choose to participate in the BM. It will reduce costs for the ESO, DNO's and Generators with respect to agreements and metering issues bit not necessarily BM costs

Options 2 and 3 are a mix of Options 1 and 4 but are not necessarily the cheapest or most efficient.

In all cases it is not possible to define the best case without numbers which is where the CBA will be of importance

What are the Implications and What needs to be considered

- Changes to the Grid Code
- Retrospectivity
- Volumes involved for each Option
- Costs – Both to Generators and the ESO/DNO's
- Benefits
- Impacts on other Industry Codes

Expected Changes to the Grid Code

- Irrespective of the Option eventually selected, Grid Code and Distribution Code changes are expected to be minimal.
- Medium Power Stations would be removed including LEEMPS
- Data requirements would be consistent across the whole of GB (Structural, Scheduled and Real Time) and therefore achieves the requirements of SOGL
- The BELLA Approach would effectively be applied across the whole of GB – Options 1 – 3 only)
- Option 4 simply sets the threshold between Large and Small at 100MW
- Any Plant which is 100MW or greater or directly connected would have to be in the BM
- Any Plant which is Large and less than 100MW (Options 1 – 3 only) would be treated in the same way as a BELLA unless they choose to apply for TEC in which case they would become a BEGA – This is the choice of the Generator
- In summary, the Existing Grid Code requirements would apply other than removal of Medium Power Stations and changes to the definitions
- Consequential changes to other Industry Codes including the Distribution Code would need to be assessed.

Retrospectivity

- It is envisaged that these requirements could apply retrospectively
- There would be no requirement for existing plant to meet the technical requirements of RfG however they would be required to satisfy the requirements of the other relevant parts of the Grid Code (eg Planning Code, Operating Codes, Balancing Codes and DRC) to achieve the requirements of SOGL.
- There will be costs upon currently Small Power Stations who subsequently become Large Power Stations other than Option 3 and 4
- There will also be costs for current Medium Power Stations who become Large though these are expected to be more limited.
- Existing Small and Medium Power Stations caught by the new threshold of a "Large Power Station" would potentially have to sign up to the CUSC and Grid Code.

Next Steps

- Restart Workgroup with new members
- Provide background to new members and propose ways forward based on existing or new options.
- Review individual costs
- Review Benefits
- Establish overall most reasonable, economic and proportional option
- Finalise preferred option and develop legal text changes

GCDF – Frequency control for PPMs

Review of current Grid Code requirements

Ørsted

Nicola Barberis Negra, Sridhar Sahukari

April 2020

Scope of the Proposal

Review current requirement for frequency control of Power Park Modules (CC.6.3.7(a) and ECC.6.3.7.3.1(a)) to ensure it is fit for purpose for the offshore wind industry

- Outline of this presentation
  - Definitions, control design and Grid Code requirements
  - Current requirement vs. alternative solution (proposal)
  - Benefits of proposal
  - Propose change to Grid Code legal text

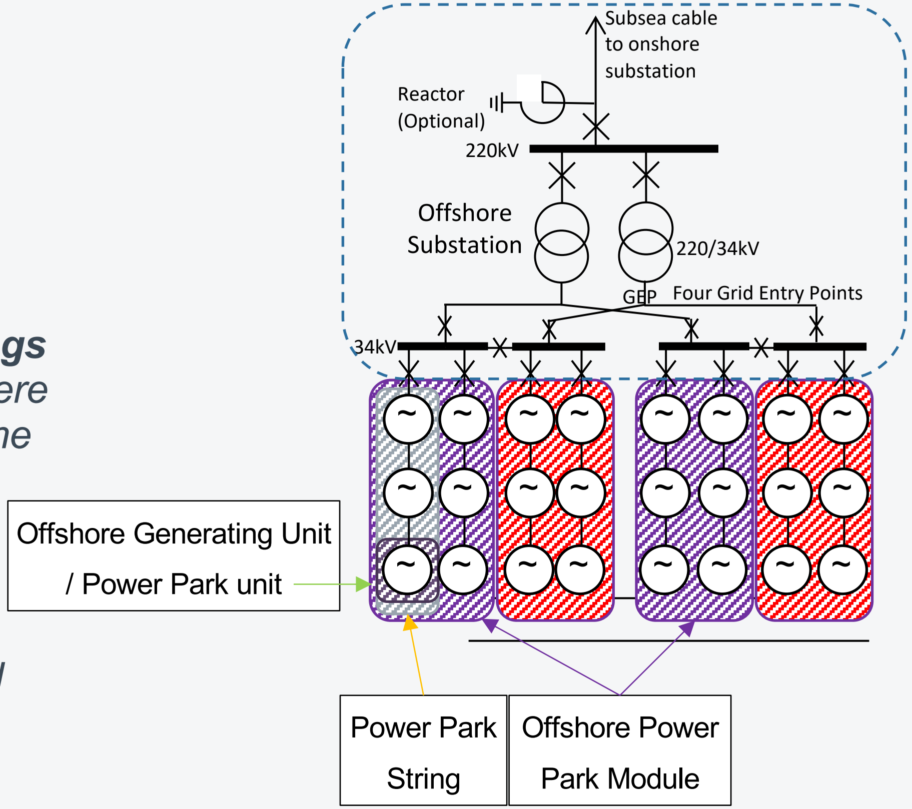
Grid Code Key Definitions

- Key definitions from the Grid Code (see diagram here)
  - Offshore Generator Unit / Power Park Unit
  - Power Park String
  - Offshore Power Park Module (PPM)

    *"A collection of one or more **Offshore Power Park Strings** (registered as a **Power Park Module** under the **PC**). There is no limit to the number of **Power Park Strings** within the **Power Park Module**, so long as they either:*

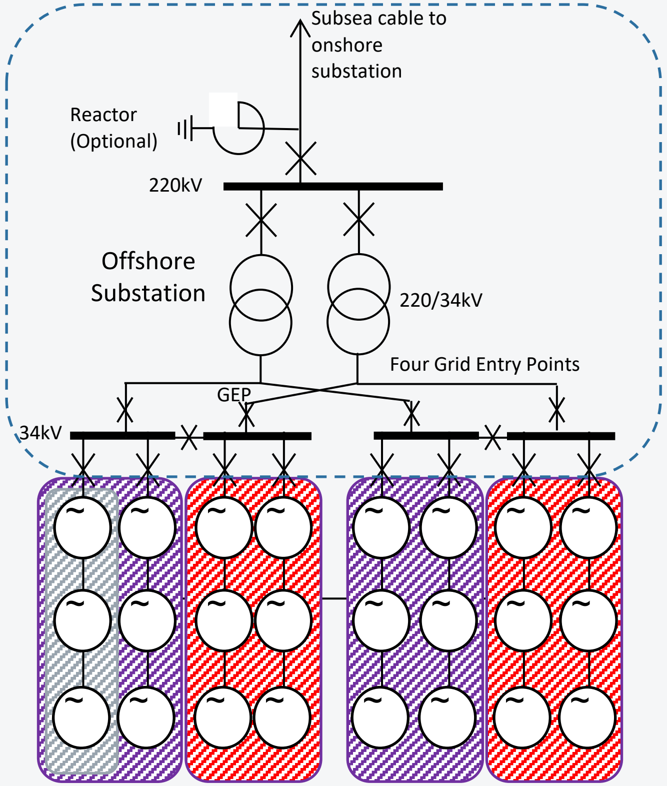
    (a) connect to the same busbar which cannot be electrically split; or

