SONI Grid Code Proposed Minimum Generation Studies
Phase 2: Techno-economic Study in PLEXOS

External Studies Support resulting from proposed Modification to CC.S1.1.3.8 and CC.S1.2.3.3 of the SONI Grid Code

SONI Grid Code Proposed Minimum Generation Studies
Phase 2: Techno-economic Study in PLEXOS

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Executive summary

Jacobs has been engaged to evaluate the proposal and to help SONI obtain understanding of wider impact of modifying the Grid Code minimum generation requirements. This report summarises the Phase 2 techno-economic studies in PLEXOS.

The aim of these studies is to provide some analysis, assessing the impacts of a range of minimum generation (min gen) level from a techno-economic point-of-view.

This report focuses on phase 2 activities which simulates the impact on the electricity market of four minimum generation levels (35%, 40%, 45% and 50%) relative to the current min gen rule.

Overall summary

A modification to the SONI Grid Code was proposed by EPUK, that would effectively alter the lowest allowable minimum generation requirement imposed on a generating unit. The proposal changes the requirement for a generating unit to be capable of remaining synchronised to the NI system at an output.

- no greater than the lower of 80 MW or 40% of its maximum continuous rating,

to

- no greater than 40% of its maximum continuous rating.

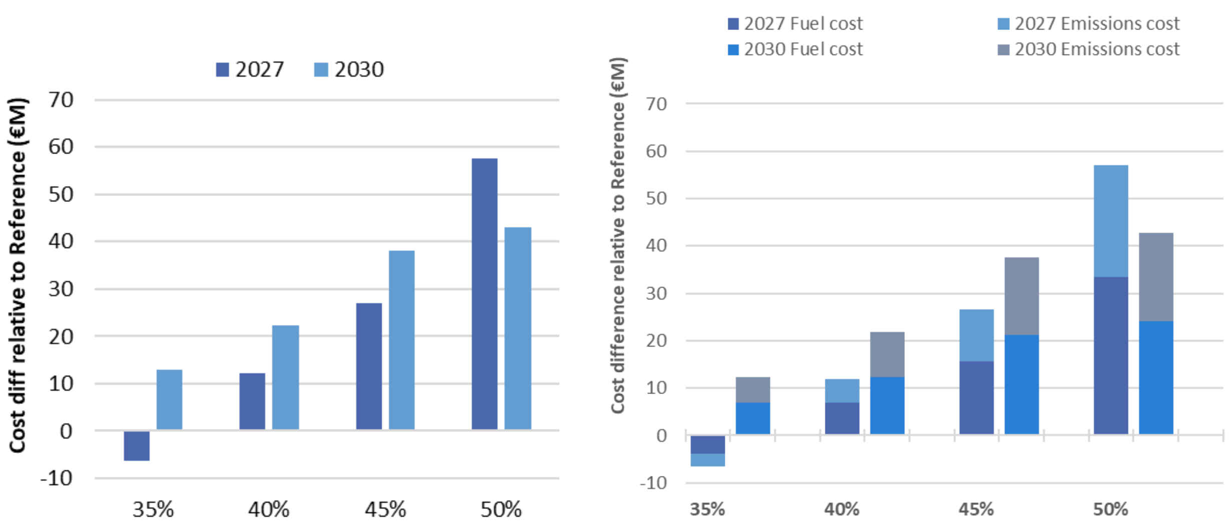
Using the PLEXOS electricity market modelling package, we have studied the net cost-benefit, market and emissions impact of this rule change for the year 2027 and 2030 under four min gen Sensitivities i.e., 35%, 40%, 45% and 50%.

The left-hand chart of Figure 1 shows that under all min gen Sensitivities across 2027 and 2030, with the exception of the 35% Sensitivity in 2027, implementing the rule change results in an increase in cost to the Northern Ireland grid. In 2027 the increase in cost relative to the reference scenario[1] ranges from €12.3M under the 40% Sensitivity up to €57.6M under the 50% Sensitivity. In 2030 the cost ranges from €12.9M under the 35% Sensitivity up to €43.1M under the 50% Sensitivity. It is clear from the above that the net cost increases as the min gen setting increases.

Comparing the right-hand chart of Figure 1 to the left-hand chart in Figure 1 shows that the main source of the cost increases can be attributed to increases in fuel and emission costs. Increasing costs are incurred as the min gen value is raised because more fuel is consumed per dispatch interval by OCGT and CCGT units that are impacted by the rule change. This in turn produces more emissions whenever these affected units are operating.

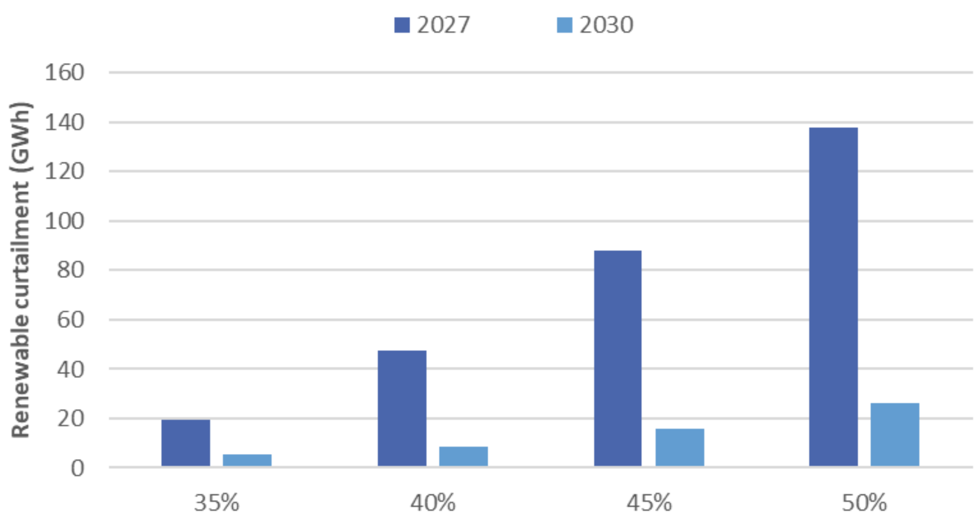
[1] The Reference scenario represents the current form of the min gen requirement.

