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

Stevie Lochran¹

Received: 13 March 2021 / Accepted: 27 October 2021 / Published online: 23 November 2021
© The Author(s) 2021

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

1 Introduction

European gas¹ 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 Index² (HHI) for gas imports between 1998 and 2018.³ 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 particular 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.⁴ 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

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.

Fig. 1 Evolution of Herfindahl–Hirschman Index for gas import market by country (1998–2018). Source: Authors own presentation, data from Eurostat [22]

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. 2 EU Member State performance against the PF-1 and PF-2 resilience standards for 2016. Source: [4], p. 85)

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 unnamed⁵ models presented by Egging et al. [15] and Deane et al. [13].

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]”.

Table 1 Characteristics of existing gas models available in the literature

Model	Developer	Problem type	Market power	Spatial	Temporal		
					Coverage	Nodes	Static or dynamic Time horizon Time slices
<i>GNOME</i>	<i>Stevie Lochran</i>	<i>MILP</i>		<i>Europe</i>		40	<i>Dynamic</i> 2040 12
Wood Mackenzie Global Gas Model	Wood Mackenzie	LP		Global		> 1000	<i>Dynamic</i> 2040 12
TIGER	EWI Cologne	LP		Europe		> 1000	<i>Dynamic</i> 2020 12
InTraGas	DIW Berlin	NLP		EU15		29	<i>Dynamic</i> 2015 12
MAGELAN	EWI Cologne	LP		Europe		139	<i>Dynamic</i> 2035 1
EUGAS	EWI Cologne	LP		Europe		35	<i>Dynamic</i> 2030 1
"Egging et al. [15]"	Egging, Gabriel, Holz, Zhuang	NCP	Cournot	Europe		64	<i>Dynamic</i> Annual snapshot 3
GASMOD	DIW Berlin	MCP	Cournot	Europe		28	<i>Dynamic</i> 2025 1
FRISBEE	Aune, Glomsrød, Lindholt, Rosendahl	PE		Global		13	<i>Dynamic</i> 2030 1
MC-GENERICIS	Monforti, Szikszai	CGE		Europe		29	<i>Static</i> 1
World Gas Trade Model	Baker Institute (Rice University)	CGE		Global		460	<i>Dynamic</i> 2040 1
COLUMBUS	EWI Cologne	MCP	Cournot	Global		215	<i>Dynamic</i> Flexible Flexible
GaMMES	Abada, Gabriel Briat, Massol	MCP	Cournot	Major Euro. demand/ supply nodes		10	<i>Dynamic</i> 2040 2
GASTALE	Energy Research Centre of the Netherlands	MCP	Cournot	Major Euro demand nodes		8	<i>Dynamic</i> 2030 3
NATGAS	Netherlands Bureau for Economic Policy Analysis	MCP	Cournot	Major Euro demand/ supply nodes		11	<i>Dynamic</i> 2035 2
World Gas Model	University of Maryland	MCP	Cournot	Global		41	<i>Dynamic</i> 2030 2
World Gas Model (stochastic)	University of Maryland	MCP	Cournot	Global		19	<i>Dynamic</i> 2040 2

Table 1 (continued)

Model	Developer	Problem type	Market power	Spatial	Temporal							
					Coverage		Nodes	Static or dynamic	Time horizon	Time slices		
PEGASUS	Poyry	LP		Europe		23	Dynamic	Flexible	365			
RAMONA	Fodstad et al. (23)	MIQP		Global		40	Dynamic	2050	1			
"[13]"	Deane et al. (13)	MILP		Europe		28	Dynamic	Annual snapshot	8760			
European Gas Market Model	Regional Centre for Energy Policy Research	LCP		Europe		33	Dynamic	Annual snapshot	12			
Nexant World Gas Model	Nexant	LP		Global		~200	Dynamic	2050	4			
EPRG Gas Market Model	Chyong and Hobbs (12)	MCP	Cournot	Europe		138	Dynamic	2030	1			
Model	Infrastructure representation			Endogenous infrastructure investment	Demand	Supply contracts						
	LNG	Pipe	Storage			Granularity	Type	Sectors	LNG	Pipe		
GNOME	Yes	Bi	Yes	Indiv. pipe, aggr. LNG, aggr. storage	Yes	Yes	Yes	Exo	1	Endo	Yes	Yes
Wood Mackenzie Global Gas Model	Yes	Bi	Yes	Indiv	Yes	Yes	Yes	Exo	1	Endo	Yes	Yes
TIGER	Yes	Bi	Yes	Indiv	Yes	Yes	Yes	Exo	2	Endo		
InTraGas	Yes	Uni	Yes	Indiv. pipe, aggr. LNG, aggr. storage	Yes		Linear	Endo	1	Endo		
MAGELAN	Yes	Bi	Yes	Aggr	Yes	Yes	Yes	Exo	1	Endo		
EUGAS	Yes	Uni	Yes	Aggr			Exo	Exo	1	Endo	Yes	Yes

