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 GNOME: A Dynamic Dispatch and Investment Optimisation Model of the European Natural Gas Network and Its Suppliers

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Abstract

As indigenous production declines, the European gas market is becoming increasingly dependent on imports. This poses energy security questions for a number of countries, particularly in the north-east of Europe. A suite of mathematical models of the European natural gas network has been borne from these concerns and has traditionally been used to assess supply disruption scenarios. The literature reveals that most existing European gas network models are insufficiently specified to analyse changes in supply and demand dynamics, appraise proposed infrastructure investments, and assess the impacts of supply disruption scenarios over a range of time horizons. Furthermore, those that are suited to these applications are typically proprietary and therefore publicly unavailable. This offers an opportunity to present a new model. The Gas Network Optimisation Model for Europe (GNOME) is a dynamic, highly granular mixed-integer linear optimisation model of the European natural gas network and its exogenous suppliers. GNOME represents demand and supply for all EU-27 Member States except Cyprus, Luxembourg, and Malta. The UK, Norway, Switzerland, Belarus, Ukraine, and Turkey are also included. Russia, the Southern Corridor suppliers, Qatar, North Africa, Nigeria, and the Americas are modelled as supply-only regions. GNOME satisfies gas demand in each country by generating a cost-minimal mix of indigenous gas production, pipeline flows, LNG imports, and storage use. If demand cannot be met using existing infrastructure, GNOME will generate a cost-optimal investment strategy of pipeline, LNG regasification, and gas storage capacity additions. The model solves on a monthly basis, from 2025 to 2040, in 5-year steps. The capabilities of GNOME are demonstrated by tasking it to analyse the impacts of a failure to complete the upcoming Nord Stream 2 pipeline between Russia and Germany. The complete formulation of GNOME including input files, equations, and source code is provided.

Keywords Gas network optimisation · Europe energy security · Gas pipelines · LNG · Gas storage · Infrastructure investment · Mixed integer programming

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1 Introduction

European gas production peaked in 2004 at 318 BCM/year and has been in steady decline since. This decline has been driven primarily by the maturation of the UK Continental Shelf (UKCS) and the rolling shutdown of the giant Groningen gas field in the Netherlands [60]. This has resulted in the production-to-demand ratio falling from 97% in 1970 to 43% in 2019 and an increased dependence on non-EU suppliers as a result.

Figure 1 shows the evolution of the Herfindahl–Hirschman Index (HHI) for gas imports between 1998 and 2018. The HHI is an indicator of market concentration, and in the context of the European natural gas market, it can be applied to highlight the market power of individual gas exporters for a particular importing country.

The general reduction in size of each coloured area from 1998 to 2018 shows that diversity of import sources has increased for most countries, primarily driven by expansion of the global LNG market. Despite this progress, Fig. 1 shows that some European countries were still facing low levels of supply diversification in 2018. These countries are mostly located in east and north-east Europe, where dependence on Russian gas is common. Estonia, Latvia, Slovakia, and Bulgaria have been 100% reliant on imports of Russian pipeline gas during the entire 1998–2018 period.

Figure 2 shows a snapshot of European gas network resilience in 2016, using the “PF-1” (“Peak Flow Minus One”) and “PF-2” (“Peak Flow Minus Two”) standards developed by BEIS [4], p. 85). PF-1 sums the maximum capacities of all gas supplies available to particularly country and then removes the single largest supply route. The remaining peak supply, as a percentage of peak demand, is the PF-1 metric. The equation is similar for the PF-2, the only difference being the two largest supply routes is removed. The full equation is provided in BEIS [4], p. 84).

Sweden, Finland, Bulgaria, Greece, and Ireland fall underneath the 100% level under the PF-1 metric, meaning that they would have been unable to meet daily peak demand in 2016 in the event of the most significant import route going offline. The PF-2 metric shows that Estonia, Slovenia, Poland, Luxembourg, Croatia, Romania, and Italy would have been unable to meet daily peak demand in 2016 if the second largest import route simultaneously became unavailable.

Continued high levels of single-supplier gas import dependence and the inability of some Member States to meet demand during a supply disruption event highlight potential deficiencies in the specification of the European natural gas network. However, static metrics such as the HHI for gas imports and the PF-1 standard only provide warnings of potential problems. They do not in themselves offer solutions.

1 “Gas” in the context of this paper refers to natural gas.
2 The HHI is used by regulators such as the US Department of Justice Antitrust Division when assessing the potential impacts of activities such as mergers and acquisitions on market competitiveness.
3 Where there are gaps in the data (for example, Denmark and Luxembourg in 1998), it is because the data was not published by Eurostat.
The application of dedicated, bespoke models of the European gas network can not only help policymakers develop a deeper understanding of such issues, but also help suggest investment strategies to alleviate them. Such models have been applied to ex-post analyses of supply disruptions such as the Ukraine-Russia gas disputes [11], [46] as well as hypothetical supply disruption scenarios for gas exports from North Africa [27]. They can also be applied to a range of scenarios such as changes to gas demand and supply levels, failures in pieces of critical gas network infrastructure, or appraisal of potential projects such as pipelines or LNG import terminals.

Section 2 reviews the current suite of European gas models identified from the literature. Section 3 provides a detailed presentation of the Gas Network Model for Europe (GNOME), a new dispatch and investment model of the European gas network that seeks to address a gap in the current complement of models. Section 4 demonstrates the capabilities of GNOME by applying it to a scenario where construction of the Nord Stream 2 pipeline never happens, in order to explore the effects on gas production, trade, storage, infrastructure investment, and costs.

2 Existing European Gas Models

A review of the literature was conducted to gauge the capabilities of the existing range of gas models. A less comprehensive review of such models is presented by Chyong and Hobbs [12] but was limited to only nine attributes of twelve models. Each of the 22 models identified for inclusion was appraised based on a range of attributes including scope, granularity, and the endogenous generation of key variables. Table 1 summarises the results of this review. The formulation of the proposed GNOME model is included in italics at the top of the table for comparison.

2.1 Model Attributes

This section discusses the features of the existing suite of gas network models under seven main headings. These are problem type, geographical features, temporal features, granularity of infrastructure, representation of demand, representation of production, and endogenous infrastructure investment.

2.1.1 Problem Type

The literature reveals four main problem styles. Linear (LP) and nonlinear (NLP) programming models of the European natural gas model do not typically attempt to represent market power, but instead produce an optimal combination of gas

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4 Nomenclature: LP = linear programming; NLP = non-linear programming; MILP = mixed-integer linear programming; LCP = linear complementarity problem; NCP = nonlinear complementarity problem; MCP = mixed complementarity problem; PE = partial equilibrium; CGE = computable general equilibrium; MIQP = mixed integer quadratic programming; Endo. = endogenous; Exo. = exogenous; Aggr. = aggregated; Indiv. = individual.
production and trade in order to satisfy demand whilst minimising total costs or maximising welfare. Examples of these models include InTraGas [53], TIGER [47], EUGAS [55], MAGELAN [48], the Wood Mackenzie Global Gas Model (WM-GGM) [28], PEGASUS [58], and the Nexant World Gas Model (N-WGM) [50].

Mixed-integer linear (MILP) and mixed integer quadratic programming (MIQP) allow specified variables to only take a discrete range of user-defined values. One example of a MILP model is the EU-27 + UK integrated gas and power model presented by Deane et al. [13]. The RAMONA model [23] is a MIQP model of the global gas markets.

Mixed complementarity problem (MCP) dispatch models seek to represent market power through the application of game theory to the downstream and midstream sectors of the gas market. In doing so, such models typically sacrifice

Fig. 1 Evolution of Herfindahl–Hirschman Index for gas import market by country (1998–2018). Source: Authors own presentation, data from Eurostat [22]
network fidelity for a more complete representation of the gas market itself. Examples include GASTALE [7], NATGAS [71], GASMOD [34], COLUMBUS [32], GaMMES [1], the World Gas Model (WGM) [17], and the EPRG Gas Market Model (EPRG-GMM) [12]. The European Gas Market Model (EGMM) [42] is a linear complementarity problem (LCP).

Computable general equilibrium (CGE) models such as MC-GENERCIS [51] and the Baker Institute World Gas Trade Model (BI-WGTM) [30] use historical data to estimate how gas markets might react in a specific scenario.

### 2.1.2 Geographical Scope and Granularity

Models should at a minimum represent countries that exhibits either demand for and/or supply of gas. External pipeline suppliers, as well as LNG exporters to Europe, should also be included with their individual delivered costs to each destination country specified. Transit countries that allow gas to flow from external suppliers to Europe such as Ukraine, Belarus, and Turkey are also important additions. Table 1 shows that 13 of the models presented represent the whole of Europe with a granularity of at least one node per country. They are WM-GGM, TIGER, InTraGas, MAGELAN, EUGAS, MC-GENERCIS, BI-WGTM, COLUMBUS, EPRG-GMM, Nexant-WGM, EGMM, and the unnamed\(^5\) models presented by Egging et al. [15] and Deane et al. [13].

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\(^5\) For simplicity, models that have not been named by the authors are referred to by their citation enclosed in quotation marks. For example, “Egging et al. [15]” and “Deane et al. [13]”.

![Fig. 2 EU Member State performance against the PF-1 and PF-2 resilience standards for 2016. Source: [4], p. 85)](image-url)
| Model                  | Developer                          | Problem type | Market power | Spatial Coverage | Temporal Static or dynamic | Temporal Time horizon | Temporal Time slices |
|------------------------|------------------------------------|--------------|--------------|-----------------|---------------------------|-----------------------|----------------------|
| GNOME                  | Stevie Lochran                     | MILP         | Europe       | 40              | Dynamic                   | 2040                  | 12                   |
| Wood Mackenzie         | Wood Mackenzie                     | LP           | Global       | >1000           | Dynamic                   | 2040                  | 12                   |
| Global Gas Model       | Wood Mackenzie                     | LP           | Europe       | >1000           | Dynamic                   | 2020                  | 12                   |
| TIGER                  | EWI Cologne                        | LP           | Europe       | 1000            | Dynamic                   | 2040                  | 12                   |
| InTraGas               | DIW Berlin                         | NLP          | EU15         | 29              | Dynamic                   | 2015                  | 12                   |
| MAGELAN                | EWI Cologne                        | LP           | Europe       | 139             | Dynamic                   | 2035                  | 1                    |
| EUGAS                  | EWI Cologne                        | LP           | Europe       | 35              | Dynamic                   | 2030                  | 1                    |
| "Egging et al. [15]"   | Egging, Gabriel, Holz, Zhuang      | NCP          | Cournot      | Europe          | Dynamic                   | Annual snapshot       | 3                    |
| GASMOD                 | DIW Berlin                         | MCP          | Cournot      | Europe          | Dynamic                   | 2025                  | 1                    |
| FRISBEE                | Aune, Glomsrød, Lindholt, Rosendahl| PE           | Global       | 13              | Dynamic                   | 2030                  | 1                    |
| MC-GENERCIS            | Monforti, Szikszai                 | CGE          | Europe       | 29              | Static                    | 2040                  | 1                    |
| World Gas Trade Model  | Baker Institute (Rice University)  | CGE          | Global       | 460             | Dynamic                   | 2040                  | 1                    |
| COLUMBUS               | EWI Cologne                        | MCP          | Cournot      | Europe          | Dynamic                   | Flexible              | Flexible             |
| GaMMES                 | Abada, Gabriel Briat, Massol       | MCP          | Cournot      | Major Euro. demand/supply nodes | Dynamic | 2040 | 2 |
| GASTALE                | Energy Research Centre of the Netherlands | MCP        | Cournot      | Major Euro demand nodes | Dynamic | 2030 | 3 |
| NATGAS                 | Netherlands Bureau for Economic Policy Analysis | MCP | Cournot | Major Euro demand/ supply nodes | Dynamic | 2035 | 2 |
| World Gas Model        | University of Maryland             | MCP          | Global       | 41              | Dynamic                   | 2030                  | 2                    |
| World Gas Model (stochastic) | University of Maryland         | MCP          | Global       | 19              | Dynamic                   | 2040                  | 2                    |
| Model                          | Developer                                      | Problem type | Market power | Spatial Coverage | Nodes | Temporal Static or dynamic | Time horizon | Time slices |
|-------------------------------|-----------------------------------------------|--------------|--------------|-----------------|-------|---------------------------|--------------|-------------|
| PEGASUS                      | Poyry                                         | LP           | Europe       | 23              | Dynamic Flexible   | 365          |             |
| RAMONA "[13]"                | Fodstad et al. (23)                           | MIQP         | Global       | 40              | Dynamic           | 2050         | 1           |
| European Gas Market Model    | Deane et al. (13)                             | MILP         | Europe       | 28              | Dynamic Annual snapshot | 8760        |             |
| Nexant World Gas Model       | Nexant                                        | LP           | Global       | ~ 200           | Dynamic           | 2050         | 4           |
| EPRG Gas Market Model        | Chyong and Hobbs (12)                         | MCP          | Cournot      | Europe          | Dynamic           | 2030         | 1           |

