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Abstract

This study evaluates the economic, environmental, and operational impacts of electricity load shifting in Ireland's Single Electricity Market (SEM). Using a PLEXOS-based fundamental modelling framework, demand flexibility is represented through a virtual battery to capture aggregated consumer response to dynamic price signals.

The results show that load shifting reduces total system generation costs, lowers CO_2 emissions, and improves system reliability by mitigating capacity tightness. These benefits arise from better alignment of electricity demand with periods of high renewable generation, reducing reliance on high-cost and carbon-intensive peaking units. However, increasing levels of load shifting reduce price spreads between peak and off-peak periods, potentially affecting investment incentives for storage technologies. The findings demonstrate that demand-side flexibility can play a key role in supporting Ireland's renewable integration targets and enhancing overall system efficiency.

1- Introduction

Ireland is pursuing an ambitious goal of achieving 80% renewable electricity by 2030. This presents the power system with significant challenges, not least due to the significant growth in electricity demand and increasing penetration of variable renewable generation. Specifically, the profile (or the hour-by-hour 'shape') of electricity demand is vital to achieving Ireland's targets. As the share of variable renewable generation increases, aligning demand more closely with periods of renewable supply becomes increasingly important. Effective demand management improves the utilisation of clean energy, and reduces renewable energy curtailment and hence, the reliance on fossil fuel generation during peak periods. This not only supports system reliability but also enhances the economic and environmental sustainability of the energy transition.

Electricity load shifting, the temporal reallocation of demand from peak to off-peak periods, offers a promising solution. This study aims to quantify the potential benefits by using a fundamental modelling framework via a virtual battery storage system as a proxy for the aggregated demand response. This approach assumes behavioural change in consumers' electricity consumption is achieved through economic incentives such as dynamic tariffs. This enables consumers to respond to wholesale price signals.

1-1- Objectives

The objective of this study is to quantify the system-wide benefits of electricity load shifting in Ireland, focusing on three key areas:

1. Economic impact: to assess the potential for load shifting to reduce the production cost within the wholesale market.
2. Environmental Impact: to evaluate the effect of load shifting on carbon emissions and renewable energy penetration.
3. Operational reliability: to analyse how load shifting can improve system adequacy and reduce intervals of capacity tightness.

To achieve these targets, the study employs a production cost minimisation modelling approach using ESB's electricity market fundamental model in PLEXOS. Fundamental modelling refers to the use of mathematical and computational techniques to simulate the physical and economic characteristics of the market. This approach incorporates key factors such as generation costs, demand profiles, fuel prices, and system constraints to produce realistic market forecasts. It enables a detailed analysis of how load shifting, renewable integration, and consumers' behaviour influence Ireland's electricity market and makes it possible to quantify economic, environmental, and operational impacts.

The electricity market in the Republic of Ireland and Northern Ireland operates as a single market known as the Integrated Single Electricity Market (ISEM). Hence the scope of this study covers the ISEM, i.e., the island of Ireland.

2- Potential Scale of Demand Flexibility

Ireland has set targets for demand flexibility of 20–30% by 2030. This corresponds to a theoretical peak reduction of 1,200-1,800 MW at current peak levels. Realistically, 200–500 MW of peak reduction is achievable, depending on program participation, automation, and market design. ESB Networks, directed by CRU, is procuring up to 500 MW of demand flexibility by 2030, with flexibility providers contracted to deliver reductions or load shifting for at least four hours daily during evening peaks. However, it is important to note that this study excludes ESB Networks' 500MW programme from the model, to avoid any potential 'over-provision' of demand flexibility within the base model.

The demand flexibility requires demand reduction in four hours per day mainly during winter evenings. The system impact includes flattening the peak load, reducing the reliance on the costly peaking generation, mitigating supply risks, deferring network upgrades, and lowering renewable curtailment and carbon emissions.

In summary, Ireland's practical peak load reduction potential is estimated at 200–500 MW over 4-hour peak periods, with shifted demand redistributed across an 8-hour off-peak window.

3- Modelling Methodology

This study employed a least generation cost modelling approach using ESB's ISEM fundamental model in PLEXOS. The Base Scenario is used as a baseline for assessing the impact of load shifting, which is represented by a virtual battery storage system within the model.

