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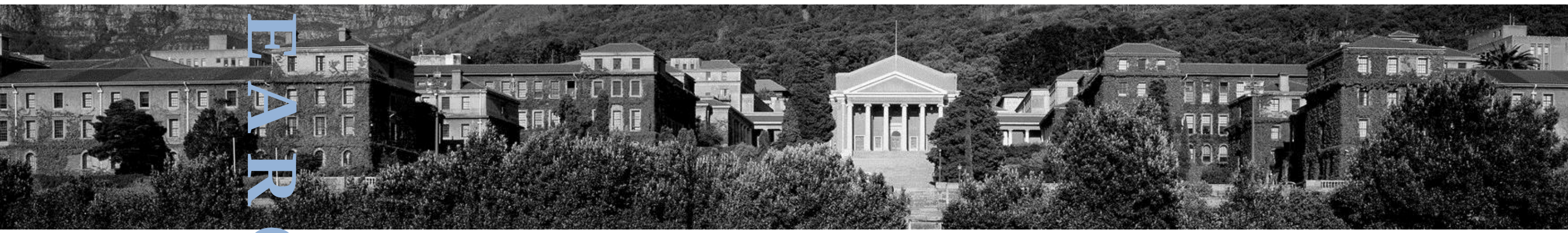

The long-term uptake of natural gas in the South African energy system

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Abbreviations

CCGT	Combined cycle gas turbine
CBM	Coal-bed methane
CNG	Compressed natural gas
CHP	Combined heat and power
CSP	Concentrating solar power
CTL	Coal-to-liquids
GHG	Greenhouse gases
LNG	Liquefied natural gas
CO_2-eq	Carbon dioxide equivalent
NERSA	National Energy Regulator
OCGT	Open cycle gas turbine
SATIM	South African TIMES model
TPES	Total primary energy supply

1. Introduction

The contribution to total primary energy supply from natural gas in South Africa is currently low (2–3%), yet the potential for growth of the sector is believed to be significant (McKinsey, 2015). South Africa currently uses notably less gas in all sectors of the economy than other countries, but the potential for gas to address several challenges facing its energy sector has been recognised in policy, including in the 1998 White Paper on Energy Policy (DME, 1998); in legislation (South Africa: Gas Act section 2b); in the National Development Plan (NPC, 2011); and by various actors in the energy sector. Given technological advancements in hydraulic fracturing and offshore drilling, recent large gas finds in the region, notably Mozambique, and growing liquefied natural gas (LNG) markets globally, options for the supply of natural gas are growing. At the same time, end-uses are manifold, but fuel-switching depends on availability, relative prices and the development of significant infrastructure and appropriate regulatory regimes.

There are many potential benefits of diversification of South Africa's energy system towards gas, including helping to meet the challenges of a coal-based electricity system facing climate change mitigation targets and diversifying primary energy sources in a coal-dominated system, along with numerous additional applications in the electricity system, and possible widespread uses in transport, industry and commercial buildings. The development and utilisation of domestic energy resources has also been assumed to lead to economic growth and development, and indigenous sources of gas are viewed as important potential future supply options; there are also significant potential benefits to the further development of regional energy trade, and the development of the regional economy (DME, 1998; McKinsey, 2015; NERSA, 2012).

The development of the domestic industry has, however, been limited historically, primarily by very low coal prices and the lack of domestic or regional gas resources. The potential availability of domestic and regional gas resources on a large scale, and the availability of LNG, combined with rising coal prices and national greenhouse gas (GHG) mitigation targets, has renewed interest in large-scale deployment of gas in South Africa. The aim of this study is, therefore, to understand the potential roles of natural gas in the South African energy system between now and 2050, in the context of uncertainties about economic growth, the cost of key non-gas technologies such as nuclear power and renewable energy technologies, and the cost of natural gas and other fuels.

The key policy context for considering the role of fossil fuels in the South African energy system in the long term is climate change mitigation, so the study focuses on the impact on the energy system of an economy-wide carbon constraint, and on the role of gas within it. Since South Africa is a coal-intensive economy, substitution of gas for coal use has a potentially significant mitigation impact; in addition to this, gas complements renewable energy sources in the electricity system because of its flexibility, and so could increase the speed at which the electricity system is able to shift from a coal-centric system to a low-carbon one. Furthermore, availability of gas gives rise to mitigation opportunities in the industrial and commercial sectors via cogeneration and trigeneration, both of which have overall efficiencies far higher than centralised gas power generation. The aim of the study is to provide a map of the potential for gas utilisation over the long term in the South African energy system. More specific shorter-term policy questions (such as the best pathway to establishing such an industry in the short term) would require more detailed analysis, and this study provides the context for such further work. This is primarily a long-term techno-economic study, and does not address key policy indicators such as employment, economic growth or any of the more complex implementation challenges.