    *(b) connect to a collection of directly electrically connected busbars of the same nominal voltage and are configured in accordance with the operating arrangements set out in the relevant **Bilateral Agreement** ".*



Offshore Wind Farm Control Design Solutions

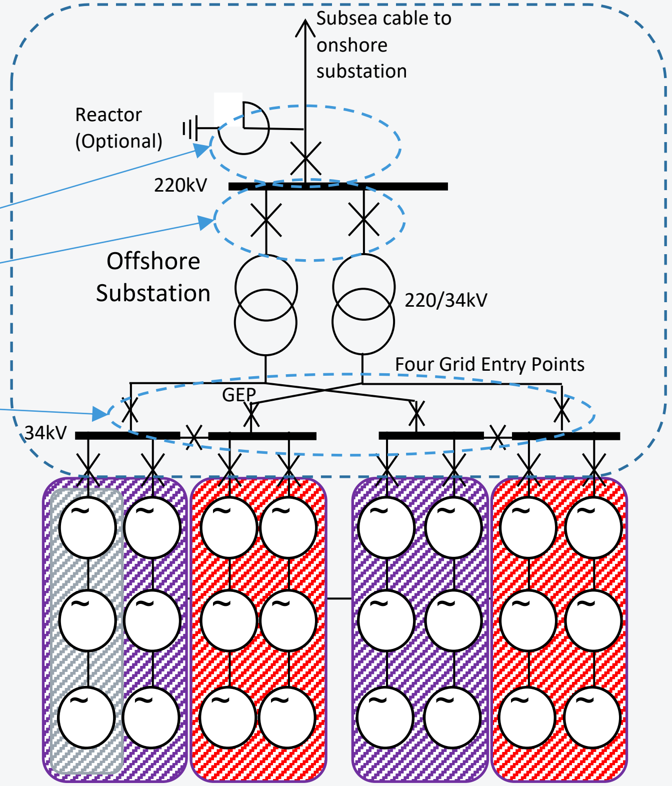
– Current control arrangements for Offshore wind farms



Offshore Wind Farm Control Design Solutions

– Current control arrangements for Offshore wind farms
  – Frequency control

Frequency control
- Respond to frequency variations to support the entire system



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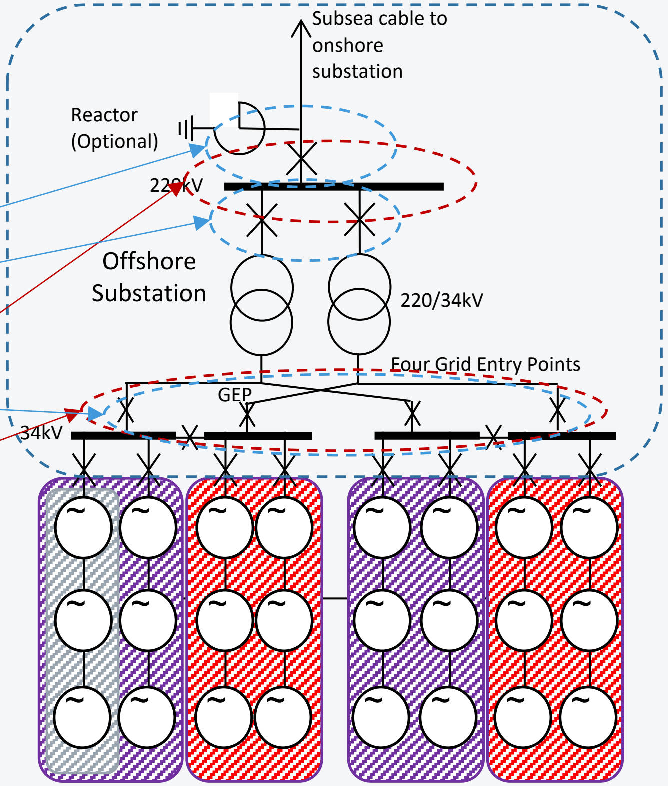
Offshore Wind Farm Control Design Solutions

- Current control arrangements for Offshore wind farms
  - Frequency control
  - Reactive power/Voltage control at offshore platform

Frequency control
- Respond to frequency variations to support the entire system

Reactive Power
- Maintain unity power factor at GEP
- Provide support to OFTO asset reactive power requirements

Voltage control
- Maintain constant voltage at OSS



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Frequency Control Requirement

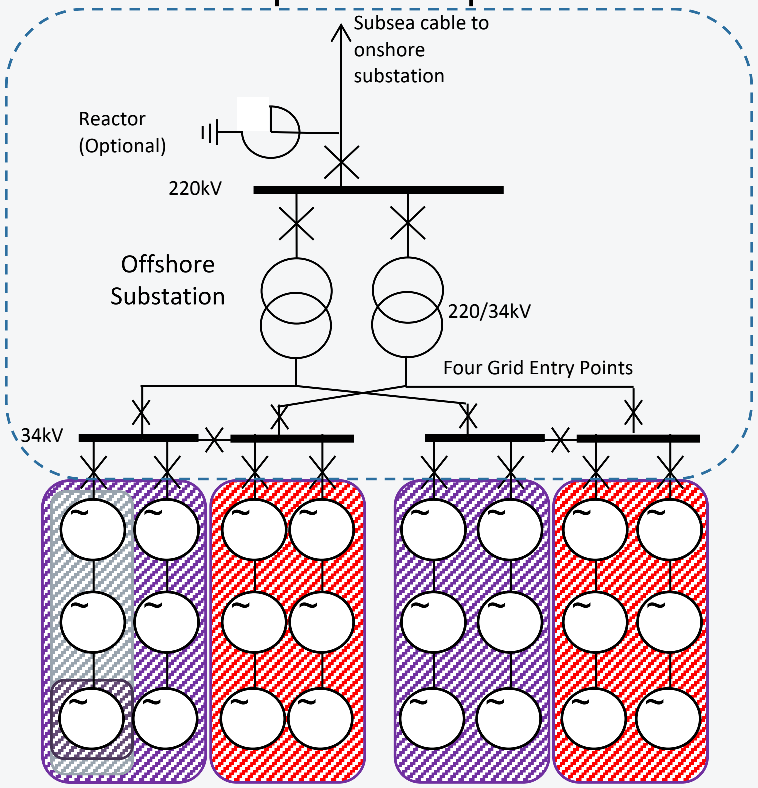
– CC.6.3.7 (a)

