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Investing in Flexibility in an Integrated Planning of Natural Gas and Power Systems

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Abstract: The growing interdependencies between natural gas and power systems, driven by gas-fired generators and gas compressors supplied by electricity, necessitates detailed investigation of the interactions between these vectors, particularly in the context of growing penetration of renewable energy sources. In this research, an expansion planning model for integrated natural gas and power systems is proposed. The model investigates optimal investment in flexibility options such as battery storage, demand side response, and gas-fired generators. The value of these flexibility options is quantified for gas and electricity systems in GB in 2030. The results indicate that the flexibility options could play an important role in meeting the emission targets in the future. However, the investment costs of these options highly impact the future generation mix as well as the type of reinforcements in the natural gas system infrastructure. Through deployment of the flexibility options up to $£24.2\text{b}$ annual cost savings in planning and operation of natural gas and power systems could be achieved, compared to the case that no flexibility option is considered.

Nomenclature

Parameters & Variables

C	cost (£)
CR	compressor ratio
D	diameter of the pipe (mm)
e	produced green house gas emissions (tonnes).
E^{estor}	energy level of electricity storage (MWh)
$E_b{}^{\text{max}}$	maximum energy level of electricity storage at busbar b (MWh)
E^{estor}	energy level of electricity storage (MWh)
$E^{\text{storlimit}}$	maximum available capacity of electricity storage, which could be installed in the system (MWh)
$h_{l,i}$	Sensitivity coefficient of flow on line l with respect to power injection of supply point i (based on DC load flow model)
Le	length of a gas pipeline (km)
n	economic lifetime of the technology or asset
F	power flow of line (MW)
p	pressure (bar)
P	power output (MW)
P^{caplimit}	maximum available capacity of electricity demand, which could be shifted (MW)
P^{dsrcap}	maximum installed capacity of flexible demand (MW)
$P^{\text{FlexGPlimit}}$	maximum available capacity of flexible CCGTs, which could be installed in the system (MW)
Q	gas flow (mcm/h)
r	provided reserve (MW)
ur	unserved reserve (MW)
Y	capacity of a generation unit (MW)
Z	cost in the objective function (£)
α	the WACC of each technology or asset
β	polytropic exponent (4.70)
η	efficiency (%).
γ^{et}	carbon emission target of the system (grCO_2/KWh)
λ	decision variable on presence of generator in the generation mix (1/0)
Ω	proportion of wind for reserve requirements
ω	number of installed compressor units
ψ	fraction of electricity demand that is flexible
Ψ	maximum ramp up/down power of a generation unit (MW/h)
ζ^{tap}	amount of gas tapped by a compressor

Superscripts

ACAPEX	annualised capital cost expenditure
Avail	available
avg	average
cap	capacity
CAPEX	capital cost expenditure
comp	compressor
cur	curtailment
dis	discharge
dsr	demand side response
d−	decreased demand
d+	increased demand
ecomp	electrical-driven compressor
elec	electricity
eload	electricity demand
em	emission
estor	electricity storage
eshed	electrical load shedding
eq	equivalent
ex	existing
dem	demand
flex	flexibility
flexGP	flexible gas-fired plant
FOPEX	annualised fixed operational cost expenditure
gen	generator
gshed	gas load shedding
gstor	gas storage
inj	injection
inv	investment
max	maximum
min	minimum
new	new installed

op	operation
plan	planning
suc	suction
supp	supply
var	variable
VOPEX	variable operational cost expenditure
with	withdrawal

Sets

$\mathcal{B}$	set of electricity busbars
$\mathcal{C}$	set of compressors
$\mathcal{G}$	set of generation units
$\mathcal{K}$	set of thermal generation units
$\mathcal{K}_{\mathrm{FlexGP}}$	set of flexible gas-fired generation units
$\mathcal{L}_e$	set of electricity transmission lines
$\mathcal{L}_g$	set of gas pipelines
$\mathcal{M}$	set of gas nodes
$\mathcal{N}_s$	set of supply points
$\mathcal{N}_d$	set of demand points
$\mathcal{P}$	set of pump units
$\mathcal{S}_g$	set of gas storage facilities
$\mathcal{T}_{\mathrm{d}}$	time step within a day
$\mathcal{T}_{\mathrm{y}}$	representative days of a year
$\mathcal{Y}$	set of gas terminals

1 Introduction

Many countries are committed to increase their share of renewable sources to reduce their Greenhouse Gas (GHG) emissions by at least 80% until 2050 (compared to 1990) [1]. For example, in order to achieve these targets, in United Kingdom (UK) the projection is that the renewable sources should provide 27% of the total energy consumption by 2030 [2]. Given the abundant wind resources across UK, wind generation could play a significant role in the future generation mix to meet the renewable and emission reduction targets [3].

Although the volume of gas is decreasing due to the presence of renewables, but the value of gas as the main compensation source to produce electricity in lack of renewables is increasing. Therefore, the interdependency of the natural gas and power systems is increasing, which means more interaction between the gas and electricity system operators in supporting the balancing of electricity supply and demand. Utilising gas-fired plants to compensate for wind variability leads to variable gas demand for power generation [4], making it difficult to operate the natural gas system.

The interaction of these systems can be seen from operation and planning perspectives. From operation point of view, many researches such as [5–11], investigate the interaction of natural gas and power systems in terms of aspects such as security of supply, market, demand constraints, resiliency, and flexibility participation.

Due to interdependency of gas and electricity networks, some studies investigated operation of these networks in an integrated manner. For instance, in [5], a robust optimization model for scheduling natural gas and electricity networks was proposed taking into consideration uncertainties in electricity demand and wind farms' output power. In this model, the electricity and gas subproblems were iteratively solved devising Column and Constraint Generation (CCG) and Outer Approximation (OA), respectively. The obtained results indicated the capability of gas-fired units to reduce wind curtailment in co-optimization of these networks. In [6], a coordinated operation of natural gas and electricity infrastructures model was presented, in which different cases from non-integrated to fully-integrated optimization were investigated. The results demonstrated the benefits of fully-integrated optimization in enhancing the security and economic efficacy of these infrastructures. In [7], the value of different flexibility options including power-to-gas (P2G), electricity storage, and more flexible gas plants in an integrated operation of gas and electricity system is quantified. In [8], authors demonstrated how making the gas infrastructure more flexible through multi-directional compressors can improve the operation of gas and electricity systems and prevent gas load shedding in contingency condition. In [9], in order to optimize coordinated operation of gas and electricity networks, a hybrid approach was introduced, including a game-theoretic approach and multi-objective optimization. The aim of this game was to reflect the relationship between the amount and price of energy that distributed energy stations purchased from a utility network. After that, the multi-objective model was solved, which minimizes the conflicting cost of gas and electricity networks. In [10], it is demonstrated how provision of flexibility in gas and electricity systems, decrease the value of interdependency of these systems. In [11], a robust model was introduced to enhance the resiliency of integrated gas and electricity systems against probable outages which are caused by natural disasters. In this approach, an algorithm was also devised to solve the model consisting of Benders decomposition CCG.

Due to the electrification of segment of heat and transport sectors in the future, the electricity peak demand would be increased significantly. Therefore, the efficiency of the current natural gas and power systems as well as limited resources capacity highlights the need of optimal expansion of these systems. Furthermore, finding optimal pathways to meet the future emission targets according to such as the Paris agreement on climate change [12] is of a great importance. A coordinated expansion and planning for gas and electricity infrastructure facilitates cost-effective transition to a low carbon and secure energy system. In a planning strategy, economic, environmental as well as security of supply aspects should be considered.

