Independent Assurance Report on compliance with specified elements of the Scheduling and Dispatch process for the 12-month period ended 31 December 2022

Use of this report

This report is intended solely for the use of the Directors of EirGrid plc and SONI Limited. While we acknowledge that this report will be published on the EirGrid (www.eirgridgroup.com), SONI (www.soni.ltd.uk), and SEMO (www.sem-o.com) websites, it (as per the terms set out in the click through) is for information purposes only and it should not be relied upon by anyone other than the Directors of EirGrid plc and SONI Limited. We accept no liability (including for negligence) to anyone else in connection with this document

The Directors
EirGrid plc
Block 2
The Oval
160 Shelbourne Road
Dublin 4
D04 FW28

The Directors
SONI Limited
12 Manse Rd
Belfast
BT6 9RT
United Kingdom

27 July 2023

Dear Ladies and Gentlemen,

Independent Assurance Report on compliance with specified elements of the Scheduling and Dispatch process for the 12-month period ended 31 December 2022

Introduction

1. We have been engaged by EirGrid plc and SONI Limited ("the Transmission System Operators") to provide an Independent Assurance Report ("Assurance Report") in respect of compliance with specific regulatory requirements as they relate to specified elements of the scheduling and dispatch process for the period 1 January 2022 to 31 December 2022 ("the period"), in order for the Transmission System Operators to complete the required reporting to the Commission for Regulation of Utilities in Ireland and the Utility Regulator in Northern Ireland (each the "Regulator") to satisfy the EirGrid plc and SONI Limited Licence obligations as set out in paragraph 9 of Condition 10A and Condition 22A of their Transmission System Operator Licence agreements respectively.

PricewaterhouseCoopers, One Spencer Dock, North Wall Quay, Dublin 1 Ireland
T: +353 (0) 1 792 6000, F: +353 (0) 1 792 6200, www.pwc.ie

Scope of work

2. The specified elements of the scheduling and dispatch process that are included in the scope of this report have been grouped into six "pillars". These are set out in the table below under the column "In scope items". The criteria that have been used to measure the Transmission System Operators' compliance with the specified elements of the scheduling and dispatch process have been set out in the table below and are hereinafter referred to as "The Requirements". We have assessed the extent to which the Transmission System Operators, in specified elements of their scheduling and dispatch process, have complied with The Requirements for the period.

		The Requirements	
Pillar #	**In scope items**	**Criteria EirGrid**	**Criteria SONI**
1	Priority Dispatch	**Transmission System Operator Licence ("TSO Licence")** Condition 10A - Para. 4(a)/(b) & 5(f),(i) **Other requirements:** SEM-11-062 Principles of Dispatch and the Design of the Market Schedule in the Trading and Settlement Code SEM Committee Decision Paper	**TSO Licence** Condition 22A - Para. 4(a)/(b) & 5(f), (i) Condition 9A **Other requirements:** SEM-11-062 Principles of Dispatch and the Design of the Market Schedule in the Trading and Settlement Code SEM Committee Decision Paper
2	Dispatch Instructions	**TSO Licence** Condition 10A - Para. 2, 4 and 5 **Other requirements:** SEM-21-088 Trading and Settlement Code Scheduling and Dispatch Parameters 2022 Decision Paper Grid Code CC. 8.2.1	**TSO Licence** Condition 22A - Para. 2, 4 and 5 **Other requirements:** SEM-21-088 Trading and Settlement Code Scheduling and Dispatch Parameters 2022 Decision Paper Grid Code CC. 5.3.1
3	Merit Orders	**TSO Licence** Condition 10A - Para. 3 **Other requirements:** Grid Code SDC 1.4.7.3 / SDC1.4.7.4 and SDC2.4.2.14	**TSO Licence** Condition 22A - Para. 3 **Other requirements:** Grid Code SDC 1.4.8.3 / SDC1.4.8.4 and SDC2.4.2.14
4	Operational Constraints	**TSO Licence** Condition 10A - Para. 4(a)(b) & 5(d)	**TSO Licence** Condition 22A - Para. 4(a)(b) & 5(d)
5	Constraint Flagging	**Trading and Settlement Code – Part B** Flagging of Accepted Bids and Offers E.3.3.1 Trading and Settlement Code Part B, Appendices, APPENDIX N: Flagging and Tagging, System	**Trading and Settlement Code – Part B** Flagging of Accepted Bids and Offers E.3.3.1 Trading and Settlement Code Part B, Appendices, APPENDIX N: Flagging and Tagging, System

		The Requirements	
Pillar #	**In scope items**	**Criteria EirGrid**	**Criteria SONI**
		Operator and Non-Marginal Flagging Paragraph 1-5	Operator and Non-Marginal Flagging Paragraph 1-5
6	IT General Controls required to support the areas noted in items 1-5 above	While not specifically discussed in the regulations, the Transmission System Operators' maintenance of IT General Controls over key systems supporting items 1-5 above is key to the overall testing approach.	

3. For the avoidance of doubt, certain parts of the scheduling and dispatch process are not covered in the scope of this report. Please refer to the "Scheduling and Dispatch process Assurance Engagement approach for the 12-month period ended 31 December 2022" ("The Supplement") that is appended to this report. The Supplement includes further information in relation to the Assurance Engagement, including the approach and items excluded from the scope of our assurance engagement, materiality, detailed work undertaken per Pillar as well as Appendix A - Risk and Response and Appendix B - Glossary of terms.
4. The Supplement provides a detailed description of the approach we have adopted to the assurance engagement. In particular, it describes those aspects of the specified elements of the scheduling and dispatch process that we have tested and those which are outside the scope of this assurance engagement. This report should be read in conjunction with The Supplement.
5. We have completed our work in accordance with the Letter of Engagement, agreed between ourselves and the Transmission System Operators on 13 April 2023.
6. The Letter of Engagement includes a clause limiting the total liability of PricewaterhouseCoopers to the Transmission System Operators, to a maximum of 3 times fees (excluding VAT) or €300,000, whichever is greater.
7. We have relied on our own knowledge and skills in interpreting The Requirements. We are not legal advisors and have not taken independent legal advice and shall therefore have no responsibility to the Transmission System Operators were a court to interpret or construe The Requirements in a different way from us.
8. Unless the context otherwise requires, words and expressions defined in The Requirements have the same meanings in this report as in the Requirements. The versions relevant to our opinion are:
    a. EirGrid Transmission System Operator Licence, 10 March 2017
    b. SONI's Licence to Participate in the Transmission of Electricity, 28 February 2019, 26 January 2022, 18 November 2022
    c. EirGrid Grid Code Version 10, 15 December 2021, Version 11, 14 October 2022
    d. SONI Grid Code 8 October 2020
    e. Trading and Settlement Code – Part B Versions 25, 26 and 27