Table 1 (continued)

Model	Infrastructure representation				Endogenous infrastructure investment			Demand	Production	Supply contracts		
	LNG	Pipe	Storage	Granularity	LNG	Pipe	Storage	Production	Type	Sectors	LNG	Pipe
"Egging et al. [15]" GASMOD FRISBEE MC-GENERICIS World Gas Trade Model	Yes	Uni	Yes	Aggr					Endo	3	Endo	Yes
	Yes	Bi	Yes	Aggr					Constant	1	Endo	
	Yes	Bi		Aggr	Yes	Yes			Endo	3	Endo	
	Yes	Bi	Yes	Aggr					Exo	1	Exo	
	Yes	Yes, directionality unknown	Yes	Aggr	Yes	Yes	Yes	Yes	Endo	1	Endo	Yes
COLUMBUS GaMMES GASTALE NATGAS World Gas Model	Yes	Bi	Yes	Aggr	Yes	Yes	Yes	Yes	Exo	2	Endo	
	Yes	Bi	Yes	Aggr	Yes	Yes			Endo	3	Endo	Yes
	Yes	Uni		Aggr	Yes	Yes			Linear	3	Endo	Yes
	Yes	Bi	Yes	Aggr	Yes	Yes	Yes	Yes	Linear	1	Endo	Yes
	Yes	Bi	Yes	Aggr	Yes	Yes	Yes		Linear	3	Endo	Yes
World Gas Model World Gas Model (stochastic) PEGASUS	Yes	Bi	Yes	Aggr	Yes	Yes	Yes	Yes	Linear	1	Endo	Yes
	Yes	Yes, directionality unknown	Yes	Indiv	Yes	Yes	Yes	Yes	Endo, for power, else exo	2	Endo	Yes
												Yes
RAMONA "[13]" European Gas Market Model	Yes	Uni		Aggr		Yes	Yes		Exo	3	Endo	
	Yes	Yes, directionality unknown	Yes	Aggr					Exo	5	Endo	
	Yes	Uni	Yes	Indiv					Linear	1	Endo	Yes
Nexant World Gas Model	Yes	Bi	Yes	Indiv					Exo	1	Endo	Yes

Table 1 (continued)

Model	Infrastructure representation		Endogenous infrastructure investment			Demand		Production	Supply contracts
	LNG	Pipe	Storage	Granularity		Type	Sectors		
EPRG Gas Market Model	Yes	Yes, directionality unknown	Yes	Indiv		Exo	1	Endo	LNG Pipe

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. ((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 bcm⁶ 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

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 winter⁷ 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 2 Percentage of total LNG exports shipped to European destinations by source in 2019, and the multiplier applied to the LNG liquefaction capacity of each source

	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 transshipment 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 planned⁸ 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,⁹ Qatar, North Africa,¹⁰ Nigeria, and the Americas¹¹ 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.

