Submission on EirGrid's consultation on 'Shaping Our Electricity Future'

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This submission draws on the Economic and Social Research Institute's research surrounding electricity and the Single Electricity Market on the Island of Ireland. This document summarises prior research findings across a number of topics with relevance to the consultation, rather than repeat the full analysis here. The original research papers are listed at the end.

1. Developers of renewable energy infrastructure, as well as transmission grid infrastructure, often face public opposition to new projects. Scenario analysis of generation and transmission system investment show that many future pathways are feasible but alternatives are not without impacts on system costs and electricity prices [1–5]. As the power system expands with greater generation and transmission capacity required over the coming decade, system costs and electricity prices could dramatically escalate if there is a sharp deteri-oration in the public's acceptance of new energy infrastructure [4]. The implication for the electricity sector and society in general is that community and stakeholder engagement on new energy infrastructure projects should continue to be a key priority. Public acceptance of energy infrastructure is often characterised as a local issue where the new infrastructure is to be located. Both developer and public policy initiatives exist to encourage acceptance of new infrastructure in local communities, often conceptualised in terms of willing-ness to accept costs. But the impact on the power system's costs and (implicit) electricity prices are neither necessarily local to the area of potential new infrastructure nor uniform across the network. For example, impacts can occur on opposite sides of the country in terms of unserved power or higher system costs, es-pecially in the Dublin region where network congestion is most acute [4]. The estimates by Koecklin et al.
[4] of implicit (or shadow) regional electricity prices conditional on varying levels of public acceptance of electricity infrastructure are a metric of both system-wide and regional network values of development of new infrastructure necessary to maintain electricity supply security and achieve renewable electricity targets.

2. While electricity infrastructure investments are often viewed in isolation by the public, the evidence is that they often have important effects across the network. As an example, the North-South interconnector, which has been planned for some time, would significantly increase the level of interconnection between the two systems on the island of Ireland. Modelling analysis shows that the absence of a North-South interconnector leads to a more pronounced congestion levels across the island, particularly in high demand areas, where the number of network components that are heavily loaded for a substantial periods of time (e.g. more than 2000 hr/year) is substantially higher. A key benefit of the interconnector would be a reduction in both the number of hours and the number of locations of electricity supply interruptions [3]. During the public planning phases of new energy infrastructure, discussion about impacts often focus on the local environment, e.g. impact on the landscape. The merits of new energy infrastructure, such as wind farms or transmission lines, also include the provision of a reliable power system, which is important for business and society, and facilitating the transition to a low carbon power system.

3. The 70% renewable electricity target for 2030 includes the implicit target that conventional (thermal) gener-ators will provide up to 30% of electricity by 2030. Consequently, as electricity demand increases, it is likely that new conventional generation capacity may be necessary, including for security of supply and system inertia reasons. The decommissioning of old inefficient thermal power generation stations (e.g. Moneypoint) and, where necessary, commissioning new thermal generation plant leads to lower system-wide electricity costs, beneficial to both businesses and households. The combined impact of decommissioning old inefficient plant and commissioning more efficient new plant, in many instances combined cycle gas turbines (CCGT), will make a significant contribution to the reduction in carbon emissions from the electricity system [3].

4. Generally, the level of generation investment increases nonlinearly in demand. With high renewable elec-tricity targets and as electricity demand increases, proportionally greater levels of (renewable) generation in-vestment is required to satisfy demand [5]. The growth in electricity demand from datacentres over the next decade is expected to be as much as 75% of total electricity demand growth and in aggregate, datacentres are expected to account for approximately one-third of total electricity demand by 2030. The nonlinear growth in costs is therefore exacerbated by datacentre demand. The location of existing and proposed datacentres is

concentrated primarily in the Dublin region, where network infrastructure is already under stress due to congestion. The strong growth in datacentre demand will continue to have an impact on the transmission system, as the location of the strongest demand growth is distant from the growth in renewable generation. Optimally locating new datacentres in a spatially dispersed manner around the digital (fibre) network will substantially reduce grid investment needs, with up to 39% reduction in network investment required in some instances [5]. Transmission system costs are ultimately borne by all electricity consumers. Transmission system costs driven by datacentre demand may therefore disproportionately burden other electricity customers [1]. To address these issues there is an arguable case that datacentres assume greater responsibility for transmission costs associated with datacentres and that new datacentres be located, or be incentivised to locate, at sites more optimal for the power system in terms of reducing congestion and lowering total system costs.

5. In addition to new large demand centres connecting to the network, more generally all new infrastructure connecting with the transmission network (e.g. wind, solar, and thermal generation, storage, electrolysers, etc.) have the potential to contribute costs, as well as, benefit the network. Research on optimal generation and transmission investment planning shows that the net impact of new infrastructure on the network varies by location [2–4, 6]. All else equal, network connections for new infrastructure should be prioritised or incentivised towards locations that deliver the greatest network benefits, whether reducing congestion, lowering system costs or providing system services.

6. To-date the Irish Single Electricity Market (SEM) design has performed well in a fossil fuel dominated energy sector but facilitation of a 70% renewable electricity target requires a redesign of the energy market. Lynch et al. [7] outlines general principles of good electricity market design in the context of a market with high levels of renewable generation:

   (a) Completeness across time, space, and externalities. This requires markets to have as high a spatial and temporal granularity as possible, without introducing other distortions (for example, market power). It also requires all externalities to be reflected in the market price. These externalities include not only the cost of carbon, but also whether a particular source of generation incurs extra costs or benefits on the system that fall on other producers and/or consumers (for example, flexibility or the ability to defer transmission investment).