Respective responsibilities of the Transmission System Operators and the Scheduling and Dispatch Auditor

The Transmission System Operators are responsible for the items set out below:

9. Defining appropriate criteria against which to assess the Transmission System Operators' performance in relation to the specified elements of the scheduling and dispatch process and applying these consistently (The Requirements).
10. Ensuring that those criteria are relevant and appropriate to the Transmission System Operators and the users of the specified elements of the scheduling and dispatch process.
11. Ensuring that the Transmission System Operators comply with all regulations applicable to the specified elements of the scheduling and dispatch process.
12. Designing, implementing, and maintaining internal control procedures that provide adequate control over information in respect of the specified elements of the scheduling and dispatch process.
13. Selecting and applying appropriate policies and making estimates that are reasonable in the circumstances in respect of the specified elements of the scheduling and dispatch process.
14. Addressing all day-to-day queries received from participants and/or Regulators.
15. Determining the best way to operate the specified elements of the scheduling and dispatch process having due regard to the safe operation of the grid, including any security considerations.
16. Ensuring that all data published in relation to the specified elements of the scheduling and dispatch process on the EirGrid (www.eirgridgroup.com), SONI (www.soni.ltd.uk), and Single Electricity Market Operator ("SEMO") (www.sem-o.com) websites is complete and accurate, subject to known system issues and defects as published by SEMO on the Known Issues Report.
17. Retention of sufficient, appropriate evidence to support the operation of the specified elements of the scheduling and dispatch process.

Responsibilities of the Scheduling and Dispatch Auditor

18. It is our responsibility to perform appropriate work to enable us to express an opinion on the Transmission System Operators' compliance with The Requirements in respect of the specified elements of the scheduling and dispatch process.

Independence and Quality Control

19. We complied with the Chartered Accountants Ireland Code of Ethics, which includes independence and other requirements founded on fundamental principles of integrity, objectivity, professional competence and due care, confidentiality, and professional behaviour, and which is at least as demanding as the corresponding provisions of the IESBA Code of Ethics.
20. We apply International Standard on Quality Management (Ireland) 1 and accordingly maintain a comprehensive system of quality control including documented policies and procedures regarding compliance with ethical requirements, professional standards, and applicable legal and regulatory requirements.

Basis of assurance and scope of work

21. We have performed the reasonable assurance engagement in accordance with the requirements of International Standard on Assurance Engagements 3000 (Revised), *'Assurance engagements other than audits or reviews of historical financial information'* issued by the International Auditing and Assurance Standards Board.

22. We have planned and performed our work in accordance with The Supplement, which is appended to this report.

23. In reaching our conclusion we assessed the risk of a material breach of the way the Transmission System Operators operated the specified elements of the scheduling and dispatch process compared with The Requirements, whether caused by fraud or other irregularity or error and determined the adequacy of procedures established by the Transmission System Operators to eliminate or reduce such risks.

Other matters

24. The scope of the scheduling and dispatch process audit was initially published on 27 October 2022 by the Transmission System Operators on the SEMO website in a document entitled, "*Annual Audit of the Scheduling and Dispatch Process*". Following more detailed scoping discussions it was agreed with the Transmission System Operators and their Regulatory Authorities (Commission for Regulation of Utilities in Ireland and the Utility Regulator in Northern Ireland) that the scope of this Assurance Report would differ from the previously published scope. The scope of this Assurance Report is clearly set out in the "Scope of work" section (paragraph 2-8) above. Further detail and a list of items excluded from the scope can be found in paragraphs 5 and 6 of The Supplement.

Opinion

25. Based on our procedures, in our opinion, in all material respects, the Transmission System Operators have complied with The Requirements as they relate to the specified elements of the scheduling and dispatch process during the 12-month period ended 31 December 2022.

Use of this report

26. This report is intended solely for the use of the Directors of EirGrid plc and SONI Limited. While we acknowledge that this report will be published on the EirGrid (www.eirgridgroup.com), SONI (www.soni.ltd.uk), and SEMO (www.sem-o.com) websites, it (as per the terms set out in the click through) is for information purposes only and it should not be relied upon by anyone other than the Directors of EirGrid plc and SONI Limited. We accept no liability (including for negligence) to anyone else in connection with this document.

27. The maintenance and integrity of the websites referenced in paragraph 26 above, is the responsibility of the Transmission System Operators. The work that we carried out does not involve consideration of the maintenance and integrity of those websites and, accordingly, we accept no responsibility for any changes that may have occurred to this report since it was initially presented on those websites.

28. This report has been prepared on the expectation that the Transmission System Operators will have sufficient experience of the specified elements of the scheduling and dispatch process to understand the scope of our work performed without further background explanation and to evaluate the contents of this report in the context of the scope of our work.

Yours faithfully

PricewaterhouseCoopers

Dublin

Chartered Accountants

Scheduling and Dispatch process Assurance Engagement approach for the 12-month period ended 31 December 2022 (“The Supplement”)

Contents

Objective and scope of the Scheduling and Dispatch process assurance engagement

1. The objective of our assurance engagement was to form an independent opinion based on our work as to the compliance of EirGrid plc and SONI Limited ("the Transmission System Operators"), in all material respects, with The Requirements (refer to paragraph 5 below) as they relate to specified elements of the scheduling and dispatch process for the 12-month period ended 31 December 2022 ("the period").

2. The reasonable assurance engagement was performed in accordance with the requirements of International Standard on Assurance Engagements 3000 (Revised), '*Assurance engagements other than audits or reviews of historical financial information*' issued by the International Auditing and Assurance Standards Board.

3. This approach has been prepared by PricewaterhouseCoopers ("PwC") and accepted by the Transmission System Operators as the basis for the current period's engagement, as set out in the contractual arrangements in place between PwC and the Transmission System Operators.

