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Working Paper

Modelling natural gas resource uncertainties and regional gas markets: a review of current models and an introduction to a new field-level gas production and trade model

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Acronyms

BGR:	Bundesanstalt für Geowissenschaften und Rohstoffe (Federal Institute for Geosciences and Natural Resources, Federal German Government)
BUEGO:	Bottom-Up Economic and Geological Oil field production model
CNG:	Compressed Natural Gas
EIA:	Energy Information Administration
IEA:	International Energy Agency
INGM:	International Natural Gas Model (EIA)
LNG:	Liquefied Natural Gas
MESSAGE:	Model for Energy Supply Strategy Alternatives and their General Environmental impact
NDC:	Nationally Determined Contributions (agreed in Paris at COP-21)
NEMS:	National Energy Modelling System (EIA)
NGTDM:	Natural Gas Transmission and Distribution Module (EIA)
POLES:	Prospective Outlook on Long-Term Energy Systems
REMIND:	Regional Model of Investments and Development
RES:	Reference Energy System
RWGTM:	Rice World Gas Trade Model
SDG:	(United Nations) Sustainable Development Goals
TIAM-UCL:	TIMES Integrated Assessment Model at University College London
WEM:	World Energy Model (IEA)
WEPS:	World Energy Projection System (EIA)
WGM:	World Gas Model

Executive Summary

This working paper is part of UKERC's Resources and Vectors theme, which focuses on the current and future roles of resources and energy vectors in both the UK and global energy system. The paper aims to provide a general overview of existing natural gas models, across the supply chain, and include how natural gas is represented in wider energy system and integrated assessment models. This modelling review is part of the work on a new, global gas model at the Institute for Sustainable Resources at University College London, though a UKERC PhD Studentship. The focus of the new model is on upstream and midstream natural gas supply chain dynamics:

1. A bottom-up geological-economic model of natural gas resources, determining how much can be produced and at what cost
2. Future uncertainty in natural gas markets: demand, price formation mechanisms and levels, trade volumes, infrastructure costs, and inter-fuel competition.

The modelling review in Section II of this working paper is split into three sections, by grouping different literature based on its coverage of a specific aspect of the gas supply chain, or where natural gas is incorporated into the wider energy-environment-economic systems.

1. Resource estimates and production potential
2. Wider energy-system models (including Integrated Assessment Models)
3. Gas market models, generally incorporating at least two of the supply chain stages

Whilst there are a number of existing reviews of wider energy models from both demand and supply perspectives (Bhattacharyya and Timilsina, 2010; Capellan-Perez et. al, 2013; Suganthi and Samuel, 2012), there are relatively few systematic reviews of existing natural gas models, whether regional or global. The EIA (Busch, 2014) generated an assessment of existing natural gas models in conjunction with the redesign of the Natural Gas Transmission and Distribution Module (NGTDM) within the wider National Energy Modelling System (NEMS) framework – however these models generally focus on the interaction of gas market agents and gas transportation systems via arc-nodal modelling. Additionally, McGlade et al. (2012) examined the differing methods used to estimate unconventional gas resources. The primary motivation behind the study was the significant differentials in existing resource estimates, and the uncertainty surrounding unconventional resources given their limited exploitation outside of North America.

This paper focuses exclusively on modelling methods rather than modelling results, which naturally differ due to the significant divergence in both the research aims of each model, and mathematical/formulation differences. The paper proposes the question:

What are the main methods in existence that attempt to model natural gas, from reserve or resource estimates to gas market dynamics, and what are the strengths and limitations of the current modelling literature?

The working paper concludes by introducing a new field-level gas production and trade model, which will address some of the research gaps and limitations identified in Section II (the modelling review). A key contribution of the initial stages of this work has been the construction of a natural gas field reserve and resource database, and corresponding costs for these fields. Additionally, the modelling review conclusion suggests the combination of bottom-up natural gas market specific dynamics, within the context of the wider energy and environmental systems.

Introduction – Main challenges in gas market modelling

Natural gas supply and demand dynamics (and the interaction between the two) provide a significant challenge to energy modellers, not least because an integrated global market (as with oil) does not yet exist. Even describing natural gas markets as 'regionalised' can be problematic, not least because even markets within geographic regions can prove heterogeneous (Stern, 2012, p. 476). In order to model the entire global natural gas system, often some degree of regional simplification is necessary.

Firstly, it is important to define what is meant by a natural gas market in this review paper, with Table 1 below splitting a market into three streams.

Table 1: Natural gas supply value-chain, adapted from Weijermars (2010, p. 94)

Segment	
Upstream (exploration and development companies (E&D))	Exploration and Discovery
	Project Appraisal
	Field Development and Production
	Processing (bringing gas to pipeline quality)
Midstream (Transmission companies and shippers/traders)	Transmission (Pipeline and LNG)
	Storage and Buffer – mechanics with demand side
Downstream (includes utility distribution companies)	Distribution Pipeline
	End-users & retail metering dispatch services

Natural gas markets provide some complications and uncertainties which are similar for oil markets, however other features are unique to natural gas. Unlike oil markets, where broadly speaking there is a benchmark global oil price, natural gas markets are far more complex, particularly when it comes to differing price formation mechanisms both for domestic and international consumption and trade. Table 2 provides a brief introduction to key uncertainties when modelling natural gas, and which provide a significant challenge to any modelling literature.

Table 2: Complications of modelling natural gas markets

Complication	Examples
Geological-economic uncertainty over conventional and unconventional resources	As with unconventional oil, unconventional gas is generally more expensive, and has a hugely uncertain future outside North America; new projects of conventional gas development increasingly involve significant technical risk (e.g. Shah sour gas project; deep offshore projects in Mozambique)
Geopolitical and economic issues relating to pipelines which cross numerous borders	Disagreement over transit tariffs; national sovereignty and attempts to use pipelines to influence regional politics; energy security (both of the physical pipeline at terminal/choke points and energy system security)
Range of price formation mechanisms for traded natural gas	Historically internationally traded natural gas has been indexed to oil (-product) prices, and whilst increasing amounts of traded gas are moving to spot/gas-on-gas competition, oil indexation looks set to retain at least part of the global gas trade picture (e.g. India's recent contract renegotiation with Gazprom, away from JCC and towards a Brent index (Platts, 2018))
Range of subsidised domestic pricing	Particularly prevalent in large oil producing (where associated gas is produced as a by-product of oil production) or gas producing countries, where the price paid by end use consumers for gas does not even cover production and distribution costs – generally employed for political reasons and requires significant use of export revenues/depreciation of state revenue
Interaction between buyers (demand) and sellers (supply), especially in the LNG market	Traditionally, Asian LNG buyers have been a captive market (i.e. price takers), however with new LNG supply coming online (Australia and US in particular), this balance may change

Uncertainty over whether natural gas is a 'lower carbon bridge'	Role gas as a 'bridge'[1] fuel or a potential for a dangerous 'lock-in' (especially given investment required for gas transmission and distribution infrastructure) to a new fossil fuel regime (Aghion et. al, 2014; McGlade et. al, 2014); i.e. is the consumption of natural gas in some energy-economic sectors consistent with climate mitigation goals, especially when gas consumption increases to displace coal and oil
Environmental regulation, particularly for unconventional natural gas	Fugitive emissions from production and gathering equipment, potential for aquifer contamination; emissions from ageing transportation capacity (pipeline and liquefied natural gas facilities)

There are three main sections to this report:

1. Section I – Definitions
2. Section II- Modelling review
3. Section III – Conclusions and development of a new natural gas model

[1] A natural gas 'bridge' is defined as gas consumption in a climate mitigation scenario (e.g. 2°C maximum warming) increasing above a 'business-as-usual' (baseline) scenario until a certain point (i.e. natural gas works as a transition fuel whilst coal and oil are phased out in the constrained scenario). An additional distinction was made between an absolute gas bridge, where gas consumption in a temperature constrained scenario is rising at any point in time, and a relative bridge where gas consumption in a constrained scenario is above a baseline run for a period (McGlade et. al, 2014, pp. 25-6).

Section I - Definitions

The following section briefly discusses some of the frequently used terminology for natural gas across the supply chain. The importance of using terminology consistently has been is discussed in detail below.

Natural Gas Reporting Terminology

In order to assess different methods of assessing natural gas resources, a fundamental characteristic of all studies which estimate the quantity of hydrocarbons must be taken into account - the fact that definitions regarding reserves, resources, and reserve additions (including proved vs. probable, ultimate vs. technical vs. economical) remain open to interpretation (i.e. there is no fixed definition). Thus, two studies may refer to a particular sub-set of resources, but have significant differences in the classifications which define said sub-set (McGlade et. al, 2012, pp. 3-12; Herrmann et. al, 2013, pp. 96-102). This is of fundamental importance if policy makers and investors are to have confidence in the reported figures for a specific prospect; Herrmann et. al (2013, p. 95) identify the example of Shell having to write off 20% of its "previously reported proven oil and gas reserve base", due to booking assets in the wrong classification. The importance of consistent terminology is considered at length by numerous authors, including McGlade (2013), Hermann et. al (2013), BGR (2009), and the short definitions below reflect a consistent use of these terms throughout the rest of this paper.

Conventional and Unconventional[2] Natural Gas

The two broadest categories of natural gas are conventional and unconventional, which unlike oil, do not refer to its physical characteristics (oil density), but instead to different "techno-economic" characteristics (McGlade, 2013, p. 32).

Conventional natural gas – including most associated natural gas (discussed briefly below) – can be extracted using techno-economically well-established drilling techniques, where the pressure, porosity, and permeability of the reservoir are such that the natural gas can be extracted to the surface without any additional stimulation required.

In contrast, unconventional natural gas formations require 'enhanced' recovery techniques, where the geological composition of the formation/reservoir must be artificially stimulated (increasing the permeability), for example via horizontal fracturing of the surrounding shale or tight sandstone.

Examples of unconventional natural gas include:

[2] The USGS term "continuous" used later refers broadly to unconventional gas – continuous resources are poorly defined accumulations, and are linked through two key geological characteristics: large volumes of rock with random allocations of hydrocarbons, rather than well-defined reservoirs, and they "do not depend upon the buoyancy of oil or gas in water for their existence" (Schmoker, 2005, p. 1).

- Shale Gas: Natural gas trapped in shale formations (predominantly sedimentary clay) – along with tight gas, shale gas is also referred to as a continuous formation, as instead of one defined reservoir, there is a continuous chain of natural gas pockets within the rock, with low permeability and porosity.
- Tight Gas: Natural gas trapped in tight sandstone formations – as mentioned in McGlade (2013, p. 32), the Bundesanstalt für Geowissenschaften und Rohstoffe (Federal Institute for Geosciences and Natural Resources, BGR) now reports tight gas within its conventional reserve assessments, however this is perhaps more indicative of a lack of country estimates, rather than a reflection of its geological-technical or economic characteristics (BGR, 2014, p. 35).
- Coal Bed Methane (CBM): natural gas compounds are adsorbed in a coal matrix (i.e. the natural gas surrounds the structure of coal).
- Gas Aquifers: methane (natural gas) dissolved in water – can be used for storage in particular, and the gas extracted once the water is brought to the surface.
- Methane/Natural Gas Hydrates: found either in permafrost as crystal like structures or at the oceanic continental ridges, where temperatures are extremely low and pressure is extremely high.

Associated vs. Non-Associated Natural Gas

Associated natural gas refers to natural gas found within petroleum accumulations – often associated natural gas is considered to be an unwanted by-product of petroleum production (due to the logistics of storing, processing, and transporting natural gas) and is either vented (released into the atmosphere) or flared (burnt off) at the well-head, in order to release pressure within the drilling pipe and ensure the oil is of pipeline quality for processing and/or transportation.

Non-associated natural gas refers to natural gas, and other chemical formulations of natural gas, including natural gas liquids, which form independently of oil, given certain reservoir conditions (including the depth and temperature of the reservoir in question).

Both associated and non-associated natural gas can be split into two broad categories:

- Dry natural gas – where the natural gas in place is of a gaseous chemical form (i.e. predominantly methane).
- Wet natural gas – where in addition to methane, other longer hydrocarbon compounds including propane, butane, and ethane[3], are also found (exploration and development of fields rich in wet natural gas is particularly

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[3] Propane, butane, ethane, etc. are also known as natural gas liquids (NGL's), as at normal atmospheric pressure and temperature they begin to condensate and are separated from the natural gas (methane) stream in a gas processing plant.

prevalent when oil prices are high, due to their substitutability for crude oil (EIA, 2012)).

Sour natural gas

Sour gas refers to any accumulation of natural gas where the chemical composition includes high concentrations of hydrogen sulphide (H_2S) and carbon dioxide (CO_2). For reference, natural gas is considered sour if concentrations of H_2S exceed 1% and CO_2 exceeding 2% (e.g. on a parts-per-million basis) (IEA, 2013; McGlade, 2013). The removal of these impurities is fundamental before transportation:

- H_2S and CO_2 corrode pipelines
- CO_2 begins to freeze in liquefaction processes at around the same temperature as methane liquefies (~ -160°C); CO_2 concentrations in liquefaction plants have to be < 50ppm in order to avoid blockages in the liquefaction process (Huo, 2012).

Major examples of recent (and ongoing) sour gas projects include the Gorgon gas LNG project in Australia (high CO_2 concentrations) and the Shah gas field in the UAE (high H_2S concentrations).

Volumetric

Original/Initial-Gas-In-Place (OGIP/GIP) or In-Situ Natural Gas

The term original/initial gas-in-place is used in numerous studies as the foundation of resource and reserve estimates, given that it refers to the total volume of natural gas in a given assessment area (individual reservoirs, fields, plays, regions and countries (i.e. aggregated in place estimates), etc.). Whilst OGIP/GIP is used more frequently, in-situ gas is an analogous term. The fundamental issue with using OGIP estimates is they are open to the largest degree of uncertainty – reflected by Rogner's use of a single analogue for unconventional in-place estimates which were then applied globally (1997, p. 242).

Studies, including the EIA-ARI shale assessment (EIA, 2013a) and USGS reserve growth assessment (Klett et. al, 2011), use in-place estimates and apply recovery factors to generate recoverable volume estimates which are broadly defined recoverable resources. However, fundamental issues surround the scale of these recovery factors, including economic, geological, and technological uncertainty (McGlade, 2013, p. 22).

In general, estimates of GIP require detailed information, with the USGS (Verma, 2012, pp. 4-5) utilising a huge range of geological parameters to determine in-place estimates of as-of-yet undiscovered (discussed below) natural gas, including:

- Reservoir pressure, temperature and depths
- Compositions of hydrocarbons and their molecular weights
- Rock porosity and permeability
- Gas/water saturation
- Drainage area of reservoir (i.e. size of the reservoir)

- Rock thickness
- Total organic content (i.e. share of carbon within rock structure; crucial for volumetric estimates of unconventional natural gas)

Discovered and Undiscovered Natural Gas

When reporting in-place resource estimates, two general classifications are used by the USGS based on the level of localised development, and geological knowledge:

1. Discovered Natural Gas: fields/plays/reservoirs are known to exist – i.e. either developed or enough geological evidence that no more exploratory activity is required (Herrmann et. al, 2013, p. 96)
2. Undiscovered Natural Gas: "*…postulated from geological knowledge to…exist outside of known accumulations, and which resides in accumulations having sizes equal to or exceeding a stated minimum volume*" (Schmoker and Klett, 2005, p. 2)

Resources

In the broadest possible sense, resources are the percentage of in-place hydrocarbons which are potentially recoverable, given certain technical, geological and economic constraints (Hermann et. al, 2013, pp. 96-7). The simplest, and perhaps most effective reporting of natural gas resources can generally be split into three main categories:

1. Ultimately Recoverable Resources (URR)

Ultimately recoverable resources (URR) refers to the total recoverable resources from in-place gas volumes. URR are a hypothetical situation where there are no constraints on the potential development of natural gas volumes from a technical or economic perspective, suggesting implicitly that at some point in the future, demand for natural gas could drive the development of these resources. For URR estimates, generally no constraint is placed on time – whether from a technical or economic perspective – giving these estimates more flexibility to account for highly dynamic energy and technological markets (McGlade, 2013, p. 27).

The term estimated ultimate recovery (EUR) can be used as an analogue for URR, but is generally used in studies which take into account individual wells (whether for economic or geological purposes). In this sense, the EUR of a gas well refers to its cumulative historical production plus its projected future production, given geological uncertainties and production decline profiles – the form of this decline profile (e.g. exponential, hyperbolic, linear) has been discussed widely (Swindell, 2001; Browning et. al, 2013a,b; IHS, 2014; Lund, 2014; Rahuma et. al, 2013) and is beyond the scope of this paper.

2. Technically Recoverable Resources (TRR)

Technically recoverable resources (TRR) are the subset of total resources that are feasibly producible (i.e. extractable) given the current technology stock.

3. Economically Recoverable Resources (ERR)

Economically recoverable resources (ERR) are a subset within TRR, whereby only those resources which can be recovered with current extraction technologies and economic conditions, are included. This static representation has come under criticism, as any change in the market price of natural gas and in the costs of supply, should in theory render a change in volume of resources considered economically recoverable (McGlade et. al, 2012, pp. 5-6). The 'economic' condition normally requires a positive net present value (NPV) or internal rate of return (IRR) of a project (from individual wells to field development), or on a simpler basis, by taking the market price of the resource at a given point in time, and assessing economically feasible extraction given the costs.

Measuring resource uncertainty

As with reserves (discussed below), resources can also be categorised into probabilistic estimates of a certain volume becoming hypothetically recoverable. These probabilistic estimates, as with the corresponding terminology in reserves, are based on the level of geological knowledge available. Deutsche Bank and the SEC identify two main sub-divisions (Herrmann et. al, 2013, p. 98):

1. Contingent Resources: "*quantities of hydrocarbons estimated, on a given date, to be potentially recoverable from known (discovered) accumulations, but which are not yet considered commercially recoverable*":
    i. 1C resources = 90% confidence that URR will be of a certain volume, lower bound/low
    ii. 2C resources = 50% confidence that URR will be of a certain volume, median/"best"
    iii. 3C resources = 10% confidence that URR will be of a certain volume, upper bound/high
2. Prospective Resources: "*quantities of hydrocarbons which are estimated to be potentially recoverable from undiscovered hydrocarbons*" (these prospective resources can also be given probabilistic confidence based on geological knowledge).

The Russian system of reporting natural gas resource (and reserve) volumes follows largely on this probabilistic model of geological, rather than economic feasibility (Gazprom, 2013, p.7).

Reserves

Natural gas reserves are a subset of discovered economically recoverable resources, which are given various degrees of deterministic or probabilistic confidence levels/"qualitative criteria" that certain amounts of the in-place resources will be extracted economically (McGlade, 2013, p. 24). In general, probabilistic reporting of reserve estimates tend to be more robust, as qualitative criteria are hugely open to interpretation. Three categories of reserves can thus be inferred from the numerous studies reporting reserve estimates:

- 1P/P90 = Proved Reserves – generally a lower bound estimate, with probabilistic assessments yielding a 90% chance of the reported volume being extracted economically and within current technological conditions
- 2P/P50 = Proved + Probable Reserves – generally a median estimate, with probabilistic assessments yielding a 50% chance of the reported volume being extracted economically and within current technological conditions
- 3P/P10 = Proved + Probable + Possible Reserves – generally an upper bound estimate, with probabilistic assessments yielding a 10% chance of the reported volume being extracted economically and within current technological conditions

The above definitions correspond broadly to the Society of Petroleum Engineers (SPE) probabilistic definition of reserves (Herrmann et. al, 2013, p. 97). For reference, the majority of studies using the term reserves, apply this only to 1P (P90) or 2P (P50), as 3P is considered too speculative (BGR, 2009, pp. 25-6; Hermann et. al (Deutsche Bank), 2013, pp. 104-5).

Stranded reserves

The term stranded natural gas reserves has been increasingly used to describe fields which are isolated geographically, have significant complications to commercialise, or are considered 'small' (Attanasi and Freeman, 2013; Dong et. al, 2008). However, there is disagreement over what size fields should be considered 'stranded', with Attanasi and Freeman (2013) including some giant and super-giant gas fields within their definition of 'stranded', whilst McGlade (2013) suggests only 'small' sub-economical fields should be considered as truly stranded. Due to the variations in definitions, and the lack of consistency across the literature, any gas field considered 'stranded' is included in estimates of reserve additions, rather than have two separate categories; in short, individual fields which are discovered but undeveloped, are considered potential reserve additions (discussed below), given changes to:

- Technologies (including the commercialisation of assets for export, such as floating LNG)
- Economics (whether gas prices or field/infrastructure costs)
- Demand (e.g. sudden increase in demand in region close to previously stranded assets)

This to some extent should limit double counting due to the similarity in definition used by Attanasi and Freeman (2011) for stranded reserves[4] and Klett et. al (2011) for reserve growth, which is discussed next.

Reserve Growth

[4] "*Stranded gas, as defined for this study, is natural gas in discovered conventional gas and oil fields that is currently not commercially producible for either physical or economic reasons*"

The USGS utilise the following definition for reserve growth, which will refer to any subsequent use of the term reserve growth in this paper:

"*Estimated increases in quantities of crude oil, natural gas, and natural gas liquids that have the potential to be added to remaining reserves in discovered accumulations through extension, revision, improved recovery efficiency, and additions to new pools or reservoirs*" (Klett et. al, 2011, p. 1).

The USGS has also used the term Production Replacement Ratio (PRR) as a substitutable term for reserve growth, referring to the "difference in estimated ultimate field size between any two points in time divided by the cumulative production over that same period of time" (Cook, 2013, p. 4).