1.1 Research objectives

This study has two primary objectives: (i) to explore the potential uptake of natural gas in the South African energy system to 2050 under conditions of uncertainty in economic growth, technology costs and fuel costs, and to explore the impact of a GHG constraint on the uptake of natural gas; and (ii) the development of the South African TIMES Model's (SATIM) capability to model natural gas effectively in the South African energy system.

As alluded to above, and explored further below, the research goals stated here will inform policy on gas uptake in the South African energy system in several respects – the scale of gas uptake in the long term, given different economic growth rates and technology assumptions, the impact of a GHG constraint on the uptake of natural gas, the impact of the gas price on uptake, and a clearer understanding of some of the complex interactions within the South African energy system which would influence, and result from, the uptake of natural gas. An energy systems model such as SATIM is well-suited for this kind of analysis, since its structure captures cross-sectoral interactions like these. Where the analysis is less useful for policy is in respect of the short term (five to ten years), given the granularity of the modelling analysis (five-year periods), and in respect of a detailed insight into infrastructure choices, especially in the short term. These points will be elaborated below.

1.2 Key policy research questions

The key policy research questions in this study are listed below:

- What are the long-term pathways for the development of a South African gas industry, and which factors (GDP growth, technology costs, fuel costs), will influence these?
- Which sectors will adopt gas within the South African energy system, on what scale, and how will variations in the factors listed above influence this?
- How would the imposition of a national GHG budget to 2050 affect the adoption of gas in the economy?
- What impact would higher leakage rates in the production of gas have on gas uptake under a GHG constraint?

It is important to emphasise again that this study does not address many of the complex short- and medium-term dilemmas currently faced by policymakers, the resolution of which is required to stimulate an expansion in the gas value chain and in demand for gas, including questions of finance, regulation, pricing and market structure, ownership and control, and many of the key institutional questions which will require addressing. This study can, however, outline the implications of different gas prices on demand, the concomitant scale of infrastructure which will be required, and the effect of climate mitigation policy the choice of energy supply options for South Africa. For an overview of regulatory issues, see National Energy Regulator (NERSA 2012); the forthcoming Gas Utilisation Master Plan is also expected to deal with addressing regulatory issues in the development of a gas economy.

It needs to be noted that we have identified two primary sources of gas – conventional natural gas, in the form of LNG, and unconventional gas potentially produced from domestic resources in the Karoo – shale gas. The two sources of gas supply differ in only two respects: i) price – shale gas has a wider price range than LNG, and extends significantly on each side of the LNG range, capturing the large uncertainty that exists around domestic shale's availability, and extractability; and ii) we have assumed higher methane leakage rates for shale gas, which has an impact on its GHG footprint. It needs to be stressed that this study does not take into account any other potential environmental impacts of the production of shale gas, such as contamination of ground water or the associated opportunity costs.

2. The current state of natural gas production and use

2.1 The global gas market

As can be seen in Figure 1, gas use globally has grown significantly since 1973, when 16% of total primary energy supply and 12% of electricity generation came from natural gas. This grew to 21% of total primary energy supply and 22% of electricity generation by 2011 (EIA, 2014).

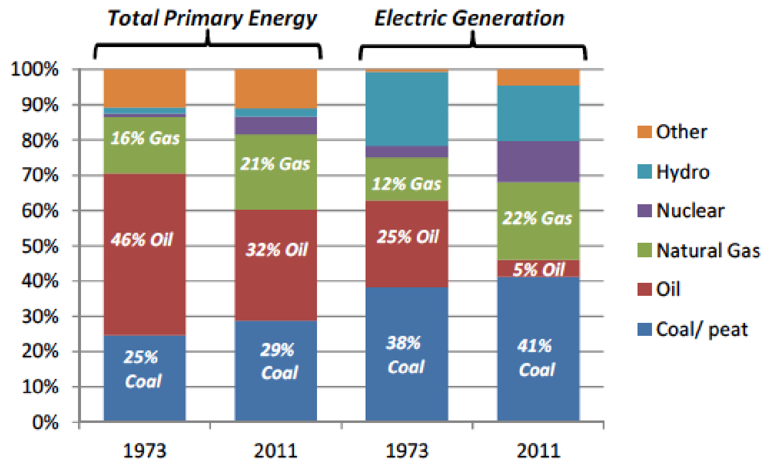

Figure 1: Global fuel shares of TPES and electricity generation (EIA2014)