4. The "scheduling and dispatch process" is the overall process resulting from the multiple inputs, processes and outputs which enable the Transmission System Operators to operate a secure system and efficient balancing market. It is a continuous process managed in a coordinated manner from the Transmission System Operators' Control Centres using a range of operational systems, processes, and procedures.

5. The specified elements of the scheduling and dispatch process that are included in the scope of this report have been grouped into six "pillars". These are set out in the table below under the column "In scope items". The criteria that have been used to measure the Transmission System Operators' compliance with the specified elements of the scheduling and dispatch process have been set out in the table below ("The Requirements"). We have assessed the extent to which the Transmission System Operators, in specified elements of their scheduling and dispatch process, have complied with The Requirements for the period.

		The Requirements	
Pillar #	**In scope items**	**Criteria EirGrid**	**Criteria SONI**
1	Priority Dispatch	**Transmission System Operator Licence ("TSO Licence")** Condition 10A - Para. 4(a)/(b) & 5(f), (i) **Other requirements:** SEM-11-062 Principles of Dispatch and the Design of the Market Schedule in the Trading and Settlement Code SEM Committee Decision Paper	**TSO Licence** Condition 22A - Para. 4(a)/(b) & 5(f), (i) Condition 9A **Other requirements:** SEM-11-062 Principles of Dispatch and the Design of the Market Schedule in the Trading and Settlement Code SEM Committee Decision Paper
2	Dispatch Instructions	**TSO Licence** Condition 10A - Para. 2, 4 and 5 **Other requirements:** SEM-21-088 Trading and Settlement Code Scheduling and Dispatch Parameters 2022 Decision Paper Grid Code CC. 8.2.1	**TSO Licence** Condition 22A - Para. 2, 4 and 5 **Other requirements:** SEM-21-088 Trading and Settlement Code Scheduling and Dispatch Parameters 2022 Decision Paper Grid Code CC. 5.3.1

		The Requirements	
Pillar #	**In scope items**	**Criteria EirGrid**	**Criteria SONI**
3	Merit Orders	**TSO Licence** Condition 10A - Para. 3 **Other requirements:** Grid Code SDC 1.4.7.3 / SDC1.4.7.4 and SDC2.4.2.14	**TSO Licence** Condition 22A - Para. 3 **Other requirements:** Grid Code SDC 1.4.8.3 / SDC1.4.8.4 and SDC2.4.2.14
4	Operational Constraints	**TSO Licence** Condition 10A - Para. 4(a)(b) & 5(d)	**TSO Licence** Condition 22A - Para. 4(a)(b) & 5(d)
5	Constraint Flagging	**Trading and Settlement Code – Part B** Flagging of Accepted Bids and Offers E.3.3.1 Trading and Settlement Code Part B, Appendices, APPENDIX N: Flagging and Tagging, System Operator and Non-Marginal Flagging Paragraph 1-5	**Trading and Settlement Code – Part B** Flagging of Accepted Bids and Offers E.3.3.1 Trading and Settlement Code Part B, Appendices, APPENDIX N: Flagging and Tagging, System Operator and Non-Marginal Flagging Paragraph 1-5
6	IT General Controls required to support the areas noted in items 1-5 above	While not specifically discussed in the regulations, the Transmission System Operators' maintenance of IT General Controls over key systems supporting items 1-5 above is key to the overall testing approach.	

6. In agreement with the Transmission System Operators, and for the purposes of clarity, items excluded from the scope of our assurance engagement include:

- The algorithms associated with the optimisation engines, which produce the Long-Term Scheduling ("LTS"), Real Time Commitment ("RTC") and Real-Time Dispatch ("RTD") schedules, used in the scheduling and dispatch process.
- The Imbalance Pricing process which takes place after the scheduling and dispatch process has ended.
- Validation of data submitted to the Transmission System Operators by participants.
- Inputs such as forecasts which are provided by third parties.
- Inputs such as transmission and generator outage plans.
- The derivation of operational constraints.
- Actions taken with market participants by the Transmission System Operators to resolve performance issues during the scheduling and dispatch process.
- Resolution and validation of known system issues and defects as published by SEMO on the periodic Known Issues Reports which were not resolved in advance of the start of the audit period, 1 January 2022.
- An assessment of the compliance of the Transmission System Operators in relation to any regulations other than those specifically referenced in the table above as documented in paragraph 5 of this document.

- Any regulations which are cross referenced within the regulations listed as the criteria but not specifically identified as criteria themselves, other than those specifically referenced in the table above as documented in paragraph 5 of this document.

- Validation that data published in relation to the specified elements of the scheduling and dispatch process on the EirGrid (www.eirgridgroup.com), SONI (www.soni.ltd.uk), and SEMO (www.sem-o.com) websites is complete and accurate unless specifically included in testing procedures, for example, Operational Constraint Updates are specifically included and referenced in procedures 29-31 of this document.

- An assessment of the compliance of the Transmission System Operators with the Regulation on Wholesale Energy Markets Integrity and Transparency (REMIT).

- An assessment of the engineering decisions that the Transmission System Operators make when actioning internal operating procedures relevant to the specified elements of the scheduling and dispatch process.

- Validation that system security has been maintained at all times.

- The Articles 3: 15 & 16; 4: 24 and 5: 26 & 27 associated with the Interim Cross-zonal arrangements as set out in the document entitled, "*Annual Audit of the Scheduling and Dispatch Process*" published on 27 October 2022 by the Transmission System Operators on the SEMO website.

Approach

7. Our approach consisted of the following, in respect of the Transmission System Operators' operation of the specified elements of the scheduling and dispatch process:

a) obtaining an understanding of the internal operating procedures that the Transmission System Operators have in place that relate to the use of specified elements of the scheduling and dispatch process and/or the Information Technology General Controls ("ITGCs") supporting the relevant computer systems as defined in paragraph 36 below ("the in-scope systems");

b) testing on a sample basis, to the extent we considered necessary to support our opinion over the Transmission System Operators' compliance with The Requirements as they relate to the specified elements of the scheduling and dispatch process, the operation of the ITGCs supporting the relevant computer systems and/or internal operating procedures during the period; and

c) testing on a sample basis, to the extent that we considered necessary to support our opinion over the Transmission System Operators' compliance with The Requirements as they relate to the specified elements of the scheduling and dispatch process, certain data processed by the relevant computer systems and internal operating procedures during the period.

