SUBMISSION TO THE COMMISSION FOR REGULATION OF UTILITIES

What It Takes to Cost Both Sides

A response to CRU202704 — Grid Code Modification MPID 345 and the Compliance and Derogation Framework. What a proportionality assessment requires, and which of its inputs the public record does not currently contain.

Amata Consulting supports approval of MPID 345 as a matter of urgency. The system risk is real, evidenced and escalating, and the status quo is not costless. This submission answers each of the Commission's five invitations in turn. The Commission's technical advisor judges FRT compliance likely to be the more cost-effective route, but states that no Cost Benefit Analysis exists and that no definitive conclusion on relative costs can therefore be drawn. We agree with that judgement, and we attempted to quantify it. We concluded that the public record does not currently support a quantification robust enough to place before the Commission — and we regard that conclusion as a finding in itself. In place of a number we cannot defend, we set out at Annex A the specification a defensible Cost Benefit Analysis would have to meet, together with the seven inputs it requires — six of which are not currently published, and five of which are held by EirGrid.

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STANDING AND DECLARED INTEREST

1. Who is making this submission, and why

Amata Consulting (aifactor.ie) is a Dublin-based advisory practice working on the intersection of artificial-intelligence compute, data-centre infrastructure and Irish electricity-grid policy.

We are not an affected party. Amata holds no grid connection, no Maximum Import Capacity and no Demand Utilisation Threshold. We will bear no compliance cost under MPID 345 and we suffer no business impact from it. We make this submission as an analyst and a contributor to the public record.

Declared interest. Amata advises on data-centre density and cooling retrofit, a market whose prospects are affected by how the Commission resolves the questions in this paper. We state this so that the Commission and other respondents may discount our submission accordingly. Nothing in this document is written on behalf of, or at the request of, any operator, vendor or client.

> **Our position.** Amata supports approval of MPID 345 and the Compliance and Derogation Framework as a matter of urgency. We ask the Commission to adopt five refinements to the Framework, and to require the cost evidence on which its calibration depends.

This submission answers each of the Commission's five invitations in the order the Commission put them.

CRU202704 invites views on	Answered at
EirGrid's assessment of alternative solutions (CRU202705)	**Section 2**
TNEI's technical review and recommendation on MPID 345 (CRU202707)	**Section 3**
TNEI's review of the Compliance and Derogation Framework (CRU202708)	**Section 4**
EirGrid's proposed change to the Framework — DUT Options 1, 2 and 3	**Section 5**
Impact on respondents' businesses, and the impact of the ongoing operational measures	**Section 6**
Two matters not raised in the paper	**Section 7**

THE COMMISSION'S FIRST QUESTION

2. Views on EirGrid's assessment of alternative solutions (CRU202705)

We concur with EirGrid and with TNEI. System Service and Grid solutions alone do not offer a credible alternative to demand-side Fault Ride Through. We say so as a party with no commercial stake in the answer.

Three elements of EirGrid's analysis are, in our view, decisive:

- **The inertia requirement is not deliverable on the relevant timescale.** Holding RoCoF within 0.9 Hz/s for the modelled disturbance requires system inertia of approximately 59–60 GVA·s against an operational floor of 23 GVA·s. The Low Carbon Inertia Service is expected to deliver approximately 25 GVA·s by 2030. Closing the remainder would require sustained additional synchronous thermal running, which is inconsistent with statutory climate objectives.
- **The reserve requirement compounds rather than resolves.** Even at 59 GVA·s, approximately 700 MW of additional BESS import capacity is required to hold frequency, rising to 1.1–2.1 GW at twice standard response speed to bring Over-Frequency Generation Shedding to near zero. EirGrid's concern that a large number of devices interacting on millisecond timescales creates a risk of oscillatory control interaction is, in our view, well founded.
- **The international comparison is persuasive.** A potential imbalance-to-peak-demand ratio of 0.31, against 0.03–0.06 in ERCOT, Great Britain and Australia, would place Ireland far outside the range any comparable system secures for. ERCOT's own transmission-upgrade study reached a consistent conclusion: load-side ride-through was the most effective measure examined.

Three limits of the assessment

(a) It does not answer the proportionality question. CRU202705 establishes that grid solutions cannot *wholly replace* demand-side FRT. We accept that. It does not establish what the *least-cost mix* is, and only the second question is a proportionality analysis. The Commission should not treat an answer to the first as disposing of the second.