*"Each **Generating Unit**, **DC Converter** or **Power Park Module** […] must be fitted with a fast acting proportional **Frequency** control device (or turbine speed governor) and unit load controller or equivalent control device to provide **Frequency** response under normal operational conditions in accordance with **Balancing Code 3** (BC3). In the case of a **Power Park Module** the Frequency or speed control device(s) may be on the **Power Park Module** or on each individual **Power Park Unit** or be a combination of both […]"*

– ECC.6.3.7.3.1 (a)

*"In addition to the requirements of ECC.6.3.7.1 and ECC.6.3.7.2 each **Type C Power Generating Module** and **Type D Power Generating Module** (including **DC Connected Power Park Modules**) or **HVDC Systems** must be fitted with a fast acting proportional **Frequency** control device (or turbine speed governor) and unit load controller or equivalent control device to provide **Frequency** response under normal operational conditions in accordance with **Balancing Code 3** (BC3). In the case of a **Power Park Module** including a **DC Connected Power Park Module**, the **Frequency** or speed control device(s) may be on the **Power Park Module** (including a **DC Connected Power Park Module**) or on each individual **Power Park Unit** (including a **Power Park Unit** within a **DC Connected Power Park Module**) or be a combination of both. […]"*

Compliant setup



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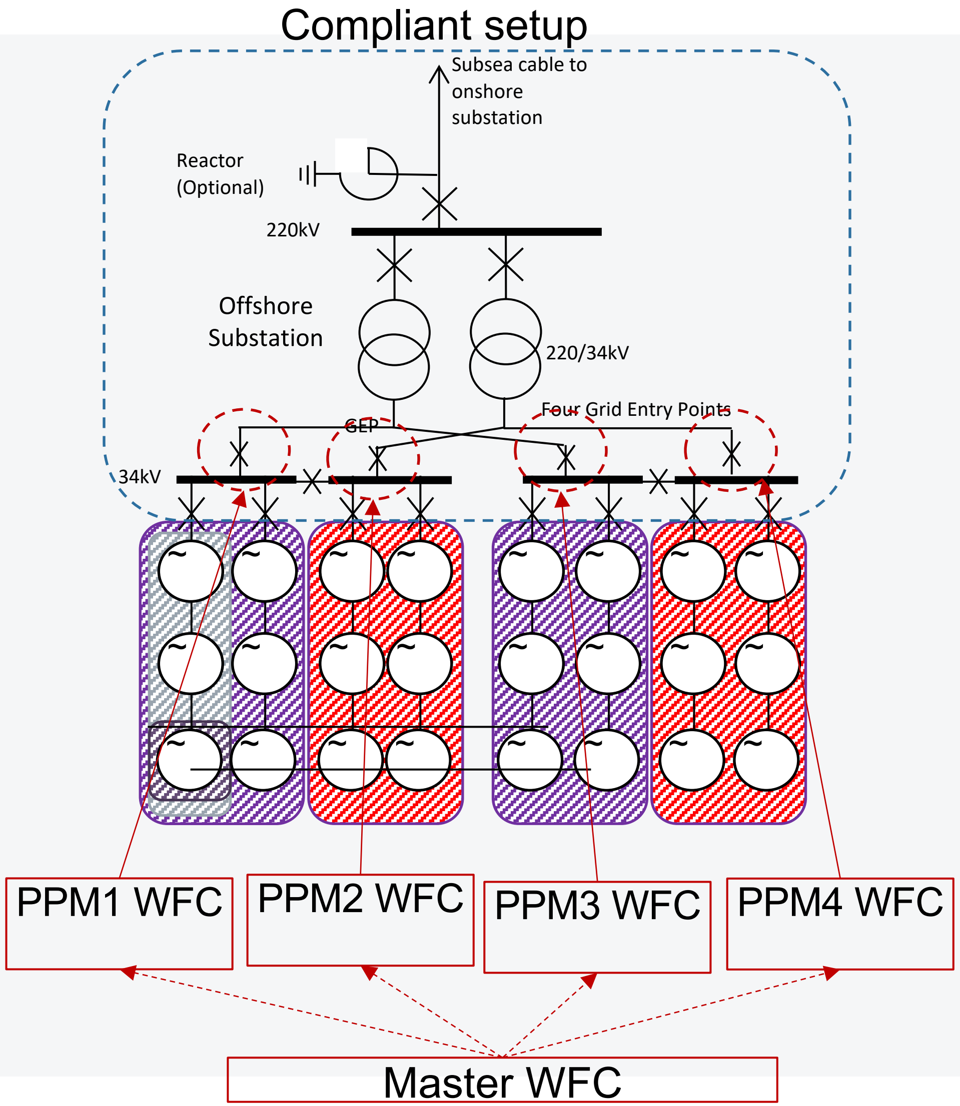
Implication of Current Frequency Control Requirement and Proposed Solution

- The current requirement implies that
  - At least four Wind Farm Controllers (WFC) are required to meet the existing Grid Code requirement, one for each PPM.
  - A Master Wind Farm Controller (Master WFC) may be required to coordinate the four individual WFCs.
  - Depending on the way the reactive power / voltage is controlled and the location of the measuring point, additional control systems including additional measurement points may be required
  - Multiple BM Units could be required for this solution



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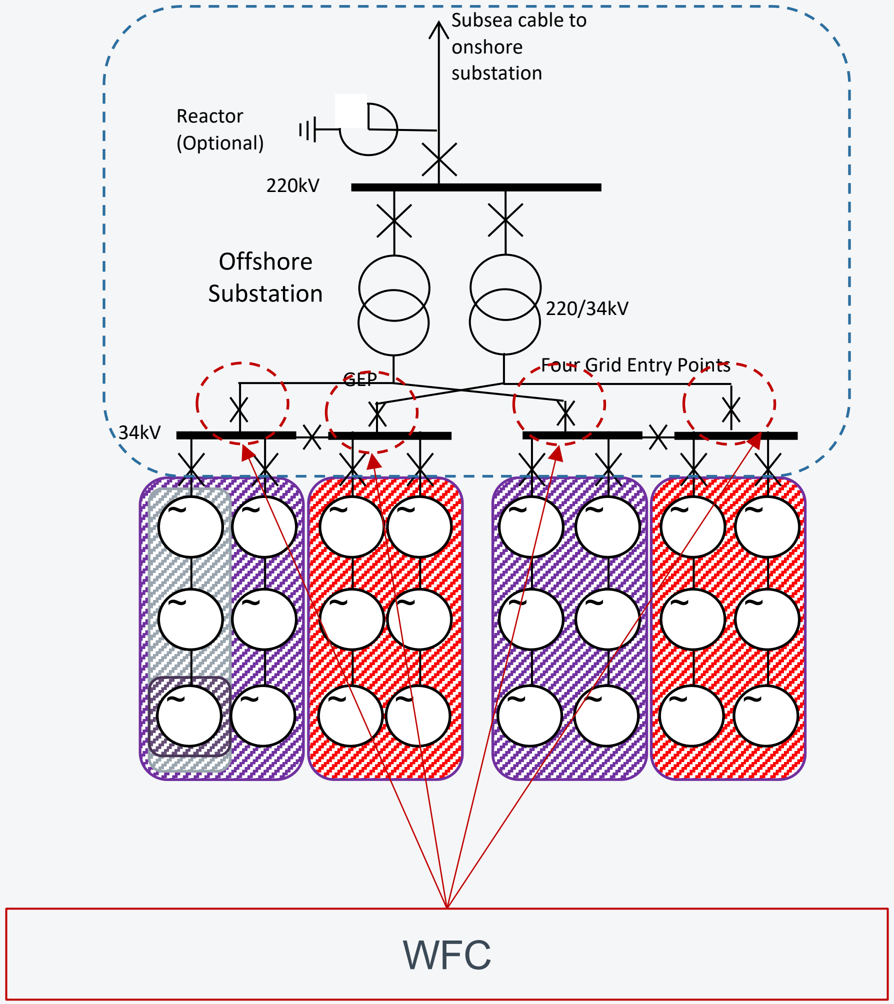
  - Depending on the way the reactive power / voltage is controlled and the location of the measuring point, additional control systems including additional measurement points may be required
  - Multiple BM Units could be required for this solution