In the following studies [13–15], the planning and operation optimisation for gas transmission networks are studied. In these researches, investments on compressors and gas pipelines are proposed as the options to reinforce the gas system infrastructure to improve the operation of the natural gas system. In [13], a cost-based Mixed Integer Non-Linear Programming (MINLP) optimisation model is implemented to design a new or expand pipeline network to meet the future network condition changes. It is shown how this can help the policy makers about the location and capacity of the pipelines and compressors. In [14], a Genetic Algorithm (GA) based optimisation has been derived for the design of natural gas system transmission network. It is demonstrated that the shortest total length is not necessary the optimal layout for the system, and cost savings is achieved in the used optimised layout in this research. Furthermore, it is concluded that the optimal pressure of a supply node is the maximum available pressure if the supply node is at the starting point of each pipeline connected to the supply node. From the other side, the optimum pressure for the demand node is the minimum required pressure if the demand node is at the end point of each pipeline connected to that node. In [15], an optimization model was introduced for expansion of natural gas fields, processing, and transport system. In this study, related decisions to model expansion was continuously proposed which reduces solving time of the problem considerably.

The lack of these studies is in not taking into account the whole-system (e.g., electricity) constraints, since in the future the interaction of different energy vectors will increase significantly. Chaudry et al. [16] developed a planning strategy for the infrastructures based on the Combined Gas and Electricity Network (CGEN) model. Two possible scenarios including base and low-carbon have been investigated. It was shown that this model is able to allocate timely and efficiently the required resources across the energy system. In addition, different aspects of planning and expansion of natural gas and power systems have been presented in [17–24]. In [17], a Mixed-Integer Linear Programming (MILP) optimisation problem is formulated to minimise costs of expansion planning of natural gas and power systems. It is found that jointly planning of these networks will result in cheaper costs compared to separate planning. In [18], a multi-stage co-planning approach comprising of non-linear constraints has been implemented to optimise the installation time and location of gas plants, gas pipes and power transmission lines. The performance of this approach is tested on a small system (IEEE 14-bus and a 14-node test gas system). The results indicate the efficacy of this method in long term market forecasting. In [19], a two-stage chance constrained programing was applied to optimize the cost of planning new gas-fired power plants, gas pipelines, and other flexibility options (e.g., energy storages and compressors) to ensure to meet gas and electricity demand under uncertainty. The obtained results indicated the role of storage systems in dealing with short time uncertainties. In another study [20], a two-stage co-planning model for optimal decision making on generating units, transmission lines, and gas pipelines to meet the load forecast is proposed. It is demonstrated that due to the constraints on gas transportation in the pipelines to the gas-fired plants, the scheduling planning in electricity system can be affected significantly. In [21], multi-stage stochastic programming was devised to cope with uncertainty of renewable energies in optimizing expansion of natural gas and electricity networks. The obtained results demonstrated the enhancement of feasibility robustness in the case of multi-stage decision making. In [22], a decentralized stochastic model was introduced for co-expansion of gas and electricity systems. In this model, uncertainties in output power of renewable energies, demand growth, and interest rate were taken into consideration. Moreover, the role of renewable energy expansion and demand response programs in preventing extra capacity investment was investigated. Alternating Direction Method of Multipliers (ADMM) was also developed to solve the mathematic model of this study. In [23], a multi attribute decision making method for expansion planning of gas and electricity networks was introduced taking into account the privacy of gas and electricity parties. In the proposed model, minimum of maximum regret and β-robustness approaches were also applied to deal with uncertainties and find a more suitable plan. Finally, Pareto optimal approach was devised to show the accuracy of the approach. In [24], an energy hub planning model consisting of different energy carriers (i.e., electricity, heat, and gas) is presented. The role of Combined Heat and Power (CHP) in providing the link between heat and electricity for optimising the energy system is highlighted. Furthermore, it is illustrated that the coupled modelling of these energy vectors can provide more flexibility for the energy supply, as the whole system constraints are considered.

Flexibility options such as Demand Side Response (DSR), flexible Combined Cycle Gas Turbines (CCGTs), electricity storage, and interconnection could participate in real-time system balancing requirements and the need to effectively maintain security of supply [25]. Employment of different mitigation techniques in future is highly dependent on costs, technical, and social characteristics. As an example, DSR (especially from domestic households) has several non-technical barriers to be available at scale as well as to be at low cost. Barriers such as driving behavioural change in consumers, contract design, incentive structures to encourage adoption and efficient business processes to manage interactions with large numbers of customers [25]. Each flexibility option only becomes economically attractive when the benefits are more than the associated costs of these options. Otherwise, actions such as using conventional generation capacity to provide backup, or curtailing renewable instead of storing is chosen, alternatively. Another advantage of investment on flexibility is it can also provide 'option value'. Option value means that small investments in flexibility could postpone decision-making on larger investments such as reinforcement of natural gas and power system infrastructure to whenever better information is available [25].

Considering flexibility options in expansion planning of integrated gas and electricity system is limited in the literature (e.g., role of DSR [22]), hence, this paper investigates an integrated planning strategy based on the operational model presented in [10], for the natural gas and power systems, considering detailed modelling of the mentioned flexibility options. The optimisation problem of expansion planning of integrated natural gas and power systems is a MINLP (i.e., due to binary variables representing decision making on investment in new generating units and decommissioning of existing units as well as non-linear equations in natural gas system operation). The Successive Linear Programming (SLP) is employed to solve this optimisation problem. The model minimises annual costs related to integrated operation and planning of the natural gas and power systems whilst meeting demand requirements over a year. In the power system, decision on decommissioning the existing plants (e.g., coal plants), investment on installing power plants of onshore wind, off- shore wind, solar, nuclear, CCGTs, and CCGT based CCS in terms of location and capacity is determined optimally. In the natural gas system, reinforcement on physical assets of the gas system infrastructure, namely, gas pipelines and compressor units are decision variables in the investment modelling. Additionally, optimal allocation and capacity of the aforementioned flexibility options to meet the emission targets in the future is determined. The model is quantified on a GB natural gas and power system in the year of 2030. Due to uncertainty associated with the capital cost of the flexibility options in the future, case studies are derived by considering different investment assumptions. It is demonstrated how the mentioned flexibility options in the power system can decrease the investments on the natural gas system infrastructure.

2 Modelling Methodology

2.1 Natural Gas and Power Systems Operation

In the modelling of the operation of natural gas system constraints for (a) power consumption by the compressors, (b) gas flow along a pipe , (c) changes in the gas system linepack, (d) pipeline pressure limits, and (e) nodal gas balance are taken into account. In the power system operational model, the general formulation of the power flow model (based on DC power flow model [26]) is applied to represent the power system (1)-(3). Hourly system demand-supply balance constraints (1) and the hourly network lines' capacity constraint (2). The power flow through the transmission line is calculated through (3). Furthermore, following constraints are considered; (a) minimum and maximum power generation limits for generators (4), (b) operational characteristics of the thermal generators including ramp up/down limits of generators (5), maximum limit for power generation and provision of reserve by thermal generators (6), (b) generated wind absorbed by the grid (7) (c) minimum reserve requirement [10] (8), and (d) electricity demand-supply balance (9) (detailed operational modelling of natural gas and power systems is presented in [7]-[10]). It is worth mentioning that in order to reduce the complexity of the model, the unit commitment problem is not considered in this model.

$$\forall t \in \mathcal{T}: \quad \sum_{i \in \mathcal{N}_s} P_{i,t}^{\mathrm{supp}} - \sum_{j \in \mathcal{N}_d} P_{j,t}^{\mathrm{dem}} = 0 \tag{1}$$

$$\forall l \in \mathcal{L}_e, t \in \mathcal{T}: \quad F_{l,t} \le |F_l{}^{\mathrm{cap}}| \tag{2}$$

$$F_{l,t} = \sum_{i \in \mathcal{N}_s} h_{l,i}^{\mathrm{supp}} \cdot P_{i,t}^{\mathrm{supp}} - \sum_{j \in \mathcal{N}_d} h_{l,j}^{\mathrm{dem}} \cdot P_{i,t}^{\mathrm{dem}} \tag{3}$$

$$\forall i \in \mathcal{G} - \mathcal{K}, t \in \mathcal{T}: \quad P_i^{\min} \le P_{i,t} \le P_i^{\max} \tag{4}$$

$$\forall i \in \mathcal{K}, t \in \mathcal{T}: \quad |P_{i,t} - P_{i,t-1}| \le \Psi_i \tag{5}$$

$$\forall i \in \mathcal{K}, t \in \mathcal{T}: \quad P_{i,t} + r_{i,t} \le P_i^{\max} \tag{6}$$