(b) The sub-transient window is unmodelled. TNEI records that the first 150 ms after the fault has been analysed in RMS rather than EMT — and that EirGrid proposes to permit demand facilities to reduce consumption to zero MW for precisely that window, during which the combined loss of demand and interconnector export exceeds 2 GW in EirGrid's models. The interval in which the system is most exposed is the interval least rigorously simulated. We do not suggest this invalidates the conclusion. We suggest it should be closed.

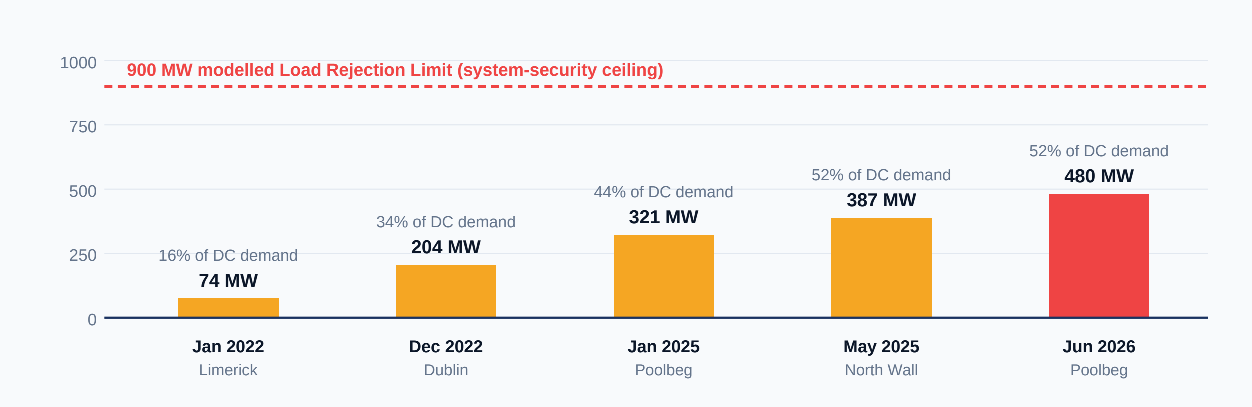
(c) On-site conventional generation was not formally assessed. TNEI states that EirGrid "did not provide information or evidence to TNEI to indicate that this mitigation was formally considered as part of the FRT proposal," and inferred that it had been considered and dismissed. TNEI's reasoning for dismissing it is sound — behind-the-meter transfer reproduces the same imbalance the requirement exists to prevent. But an inference is not an assessment, and the record should reflect that distinction.

THE COMMISSION'S SECOND QUESTION

3. Views on TNEI's review of MPID 345 (CRU202707)

We support TNEI's overarching recommendation: approve MPID 345 as a matter of urgency. The recorded events escalate, the most recent is the largest, and the load-rejection limit has been reached.

EXHIBIT 1 — The case for urgency, on EirGrid's own data



Bars: observed data-centre demand reduction following transmission faults, 2022–2026. All five events were single-phase. **Line:** the separate 900 MW modelled load-rejection limit — the system-security ceiling, not an observed value. The two are different measures. EirGrid's modelling indicates approximately 90% of data-centre demand could reduce for a credible three-phase fault, and reports that aggregate data-centre demand of approximately 1,000 MW was recorded in June 2026, at which level the ceiling is engaged. Sources: CRU202704 Table 1 and §1.4; CRU202705 §3.3–3.4.

3.1 The cost basis: TNEI has made a directional judgement, not a quantified one

We quote TNEI in full, including the passages that cut against the case for further analysis:

> *"TNEI has not received, nor is it aware of, any formal Cost Benefit Analysis (CBA) comparing the cost of requiring demand facilities to comply with FRT against the cost of procuring alternative mitigation solutions … TNEI is not aware of the actual cost to demand facilities of implementing FRT compliance across all connected and contracted sites, and therefore a fully informed cost comparison cannot be made at this stage. In the absence of such analysis, it would not be appropriate to draw definitive conclusions on relative costs. However … it appears reasonable to suggest that the cost of procuring these alternative solutions at the scale required could be considerably greater than the cost of implementing FRT compliance at the point of connection … the available evidence suggests that FRT compliance at the point of connection is likely to represent the more cost-effective solution for the system." — CRU202707, §3.3.2*

We agree with TNEI's direction and we do not seek to displace it. TNEI judges FRT compliance likely to be the more cost-effective route. So do we. The point we make is narrower: TNEI is explicit that it cannot draw definitive conclusions on relative costs, because it was not given the inputs. The Framework that follows from this decision will bind commercial behaviour for years, and its calibration — the thresholds, the timelines, the derogation lengths — turns on magnitudes that no party has established.

