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LNG and gas storage optimisation and valuation: Lessons from the integrated Irish and UK markets

Mel T. Devine[abc], Marianna Russo[bc]*

Abstract: *To guarantee European countries with greater access to competitive energy sources, the European Union has identified new infrastructures for the achievement of a diversified, secure and affordable European single energy market. This paper aims to evaluate the impact on consumers' energy bill of new LNG and gas storage facilities. We focus on the integrated UK-Ireland gas system, which provides an interesting framework to assess socioeconomic benefits of new energy routes. We utilise a stochastic mixed complementarity problem model, which also incorporates stochastic gas supply cost and demand scenarios. Therefore, we assess the expected benefits for consumers of a diversified gas supply, and their sensitivity to changing market conditions. Our results imply the complementary of LNG and gas storage investments to manage shortterm peak loads and long-term seasonal loads and prices in gas markets. Nonetheless, economic benefits for consumers are dependent on market conditions. Overall, our results provide some suggestions on investments in new gas facilities, which are of interest to policy-makers and market participants.*

a. Energy Institute, School of Electrical and Electronic Engineering, University College Dublin, Ireland
b. Economic and Social Research Institute, Dublin
c. Department of Economics, Trinity College Dublin

1. Introduction

The European Union (EU) is the biggest importer of natural gas worldwide. Diversification of supply sources is therefore paramount to ensure energy security and competitiveness. To reduce its dependence on a single supplier, the EU has identified new routes, which aim to ensure diversified, secure and affordable gas supply to the European consumers. Following the Regulation (EU) 347/2013 for trans-European energy infrastructure in November 2017, the European Commission published its third list of Projects of Common Interest (PCIs), which aim to guarantee European Countries with greater access to the international energy markets and diversified supply sources [1]. Among these projects, 53 are new gas infrastructures across 24 EU and 7 non-EU countries. Of these new infrastructures, 6 are LNG imports terminals (in Cyprus, Croatia, Greece, Ireland, Poland and Sweden) and 8 are gas storage facilities (in Bulgaria, Estonia, Greece, Ireland, Latvia, Lithuania, Romania, the UK).

The PCIs highlight the importance and complementarity of LNG and natural gas storage facilities to guarantee secure, affordable and diversified gas supply in the EU. However, there are questions about the expected benefits associated with the projects, as raised by the European Agency for the Cooperation of Energy Regulators, [1]. Yet, little research has been done to evaluate the impact of new gas infrastructure on consumers' energy bill. Our paper aims to fill this gap by assessing the impact of gas PCIs for consumers.

Our contribution to the literature is twofold. First, we focus our analysis on the Irish and UK natural gas markets in an integrated setting by considering investments in both LNG and gas storage facilities. The Irish market is particularly interesting because Ireland is the only EU country without LNG and storage facilities. Some previous research has focused on the future development of natural gas infrastructure in different geographic regions (for a survey, see [2]). Ref. [2] also highlight the implications of socioeconomic conditions for such a development. Ref. [3] addresses supply management problems in the US over the period 2015-39 under different economic scenarios and the associated realisations of natural gas supply, demand and prices. They focus on optimising investment and operating decisions while minimising overall costs. In a similar vein, [4] assume realistic investment and operating decisions over the period 2000-10 to assess the response of gas prices to investments in the upstream sector. Ref. [5] evaluate

[1] Available at `https://ec.europa.eu/energy/sites/ener/files/documents/memberstatespci_list_2017.pdf`. Updated on April 2018, as available at `https://ec.europa.eu/energy/sites/ener/files/technical_document_3rd_list_with_subheadings.pdf`. Access on 12 September 2018.

the configuration of gas storage facilities for gas-fired power plants using European Union as a representative model. They assess the day-ahead gas storage schedule that matches short-term peak loads and long-term seasonal loads and price, thus providing information about transmission management operations and network investments in the EU gas system. Further studies focusing on the implications of developing natural gas infrastructures for the reliability of energy system include [6] [7] [8] [9] [10]. These studies also highlight the relevance of adequate gas infrastructures for the integration of renewable sources in the power sector. We contribute to this literature by assessing the potential economic benefits of PCIs, in particular LNG and storage facilities, for consumers.

Second, our study is of interest for the European policy-makers, concerned about a secure, affordable and diversified single energy system. Ireland is only connected to the European energy system through the UK. In the absence of further gas routes, any bottleneck in the UK gas market can have critical impacts on Ireland, thus compromising the achievement of a single EU-wide energy market, as mandated by the European Union.

We use a stochastic Mixed Complementarity Problem (MCP) to model the Irish and UK natural gas markets in 2025. The model also incorporates the Moffat pipeline which connects these two markets. MCPs allow optimisation problems of multiple individual players to be solved simultaneously and in equilibrium by combining the Karush-Khun-Tucker (KKT) conditions for optimality of each of the players and connecting them via market clearing conditions. In addition, MCPs allow both primal variables (e.g., sales) and dual variables (e.g., prices) to be constrained together [11]. In this work, the MCP considers a number of probabilistic scenarios which represent different demand curve and supply cost possibilities for 2025.

In the literature, MCPs have been used to model natural gas markets across the world. For instance, [12] and [13] use MCP frameworks to model the North American natural gas market. Similarly, [14, 15] and [16] use MCPs to model the European natural gas market. Similarly, [7], [17], [18], [19], [20] use MCPs to model the global gas market. The closest work to current study can be found in [21], which focuses on modelling the UK natural gas market solely.

The remainder of this paper is structured as follows: in Section 2 we provide a background of the Irish natural gas market. In Section 3 we describe the MCP methodological framework while in Section 4 we introduce the data used to parametrise the model. In Section 5 we present the results, which are discussed in Section 6. Section 7 concludes the paper.

2. Background

Similar to other European countries, natural gas plays a pivotal role in the energy mix and economic development of Ireland. In 2016, it met 29% of the total energy demand of Ireland compared to 23% of the EU-28[2]. The flexibility and efficiency of gas-fired power plants have supported the increasing use of renewable energy sources in the power sector. On average, natural gas accounted for 49% of the fuel used for electricity generation in the period 2012-16 [22].

Ireland's natural gas comes from both indigenous production and imports. The indigenous production is mostly satisfied by the Corrib gas field. Production at Corrib started in December 2015 and amounted to 54% of 2016 gas demand. In low demand days, during the summer months, it amounted to 100% of the Irish gas demand. The balance on Ireland's natural gas requirement is imported from the UK through the Scotland-Ireland Interconnector Moffat. In 2016, 40% of the Irish gas demand was satisfied through import from the UK, thus making Ireland highly dependent on a single supply source. Nevertheless, Corrib production is expected to decline quickly and deplete by 2025 [22]. The declining indigenous production in Ireland is of particular concern among policy-makers, in particular when considering that the island's only energy link to the EU will disappear in March 2019, after Brexit [3].

The PCIs envisage the development of alternative sources of supply and supply routes to Ireland [23]. The Shannon Liquefied Natural Gas (LNG) import terminal, which was granted planning permission in 2008, is listed on the EU PCIs. While construction for this project has yet to begin, it would allow Ireland to import gas from the Atlantic Basin (incl. US) and Middle East, thus bypassing the UK and providing Ireland with diversified gas supplies. The development of the Islandmagee Underground Gas Storage (UGS) facility in Northern Ireland, which is expected by 2021, would further improve the security of supply and the flexibility of the gas market in Ireland. However, their implications for consumers are not addressed. Developing a LNG import terminal would provide access to the increasingly competitive international gas market, making the Irish gas market more competitive. The development of a storage facility would allow the management of seasonal loads, thus reducing gas price volatility and the risks of supply shortage. In the following section, we investigate what is the optimal and most

[2] `https://ec.europa.eu/info/news/eu-energy-statistics-latest-data-now-available-2018-oct-04_en`

[3] *EU closer to genuine Energy Union as MEPs support gas supply solidarity*, Euractiv 12 September 2017. Available at `https://www.euractiv.com/section/energy/news/eu-closer-to-genuine-energy-union-as-meps-support-gas-supply-solidarity/`. Access on 17/10/2018

competitive option for Irish consumers in 2025, i.e. when the Corrib field is expected to be depleted and when LNG and storage facilities should be operational.

