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One Year of I-SEM: Preliminary Assessment of Capacity Mechanism Outcomes

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Abstract

The aim of this paper is to assess the outcomes of the Reliability Options scheme for Capacity Mechanism, as implemented in the Integrated Single Electricity Market in Ireland (I-SEM). This research leverages econometric and data handling techniques to provide evidence over the effectiveness of this scheme in terms of system reliability, as well as to help understanding the functioning and potential best practices for early adopters of a technically complex and sophisticated market solution and derive potential policy implications. The originality of this contribution is given by the regional focus, as well as the inclusion of the time dimension, by modelling three different datasets (Full, Ante I-SEM and Post I-SEM), and by adding specifications of fundamental variables related to the electricity system.

Keywords: Electricity Market; Electricity Regulation; Capacity Mechanism; Capacity Payment; Reliability Options

JEL Classification: Q41, Q47, Q48

1. Introduction

The remuneration of capacity is one of the current most pivotal challenges in the regulation and development of electricity markets. The steady process of de-carbonisation and the deployment of intermittent renewable energy sources calls for the creation of a diversified and flexible system to meet peak demand. Concerns arise about the opportunity to guarantee an adequate level of investment in conventional, dispatchable generation capacity, whereas renewables often enjoy incentive schemes (feed-in tariffs, feed-in premiums, green certificates, priority dispatching) matched with competitive marginal generation costs. Virtually all EU Member States have introduced remuneration schemes for making capacity available in the form of capacity mechanisms. Essentially, generators are not only paid for the energy they produce, but also receive a remuneration for being available to produce and assure the system's operational reliability. This reliability is twofold and generally declined in system adequacy and system security. System adequacy encompasses the long term, and has two components: the ability of the generation assets to serve the peak load, given the uncertainties in the generation availability and the load level; and the capability of the transmission network to regularly function, with the flexibility provided by interconnection and import and export flows. Roques (2008) highlights how generation adequacy can be further separated into three different dimensions: (i) the provision of an optimal level of generation capacity at the equilibrium consistent with socially optimal system reliability design criteria; (ii) the choice of the ideal timing of investment to reduce the length of investment cycles and the transitory adjustment periods; and (iii) the selection an optimal mix of different generation technologies, taking into consideration both the load profile (mix of baseload, mid-merit and peaking units) and the fuel inputs. Conversely, system security deals with short-term operational integrity, generally managed by the system operator in real time via the provision of ancillary services and the activation of reserves, in order to prevent outages or equipment failure, with the goal to ensure quality of supply in safe conditions (Battle and Arriaga, 2008)

Capacity mechanisms are considered a regulatory tool to support system adequacy in a scenario where a growing injection of non-programmable/dispatchable renewable generation is steadily increasing the risks to the system. However, capacity mechanisms are also deemed problematic as a potential market distortion, because of the remuneration assigned to conventional (i.e. generally thermal) generation, which is usually paid for by final users. Moreover, purely national mechanisms are not as cost-effective compared to the ones that allow for cross-border participation, and this requires a certain degree of integration. The second most relevant concern is to guarantee an adequate level of incentives to replace existing generation technology and improve the overall energy mix, by taking into consideration the pan-European targets in terms of decarbonization and the system reliability. Dispatchable plants are the most adequate and flexible to provide back-up capacity, but at the same time require a diverse fuel mix to be factored in.

At the same level how likely are capacity mechanisms to impact market security and operations in the short-medium term? Is it possible to quantitively gauge the effects of their roll-out? The scope of this paper is to assess a specific model of capacity mechanism, the so-called reliability options, as outlined by the first example currently being pursued within the EU: the recently launched regulation within I-SEM (Integrated Single Electricity Market) between the Republic of Ireland and Northern Ireland (politically part of the United Kingdom). The reliability options scheme is a particularly interesting one as it envisages a less “invasive” degree of market manipulation, while at the same time vehiculating market information and setting a measurable a cap on electricity spot markets. The I-SEM went live in October 2018, and it is already possible to assess the very preliminary outcomes of the market reform according to specific metrics. To the best of the author’s knowledge, the novelty of this contribution sits on the use of historical data and econometric modelling techniques to derive market assessment and potential policy implications for the Irish market, whereas past approaches relied on market simulation techniques and fundamental inputs. Schwenen (2015) used a similar empirical method to model the outcomes of strategic bidding in the New York capacity market, but his analysis was not focused in terms of impacts on reliability.

2. Capacity Mechanism Models

As evidenced by Statnett (2015), there are essentially two approaches to cope with the challenges of increasing amounts of intermittent renewables. (i) Capacity markets, where capacity is secured by giving thermal (or dispatchable) power plants and other capacity providers the necessary income, via designated market mechanism or external auctioning processes. and (ii) energy-only markets, where thermal (or dispatchable) power plants and other suppliers of flexible generation will receive income from the day-ahead and balance markets alone. The market forces will find a balance between thermal production and inputs from load shifting, energy storage and load shedding. The Statnett's study however argues that energy-only markets might achieve higher prices during periods with minor contributions from renewables. Over short periods, the power prices may reach several thousand €/MWh, several times above the marginal generation technology. Possible explanations are: expensive gas turbines must be started more frequently; idle costly capacity can participate in the day-ahead market, and demand with a high willingness to pay for electricity sheds load voluntary and sets the price at the Value of Lost Load (VOLL).

There is a relevant literature hinting to the so-called "missing money problem" characterizing energy-only markets as initially assessed with regard to power markets in the eastern United States by Cramton and Stoft (2006), Joskow (2008) and more recently Brown (2018). Essentially, the key findings are that when demand is at or near its peak level and generating capacity is fully utilized (i.e. all capacity available on the system is needed to supply energy or ancillary services), prices for energy and ancillary services would rise to clear the market consistently with network reliability. Specifically, wholesale prices would increase to reflect the opportunity cost of a network failure or the VOLL. In practice, in most of the markets and due to technical reasons, these prices do not rise fast or high enough to clear the market and maintain network reliability, and some other non-market measures are adopted instead. This implies a relevant amount of peak generating capacity on an efficient system is "in the money" to generate electricity for only a small fraction of the hours in the year, just standing ready to meet low-probability high-demand contingencies. These generators must earn all their net revenues (revenues net of fuel and operating costs) required to cover their investment costs during these few critical hours. To achieve this, energy and ancillary service prices must be relatively high during these hours in energy only markets to foster investment in generation consistent with the reliability criteria imposed on system operators. This "missing money" issue therefore triggers unfavorable conditions to support the efficient quantity and mix of generating capacity.

In practice, many capacity mechanism options require the pairing of a capacity market to the existing energy market. In an energy-only market, the adequacy problem cannot be efficiently solved. Therefore, in order cope for adequacy and avoid market distortions, several models have been engineered and adapted to the specific market situations.

2.1. Economics of Capacity Mechanism

Customers receiving electricity wish not to be disconnected even if supply is scarce and hence some customers may be willing to pay more to get served even in times of scarcity. This is the so-called Value of Lost Load (VOLL), measured in €/MWh and expressed as a customer damage function:

$$VOLL\ (€/kWh) = f\ (duration,\ season,\ time\ of\ day,\ notice) \quad (1)$$

Of course, the VOLL is an engineering model that determines the value of unavailable capacity rather than the actual price customers are willing to pay. It functions as a price cap on the spot market. If capacity is scarce and demand is only little above supply, the electricity price spikes in order to reduce load to the available supply. The probability to reach these prices is the Loss of Load Probability (LOLP). To calculate and estimate LOLP the electricity mix, load forecasts and probabilities of forced outages needs to be taken into consideration. Table 1 in Appendix, taken from the "Final Report of the Sector Inquiry on Capacity Mechanisms" (2016) by the European Commission, provides an overview of the price caps set up in organized wholesale markets. When VOLLs are not fixed at regulatory level, their quantification is the result of computational models based on ex-ante expectations or ex-post historical observations, declined over the existing technology of the generation mix. As noted by Finon and Pignon (2008), policy makers identified and selected a LOLP that equated the mathematical expectation of the VOLL with the long-term marginal cost by an additional peak unit, after having determined the mean VOLL from sector inquiries. The rationale behind is that prices can reach extremely high levels, ultimately set by demand and very far from the marginal cost of a peak generator, over several yearly price spikes, for investments in capacity to be fully recovered. This, however, raises two problems. On one hand, such high prices are difficult to accept, socially and politically, since the transfer of surplus toward generators implied is perceived as excessive during the periods of peak pricing, and therefore price caps are often envisaged in the wholesale market. These price caps often represent only a small fraction of the speculative value of VOLL. On the other hand, the timeframes required for licensing and for commissioning force agents to strategic bidding to avoid under capacity in peak and long periods, thus triggering potential issues in achieving the market equilibrium, with high probability of load shedding.

In the specific capacity remuneration mechanism called Capacity Payment (CP), this value is computed ex post on an hourly basis and equated to the expected social gain of avoiding Loss of Load less the expected revenue (Roques, 2008). The expected revenue is proxied by the System Marginal Price (SMP), see Finon and Pignon (2008):

$$CP = (LOLP\ x\ VOLL) - SMP \quad (2)$$

If the generating facility is not dispatched, the system marginal price cannot be used as a reference for the expected revenue. In that case, the plant's bid price is used:

$$CP = (LOLP \times VOLL) - bid\ price \tag{3}$$

Obviously, the equilibrium capacity price should be low, if not zero, during periods of excess capacity and should rise with capacity becoming scarce. The increasing payments therefore stimulate generating companies to invest in more peaking units. However, the system is very vulnerable to the exercise of market power. As an ex post determination with these parameters is easily predictable, generators can withhold their capacity or bid inadequate hourly offers in order to increase LOLP and thereby benefit from higher capacity payments as well as from increasing prices on the market. Another difficulty is that the regulator needs to estimate LOLP and VOLL correctly because an overestimation of either of these parameters leads to artificially increasing capacity payments which in turn may result in overcapacity and social inefficiency.