What we attempted, and why we are not presenting it. Amata set out to quantify both sides of the trade-off and to publish the result. We concluded that the public record does not support a quantification robust enough to place before the Commission. The available benchmarks for grid-side stability provision are multi-service contract values that cannot be attributed to inertia alone without arbitrary allocation; the demand-side compliance cost has no empirical anchor we could locate in the jurisdictions and sources reviewed, and is in any event unlikely to scale linearly with megawatts.

We regard that as a finding rather than a failure, and we report it rather than publishing a number we could not defend. Annex A sets out instead the **specification a defensible Cost Benefit Analysis would have to meet**, and the inputs it requires — which are held variously by EirGrid, by demand-facility owners and OEMs, and by the SEM Committee.

3.2 The EMT gap should be closed, and the 150 ms allowance made provisional

We endorse TNEI’s recommendation on EMT models, and would add one step: the proposed permission for demand facilities to reduce to zero MW for the first 150 ms should be expressed as *provisional pending EMT validation*, and delivery of EMT-grade models should be a standing condition of any derogation granted under the Framework. A facility seeking relief from a Grid Code requirement can reasonably be asked to supply the data that allows the TSO to model the relief it has been given.

3.3 The absence of a commercially available solution

TNEI records that OEMs are awaiting approval of the modification before developing a solution, that at least one OEM may deliver for *some* sites in 2026, and that a Grid Code requirement which cannot presently be met by any available product is without precedent. We agree with TNEI that this does not justify inaction: the system risk does not wait for the supply chain. It does mean the derogation should be conditioned on **good-faith engagement** rather than on an outcome the market cannot currently supply, and that the Framework should carry an explicit review trigger if commercial solutions have not materialised by a stated date.

THE COMMISSION'S THIRD QUESTION

4. Views on TNEI's review of the Compliance and Derogation Framework (CRU202708)

We address all eight of TNEI's recommendations, in TNEI's numbering.

TNEI recommendation	Amata position
§3.1 Careful consideration of any incentive to avoid the group derogation process	**Agree.** We propose a remedy at Section 4.1 of this submission.
§3.2 Extend compliance-plan timelines to 6 months (data centres, both routes) and 12 months (non-data centres)	**Agree.** A 5-week effective timeline for non-group applicants will produce thin plans rather than fast ones. TNEI's alternative — an early commitment to engage, with the detailed plan to follow — is the sounder structure.
§3.3 24-month derogation for data centres; 5-year for non-data centres	**Agree.** The behavioural evidence justifies the asymmetry. We would add the review trigger we propose at Section 3.3 of this submission — on the absence of a commercially available solution.
§3.4 Approve the Demand Utilisation Threshold	**Agree — subject to the reallocation question being answered.** TNEI expressly holds no view on the treatment of freed capacity. We address this at Section 7.1.
§3.5 Further consideration of the portfolio approach	**Agree.** TNEI's reasoning is persuasive: reallocation between electrically distinct areas could concentrate non-compliant demand and increase system risk, and the approach has no evident basis in the structure of network access rights. Pro-rata allocation at connection-agreement level is the non-discriminatory alternative.
§3.6 Approve the data centre / non-data centre categorisation	**Agree.** A 44–52% versus 1–5% differential in observed fault response, with non-data-centre demand falling 6% between May and December 2025, is a defensible basis for separate treatment.
§3.7 EirGrid to consider industry feedback on compliance-assessment efficiencies	**Agree.** We add that TNEI's review of the two study guides is stated to be ongoing; it should be completed and published before the modification effective date, so that facilities know the criteria against which they will be assessed.
§3.8 Allow a 10% temporary peak above DUT, with monitoring and a revision clause	**Agree.** The revision clause matters: correlated peaks across multiple sites in warm weather are precisely the scenario in which the aggregate limit is placed at risk.