8. We designed our testing to provide reasonable assurance that in our opinion, in all material respects, the Transmission System Operators have complied with The Requirements as they relate to the specified elements of the scheduling and dispatch process during the period.

9. In undertaking our assurance engagement, we assessed the risk of a material non-compliance with The Requirements of the areas within the scope of our assurance engagement. In areas where we have identified specific risks, or where weaknesses have been identified in the operation of specific internal controls, the tests undertaken have been supplemented by further substantive tests of detail of the relevant underlying data. Our assessment of risks is presented in Appendix A below.

10. We have selected a sample of Settlement Days for testing in the period. The selection of the particular days tested was based on our assessment of risk. It represented a mixture of "normal" days and other days where we identify unusual factors (e.g., outages, Amber Alerts, Generator Trips, weekends, peak wind days or days around a specific event) which, in our view, represent a risk as to compliance with internal operating procedures.

11. Throughout the engagement, we have considered the results of our work and the impact on the specified elements of the scheduling and dispatch process and updated our risk assessment and determined appropriate responses where additional risks have been identified.

Materiality

12. We have planned and performed our assurance engagement so as to be able to provide reasonable assurance that the Transmission System Operators have operated the specified elements of the scheduling and dispatch process in all material respects in accordance with The Requirements.

13. We considered a failure on the Transmission System Operators' part to comply with The Requirements as being material if, in our opinion, a reasonable professional person, on consideration of the Transmission System Operators' adherence to The Requirements, would form a different view as to whether the Transmission System Operators have complied with The Requirements. In applying this judgement, we have taken into account the following quantitative and qualitative factors to conclude on materiality:

a. the extent to which the actual outcome would have been different had the principles set out in The Requirements been applied;

b. the surrounding circumstances at the time(s) of any failure to comply with The Requirements;

c. the aggregate impact in the period of any failures to comply with The Requirements; and

d. the relative significance of the particular provision of The Requirements that the Transmission System Operators have failed to comply with.

More detailed description of work undertaken

14. The work that we have carried out on pillars 1-6 is set out below.

Pillar 1: Priority Dispatch

The following procedures have been designed to assess the Transmission System Operators' compliance with The Requirements for Pillar 1: Condition 10A - Para. 4(a)/(b) & 5(f)/(i) of the EirGrid TSO Licence; Condition 22A - Para. 4(a)/(b) & 5(f)/(i) and Condition 9A of the SONI TSO Licence; and SEM-11-062 Principles of Dispatch and the Design of the Market Schedule in the Trading and Settlement Code SEM Committee Decision Paper.

15. **Accuracy of Participants reflected in the Market Management System ("MMS")/Resource balancing**

For a sample of participants from the Resource Balancing table maintained by the Registration team:

a. Checked that the participant was accurately reflected in MMS in line with its fuel type and where a participant is noted as a Priority Dispatch unit on the Resource Balancing table, if it was assigned the correct Priority Dispatch category in line with the hierarchy of SEM-11-062.

For a sample of participants from the LTS run:

b. Checked that participants in MMS were accurately noted as Priority Dispatch/non-priority dispatch participants as per the Resource Balancing listing (maintained by Registration team).

16. **Curtailment Events**

For a sample of curtailment events and curtailment dispatch instructions ("set point/set points") checked that:

a. There was a valid reason for the curtailment event;

b. Before a curtailment event occurred, other options were considered, including but not limited to, initiating Interconnector trades or turning down conventional units to their minimum generation where applicable;

c. Wind units were curtailed in line with controllability categories (Category 1-3);

d. Units receiving a set point were included in the predefined curtailment group that was curtailed; and

e. Set points issued to Priority Dispatch units were done on a pro rata basis.

For a sample of the remaining wind farms/solar units not tested as part of procedure 16d above:

f. Checked that a sample of wind farms/solar units which were part of the predefined curtailment group were issued a set point.

17. **Constraint Events**

For a sample of local constraint events ("constraint event") and constraint dispatch instructions ("set point/set points") checked that:

a. There was a valid reason for the constraint event;

b. Before a constraint event occurred, other options were considered when applicable;

c. Units receiving a set point were included in the predefined local constraint group that was constrained; and

d. Set points issued to Priority Dispatch units were done on a pro rata basis.

For a sample of the remaining wind farms/solar units which were not tested as part of procedure 17c above:

e. Checked that a sample of wind farms/solar units which were part of the predefined local constraint group were issued a set point.

18. **Curtailment and Constraint Events**

Observed the Wind Dispatch Tool automatically omit wind/solar units from dispatch down events when signals are categorised by the Wind Dispatch Tool as suspect.

Pillar 2: Dispatch Instructions (+Schedules)

The following procedures have been designed to assess the Transmission System Operators compliance with The Requirements for Pillar 2: Condition 10A - Para. 2, 4 and 5 of the EirGrid TSO Licence; Condition 22A - Para. 2, 4 and 5 of the SONI TSO Licence, SEM-21-088 Trading and Settlement Code Scheduling and Dispatch Parameters 2022 Decision Paper and EirGrid Grid Code CC. 8.2.1 / SONI Grid Code CC. 5.3.1.

19. **Frequency (Condition 10A Para 2 / 22A Para 2 and EirGrid Grid Code CC. 8.2.1 /SONI Grid Code CC. 5.3.1)**

For the period under review, analysed if frequency remained within the normal limits set out in the respective EirGrid (CC.8.2.1) and SONI (CC.5.3.1) Grid Codes. Any periods outside of the normal operating limits were considered for inclusion in our sample selection as these dates were considered, in our view, to represent a risk as to the Transmission System Operators' compliance with internal operating procedures.

20. **Physical Notifications (Condition 10A Para 2(a)(i), 4 and 5(b) / 22A Para 2(a)(i), 4 and 5(b))**

For a sample of generators' Physical Notifications in the MMS:

a. Checked that the generator is listed on the Physical Notification listing on the Market Participant Interface ("MPI"); and

b. Checked that the Physical Notifications information used in scheduling is accurate based on the Market Participant Information submitted.

For a sample of generators reflected on the MPI Physical Notification listings:

c. Checked that the generators are listed on the Physical Notification listing in MMS.