$$\forall b \in \mathcal{B}, t \in \mathcal{T}: \quad P_{b,t}^{\mathrm{avail}} = P_{b,t}^{\mathrm{wind}} + P_{b,t}^{\mathrm{cur}} \tag{7}$$

$$\forall t \in \mathcal{T}: ur_t + \sum_{i \in \mathcal{K}} r_{i,t} + \sum_{p \in \mathcal{P}} r_{i,t}^{\mathrm{pump}} \ge \max_{i \in \mathcal{K}} \left(P_i^{\max}\right) + \Omega \cdot \sum_{b \in \mathcal{B}} P_{b,t}^{\mathrm{wind}} \tag{8}$$

$$\forall t \in \mathcal{T}: \quad \sum_{i \in \mathcal{G}} P_{i,t} + \sum_{b \in \mathcal{B}} P_{b,t}^{\mathrm{wind}} + \sum_{p \in \mathcal{P}} \left(P_{p,t}^{\mathrm{pumpwith}} - P_{p,t}^{\mathrm{pumpinj}}\right) = \sum_{b \in \mathcal{B}} \left(P_{b,t}^{\mathrm{eload}} - P_{b,t}^{\mathrm{eshed}} + P_{b,t}^{\mathrm{ecomp}}\right) \tag{9}$$

$$Z_{\mathrm{op,elec}} = \sum_{r=1}^{\mathcal{T}_{\mathrm{y}}} \sum_{t=1}^{\mathcal{T}_{\mathrm{d}}} \Bigg(\underbrace{\sum_{i \in \mathcal{G}} \left(C_i^{\mathrm{fuel}} + C_i^{\mathrm{var}}\right).P_{i,r,t}}_{\text{Power by existing generators}} + \underbrace{\sum_{i \in \mathcal{G}_{\mathrm{new}}} \left(C_i^{\mathrm{fuel}} + C_i^{\mathrm{var}}\right).P_{i,r,t}}_{\text{Power by new generators}} \quad \underbrace{\sum_{i \in \mathcal{K}} C_i^{\mathrm{em}}.e_{i,r,t}}_{\text{Emission of existing thermal generators}} \quad + \tag{13}$$

$$+ \quad \underbrace{\sum_{i \in \mathcal{K}_{\mathrm{new}}} C_i^{\mathrm{em}}.e_{i,r,t}}_{\text{Emission of new thermal generators}} \underbrace{\sum_{b \in \mathcal{B}} C^{\mathrm{eshed}}.P_{b,r,t}^{\mathrm{eshed}}}_{\text{Electrical load shedding}} + \underbrace{\sum_{i \in \mathcal{G}} (C_i^{\mathrm{FOPEX}}).Y_i^{\mathrm{ex,gen}} \cdot \lambda_i^{\mathrm{gen}}}_{\text{Annualised fixed cost of existing generators}} \Bigg)$$

2.2 *Power System Planning*

In this study, for sake of simplicity, two assumptions are considered. Firstly, the lifetime of the existing units, which could be retired in the future due to the number of installed years, is not considered. This means decommissioning of the existing generation units is decided according to the minimisation of planning and operation costs of natural gas and power systems along with meeting the carbon emission targets. Secondly, expansion. planning on power transmission lines are not taken into account and the capacity of the lines are provided as input to the model. The model is implemented for a year. Therefore, based on Weighted Average Cost of Capital (WACC) and economic lifetime of different technologies and assets, capital costs are annualised [27] through the following expression (10):

$$C^{\mathrm{ACAPEX}} = C^{\mathrm{CAPEX}} \cdot \frac{\alpha}{1-(1+\alpha)^{-n}} \tag{10}$$

In the generation expansion modelling, investment decisions on the following technologies is made: (a) Renewables (Offshore wind, onshore wind, and solar), (b) Nuclear, (c) CCGTs, and (d) Gas based Carbon Capture and Storage (CCS).

2.2.1 *Generation Expansion Planning:*

In order to model the future generation portfolio, binary decision variables on all of the generation units is considered. In other words, if the binary variable is 1, for an existing unit, it means that it is needed to be still connected to the system in the future generation mix. If the binary variable is 0, it means that unit needs to be decommissioned in order to reduce the total energy system costs and/or emissions. For new generation units, if the binary variable is 1, the unit is required to be installed in the system. The power generation limits in the investment modelling for non-thermal and thermal units are expressed by (11) and (12), respectively:

$$\begin{aligned} &\forall i \in (\mathcal{G}-\mathcal{K}) + (\mathcal{G}_{\mathrm{new}} - \mathcal{K}_{\mathrm{new}}), r \in \mathcal{T}_{\mathrm{y}}, t \in \mathcal{T}_{\mathrm{d}}: \\ &P_{i,r,t} \leq P_i^{\max} \cdot \lambda_i^{\mathrm{gen}} \end{aligned} \tag{11}$$

$$\begin{aligned} &\forall i \in \mathcal{K} + \mathcal{K}_{\mathrm{new}}, r \in \mathcal{T}_{\mathrm{y}}, t \in \mathcal{T}_{\mathrm{d}}: \\ &P_{i,r,t} + r_{i,r,t} \leq P_i^{\max} \cdot \lambda_i^{\mathrm{gen}}. \end{aligned} \tag{12}$$

2.2.2 *Planning and Operational Costs of Power System:*

Costs of power system expansion consists of power generation and emission penalties of the existing and new generators, annualised fixed cost of the existing generators, electrical load shedding penalties (13) (top of page 4), and the annualised investment cost of new installed generators (14).

$$Z_{\mathrm{inv,elec}} = \sum_{i \in \mathcal{G}_{\mathrm{new}}} (C_i^{\mathrm{ACAPEX}} + C_i^{\mathrm{FOPEX}}).Y_i^{\mathrm{new,gen}} \cdot \lambda_i^{\mathrm{gen}}. \tag{14}$$

2.3 *Natural Gas System Infrastructure Planning*

In natural gas system planning model, expansion of the gas pipelines and compressor units are considered. Pipelines expansion is based on installing new pipes parallel to the existing pipelines. In compressor investment, installing new compressors in series with the existing one is considered [28].

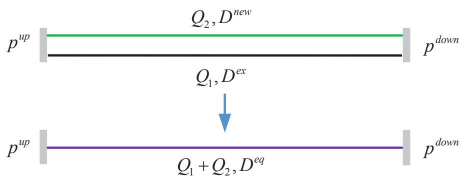

Fig. 1: Parallel pipes and the equivalent pipe.

2.3.1 *Natural Gas Pipes Transmission System Expansion:*

As mentioned, new pipelines are installed parallel to the existing pipelines. This means that total gas flow is summation of the gas flow in the existing and new pipelines. Therefore, the length of the new pipelines is assumed to be the same as existing parallel pipelines. The Panhandle A equation for high-pressure networks [29] for gas flow (15)-(16) is implemented:

$$\forall l \in \mathcal{L}_g, r \in \mathcal{T}_y, t \in \mathcal{T}_d: \; K_l = \frac{\left(\eta_l^{\mathrm{pipe}}\right)^2}{18.43 \cdot Le_l} \tag{15}$$

$$Q_{l,r,t}^{\mathrm{avg}} = \left(K_l \cdot \left((p_{l,r,t}^{\mathrm{in}})^2 - (p_{l,r,t}^{\mathrm{out}})^2\right) \cdot D_l^{4.854}\right)^{1/1.854}. \tag{16}$$

From modelling point of view, in order to reduce the non-linear equations, by combining gas flow of the existing and new pipelines, an equivalent pipe with the same length and new diameter is replaced (Fig. 1).

In (17)-(18) (Top of page 5), diameter of the equivalent pipe is calculated. In light of this, in the gas flow equations, a combination of the existing pipeline (i.e., given as input), and new pipelines (i.e., decision variable), are taken into account.