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	
μ	LNG liquefaction (export) loss factor
η	LNG regasification (import) loss factor
β	Pipeline leakage loss factor
α	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/month)
$CostProduction_{i,t,type}$	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	
<i>FixedCostInvestLNG</i>	Fixed cost of building LNG regasification capacity (million USD)
<i>FixedCostInvestStorage</i>	Fixed cost of building gas storage capacity (million USD)
<i>UnitCostInvestPipe</i> _{route_pipe,i,j}	Variable cost of building pipeline capacity (million USD / KM)
<i>UnitCostInvestLNG</i>	Variable cost of building LNG regasification capacity (million USD / BCM)
<i>UnitCostInvestStorage</i>	Variable cost of building gas storage capacity (million USD / BCM)
<i>RouteLength</i> _{a,i,j}	Length of gas transportation route (KM)
<i>Compressors</i> _{route_pipe,i,j}	Number of compressor stations on pipeline route
<i>ContractedFlow</i> _{a,i,j,t}	Volume of gas to be transported between the seller <i>i</i> and the buyer <i>j</i> in period <i>t</i> as specified in existing long-term supply contracts (BCM / month)
<i>LNGAvailabilityMultiplier</i> _i	Multiplier applied to LNG liquefaction capacity at each exporter <i>i</i> to limit the volume available to Europe
Variables	
<i>CostSystemDiscounted</i>	Objective function (million USD)
<i>CProd_t</i>	Total production costs in periods <i>t</i> (million USD)
<i>CTPipe_t</i>	Total pipeline transport costs in period <i>t</i> (million USD)
<i>CTLNG_t</i>	Total LNG transport costs in period <i>t</i> (million USD)
<i>CInvPipe_t</i>	Total new pipeline investment costs in period <i>t</i> (million USD)
<i>CInvLNG_t</i>	Total new LNG import investment costs in period <i>t</i> (million USD)
<i>CInvStorage_t</i>	Total new gas storage investment costs in period <i>t</i> (million USD)
<i>SalvageValuePipe_t</i>	Residual value at period <i>t</i> of new pipeline investments (million USD)
<i>SalvageValueLNG_t</i>	Residual value at period <i>t</i> of new LNG investments (million USD)
<i>SalvageValueStorage_t</i>	Residual value at period <i>t</i> of new gas storage investments (million USD)
<i>Production</i> _{i,t,type}	Gas produced in country <i>i</i> in period <i>t</i> by type (BCM/month)
<i>Flow</i> _{a,i,j,t}	Gas flow along route <i>a,i,j</i> in period <i>t</i> (BCM/month)
<i>PipeCapacityNew</i> _{a,i,j,t}	New pipeline capacity constructed on route <i>a,i,j</i> in period <i>t</i> (BCM/month)
<i>LNGImportCapacityNew</i> _{i,t}	New LNG import capacity constructed in country <i>i</i> in period <i>t</i> (BCM/month)
<i>StorageCapacityNew</i> _{i,t}	New gas storage capacity constructed in country <i>i</i> in period <i>t</i> (BCM)
<i>StorageInjectionCapacityNew</i> _{i,t}	Increase in gas storage injection capacity in country <i>i</i> in period <i>t</i> as a result of increase in <i>StorageCapacityNew</i> _{i,t} (BCM/month)
<i>StorageWithdrawalCapacityNew</i> _{i,t}	Increase in gas storage withdrawal capacity in country <i>i</i> in period <i>t</i> as a result of increase in <i>StorageCapacityNew</i> _{i,t} (BCM/month)
<i>StorageInjections</i> _{i,t}	Storage injections in country <i>i</i> in period <i>t</i> (BCM)
<i>StorageWithdrawals</i> _{i,t}	Storage withdrawals in country <i>i</i> in period <i>t</i> (BCM)
<i>StorageLevel</i> _{i,t}	Volume of gas held in storage in each country <i>i</i> in period <i>t</i> (BCM)

3.3 Equations

$$\begin{aligned}
 \sum_{type=1}^n Production_{i,t,type} &+ \left[((1-\beta) \times compressors_{route_pipe,i,j} \times Route\ Length_{route_pipe,i,j}) \times \left((1-\alpha) \times \sum_{route_pipe=1}^n Flow_{route_pipe,i,j,t} \right) \right] \\
 &+ \left[(1-\eta) \sum_{route_LNG=1}^n Flow_{route_LNG,i,j,t} \right] + Storage\ Withdrawals_{i,t} = Demand_{i,t} \\
 &+ \left[((1-\beta) \times compressors_{route_pipe,i,j} \times Route\ Length_{route_pipe,i,j}) \times \left((1-\alpha) \times \sum_{route_pipe=1}^n Flow_{route_pipe,i,j,t} \right) \right] \\
 &+ \left[\left(\left(\frac{1}{1-\mu} \right) \times Route\ Length_{route_LNG,i,j} \right) \times \sum_{route_LNG=1}^n Flow_{route_LNG,i,j,t} \right] + Storage\ Injection_{i,t}
 \end{aligned}$$

Energy balance

$$\begin{aligned}
 indigenous\ production_{i,t} + LNG\ imports_{i,t} + pipeline\ imports_{i,t} + storage\ withdrawals_{i,t} \\
 = \\
 indigenous\ demand_{i,t} + LNG\ exports_{i,t} + pipeline\ exports_{i,t} + storage\ injections_{i,t}
 \end{aligned} \quad (2)$$

$$\sum_{type=1}^n Production_{i,t,type} \leq Production\ Capacity_{i,t,type} \quad (3)$$

Production constraints

$$Flow_{route_pipe,i,j,t} \geq Contracted\ Flow_{route_pipe,i,j,t} \quad (4)$$

Flow constraints

$$Flow_{route_LNG,i,j,t} \geq Contracted\ Flow_{route_LNG,i,j,t} \quad (5)$$

$$Flow_{route_pipe,i,j,t} \leq Pipe\ Capacity\ Existing_{route_pipe,i,j,t} + \sum_t Pipe\ Capacity\ New_{route_pipe,i,j,t} \quad (6)$$

$$Flow_{pipe_uni,i,j,t} \geq 0 \quad (7)$$

$$[Flow_{pipe_bi,i,j,t} \leq \left[\left(Pipe\ Capacity\ Existing_{route_pipe,i,j,t} + \sum_t Pipe\ Capacity\ New_{route_pipe,i,j,t} \right) \times -1 \right] \quad (8)$$

$$\sum_{j=1}^n Flow_{route_LNG,j,i,t} \leq LNG\ Export\ Capacity_{i,t} \times LNG\ Availability\ Multiplier_i \quad (9)$$

$$\sum_{j=1}^n Flow_{route_LNG,i,j,t} \leq LNG\ Import\ Capacity\ Existing_{i,t} + \sum_t LNG\ Import\ Capacity\ New_{i,t} \quad (10)$$

$$Storage\ Level_{i,t} \leq Storage\ Capacity\ Existing_{i,t} + \sum_t Storage\ Capacity\ New_{i,t} \quad (11)$$