Figure 1: Cost-benefit summary for Northern Ireland (LHS) and contribution of fuel and emissions to costs (RHS)



Another finding of the study is that total curtailment of renewable generation in the Integrated Single Electricity Market (ISEM) increases as the min gen level increases, as shown in Figure 2. This occurs at times of high renewable output when renewable supply exceeds the sum of grid demand and export capacity of the interconnectors. In these cases, with all else being equal, a higher min gen level will displace more renewable capacity relative to a lower min gen level.

Figure 2: Curtailed renewable generation by min gen sensitivity



Conclusion

The PLEXOS modelling results have shown that a lower min gen requirement is better from a cost-benefit and emissions impact perspective. This implies that having a lower minimum generation requirement is more beneficial from both an environmental and market standpoint. A lower min gen requirement implements a more flexible power system that burns less fuel, produces less emissions and curtails less low-cost renewable power.

According to the conducted studies, at 35% min gen a reduction in the net costs and emissions is achievable compared to the reference case under some circumstances. At 40% and above min gen, an increase in the net costs and emissions is indicated.

However, the low min gen requirement needs to be balanced with the capabilities of real-world generating units as well as the regulatory regime these units are required to comply with. Setting the min gen requirement below the capabilities of modern power generators is clearly an infeasible solution. The best outcome would be to set the lowest practical min gen level that can be comfortably accommodated by at least two or three of the best candidate generation options.

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Acronyms and abbreviations

ISEM	Integrated Single Electricity Market (the Irish electricity market)
LHS	Left-hand side
NI	Northern Ireland
RHS	Right-hand side
SONI	System Operator for Northern Ireland
VO&M	Variable operating and maintenance cost

1. Introduction

A modification to the SONI Grid Code was proposed by EPUK, that would effectively alter the lowest allowable minimum generation requirement imposed on a generating unit. The proposal changes the requirement for a generating unit to be capable of remaining synchronised to the NI system at an output.

- no greater than the lower of 80 MW or 40% of its maximum continuous rating,

to

- no greater than 40% of its maximum continuous rating.

The proposed change has no impact for generating units with a maximum continuous rating below 200 MW, but for units with maximum capacity greater than 200 MW it effectively raises their minimum generation requirement from the current standard, which effectively requires them to be less flexible relative to the current standard.

SONI has engaged Jacobs to provide market research and a techno-economic study to assess the impact of the proposed change to Clause CC.S 1.1.3.8 and CC.S1.2.3.3. This report addresses the second phase of the scope, which relates to the techno-economic study of the ISEM using the PLEXOS market modelling software.

The rest of this report is comprised of the following sections:

Section 2: describes the methodology used to carry out the study.

Section 3: describes the model assumptions and limitations of the study,

Section 4: presents the modelling outcomes and the accompanying cost-benefit analysis relating to the proposed change in Clause CC.S 1.1.3.8 and CC.S1.2.3.3.

1.1 Study scope

The scope of the techno-economic study is to perform a cost-benefit analysis, an emissions impact analysis and a market impact analysis to assess the effect on the ISEM of accepting the proposed changes to Clause CC.S 1.1.3.8 and CC.S1.2.3.3. It was agreed to perform this analysis for four distinct sensitivities:

- Minimum generation set to 35% of a generating unit's maximum continuous rating.
- Minimum generation set to 40% of a generating unit's maximum continuous rating.
- Minimum generation set to 45% of a generating unit's maximum continuous rating.
- Minimum generation set to 50% of a generating unit's maximum continuous rating.

These analyses also require a Reference scenario, against which the costs and benefits of the proposed change along with the emissions and market impacts will be assessed. The Reference scenario represents the current market rules with respect to the min gen criterion.

2. Methodology

SONI has provided Jacobs with two separate PLEXOS databases of the SEM, where one database represents the 2027 year and the other represents the 2030 year. Jacobs spent some time verifying that the databases were producing reasonable outcomes. This is detailed in section 2.3.

The analysis was then conducted under five cases as follows:

- Reference scenario: the minimum generation of all thermal generating units in Northern Ireland set to the current standard[2]. Namely, their minimum generation will be the lesser of 80 MW or 40% of the generator's maximum capacity as defined in the PLEXOS model.
- 35% Sensitivity: the minimum generation of all thermal generating units in Northern Ireland set to 35% of their maximum capacity as defined in the PLEXOS model.
- 40% Sensitivity: the minimum generation of all thermal generating units in Northern Ireland set to 40% of their maximum capacity as defined in the PLEXOS model. This sensitivity represents the exact version of the proposed rule change.
- 45% Sensitivity: the minimum generation of all thermal generating units in Northern Ireland set to 45% of their maximum capacity as defined in the PLEXOS model.
- 50% Sensitivity: the minimum generation of all thermal generating units in Northern Ireland set to 50% of their maximum capacity as defined in the PLEXOS model.

2.1 PLEXOS model of the SEM

The PLEXOS model of the SEM is a nodal model representing the transmission system at 110kV detail and above. It includes all generators located in the ISEM and represents existing and future interconnections with Great Britain and France.

The model captures CO_2 production from all generators on the grid and also represents primary, secondary and tertiary contingency reserves for the region of Northern Ireland and separately for Ireland. All contingency reserves at the regional level are modelled dynamically, which means that in each hour they cover the risk associated with each reserve category[3]. The zonal reserves for Northern Ireland and Ireland are modelled as a static target.

Minimum generation output of generators is modelled via the use of the rounded relaxation option for unit commitment[4]. Jacobs evaluated potentially using integer unit commitment but concluded this was

[2] We note that some of the existing generating units in Northern Ireland are unable to comply with the min gen requirement as it currently stands. This will not impact the conclusions of this study because all sensitivities will refer to the same Reference scenario. This assumption may introduce some variance in the calculated costs and benefits, but these variances will be identical for all sensitivities. Therefore, the relativity of the costs and benefits will be accurately reflected using this modelling approach.