| Model                          | Infrastructure representation | Endogenous infrastructure investment | Demand Type | Production Sectors | Supply contracts |
|-------------------------------|-------------------------------|--------------------------------------|--------------|--------------------|------------------|
| GNOME                         | Yes Bi                        | Indiv. pipe, aggr. LNG, agg. storage | Exo 1        | Endo               | Yes Yes          |
| Wood Mackenzie Global Gas Model | Yes Bi                        | Indiv                                | Exo 1        | Endo               | Yes Yes          |
| TIGER                         | Yes Bi                        | Indiv. pipe, aggr. LNG, agg. storage | Exo 2        | Endo               |                  |
| InTraGas                      | Yes Uni                       | Indiv                                | Linear 1     | Endo               |                  |
| MAGELAN                       | Yes Bi                        | Aggr                                 | Exo 1        | Endo               |                  |
| EUGAS                         | Yes Uni                       | Aggr                                 | Exo 1        | Endo               |                  |
| Model                                      | Infrastructure representation | Endogenous infrastructure investment | Demand          | Production | Supply contracts |
|-------------------------------------------|-------------------------------|--------------------------------------|-----------------|------------|------------------|
|                                           | LNG Pipe Storage Granularity  | LNG Pipe Storage Production Type Sectors | LNG Pipe Endo 3 | Endo | Yes Yes |
| "Egging et al. [15]"                      | Yes Uni Yes Aggr              | Yes Yes Endo 3                       | Endo 3          | Endo | Yes Yes |
| GASMOD                                    | Yes Bi Yes Aggr               | Endo 3                              | Endo 3          | Endo | Yes Yes |
| FRISBEE                                   | Yes Bi Yes Aggr               | Yes Yes Endo 1                       | Exo 1           | Exo | Yes Yes |
| MC-GENERICIS                              | Yes Bi Yes Aggr               | Yes Yes Endo 1                       | Exo 1           | Exo | Yes Yes |
| World Gas Trade Model                     | Yes Yes, directionality unknown Yes Aggr | Yes Yes Endo 1 | Exo 2 | Endo | Yes Yes |
| COLUMBUS                                  | Yes Bi Yes Aggr               | Yes Yes Endo 2                       | Endo 2          | Endo | Yes Yes |
| GaMMES                                    | Yes Bi Yes Aggr               | Yes Yes Endo 3                       | Endo 3          | Endo | Yes Yes |
| GASTALE                                   | Yes Uni Yes Aggr              | Yes Yes Endo 3                       | Endo 3          | Endo | Yes Yes |
| NATGAS                                    | Yes Bi Yes Aggr               | Yes Yes Endo 1                       | Exo 1           | Exo | Yes Yes |
| World Gas Model                           | Yes Bi Yes Aggr               | Yes Yes Endo 3                       | Endo 3          | Endo | Yes Yes |
| World Gas Model (stochastic)              | Yes Bi Yes Aggr               | Yes Yes Endo 1                       | Exo 1           | Exo | Yes Yes |
| PEGASUS                                   | Yes Yes, directionality unknown Yes Indiv | Yes Yes Endo 2 | Endo, for power, else exo 2 | Endo | Yes Yes |
| RAMONA [13]                                | Yes Uni Yes Aggr              | Yes Yes Exo 3                        | Exo 3           | Endo | Yes Yes |
| European Gas Market Model                 | Yes Uni Yes Indiv             | Linear 1 Exo 1                      | Endo 1          | Endo | Yes Yes |
| Nexant World Gas Model                    | Yes Bi Yes Indiv              | Linear 1 Exo 1                      | Endo 1          | Endo | Yes Yes |
Table 1 (continued)

| Model                      | Infrastructure representation | Endogenous infrastructure investment | Demand | Production | Supply contracts |
|----------------------------|--------------------------------|---------------------------------------|--------|------------|-----------------|
| EPRG Gas Market Model      | Yes                            | Yes, directionality unknown           | Yes    | Indiv      | Exo             |

Operations Research Forum (2021) 2: 67
2.1.3 Temporal Scope and Granularity

Of the models identified from the literature, the longest model horizon is to 2050 in RAMONA and N-WGM. Most models have time horizons that are explicitly stated as being 2025 or later, except for TIGER (2020), InTraGas (2015), and the static MC-GENERCIS model. It should also be noted that such models are often in a state of development, and it is entirely possible that time horizons can be easily extended in dynamic variants.

For models that seek to analyse supply disruptions and appraise infrastructure projects, a high level of temporal granularity is desirable. At a minimum, monthly time slices allow the network to be stress-tested in the peak winter gas demand months, whilst keeping computational load and solve time manageable. The hourly time slices by Deane et al. ([13]) were the most granular identified from the literature, however, their model was run in a 1-year snapshot only. PEGASUS can be run at a daily granularity across multiple years. Eight of the models identified solve on an annual basis only.

2.1.4 Granularity of Network Infrastructure

Aggregation of cross-border pipeline capacity in European gas network models means that important levers of network flexibility such as reverse-flow capability are not represented [29], [41]. The value of bidirectionality in European gas pipelines was highlighted during the 2014 Russia-Ukraine gas dispute, when Ukraine imported gas from Poland through a pipeline that had traditionally carried Russian gas in the opposite direction. More recently, Slovakia, Poland, and Hungary have converted existing infrastructure to allow bidirectional flows to and from Ukraine. This allows Ukraine to reduce reliance on Russian gas imports and allows the European gas market to smooth demand shocks by allowing gas to be both injected into and withdrawn from Ukraine’s 30 bcm of storage capacity [57]. Table 1 shows that 12 of the 22 models identified have reverse-flow capabilities represented.

Aggregation of LNG import capacity at the country level is sufficient if that country is represented by only one node in the network. As with pipelines, LNG shipping routes should be specified by distance in order to apply appropriate delivered costs to market. Of the models identified, only five models (WM-GGM, TIGER, PEGASUS, EPRG-GMM, and EGMM) represent both European pipelines and LNG terminals individually. InTraGas represents individual pipelines, but aggregates LNG import capacity by country.

The aggregation of a country’s gas storage capacity is appropriate if that country is represented by a single node in the network. Storage is represented in all models

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6 Capacity as of December 2020.
identified except FRISBEE [3], GASTALE, and RAMONA. Storage is a crucial component of gas network models of Europe because it is a significant source of demand in summer and supply in winter\(^7\) and acts as a balancing mechanism during demand and/or supply shocks.

### 2.1.5 Representation of Gas Demand

The literature reveals two main methods of representing gas demand. Four models (“Egging et al. [15]”, FRISBEE, BI-WGTM, and GaMMES) generate demand levels endogenously based on a set of user-specified drivers such as GDP and population growth. PEGASUS generates gas demand for power endogenously and requires exogenous demand for all other sectors. Six models (InTraGas, GASTALE, NATGAS, WGM, WGM-S, EGGM) assume linear demand functions. The remaining models require demand levels to be defined by the user. Exogenous demand definition has the advantage of allowing specific demand-side scenarios to be examined. These scenarios can be obtained from external sources or generated in an energy systems model such as the European TIMES Model [61].

### 2.1.6 Gas Production and Producer Behaviour

All models identified in the literature except the Monte Carlo analysis presented by Monforti and Szikszai [51] generate gas production levels endogenously. With regard to market power, the European market has been described as an oligopoly [12], [15], [16], [33]. Nine of the 22 models represent market power and do so through MCP models that assume the European gas market is a Cournot duopoly.

### 2.1.7 Endogenous Infrastructure Investment

The endogenous generation of infrastructure additions is beneficial because not only are potential security-of-supply problems identified, but efficient investment strategies can also be generated to alleviate them. The ability to manually specify infrastructure additions is also useful as it allows the appraisal of competing projects such as pipelines or LNG import terminals.

Of the models identified, 12 out of 22 produce endogenously pipeline and LNG regasification investments. RAMONA produces investments for pipelines only. TIGER, WGM, and WGM-S also generate investments in gas storage capacity. MAGELAN, BI-WGTM, COLUMBUS, NATGAS, PEGASUS, and RAMONA additionally produce investments in gas production capacity.

\(^7\) Storage injections/withdrawals accounted for approximately 10% of total EU-27 demand/supply respectively between 2012 and 2019.
Table 1 reveals several inadequacies in the specification of a number of the models identified from the literature. These include:

- Insufficient spatial granularity due to aggregation of pipeline or LNG capacity or the aggregation of several countries into regions.
- Insufficient temporal granularity where the model solves on an annual or seasonal basis, limiting the ability to assess network resilience in peak demand months.
- Insufficient geographical scope, where relevant European countries or important extra-EU suppliers are omitted.
- Omission of important technical features such as reverse-flow capabilities in pipelines.
- Omission of endogenous infrastructure investment that can provide solutions to identified security-of-supply issues.

From the 22 models identified in the literature, only TIGER and WM-GGM exhibit the necessary scope, granularity, and endogenous infrastructure investment capabilities required to robustly examine the European natural gas network. TIGER details the European natural gas network at a very high level of granularity, generating gas production, trade, and infrastructure investment decisions at a daily resolution. However, the model is owned and maintained by the University of Cologne and is not publicly available. The global WM-GGM is also highly granular at the European level with production, trade, and endogenous infrastructure investments generated at a monthly resolution. Similarly, WM-GGM is owned and operated by consultants Wood Mackenzie and is therefore also not available to the general public.

| Percentage of total LNG exports shipped to European destinations (2019) | LNG availability multiplier | Assumed cost ($/MMBtu) |
|---------------------------------------------------------------|---------------------------|------------------------|
| Russia LNG                                                   | 52%                       | 0.52                   | 6.7                    |
| North Africa LNG                                             | 64.3%                     | 0.643                  | 6.75                   |
| Norway LNG                                                   | 88.4%                     | 0.884                  | 6.25                   |
| Nigeria LNG                                                  | 54.8                      | 0.548                  | 5.1                    |

2.2 Appraisal of Existing Models

Table 1 reveals several inadequacies in the specification of a number of the models identified from the literature. These include:

- Insufficient spatial granularity due to aggregation of pipeline or LNG capacity or the aggregation of several countries into regions.
- Insufficient temporal granularity where the model solves on an annual or seasonal basis, limiting the ability to assess network resilience in peak demand months.
- Insufficient geographical scope, where relevant European countries or important extra-EU suppliers are omitted.
- Omission of important technical features such as reverse-flow capabilities in pipelines.
- Omission of endogenous infrastructure investment that can provide solutions to identified security-of-supply issues.

From the 22 models identified in the literature, only TIGER and WM-GGM exhibit the necessary scope, granularity, and endogenous infrastructure investment capabilities required to robustly examine the European natural gas network. TIGER details the European natural gas network at a very high level of granularity, generating gas production, trade, and infrastructure investment decisions at a daily resolution. However, the model is owned and maintained by the University of Cologne and is not publicly available. The global WM-GGM is also highly granular at the European level with production, trade, and endogenous infrastructure investments generated at a monthly resolution. Similarly, WM-GGM is owned and operated by consultants Wood Mackenzie and is therefore also not available to the general public.
The highlighted deficiencies in the current complement of European gas models, coupled with the public unavailability of the two potentially suitable models in TIGER and WMGGM, provides an opportunity to introduce a new model. Section 3 presents the Gas Network Optimisation Model for Europe ( GNOME), a highly granular dispatch and investment model of the European natural gas network. All inputs, equations, and source code to reproduce GNOME are provided.

3 Methodology

3.1 Model Outline and Scope

GNOME is a dynamic, highly granular cost optimisation model of the European natural gas network and is formulated as an extension of the classical transhipment problem presented by Orden [54]. The objective is to satisfy gas demand in each country at the lowest discounted cost subject to a range of technical constraints. GNOME optimises the supply, transportation, and storage of natural gas on a monthly basis, from 2015 to 2040, in 5-year steps. Demand is satisfied through a combination of indigenous production, pipeline imports, LNG imports, and storage withdrawals. The model generates pipeline, LNG regasification, and gas storage capacity investments where cost optimal to do so (Sect. 3.4.9). Existing and planned cross-border gas pipelines are individually modelled in capacity and directional capability (Sect. 3.4.5). LNG import and export capacity (Sect. 3.4.6), storage capacity (Sect. 3.4.7), and gas supply capacity (Sect. 3.4.3) for each country are modelled. Gas demand is sourced exogenously and gas production volumes are generated endogenously (Sect. 3.4.2). The model represents demand and supply in all EU-27 countries except Cyprus, Luxembourg, and Malta. The UK, Norway, Switzerland, Belarus, Ukraine, and Turkey are also included as endogenous to the model. Russia, the Southern Corridor, Qatar, North Africa, Nigeria, and the Americas are modelled as exogenous supply-only regions. GNOME was developed in the General Algebraic Modeling System (GAMS) modelling package [24] and is formulated as a mixed-integer linear programming problem (MILP) with the CPLEX solver performing the optimisation.