Storage constraints

$$Storage\ Withdrawal\ Capacity\ New_{i,t} = Storage\ Capacity\ New_{i,t} \times 0.54 \quad (12)$$

$$\text{Storage Injection Capacity New}_{i,t} = \text{Storage Capacity New}_{i,t} \times 0.32 \quad (13)$$

$$\begin{aligned} \text{Storage Withdrawals}_{i,t} &\leq \text{Storage Withdrawal Capacity Existing}_{i,t} \\ &+ \sum_t \text{Storage Withdrawal Capacity New}_{i,t} \end{aligned} \quad (14)$$

$$\begin{aligned} \text{Storage Injections}_{i,t} &\leq \text{Storage Injection Capacity Existing}_{i,t} \\ &+ \sum_t \text{Storage Injection Capacity New}_{i,t} \end{aligned} \quad (15)$$

$$CProd_t = \frac{\sum_{type=1}^n \text{Production}_{i,type} \times \text{Cost Production}_{i,type}}{1 + \text{Monthly Discount Rate}^{(1+card(t))}} \quad (16)$$

Production and transport costs

$$CTPipe_t = \frac{\sum_{route_pipe=1}^n \left| \text{Flow}_{route_pipe,i,j} \right| \times \text{Route Length}_{route_pipe,i,j} \times \text{Unit Cost Trans Pipe}}{1 + \text{Monthly Discount Rate}^{(1+card(t))}} \quad (17)$$

$$\begin{aligned} CTLNG_t &= \frac{\sum_{route_LNG=1}^n \text{Flow}_{route_LNG,i,j} \times \text{Route Length}_{route_LNG,i,j} \times \text{Unit Cost Trans LNG} \\ &+ [\text{Flow}_{route_LNG,i,j} \times (\text{Unit Cost Liquefied} + \text{Unit Cost Regas})]}{1 + \text{Monthly Discount Rate}^{(1+card(t))}} \end{aligned} \quad (18)$$

$$CInvLNG_t = \frac{\sum_{i=1}^n \text{Fixed Cost Invest LNG} + (\text{LNG Import Capacity New}_{i,t} \times \text{Unit Cost Invest LNG})}{1 + \text{Monthly Discount Rate}^{(1+card(t))}} \quad (19)$$

Investment costs and salvage values

$$CInvPipe_t = \frac{\sum_{route_pipe=1}^n (\text{Route Length}_{route_pipe,i,j} \times \text{Unit Cost Invest Pipe}_{route_pipe,i,j})}{1 + \text{Monthly Discount Rate}^{(1+card(t))}} \quad (20)$$

$$CInvStorage_t = \frac{\sum_{i=1}^n \text{Fixed Cost Invest Storage} + (\text{Storage Capacity New}_{i,t} \times \text{Unit Cost Invest Storage})}{1 + \text{Monthly Discount Rate}^{(1+card(t))}} \quad (21)$$

$$\text{Salvage Value Pipe}_t = \frac{\sum_{route_pipe=1}^n CInvPipe_t \times \left[1 - (1 + \text{Monthly Discount Rate}_t)^{(\text{base}(t)+card(t)-t)-1} \right]}{1 + \text{Monthly Discount Rate}^{(1+card(t))}} \quad (22)$$

$$\text{Salvage Value LNG}_t = \frac{\sum_{i=1}^n CInvLNG_t \times \left[1 - (1 + \text{Monthly Discount Rate}_t)^{(\text{base}(t) + \text{card}(t) - t) - 1} \right]}{1 + \text{Monthly Discount Rate}^{(1 + \text{card}(t))}} \quad (23)$$

$$\text{Salvage Value Storage}_t = \frac{\sum_{i=1}^n CInvStorage_t \times \left[1 - (1 + \text{Monthly Discount Rate}_t)^{(\text{base}(t) + \text{card}(t) - t) - 1} \right]}{1 + \text{Monthly Discount Rate}^{(1 + \text{card}(t))}} \quad (24)$$

MINIMISE *Cost System Discounted*

$$\text{Cost System Discounted} = \sum_t CProd_t + CTPipe_t + CTLNG_t + CInvPipe_t + CInvLNG_t + CInvStorage_t - \text{Salvage Value Pipe}_t - \text{Salvage Value LNG}_t - \text{Salvage Value Storage}_t$$