2.2. Models of Capacity Mechanism

The European Union envisages an important decommissioning of thermal capacity to meet its 2030 targets adopted by the European Council in 2014: (i) 40% cuts in greenhouse gas emissions (from 1990 levels); (ii) 32% share for renewable energy and (iii) 32.5% improvement in energy efficiency. According to Statnett (2015), around 150 GW of thermal capacity will be decommissioned over the next 20 years due to lifetime expiration and regulations, while at the same time investments in new capacity are seriously challenged as not profitable, particularly with regard to new flexible gas power plants. On this basis, several countries have already introduced capacity markets where sufficient capacity in the power system is secured by giving thermal power plants and other capacity providers necessary income outside the energy markets. The alternative, energy-only, is to allow the day-ahead and balancing markets to find an equilibrium without using subsidies, but preferably with a strategic reserve outside the ordinary energy market to ensure sufficient security of supply. There is evidence that, in a capacity market, a low required capacity margin and a high level of participation from consumers (demand side management) would equal in outcomes an energy-only one, where load shifting, load shedding and demand response integrate price movements in remunerating capacity.

The European Commission set ambitious targets within the deadlines of 2020 and 2030 for each specific member state regarding the share of generation from renewables and the improvements in greenhouse gas emissions and energy efficiency. No figures are expressly specified in terms of level of capacity adjustments, and decisions are left to the single legislators of the member states. The Commission in 2014 issued the “Guidelines on State aid for environmental protection and energy for 2014-2020”, introducing theoretical frameworks as well as state-of-the-art models, but no quantitative targets were set. The report mentioned a study commissioned by Cowi stating how 14 EU countries were likely to have a reserve margin below 15% in 2020 if no new investment in dispatchable plants would have taken place. By 2030 all member states except three could experience reserve margins below 15%, with very acute needs in the decade 2020s.

There is no single European best practice concerning capacity remuneration mechanisms, as each country adapts to the specific features of its internal market. The Commission adopted in November 2016 the "Clean Energy For All Europeans" package and the following revised renewable energy directive 2018/2001/EU to foster renewables, but no goals are set at EU-level, leaving the decision on reserves and/or capacity mechanisms to the National Energy and Climate Plans (NECPs). The recast Regulation 2019 of 5 June 2019 "On the Internal Market for Electricity" labels capacity mechanism as "market distortive measures" and assigns the ENTSO-E (European Network of Transmission System Operators) the task to "*carry out a robust medium to long-term European resource adequacy assessment to provide an objective basis for the assessment of adequacy concerns.*" . The provision also stresses the temporary nature of capacity mechanisms that "*should not result in overcompensation, while at the same time they should ensure security of supply. In that regard, capacity mechanisms other than strategic reserves should be constructed to ensure that the price paid for availability automatically tends to zero when the level of capacity which would be profitable on the energy market in the absence of a capacity mechanism is expected to be adequate to meet the level of capacity demanded*." Specific dispositions are set for emissions thresholds in terms of g/CO2 per kWh, starting from July 2019 and July 2025, in order to receive payments from existing capacity mechanisms.

The selected market design is key to how the various countries will meet the challenges related to low renewables generation. As explained above, there are in principle two relevant solutions, the capacity market and the energy-only market. A specific taxonomy for capacity mechanism is currently in place, broadly divided into volume-based and price-based methods. In the former, policymakers set a required volume of capacity and let market forces fix a price. In the latter, policymakers set a price and let potential investors decide how much they are willing to commit. Targeted mechanisms may remunerate only specific plants or technologies, whereas market-wide mechanisms reward all capacity providers.

The Agency for the Cooperation of Energy Regulators (ACER) individuated five different categories of capacity mechanisms (2013), volume-based and price-based, targeted and market-wide, see figure 1 in the Appendix. In the strategic reserve model, currently adopted in Belgium, Germany, Poland and Sweden, a central authority sets an amount of capacity needed a few years in advance and contracts capacity (the strategic reserve) generally via a competitive tender. These plants cannot participate in the electricity wholesale market and are only activated in case of capacity deficits. Capacity auctions, adopted in the United Kingdom, are decided upon a few years in advance and centrally procured via an auction: providers submit bids to receive a capacity payment that reflects the cost of building new capacity. The capacity obligation model, adopted in France, is similar to the former, but an obligation is imposed on large consumers or electricity suppliers to contract an amount of capacity based on their self-assessed future consumption or supply, plus a reserve margin, through certificates that are issued by capacity providers. Penalties are levied on suppliers or consumers who fail to have the required level of capacity contracted. Reliability options are a technically more complex solution that present a series of advantages (Finon and Pignon, 2008). A capacity provider enters sells an option contract to a counterparty (a transmission system operator or a large consumer or supplier), who receives acquires the possibility to procure electricity at a predetermined strike price. The counterparty will exercise the option in situations of scarcity. This model is adopted in Ireland and under implementation in Italy. Capacity payments are pre-determined fees set by the authority and paid to capacity providers, plants receiving these payments can still participate in the energy-only market. They are adopted in Poland and Spain.

2.3. Literature Review

The topic of the build-up of capacity has long been intrinsically associated to the issues of system adequacy and reliability, therefore it received attention more at engineering and technical level, rather than from an economic and regulatory point of view. Traditional electricity systems were based on dispatchable hydro and thermal generation embedded in a vertically integrated supply chain (generation, transmission and distribution) managed by a market incumbent. Investment decisions on capacity expansion were centrally planned and delivered according to expectation on demand growth and cost minimization approaches (Arriaga 2013). The subject turned out to be more relevant from a regulatory point of view starting from the early 2000s when it became evident that the ongoing process of market liberalization and unbundling, paired with an ever-increasing injection of variable, non-dispatchable renewables, would have required a different angle of analysis. Therefore, a separate assessment between energy markets (wholesale and balancing) and capacity markets became more customary in order to understand mutual interactions and discern potential market distortions. This was the approach followed by the first contributors, trying to highlight the benefits and weaknesses of a capacity market versus an energy-only one. Cramton and Stoft (2006) were among the first to run a systematic comparison of models and to identify three orders of problems: the quantitative one, i.e. to achieve an adequate level of generation capacity, the qualitative, i.e. to address the need for flexibility and the performance problem represented by operational performance versus real time prices. Battle and Arriaga (2008) also provided a comparative overview of the main market designs, by assessing pricing mechanisms, auctioning procedures and compliance with critical periods. Roques (2008) analysed the aspects of integration of the energy and capacity markets and stressed the need to decline solutions according to the institutional differences among the countries: the author mentioned the biases of capacity payments and introduces the concept and the potential benefits of reliability options.

The most typical framework of analysis involves the economic modelling of fundamental inputs to perform market simulation and assessing performances and behaviours of each specific model. Included inputs comprise technology parameters (e.g. investment and variable costs of technology, forced outage rate, capacity factor, operational costs, fuel costs), economic parameters (e.g. growth rate, depreciation, construction schedules) and market parameters (e.g. wholesale prices, interconnection capacity, demand and supply). Cepeda and Finon (2011) tested two interconnected and interdependent markets by simulating an energy-only market, a price-capped without capacity mechanisms and a price-capped with forward capacity contracts obligation. A key finding was that when both markets adopt common approach to managing capacity adequacy, the average price and reliability, as well as the overall efficiency the integrated market, increase. Similar evidences, in terms of preference for hybrid energy-capacity models, were achieved by Hasani and Hosseini (2011), who performed a Monte Carlo simulation on a causal loop model comprising the roll-out of capacity and the participation on the market. Petitet, Finon and Janssen (2017) consistently used a causal loop framework to compare three different market design: energy-only with price cap, energy-only with scarcity pricing and capacity mechanism, the latter two outperforming the former. Cepeda (2018) built on his previous contribution by analysing four different case tailored on the interconnected market between France and the United Kingdom. Results endorsed the evidence for including interconnectors as a way towards a greater efficiency, in absence of an EU-wide capacity market.

Much attention has also been given to capacity mechanisms applied to the power pool model, widely adopted in the United States, that presents different market features compared to the power exchange model implemented in Europe. For the scope of this work, it is relevant to highlight that reliability options have been first introduced in the New England power pool. A pioneering work was presented by Bidwell (2005) who proposed reliability options to reduce price volatility, assure system adequacy and avoid a higher degree of market distortion. Cramton and Stoft (2008) further explored the topic by differentiating between a thermal-dominated market and a hydro-dominated one. They also stressed the need to implement reliability options to suppress risk and market power without interfering with real-time price signals: while the price cap is valid for real time pricing, it does not impact the marginal pricing on the balancing market where capacity operates.

2.4. The I-SEM and the Reliability Options

The Single Electricity Market (SEM) was the single wholesale market for electricity in the Republic of Ireland and in Northern Ireland, which had been in operation from 2007 until 30th September 2018. As a mandatory gross pool, in the SEM all generators were required to sell and suppliers were required to buy power through the pool. The pool set the spot price for electricity, known as the System Marginal Price (SMP) every half hour. Generators received separate payments for the provision of stable generation capacity through a capacity payment mechanism. Price volatility in the pool was managed by generators and suppliers who entered into fixed financial contracts (contracts for differences). On 1st October 2018, in order to comply with the European Target Model, the Integrated Single Electricity Market (I-SEM) came into existence, the rationale behind its creation was i) to improve wholesale pricing efficiency, ii) to implement an auction-based capacity market, iii) to introduce advanced forward products and iv) to jointly enable the transition towards renewables, targeting 40% of total generation by 2020 (source: SEAI). The new market framework is non-mandatory, so generators can potentially bid on a specific market segment. The I-SEM generation sector comprises approximately 15,985 MW of capacity connected to the system on an all-island basis, up from 15,291 MW in 2017 (source: ESB). The available capacity in the system includes a mix of old thermal plants alongside modern combined cycle gas turbine (CCGT) plants and renewables such as wind power. These stations generate electricity from fuels such as gas, coal and oil as well as indigenous resources including hydro, peat and biomass. Regarding renewables, I-SEM has 4,790MW of wind installed. Wind contributed 25% of generation in 2018, up from 22% in 2017. ESB was responsible for 38% of generation in I-SEM in 2018, slightly down from last year. 2018 saw 76% availability of baseload thermal generation in I-SEM, with gas and coal continuing to be the dominant fuels in the market. Thanks to the favourable business environment for international IT companies, data centre demand growth (particularly in Dublin) has increased significantly in recent years and is forecasted to rise to about 30% of total electricity demand by 2027 (source: ESB). This increase in load profile would represent a step change in demand growth in a relatively short time frame, potentially resulting in an erosion of traditional reserve capacity available for the adequacy of the system. It is up to debate how the growing share of variable renewables in the energy mix will cope with this challenge.