- A solution with a single WFC would offer a less complex solution and meet the same objective of the Grid Code requirement
  - Frequency could still be controlled providing the same compliant response
  - Less control systems would be required (4+1 vs. 1)
  - A Combined BM Unit could be defined here, simplifying both operation and control of the wind farm for both User and NG

Proposed setup



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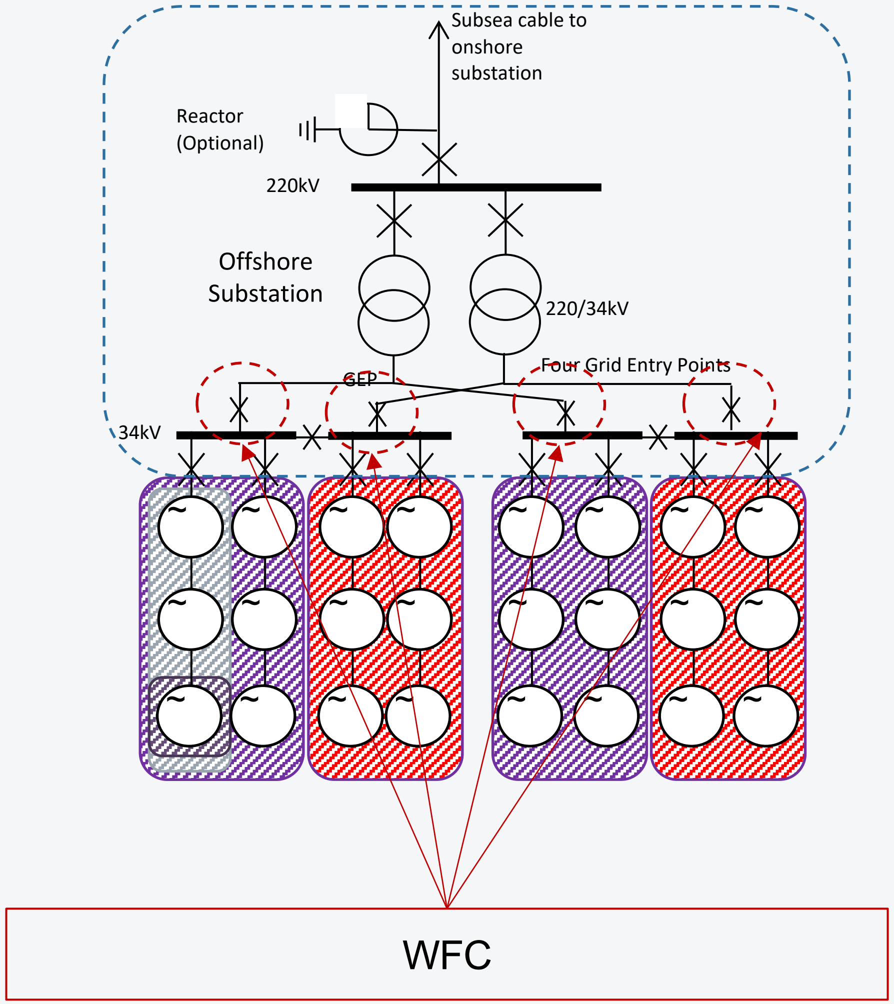
Benefits of the Proposed Solution

Advantages of a solution with one WFC

– CAPEX reduction between £320-400k per offshore platform

Proposed setup



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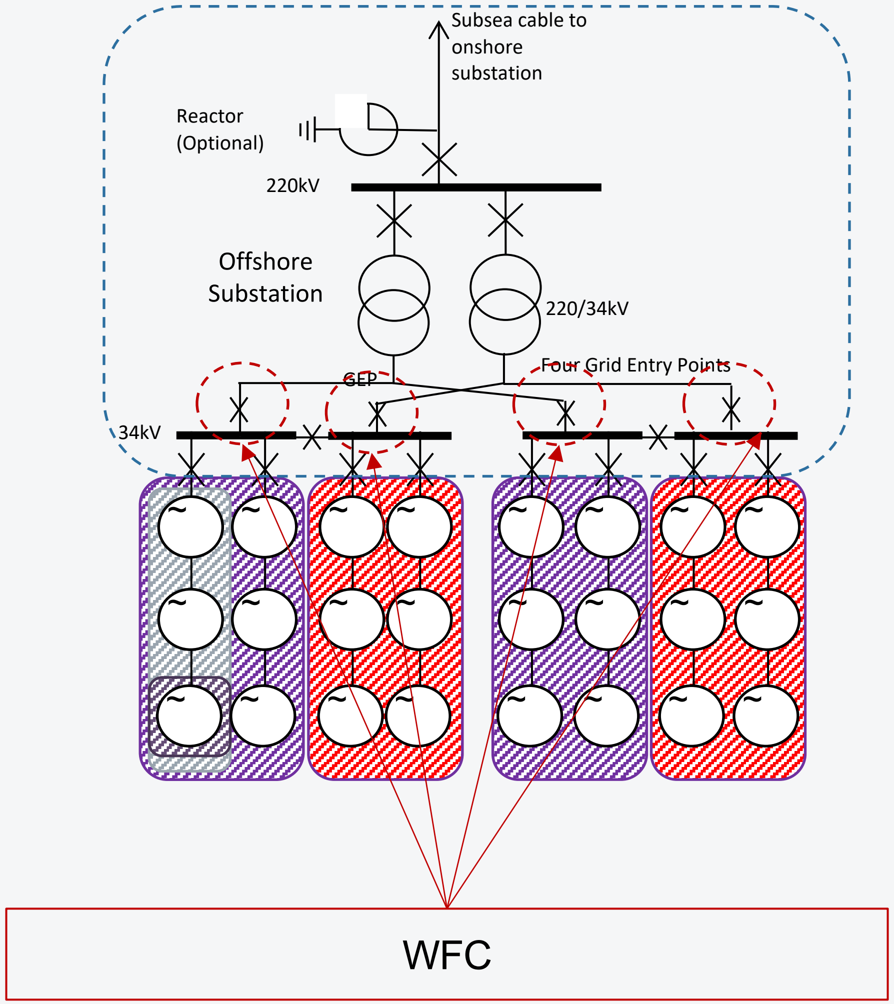
Benefits of the Proposed Solution