Objective function (25)

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, α , and compressor fuel factor, β . This is multiplied by the number of stations ($compressors_{route_pipe,i,j}$) 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 μ 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

¹² 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 η . Finally, μ 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 ($Production_{i,t,type}$) for each country i for each month t . Per-unit production costs ($CostProduction_{i,t,type}$) 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 discounted¹³ 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-status¹⁵ 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 ENTSG [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 capacity¹⁶ 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

¹⁵ Projects that had reached Final Investment Decision status according to the ENTSG *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 ($a_{\text{route_LNG}}$) 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 ($\text{Flow}_{\text{route_LNG}}$) 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 ENTSG [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 ENTSG [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 existing¹⁸ European gas

¹⁸ As correct on 6 September 2021.

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 (*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 ($|Flowroute_pipe|$) is used to prevent reverse flows generating negative costs in the model.

The cost of shipping one BCM of gas along an LNG route (*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 (*UnitCostLiquef*) are 2.3 million USD/BCM and are averages of US Gulf Coast and Qatari liquefaction costs. European regasification costs (*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 (*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 Stream²¹ 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.²² Therefore, GNOME assumes that fixed costs for a new LNG liquefaction project (*FixedCostInvestLNG*) are 449 million USD, and per-BCM variable investment costs (*UnitCostLNGInvest*) are 59 million USD/BCM. The calculation of $CInvLNG_t$, the sum of all LNG import capacity investment costs in all countries i for each period t , is shown in (19).

$CInvPipe_t$ 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 (*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 (*FixedCostInvestStorage*) are 544.9 million USD, and per-BCM variable investment costs (*UnitCostStorageInvest*) are 590.4 million USD/BCM of new capacity. The calculation of $CInvStorage_t$, 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.

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 (*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,²³ 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.²⁴ 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

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/w8fwpsy0tz36gya/AAAz6kvVMEI6L3qJ_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.

Table 3 Annual gas demand (BCM/year)

	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

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

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

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

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

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

	2025			2030		
	FID	Ref	No NS2 Δ	FID	Ref	No NS2 Δ
Poland	2.5	2.5				
Spain	1.3	1.3		1.3	1.3	
Total	3.8	3.8		1.3	1.3	

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	

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 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	0.8	488.0	0.8	471.3	0.6

Table 8 Pipeline flows in GNOME by scenario (BCM/year)

From	To	2025		2030		2035		2040	
		Ref	No NS2 Δ	Ref	No NS2 Δ	Ref	No NS2 Δ	Ref	No NS2 Δ
Austria	Germany				6.2		4.8		
	Hungary	5.0							
	Italy			20.3	17.5	14.6	22.1	23.0	-10.5
	Slovakia								-2.4
	Slovenia	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							-2.5	
	Turkey			3.8		3.5			
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			0.8	-0.3	0.5	-0.5		
	Netherlands	6.2		33.5	-18.0	34.9	-22.2	46.1	-0.5
	Poland	5.2						-1.6	
	Switzerland			2.8		2.7		3.0	
	Czech Rep	11.1		6.8		6.6			
Greece	Italy	10.5		10.5		10.5			10.5
Hungary	Croatia			0.8		0.8		0.8	
	Romania							-3.8	
Italy	Slovenia	0.9						-0.9	
Latvia	Estonia	0.4							
Lithuania	Latvia	1.6							
Netherlands	Belgium			8.8	-8.8	9.1	-9.1	20.9	-0.5
	Germany							-2.1	
Norway	Belgium	9.9				4.0	2.3		
	France	11.4		4.3		6.5	-2.3	10.2	-0.5
	Germany	58.4							
	UK	24.2		23.8		24.2		16.1	0.5
Poland	Germany				30.4		26.2		19.2
	Slovakia							-5.7	5.7
Romania	Bulgaria	7.7		15.3		14.9			

Table 8 (continued)