3. Model Formulation

In this section, we describe the formulation of the stochastic mixed complementarity problem (MCP) approach. The MCP allows both primal variables (demand and supply) and dual variables (prices) to be constrained together [11]. It models a natural gas system with $|M|$ nodes/markets and $|K|$ suppliers. Suppliers buy and sell gas, subject to constraints, in order to maximise their profits. Each of the $|K|$ suppliers has separate optimisation problems that are connected through market clearing conditions. The stochastic MCP is made up of these market clearing conditions along with the Karush-Kuhn-Tucker (KKT) conditions for optimality from each of the suppliers. Thus, the MCP solves $|K|$ optimisation problems simultaneously and in equilibrium. All players are modelled as price-takers. In this work, the MCP considers different stochastic scenarios $|S|$, which represent different demand and supply curves in 2025. Each scenario has a probability ($PROB^s$) associated with it. Tables A.5 - A.8 describe the sets, variables and parameters used in the model. The following conventions are used: lower-case Roman letters indicate indices or variables, upper-case Roman letters represent parameters (i.e., data, functions), while Greek letters indicate endogenous prices. The variables in parentheses alongside each constraint are the Lagrange multipliers associated with those constraints.

3.1. Supplier k's problem

Supplier k maximizes expected profit (revenues less cost) by deciding how much gas to sell ($sales^s_{kmt}$), to buy ($supply^s_{kmt}$), inject to storage (inj^s_{kmt}) and extract from storage (xtr^s_{kmt}), in each scenario s. In addition, it also decides how much gas to flow ($flows^s_{kat}$) through $|A|$ pipelines to other nodes/markets explicitly modelled, e.g., the Irish and UK markets in this work. Furthermore, each supply source k may have a storage facility associated with it.

The marginal price suppliers in node m at time t receive is π^s_{mt}. The marginal cost values associated with supply, injection to storage, extraction from storage and flowing gas through pipelines are $C^{supply,*}_{mtr}$, C^{inj}_{mt}, C^{xtr}_{mt} and C^{pipe}_{at}, respectively. Supplier k's optimisation is given below with the associated KKT conditions shown in the Supplementary Appendix. Suppliers k's optimisation problem is

$$\max_{\substack{sales^s_{kmt},\\ supply^s_{kmt},\\ flows^s_{kat},\\ inj_{kmt},\\ xtr^s_{kmt}}} \sum_{t,m} DAYS_t \Bigg\{ \sum_s PROB^s \Bigg[\pi^s_{mt} sales^s_{kmt} - C^{supply,s}_{mt} supply^s_{kmt} - C^{inj}_{mt} inj^s_{kmt} - C^{xtr}_{mt} xtr^s_{kmt} - \sum_{a \in A(m)} C^{pipe}_{at} flows^s_{kat} \Bigg] \Bigg\}, \tag{1}$$

subject to:

$$\begin{aligned} supply^s_{kmt} + xtr^s_{kmt} \quad &+ \sum_{a \in a^{in}(m)} (1 - LOSS_a) flows^s_{kat} \\ = sales^s_{kmt} \quad &+ \sum_{a \in a^{out}(m)} flows^s_{kat} + inj^s_{kmt}, \ \forall s, m, t, \ (\lambda^{s,k1}_{kmt}), \end{aligned} \tag{2a}$$

$$\sum_t DAYS_t supply^s_{kmt} \quad \leq \quad TP^{\max}_{km}, \ \forall s, m, \ (\lambda^{s,k2}_{km}), \tag{2b}$$

$$supply^s_{kmt} \quad \geq \quad DP^{\min}_{km}, \ \forall s, m, t, \ (\lambda^{s,k3}_{kmt}), \tag{2c}$$

$$supply^s_{kmt} \quad \leq \quad DP^{\max}_{km}, \ \forall s, m, t, \ (\lambda^{s,k4}_{kmt}), \tag{2d}$$

$$inj^s_{kmt} \quad \leq \quad DI^{\max}_{km}, \ \forall s, m, t, \ (\lambda^{s,k5}_{kmt}), \tag{2e}$$

$$xtr^s_{kmt} \quad \leq \quad DX^{\max}_{km}, \ \forall s, m, t, \ (\lambda^{s,k6}_{kmt}), \tag{2f}$$

$$MINSTOR_{km} \quad \leq \quad INITSTOR_{km} + \tag{2g}$$

$$+ \quad \sum_{e=1}^{t} DAYS_e [(1 - LOSS_m) inj^s_{kme} - xtr^s_{kme}], \forall s, m, t, \ (\lambda^{s,k7}_{kmt}), \tag{2h}$$

$$INITSTOR_{km} + \sum_{e=1}^{t} DAYS_e [(1 - LOSS_m) inj^s_{kme} - xtr^s_{kme}] \leq MAXSTOR_{km}, \forall s, m, t, \ (\lambda^{s,k8}_{kmt}), \tag{2i}$$

where $DAYS_t$ represent the number of days in timestep t and and $PROB^s$ represents the probability associated with scenario s. Supplier k's objective function (1) maximizes their expected profit in all time periods. We assume that there is one day in each time period ($DAYS_t = 1 \ \forall t$) and 365 time periods in total. The first time period represents the 1st January 2025.

The expected profit of suppliers is the money they receive from sales less the cost of supply, less the cost associated with flowing gas through pipelines and less the cost of injections and extractions to and from storage. Constraint (2a) ensures that the amount of gas supplier k has entering market m equals the amount of gas they have exiting that market, where $LOSS_a$ represents the percentage losses associated with pipeline a. An upper bound for the total amount of gas supplier k sources from source p in market m, across all time steps, is provided by constraints (2b). Constraints (2c) and (2d) give minimum and maximum supply rates for source p, respectively, while constraints (2e) - (2f) give maximum injection and extractions rates to and from storage. Lower and upper bounds for the amount of gas supplier k can have in storage, for source p, at time t is provided by constraints (2h) and (2i) respectively, where $LOSS_m$ represents the percentage losses associated with storage facilities in market m.

Finally, all primal variables in supplier k's problem, except $sales^s_{kmt}$, are constrained to be non-negative. When supplier k purchases more than it sells, $sales^s_{kmt}$ takes a negative value. This situation may only occur when suppliers k injects gas to storage.

3.2. Market-Clearing Conditions

The $|K|$ optimisation problems are connected via the following market clearing conditions:

$$\sum_k DAYS_t sales^s_{kmt} = Z^s_{mt} + B_{mt} \times \pi^s_{mt}, \;\; \forall m, s, t, \;\; (\pi^s_{mt} \text{ free}), \tag{3a}$$

$$\sum_k flows^s_{kat} \leq DA^{\max}_a, \;\; \forall a, s, t, \;\; (\tau^s_{at}). \tag{3b}$$

Equation (3a) states, for each timestep and scenario, that the total amount of gas sold by the suppliers in market m equals a linear demand curve, where Z^s_{mt} and B^s_{mt} are the demand curve intercept and slope respectively. Condition (3b) constrains the total amount of gas that can flow through pipeline a in each timestep and scenario.

The Karush-Kuhn-Tucker (KKT) conditions for suppliers are presented in the Supplementary Appendix. As supplier k's problem is linear, these conditions are both necessary and sufficient for optimally for all players. The MCP model consists of these KKT conditions in addition to the market clearing conditions (3).

4. Data

In this section, we describe the data used in the MCP model. Section 4.1 focuses on the supply side in 2025; Section 4.2 presents data on demand.

4.1. Supply side capacity data

Firstly, we assume there are $|M|$=2 nodes, representing the Irish and UK gas markets. Secondly, we assume that there are $|K|$=10 supply sources in total, three Irish and seven from the UK. These supply sources are listed in Table 1, where their projected daily maximum capacities in 2025 are reported. The three Irish sources represent the Corrib gas field, the proposed Shannon LNG import terminal (Irish LNG)[4] and a potential gas storage facility. The seven UK sources include the UK Continental Shelf (UKCS), imports from Norway, the Netherlands (via the BBL pipeline) and Belgium (via the IUK inter-connector). A long-range (LRS) and a medium-range (MRS) storage facility are also included, along with a UK LNG import facility. The long-range capacity represents the Rough storage facility; the medium-range storage capacity represents the sum of all medium-range facilities projected to be in the UK in 2025 [24]. Regarding UK LNG, today there are three operational LNG import terminals located in Wales and England (South Hook, Dragon and Grain). However, we assume these terminals import gas at the same price, thus implying they work as one combined LNG import facility. The depicted values of the Irish supply sources were obtained from [25] while the UK numbers were obtained from [26] and [24].

