Enduring Connection Policy 2.4

Frequently Asked Questions

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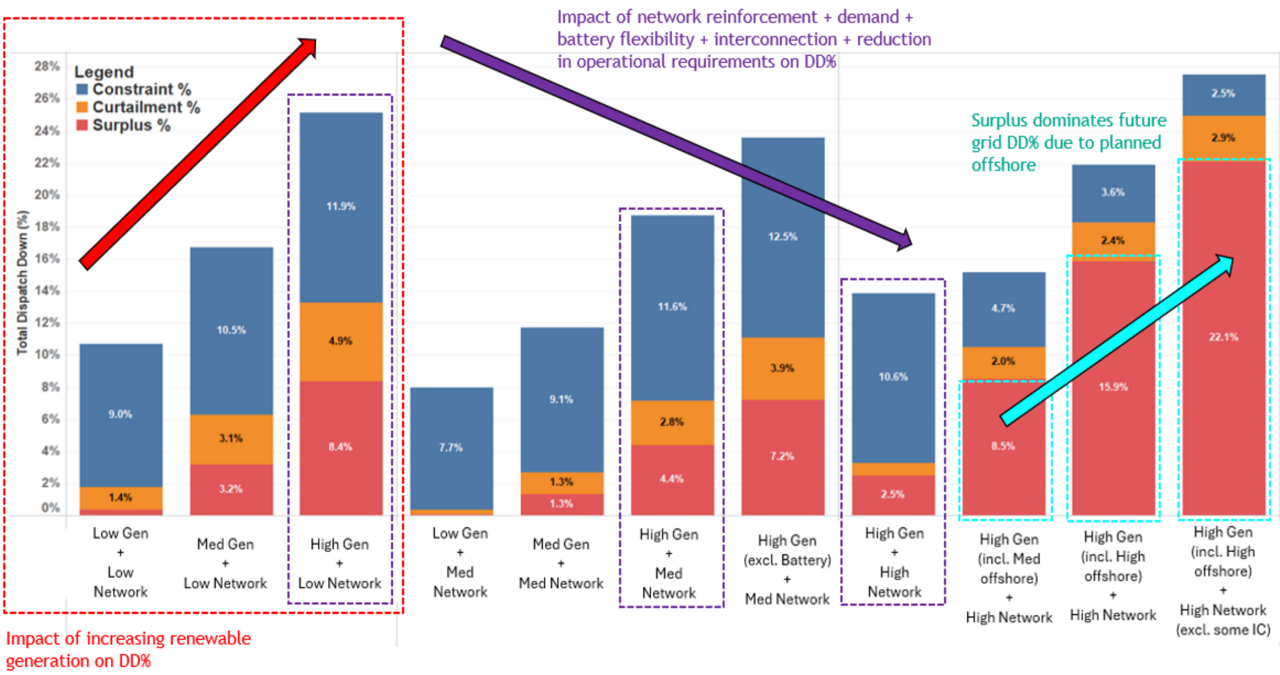
Introduction

After the ECP 2.4 constraint forecast publications and webinars, several queries were received from the industry. The purpose of this paper is to capture and respond to queries received from industry through different engagements to benefit the wider industry. The productive engagements with different stakeholders have led to changes, updates, additional information published for ECP 2.4 constraint forecast, and improvements for consideration in ECP -2.5 constraint forecast.

Q1: The diagram below aims to enhance understanding of the interactions between major system developments and total dispatch down. The definitions along the vertical axis have generic labelling, but within the ECP-2.4 context, they correspond to the following:

- **Low Gen:** Initial generation, consisting of already connected renewable generators.
- **Med Gen:** Low Gen plus 50% of difference between High Gen and Low Gen.
- **High Gen:** Initial generation combined with all committed and contracted generation through the renewable energy connection processes: Gate 3, non-GPA, and ECP.
- **Low Network:** Initial (2027) power network infrastructure, based on the NDP.
- **Med Network:** Near-future (2029) power network infrastructure, based on the NDP.
- **High Network:** Future grid power network infrastructure, inclusive of SOEF 1.1 candidate reinforcements.
- **Med Offshore:** Moderate forecast offshore wind generation forecast (i.e., 3.1 GW).
- **High Offshore:** High forecast offshore wind generation (i.e., 5 GW).
- **Some IC:** Interconnector sensitivity, excluding Liric and 2nd France interconnectors.



From the red dashed box in the chart above, it is evident that increasing levels of renewable generation can potentially lead to increased total dispatch down, assuming all other electricity sector factors, such as policy and infrastructure remain constant (ceteris paribus). However, comparing the purple dashed boxes shows that total dispatch down decreases from the initial to the future grid scenario. This reduction is attributed to several factors: rising demand, increased battery flexibility, enhanced interconnection, reduced operational constraints, and progressive network reinforcements (from low to high).