From	To	2025		2030		2035		2040	
		Ref	No NS2 Δ	Ref	No NS2 Δ	Ref	No NS2 Δ	Ref	No NS2 Δ
Russia	Belarus	17.5		30.1	27.7	30.6	26.8	25.5	25.5
	Estonia			1.6		1.5		1.5	
	Finland	2.2		2.1		2.1		2.0	
	Germany	39.3		110.0	−55.0	108.9	−53.9	110.0	−55.0
	Turkey	16.0						6.5	10.8
	Ukraine	18.1		55.8	27.6	49.2	27.4	74.2	18.9
Slovakia	Austria			27.8	23.9	21.9	27.2	28.7	−3.6
	Hungary	2.0		7.6		7.4		3.4	−3.4
Slovenia	Croatia	0.8							
Switzer-land	Italy	2.7							
Turkey	Greece	2.8		4.8		4.8		2.7	10.6
UK	Belgium	1.9		5.3	4.5	0.3	0.7	−13.1	0.5
	Ireland	4.3		4.1		4.0		3.8	
Ukraine	Hungary								3.4
	Poland				3.4				
	Romania								
	Slovakia	2.3		39.7	24.1	33.5	27.3	58.8	15.4
Czech Rep	Germany							8.1	28.2
	Poland								
	Slovakia	4.0						−14.5	−28.2
North Africa	Italy	26.9		10.5	−10.5	10.1	−6.2	9.7	
	Spain				10.5		6.2		
Southern Corridor	Turkey	31.4		43.6		42.6		36.2	
Total		361.5		499.4	110.8	475.3	103.7	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		2030		2035		2040	
		Ref	No NS2 Δ	Ref	No NS2 Δ	Ref	No NS2 Δ	Ref	No NS2 Δ
Americas LNG	Belgium						2.7		
	France	2.1				0.2	-0.2		
	Netherlands								
	Portugal	2.1							
	Spain	16.5		10.5	0.7	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	10.1	-9.1	4.9	0.5
	Italy	1.5							
	Netherlands				4.1		8.0		
	Portugal	2.0			4.5	3.6	0.7		
	Spain	5.1		15.9	-12.5	4.4	-4.4	13.3	-0.5
North Africa LNG	France	18.5		26.1	5.7	15.2	15.9	15.2	
	Greece								
	Italy	10.1		7.0	-7.0	17.9	-15.9	17.9	
	Spain	4.6			1.3				
Norway LNG	Belgium			0.6	-0.6	0.8	-0.8		
	France	1.8		4.4	-4.4	4.2	-4.2	5.1	
	Lithuania	1.7							
	Netherlands				5.1		5.1		
	Spain	1.6							
	Poland								
Qatar LNG	Belgium	2.8							
	Greece	5.9							
	Italy	6.3		6.3					
	Netherlands								
	Portugal	0.6		4.5	-4.5	0.7	-0.7	4.2	
	Spain								
	UK	17.8		21.5	4.5	17.1	0.7	13.1	
Russia LNG	Poland	1.4		1.4					
	Belgium	13.0							
	France								
	Lithuania	2.3							
	Netherlands	13.1							
Total	Poland	6.3							
		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.

Fig. 3 European gas storage level (bcm) under the Reference case and the No NS2 case

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

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

	2025		2030		2035		2040	
	Ref	No NS2 Δ	Ref	No NS2 Δ	Ref	No NS2 Δ	Ref	No NS2 Δ
Supply and transportation costs	789.84		584.93	3.35	576.73	3.12	561.94	2.73
Investment costs	16.87	− 7.99	10.32					
Total	806.71	− 7.99	595.25	3.35	576.73	3.12	561.94	2.73

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 is 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

Acknowledgements Thank you to both Dr Gabriel Anandarajah and Professor Paul Ekins of the Bartlett School Environment, Energy & Resources at University College London for their excellent and continuing supervisory support. Many thanks to the editor and reviewers of SN Operations Research Forum for their helpful comments on the initial manuscript and revisions.

Author Contribution Stevie Lochran: conceptualisation, methodology, software, formal analysis, investigation, data curation, writing — original draft, visualisation. Paul Ekins: supervision. Gabriel Anandarajah: supervision

Funding This research was supported by funding from the UK Energy Research Centre (UKERC) and the Engineering and Physical Sciences Research Council (grant numbers EP/P505771/1 and EP/J500331/1).

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/w8fwpy0tz36gya/AAAz6kvVMEI6L3qJ_oCI7yKEa?dl=0

Code Availability GAMS source code for the model is available at the following repository: https://www.dropbox.com/sh/w8fwpy0tz36gya/AAAz6kvVMEI6L3qJ_oCI7yKEa?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: ENTSG [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: ENTSG [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	12
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	4	5	8	11	13
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
α	Pipeline transport leakage factor	$5.37 \times 10^{-6}\%$ per km travelled	[49]
β	Compressor station loss factor	$3.89 \times 10^{-3}\%$ of all gas passing through each station	[70]
μ	LNG liquefaction loss factor	0.1% of all gas liquefied	[14]
ε	LNG shipping loss factor	$1.87 \times 10^{-4}\%$ per km travelled	[31]
η	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.