21. **Generators declaring unavailable (Condition 10A Para 2(a)(ii) / 22A Para 2(a)(ii))**

For a sample of Generators that declared as unavailable as per submitted participant information:

a. Checked that generators that declared unavailable were not included in the LTS schedule run for period of unavailability declared;

b. Checked that generators that declared unavailable did not receive a dispatch instruction for the period of unavailability declared.

For a sample of generators scheduled in an LTS schedule:

c. Checked that the generator did not declare as unavailable as per availability notices.

22. **Generation units not subject to central dispatch (Condition 10A Para 2(a)(iv) / 22A Para 2(a)(iv))**

For a sample of LTS schedules inspected that units not subject to central dispatch (Fixed Generation) were scheduled.

23. **Transmission System Outage (Condition 10A Para 2(b) / 22A Para 2(b))**

Checked that the send statuses (Success, pending, N/A and failed) as per the Outage Management System are accurately applied in the LTS schedules.

24. **Daily forecast demand (Condition 10A Para 4 and 5(a) / 22A Para 4 and 5(a))**

For a sample of time periods in an LTS schedule:

a. Checked that the GDX Scheduled Demand Forecast reconciles to the scheduled Load Forecast as included on the selected LTS schedules.

25. **Scheduling and Dispatch Policy Parameters (Condition 10A Para 4 and 5(c) / 22A Para 4 and 5(c) and SEM-21-088 Trading and Settlement Code Scheduling and Dispatch Parameters 2022 Decision Paper)**

For a sample of time periods within an LTS schedule:

a. Checked that the value as per the Long-Notice Adjustment Factor ("LNAF") MMS display matched the LNAF as set out in the Single Electricity Market Committee Decision paper published on the SEM-21-088 Trading and Settlement Code Scheduling and Dispatch Parameters 2022 Decision Paper; and

b. Checked that the value as per the System Imbalance Flattening Factors ("SIFF") MMS display matched the SIFF as set out in the Single Electricity Market Committee Decision paper published on the SEM-21-088 Trading and Settlement Code Scheduling and Dispatch Parameters 2022 Decision Paper.

26. **Generators Technical Offer data (Condition 10A Para 4 and 5(e) / 22A Para 4 and 5(e))**

For a sample of dispatch instructions:

a. Checked that generators received dispatch instructions in line with their submitted Technical Offer data (Maximum generating capability, Minimum generating capability).

27. **Interconnector Reference Programs ("ICRPs") (Condition 10A Para 4 and 5(f) / 22A Para 4 and 5(f))**

For a sample of ICRPs:

a. Checked that the ICRPs matched to the MW scheduled for the interconnectors in the LTS runs; and

b. Checked that the ICRPs were within the operating limits of the interconnectors.

Pillar 3: Merit Orders

The following procedures have been designed to assess the Transmission System Operators' compliance with The Requirements for Pillar 3: Condition 10A - Para. 3 of the EirGrid TSO Licence; Condition 22A - Para. 3 of the SONI TSO Licence and EirGrid Grid Code SDC 1.4.7.3 / SDC1.4.7.4 and SDC2.4.2.14 and SONI Grid Code SDC1.4.8.3/ SDC1.4.8.4 and SDC2.4.2.14.

The Transmission System Operators implemented the requirement to operate a Merit Order by using Real Time Merit Orders within MMS, which ranks available plants in price order i.e., economic Merit Order. These Real Time Merit Orders are used by the dispatch engineer in the Control Centre as a guide for dispatching available plants at the most economical prices as and when needed while operating a safe and secure network.

The Real Time Merit Orders are refreshed within MMS each 5 minute period (Online Merit Orders) and 15 minute period (Offline Merit Orders).

In the prior Assurance Report periods, these Real Time Merit Orders within MMS were not stored or backed up once refreshed in MMS. However, as the Real Time Merit Orders are merely a visual representation of data that is available within MMS, it was possible to recreate them by using the data sets stored in "save cases" within MMS for sample days and time periods. For the period 1 January 2022 – 31 December 2022, these Real Time Merit Orders were available for test procedures.

The Real Time Merit Orders in MMS are impacted by any known system limitations, some of which were relevant to our test samples. These limitations could result in a participant being omitted from the Merit Order in very limited circumstances. For this reason, before the testing in procedure 28a was undertaken, the impact of these limitations on the Real Time Merit Order sample selected was considered. In the cases where it was found that there was an impact, an adjusted Merit Order was created and used in the test procedures to account for any omitted participants and reflect the expected Merit Order. References in procedure 28 to Real Time Merit Orders includes the adjusted Merit Orders where relevant.

The strict adherence of dispatching in line with the Merit Order is not always feasible. The Grid Codes outline acceptable reasons for deviating from the Merit Order. We therefore considered if dispatch was in line with the Merit Order in the context of the Grid Codes.

If we noted in our sample of dispatch instructions tested, that a potential deviation from the merit order occurred due to known issues impacting the merit orders which were not considered by the Transmission System Operators or no reason could be provided for the deviation and a more expensive unit was dispatched while a cheaper unit was available, an assessment was undertaken to confirm if the cheaper unit would have been able to respond to the same dispatch instruction based on its technical capability. If the cheaper unit would have been technically capable of responding to the dispatch instruction, we completed an assessment as to whether dispatching the more expensive unit was material to the scheduling and dispatch process as a whole.

28. **Merit Orders**

For a sample of dispatch instructions:

a. Checked that dispatch instructions were issued in line with the Merit Order (taking into account acceptable deviations from the Merit Order as outlined in the Grid Code); and

b. Checked that dispatch instructions were issued by the Transmission System Operators after market gate closure. For those noted as Long Notice actions, inspected that dispatch instructions were issued by the Transmission System Operators in line with the generator's Technical Offer Data and heat state.

Pillar 4: Operational Constraints

The following procedures have been designed to assess the Transmission System Operators' compliance with The Requirements for Pillar 4: Condition 10A - Para. 4(a)(b) & 5(d) of the EirGrid TSO Licence; Condition 22A - Para. 4(a)(b) & 5(d) of the SONI TSO Licence. Please note that the procedures included in paragraphs 29, 30a and 30b below are not a specific requirement as per the TSO Licences. However, they were included in the procedures as they support the testing performed under paragraphs 30c, 30d and 31 below.