Using the daily maximum flow rates in Table 1, the corresponding minimum capacities were computed. For Corrib, UKCS and Norway they were set at 34%, 46% and 21% of the daily maximum capacities from Table 1, respectively. These percentages reflect long-term contracts and were calculated by examining the actual minimum flow rates and maximum capacities at 2015 and 2016, as recorded by Gas Networks Ireland[5] and the UK National Grid[6]. For all other sources of supply, the daily minimum capacities were set to zero.

Table 2 displays the total yearly maximum capacities. Values for the UKCS and Norway were obtained from [26]. The remaining yearly values were calculated by multiplying the daily values in Table 1 by 365. For both the Irish and UK LNG sources, the yearly values where discounted by a factor of 0.7. This factor is in accordance with the UK National Grid [26] and [21] and accounts for the actual LNG operating hours (a factor of 1 would imply the LNG facility operates at 100% of its capacity, thus injecting gas into the network without interruption during 1-year period). Consequently, the total yearly maximum capacities of Irish LNG and UK LNG in Table 2 were obtained as $TP_{km}^{\max} = 0.7 \times 365 \times DP_{km}^{\max}$. Storage facilities can allow for the

[4] http://www.shannonlng.ie/

[5] https://www.gasnetworks.ie/corporate/gas-regulation/transparency-and-publicat/

[6] http://mip-prod-web.azurewebsites.net/DataItemExplorer/Index

Supply sources (k)	Ireland ($m = 1$)	UK ($m = 2$)
Corrib	55.22	0.00
Irish LNG	311.08	0.00
UKCS	0.00	699.93
Norway	0.00	1722.05
BBL	0.00	588.83
IUK	0.00	822.14
UK LNG	0.00	1622.06

Table 1: Daily maximum capacities ($DP_{km}^{\max}$, GW h/day).

Supply sources (k)	Ireland ($m = 1$)	UK ($m = 2$)
Corrib	15776.20	0.00
Irish LNG	79480.94	0.00
UKCS	0.00	199980.00
Norway	0.00	333300.00
BBL	0.00	214922.95
IUK	0.00	300081.10
UK LNG	0.00	414436.33

Table 2: Yearly maximum capacities ($TP_{km}^{\max}$, GW h).

	Irish LNG Storage	Irish Independent Storage	UK LRS	UK MRS
$MAXSTOR_{km}$ (GW h)	8.89	8888.00	36663.00	15998.40
$MINSTOR_{km}$ (GW h)	0.00	0.00	957.00	3719.00
$INITSTOR_{km}$ (GW h)	0.00	4266.24	12625.00	12438.00
$DI_{km}^{\max}$ (GW h /day)	2.93	222.20	455.51	1422.08
$DX_{km}^{\max}$ (GW h /day)	2.93	222.20	455.51	1422.08

Table 3: Storage parameters.

	Summer	Winter
C_{pmt}^{inj}	7.315	255.64
C_{pmt}^{xtr}	255.64	7.315

Table 4: Storage marginal costs (€/GW h)

injection or withdraw of gas, but not its production. In contrast, LNG terminals are associated with tanks that permit to stockpile gas. Therefore, Irish LNG is assumed to operate as a source of gas supply, likewise as a storage facility.

The parameters associated with the different storage facilities are displayed in Table 3. As Shannon LNG import terminal also consists of four storage tanks, each with a capacity of 200,000 cubic meters (cm), an Irish LNG storage capacity of 8.89 GW h is assumed. Following [27], we consider a storage loss factor of $LOSS_m = 0.015\ \forall m$, which corresponds to a minimum amount of gas required to maintain a pressure level in the storage facility for normal operations. A potential independent Irish storage facility with a maximum capacity of 8888 GW h (800 mcm) is also considered in the model. We assume that this storage facility is initially 48% full.

For the UK facilities (LRS and MRS), the maximum capacities and maximum daily rates were obtained from [24]. The minimum values correspond to the actual minimum values for these facilities across 2015 and 2016 while the initial values were taken from the actual values from the 1st January 2018.

The storage marginal costs (Table 4) are the same for each facility but vary depending on the season: In the summer (March - September, inclusive), injection costs are lower than in the winter, and *vice versa*. These costs were obtained from [28].

Finally, we consider $|A|$=1 pipeline interconnecting the Irish and UK markets. This pipeline represents the Moffat interconnector, which has a maximum daily capacity of 344.41 GW h/day

[25] [24]. Following [27], we consider a pipeline loss factor of 0.22% per 100Km. As Moffat is 258.88 Km in length, this corresponds to a loss factor of $LOSS_{a=1} = 0.0063$. For the marginal cost of the pipelines, we assume a value of $C^{pipe}_{a=1,t} = 442$ (€/GW h) $\forall t$, a number determined from Gas Networks Ireland [29].

4.1.1. Supply side cost data

The marginal supply cost values ($C^{supply,s}_{mt}$) for $|S|$=10 scenarios were set as follows. The UKCS production costs were based on operating costs recovered from the UK Oil & Gas Economic Report 2017 [30]. In accordance with the outlook in [30], in the period 2017-25 we assumed different trends in these costs to account for the depleting path underlying UKCS production and the uncertainty in its recovery costs. These trends were set by assuming costs linearly increasing/decresing at progressively higher annual rates, such as to achieve UKCS production costs for 2025 in the range of ± 20% compared to the 2016 level. Corrib production costs were assumed to be the same as the UKCS costs.

Pipeline and LNG import costs for 2017 were retrieved from Thomson Reuters Eikon. For LNG, we considered separate import costs scenarios for Qatar and Trinidad & Tobago, since these countries are the two most important LNG suppliers in the UK, and accounted on average for 90% and 3% of the total LNG supply during the period 2013-17, respectively[7]. The expected import cost profiles over the period 2018-25 where set based on the forward curves as follow: Pipeline import costs from Norway were assumed to follow the forward price curve at the UK National Balancing Point (NBP) gas trading hub [31]; Expected pipeline import costs through IUK (from Belgium) and BBL (from the Netherlands) were assumed to mimic the forward curves of TTF[8] and Zeebrugge[9], respectively; LNG import costs were assumed to proceed along with the NBP forward curves. The natural gas forward curves were recovered from Thomson Reuters Eikon as published on 19 April 2018.

To account for the unpredictability of the natural gas prices and changing market conditions, a Monte Carlo exercise was set to design different scenarios for each supply source. Brownian motions were simulated with increasing levels of volatility. We assumed greater variability in

[7] https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/736148/DUKES_2018.pdf

[8] Natural gas price at the Title Transfer Facility (TTF) Virtual Trading Point, operated by Gasunie Transport Services (GTS), the transmission system operator in the Netherlands

[9] Natural gas price at the Zeebrugge Trading Point (ZTP), operated by Fluxys Belgium SA, the transmission system operator in Belgium

the winter than in the summer, thus in accordance with empirical evidence in the natural gas markets [32] [33]. The Brownian motions were therefore added to the price series above in a proportional way and accounting for seasonalities in the series, so that all import costs show the same amount of uncertainty under each scenario. We chose the first ten Monte-Carlo simulations to populate the $|S| = 10$ scenarios for each supply source, that is the parameter $C^{supply,s}_{mt}$. Consequently, we assumed each scenario had an equal probability, i.e., $PROB^s = \frac{1}{10}$, $\forall s$.

4.2. Demand side data

In order to obtain the parameters associated with the linear stochastic demand curves in 2025, we assume different demand profiles. For the UK, the demand profiles were set such as to reflect the 2017 energy and emissions projections published by the UK Department for Business, Energy and Industrial Strategy [34]. These projections are based on different assumptions of economic growth and fossil fuel prices. We consider the BEIS reference case, which reflects the economy forecast published in the UK Office for Budget Responsibility (OBR) January 2017 Fiscal Sustainability Report [35]. Our demand profiles consider the BEIS low and high economic growth cases as well, which reflect the OBR's alternative economic trends. These trends embody the UK's exit from the EU (low case) and the assumption of no-Brexit (high case). The two alternative economic trends are broadly symmetric around the central reference case.