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8 Existing European infrastructure is that which is defined as operational in the ENTSOG Transmission Capacity Map 2017, published on 1 July 2017 [19]. In the context of this paper, “planned” infrastructure projects are those that have at least reached FID status as of the publication of the ENTSOG Ten-Year Network Development Plan 2018, published 27 December 2018 [20].

9 Azerbaijan and Iran.

10 Algeria, Libya, Egypt.

11 The USA, Canada, Brazil, Peru, Trinidad and Tobago.
### 3.2 Notation

**Sets and subsets**

- $a$: Arcs (gas transit routes)
- $a_{route\_pipe}$: Pipeline routes
- $a_{pipe\_uni}$: Unidirectional pipelines
- $a_{pipe\_bi}$: Bidirectional (reversible flow) pipelines
- $a_{route\_LNG}$: LNG shipping routes
- $i$: Nodes (countries)
- $j$: Clone of $i$. Used to denote destination of transiting gas (where $i$ is the origin)
- $t$: Time slices (month)
- $base(t)$: First time slice in model horizon
- $card(t)$: Cardinality of set $t$
- $t_{terminal}$: Last time slice in model horizon
- $type$: Gas type (LNG or pipeline, and cost tranche identifier)

**Parameters**

- $\mu$: LNG liquefaction (export) loss factor
- $\eta$: LNG regasification (import) loss factor
- $\beta$: Pipeline leakage loss factor
- $\alpha$: Compressor station fuel use factor
- $MonthlyDiscountRate$: Discount rate for each monthly period $t$
- $Demand_{i,t}$: Demand for gas in country $i$ in period $t$ (BCM/month)
- $ProductionCapacity_{i,t,type}$: Gas production capacity for each gas type in country $i$ in period $t$ (BCM/month)
- $PipeCapacityExisting_{route\_pipe,i,j,t}$: Capacity of existing pipeline route $route\_pipe,i,j$ (BCM/month)
- $LNGExportCapacity_{i,t}$: Forecasted aggregated LNG export capacity in country $i$ in period $t$ (BCM/month)
- $LNGImportCapacityExisting_{i,t}$: Existing aggregated LNG import capacity in country $i$ in period $t$ (BCM/month)
- $StorageCapacityExisting_{i,t}$: Existing aggregated gas storage capacity in country $i$ in period $t$ (BCM)
- $StorageInjectionCapacityExisting_{i,t}$: Existing aggregated gas storage injection capacity in country $i$ in period $t$ (BCM/month)
- $StorageWithdrawalCapacityExisting_{i,t}$: Existing aggregated gas storage withdrawal capacity in country $i$ in period $t$ (BCM)
- $CostProduction_{i,t,type}$: Production costs for each gas type in each country $i$ in each month $t$ (million USD / BCM)
- $UnitCostTransPipe$: Cost of sending one unit of gas along a pipeline route (million USD / BCM)
- $UnitCostTransLNG$: Cost of sending one unit of gas along LNG shipping route excluding liquefaction and regasification costs (million USD / BCM)
- $UnitCostLiquef$: Cost of converting one BCM of gas into LNG (million USD / BCM)
- $UnitCostRegas$: Cost of converting one BCM of LNG back into gas (million USD / BCM)
### Parameters

| Parameter                                      | Description                                                                 |
|-----------------------------------------------|-----------------------------------------------------------------------------|
| FixedCostInvestLNG                            | Fixed cost of building LNG regasification capacity (million USD)             |
| FixedCostInvestStorage                        | Fixed cost of building gas storage capacity (million USD)                    |
| UnitCostInvestPipe$_{route\_pipe,i,j}$        | Variable cost of building pipeline capacity (million USD / KM)               |
| UnitCostInvestLNG                             | Variable cost of building LNG regasification capacity (million USD / BCM)    |
| UnitCostInvestStorage                         | Variable cost of building gas storage capacity (million USD / BCM)           |
| RouteLength$_{a,i,j}$                         | Length of gas transportation route (KM)                                      |
| Compressors$_{route\_pipe,i,j}$               | Number of compressor stations on pipeline route                              |
| ContractedFlow$_{a,i,j,t}$                    | Volume of gas to be transported between the seller $i$ and the buyer $j$ in period $t$ as specified in existing long-term supply contracts (BCM / month) |
| LNGAvailabilityMultiplier$_{i}$               | Multiplier applied to LNG liquefaction capacity at each exporter $i$ to limit the volume available to Europe |

### Variables

| Variable                                      | Description                                                                 |
|-----------------------------------------------|-----------------------------------------------------------------------------|
| CostSystemDiscounted                          | Objective function (million USD)                                            |
| CPProd$_{t}$                                  | Total production costs in periods $t$ (million USD)                          |
| CTPipe$_{t}$                                  | Total pipeline transport costs in period $t$ (million USD)                   |
| CTLNG$_{t}$                                   | Total LNG transport costs in period $t$ (million USD)                        |
| CInvPipe$_{t}$                                | Total new pipeline investment costs in period $t$ (million USD)             |
| CInvLNG$_{t}$                                 | Total new LNG import investment costs in period $t$ (million USD)           |
| CInvStorage$_{t}$                             | Total new gas storage investment costs in period $t$ (million USD)          |
| SalvageValuePipe$_{t}$                        | Residual value at period $t$ of new pipeline investments (million USD)      |
| SalvageValueLNG$_{t}$                         | Residual value at period $t$ of new LNG investments (million USD)           |
| SalvageValueStorage$_{t}$                     | Residual value at period $t$ of new gas storage investments (million USD)   |
| Production$_{i,t,type}$                       | Gas produced in country $i$ in period $t$ by type (BCM/month)               |
| Flow$_{a,i,j,t}$                               | Gas flow along route $a,i,j$ in period $t$ (BCM/month)                      |
| PipeCapacityNew$_{a,i,j,t}$                   | New pipeline capacity constructed on route $a,i,j$ in period $t$ (BCM/month) |
| LNGImportCapacityNew$_{i,t}$                  | New LNG import capacity constructed in country $i$ in period $t$ (BCM/month) |
| StorageCapacityNew$_{i,t}$                    | New gas storage capacity constructed in country $i$ in period $t$ (BCM)     |
| StorageInjectionCapacityNew$_{i,t}$           | Increase in gas storage injection capacity in country $i$ in period $t$ as a result of increase in StorageCapacityNew$_{i,t}$ (BCM/month) |
| StorageWithdrawalCapacityNew$_{i,t}$          | Increase in gas storage withdrawal capacity in country $i$ in period $t$ as a result of increase in StorageCapacityNew$_{i,t}$ (BCM/month) |
| StorageInjections$_{i,t}$                     | Storage injections in country $i$ in period $t$ (BCM)                      |
| StorageWithdrawals$_{i,t}$                    | Storage withdrawals in country $i$ in period $t$ (BCM)                     |
| StorageLevel$_{i,t}$                          | Volume of gas held in storage in each country $i$ in period $t$ (BCM)       |


3.3 Equations

\[
\sum_{\text{type}=1}^{n} \text{Production}_{i,t,\text{type}} + \left( (1 - \beta) \times \text{compressors}_{\text{route,pipe},i,j} \times \text{Route Length}_{\text{route,pipe},i,j} \times \left( (1 - \alpha) \times \sum_{\text{route,pipe}=1}^{n} \text{Flow}_{\text{route,pipe},i,j} \right) \right) \\
+ \left( (1 - \eta) \times \sum_{\text{route,LNG}=1}^{n} \text{Flow}_{\text{route,LNG},i,j} \right) + \text{Storage Withdrawals}_{i,t} = \text{Demand}_{i,t} \\
+ \left( (1 - \beta) \times \text{compressors}_{\text{route,pipe},i,j} \times \text{Route Length}_{\text{route,pipe},i,j} \times \left( (1 - \alpha) \times \sum_{\text{route,pipe}=1}^{n} \text{Flow}_{\text{route,pipe},i,j} \right) \right) \\
+ \left( \left( \frac{1}{(1 - \mu)} \times \text{Route Length}_{\text{route,LNG},i,j} \right) \times \sum_{\text{route,LNG}=1}^{n} \text{Flow}_{\text{route,LNG},i,j} \right) + \text{Storage Injection}_{i,t}
\]

Energy balance:

\[
\text{indigenous production}_{i,t} + \text{LNG imports}_{i,t} + \text{pipeline imports}_{i,t} + \text{storage withdrawals}_{i,t} = \\
\text{indigenous demand}_{i,t} + \text{LNG exports}_{i,t} + \text{pipeline exports}_{i,t} + \text{storage injections}_{i,t}
\]

\[
\sum_{\text{type}=1}^{n} \text{Production}_{i,t,\text{type}} \leq \text{Production Capacity}_{i,t,\text{type}} 
\]

Production constraints

\[
\text{Flow}_{\text{route,pipe},i,j,t} \geq \text{Contracted Flow}_{\text{route,pipe},i,j,t}
\]

Flow constraints

\[
\text{Flow}_{\text{route,LNG},i,j,t} \geq \text{Contracted Flow}_{\text{route,LNG},i,j,t}
\]

\[
\text{Flow}_{\text{route,pipe},i,j,t} \leq \text{Pipe Capacity Existing}_{\text{route,pipe},i,j,t} + \sum_{t} \text{Pipe Capacity New}_{\text{route,pipe},i,j,t}
\]

\[
\text{Flow}_{\text{pipe,uni},i,j,t} \geq 0
\]

\[
\left[ \text{Flow}_{\text{pipe,uni},i,j,t} \right] \leq \left( \text{Pipe Capacity Existing}_{\text{route,pipe},i,j,t} + \sum_{t} \text{Pipe Capacity New}_{\text{route,pipe},i,j,t} \right) \times -1
\]

\[
\sum_{j=1}^{n} \text{Flow}_{\text{route,LNG},i,j,t} \leq \text{LNG Export Capacity}_{i,t} \times \text{LNG Availability Multiplier}_{i}
\]

\[
\sum_{j=1}^{n} \text{Flow}_{\text{route,LNG},i,j,t} \leq \text{LNG Import Capacity Existing}_{i,j,t} + \sum_{t} \text{LNG Import Capacity New}_{i,j,t}
\]

Storage Level:

\[
\text{Storage Level}_{i,t} \leq \text{Storage Capacity Existing}_{i,t} + \sum_{t} \text{Storage Capacity New}_{i,t}
\]

Storage constraints

\[
\text{Storage Withdrawal Capacity New}_{i,t} = \text{Storage Capacity New}_{i,t} \times 0.54
\]
\[ \text{Storage Injection Capacity New}_{i,t} = \text{Storage Capacity New}_{i,t} \times 0.32 \quad (13) \]

\[ \text{Storage Withdrawals}_{i,t} \leq \text{Storage Withdrawal Capacity Existing}_{i,t} + \sum_i \text{Storage Withdrawal Capacity New}_{i,t} \quad (14) \]

\[ \text{Storage Injections}_{i,t} \leq \text{Storage Injection Capacity Existing}_{i,t} + \sum_i \text{Storage Injection Capacity New}_{i,t} \quad (15) \]

\[ C_{\text{Prod}_t} = \frac{\sum_{\text{type}=1}^n \text{Production}_{i,\text{type}} \times \text{Cost Production}_{i,\text{type}}}{1 + \text{Monthly Discount Rate}^{(1+\text{card}(t))}} \quad (16) \]

Production and transport costs

\[ C_{\text{TPipe}_t} = \frac{\sum_{\text{route}_\text{pipe}=1}^n \left[ \text{Flow}_{\text{route}_\text{pipe},i,j} \times \text{Route Length}_{\text{route}_\text{pipe},i,j} \times \text{Unit Cost Trans Pipe} \right]}{1 + \text{Monthly Discount Rate}^{(1+\text{card}(t))}} \quad (17) \]

\[ C_{\text{TLNG}_t} = \frac{\sum_{\text{route}_\text{LNG}=1}^n \left[ \text{Flow}_{\text{route}_\text{LNG},i,j} \times \text{Route Length}_{\text{route}_\text{LNG},i,j} \times \text{Unit Cost Trans LNG} + \left( \text{Unit Cost Liquefied} + \text{Unit Cost Regas} \right) \right]}{1 + \text{Monthly Discount Rate}^{(1+\text{card}(t))}} \quad (18) \]

Investment costs and salvage values

\[ C_{\text{InvPipe}_t} = \frac{\sum_{\text{route}_\text{pipe}=1}^n \left( \text{Route Length}_{\text{route}_\text{pipe},i,j} \times \text{Unit Cost Invest Pipe}_{\text{route}_\text{pipe},i,j} \right)}{1 + \text{Monthly Discount Rate}^{(1+\text{card}(t))}} \quad (19) \]

\[ C_{\text{InvLNG}_t} = \frac{\sum_{i=1}^n \text{Fixed Cost Invest LNG} + \left( \text{LNG Import Capacity New}_{i,t} \times \text{Unit Cost Invest LNG} \right)}{1 + \text{Monthly Discount Rate}^{(1+\text{card}(t))}} \quad (20) \]

\[ C_{\text{InvStorage}_t} = \frac{\sum_{i=1}^n \text{Fixed Cost Invest Storage} + \left( \text{Storage Capacity New}_{i,t} \times \text{Unit Cost Invest Storage} \right)}{1 + \text{Monthly Discount Rate}^{(1+\text{card}(t))}} \quad (21) \]

\[ \text{Salvage Value Pipe}_t = \frac{\sum_{\text{route}_\text{pipe}=1}^n \text{C}_{\text{InvPipe}_t} \times \left[ 1 - \left( 1 + \text{Monthly Discount Rate}_{t}^{(\text{base}(t)+\text{card}(t(t)-1))} \right) \right]}{1 + \text{Monthly Discount Rate}^{(1+\text{card}(t))}} \quad (22) \]
3.4 Description

 GNOME acts as a gas dispatch and investment planner with perfect foresight that seeks to minimise the total discounted cost of the European natural gas system. This section describes each of the fundamental elements of the model formulation in turn.