[3] This is determined to be the largest output from an individual generating unit (modified by a risk factor).

[4] Two variables are required to accurately model the output of a generating unit – the unit commitment variable and the generation variable. The unit commitment variable represents whether a generator is on or off and is therefore by its very nature a binary number (which is also an integer). The generation variable is a linear variable and takes a value between 0 and 1. When the unit commitment variable is zero this represents the generating unit being switched off and its output is also zero. When the unit commitment variable is 1 and the generation variable is zero this represents the generating unit operating at its minimum generation level. When the unit commitment variable is 1 and the generation variable is also 1, this represents the generating unit operating at its maximum generation level.

Representing the unit commitment variable as a binary variable is a much more difficult mathematical problem to solve than if it is represented as a linear variable taking values between 0 and 1. In PLEXOS, the rounded relaxation option for unit commitment performs the optimisation by treating the unit commitment variable as a linear variable, making the problem much simpler and much faster to solve. After the solution is found PLEXOS rounds the unit commitment variable up to 1 or down to zero based on a user-specified cut-off, which is typically set to about 0.3.

impractical given that model run times grew exponentially with this option. Jacobs is satisfied that the current rounded relaxation unit commitment setting, although an approximation, yields credible results for the present study.

The model also includes a number of constraints that are required to ensure secure operation of the grid. These include:

- **Inertia**: set at 20,000 MWs in 2027 and 17,500 MWs in 2030
  - Inertia is partly supplied by a synchronous condenser that is included in the model, as well as from existing and future generators.
- **Min sets**: separate constraints for the Northern Ireland zone and the Ireland zone, specifying the minimum number of synchronous generating units that need to be online in any given hour. This is set to two units for the Northern Ireland zone in 2027 and 2030, and three units for the Ireland zone in 2027, stepping down to two units in 2030.
- **SNSP (System Non-Synchronous Penetration)**: a constraint that limits the percentage of instantaneous renewable output relative to all-island demand. This is set at 85% in 2027 and 95% in 2030.

2.2 General approach

The approach is to run all five cases of the PLEXOS database for one full year (2027 and 2030). This included reporting the following variables, which would form part of the analysis:

- Market prices
- Generator costs
  - Fuel cost
  - VO&M cost
  - Start and shutdown costs
  - Emission costs
- Generation output
- Generator emissions
- Constraint information
  - Violation
  - Hours binding
  - Cost

The cost-benefit analysis is carried out as a post-modelling exercise by comparing total resource costs of each sensitivity to the Reference scenario. Similarly, the market impact analysis is also carried out by comparing variables of interest to the Reference scenario.

2.3 Model validation

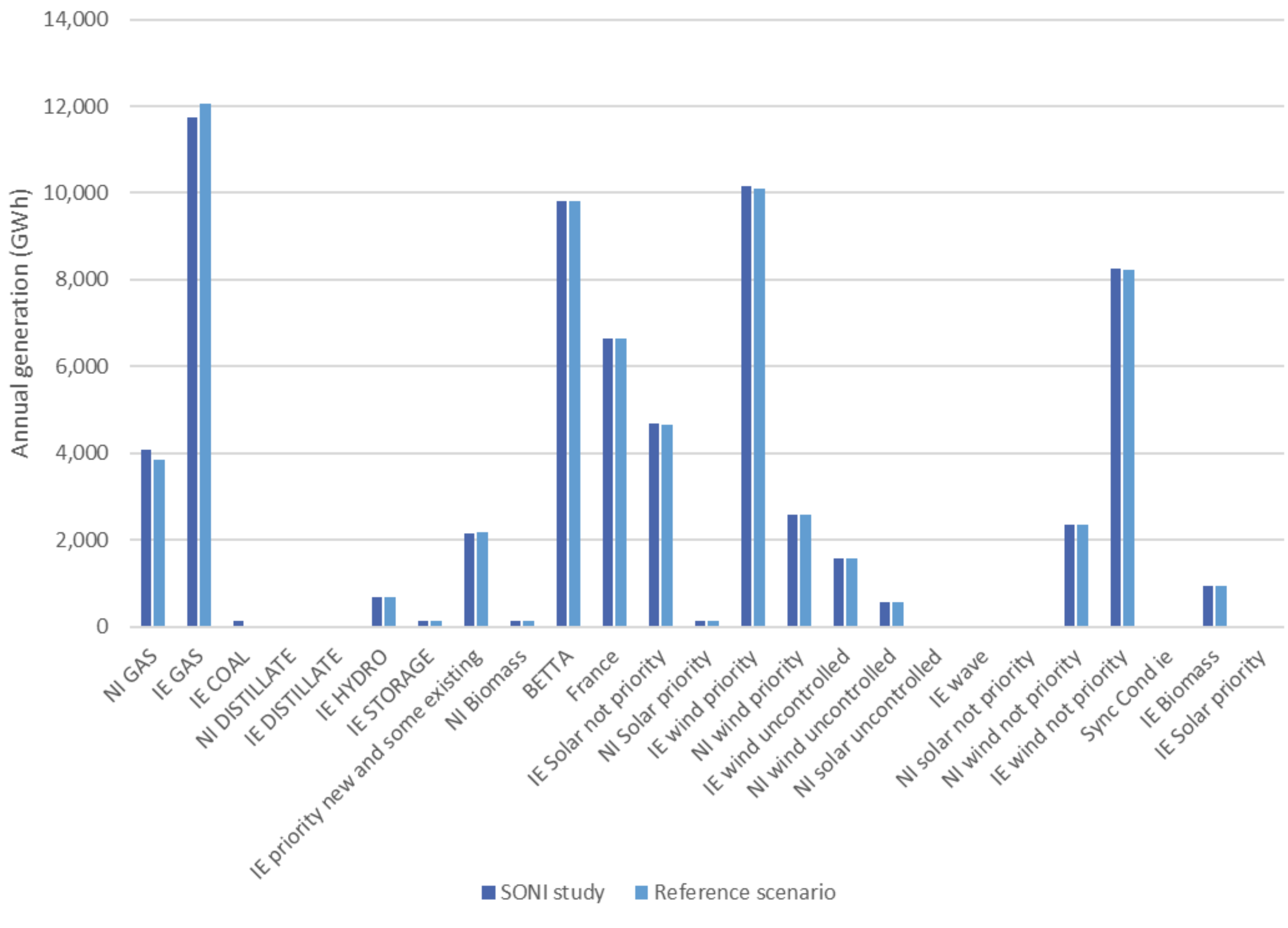
We have performed a number of trial simulations to satisfy ourselves that the PLEXOS model supplied by SONI is suitable for the scope of this study and provides credible outcomes. We have validated the model by comparing annual generation outcomes in 2027 and 2030 for each generation category for our Reference scenario to one of SONI's studies of the future market. The comparison for 2027 is presented in Figure 3.