4.1 The opt-out incentive

TNEI has identified this defect and the Commission has already sought further representations from EirGrid on it. We offer a remedy, and we state the counterweight first.

The counterweight. TNEI notes that a facility outside the group process which is neither compliant nor holder of a CRU-approved derogation by the effective date is in breach of the Grid Code, and is "at increased risk of demand control actions taken by the TSO which could apply in respect of the entirety of their demand use." That is a materially heavier sanction than a DUT. Any characterisation of the holdout position as consequence-free would overstate the case.

The defect nonetheless remains, and it is one of certainty rather than of ultimate exposure. The holdout's sanction is contingent, discretionary and deferred. The opt-in's constraint is immediate, certain and binding for the derogation term. A commercially rational operator may discount the former against the latter. That is the incentive TNEI identified, and it does not require the holdout to escape consequence — only for the consequence to be less certain than the cap.

Recommendation 1. The Demand Utilisation Threshold should attach to **non-FRT-compliant demand at any transmission-connected data centre**, irrespective of derogation route, so that the constraint follows the risk rather than the procedural election.

Mechanism, and the window that matters. We recognise that a DUT is presently a *condition of derogation* rather than a freestanding Grid Code obligation, and we do not suggest the Commission can impose one on a facility that has neither sought nor been granted a derogation.

The incentive TNEI identifies, however, operates in the **pre-grant window** — the holdout can grow consumption “while the review process associated with their individual derogation requests is ongoing.” A remedy that disciplines only the terms of an eventual grant misses precisely the period in which the incentive bites. **Any mechanism the Commission adopts must therefore bind from the modification effective date, not from the date of derogation grant.**

Two limbs are available within the existing architecture. First, the Commission may indicate that, in exercising its derogation powers, it will not grant a standard-route derogation on terms materially less constraining than the group route — this disciplines the end state. Second, and necessarily, EirGrid should confirm that from the effective date the FRT Demand Curtailment Procedure applies to non-derogated non-compliant demand on a basis no more favourable than the DUT would impose — this reaches the interim. Only the second limb closes the window, and it depends on EirGrid’s election. We invite the Commission to confirm the mechanism it considers available to it, and to state expressly that it binds from the effective date.

THE COMMISSION'S FOURTH QUESTION

5. Views on the proposed change to the Framework — DUT Options 1, 2 and 3

The Commission notes this change has not been shared with impacted users. It is presented as a question of data sources. It also determines how much of the 900 MW load-rejection limit is allocated, and on what margin — and that consequence is not disclosed.

Option	Source	Peak margin	Amata view
1 Existing (submitted 1 April 2026)	SCADA	10%	**Not preferred.** SCADA is not visible to the customer and does not align with billing data. A limit a party cannot observe is a limit it cannot manage, and measurement disputes will consume time the Commission does not have.
2 Meter data	Metering	10%	**Preferred for compliance measurement.** Metering data is validated, used for billing, and available to the customer through its supplier. Verifiability is the decisive criterion for a limit carrying curtailment and disconnection consequences.
3 Higher of 1 and 2	Both	**6.5%**	**Not supported without disclosure.** Option 3 raises aggregate DUTs and funds the increase by reducing the peaking margin from 10% to 6.5%. That is a system-security trade-off, and no respondent can evaluate it because the aggregate DUT under each option is not published.

EirGrid's dual-source proposal for *monitoring* — SCADA in real time for system security, metering for monthly compliance assessment — is sound and we support it. Our objection is confined to the *setting* of the threshold and to the undisclosed aggregate consequence of Option 3.

> **Recommendation 2.** DUT compliance should be measured on **metering data** (Option 2), with SCADA retained for real-time operational monitoring. Before choosing between the options, the Commission should require EirGrid to publish **the aggregate sum of DUTs under each option**, expressed against the 900 MW load-rejection limit, so that the security headroom implied by each choice is visible to respondents.

THE COMMISSION'S FIFTH QUESTION

6. Business impact, the operational measures, and the missing cost evidence

Amata has no business impact to report. We hold no connection agreement and face no compliance cost. We decline to manufacture an impact we do not have.