Reserve/Resource Additions

Reserve additions and reserve growth are relatively interchangeable, with reserve growth in its various forms discussed above, contributing to reserve additions. For the purpose of Part I of this paper in particular, both reserve and resource additions are considered to be any movement of natural gas volumes from one reported classification, into a higher probability of recovery classification.

Studies utilising reserve addition estimates focus generally on already producing, known accumulations. These estimates are often used to generate exploration and production (E&P) cost profiles for field-economic studies (McGlade, 2013, p. 118). An example of this is the extension of reserves in a gas field by improved drilling economics to deeper/more complicated reservoirs, such as Gazprom's (2013) production expansion of its Soviet West Siberian assets into deeper Achimov (Urengoy) and Valanginian (Zapolyarnoye) deposits.

Section II - Modelling Review

Table 2 shows the modelling studies reviewed in this working paper. For Parts I, II, and III of the modelling review, a general structure is employed. Firstly, the overall research aim and modelling methods of the studies are discussed. Secondly, the overall strengths of the methods employed are considered, and particularly the practicalities of employing such methods for other aspects of closely related research, namely future gas market dynamics and uncertainties over availability and costs. Thirdly, the limitations of each study are considered.

Table 2: Key Natural Gas Models Reviewed in Paper

	Geographical Scope of Model/Method	Time-Span	Natural gas coverage	Modelling Approach	Gas infrastructure capacity expansion (e.g. pipeline and LNG)
Model Developer and model name					
Part 1: Resource Assessment modelling methods – Upstream Focus					
Bundesanstalt für Geowissenschaften und Rohstoffe (BGR) (Federal Institute for Geosciences and Natural Resources) – Reserves, Resources, and Resource Availability	Global	2050	Conventional and Unconventional	Literature Review	N/A

Rogner – Global Hydrocarbon Resource Assessment	Global	2100	Conventional and Unconventional	Literature Review and Top-down Probabilistic Approach - Technological Assessment based on existing extraction cost method and uniform analogues between countries	N/A
McGlade – Times Integrated Assessment Model – University College London (TIAM-UCL) and the Bottom-up Economic and Geological Oil Field model (BUEGO)	Global	2100 (end of TIAM-UCL time horizon)	Conventional and unconventional	Bottom-Up: probabilistic assessment of resource uncertainty, with key parameters assigned probability distributions and Monte Carlo analysis applied	N/A
United States Geological Survey (USGS) – Conventional Reserve Growth Assessment including undeveloped	US and Global	N/A	Conventional	Bottom-up: individual accumulation assessment of gas-in-place estimates are assigned recovery parameter factors from probability distributions, the product of which (GIP*RF), determines probabilistic reserve growth	N/A
Bureau of Economic Geology (BEG) – University of Austin, Texas	Specific Shale Plays in United States	N/A	Upstream (Shale)	Bottom-Up: Well-Level production profiles based on geological parameters including TRR estimations and productivity heterogeneity	N/A
Part 2: Integrated Assessment Models and other Energy System Models					

TIMES Integrated Assessment Model – University College London (TIAM-UCL)	Global	2100 (2050 for paper assessed)	Whole Energy System (RES)	TIMES Integrated Assessment Model: Linear Programming (LP) optimisation for cost-minimisation and economic-surplus maximisation	Endogenous
Enerdata Intelligence and Consulting - Prospective Outlook on Long-Term Energy Systems (POLES)	Global	2050	Whole Energy System	Econometric Simulation (i.e. simulating the energy system based on pre-defined functions and step-by-step processes)	Endogenous
Potsdam Institute for Climate Impact Research (PIK) - Regional Model of Investments and Development (REMIND)	Global	2050 (with potential to analyse out to 2100)	Economic-Energy System Hybrid	Macro-economic CGE: Non-linear programming (NLP) optimisation which maximises "intertemporal global welfare" (i.e. generates a pareto-optimal equilibrium for the entire model timeframe) or regionalised non-cooperative Nash equilibrium	Endogenous
International Institute for Applied Systems Analysis (IIASA) - Model for Energy Supply Strategy Alternatives and their General Environmental Impact (MESSAGE)	Global	2100	Myopic (Limited foresight – optimisation occurs in each time-slice) hybrid whole energy systems model (RES)	Mixed Integer Linear Programming (Energy Systems Module), Non-Linear Program (Macro-Economic Module)	Endogenous

International Energy Agency (IEA) – World Energy Model (WEM)	Global	2040	Whole energy system	Simulation: NPV calculation for investment decisions	Exogenous
PBL Netherlands Environmental Assessment Agency (PBL) - Integrated Model to Assess the Global Environment (IMAGE)	Global	2100	Integrated Assessment Model	Simulation (myopic)	Not explicitly modelled
Part 3: Natural Gas Market modelling methods – Economic and Market					
Energy Information Administration (EIA) – Natural Gas Transmission and Distribution Model (NGTDM)	North America	2040	Whole supply chain	Heuristic Network Model	Endogenous
EIA – International Natural Gas Model (INGM) (gas module for World Energy Projection System)	Global	2035	Whole supply chain	LP Optimisation Model	Endogenous (however no asset lifetime, meaning investments are a 'one-off)
Institute of Energy Economics (EWI) - Global Gas Market Model (COLUMBUS)	Global	2050	Whole supply chain	Agent-Based (multiple players): MCP	Endogenous

German Institute of Economic Research (DIW) - World Gas Model (WGM)	Global	2030	Upstream focus (but includes mid-/down-stream)	Agent-Based (multiple players – market power): MCP	Endogenous
Rice University World Gas Trade Model (RWGTM)	Global	2100	Upstream/Midstream focus	Econometric – Hybrid (i.e. bottom-up and top-down elements included)	Endogenous
Gas Exporting Countries Forum (GECF) – Global Gas Model (GGM)	Global	2040	Upstream/Midstream	Limited Public Information	Limited Public Information
Oslo Centre for Research on Environmentally Friendly Energy (CREE) - Framework of International Strategic Behaviour in Energy and the Environment (FRISBEE)	Global	2030	Upstream focus (includes midstream)	Bottom-up, dynamic partial equilibrium	Endogenous
RBAC Inc. Energy Industry Forecasting System - Gas Pipeline Competition Model (GPCM)	North America	Unknown (at operators prerogative)	Whole supply chain	Network LP – step-wise supply and demand curves which brings supply online in stages with cheapest first (RBAC, 2015).	Endogenous
Inner City Fund International (ICFI) Consulting – Gas Market Model (GMM)	North America	2025	Midstream	Network Price Equilibrium Model - NLP	Exogenous

Part 1 – Resource Assessment Modelling

This section aims to provide an overview of existing modelling methods for estimating natural gas resources. The models cover three broad groups:

1. Global estimates of natural gas resources and reserves
2. Reserve growth and undiscovered gas estimates
3. Individual field/play estimates (Bureau of Economic Geology, University of Austin).

Previous UKERC work (McGlade et. al, 2012) and a follow up study focusing on shale gas in isolation (McGlade et. al, 2013) has already focused on the methods employed to estimate volumes of unconventional natural gas. The studies highlighted varying degrees of reported volumes of shale, tight and CBM gas, from both the reviewed studies'[5] methods and inconsistent definitions, as well as identifying strengths and limitations of the current literature. Additionally, Sorrell et. al (2009) reviewed in detail the dynamics of conventional oil depletion, including estimating ultimately recoverable resources, reserves, and reserve growth potential, and the methods employed[6]. In practice, these do not differ significantly from methods used to estimate conventional gas reserves, reserve growth, and recoverable resources. Due to the previously mentioned UKERC research and to limit unnecessary repetition, this section focuses in more detail on the estimates of conventional natural gas: proved reserves, reserve growth, ultimately recoverable resources[7], and undiscovered accumulations. Additionally, an extension of the McGlade et. al (2012, 2013) work on shale gas includes a review of several bottom-up studies of shale gas plays conducted by the BEG.

Global estimates of natural gas volumes and supply cost

Bundesanstalt für Geowissenschaften und Rohstoffe (BGR) (Federal Institute for Geosciences and Natural Resources) – Global Reserves, Resources, and Resource Availability

General Structure and modelling method

[5] The report by McGlade et. al (2012, 2013) includes work by the EIA-ARI (2013a,b) and the USGS (Schmoker, 2005; Cook, 2005; Charpentier and Cook, 2012)

[6] The focus on natural gas was generally as a by-product of oil production (i.e. separation techniques) and a method of enhanced oil recovery

[7] Whilst the vast majority of ultimately recoverable conventional gas resources could be considered technically recoverable resources (i.e. can be recovered with current technologies), there remains pockets of natural gas which require advances in current technologies if they are to be extracted (without even taking economic factors into account); these include ultra-deep water/reservoir drilling whether temperature and pressure are too extreme, and some Arctic drilling

The German Federal Institute for Geosciences and Natural Resources (BGR) study on energy reserves, resources, and availability relies on a systematic literature review of available reported reserve and resource estimates; in order to generate country-wide estimates, before aggregating these to give global figures. The BGR assesses reserves and resources with a “conservative” outlook: the assessment of resources and reserves follows a definition outlined previously of proved reserves (1P) and technically recoverable resources (BGR, 2009, p. 23; BGR, 2014, p. 16).

Strengths

One of the main strengths of a systematic literature review when making reserve/resource assessments is that the huge range of estimates in the literature can be aggregated, and thus some of the uncertainty and parameter choices of each individual study can be “averaged out”.

In the case of estimating volumes of conventional natural gas, there is generally a large and well established literature on reserves and technically recoverable resources, from disaggregated (field) to country-level estimates. From this broad literature, the author can therefore make a more informed decision on which volumetric estimates are ‘high’, ‘low’ and ‘best’ (SPE, 2005).

Additionally, a literature review allows the assessment of reserve and resource estimates from a huge range of modelling methods, and thus can be seen as pooling the strengths and weaknesses of individual methods (conversely, this could also be seen as a limitation). An example of where a systematic literature review could prove effective at differentiating between different categories of natural gas is when a particular field/collection of fields is in a ‘no-mans-land’ between one reporting category and another. Taking the case of Mozambique, the OGJ and EIA report Mozambique to have proved gas reserves of 2830 bcm, whilst Cedigaz reports a much lower figure of 75 bcm. Virtually all of this larger figure is due to the assumption that the Mamba field complex is commercially viable, despite the fact that only part of the resource base has been approved for final investment decision: the Coral FLNG project with an estimated reserve base of ~ 140 bcm (Offshore-Technology, 2018). Thus, a literature review can allow for an informed decision of which volume classification a particular project should fall into, ideally based on probabilistic geological studies and a fixed timeline for development of said project.

Limitations

Whilst the above discussion regarding the strengths of a systematic literature review identified the fact that the author has the ability to scrutinise the available literature, there are also some fundamental flaws to this practice. Firstly, it leaves a huge amount of influence to the author on what constitutes a reliable estimate in the literature, especially if reported volumes of natural gas for reserves and resources are too conservative or too optimistic (i.e. constrained too highly by current market and technical conditions, or including resources which will in reality be more likely to be techno-economically infeasible). Secondly, some resource estimates attract significantly less attention than others, resulting in limited data, particularly at a disaggregated level, thus unpicking these highly aggregated (i.e. global/large regional) volumes generates even more uncertainty (McGlade, 2013, p. 106). The limitations of using highly aggregated data also requires lumping together significantly different techno-economic conventional resources: associated and non-associated gas, sour gas, onshore and offshore.

As previously mentioned, the BGR method of employing a widescale literature review allows for in-depth analysis of which gas belong in each classification of volumetric estimates. However, and particularly given the differences between reserves (whether 1P or 2P), reserve additions, and technically recoverable resources can be porous, a probabilistic estimate using bounds from the literature is a more robust method for estimating natural gas volumes, especially if these volumes are subject to change over time.

Rogner – Global Hydrocarbon Resource Assessment

General Structure and modelling method

Rogner's (1997) global resource assessment of natural gas splits resources into categories based on their ultimate recoverability (i.e. the probability of a certain percentage of a volume of gas becoming recoverable over time) (Rogner, 1997, p. 253). Rogner's method of estimating gas volumes is based on a modified interpretation of the McKelvey matrix (shown below in Figure 1), as well as through the review of existing studies generating resource estimates based on contrasting interpretations (geological and economic success rates) of resource categories (Rogner, 1997).

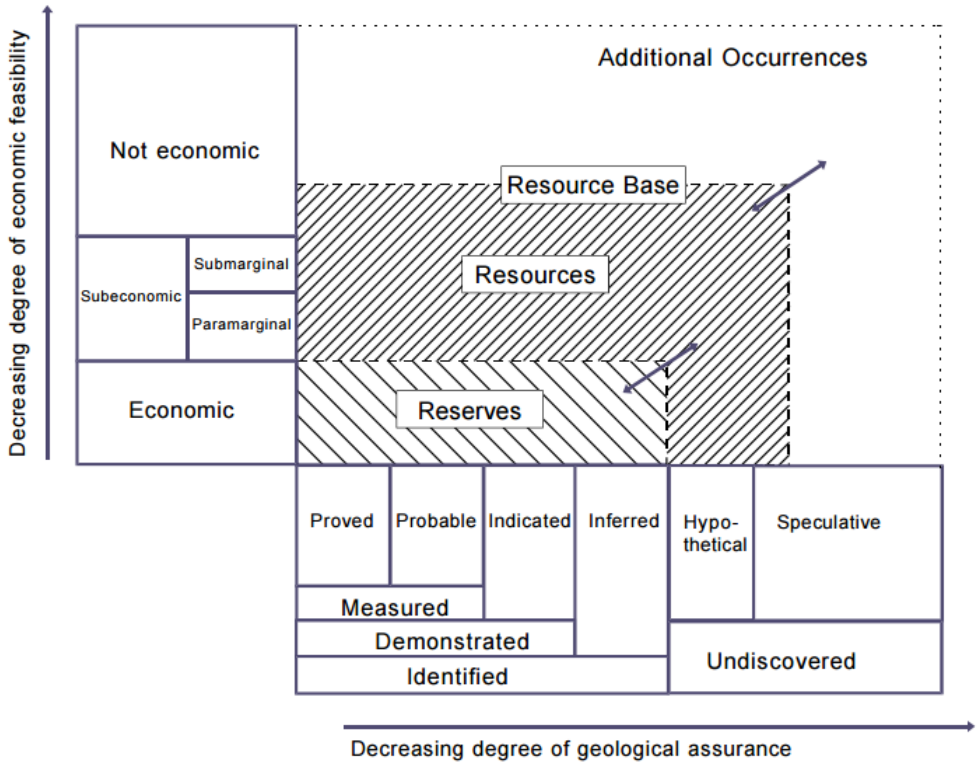


Figure 1: McKelvey matrix used by Rogner (1997)

Rogner's resource estimates are based on declining geological assurances (with a recoverability probability factor used as a proxy) moving from Category I (generally proved reserves) to Category VIII (with extremely low recoverability factors).

Strengths

Within the estimates, Rogner allows technological advancement to increase the estimates of recoverable resources via enhanced recovery methods, and with dynamic boundaries, meaning the various categories within the McKelvey are porous. This allows for significant flexibility in moving natural gas occurrences from one geological assurance category to another, which can be hugely important given the inherent uncertainty surrounding future viability of resources – for example, the shale 'revolution' in the US was the result of cost reductions over time, starting in the 1980's, and culminating with commercially viable hydraulic fracturing technologies which came to the fore in the early-/mid-2000's (Badessich et. al, 2016).

The inclusion of additional occurrences in Rogner's resource assessment is fundamental and based on the assumption that both techno-economic factors are dynamic through time (i.e. the potential for the extended commercial viability of discovered but undeveloped and as-of-yet undiscovered conventional resources, and the widespread exploitation of unconventional resources) (Rogner, 1997, p. 223; p. 250). This results in estimates which more closely follow a definition of ultimately recoverable resources (URR) rather than technically recoverable resources (McGlade et. al, 2012, p. 5).

Limitations

Rogner's analysis of conventional gas reserves and resources follow the same limitations as the BGR, given both use literature reviews. The highly aggregated nature of the conventional resources reported by Rogner thus fails to distinguish between the categories of conventional natural gas, which becomes increasingly important when supply-cost dynamics come into play (i.e. associated vs. non-associated; sour vs. sweet; offshore vs. onshore)

The classification of resources and reserves in Rogner (1997, pp. 220-3) results in ambiguous definitions – distinguishing between each category is challenging, with Rogner addressing the blurred distinctions between categories, which only become increasingly "fuzzy" as more categories are added.

Additionally, using uniform recovery rates across an entire category (e.g. increasing recovery of proved reserves through enhanced extraction techniques etc.) over-simplifies Rogner's analysis, with recovery factors highly dependent on individual field, and even reservoir, characteristics (1997, pp. 227-31).

Rogner's estimates of ultimately recoverable resources and reserve/resource additions, in particular, are undermined by the application of a single analogue from developed occurrences to undeveloped areas (Rogner, 1997, pp 220-221; pp. 250-251). This is particularly important when Rogner generates supply-cost curves from analogous productivity and quantity-cost data, meaning several fundamentally important factors are omitted:

- Geological heterogeneity between and within natural gas deposits
- Economic variations (i.e. cost) due to available technology, fiscal regime changes, demand, infrastructural capacity

It must be noted however that Rogner's global study of hydrocarbon occurrences was conducted in 1997, and thus more data and robust methods for estimating natural gas deposit volumes is now available. This is reflected in a subsequent review of conventional and unconventional natural gas reserves, resources, and supply-costs conducted in 2012 (Rogner et. al, 2012).

McGlade – Bottom-up Economic and Geological Oil Field Production Model (BUEGO) and TIMES Integrated Assessment Model at University College London (TIAM-UCL)

General structure and modelling method

McGlade (2013) focuses on quantifying the uncertainties in the availabilities and costs of oil and natural gas resources, as well as the consequences on wider energy-climate interactions. Two models are used: the Bottom-Up Economic and Geological Oil field production model (BUEGO) and the TIMES Integrated Assessment Model at UCL (TIAM-UCL). McGlade uses Monte Carlo simulations in order to account for the huge range of uncertainty in reserve and resource estimates, particularly for unconventional oil and gas. For example, tar sands oil-in-place (unconventional bitumen which has to be mined) is applied a probability distribution to account for the inherent uncertainty surrounding in-place estimates, whilst the geological recovery factor (i.e. the share of the in-place accumulation which could be ultimately recoverable) is also applied a distribution. Random and repeated sampling from the product of these two distributions then gives an aggregated distribution, from which high (P5), central (P50) and low (P95) estimates are inferred[8].

Strengths

An undoubted strength of McGlade (2013) refers back to Section I of this paper: consistent, clear, and transparent definitions of natural gas reporting terminology from both an economic and geological perspective. This consistency allows for a highly robust assessment of an increasingly disaggregated representation of natural gas, as compared to the reporting from other studies. For example, the separation in McGlade's study of conventional natural gas allows for a far better understanding of the availability and economic characteristics of each category: associated vs. non-associated; deep-water vs. shallow offshore; sour vs. sweet; proved reserves vs. reserve growth and stranded reserves. In much of the literature, non-associated and associated natural gas in particular are not separated, giving McGlade's study a significant advantage. As mentioned subsequently, consistent definitions of what

[8] This method is also applied to undiscovered conventional natural gas, conventional reserve growth, and ultimately recoverable resources of unconventional natural gas (shale, tight and coalbed methane)

constitutes a proved reserve vs. reserve growth etc. could help limit the spread of uncertainty across the estimates of natural gas volumes.

Additionally, one of the main research goals of McGlade (2013) was the quantification of uncertainties surrounding the availability and cost of oil and natural gas resources. By employing Monte Carlo sampling, a range of potential resource availabilities can be constructed and sensitivities undertaken for a range of natural gas categories (shale, non-associated conventional, tight, CBM). For example, McGlade found the 'spread'[9] of uncertainty for conventional natural gas proved 2P reserves in the Middle East to be relatively small, given the huge concentrations in only a few fields. However, the spread of uncertainty increased significantly when comparing 2P reserves in the Former Soviet Union, particularly when sub-economic Arctic assets such as the Shtokman field are included in some studies estimates of 'proved' Russian reserves. As with other studies (including the two subsequent USGS papers), the use of Monte Carlo sampling provides a systematic and robust method for transforming discrete volumetric and other geological parameters into continuous distributions, capable of quantifying the uncertainty inherent in any estimation of gas reserves, resources, and in-place quantities.

Limitations

For both conventional and unconventional natural gas, volumetric estimates were generally at a highly aggregated level. For example, a lack of data meant that McGlade used a single USGS global aggregate estimate of conventional gas reserve growth additions outside of the US (Klett et. al, 2011; Klett, 2012). This figure was then attributed on a country and regional level by subtracting 'known discovered' from 'grown discovered' volumes, for each assessment unit in the 2000 USGS World Petroleum Assessment (McGlade, 2013, pp. 287-8; Ahlbrandt et. al, 2000). This method leaves large areas of uncertainty, in the country level of allocation of reserve growth, including but not limited to:

- Some basin assessment units noted in the USGS Petroleum Assessment Data Tables (USGS, 2000) are highly aggregated, and ideally reserve growth should be done on a field-by-field basis, rather than taking average field sizes and average field numbers; for example, the West Siberian Onshore Gas Assessment Unit contains several supergiant Russian gas fields (Urengoy, Yamburg, etc.) which in order to minimise uncertainty, should be considered at a field level.
- The assessment units used for potential reserve growth are chosen to match the USGS assessment units for undiscovered resources, therefore whilst this was done so the two could be isolated from one another (Schmoker and Klett, 2000), there is likely some degree of cross-over potentially leading to 'double-counting' if using McGlade's method to estimate reserve growth
- The tabular data provide by Ahlbrandt et. al (2000) is now relatively outdated, although no other disaggregated publically available dataset of reserve growth exists; in short, disaggregating the 2012 estimate with 2000 data is still open to significant

[9] The spread was defined as the difference between the P5 and P95 values, divided by the median P50 (McGlade, 2013, p. 148)

uncertainty as the distribution of reserve growth is highly dynamic depending on localised technological improvements, market conditions, etc.

