Modelling of a Large Number of Electric Vehicles (EVs) in the All-Island Ireland Energy System

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This study considers the effects of Electric Vehicle (EV) uptake on power generation in all-island Ireland. A detailed power dispatch model of Ireland is used to simulate the operation of individual generating units which are dispatched on an hourly basis to meet demand given constraints on generation, plant operation, fuel use and emissions. The analysis demonstrates the effect of EV charging on electricity demand and wholesale electricity prices in Ireland. The use of managed charging strategy is considered as a way of shifting the EVs charging load from peak hours.

Keywords: power dispatch modelling, electric vehicles, managed charging, electricty price forecast

I. INTRODUCTION

Light vehicles (gross weight less than 3.5 tonnes) are major contributors to the CO_2 emissions and urban air quality. Efforts to reduce emissions from transport include electrification of light vehicles. A wider introduction of plug-in Electric Vehicles (EV) in the next two decades will have an impact on energy systems in many countries. This comes both as an opportunity and as a challenge, particularly for relatively small energy systems with high penetration of renewable generation. The aggregated battery storage created by a large number of EVs can be beneficial to the grid as it can help to balance the intermittent renewable generation. On the other hand, the load from charging a significant number of EVs simultaneously can create an additional strain on the grid.

All-island Ireland (referred as Ireland further in the text) has one of the highest penetration of intermittent generation – the installed capacity of wind generation constitutes around 27% of the total capacity [1]. EirGrid Group, the transmissions system operator (TSO) in Ireland, expects up to 560 000 EVs (in Consumer Action scenario) on the road in 2030 [2]. A typical battery pack has the capacity of 24 kWh. Thus, plugged into a 7.4 kW domestic charger, EVs have a potential to create an aggregated storage of 13.4 GWh and an additional load of 4.1 GW in 2030. This translates into ca. 14% of the current average daily demand and 60% of the peak load in Ireland.

This study demonstrates the effect of EV uptake and charging strategies on the entire power system in Ireland. Specifically, it considers the economic benefits of managed charging that has been shown to reduce system load during peak hours in a similar study of the Australian power system [3]. The focus of the modelling exercise is on the economic aspects of generation on a country level. It is acknowledged that transmission network considerations on a local level, such as additional load on low voltage networks, are important for successful EV integration. However, this is out of scope of this research.

II. METHODOLOGY

A. Model inputs

The impact of EV integration on electricity prices is modelled with a detailed plant-level power dispatch model of Ireland using Energy Exemplar Plexos fundamental market modelling framework [4]. The model simulates the operation of individual generating units which are dispatched on an hourly basis to meet demand given constraints on generation, plant operation, fuel use and emissions.

For this analysis, all dispatchable thermal and hydro power plants in Ireland are modelled as individual units, while wind and solar farms are aggregated. To capture the power flows between Ireland and Great Britain, the latter is also included in the model with all generators aggregated by owners. Transmission between Ireland and Great Britain is modeled through Moyle and East-West interconnectors using the physical capacities of these transmission lines. The key generator properties in the model are listed in TABLE I.

The model dispatches thermal and hydro units considering system constraints. The constraints that ensure synchronization between Republic of Ireland and Northern Ireland, as well as overall system stability, are included in the model. The constraint on maximum wind generation, i.e. wind curtailment, is also observed.

Future hourly demands in Ireland and Great Britain are calculated using regression analysis to establish a relationship between historic annual demand in three sectors (industry, households & services and transport) and economic indicators, plus temperature. Oxford econometrics values for population growth and Gross Domestic Product

(GDP) are used for these projections. Demand and peak load in Ireland are shown in Figure 1.