In the turquoise dashed boxes (offshore wind scenarios), surplus becomes the dominant driver of total dispatch down, as the increased availability of offshore renewable energy often exceeds demand and the net interconnector capacity, leading to higher levels of dispatch down due to surplus.

Q2: What discussion and next steps are planned for EirGrid to address the constraint and curtailment dispatch down? EirGrid need to take action on this.

EirGrid has multiple workstreams underway, including the Enduring Connection Policy (ECP) 2.4 constraint forecast, as well as other initiatives such as the Climate Action Plan, regulatory and policy frameworks at both EU and Irish levels, a multi-year plan for the DSO/TSO, various stakeholder engagements, and operational policy development.

EirGrid is committed to take steps in the short and long term in accordance with the above.

Q3: Can you touch on more detail to understand the battery impact on DD and the battery impact on governing constraints? Was there a notable change of governing constraints in 2029 in scenarios with compared to without BESS?

The batteries are modelled in the ECP 2.4 constraint forecast as price takers. The general battery modelling assumptions are given in "Enduring Connection Policy 2.4 Solar and Wind Constraints Report: Assumptions and Methodology[1] section 3.5. The batteries are allowed to charge and discharge as deemed optimal by the Plexos dispatch algorithm. Since wind generation is cheaper than battery generation, the batteries won't generate while the wind/solar is dispatch down on the same node. With the battery scenario exclusion study, the batteries are removed and hence the surplus dispatch down and curtailment dispatch down are much higher while for the constraint studies are generally lower. Same trend has also been observed in the contingency binding hours as without battery case has lower binding hours.

Q4: In the published list of battery, MWh is not provided for due to connect battery. Could you provide this info?

We have published the list of batteries[2] with their corresponding Maximum Export Capacity (MW) and their battery capacity (MWh) by node and area. Due to the nature of technology configuration, an estimate may have been applied for Battery Capacity (MWh) due to far out date of connection or the data not being available.

[1] ECP-2.4-Solar-and-Wind-Constraints-Report-Assumptions-and-Methodology-v1.0.pdf
[2] https://cms.eirgrid.ie/sites/default/files/publications/ECP-2.4-IE-Battery-List.xlsx

Q5: Can you re-cap on the demand assumptions, in particular Data Centres?

The data centre demand information comes from All Island Resource Adequacy Assessment[3]. The median scenario in Figure 4-1 is used to model data centre demand as fixed demand throughout the study year.

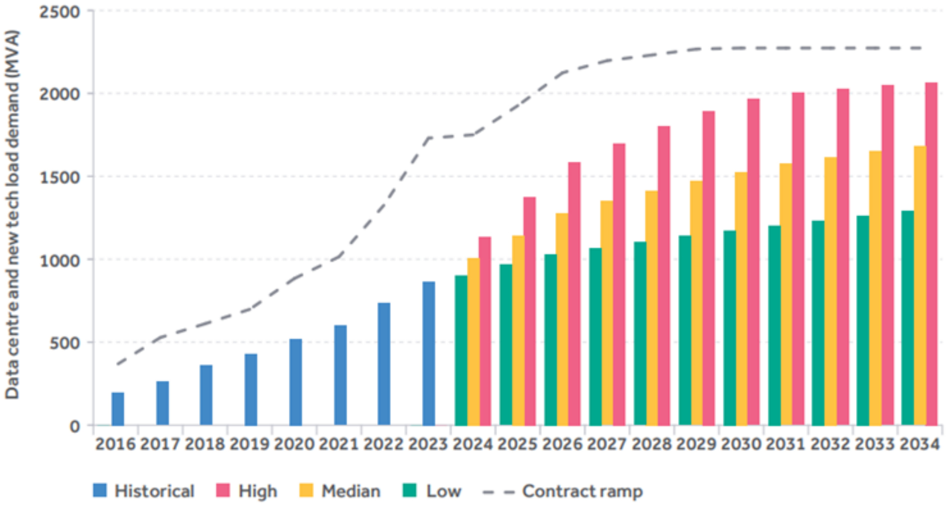


Figure 4.1 Ireland demand expected from assumed build out of data centres and new technology loads

Q6: Does the above answer to Q5 means no dynamics for data centre modelling?

The current modelling methodology cannot capture dynamic characteristics of data centres and hence they are modelled as fixed load.

Q7: Is there an EirGrid position on the earliest timeline that grandfathering could be implemented by? Inclusion of this in FAQ would be helpful.

The ECP team captures data at a point in time based on best source of data available. Future Power Market (futurepowermarkets@eirgrid.com) and customer information team can provide information on implementation.

[3] All-Island Resource Adequacy Assessment 2025-2034

Q8: Why is there a significant increase in wind constraints in the 'G North' constraint subgroup for the 'Future Grid' scenario?