The Irish market is an interesting topic of academic and regulatory study, presenting several innovative and peculiar features: it spans across two different countries and jurisdictions, shares two interconnections with Great Britain (the Moyle and the East-West interconnections, providing a nominal capacity of 1000 MW, while additional capacity is currently under planning and/or commissioning) and adopts a pioneering approach to renewables deployment and capacity remuneration. Lehay and Tol (2011) assessed the robustness of regulatory VOLL in Ireland by estimating production functions on sectorial and hourly basis and found the "real" VOLLs to be substantially higher. Di Cosmo and Lynch (2016) argued against the suitability of the reliability option system, as renewable wind generation, paired with priority dispatching, cannot be scheduled behind a unit holding a reliability option requested to generate. Therefore high energy prices may be paid to all generators that are scheduled, including wind generators, but the difference between the reference price and strike price is only recovered from the thermal generators under the reliability options scheme, leaving the system exposed to the high prices corresponded to wind generators. Another concern was the potential market power exercised by the incumbent, whose capacity could have been decisive in order to cover the amount of capacity needed, leaving space for higher bidding in the auctions. Teirilä (2017) came to the same conclusions by simulating a two-stage model comprising behaviour in capacity and electricity markets: the incumbent, ESB, has still the opportunity and the incentive to exercise market power on the I-SEM, a potential solution would be, according to the author, to introduce bid caps on the capacity market.

In the reliability options model, a governmental authority firstly forecasts the peak demand and adds a reserve margin in order to determine the appropriate volume of reliability contracts. Secondly, the options' Strike Price (SP) must be determined. In order to have an incentive for periods of scarce supply, the Strike Price should be set above the most expensive unit on the system and is thereby higher than the Reference Price (RP) under non-scarcity conditions. The Strike Price functions as a price cap, leading to a reduction of price spikes. The governmental authority then organizes periodical auctions in which the system operator purchases the contracts from the generators. It is possible for both existing and new facilities to participate in the auction. The price for the contracts is determined in the competitive auction process and should approximate the generator's expected loss of price spike revenues, which is sum of (RP - SP) over all hours that RP > SP. Figure 2 in Appendix shows how electricity spikes are capped and recovered via reliability options in the Irish I-SEM. The difference payments are calculated against the Reference Price for each market segment in which the generator with awarded capacity sold the energy, either the Day Ahead Market, the Intra-Day Market or the Balancing Market, or the provision of DS3 System Services. If the capacity is not made available to the market at times of high energy prices, then generators will not earn revenue to cover these difference payments and the Reference Price will be derived from the Balancing Market. This mechanism facilitates the availability of awarded capacity at times of system stress.

Options are allocated via an auctioning mechanism, structured on a primary auction, to designate a plant from potential candidates to active units within the capacity markets, and a secondary auction, to allow a capacity provider with a unit on an outage to purchase additional capacity from another generator and offset its capacity obligations while the unit is offline. Transitional one-year-ahead and two-year primary capacity auctions (T-1 and T-2) will be run for the first three years of operation of the I-SEM. Secondary capacity auctions will be run at regular intervals up to the start of each capacity year. Therefore, primary capacity auctions will be run four years ahead (T-4) of each capacity year and T-1 and T-2 auctions will be held just before the start of the capacity year and two year ahead, respectively. Locational capacity constraints may be introduced by the system operator, determining geographical areas where a minimum capacity is cleared for the purpose of system security. To present date, five capacity auctions have taken place. The first T-4 auction was run on 28th March 2019, procuring capacity to meet security of supply for the period October 2022 to the end of September 2023. The auction secured a total of 7,412 megawatts (MW) of capacity. The auction clearing price was €46,150 per MW per year. Of the 112 generating units that qualified to take part in the auction, 93 were successful. A total of €342 million of capacity payments will be paid during the period October 2022 to September 2023. Before the introduction of capacity auctions in 2017, annual capacity payments averaged €550 million. The latest T-1 and T-2 capacity auctions were held on 26th November and on 5th December 2019. Through the T-1 auction, sufficient capacity was procured to meet security of supply for the period October 2020 to October 2021.Through the T-2 auction, capacity was procured for the period October 2021 to October 2022. Cleared prices were €46,150 per MW and €45,950 per MW, respectively, with awarded capacity of 7,605 MW and 7,511 MW.

3. Data and Methodology

All modelled data is publicly available and takes into consideration the beginning of the market reform as well as the ex-ante situation. I-SEM was originally due to launch on 1st October 2017, but in late 2016 the regulators pushed this date back to allow more time for participants to test the market's new systems. Full operativity took place in October 2018, after the completion of the first auctioning processes. It is therefore possible to control for variables that are likely to be impacted by the new policy. Di Cosmo and Lynch (2016) for instance mention some features of the system, such as forced outage rates and scheduled outage durations (e.g. for maintenance), that are used to determine the installed capacity required in order to meet total demand according to predetermined reliability standards. In this paper, the opposite is also held true, i.e. forced, or unplanned, outages are considered one metric to assess the overall system reliability in times of distress. By considering the definition of forced outages adopted by the United States Nuclear Regulatory Commission[1], outages represent a metric of the impact of reliability options in three ways: i)

[1] *"The shutdown of a generating unit, transmission line, or other facility for emergency reasons, or a condition in which the equipment is unavailable as a result of an unanticipated breakdown. An outage (whether full, partial, or*

awarded generation plants are largely dispatchable ones, incurring for instance disruptions or fuel supply discontinuity, therefore the implementation of the new policy is susceptible to affect the degree of reliability by adding new programmable capacity, ii) the roll-out of renewables, as the ultimate goal of the new policy, is susceptible to decrease outages, as renewables are not impacted by fuel interruptions, iii) awarded capacity may have arbitrage option across the different markets and even be remunerated while idle when the Reference Price is below the Strike Price and no payments are due (i.e. less incentives to solve recurring outages). The second metric analysed is the standard Reference Price, i.e. the wholesale price System Marginal Price (SMP), calculated on half-hourly basis, which comprises the shadow price (representing the marginal cost per 1 MW of power necessary to meet demand in a given trading period) and the uplift (representing the recovery of the total generator costs, including expenses associated with start-up and no-load costs). The SMP is directly impacted by the new I-SEM configuration due to the price cap penalty that reliability options impose on awarded capacity generators. One of the explicit goals of the new policy is to reduce price peaks and benefit final consumers. According to ESB, for instance in 2018, in the three month timeframe from the launch of the I-SEM, there have been five reliability option events on the Balancing Market, where the imbalance settlement price has spiked above €500/MWh, triggering difference payments from generators holding reliability options from the capacity market. Tables 2 and 3 in Appendix reports the descriptive statistics of outages for each country and system marginal price.

3.1. Data Description

To perform the analysis, data was collected by the following publicly available sources: the ENTSO-E Transparency Platform, providing homogeneous data aggregated by country and/or market; SEM-O (Single Electricity Market Operator), the market operator of the I-SEM; EirGrid and SONI, the TSOs of the Republic of Ireland and Norther Ireland, respectively. In order to standardize and uniform all data, we considered 24 hourly observations for each day, when data was collected every half an hour, averages where computed. Notwithstanding no definite European standard or procedure is currently in place in the organization of wholesale electricity markets, according to the author's experience, setting an hourly granularity of observation increases the degree of comparability across several systems. The time series stretch from 01/10/2016 to 30/09/2019, for a total of 26,280 hourly observations for each variable. The dataset includes the day ahead SMP (€/MWh); the unplanned outages (MW but re-scaled to GW) the disaggregated demand (MW) for the Republic of Ireland and Northern Ireland; import and export hourly flows (MW) through the two interconnectors with the United Kingdom and the hourly generation (MW) divided by technology and country. In particular, the latter is broken-down by thermal generation (hard coal, oil, peat, gas), hydro (pumped storage and run-of-river) and renewables (namely onshore wind).

All outliers are included in the dataset, differently from what other authors (Weron 2007) suggest: for the scope of this paper, the inclusion of the effects of outliers or spikes (such as electricity

attributable to a failed start) is considered "forced" if it could not reasonably be delayed beyond 48 hours from identification of the problem, if there had been a strong commercial desire to do so."

prices) is essential in order to assess the mitigation effects triggered by the new market framework. For the same reasons, no logarithmic transformation was applied in order to stabilize variance and volatility dynamics. An exhaustive set of dummy variables is added, to include the strong seasonality factor characterizing variables such as electricity prices and demand: intra-week seasonality is modelled via a Monday dummy and a Weekend / Holiday dummy, while single months are also accounted for, as presented in Gianfreda, Ravazzolo and Rossini (2020) among others.

3.2. Methodology

The chosen approach to run this analysis is an econometric technique based on the estimate of a simultaneous equations model. The rationale behind this choice is to try to capture the mutual effects of variables that are contemporaneously correlated, given how the disturbance term in one equation is likely to exert an influence on the disturbance terms in other equations. A simultaneous linear equations model, firstly introduced by Klein (1950) in the field of public economics, also delivers more efficient estimates in presence of cross equations (Hennigsen and Hamann, 2007). The estimation procedures chosen is the Seemingly Unrelated Regression (SUR), given the strict conditions of independence of error terms and homoskedasticity do not hold. Also Ordinary Least Squares were calculated as robustness check, but only the SUR results are presented in the Appendix. The analysis suite is R, and the adopted package is Systemfit.