In both cases Northern Ireland gas produces less annual output under the Reference scenario compared to the SONI study. This is expected because under the Reference scenario we are assuming lower min gen values of some gas-fired generators to align them with the current form of Clauses CC.S 1.1.3.8 and CC.S1.2.3.3. In contrast, under the SONI study the min gens of these generators are higher than is specified in the above clauses. In the 2027 simulations all of the generation output from the other categories are very well matched with the exception of Ireland gas. In this case Ireland gas in the Reference scenario is producing more output in order to compensate for the reduced output of Northern Ireland gas.

In conclusion, we can explain the differences between the two model outcomes in 2027 and we are satisfied this validates the 2027 model we are using for this study.

A similar outcome was found when comparing our 2030 model to the relevant 2030 SONI study.

Figure 3: Comparison of annual generation output of Reference scenario to SONI study, 2027



3. Study assumptions and limitations

3.1 Study assumptions

The main tool used for this analysis is SONI's PLEXOS model of the SEM, which was provided to Jacobs for the 2027 and 2030 future years. Jacobs' understanding is that both of these models reflect the Irish SEM as it is expected to be operated in these future years. This includes:

- Demand growth
- Transmission augmentations
- Generator retirements
- New generation capacity
- Inertia requirements, including partial supply by new synchronous condensers
- Security constraints, including SNSP and min sets for Northern Ireland and Rest of Ireland zones

Jacobs has assumed that under each modelled Sensitivity each of these system characteristics will remain the same. This is a reasonable assumption as in Jacobs' experience changing minimum generation levels of a synchronous generating unit would not be expected to influence any of the above system settings.

3.2 Limitations

One of the key limitations in the present study is that unit commitment is not optimised, but rather an optimal solution is approximated using PLEXOS' rounded relaxation algorithm. Jacobs investigated the possibility of optimising unit commitment using mixed integer-linear programming but found that model run times grew to unmanageable levels under this approach. In light of this, we have retained the rounded relaxation approach due to time limitations. However, our expectation is that modelled market outcomes should be near optimal, if not optimal, using this approach and the findings of this study are expected to be robust with respect to this limitation.

4. Results

4.1 Cost-benefit analysis

This section presents the outcome of the cost-benefit analysis associated with the proposed modification to Clause CC.S 1.1.3.8 and CC.S1.2.3.3. The cost-benefit analysis is assessed for the Northern Ireland zone, however, due to the synchronously interconnected nature of the Northern Ireland and Ireland electricity grids we also present the results for the ISEM.

The cost-benefit analysis assesses the differences in resources costs between the Reference scenario, which models the current SONI Grid Code and the sensitivities, each of which proposes a different setting for the future minimum generation requirement for a generating unit. Differences in resource costs in the context of an electricity market would normally include:

- Capital cost differences, relating to future build of generation and transmission capacity
- Fixed cost differences, relating to future build of generation and transmission capacity
- Total generation cost differences, which includes:
  - Fuel costs
  - Emission costs
  - VO&M costs
  - Start and shutdown costs

In our particular case, we are using exactly the same future build in all of the sensitivities as in the Reference scenario and therefore the first two categories of resource costs are identical. This is a reasonable assumption to make because changing min gen levels would not generally result in a change of future plant build in an integrated resource plan exercise. The only source of difference in costs or benefits in comparing the sensitivities to the Reference scenario is differences in the total generation cost.

4.1.1 Northern Ireland zone

The left-hand chart in Figure 4 shows the difference in the total generation cost for each sensitivity relative to the Reference scenario for 2027 and 2030. This can also be interpreted as the net cost-benefit of implementing the proposed rule change. It shows that implementing the 35% Sensitivity results in a net benefit to the Northern Ireland zone in 2027, whereas implementing the 40%, 45% and 50% Sensitivities results in a net increase in cost. Another important characteristic of this chart is that costs increase monotonically as the min gen level also increases.

The right-hand chart in Figure 4, when compared to the left-hand chart in Figure 4 sheds light on the main source of the costs associated with adopting the rule change. Namely, increasing fuel costs and increasing emissions costs as the min gen level increases. These two sources of costs account for almost all of the total generation cost. The chart also shows that fuel costs tend to contribute slightly more when compared to emission costs.

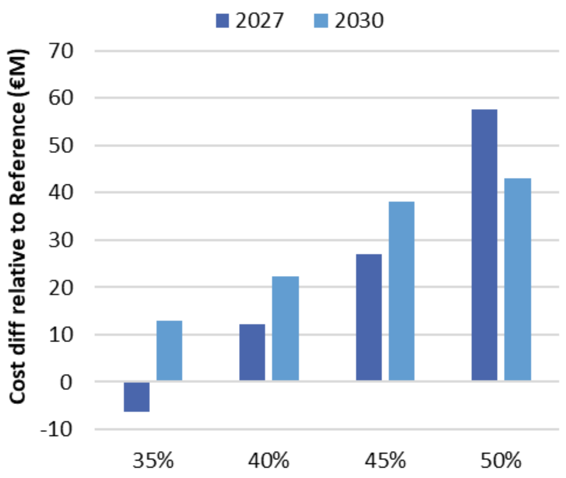
The two other possible cost sources are VO&M costs as well as start and shutdown costs, but these are one to two orders of magnitude smaller than the fuel and emission costs[5].