3.4.1 Energy Balance

For each country $i$ in each month $t$, the sum of all indigenous gas production, pipeline imports, LNG imports, and storage withdrawals must equal the sum of all indigenous gas demand, pipeline exports, LNG exports, storage injections, and system losses including pipeline leakage, pipeline compressor station fuel use, and LNG boil-off. This node balancing equation is described in full by (1) and is reduced to a simpler form in (2).

Pipeline flows are reduced by a leakage factor, $\alpha$, and compressor fuel factor, $\beta$. This is multiplied by the number of stations ($\text{compressors}_{\text{route.pipe},i,j}$) along that route. Data on the number of compressor stations sited along each pipeline in Europe was not publicly available; therefore, an assumption of 200 km between stations is assumed [67], p. 411).

Energy losses are incurred at three main stages in the LNG supply chain. Firstly, LNG exports in the model are increased by the factor $\mu$ to account for energy used in the liquefaction process. Secondly, due to increasing pressure to diversify away from high-sulphur marine diesel as a fuel source [40], GNOME assumes that all tankers are powered by bunker LNG in the long term.12 Gas is also lost to “boil-off” as stored LNG returns to a gaseous state and is typically vented. The combined effects of in-transit refrigeration requirements, ship fuel use, and boil-off losses are

\[ \text{Salvage Value LNG}_t = \sum_{i=1}^{n} C_{\text{InvLNG},i} \times \left[ 1 - \left( 1 + \text{Monthly Discount Rate}_t \right)^{\text{(base}(t)+\text{card}(t)-t)-1} \right] / (1 + \text{Monthly Discount Rate}_t^{1+\text{card}(t)}) \]  

\[ \text{Salvage Value Storage}_t = \sum_{i=1}^{n} C_{\text{InvStorage},i} \times \left[ 1 - \left( 1 + \text{Monthly Discount Rate}_t \right)^{\text{(base}(t)+\text{card}(t)-t)-1} \right] / (1 + \text{Monthly Discount Rate}_t^{1+\text{card}(t)}) \]  

\[ \text{MINIMISE Cost System Discounted} \]

\[ \text{Cost System Discounted} = \sum_1 \left( \text{Prod}_t + C_{\text{Pipe}_t} + C_{\text{LNG}_t} + C_{\text{Pipe}_t} + C_{\text{LNG}_t} + C_{\text{Storage}_t} \right) - \text{Salvage Value Pipe}_t - \text{Salvage Value LNG}_t - \text{Salvage Value Storage}_t \]  

\[ \text{Objective function} \]

\[ 12 \text{ Le Fevre [45] estimates that by 2030, 68% of the global LNG transportation tanker fleet will be dual-fuel units that use both LNG and fuel oil for locomotion and refrigeration.} \]
represented by \( \eta \). Finally, \( \mu \) represents losses incurred during the regasification process. Assumed values for all loss factors are given in Table 15 in the Appendix.

### 3.4.2 Gas Demand

GNOME requires exogenous country level demand inputs at a monthly resolution, which were not available in the public domain. However, annual gas demand scenarios for Europe as a whole were available [68], [9], [21], [37]. GNOME calculates the growth rate of the chosen annual whole-Europe demand curve and uses it to grow or decline gas demand for each country, using actual country-level data from BP [8] as a starting point. This is further disaggregated into monthly time slices, using the 5-year (2014–2018) historical average seasonal gas demand profile from Eurostat [22] for each individual country. This accounts for the significant diversity in seasonal heating and cooling requirements across Europe and provides the monthly, country-level demand input required by GNOME.

### 3.4.3 Gas Supply

GNOME generates gas production levels \((\text{Production}_{i,t,\text{type}})\) for each country \(i\) for each month \(t\). Per-unit production costs \((\text{CostProduction}_{i,t,\text{type}})\) are differentiated by both the producing country \(i\), the time period \(t\), and gas type. The type of gas refers to either pipeline gas or LNG, which is further disaggregated into numbered cost silos (1–6) to represent incrementally more expensive tranches of gas supply available from the same source country.

Ideally, a full dataset of forecasted production capacity and costs would be used in GNOME. However, this information was not publicly available and procurement from consultancies such as Wood Mackenzie and Platts Analytics was prohibitively expensive. Therefore, costs and available volumes were derived from supply cost curves produced by Rystad Energy [63] which were commissioned by BEIS (UK Gov Department of Business, Energy and Industrial Strategy) to form the basis for their 2020 Fossil Fuel Price Assumptions [5]. These curves were available for the years 2025, 2030, 2035, and 2040 and are presented in Figs. 4, 5, 6, and 7 in the Appendix, respectively. Volumes available to Europe and their corresponding delivered costs were derived from these charts and used to implement upper constraints for each tranche of supply. The primary external suppliers to Europe — Russia, Norway, the USA, North Africa, and Qatar — are represented. A full description of the supply curve methodology and underlying gas-specific assumptions is available from Rystad Energy [63], pp. 31–39.

When contacted, BEIS were reluctant to elaborate on the countries represented in the “Other” and “Europe” categories in the Rystad supply curves shown in Figs. 4–7. It was therefore necessary to make assumptions regarding production costs and available volumes for countries not explicitly defined in the supply curves. The category “other” is assumed to be Azeri and Iranian gas entering Europe via the Southern Corridor, as they are the only significant source of pipeline imports to Europe not explicitly represented in the Rystad curves. The pipeline route into
Europe from both countries is the same; therefore, they are amalgamated into a “Southern Corridor” supply region in GNOME model, using the “other” category to apply available volumes and costs.

For indigenous European producers not represented in the supply curves, production capacity for 2020 was assumed to be actual production volumes in 2019. Using this as a starting point in 2020, production capacity is assumed to decline at the same rate as total European gas production in the IEA World Energy Outlook 2018 Stated Policies scenario [37]. This produces an average year-on-year decline rate between 2020 and 2030 of 2.1%, and 0.9% between 2031 and 2040.

Production costs for these unrepresented indigenous producers are set deliberately low ($1.4/MMBtu in 2025, $1.2/MMBtu in 2030, $1.8/MMBtu in both 2035 and 2040) in order to encourage these countries to satisfy as much of their own demand as possible. These costs mimic those of Norwegian pipeline gas and the lowest-cost source of gas supply in the model. Total discounted\(^{13}\) gas production costs in each period \(t\) are defined in (16).

Due to the lack of representation of LNG volumes from Russia, North Africa, Norway, and Nigeria available to Europe in the Rystad cost curves, these regions are assigned an arbitrary upper production capacity constraint of 100 BCM/year in GNOME. This is purely to reduce the size of the optimisation problem to be solved. In reality, global LNG trade is determined by netbacks, and the Asia–Pacific region will take a significant share of volumes from these exporters. As GNOME only exports to European destinations, it was necessary to impose a tighter upper constraint on LNG export capacity from these regions in order to prevent the model from sending abnormally high volumes of LNG to Europe. To do this, the percentage of exports from each of these regions that were delivered to European destinations in 2019 was derived from BP [10] and applied as a multiplier to available liquefaction capacity in each region. Cost assumptions for Russian and Nigerian LNG delivered to Europe were taken from estimates for 2025 [66], p. 21). Norwegian LNG costs were taken from details of a ten-year LNG supply contract signed in 2016 between Statoil and Lithuania [36].\(^{14}\) North African LNG costs were derived from average realised prices for Algerian LNG cargos arriving in Europe in March 2019 [2].

The resultant liquefaction constraints and delivered costs to Europe are shown in Table 2.

Using these supply capacity and cost assumptions, gas production in GNOME is subject to an upper constraint on gas supply (3) for each gas type based on the volume available to Europe from each supply country \(i\) in each month \(t\).

\(^{13}\) The annual discount rate for all discounting activities is 10%, which is divided into monthly periods depending on the length of the modelling horizon.

\(^{14}\) Average price of 18 EUR/MWh, equating to $6.25/MMBtu using an FX rate of 1.19 USD/EUR.
3.4.4 Representation of Market Power and Gas Supply Contracts

 GNOME assumes that the European gas market is perfectly competitive with no market power exerted, the majority assumption (13 out of 22) in the gas models identified in Table 1. The deliberate omission of market power in the GNOME model is discussed in Sect. 3.4.11.

 In the absence of market power representation, GNOME assumes that 100% of the Annual Contract Quantity (ACQ) volume in existing pipeline and LNG contracts is delivered. No new or extended contracts are assumed; therefore, all existing contracts represented in the model expire without renewal. The volumes and timescales of existing contracts were taken from a literature review of long-term gas supply contracts [52]. The representation of gas supply contracts in the GNOME model for pipeline and LNG contracts is shown by (4) and (5), respectively.

3.4.5 Infrastructure: Pipelines

 GNOME models all 126 cross-border pipelines that serve the countries outlined in Sect. 2.1.2. Fifty of these pipelines are specified as bidirectional ($a_{pipe\_bi}$) and the rest unidirectional ($a_{pipe\_uni}$). All proposed FID-status pipeline projects that will serve endogenous countries in GNOME are modelled and assumed to be completed on budget and on schedule. Data on pipeline routes and technical features is taken from ENTSOG [19]. Where data on pipeline length was available for a particular pipeline, it is specified. Where not, it is assumed that the length of each pipeline is the distance between the geometric centres of the exporting and importing countries. For exogenous supply regions that are aggregated with two or more countries, the average distance of the aggregated exporting countries to the importing country is assumed to be the point of export.

 The upper constraint on gas flow along all pipeline routes is described in (6). It states that total gas flow in any period $t$ must not exceed the technical capacity $^{16}$ of the existing pipeline, plus any new pipeline capacity built by the model along that route.

 The lower bound on unidirectional pipeline flows is shown in (7), indicating that they cannot exhibit negative (reverse) flows. The lower bound on bidirectional pipeline flows is described by (8). It states that these pipelines may send gas in reverse (negative flow) at the same rate as the forward flow capacity. $^{17}$

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$^{15}$ Projects that had reached Final Investment Decision status according to the ENTSOG 10-Year Network Development Plan 2018 [20]

$^{16}$ Whereas “hydraulic capacity” treats each pipeline in isolation and calculates flow capacity using the laws of fluid dynamics, “technical capacity” considers interdependencies in the network that may affect flow rates. Technical capacity also factors in a 1.5% buffer to allow for small operational disturbances in gas flow [43].

$^{17}$ The importance of reverse-flow capabilities in the European gas network was discussed in Sect. 2.1.4.
3.4.6 Infrastructure: LNG

GNOME represents all existing LNG import capacity in the endogenous countries described in Sect. 2.1.2, plus any proposed FID-status projects. Countries that have historically exported LNG to Europe are included as exogenous supply-only nodes, with their current and forecasted future liquefaction capacities modelled. LNG export capacity data is taken from [39] and includes all existing and FID-status projects. Any region in the model with liquefaction capacity may export LNG to any country with regasification capacity, subject to capacity constraints at both sides.

Regasification capacity is aggregated at the country level. This creates 100 shipping routes \( (a_{\text{route}, \text{LNG}}) \) to European countries, from six LNG exporting nodes (North Africa LNG, Nigeria LNG, Middle East LNG, Norway LNG, Russia LNG, and Americas LNG).

The upper constraint on LNG exports \( (\text{Flow}_{\text{route}, \text{LNG}}) \) is shown by (9), which states that they must be equal to or less than the aggregated liquefaction capacity of the exporting country or region multiplied by the assumed percentage of export capacity available to Europe discussed in Sect. 3.4.3.

Equation (10) states that the sum of all inbound flows of LNG to an importing country \( j \) are constrained by existing regasification capacity plus any new capacity built by GNOME. LNG import capacity data is taken from ENTSOG [19]. LNG shipping route distances were taken from Platts [56]. It is assumed that the Suez Canal, the Strait of Gibraltar, and the Northeast Passage are fully accessible and the Turkish embargo on all LNG traffic through the Bosphorus Strait remains in place throughout the modelling horizon [6].