29. **Publication of weekly Operational Constraints Updates**

Checked that a sample of Weekly Operational Constraints Updates as used in the LTS schedule has been published to the SEMO website timely (before or on the effective date).

30. **Accuracy of Constraints taken into account in the scheduling and dispatch process**

For a sample of constraints published on the Weekly Operational Constraints Updates:

a. Checked that the constraints had been inputted into MMS for a sample of LTS runs;

b. Checked that the constraints were accurately set up in MMS (TCG Limits Constraints) for a sample of LTS runs;

c. Checked that the constraints had been accurately used/processed by the optimiser for a sample of LTS runs; and

d. Checked that the constraints had accurately been actioned and maintained by the Control Centre in real time dispatch.

31. **Completeness of Constraints published to participants**

Confirmed for a sample of constraints included in the MMS that each constraint has been published on the Weekly Operational Constraints Update as applicable (active constraints) or the relevant scheduling and dispatch procedure document (inactive constraints).

Pillar 5: Constraint Flagging

The following procedures have been designed to assess the Transmission System Operators' compliance with The Requirements for Pillar 5: Trading and Settlement Code – Part B, Flagging of Accepted Bids and Offers E.3.3.1 and Trading and Settlement Code Part B Appendices, APPENDIX N: Flagging and Tagging, System Operator and Non-Marginal Flagging Paragraph 1-5

32. **Creation of System Operator flags**

Trading and Settlement Code – Part B, Flagging of Accepted Bids and Offers E.3.3.1 and Trading and Settlement Code Part B Appendices, APPENDIX N: Flagging and Tagging, System Operator and Non-Marginal Flagging Paragraph 1-2.

For a sample of Constraints that impact on pricing in a selection of imbalance periods:

a. Confirmed that flags were created accurately in line with constraint logic; and

b. Confirmed that the Non-Energy flag listing, for use in settlement, was complete by ensuring that all units that met the constraint logic as per procedure 32a above were reflected on the listing for the constraint sampled.

For a sample of Constraints in an RTD run:

c. Confirmed that each constraint has been published on the Weekly Operational Constraints Update as applicable (active constraints) or has been turned off in pricing (inactive constraints).

33. **Creation of Non-Marginal flags**

Trading and Settlement Code – Part B, Flagging of Accepted Bids and Offers E.3.3.1 and Trading and Settlement Code Part B Appendices, APPENDIX N: Flagging and Tagging, System Operator and Non-Marginal Flagging Paragraph 3

For a sample of generators Non-Marginal Flagged in a selection of imbalance periods:

a. Confirmed that the generators were operating within the correct criteria to be flagged as Non-Marginal for the RTD run.

For a sample of generators not Non-Marginal Flagged in a selection of imbalance periods:

b. Confirmed that generators were operating within the correct criteria to not be flagged as Non-Marginal for the RTD run.

34. **Publication of Methodology for determining System Operator and Non-Marginal flags**

Trading and Settlement Code – Part B, Flagging of Accepted Bids and Offers E.3.3.1 and Trading and Settlement Code Part B Appendices, APPENDIX N: Flagging and Tagging, System Operator and Non-Marginal Flagging Paragraph 4-5

a. Checked that a Methodology for determining System Operator and Non-Marginal flags has been published to the SEMO website.

b. For a sample of System Operator and Non-Marginal Flags, checked that the published document entitled "Methodology for determining System Operator and Non-Marginal flags (Version 1.0)" includes detailed information on how System Operator Flags and Non-Marginal Flags are determined for each Operational Constraint and Unit Constraint in accordance with paragraphs 1-3.

Pillar 6: IT General Controls Testing

35. The majority of transactions regarding input and output of data are sent and processed electronically. Consequently, to the extent necessary to support the testing approach, we have tested the design and operating effectiveness of the relevant IT controls in place during the period over these areas.

36. Our testing focused on the following areas, where applicable, in respect of controls owned and operated by the Transmission System Operators over the in-scope systems - being MMS, Electronic Dispatch Instruction Logger (“EDIL”), Wind Dispatch Tool and Interconnector Management Platform (“ICMP”).

a. Program development;

b. Program changes;

c. Computer Operations; and

d. Access to programs and data.

We noted an ITGC relating to user access which could not be adequately tested due to documentation issues. Furthermore, we identified a number of areas where ITGCs would be expected but were not in place during the period. As set out in Appendix A, in these cases, we completed further substantive testing procedures. Based on the ITGCs which were tested and the substantive testing procedures performed, sufficient evidence was obtained to support our opinion.

Appendix A – Risk and Response

In the table below we have outlined our assessment of the key risks identified by us and the work completed to address those risks. Where relevant, we have also provided detail on the specific results of our work completed. These matters, and any comments we make on the results of our procedures thereon, were addressed in the context of our engagement as a whole, and in forming our opinion thereon, and we do not provide a separate opinion on these matters. This is not a complete list of all risks identified by our engagement.