TABLE I. KEY GENERATOR PROPERTIES

Category	Key modelling parameters
Thermal	Max Capacity, Min Stable Level, Heat Rate (3 bands), Start Cost (3 bands), Max Ramp Up/Down, Firm Capacity, Maintenance Rate, Forced Outage Rate, Mean Time to Repair, Variable Operating and Maintenance Charge
Hydro	Max Capacity, Min Stable Level, Firm Capacity, Maintenance Rate, Forced Outage Rate, Mean Time to Repair, Variable Operating and Maintenance Charge, Max/Min Head Reservoir Volume, Natural Inflow
Wind and Solar	Max Capacity, Firm Capacity, Rating Factor

The current focus in the Irish power sector is on the expansion of renewable generation. Therefore, the model includes projections for renewable generation capacity. The largest capacity addition is expected to come from new wind farms capacity increase from the current 3.5 GW to 5.9 GW in 2030.

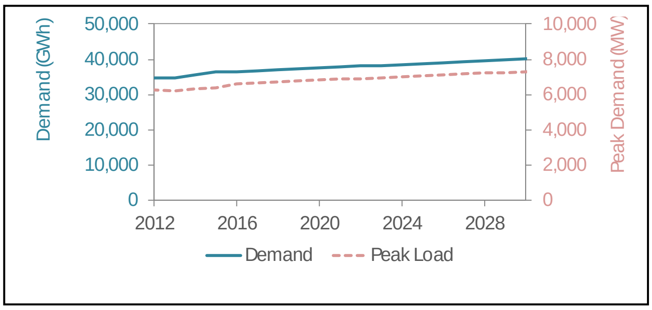

Figure 1. Modelled demand (solid, left axis) and peak load (dashed, right axis) in Ireland

TABLE II. INSTALLED CAPACITY IN IRELAND BY CATEGORY

Category	Capacity in 2017 (MW)	Capacity in 2030 (MW)
CCGT	4438	5238
Steam (Coal)	1331	0
Steam (Gas)	598	0
Steam (Oil)	594	0
Steam (Biomass)	174	396
OCGT	1352	562
Hydro (Pumped)	292	292
Hydro (River)	251	251
Solar (PV)	11	3848
Wind (On-shore)	3499	5519
Wind (Off-shore)	25	455

A number of thermal power plant units in Ireland are expected to be decommissioned by 2023 due economic considerations and the requirement to comply with the Industrial Emissions Directive (IED). This is captured in the model and will affect the following power plants: Aghada Open Cycle Gas Turbine (OCGT), Marina OCGT, North Wall OCGT, Ballylumford OCGT, Talbert Steam Turbine (Oil) and Kilroot Steam Turbine (Coal). Thermal unit additions are modelled to meet 10% reserve margin in the region (not considering the load from EVs). On that basis, one new Combined Cycle Gas Turbine (CCGT) and another OCGT unit are added to the model in 2024. The total modelled capacities by generator category in 2017 and 2030 are shown in TABLE II.

B. *Simulation parameters*

The model uses Xpress-MP engine to determine the least cost dispatch of generating resources to meet the power demand by solving a mixed integer problem. Plexos modelling framework has been chosen for this study because this is the tool that the Regulatory Authorities in Ireland use for forecasting market outcomes [5].

C. *Electric Vehicle modelling*

The uptake of innovative technologies often can be characterized by an S-shaped or sigmoid curve that has three stages [6]. In the first stage, early adopters start using the technology and the uptake rate is relatively low until the second stage of wider adoption is reached. At this point, the rate of the uptake is the highest. The third stage is again characterized by a slow increase in the number of users. The S-shape approach has been applied to calculate the number of EVs in Ireland between now and 2030, as shown in Figure 2. The final number of EVs on the roads in 2030 is taken from the Consumer Action scenario in EirGrid report [2]. The key narrative for Consumer Action scenario is that strong economy leads to high levels of consumer spending ability and the public wants to reduce GHG emissions.