The constraints apportioning in the ECP 2.4 constraint forecast studies follows the constraints groups identified. These groups are identified to share the bottleneck created by contingency overloading in that area. However, as identified in the report, resolving congestion in one area can result in additional flow in another area which could result in congestion in second area. In Future Grid, the subgroup A, B North has lesser total dispatch down compared to the 2029 study year due to higher system demand and to additional network reinforcement. This produces additional flow towards the Area G through Flagford – Louth 220kV line in the Future Grid scenario and subsequently has additional contingency binding hours for loss of this line compared to 2029. Thus, in the G North subgroup, constraint dispatch down increases in Future grid scenario. Further, with Future Grid offshore scenario, the additional surplus dispatch down reduces the available energy in the A, B North subgroup and the G North subgroup, which results into lower binding hours with offshore scenario compared to without offshore scenario (lower constraints with offshore than the without offshore scenario).

Q9: For the listed brown "line and contingency" table, is that for 2027 or 2029?

The posed question refers to the binding contingencies presented in the individual area presentation below. This is a list of contingencies in the area and is not for a particular year. A detailed table for 2027 and 2029 ECP is in the appendix section of the Enduring Connection Policy 2.4 Solar and Wind Constraints Report[1].

Line	Contingency
Line (Cauteen - Killonan_110_1)	Loss of Cauteen Tipperary
Line (Arklow T2101)	Loss of Arklow 220-110 2
Line (Great Island - Kellis_220_1)	Loss of Arklow Carrickmines 220 1
Line (Great Island - Kellis_220_1)	Loss of Great Island - Lodgewood 220
Line (Killoteran - Waterford_110_1)	Loss of Cullenagh-Waterford
Line (Carlow - Kellis_110_2)	Loss of Dunstown-Kellis 220
Line (Arklow T2101)	Loss of Lodgewood 220-110 1
Line (Cahir - Barrymore-T_110_1)	Loss of Cahir-Doon
Line (Cahir - Doon_110_1)	Loss of Cullenagh-Knockraha 220
Line (Cullenagh - Waterford_110_1)	Loss of Cullenagh-Great Island 220
Line (Great Island T2102)	Loss of Cullenagh-Great Island 220

Q10: “The two 400kV lines are the backbone to delivering electricity across the country”. Can you comment on how the 5GW+ offshore wind could affect the power flow on these lines in 2029 and onward? You can comment at substation level (Woodland/Dunstown), if it is easier.

In the ECP 2.4 constraint forecast, a sensitivity for the 5GW+offshore wind in 2029 is not included. However, based on the existing network topology, the predominant power flow is expected to be directed towards high demand region which occurs in Area J. For offshore centric case in Future Grid scenario, significant power transfers are observed from offshore generation zones located outside the immediate vicinity of Area J towards this region.

Q11: Could a sensitivity for area J/G be run with hubs, if this info is now available?

The finalised information required to model renewable energy hubs were not available while the ECP 2.4 constraint forecast study was conducted. With work to begin on ECP-2.5 constraint forecast we may have to consider this as a potential sensitivity to be included in the scenario list if all necessary data becomes available.

Q12: Is the level of DD in Area J due to constraint because of the flows of the lines?

This would depend on the scenario or sensitivity considered, but generally the level of DD in Area J is because of the network bottleneck due to the very high net power import to serve demand. As mentioned in the report, resolving constraints in an area will allow additional generation that may now need to flow through another area which could potentially increase congestion. Such scenarios are more predominant when a 110kV lines are added in parallel to 220kV/400kV line that are connecting multiple areas. However, in Area J country, as seen from the contingency lists provided, major set of issues are within the meshed 110 kV circuits.

Q13: Line Cauteen - Killonan may have less of an overload during the contingency of the loss of Cauteen Tipperary, if the BESS units at Tipperary operate in a way that is driven by high solar generation.

The batteries are modelled in the ECP 2.4 constraint forecast as price takers. The batteries are allowed to charge and discharge as seen optimal by the Plexos dispatch algorithm. Since wind/solar generation is always cheaper than battery generation, the batteries won't generate while the wind/solar is dispatch down on the same node. However, the charging or discharging during any time is based on the system price and on the optimality the algorithm finds. However, the batteries in the SEM may be able to do energy arbitrage based on bidding strategies. It would be difficult to replicate the behaviour exactly in the modelling tool and hence an approximation in the modelling employed as given in the "Enduring Connection Policy 2.4 Solar and Wind Constraints Report: Assumptions and Methodology[1] section 3.5.

Q14: Can you please provide supplemental data in spreadsheet format already requested by industry, such as a spreadsheet including hourly data such as interconnector flows, and hours when oversupply, curtailment and constraints occur?

The data on the interconnector flows has been published on EirGrid website[4] and available to the industry. Please note positive figures are exporting in all flows, while negative figures are importing.