Historically, production and consumption was concentrated in the USA, Canada and Europe (including the USSR/FSU), with those countries collectively producing and consuming over 90% of natural gas in the 1970s. Recent growth in gas production and consumption has been concentrated in Asia and the Middle East. Currently Europe has the highest level of consumption, followed by the USA and Canada, the Middle East and Asia (International Energy Agency, 2012). The fastest growing regional consumer of natural gas is Asia, while the Middle East is the fastest growing producer and exporter of natural gas.

With increasing exploration and new discoveries of reserves, as well as other supply-side drivers (new infrastructure, development of unconventional gas), demand-side policies including climate change mitigation imperatives and air pollution concerns, the contribution of natural gas to total primary energy supply is expected to increase globally. Indeed, the International Energy Agency projects a 64% increase in global gas consumption between 2010 and 2040. Moreover, global natural gas reserves have doubled since 1980 (International Energy Agency, 2012), and gas markets have matured. In particular, the development of LNG technology and the rapid development of an LNG industry are creating a global gas market. Historically, gas markets have been primarily regional and national, with 69% of global gas flows transported within producer countries, and 21% piped internationally (Figure 2). The development of LNG technology has begun to change this in a number of important ways. First, gas consumption is no longer tied to regional proximity to a gas producer, or to pipeline infrastructure; LNG can be shipped from anywhere to anywhere in the world, much like crude oil. This opens up significant possibilities for producers (who no longer require proximity to a pipeline network to sell their gas) and consumers (whose distance from suppliers is no longer a limitation on gas supply). Second, the ability to transport gas by ship has led, as in crude oil, to the emergence of a true global market, and possibilities for arbitrage between different regional markets. Current trends indicate the recent emergence of an LNG spot market. The LNG market is generally characterised by long-term take-or-pay contracts that account for around two-thirds of volume, but there is a growing spot market, which in 2014 made up just over one quarter of the total. LNG currently comprises 10% of the global gas market (IGU, 2015; EIA, 2014). The growing availability of LNG puts gas at the disposal of countries with limited access to pipeline gas, such as South Africa, and therefore projected LNG prices are now a major determinant of uptake rather than the availability of gas resources, since LNG can be procured globally. The gas price has traditionally followed the price of crude oil, but developments over the last decade have led to a more complex picture (Figure 3) triggered by a range of factors, including the rapid development of unconventional oil and gas resources in the USA and Canada and slower global demand growth, especially in east Asia (with the exception of Japan). Substitutability between gas and crude oil has also come under pressure from climate mitigation and air pollution policies.