2.3.2 *Gas Compressor Facilities Expansion:*

To enhance the compression ratio, installing new compressors in series with the existing units is considered. As presented in [30], in the simplified version of NTS of natural gas, an equivalent compressor, represents the compressor units in the station yard. Hence, it is assumed at each compressor station, an equivalent compressor is installed. Here, in a specific compressor station, type of the new compressor unit is the same as the existing compressor unit in the station yard. Compressor modelling is presented in (19)-(21). Each compressor is subjected

IET Research Journals, pp. 1–11

$$\forall l \in \mathcal{L}_g, r \in \mathcal{T}_y, t \in \mathcal{T}_d: \quad Q_{1l,r,t} + Q_{2l,r,t} = \left(K_l \cdot ((p^{\text{in}}_{l,r,t})^2 - (p^{\text{out}}_{l,r,t})^2)\right)^{1/1.854} \cdot \left((D^{\text{ex}}_l)^{4.854/1.854} + (D^{\text{new}}_l)^{4.854/1.854}\right) \tag{17}$$

$$\Rightarrow D^{\text{eq}}_l = \left((D^{\text{ex}}_l)^{4.854/1.854} + (D^{\text{new}}_l)^{4.854/1.854}\right)^{1.854/4.854}. \tag{18}$$

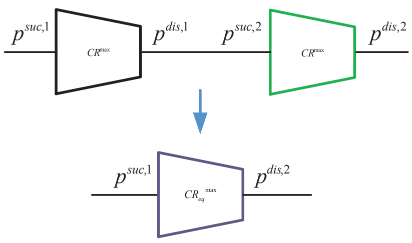

Fig. 2: Two compressor units in series and the equivalent unit.

to maximum flow rate, power consumption, and pressure constraints [8]. The tapped gas is calculated through (21).

$$\forall c \in \mathcal{C}, r \in \mathcal{T}_y, t \in \mathcal{T}_d: \frac{p^{\text{dis}}_{c,r,t}}{p^{\text{suc}}_{c,r,t}} = \left(P^{\text{comp}}_{c,r,t} \cdot \left(\frac{\beta.Q^{\text{comp}}_{c,r,t}}{\eta^{\text{comp}}}\right)^{-1} + 1\right)^{\beta} \tag{19}$$

$$1 \leq \frac{p^{\text{dis}}_{c,r,t}}{p^{\text{suc}}_{c,r,t}} \leq CR^{\max} \tag{20}$$

$$\zeta^{\text{tap}}_{c,r,t} = \mu.P^{\text{comp}}_{c,r,t}. \tag{21}$$

The conversion of two compressors in series into an equivalent compressor is presented in Fig. 2. Discharge node of the first compressor is the same as suction node of the second compressor. Therefore, through product of the pressure ratio of the first compressor and the second compressor, the pressure ratio of $\frac{p^{\text{dis},2}_{c,t}}{p^{\text{suc},1}_{c,t}}$ is calculated (22):

$$p^{\text{dis},1}_{c,t} = p^{\text{suc},2}_{c,t} \quad \Rightarrow \frac{p^{\text{dis},1}_{c,t}}{p^{\text{suc},1}_{c,t}} \cdot \frac{p^{\text{dis},2}_{c,t}}{p^{\text{suc},2}_{c,t}} = \frac{p^{\text{dis},2}_{c,t}}{p^{\text{suc},1}_{c,t}}. \tag{22}$$

As a result, these compressors in series are replaced with an equivalent compressor unit. This procedure is expanded for all compressors in series. The general formula of the power consumption of the equivalent compressor with ω_c number of compressor units in series is presented in (23)-(25):

$$\forall c \in \mathcal{C}, r \in \mathcal{T}_y, t \in \mathcal{T}_d: P^{\text{comp}}_{c,r,t} = \frac{\beta.Q^{\text{comp}}_{c,r,t}}{\eta^{\text{comp}}} \cdot \left[\left(\frac{p^{\text{dis},\omega}_{c,r,t}}{p^{\text{suc},1}_{c,r,t}}\right)^{\frac{1}{\omega_c \cdot \beta}} - 1\right] \tag{23}$$

$$CR^{\max}_{\text{eq}} = (CR^{\max})^{\omega_c} \tag{24}$$

$$1 \leq \frac{p^{\text{dis},\omega_c}_{c,r,t}}{p^{\text{suc},1}_{c,r,t}} \leq CR^{\max}_{\text{eq}}. \tag{25}$$

2.3.3 Planning and Operational Costs of Natural Gas System: Costs of the natural gas system expansion consists of operational cost of the natural gas system and investments on new physical assets in the infrastructure. Cost of gas supply, cost of gas storage, and gas load shedding penalties are considered in the operation of natural gas system (26) (top of page 6). In investment part, annualised capital and fixed costs of reinforcement in new pipelines and compressor units are taken into account (27) (top of page 6).

In (27), decision variables of D^{new}_l as the diameter of the new pipeline, and ω_c, as the number of new compressors that are required to be installed, are optimised.

2.4 Investments on Flexibility Options in the Power System

Flexibility options can improve the system operability to meet the carbon emission targets. Flexibility options including increased flexible generation, demand-side response, electrical storage, and enhanced transmission regional interconnections is considered in this study. The power-to-gas option is not studied, since the overall efficiency of this technology is still low and it is not economically competitive to other flexibility options.

The investment and operational modelling of flexibility options are presented in (28)-(39). Contrary to the operational model of electricity storage [7] and demand side response [31], in the investment model, the terms of $E^{\max}_b$ and ψ in (33) and (37) are not model input and these terms are decision variables. Equation (38) illustrates the limitation on installed capacity of DSR in the system. Through (39), the installed capacity of flexible CCGTs are constrained. Compared to the conventional CCGTs, for the flexible CCGTs higher ramping up/down, higher efficiency and lower emission production is assumed.

$\forall b \in \mathcal{B}, r \in \mathcal{T}_y, t \in \mathcal{T}_d:$

$$E^{\text{estor}}_{b,r,t} = E^{\text{estor}}_{b,r,t-1} + \left(\eta^{\text{estor}}.P^{\text{estor,with}}_{b,r,t} - P^{\text{estor,inj}}_{b,r,t}\right) \cdot \text{ts} \tag{28}$$

$$P^{\text{estor,inj}}_{b,r,t} \leq P^{\text{inj,max}}_b \tag{29}$$

$$P^{\text{estor,with}}_{b,r,t} \leq P^{\text{with,max}}_b \tag{30}$$

$$E^{\text{estor}}_{b,r,t} \leq E^{\max}_b \tag{31}$$

$$P^{\text{estor,inj}}_{b,r,t} \cdot \text{ts} \ + r^{\text{estor}}_{b,r,t} \cdot \text{ts} \leq E^{\text{estor}}_{b,r,t-1} \tag{32}$$

$$\sum_{b \in \mathcal{B}} E^{\max}_b \leq E^{\text{estor,limit}} \tag{33}$$

$$P^{\text{d}-}_{b,r,t} \leq \psi \cdot P^{\text{eload}}_{b,r,t} \tag{34}$$

$$P^{\text{dsr}}_{b,r,t} = P^{\text{eload}}_{b,r,t} - P^{\text{d}-}_{b,t} + P^{\text{d}+}_{b,r,t} \tag{35}$$

$$\sum_{t=1}^{\mathcal{T}} P^{\text{d}-}_{b,r,t} \leq \eta^{\text{dsr}} \cdot \sum_{t=1}^{\mathcal{T}} P^{\text{d}+}_{b,r,t} \tag{36}$$

$$P^{\text{dsr,cap}} = \psi \cdot \max_{t \in \mathcal{T}_d} \frac{1}{\text{ts}} \left(\sum_{b \in \mathcal{B}} P^{\text{eload}}_{b,r,t}\right) \tag{37}$$

$$P^{\text{dsr,cap}} \leq P^{\text{cap,limit}} \tag{38}$$

$$\sum_{i \in \mathcal{K}_{\text{FlexGP}}} P^{\max}_i \cdot \lambda^{\text{gen}}_i \leq P^{\text{FlexGP,limit}}. \tag{39}$$

The capital cost, economic lifetime, and the variable operational cost of the flexibility options is considered (40)-(41). In (40), the operational costs of DSR is assumed to be zero, and the costs of flexible CCGTs are included in (13). Through the model, optimal placement and capacity for the mentioned flexibility options is determined. Furthermore, the model proposes replacement for current inflexible CCGTs with flexible units.