6.1 What we can and cannot contribute

We set out to quantify both sides of the trade-off and to publish the result in this submission. We did not succeed, and we think the Commission is better served by our saying so than by our publishing an estimate we could not defend under examination. Three obstacles proved decisive, and each of them is a property of the public record rather than of our method:

- **Grid-side stability costs cannot be attributed to inertia alone.** The available benchmarks — the Low Carbon Inertia Services procurement in Ireland, and the Stability Pathfinder contracts in Great Britain — are multi-year service contracts procuring inertia, short-circuit level and dynamic reactive power together. Dividing a multi-service contract value by a volume of inertia assigns the whole cost to one of several outputs. Any figure derived that way is an artefact of the allocation, not a measurement.
- **Demand-side compliance cost has no empirical anchor we could locate.** We identified no published per-site or per-megawatt benchmark in the jurisdictions and sources reviewed — including Ireland, ERCOT's Large Load process, NERC's Large Loads work, and OEM literature. Nor is compliance cost likely to scale linearly with megawatts: it will be driven by site topology, UPS and static-transfer-switch architecture, equipment age, outage windows and largely fixed engineering costs per site. A per-MW scenario range would convey a precision the underlying structure does not possess.
- **The two sides are not measured on a common basis.** Compliance is a largely one-off capital cost at the customer's premises. Grid-side provision is a stream of contracted service payments over a decade. Comparing them requires a common time horizon and discounted cash flows. Neither exists in the record, and constructing one requires inputs held by EirGrid, by the demand facilities and their equipment suppliers, and by the SEM Committee.

> **This is a finding, not an absence of one.** The obstacles above are not peculiar to Amata. They will defeat any respondent, and they defeated TNEI, which states in terms that a fully informed cost comparison cannot be made at this stage. The proportionality concern raised across the first round of representations cannot be resolved on the current record by anyone — including the Commission.
>
> Annex A therefore sets out what a defensible Cost Benefit Analysis would need to contain, and Exhibit 2 identifies the seven inputs it requires, six of which are not currently published.

6.2 The cost of the status quo

The operational measures now in force — restriction of interconnector exports, must-run synchronous condensers holding the inertia floor at 28 GVA·s against a standard of 23, battery charging capped at 200 MW and state of charge at 85%, SNSP frozen at 75% with the 80% trial paused, and the inertia-floor update paused — impose costs on electricity consumers and on renewable integration. EirGrid says so in terms. What is not published is the magnitude.

For scale, and **without attributing any of it to this issue**: the all-island imperfections charge was decided at €790.24 million for tariff year 2025/26, against €567.21 million the year before; all-island wind dispatch-down reached 2,181 GWh in 2024, or 14.0% of available wind energy. We make no claim that either figure is caused by the Fault Ride Through issue — the majority of dispatch-down is driven by minimum-generation requirements, not by this — and we note that the FRT-attributable share of both is not quantified on the public consultation record.

EXHIBIT 2 — The evidence gap: inputs a proportionality assessment requires

Required input	Status	What the record says
Per-site FRT compliance cost, from a representative sample	NOT PUBLISHED	TNEI: "not aware of the actual cost to demand facilities of implementing FRT compliance" (CRU202707 §3.3.2)
Count and topology profile of captured sites (110 kV+, MIC > 5 MW)	NOT PUBLISHED	The population bound by the FRT Demand Curtailment Procedure is not stated in any consultation document
Cost of FRT-driven operational measures, separated within imperfections	NOT PUBLISHED	TNEI: "not in a position to accurately quantify the cost involved with this countertrading" (CRU202708 §3.4). No FRT attribution appears in the imperfections record.
Dispatch-down attributable to FRT-driven export restriction and the paused SNSP trial	NOT PUBLISHED	The measures are confirmed at CRU202704 §1.5; their effect is not quantified
Allocation of stability contract value across inertia, short-circuit level and reactive power	NOT PUBLISHED	Required to price any grid-side counterfactual; not separable in LCIS or comparable procurements
Duration, connection and grid-forming premium assumptions for any BESS counterfactual	NOT PUBLISHED	No published basis on which to price the reserve volumes at CRU202705 §5.2
Value of Lost Load basis for valuing avoided load shedding	**PUBLISHED**	SEM Committee, SEM-23-072. The only one of the seven that is available.