Risk	Our Response
Transmission System Operators' action to address prior year findings for the current period: The formal Assurance Report for the 12-month period ending 31 December 2021, was issued on 9 February 2023, which is after the end of the 12-month period covered by this Report. This increased the risk that observations raised as part of the previous formal Assurance Report would still impact a substantial part of the current reporting period.	We addressed this risk by firstly obtaining a detailed understanding of the underlying subject matter. We also discussed with the Transmission System Operators the status of actions undertaken based on items reported by PwC as part of the 12-month Assurance Report for the period ending 31 December 2021. From this and our testing, we noted that two findings in relation to logical access remain open. These findings related to the inability to adequately test user access reviews due to documentation issues and to a lack of password controls within the Wind Dispatch Tool. As a result of this, we completed further substantive testing procedures. Based on the ITGCs which were tested, and the substantive testing procedures performed, sufficient evidence was obtained to support our opinion.
Engineering decisions not most economical: During the dispatch decision making process, factors beyond price (Merit Order) need to be considered including ensuring constraints are met, the required reserve is kept on the system and ensuring frequency remains within the correct parameters. Such factors are required to support overall system security. Deviating from the merit order for factors such as these may not result in the most economical decision but are required to meet the overarching obligation of system security and such deviations should adhere to the Grid Codes. As deviations from the Merit Order are not always logged by dispatch engineers in real time, this creates a risk that the Dispatch Auditor is unable to substantiate that the deviation is in line with the Grid Codes.	To address the risk of engineering decisions not being the most economical during the dispatch process (i.e., deviating from the merit order) we performed the tests detailed in paragraph 28a. As part of these tests, for each of the 55 attribute samples tested, where the most economical unit was not dispatched, a reason and relevant supporting evidence as considered necessary was requested from the Transmission System Operators to explain the deviations. We completed procedures over these reasons including assessing if the deviations fell within the acceptable deviations allowed by the Grid Codes. We concluded that all dispatch decisions were made in line with the Merit Order or, in the case of deviations, we concluded that these fell within the acceptable deviations allowed by the Grid Codes. No material issues noted.
Errors in manual input data relating to Constraints: The Licence Condition 10A - Para 4 (a)/(b) and 5(d) of the EirGrid TSO Licence and Licence Condition 22A - Para 4(a)/(b) and 5(d) of the SONI TSO Licence requires that constraints are appropriately scheduled and dispatched.	To address the risk of inaccurate or incomplete input of constraints into the scheduling and dispatch systems, we performed tests over a sample of days to agree the actual constraints in the scheduling and dispatch systems to the expected constraints published on the EirGrid (www.eirgridgroup.com) and SONI (www.soni.ltd.uk) websites in the Weekly Operational Constraints Update or the relevant scheduling and dispatch procedure document as applicable. We also agreed a sample of expected constraints to the scheduling and dispatch systems.

Risk	Our Response
Constraints are manually entered into the systems supporting the scheduling and dispatch process by the Transmission System Operators. Due to the manual nature of the process, there is a risk that the Transmission System Operators may inadvertently have input errors. Such errors may have an impact on the scheduling and dispatch process and result in a risk of errors in the schedules produced and subsequent dispatch instructions.	These tests are detailed in paragraphs 30b and 31 of this document. Individual units and/or constraint limits are mapped to each constraint as applicable. Our test procedures included checking that the units and/or constraint limits associated with the constraint included in the schedules produced by the scheduling and dispatch system agreed to the expected units and constraint limits for that constraint as published in the Weekly Operational Constraints Update and that both agreed to the subsequent dispatch instructions. From the 115 attribute samples selected, we identified three instances from two constraint types (Tie line flow for Northern Ireland and Tertiary Reserve 2 for Republic of Ireland) whereby the limits associated with the constraint differed between the scheduling and dispatch system and the expected constraint limits as published in the Weekly Operational Constraint update. PwC further assessed these instances and found that in all cases, the constraint itself was correctly scheduled (procedure 30c) and dispatched (procedure 30d) as applicable on the system which is in line with the specific licence conditions noted above for the Transmission System Operators respectively. We evaluated and understood the nature and cause of the three identified instances, and we considered the likelihood of the same occurrence being present in any other constraint operated by the Transmission System Operators for the period 1 January 2022 - 31 December 2022. After this further assessment was completed, we concluded that the three instances identified during the initial test procedures can be contained to these constraints only and concluded that the incorrect limits used were not material to the scheduling and dispatch process as a whole.
Priority Dispatch principles not met: The Licence Condition 10A - Para. 4(a)/(b) & 5(f), (i) of the EirGrid TSO Licence and Licence Condition 9A and 22A - Para. 4(a)/(b) & 5(f), (i) of the SONI TSO Licence and SEM-11-062 requires that the priority dispatch principles are complied with. The reasons for deviating from the priority dispatch hierarchy are not always logged by dispatch engineers in real time. This poses a risk that the Transmission System Operators are unable to provide evidence to support real time decisions which resulted in a deviation from the hierarchy, and consequently demonstrate adherence with the licence condition noted above.	To address the risk of priority dispatch principles in relation to Constraint and Curtailment not being followed, we performed the tests detailed in paragraphs 16 to 18 of this document over a sample of constraint and curtailment events. From the 115 samples selected from six distinct constraint and curtailment events respectively, we concluded that these events were adequately scheduled and dispatched in line with the License Obligations with no material issues noted.

Risk	Our Response
Errors in manual input data relating to the Wind Dispatch Tool: Constraint and Curtailment groups are manually entered into the systems supporting the scheduling and dispatch process by the Transmission System Operators. Due to the manual nature of the process, there is an increased risk of input error by the Transmission System Operators. Such errors may have an impact on the scheduling and dispatch process and result in errors within the Constraint and Curtailment groups and subsequent set points issued to these groups.	To address the risk of errors within the manually entered Constraint and Curtailment groups used in the scheduling and dispatch process, we performed the tests detailed in paragraphs 16d, 16f, 17c and 17e of this document over a sample of constraint and curtailment events. The test procedures for constraints (17c/17e) and curtailment (16d/16f) are designed to address the completeness and accuracy of the predefined constraint/curtailment groups configured on the Wind Dispatch Tool by the Transmission System Operators for the sampled events. **Procedure 17e** From six distinct local constraint events for procedure 17e, which contained 115 individual samples (windfarm/solar units), four samples did not receive a set point relating to a local constraint event on 16 June 2022, as would have been expected. Further procedures identified that the NW Southern predefined constraint group was incorrectly configured on the Wind Dispatch Tool for the period 1 January 2022 – 31 December 2022 due to human error, which resulted in these four samples being omitted. It should be noted that for the individual local constraint event described above, the constraint event was found to be valid. The incorrect omission of a unit or group of units to a specific predefined constraint group in the Wind Dispatch Tool resulted in a negative impact for the units correctly allocated to the predefined constraint group in the Wind Dispatch tool (as less units were addressing the constraint) and a positive impact for the unit that was incorrectly omitted. The inverse would be true in the case where a unit was incorrectly included in the Wind Dispatch Tool even though it did not form part of the constraint group. PwC further assessed all the local constraint groups that these four units were allocated to as per the predefined local constraint listings and confirmed it was correctly included in these other local constraint groups. After we evaluated and understood the nature and cause of the four omitted units from the NW Southern local constraint group, we considered the likelihood of the same occurrence being present in any other local constraint groups set up by the Transmission System Operators for the period 1 January 2022 - 31 December 2022 that did not form part of the initial sample testing procedures for procedure 17e. After further procedures were completed over twenty-six other local constraint groups not included in the initial sample testing, we concluded that the four samples identified during the initial test procedures