3.4.7 Infrastructure: Storage

GNOME represents all existing gas storage capacity in the endogenous countries described in Sect. 2.1.2, plus any proposed FID-status projects. Data on existing European storage facilities for the base year 2015 was taken from ENTSOG [18] and updated for 2020 with data from the AGSI data platform (2020). Storage projects that were identified as having reached FID-status by July 2021 in the 2021 GIE Storage Database [26] were assumed to go ahead. Storage capacity is aggregated at the country level.

The upper constraint on the volume of gas in storage is shown in (11) which must be equal to or less than the aggregated cumulative gas storage capacity of country \( i \) in period \( t \). The model does not apply any cost to gas storage, and assumes no gas is lost whilst being stored. GNOME may only inject gas during the traditional 1 April–30 September filling season, and withdraw only during the 1 October–31 March withdrawal season.

As the injection and withdrawal rates of future gas storage facilities is unknown, the withdrawal and injection rates as a proportion of total existing\(^{18}\) European gas storage capacity.
storage capacity \( [25] \) were used as proxies and applied as multipliers to new storage capacity additions in the model. Daily storage withdrawal capacity in Europe was calculated as 1.77\% of working gas capacity. When annualised and converted into a monthly capacity multiplier for each month \( t \), this equates to a monthly withdrawal multiplier of 0.54.\(^{19}\) Daily storage injection capacity in Europe was calculated as 1.06\% of working gas capacity. When annualised and converted into a monthly capacity multiplier for each month \( t \), this equates to a monthly injection multiplier of 0.32.\(^{20}\) Equations (12) and (13) show these multipliers as applied in the GNOME model for new withdrawal and injection capacity, respectively.

The upper constraint on withdrawals from gas storage is shown in (14), which must be equal to or less than the aggregated cumulative gas storage withdrawal capacity of country \( i \) in period \( t \). The upper constraint on injections into gas storage is shown in (15), which must be equal to or less than the aggregated cumulative gas storage injection capacity of country \( i \) in period \( t \).

### 3.4.8 Gas Transportation Costs

The supply costs in the Rystad supply curves outlined in Sect. 3.4.3 are specified as “delivered to Europe”. To account for the supply countries explicitly represented in the cost curves already having transportation costs built into their “delivered” costs, transportation costs from these countries are set to zero in GNOME. This section shows how transport costs are assigned to other suppliers and for intra-Europe gas flows.

The calculation of total pipeline transportation costs in each period \( t \) is described in (17). The cost of transporting one BCM of gas along a gas pipeline (\( \text{UnitCostTransPipe} \)) in GNOME is assumed to be 0.0525 million USD/km. This is an average of 8/km OPEX costs for natural gas pipeline transport with varying pipeline diameters and operating pressures derived from Saadi et al. [64], p. 3). The absolute value of the flow (\( |\text{Flowroute}_\text{pipe}| \)) is used to prevent reverse flows generating negative costs in the model.

The cost of shipping one BCM of gas along an LNG route (\( \text{UnitCostTransLNG} \)) is assumed to be 0.0034 million USD/km. This is an average of shipping costs (excluding liquefaction and regasification) from the US Gulf Coast-UK and Qatar-UK. Assumed per-BCM liquefaction costs (\( \text{UnitCostLiquef} \)) are 2.3 million USD/BCM and are averages of US Gulf Coast and Qatari liquefaction costs. European regasification costs (\( \text{UnitCostRegas} \)) are assumed to be 0.69 million USD/BCM. All LNG transportation costs were derived from Rogers [62]. The calculation of total LNG transportation costs (\( \text{CTLNG}_t \)) in each period \( t \) is shown in (18).

\[^{19}\] 0.017655546, multiplied by 365 days, divided by 12 months.

\[^{20}\] 0.010577096, multiplied by 365 days, divided by 12 months.
3.4.9 Infrastructure Investment

If demand cannot be satisfied using existing infrastructure, GNOME will generate a cost-minimising investment strategy of cross-border pipelines, LNG regasification capacity, and gas storage capacity. To keep the model size tractable, GNOME may only add pipeline capacity to existing routes. For LNG regasification and gas storage investments, new capacity may only be built in countries with existing capacity.

**Pipelines** Given the various legal and regulatory hurdles faced by Nord Stream 2, GNOME assumes that Russia is unable to build any more pipelines into the European Union except the Nord Stream 2 and Turk Stream\(^{21}\) projects, which were both already under construction as of December 2020. Pipeline projects that had reached Final Investment Decision (FID) status in the ENTSOG Ten Year Network Development Plan 2018 (ENTSOG\(^{[20]}\)) are assumed to go ahead and completed on time and on budget. These projects are outlined in Table 11 in the Appendix.

GNOME is formulated as a MILP problem specifically to allow the imposition of both a lower and upper constraint on infrastructure investments. This stops the model building implausibly sized pipelines or LNG import terminals. As such, the model can either invest in a user-defined semicontinuous range of capacity additions, or nothing at all. This range is between 0.08 and 110 BCM/year, which represents the smallest cross-border pipeline represented in the model (Haanrade) and the size of a very large hypothetical project such as a combined Nord Streams 1 and 2.

**LNG Regasification** It is assumed that all regasification projects that are identified as FID status go ahead on time and on budget. These are shown in Table 12 in the Appendix. GNOME may invest in either no additional LNG regasification capacity at all, or a semicontinuous range between 3.7 and 59 BCM/year. This represents the smallest existing LNG import terminal in Europe (Panigaglia, Italy) and the largest regasification terminal in existence at Incheon, South Korea.

**Gas Storage** It is assumed that all gas storage projects that are identified as FID-status go ahead on time and on budget. These are shown in Table 13 in the Appendix. GNOME may invest in either no additional gas storage regasification capacity at all, or a semicontinuous range between 0.0027 and 5.34 BCM. This represents the smallest (Brugggraf-Bersdorf, Germany) and the largest (Norg Langelo, Netherlands) existing storage facilities in Europe.

**Infrastructure Investment Costs** LNG investment costs are derived from a range of European LNG project budgets (Dunkirk, South Hook, Mugardos, Adriatic LNG, 21 Although Turk Stream enters the EU from Turkey, it is a supply route for Russian gas into Southern Europe.
FSRU Independence, Gate Rotterdam, and Świnoujście). The average cost of these projects was 935 million USD, with an average liquefaction capacity of 9.5 BCM/year. Songhurst [65] finds that 48% of total LNG project costs are fixed. Therefore, GNOME assumes that fixed costs for a new LNG liquefaction project \( \text{FixedCostInvestLNG} \) are 449 million USD, and per-BCM variable investment costs \( \text{UnitCostLNGInvest} \) are 59 million USD/BCM. The calculation of \( C_{\text{InvLNG}} \), the sum of all LNG import capacity investment costs in all countries \( i \) for each period \( t \), is shown in (19).

\( C_{\text{InvPipe}} \), represents the sum of all pipeline investment costs between all countries \( i \) and \( j \) in period \( t \). Fixed costs for pipelines do not matter in GNOME because pipelines can only be built along existing routes, therefore the distances are predetermined and full CAPEX costs are incurred for any level of capacity addition. For onshore pipelines, an average per-kilometre unit investment cost \( \text{UnitCostInvestPipe} \) in GNOME of 5.25 million USD/km was derived from the average of nine onshore gas pipeline project budgets in the US Northeast (2018). Offshore pipelines are assumed to cost 1.959 times that of analogous onshore pipelines (2008), giving a per-kilometre unit cost of investment of 10.28 million USD/km in GNOME. The calculation of new pipeline investment costs between all countries \( i \) and \( j \) in each period \( t \) in million USD is shown in (20).

Storage investment costs are derived from Le Fevre [44], who estimates per-BCM gas storage investment costs in Great Britain to be within a range of £400–800 m (Sterling) for depleted field facilities and £800–1200 m for salt cavern facilities. As GNOME does not discern between these types of storage, a midpoint of £800 m/bcm of storage capacity is assumed. The same fixed cost assumptions used for LNG and pipeline — that 48% of total storage investment costs are fixed — were applied for gas storage investments. Therefore, GNOME assumes that fixed costs for a new gas storage facility \( \text{FixedCostInvestStorage} \) are 544.9 million USD, and per-BCM variable investment costs \( \text{UnitCostStorageInvest} \) are 590.4 million USD/BCM of new capacity. The calculation of \( C_{\text{InvStorage}} \), the sum of all storage capacity investment costs in all countries \( i \) for each period \( t \), is shown in (21).

Salvage value represents the residual value of any new investment made by GNOME that is still within its operational life. Salvage values are determined by the time the investment was made, the operational life of the investment, and the discount rate. The salvage value is discounted to the start of the modelling horizon using the discount rate. Discount rates for all activities are 10% per year, and operational lifetime is assumed to be 30 years for pipelines, LNG, and storage facilities. This method of applying sinking fund depreciation to calculate salvage values was taken from Howells et al. [35]. The calculation of salvage value for new pipeline, LNG regasification, and gas storage investments are shown in (22), (23), and (24), respectively.

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22 These include owner’s costs (10%), engineering and project management (8%), and equipment (30%). Bulk materials and construction make up the remainder and are excluded.
3.4.10 Objective Function

The complete objective function (25) minimises the total discounted system cost \((\text{CostSystemDiscounted})\) of the modelled network including gas production costs, gas transportation costs, and infrastructure investment costs, minus any remaining salvage value of investments.

3.4.11 Uncertainties, Problem Style, and Market Power

As a simplified representation of a complex system, GNOME contains a range of input assumptions and consequently a range of uncertainties that should be considered when evaluating its output. The European gas markets, and the global gas market within which they operate, are shaped by a range of factors. These include but are not limited to:

- Climate and weather patterns
- Geopolitics
- European energy and climate policy
- The global decarbonisation pathway and its impact on global gas demand, particularly in Asia
- European energy investments such as renewables, hydrogen production, and gas storage capacity
- Technological advancements and cost reductions in areas such as energy storage, carbon capture utilisation and storage (CCUS), and hydrogen production
- Global investment in upstream gas production and the LNG liquefaction capacity needed to export it.

The version of GNOME presented in this paper is deterministic and as such is subject to the inherent uncertainty of the input assumptions. The advantage of the model being deterministic is that it can be formulated as a mixed-integer linear program (MILP). For GNOME, this was desirable because the final model is large, and defining it as a linear problem keeps the problem size compact enough to be solved in a reasonable amount of time (around 20 min) using non-specialised IT equipment. The open-source nature of GNOME allows the model to be modified in future to explore such uncertainties, however, and the potential development of a stochastic variant of GNOME is noted in Sect. 5.2.

As shown in Table 1, all models identified in the literature that include market power do so by presenting the gas market as a Cournot duopoly. However, the dynamics of market power in the European gas market are changing. New supply contracts are becoming increasingly shorter and less voluminous [52]. The

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23 The latest iteration of GNOME solved before the publication of this paper contained 118,873 single equations, 26,099,602 single variables, 14,793 discrete variables, and a total of 26,565,892 non-zero elements.

24 Windows 10 laptop, Intel Core i7-3610QM CPU at 2.30 GHz, 16 GB RAM.
expanding global LNG market is allowing Europe to access new sources of gas supply, placing pressure on traditional exporters such as Russia to renegotiate terms [59] and Algeria to move away from oil-indexation and embrace the hub-based pricing structure of their European target markets [69]. This suggests that the model of oligopolistic supply in the European gas market is becoming increasingly obsolete, and market power is in decline. This, combined with the desire to keep the problem linear for the reasons outlined, formed the rationale for not including market power in this variant of GNOME.

4 Scenario Analysis and Results

To demonstrate the capabilities of GNOME, two scenarios were developed. First, a Reference scenario where all infrastructure projects that have reached FID status go ahead and Nord Stream 2 is completed and fully operational by 2025.25 This was compared to a second scenario, No NS2, which assumes that construction of the Nord Stream 2 never happens. No other Russian pipelines except the FID-status Turk Stream may be built in either scenario. The model was run at a monthly resolution for 2025–2040 in 5-year steps. The objective is to examine not only whether gas demand can still be met without the Nord Stream 2 pipeline, but also whether it costs more to do so.

The high levels of granularity and scope of GNOME make it impractical to present all outputs here. Instead, selected annual results for main output variables are presented in this section, with full annual and monthly results for all outputs made available at https://www.dropbox.com/sh/w8fpky0tz36gya/AAAz6kvVME1L3qJ_oCI7yKEa?dl=0.

4.1 Demand

Annual EU-27 gas demand was taken from the IEA World Energy Outlook 2020 Stated Policies Scenario [38] and disaggregated into country-level monthly demand using the methodology outlined in Sect. 3.4.2. Table 3 shows assumed demand levels for each country, which are the same for both scenarios.