Open Access This article is licensed under a Creative Commons Attribution 4.0 International License, which permits use, sharing, adaptation, distribution and reproduction in any medium or format, as long as you give appropriate credit to the original author(s) and the source, provide a link to the Creative Commons licence, and indicate if changes were made. The images or other third party material in this article are included in the article's Creative Commons licence, unless indicated otherwise in a credit line to the material. If material is not included in the article's Creative Commons licence and your intended use is not permitted by statutory regulation or exceeds the permitted use, you will need to obtain permission directly from the copyright holder. To view a copy of this licence, visit <http://creativecommons.org/licenses/by/4.0/>.

References

1. Abada I, Gabriel S, Briat V, Massol O (2013) A generalized Nash-Cournot model for the North-western European natural gas markets with a fuel substitution demand function: the GaMMES model. *Netw Spat Econ* 13:1–42
2. Argus Media (2020) Sonatrach offers spot LNG cargoes as exports slow, s.l.: Argus Media
3. Aune FR, Rosendahl KE, Sagen EL (2009) Globalisation of natural gas markets - effects on prices and trade patterns. *Energy J* 30:39–53
4. BEIS (2016) Physical gas flows across Europe and diversity of gas supply in 2016, s.l.: s.n
5. BEIS (2020) Fossil fuel price assumptions, s.l.: s.n
6. Bloomberg (2014) Shipping chokepoint strangles Ukraine hopes for U.S. LNG. s.l.:s.n
7. Boots MG, Rijkers FAM, Hobbs BF (2003) GASTALE: An oligopolistic model of production and trade in the European gas market, Amsterdam: s.n
8. BP (2018) BP statistical review of world energy 2018, London: s.n
9. BP (2019) Energy Outlook 2019, s.l.: s.n
10. BP (2020) Statistical review of world energy 2020, London: s.n
11. Buzna L et al (2014) Congestion dependencies in the European gas pipeline network during crises. s.l., IEEE
12. Chyong CK, Hobbs BF (2014) Strategic Eurasian natural gas market model for energy security and policy analysis: formulation and application to South Stream. *Energy Eco* 7(44):198–211
13. Deane JP, Ciaráin MÓ, Gallachóir BÓ (2017) An integrated gas and electricity model of the EU energy system to examine supply interruptions. *Appl Energy* 193:479–490
14. DESFA (2018) LNG Facility Losses. s.l.:s.n

15. Egging R, Gabriel SA, Holz F, Zhuang J (2008) A complementarity model for the European natural gas market. *Energy Policy* 36:2385–2414
16. Egging RG, Gabriel SA (2006) Examining market power in the European natural gas market. *Energy Policy* 11(34):2762–2778
17. Egging R, Holz F, Gabriel SA (2010) The world gas model. A multi-period mixed complementarity model for the global natural gas market. *Energy* 35:4016–4029
18. ENTSOG (2016) Storage map 2016. s.l.:s.n.
19. ENTSOG (2017) Transmission capacity map 2017. s.l.:s.n.
20. ENTSOG (2018) Ten-year network development plan 2018. s.l.:s.n.
21. ENTSOG (2020) Ten year network development plan 2020: scenario report, s.l.: s.n
22. Eurostat (2020) Energy Statistics Database. s.l.:s.n
23. Fodstad M, Egging R, Midthun K, Tomasgard A (2016) Stochastic modeling of natural gas infrastructure development in Europe under demand uncertainty. *Energy J* 37
24. GAMS Development Corporation (2015) GAMS Online Documentation. s.l.:s.n
25. Gas Infrastructure Europe (2020) AGSI gas storage data platform. s.l.:s.n
26. Gas Infrastructure Europe (2021) GIE Storage Database, Avenue de Cortenbergh 100, Second floor, B-1000, Brussels: s.n
27. Growitsch C, Hecking H, Panke T (2014) Supply disruptions and regional price effects in a spatial oligopoly-an application to the global gas market. *Rev Internatl Eco* 7(22):944–975
28. Haftendorn C (2016) Energy market models at Wood Mackenzie - applications and challenges. Edinburgh: Wood Mackenzie
29. Happach RM, Größler A, Groessler A, Größler A (2014) Modeling the inner-European trade volumes of natural gas. s.l., s.n, 1–27
30. Hartley P, Medlock KB (2005) The Baker Institute world gas trade model, Houston: s.n
31. Hasan MMF, Zheng AM, Karimi IA (2009) Minimizing boil-off losses in liquefied natural gas transportation. *Indust Eng Chem Res* 11(48):9571–9580
32. Hecking H, Panke T (2012) COLUMBUS - a global gas market model, Cologne: s.n
33. Holz F (2009) Modeling the European natural gas market — static and dynamic perspectives of an oligopolistic market, s.l.: s.n
34. Holz F, von Hirschhausen C, Kemfert C (2008) A strategic model of European gas supply (GAS-MOD). *Energy Econ* 30:766–788
35. Howells M et al (2011) OSeMOSYS: The Open Source Energy Modeling System. *Energy Policy* 10(39):5850–5870
36. Institute of Energy for South-East Europe (2016) Norway's Statoil reduces LNG price for Lithuania. s.l.:s.n
37. International Energy Agency (2019) World Energy Outlook 2018, Paris: s.n
38. International Energy Agency (2020) World Energy Outlook 2020
39. International Gas Union (2020) World LNG Report, Barcelona: s.n
40. International Maritime Agency (2020) Sulphur 2020 – cutting sulphur oxide emissions, s.l.: s.n
41. Johnson C, Boersma T (2013) Energy (in)security in Poland the case of shale gas. *Energy Policy* 53:389–399
42. Kiss A, Selei A, Tóth BT (2016) A top-down approach to evaluating cross-border natural gas infrastructure projects in Europe. *Energy J* 37
43. Langelandsvik LI, Postvoll W, Aarhus B, Kaste KK (2009) Accurate calculation of pipeline transport capacity, Karmøy: s.n
44. Le Fevre C (2013) Gas storage in Great Britain, s.l.: Oxford Inst Energy Stud
45. Le Fevre C (2018) A review of demand prospects for LNG as a marine transport fuel, s.l.: s.n
46. Lochner S (2011) Modeling the European natural gas market during the 2009 Russian-Ukrainian gas conflict- ex-post simulation and analysis. *J Nat Gas Sci Eng* 3(3):341–348
47. Lochner S, Bothe, D, Lienert M (2007) Analysing the sufficiency of European gas infrastructure-the Tiger model. s.l., s.n
48. Lochner S, Richter J (2010) The impact of recent gas market developments on long-term projections for global gas supply. *Zeitschrift Energiewirtschaft* 34:61–69
49. McGlade C, Speirs J, Sorrell S (2013) Unconventional gas - a review of regional and global resource estimates. *Energy* 6(55):571–584
50. Mitrova T, Boersma T, Galkina A (2016) Some future scenarios of Russian natural gas in Europe. *Energy Strat Rev* 11:19–28