The system of linear equations presents the form introduced by equations (4), (5) and (6) below.

$$Unplanned\_Outages\_IE_t = \alpha + \beta_1 Unplanned\_Outages\_IE_{t-1} + \beta_2 Unplanned\_Outages\_IE_{t-24} + \beta_3 Demand\_IE_t + \beta_4 Thermal\_IE_t + \beta_5 Hydro\_IE_t + \beta_6 Renewable\_IE_t + \beta_7 Import_t + \beta_8 Export_t + \Sigma k_s D_s + \varepsilon_t \tag{4}$$

$$Unplanned\_Outages\_NI_t = \alpha + \beta_1 Unplanned\_Outages\_NI_{t-1} + \beta_2 Unplanned\_Outages\_NI_{t-24} + \beta_3 Demand\_NI_t + \beta_4 Thermal\_NI_t + \beta_5 Renewable\_NI_t + \beta_6 Import_t + \beta_7 Export_t + \Sigma ksDs + \varepsilon_t \tag{5}$$

$$Day\_Ahead\_Price_t = \alpha + \beta_1 Day\_Ahead\_Price_{t-24} + \beta_2 Demand\_Island_t + \beta_3 Unplanned\_Outages\_Island_t + \beta_4 Import_t + \beta_5 Export_t + \Sigma ksDs + \varepsilon_t \tag{6}$$

Where IE stands for the Republic of Ireland and NI stands for Northern Ireland. Thermal_IE is a matrix comprising the variables Gas_IE, Hard_Coal_IE, Oil_IE, Peat_IE; Thermal_NI includes Gas_NI, Hard_Coal_NI, Oil_NI. Hydro_IE includes Hydro_Pumped_Storage_IE and Hydro_Run_Of_River_IE. Renewable is always referred to Wind_Onshore_IE and Wind_Onshore_NI. *ΣksDs* represents the dummy matrix, as described in the previous paragraph. The Republic of Ireland exchanges electricity with the UK via the East-West Interconnector, while Northern Ireland is linked via the Moyle Interconnector: given that all electricity is pooled in the I-SEM, there is no separate effect or market splitting, and therefore no need to separate these flows by country. The Ljung-Box and Breusch-Pagan (White) tests were performed to control for autocorrelation of errors and heteroskedasticity, Tables 4 to 9 in the Appendix also show the covariance matrix and correlation matrix of residuals for each computation. Autoregressive components are added to all equations, as both outages and day ahead price, feature a significant persistence of short memory. Outages in particular, see Figures 4 and 5 in the Appendix, present a flat profile corresponding to the duration of the unplanned unavailability of generation capacity, which might last for many hours or even several days: in order to capture both the effects, a 1-hour lag and a 24-hour lag are included. Regarding the autoregressive behaviour of prices, there is ample literature concerning in particular the forecasting and the way stationary electricity prices time series can be handled (see Gianfreda, Ravazzolo and Rossini, 2020): it is possible to add further specifications, such as an adaptive fine-tuning of lags or a moving average component (ARIMA) on the mean equation, or a GARCH (Generalized Autoregressive Conditional Heteroskedasticity) process on the residuals. For the scope of this paper, a simpler approach is preferred, and a single 24-hour lag is included, to account for weekly seasonality and latent memory.

To assess the impact of the new market framework (or policy) and explain the variability of the key metrics over time, the dataset is divided into two sections, with cut-off date on October 1st 2018. Therefore, the model is run for the ex-ante and the ex-post dataset, as well as for the entire one. Both the OLS and the SUR are calculated.

4. Results

Computation results of the system of equations are reported in Tables 10 to 18 in the Appendiy for the SUR. The analysis is structured according to two clustering criteria, i) geographical dimension, with separated assessments for the Republic of Ireland (IE) and Northern Ireland (NI) and ii) time dimension, by dividing the dataset into Full, Ante I-SEM and Post I-SEM. Both equations of Unplanned:Outages_IE and Unplanned_Outages_NI fit well, as the Adjusted R^2 metric seems to suggest (see Tables 19-21 in the Appendix), while Day_Ahead_Price follows a greater volatility pattern and it is more complex to specify. Unplanned outages are, by definition, unpredictable events, but their duration is effectively captured by the introduction of the autoregressive components. The descriptive statistics offer the intuition that in Post I-SEM, Unplanned_Outages_IE relatively increased in terms of mean value and the ratio of MW of unavailable capacity on total hours, while Unplanned_Outages_NI decreased. Day_Ahead_Price recorded an average increase of almost 4 €/MWh between the Full and Post I-SEM dataset, suggesting, apart from possible external factors (e.g. fuel prices or fluctuations in imports), that the market reform has not been immediately beneficial to final consumers.

IE is characterized by a more diversified energy mix, with four main technologies of thermal generation and two of hydro generation (in terms of output), while NI is a comparably smaller market, on average less than one third in demand volumes and features only thermal generation capacity. The bulk of load is mainly served by thermal gas in both countries (see Figures 6 and 7) while other generation sources follow a more irregular trend. Interestingly, in IE there seem to be a pattern regarding the impact of emission-intensive CHP generation technologies, such as peat and oil, which are less prone to trigger outages in the Full dataset: this might imply better fuel reliability, but also a gradual shift towards generation via "cleaner" technologies. The second conclusion seems to be further corroborated in the Post I-SEM dataset, where thermal generation in IE, with the sole exception of gas, does not impact Unplanned_Outages_IE, though the increase in unavailability does not seem to support the former hypothesis of greater reliability. Northern Ireland is similar, except that only oil generation seems to be positively and significantly impacting Unplanned_Outages_NI in the full Dataset.

Hydro generation is significative only in the Full and Ante I-SEM datasets, and not in the Post I-SEM dataset: pumped storage impacts positively, as it is linked to the backing of defaulting capacity, while the more seasonal run-of-river has a negative impact. Renewables, on the opposite, exhibit a high degree of significance with a negative impact on outages for all datasets in IE, where the deployment of wind generation capacity is more robust. Demand is always positively significant for both IE and NI across all datasets, as it is naturally highly correlated with the possibility to incur into disruptions when more capacity is put in production. Import is negatively correlated with outages, representing a partial substitution of the internal generation, and significant only for IE. Export is also negatively correlated for NI in the Full and Ante I-SEM datasets, a possible explanation is that it represents a price difference event with the Scottish system, and therefore prices are comparably lower, e.g. due to low internal demand or strong generation from renewables, and no peak thermal plants are needed. Lags are generally significative and by construction positively correlated for both IE and NI across all datasets.

The modelling of the SMP, or Day_Ahead_Price follows an approach consistent with the main literature, i.e. an autoregressive model paired with exogenous regressors representing fundamental system inputs. The overall fit is good (see Tables 19-21 in the Appendix), and it sensibly improves for the Post I-Sem dataset. As expected, the autoregressive component and the all-island demand are significant and with positive coefficients for all datasets. Unplanned outages present an apparently contradictory behaviour: in the Full dataset only Unplanned_Outages_IE are significant, while in the Post I-SEM neither are: the latter might imply that, notwithstanding their overall increase in IE, outages are less important in the price formation after the introduction of the new policy, potentially suggesting a relatively greater role played by renewables. Import and Export flows, similarly to other interconnected electricity systems, are fundamental inputs in the creation of prices, with a positive and negative impact, respectively. This finding is also consistent: higher prices are correlated with an import of cheaper energy from the UK, and vice versa.

5. Conclusions

This paper proposes a quantitative methodology to assess the preliminary impact of the first 12 months of the new Integrated Single Electricity Market (I-SEM) in Ireland. In particular in this contribution the focus is on the implementation of the new capacity mechanism called reliability options, whose goal is to enhance the overall system's reliability. Hourly data are assessed via a simultaneous equations system based on three market parameters, Unplanned_Outages_IE, Unplanned_Outaged_NI and Day_Ahead_Price, representing suitable metrics for reliability. The analysis is carried out by clustering data at geographical level (Republic of Ireland and Northern Ireland) and according to the roll-out of the new market (Full, Ante I-SEM and Post I-Se, datasets). It is relevant to highlight how one single year data on new policy implementation may not be sufficient in order to draft definite conclusions, but the main scope is to propose a framework of analysis to be potentially implemented and expanded. According to a preliminary analysis on descriptive statistics, two metrics, Unplanned_Outages_IE and Day_Ahead_Price have both increased after the go live of the I-SEM: while there is no direct evidence that these changes are due to the implementation of the new policy, as in particular prices may be driven by fundamental factors such as demand or fuel prices, some potential causality effect are investigated. The results support the conclusions that a gradual change in the generation mix is taking place through i) a gradual roll-out of renewables, ii) a cross substitution of part of the thermal generation mix, but at the same time no immediate impacts in terms of system reliability can be inferred.