Advantages of a solution with one WFC

- CAPEX reduction between £320-400k per offshore platform
- Use of a Combined BM Unit for the entire Offshore platform
  - Better optimisation of the power output from the individual wind turbines on a second by second basis, under both normal operation and when there are outages
  - Higher energy capture during curtailment scenarios

Proposed setup



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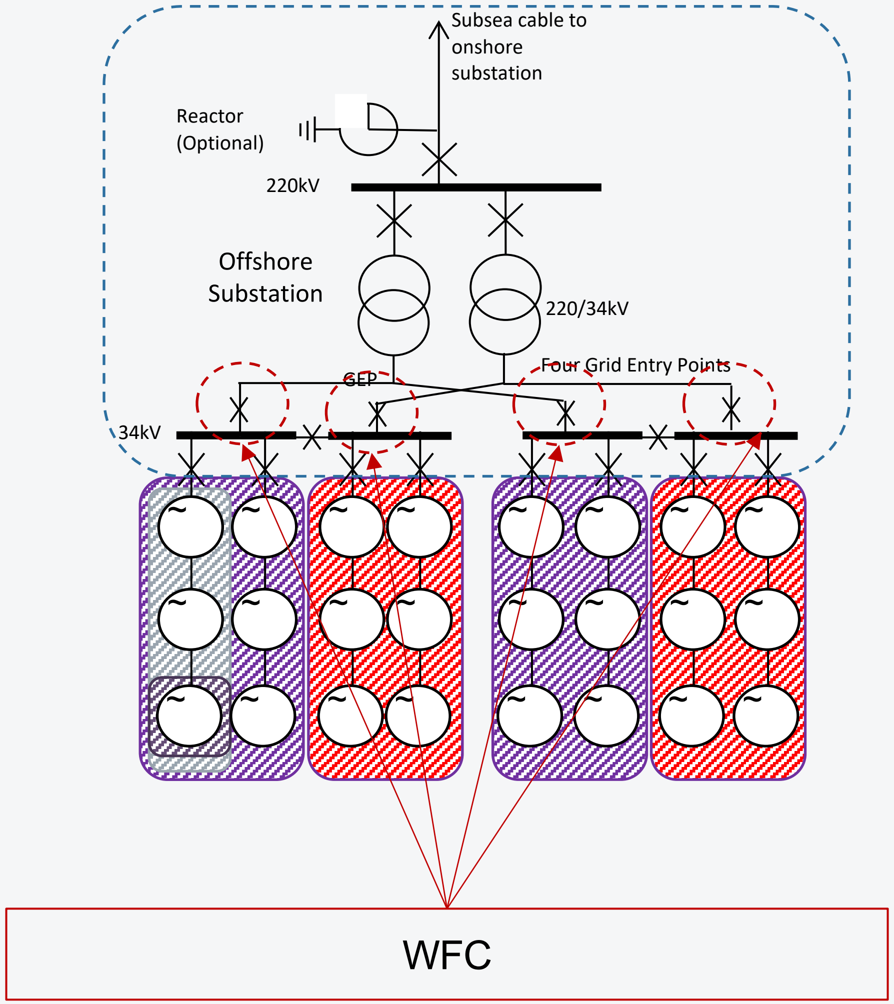
- CAPEX reduction between £320-400k per offshore platform
- Use of a Combined BM Unit for the entire Offshore platform
  - Better optimisation of the power output from the individual wind turbines on a second by second basis, under both normal operation and when there are outages
  - Higher energy capture during curtailment scenarios
- The reactive power / voltage control performed with a single WFC will eliminate the risk of instability due to multiple WFCs controlling the same point and reduce the risk of limiting the support that can be provided to the OFTO

Proposed setup



Benefits of the Proposed Solution

Advantages of a solution with one WFC

- CAPEX reduction between £320-400k per offshore platform
- Use of a Combined BM Unit for the entire Offshore platform
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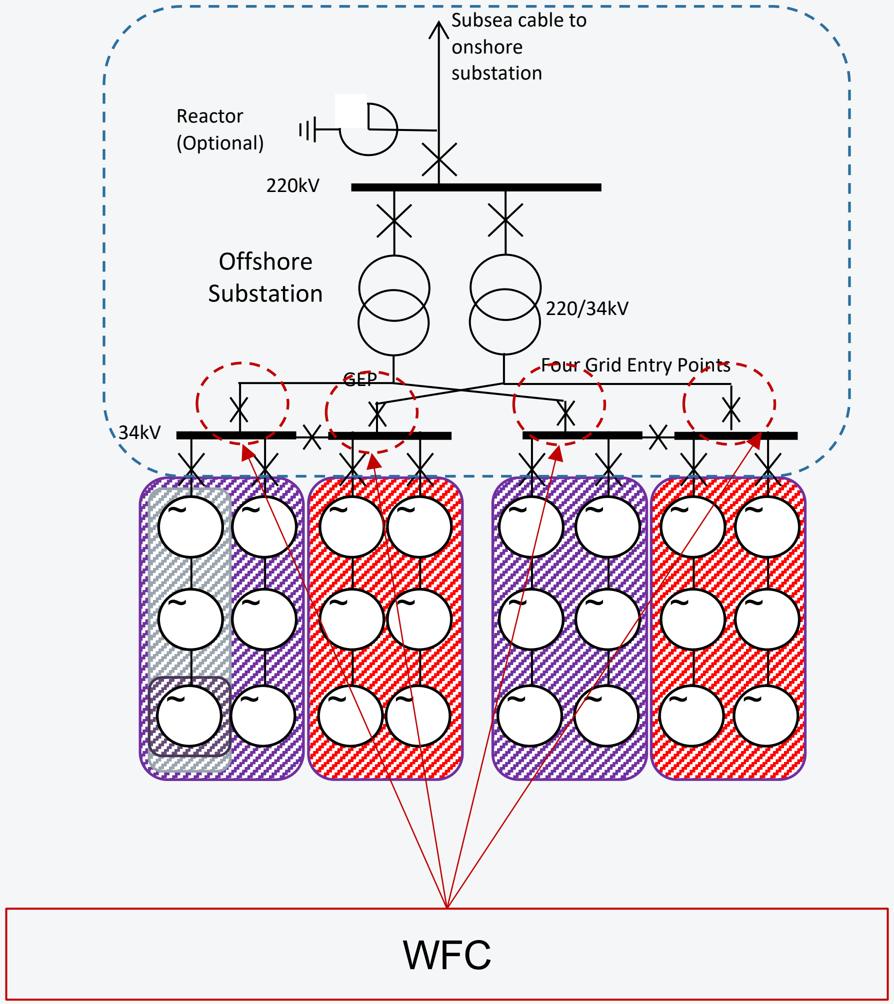
  - Higher energy capture during curtailment scenarios
- The reactive power / voltage control performed with a single WFC will eliminate the risk of instability due to multiple WFCs controlling the same point and reduce the risk of limiting the support that can be provided to the OFTO
- Simpler and less error-prone system