Additionally, the application of probability distributions to country-level estimates of tight, and shale gas resources could be improved by accounting for recoverable resource uncertainty at a play-level. Due to the highly heterogeneous nature of shale plays, some accumulations could have much larger uncertainty spreads in terms of the ultimately recoverable resources than others. Although this is certainly not possible for all countries, there is now at least a wide range of estimates for most individual major shale plays globally, as well as increased tight natural gas activity, particularly in China and Canada (EIA-ARI, 2013; Medlock, 2013; ACOLA, 2013; NRCAN, 2017; Chong and Simikian, 2014). As far as CBM is concerned, data on volumes-in-place and technically recoverable resources remain limited at a country-level.

United States Geological Survey (USGS) – Conventional Reserve Growth Assessment

General Structure and modelling method

The United States Geological Survey (USGS) estimates reserve growth as a subset of technically recoverable resources, either from already developed, technologically accessible formations or "extrapolated from geologically similar trends or plays" (Klett et. al, 2011, p. 1).

The USGS model for assessing conventional resources is based on a forecast lifespan which represents inter-temporal preferences of resource extraction and depletion (i.e. resource inventory) and based only on those formations which reach a probabilistic 'hurdle-rate' of resources (technically recoverable) becoming reserve additions in the specified lifespan (~ 30 years). The key distinction between TRR and potential reserve additions in the USGS model is made by adding additional technical constraints to resources considered technically recoverable, in order to constrain potential for technological advance (Schmoker and Klett, 2005, pp. 5-6). Reserve growth has already been defined as potential addition to reserves in already discovered and proved accumulations, via techno-economic developments and improvements in recovery or additional exploratory activity.

The revised USGS method focuses on the identification of individual accumulations most likely to contribute to reserve growth (RG), with bottom-up analysis of geological parameters analysed and statistical distributions attributed to the potential recovery factor of these formations. The USGS method utilises a range of recovery factors (to reflect uncertainty over recoverability given different geological characteristics under the assumption of current technological knowledge). Once the accumulations with the highest prospectivity for reserve growth have been identified, Equation x shows the method employed for implementing Monte Carlo simulations from the distributions of in-place gas quantities (lognormal) and recovery factors (triangular).

Equation x

$$[(\text{In-place gas} * \text{Recovery factor}) - \text{Reported (known) recoverable resources}]_{\text{repeated } n=1:1:50000} = \text{RG}$$

Equation x is repeated 50,000 times in order to generate an aggregate distribution of reserve growth, from which high (P5), central (P50) and low (P95) estimates can be inferred (Klett et. al, 2011; Klett, 2012).

Strengths

The USGS heavily relies on probabilistic distributions when modelling resource and reserve addition estimates for undeveloped conventional resources. Given the fact that systematic assessments cannot take place without significant exploration and field development, incorporating probabilistic assessments consistently reflects the underlying uncertainty surrounding key parameters of natural gas volume assessments. In addition, the division of gas accumulations into assessment units allows the heterogeneity of hydrocarbon plays and fields to be taken into account, whilst limiting the life-span of the assessment makes for a more realistic assessment of the impact of technology.

A key addition to the USGS assessment of reserve growth estimates is the focus on individual accumulations, giving the model more flexibility to look further in depth at the determinants of field/play/reservoir recoverability characteristics. The uncertainties of key parameters and data inputs are taken into account using probability distributions:

- Truncated lognormal distribution – gas-in-place estimates for individual formulations
- Triangular distribution – recovery factor (based on engineering and geological data, and data from historical development (if applicable to the formulation in question)).

This limits some of the inherent uncertainties surrounding in-place and recovery factor estimates, as the Monte Carlo simulation samples tens of thousands of times, generating an aggregate distribution of reserve growth from technically recoverable resources, including a huge range of parameter values, from which low, central and estimates can be inferred (Klett, 2012).

Limitations

Critically, the USGS applies US analogues to reservoirs and formations outside of the US, due to a lack of production history and the required data (Klett et. al, 2011, p. 5; Klett, 2012), thus falling into the same fundamental limitation as Rogner (1997) – the heterogeneity between accumulations (geological, field-economics, exploration and production experiences), whether conventional or unconventional, is not fully taken into account.

Additionally, it is difficult to transfer the USGS method for generating reserve growth estimates from conventional prospects to unconventional prospects, as recovery factors (and decline rates) in unconventional prospects tend to be far more diverse and volatile, even within the same accumulation. This is best reflected by the fact that in unconventional accumulations, more time and capital resources are allocated to the exploration phase, in order to locate the most productive area of a play/field, the ‘sweet spot’ (Glaser et. al, 2014; Herrmann et. al, 2013, pp. 53-9).

Whilst the use of analogues is inevitably unavoidable for geological formations and deposits which have not been discovered or developed yet, careful consideration should be given to which analogues are used by choosing regions with as similar geological properties as possible, rather than the application of one or two analogues globally (Grigorenko et. al, 2011).

The fundamental limitation of the USGS study into conventional accumulations in the US, and subsequently applied globally, is the requirement that significant amounts of production and development data be available as the reference point for input parameters (Schmoker and Klett, 2005, p. 4). Thus, in areas with limited production or development history, it is highly uncertain on what basis the input parameters, including geological recovery factors, can be modelled in terms of projecting the impact of future technological improvements. Additionally, McGlade (2013, p. 91) identifies that reserve growth should ideally be at a field-/reservoir level, but that only two US gas (non-associated) fields were independently assessed by the USGS to model reserve growth dynamics (Klett et. al, 2012).

Bureau of Economic Geology (BEG), University of Austin - Recoverable Shale Resource, Reserves, and Productivity Assessments

General Structure and Modelling Method

Given that the United States accounts for the vast majority of shale gas development and production history, assessing production estimates for US shale plays provides the only substantiated (in terms of both production history and widespread geological exploration) foundation for shale gas resource estimates and production projections. In this respect, the method employed by the Bureau of Economic Geology (BEG) in their productivity estimates and analysis of well economics in the major US shale plays is of significant interest. Several studies from the BEG follow generally the same modelling method for assessing the productivity potential of the main US shale plays, and are thus assessed together in this review:

- Browning et. al, 2013a,b: Barnett – production and reserves forecasts based on geological parameters
- Browning et. al, 2014: Fayetteville – reserves and production forecast
- Gulen et. al, 2013: Barnett – well economics in geologically defined productivity tiers
- Ikonnikova et. al, 2015a: Barnett, Fayetteville, Haynesville, and Marcellus – production forecast
- Ikonnikova et. al, 2015b: Fayetteville – well and drilling economics

The BEG studies delineate the US shale plays into highly disaggregated areas; for estimates of reserves and technically recoverable resources the play is generally split into 1-square mile areas whilst for the productivity estimates wells are split into around 10 tiers of estimated ultimate recovery's (Browning et. al, 2013b).

For key geological (depths, zonal thickness, drainage area, porosity, recovery rates) and economic (CAPEX, OPEX, gas prices) parameters, probability distributions are applied and sampled from repeatedly in Monte Carlo simulations, yielding aggregated distributions for a range of outputs: economic rates of return, recoverable reserves, individual well productivity across production zones (Ikonnikova et. al, 2015a).

Strengths

In order to reflect highly variant gas-in-place estimates across shale formations, the BEG method includes the fundamental foundations of shale gas resource and productivity assessments, by including productivity tiers to reflect:

- the geological heterogeneity of shale plays
- 'sweet spot' (the most productive yields of hydrocarbons within a formation and often exploited first) vs. 'non-sweet spot' areas - using 'sweet spots' (which are generally developed first) as an analogue for an entire formation, can lead to systematic over-/under-estimations of shale resources

The productivity tiers generated by the BEG studies were generated using a bottom-up, geological assessment of porosity and shale thickness per square mile for the assessed area, which were then used to determine the TRR of each 'productivity zone'. This reflects not only the geological characteristics which underpin TRR, but the impact of varying recovery factors and decline rates on well economics (i.e. the overall economics of development, usually measured as an investment decision in terms of net present value (NPV) or internal rate of return (IRR)):

- Drilling costs from required well-lengths
- Increased resistance to drilling, leakage factors
- Less wells per rig due to higher requirements on well spacing

(Browning et. al, 2013a,b; Ikonnikova et. al, 2015a; Ikonnikova et. al, 2015b).

In order to calculate individual wells EUR, the studies utilise historical production data to fit decline curves to each individual well in each productivity tier, as decline curves tend to differ, particularly at later stages, due to geological differences (Ikonnikova et. al, 2015b).

In order to incorporate some of the inherent uncertainty in estimating individual shale gas wells ultimate recovery, continuous probability distributions (normal, uniform, and triangular) were assigned to key parameters (both geological and economic), and repeated iterative sampling generated a range of results for which a respective well in each productivity tier would reach a certain investment floor (i.e. minimum internal rate of return) (Gulen et. al, 2013). The use of Monte Carlo analysis in the BEG studies is critical as it allows for the inclusion of stochastic (random probabilistic change) parameters, which generates a range of potential results (i.e. probabilistic outcomes), rather than having static outputs. For unconventional gas in particular this is key, as recovery rates etc. can change significantly across a play, even in relative geographical proximity.

Limitations

The limitations of the BEG studies, particularly when attempting to model the impact of shale gas exploitation outside of North America on natural gas markets, are twofold:

1. The level of data intensity – a huge amount of geological information and long-term production history is required, along with natural gas markets where unconventional drilling and exploitation is entrenched
2. Limited scope for repetition outside of North America – studies conducted by the BEG would be challenging to replicate elsewhere, due to the fundamental lack of shale gas development; as such, the study methods employed would be challenging to replicate on a global scale

Additionally, there is a significant risk in using US analogues for near-term shale gas production potential in other countries. Firstly, the US has a long history of onshore natural gas and oil exploration and production, resulting in widespread infrastructural capacity across the supply chain. Secondly, sectoral demand in the United States is sufficient – and varied[10] - to absorb the high initial flow rate characteristic of shale gas production. Thirdly, technical advances (e.g. hydraulic fracturing, directional drilling, multiple wells per drilling pad) which are now commercially viable and widespread in the United States were accrued over decades of production experience (e.g. unconventional tight gas production in the Jonah field from 1996) and fiscal incentives (tax credit)/government funding of R&D for unconventional drilling from the 1980's (Aldy, 2013; Wang and Krupnick, 2013). Therefore, whilst these technical advances do not need to be replicated (i.e. the technology has already been developed), that does not guarantee that the techno-economic conditions experienced in the US will have the same impact everywhere, as was shown in Poland (DW, 2016).

Have Resource Estimates Converged as Shale Plays Are Developed? Results of Different Methods for Unconventional (Shale) Resource Assessment Estimates

The below results reflect both the importance of differing methods, but also – and crucially – the fundamental importance of actual field development and exploration in estimating technically recoverable resources, reflected in this case by a largely undeveloped shale basin (Sichuan - China) and a developed basin (Barnett - US).

Sichuan

Source	Technically Recoverable Resources (tcf)
United States Geological Survey (USGS) (2015a)	23.9
Energy Information Administration-Advanced Resources International (EIA-ARI) (2015b, p. 10)	626

[10] US gas demand is across the industrial (29%), electricity generation (34%), residential (16%) and commercial (12%) sectors, therefore it retains a sufficient level to absorb the supply of shale year round, despite large seasonal fluctuations (EIA, 2018)

Table 3: Technically recoverable resource estimates for the Sichuan Basin in China

Barnett

Source	Technically Recoverable Resources (tcf)
Bureau of Economic Geology (BEG) (Browning et. al, 2013a, p. 63)	86
EIA-Intek (2011, p. 4)	43.4
USGS (2015b), 2003 estimate	26.2
USGS (2015c), 2015 estimate	53

Table 4: Technically recoverable resource estimates for the Barnett shale play in the United States

The results above reflect the importance of how geological parameters are assigned when widespread production and development within a field has not yet been undertaken. The variation in the results for the Sichuan is twenty-six fold, whereas the Barnett – which has experienced significant development and exploration of the formation – yields a two-fold variation in technically recoverable resource estimates (from the most recent estimates shown). The importance of field development, in improving geological knowledge of a play is reflected in the USGS reassessment of estimates from the original study in 2003, to the latest in 2015. Thus, the increased development of a shale play through time, would appear to lead to converging estimates, despite slight differences in assessment methods:

- Both the USGS (2015c, p. 2) and the EIA-Intek (2011, pp. 51-2) assessments use a 'law of average' bottom-up approach, with average well spacing, and rock porosity and permeability, amongst other parameters, assigned to 2-3 assessment units of the entire play, with the estimated in-place volumes assigned recovery factors per well, which were then multiplied across the aggregated areas to generate a TRR.
- The BEG study on the other hand disaggregates the assessment units even further, with the play split into ten productivity tiers - before similar geological characteristics to the USGS/EIA-Intek were used - in addition to well productivity decline rates, to calculate estimated ultimate recoveries (EUR's) (Browning et. al, 2013).

The above discussion of showing that resource estimates increased, and became increasingly correlated as the play was developed through time, is not suggesting that resource estimates always increase, but instead that the physical development of a prospect decreases geological uncertainties. In addition to this, the previously discussed section on generating a consistent and relatively stringent definition of reported reserves and resources, leads to more reliable estimates, both for investors and policy makers.

Part 2 – Use of Integrated Assessment Models and Energy Simulation Models for Natural Gas Modelling

The following section focuses on wider energy-economic-climate models, with a brief discussion of how natural gas is represented in these models, from the supply chain to overall energy demand. It should be noted that each of the models in this section has a global geographical scope. The analysis focuses on the overall modelling methods and structure of each of the wider energy models covered. Additionally, the strengths and limitations of both the modelling method, and more specifically the representation of natural gas from both a supply and demand perspective is discussed. The overall aim of this section is to determine the appropriateness of each model's ability to work in conjunction with a new global, field-level natural gas model introduced at the end of this review.

In general, the models reviewed below are consistent in the sense they have the ability to broadly incorporate the following, although the implementation depends on the modelling method:

- Interactions between the energy system and climate change; e.g. carbon budgets, constraints on global temperature rise
- Variations in technology costs and availabilities
- Constraints or ramp-up rates (i.e. forced acceleration of diffusion) on certain technologies (e.g. constraining the model not to develop certain resources, or forcing the model to meet certain levels of low-carbon technology).

TIMES Integrated Assessment Model – University College London (TIAM–UCL)

General Structure and Modelling Method

The TIMES Integrated Assessment Model at University College London (TIAM-UCL) is a 16-region, technology-rich, bottom-up linear optimisation model. TIAM represents economic-energy-environment interactions via a reference energy system (RES), which shows the interaction of technological processes and the flow of energy/environmental[11] commodities between these (Anandarajah et. al, 2011a, pp. 2-3), in order to meet energy service demands (e.g. passenger kilometres, kilowatt hours for lighting, etc.). The optimal solution is found by an endogenous calculation of the technological energy mix, based on costs and linear user constraints. TIAM computes a partial equilibrium, in that the optimal solution for the energy system minimises costs/maximises producer and consumer surplus, however there is no feedback into/from the wider economy (Anandarajah et. al, 2011; Keramidas et. al, 2017).

[11] An example of an environmental 'commodity' is methane emissions from the venting of natural gas from oil extraction technologies

Energy demand in TIAM is driven by exogenous drivers, with final energy service demands (e.g. residential lighting, industrial iron and steel, light road transport) satisfied by the range of technologies and energy commodities within the model. Additionally, shared socio-economic pathway (SSP) narratives (O'Neill et. al, 2014) have been applied to the representation of demand in TIAM and used recently in Price and Keppo (2017) and Winning et. al (2018). TIAM can also extend standard runs of the model to include demand elasticity's, whereby energy service demands react to changes in the costs of input supply commodities (Anandarajah et. al, 2011, p. 3).

As an integrated assessment model (IAM), TIAM-UCL generates possible pathways for decarbonised futures, with significant detail of the techno-economic characteristics of the energy system. TIAM can be run with an exogenous climate module to constrain the model to certain maximum temperature increases using a range of corresponding climate parameters (e.g. radiative forcing represented by the concentration of a GHG). When used in conjunction with the climate module, the endogenous creation of emissions (CO_2, CH_4, N_2O) from energy system activities and land use changes in TIAM are sent to the climate module in order to determine the concentrations of each emission commodity, and therefore the impact on global temperatures from 2005-2100 (Anandarajah et. al, 2011). Additionally, carbon budgets can also be implemented, either in conjunction with the climate module (Winning et. al, 2018), or as a standalone constraint to limit the amount of carbon dioxide generated by the energy system, either at regional or global levels.

TIAM-UCL utilises linear programming to optimise (minimise) the objective function: total energy system costs, discounted to the base year (2005). Thus under each of the scenario's generated, the model will choose the combination of technologies (processes) and feedstock fuels associated with these, which can satisfy end-use demand at the least cost, taking into account any constraints. Additionally, the dual solution of the linear program involves optimising the shadow prices[12] for the various user constraints.

Representation of natural gas

The method for generating natural gas resource and reserve estimates, as well as generating supply cost curves, has been discussed in Part I in the discussion of McGlade's work on BUEGO and TIAM-UCL (2013). Each resource category of natural gas[13] in TIAM-UCL is split into three cost stages, whilst production is constrained annually through the implementation of decline and growth rates on each category. These decline rates differ depending on whether the gas resource in question is conventional or unconventional. Decline rates for production are exogenously set, however because they are applied to production which is determined by the model, there is a degree of endogenous production growth and decline. Additionally, limits are placed on the level of production decline and growth (i.e. if new

[12] "*The shadow price of a constraint of a linear program is the increase in the optimal objective value per unit increase in the RHS of the constraint*" (MIT, 2013); for example, the shadow price of a constraint on investments in pipeline infrastructure would be the (marginal) increase in the objective function from a (marginal) increase in the constraint on pipeline capacity expansion

[13] Conventional gas: proved reserves, reserve additions, undiscovered, Arctic; Unconventional gas: shale, tight, CBM

production outpaces decline): if new gas production is cost-optimal to enter the energy mix, then the model can essentially choose a 'negative' decline rate, thus leading to increased production.

TIAM separates upstream resource extraction (i.e. production) costs and trade into two distinct modules, with the costs of the feedstock commodities which are traded (e.g. hard coal, natural gas, crude oil, biomass, etc.) determined in the upstream modules, and the direct costs of trading determined in the trade module. Additionally, and as with the other wider energy systems models discussed subsequently, a distinction between pipeline and LNG trade is made. An underlying trade matrix determines which regions can trade with each other, and as expected, there are far more interlinkages for LNG trade than pipeline.

For both forms of natural gas trade, parameters include:

- Costs (capital costs for infrastructure, operational costs for infrastructure and transportation)
- Efficiencies (i.e. losses during transportation procedure)
- Emissions (including leakage)
- Constraints:
    - Capacity
    - Geographical
    - (Geo)political
    - Economic (investment costs)
    - Historical investment

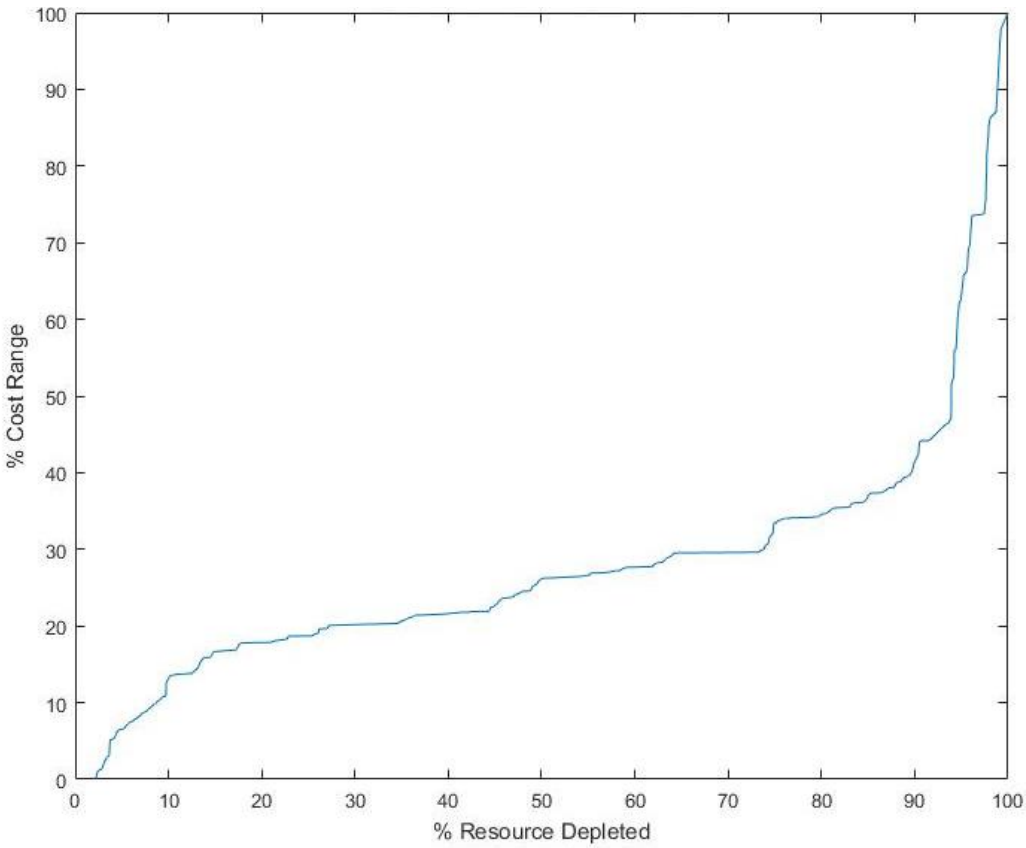
The natural gas, whether domestically consumed or internationally traded, then flows through to the downstream in order to satisfy energy service demand; in some cases, this involves directly processed gas satisfying, for example, residential cooking demand, and in other cases, the gas is input into the power generation secondary transformation sector. With all processes as gas is tracked through the RES, individual efficiencies, costs and emissions factors are applied.