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Appendix

Table 1 – Wholesale Price Caps and Estimate of VOLL

Wholesale Price Caps and estimates of VOLL (EUR/MWh)				
Country	Day-ahead	Intraday	Balancing	Estimate of VOLL[29]
Belgium	3,000	9,999	4,500	n.a.
Denmark	3,000	No cap	5,000	Between 2,933 and 36,800
Croatia	3,000	No exchange trading. No OTC cap.	No cap	n.a.
France	3,000	9,999	9,999	26,000
Germany	3,000	9,999	No cap	n.a.
Ireland	1,000 (moving to 3,000 in future)	1,000 (moving to 3,000 in future)	No balancing market. Price cap TBC for future market design	11,017.98
Italy	3,000	3,000	3,000	3,000
Poland	~350	No cap	~350	Between ~1,250 and ~2,100
Portugal	180	180	No cap	3,000
Spain	180	180	No cap	n.a.
Sweden	3,000	No cap	5,000	Between ~2,800 and ~7,600

Source: European Commission based on replies to sector inquiry

Figure 1 – Taxonomy of Capacity Remuneration Mechanisms

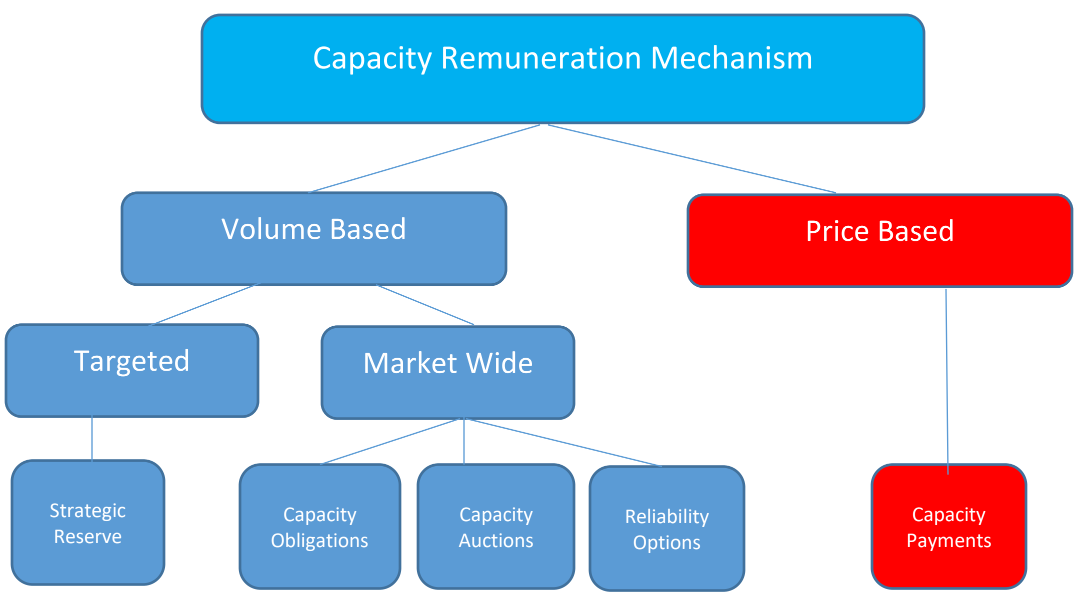
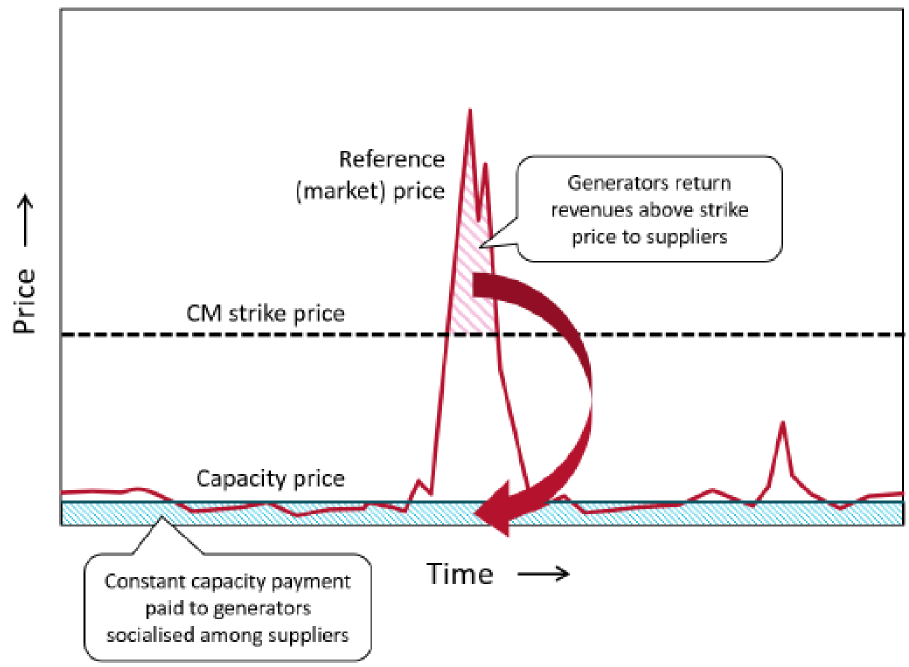


Figure 2 – Reliability Options at work



Source: I-SEM Industry Guide

Table 2 – Descriptive Statistics, full Dataset

	Day_Ahead_Price	Unplanned_Outages_IE	Unplanned_Outages_NI
Mean	52.93	117.29	40.58
St Error	0.14	1.19	0.66
Median	48.69	10.00	0.00
St Deviation	23.48	192.76	107.30
Variance	551.44	37,154.94	11,512.23
Kurtosis	117.50	5.97	16.35
Skewness	5.06	2.21	3.64
Range	1,079	1,658	1,371
Minimum	-79	0	0
Maximum	1,000	1,658	1,371
Sum	1,391,072	3,082,266	1,066,374
Count	26,280	26,280	26,280

Table 3 – Descriptive Statistics, Dataset Post I-SEM

	Day_Ahead_Price	Unplanned_Outages_IE	Unplanned_Outages_NI
Mean	56.73	165.77	33.40
St Error	0.29	2.71	1.05
Median	53.00	24.00	0.00
St Deviation	26.86	254.11	98.59
Variance	721.24	64,570.12	9,720.09
Kurtosis	14.47	3.17	20.49
Skewness	2.33	1.85	3.90
Range	375	1,658	1,371
Minimum	-10	0	0
Maximum	365	1,658	1,371
Sum	496,956	1,452,178	292,592
Count	8,760	8,760	8,760

Figure 3-4-5: time series chart of Day Ahead Price, Outages IE and Outages NI

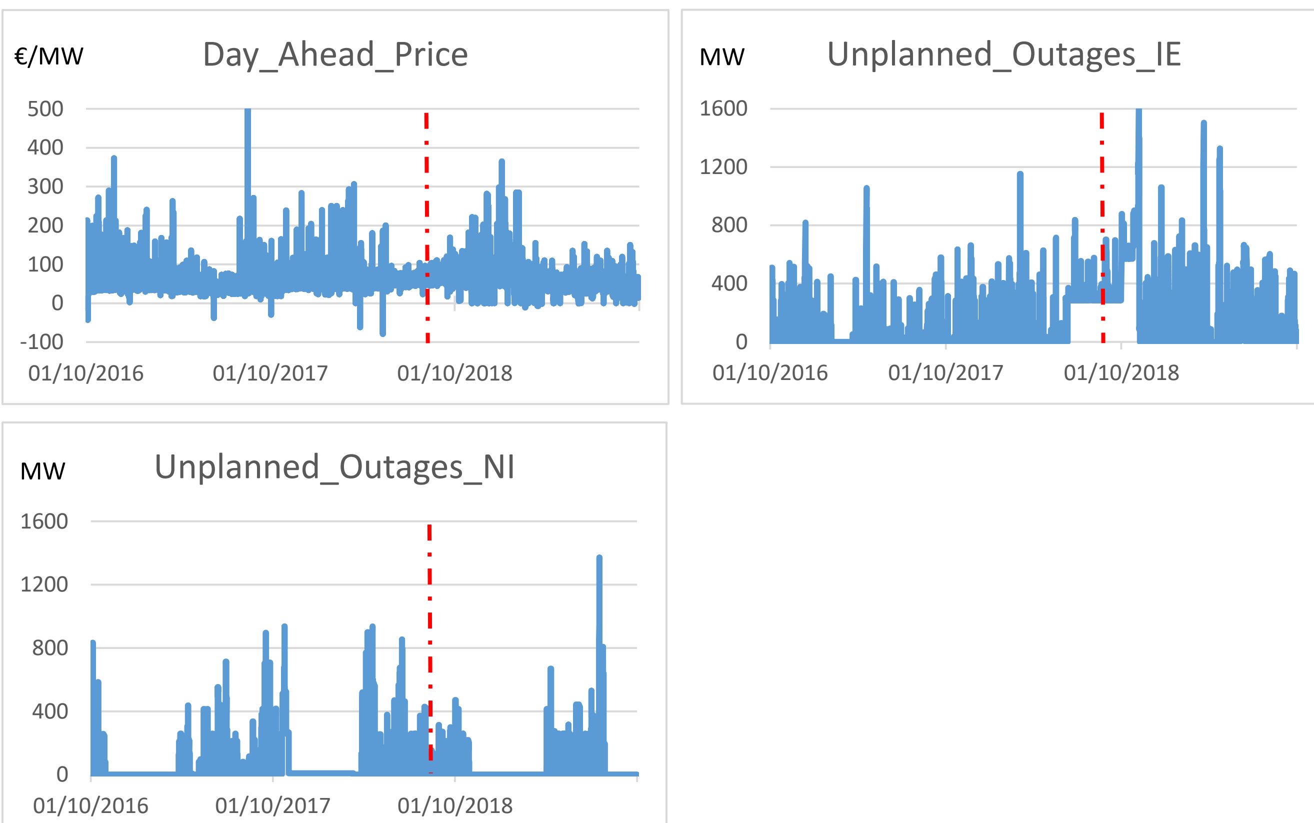
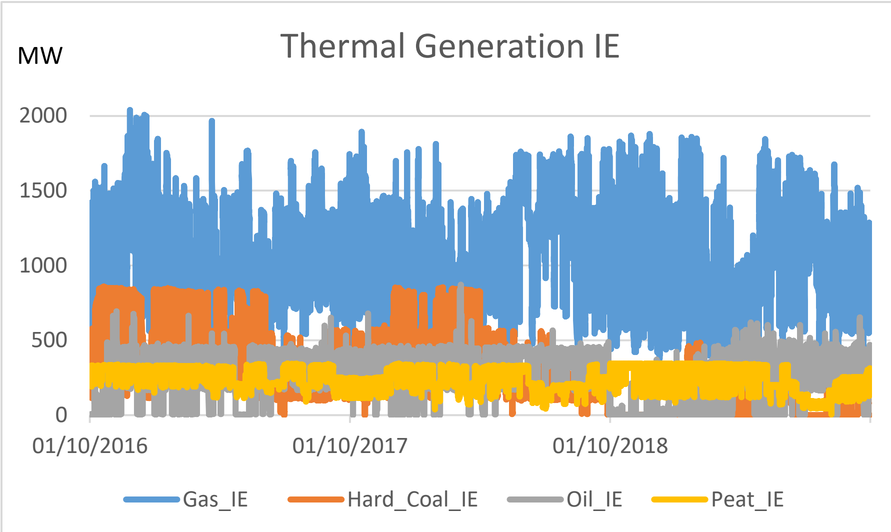
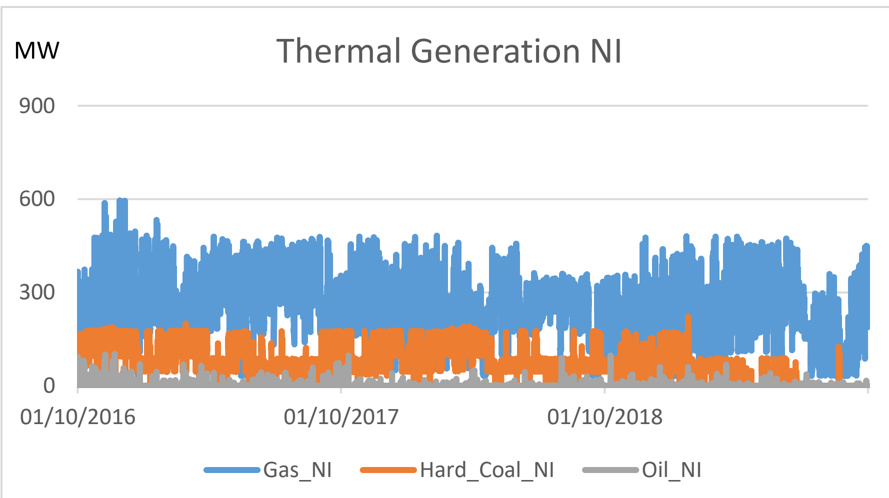
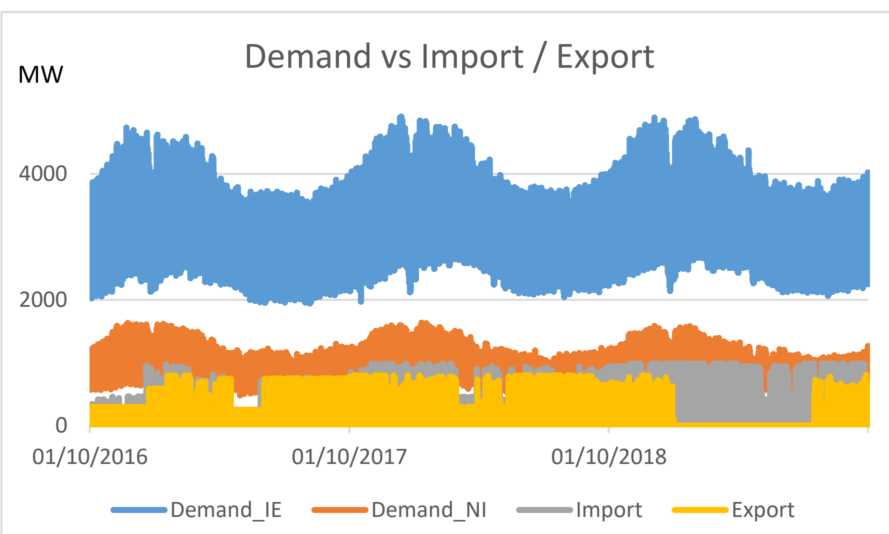