[4] https://cms.eirgrid.ie/sites/default/files/publications/ECP-2.4-Constraints-Analysis-Interconnector-Flows.xlsx

Q15: When comparing oversupply of both wind and solar in each of the ten constraint subgroups, can you please explain: 1) why solar percentage oversupply is materially higher (or equal in some cases) than wind for the vast majority of non-offshore scenarios?; 2) why is there a material variation in wind oversupply across the ten constraint subgroups, but no variation in solar oversupply? 3) When comparing constraints in the 'Future Grid ECP' and '2029 ECP' scenarios, it is noted that wind constraints are generally higher in the 'Future Grid ECP' scenario, where the main reason appears to be due to a reduction in oversupply and curtailment due to additional interconnector exports (as a result of the addition of LirIC and 2nd France interconnectors) and higher demand. However, the same is not case for solar constraints where they only increased in 3nr. subgroups. Can you please explain these differing trends?

The different percentages of dispatch down quantities are calculated based on the available energy in the Surplus study, which is dependent on the profile used and hence dependent on the capacity factor. For more detail, please see Section 3.10.3 in the published Assumptions and Methodology report[1]. In ECP-2.4 constraint study, three solar profiles were used: solar north, solar middle, and solar south, with updated profiles synthesised from 2020 data. With 3 profiles spanning the whole Island of Ireland, the differences in the solar Surplus percentages are comparatively lower (compared to wind) considering the 13-wind profile used to represent the same region. These differences are due to the difference in the hourly profile and the capacity factor of these profiles. The Surplus and Curtailment pro-rata allocations are applied per hour in the post calculation process.

However, the constraints are averaged over the year due to the computational challenges associated with reallocating large volumes of simulation data on an hourly basis. Further, the wind and solar availabilities are vastly different due to the seasonal and daily variations. With such variations and the averaging method applied, the wind and solar categories are grouped separately for the constraints reallocation. This is evident in the results published.

Q16: With regards to the sensitivity scenarios ('2027 50% ECP', '2029 50% ECP' and 'Future Grid ECP + 3.1 Offshore'), highlighting the impact of pro-rata vs grandfathered constraints, it is noted that Wind Non-Priority constraints increase (due to grandfathering) by varying degrees in each of the constraint subgroups, which is to be expected. However, it is noted that solar percentage constraints do not change (due to grandfathering) in any of the constraint subgroups which does not seem to make sense. Can you please clarify?

In the ECP-2.4 constraint forecast study, the generators connected before 4th July 2019 is considered as priority generators. In the current generator list, there are no solar generators that are considered as priority, so constraint dispatch down will be only applied to all solar as non-priority in grandfathering or pro-rata scenario.

Q17: In terms of the sensitivity scenario relating to the removal of the LirIC and 2nd France interconnectors, it is noted that this results in an increase in oversupply and curtailment, and a subsequent reduction in constraints. However, can you please explain why there are no material variations in the increase of solar oversupply and curtailment across the ten constraint subgroups, but the same is not the case in terms of wind oversupply and curtailment? Can you also please provide some insights into the reasons why the removal of the two interconnectors results in differing impacts on dispatch down across the ten constraint subgroups?

On the first question:

Please see answer to Q15.

On the second question:

In the offshore cases, ICs are playing a net export role. When two ICs are lost, the volumes of generation that is supposed to be exported now has to be dispatched down in surplus study.

In the offshore case, with increased installed capacity (available energy), the surplus has substantially increased when compared to non-offshore scenarios. Since the Surplus is applied pro-rata to the non-priority generator in the SEM, the available energy in the curtailment study is reduced in all areas. This has now resulted in reduced available energy in the constraints study for each area (but the total energy in the SEM has increased as there is higher MW installed). Which in effect has reduced the congestion in different areas and reduced the constraint percentages.

Since the Surplus percentage is dependent on the interconnector export, the case without LirIC and 2nd France interconnector would have higher Surplus percentage and subsequently lower constraints in general. Combining this with the previous response on capacity factor differences leads to difference in the dispatch down quantities in different constraint groups.

Q18: It is noted that extremely low (and zero) solar constraints are estimated for the 'D & E North' subgroup, which appears unusual compared to the ECP-2.3 Constraint Reports. Can you please explain these unusual trends?

The ECP 2.3 constraint forecast (and prior) employed an adjustment in dispatch down wherever the total dispatch down was less than 5%, the constraints were rounded up to 5% total dispatch down. The ECP 2.4 Constraint forecast has deviated from this approach and has calculated the constraint dispatch down as per the constraint group.