$$Z_{\mathrm{op,gas}} = \sum_{r=1}^{\mathcal{T}_{\mathrm{y}}} \sum_{t=1}^{\mathcal{T}_{\mathrm{d}}} \left(\underbrace{\sum_{y \in \mathcal{Y}} C^{\mathrm{gas}}.Q^{\mathrm{supp}}_{y,r,t}}_{\text{Gas supply}} + \underbrace{\sum_{s \in \mathcal{S}_g} C^{\mathrm{gstor,with}}.Q^{\mathrm{gstor,with}}_{s,r,t} - C^{\mathrm{gstor,inj}}.Q^{\mathrm{gstor,inj}}_{s,r,t}}_{\text{Gas storage}} \underbrace{\sum_{x \in \mathcal{M}} C^{\mathrm{gshed}}.Q^{\mathrm{gshed}}_{x,r,t}}_{\text{Gas load shedding}} \right) \tag{26}$$

$$Z_{\mathrm{inv,gas}} = \sum_{l \in \mathcal{L}_g} (C_l^{\mathrm{ACAPEX}} + C_l^{\mathrm{FOPEX}}) \cdot Le_l \cdot D_l^{\mathrm{new}} + \sum_{c \in \mathcal{C}} (C_c^{\mathrm{ACAPEX}} + C_c^{\mathrm{FOPEX}}) \cdot \omega_c. \tag{27}$$

$$Z_{\mathrm{op,flex}} = \sum_{r=1}^{\mathcal{T}_{\mathrm{y}}} \sum_{t=1}^{\mathcal{T}_{\mathrm{d}}} \sum_{b \in \mathcal{B}} C_b^{\mathrm{VOPEX}}.E^{\mathrm{estor}}_{b,r,t} \tag{40}$$

$$\begin{aligned} Z_{\mathrm{inv,flex}} = & \sum_{i \in \mathcal{K}_{\mathrm{FlexGP}}} (C^{\mathrm{ACAPEX}}_{\mathrm{FlexGP}} + C^{\mathrm{FOPEX}}_{\mathrm{FlexGP}}).P_i^{\max} \cdot \lambda_i^{\mathrm{gen}} \\ & + (C^{\mathrm{ACAPEX}}_{\mathrm{dsr}} + C^{\mathrm{FOPEX}}_{\mathrm{dsr}}).P^{\mathrm{dsrcap}} \\ & + \sum_{b \in \mathcal{B}} (C^{\mathrm{ACAPEX}}_{\mathrm{estor}} + C^{\mathrm{FOPEX}}_{\mathrm{estor}}).E_b^{\max}. \end{aligned} \tag{41}$$

2.5 *Objective Function*

The objective function of the integrated expansion planning of natural gas and power systems is to minimise the total costs of operation and investment of natural gas and power systems considering flexibility options (42). In addition, carbon emission targets are taken into account in the optimisation problem (43). It is worth mentioning that, operational constraints such as power balance, generation characteristics of the thermal power plants, reserve requirements, and gas nodal balance [7, 8] are considered in the optimisation model.

$$\begin{aligned} Z_{\mathrm{plan}} = & Z_{\mathrm{op,elec}} + Z_{\mathrm{op,gas}} + Z_{\mathrm{op,flex}} \\ & + Z_{\mathrm{inv,elec}} + Z_{\mathrm{inv,gas}} + Z_{\mathrm{inv,flex}} \end{aligned} \tag{42}$$

$$\sum_{r=1}^{\mathcal{T}_{\mathrm{y}}} \sum_{t=1}^{\mathcal{T}_{\mathrm{d}}} \sum_{i \in \mathcal{K}+\mathcal{K}_{\mathrm{new}}} e_{i,r,t} \leq \gamma^{\mathrm{et}} \cdot 10^3 \cdot \sum_{r=1}^{\mathcal{T}_{\mathrm{y}}} \sum_{t=1}^{\mathcal{T}_{\mathrm{d}}} \sum_{i \in \mathcal{G}+\mathcal{G}_{\mathrm{new}}} P_{i,r,t}. \tag{43}$$

3 Case Study: GB Natural Gas and Power Systems

An expansion planning model for a GB natural gas and power systems is proposed to investigate cost-effective strategies for meeting the carbon emission target in 2030. In Table 1, the current installed capacity of each technology based on [32] is presented. A simplified representation of the GB power transmission system is shown in Fig. 3. It is worth mentioning that planned HVDCs are considered in the GB power transmission system [33]-[34]. According to the Large Combustion Plant Directive (LCPD) report [35], after 2025 coal power stations are planned to be decommissioned. However, in this research, the decommissioning of coal power stations due to LCDP is not implemented in the optimisation model as a constraint (i.e. $\sum_{i \in \mathcal{K}_{\mathrm{Coal}}} P_i = 0$), but an emission target is set and the capacity of various types of power station in 2030 is endogenous.

The expansion planning optimisation problem is for the year 2030. In order to make the optimal expansion planning decision for the year in a single problem, due to complexity of the model (i.e., MINLP), an annual time horizon with an hourly time step (i.e., 8760 hours) optimisation may not be feasible. In light of this, in the literature such as in [36], the day is divided into three time steps including off-peak, intermediate, and peak. In this research, as the role of the flexibilities is considered, the representation of the day should be

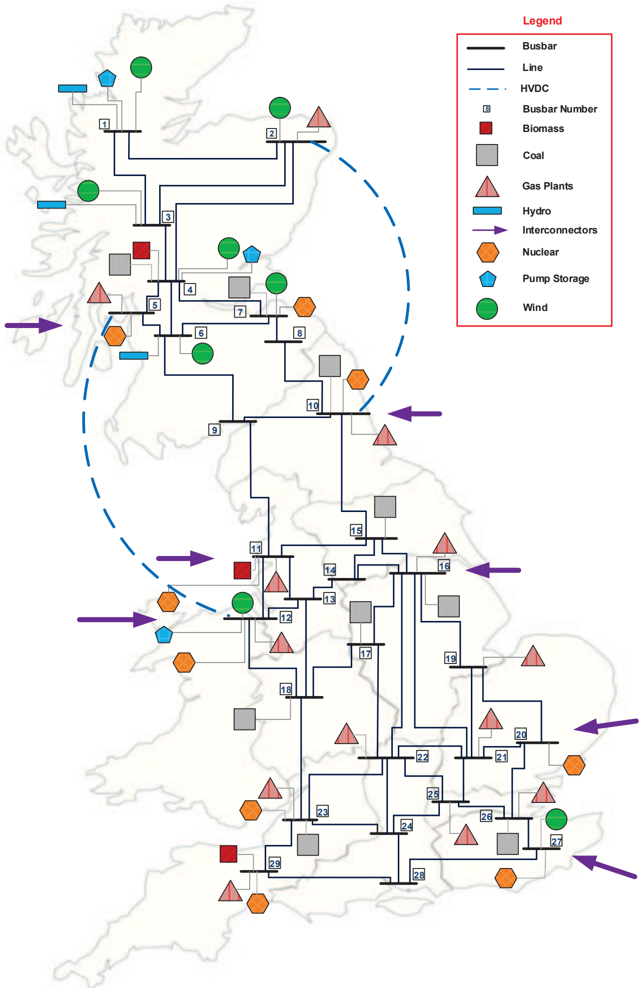

Fig. 3: A current GB 29-Busbar electricity transmission system with interconnectors.

Table 1 A GB current generation mix (based on [32]).