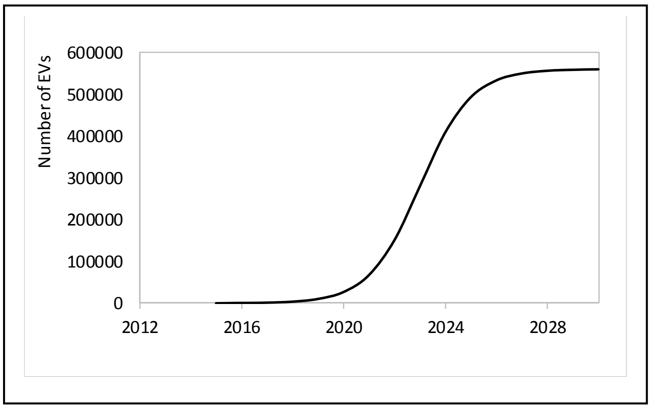

Figure 2. Modelled uptake of EVs in Ireland

Each EV battery in the model has the capacity of 24 kWh, based on Nissan Leaf 2015 model. Although the average EV battery capacity may increase overtime, the large batteries are less likely to require daily charging. Therefore, the overall effect is similar if the size of the battery pack is kept constant and daily charging is assumed. The charging power is modelled as 7.4 kW with 95% charging efficiency, based on a single phase domestic EV charger. It is assumed that all EVs are charged to 100% by 7am and are depleted to 20% every working day. It is acknowledged that it is unlikely that all EVs will be discharged to 20% every day. However, such a situation represents the worst-case scenario and this assumption is appropriate for demonstrating the maximum impact that EVs can have of the grid.

Two charging strategies are modelled. In the case of Standard charging, EVs can charge from 5pm to 11pm emulating the situation when they are plugged in the evening and start charging at once. In the case of Managed charging, the window available for charging is increased to 5pm till 7am and the model optimises charging patterns to achieve the minimum total system cost solution. In both cases, charging can be paused and then resumed within the allowed timeframe for charging.

The model has been calibrated using historical electricity prices sourced from SEM-O [7]. Historical and modelled electricity prices in Ireland, averaged monthly, are shown in Figure 3.

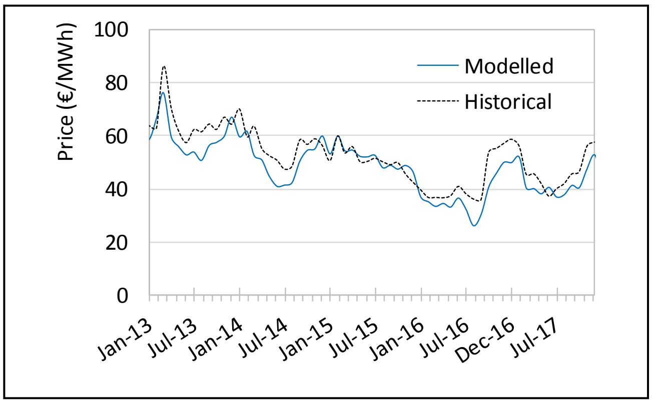

Figure 3. Calibration of the modelled electricity prices using historical data

III. RESULTS

The modelled number of EVs remains relatively small up to 2020 and a significant uptake is modelled between 2020-2025 as shown in Figure 2. Therefore, it is instructive to look at the modelled system load on a typical week in 2025 first, to discuss the effect of a large number of EVs on the system. The modelled load with hourly resolution for the week starting on 03/02/2025 is shown in Figure 4. for three separate cases: a) there are no EVs connected to the grid (No EV uptake); b) EVs can charge between 5pm to 11pm (Standard charging); c) EVs can charge between 5pm to 7am (Managed charging).

In the absence of EVs in the Irish power system, the load between 12pm and 7am is reduced to almost half of the daily peak load. In the case of Standard charging, EVs are expected to charge as soon as they are plugged in the grid at the end of the day and be at full charge by 12pm. This charging pattern exacerbates the load on the system during peak hours and does not take the advantage from the low demand at night as shown in Figure 4.