Proposed setup



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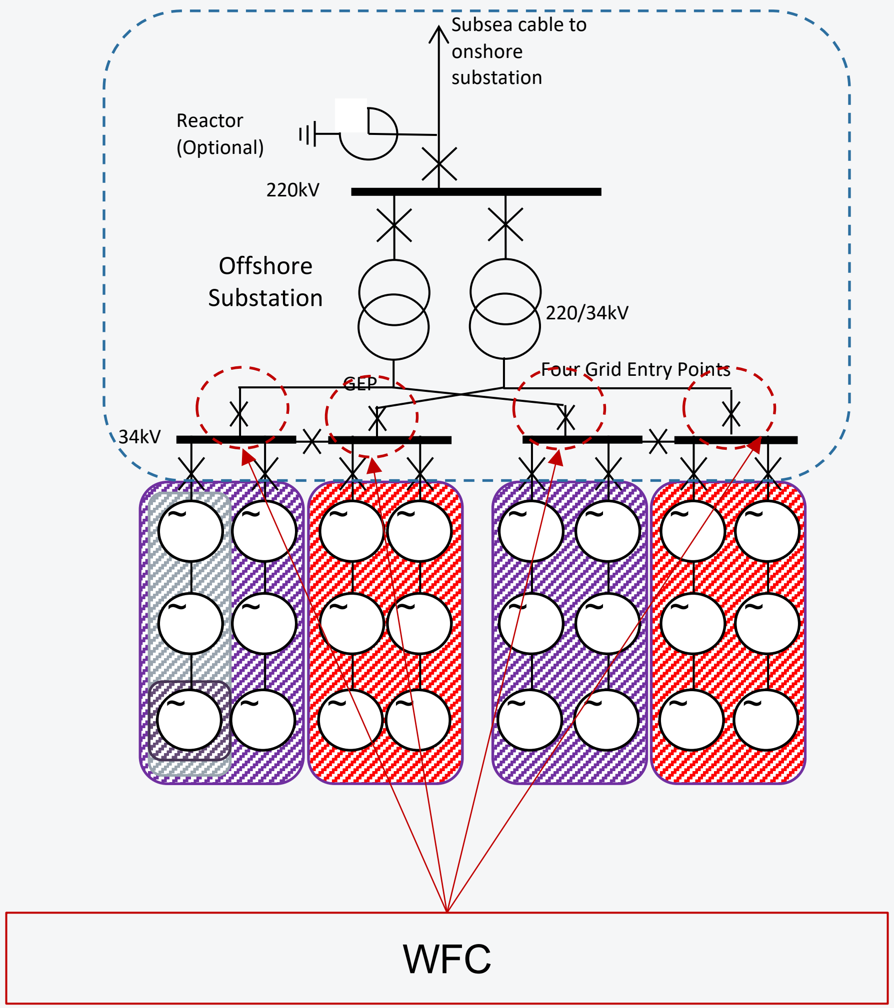
Benefits of the Proposed Solution

Advantages of a solution with one WFC

- CAPEX reduction between £320-400k per offshore platform
- Use of a Combined BM Unit for the entire Offshore platform
  - Better optimisation of the power output from the individual wind turbines on a second by second basis, under both normal operation and when there are outages
  - Higher energy capture during curtailment scenarios
- The reactive power / voltage control performed with a single WFC will eliminate the risk of instability due to multiple WFCs controlling the same point and reduce the risk of limiting the support that can be provided to the OFTO
- Simpler and less error-prone system
- Ørsted experience is that there is no visible benefit in having multiple WFCs for an offshore wind farm, mainly due the way the frequency control system is designed.

Proposed setup



Proposed Legal Text Change for CC.6.3.7

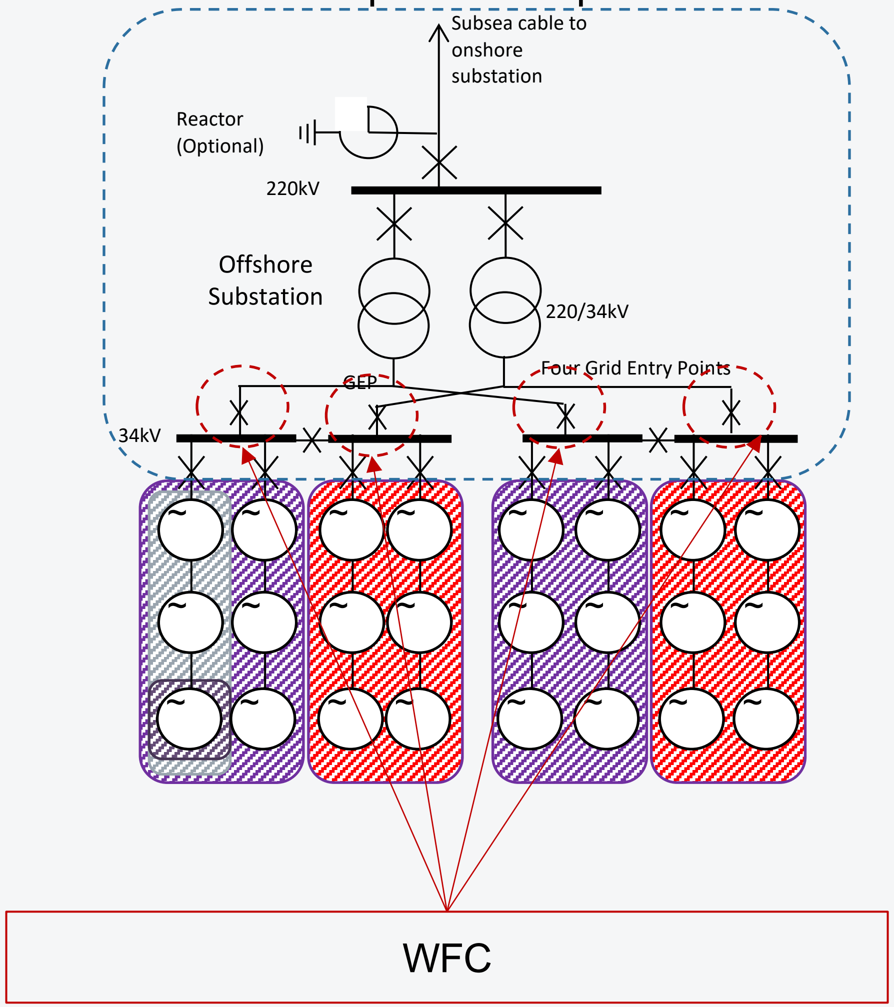
Proposal: modify the Grid Code requirement in CC.6.3.7 to allow wind farm developers to choose either solution for the control of frequency in the system