4.2 Infrastructure Investment

Table 4 shows pipeline investments produced by GNOME. The “FID” column shows the FID-status investments the model is forced to build. The absence of deltas in the No NS2 scenario (except the absence of the 55 BCM Nord Stream 2 pipeline)

25 At the time of writing in December 2020, Nord Stream 2 was not completed. The pipeline is likely to be completed sometime before 2025, however due to the five-year steps in GNOME, 2025, is the next opportunity to include it in the model.
demonstrates that the cancellation of Nord Stream 2 does not cause the model to build any additional pipeline capacity to compensate.

Table 5 shows LNG regasification investments. GNOME does not need to build any additional LNG capacity to compensate for the loss of Nord Stream 2.

Table 6 shows gas storage investments. GNOME does not need to build any additional storage capacity to compensate for the loss of Nord Stream 2.

The removal of the Nord Stream 2 pipeline does not prevent the model from satisfying demand in any country in any month. Additional infrastructure investments in excess of the mandatory FID-status pipelines, LNG regasification, and storage

| Country      | 2025   | 2030   | 2035   | 2040   |
|--------------|--------|--------|--------|--------|
| Austria      | 7.80   | 7.44   | 7.22   | 7.00   |
| Belarus      | 17.46  | 16.64  | 16.15  | 15.65  |
| Belgium      | 15.41  | 14.69  | 14.25  | 13.82  |
| Bulgaria     | 2.93   | 2.79   | 2.71   | 2.62   |
| Croatia      | 2.34   | 2.23   | 2.17   | 2.10   |
| Czech Rep    | 7.32   | 6.97   | 6.77   | 6.56   |
| Denmark      | 3.22   | 3.07   | 2.98   | 2.89   |
| Estonia      | 0.39   | 0.37   | 0.36   | 0.35   |
| Finland      | 2.24   | 2.14   | 2.07   | 2.01   |
| France       | 39.80  | 37.94  | 36.81  | 35.68  |
| Germany      | 75.12  | 71.60  | 69.46  | 67.33  |
| Greece       | 3.02   | 2.88   | 2.80   | 2.71   |
| Hungary      | 8.49   | 8.09   | 7.85   | 7.61   |
| Ireland      | 4.29   | 4.09   | 3.97   | 3.85   |
| Italy        | 62.73  | 59.79  | 58.01  | 56.22  |
| Latvia       | 1.27   | 1.21   | 1.17   | 1.14   |
| Lithuania    | 2.34   | 2.23   | 2.17   | 2.10   |
| Netherlands  | 33.27  | 31.71  | 30.76  | 29.82  |
| Norway       | 4.39   | 4.18   | 4.06   | 3.93   |
| Poland       | 16.68  | 15.90  | 15.43  | 14.95  |
| Portugal     | 4.68   | 4.46   | 4.33   | 4.20   |
| Romania      | 10.15  | 9.67   | 9.38   | 9.09   |
| Slovakia     | 4.39   | 4.18   | 4.06   | 3.93   |
| Slovenia     | 0.78   | 0.74   | 0.72   | 0.70   |
| Spain        | 27.80  | 26.50  | 25.71  | 24.92  |
| Sweden       | 0.88   | 0.84   | 0.81   | 0.79   |
| Switzerland  | 2.93   | 2.79   | 2.71   | 2.62   |
| UK           | 70.24  | 66.95  | 64.95  | 62.96  |
| Ukraine      | 31.22  | 29.76  | 28.87  | 27.98  |
| Turkey       | 44.87  | 42.77  | 41.50  | 40.22  |
| **Total**    | 508.45 | 484.64 | 470.19 | 455.73 |
projects outlined in Tables 11, 12, 13 and 14 in the Appendix are unnecessary to meet demand under the IEA World Energy Outlook 2020 Stated Policies Scenario [38].

### 4.3 Production

Table 7 shows annual gas production volumes generated by GNOME in the Reference scenario (Ref) and the delta caused by implementing the No NS2 scenario (No NS2 Δ).

As expected, the model produces around the same total volume in both scenarios as demand must still be met regardless of the infrastructure configuration. Production reported by GNOME for supply-only regions in the model (Americas LNG, Nigeria LNG, North Africa, North Africa LNG, Norway LNG, Qatar LNG, Russia, Russia LNG, Southern Corridor) is significantly lower than the expected production for these regions. This is because indigenous demand in and exports from these countries to non-modelled regions are not represented.

### 4.4 Pipeline Flows

Table 8 shows aggregate annual pipeline flows generated by GNOME in each scenario.

From 2030, Russia exports around 55 bcm/year (the capacity of Nord Stream 2) less to Germany in the No NS2 scenario. To compensate, the model reroutes approximately half of these exports through Ukraine and the other half through Belarus. Slovakia distributes around 22 bcm/year of additional Russian gas

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**Table 4** Endogenous pipeline investments (BCM/year of transportation capacity)

|            | 2025 FID | 2025 Ref | 2025 No NS2 Δ | 2030 FID | 2030 Ref | 2030 No NS2 Δ |
|------------|----------|----------|---------------|----------|----------|---------------|
| Bulgaria   | Greece   | 1.7      | 1.7           |          |          |               |
| Romania    |          | 18.7     | 18.7          |          |          |               |
| Hungary    | Romania  | 18.7     | 18.7          |          |          |               |
| Russia     | Germany  | 55.0     | 55.0          | −55.0    |          |               |
| Slovakia   | Hungary  | 18.7     | 18.7          |          |          |               |
| Total      |          | 112.8    | 112.8         | −55.0    | 56.2     | 56.2          |

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**Table 5** Endogenous LNG regasification investments (BCM/year of regasification capacity)

|        | 2025 FID | 2025 Ref | 2025 No NS2 Δ | 2030 FID | 2030 Ref | 2030 No NS2 Δ |
|--------|----------|----------|---------------|----------|----------|---------------|
| Poland | 2.5      | 2.5      |               |          |          |               |
| Spain  | 1.3      | 1.3      | 1.3           | 1.3      | 1.3      |               |
| Total  | 3.8      | 3.8      | 1.3           | 1.3      | 1.3      |               |
transiting Ukraine into Austria and onward into Italy. Poland transits an average of around 26 bcm/year of the additional Russian flows coming via Belarus into Germany in the No NS2 case. Germany’s role as a hub for Russian gas flows to NW Europe is diminished in the No NS2 case, shown by an average decreased flow from Germany to the Netherlands of around 20 bcm/year in 2030–2035.

Table 6 Endogenous gas storage investments (BCM of storage capacity)

|          | 2030 |       |       |
|----------|------|-------|-------|
|          | FID  | Ref   | No NS2 Δ |
| Italy    | 0.59 | 0.59  |        |
| Total    | 0.59 | 0.59  |        |

Table 7 Annual gas production by scenario (BCM/year)

|                | 2025 | 2030 | 2035 | 2040 |
|----------------|------|------|------|------|
|                | Ref  | No NS2 Δ | Ref  | No NS2 Δ | Ref  | No NS2 Δ | Ref  | No NS2 Δ |
| Americas LNG   | 26.4 | 14.8 0.8 | 27.4 | 0.8      | 13.3 | 0.6      |
| Austria        | 1.0  | 0.9   | 0.8  |          | 0.8  |          |
| Bulgaria       | 0.1  | 0.1   | 0.1  |          | 0.1  |          |
| Croatia        | 1.6  | 1.4   | 1.3  |          | 1.3  |          |
| Czech Rep      | 0.2  | 0.2   | 0.2  |          | 0.2  |          |
| Denmark        | 4.3  | 3.8   | 3.6  |          | 3.5  |          |
| Germany        | 6.5  | 5.8   | 5.6  |          | 5.3  |          |
| Hungary        | 1.5  | 1.3   | 1.2  |          | 1.2  |          |
| Italy          | 5.8  | 5.2   | 5.0  |          | 4.8  |          |
| Netherlands    | 10.0 | 7.0   | 5.0  |          | 2.5  |          |
| Nigeria LNG    | 20.8 | 20.8  | 20.8 |          | 20.8 |          |
| North Africa   | 27.1 | 10.6  | 10.2 |          | 9.7  |          |
| North Africa LNG | 37.5 | 37.5  | 37.5 |          | 37.5 |          |
| Norway         | 109.0| 32.4  | 38.9 |          | 30.4 |          |
| Norway LNG     | 5.7  | 5.7   | 5.7  |          | 5.7  |          |
| Poland         | 3.8  | 3.4   | 3.3  |          | 3.1  |          |
| Qatar LNG      | 40.6 | 39.2  | 20.6 |          | 20.1 |          |
| Romania        | 17.9 | 25.0  | 24.3 |          | 15.4 |          |
| Russia         | 93.9 | 201.2 | 193.9|          | 221.5|          |
| Russia LNG     | 39.7 |       |      |          |      |          |
| Slovakia       | 0.1  | 0.1   | 0.1  |          | 0.1  |          |
| Southern Corridor | 31.9 | 44.3  | 43.3 |          | 36.7 |          |
| Spain          | 0.1  | 0.1   | 0.1  |          | 0.1  |          |
| Turkey         | 0.3  | 0.3   | 0.3  |          | 0.3  |          |
| UK             | 32.1 | 28.6  | 25.6 |          | 24.5 |          |
| Ukraine        | 15.4 | 13.7  | 13.1 |          | 12.6 |          |
| **Total**      | 533.3| 503.7 | 488.0| 471.3    | 0.6  |          |
| From          | To             | 2025 | No NS2 | 2030 | No NS2 | 2035 | No NS2 | 2040 | No NS2 |
|--------------|---------------|------|--------|------|--------|------|--------|------|--------|
| Austria      | Germany       | 6.2  | 4.8    |      |        |      |        |      |        |
| Hungary      | 5.0           |      |        |      |        |      |        |      |        |
| Italy        | 20.3          | 17.5 | 14.6   | 22.1 | 23.0   | -10.5|        |      |        |
| Slovakia     | 0.6           | 0.7  | 0.7    |      |        | 1.6  |        |      |        |
| Slovakia     | 0.6           | 0.7  | 0.7    |      |        | 1.6  |        |      |        |
| Belarus      | Lithuania     | 2.2  | 2.2    |      |        | 2.1  |        |      |        |
| Poland       | 11.1          | 27.4 | 12.1   | 26.5 | 7.6    | 25.2 |        |      |        |
| Belgium      | France        | 2.2  | 0.3    |      |        | 0.5  |        |      |        |
| Germany      | 6.0           |      |        |      |        | -6.0 |        |      |        |
| Netherlands  | 4.0           |      |        |      |        |      |        |      |        |
| Bulgaria     | Greece        | 4.9  | 8.6    | 8.6  |        |      |        |      |        |
| Romania      | 3.8           |      |        |      |        | -2.5 |        |      |        |
| Denmark      | Sweden        | 0.9  | 0.8    | 0.8  | 0.8    |      |        |      |        |
| Estonia      | Latvia        | 1.2  | 1.2    |      |        | 1.1  |        |      |        |
| France       | Switzerland   | 5.6  |        |      |        | -0.3 |        |      |        |
| Germany      | Austria       | 12.5 |        |      |        | -7.0 |        |      |        |
| Denmark      | 0.2           |      |        |      |        |      |        |      |        |
| France       | 6.2           | 33.5 | -18.0 | 34.9 | 22.2   | 46.1 | -0.5  |      |        |
| Netherlands  | 5.2           | 2.8  | 2.7    |      | 3.0    |      |        |      |        |
| Poland       | 11.1          | 6.8  | 6.6    |      |        |      |        |      |        |
| Czech Republic| Italy       | 10.5 | 10.5   | 10.5 | 10.5   |      |        |      |        |
| Hungary      | Croatia       | 0.8  | 0.8    |      | 0.8    |      |        |      |        |
| Romania      | 0.9           |      |        |      |        | -3.8 |        |      |        |
| Lithuania    | 0.4           |      |        |      |        | -0.9 |        |      |        |
| Latvia       | 1.6           |      |        |      |        |      |        |      |        |
| Netherlands  | Belgium        | 8.8  | -8.8   | 9.1  | -9.1   | 20.9 | -0.5  |      |        |
| Germany      | 9.9           | 4.0  | 2.3    |      |        | -2.1 |        |      |        |
| Norway       | Belgium        | 11.4 | 4.3    | 6.5  | -2.3   | 10.2 | -0.5  |      |        |
| France       | 58.4          |      |        |      |        |      |        |      |        |
| Germany      | 24.2          | 23.8 | 24.2   |      |        | 16.1 | 0.5   |      |        |
| Poland       | 30.4          | 26.2 | 19.2   |      |        |      |        |      |        |
| Slovakia     | 7.7           | 15.3 | 14.9   |      |        |      |        |      |        |
Table 8 (continued)