Seven inputs a proportionality assessment requires. **Six are not currently published.** These are inputs, not outputs — the Cost Benefit Analysis itself is the output they would produce, and TNEI confirms it does not exist (CRU202707 §3.3.2). This table is reproduced with its holders identified at Annex A.2.

Recommendation 3. We distinguish two decisions and ask that they be sequenced.

(i) Approval of MPID 345 should not wait. The system-security case is made out and the urgency is real. We do not ask the Commission to defer it for cost evidence.

(ii) The Framework's calibration should be designated interim, and reviewed on evidence. The DUT level, the derogation lengths and the compliance timelines are proportionality judgements that cannot presently be made on the record. If the Framework is adopted before the evidence exists — as we accept it must be — then its initial DUTs, timelines and derogation periods should be expressly designated **interim** and made subject to a mandatory review by a stated date.

(iii) The evidence should be assembled from those who hold it. The Commission should direct EirGrid to publish the inputs it holds; obtain representative compliance-cost evidence from demand-facility owners and OEMs, whether through the derogation compliance plans or otherwise; commission a Cost Benefit Analysis meeting the specification at Annex A; and review the Framework's calibration once that evidence is available.

TWO MATTERS NOT RAISED IN THE PAPER

7. The treatment of freed capacity, and the measurement basis for Active Power Recovery

We raise two questions the Commission did not put, because in our assessment the Framework cannot achieve its purpose without them being answered. We place them last in acknowledgement that they are ours and not the Commission's.

7.1 The treatment of capacity freed by compliance

> *"TNEI does not hold a view on how compliant capacity should be reallocated as demand facilities achieve compliance with FRT requirements. This capacity could either be allocated to additional non-FRT compliant demand connections, or alternatively used to relax current operational measures — such as the existing limitations on Interconnector exports — rather than enabling further non-compliant demand." — CRU202708, §3.4*

As facilities certify compliant, headroom is freed beneath the load-rejection limit. Its treatment determines what the regime achieves. If freed headroom is recycled into further non-compliant demand, the system remains at its limit indefinitely, the operational mitigations and their costs become permanent, and compliance confers no system benefit. If it is applied first to restoring normal operation, each certification delivers a measurable public benefit and compliance acquires value to the party bearing its cost.

> **Recommendation 4.** The Commission should adopt and publish a **transparent decision principle** governing capacity freed by compliance: that it is applied *first* to relaxing the operational mitigations — interconnector export restrictions, the SNSP limit, must-run inertia — until the system is restored to its normal operating envelope, and only *thereafter* to accommodating further non-compliant demand.
>
> We frame this as a decision principle rather than a fixed dispatch rule. Real-time operation must remain the TSO's to optimise, and we do not propose to constrain it. What we ask is that the *presumption* and the reporting against it be published, so that the benefit of compliance is visible and does not accrue silently to non-compliant demand. The Commission should further confirm that FRT-compliant demand is not subject to a Demand Utilisation Threshold.

7.2 The measurement basis for Active Power Recovery

CRU202704 §2 records the proposed Active Power Recovery requirement as follows: demand facilities "must recover their active power to 90% of the pre-fault value within 500 milliseconds after fault clearance and voltage recovery to 0.9 per unit." The fault-ride-through voltage profile is located at the Connection Point. **What is not stated is whether the pre-fault active power value against which recovery is assessed is measured as net active power at the Connection Point, or as the underlying facility load.**

The distinction is material. If compliance is assessed net at the Connection Point, a facility may in principle satisfy the requirement through co-located generation or storage injecting during and after the fault, while its internal load still transfers to backup. If it is assessed on the underlying load, that route is closed. The two readings imply different technologies, different costs and different lead times, and the ambiguity is being priced into investment decisions now.

Amata takes no position on which reading is correct. We say only that the ambiguity is costly, that it bears directly on the compliance-cost question at the centre of this consultation, and that the Commission is the only body able to resolve it.

> **Recommendation 5.** The Commission should confirm in its decision whether the pre-fault active power value against which recovery is assessed under MPID 345 is measured as net active power at the Connection Point or as the underlying facility load — and, if the former, whether a co-located generation or storage asset may discharge the demand facility's ride-through obligation.

SUMMARY

8. What we ask the Commission to do

Amata Consulting **supports approval of MPID 345 and the Compliance and Derogation Framework as a matter of urgency**, and asks the Commission to adopt five refinements.