*"Each **Generating Unit**, **DC Converter** or **Power Park Module** […] In the case of a **Power Park Module** the Frequency or speed control device(s) may be*

- *i) on the **Power Park Module;** or*
- *ii) on an aggregation of **Power Park Modules** which are registered under the same **BM Unit**; or*
- *iii) on each individual **Power Park Unit**; or*
- *iv) a combination of i) and iii) or a combination of ii) and iii).*

[…]"

Proposed setup



Ørsted

Proposed Legal Text Change for ECC.6.3.7.3.1(a)

Proposal: modify the Grid Code requirement in ECC.6.3.7.3.1 (a) to allow wind farm developers to choose either solution for the control of frequency in the system

*"In addition to the requirements of ECC.6.3.7.1 and ECC.6.3.7.2 […] In the case of a **Power Park Module** including a **DC Connected Power Park Module**, the **Frequency** or speed control device(s) may be*

*i) on the **Power Park Module** (including a **DC Connected Power Park Module**); or*

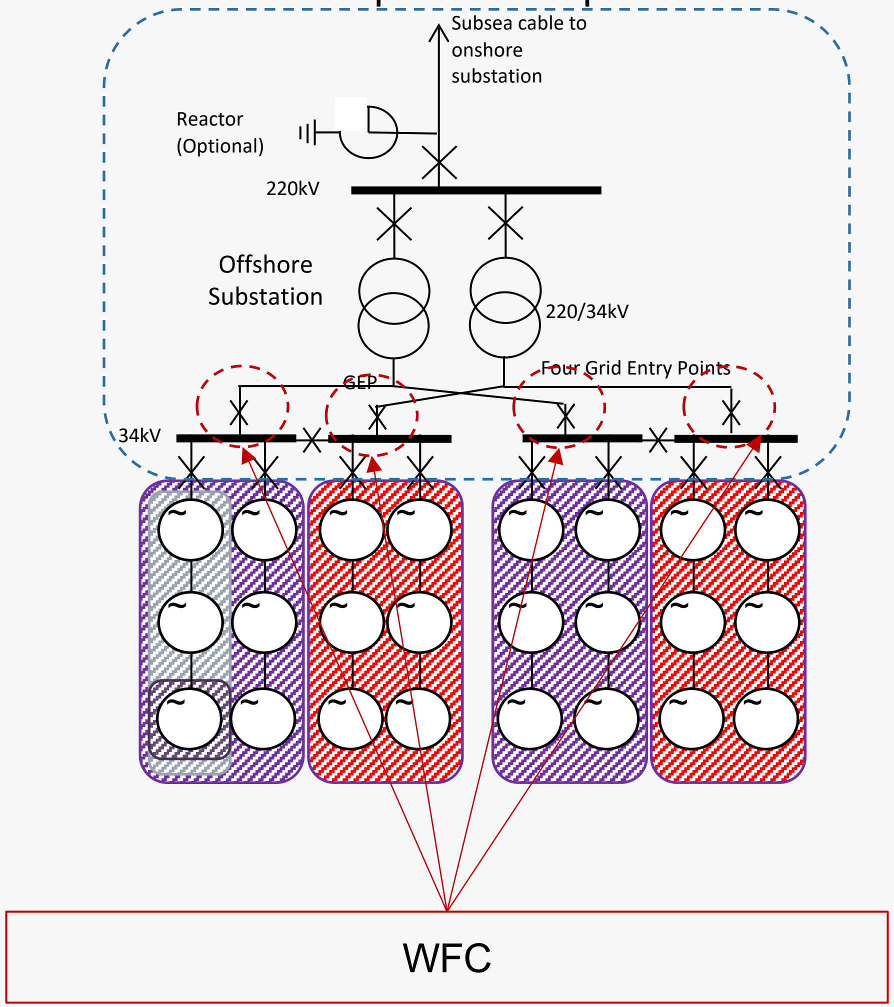
*ii) on an aggregation of **Power Park Modules** (including a **DC Connected Power Park Module)** which are registered under the same **BM Unit**; or*

*iii) on each individual **Power Park Unit Unit** (including a **Power Park Unit** within a **DC Connected Power Park Module**) ; or*

iv) a combination of i) and iii) or a combination of ii) and iii).

[…]"