Similar to the UK, demand profiles in Ireland were designed to reflect a broad range of likely economic outcomes, depending upon external and internal factors. These profiles are in accordance with the low, median and high gas demand forecasts published by Gas Network Ireland (GNI) in the Network Development Plan 2017 [36].

To explore the impact of uncertainty and changing markets conditions, in each scenario the same Brownian motions simulated for the supply costs were added to the demand profiles in a proportional way. This ensured that the same amount of uncertainty was added to demand and supply costs in each scenario. We chose the first four Monte-Carlo simulations based off the reference case, the first three based off the low case and the first three based off the high case. In total, this gives us $|S| = 10$ scenarios for the demand curve intercepts (Z^s_{mt}). For the slope of the demand curves (B_{mt}), we assumed values of -0.005 and -0.051 for Ireland and the UK, respectively. These values are scenario independent and were calculated using the following formula:

$$B_{mt} = \text{elasticity} \times \frac{\hat{Q}}{\hat{P}}, \tag{4}$$

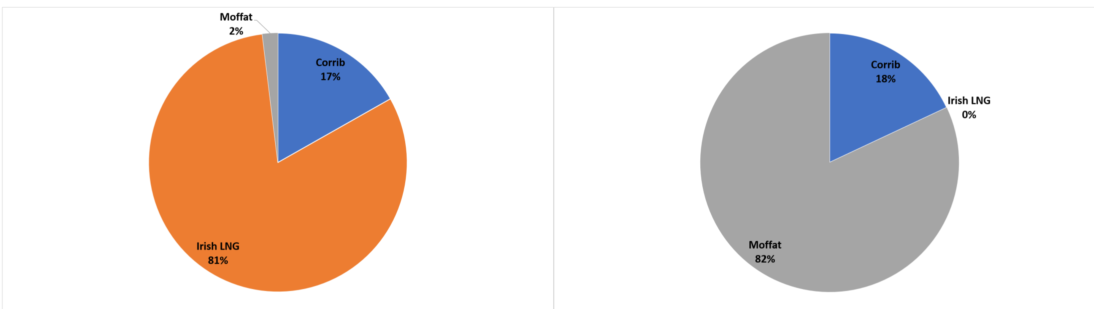
where $\hat{Q}$ and $\hat{P}$ represent the average quantities and price of gas, respectively, and were calculated based on the 2016 values. Moreover, for the Irish market we chose an elasticity of -0.347 [37] while for the UK we used a value of of -0.3 [38].

5. Results

5.1. PCIs: The Impacts of an LNG facility on consumers' energy bill

5.1.1. Low LNG prices

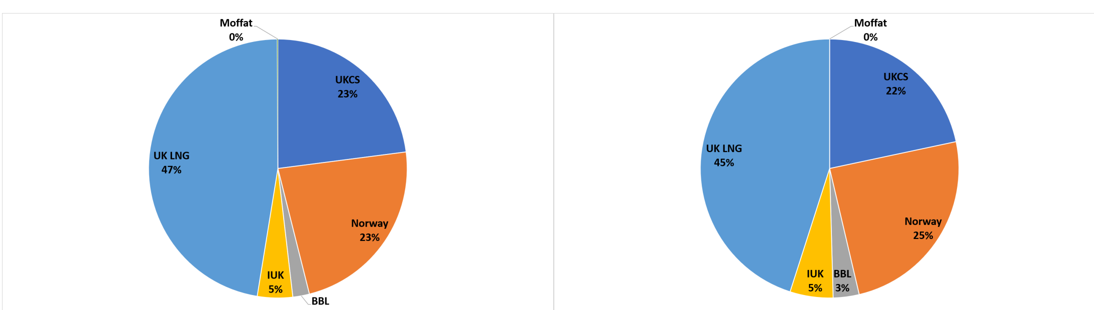
In order to determine the impact of PCIs on the consumers' energy bill in Ireland, we run the MCP model twice, once with the Irish LNG project operational and once without it. The 10 scenarios for the marginal LNG prices are based on projections for Qatari LNG prices.



(a) With Irish LNG facility (b) Without

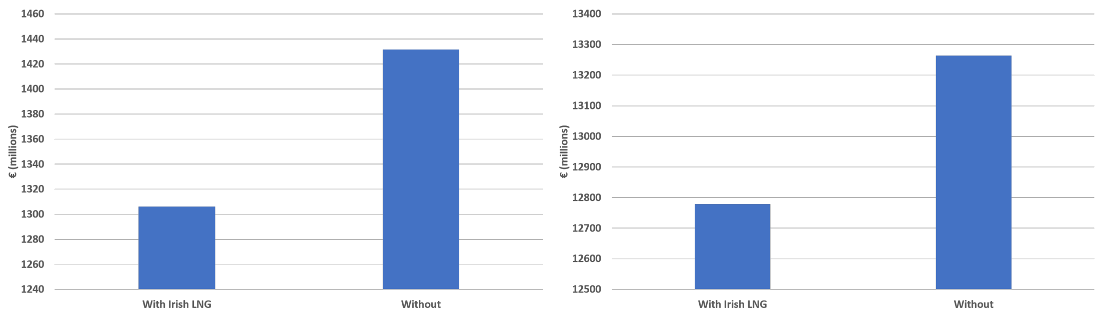
Figure 1: Sources of supply in Irish gas market (Qatar LNG prices and no Irish storage)

As summarised in Figure 1, the dependency of Ireland on gas imported from the UK (through the Moffat pipeline) reduces from 82% to 2% with the Irish LNG import facility. In contrast,



(a) With Irish LNG facility (b) Without

Figure 2: Sources of supply in UK gas market (Qatar LNG prices and no Irish storage)



(a) Ireland

(b) UK

Figure 3: Expected consumer cost (Qatar LNG prices and no Irish storage)

the composition of UK supplies is relatively unchanged following the introduction of the Irish LNG facility, as depicted in 2.

Figure 3a shows that total expected consumer costs ($\sum_s PROB^s \sum_{k,t} \pi^s_{mt} DAYS_t sales^s_{kmt}$) in Ireland decrease by €125M in 2025, which represents an average annual saving of 8.8%. This saving occurs despite the fact that gas supply costs in the UK and Ireland are driven by the same LNG import prices (Qatar). The cost reduction tallies with evidence in Figure 4, which depicts the expected net flow of gas into Ireland from the UK via the Moffat pipeline. Without an LNG import facility, gas flows from the UK to Ireland through Moffat everyday. Consequently, the cost of using Moffat is added to the Irish marginal cost of gas. When Ireland has its own LNG facility, these flows are significantly lower. Furthermore, in some days, during the summer, gas flows in reversed direction, that is from Ireland to the UK. During these days, the Moffat cost is paid by consumers in the UK, thus representing a saving for consumers in Ireland.

Figure 3b implies that, following the introduction of an LNG facility in Ireland, total expected consumer costs in the UK reduce by €485M (3.7%). Currently, Ireland can only import gas through the UK. In order to satisfy Irish gas demand, the UK needs to increase its own gas import. The observed lower consumer costs in the UK can be regarded thus as a consequence of the lower volumes of gas that, with an Irish LNG import terminal, the UK needs to import from international markets to satisfy the gas demand of Ireland.