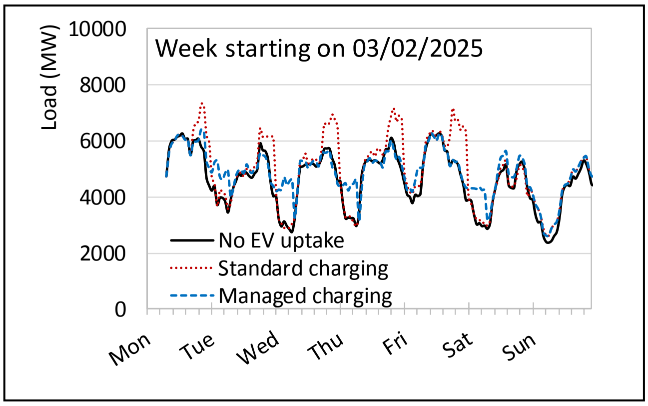

Figure 4. Total system load in ireland between 03/02/2025 and 10/02/2025 for a) No EV uptake, b) Stardard and c) Managed charging

Conversely, the Managed charging approach helps to avoid additional load during peak hours by shifting the EV load to periods of low demand as shown in Figure 4. The main advantage of this is that the start of expensive and less efficient peaking power plants can be avoided more often. For example, wind generation on 04/02/2025 was forecasted to be low (based on a historical profile used in the model) and several OCGT power plants had to come on-line to meet extra load from EVs during peak hours in the Standard charging case. In the case of Managed charging, the additional load from EVs was distributed during off-peak hours and did not require additional generation from peaking plants in this case.

The additional load from a large number of EVs can have a significant effect on electricity price and thus the total cost of electricity to end-user. To estimate this impact, it is instructive to look at the total annual cost of electricity to load, net of EV charging load cost. This metric is shown in Figure 5. along with the wholesale electricity prices. The modelling results indicate that there is an increase in the wholesale electricity prices with both the Standard and Managed charging approaches. The increase is smaller if Managed charging is deployed: the price in 2025 is €50.8/MWh without EV uptake, €61.5/MWh in the case of Standard charging and €59.4/MWh in the case of Managed charging.