Figure 6-7-8: Thermal Generation IE and NI, Demand vs Import / Export







Tables 4- 9 Variance and Correlations Matrices of Residuals

Table 4 Covariance – SUR Full Dataset

	eq1	eq2	eq3
eq1	2.44E-03	-9.14E-06	-0.02378
eq2	-9.14E-06	1.31E-03	-0.00459
eq3	-2.38E-02	-4.59E-03	309.3774

Table 5 Correlation – SUR Full Dataset

	eq1	eq2	eq3
eq1	1	-0.00511	-0.02737
eq2	-0.00511	1	-0.00721
eq3	-0.02737	-0.00721	1

Table 6 Covariance – SUR Ante I-SEM

	eq1	eq2	eq3
eq1	1.74E-03	-1.78E-05	-0.01585
eq2	-1.78E-05	1.45E-03	-0.00733
eq3	-1.59E-02	-7.33E-03	303.4123

Table 7 Correlation – SUR Ante I-SEM

	eq1	eq2	eq3
eq1	1	-0.01121	-0.0218
eq2	-0.01121	1	-0.01107
eq3	-0.0218	-0.01107	1

Table 8 Covariance – SUR Post I-SEM

	eq1	eq2	eq3
eq1	3.85E-03	7.54E-06	-6.56E-03
eq2	7.54E-06	1.02E-03	4.37E-05
eq3	-6.56E-03	4.37E-05	2.64E+02

Table 9 Correlation – SUR Post I-SEM

	eq1	eq2	eq3
eq1	1	3.81E-03	-6.51E-03
eq2	0.003805	1	8.42E-05
eq3	-0.00651	8.42E-05	1

Table 10 – SUR Results Full Dataset – Outages IE

	Estimate	Std.Error	t value	Pr(>|t|)	
(Intercept)	-3.15E-02	2.96E-03	-10.6384	< 2.22E-16	***
Lag1_Unplanned_Outages_IE	9.41E-01	2.12E-03	443.6463	< 2.22E-16	***
Lag24_Unplanned_Outages_IE	2.50E-02	2.13E-03	11.73342	< 2.22E-16	***
Demand_IE	1.45E-05	9.93E-07	14.61606	< 2.22E-16	***
Thermal_Gas_IE	-3.43E-06	1.63E-06	-2.09828	0.03589	*
Thermal_Hard_Coal_IE	-9.74E-06	1.57E-06	-6.20119	5.69E-10	***
Thermal_Oil_IE	-4.24E-06	2.48E-06	-1.70512	0.088183	.
Thermal_Peat_IE	-5.34E-06	4.83E-06	-1.10538	0.269007	
Hydro_Pumped_Storage_IE	2.67E-05	4.58E-06	5.82551	5.76E-09	***
Hydro_Run_Of_River_IE	-2.69E-05	7.82E-06	-3.43564	0.000592	***
Renewable_IE	-5.37E-06	1.06E-06	-5.05359	4.37E-07	***
Import	-4.23E-06	1.53E-06	-2.75627	0.00585	**
Export	2.43E-06	1.66E-06	1.46395	0.143221	
DUMMY_MONTHDUMMY_JANUARY	5.94E-04	1.44E-03	0.4136	0.679168	
DUMMY_MONTHDUMMY_FEBRUARY	1.07E-03	1.47E-03	0.72429	0.468893	
DUMMY_MONTHDUMMY_MARCH	-1.68E-04	1.50E-03	-0.11199	0.91083	
DUMMY_MONTHDUMMY_APRIL	-3.42E-07	1.53E-03	-0.00022	0.999822	
DUMMY_MONTHDUMMY_MAY	7.10E-04	1.60E-03	0.44437	0.656779	
DUMMY_MONTHDUMMY_JUNE	1.85E-03	1.86E-03	0.9922	0.321107	
DUMMY_MONTHDUMMY_JULY	2.92E-03	1.88E-03	1.55552	0.119834	
DUMMY_MONTHDUMMY_AUGUST	4.31E-03	1.67E-03	2.58237	0.009818	**
DUMMY_MONTHDUMMY_SEPTEMBER	4.19E-03	1.57E-03	2.67201	0.007545	**
DUMMY_MONTHDUMMY_OCTOBER	7.85E-03	1.46E-03	5.36793	8.03E-08	***
DUMMY_MONTHDUMMY_NOVEMBER	-1.41E-04	1.44E-03	-0.09832	0.921681	
DUMMY_MONDAY	1.59E-03	9.04E-04	1.76282	0.077942	.
DUMMY_WEEKEND_HOLIDAY	3.47E-03	7.37E-04	4.71364	2.45E-06	***

Table 11 – SUR Results Full Dataset – Outages NI

	Estimate	Std.Error	t value	Pr(>|t|)	
(Intercept)	-1.03E-02	1.56E-03	-6.57426	4.98E-11	***
Lag1_Unplanned_Outages_NI	9.18E-01	2.37E-03	386.8258	< 2.22E-16	***
Lag24_Unplanned_Outages_NI	3.55E-02	2.36E-03	15.04604	< 2.22E-16	***
Demand_NI	1.12E-05	1.66E-06	6.72772	1.76E-11	***
Thermal_Gas_NI	-6.23E-06	3.72E-06	-1.67524	0.093899	.
Thermal_Hard_Coal_NI	4.49E-06	6.10E-06	0.73664	0.46135	
Thermal_Oil_NI	2.38E-04	4.57E-05	5.20784	1.92E-07	***
Renewable_NI	2.49E-06	1.78E-06	1.39743	0.162295	
Import	-4.64E-07	1.02E-06	-0.45251	0.650904	