Risk	Our Response
	can be contained to the NW Southern local constraint group only. To assess the estimated impact of the omission of the four units on the respective local constraint group during the period 1 January 2022 – 31 December 2022, an assessment was undertaken by the Transmission System Operators for the local constraint group where units were incorrectly omitted from the group. It was found that a total of 75 separate constraints were applied to the NW Southern local constraint group and in some cases this group was constrained in combination with other local constraint groups. From the 75 instances: - 40 constraint events were applied to the NW Southern group only with a total of 21 units included in the group. - 25 constraint events were applied in combination with the NW Northern local constraint group with a total of 43 units included in the two groups. - 7 constraint events were applied in combination with the NW Northern and Omagh-Dramore local constraint group with a total of 48 units included in the three groups. - 3 constraint events were applied in combination with the Omagh-Dramore local constraint group with a total of 27 units included in the two groups. For the events where the constraint is applied in combination with the other local constraint groups, the impact will be reduced as the groups are larger and the impact is shared by more wind farms/solar units. In the case of the constraint applying in combination with the Omagh-Dramore group the impact will be reduced more significantly as three of the units omitted from the NW Southern Group forms part of the Omagh-Dramore group. The estimated market impact to the units was calculated by the Transmission System Operators and further evaluated by PwC. After considering the number of events, whether the events occurred in combination with other local constraint groups, the duration of each individual event, the amount of units in each local constraint group, the unavailability of omitted units during the local constraint events as well as the set points issued for each local constraint event, the omission of the four units from the NW Southern constraint group was assessed as being not material to the scheduling and dispatch process as a whole.

Risk	Our Response
Non Marginal Flagging incorrectly created The Trading and Settlement Code – Part B, Flagging of Accepted Bids and Offers E.3.3.1, APPENDIX N: Flagging and Tagging, System Operator and Non-Marginal Flagging Paragraph 3 states that: "*For each Imbalance Pricing Period, the System Operators shall use information from the most recent Indicative Operations Schedule to identify whether a Generator Unit's scheduled output is bound by the presence of a Unit Constraint and where they determine that the Generator Unit is so bound, shall set the Non-Marginal Flag for that Generator Unit equal to zero for that Imbalance Pricing Period. Otherwise, the System Operators shall set the Non-Marginal Flag for that Generator Unit, equal to one for that Imbalance Pricing Period*". The RTD schedule (Indicative Operations Schedule) can be impacted by the classification in MMS of a unit's Follow Physical Notification parameters (Follow PN Parameters) as setting this parameter to "on" will cause the algorithms associated with the optimisation engines which produce the RTD schedules to schedule the unit to its PN except when system conditions do not allow for it. As the RTD schedule is the starting point to identify whether a Generator Unit's scheduled output is bound by the presence of a Unit Constraint and if a Non-Marginal flag should be created for the imbalance period, an incorrect classification to this parameter will increase the risk of Non-Marginal flags being incorrectly created as the setting of this parameter to "off" may result in an adjusted schedule.	While conducting the testing detailed in paragraph 33, PwC noted that a priority dispatch unit incorrectly had their Follow PN Parameter in MMS set to "on" for the period 1 January 2022 – 31 December 2022 when this Follow PN Parameter should have been set to "off". To assess the impact of the unit's Follow PN Parameter incorrectly set to "on", PwC extended the original sample and used adjusted MMS output which reflected the correct Follow PN Parameter as an input into the testing of the 115 samples completed. From the 115 samples tested across eight distinct settlement days, we concluded that the Follow PN Parameter had no impact on the Non-Marginal Flags that were created on each settlement day, and Non-Marginal Flags were accurately created in line with the Trading and Settlement Code with no material issues noted.
Severe System failures (failure of the scheduling and dispatch systems and other events that prevented the Transmission System Operators from utilising the in-scope systems to complete the scheduling and dispatch processing for a continuous period of 24 hours or more): Severe System failures may require the operations staff to: - Perform certain actions and subsequently recover systems and potentially data; or - Take special decisions to ensure continuity of the scheduling and dispatch process. Such events increase the risk of error or actions that are not consistent with The Requirements.	Through discussion with the Transmission System Operators, and review of: a. SEMO publications; b. Meeting minutes of the Board of Directors; and c. System data we have identified no such severe system failures or events impacting the period.

Risk	Our Response
Operation of the scheduling and dispatch process during prolonged planned computer system outages (planned outages of the scheduling and dispatch computer systems that prevented the Transmission System Operators from utilising the in-scope systems to complete the scheduling and dispatch processing for a continuous period of 24 hours or more): Scheduling and dispatch systems outages can be planned or unplanned and occur due to various reasons. Unplanned outages for a continuous 24-hour period or more are regarded as system failures. The duration of planned outages can vary and consequently the Transmission System Operators response will depend on the conditions existing during the outage. During some outages data is required to be input manually into the system and there is a greater risk of error than where this is performed electronically using a stable and proven system. Also, where an outage, including an outage of communication links, requires fall back to manual processes there is again a greater risk of error as operations staff implement processes, they are less familiar with.	Through discussion with the Transmission System Operators, and review of: a. SEMO publications; b. Meeting minutes of the Board of Directors; and c. System data we have identified no such system failures or events impacting the period.

Appendix B – Glossary of terms

Curtailment	Curtailment refers to the dispatch-down of wind/solar for systemwide reasons (where the reduction of any or all wind/solar generators would alleviate the problem).
EDIL	Electronic Dispatch Instruction Logger
ICMP	Interconnector Management Platform
ICRP	Interconnector Reference Programs
ITGCs	Information Technology General Controls
LNAF	Long-Notice Adjustment Factor
Local Constraint	Constraint refers to the dispatch-down of wind and solar generation for localised network reasons (where only a subset of wind/solar generators can contribute to alleviating the problem).
LTS	Long-Term Scheduling
MMS	Market Management System
MPI	Market Participant Interface
MW	MegaWatt
PwC	PricewaterhouseCoopers
RTC	Real Time Commitment
RTD	Real-Time Dispatch
SIFF	System Imbalance Flattening Factors
SEMO	Single Electricity Market Operator
TSO Licence	Transmission System Operator Licence

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