   (b) Minimisation of cost. Electricity demand should be met at the lowest possible cost.

   (c) Minimisation of risk. Markets should be designed so as to remove as many sources of risk as possible and allow appropriate risk management for any remaining risk.

   (d) Allocation of risk to those best able to afford it. In the case of electricity, consumers are best able to bear risk, as they are far greater in number than producers, but the informational asymmetries between producers and consumers mean that strong regulation is required in order to ensure that producers manage their risk appropriately and do not simply shift all risk to consumers.

   (e) Compensation of fixed costs with fixed revenue streams and variable costs with variable revenue streams. Variable revenue streams in particular should be based on the marginal pricing principle.

   (f) Flexibility to respond to future events. Market design should recognise the considerable uncertainties that exist regarding future market outcomes and should be flexible to respond and evolve as necessary.

   (g) Co-optimisation of various market objectives to arrive at a global least cost solution. Equilibrium solutions that simultaneously arrive at the optimal level of energy, capacity, transmission, system services and emissions, where possible, are preferable to a solution that determines the optimal level of each independently.

7. Lynch et al. [7] also sets out options that may be considered for future market design, which are briefly summarised here. All options represent substantial change from current market design and necessitate comprehensive examination, research, and design prior to implementation to minimise unintended outcomes.

The nature of the marketplace is evolving and it is imperative that market redesign anticipates the evolving circumstances and establishes a framework for an efficient and equitable marketplace.

(a) **Move to a higher frequency of market dispatch**
Higher frequency of dispatch mitigates the potential source of inefficiencies arising from the mismatch in the balancing market between the dispatch and settlement periods. Such a design moves towards the principle of market completeness across time, allowing generators to naturally address the imbalances between supply and demand that arise on a sub-hourly basis. It also gives more opportunity to flexible generators and other market players such as interconnectors and storage operators: generators that can adjust their output at higher time frequencies have an advantage over generators that require more time to adjust their output.

(b) **Allow explicit compensation for flexibility**
Compensation for flexibility could address problems that manifest at hours of low or negative net demand, where there is arguably insufficient remuneration of demand flexibility which in turn leads to excess supply. Compensating flexibility respects the principle of market completeness by ensuring the demand side becomes a more active participant in the market.

(c) **Split markets at wholesale and retail level to allow consumers to choose between conventional and renewable generation.**
A more radical market redesign option is that electricity markets be split into an "on demand" market for dispatchable generation, and an "as available" market for renewable generation. The former clears in a manner similar to the current wholesale market, and provides price signals for demand response, as well as interconnector and storage operation. This option has many attractive features on a theoretical level, but would require a radical shift from the current market design and therefore a high degree of risk. There are also equity considerations, where lower income households cannot afford the scarcity prices that arise in the "on demand" market and may have to opt for the "as available" market. This would essentially split the market according to those who can and cannot afford the cost of a secure electricity supply. Substantial further research is necessary to investigate the feasibility of this option in the long run.

(d) **Switch renewable electricity subsidisation from an energy to a capacity basis**
At present, renewable energy auctions are held on the basis of a price per unit of energy produced. Compensating RES-E on the basis of capacity aligns RES's compensation with its cost structure, respecting the principle of providing fixed compensation for fixed costs, and reduces risk for both producer and consumer. This design option respects the principle of completeness of markets as the prices reflect true market conditions rather than distortions arising from a subsidy scheme.

(e) **Co-optimisation of system services procurement with energy and/or capacity procurement**
The provision of system services can impact on both investment and operational decisions by generators, and the revenue earned in various markets will also impact on generators' decisions in each market. Ideally, therefore, all three services would be procured using one joint mechanism.

(f) **Determine capacity requirement on the basis of improved risk criteria**
In the presence of high levels of variable generation, the new market design should enhance current risk assessment criteria. This supports the principle of minimisation of risk. Presently risk is measured through the Loss of Load Expectation (LOLE) and the Value of Lost Load (VOLL). Until now, in a system composed primarily of synchronous generators that provide enough inertia for fast primary response, planning only for the risk of forced outages was sufficient. But missing inertia and uncertainty in generation makes risk handling more complex. Fast ramping capacity, either up or down, will become crucial in the 2030 power grid. In a power system dominated by RES more sources of uncertainty will play a significant role. To keep the system reliable, avoiding extreme and undesirable events, market

design and planning must take into account both risk and uncertainty in all its forms. One way to maintain safe operation of the grid is by introducing new quantifiers of uncertainty into capacity markets.

(g) **Move away from volumetric charges for electricity generation and towards fixed or service type retail contracts**

Over time the cost base of the power system will move from one dominated by variable costs to one dominated by fixed costs. A natural consequence of this is a potential shift at the consumer level away from volumetric charges and towards fixed retail charges. Such a move respects the principle of compensating fixed costs with fixed revenues, and helps provide certainty for energy companies and reduce risk. Under this proposal, instead of paying per unit of electricity, consumers instead pay for electricity as a service, similar to the types of contracts available in the communications sector. Risk-averse consumers benefit from certainty in their energy bills. The major downside of this option is that it may undermine energy efficiency incentives and policy, consequently a strong regulatory response would be required to protect vulnerable consumers, and new mechanisms to incentivise energy efficiency.

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