Export	-7.37E-06	1.20E-06	-6.16317	7.23E-10	***
DUMMY_MONTHDUMMY_JANUARY	2.84E-04	1.03E-03	0.27481	0.783461	
DUMMY_MONTHDUMMY_FEBRUARY	1.82E-04	1.03E-03	0.17546	0.860721	
DUMMY_MONTHDUMMY_MARCH	2.52E-03	1.04E-03	2.42758	0.015207	*
DUMMY_MONTHDUMMY_APRIL	5.55E-03	1.08E-03	5.13844	2.79E-07	***
DUMMY_MONTHDUMMY_MAY	4.86E-03	1.09E-03	4.453	8.50E-06	***
DUMMY_MONTHDUMMY_JUNE	8.41E-03	1.18E-03	7.15469	8.61E-13	***
DUMMY_MONTHDUMMY_JULY	6.74E-03	1.17E-03	5.77968	7.57E-09	***
DUMMY_MONTHDUMMY_AUGUST	3.93E-03	1.09E-03	3.61178	0.000305	***
DUMMY_MONTHDUMMY_SEPTEMBER	4.55E-03	1.06E-03	4.28558	1.83E-05	***
DUMMY_MONTHDUMMY_OCTOBER	5.88E-03	1.06E-03	5.55256	2.84E-08	***
DUMMY_MONTHDUMMY_NOVEMBER	3.75E-04	1.03E-03	0.36338	0.716321	
DUMMY_MONDAY	7.35E-05	6.63E-04	0.11088	0.911709	
DUMMY_WEEKEND_HOLIDAY	7.01E-04	5.37E-04	1.30571	0.191663	

Table 12 – SUR Results Full Dataset – Day Ahead Prices

	Estimate	Std.Error	t value	Pr(>|t|)	
(Intercept)	7.670703	0.849997	9.02439	2.22E-16	***
Lag24_Day_Ahead_Price	0.428208	0.005358	79.92102	2.22E-16	***
Demand_Island	0.005163	0.000176	29.38566	2.22E-16	
Unplanned_Outages_IE	11.44031	0.609843	18.75943	2.22E-16	***
Unplanned_Outages_NI	1.054275	1.079962	0.97622	0.328967	
Import	0.014531	0.00044	33.00542	< 2.22E-16	***
Export	-0.00118	0.00056	-2.1063	0.035188	
DUMMY_MONTHDUMMY_JANUARY	-5.13632	0.503539	-10.2005	< 2.22E-16	***
DUMMY_MONTHDUMMY_FEBRUARY	-7.04189	0.508048	-13.8607	< 2.22E-16	***
DUMMY_MONTHDUMMY_MARCH	-4.91547	0.503252	-9.76741	< 2.22E-16	***
DUMMY_MONTHDUMMY_APRIL	-5.62541	0.512513	-10.9761	< 2.22E-16	***
DUMMY_MONTHDUMMY_MAY	-5.0483	0.514428	-9.81343	< 2.22E-16	***
DUMMY_MONTHDUMMY_JUNE	-5.72615	0.550546	-10.4009	< 2.22E-16	***
DUMMY_MONTHDUMMY_JULY	-4.68096	0.538712	-8.68916	< 2.22E-16	***
DUMMY_MONTHDUMMY_AUGUST	-4.07132	0.505845	-8.04855	8.88E-16	***
DUMMY_MONTHDUMMY_SEPTEMBER	-3.31898	0.508909	-6.52175	7.08E-11	***
DUMMY_MONTHDUMMY_OCTOBER	-3.96109	0.524228	-7.55604	4.29E-14	***
DUMMY_MONTHDUMMY_NOVEMBER	-3.00975	0.502696	-5.98723	2.16E-09	***
DUMMY_MONDAY	3.53675	0.321749	10.99227	< 2.22E-16	***
DUMMY_WEEKEND_HOLIDAY	2.622873	0.260657	10.06255	< 2.22E-16	***

Table 13 – SUR Results Ante I-SEM Dataset – Outages IE

	Estimate	Std.Error	t value	Pr(>|t|)	
(Intercept)	-2.18E-02	3.92E-03	-5.55814	2.77E-08	***
Lag1_Unplanned_Outages_IE	9.30E-01	2.75E-03	338.5845	< 2.22E-16	***
Lag24_Unplanned_Outages_IE	2.38E-02	2.78E-03	8.56254	< 2.22E-16	***
Demand_IE	1.42E-05	1.09E-06	12.97062	< 2.22E-16	***
Thermal_Gas_IE	-4.35E-06	1.80E-06	-2.4141	0.015784	*
Thermal_Hard_Coal_IE	-6.54E-06	2.32E-06	-2.81824	0.004834	**
Thermal_Oil_IE	-2.54E-06	2.80E-06	-0.90822	0.363776	
Thermal_Peat_IE	-3.44E-05	5.79E-06	-5.93394	3.01E-09	***
Hydro_Pumped_Storage_IE	3.16E-05	4.83E-06	6.54901	5.95E-11	***
Hydro_Run_Of_River_IE	-2.25E-05	8.80E-06	-2.55316	0.010683	*
Renewable_IE	-5.94E-06	1.21E-06	-4.89491	9.92E-07	***
Import	-1.16E-06	1.79E-06	-0.64598	0.518302	
Export	1.83E-06	1.81E-06	1.01159	0.311746	
DUMMY_MONTHDUMMY_JANUARY	-8.25E-04	1.56E-03	-0.52954	0.596438	
DUMMY_MONTHDUMMY_FEBRUARY	-1.16E-03	1.61E-03	-0.7159	0.47406	
DUMMY_MONTHDUMMY_MARCH	-2.29E-03	1.61E-03	-1.4289	0.153052	
DUMMY_MONTHDUMMY_APRIL	-1.04E-03	1.62E-03	-0.643	0.520235	
DUMMY_MONTHDUMMY_MAY	-1.37E-03	1.78E-03	-0.77112	0.440646	
DUMMY_MONTHDUMMY_JUNE	1.32E-03	1.97E-03	0.66749	0.504466	
DUMMY_MONTHDUMMY_JULY	3.33E-03	2.03E-03	1.63567	0.101927	
DUMMY_MONTHDUMMY_AUGUST	5.61E-03	1.95E-03	2.8824	0.003951	**
DUMMY_MONTHDUMMY_SEPTEMBER	5.52E-03	1.79E-03	3.0788	0.002082	**
DUMMY_MONTHDUMMY_OCTOBER	1.75E-03	1.62E-03	1.08147	0.279505	
DUMMY_MONTHDUMMY_NOVEMBER	-1.40E-03	1.57E-03	-0.89449	0.371071	
DUMMY_MONDAY	1.45E-03	9.40E-04	1.54713	0.121849	
DUMMY_WEEKEND_HOLIDAY	2.91E-03	7.68E-04	3.78337	0.000155	***

Table 14 – SUR Results Ante I-SEM Dataset – Outages NI

	Estimate	Std.Error	t value	Pr(>|t|)	
(Intercept)	-9.64E-03	2.37E-03	-4.06445	4.84E-05	***
Lag1_Unplanned_Outages_NI	9.07E-01	3.00E-03	301.9544	< 2.22E-16	***
Lag24_Unplanned_Outages_NI	4.94E-02	2.99E-03	16.5262	< 2.22E-16	***
Demand_NI	1.31E-05	2.32E-06	5.66012	1.54E-08	***
Thermal_Gas_NI	-1.08E-05	5.34E-06	-2.02777	0.042598	*
Thermal_Hard_Coal_NI	-1.15E-06	8.59E-06	-0.13347	0.893827	
Thermal_Oil_NI	2.73E-04	5.25E-05	5.20079	2.01E-07	***
Renewable_NI	1.87E-06	2.53E-06	0.73871	0.460091	
Import	-1.45E-06	1.57E-06	-0.92625	0.354329	

Export	-8.18E-06	1.62E-06	-5.06236	4.18E-07	***
DUMMY_MONTHDUMMY_JANUARY	3.50E-04	1.41E-03	0.24835	0.803866	
DUMMY_MONTHDUMMY_FEBRUARY	5.52E-05	1.44E-03	0.03833	0.969429	
DUMMY_MONTHDUMMY_MARCH	1.07E-03	1.41E-03	0.75973	0.447429	
DUMMY_MONTHDUMMY_APRIL	5.05E-03	1.47E-03	3.42139	0.000624	***
DUMMY_MONTHDUMMY_MAY	4.10E-03	1.47E-03	2.78096	0.005426	**
DUMMY_MONTHDUMMY_JUNE	8.27E-03	1.53E-03	5.4098	6.39E-08	***
DUMMY_MONTHDUMMY_JULY	5.83E-03	1.54E-03	3.79182	0.00015	***
DUMMY_MONTHDUMMY_AUGUST	4.33E-03	1.51E-03	2.87031	0.004106	**
DUMMY_MONTHDUMMY_SEPTEMBER	4.87E-03	1.45E-03	3.35601	0.000792	***
DUMMY_MONTHDUMMY_OCTOBER	6.27E-03	1.48E-03	4.24919	2.16E-05	***
DUMMY_MONTHDUMMY_NOVEMBER	-1.58E-04	1.42E-03	-0.11151	0.911215	
DUMMY_MONDAY	6.82E-05	8.56E-04	0.07971	0.936468	
DUMMY_WEEKEND_HOLIDAY	5.56E-04	6.93E-04	0.80212	0.422496	

Table 15 – SUR Results Ante I-SEM Dataset – Day Ahead Prices

	Estimate	Std.Error	t value	Pr(>|t|)	
(Intercept)	11.23785	1.190894	9.43649	< 2.22E-16	***
Lag24_Day_Ahead_Price	0.375805	0.006879	54.63033	< 2.22E-16	***
Demand_Island	0.00437	0.000237	18.47764	< 2.22E-16	***
Unplanned_Outages_IE	19.22142	0.999977	19.22186	< 2.22E-16	***
Unplanned_Outages_NI	4.760481	1.285762	3.70246	0.000214	***
Import	0.005268	0.00067	7.85952	4.00E-15	***
Export	-0.00597	0.000726	-8.22456	2.22E-16	***
DUMMY_MONTHDUMMY_JANUARY	0.326564	0.642402	0.50835	0.611216	
DUMMY_MONTHDUMMY_FEBRUARY	-0.11703	0.659655	-0.17741	0.859189	
DUMMY_MONTHDUMMY_MARCH	0.38611	0.642075	0.60135	0.547617	
DUMMY_MONTHDUMMY_APRIL	-1.77748	0.659004	-2.69722	0.006999	**
DUMMY_MONTHDUMMY_MAY	0.078383	0.654089	0.11984	0.904615	
DUMMY_MONTHDUMMY_JUNE	-2.54268	0.671904	-3.78429	0.000155	***
DUMMY_MONTHDUMMY_JULY	-0.91124	0.660105	-1.38044	0.167468	
DUMMY_MONTHDUMMY_AUGUST	1.659776	0.659348	2.5173	0.011835	*
DUMMY_MONTHDUMMY_SEPTEMBER	3.791755	0.668842	5.66914	1.46E-08	***
DUMMY_MONTHDUMMY_OCTOBER	-2.36812	0.6659	-3.55627	0.000377	***
DUMMY_MONTHDUMMY_NOVEMBER	-0.17159	0.644047	-0.26643	0.789911	
DUMMY_MONDAY	2.237239	0.391343	5.71682	1.10E-08	***
DUMMY_WEEKEND_HOLIDAY	3.113002	0.318108	9.786	< 2.22E-16	***