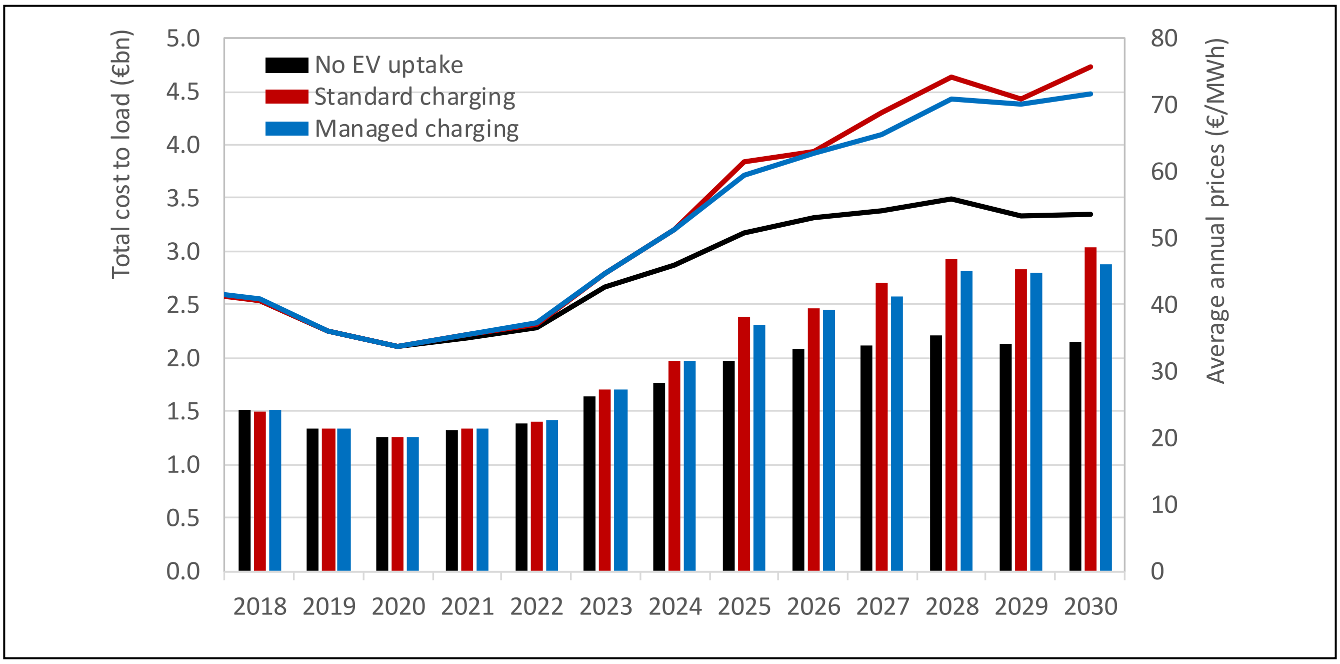

Figure 5. The total cost to load (net of EV load) and average load-weighted wholesale electricity prices modelled with a) no EV uptake, b) EV uptake with Stardard and c) EV uptake with Managed charging

Equally, the total cost to load in Figure 5. start to become noticeably higher from 2023 as the number of EVs in the system becomes larger than 300000 units. The increase is smaller if Managed charging is deployed: the total cost to load in 2025 is €1.97bn without EV, €2.39bn in the case of Standard charging and €2.30bn in the case of Managed charging. These numbers exclude the cost of EV charging and demonstrate the repercussions of additional load from EVs to the customers. The relative increase of the cost to load is 20.9% in 2025 and up to 41% in 2030 if the charging is not managed. The corresponding figures for the case of Managed charging are 16.8% in 2025 and 33.5% in 2030. This is a significant increase in wholesale electricity prices that needs to be considered when planning the integration of EVs into the power grid.

Apart from causing price increases, the load from EVs may cause the average CO_2 intensity of the grid to change. This has been modelled and the results are shown in TABLE III. These data suggest that the potential impact of the EVs on the grid CO_2 intensity is marginal, given the assumptions made on the number of EVs and the charging patterns. The Managed charging results in a slightly lower CO_2 intensity compared to the Standard charging case. A slight increase in the grid CO_2 intensity between 2020 and 2025 is due to increased generation from Moneypoint coal power plant that displaces some of the gas generation following the forecasted increase in natural gas prices. Generation from coal is eliminated by 2030 as the emission prices are increased rendering coal generation uneconomic.

TABLE III. AVERAGE INTENSITY OF THE ALL-ISLAND ELECTRICITY GRID IN KGCO_2/MWH

	2020	2025	2030
No EV uptake	256	269	193
Standard charging	256	273	199
Managed charging	256	271	195

IV. CONCLUSIONS

It has been shown that the EV uptake has a potential to substantially increase the wholesale electricity prices and the cost of electricity to load in Ireland. The increase in these metrics becomes noticeable when the load from EVs is relatively large compared to the total load on the system, at around 300000 EVs in the case of Ireland. All power system customers will bear the increased cost of electricity and therefore any policies around the integration of EVs into the power system need to take this into account. The increase in the cost to load was found to be reduced when Managed charging strategy was employed. This is achieved by shifting EV load to the night hours when the demand on the network is lowest.

The effect on grid CO_2 emissions was found to be marginal with both Standard and Managed charging.

Finally, it is acknowledged that EV have the potential to reduce the cost of generating electricity if used for system balancing. Thus, Vehicle to Grid (V2G) operation should be the next step in analysing the impact of EVs on the power system in Ireland.

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