Generation Technology	Capacity (GW)
Wind	14.7
Solar	12.2
Gas	30.8
Interconnection	14.1
Nuclear	9.7
Pumped Storage	4.8
Coal	12.7
Biomass	3.8
Hydro	1.1
Other	1.2

more accurate since by carrying out three time steps for a day, the dynamics of the demand profile during 24 hours is not considered, notably. For example, the off-peak hours after the peak hours cannot be seen in this approach, which can have a negative impact especially on the value of DSR and electricity storage. Thus, in this case study, to model the dynamics of the system more precisely, a day is divided into six time steps; morning off-peak, morning intermediate, noon intermediate, afternoon intermediate, evening peak, and evening off-peak. As an advantage of this modelling, this division represents a dynamic behaviour of the demand during the day. In Fig. 4, the quasi-dynamic electricity demand profile against the real electricity demand is presented. It is shown that the dynamic electricity demand is an appropriate approximation of the real electricity demand. Furthermore, the entire year is represented by twelve days by applying a demand clustering method. In summary, in this research, the integrated expansion planning model of natural gas and power systems for the entire year is modelled through 72 time steps.

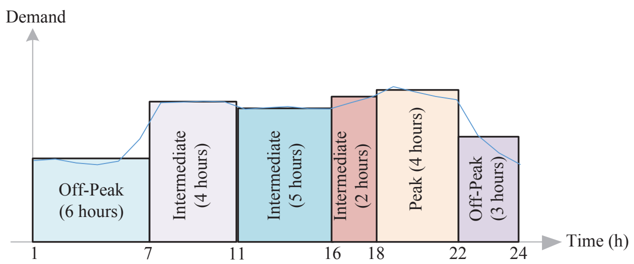

Fig. 4: Representation of a day with six time steps.

The impacts of power system flexibility options including DSR, electricity storage, and flexible CCGTs on the future expansion of natural gas and power systems infrastructure to meet the emission target of 100 $grCO_2/kWh$ [25, 37] is investigated. The capacity of DSR, electricity storage, and flexible gas plants is uncertain in the future, which is imposed by technical, economical, and political barriers and uncertainties. In light of this the data from [25] is used, which it is stated that the maximum technical potential capacity of demand side response varies between 13 GW-20 GW for different demand scenarios. Hence, in this study 15 GW is assumed as the maximum technical potential capacity for demand, which could be shifted. Consequently, in order to realise a comparison between different flexibility options, 15 GW is also assumed as the maximum capacity that can be installed in the system for electricity storage and flexible gas plants. As mentioned in section 2.4, the actual installed capacity of DSR (as a proportion of demand), Storage (installed capacity), and more flexible CCGTs (installed capacity) are variables and is determined in the optimisation problem. Therefore, to evaluate the impacts of each flexibility options on the future generation mix and natural gas system reinforcements, the following case studies are defined:

- *Reference (Ref)*: In this case, none of the flexibility options are employed.
- *Demand side response (DSR)*: A maximum of 15 GW of demand can be flexible.
- *Electricity storage (EStor)*: Maximum rated power of 15 GW of electricity storage with duration time of six hours [27] and 81% efficiency can be installed in the power system.
- *Flexible gas plants (FlexGP)*: A fraction of the existing gas plants can be operated more flexible (15 GW maximum capacity).
- *Fully flexible (Full Flex)*: In this case, all aforementioned flexibility options are considered. This case is to compare the role of different flexibility options in the future paradigm.

For each of the above-mentioned case studies, due to uncertainty associated with the capital costs of the flexibility options in the future, two different options is considered (i.e., low capital cost (LC), and high capital cost (HC)), which are presented in detail in Appendix. Furthermore, it is assumed that the capacity of current RES and nuclear is maintained and none of these generation units are decommissioned for the year of 2030. It is worth mentioning that, constructing new interconnectors can provide more flexibility to the system. However, as this requires an online monitoring of the supply-demand balance in the other part of interconnection (e.g., France), this option is not compared to the other flexibilities, and it is investigated separately.

A computer with 3.20 GHz Intel(R) Xeon(R) processor and 16 GB of RAM was used to solve the optimization problem. In order to solve the MINLP problem of integrated planning of gas and electricity systems, the SLP algorithm of Xpress solver [38] has been employed. The Successive linear programming is a first order, iterative-based approach, which can be employed for solving nonlinear models. This method solves a sequence of linear programming problems. The Xpress SLP method is scalable and efficient for large problems [38]. This method has the following steps:

- Step1: Solving linear approximation of the original problem at the current points.
- Step2: Examining the distance of the output with the selected points.
- Step3: Checking if the output is sufficiently close to the selected point. If yes terminate, otherwise return to step1.

4 Results and Discussions

4.1 New Capacity of Generation Technologies

The new added generation capacities in GB in 2030 are presented in Fig. 5 and Fig. 6 (except for gas-fired power stations, which is presented separately) for different capital investment assumptions of flexibilities. New installed capacities of RES and nuclear, shown in Fig. 5 and Fig. 6, is added to the current capacity of these plants (Table. 1), to build the generation mix in 2030.

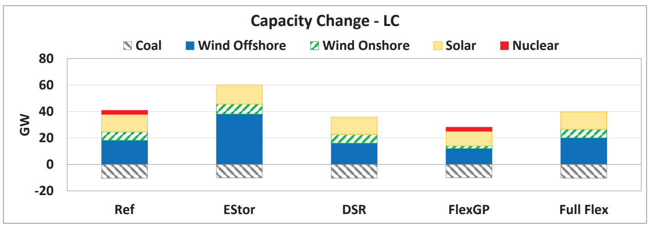

Fig. 5: Added/decommissioned capacity of generation technologies to the current capacity in low investment costs of flexibilities.

In both LC and HC modelling assumptions of flexibility options, to meet the emission targets, majority of coal plants is decommissioned (i.e., negative values). On the other hand, installation of RES including offshore wind, onshore wind, and solar are increased.

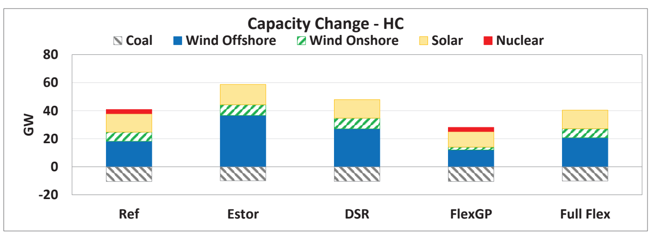

Fig. 6: Added/decommissioned capacity of generation technologies to the current capacity in high investment costs of flexibilities.

In *Ref* and *FlexGP* cases, 3 GW new nuclear plants is built. In other cases, due to the ability to store energy, or shift the energy demand, no investment on new nuclear power plants is required. The largest level of integration of RES is observed in *EStor* cases, where storing the excess energy and withdrawing energy when required is possible. Moreover, the lowest decommissioning of coal plants as base load generation units is happened.

In *DSR* case, if the investment costs of this flexibility is low, lower capacity of RES is installed (Fig. 5) compared to the case that the DSR costs are high (Fig. 6). This is due to the fact that, low costs in DSR, enables more energy demand shifting within a day (17.14% of the demand across all the busbars), and in particular in order to meet the peak-demand, lower installed capacity of RES is needed (Fig. 5). In high capital costs of DSR, the fraction of flexible demand is 13.9%, which leads to an increase in the installed capacity of RES (Fig. 6). This indicates that the costs of DSR plays an important role in the future generation portfolio.

In *FlexGP* cases, it is demonstrated that although using these technologies, leads to less investment in new RES, new base load plants (i.e., nuclear plants) is installed. This is mostly due to the fact that in *FlexGP* cases, the conventional CCGT plants units are replaced by flexible units and additional generation capacity is not added to the system.

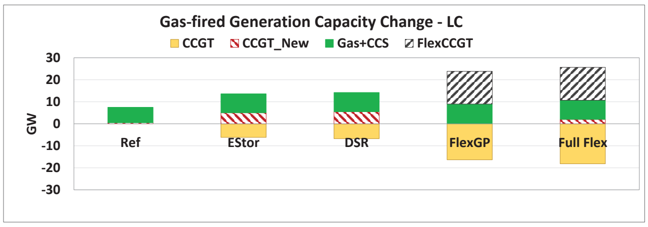

Fig. 7: Added/decommissioned capacity of gas-fired generation technologies to the current capacity in low investment costs of flexibilities.