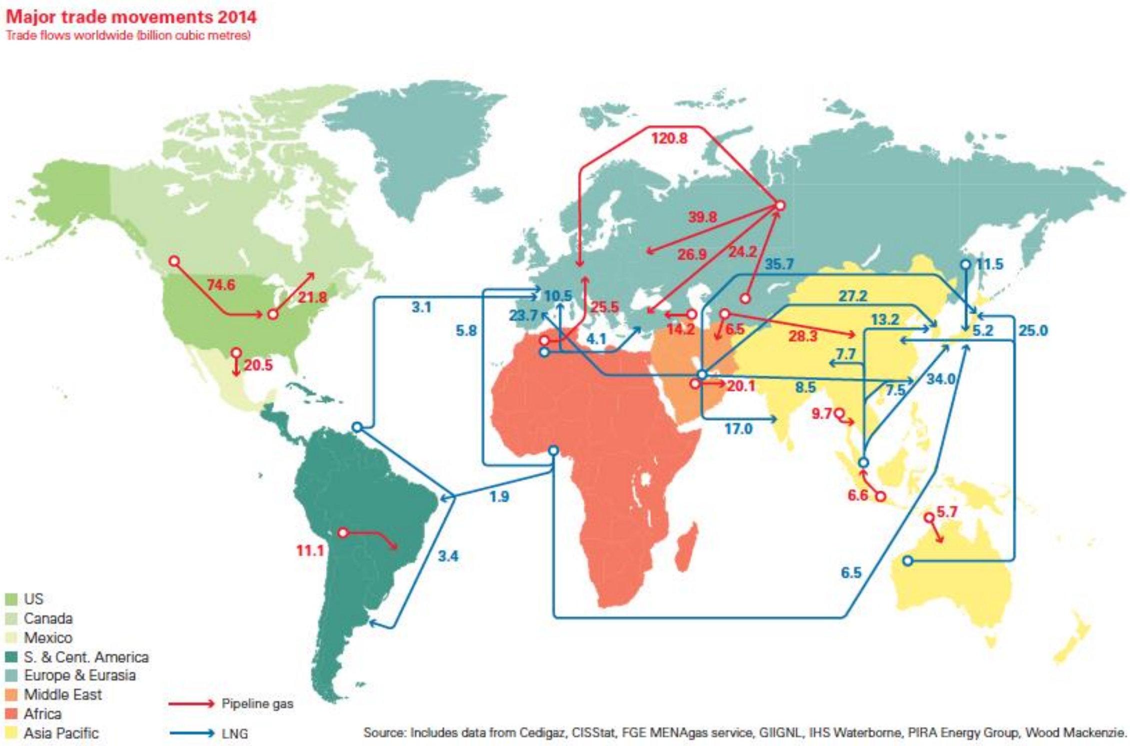

Figure 2: Major natural gas trade flows (LNG and pipeline) in 2014 (BP, 2015)