| From          | To          | 2025 Ref | No NS2 | Δ | 2030 Ref | No NS2 | Δ | 2035 Ref | No NS2 | Δ | 2040 Ref | No NS2 | Δ |
|---------------|-------------|----------|--------|---|----------|--------|---|----------|--------|---|----------|--------|---|
| Russia        | Belarus     | 17.5     | 30.1   | 27.7 | 30.6     | 26.8   | 25.5 | 25.5     | 25.5   |   | 25.5     | 25.5   |   |
| Estonia       |             | 1.6      | 1.5    | 1.5  | 1.5      | 1.5    | 1.5 | 1.5      | 1.5    |   | 1.5      | 1.5    |   |
| Finland       |             | 2.2      | 2.1    | 2.1  | 2.0      | 2.0    |     | 2.0      |        |   | 2.0      |        |   |
| Germany       |             | 39.3     | 110.0  | −55.0| 108.9    | −53.9  | 110.0| −55.0    | 110.0  |   | 108.9    | −53.9  |   |
| Turkey        |             | 16.0     |        |     | 6.5      |        |     | 10.8     |        |   | 6.5      |        |   |
| Ukraine       |             | 18.1     | 55.8   | 27.6 | 49.2     | 27.4   | 74.2 | 18.9     |        |   | 27.4     | 18.9   |   |
| Slovakia      | Austria     | 27.8     | 23.9   | 21.9 | 27.2     | 28.7   | −3.6 | 10.8     |        |   | 28.7     | −3.6   |   |
| Hungary       |             | 2.0      | 7.6    | 7.4  | 3.4      | 3.4    |     | 3.4      |        |   | 3.4      |        |   |
| Slovenia      | Croatia     | 0.8      |        |     |          |        |     |          |        |   |          |        |   |
| Switzerland  | Italy       | 2.7      |        |     |          |        |     |          |        |   |          |        |   |
| Turkey        | Greece      | 2.8      | 4.8    | 4.8  | 2.7      | 10.6   |     |          |        |   | 2.7      | 10.6   |   |
| UK           | Belgium     | 1.9      | 5.3    | 4.5  | 0.3      | 0.7    | −13.1| 0.5      |        |   | −13.1    | 0.5    |   |
|              | Ireland     | 4.3      | 4.1    | 4.0  | 3.8      |        |     |          |        |   | 3.8      |        |   |
| Ukraine       | Hungary     |          |        |     |          | 3.4    |     |          |        |   | 3.4      |        |   |
|              | Romania     |          |        |     |          |        |     |          |        |   |          |        |   |
|              | Slovakia    | 2.3      | 39.7   | 24.1 | 33.5     | 27.3   | 58.8 | 15.4     |        |   | 58.8     | 15.4   |   |
| Czech Rep    | Germany     |          |        |     |          | 8.1    | 28.2 |          |        |   | 8.1      | 28.2   |   |
|              | Poland      |          |        |     |          |        |     |          |        |   |          |        |   |
|              | Slovakia    | 4.0      |        |     | −14.5    | −28.2  |     |          |        |   | −14.5    | −28.2  |   |
| North Africa | Italy       | 26.9     | 10.5   | −10.5| 10.1     | −6.2   | 9.7  |          |        |   | 9.7      |        |   |
|              | Spain       |          |        |     | 10.5     | 6.2    |     |          |        |   | 10.5     | 6.2    |   |
| Southern Corridor | Turkey | 31.4     | 43.6   | 42.6 | 36.2     |        |     |          |        |   | 36.2     |        |   |
| **Total**    |             | 361.5    | 499.4  | 110.8| 475.3    | 103.7  | 451.7| 65.3     |        |   | 451.7    | 65.3   |   |

### 4.5 LNG Flows

Table 9 shows LNG trade by scenario.

With total production and pipeline trade remaining similar under the No NS2 scenario, the total volume of LNG flows is also essentially the same. Like pipeline flows, there is a reconfiguration of flows from 2030, however. The largest change is North Africa shipping an average of 12 bcm/year less to Italy in the 2030–2035 period, driven by the increased Russian pipeline exports to Italy transiting Ukraine and Austria discussed in Sect. 4.4.
### Table 9 LNG flows by scenario (BCM/year)

| From          | To     | 2025 Ref | 2025 No NS2 | Δ Ref | Δ No NS2 | 2030 Ref | 2030 No NS2 | Δ Ref | Δ No NS2 | 2035 Ref | 2035 No NS2 | Δ Ref | Δ No NS2 | 2040 Ref | 2040 No NS2 | Δ Ref | Δ No NS2 |
|---------------|--------|----------|-------------|-------|----------|----------|-------------|-------|----------|----------|-------------|-------|----------|----------|-------------|-------|----------|
| Americas LNG  | Belgium| 2.7      |             |       |          | 2.1      |             | 0.2   | −0.2     | 11.6    |             | 0.5   |          | 85.1    |             | 0.5   |          |
|               | France | 2.1      |             |       |          | 10.5     | 0.7         | 21.3  | −1.9     | 11.6    |             | 0.5   |          | 85.1    |             | 0.5   |          |
|               | Portugal| 2.1     |             |       |          | 2.4      |             | 2.4   |          |          |             |       |          |          |             |       |          |
|               | Spain   | 16.5     | 10.5        | 0.7   | −1.9     | 21.3     | −1.9        | 11.6  | 0.5      |          |             |       |          |          |             |       |          |
|               | UK      | 2.4      |             |       |          | 2.4      |             | 2.4   |          |          |             |       |          |          |             |       |          |
| Nigeria LNG   | Belgium | 5.2      |             |       |          | 4.8      |             |       |          |          |             |       |          |          |             |       |          |
|               | France  | 9.6      | 2.3         | −1.3 | −0.1     | 10.1     | −9.1        | 4.9   | 0.5      |          |             |       |          |          |             |       |          |
|               | Italy   | 1.5      |             |       |          | 4.1      |             | 8.0   |          |          |             |       |          |          |             |       |          |
|               | Portugal| 2.0      |             |       |          | 4.5      |             | 3.6   | 0.7      |          |             |       |          |          |             |       |          |
|               | Spain   | 5.1      | 15.9        | −12.5 | −4.4     | 4.4      | −4.4        | 13.3  | −0.5     |          |             |       |          |          |             |       |          |
| North Africa LNG | France | 18.5     | 26.1        | 5.7   | −1.9     | 15.2     | −1.9        | 15.2  |          |          |             |       |          |          |             |       |          |
|               | Greece  | 10.1     | 7.0         | −7.0 | −1.9     | 17.9     | −15.9       | 17.9  |          |          |             |       |          |          |             |       |          |
|               | Italy   | 4.6      |             |       |          | 1.3      |             |       |          |          |             |       |          |          |             |       |          |
|               | Spain   | 4.6      |             |       |          | 1.3      |             |       |          |          |             |       |          |          |             |       |          |
| Norway LNG    | Belgium | 1.8      |             | 4.4   | −4.4     | 4.2      | −4.2        | 5.1   |          |          |             |       |          |          |             |       |          |
|               | France  | 1.8      |             | 4.4   | −4.4     | 4.2      | −4.2        | 5.1   |          |          |             |       |          |          |             |       |          |
|               | Lithuania| 1.7     |             |       |          | 5.1      |             | 5.1   |          |          |             |       |          |          |             |       |          |
|               | Netherlands| 1.7    |             |       |          | 5.1      |             | 5.1   |          |          |             |       |          |          |             |       |          |
|               | Spain   | 1.6      |             |       |          | 1.3      |             | 1.3   |          |          |             |       |          |          |             |       |          |
|               | Poland  | 1.6      |             |       |          | 1.3      |             | 1.3   |          |          |             |       |          |          |             |       |          |
| Qatar LNG     | Belgium | 2.8      |             | 6.3   | 3.6      | 6.3      |             | 6.3   |          |          |             |       |          |          |             |       |          |
|               | Greece  | 5.9      |             |       |          | 6.3      |             | 6.3   |          |          |             |       |          |          |             |       |          |
|               | Italy   | 6.3      |             |       |          | 6.3      |             | 6.3   |          |          |             |       |          |          |             |       |          |
|               | Portugal| 0.6      |             | 4.5   | −4.5     | 0.7      | −0.7        | 4.2   |          |          |             |       |          |          |             |       |          |
|               | Spain   | 17.8     | 21.5        | 4.5   | 7.1      | 17.1     | 0.7         | 13.1  |          |          |             |       |          |          |             |       |          |
|               | UK      | 17.8     | 21.5        | 4.5   | 7.1      | 17.1     | 0.7         | 13.1  |          |          |             |       |          |          |             |       |          |
|               | Poland  | 1.4      |             | 1.4   |          | 1.4      |             | 1.4   |          |          |             |       |          |          |             |       |          |
| Russia LNG    | Belgium | 13.0     |             |       |          | 13.0     |             | 13.0  |          |          |             |       |          |          |             |       |          |
|               | France  | 2.3      |             |       |          | 2.3      |             | 2.3   |          |          |             |       |          |          |             |       |          |
|               | Lithuania| 2.3     |             |       |          | 2.3      |             | 2.3   |          |          |             |       |          |          |             |       |          |
|               | Netherlands| 13.1   |             |       |          | 13.1     |             | 13.1  |          |          |             |       |          |          |             |       |          |
|               | Poland  | 6.3      |             |       |          | 6.3      |             | 6.3   |          |          |             |       |          |          |             |       |          |
| **Total**     |         | 148.9    | 102.9       | 0.7   | 97.9     | 0.6      | 85.1        | 0.5   |          |          |             |       |          |          |             |       |          |

### 4.6 Storage Profile

Figure 3 shows the total volume of gas in European storage in each scenario.
As shown, European gas storage is typically fullest by October, and depleted by January. As the model runs in 5-year increments, this profile should not be considered continuous, but rather an illustration of how the model utilises storage to balance throughout each year. The most discernible difference between the scenarios is that less gas is injected during the summers of 2030 and 2035 during the No NS2 case. This is predominantly being driven by Italy, who is receiving more pipeline gas from Russia via Austria, reducing their requirement to fill storage ahead of winter.

In reality, European gas storage would not be allowed to fall to zero. This happens in GNOME because it lacks a gas pricing function, and as such, no value is placed on having gas in storage for the duration of winter if it is not needed to meet demand under the defined constraints. In a real gas market, the summer–winter spread would ensure that some gas remains in storage throughout the majority of winter when prices are highest. Furthermore, security of supply commitments in individual countries and contractual supply obligations would also prevent storage completely emptying before the end of winter. However, as shown in Fig. 3, GNOME is capable of

![European gas storage level (bcm) under the Reference case and the No NS2 case](image)

**Table 10** Annual costs by type and scenario (billion USD, nominal, not discounted)

|          | 2025 | 2030 | 2035 | 2040 |
|----------|------|------|------|------|
| **Ref**  | 789.84 | 584.93 | 576.73 | 561.94 |
| **No NS2** | 584.93 | 3.35 | 3.12 | 2.73 |
| **Δ**    | -7.99 | 10.32 | 576.73 | 561.94 |

Supply and transportation costs

Investment costs

**Total**
producing storage profiles analogous with the real world without being forced to by explicit constraints on how much gas must be stored at any given time.

4.7 Costs

Table 10 shows total annual undiscounted costs by category.

Gas production costs are added to pipeline and LNG transportation costs to give a “supply and transportation costs” value because, as discussed in Sect. 3.4.8, the gas suppliers explicitly represented in the Rystad supply curves outlined in Sect. 3.4.4 are specified as “delivered to Europe”. This means that transportation costs from these suppliers are built into their “delivered” costs, and therefore, transportation costs are set to zero in GNOME. Therefore, showing LNG and pipeline transportation costs separately would be misleading, as they would be artificially low. Bundling them together with production costs negates this issue and allows a genuine comparison to be made between the scenarios.

The cumulative cost impact between 2025 and 2040 of the No NS2 scenario is an increase in total undiscounted system costs of 1.2 billion USD. This suggests that GNOME can still satisfy demand without Nord Stream 2, and under the stated assumptions, it can do so without significantly increases in total costs.

5 Conclusions and Further Work

This paper has discussed potential gas security of supply issues facing European countries arising from declining indigenous production and an increased reliance on imports. The literature review in Sect. 2 reveals deficiencies in the specification of existing models of the European gas network, particularly in the areas of granularity and scope. This gap in the literature allows the opportunity to introduce the new GNOME dispatch and investment model of the European gas network, which is presented in full in Sect. 3. Section 4 demonstrated the capabilities of GNOME by applying it to a Reference scenario where all FID status infrastructure status projects are completed. This is then compared to a No NS2 scenario where the Nord Stream 2 pipeline is never built. The purpose of this is to ascertain not only whether the Nord Stream 2 pipeline in necessary to meet demand, but also whether or not it is actually cost optimal to build at all. The modelled results indicate that the Nord Stream 2 pipeline is not required to meet demand under the IEA World Energy Outlook [38] Stated Policies Scenario, and that by re-configuring gas production and trade, no additional infrastructure is required to compensate. However, total system costs incurred between 2025 and 2040 are slightly increased without the inclusion of the Nord Stream 2 pipeline.
5.1 Contribution of GNOME to the State of the Art

Table 1 concisely compares GNOME’s feature set within the existing suite of European gas models, and as such, it is not necessary to compare each feature here. In general terms, GNOME is reasonably scoped and granular in a spatial context for its intended purpose of analysing the European natural gas network, with 40 demand and supply node countries connected by 242 pipeline and LNG shipping route arcs. Solving at a monthly time resolution is reasonable to analyse network resilience in all but very short-term disruption scenarios, although the model would undoubtedly benefit from further disaggregation to daily time slices such as in PEGASUS [58]. The combined gas and power model presented by Deane et al. [13] not only solves at an hourly resolution, but also benefits from the reduced scope of only being run on a 1-year snapshot basis which vastly reduces model size and computational requirements of such granular temporal resolution.