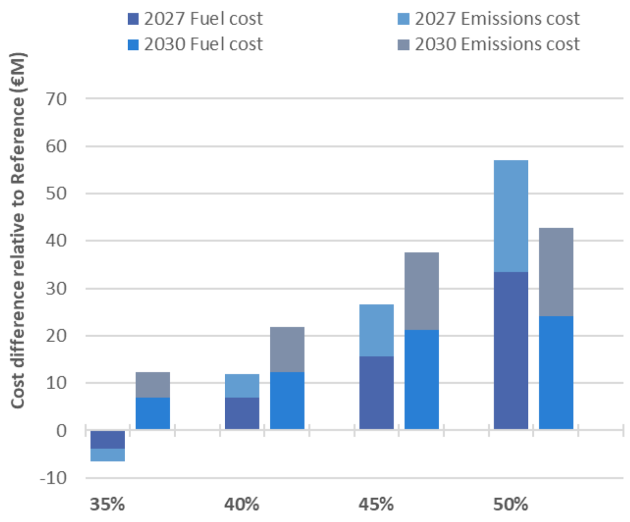
[5] Fuel and emission cost differences are in the order of tens of millions of Euro, whereas VO&M and start and shutdown cost differences are in the order of a few hundred thousand Euros.

The main driver underlying the relationship between increasing costs and increasing min gen levels is the set of generators in Northern Ireland that are deployed to meet the Northern Ireland minimum sets constraint whenever this constraint is binding[6]. These time intervals will mostly be common across the Sensitivities, although there may be some minor variation depending on the unit commitment chosen by the optimisation. During these time intervals this set of generators increase their output as the min gen requirement increases, which in turn increases their fuel consumption and emissions production.

The secondary driver for the relationship between increasing costs and increasing min gen requirements are the time periods when thermal generators are dispatched at or just above their min gen level. In these cases, the increase in cost is driven by the same dynamic, namely that higher min gen requirements will result in higher fuel consumption and higher emissions production. These types of intervals tend to occur less frequently than the binding of the min sets constraint, which is why they make a smaller contribution to the cost increase.

Figure 4: Cost-benefit summary for Northern Ireland (LHS) and contribution of fuel and emissions to costs (RHS)





Breaking down the cost differences between the Reference case and the Sensitivities for the Northern Ireland zone by technology type shows that all of the differences are attributable to Northern Ireland gas generators in both 2027 and 2030. This set of generators is categorised in the model to include both existing and future gas generators. The reason for this outcome is that the min sets constraint can only be satisfied by this set of generators and their annual costs change for each min gen Sensitivity.

4.1.2 All-island costs

Figure 5 shows the all-island cost for the rule change, split between Northern Ireland and Ireland. The left-hand chart presents the costs for 2027 and the right-hand chart for 2030. Costs in both years are primarily incurred by Northern Ireland as this is the region in which the rule change takes effect. In both 2027 and 2030 Ireland incurs diminishing costs as the min gen level increases. This occurs because as the output of Northern Ireland gas units rises with increasing min gen levels, Ireland synchronous generation is increasingly displaced and therefore incurs lower costs on an annual basis.

[6] This constraint defines the minimum number of synchronous generating units to be operating at all times in Northern Island and is required to ensure stable operation of the grid. When this constraint binds then the generators that are dispatched to satisfy this constraint will typically operate at their minimum generation level.

In 2027 under the 50% Sensitivity, the rule change does not incur a cost for Ireland, but it receives a net benefit as Northern Ireland supplies some of the Ireland demand. This outcome is dependent on the second north-south transmission line, which increases the transfer capacity between the two zones. By 2030 the rule change is a net benefit for Ireland under the 40%, 45% and 50% Sensitivities.

Figure 5: All-island cost/benefit 2027 (LHS) and 2030 (RHS)