A virtual battery is used to model the load shifting because aggregated flexible demand (e.g., EV charging, electric heating/hot water, smart appliances, and deferrable industrial processes) behaves like a resource that is power-limited, energy-constrained, and time-coupled. These are

the same core characteristics of battery storage technologies. By modelling this flexibility as a battery, the model can co-optimise "charging" (increasing demand in low-price/high-renewables periods) and "discharging" (reducing demand during peak/scarcity periods) enforcing the familiar constraints of batteries such as MW and MWh limits, availability windows, and energy neutrality (i.e., demand is shifted rather than reduced overall). This approach is widely used in production-cost tools because it provides a tractable, low-complexity way to quantify system-wide impacts of load shifting on production costs, renewable curtailment, emissions, and reliability, while acknowledging that real load shifting differs from physical batteries (notably through variable "round-trip efficiency" and comfort/process constraints).

The virtual battery round-trip efficiency is modelled as 100%. In this framework, the "battery" is not storing energy physically. It is re-timing the same underlying electricity service (e.g., heating, cooling, EV charging) within a defined window subject to energy-neutrality constraints (often daily). This indicates the model represents pure shifting, not net energy reduction.

Based on the potential scale of load shift in Ireland, three cases (100, 300 and 500 MW) are assessed against the Base Scenario for 2030 and 2035. In addition, to closely represent the requirements of temporal windows, the virtual battery is optimised to reduce demand over a 4-hour window during peak hours, whilst the shifted load is consumed over an 8-hour window during off-peak hours. Table I presents the assumed system generation capacities used in the modelling for 2030 and 2035.

	2030	**2035**
SEM system demand (TWh)	50	55
Offshore wind capacity (MW)	675	4,724
Onshore wind capacity (MW)	7,657	8,123
Solar (MW)	4,151	5,391
Battery storage system (MW)	1,027	1,027
Gas generation capacity (MW)	7,918	8,216

Table I. Key assumptions in the Base Scenario

3-1- Key Considerations

Battery Storage Proxy

In power system modelling, load-shifting demand response is often represented using a battery storage proxy due to their shared ability to shift energy across time. This approach simplifies the modelling and produces reliable results, provided that coordination across flexible resources is achieved. The last point might not be experienced in practical applications. This indicates while the battery proxy offers modelling simplicity, it may misrepresent the true impacts of load shifting, especially for thermal loads. More detailed modelling or sensitivity analysis are recommended. The results of this study can be looked at as an upper-bound on the load shifting positive effects.

Wholesale Price Dynamics

Consumers who participate in load shifting clearly benefit when their behavioural changes are driven by wholesale price signals. However, the wholesale price effect of load shifting can be

uncertain. The wholesale electricity market is operated on a marginal pricing basis. This means the electricity market reduces peak prices by lowering the demand during high-cost periods but can increase off-peak prices if the shifted demand increases the marginal cost. In other words, depending on specific conditions, the average wholesale price could be lower or higher with load shifting. This might expose non-participating consumers to higher wholesale electricity cost.

For this reason, this study uses total generation cost as the key economic benefit measure. The total generation cost refers to all variable costs, e.g., fuel, carbon credit, and variable operation costs, incurred by all producers in the market.

4- Modelling Results

1. **Total generation cost savings:**

The total system generation costs for all scenarios are presented in Table II. The results show that load shifting reduces total system generation costs by avoiding the commitment and dispatch of higher-cost generation units during peak demand periods.

Cases	**2030**		**2035**	
	€'000	Reduction vs Base (%)	€'000	Reduction vs Base (%)
Base No LS	576,616	NA	235,007	NA
100 MW LS	571,522	0.9	229,426	2.4
300 MW LS	559,893	2.9	216,156	8
500 MW LS	548,528	4.9	208,539	11.3

Table II. Total system generation costs

On the demand side, a share of customers participating in load-shifting programmes can achieve a reduction in their electricity costs. Table III reports the total cost savings obtained for maximum daily load-shifting capacities of 400, 1,200, and 2,000 MWh. Given the demand is being rescheduled from 4 peak hours to 8 off-peak hours, these energy capacities result in load increases of 50, 150, and 250 MW, and load reductions of 100, 300, and 500 MW, respectively.

The results show that, although higher load-shifting capacities lead to increased total cost savings, the savings per shifted MWh decline as the available load-shifting capacity grows. This trend reflects the cannibalisation effect of load-shifting, whereby increased participation progressively reduces marginal economic benefits due to the narrowing price spread between peak and off-peak periods.