 GNOME represents all cross-border pipelines (with bidirectionally where applicable), individually, and aggregates LNG regasification and storage capacity at the country level. Of the models that represent all three infrastructure elements, TIGER, PEGASUS, WM-GGM, EPRG-GMM, N-WGM, and EGMM go a step further than GNOME and model LNG import and gas storage terminals individually. The aggregating of LNG and storage in the current version of GNOME is appropriate because each country is represented by a single node; however, the modelling of individual storage and LNG import terminals would be an enhancement should future versions of the model be more spatially disaggregated.

A key feature that sets GNOME apart from most existing gas models is its ability to generate endogenous infrastructure investment decisions should the existing European gas network be unable to satisfy gas demand in a particular scenario. Excluding GNOME, only three of the 22 models identified in Table 1 generate endogenous investments for pipelines, LNG import terminals, and gas storage. These are the WGM and WGM-Stochastic and the TIGER model.

The World Gas Models are highly aggregated models of the global gas market and as such are not suitable for analysing the dynamics and resilience of the European natural gas network. On the other hand, TIGER is highly disaggregated at the European level and is potentially the best-specified of the European-focused models identified, including GNOME. However, unlike TIGER, GNOME is available on an open-source basis, allowing complete examination of its inputs and structure. Importantly, this also allows further development by the community.

5.2 Potential Improvements to the GNOME Model

The following alterations may increase the future usefulness of the GNOME model and can be broadly categorised into “spatial”, “temporal”, and “other features and data availability” developments:

Spatial

1. Disaggregation of aggregated supply-only regions into individual countries with individual costs of supply modelled
2. Inclusion of indigenous demand and non-European exports for supply-only regions
3. Addition of a “North East Asia” region (China, South Korea, Japan) as a demand node, to provide competition with Europe for LNG volumes

**Temporal**

4. Extension of the modelling horizon to capture more decarbonisation-driven global gas demand dynamics
5. Disaggregation to daily time slices to allow analysis of short-term supply and demand shocks

**Other features and data availability**

6. Connection of GNOME to an energy systems model to obtain gas demand volumes, with disaggregation of the demand sector into component parts to allow demand-side responses to be fed back into GNOME. Development of such a linkage between GNOME and the European TIMES Model (ETM-UCL) [61] is underway and will be presented in future publications.
7. Obtain and implement a complete dataset on European gas pipeline distances
8. Obtain and implement a full dataset on current and projected gas production costs for all suppliers
9. Inclusion of a pricing mechanism to generate European gas hub prices, allowing non-contracted trade flows to be shaped by regional price differentials
10. Development of a stochastic variant of GNOME to represent firm behaviour

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**Data Availability** The full GAMS code and input data for GNOME and full output results of the scenario analysis are available at https://www.dropbox.com/sh/w8fwpyk0tz36gy/aAAAa0vVMEJ6L3qJ_oCl7yKEa?dl=0

**Code Availability** GAMS source code for the model is available at the following repository: https://www.dropbox.com/sh/w8fwpyk0tz36gy/aAAAa0vVMEJ6L3qJ_oCl7yKEa?dl=0
Appendix

Fig. 4 Rystad Energy gas supply cost curve for 2025. Source: BEIS [5]

Fig. 5 Rystad Energy gas supply cost curve for 2030. Source: BEIS [5]

Fig. 6 Rystad Energy gas supply cost curve for 2035. Source: BEIS [5]
**Fig. 7** Rystad Energy gas supply cost curve for 2040. Source: BEIS [5]

**Table 11** FID-status pipeline projects assumed to go ahead in GNOME. Source: ENTSOG [20]

| Project name                       | Origin      | Destination | Capacity (BCM/year) | Assumed start-up date in GNOME |
|------------------------------------|-------------|-------------|---------------------|--------------------------------|
| Tarvisio expansion                | Austria     | Italy       | 6.21                | Jan 2020                       |
| TANAP                             | Azerbaijan  | Turkey      | 16.1                | Jan 2020                       |
| TANAP                             | Turkey      | Greece      | 16.1                | Jan 2020                       |
| Bulgaria-Greece interconnection   | Bulgaria    | Greece      | 2.96                | Jan 2020                       |
|                                   | Bulgaria    | Greece      | 4.66                | Jan 2025                       |
| N/A                               | Czech Rep   | Slovakia    | 24                  | Jan 2020                       |
| Baltic Connector                  | Estonia     | Finland     | 2.81                | Jan 2020                       |
| Estonia-Latvia interconnection    | Estonia     | Latvia      | 2.33                | Jan 2020                       |
| TAP interconnection               | Greece      | Italy       | 10.45               | Jan 2020                       |
| Passo Gries expansion             | Italy       | Switzerland | 13.82               | Jan 2020                       |
| Poland-Lithuania interconnection  | Poland      | Lithuania   | 2.43                | Jan 2020                       |
| Poland-Slovakia interconnection   | Poland      | Slovakia    | 5.73                | Jan 2020                       |
| Nord Stream 2                     | Russia      | Germany     | 55                  | Jan 2025                       |
| Turk Stream                       | Russia      | Turkey      | 31.5                | Jan 2020                       |
| Eastring Line 1                   | Bulgaria    | Romania     | 18.72               | Jan 2025                       |
|                                   | Hungary     | Romania     |                     |                                |
|                                   | Slovakia    | Hungary     |                     |                                |
| Eastring Line 2                   | Bulgaria    | Romania     | 18.72               | Jan 2025                       |
|                                   | Hungary     | Romania     |                     |                                |
|                                   | Slovakia    | Hungary     |                     |                                |

**Table 12** FID-status LNG regasification projects assumed to go ahead by the GNOME model. Source: ENTSOG [20]

| Project name                  | Location | Capacity (BCM/year) | Assumed start-up date in GNOME |
|------------------------------|----------|---------------------|--------------------------------|
| Revithoussa expansion        | Greece   | 2.66                | Jan 2020                       |
| Musel                        | Spain    | 7.7                 | Jan 2020                       |
| Swinoujscie expansion        | Poland   | 2.5                 | Jan 2025                       |
| Gran Canaria                 | Spain    | 1.3                 | Jan 2025                       |
| Tenerife                     | Spain    | 1.3                 | Jan 2030                       |
Table 13  FID-status gas storage projects assumed to go ahead by the GNOME model. Source: ENT-SOG [20]

| Project name                                | Location | Capacity (BCM) | Assumed start-up date in GNOME |
|----------------------------------------------|----------|----------------|--------------------------------|
| Conegliano UGS                               | Italy    | 0.8            | Jan 2020                       |
| Bordolano — second phase                    | Italy    | 0.757          | Jan 2020                       |
| Stogit — system enhancements                | Italy    | 0.588          | Jan 2030                       |

Table 14  Assumed monthly gas demand profile for each country used to disaggregate annual demand inputs into monthly time slices for GNOME (% of annual total). Source: Five-year averages (2014–2018), derived from Eurostat [22]

|                  | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|------------------|-----|-----|-----|-----|-----|-----|-----|-----|-----|-----|-----|-----|
| Austria          | 14  | 12  | 11  | 7   | 6   | 4   | 5   | 5   | 6   | 8   | 11  | 13  |
| Belarus          | 12  | 10  | 10  | 8   | 7   | 6   | 6   | 6   | 6   | 9   | 10  | 11  |
| Belgium          | 13  | 11  | 10  | 8   | 6   | 5   | 5   | 5   | 6   | 8   | 11  | 12  |
| Bulgaria         | 13  | 10  | 10  | 8   | 7   | 6   | 6   | 5   | 6   | 8   | 10  | 12  |
| Croatia          | 12  | 11  | 10  | 7   | 6   | 5   | 5   | 6   | 6   | 9   | 11  | 13  |
| Czech Rep        | 15  | 12  | 11  | 7   | 5   | 4   | 4   | 4   | 5   | 8   | 11  | 13  |
| Denmark          | 14  | 12  | 11  | 8   | 6   | 5   | 4   | 5   | 6   | 8   | 10  | 11  |
| Estonia          | 16  | 13  | 12  | 8   | 5   | 4   | 4   | 4   | 4   | 8   | 10  | 12  |
| Finland          | 14  | 11  | 11  | 8   | 6   | 6   | 5   | 6   | 7   | 8   | 9   | 10  |
| France           | 14  | 13  | 11  | 7   | 5   | 4   | 4   | 4   | 5   | 8   | 11  | 13  |
| Germany          | 13  | 11  | 10  | 7   | 6   | 5   | 5   | 5   | 6   | 8   | 11  | 11  |
| Greece           | 11  | 9   | 7   | 6   | 6   | 7   | 8   | 8   | 8   | 8   | 9   | 10  |
| Hungary          | 15  | 12  | 10  | 7   | 5   | 4   | 4   | 4   | 5   | 8   | 11  | 14  |
| Ireland          | 9   | 9   | 9   | 8   | 8   | 7   | 8   | 8   | 8   | 8   | 9   | 9   |
| Italy            | 13  | 11  | 10  | 6   | 6   | 6   | 6   | 5   | 6   | 7   | 10  | 13  |
| Latvia           | 15  | 12  | 10  | 7   | 4   | 4   | 5   | 5   | 5   | 9   | 12  | 12  |
| Lithuania        | 12  | 10  | 10  | 8   | 7   | 6   | 5   | 5   | 7   | 9   | 10  | 11  |
| Netherlands      | 13  | 11  | 9   | 8   | 6   | 5   | 6   | 6   | 6   | 8   | 10  | 12  |
| Norway           | 6   | 08  | 10  | 9   | 6   | 10  | 15  | 11  | 5   | 6   | 7   | 9   |
| Poland           | 12  | 10  | 10  | 8   | 7   | 6   | 6   | 6   | 6   | 9   | 10  | 11  |
| Portugal         | 9   | 07  | 7   | 7   | 8   | 9   | 10  | 9   | 9   | 8   | 9   | 9   |
| Romania          | 12  | 12  | 10  | 7   | 6   | 6   | 5   | 6   | 6   | 8   | 10  | 12  |
| Slovakia         | 17  | 13  | 12  | 7   | 3   | 3   | 3   | 3   | 4   | 5   | 8   | 11  |
| Slovenia         | 13  | 11  | 10  | 7   | 6   | 6   | 5   | 5   | 6   | 8   | 10  | 12  |
| Spain            | 10  | 9   | 9   | 7   | 7   | 7   | 7   | 7   | 7   | 8   | 10  | 10  |
| Sweden           | 13  | 12  | 16  | 7   | 6   | 4   | 4   | 5   | 5   | 7   | 10  | 11  |
| Switzerland      | 14  | 12  | 11  | 7   | 6   | 4   | 5   | 5   | 6   | 8   | 11  | 13  |
| UK               | 12  | 11  | 11  | 8   | 7   | 6   | 5   | 5   | 6   | 8   | 10  | 11  |
| Ukraine          | 17  | 13  | 12  | 7   | 3   | 3   | 3   | 4   | 5   | 8   | 11  | 13  |
| Turkey           | 11  | 9   | 7   | 6   | 6   | 7   | 8   | 8   | 8   | 8   | 9   | 12  |
Table 15  Gas transportation loss assumptions in GNOME

| Loss factor | Description                                | Value                                      | Source |
|-------------|--------------------------------------------|--------------------------------------------|--------|
| $\alpha$    | Pipeline transport leakage factor          | $5.37 \times 10^{-6}\%$ per km travelled   | [49]   |
| $\beta$     | Compressor station loss factor             | $3.89 \times 10^{-3}\%$ of all gas passing through each station | [70] |
| $\mu$       | LNG liquefaction loss factor               | $0.1\%$ of all gas liquefied              | [14]   |
| $\epsilon$  | LNG shipping loss factor                   | $1.87 \times 10^{-5}\%$ per km travelled  | [31]   |
| $\eta$      | LNG regasification loss factor             | $1.64 \times 10^{-2}\%$ of all LNG regasified | [14] |

Average LNG tanker boil-off losses of 0.125% of total cargo per day. Assuming an average speed of 15 knots (27.8 km/h), an LNG tanker will travel 667 km/day = 0.1874% of cargo lost per km travelled [31]

Declarations

Competing Interests  The author declares no competing interests.

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