Q19: When comparing constraints in the '2029 ECP' and '2029 ECP w/o batteries' scenarios, constraints are usually higher in the '2029 ECP w/o batteries' scenario. However, in the case of the 'B South' subgroup, wind & solar constraints reduce, while solar constraints reduce in the 'E,F & I', and 'H1' subgroups, and wind constraints reduce in the 'J Country' subgroup. Can you please these unusual trends? Can you also explain in detail the occurrences where ECP Battery results in a lower constraint percentage compared to ECP? For Example, in the case of Tipperary and Cauteen, the observed overload on Killonan - Cauteen 110kV circuit and noted contingency would appear to be made less constrained by the operation of previously listed battery storage projects, not worse.

In some areas and nodes, the constraint dispatch down may be lower in the "without battery" sensitivity as the constraints study will have higher available energy in the "with battery" case. This is due to more dispatch down from the surplus and the curtailment, meaning less energy being available in the final constraint study. Nevertheless, the total dispatch down is higher in the "without battery" sensitivity. Additional battery capacity can increase the number of periods of overloading on some lines as there is increased amount of available RES energy due to reduced surplus/curtailment.

Q20: When comparing wind constraints in the 'Future Grid ECP + 5GW Offshore' and 'Future Grid ECP + 5GW Offshore w/o 2nr. ICs' scenarios, constraints are lower in the 'Future Grid ECP + 5GW Offshore w/o 2nr. ICs' scenario. However, in the case of the 'E,F,I' subgroup, wind constraints increase, while in the case of the 'J City & G South' subgroup, solar constraints do not change. Can you please explain these unusual trends?

In some areas and nodes, the constraint dispatch down may be lower in the interconnector sensitivity. However, in these cases, the total dispatch down is still higher in the interconnector sensitivity - this is due to more dispatch down from the surplus and the curtailment, meaning less energy being available in the final constraint study. Further, in certain areas (e.g., E, F and I), without interconnector, the power needs to flow towards the high demand region. The reroute of power flow can lead to additional congestion to some areas which can result in higher constraints. For J City & G South solar subgroup, the difference in constraints is marginal; however, the total dispatch down has increased.

Q21: In the case of the 'H2 & K' subgroup, it is noted that the grandfathered wind constraint estimate of 9% for the '2029 Initial' scenario is significantly higher than all other scenarios, which appears unusual. Can you please explain this unusual trend?

For the subgroup H2 & K, the wind nonpriority generators for initial study is only 74MW, while the priority is 309MW. When the grandfathering of constraints is applied, the 74MW non priority generator is allocated the whole constraints apportioned. However, in the 2029 ECP case, the quantity of non-priority generator is 463MW, while the priority generator MW stays the same. When the grandfathering of constraints is applied, the higher available energy of non-priority generators at the denominator of percentage calculations will show a lower percentage of constraints. Furthermore, the available energy of same non-priority generators in the constraint study is lower in full ECP scenario compared to the initial case.

Q22: When comparing various scenarios in ECP 2.3 Versus 2.4 Constraint Report, can you please explain these different trends?

A comparison of results from ECP 2.3 constraint forecast to ECP 2.4 constraint forecast is not considered feasible under the time constraint of the project as per following reasons:

1) Power systems involve hundreds of components with nonlinear interactions. PLEXOS models involve non-linear relationships among inputs including demand forecasts, generator properties (e.g., fuel prices), operational policy changes, network limits and reinforcements, etc. A change in one input can lead to disproportionately large or unexpected changes in outputs. Even though each iteration results are meticulously reviewed, it could be a time-consuming process to isolate a root cause difference between subsequent iterations as there are multiple variable changes between the models.

2) Each model run is based on a unique combination of inputs, some of which have been updated simultaneously. This makes it difficult to isolate the impact of any single change.

3) PLEXOS is designed to optimise system operation based on a defined objective (e.g., cost minimisation). This means the model may find entirely different solutions depending on the input set, even if the changes seem minor.

Q23: How are constraint subgroups handled in cases where a listed governing constraint is caused by a contingency where the constraint of a group of generators actually has no impact on the listed overloaded branch? For example, for 2029 model year, the contingency of Derryiron - Kinnegad 110kV would appear to separate the generators located at Derryiron compared to those at Dunfirth as only one node would negatively contribute to the overload of Timahoe - Maynooth 110kV. Yet they are still grouped together. Are contingencies such as that handled differently compared to other contingencies were grouping those nodes together would alleviate a governing constraint?