Strengths

As mentioned previously, TIAM-UCL has a climate module which is calibrated to the Model for the Assessment of Greenhouse-Gas Induced Climate Change (MAGICC) which determines the radiative potential and atmospheric concentrations of the GHG emissions generated by the energy system. This can then be used as a feedback to constrain the model based on certain scenarios, such as maximum temperature increases (Luderer, 2015, pp. 4-5; Anandarajah et. al, 2011b, pp. 121-2). Thus, TIAM is well-placed to assess decarbonisation pathways for the energy system, and in particular to track carbon emissions through the RES, due to the bottom-up nature of the model. Additionally, regional specific carbon budgets can be implemented to attempt to model globally disaggregated commitments to climate mitigation regimes, such as the NDC's (Winning et. al, 2018). As with other models which use a reference energy system (RES), a diverse range of environmental impacts associated with natural gas production, consumption, and trade, are assessed in TIAM, including methane leakage from production, transmission and distribution. For example, fugitive emissions from natural gas systems can be researched due to the structure of the reference energy system, as emissions factors can be placed at each stage of the supply chain, and sensitivity analysis conducted both on the level of these factors (i.e. the actual CH_4) emitted and the overall increase in emissions (EDF, 2016; EPA, 2016; Balcombe et. al, 2015).

A key strength of the treatment of natural gas in the upstream sector in TIAM-UCL is the disaggregation of categories of conventional and unconventional gas into different cost ranges using cost-depletion curves. This generates a far more realistic supply-cost profile, and a more detailed representation of costs with which to generate endogenous 'prices' through time. McGlade (2013) employs a range of field development and production costs, mainly derived from the IEA (2010; 2013) and the EIA (2011, 2016) are applied to cost depletion curves, which are used to create (within the Monte Carlo process) a huge range of supply cost curves. An example of a cost depletion curve, created by the author, is shown in Figure 2. Whilst other models such as POLES use an energy return on investment (EROI) method for reflecting depletion of natural gas resources (i.e. higher energy and investment requirements as resources are depleted) (Keramidas et. al, 2017), TIAM has a significant advantage in that more categories of natural gas and oil are included meaning more detailed representations of supply cost dynamics, as well as field level analysis, now for both oil and natural gas.

Figure 2: Representative cost depletion curve



Source: cost depletion curve for global non-associated conventional natural gas reserves from author, for illustrative purposes

TIAM's disaggregation of energy-service demand is also a significant strength. TIAM has more than 50 energy-service demands, meaning sensitivities can be analysed at a highly disaggregated level, by inflating/deflating individual demands, and analysing either the increase/decrease in primary or secondary energy consumption this yields. The disaggregation within TIAM includes separating urban from rural residential energy service demands, which is particularly important in developing regions, and gives the model an advantage over, for example, the REMIND (discussed subsequently) model which has highly aggregated final energy demand sectors, including the aggregation of industry, commercial and residential demand (Luderer et. al, 2015).

Limitations

As with some of the other wider energy system and integrated assessment models in this section given their significant scope (REMIND, MESSAGE, POLES), TIAM-UCL is relatively limited to reflect seasonal changes in natural gas demand, due to the nature of its time-slices (generally five years out to 2060, and then ten years). Due to the shorter-term nature of natural gas demand fluctuations which can have a huge impact on natural gas networks and supply-demand balancing, TIAM-UCL cannot account for such fluctuations. However, this is mitigated to some extent by including seasonal variations to the time-slices for some key energy service demands, such as residential heating and cooling. Additionally, given the time horizons of TIAM-UCL and the other wider energy models in this section, having highly disaggregated time-slices (e.g. daily) is simply not practical.

Two key limitations of TIAM-UCL lie in the architecture of the model itself:

1. Linear optimisation: some constraints within the model have to be given linear approximations, when in reality they are highly non-linear; for example, step functions across percentage shares of natural gas resources extraction costs are employed rather than the non-linear supply-cost curves
2. Perfect foresight: the model can see all costs and demands throughout the time horizon, which is a simplified representation of a highly asymmetric investment climate, especially for long-term infrastructure projects such as gas pipelines. Additionally, by implication, this assumes the presence of a single ‘central’ decision maker for energy system investments

Unlike oil, the assessment of natural gas costs was at a highly aggregated level, and McGlade identifies the lack of a natural gas field level database in the work (2013, p. 269). This limitation was one of the key motivations for the UKERC funded PhD this working paper is based on. In particular, it is unclear how the percentage range of resources was applied to the percentage range of costs, i.e. the shape of the cost depletion curves. Additionally, there was limited assessment of the key drivers of unconventional natural gas economics at a play level (shale, tight, etc.), largely driven by a lack of available data, particularly outside North America. Within TIAM, there is a dummy process which allows associated natural gas to be produced as a by-product of oil. Whilst the costs of associated gas production are relatively minimal (costs are due to the processing and separation in a processing plant), the required infrastructural capacity is often absent, particularly for relatively isolated oil fields. This lack of infrastructure is one of the key drivers of flaring, along with limited domestic demand (Haugland et. al, 2013; PFC, 2007). Previously in TIAM, this production of associated natural gas was ‘free’ (i.e. there was no cost), leading to over-production of this particular resource base.

Due to the mathematical formulation and energy-system wide scope of TIAM (as well as most of the other whole energy system models discussed subsequently), some of the intricacies of natural gas markets, as well as potential developments, have to be omitted, including:

- Price formulation mechanisms (and transitions from one form to another)
- Transit tariffs between individual countries and regions
- Regionalisation of markets, particularly the increased divergence between Russia and the CIS/non-Russia FSU (which are grouped in TIAM); intra-regional trade dynamics in TIAM are absent
- Exogenous geopolitical complications

Finally, in its current form, the partial equilibrium solution leaves a significant limitation in that there is no feedback between energy system dynamics and the wider economy. For example, the impact of rising fossil energy costs, both from cost-depletion effects and endogenous carbon pricing, can be reflected in terms of altering energy service demands in the elastic demand version of TIAM, however, wider impacts on the economy and feedback loops between the energy system and the economy[14] cannot be incorporated currently. It should however be noted that a hard-linkage between TIAM-UCL and a macro-economic general equilibrium model is under development (Winning et. al, 2015), with future outputs expected in 2018/19.

Enerdata - Prospective Outlook on Long-Term Energy Systems (POLES)

General Structure and Modelling Method

Enerdata’s Prospective Outlook on Long-Term Energy Systems (POLES) model, like TIAM-UCL, is a partial-equilibrium model in that there is no feedback mechanism between the energy system and the wider economy, such as the implications of rising fossil fuel costs on GDP etc. (Keramidas et. al, 2017). However, unlike the optimisation based modelling approach in TIAM, POLES is a recursive-simulation model, and thus solves for each time-slice individually, with results passed onto the next period. This also means various decision simulations can be made based on repetitive behaviour, whilst allowing the model to change paths as long as the investment decision can still be reversed, i.e. as long as construction of infrastructure hasn’t actually started (Keramidas et. al, 2017, p. 8). POLES does not attempt to minimise system costs, but instead develops pathways for energy systems scenarios, under varying energy and climate mitigation policies, and with endogenous behavioural responses to change (Keramidas et. al, 2017; Kitous, 2006):

- Climate mitigation policies including carbon taxes
- Different diffusion scenarios for renewable technologies

[14] For example, rising fossil fuel prices and corresponding changes to fossil fuel demand, would almost certainly have an impact on the overall economy, such as restructuring employment away from fossil intensive industries etc.

- Different supply-demand scenarios, with demand responses to endogenous changes in prices (elastic demand).

POLES has three predominant modules, with their outputs in brackets (Bhattacharyya and Timilsina, 2010, pp. 514-5; Keramidas et. al, 2017; Kitous, 2006):

1. Fossil and renewable primary energy carriers (Primary Energy Supply)
2. Secondary transformation (Secondary/Final Energy Supply)
3. Demand sectors (Final Energy Demand)

Energy demand for each sector is driven by exogenous socioeconomic drivers as with TIAM-UCL, and is satisfied by both primary and secondary energy carriers. Once final energy demand has been met for each region (including any trade of energy commodities, which is constrained by capacities of infrastructure), the prices generated in time *t* are used to alter demand in time *t+1*; in this sense prices are 'sticky', in that demand in *t* is impacted by the prices in *t-1*.

POLES was developed by Enerdata, and has been used by the European Commission to model spill-over economic impacts of shale gas development in Europe, and by the Department of Business, Energy and Industrial Strategy (BEIS) in the UK, for fossil fuel pricing and the development of an emissions trading scheme in the European Union.

Representation of natural gas

The representation of natural gas reserves and resources in Prospective Outlook on Long-Term Energy Systems (POLES) is static, in the sense that singular discrete reserve and resource data is taken from BP and the BGR (Keramidas et. al, 2017, p. 52). However, a dynamic process of resources moving along the McKelvey matrix into producible reserves is endogenous in the model through increasing investment in exploration activity, i.e. a creaming curve whereby new discoveries are a function of "drilling effort".

Domestic and international markets are then supplied based on existing capacities – both of production and trading infrastructure – with trade costs a function of distance and infrastructural capacity. Unlike TIAM where natural gas trade is optimised based on cost (with constraints on production and trade capacities), POLES includes a return on investment calculation, reflecting a strategic 'management' of resources on behalf of major exporters to maximise investment returns on gas trade, including the construction of new infrastructure.

Strengths

A key strength of the Prospective Outlook on Long-Term Energy Systems (POLES) model is the incorporation of discrete choice modelling, which is not incorporated in other energy system models. The ability of the simulations to incorporate behavioural preferences and inertia allows the model to extend beyond a purely techno-economic approach (Keramidas, 2017). Additionally, the ability of the model to simulate expectations based on historical trends and behavioural inertia over a 10-year period, without allowing perfect foresight across the whole modelling horizon, provides a robust representation of investment decisions in large-scale power system capacity additions.

The inbuilt demand elasticity function within POLES is also a key strength of the model. Energy demand within the model not only reacts to changes in energy commodity inputs, but also to changes in income per capita, the added-value of the commodity produced, short- and long-term price elasticities, exogenous changes in technical efficiency and performance, and a saturation factor reflecting, for example, certain energy service demands increasing with income to a certain point, and then flattening out.

POLES includes dynamic endogenous technological functions, which allow the model to simulate the impact of learning-by-doing including cumulative investments in technologies over time, leading to cost reductions and reflecting the reality of changing industry-cost structures (Kitous, 2006, p. 25) - as technologies (such as renewables) gradually gain market share and production experience, in general their costs will fall and they will become increasingly competitive with more established, locked-in processes. This can be seen in the reduction of modules in POLES from four to three, as renewable sources of supply have been moved into the fossil supply module (previously less established renewable technologies were considered separately) (Bhattacharyya and Timilsina, 2010, pp. 514-5; Keramidas et. al, 2017; Kitous, 2006). These one-factor learning curves are key to the endogenous changing of technology costs in each simulation of POLES (Enerdata, 2014a, p. 26).

In comparison to other wider energy models[15], the representation of trade in POLES is far more disaggregated, with 88 individual producers satisfying demand across 14 import markets, reflecting far better the nature of intra-regional trade than is possible in other integrated assessment/wider energy system models. As a simulation model, POLES is also far better equipped vis-à-vis TIAM to reflect demand responses to changes in market prices and different market structures, rather than relying on cost optimisation. POLES can additionally utilise this pricing simulation to model endogenous investment in upstream natural gas, with dynamic prices driving additional exploration efforts and discovery success (Kitous, 2006, pp. 31-2). As mentioned previously, this includes individual producers 'managing' their resource base in order to maximise an expected return on investment.

Limitations

Due to the fact that Prospective Outlook on Long-Term Energy Systems (POLES) is a simulation model, rather than a bottom-up optimisation RES, the representation of individual technologies which satisfy energy service demands is limited in comparison to TIAM and the Model for Energy Supply Strategy Alternatives (MESSAGE; discussed subsequently).

The static representation of resources and reserves in POLES, across both conventional and unconventional gas, systematically underestimates the inherent uncertainty of quoted volumes. Additionally, using an energy return on investment (EROI) method for generating cost curves fails to incorporate some of the key geological and geographical drivers[16] of costs for natural gas extraction. Thus, whilst the research aim of POLES is to simulate the impact of different climate and economic policies on the whole energy system, it lacks the bottom-up

[15] TIAM-UCL, Model for Energy Supply Strategy Alternatives (MESSAGE), Regional Model of Investments and Development (REMIND)

[16] These include reservoir depths, composition of the natural gas in the reservoir (e.g. associated vs. non-associated; sour vs. sweet), permeability and porosity (for unconventional), thickness (for shale and CBM)

detail which, for example, TIAM includes (i.e. in terms of resource disaggregation and the inclusion of crucial geological parameters in generating supply cost curves). The level of geological detail in POLES is highly simplified and aggregated at a country/regional level.

The use of POLES in the Mathis et. al (2014, pp. 12-26) study of the macroeconomic impacts of shale gas in the EU reflects some key limitations of using a model such as POLES to assess the potential of natural gas in regional energy balances. The study's' use of a literature review to determine ultimately recoverable shale gas, and the subsequent assignment of numerous uniform parameters across whole shale plays/countries, results in a highly simplified assessment of producible European shale resources. Some of the key – and in reality highly variable parameters – which were assigned uniform rates across individual plays and countries in the Mathis et. al (2014) report were:

- Drilling costs (US average taken and 'European-adjusted')
- US analogue for the relationship between the number of wells drilled and population density.
- O&M costs
- Uniform decline rates under a hyperbolic decline curve

Whilst being able to model the environmental impact of the energy system on the global climate, through an accounting procedure for emissions and an exogenous construction of marginal abatement cost curves, the assignment of emissions factors is highly aggregated, with, for example, each fuel involved in combustion-related emissions assigned a single factor. In this sense, POLES lacks the technical detail of TIAM and MESSAGE, where individual environmental commodity flows (i.e. emissions) are assigned to all technical processes across the whole RES, and thus generating endogenous carbon prices.[17]

Potsdam Institute for Climate Impact Research (PIK) - Regional Model for Investments and Development (REMIND)

General Structure and Modelling Method

The Potsdam Institute for Climate Impact Research (PIK) Regional Model for Investments and Development (REMIND) is an Integrated Assessment Model (IAM), combining a core macro-economic growth module, with an energy system module and a climate module for assessing the impact of economic growth and the energy system on the global environment and climate. The model solves for one of two cases:

1. Global pareto-optimal equilibrium in the case of cooperation (i.e. inter-regional trade and investment, resulting in a market equilibrium where one region cannot gain a more optimal outcome, without making another region worse off):

[17] As mentioned previously, these are then fed into a climate module transforming emissions into particulate concentrations and radiative forcing potentials, which are then fed back as a constraint to the model (e.g. in the form of a maximum temperature constraint).

    a. Weights are assigned to each region based on the maximisation of utility across time, ensuring that potentially prohibitive mitigation now does not adversely impact economic growth for the poorest, and on the other hand ensure that future generations are not lumped with the entire costs of climate change damages (Stanton, 2009, pp. 2-3).
    b. These weights are adjusted through time, thus reaching a pareto-optimal convergence, i.e. whereby one region cannot be made better off without making another worse off, and as with the Heckscher-Ohlin theory of factor price equalisation amongst regions, the redistributive weighting is assumed to eventually converge for all regions.
2. A non-cooperative Nash equilibrium – where regions do not cooperate, and thus the pareto optimal solution is not obtained, but each region seeks to maximise their own surplus

The macro-economic core module is "hard-linked" to the energy system, with the macro-economic growth module determining energy-service demand, and with the costs of the energy system directly fed back into the macro-economic module in order to assess the "budgetary" effects of changing energy system costs (Luderer et. al, 2015, p. 5).

A brief description of 'hard-linking' and 'soft-linking' between macro-economic growth models and energy system models is taken from Bauer et. al (2007, pp. 1-2):

- *"The hard-link approach integrates the techno-economics of the Energy System Module (ESM) into the Macro-Economic Growth Model (MGM) and solves one highly complex optimisation problem."* – in this sense, the solution to the optimisation of the ESM and MGM are solved simultaneously, which hugely increases the computational complexity (i.e. simultaneous algorithms are far more difficult to solve than sequential algorithms), and thus requires some sacrifice on model detail (Luderer et. al, 2015, pp. 35-6).
- *"The soft-link leaves the two models separate and energy supply functions are integrated into the MGM that are derived from the optimal solution of the ESM."* [i.e. models are solved sequentially and independently].

As with TIAM-UCL, REMIND prescribes cost-effective mitigation strategies based on exogenous climate scenarios (e.g. 2^{o}C maximum temperature increase), rather than "monetise climate damages…to determine a (hypothetical) economically optimal level of climate change mitigation (cost benefit mode)" such as in the DICE model. Similar to TIAM, a climate module using MAGICC determines the radiative potential and atmospheric concentrations of the GHG's emissions generated by the energy system, which can be used to constrain/regulate the model based on certain scenarios, such as maximum temperature increases or particulate concentrations (Luderer et. al, 2015, pp. 4-5; Anandarajah et. al, 2011b, pp. 121-2). Both TIAM-UCL and REMIND use climate modules as a feedback loop, with the emissions from the energy system being transformed into radiative forcing effects and GHG atmospheric concentrations, which are then fed back into the system as constraints, and instigate the endogenous creation of carbon (including other GHG's) prices in order to dis-incentivise consumption of carbon-intensive processes – both models thus assume that as the cost of carbon-intensive processes increase, consumption demand is elastic and thus decreases.

REMIND has a macro-economic module at its core with a constant elasticity of substitution (CES) production function based on the Ramsey paradigm of a social planner's optimisation (maximisation of utility) problem in an intertemporal framework. The objective function of REMIND is the maximization of regional utility (based on per capita consumption) and can be generated either under the cooperative or non-cooperative solution discussed previously (Luderer et. al, 2015, pp. 10-11).

Representation of natural gas

Natural gas in REMIND is generally highly aggregated, with a singular supply cost curve and estimate of available resources at a regional level. Underpinning the supply cost curve for each exhaustible resource in REMIND is a cost-depletion curve, i.e. as resources are depleted and readily accessible reserves are extracted, the remaining resource base is increasingly expensive. Individual country reserve and resource data from the BGR are aggregated into the REMIND regions for both conventional and unconventional gas, and the same cost range applied to all regions (albeit with different weighting as far as how much of a resource base can be extracted across the cost range (Bauer et. al, 2017).

Once the natural gas has been extracted, it is either used for domestic consumption (either as a primary energy input or as an input into the secondary transformation (electricity) sector) or can be traded between the regions. Once again, this trading process does not explicitly separate whether the gas is traded via pipeline or LNG, but instead assigns a trade cost depending on the regions in question.

Strengths

Undoubtedly the main strength of the Regional Model for Investment and Development (REMIND) is the 'hard' interlinkage of the macro-economic module, which includes capital and labour factors of production, to the energy systems model. The inclusion of 'final energy' as a factor of production thus links all the costs of the energy system, including dynamic costs associated with technological learning and the feedback costs from a soft-linkage to the climate module which transforms emissions into temperature and emission concentration constraints, into the macro-economic growth module. REMIND uses this linkage to generate costs of mitigation, which are then deducted from GDP to reflect the neo-classical paradigm that as costs rise, consumption falls (Luderer et. al, 2015, p.8). In this sense, the externalities associated with the energy system (emissions) are fed back in to the macro-module as costs to generate a final overall optimisation which maximises welfare in one of the two scenarios described above (weighted-cooperative or Nash non-cooperative), and provides a robust assessment of societally optimal mitigation pathways for each region, taking into account intergenerational ability to pay for these climate change-response measures. Additionally, the hard linkage of the energy module to the macro-economic module, allow an improved representation of investment decisions under changing economic conditions, particularly when climate mitigation commitments are taken into account.

Given the hugely complex negotiations surrounding a global response to climate change, and in particular the issues of historical contribution to GHG concentrations and the Nationally Determined Contribution (NDC's) frameworks agreed on at COP-21 in Paris, a model which can assign differentiated mitigation costs based on a summed, weighted regional maximisation of utility in addition to a unilateral Nash approach (leader-follower), has a significant role in reflecting not just the willingness-to-pay for climate mitigation measures, but the ability-to-pay by region in a socially optimal framework (Luderer et. al, 2015, p. 35).