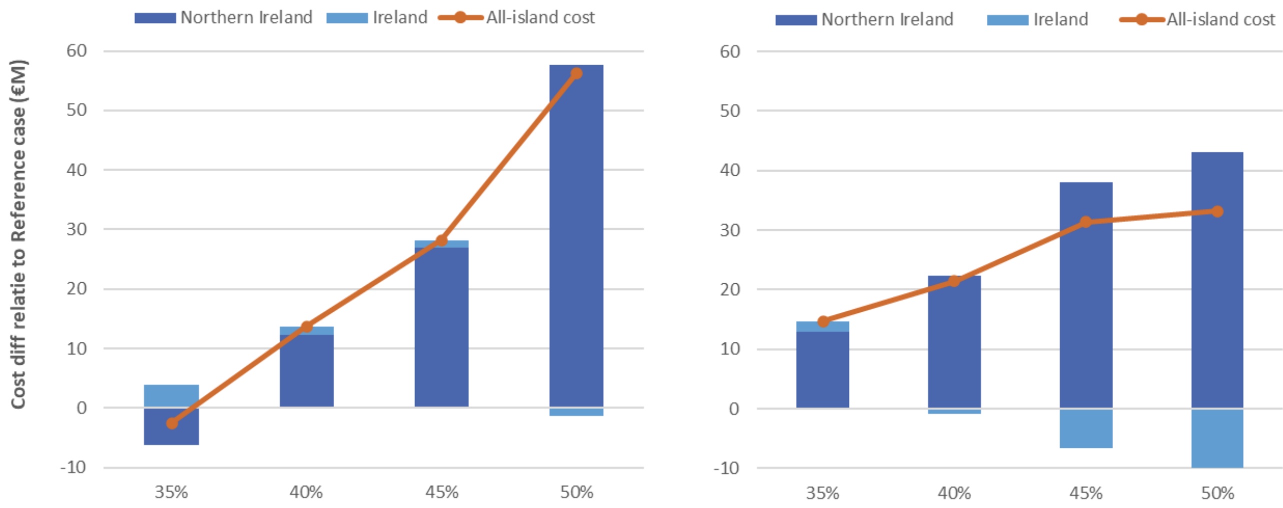
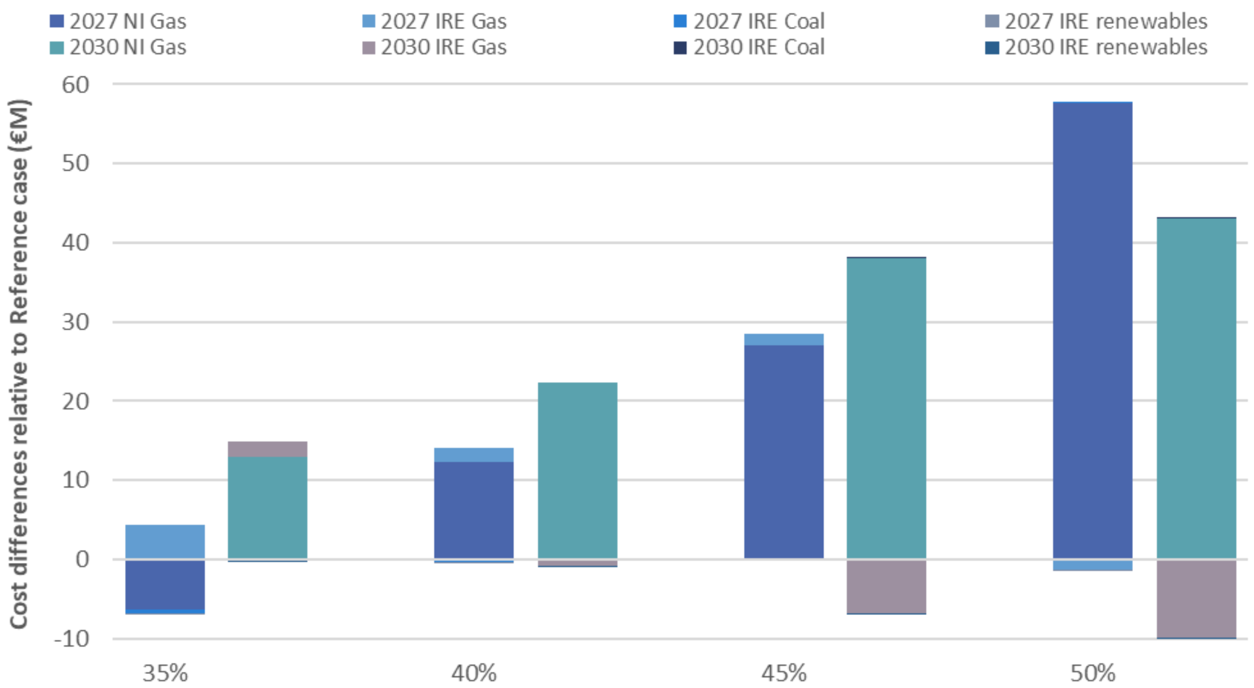


Figure 6 shows the cost/benefit by generator category across 2027 and 2030, where the categories are split by zone by technology. It shows that most of the costs are typically incurred by Northern Ireland gas plants, which reflects the fact that these are directly impacted by the rule change. The one exception to this occurs in 2027 where Northern Ireland gas plants receive a benefit from the rule change under the 35% Sensitivity as they generate less relative to the Reference case. In this case the deficit in generation is made up by gas plants located in Ireland.

The chart also shows that Ireland gas plants are increasingly displaced by rising Northern Ireland gas output as the min gen level increases. The cost impact on Ireland coal plants[7] and renewable plants, which are also shown in the chart, is negligible in comparison.

[7] Some Ireland coal plants are retained in the model to provide security services, even though these plants officially retire in 2025.

Figure 6: Cost/benefit by generator category, 2027 and 2030



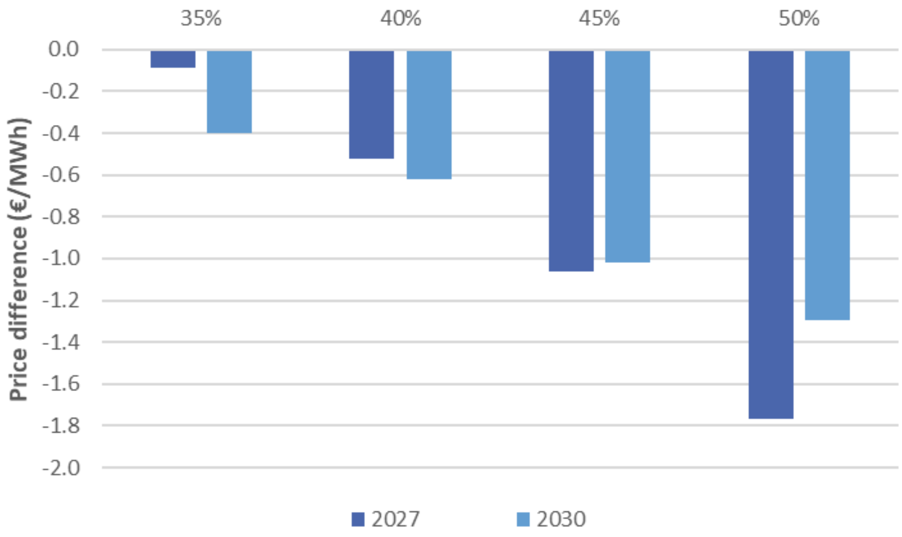
4.2 Market impact analysis

4.2.1 Market price

Figure 7 shows the difference in the average annual zonal price of the ISEM for each Sensitivity relative to the Reference scenario and for both modelled years. Average prices are lower across all four Sensitivities and the price becomes lower as the minimum generation level increases. This reflects the fact that a generator that is constrained on cannot set the market price. As the min gen level increases, the amount of constrained on capacity also increases and the residual demand that is supplied by the rest of the market decreases. We would therefore expect prices to be lower as min gen levels increase with all else being equal.

The change in market price implies that, in the absence of a compensatory payment such as a constraint payment, generators under the Sensitivities would receive less market revenue relative to the Reference scenario, and consumers would also be paying less for each unit of electricity. Both of these impacts increase in magnitude as the min gen level increases.