Table 16 – SUR Results Post I-SEM Dataset – Outages IE

	Estimate	Std.Error	t value	Pr(>|t|)	
(Intercept)	-3.36E-02	5.71E-03	-5.88436	4.14E-09	***
Lag1_Unplanned_Outages_IE	9.40E-01	3.78E-03	248.5759	< 2.22E-16	***
Lag24_Unplanned_Outages_IE	1.41E-02	3.72E-03	3.80275	0.000144	***
Demand_IE	1.53E-05	2.30E-06	6.65203	3.06E-11	***
Thermal_Gas_IE	-7.90E-06	3.85E-06	-2.05194	0.040205	*
Thermal_Hard_Coal_IE	8.23E-06	1.06E-05	0.77552	0.438053	
Thermal_Oil_IE	-4.13E-06	6.45E-06	-0.6408	0.521671	
Thermal_Peat_IE	1.14E-05	1.26E-05	0.90712	0.364367	
Hydro_Pumped_Storage_IE	6.78E-06	1.24E-05	0.54636	0.584835	
Hydro_Run_Of_River_IE	-2.05E-05	1.95E-05	-1.05003	0.293735	
Renewable_IE	-6.28E-06	2.39E-06	-2.62828	0.008597	**
Import	-7.18E-06	3.15E-06	-2.2808	0.022584	*
Export	9.16E-07	4.64E-06	0.19749	0.843447	
DUMMY_MONTHDUMMY_JANUARY	-4.78E-04	3.11E-03	-0.15342	0.878074	
DUMMY_MONTHDUMMY_FEBRUARY	1.22E-03	3.34E-03	0.36517	0.714996	
DUMMY_MONTHDUMMY_MARCH	-1.11E-03	3.66E-03	-0.30441	0.760821	
DUMMY_MONTHDUMMY_APRIL	2.59E-03	3.94E-03	0.65757	0.510831	
DUMMY_MONTHDUMMY_MAY	6.21E-03	4.00E-03	1.55193	0.120715	
DUMMY_MONTHDUMMY_JUNE	5.94E-03	5.50E-03	1.07934	0.280464	
DUMMY_MONTHDUMMY_JULY	7.60E-03	5.32E-03	1.42876	0.153109	
DUMMY_MONTHDUMMY_AUGUST	6.29E-03	3.83E-03	1.64079	0.100876	.
DUMMY_MONTHDUMMY_SEPTEMBER	4.12E-03	3.53E-03	1.1657	0.243769	
DUMMY_MONTHDUMMY_OCTOBER	2.81E-02	4.11E-03	6.83671	8.65E-12	***
DUMMY_MONTHDUMMY_NOVEMBER	5.08E-03	3.38E-03	1.50085	0.133431	
DUMMY_MONDAY	2.24E-03	1.96E-03	1.14626	0.251717	
DUMMY_WEEKEND_HOLIDAY	4.70E-03	1.60E-03	2.93905	0.003301	**

Table 17 – SUR Results Post I-SEM Dataset – Outages NI

	Estimate	Std.Error	t value	Pr(>|t|)	
(Intercept)	-9.35E-03	2.25E-03	-4.16211	3.18E-05	***
Lag1_Unplanned_Outages_NI	9.32E-01	3.96E-03	235.5084	< 2.22E-16	***
Lag24_Unplanned_Outages_NI	-2.98E-03	3.98E-03	-0.74956	0.453542	
Demand_NI	8.05E-06	2.47E-06	3.26234	0.001109	**
Thermal_Gas_NI	-2.73E-06	5.90E-06	-0.46268	0.643605	
Thermal_Hard_Coal_NI	1.01E-05	1.43E-05	0.7039	0.481513	
Thermal_Oil_NI	4.38E-05	1.04E-04	0.42048	0.674148	
Renewable_NI	2.05E-06	2.58E-06	0.79557	0.426303	
Import	1.09E-06	1.34E-06	0.8149	0.415151	

Export	-1.33E-06	2.35E-06	-0.56539	0.571822	
DUMMY_MONTHDUMMY_JANUARY	3.57E-04	1.58E-03	0.22531	0.821744	
DUMMY_MONTHDUMMY_FEBRUARY	7.37E-04	1.53E-03	0.48206	0.629773	
DUMMY_MONTHDUMMY_MARCH	6.89E-03	1.72E-03	4.01797	5.92E-05	***
DUMMY_MONTHDUMMY_APRIL	6.97E-03	1.68E-03	4.14707	3.40E-05	***
DUMMY_MONTHDUMMY_MAY	8.13E-03	1.76E-03	4.63119	3.69E-06	***
DUMMY_MONTHDUMMY_JUNE	1.07E-02	2.27E-03	4.71578	2.45E-06	***
DUMMY_MONTHDUMMY_JULY	1.27E-02	2.29E-03	5.55895	2.79E-08	***
DUMMY_MONTHDUMMY_AUGUST	2.44E-03	1.81E-03	1.35166	0.17652	
DUMMY_MONTHDUMMY_SEPTEMBER	2.34E-03	1.76E-03	1.33248	0.182736	
DUMMY_MONTHDUMMY_OCTOBER	4.44E-03	1.48E-03	3.0058	0.002656	**
DUMMY_MONTHDUMMY_NOVEMBER	3.29E-04	1.50E-03	0.21917	0.826526	
DUMMY_MONDAY	-1.07E-04	1.01E-03	-0.10575	0.915779	
DUMMY_WEEKEND_HOLIDAY	4.82E-04	8.25E-04	0.58467	0.558784	

Table 18 – SUR Results Post I-SEM Dataset – Day Ahead Prices

	Estimate	Std.Error	t value	Pr(>|t|)	
(Intercept)	3.78E+00	1.19E+00	3.17223	0.001518	**
Lag24_Day_Ahead_Price	3.53E-01	8.56E-03	41.20792	< 2.22E-16	***
Demand_Island	8.43E-03	2.69E-04	31.32274	< 2.22E-16	***
Unplanned_Outages_IE	-2.13E+00	8.78E-01	-2.42189	0.01546	*
Unplanned_Outages_NI	-2.98E+00	1.97E+00	-1.51267	0.130401	
Import	1.96E-02	5.71E-04	34.40098	< 2.22E-16	***
Export	-1.40E-02	1.15E-03	-12.1686	< 2.22E-16	***
DUMMY_MONTHDUMMY_JANUARY	-1.17E+01	7.93E-01	-14.7985	< 2.22E-16	***
DUMMY_MONTHDUMMY_FEBRUARY	-1.56E+01	7.72E-01	-20.1789	< 2.22E-16	***
DUMMY_MONTHDUMMY_MARCH	-1.33E+01	7.89E-01	-16.8149	< 2.22E-16	***
DUMMY_MONTHDUMMY_APRIL	-1.12E+01	7.80E-01	-14.3047	< 2.22E-16	***
DUMMY_MONTHDUMMY_MAY	-1.28E+01	8.16E-01	-15.6869	< 2.22E-16	***
DUMMY_MONTHDUMMY_JUNE	-1.17E+01	1.01E+00	-11.6389	< 2.22E-16	***
DUMMY_MONTHDUMMY_JULY	-9.59E+00	1.01E+00	-9.5183	< 2.22E-16	***
DUMMY_MONTHDUMMY_AUGUST	-1.25E+01	7.67E-01	-16.2964	< 2.22E-16	***
DUMMY_MONTHDUMMY_SEPTEMBER	-1.41E+01	7.82E-01	-17.997	< 2.22E-16	***
DUMMY_MONTHDUMMY_OCTOBER	5.37E+00	8.95E-01	6.00087	2.04E-09	***
DUMMY_MONTHDUMMY_NOVEMBER	7.34E-01	7.79E-01	0.9424	0.346013	
DUMMY_MONDAY	5.68E+00	5.16E-01	11.00313	< 2.22E-16	***
DUMMY_WEEKEND_HOLIDAY	1.52E+00	4.16E-01	3.65678	0.000257	***

Table 19 – SUR Full Dataset

	N	DF	SSR	MSE	RMSE	R2	Adj R2
eq1	26280	26254	6.41E+01	0.002441	0.049403	0.934374	0.934311
eq2	26280	26257	3.44E+01	0.00131	0.036192	0.886318	0.886223
eq3	26280	26260	8.12E+06	309.3774	17.58913	0.439367	0.438962

Table 20 – SUR Ante I-SEM Dataset

	N	DF	SSR	MSE	RMSE	R2	Adj R2
eq1	17520	17494	3.05E+01	0.001742	0.041736	0.919793	0.919678
eq2	17520	17497	2.53E+01	0.001445	0.038014	0.883326	0.88318
eq3	17520	17500	5.31E+06	303.4123	17.41873	0.334992	0.33427

Table 21 – SUR Post I-SEM Dataset

	N	DF	SSR	MSE	RMSE	R2	Adj R2
eq1	8760	8734	3.36E+01	0.003846	0.062012	0.940614	0.940444
eq2	8760	8737	8.93E+00	0.001022	0.031965	0.895143	0.894879
eq3	8760	8740	2.30E+06	263.5434	16.23402	0.635387	0.634595