Additionally, the use of final energy as a factor of production can be interpreted as a proxy for natural capital endowments, given that for resource-rich countries, the costs of the energy systems module to satisfy output demand, and the subsequent transformation of energy into 'useful' final energy, will be far lower, and thus these countries will have relatively more (or at least at a lower cost) final energy as a factor of production. Endogenous technological learning in the energy system, characterised by one-factor learning curves, allow cost reductions which are hard-linked back into the macro-economic module, thus fully integrating the impact of learning-by-doing (experience curves) on the macro-economy as a whole (Luderer et. al, 2015, pp. 4-5).

Limitations

Some limitations due to the computational complexity of Regional Model for Investments and Development (REMIND) are identified by the authors themselves, including the "spatial resolution of the model", representation of renewable intermittency, and a lack of technological detail for the energy system module such as the choice between different technologies based on efficiency improvements (Luderer et. al, 2015, pp. 35-6).

The development of extraction-cost curves for exhaustible resources in REMIND's energy system module aggregates regional resources into singular categories (oil, coal and gas), with representative extraction costs and decline parameters for each region. For all three fossil fuels, the range of resource categories (e.g. for gas, conventional onshore and offshore, shale, tight, CBM, etc.) is aggregated into a single production curve. On the one hand this allows a more simplistic and readily available assessment of fossil resources. However, the method systematically oversimplifies extraction economics, as once decline parameters are assigned to these singular categories, much of the heterogeneous geological and economic characteristics of natural gas resources are overlooked. Additionally, it would appear from the literature, that whilst the decline rate and cost parameters change depending on the phase of extraction, these parameters are prescribed homogenously across a singular category for natural gas, regardless of resource categorisation or the potential impact of technological progress (Luderer et. al, 2015, pp. 16-7). This would appear a fundamental simplification of production dynamics, especially for unconventional natural gas, where decline rates vary significantly not just between (shale) plays but within them (Browning et. al, 2013a,b; Ikonnikova et. al, 2015a; Ikonnikova et. al, 2015b).

A significant limitation of modelling natural gas resources and markets in REMIND is the regional representation in the model (Luderer, 2015, pp. 7-8,35-6). Firstly, the 'Rest of the World' region, incorporates countries as diverse and heterogeneous (in terms of their economic structure and particularly gas market dynamics) as Norway (large exporter of pipeline and LNG), Turkey (large importer), Canada (self-sufficient – apart from some pipeline imports from the United States for supply and demand centre geographical proximity) and Australia (increasingly large LNG importer). This is a crucial limitation: whilst the inclusion of Russia as a single entity is an improvement on TIAM-UCL for gas and energy market analysis,[18] the 'MEA' region in REMIND includes North Africa and Central Asia which, given both the potential levels of natural gas trade within this region and market structure heterogeneity, results in the model failing to capture some key intra-regional interactions. This limitation is identified by Luderer et. al (2015, p. 35) for the lack of explicit infrastructure detail including pipelines.

International Institute for Applied Systems Analysis (IIASA) - Model for Energy Supply Strategy Alternatives and their General Environmental Impacts (MESSAGE)

General Structure and Modelling Method

As with TIAM-UCL, the International Institute for Applied Systems Analysis (IIASA) Model for Energy Supply Strategy Alternatives and their General Environmental Impacts (MESSAGE) includes a Reference Energy System (RES) that maps the flow of energy and environmental commodities across the energy system, through each technological process, from upstream resources, through to secondary processing, transportation and distribution, to the end-goal of satisfying end-use energy service demand (IIASA, 2006).

MESSAGE uses its MAGICC climate module to transform emissions from the energy sector into atmospheric concentrations of GHG particulates and ultimately the radiative forcing effect these concentrations have, which are then translated into temperature increases – this allows the model to generate scenarios based on limiting temperature increases and the endogenous creation of taxes on emissions (i.e. taxing externalities) which are expected to decrease consumption demand for emission-intensive products via endogenous (price) elasticity of demand functions. As with TIAM and REMIND, the model therefore does not monetise climate damages.

MESSAGE is solved using two programming techniques: the energy systems module is solved using mixed integer linear programming (MILP) (i.e. some decision variables are constrained to integer values so, for example, a binary decision (YES-NO) such as building a power plant, can be modelled), whilst the macroeconomic module is modelled using non-linear programming (NLP) (IIASA, 2006; Messner and Schrattenholzer, 2000).

As with TIAM, the overall principal function of MESSAGE is to provide "estimates of technology-specific multi-sector response strategies for specific climate stabilisation targets", and optimising costs across the energy system within this process (i.e. choosing the lowest cost technologies) (Howells, 2011).

[18] The break-out of the FSU region in TIAM-UCL into separate countries (or at least for Russia to be treated as a single entity) is currently under discussion and proposed for future development of the model (Energy Systems Internal Meeting, UCL, 2016).

Representation of natural gas

The overarching research focus of MESSAGE is generating a robust integrated assessment modelling paradigm. In light of this, the representation of natural gas reserves, resources, and costs is relatively simplistic and static. For example, discrete single-point figures are used to assign regional natural gas reserves and resources taken from the literature review conducted by Rogner et. al (2012), and from Rogner's (1997) original global hydrocarbon occurrence assessment. These reserve and resource volumes were then applied to a cost range, although it is unclear exactly how the cost-depletion curve is generated (i.e. how the resource is split into each cost strata).

Natural gas can be traded amongst the regions in MESSAGE: the energy model determines which regions are net exporters/importers, depending on the exogenous prescription of demand, with the costs of these flows then fed back into the macro-economic module to determine changes in demands based on changing import costs, as well as the overall impact on consumption, etc. The marginal changes to overall energy system costs, from any price changes for importers and exporters, is then reflected in the regional optimisation (maximisation of utility) in the macro module (IIASA, 2016).

Strengths

The Mixed Integer Linear Programming (MILP) used in the energy systems module is hugely beneficial as it can more accurately reflect decisions to start-up or shut-down a plant, plant expansion, and deciding on which technology (i.e. plant type) to build, which are all discrete (YES-NO) decisions and can be more effectively modelled with MILP than LP, as with TIAM-UCL (Messner and Strubegger, 1995a, p. 3; Howells, 2011). This increases the computational complexity of the model, however, it also allows for a more realistic representation of some decision variables, in cases where the spatial resolution of the model is highly detailed. MILP solutions have been used to represent future hydrogen supply networks, where key parameters (e.g. number of hydrogen cars, number of hydrogen re-filling stations) take integer values (ε $\mathbb{Z}$) (Samsatli and Samsatli, 2015; Agnolucci et. al, 2013), as well as in spatial-optimisation models for the allocation of wind turbines (Zeyringer et. al, 2018; Fischetti et. al, 2015).

Similarly, the use of NLP for the macro-economic module allows non-linear relationships between variables. For example, the relationship between GDP and energy consumption, with decoupling effects, is highly non-linear, and can reflect a concave curve in some cases, with consumption increasing to a certain level of economic development, then decreasing as technological efficiency and structural transitions to a service economy take hold. As with REMIND, this allows for systematic analysis of the interactions between the macro-economy and the energy-system, with the relationship interdependent and reflecting energy and economic system behaviour more accurately (i.e. impacts in one sector affect the other, and vice versa).

Given that the technological processes are modelled from a bottom-up perspective, MESSAGE as with TIAM-UCL, is able to generate a hugely detailed assessment of the costs and efficiencies of different mitigation technologies, as well as track the emissions profiles of different technologies which are then fed into the climate module to generate particulate concentrations and radiative forcing (i.e. temperature increases).

Additionally, recent work by Fricko et. al (2017) has directly linked the availability and costs of fossil resources to different SSP pathways. This means MESSAGE has essentially soft-linked different socio-economic narratives to various extraction regimes for coal, oil and natural gas, including both the technical availability of resources, and the cost of extraction. This allows MESSAGE to model different gas resource-cost relationships based on socio-economic developments, including society's ability/desire to mitigate/adapt, and the techno-economic conditions generated by, and feeding back into, the level of mitigation and adaptation.

Limitations

The static input of natural gas reserve and resource data in MESSAGE, taken from literature reviews by Rogner (1997) and Rogner et. al (2012), does little to limit the huge range of uncertainty surrounding recoverable volumes of natural gas. In particular, the aggregation of all unconventional natural gas highly simplifies huge regional variations, particularly in terms of supply costs, with accumulated production experience over time crucial. Additionally, the supply cost curve generated for natural gas relies to a large extent on highly aggregated studies including Rogner (1997) and other pre-2010 studies (Rogner et. al, 2012), meaning techno-economic characteristics of individual categories of both conventional and unconventional gas are not fully taken into account. In short, both conventional and unconventional gas economics should ideally be done at a highly disaggregated field-/play-level. This aggregation also means that MESSAGE cannot track upstream individual process emissions in the same way that TIAM-UCL can, which can be crucial for potential future sensitivities of increased unconventional gas use in the energy system,

As with REMIND, the ability of MESSAGE to coherently model natural gas techno-economic and market dynamics, is limited by its regional aggregation which undermines its effectiveness to be used in conjunction with a bottom-up gas field model. For example, the aggregation of Australia and Japan in the Pacific OECD region combines the former which by 2020 is projected to have the largest LNG liquefaction capacity with the latter who are historically the largest importer of LNG (Japan) (IGU, 2015, pp. 76-82) – thus, given these nations respective positions in the LNG market in particular, modelling them as separate entities would allow a far more accurate representation of the constraints (including cost parameters) facing both (IIASA, 2016).

International Energy Agency (IEA) – World Energy Model (WEM)

General Structure and Modelling Method

The International Energy Agency's World Energy Model (IEA WEM) is an energy system simulation model, providing projections of energy supply and demand dynamics for the World Energy Outlook (WEO) under various pathways driven by future energy policy decisions and developments. The WEM includes three main modules (IEA, 2017a):

- Final energy demand (sectoral breakdown into residential, services, agriculture, industry, transport, and non-energy);
- Energy transformation (electricity and heat generation, refining and processing, etc.);
- Primary energy supply (generally upstream).

The IEA consider three scenarios based on varying levels of energy policy intervention on behalf of governments to mitigate the impacts of climate change, as well as meeting wider socio-economic targets:

- New Policies Scenario; includes the NDC's
- Current Policies Scenario; only existing policies that have been formally enacted or adopted
- Sustainable Development Scenario; combines three of the UN SDG's (universal access to electricity and clean cooking fuels; peak emissions as soon as possible, followed by rapid decline, with the overall aim of minimising global temperature increases to 2^oC or below, by 100; significant increase in global air quality, especially in urban areas).

As a simulation model, the WEM iterates repeatedly until energy supply equilibrates with sectoral end-use energy demand (i.e. all energy service demands can be met by energy supply within the system). In the case of fossil fuels, this means the simulation iterates until a price is reached which generates positive returns on any investments, whilst simultaneously ensuring that demand is altered to reflect rising prices (IEA, 2017a, p. 13). As with other models discussed in this section (POLES, TIAM-UCL), the demand in the WEM is exogenously driven by socio-economic drivers including GDP, population growth, urbanisation rates, etc.

Representation of natural gas

Whilst the modelling method for natural gas has the same overarching aim of the oil supply module, in representing the investment behaviour of upstream companies in field development[19] (IEA, 2017a), the natural gas module has some key differences:

- Natural gas is modelled as a predominantly regionalised market.
- Exogenous trade constraints include:
  - Existing or planned pipelines
  - LNG terminal capacities (regasification plants, liquefaction plants, tankers)
  - Long-term contracts (i.e. take-or-pay contracts under oil price indexation) which leads to price rigidities

For each region, exogenous, bottom-up, field-level (fields disaggregated into super-giant, giant, onshore, offshore, deep-water) estimates of remaining technically recoverable resources (TRR) are adopted from existing literature (predominantly the USGS).

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[19] The WEM distinguishes between short-term and long-term investments in the upstream sector:

Short term = investment plans and prospects over five-year period in response to current prices (production capacity, capacity additions), based on actual company-level data.

Long term = generated in supply-side module; generates link between new capacity additions, discounted cash flows, and the investment required (new capacity costs generated from geological parameters of field investments, technological learning, inflationary pressures based on exogenous oil prices under different scenarios)

In order to determine import-export requirements for each region, aggregated regional demand is subtracted from indigenous production, and thus:

- If the region has surplus supply, it becomes a net exporter - exports depend on the level of demand for that gas and supply costs (cost of production and transportation to demand market)
- If the region has supply shortage, it becomes a net importer – contracts (long-term) are adhered to first in the model, due to their binding nature, after which exporting regions can sell gas on a spot-basis (where the price generated depends on marginal cost of production and transportation costs)

In order to ensure supply meets demand across both exporting and importing regions within the trade matrix, fossil fuel prices are iteratively increased in the case where supply does not meet demand, thus more projects become economically incentivised with inflation (IEA, 2017a); prices are thus both an input (starting the market clearing simulation algorithm) and an output (market clearing prices for investment) in the IEA WEM.

Strengths

A key strength of the IEA World Energy Model method is the in-depth replication of investment decisions. The WEM applies dynamic decline rate parameters (which vary depending on the resource category, e.g. unconventional formation decline rates are much greater than conventional) on a regional basis for the projection time-period, in order to generate production profiles of each individual field/accumulation. The cost of extraction (supply) increases with the dynamic change in depletion rates for a number of reasons:

- Scarcity rent increases (i.e. inter-temporal opportunity costs)
- As reservoir/field depletion becomes greater, enhanced recovery techniques may become necessary
- A Golombek type production function becomes applicable as each well reaches capacity; i.e. economies of scale reach a saturation point

Additionally, the use of prices as an input in the WEM, allows the simulation model to generate a guideline price for natural gas based on different supply- and demand-side scenarios. For example, by iteratively increasing/decreasing the price of natural gas, a reference price can be generated to reflect different levels of production, changing demand based on government policies (e.g. incentives for energy efficiency, increased taxation on fossil fuels, changing fiscal regimes, carbon taxes, etc.), and the price required to incentivise investments in more geologically and economically complex gas projects.

Recent improvements in the WEM have also included delineating US shale plays to include a far more robust representation of heterogeneous supply-cost dynamics both between different plays, and within individual plays (IEA, 2017a, p. 9). This delineation follows the BEG method discussed in Part I of Section 2 (Resource Assessment Modelling), by using individual well level production and performance.

Limitations

As with the other wider energy system models discussed in this section, the static assumption of resources and reserves in the WEM limits its ability to run sensitivities on varying levels of resources available at different cost strata. Both conventional and particularly unconventional gas have large uncertainties, both in terms of their availability and cost. The WEM, as with the other models reviewed above, would significantly benefit from a more robust assessment of these resource and cost uncertainties, and the impact of these on both natural gas supply and demand dynamics.

As with TIAM-UCL, the WEM is limited by its inability to incorporate feedback loops between developments in the energy system and the wider economy. In short, the lack of a hard-linked macro-economic module – as with REMIND and MESSAGE – means there is little feedback between huge changes in the energy system and the wider economy, with economic restructuring a huge consideration, particularly under more stringent climate mitigation scenarios.

Whilst the WEM considers fossil-fuel consumption subsidies using a relatively simplistic price-gap approach (i.e. the difference between the consumption price and the theoretical price which should exist in the perfectly competitive market given netback costs etc.), not all interventions are taken into account including production subsidies (IEA, 2017a; IEA, 2016). Some of these interventions will play an increasingly important role as fields become depleted and extraction methods become increasingly costly and technologically intensive, especially in increasingly hazardous and hostile regions. The consumption price-gap approach, whilst being simplistic for modelling, also depends on the difference between the price paid by consumers and a reference price based on the assumption of perfect competition, which is unrepresentative of some hydrocarbon markets given barriers to entry and lock-ins – technological, economic and commercial – that exist.

PBL Netherlands Environmental Assessment Agency (PBL) - Integrated Model to Assess the Global Environment (IMAGE)

General Structure and Modelling Method

The Integrated Model to Assess the Global Environment (IMAGE) is a multi-module, soft-linked 'human' and 'natural' systems model. The individual modules are heavily interdependent; "human activities on the Earth system, and by the impacts of environmental change in the Earth system on the Human system" (van Vuuren and Stehfest, 2014). As with POLES and TIAM-UCL, exogenous socio-economic drivers determine levels of energy demand, which are satisfied in a separate energy supply and demand module, TIMER (Van Vuuren et. al, 2008). In the latest version of IMAGE, the human system modules are split into 26 regions.

IMAGE is a simulation model and runs with myopic uncertainty (i.e. simulations are run in each time-slice without being able to see future demands, costs, etc.). The model includes endogenous technological learning in the form of a 'learning-by-doing' function; in short, as cumulative production (experience) increases, costs fall (van Vuuren et. al, 2014a). The overall structure of the energy supply and demand modules is such that energy demand is always met, with simulations ensuring prices are sufficient to bring online enough energy supply. In the energy supply module, two counteracting forces work against each other: resource depletion which makes primary energy costs more expensive, and the previously mentioned cost reductions from cumulative production via an endogenous learning-by-doing function.

Representation of natural gas

Natural gas reserves and resources are represented relatively simply, with disaggregation only into two broad categories: conventional and unconventional. Within the supply module, production costs are based on the assumption that the cheapest resources are exploited first, and then as these are depleted, more expensive assets are developed. From the model documentation, IMAGE appears to rely on Rogner's (1997) global hydrocarbon resource and cost assessments, as well as a subsequent study in 2006 (PBL, 2016).

As mentioned in the limitations section, there is also no explicit modelling of natural gas trade infrastructure.

Strengths

In comparison to other Integrated Assessment Models's (IAM's) discussed previously, the Earth systems module of IMAGE can incorporate even more impacts of energy system developments, including sea level rises, water scarcity, changes in precipitation, air quality, and "terrestrial and aquatic biodiversity" (Kram et. al, 2014). Whilst the energy module is disaggregated into 26 regions, "land-use, land cover, and associated biophysical processes" is covered in even more spatial detail, with the globe delineated into individual 10x10km grids.

Thus, IMAGE has a significant advantage over other energy-economic-environment models discussed in this section, in terms of a hugely robust assessment of the impacts of 'human systems' including: climate impacts, agricultural impacts, water stress, terrestrial and aquatic biodiversity, flood risks, land degradation, ecosystem services, and human development. This ability to model not only emissions but also the overall impact of emissions *concentrations* on the overall biosphere, was one of the reasons IMAGE was used to develop the representative concentration pathway 2.6 (generally consistent with meeting 2^{o}C or less). Additionally, van Vuuren et. al (2008) used IMAGE to generate probabilistic spreads of greenhouse gas emissions under various socio-economic and policy based storylines. The study utilised Monte Carlo analysis to determine, for example, a range of fossil fuel resources which could be consumed under the different narratives, as well as the implications for supply cost curves which the resource availability uncertainty yielded.

Limitations

In comparison to other IAM's (MESSAGE, TIAM-UCL) which are structured around a reference energy system (RES), IMAGE has far less detailed sectoral detail for the application of technologies which satisfy energy service demands. For example, whilst the industrial sector is split into heavy industry (cement and steel production) and other light industry (i.e. three sub-sectors), TIAM-UCL has 6 separate energy service demands for industry, as well as 14 energy service demands covering the services/commercial sector, as opposed to singular aggregation in IMAGE (van Vuuren et. al, 2014b). In particular, this has significant implications where explicit technology efficiencies are missing, and the concurrent impact this has on energy service demands (van Vuuren et. al, 2014b, p. 85).

As with MESSAGE and REMIND, natural gas reserves and resources are highly aggregated in IMAGE; gas resources are split into conventional and unconventional, without any further separation. Additionally, the use of Rogner's 1997 hydrocarbon assessment yields the same limitations, both of resource assessments and costs, as discussed in Part I (pp. 21-3).

Whilst there is a regional trade element to the energy system module in IMAGE, it is "generic" in the sense that actual infrastructural constraints are not taken into account, and instead a cost mark-up is implemented to "reflect geographical, political and other constraints in the interregional fuel trade" (van Vuuren et. al, 2014a, p. 102). This limitation of not representing the crucial role of capacity also extends to supply costs; both production capacity and trade infrastructure capacities (or lack of them) are now key drivers of natural gas commodity prices, which is overlooked in IMAGE (van Vuuren et. al, 2014a). For example, field supply costs for some major projects currently under development have to include infrastructural investments, which are required to transport the gas, either to domestic or international markets. Thus, the actual cost of natural gas extraction may not be prohibitive, but instead the isolated nature of the asset and/or a lack of domestic demand.

Part 3 – Standalone Gas Models: modelling gas markets including the interaction between upstream, midstream and downstream elements

Part Three assesses more economic-focused natural gas market models. Some of the models have more of a focus on behavioural interactions between economic agents than the wider energy-economic-environment models discussed in Part 2. Due to the fact these models specifically focus on some aspect of natural gas markets, more attention is paid to the modelling inputs and outputs (i.e. the research aim of each).

Energy Information Agency (EIA) – Natural Gas Transmission and Distribution Module (NGTDM)

General Structure and Modelling Method

The Natural Gas Transmission and Distribution Model (NGTDM) is the intermediary between the natural gas resource supply and demand modules in the National Energy Modelling System (NEMS) (EIA, 2014, p. 14), developed by the Energy Information Agency (EIA). As such, it can be used to model future capacity requirements and cost flows for the whole of the United States' natural gas infrastructural transmission and distribution system, from producers to end-use consumers, in order to ensure supply and demand equilibrate.

The NGTDM network consists of three main submodules (EIA, 2014):

1. Interstate Transmission Submodule (ITS) – central module constructed as a system of nodes and arcs – used to derive network flows and prices (based on seasonal demand and supply equilibrium)
2. Pipeline Tariff Submodule (PTS) – determines revenue requirements associated with interregional/interstate pipeline transportation and storage services, using a cost-based, volume dependent tariff curves etc.
3. Distributor Tariff Submodule (DTS) – sets mark-ups for inter-/intra-state transmission and distribution services using econometric relationships driven in large part by exogenous independent variables (such as income-consumption elasticity).