Since the load-shifting capacity considered in this study represents the maximum allowable energy that can be shifted per day, the system does not necessarily utilise the full available capacity on all days. Depending on system conditions and price signals, a smaller portion of the load-shifting capacity may be sufficient to achieve cost minimisation in some days. Consequently, the results indicate that increasing the daily load-shifting capacity does not translate into a linear improvement in system performance indices, as the marginal value of additional flexibility diminishes beyond a certain capacity level.

Cases	2030		2035	
	Cost saving (1000 €)	Saving per MWh of shiftable load	Cost saving (1000 €)	Saving per MWh of shiftable load
Base No LS	-	-	-	-
100 MW LS	5,886	14,700	7,079	17,700
300 MW LS	16,273	13,600	19,718	16,400
500 MW LS	24,324	12,200	30,198	15,100

Table III. Total and Marginal Cost Savings Associated with Load-Shifting Capacity

2. CO_2 Emissions:

Table IV shows that increasing levels of load shifting leads to a consistent reduction in total system CO_2 emissions in both 2030 and 2035. These reductions are driven primarily by changes in the generation mix rather than from any reduction in total electricity demand. By shifting demand away from peak hours, the system relies less on fossil-fuel-based peaking generators, particularly from open-cycle gas turbines, and instead serves greater demand during off-peak periods when less carbon-intensive generation, e.g., renewables, is more readily available.

Cases	2030		2035	
	Tonne	Improvement vs Base (%)	Tonne	Improvement vs Base (%)
Base No LS	3,370,408	NA	1,793,662	NA
100 MW LS	3,353,046	0.5	1,777,885	0.9
300 MW LS	3,314,832	1.6	1,741,558	2.9
500 MW LS	3,275,881	2.8	1,719,465	4.1

Table IV. Total CO_2 emissions in the SEM

3. System security:

The Loss of Load Expectation (LOLE) is a key index used to assess power system reliability. It represents the expected number of hours per year during which the system may be at risk of not meeting the demand because the available generation capacity is insufficient.

In 2030 and 2035, the system needs higher thermal/battery capacity than it does in 2026. With that additional capacity added to the system, the reliability is guaranteed even in the base case and the load shifting programmes might not be relevant to reliability improvement. In the previous sections we assumed that the system is upgraded properly in terms of thermal and battery capacities. However, in practice, in 2030 the system capacity could be tighter.

In the study, it is assumed that no new thermal/battery capacity is added over the study horizon (the renewable capacity has increased to the expected levels), and hence, the system

experiences hours with loss of load. Therefore, the LOLE is higher than the standard level that is targeted by the system operators. In practice the system could not be as tight as it is assumed in the base case, and it is important to focus on the difference between the sensitivity case versus the base case, rather than the absolute figures. The resulting LOLE values, expressed in hours per year, are presented in Table V. The results demonstrate that the implementation of load-shifting strategies can significantly improve system reliability materially, as reflected by a reduction in the LOLE index.

Cases	2030	2035
Base No LS	162	567
100 MW LS	135	540
300 MW LS	108	459
500 MW LS	81	432

Table V. LOLE (Hour/Year)

Conclusions and Future work

This study demonstrates that electricity load shifting can deliver meaningful economic, environmental, and operational benefits to the Irish power system under high renewable penetration. Representing aggregated demand flexibility through a virtual battery provides a practical framework for assessing system-wide impacts. The modelling shows that shifting demand from peak to off-peak periods reduces total system generation costs, lowers carbon emissions, and improves system reliability. However, considerations should be given to the cannibalising effect on the market, which could weaken the business cases for the actual grid-scale battery storage systems. Overall, demand-side flexibility that can be achieved through behavioural changes is a valuable complement to renewable generation and storage in supporting Ireland's decarbonisation and security-of-supply objectives.

Despite these insights, several important aspects remain outside the scope of this study and warrant further investigation. Future work should extend the analysis to capture broader market and behavioural dynamics associated with load shifting. In particular, the impact of large-scale demand flexibility on capacity market outcomes and long-term generation investment signals should be assessed, especially in systems with evolving adequacy requirements. In addition, the interaction between load shifting and battery storage development merits deeper examination, including potential competitive and complementary effects under different market conditions.

Finally, incorporating more realistic representations of customer behaviour—such as participation rates, responsiveness to dynamic price signals, and heterogeneity across demand segments—would improve the robustness of the analysis and provide a more accurate reflection of the practical effectiveness of load-shifting programmes.