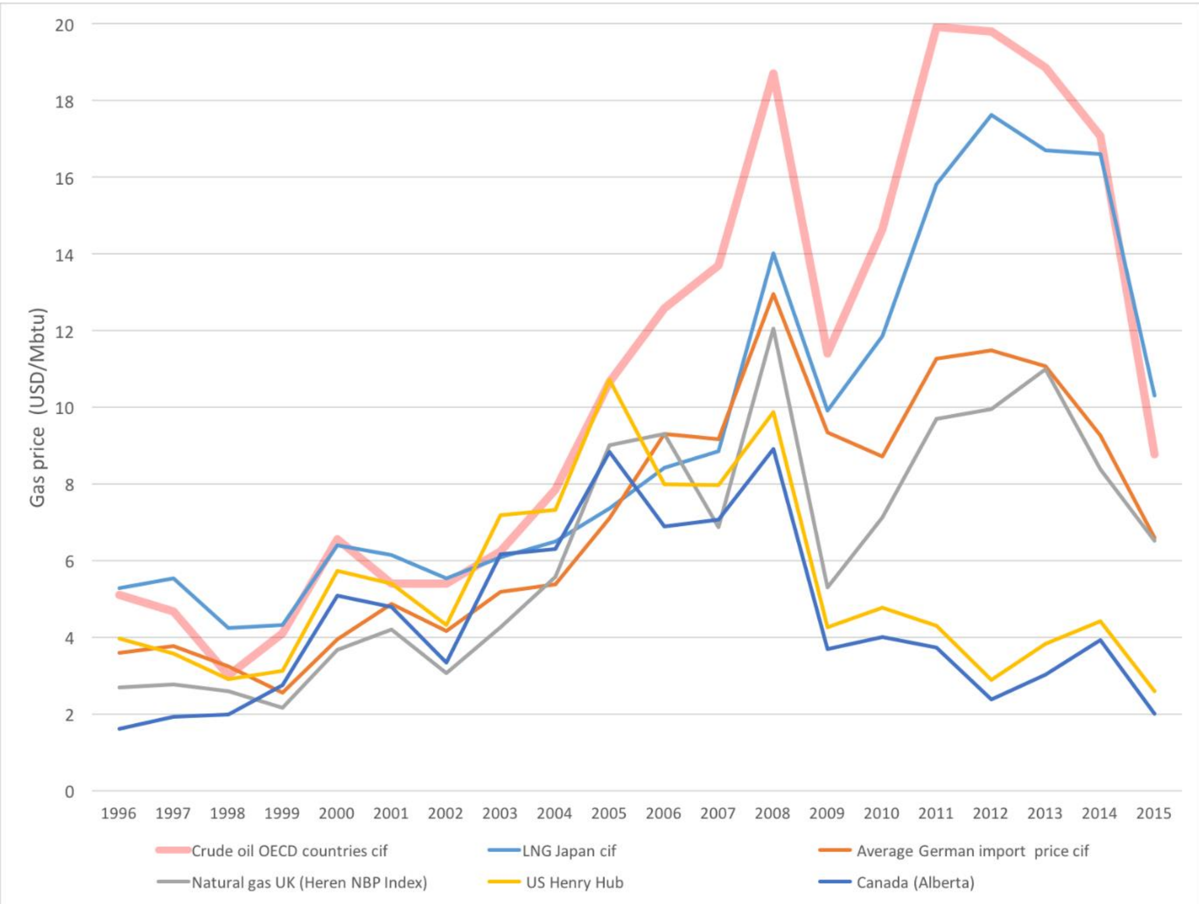

Figure 3: Natural gas prices in regional markets (BP 2016)

Thus the emergence of shale gas, the sharp increase in the demand for LNG in Japan after Fukishima, and slower than expected demand growth elsewhere, have led to significant divergence between US, European and Asian gas markets, with some convergence in 2012. Price dynamics are complex, however, and a key question for South Africa is the price at which LNG can be landed, and how this price compares to the cost of conventional gas production in the region, and to the possible local exploitation of shale gas. South Africa is, however, in the fortunate position of being located at the confluence of all major markets (although far from all of them).

2.2 Potential natural gas sources available to the South African economy

Natural gas has had historically, and still has, a very limited role in the South African economy. Until the completion of the pipeline from Mozambique in the early 2000s, the only natural gas sources in the country were the offshore fields south of Mossel Bay, which were exploited solely for the production of liquid fuels. Synthetic gas was available in limited quantities from Sasol’s Secunda plant as a by-product of the coal-to-liquids process. The Mozambique pipeline, completed just over a decade ago, gave South Africa access to the gas resources in southern Mozambique, and gas has been piped to South Africa for use in both Sasol’s chemicals plants in Sasolburg and its synfuel plant in Secunda, and also in industry. Gas use, however, remains limited. A significant increase in natural gas use in the economy could draw on a number of potential sources:

- potential gas fields offshore of the west and east coasts within South Africa’s territorial waters;
- exploitation of regional known gas fields in Mozambique (north), Namibia (the as yet unexploited Kudu gas field), off the west coast of South Africa (Ibubhesi), all of which would require additional pipeline infrastructure;
- potential shale gas resources in the Karoo Basin;
- coal-bed methane (CBM), primarily from the Waterberg region; and
- imported LNG, probably landed at Richards’ Bay, Saldhana Bay or Coega (South Africa’s three deep-water ports).

The future price of LNG can be speculated on based on historical trends, and the costs for regasification infrastructure and operation are known. The cost of producing gas from unconventional sources (shale, CBM) in South Africa is unknown, and a possible range can only be inferred from experience elsewhere. Proven reserves of gas within South Africa’s borders and territorial waters are limited, whereas the supply of LNG is effectively unlimited. The scale of the shale gas resource is unknown but estimated to be large.

2.3 Current natural gas use in South Africa

In South Africa, only 3% of total primary energy was met by natural gas in 2013 (DoE 2013). Before 2004, all of the natural gas used in the country came from the Mossel Bay fields in the Western Cape, and the gas was mainly used to produce liquid fuels by PetroSA in their gas-to-liquids plant in Mossel Bay. In 2004 Sasol started importing conventional natural gas from Mozambique and the share of natural gas increased from 1% to between 2% and 3%.

Coal is still the dominant energy resource in South, meeting 76% of primary energy supply in 2013, and the source of over 90% of South Africa’s electricity. Increasing the share of natural gas in the economy could reduce reliance on both coal in the power sector and crude oil in the transport sector, since natural gas can be used for transportation purposes in the form of liquefied natural gas (LNG) for heavy-duty freight and as compressed natural gas (CNG) for light-duty vehicles, replacing diesel and petrol demand. Reducing the reliance on coal and crude oil will benefit South Africa in terms of contributing towards its mitigation goals, and also supporting renewable energy technologies on the grid.