The heuristic formulation within the ITS is of significant importance as it reflects the critical importance of information and foresight in natural gas modelling. The network representation of the ITS core module within the NGTDM is shown below in Figure 3.

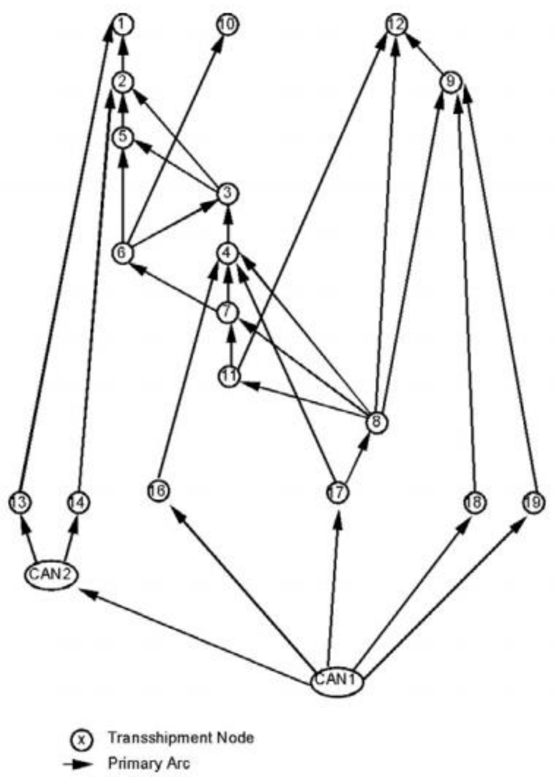

Figure 3: Network representation of the nodes and connecting arcs in the NGTDM (Busch, 2014, p. 5)

Strengths

Within the module, perfect information and foresight are rejected[20], reflecting real-world conditions of imperfect and often asymmetric information, as well as changing market conditions (Busch, 2014, pp. 4-5). The network algorithm minimises costs of flows between each agent (producers, consumers, transportation nodes, distribution hubs, etc.) based on limited network information and imperfect signalling, making the model more adept at replicating an 'best-guess' scenario, where the optimal pathway from production to end-use consumers is not known. The heuristic solution aims to utilise actual recorded behaviour of agents within the market and saves on programming time, as without a heuristic solution, a more time-consuming entire network solution, such as Dijkstra's algorithm, would have to be employed. In short, a market clearing price which satisfies demand across the network is found, without that price necessarily having to be a network minimum, whilst the heuristic algorithm allows 'learning' between each node.

An extremely simplified example of Dijkstra's algorithm showing the cost associated with getting a unit of natural gas from the producer to the consumer is presented below in Figure 4:

[20] There is no foresight for future prices and costs, however capacity is assumed to be relatively available in each year if required, therefore some degree of foresight is inevitably assumed.

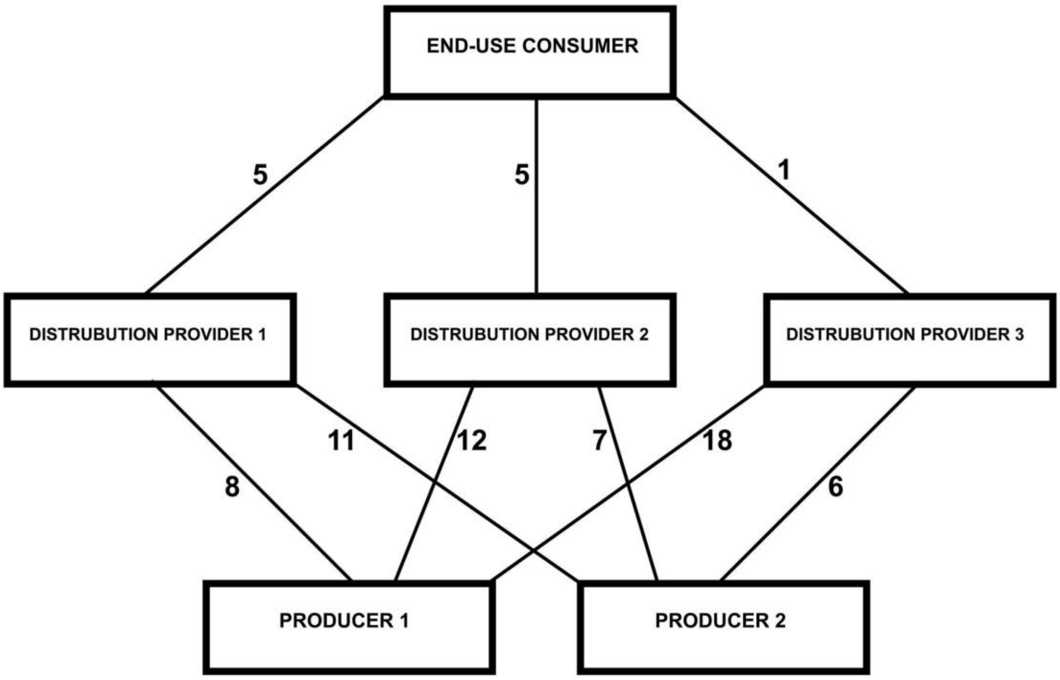

Figure 4: Author's representation of a simplified natural gas network using Dijkstra's algorithm requiring coverage of the entire network to find the optimal solution

If perfect information and foresight is available, Dijkstra's algorithm yields that the least cost pathway (given the numbers next to the arcs represent the costs related to getting natural gas from the well-head to the consumer) is:

Producer 2 – Distribution Provider 3 – End-Use Consumer = 7

However, in the often real-life situation where the exact costs (the numbers next to the arcs in the Figure above) are withheld due to imperfect and asymmetric information, the optimal pathway will not always be chosen. Thus a heuristic algorithm which does not assume perfect foresight is extremely helpful, if computationally difficult (especially given the scale of natural gas market interactions). This is because the algorithm 'learns' or 'remembers' which pathways are the best alternative, when the optimal solution is not immediately available, in a far more efficient time than Dijkstra's algorithm shown above, which would require coverage of the entire network to yield an optimal outcome. In short, a heuristic algorithm can find optimal (least cost) solutions for sub-stages of the whole network, without having to solve optimally for the entire network, thus reflecting the imperfect information which often characterises energy markets, particularly inter-temporally. In this sense, the solution of the NGTDM is myopic, with the optimal solution of the sub-sets not necessarily the overall optimal solution for the entire network – this gives the NGTDM a significant advantage over perfect foresight models.

Limitations

The NGTDM provides a systematic assessment of transmission and distribution networks in the United States and North America more generally, and feeds into the wider NEMS model. However, this requires a hugely data intensive process, which makes replicating the NGTDM in countries where gas markets are either less well developed or far more rigid (in terms of the level of market liberalisation in the upstream, midstream, and downstream) highly unlikely.

The heuristic algorithm employed in the Interstate Transmission Submodule (ITS) submodule is computationally very complicated, and can only be effectively applied in a network algorithm on the scale of the NGTDM, where huge amounts of recorded data can provide a 'best case' scenario based on actual agent behaviour under different scenarios, and where the model algorithm can learn from itself in each iteration by ranking each model run.

Whilst the geological information of the NGTDM is significant and extensive, the use of econometric extrapolations from historical data for reserve additions and the use of these trends into the future, relies on the assumption that future reserve additions will follow those of the past (EIA, 2013d, pp. 33-4). Given the increasing prevalence of stranded[21] and geologically complex deposits having to be developed as established fields naturally decline, using historical reserve addition rates could significantly overestimate (or underestimate) actual additions to the reserve base. In light of this, the econometric extrapolation of finding rates for reserve additions was abandoned in favour of a decline rate, however this decline rate is set at a basin level, and thus is a significant simplification of the geological uncertainty and heterogeneity within natural gas formations (EIA, 2014, pp. 32-3).

Energy Information Administration (EIA) – International Natural Gas Model (INGM)

General Structure and Modelling Method

The Energy Information Administration's (EIA) International Natural Gas Model (INGM) is an optimisation (maximization of total economic surplus), market equilibrium model, representing upstream production, demand (consumption), and trade dynamics. The INGM differs from other global natural gas models in the level of its regional disaggregation – there are 61 regional nodes, thus reflecting both the distinct regional development of natural gas markets, and the large heterogeneity within regions that are frequently aggregated together in models, even if they contain vastly different supply-demand dynamics.

The key inputs and outputs of the INGM are listed below (EIA, 2013c, pp. 3-4).

Inputs

- Geological parameters for resource estimation – regional assessment units are used to generate resource availability data (taken from USGS)

[21] Stranded assets are geologically proved as recoverable but the fields are small and isolated, meaning cost reductions are required before those geological reserves can become monetised (Attanasi and Freeman, 2013).

- Extraction costs (combined with geological parameters to form resource-supply extraction cost curves for individual formations)
- Exogenous demand data (taken from NEMS) for individual demand sectors (residential, commercial, industrial, power generation, transportation)
- Transportation, distribution, energy conversion – includes capacities related to pipelines, LNG infrastructure, gas-to-liquid (GTL) energy requirements, and investment costs.
- LNG trade routes – length of journey, time at port (proxy for LNG terminal efficiency – opportunity costs of inefficient terminal activity)

Outputs

- Production for each regional node and disaggregated into different resource categories:
    - Conventional onshore
    - Conventional offshore
    - Tight gas
    - Shale gas
    - Coal bed methane
- Natural gas demand regionally for each node, by end-use sector, and with seasonal variations.
- Pipeline, LNG, gas processing (including GTL's) capacities
- Utilisation rates for pipelines, LNG, gas processing
- Annual and seasonal regional wholesale natural gas prices

A fundamental assumption within the modelling solution under linear programming is the convergence of prices to that which maximises economic surplus in each regional node – the price equals the marginal cost of production (EIA, 2013c, p. 6). The optimisation of the objective function variable is constrained to reflect a range of limits on capacity and costs owing to (EIA, 2013c):

- Seasonal constraints - e.g. capacity on gas storage in lower demand seasons
- Regional constraints - capacity on import capabilities constrained due to geographical distance, geographical/geophysical barriers to transportation, resource availability constraints
- Financial constraints - investment cost constraints, especially relating to LNG
- Time constraints – build rates for capacity additions, planning and approval dynamics within a region (similar to an 'ease of doing business' index)
- Technological constraints - scalar used in the linear programming formulation to reflect technological improvements (and thus the limits on them) (EIA, 2013c, p. 141).

Strengths

A key strength of the INGM is the bottom-up assessment of natural gas supply reserves, resources, and costs. These include techno-economic and geological parameters[22], as well as splitting cost data into various sub-categories: drilling CAPEX, variable operating costs, required infrastructure capacity CAPEX and OPEX. In particular, when modelling the development of new resources, this allows the model flexibility in determining the time period for investment cost amortisation, as well as project specific costs.

Another strength of the INGM is the representation of demand. The INGM takes demand across seven demand sectors from the World Energy Projection Plus (WEPS +) model, and includes sectoral level demand elasticities. This inclusion means the reaction of consumption demand to price changes is at a sectoral level, reflecting varying elasticities depending on the availability of substitutes, etc.

Another strength of the INGM is that within the simulation process, two possibilities are available:

1. Rolling optimisation – capacity utilisation decisions which maximise economic surplus are held for a lumped time-period, and restarted (allowed to take new optimal values) after (usually) five years, thus reflecting the fact that capacity decisions generally impact for a relatively long time-period (decision in time period *t* will generally affect the system for much longer than a single year to time period *t+1*). This process also reflects reality where future capacities and costs are unknown.
2. Perfect foresight – optimisation runs annually and past the end of the time horizon, to reflect the fact that the model builds the exact amount of capacity required (because the model can see future costs and capacity requirements), at least cost, with economic welfare maximised.

Both of these simulation processes thus generate different key outputs – production, prices, capacity utilisation, end-use demand – and provide flexibility to the modeller to fit the linear programming process to the scenarios developed.

Limitations

A key limitation of the INGM in reflecting current and future gas markets is the fact that contractual flows and contractual price formation mechanisms are not taken into account (EIA, 2013c, p. 6).

Another limitation of the INGM lies in the maximisation of societal welfare (consumer and producer surplus), under the assumption that regional prices will equal the regionalised marginal cost of production (i.e. a perfect competition price formulation) (EIA, 2013c, p. 6). This assumption would appear to be an over-simplification, given the complexity of price formation mechanisms (including both international trade mechanisms and domestic

[22] These parameters include: field size, reservoir depths, water depths

regulated pricing which heavily impacts demand), differing fiscal regimes, and the availability, cost and access to transportation infrastructure.

Additionally, the costs of developing unconventional natural gas resources outside of the United States/Canada have been assigned North American analogues for much of the field-level economics (e.g. number of wells per field and production-development costs), thus potentially vastly underestimating production costs (EIA, 2013c, pp. 23-4). Whilst the INGM uses the USGS global assessment of undiscovered resources which provides a substantial assessment from bottom-up geological parameters, the use of US field economics significantly undermines the global appraisal of resource-extraction costs; the model could develop resources, which in reality are sub-economical, when techno-economic characteristics for that accumulation are assessed.

Institute of Energy Economics (EWI), Cologne - COLUMBUS Global Gas Market Model (GGMM)

General Structure and Modelling Method

The COLUMBUS GGMM focuses on production, transport, and storage in an optimisation network, allowing the model to reflect changing strategic behaviour of the represented agents, reflected through the use of Mixed Complementarity Programming (MCP), which whilst being computationally intensive and highly complex, allows for variations in the inequality constraints, and therefore a more accurate representation of strategic behaviour which is key to several facets of gas market dynamics (e.g. market power when the restrictive and generally unrealistic assumption of perfect competition is dropped) (Hecking and Panke, 2012).

The model can be presented as a network structure (Hecking and Panke, 2012, p. 2), where:

- Nodes/Vertices = demand sinks (consumption) and production sources (suppy)
- Arcs/edges = transportation routes (either pipeline or LNG)

The optimisation of the payoff function (either profit maximisation or cost minimisation) in COLUMBUS is applied to all the players in the model and is done under two key assumptions/scenarios within the model (Hecking and Panke, 2012, pp. 1-2):

1. Perfect competition – standard economic theory suggests that profit is maximised at zero, given that abnormal profits/losses cannot be made.
2. Strategic behaviour under a Golombek production function – endogenous behaviour, based on production function suggesting natural gas production, storage, and transportation costs increase rapidly as capacity is approached (Huppmann, 2012, pp. 2-4).

The players considered within the model are subject to constraints unique to that player, with the key characteristics of each shown below (Hecking and Panke, 2012, pp. 5-10):

- Exporter:
    - Can either be modelled as price-takers, or exercising market power.

    - Delivery to demand nodes is constrained by decision vector feasible region, which depends on the cost of delivery and physical transport constraints (LNG terminal/tanker and pipeline capacities).
- Producer:
    - Price takers in the market.
    - Maximum production capacity constraint
    - Resource constraints
    - Investment decision based on marginal value of expanding production capacity over an economic lifetime, being greater than or at least equal to investment costs
- Transmission System Operator (TSO):
    - Constrained by regulation
    - Allocates pipeline capacity to exporter, and can invest in additional pipeline capacity
    - Physically controls the flow of natural gas
    - Congestion rent determined by available capacity
- Liquefier:
    - Liquefaction plant capacity constraints which means places upper bounds on the amount *liquefiers* can receive from *exporters*, and an upper bound which *traders* can receive from *liquefiers*.
    - Sum of short-run variable liquefaction costs and congestion rent (determined by liquefaction capacity) equals long-run marginal costs (due to perfectly competitive assumption).
- Regasifier:
    - Natural gas received by regasifiers from LNG tankers, is transported to demand sinks by the pipeline TSO.
    - Congestion rent determined by regasification capacity constraint – only a finite amount of natural gas can be regasified based on capacity constraints
- LNG – no specific players involved
    - Assumption of a 'virtual' (representative) investor who decides on whether to invest in LNG transportation (new tanker capacity).
    - Investor behaviour adheres to perfect competition (investment goes ahead when marginal cost = marginal benefit).
    - Congestion rent determined by LNG tanker capacity constraint.
- Storage Operator:
    - As with TSO, one storage operator to each storage facility.
    - Assumed to behave with seasonal arbitrage (buying in low price season, and selling in high price season)
    - Can choose to invest in new storage capacity – endogenous increase in capacity based on storage operator decision
    - Optimisation based on storage capacity constraint, and dynamic injection and depletion functions.

COLUMBUS has a temporal horizon out to 2050, with user-defined time-slices; a maximum of 12 time-slices (i.e. monthly) can be employed for every year out to 2050.

Strengths

COLUMBUS, as with the WGM discussed subsequently, benefits from 'family' modelling development at the EWI in Cologne. In short, the scale and scope of modelling natural gas markets was extended, with several of the models aiding in the development of their successors. For example, the EWI's TIGER model is a pipeline-dispatch optimisation model, with an explicit focus on "identifying bottlenecks" in European natural gas supply (Lochner, 2011, pp. 2485-6). TIGER minimises the total cost of satisfying an exogenously constrained level of European gas demand using linear optimisation, with additional exogenous assumptions placed on existing and future pipeline and LNG receiving capacity (Hecking and Panke, 2012, p. 2; Lochner, 2011, p. 2486). As discussed subsequently, the EWI extended TIGER into the MAGELAN linear supply optimisation model, which allows for endogenous investment in new infrastructure, and then extended to include non-linear solutions in COLUMBUS.

COLUMBUS (as with the WGM discussed next) is highly effective at representing the interaction between different key players in natural gas markets, which the wider climate models, and the resource assessment models cannot do (i.e. they can capture behavioural aspects of players on both the supply and the demand side). COLUMBUS is also able to reflect seasonal variations in demand (due to its monthly time-slices), and the interaction between market agents including storage operators which is a key facet of inter-temporal natural gas demand. As mentioned previously, COLUMBUS is an extension of the MAGELAN optimisation model with the objective function to minimise supply costs to satisfy a relatively simplistic regional demand estimate, with endogenous investment in trade and production infrastructure. COLUMBUS thus provides a more market-orientated outlook to MAGELAN, by allowing strategic interactions in a far more disaggregated (monthly) temporal horizon, allowing the model to far more realistically capture natural gas storage economics in particular (Hecking and Panke, 2012, p. 2).

The advantage of using Mixed Complementarity Programming (MCP) formulations is that they can reflect strategic, 'non-competitive' behaviour, by optimising the objective function under decision variables exhibiting time-varied (i.e. non-linear) constraints, giving the model more flexibility to reflect real-world behaviour. For example, taking the equation below from Hecking and Panke (2012, p. 5) reflecting the primary solution to the optimisation (maximisation) of an exporters profits (Π_{el}), the endogenous decision vector yielded for traded volumes ($tr_{e,d,t}$) can be based on non-linear marginal costs/prices received by the exporter ($\beta_{d,t}$) and the costs the exporters incur to supply the natural gas ($\lambda_{e,n,t}$).

$$\max_{tr_{e,d,t}} \Pi_{el}\,(tr_{e,d,t}) = \sum_{t\in T} \sum_{d\in D} (\beta_{e,d,t} * tr_{e,d,t} - \lambda_{e,d,t} * tr_{e,d,t})$$

These formulations can thus take into account dynamics such as economies of scale which reduce costs, and imperfect pricing, where for example, strategic behaviour to withhold supply inflates prices in a non-linear fashion.

Limitations

As with other gas market models, such as the World Gas Model (Egging at. al, 2010) and the Rice World Gas Trade Model (Medlock, 2011), the representation of energy demand is limited by the scope of the modelling coverage. For example, these models generally cover gas price elasticity of demand, as well as cross-price elasticity of demand for fossil substitutes, including oil and coal, however long-term energy consumption demand, driven by dynamic efficiencies and costs of technologies across the energy system (e.g. reducing costs of renewable competitive technologies in the electricity generation sector), cannot be taken into account in these models. Thus, whilst there is a representation of energy intensity decoupling in the market models (i.e. decreasing energy consumption per unit of economic growth), the whole energy system representation of technology efficiency gains and cost reductions cannot be taken into account due to the limitations in the modelling scope. Additionally, the end-use demand sectors in COLUMBUS, WGM, and RWGTM are highly aggregated. Thus, whilst these models are highly effective at analysing gas market developments on an annual, and sub-annual basis, and in particular the interaction between various agents, they are limited in their ability to look into longer term wider energy system developments, such as the role of gas under various decarbonisation pathways.

The fact that the model is built on a perfect competition framework, to some extent limits the representation of market power, which is not limited to an agent's ability to set prices, but also includes dominant players utilising asymmetric information and market barriers to capture a greater share of the market. These are mitigated to some extent by the more realistic representation of inter-temporal preferences in the model, which in particular compensate for the lack of bottom-up geological foundations in the production (extraction sector), by reflecting the opportunity cost to the producer and other players in the network of extracting/consuming in the present and thus extracting/consuming less in the future, and vice versa.

The significant lack of geological detail, and in particular the lack bottom-up analysis of resources and reserves for different categories of natural gas and the respective dynamic extraction costs, severely undermines the Mixed Complementarity Programming (MCP) function formulation of the producer as an agent, and thus the rest of the supply chain, reflected by the fact that a representative producer is used for a single production region (Hecking and Panke, 2012, pp. 5-6). In short, the producer's dilemma of whether to expand production over an economic lifetime based on an expected rate of return is over-simplified in COLUMBUS. For example, there is little or no representation of heterogeneous extraction costs, with significant aggregation of the representation of resources, in addition to a complete lack of representation for government interventions and fiscal regimes, which can influence upstream investments and supply-side dynamics.