5.1.2. High LNG price

In this section, the impact of an Irish LNG facility on consumers' energy bill is assessed by assuming Trinidad and Tobago LNG import prices, which are higher than the Qatari LNG prices, considered in the previous section. Based on 10 different scenarios for the gas demand

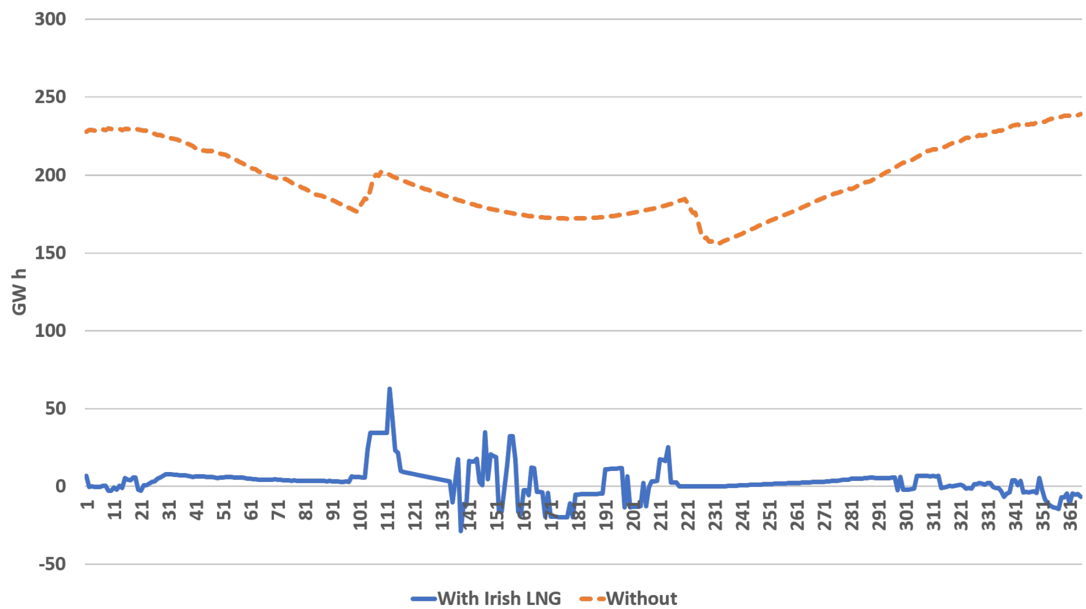


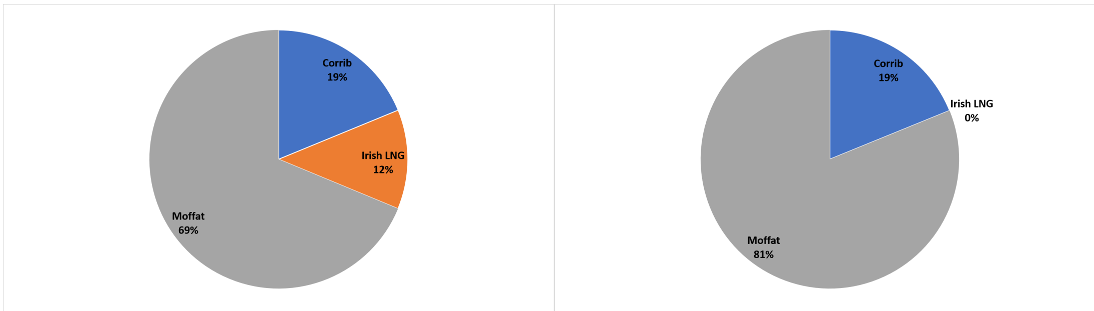
Figure 4: Net flows into Ireland via Moffat (Qatar LNG prices and no Irish storage)

and supply costs, results in Figure 5 show that with a LNG import facility, Ireland's dependency on gas import from the UK reduces from 82% to 69%. This reduction is lower when compared with that observed in Figure 1 and suggests that, because of the higher LNG prices, there are many days when it is cheaper to import gas through the UK than from the international LNG markets. Figure 6 implies that the composition of the UK supplies is largely unaffected by an Irish LNG facility. Yet, when compared to Figure 2, evidence in Figure 6 suggests that the proportion of LNG supply in the UK reduces from 45% to 3%. That is, with high LNG import costs it is more convenient for the UK to import gas from Norway and continental Europe.

Figure 7 suggests that total expected consumer costs reduce in both Ireland and the UK as a result of the Irish LNG facility. However, in contrast to results in Figure 3, this reduction is limited (0.7% and 0.2% respectively). This result provides a measure of the sensitivity of the consumers' cost saving, resulting from the presence of a LNG facility, to changing market conditions.

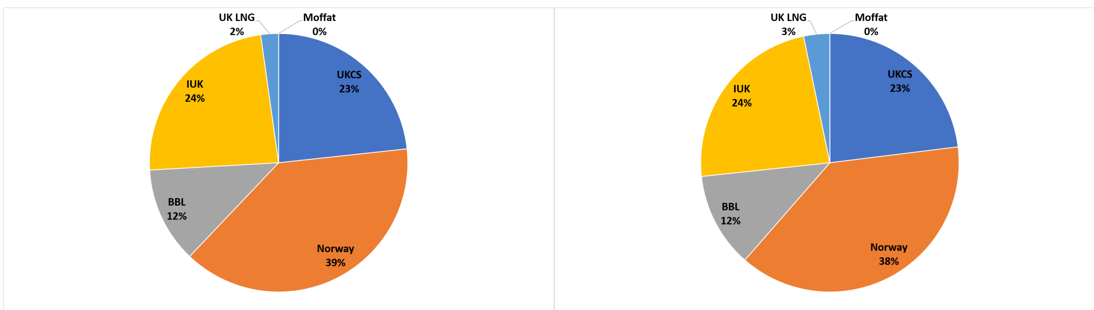
5.2. Impacts of Irish storage facility

The results from the sensitivity analysis on the impact of a 800 mcm independent storage facility in Ireland (with and without an Irish LNG facility) are presented in this section. In this analysis, we assumed that LNG import costs are based on Qatari LNG prices. With a storage



(a) With Irish LNG facility (b) Without

Figure 5: Sources of supply in Irish gas market (Trinidad & Tobago LNG prices and no Irish storage).

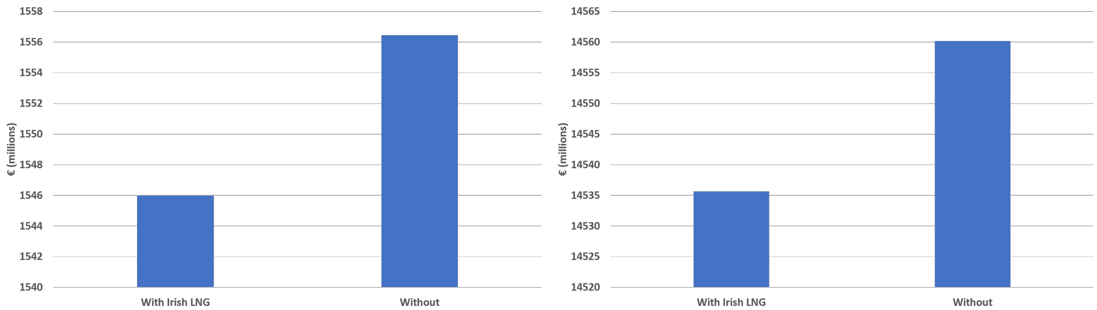


(a) With Irish LNG facility (b) Without

Figure 6: Sources of supply in UK gas market (Trinidad & Tobago LNG prices and no Irish storage).

facility in Ireland, gas import increases both in Ireland and the UK, regardless of the presence of an Irish LNG facility (Figure 8). Yet, results show that gas import is greater with an Irish LNG import terminal. That is, the Irish storage facility allows for higher volumes of gas to be imported into Ireland during the summer, when gas prices are lower compared to winter. These volumes mostly come to Ireland through the UK. During winter, i.e. when gas demand is higher, the storage facility allows the gas to flow back to the UK via the Moffat pipeline. Therefore, an Irish storage facility would enable arbitrage opportunities in the gas markets to be exploited by allowing the gas to be imported (and stored) into Ireland from the UK in the summer at lower costs, and to be reexported to the UK in the winter, at higher costs.