Natural gas imported from Mozambique, and methane-rich synthetic gas (from the coal-to-liquids process at Secunda) are currently sold via a distribution network in Gauteng, mostly to industrial customers, and also via a converted liquid fuels pipeline via Richards Bay to heavy industry in Durban. Further development of national gas resources (offshore, shale or CBM) would require the development of considerable transmission infrastructure, while importing LNG would require regasification facilities at one or more of South Africa’s three deepwater ports, and both would require the development of extensive distribution infrastructure.

Natural gas is currently included in planning activities as an option for electricity supply in terms of investment in gas-fired electricity plant. Gas-to-power would serve as an anchor market to attract investment in the primary infrastructure needed to supply gas to a more extensive distribution network, thereby significantly lowering barriers to other uses of gas in the economy. The Policy Adjusted Scenario of the Integrated Resource Plan of 2010 (IRP2010) determined that 13% of the proposed new capacity (56,539 MW excluding cogeneration) which will be added by 2030, should be supplied by natural gas-fired open cycle gas turbines (OCGT; 9%) and combined cycle gas turbines (CCGT; 4%) between 2019 and 2030 (Department of Energy, 2011). Eskom spent R10.5 billion on diesel to fuel its current Gourikwa and Ankerlig OCGT plants in 2013/14, equating to a capacity factor of over 19% – well in excess of the economic operating limit of 6% (Creamer, 2014). Additionally, if enough natural gas is procured, Eskom can convert their 2,460 MW of OCGT plant capacity which is currently running on diesel to run on natural gas.

Useful insights can be drawn from South Africa’s resulting GHG emissions profiles if gas usage increases in the economy, and the impact of increased usage of gas on mitigation goals, including the use of renewable energy, cogeneration and other options. Increased use of natural gas has been shown to favour the increased usage of renewable energy resources (Energy Research Centre, 2013b). With regard to shale, gas leakage rates during production are also a critical issue in considering the emissions impact of increased use of gas from unconventional sources (Howarth & Santoro, 2011). High leakage rates can render the overall GHG impact of shale gas production and use equal to or worse than coal.

3. South African Times model and sector descriptions

3.1 Introduction to the modelling methodology

This research work was carried out using the IEA’s TIMES model, the South African version of which is referred to as the South African TIMES model (SATIM). TIMES is a bottom-up, dynamic partial equilibrium linear optimisation model. The objective function is usually (and in this case) overall discounted system cost, and other objectives (for instance a GHG constraint) are explored using constraints imposed on the model. The detailed methodology of how the South African energy sector is modelled in TIMES can be found in Energy Research Centre (2013a). The section below gives a brief description of how each sector is represented in the model and highlights major enhancements and updates which have been undertaken since the methodology report was published in January 2013.

SATIM represents the entire South African energy system from imports and domestic production of fuel resources, through to fuel processing and supply. The energy system is represented by a ‘reference energy system’, consisting of nodes representing technologies, from supply to demand, which are linked by the flow of energy carriers. At the heart of the model’s conceptual framework is the concept of ‘useful energy’ required by the economy, expressed as the final form in which energy services are required, and disaggregated by sector and subsector. For instance, process heat in industry can be produced from electricity, coal, gas or via cogeneration. This in turn results in a chain of supply technologies and the use of a primary resource. SATIM optimises the whole energy system for a given set of useful energy demands. The model also accounts for associated emissions (GHGs and others), including fugitive emissions from energy production and industry, and for the operation and investment costs of the energy system. Since SATIM is not a full equilibrium model, useful energy demand is specified exogenously, and does not respond to the potential economic impacts of different investment paths.

What SATIM is extremely well-suited for is modelling cross-system impacts of changes in the energy system – in other words, changes which significantly affect more than one subsystem – which makes it an ideal model to explore the complex changes potentially brought about by both a GHG constraint and changes in the availability and cost of natural gas. In order to capture the impacts of uncertainty, we have used a range of values for key parameters, which are described in more detail below.

3.2 Representation of the energy system in SATIM

SATIM features five demand sectors and two transformation sectors representing the South African energy system. The two transformation sectors are the electricity generation and liquid fuel supply sectors (refineries), which are also consumers of energy resources. The transformation sectors get their primary energy supply from mining, production and import activities and convert the energy resources into secondary energy carriers, which are ultimately used in demand sectors. The demand sectors are industry, commerce, agriculture, residential and transport. In some cases, demand sectors use primary energy commodities (for instance, coal or gas in industry). In the base year of 2013, the industrial sector accounted for 49% of final energy demand, followed by transport with 33%.