Constraints subgroupings are part of the ECP analysis to ensure fair allocation of congestions. The socialisation of constraints is developed based on contingency and line overload analysis of the network. However, with the size of the modelling horizon and the number of contingencies observed, it becomes a significant challenge to redispatch generators each hour based on every contingency. Hence, an engineering judgement is employed with the help of SMEs in this field to identify the constraint group based on the observed list of contingencies in an area. As in the case of the Derryiron - Kinnegad 110KV contingency, the overload on Maynooth - Timahoe 110KV will need the power flow to reroute to other parallel sections which connects towards Maynooth. As these parallel sections are shared by most of the nodes in this region, they share the constraints. The Dunfirth node may not have direct contribution in this case, however, any overload of Dunfirth - Rinawade 110kV can cause rescue flow to other parallel sections. With this in mind, the 110kV sections in Area J was considered as subgroup. This study does not act to predict future wind dispatch tool subgroups, rather it aims to enable appropriate allocation of network constraints within the boundaries of the ECP- 2.4 studies. Future iterations of the ECP constraint reports may re-assess the constraint groups.

Q24: Can the ECP battery scenario be relabelled as ECP w/o Battery?

Appreciate the suggestion, this will be resolved for ECP-2.5 and beyond.

Q25: DLR roll out is now expected earlier than expected, do you think that this will significantly improve the levels of constraints reported in the analysis.

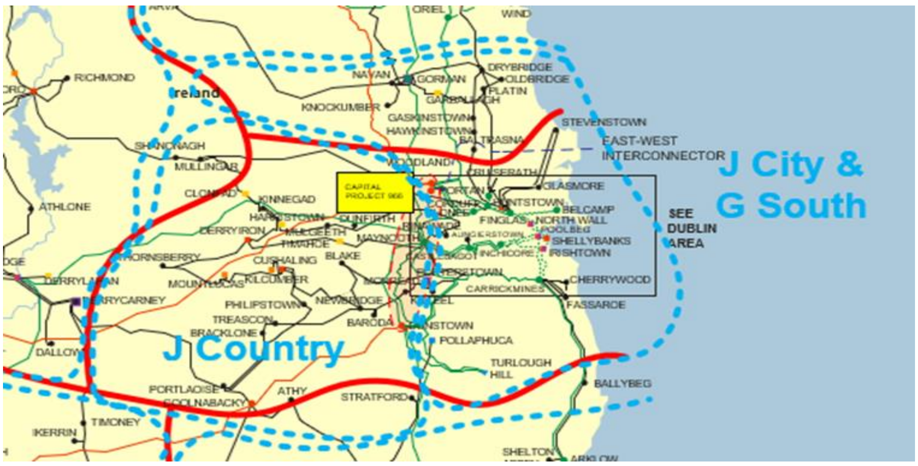
Dynamic Line Rating (DLR) technologies were applied to relevant lines based on the timelines associated with the Network Delivery Portfolio (NDP) database and the Shaping Our Electricity Future (version 1.1) network development plans. The impact of DLR lines were not explicitly studied during the work of ECP 2.4 constraint forecast. However, the DLRs are modelled to increase the rating of the line with increase in wind availability.

Q26: Cashla - Daltan new DLR on cct 1 included in 2027 and future grid reinforcement projects, is it a typo that it is not included in table for 2029 or was it omitted from this case, if it was omitted from case why was that and are there other reinforcements that this has also happened with?

Cashla - Dalton DLR is included in 2027 and the Future Grid (FG) because in the 2027 scenario, the DLR is applied on existing asset. However, in the Future Grid scenario, this line is uprated, leading to a recalculation of the DLR ratings, which are subsequently included in the Future Grid reinforcement list.

Q27: For an overload in a particular area i.e. Area J that is contributed to through flows from other areas, are the constraints being reported as a result of only using the projects in the area that the overload is located to resolve the overload? So, in reality constraints in Area J would be much less than as reported in the EirGrid analysis, as constraints will be applied much wider to resolve overloads? If solution to overloads in area J is only being mitigated by dispatching down projects in Area J, it is critical that a sensitivity is run to show the improvement if projects in all other areas are also considered.

As mentioned in the report, resolving constraints in an area will allow additional generation that may now need to flow through another area which could potentially increase congestion in there. Such scenarios are more predominant when a 110kV lines are in parallel to 220kV/400kV line that are connecting multiple areas. However, in Area J country, as seen from the contingency lists provided, major set of issues are within the meshed 110 kV circuits. Hence, socialising constraint dispatch down outside the J Country subgroup was not considered. In future iteration, we may consider a case analysis to assess the impact of wide range sensitivity of multi area contingencies.



Q28: In the maintenance sensitivity page 44 of the ECP-2.4 methodology and assumptions, it says "In 2027, the constraints calculated are pro-rata distributed amongst non-priority generators, and then priority generators should the constraint not be resolved by dispatching down non-priority generators, in their respective area/subgroup. However, in other years a grandfathered approach is employed". It appears from the text in Section 5.1 and Figure 5-4 that in the case of the Maintenance Outages Sensitivity scenarios that it is grandfathered constraints that are presented in Figure 5-4 in the context of the '2027 ECP' scenario?