Proposed setup



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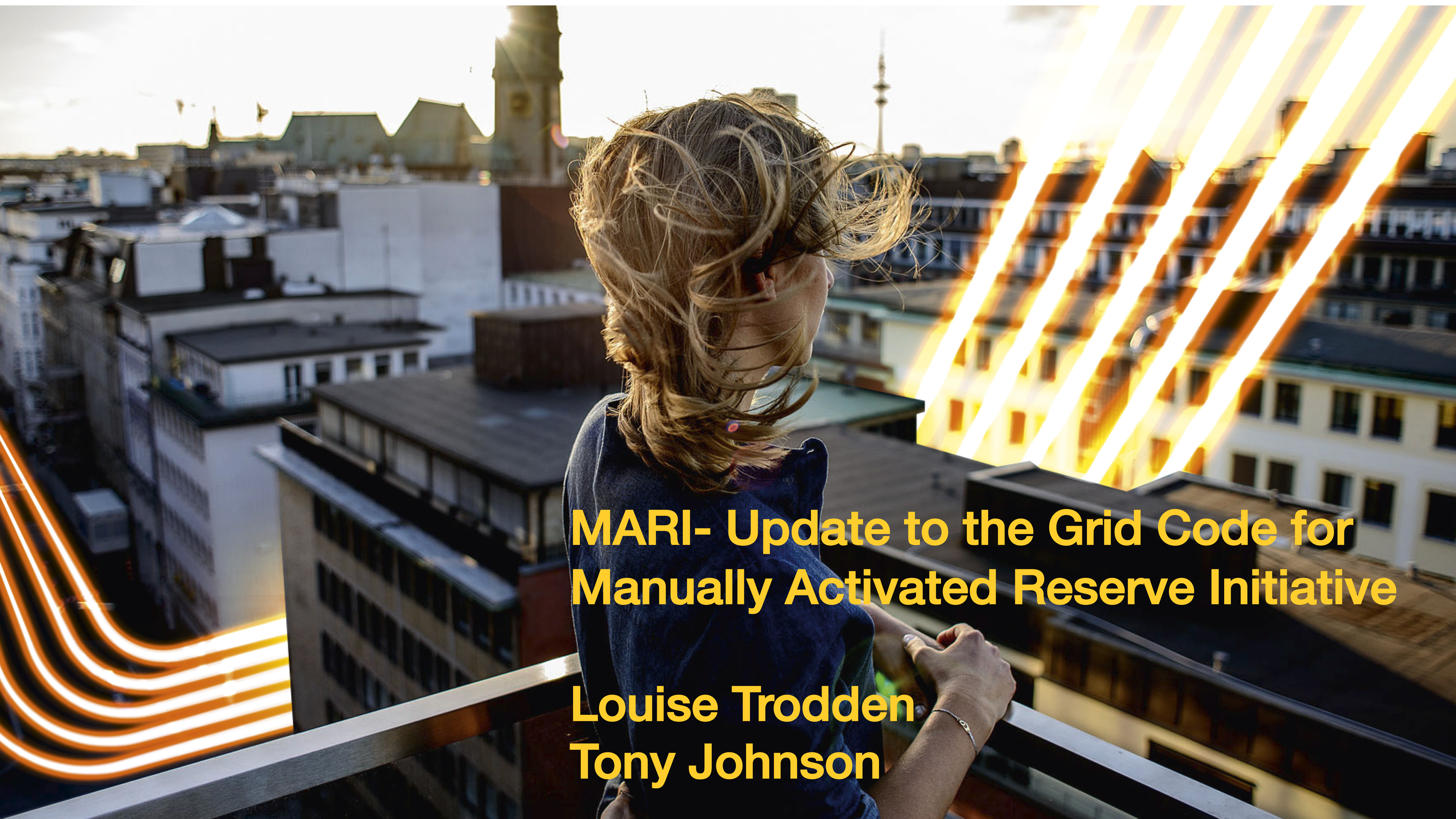


MARI- Update to the Grid Code for Manually Activated Reserve Initiative

Louise Trodden
Tony Johnson

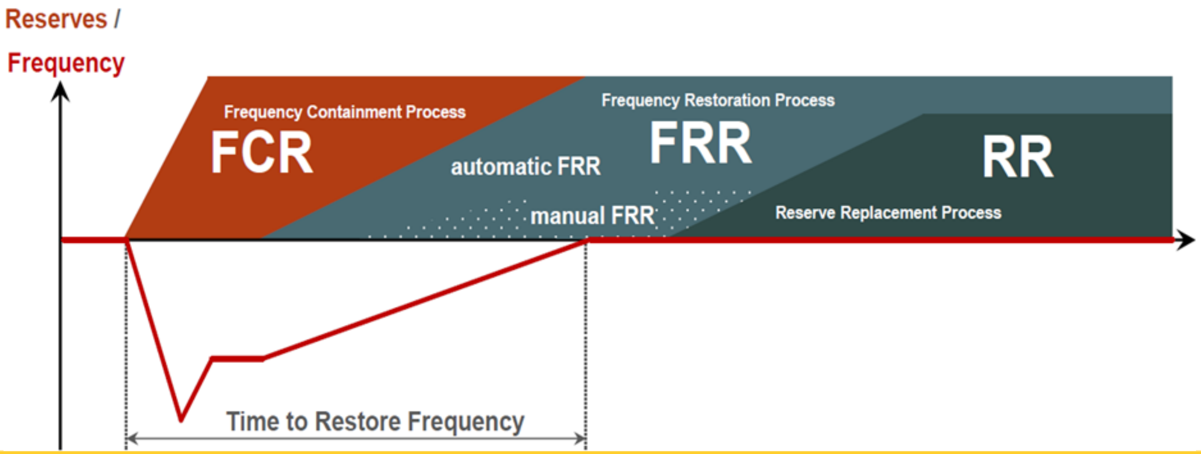
What is MARI

Manually Activated Reserve Initiative (MARI) is the platform used for exchange of manual frequency reserve restoration (mFRR). mFRR is a standard EU balancing energy product.

mFRR contributes to the creation of harmonised balancing energy products for TSOs. Unlike TERRE, MARI is mandatory for all TSOs in Europe.

MARI is a reserve balancing product activated in 12.5 minutes, in comparison TERRE is activated in 30minutes and both are settled on pay as clear mechanism. MARI aims to restore frequency containment reserves in a similar way to some BOAs, Fast Reserve and STOR (being activated in less than 15 minutes).

Additionally, MARI can be activated in two ways (either scheduled over the 15 minute window, or via a direct activation of energy within the 15 minute window).



Interaction between standard EU products. Please note that automatic FRR is not an option in GB, we are implementing manual FRR. Reserve Replacement (RR) is the EU balancing product known as TERRE.

Why

mFRR has been introduced as a new standard EU product for which GB has a legal requirement under EGBL Article 20 to implement by July 2022.

Currently the mFRR product does not have the technical requirements specified in the Grid Code, so a new section of the Grid Code will be developed to enable requirements for participation and pre-qualification to be outlined.

Given this is a new product, new processes will also be required to be undertaken by market participants and in the control room, and full industry engagement will be required for its success.

Risks / Next Steps

- Brexit implications- how does this fit with GB involvement in the IEM post January 2021.
- Time to implement – we need to complete the workgroup process by December 2020 to allow sufficient time to develop and test our IT systems
- TERRE has not gone live in GB- further derogations have been granted, expected go-live date is Oct-20
- A number of European countries are considering derogations including France, Belgium are currently still progressing MARI, therefore, - the NEMO interconnector would be the only one available for mFRR
- COVID-19- will this cause workload issues for stakeholder to participate in the workgroup phase and for internal process in the control room
- GB products – new frequency response products are being implemented in GB- how do these fit into MARI
- Only one derogation can be granted for a period of up to 2 years

- MARI will be based upon the principles of TERRE, the code changes will involve creating new sections of the Grid Code to include mFRR specifications
- Take proposal to GCRP to commence workgroup process
- Workgroups are intended to be joint BSC and Grid Code workgroups

Code Administrator General Updates

nationalgridESO

Dates for your diary

	May	June	July	August
GCDF Submission Date	27/04/2020	22/05/2020	29/06/2020	27/07/2020
GCDF Papers Day	29/04/2020	27/05/2020	01/07/2020	29/07/2020
GCDF	06/05/2020	03/06/2020	08/07/2020	05/08/2020
New Modification Proposal Submission Date	13/05/2020	10/06/2020	15/07/2020	12/08/2020
GCRP Papers Day	20/05/2020	17/06/2020	22/07/2020	19/08/2020
Grid Code Review Panel	28/05/2020	25/06/2020	30/07/2020	27/08/2020

Any Other Business (AOB)

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