3.3 Model development

In order to represent potential gas use in the energy sector in sufficient detail for this project, a number of new additions were made to SATIM, in addition to the version of SATIM documented by Energy Research Centre (2013a). These include characteristics of gas-related technologies in demand sectors, and regasification and gas transmissions and distribution infrastructure.

3.3.1 Additions in the commercial, industrial and residential sectors

Technology options using natural gas are shown in Table 1. Natural gas has applications for water-heating, space-heating and cooking in the residential sector. As is the case in other countries, some other smaller end-uses, such as clothes-drying and lighting, can also be gas-powered, but usage of natural gas for these applications is not widespread, and so was excluded from this study. If the gas market develops in the residential sector in South Africa (which would require the development of a reticulation network in residential areas), likely customers would be high- and middle-income households in urban areas, mainly because the cost of appliances and of gas reticulation (and therefore connection / fixed charges). Fixed costs would be relatively higher in South Africa because of the warm winters (and therefore low volumes of natural gas used for space-heating). Natural gas technologies are therefore added to the model for middle- and high-income households only. See Table 1.

Table 1: Natural gas end-uses and appliances

Appliances	*End-use*	*Household class*
Portable gas heater	Space-heating	Middle income
Gas fire place	Space-heating	High income
Heat pump	Space-heating	High and middle
Heat pump	Water-heating	High and middle
Natural gas geyser	Water-heating	High and middle
Natural gas /SWH geyser	Water-heating	High
Stove	Cooking	High and middle

In the industrial sector, natural gas can be used in boilers or directly for process heat (see Table 2). At the moment six energy carriers are used to meet process heat energy demand.

Table 2: End uses for natural gas use in industry

SATIM subsectors	*End uses*	*Technologies*
Mining, SIC-2	Process heat	Boiler
Iron and steel, SIC-351	Process heat	Used by various processes such as DRIEAF
Chemicals, SIC-33	Process heat	Boiler
Precious and non-ferrous metals, SIC-352	Process heat	Boiler
N.M.M products, SIC-34	Process heat	Kilns
Food, beverage and tobacco, SIC-30	Process heat	Boiler
Pulp and paper products, SIC-323	Process heat	Boiler
Other	Process heat	Boiler

In the commerce sector, natural gas can be used for cooking, space-heating and water-heating. Technologies that can be used to achieve these end-uses in the commercial sector were added. In addition, combined heat and power (CHP) plants are integrated into the model. CHP systems generally comprise an internal combustion engine or a turbine, either of which can be powered by natural gas to generate electricity, while the waste heat is utilised for meeting heating demand. In the model, the system is modelled as an internal combustion engine with natural gas as fuel, and supplies electricity and heat to the commerce sector. The CHP in commerce is set up in the model to allow for it to build as trigeneration where heat generated by the CHP plant can be redirected to an absorption chiller system (with additional costs associated with this capacity) which provides for cooling demand to be met. This configuration of CHP is shown in Figure 4 below.

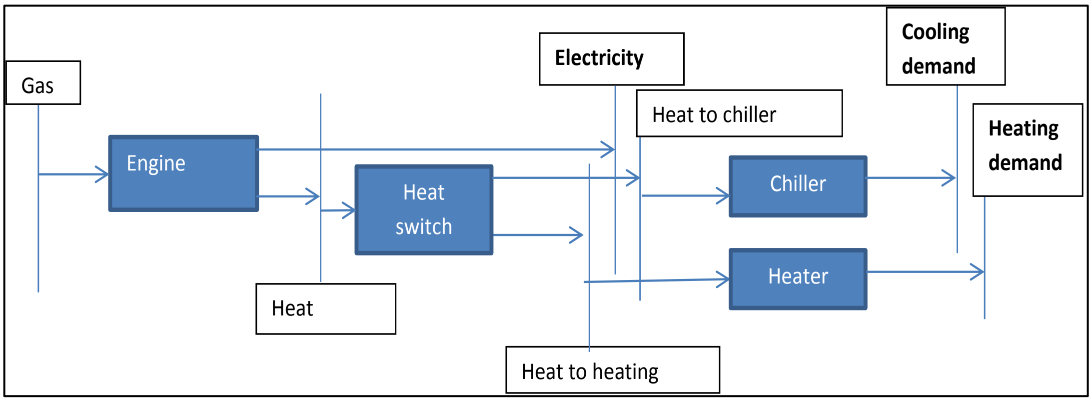

Figure 4: Configuration of cogeneration and trigeneration in the commercial sector in SATIM