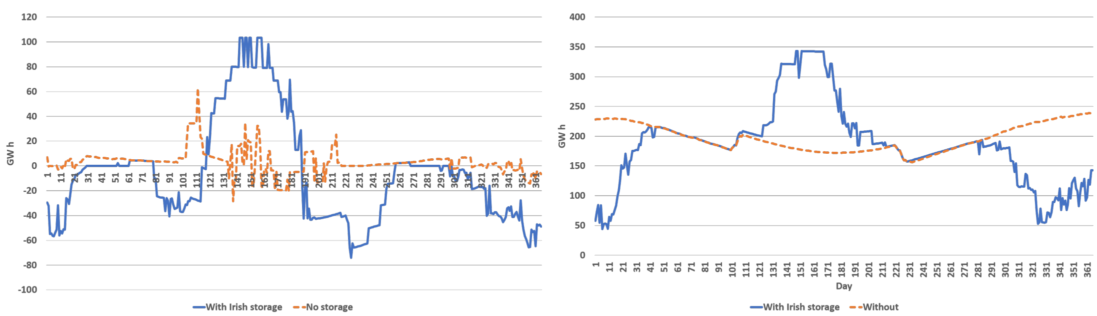
Overall, evidence in Figure 9 implies that an Irish storage facility would reduce total expected consumer costs. The cost reduction amounts to €7.83M (1%) in 2025 with an LNG facility and to €23.25M (2%) without. Compared to results in Section 5.1.1, results in this section can be explained by the different use of the Moffat pipeline, in both direct (from the UK to Ireland) and



(a) Ireland

(b) UK

Figure 7: Expected consumer cost (Trinidad & Tobago LNG prices and no Irish storage)



(a) With Irish LNG facility

(b) Without

Figure 8: Net flows into Ireland via Moffat (Qatar LNG prices and with Irish storage)

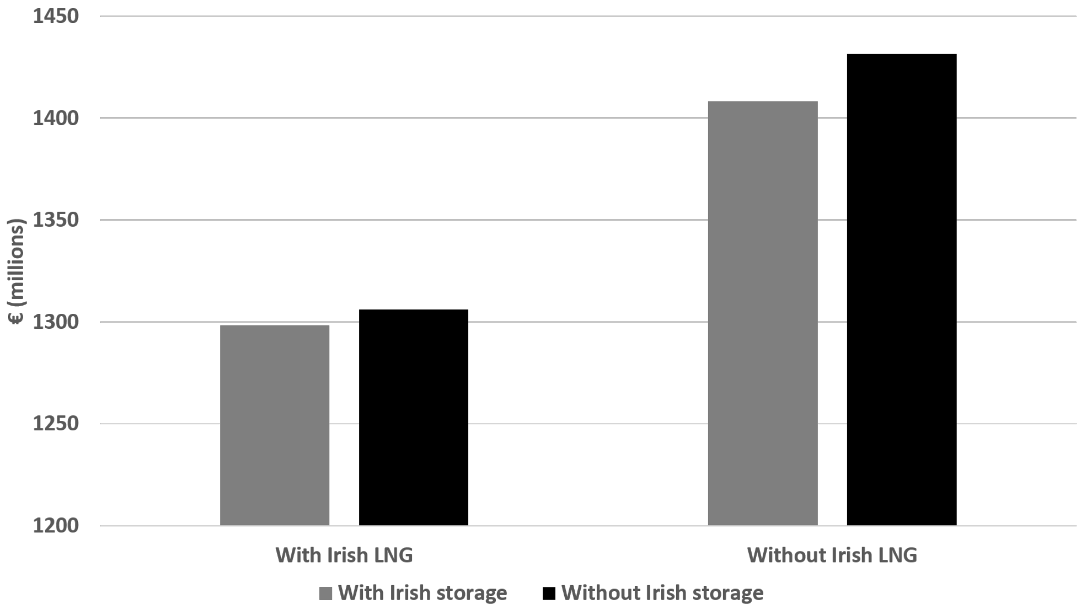


Figure 9: Expected consumer cost (Qatar LNG prices and with Irish storage)

reversed (from Ireland to the UK) flow. The reversed flow implies that consumers in the UK pay for the pipeline marginal cost in some days of the year, during the winter. This cost represents a saving for Irish consumers. Total expected consumer costs in the UK are also reduced with an Irish storage facility, although is limited to 0.3%. Consequently, results in Figure 9 suggest that LNG and storage facilities represent complementary technologies and both contribute to reduce consumers' energy bill. It is important to note that the estimated consumers' saving represents an expected, or average, saving. Depending upon market conditions, this saving can be greater, as also argued in [21].

5.3. Impact of a storage facility in the UK

In the previous sections, we have accounted for the closure of the UK Rough storage facility. [10]. Therefore, it has not been included in the model runs as operational. In this section, we consider the hypothesis of a refurbishment of Rough, which is based on the UK Competition and Markets Authority (CMA) review. According to this review, a reinstatement of Rough becomes economically valuable when assuming high gas demand and price volatility[11]

[10]https://www.ft.com/content/564a1ec0-8288-11e7-a4ce-15b2513cb3ff

[11]In October 2017, the UK Competition and Markets Authority announced the appointment of a Group to undertake a review of the Rough decision based on changes in market conditions. Conclusions from this

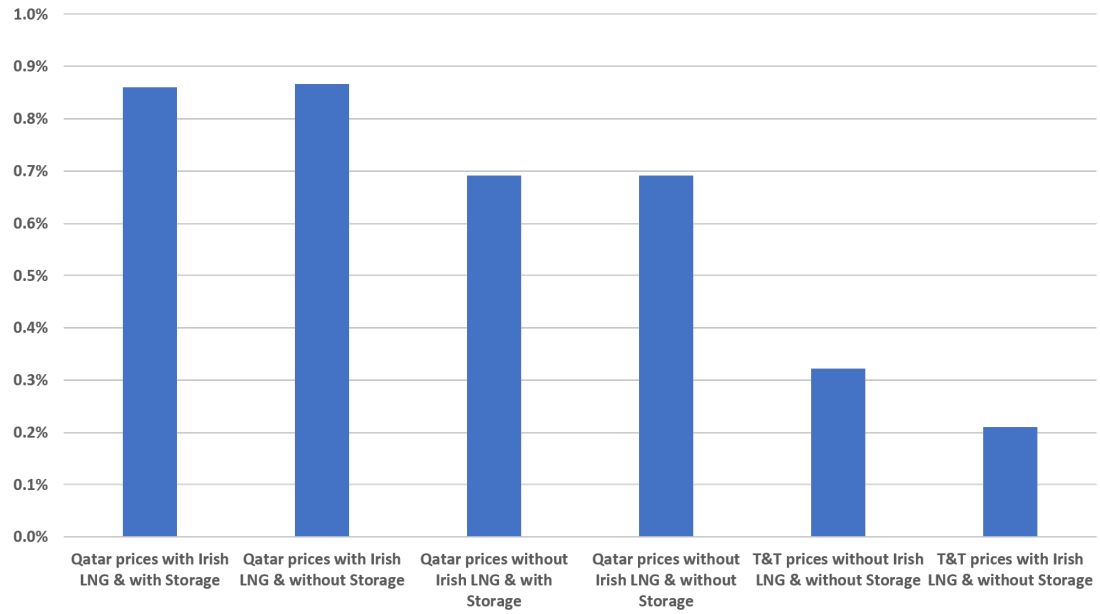


Figure 10: Percentage decrease in expected Irish consumer costs as a result of re-introduction of the Rough facility.

Figure 10 and Figure 11 show the percentage decrease in expected Irish and UK consumer costs due to a re-introduction of the Rough facility for each of the cases considered in Section 5.1 and Section 5.2. These percentages imply a saving for consumers in both the UK and Ireland. Similar to the Irish storage facility above, the Rough facility allows gas to be stored during the summer, when prices are relatively cheap, and to use it in the winter, when demand and prices are higher. Therefore, Rough allows arbitrage opportunities between summer/winter gas prices to be exploited to the benefit of UK consumers. Given Ireland's connection with the UK market, the benefit is also passed to Irish consumers in the form of lower expected gas costs. The saving is greater when LNG prices are relatively low (i.e. Qatar prices) but modest when LNG prices are higher (Trinidad & Tobago). This implies that summer/winter arbitrage opportunities are more economically exploitable in a context of low LNG import prices and with an operational Irish LNG facility. In this latter case, the expected percentage saving of UK consumers is above 1.1% when compared to the case without Rough (Figure 11); for Irish consumers, the saving

review imply the economic infeasibility of such a refurbishment, based on the current forward projections of summer/winter gas spread. `https://assets.publishing.service.gov.uk/media/5a30ff94ed915d2cf25281ac/rough-final-decision.pdf`.