#	Recommendation	At
1	Attach the Demand Utilisation Threshold to **non-FRT-compliant demand**, not to the derogation route, by the mechanism set out at §4.1.	§4.1
2	Measure DUT compliance on **metering data**; publish the **aggregate DUT under each of the three options** before choosing between them.	§5
3	**Approve MPID 345 now and designate the Framework's initial calibration interim.** Assemble the evidence from its respective holders, commission the Cost Benefit Analysis specified at Annex A, and review the calibration by a stated date.	§6.2
4	Adopt and publish a **transparent decision principle** for capacity freed by compliance: restore normal operation first, accommodate further non-compliant demand thereafter.	§7.1
5	Confirm the **measurement basis** for the pre-fault active power value against which recovery is assessed — net at the Connection Point, or underlying facility load.	§7.2

> The Commission asked whether alternatives were properly assessed, and what the proposals cost those they bind. On the first, we agree with EirGrid and TNEI: there is no credible alternative to demand-side Fault Ride Through, and the modification should be approved without delay. On the second, TNEI has reached a directional judgement but states that no definitive conclusion on relative costs can be drawn. We attempted the quantification and concluded the public record will not currently bear one.
>
> The Framework should therefore be approved on urgency grounds, its initial calibration designated interim, and the evidence assembled from the parties that hold it — EirGrid, the demand facilities and their equipment suppliers, and the SEM Committee.

ANNEX A

A. Specification for a defensible Cost Benefit Analysis

TNEI states that no Cost Benefit Analysis exists and that no definitive conclusion on relative costs can be drawn without one. This annex sets out what such an analysis would have to contain to be defensible. We offer it because the requirements are not obvious, because several of them are traps we ourselves fell into when we attempted the exercise, and because a specification the Commission can direct is more useful than an estimate the Commission would have to discount.

A.1 Six requirements

#	Requirement	Why it matters
1	**Disambiguate the two 2,300 MW quantities**	EirGrid's modelled disturbance of 2,300 MW comprises approximately 1,800 MW of data-centre demand loss plus approximately 500 MW of EWIC export loss. Ireland's contracted data-centre capacity separately comprises approximately 2,000 MW at transmission level plus approximately 300 MW at 110 kV. These are unrelated quantities that coincidentally share a total. A CBA must state which population each cost is scaled across, and must not scale a compliance cost over a disturbance magnitude.
2	**Allocate multi-service stability costs explicitly**	Stability procurements — the Low Carbon Inertia Services in Ireland, the Stability Pathfinder contracts in Great Britain — purchase inertia, short-circuit level and dynamic reactive power in a single contract. Their headline values are service-contract values over a defined term, not asset capital expenditure. Dividing such a value by a volume of inertia attributes the whole cost of several outputs to one. A CBA must state its allocation basis and test the result's sensitivity to it.
3	**Avoid double-counting capital and availability**	A grid-side counterfactual cannot be priced simultaneously as an inferred capital programme and as a stream of availability payments. These are alternative representations of the same cost. One or the other, consistently applied.
4	**Use a common time horizon and discounted cash flows**	Compliance cost is largely one-off capital at the customer's premises. Grid-side provision is a contracted service stream over a decade or more. The two are not comparable in nominal terms. A CBA must adopt a common horizon, an explicit discount rate, and present values.
5	**Model compliance cost on site topology, not per megawatt**	Compliance cost is unlikely to scale linearly with megawatts. It will be driven by site electrical topology, UPS and static-transfer-switch architecture, protection settings, equipment vintage, available outage windows, and engineering costs that are substantially fixed per site. A per-MW unit cost would convey a precision the underlying structure does not possess. The analysis should be built bottom-up from a representative sample of the captured population — which requires the site count at Exhibit 2.
6	**Value avoided load shedding on a stated and current basis**	The tail risk that FRT compliance buys down is a system incident. The SEM Committee publishes both a Value of Lost Load and a reliability-standard Value of Lost Load ($VoLL_{RS}$), which differ materially and are indexed by capacity year. A CBA must state which measure it adopts and why, and must use the current value for the relevant capacity year rather than a historical figure. We note that SEM-23-072 addresses the use of $VoLL_{RS}$ in security-of-supply assessment, and invite the Commission to confirm the appropriate basis.