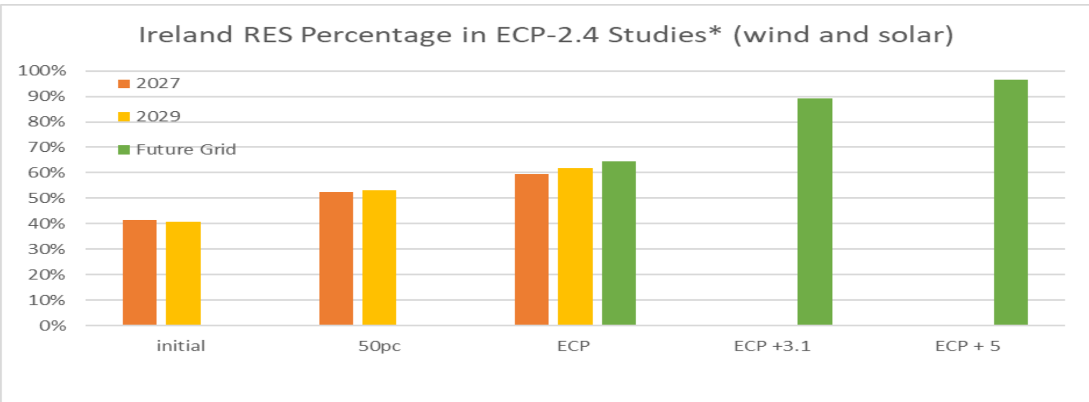
Following the publication of the ECP-2.4 constraint analysis report, the ECP constraint analysis team has reviewed the treatment of constraints in the Maintenance Outages Sensitivity scenarios in response to this feedback. During this review, it was identified that the constraints presented in Figure 5-4 and Table 5-1 of the 'Assumptions and Methodology' report were not aligned with the pro-rata allocation approach applied in the '2027 ECP' scenario. This has now been addressed, and the updated analysis is reflected in Version 1.1 of the ECP-2.4 constraint analysis. The revised report will be made available on the constraint forecast webpage.

Q29: While % RES-E data for each scenario was provided by EirGrid in the ECP-2.3 Constraint Reports 'Assumptions and Methodology' report, it has not been provided in the equivalent ECP-2.4 report. Can you please provide this information?

Renewable Energy Source (RES) percentage is calculated as the ratio of renewable energy generation to the total system load. This metric reflects the maximum utilisation of RES to meet the demand in Ireland. The RES calculated below considers the wind, solar, hydro and wave generation and is given in the table and figure below. Small scale wind and solar generation (less than 1 MW) is not considered in this calculation.

$$RES^{**}\ \% = \frac{RES\ Generation\ (GWh)}{Total\ Load\ (GWh)}\ X\ 100$$

Year	Initial	50%	ECP	ECP + 3.1 GW Offshore	ECP + 5 GW Offshore
2027	41%	52%	59%		
2029	41%	53%	62%		
Future Grid			64%	89%	97%



Q30: In the case of the '2029 ECP without batteries' scenario, can you please explain why there are no variations in the reductions (due to the batteries) of solar oversupply and curtailment across the ten constraint subgroups, but the same is not the case in terms of wind oversupply and curtailment? Can you also please provide some insights into the reasons why batteries result in differing impacts on dispatch down across the ten constraint subgroups?

There are smaller variations in the surplus and curtailment dispatch down results for solar because there are only 3 profiles being used for solar, whereas wind generation is represented by a more granular set of profiles across the system, resulting in greater variability in the outcomes.

The batteries impact on dispatch down by subgroup is dependent on the level of battery capacity in each subgroup and the starting level of dispatch down. For subgroups where the change in battery capacity is significant e.g., H2 & K, the dispatch down is seen to increase the most in the "without battery" sensitivity.

Q31: 1) In the case of the 'A & B North' and 'C' constraint subgroup, it is noted that wind constraints are significantly higher for the '2027 Initial' and '2029 Initial' scenarios in comparison to the other scenarios, which does not seem to make sense. 2) Furthermore, in the 'H1' subgroup, solar constraints in the '2027 Initial' scenario are materially higher than other comparable scenarios, which appears unusual. 3) In addition, solar constraints in the '2027 Initial' and '2029 Initial' scenarios are materially higher than other comparable scenarios. Can you please explain these differing trends?

(1) In the A & B North subgroup, the significant difference in constraint percentage for 2027 and 2029 initial versus other scenarios is due to the difference in available energy in the surplus study which is the denominator for the percentage calculation. Further, the constraint GWh increases from the 2027 initial study to the 50% ECP or 100% ECP study, owing to additional installed generation in these studies. If the generated GWh is considered, it increases from 2027 study scenarios to 2029 study scenarios.

(2 The percentage calculation may show that the constraint decreased from 2027 initial to 2027 ECP due to higher Available energy in percentage calculation. However, the constraint GWh has increased.