Additionally, the use of MCP programming, as mentioned previously, is highly complex and computationally difficult, and whilst it is highly useful for reflecting behavioural games between agents under different scenarios, it can be considered an unnecessary complication for models which do not require game theory analysis.

German Institute for Economic Research (DIW) – Word Gas Model (WGM)

General Structure and Modelling Method

The World Gas Model (WGM) developed by Egging et. al (2010) is relatively similar to COLUMBUS, in that it represents market agents/players using an MCP formulation, however it differs in its explicit representation of imperfect markets using Cournot-competitive market power (the control of supply to manipulate prices) through game theoretic interactions. These imperfect market conditions yielding market power were modelled by Gabriel et. al (2010), which utilised the WGM to forecast the potential impacts of cartelisation in the gas industry, similar to that of OPEC – in short, scenarios were constructed which modelled different geographical coverage of cartelisation (countries involved in strategic collusion to constrain output), and the impact of this on overall global trade (including non-cartel gas producers). The WGM models a relatively homogenous set of market players to COLUMBUS (Egging et. al, 2010, p. 4017):

- Producers
- Traders
- Pipeline and Storage Operators
- LNG Liquefiers and Regasifiers
- Marketers (i.e. purchase from wholesalers and sell on to consumers)

The key differential between the WGM and COLUMBUS is that the optimality conditions for strategic players in the WGM includes the exertion of market power by some agents (specifically traders and regasifiers), thus benefiting from not being constrained by the unrealistic assumption of perfect competition (Egging at. al, 2010, pp. 4016-7).

The WGM reflects some fundamental differences between regional supply and demand (consumption) dynamics, with a large range of regional disaggregation:

- 80 countries/regions are represented
- Network representation, with nodes as source-sinks, whilst arcs reflect flows between these source-sinks
- Highly heterogeneous regional natural gas market development is reflected by, for example, additional pipeline capacity constraints (Egging et. al, 2010, p. 4026).
- One limitation of this regional outlook is the simplified assumption of linear investment costs for additional storage and transport facilities between two nodes (does not include heterogeneous cost structures based on existing infrastructure and knowledge) (Egging et. al, p. 4024).

Within the mathematical foundations of the model, each player is assigned an objective function (optimisation condition which maximises profit/minimises costs) with respective variational constraints, whilst the market clearing conditions within the model, in combination with the MCP solutions, generate an overall market equilibrium from each stage of the gas market chain (Egging et. al, 2010, p. 4023).

The standard WGM is shown graphically below in Figure 5.

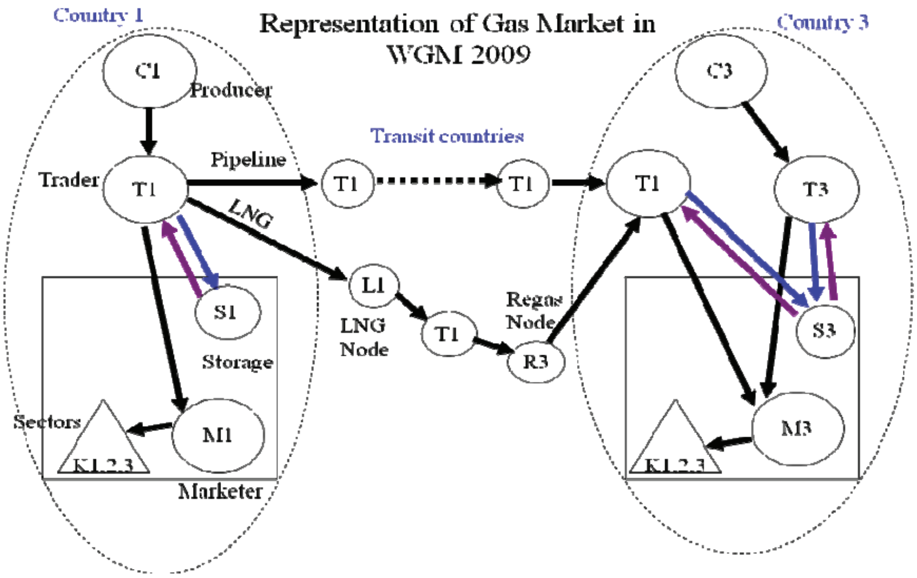

Figure 5: Representation of the interaction between different market players at different stages of the supply chain in the WGM (Gabriel et. al, 2010, p. 10)

Strengths

As with COLUMBUS, the WGM has benefited from 'family' modelling development at the DIW in Berlin, meaning successive models have been introduced and improved in scale and coverage. GASMOD, developed by Holz et. al (2008), is a non-linear optimisation model, with an objective function of minimising supply costs to European gas markets, under exogenous assumptions of pipeline, storage and LNG receiving (regasification) capacity. GASMOD functions under two distinct market structures which is key to the strength of the WGM in reflecting imperfect competition in global natural gas markets: perfect competition and imperfect Cournot competition (i.e. where major producers are able to manipulate natural gas prices by strategically controlling delivery volumes). Additionally, the original manifestation of GASMOD which was severely limited by exogenous assumptions on infrastructure capacity expansion investments, was subsequently extended to allow endogenous investment in natural gas supply capacity if required through GASMOD-dynamic (Holz, 2009). The key outputs of GASMOD – open competition in downstream markets has welfare-maximising effects even in the presence of oligopolistic, unilateral behaviour on the part of upstream suppliers, and the importance of diversified supply options for European gas markets – were crucial in extending this analysis globally in the WGM (Holz et. al, 2008).

The computational set-up of the WGM and COLUMBUS as mixed complementarity models analysing the (strategic) behaviour of players at all stages of the supply chain, allows a disaggregated representation of natural gas markets, which becomes vital when markets are open to competition at any stage of the value chain. For example, in some regions stranded export projects may involve one company at all stages of the natural gas supply chain (from upstream extraction through to further downstream liquefaction and export). However, in other regions there may be competition along the value chain meaning market players interacting, which requires the attribution of different cost functions depending on the activities of each player in each stream, and the spill-over of costs between each player. Two examples of this include Gazprom's LNG export project at Sakhalin (controlling both upstream extraction and further downstream liquefaction and processing) and the natural gas market in the US where firms have increasingly specialised in one area of the supply chain rather than vertically integrating (e.g. Cheniere: LNG liquefaction, Chesepeake: (shale) exploration and production). Additionally, and as with the COLUMBUS model, the impact of seasonality can be taken into account due to sub-annual time-slices, which is crucial for near-term analysis of supply-demand and pricing dynamics, and the interaction of players within gas markets in times of peak demand.

As mentioned previously, the WGM, with its inclusion of imperfect Cournot-competition (where imperfect prices are generated through the control of output) and strategic market behaviour, results in an extremely effective framework to model the potential for gas market collusion (setting production quotas to artificially inflate/deflate prices) by the largest producers, i.e. the creation of a gas OPEC (Gabriel et. al, 2010).

Limitations

The demand side limitations of the WGM, COLUMBUS and the Rice World Gas Trade Model (RWGTM, discussed subsequently) were discussed in detail in the limitations of the COLUMBUS model. The main weakness identified was the lack of modelling scope to include natural gas within the whole energy system, with dynamic cost and efficiency developments of all energy commodities and processes, which sees inter-fuel competition and substitution on a far larger scale than is reflected in the WGM, COLUMBUS and the RWGTM.

As discussed with the COLUMBUS model, the use of MCP programming is highly complex and computationally difficult. Whilst it is useful for reflecting behavioural games between agents under different scenarios, it is generally an unnecessary complication for models which do not require game theory analysis.

As with COLUMBUS, the WGM is a top-down model in terms of investment decisions on the supply side, and thus is unable to capture the bottom-up, geological considerations which are fundamental to investment in the development of natural gas resources. For both conventional and unconventional natural gas, costs of extraction and any infrastructure investments are based on a wide range of techno-economic, geological, geographical, and policy parameters. Furthermore, the WGM and COLUMBUS are not able to reflect the fundamentally important role of fiscal regimes or government intervention in energy markets.

Rice University (Baker Institute) – Rice World Gas Trade Model (RWGTM)

General Structure and Modelling Method

The Rice World Gas Trade Model (RWGTM) is a dynamic spatial general-equilibrium model, with two core aims:

1. Examine different future scenarios for natural gas in terms of its prevalence in the global energy mix
2. Examine the role of geopolitics in the development of natural gas markets (global vs. regional)

As a general equilibrium model, the overall market equilibrium need not be economically efficient, with taxation and strategic delaying of investment by monopolist suppliers in order to maximise profits allowed within the model (Hartley and Medlock, 2005, p. 11). The RWGTM requires that supply and demand in each spatial region is equilibrated in each time period, thus the opportunity for suppliers to take advantage of regional or temporal price arbitrage (selling to high price regions or delaying investment to artificially inflate prices through constraining supply) is not an option, as NPV must be optimised in each time period.

The RWGTM uses exogenous USGS assessments of regional resources as the basis for generating projections of resource supply-cost curves, which are econometrically derived from geological parameters based on North American data, and used as an analogue for generating supply-cost curve estimates in all regions (135 globally) (Medlock, 2011, p. 9). In this respect, the RWGTM is vulnerable to the same methodological limitation as Rogner (1997) – using a North American analogue across regions is a significant simplification and undermines the geological heterogeneity and vastly varying production history, not just between shale plays, but within them. However, and particularly for unconventional natural gas, the fact that the most robust way to determine potential productivity of a natural gas formation is via development of that resource, using a North American analogue (most notably for shale gas) can be considered best-practise given virtually no development outside the US and Canada.

The resource extraction module of the RWGTM is built on the foundation of Hotelling-rule optimisation:

- Economic scarcity rent (and therefore prices) should grow at the rate of interest – in perfectly competitive markets, this implies that:

  $P_M – MC_M = r_t$

  where,

  P_M = price in perfectly competitive market

  MC_M = marginal cost of extraction in perfectly competitive market

  r_t = rate of interest in time period t (thus r_t can either remain static through time or change)

  (Lin et. al, 2008, p. 1)

Strengths

Given that the main outputs of the RWGTM are prices and trade flows based on supply-demand dynamics in the long-term (as far as market dynamics are concerned), a general-equilibrium framework provides a readily accessible paradigm for generating these outputs. The use of MCP/NCP (mixed complementarity programming/non-linear complementarity programming) to reflect uncertain/random parameters for spot market demand and strategic production decisions, as in the shorter temporal horizon Stochastic Natural Gas Equilibrium Model (S-NGEM) (Gabriel et. al, 2006), would unnecessarily complicate the analysis.

A key strength of the RWGTM is the level of regional disaggregation in the model, with more than 140 supply regions, which provides crucial insights into highly complex and varying natural gas markets (Medlock, 2009). For example, North America (Canada and the United States) has 62 different supply hubs, reflecting both resource heterogeneity (e.g. shale gas in the Appalachian Basin versus Gulf of Mexico offshore), and competition between traditional supply hubs (Henry Hub in Louisiana) and regions growing in liquidity both in terms of gas volumes and financial markets (Marcellus (Appalachian) Tennessee Zone 4).

Additionally, whilst the RWGTM uses a more simplistic framework for ensuring supply and demand equilibrate yielding optimum prices (based on Hotelling paradigm discussed subsequently) across all markets (i.e. general equilibrium), the model is able to run a large number of scenarios which account for some inherent uncertainties. These include policy interventions, the price of fossil fuel substitutes, macroeconomic growth forecasts and their impact on energy demand, and localised 'not in my back yard' opposition to natural gas resource development (Medlock, 2009).

Limitations

The RWGTM generates regional price and flow outputs, in a non-stochastic framework (random or probabilistic uncertainty), using various scenarios (Medlock, 2011; Hartley and Medlock, 2005):

- Geopolitical influences
- Market development
- Trade dynamics
- Inter-fuel competition (based on resource availability taken exogenously)

This deterministic outlook (generating a single outcome from a set of static parameters) thus generates a significant amount of uncertainty, particularly when it comes to the development of markets, the availability and cost of resources, the interaction of agents within each sector of the supply chain, and the development of alternative fuels (inter-fuel competition).

The RWGTM's use of the Hotelling extraction paradigm as the cornerstone of extraction economics within the model is open to uncertainty, not least from increasingly unstable and unpredictable markets (including strategic behaviour of upstream companies), and the role of technological progress which can lead to cost reductions over time, whether through learning-by-doing and technical specialisation, or investment in R&D (Lin et. al, 2008, p. 2).

The RWGTM uses a North American supply cost-curve which is then applied as an analogue globally, significantly undermining the upstream representation of regional and geological differences. Additionally, in its assessment of shale gas resources, the RWGTM utilises a resource classification which more closely resembles economically recoverable resources (ERR) mentioned in Section I, which could have the effect of systematically underestimating recoverable resources, given the dynamic nature of both extraction economics and technology. Furthermore, the RWGTM only accounts for unconventional resources in North America, China, Europe and Australia, with all other resources considered conventional in the rest of the world and crucially, limited representation of offshore and stranded hydrocarbon deposits (Medlock, 2011, p.10, pp. 18-25).

In order to reflect changing demand patterns, the RWGTM reflects the decoupling of energy consumption and economic (per capita) growth, which is applied as GDP per capita increases in each region throughout the models lifespan (Medlock, 2011, pp. 6-9). However, on the demand side, and as with the World Gas Model (WGM) (Gabriel et. al, 2010, p. 12; Egging et. al, 2010) and COLUMBUS (Hecking and Panke, 2012, p. 2), the demand side in general is driven by exogenous macro parameters (such as population and economic growth), and limited representation is given to the importance of improvements in efficiency of technologies and dynamic cost reductions of new technologies, which can play a huge role in changing overall demand for natural gas across the energy sector (e.g. decreasing demand for natural gas in the electricity generation sector due to cost reductions and efficiency improvements in wind, solar, nuclear, etc.).

Gas Exporting Countries Forum (GECF) – Global Gas Model (GGM)

General Structure and Modelling Method

The Gas Exporting Countries Forum (GECF) in-house Global Gas Model (GGM) has only recently been launched, and supporting model documentation is currently limited in the public domain. The main purpose of the model is to project changes in global natural gas supply and demand, by generating "what-if" scenarios for future natural gas markets (GECF, 2015). The model is used in the GECF global gas outlook reports, which have been published in 2016 and 2017, and provide regional outlooks for supply and demand (GECF, 2016; GECF, 2017), including international trade via LNG and pipeline.

The core module of the GGM is a trade optimisation module (minimising the costs of trade), which equilibrates supply-demand imbalances in a highly disaggregated regional network (113 regions) (GECF, 2015).

From the limited information available, the main modelling forecasts generated by the model include:

- Upstream supply – analysis of existing fields/fields projected to be developed, for different categories of gas to yield the cost and quantity of potential production
- Trading networks (analysis of the main trade routes including choke points, and the potential role of LNG)
- LNG plant requirements – either existing, under development, or under certain high-demand scenarios increased capacity to satisfy increased consumption
- Demand forecast:
    - Driven by exogenous economic parameters
    - End-use consumption for different sectors
    - Inter-fuel competition (e.g. price elasticity of substitution between different fuels)
- Integrating gas trade module – absorbs information from several modules to generate long-term trend of trading routes, based on:

    - Historical flows
    - Contractual (existing) flows
    - Cost curves (based on regional upstream dynamics and trading costs)
- Key identity is an optimisation gas trade module (i.e. lowest cost solution which satisfies regional demand).

To date, a limited amount of publically available information on the GECF GGM makes a review of the modelling methods employed challenging. The 2017 Global Gas Outlook (GECF, 2017) identifies that IHS Markit is responsible for much of the data provision, calibration and continued upkeep.

Oslo Centre for Research on Environmentally Friendly Energy (CREE) - Framework of International Strategic Behaviour in Energy and the Environment (FRISBEE)

General Structure and Modelling Method

The FRISBEE model has been used for a range of diverse research projects, from projecting the impact on natural gas prices and trade flows from increasingly integrated markets (Aune et. al, 2008), to assessing the potential impact on petroleum markets if the Arctic regions were extensively developed (Lindholt and Glomsrød, 2011).

FRISBEE is a recursive[23] dynamic partial equilibrium model with 13 global regions, representing the upstream and midstream sectors of natural gas markets (Aune et. al, pp. 4-6):

- Upstream: wide range of regional and field data including discoveries, reserves, field development (in production, undeveloped but discovered, undiscovered).
- Demand: disaggregated into manufacturing industries, power generation, and other (households, commercial, etc.), and represented as a function of end-use prices for all energy goods (i.e. demand elasticities based on price of natural gas and other competitive fuels)

The key outputs of the FRISBEE model are annualised, and generate regional equilibrium quantities of supply and demand, as well as regional market clearing gas prices, and trade flows. FRISBEE bases investment decisions on an endogenous decline profile, with four phases of field development, and the ability to intensify extraction with enhanced recovery (Aune et. al, 2008, pp. 6-7; Lindholt and Glomsrød, 2011, pp. 10-11):

1. Investment Phase: time-lag between investment and production
2. Pre-peak Phase: when production builds up towards peak level

[23] Recursive and iterative functions are relatively similar – however a recursive method is where the overall solution is a combination of subsets of that problem (e.g. Fibonacci), whilst an iterative system generally involves loop repetition until the system is solved (e.g. changing gas prices until demand can be satisfied by new supply coming online due to economic viability of new price).

3. Peak Phase: capacity is at a constant and pre-specified level
4. Decline Phase: capacity declines at a constant rate per year until production is un-economical

Strengths

As with the IEA WEM (IEA, 2017a), investment decisions are modelled in FRISBEE at a field-level. Thus, decision analysis for the development of a new natural gas project is based on the expected net present value (NPV), which is determined by expected prices, operating and capital costs, as well as the prospective yield of the field in question (Aune et. al, 2008, p. 6). This bottom-up, field-by-field analysis, provides FRISBEE with a strong analysis of the cost elements (both fixed investment and operating) which drive investment decisions.

The FRISBEE model's purpose of imitating strategic investment behaviour is aided by the above simplifications, as well as the use of proxy variables, such as an exogenous risk premium to account for political, geological, and fiscal risk in investments. However, the lack of rigorous bottom-up geological assessment in the model undermines its ability to generate systematic approximations of resource-supply costs for regions, whilst the simplification of the transport costs could undermine capacity expansion dynamics of both pipeline and LNG infrastructure.

Limitations

As with the Rice World Gas Trade Model (RWGTM), World Gas Model (WGM) and COLUMBUS, FRISBEE has a limited representation of the drivers of long-term energy demand, and in particular competition between all fuels to satisfy energy-service demand. As with the models mentioned above, energy demand elasticities in FRISBEE are linked only to changes in the gas price or fossil alternatives (Egging et. al, 2010; Hecking and Panke, 2012; Aune et. al, 2008; Hartley et. al, 2005). Thus, an entire energy system approach where all competing feedstock fuels for energy sectors, including dynamic technology efficiencies and costs, are not considered.

Some key assumptions within the FRISBEE model yield limitations. Firstly, the assumption that transportation costs are a linear function of the distance between regions (Aune et. al, 2008, p. 6), is an over-simplification, with the capacity of the transportation mode (i.e. pipeline or LNG tanker) having a greater impact on the overall transportation cost; exploiting scale economics by increasing the capacity of the transportation device has a greater impact on costs (Messner and Babies, 2012, p. 1). Secondly, the assumption of static unit costs for pipeline and LNG infrastructure is a simplification of a facet of cost dynamics which is anything but static, reflected by the huge increase in LNG liquefaction plant unit cost inflation (Songhurst, 2014). Thirdly, although market power can be modelled within the model, as with Aune et. al's (2008) scenarios based on potential cartelisation of natural gas markets, the initial assumption of fully competitive and liberalised markets (Aune et. al, p. 6) is highly unrealistic, given that liberalised markets based on hub (spot) pricing is at present generally confined to the US and areas of north-western Europe (including the UK).

Robert Brooks RBAC, Inc. Energy Industry Forecasting Systems (RBAC Inc.) - Gas Pipeline Competition Model (GPCM)

General Structure and Modelling Method

The privately owned (RBAC Inc.) Gas Pipeline Competition Model (GPCM) is relatively unique in terms of privately controlled gas models in the sense there is – albeit limited - literature regarding the modelling method used. The GPCM utilises both short-term spot (including futures) and long-term contract price and volume data in a network model which reflects the North American gas market with a series of nodes (production regions, storage zones, pipeline hubs, etc.) and arcs (reflecting both physical and financial flows and transactions) (Platts, 2005; RBAC, 2015).

The GPCM reflects the "fundamental structural change in the marketplace" whereby the US inter- and intra-state transmission companies moved from competing "against each other to buy and sell gas" to competing "against each other to sell transportation and storage services" (e.g. pipeline usage), with the utility companies then competing "to buy and sell natural gas" (INGAA, 2010, pp. 5-6); in short, transmission companies now provide an intermediary service between the upstream producers and the downstream sellers.

The GPCM employs a linear programming framework to represent a "highly non-linear complex model of market clearing behaviour" in a step-wise function (RBAC, 2015, pp. 1-2):

- Each regional supply node and customer has an exogenously determined supply/demand curve, with neoclassical price paradigm foundations, i.e. as the price increases, supply increases and demand decreases until a market clearing solution is found where the price is equal to marginal cost.
- The integral of supply and demand across a range of price-levels is divided into several steps in order to generate linear approximations to non-linear formulations.
- From the Samuelson condition, the equilibrium solution is optimal from a neo-classical viewpoint, as it is the maximisation of total surplus (producer = integral of supply price function divided by supply; consumer = integral of demand price function minus demand) minus transportation costs.