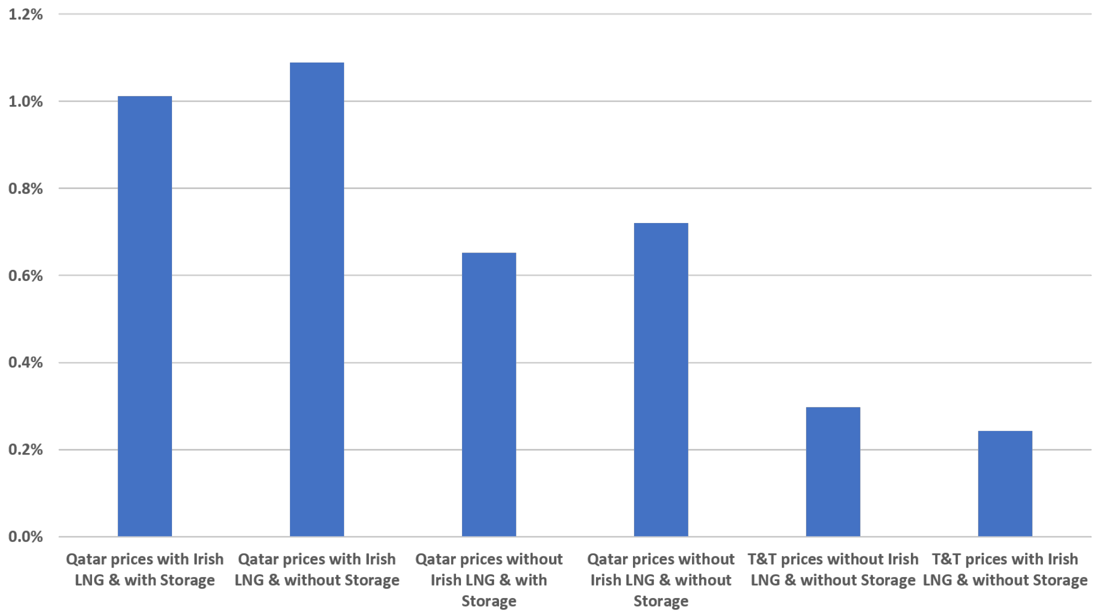


Figure 11: Percentage decrease in expected UK consumer costs as a result of re-introduction of the Rough facility.

is 0.9%. These consumer savings are based on expected gas demand and import costs. When considering high demand scenarios and/or high gas price volatility, the benefit for consumers is greater.

6. Discussion

In this work we use a stochastic Mixed Complementarity Problem (MCP) approach to evaluate the potential of EU Projects of Common Interest (PCIs) to increase natural gas supply diversification and reduce consumers' energy bill. We focus on Ireland and the UK, and present an assessment of the sensitivity of gas supply mix and consumer saving to different gas facilities in 2025. In the last two decades, the EU has focused on accomplishing the objective of a European Single Market, thus encouraging the creation of single markets for electricity and natural gas, in line with EU targets for energy and climate. PCIs are infrastructure projects that are considered pivotal for the European energy policy and hence eligible for financial support through the Connecting Europe Facility EU's funding [12]. Gas projects are of particular interest since they are aimed to improve EU's supply security through diversified gas sources, especially

[12] https://ec.europa.eu/inea/connecting-europe-facility/cef-energy

in the context of expected more competitive LNG markets [39]. In the energy system of Ireland (Republic of Ireland and Northern Ireland), PCIs have further political implications.

Ireland buys significant amount of gas from the UK. The UK is the only transit country for gas (and electricity) between continental Europe and Ireland. Ireland currently has no LNG terminal. Ensuring gas supply security in Ireland, in particular following Brexit, is therefore paramount for the achievement of EU's objective [40] [41]. Ireland and the UK have intergovernmental agreements on sharing gas supplies that will exist beyond Brexit. However, Brexit uncertainty may represent a risk for gas supply to Ireland [40]. The Shannon LNG facility, in Republic of Ireland, and the Islandmagee Underground Gas Storage (UGS) facility, in Northern Ireland, have been classified as PCIs by the European Commission to guarantee secure, affordable and diversified gas supply in Ireland. Thus, it becomes relevant to consider the economic impact of these projects on consumers.

The model developed in this study includes a detailed representation of the UK and Ireland gas markets and thus captures the change of interconnectedness between them, likewise the economic implications of such a change for consumers. The stochastic MCP incorporates ten different demand/supply cost scenarios with equal probability, so as to evaluate the expected gas supply costs for the year 2025.

Our results show that with the introduction of an Irish LNG facility, total annualised expected costs for consumers reduce both in Ireland and the UK. However, the size of this reduction depends upon the competitiveness of the global LNG market relative to pipeline import costs. Pipeline import costs mostly reflect the NBP and continental Europe hub prices. When LNG prices are more competitive than European prices, as in the case of the LNG imported from Qatar, our results suggest that expected consumer costs can fall by 8.8% in Ireland and 3.7% in the UK. This corresponds to an annual savings on the gas bill in Ireland of around €63M in the residential sector and €67M in the industrial sector [13]. When global LNG prices are less competitive, as in the case on the LNG imported from Trinidad & Tobago, an Irish LNG facility would bring annual savings of 0.7% in Ireland and 0.2% in the UK. Furthermore, the Irish LNG facility would allow the Moffat pipeline to be used in reverse flow, i.e. not only to import gas

[13] Energy saving based on the average Irish gas demand and prices of the residential and industrial sectors in 2015-16, as published by Eurostat and available at `https://ec.europa.eu/eurostat/data/database`. In the residential sector, an average gas demand of 11,000 kWh per annum has been assumed, in accordance with the Commission for Energy Regulation survey available at `https://www.cru.ie/wp-content/uploads/2017/07/CER17042-Review-of-Typical-Consumption-Figures-Decision-Paper-1.pdf`).

from the UK but also to export it into the UK. Therefore, this facility can significantly reduce Ireland's dependency on the UK for gas supply. When exporting, Moffat tariffs would be paid by consumers in the UK. Since on-land transmission and distribution costs constitute about 40% of the final gas price in Ireland, using Moffat pipeline in reverse flow can have significant positive impact on consumers in Ireland.

Our results also show that a storage facility in Ireland can reduce annualised consumer costs by 1 - 2%, depending upon the presence or not of the LNG facility. The main driver behind this saving is a change in the flow of gas through the Moffat pipeline. This flow is mainly driven by the exploitation of arbitrage opportunities: Gas is injected into storage in Ireland during the summer, when prices are lower, and withdrawn to be exported to the UK in the winter, at higher prices. As mentioned above, the cost of this reverse flow is borne by consumers in UK while consumers in Ireland benefit from more competitive supply sources. Yet, this arbitrage opportunity led by winter/summer gas price spread can also bring a cost reduction for consumers in the UK (0.3%). With the increasing importance of storage for European natural gas markets [42], the development of a storage facility in Ireland, which is the only EU country without gas storage, would allow an effective management of supply risk and seasonal supply-demand imbalances, especially when considering the closure of the UK's large-scale storage facility Rough.

In our analysis, we also consider the implications of a re-introduction of the Rough facility for consumers in the UK and Ireland. The findings suggest that this re-introduction would imply a cost decrease in Ireland in the range of 0.2% - 0.85%, depending upon LNG import prices, the presence of an Irish LNG and/or storage facility. For consumers in the UK, the cost decrease would be in the range of 0.25% - 1.2%.

Overall, depending upon the volatility of LNG prices worldwide, our study provides a quantification of the expected economic benefits for consumers associated with PCIs. Our findings also suggest the importance of ensuring long-term gas supply in Ireland, as highlighted in [43], who also envisage the need of a well diversified supply in Ireland, in order to overcome its vulnerability to gas shortages. This diversification is well documented in our paper. We observe that a LNG facility in Ireland would reduce Irish gas dependence from UK from 82% to 2% in a low LNG price scenario (69% in the high LNG price scenario). Compared to previous research, however, we also consider the impact of such a diversification on consumers.

Despite the importance of gas storage to guarantee supply diversification in Ireland [43], we find that the expected cost reduction associated with a storage facility is lower than the cost reduction led by a LNG import terminal. A link between trade volumes, forward curves and profitability of storage assets has been observed in literature (e.g. [44] [45] [46]). In particular, [44] argue that under normal market conditions, storage capacity is efficiently used and available at relatively low costs. However, in the long-term and in the presence of unexpected conditions, (e.g. shocks to the demand, high price volatility, high winter-summer spread), there may be a shortage of storage in the system, which reduces its flexibility and increases storage value. In this study, we document the value of storage for consumers when considering the impact of re-introducing the UK storage facility Rough (see Figures 10 and 11).