Figure 7: Price difference by Sensitivity relative to Reference scenario



4.2.2 Emissions[8]

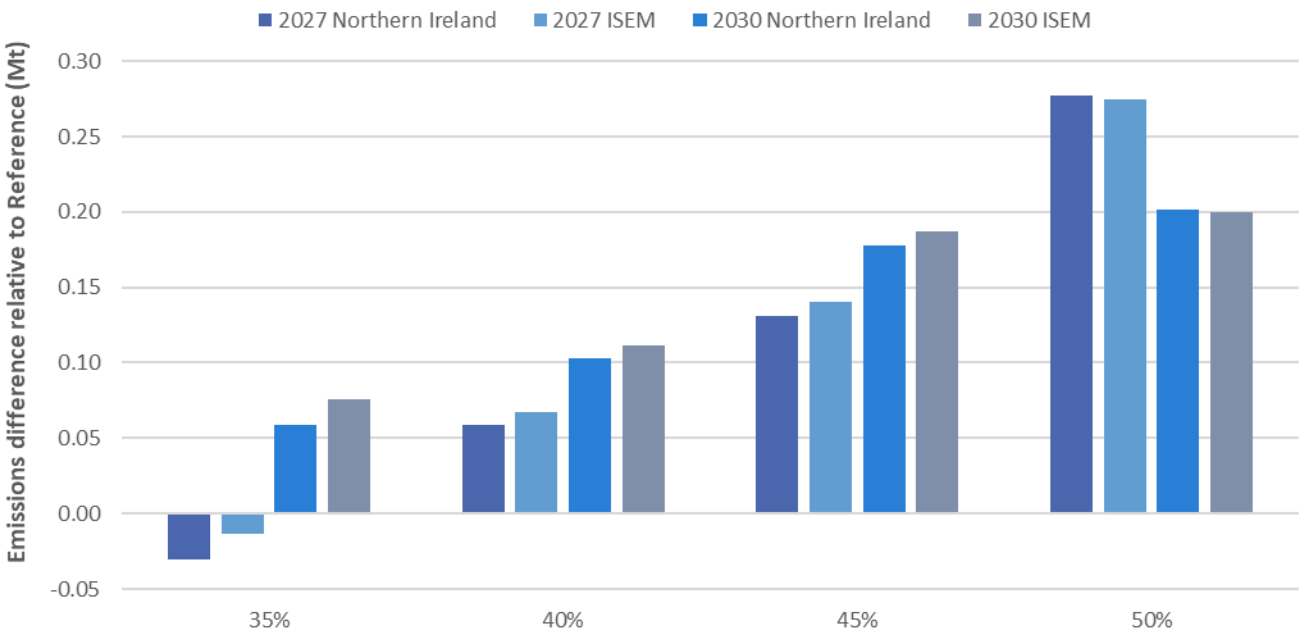
Figure 8 shows the differences in emissions for the Sensitivities relative to Reference scenario and demonstrates that:

- emissions for Northern Ireland and the ISEM increase as the min gen level increases; and
- most of the additional emissions are sourced from Northern Ireland.

Under the 35% Sensitivity in 2027, emissions in Northern Ireland reduce by more than total emission reductions in the ISEM, implying that emissions in the Ireland zone increase relative to the Reference scenario. This is consistent with Figure 6, which shows that costs (and therefore fuel consumption and emission production) of Ireland gas plants increase for this case.

[8] Emissions in this report refer only to CO_2 emissions.

Figure 8: Difference in emissions by Sensitivity relative to Reference scenario



4.2.3 Curtailment of renewables

An expected consequence of increasing min gen levels of the synchronous generating units is a corresponding increase in curtailment of renewable generation. When synchronous units are constrained on and running at min gen the power system can compensate for this by increasing exports across its interconnectors. However, the extent to which this is possible depends on the headroom in the exporting lines as well as how much capacity synchronous generators in the neighbouring system can offload before reaching min gen. If both of these conditions become simultaneously binding, then the least-cost outcome would be to curtail zero marginal-cost renewables. This means that the source of a proportion of the increase in resource costs calculated in section 4.1 is curtailment of zero marginal-cost renewable generation, which have been displaced by synchronous generation constrained on at min gen.

Figure 9 shows the annual curtailment of renewables for each of the Sensitivities in 2027 along with the estimated cost associated with the curtailment. The curtailment volumes were calculated relative to the Reference scenario and are therefore in addition to any curtailment that may be present in the Reference scenario. The technology most affected by curtailment is wind in the Ireland zone, followed by solar PV in the Ireland zone, biomass in the Ireland zone and wind in Northern Ireland. The levels of curtailment for each technology likely reflect coincidence of its output with binding hours of the min sets constraint.

The cost of curtailment was estimated by assigning the average annual dispatch-weighted price of each generator to the volume that was curtailed. The average curtailment cost across the four sensitivities amounts to €44/MWh. The cost of curtailment climbs monotonically as the min gen is increased and ranges from less than €1M under the 35% Sensitivity up to €6M under the 50% Sensitivity. It represents 16%, 14% and 11% of the net cost of the 40%, 45% and 50% Sensitivities respectively. This suggests the rule change only has a moderate impact on renewables relative to its total net cost.