(3) The trend of dispatch down with the H1 solar subgroup is similar to the trend seen in the system dispatch down where the dispatch down decreases in the 2029 scenarios compared to 2027 scenarios.

Q32: In the case of the 'H1' subgroup, it is noted that the grandfathered wind constraint estimate of 20% for the '2027 50% ECP' scenario is significantly higher than all other scenarios, which appears unusual. Can you please explain this unusual trend?

The H1 subgroup has higher wind priority compared to wind nonpriority and hence when the constraints are grandfathered the percentage constraints are significantly higher for wind non priority. However, in 2029, the Cahir–Barrymore–Knockraha 110 kV line is reinforced, addressing a major bottleneck in the region. Along with other planned reinforcements, this results in reduced constraint levels across the area

Q33: Since we submitted this question Alex has done some work to review the with and without batteries case and it appears that the nodes that change most significantly in the positive were Area A: Gortawee, and Area G: Lisdrum, Lislea and Meath Hill. This is not what we would have expected given where the connected and committed batteries are to be located. We also note that Cushaling & Philipstown nodes have disimproved when batteries are added to the case even though we are about to energise a BESS at the adjacent Philipstown node and BNM have a connected BESS into Cushaling. We would have expected that the with BESS case would have shown an improvement for the nodes where BESS were to be located. Can you consider and provide an explanation on what is occurring here to help us in our review of the constraints analysis?

Gortawee, Lislea, Meath Hill, and Lisdrum do see an increase in dispatch down in the “without battery” sensitivity, and there is a decrease in battery capacity from these nodes of 135 MW. These nodes are all in the G North subgroup, which overall sees a significant reduction in battery capacity in the “without battery” sensitivity with 350 MW being removed in this sensitivity. Therefore, a corresponding increase in dispatch down is expected.

In the “without battery” sensitivity, both Cushaling and Philipstown experience an increase in dispatch-down, which is consistent with expectations. While individual surplus, curtailment, or constraint runs may show variations in different directions, the overall change in total dispatch-down aligns with anticipated outcomes.

Furthermore, when comparing dispatch-down changes at the subgroup level against changes in battery capacity, it is evident that subgroup H2 & K experiences the largest increase in battery capacity (559 MW) and correspondingly, the largest reduction in dispatch down.

Q34: It is noted that there is no mention of the ‘Lanesboro Substation Redevelopment Project’ reinforcement in Tables A-1, A-2 or A-3 the ECP-2.4 Constraint Reports ‘Assumptions and Methodology’ report. However, this project is mentioned in Section 1.6.5 of the ‘Area C’ report. Can you please confirm if this reinforcement project has been included in the ‘Future Grid’ scenarios of the ECP-2.4 Constraint Reports?

Yes, the Lanesboro Substation Redevelopment Project was accidently omitted in the published tables but was considered in the Future Grid scenario.

Q35: Can you advise why connected projects or projects due to be connected by 2027 excluded from initial scenarios if it is an ECP project, we would question this approach and ask that it is reconsidered for next run of constraints analysis.

The methodology of ECP 2.4 constraint forecast analysis has considered 2027 as the starting study year. Following this, an initial case is created which includes all connections that are expected to be connected by the end of 2026. The connection date information is collected from an internal database. Such approach allows us to evaluate different levels of generation scenario and was deemed to be appropriate for the ECP 2.4 constraint forecast project. However, this could be reviewed in the ECP 2.5 constraint forecast industry engagement.

Q36: Area A at Gortawee shows constraints of 49% in the ECP FG wind non-priority scenario (no offshore). This is way higher than the area average of 25% and higher than the 9% (albeit with less generation in the region) in the ECP 2.3 studies. And then it drops off to 1% when 5GW of offshore connects. Is the 49% figure correct, and if so, could you please provide any info on what is driving it?

The node Gortawee is considered as a part of G North subgroup as it is directly connected to G and will be more affected by constraints in Area G. The constraints apportioning in the ECP 2.4 constraint forecast studies follows the constraints groups identified. These groups are identified to share the bottleneck created by contingency overloading in that area. However, as identified in the report, resolving congestion in one area can result in additional flow in another area which could cause a new congestion in this area. In Future Grid, the subgroup A, B North has lesser total dispatch down compared to the 2029 study year due to higher system demand and to additional network reinforcement. This produces additional flow towards the Area G through the Flagford – Louth 220kV line in the Future Grid scenario and subsequently has additional contingency binding hours for loss of this line compared to 2029. Thus, in the G North subgroup, constraint dispatch down increases in Future grid scenario. Further, with Future Grid offshore scenario, the additional surplus dispatch down reduces the available energy in the A, B North subgroup and the G North subgroup, which results in lower binding hours with offshore scenario compared to without offshore scenario (lower constraints with offshore than the without offshore scenario).