The capacity of gas-fired power stations, including existing CCGTs, new CCGTs, and CCGTs with CCS in presence of different flexibility options are presented in Fig. 7 and Fig. 8. In presence of flexibility options, approximately 1 GW less capacity of gas-fired power stations is required. In addition, when flexibility is provided, more CCGT with CCS technologies are installed instead of the existing units.

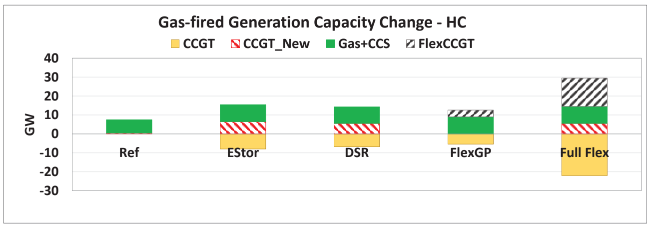

Fig. 8: Added/decommissioned capacity of gas-fired generation technologies to the current capacity in high investment costs of flexibilities.

In *FullFlex*, *EStor*, and *DSR* cases new CCGTs is installed, which can be due to the change in the amount of available energy supply realised by electricity storage or demand side response. Consequently, additional generation capacity is required. In the *FlexGP* cases, the existing CCGTs are replaced by flexible CCGTS and the available energy supply is not changing (similar to the *Ref* case, where only 0.5 GW of new CCGTs is installed), and hence there is no need to install new CCGTs.

4.2 Location of New Installed Renewable Energy Sources

Based on the renewable energy targets [2], it is assumed that a minimum capacity of 12 GW for offshore and 2 GW for onshore wind generation should be installed in the system. In Fig. 9, the new installed RES, in different case studies considering low and high investment costs of the flexibility options in different location of the electricity transmission system is presented.

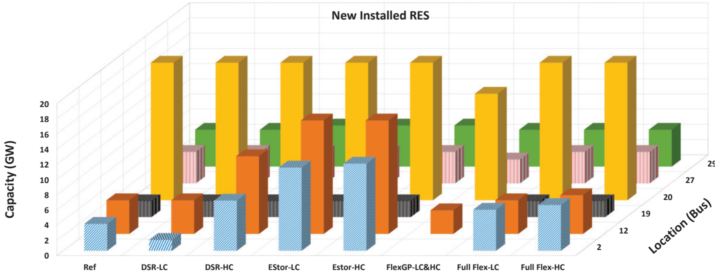

Fig. 9: Installed capacity and location of RES in different case studies.

As it can be seen in Fig. 9, the most accommodation of RES, is realised through employment of energy storage facilities. It is demonstrated that when flexible CCGTs are installed instead of the conventional CCGTs, the capacity of new RES in both LC and HC are equal, as flexible CCGTs will mainly influence investments on gas-fired generation plants. It is shown that throughout the case studies, regardless of the capital cost of the flexibility options, new RES are mainly installed in south (bus 20, 27, and 29), where the majority of gas and electricity demands are located (In buses 20-29 around 50% of the demand is located).

4.3 Location of Flexibility Options

In Table 2 and 3, the location of the electricity storage in *EStor* case (with more than 50 MW rated power capacity), and the flexible CCGTs in *FlexGP* case is presented, respectively. In both cases, the main installed capacity of electricity storage and flexible CCGTs are in south of England, where the majority of the demand is located. It is worth mentioning that it is assumed that there is no limitation on the electricity storage capacity at each busbar.

Table 2 Location of electricity storage facilities in *EStor* case in MW.

Bus Nr.	LC	HC
2	685.36	
20	318.85	169.09
22	3590.7	4004.66
Sum (MW)	**4600.8**	**4211.2**

It is demonstrated that when the costs of flexibility are low, more electricity storage (4.6 GW compared to 4.2 GW) and flexible CCGTs (13.7 GW compared to 3.8 GW) are installed in the power system. As expected, the proposed model optimally determines the location of the flexibility options to be mainly close to the RES. This is due to the fact that, the flexibility options facilitate the accommodation of RES, while bypassing the power transmission congestions. It is worth mentioning that since a fixed pre-development cost for electricity storage and flexible CCGTs is considered, hence in HC investment assumptions, fewer locations are chosen to install these units.

As mentioned previously, the DSR option is determined as a proportion of the electricity demand.

4.4 Expansion Planning of Natural Gas System Infrastructure

In Table 4 and 5, the infrastructure reinforcements in the natural gas system is presented. In *DSR* cases, although the capacity of new

Table 3 Location of flexible CCGTs in *FlexGP* case in MW.

Bus Nr.	LC	HC
2	590	
11	370	370
12	820	
16	850	400
19	405	410
21		790
23	3484	1634
24	1460	
25	2301	
26	2100	400
28	870	
29	450	
Sum (MW)	**13700**	**3604**

CCGTs is about 5 GW, however due to the role of DSR in shifting the energy consumption, less reinforcement in the natural gas system infrastructure is required. In *EStor* case, when the investment costs of electricity storage facilities are low, 38.4 GW of gas-fired generation plants including 6 GW of new CCGTs (Fig. 7) are installed, therefore two new compressors and one new gas pipeline (connected to Milford Haven gas terminal) is required to be installed. On the other hand, when the investment costs of the electricity storage facilities are high, since the amount of installed capacity of electricity storage decreases slightly, the reinforcement in the gas compressors is the same and to improve the gas system delivery, more reinforcement in the natural gas pipelines (a pipeline with 775 mm diameter) is required. Similar to *EStor* cases, in *FlexGP* cases, the costs of the flexible CCGTs plays an important role in investment on gas system infrastructure. According to Table 3 in high investment case, less flexible CCGTs are installed in the system (3.6 GW compared to 13.4). As a result, the system is less flexible and therefore consequently more investment on gas system infrastructure is required. Therefore, if investment costs of flexible CCGTs are low, lower reinforcement in gas pipelines and compressor units is required compared to the case that the investment costs are high. In *Full Flex* cases, the investments on the gas pipelines and compressors is decreased, compared to all other case studies. In this study, the pre-development (e.g., digging) costs for installing the new pipelines is not considered.

Table 4 Expansion of the natural gas system infrastructure in case of low investment costs of flexibility options.

Case Study	Compressor unit	Gas pipeline (Diameter(mm):Length(km))
Ref	2	775:128
EStor	2	750:128
DSR	1	725:128
FlexGP	1	725:128
Full Flex	1	675:128

Table 5 Expansion of the natural gas system infrastructure in case of high investment costs of flexibility options.

Case Study	Compressor unit	Gas pipeline (Diameter(mm):Length(km))
Ref	2	775:128
EStor	2	775:128
DSR	1	725:128
FlexGP	2	775:128
Full Flex	1	675:128

As a result, providing flexibility in the power system decreases the need for reinforcement in the natural gas system. Moreover, investment costs of the flexibility options, play a significant role in expansion planning decisions on the natural gas system infrastructure. It is demonstrated that low investment costs of the flexibility options, leads to higher installed capacity of the flexibility options, which makes lower reinforcements in the natural gas system infrastructures.

4.5 Planning and Operational Costs of Natural Gas and Power Systems

The total investment and operational costs of the natural gas and power systems in 2030 for low and high costs of flexibility options are presented in Fig. 10. Through the employment of each of the flexibility options, total costs are reduced. In *DSR* case, since the energy demand shifts optimally within a day, up to £24.13bn is saved in the entire year. As expected the most cost saving is achieved when all flexibility options are considered in the future portfolio (*Full Flex* case). In this case, the model is employing 14.8 GW flexible CCGTs and 17.19% DSRs. As presented in Fig. 11, especially in South of England, the conventional CCGTs are required to be replaced by more flexible CCGTs.

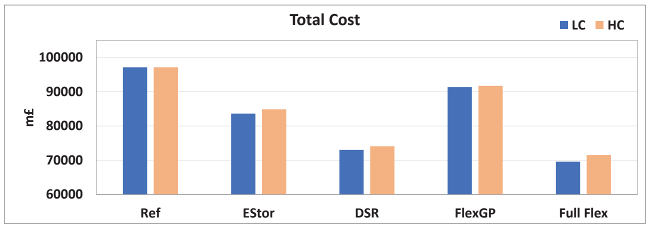

Fig. 10: Total investment and operational costs of natural gas and power systems.