Figure 9: Curtailment of renewables (LHS) and the estimated cost of curtailment (RHS), 2027

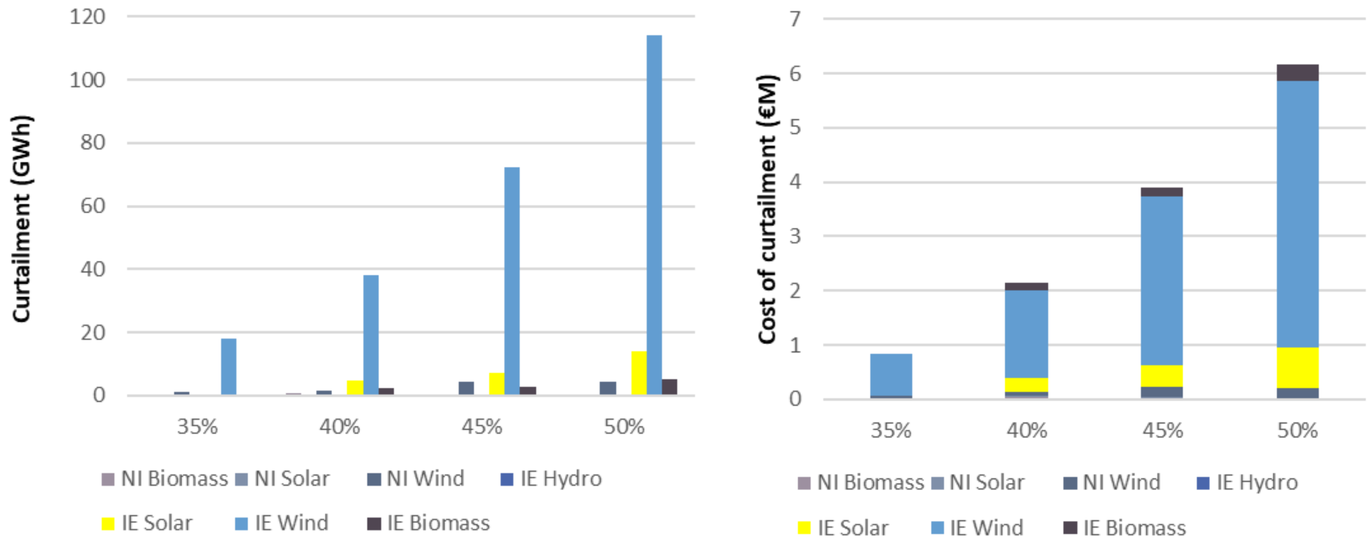
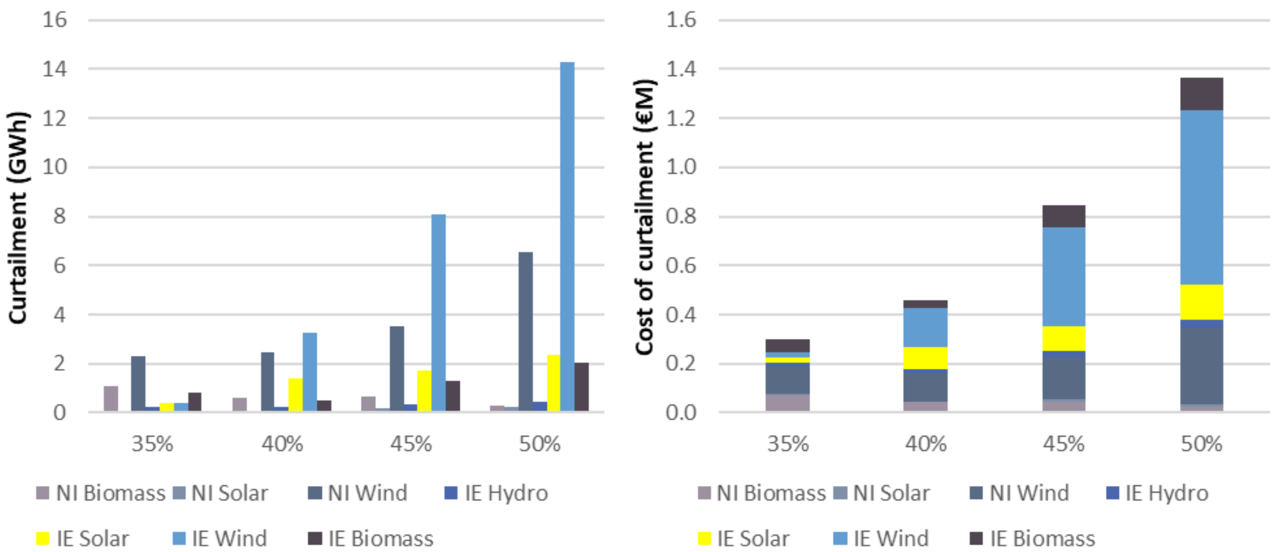


Figure 10 is the same chart on curtailment presented for 2030. It shows that curtailment of zero marginal-cost renewables is much reduced relative to the 2027 outcomes across all Sensitivities. Curtailment predominantly occurs for wind in the Ireland zone, followed by wind in Northern Ireland, solar PV in Ireland and Biomass in Ireland.

The average cost of curtailment is estimated to be €54/MWh and the total cost of curtailment is in the order of 20% of the cost calculated for 2027. When compared to the net cost of implementing the min gen rule across the Sensitivities, the cost of curtailment represents 2.0%, 2.1%, 2.7% and 4.1% of the total net cost for the 35%, 40%, 45% and 50% Sensitivities respectively. This suggests the rule change has a minimal impact on renewables relative to its total net cost in 2030.

Figure 10: Curtailment of renewables (LHS) and the estimated cost of curtailment (RHS), 2030



5. Concluding remarks

The PLEXOS techno-economic study has shown that implementing the rule change is a net cost to the ISEM under all sensitivities in both 2027 and 2030, with the exception of the 35% Sensitivity in 2027, where it represents a slight net benefit to the ISEM. The key drivers underlying changes in the resource costs are the changes in fuel and emissions costs for gas-fired generators, all of which are located in Northern Ireland and directly impacted by the rule change.

The analysis shows that net costs increase monotonically as the min gen level increases. This is directly linked to the costs of fuel and emissions at min gen of a synchronous thermal generator per trading interval, which increase as the prescribed min gen level increases.

The simple conclusion that can be drawn from the above is that the net cost of the rule change will be minimised by minimising the prescribed min gen level. Having a lower min gen level represents a more flexible power system that results in less fuel burn, lower emissions and less curtailment of low-cost renewable generation.

Having said that, the min gen requirement also needs to be balanced against the technical capability and regulatory compliance of real-world synchronous generating units. If the min gen requirement is set too low then there is a danger that no real-world synchronous generators will be able to meet the requirement, which is a counter-productive outcome. This question can only be answered by a review of the technical capabilities and regulatory landscape of real-world generators. This has been in part the subject of the Phase 1 study of this review.