51. Monforti F, Szikszai A (2010) A MonteCarlo approach for assessing the adequacy of the European gas transmission system under supply crisis conditions. *Energy Policy* 5(38):2486–2498
52. Neumann A, Ruster S, von Hirschhausen C (2015) Long-term contracts in the natural gas industry – literature survey and data on 426 contracts (1965–2014), Berlin: s.n
53. Neumann A, Viehrig N, Weigt H (2009) Intragass - a stylized model of the European Natural Gas Network. SSRN Elect J
54. Orden A (1956) The transshipment problem. *Manage Sci* 2:276–285
55. Perner J, Seeliger A (2003) Impacts of a gas cartel on the European gas market-selected results from the supply model EUGAS. *Util Policy* 12:291–302
56. Platts (2019) Portworld Distance Calculator. s.l.:s.n
57. Platts (2020) The “U” factor: Ukraine’s growing role in Europe’s natural gas market. 11
58. Pöyry, (2011) Pegasus gas model description. Pöyry, Oxford
59. Reuters (2016) India’s GAIL, Russia’s Gazprom renegotiating LNG deal -sources. s.l.:s.n
60. Reuters (2019) Netherlands to halt Groningen gas production by 2022. 9
61. Rodriguez BS, Pye S (2015) Overview of the European Times Model at University College London (ETM-UCL), London: s.n
62. Rogers H (2018) The LNG Shipping Forecast: costs rebounding, outlook uncertain, s.l.: s.n
63. Rystad Energy (2019) Fossil fuel supply curves, s.l.: s.n
64. Saadi FH, Lewis NS, McFarland EW (2018) Relative costs of transporting electricaland chemical energy. *Energy Environ Sci* 1
65. Songhurst B (2018) LNG plant cost reduction, s.l.: s.n
66. Steuer C (2019) Outlook for competitive LNG supply, s.l.: s.n
67. Ulvestad M, Overland I (2012) Natural gas and CO2 price variation: impact on the relative cost-efficiency of LNG and pipelines. *Internatl J Environ Stud* (69):407–426
68. United States Energy Information Administration, 2019. *International Energy Outlook 2019*, Washington, D.C.: s.n
69. Wood M (2017) A new era for Algerian gas Exports. 12
70. Ya ZL, Smith D, Peng Z (2008) Compressor station optimization during gas injection into underground storage. Ferguson(Missouri): Emerson Process Manage
71. Zwart G, Mulder M (2006) NATGAS: a model of the European natural gas market, Den Haag: s.n

Publisher’s Note Springer Nature remains neutral with regard to jurisdictional claims in published maps and institutional affiliations.

Authors and Affiliations

Stevie Lochran¹

✉ Stevie Lochran
stevielochran@gmail.com

¹ Energy Institute, Bartlett School of Environment, Energy and Resources, University College London, London, UK