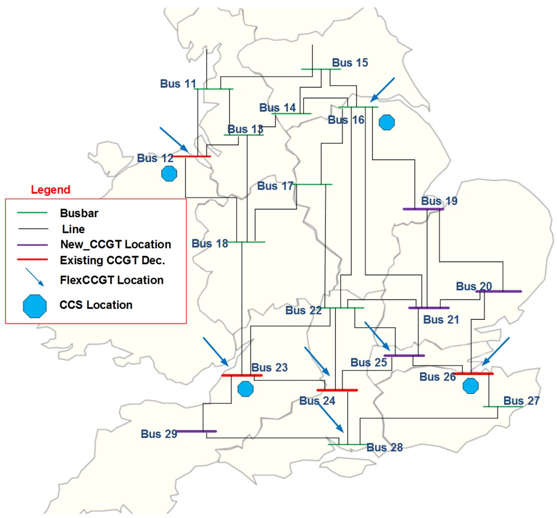

Fig. 11: Location of gas-fired power stations

4.6 Role of Interconnection

Importing electricity from interconnections can increase the flexibility of the system. To model the interconnectors accurately, the supply-demand balance of other side of the interconnector must be monitored, simultaneously. As an example, assume it is required to meet the peak demand in the evening hours (18:00-19:00). At some periods, importing electricity can help to increase the flexibility and prevents investing on additional generation units. On the other hand, since in this period there could be a peak time in western European countries such as France and Netherlands as well, exporting electricity from these countries may not be possible. Therefore, in this modelling an optimistic scenario is considered, in which it is assumed that annual imported electricity to GB is equal to the annual exported electricity from GB and the intra-day interaction between the sides of the interconnection is not taken into account. In appendix, the investment modelling assumptions for interconnectors is presented.

In Fig. 12, it is shown how interconnection can change the generation mix in the future. It is demonstrated that interconnectors can facilitate accommodation of renewable energy sources and decommissioning of the coal plants. In Table 6, the location of new interconnectors is provided.

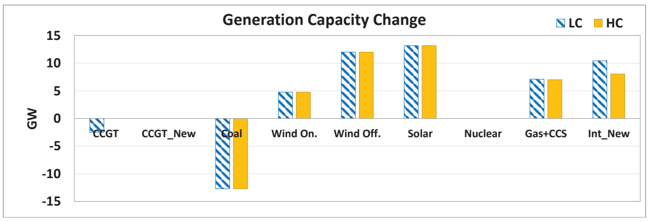

Fig. 12: Added/decommissioned capacity of generation technologies to the current capacity in presence of interconnetions.

Table 6 Location of interconnections in GW.

Bus Nr.	Country	LC	HC
5	Northern Ireland	4.63	3.88
12	Ireland Republic	3.90	3.97
16	Denmark	0.69	0.19
27	France	1.19	
	Sum (GW)	**10.42**	**8.04**

5 Conclusions

An investment modelling of different flexibility options in an integrated expansion modelling of natural gas and power systems, to identify optimal portfolio of the future energy system for achieving carbon targets at minimum whole-system costs was presented. In this model, decisions on decommissioning the existing plants (such as coal), and investment on installing new power plants including renewables, gas-fired power plants, and nuclear is optimally determined. In the natural gas system, reinforcements on the natural gas system infrastructure, including gas pipelines and gas compressor were taken into account.

To validate the investment model, the model was implemented on a GB natural gas and power systems in 2030. It was demonstrated that flexibility options including DSR, flexible CCGTs, and electricity storage can save additional investment costs of natural gas and power systems. CCGTs continue to play a significant role in providing flexibility to the system in 2030, irrespective of the cost of flexibility options. The cost of DSR affects the future generation portfolio, notably. If the DSR costs are low, less investment on new renewable technologies is required. Furthermore, system-wide unbalanced supply and demand was handled, by optimal allocation of electricity storage through storing the excess of renewable and injecting it to the grid, when it was required. As it was expected, the least investment and operational costs of natural gas and power system was achieved, when all of the mentioned flexibility options are included in the investment model. In this case, it was shown that employment of flexible CCGTs and DSRs is the most cost-effective pathway for meeting the emission targets in 2030 GB system.

It was demonstrated that integrated analysis of national infrastructures was important for considering alternative evolution pathways of the natural gas and power system infrastructures. Furthermore, any change in the capital costs of the flexibility options can highly impact the future paradigm in both natural gas and power systems.

As the future work of this research, the multi-year expansion planning of integrated natural gas and power systems should be considered. This is due to the fact that since the emission targets are changing in the future after 2030 as well as some assets should be retired, hence the investments could be different for 2030 in order to see the longer-term investments. Furthermore, to realise a full coordination of the multi-vector energy systems, the role of natural gas system flexibility options (e.g., multi-directional compressors) in supporting the decrease in investment of electricity system needs further investigation.

6 Appendix: Modelling Assumptions

6.1 *Investment Assumptions in Modelling of Natural Gas and Power Systems*

For all cases, two different investment modelling assumptions based on the research in [25] including LC and HC of the flexibility options is considered. Furthermore, the investment modelling assumptions of different generation technologies was considered based on [25, 27, 36, 39].

The investment costs of gas network infrastructure including pipelines and compressors are presented in Table 7 and 8 based on [16]. As mentioned in the previous chapter, in this modelling it is assumed that the new gas pipelines can be installed parallel to the existing pipes. In addition, the new compressors are installed in series with other existing equivalent unit in the station yard.

Table 7 Gas pipeline investment modelling assumptions.

Component	Unit	Value
CAPEX	$\frac{£}{25mm:km}$	77500
WACC [16]	%	3.5
Lifetime [16]	years	35

Table 8 Gas compressors investment modelling assumptions [36].

Component	Unit	Value
CAPEX	£m/unit	15
WACC	%	3.5
Lifetime	years	25

6.2 *Investment Assumptions in Modelling of Flexibility Options*

In Tables 9-12, low and high investment modelling assumptions for DSR, electricity storage, flexible CCGTs, and interconnection is presented, respectively [25].

7 References

1 European Commission. 'A roadmap for moving to a competitive low carbon economy in 2050'. (Brussels, Belgium, 2011.
2 European Council. '2030 framework for climate and energy policies'. (Brussels, Belgium, 2014.
3 Department of Energy & Climate Change. 'UK Renewable Energy Roadmap Update 2013'. (London, UK, November, 2013. Available from: `http://www.decc.gov.uk/en/content/cms/meeting{\_}energy/renewable{\_}ener/re{\_}roadmap/re{\_}roadmap.aspx`
4 Oswald, J., Raine, M., Ashraf.Ball, H.: 'Will british weather provide reliable electricity?', *Energy Policy*, 2008, **36**, (8), pp. 3212 – 3225

Table 9 Electricity storage investment modelling assumptions [25].

EStor	**Unit**	**Value**
CAPEX (High)	£/kW	1879
CAPEX (Low)	£/kW	673
WACC	%	10
Fixed OPEX	£/kW/year	6.1
Variable OPEX	£/MWh	0.7
Cycle efficiency	%	81
Duration	hours	6
Lifetime	years	20
Maximum capacity	GW	15

Table 10 Flexible CCGTs investment modelling assumptions [25].

FlexGP	**Unit**	**Value**
CAPEX (High)	£/kW	888
CAPEX (Low)	£/kW	444
WACC	%	10
Fixed OPEX	£/kW/year	16
Variable OPEX	£/MWh	1.4
Ramp up/down	MW/h	350
Lifetime	years	25
Maximum capacity	GW	15

Table 11 Demand side response investment modelling assumptions [25].

DSR	**Unit**	**Value**
Costs (High)	£/kW	692
Costs (Low)	£/kW	121.5
WACC	%	10
Lifetime	years	10
Maximum technical potential	GW	15

Table 12 Interconnection investment modelling assumptions.

DSR	**Unit**	**Value**
Costs (High) [25]	£/kW	1700
Costs (Low) [25]	£/kW	300
WACC	%	10
Lifetime	years	40

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