Strengths

A key strength of the GPCM is the combination of short-term, spot and futures markets in a modelling paradigm with long-term determinants of gas market dynamics including macro-economic trends such as population and GDP growth on the demand side, and reserve depreciation costs (i.e. extraction cost) on the supply side (Platts, 2005; RBAC, 2015). This allows the model to capture long-term economic trends – albeit in a neo-classical Samuelson framework where the allocation of private goods is determined at the equilibrium of marginal benefit and marginal cost – with shorter-term market dynamics and volatility (e.g. consumer reactions and expectations in the futures markets, thus introducing at least some element of Keynesian 'animal spirits' in the form of consumer expectations and confidence).

The representation of the transmission and distribution system is diverse and in significant detail with, for example, the parameterisation of six cost parameters for natural gas transportation and storage transactions and within this a function for price discrimination in the sense that some capacity can be reserved for certain large-scale customers, such as heavy industry (Platts, 2005, pp. 4-5). Thus, the role that large industrial demand (and indeed other large scale customers) has on transportation and storage economics is introduced (by-proxy) in the model.

Limitations

The formulation of the objective function for the GPCM, i.e. maximisation of economic surplus for producers and consumers and minimisation of costs, relies on "quite general" forms of supply and demand curves for constructing reactions to incremental price changes, with the form of the model relying on supply to increase and demand to decrease, as prices rise, and vice versa (RBAC, 2015, p.1). However, this is a fundamentally simplistic reflection of supply-demand and price dynamics:

- Essentially assumes the classical Say's Law which states that supply creates its own demand and not demand driving supply, and that prices are flexible such that supply and demand reactions to changing prices are effective immediately, and vice versa.
- If natural gas prices increased, the elasticity of the demand response will depend on a huge number of factors including:
    - Cost of substitute fuels
    - Revenue one can generate as a distributor (i.e. if the demand is taken to be the demand of a transmission company for natural gas from upstream suppliers)
    - Interaction of income inflation with cost inflation
    - Consumer expectations (about future prices, inflation, interest rates, etc.)
    - Availability of substitutes (i.e. for end-use demand consumers, what alternatives are available).

The representation of supply and demand elasticities in the upstream and transmission sectors, fails to reflect the role of 'sticky' prices, in the sense that inflation in one sector, may take a significant amount of time to be passed through to other sectors, especially if contracts have been agreed-upon.

A key limitation of the GPCM modelling method is its reliance on large amounts of data, most notably for both contracted and short-term pricing and volumes (Platts, 2005, pp. 2-3). This method is robust in de-regulated, relatively transparent gas markets like the US, however in highly opaque and regulated gas markets where no spot markets exist, or are only partially in existence, and contract prices and volumes are secretive, the RBAC method cannot be used.

Additionally, because the GPCM is an optimisation model, it loses the 'real-world' benefits of, for example, the EIA's heuristic Natural Gas Transmission and Distribution Model (NGTDM), in the sense that although the US natural gas market is largely transparent, a least-cost optimisation does not reflect the complexity of:

- Localised utility distribution characteristics (i.e. even if there is lower cost natural gas in other parts of the system, this may not be available to consumers),
- Not all costs are transparent, particularly when it comes to:

- Disclosing the cost of developing proved reserves – particularly with production subsidies - and the extent to which the upstream firms report costs which accurately reflect their activities (SEC, 2008, p. 30)
- The transfer of gas both to and from inter-state pipeline companies:
  - Of which there are relatively few, and as such can be considered to operate in a relatively oligopolistic manner
  - Highly complicated - the distribution of natural gas at a "just and reasonable" cost with a "fair" rate of return for the large transmission companies in a de-regulated market (INGAA, 2010, p. 25), leads to highly ambiguous terminology, even with substantial FERC oversight.

Thus unlike heuristic algorithms which reflect actual market behaviour by 'learning' through each iteration of the model which routes through the network are preferable, optimisation models can simplify what can be an incredibly complicated and asymmetric market by assuming all cost information is known across the supply chain.

Whilst it is not made clear the level of geological detail input into the upstream supply sector (i.e. the gas supplied to the pipelines), Platts (2005, pp. 3-4) state that the reserve base for each supply region is taken exogenously from USGS and National Petroleum Council (NPC) assessments and related to the costs of extraction, resulting in a reserve-to-production ratio for assessing remaining production potential, which is a highly simplified representation of field/basin dynamics, given the role of technology, economics and geology in determining the costs and complexities of extraction.

Inner City Fund International (ICFI) – Gas Market Model (GMM)

General Structure and Modelling Method

The Inner City Fund Gas Market Model (ICF GMM) is a privately owned, market equilibrium model, representing the North American natural gas market. The GMM market equilibrium solution is solved using non-linear programming (NLP), thus generating a set of constraints, some of which are non-linear (e.g. a quadratic cost optimisation function) (ICFI, 2016). This requires a more complex solution procedure, but benefits from depicting a gas supply-demand network system where linearity is often a significant simplification (for example in the relationship between injection (withdrawal) into (from) the transmission system).

The ICF GMM generates a supply-demand equilibrium at each node in the network, which yields monthly natural gas prices, with exogenous constraints (including on transportation and generation capacities) defined by the user (ICFI, 2010, pp. 76-8). Some key characteristics of the ICF GGM (2010, pp. 76-7) are:

- Supply side – prices are determined as a function of output (production) and storage costs
- Prices influenced by "pipeline discount" curve – i.e. utilisation factor of the pipeline, which changes with seasons etc.
- Demand side – prices influenced by inter-fuel competition and substitutability (e.g. cross-price elasticity of fuel substitution)

- Intersection of supply and demand curves generate market clearing equilibrium price.
- Exogenous pipeline capacity expansions based on external database
- First model run solves for gas demand across sectors, given key exogenously specified drivers (economic growth, weather, inter-fuel price competition)
- Second model run solves power generation dispatch based on exogenous capacity constraints on a regional basis, which forms model nodes (along with demand)
- Model nodes are connected with transportation arcs, and each node is solved independently (i.e. market clearing equilibrium price found) so demand and supply equilibrate.
- Any imbalances are solved introducing gas storage and injections (e.g. for seasonal imbalances).

The brief overview of the ICF GMM presented above has not been extended for two main reasons:

1. As a privately contracted model, there is a relative lack of transparency into the foundations of the model, in addition to the fact that much of the method in terms of constraints and drivers amongst others, is the users prerogative.
2. Whilst a new longer-term forecast has been introduced (quarterly time-slices out to 2025), the GMM is generally used for short-term (3-5 year) analysis of gas market supply-demand dynamics, under monthly time-slices, and therefore is limited in its ability to generate longer-term demand projections.

Section III - Conclusion and Development of a New Natural Gas Model

This paper has reviewed existing methods in modelling natural gas, across the entire supply chain and taking into account wider supply-demand interactions across the whole energy system. A major conclusion of this review is the advantage of using demand from wider energy system models as they are able to capture the interaction between competing commodities and technologies across the whole energy system. Some key research gaps and limitations of existing models identified from this working paper include:

- The wider energy models lack a bottom-up analysis of natural gas reserve and resource development costs across both conventional and unconventional categories of natural gas, and the application of cost uncertainty to resource and reserve availability;
- Incorporating natural gas demand elasticities both in longer-term whole energy system contexts, as well as shorter-term (annual and sub-annual) responses to price changes as demand and supply equilibrates;
- Quantitatively assessing future uncertainties in contracted gas volumes, and the knock-on effect on demand in the spot markets;
- Separating associated and non-associated natural gas production through constraints based on one of the key drivers of flaring and venting of associated natural gas: (localised and/or national) infrastructural deficits to process associated gas, limited demand, and limited incentives to invest in new capacity;
- Supply shocks in the future to specific gas projects and the spill-over impact into international gas markets; i.e. the impact of supply disruption across all gas markets, rather than isolated to a specific region;
- Inclusion of production subsidies for infant gas industries outside of North America;
- Modelling the prevalence of market incumbents in domestic markets; i.e. market power of an incumbent dominant player in the domestic supply chain, meaning their upstream assets are likely to be developed first over independent producers.
- Application of the shared socioeconomic pathway (SSP[24]) demand narratives to field-level investment decisions for natural gas on a global scale.

In order to account for some of these research gaps and limitations, a new field-level natural gas production and trade model is being constructed and will be used in conjunction with the energy systems model, TIAM-UCL. The new gas model includes:

- Bottom-up reserve/resource and cost database (i.e. geological and economic assessments of natural gas resource potential), including ranges of availabilities and

[24] "*[Shared Socioeconomic Pathways] …consist of two elements: a narrative storyline and a set of quantified measures of development. SSP's are "reference" pathways in that they assume no climate change or climate impacts, and no new climate policies"*. These socioeconomic pathways can then be combined with pathways for radiative concentrations and the concurrent changes to the climate, in order to determine the challenges to mitigate and adapt required to respond to a changing climate (O'Neill et. al, 2014).

different costs in order to account for these inherent uncertainties and the corresponding impact this has on natural gas demand.
- Field-level investment model which includes gas market dynamics such as: fiscal regimes, price formation mechanisms, subsidies (production and consumption)
- The ability to model supply shocks, either by reducing production from developed fields, or delaying production from undeveloped fields.

As mentioned previously, the existing gas market models (RWGTM, COLUMBUS, WGM, etc.) take each energy-demand sector (i.e. transport, industry, power generation, etc.) as highly aggregated, with no evolution of long-term technology efficiencies, costs or new technology entrants across the energy system. Thus, the use of TIAM-UCL will allow a detailed technological representation of sectoral (electricity generation, transport, commercial and residential, agriculture, industry) natural gas consumption demand.

The new bottom-up natural gas production and trade model includes over 500 conventional non-associated natural gas fields across the production spectrum: producing, fallow, and undeveloped. Additionally, major unconventional natural gas plays and fields are individually assessed, with large shale and tight gas plays split into 21 different production-cost zones.

The new global natural gas model will interact with TIAM-UCL (taking exogenous consumption demand for natural gas from TIAM), with annual time-slices to 2035. This interaction with TIAM-UCL is critical, as it facilitates a technologically-rich – in particular the demand side – reference energy system (i.e. the interaction of commodity flows and technological processes at each stage of the energy system from upstream production to end-use demand). Additionally, the consumption demand which is satisfied at a field-level by the new model, is taken from a whole energy system perspective. The use of a dual-price system (domestic and international trade) will allow the gas field model to explicitly analyse investment decisions based on a range of domestic and international parameters which TIAM-UCL cannot include in its analysis of gas markets: fiscal regimes, subsidies, various price formation mechanisms.

TIAM-UCL and the field-level production and trade model are soft-linked, in the sense that natural gas availabilities and costs are consistent through both models; the field-level databases are used as static inputs into TIAM-UCL to generate aggregated supply cost curves. Figure 6 shows an example of an aggregated supply cost curve, using field-level reserve and cost data[25], and applied to a probability distribution of the Former Soviet Union region in TIAM, to generate three curves accounting for significant resource uncertainty.

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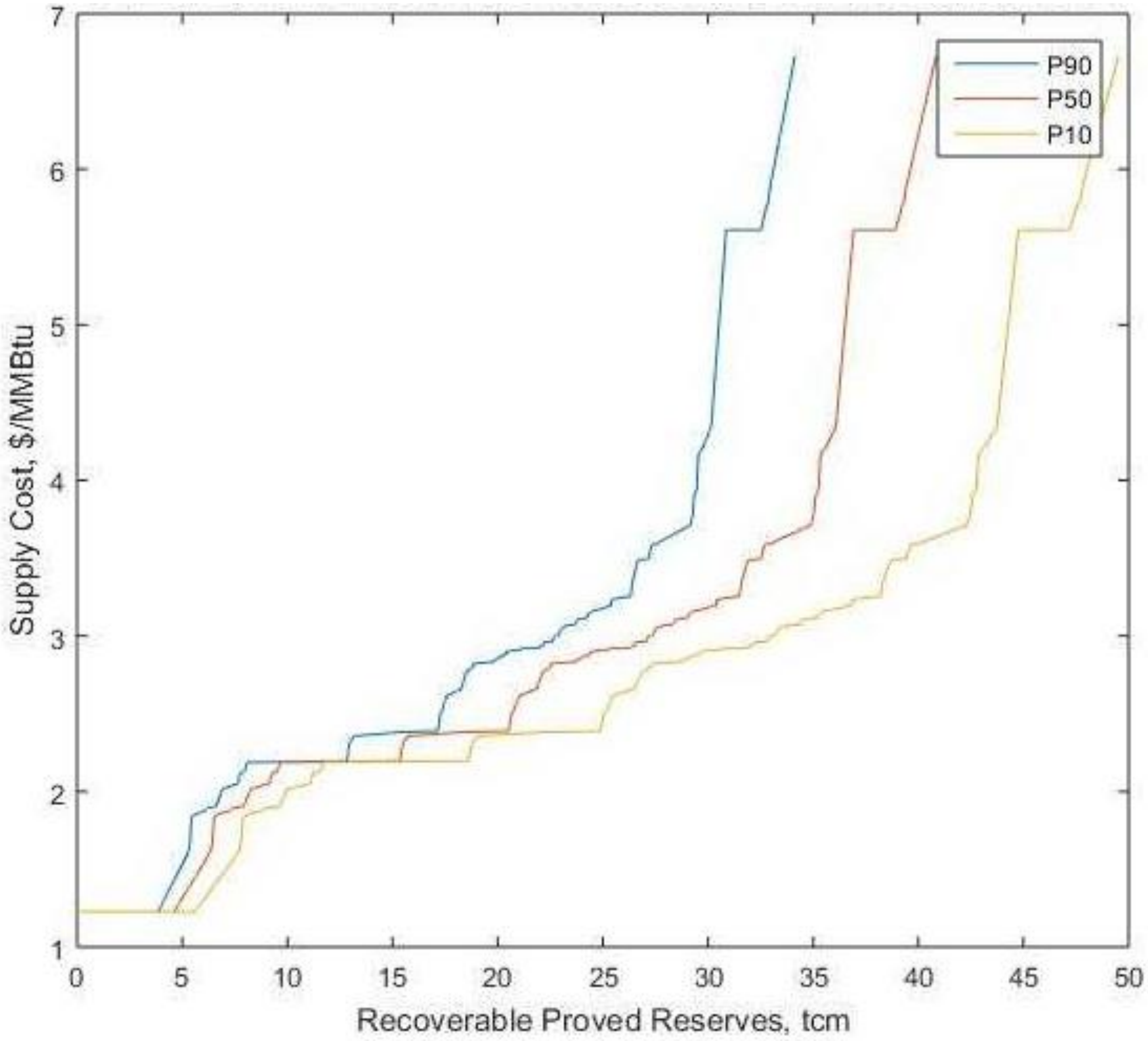
[25] The reserve data has been combined into country-level probability distributions using a range of sources including an amended database originally constructed for the AAPG by M.K. Horn (WorldMap Harvard, 2015; NETL, 2015) and Cedigaz (IEA, 2017c). Original cost data was collected from a large range of sources (Lochner and Bothe, 2009; IEA, 2009; IEA, 2011; IEA, 2012; Yermakov and Kirova, 2017; Rzayeva, 2015) and then applied to a linear regression model, discussed briefly below

Figure 6: Low (P90 = 34.1 tcm), Central (P50 = 40.8 tcm) and High (P10 = 49.5 tcm) supply cost curves for aggregated conventional non-associated gas reserves in the Former Soviet Union



The new global natural gas model, through the interaction of several modules, includes:

- Field-level database including individual resource categories and detailed geological information;
- A field level cost database has been generated, using an aggregated 'supply-cost'[26] figure; this data was then applied to a simple linear regression[27] model in order to apply statistically significant coefficients to fields where no cost data was available;

[26] Supply cost refers to 'finding and development' costs (i.e. investment costs) and lifting costs (i.e. variable production costs)

[27] Regression was applied separately to conventional onshore, conventional offshore, shale, tight, and CBM; independent variables included reservoir depth, water depth, sour vs. sweet (binary), field size, production duration, risk (binary), thickness (shale, tight, CBM), permeability (shale, tight, CBM), porosity (shale, tight, CBM)

- Exogenous production profiles for individual fields were generated, and input into a field NPV model in order to determine prices required to yield production from fields in each country
- Introduce both production and consumption subsidies into a simulation model.
- Utilise existing natural gas market conditions as a starting point for developing different medium-/long-term scenarios based on pricing developments and new infrastructure investment (e.g. gas-on-gas competition from pipeline and LNG).
- Impact of withdrawing fossil fuel subsidies – particularly from the point of view of major exporters, and expanding on the IEA WEM analysis by explicitly modelling production subsidies, which are of significant (and potentially growing) importance (e.g. in the United States) but are often overlooked (IEA, 2016; Zhao and Dahl, 2014; Ellis, 2010). The modelling of production subsidies from a field-level perspective allows a novel approach to generating insights into how these interventions influence field investment decisions directly, and the importance of these subsidies in stimulating 'infant' gas production industries.
- Field level development under various decarbonisation pathways – taking carbon pricing from TIAM-UCL and including these in the cost of future project investments of the new gas model (i.e. internalising the externalities associated with natural gas upstream and midstream in particular).
- In conjunction with TIAM-UCL, the new field-level model will allow the analysis of gas supply and demand under more ambitious mitigation commitments than those prescribed under the COP-21 Paris Meeting – this expands the work done by Winning et. al (2018) which considered aggregated global fossil fuel consumption under a range of climate futures, and the impact of delaying the ramping-up of decarbonisation commitment.

As with the IEA's World Energy Model (IEA, 2017a), there are three modules of natural gas supply and demand (long-term contracts, indigenous production, and residual demand satisfied by spot markets) which are solved sequentially.

The basic premise of the model is that the overall regional consumption demand for natural gas yielded under various scenarios and sensitivities is reduced from one module to the next, until supply and demand equilibrate. For each region and in each year, a natural gas price is output in order to ensure that supply from each module meets the total regional demand. The model is constrained by an exogenous production capacity matrix which determines how much each field can produce in each year, which includes decline or growth rates on production, depending on where the field sits in its lifecycle. Additionally, this ensures that if a field produces *x* petajoules for one module, this is subtracted from the underlying production constraint matrix for productive capacity for that field in other modules. There follows a brief introduction to each supply module[28] below.

Long-term contract module

In the standard run of the model, the long-term contract volumes are exogenously set based on annual contracted quantities and/or average historical bilateral gas trade over five years. These volumes are then extended for the duration of the natural gas contract and are summed across the importing countries in each region and subtracted from the total regional consumption demand. An extension of the model accounts for the uncertainties over future annual contracted quantities in existing gas contracts. This involves varying the take-up of contracted volumes, i.e. above the minimum take-or-pay, in each year and for each region, and the concurrent impact this has on both the volume of contracted trade, and the knock-on effect on the volume which must be met by spot markets (i.e. whether there is an increase or decrease in demand for gas on spot markets). The long-term contract module has a dynamic inflator on prices based on a lagged oil price moving forward to 2035 (for oil-indexed contracts), as well as bilateral trade costs (both investment costs of infrastructure and variable operation and maintenance costs of pipeline or LNG transportation).

Indigenous production module

The indigenous production module essentially splits net importers from net exporters. The module determines the proportion of regional demand which must come from that regions natural gas fields (the indigenous production factor (IPF)). These include field development decisions which are motivated more in the name of security and diversification of energy supply, rather than importing gas at potentially lower prices; an example of this is the development of the Shah-Bab sour gas fields in the United Arab Emirates (Munro, 2018, pp. 12-14). The module also ensures production from individual countries are taken into account

[28] It should be noted that for all three modules, an additional extension of the model is the ability of demand to react to changing prices (i.e. there is an endogenous price elasticity of demand which occurs as the price iteration increases, thus reducing the overall level of regional demand generated by TIAM).

to ensure that one country does not over-/under-represent its share of regional production. Additionally, the domestic module includes fiscal regimes and any production subsidies.

Spot module

Once the long-term contract and domestic modules have run, any residual demand is met by a spot module. Natural gas trade is constrained based on an underlying trade matrix (i.e. bilateral trade constraints based on distance, historical patterns, and geopolitical factors), and suppliers compete based on competitive costs and the prevailing gas price (once long-term contracts have been satisfied and production from domestic fields have been taken into account) in both the importing and exporting region. The spot module allows the model to reflect differing market structures and price formation mechanisms. For example, US LNG suppliers generally buy gas from the US spot market (Cheniere, 2018), and sell it on global LNG markets (i.e. there is competition across the supply chain). This is in contrast to many of the large-scale integrated LNG projects (e.g. Yamal LNG) which have secured long-term contracts for the bulk of their cargoes, either on a form of oil-indexation or under pre-agreed terms between a selling and buying monopoly (Total, 2017).

Whilst this is a brief introduction to a new field-level natural gas model, the overarching aim of this paper has been to identify current modelling literature which predominantly focuses on natural gas in a global context, and identify the strengths and limitations of these models. The construction of this bottom-up natural gas production and trade model is still ongoing, and the model architecture has been designed to answer some of the research gaps identified at the start of Section III, namely:

- Insights into the impact of variations in the uptake of contracted gas volumes on indexed long-term contracts, including their renewal, and the knock on effect on spot markets;
- Insights into the impact of supply disruptions, not just to specific regional markets, but globally;
- Insights into the impact of cost and resource availability, in order to model longer-term variations in natural gas consumption demand under different decarbonisation pathways;
- Insights into policies which impact the uptake of natural gas, both at a sectoral and regional level.

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