A.2 The inputs required, and who holds them

The six requirements above cannot be met from the public record. The table below identifies each input a CBA requires, and the party positioned to supply it. Amata holds none of them; nor, on the face of its reports, does TNEI.

Input	Held by	Status
Per-site FRT compliance cost, from a representative sample	Demand facility owners / OEMs	**Not published**
Count and topology profile of captured sites (110 kV+, MIC > 5 MW)	EirGrid	**Not published**
Cost of FRT-driven operational measures, separated within imperfections	EirGrid / SEM Committee	**Not published**
Dispatch-down attributable to FRT-driven export restriction and the paused SNSP trial	EirGrid	**Not published**
Allocation of LCIS contract value across inertia, short-circuit level and reactive power	EirGrid / SEM Committee	**Not published**
Duration, connection and grid-forming premium assumptions for any BESS counterfactual	EirGrid	**Not published**
Current $VoLL_{RS}$ for the relevant capacity year	SEM Committee	**Published**

> **The asymmetry this reveals is the point.** Of the seven inputs a Cost Benefit Analysis requires, six are unpublished and five are held by EirGrid. The party proposing the measure holds most of the evidence required to test whether it is proportionate. That is not a criticism of EirGrid, which has not been asked for it. It is a reason for the Commission to ask.

A.3 What we did not do, and why

For completeness, and so that the Commission may judge the seriousness of the attempt: Amata constructed a scenario-based estimate of both sides and elected not to publish it. The grid-side figure could not be freed of the allocation and double-counting problems at A.1(2) and A.1(3). The demand-side figure had no empirical anchor and required a per-MW linearity assumption that A.1(5) shows to be unsafe. The two could not be placed on a common time basis without inputs we do not hold. A number produced on those foundations would have been indefensible under examination by EirGrid or TNEI, and would have discredited the remainder of this submission. We record the attempt, and its failure, as evidence of how far the public record is from supporting the proportionality assessment the first round of representations called for.

SOURCES

B. Documents relied upon

This submission relies on the consultation record and on the primary regulatory sources below. Where we describe a figure as unpublished, we mean that we identified no public benchmark in the sources reviewed; we do not assert that none exists in any form.

CRU202704 — Grid Code Modification MPID 345 and Compliance and Derogation Framework: Request for Further Representations. Commission for Regulation of Utilities, 8 July 2026.

CRU202705 — Fault Ride Through / Active Power Recovery / Rate of Change of Frequency: EirGrid Update including Assessment of System Service / Grid Solution Alternatives. EirGrid, 26 June 2026.

CRU202706 — Urgency of CRU Approval of Grid Code Modification Proposal MPID345 and Associated Compliance and Derogation Framework. EirGrid Information Note, 29 May 2026.

CRU202707 — Fault Ride Through, RoCoF and Post Fault Active Power Recovery for Demand Facilities Modification Review. TNEI, IE00401-004-001-R7, 3 July 2026.

CRU202708 — Fault Ride Through Compliance and Derogation Framework Review. TNEI, IE00401-004-002-R3, 3 July 2026.

EirGrid / SONI — Large Demand Facility Fault Ride Through Issue and Proposed Solutions: Information Paper. November 2025.

EirGrid — MPID 345 Demand Facilities FRT Recommendation Paper. 1 April 2026.

SEM Committee — Value of Lost Load and reliability-standard Value of Lost Load, SEM-23-072. 29 September 2023.

SEM Committee — Imperfections Charge decisions, tariff years 2024/25 and 2025/26.

EirGrid / SONI — Annual Renewable Energy Constraint and Curtailment Report 2024.

SEM Committee — Low Carbon Inertia Services procurement, Phase 1 and Phase 2.

NESO — Stability Pathfinder procurement results. National Energy System Operator, Great Britain.

ERCOT / NERC — Large Load ride-through workstreams, including NOGRR282 and the NERC Large Loads Task Force.

Note on document references. We cite the two TNEI reports by the reference numbers under which they are published on the consultation portal — **CRU202707** (Modification Review) and **CRU202708** (Compliance and Derogation Framework Review). The Related Documents list at §1.6 of CRU202704 numbers them CRU202708 and CRU202709 respectively. We have followed the published documents. Section references are unaffected.

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