Following the liberalisation of European energy markets, players are able to pursue storage operational decisions based on a combination of available flexible sources and market prices. This leads to a more efficient use of storage capacity for the market as a whole. In our study, the implications of storage operational decisions can be inferred by comparing market dynamics with low and high LNG prices. With low LNG prices (based on Qatar prices in our study), LNG imports increase and the gas markets become more exposed to price volatility and winter-summer spread in international LNG markets. In such a context, the flexibility brought by a storage facility in the system is higher, likewise the economic value of gas storage for consumers. In contrast, when LNG prices are high (based on Trinidad & Tobago prices), LNG becomes less competitive compared to more traditional pipeline imports from Norway and continental Europe. Pipeline imports are subject to lower price volatility and winter-summer spread, which implies a lower economic value for storage, and in turn for consumers. This reasoning is in line with consumer cost evaluations in Figures 10 and 11, and in accordance with [44]. Noticeably, in our study, evaluations are based on expected demand and price profiles, which therefore may underestimate the economic impact of storage. For high demand scenarios and/or unexpected shocks in the market, consumer cost reductions can be greater. These results are of particular interest to policy-makers and investors when evaluating investment decisions in gas infrastructure.

By investigating the impact of gas infrastructure outages on power systems, [45] argue that lack of gas storage capacity in Ireland increases the risk profile of electricity generation, and in turn generation costs. They estimate that a storage facility in Ireland can reduce generation costs up to 40%. Potential under-investment in natural gas infrastructures can influence power sector functioning in Ireland, especially when considering the high penetration of wind power. With the Integrated Single Electricity Market (I-SEM) becoming operational in October 2018, any gas shortage in Ireland has the potential to erode expected benefits from increased flexibility and procurement services, while limiting the effectiveness of reliability options in guaranteeing power supply. In addition, high uncertainty in wind generation exacerbates the exposure of gas generators to spot price volatility, thus affecting their ability to economically operate gas plants. Similarly, [5] argue that, despite the extra costs to install a storage facility, gas storage avoids power generation limitations resulting from gas supply shortages and ensures power system reliability. Furthermore, it has implications when considering the maximum absorption capacity of renewable energy sources and their uncertainty. [47] also suggest that it will become beneficial for electricity systems to invest in power-to-gas electrolysers. Such investments would have a significant impact on gas supply and demand in Ireland.

Based on results in our study, we can therefore conclude that LNG and storage facilities represent complementary investments. In the context of PCIs, both these investments contribute to the competitiveness and diversification of gas markets. Furthermore, they are pivotal in supporting the increasing integration between gas and power markets with high capacity of renewable energy sources.

7. Conclusions

In this paper, we utilise a stochastic Mixed Complementarity Problem (MCP) to provide an evaluation of the EU PCIs gas infrastructures, and their implications for gas market interconnectedness and supply diversification. We contribute to the literature by proposing an optimisation model that considers both LNG and storage infrastructures, and their interaction in managing gas flows. Based on seasonal fluctuations of gas loads and prices at daily resolution, our model assesses not only annualised expect cost reductions for consumers but also their sensitivity to changing market conditions. Our results are of interest when considering consumers' benefits of EU energy policies and legislation goals.

We perform our analysis in the context of the Ireland-UK integrated gas market due to its peculiarities. First, Ireland is the only EU country without LNG and storage facilities. Second, the UK serves as transit country for gas (and electricity) flowing into Ireland. Therefore, the UK also represents the only transit route to connect Ireland's energy market to European and global energy markets. Finally, the achievement of the EU 2020 and 2030 renewable energy targets is expected to set Ireland as a leader in the penetrations of variable non-synchronous power generation worldwide [48]. Yet, according to the most recent analysis by the International Energy Agency [49], system integration of renewable energy sources remains a major challenge. The development of new infrastructures, including gas infrastructure, is thus paramount to facilitate the integration of larger volumes of renewable sources across integrated energy markets, and to improve their flexibility. Therefore, the Ireland-UK gas system provides the ideal framework to evaluate the contributions of new investments in gas infrastructures to the achievement of sustainable development, security of supply and competitiveness, along with the cost-benefits for consumers.

Results in our study suggest that whilst a LNG facility would optimise expected cost reduction for consumers in Ireland and UK, gas storage facilities would increase the natural gas (and power) system flexibility. While the methodological approach in this paper provides useful insights, there are limitations to the analysis undertaken. When analysing the impact of Irish LNG and storage facilities, only benefits of these investment options are considered. The initial investment cost of building the facilities is not available to the authors. Thus, while the consumer cost savings are clear, this paper does not quantify the net benefit of such options.

In our model specification, we only consider integrated gas markets, and not their integration with power system. Consequently, electricity demand is determined exogenously (albeit multiple demand scenarios are assumed). With expected and target-driven higher penetration of renewable sources, interactions between gas and electricity systems will increase. These interactions are of interest to policy-makers and market players, in particular in the context of a European single market, and represent an avenue for future research.

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Appendix A. Tables

$a \in A$	Arcs (gas pipelines).
$k \in K$	Suppliers.
$t \in T$	Time steps.
$m \in M$	Gas node/market m.
$a \in A(m)$	Arcs connected to market m.
$a^{in}(m)$	Arcs inward to market/node m.
$a^{out}(m)$	Arcs outward from node m.
$e \in \{1, .., t\}$	Dummy time index for storage constraint that represent timesteps from 1 to t.

Table A.5: Sets

$DAYS_t$	Number of days in time period t.
$DP_{km}^{\max}$	Maximum supply capacity for source p at node m (GW h/day).
$DI_{km}^{\max}$	Maximum storage injection rate of supply source p at node m (GW h/day).
$DX_{km}^{\max}$	Maximum storage extraction rate of supply source p at market/node m (GW h/day).
$DA_a^{\max}$	Maximum arc capacity for arc a (GW h/day).
$TP_{km}^{\max}$	Total production capacity from source p at node m over the whole time horizon for (GW h).
$MP_{km}^{\max}$	Minimum production capacity from source p at node m over the whole time horizon (GW h).
$MINSTOR_{km}$	Minimum amount of supply source p in market m must have (GW h).
$INITSTOR_{km}$	Initial amount of supply source p in market m has(GW h).
$MAXSTOR_{km}$	Maximum amount of supply source p in market m can have (GW h).
$LOSS_m$	Injection to storage loss factor for node m (%).
$LOSS_a$	Arc a loss factor (%).
Z_{mt}^s	Demand curve intercept at market/node m for timestep t and scenario s (GW h).
B_{mt}	Demand curve slope at market/node m for timestep t(€/GW h).
$PROB^s$	probability associated with scenario s.

$C_{pmt}^{supply,s}$	Marginal supply cost for source p at node m at time t and scenario s (€/GW h).
C_{mt}^{xtr}	Marginal cost of extraction from storage at node m at time t (€/GW h).
C_{mt}^{inj}	Marginal cost of injection to storage at node m at time t (€/GW h).
C_{at}^{pipe}	Marginal supply cost for flowing gas through pipeline a at time t (€/GW h).

Table A.6: Model parameters.

$sales_{kmt}^{s}$	Amount supply source p, at node m, sells at time t and scenario s (GW h/day).
$supply_{kmt}^{s}$	Amount supply source p,at node m, buys from source p at time t and scenario s. (GW h/day).
inj_{kmt}^{s}	Amount injected into supply source p's, at node m at time t and scenario s (GW h/day).
xtr_{kmt}^{s}	Amount extracted from supply source p's, at node m at time t and scenario s (GW h/day).
$flows_{kat}^{s}$	Supplier k's flows through arc a at time t and scenario s (GW h/day).

Table A.7: Primal variables: each of the primal variables have two superscripts.

π_{mt}^{s}	Market-clearing price of gas for node m, time t and scenario s (€/GW h).
$\lambda_{\cdot}^{*,k\#}$	Lagrange multiplier associated with constraint # in supplier's problem (unit depends on the constraint).
τ_{at}^{s}	Lagrange multiplier associated with maximum capacity of arc a at time t at scenario s (€/GW h).

Table A.8: Dual variables.

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