3.3.2 Natural gas vehicle retrofits

The transport sector is one of the more complex sectors in terms of its representation in the model. There are two ways in which gas-powered vehicles are introduced in SATIM: implementation of natural gas retrofits on existing technologies, and implementation of new technologies (by defining a share of new vehicles sales). Natural gas can be used directly in vehicles if the vehicles are designed to use gas. Existing light gasoline vehicles (SUVs, cars, minibus taxis, light commercial vehicles and medium duty commercial vehicles) and diesel buses can be converted to natural gas vehicles as bi-fuel or dual-fuel vehicles.[1] When introducing retrofits into the model, care must be taken such that the constraints that are introduced do not exceed the available stock that can be retrofitted.

[1] Bi-fuel vehicles means that they can use either fuel (gasoline or natural gas depending on the cost of the fuel). Dual-fuel vehicle means that the vehicle uses both fuels to move. This is usually done on buses and waste collection trucks. Most researchers discourage the conversion of heavy-duty vehicles to dual-fuel because the cost of retrofit is higher and is not economic.

3.3.3 Introduction of fugitive emissions from shale gas

Fugitive emissions from natural gas production and use can either be flared or vented. Flaring the gas means that the gas is combusted (therefore converting methane into carbon dioxide and water) while venting involves releasing methane directly to the environment (Stephenson, Valle, & Riera-Palou, 2011). Flaring is preferred because natural gas is converted into carbon dioxide, which has a far lower global warming potential than methane, but is not possible for all types of fugitive emissions. Leakage rates for conventional natural gas production are fairly well known, whereas for unconventional gas production (shale gas and CBM), estimates are far more complex to make, and cover a wide range in the literature. Since shale gas and CBM gas production do not yet currently exist at a commercial scale in South Africa, estimates of fugitive emissions from potential domestic gas production from these sources are based on international literature. Fugitive emissions from shale gas are derived from literature on US shale gas production, and fugitive emissions from CBM production are derived from literature on Australian production.

4. Modelling approach

4.1 Modelling methodology

Scenario-based energy modelling aimed at evaluating potential policies traditionally develops a reference case and three or four ‘policy’ cases. Partial equilibrium models such as TIMES optimise the modelled energy system according to an objective function (in almost all cases, total discounted system cost), and the methodology for considering the impact of specific policies is to model a reference case without constraints which would be imposed by any of the policies concerned, and use this as a basis for comparison with a number of cases in which alternative policies are modelled, using the same set of assumptions. The modelling approach taken here varies from an orthodox scenario-based approach in a number of important respects. Instead of developing a reference case and then imposing constraints to test policy options, this study varies a number of key assumptions which are subject to uncertainty – technology costs, fuel costs, population and GDP growth rates. A Monte Carlo approach is adopted, which involves varying each key assumption randomly within a range with a specific probability density, based on literature and expert elicitation. (The modelling approach is elaborated in UNEP (2016).) The model is then run 1000 times with identical constraints. In a sense, each model run is a ‘reference case’. One constraint is then imposed – a 14Gt CO_2-eq cap on GHG emissions – and the model run another 1000 times. It is then possible to see how the modelled energy system reacts to a wide range of uncertainty, and what differences arise from the GHG cap under the same conditions of uncertainty. The model is also run another 1000 times with a markedly higher methane leakage rate for shale gas production, to test the impact of these additional fugitive emissions on the uptake of natural gas in a GHG-constrained world. This raises some new problems of interpretation of results, which will be further explored below.

4.2 Sources and characteristics of natural gas in the model

Three sources of natural gas are considered: i) shale gas based on the domestic resource potentially available in the Karoo basin; ii) natural gas imported by pipeline from southern Mozambique (the potential pipeline from northern Mozambique currently under discussion is not considered); and iii) imported LNG. An additional cost for transport and regasification is assumed (in the case of LNG). The gas price for each model run is established by choosing a random price for each model run separately for LNG / pipeline gas, within the ranges portrayed in Figure 5. Shale gas is only available from 2022, whereas LNG / pipeline gas is available from 2015.

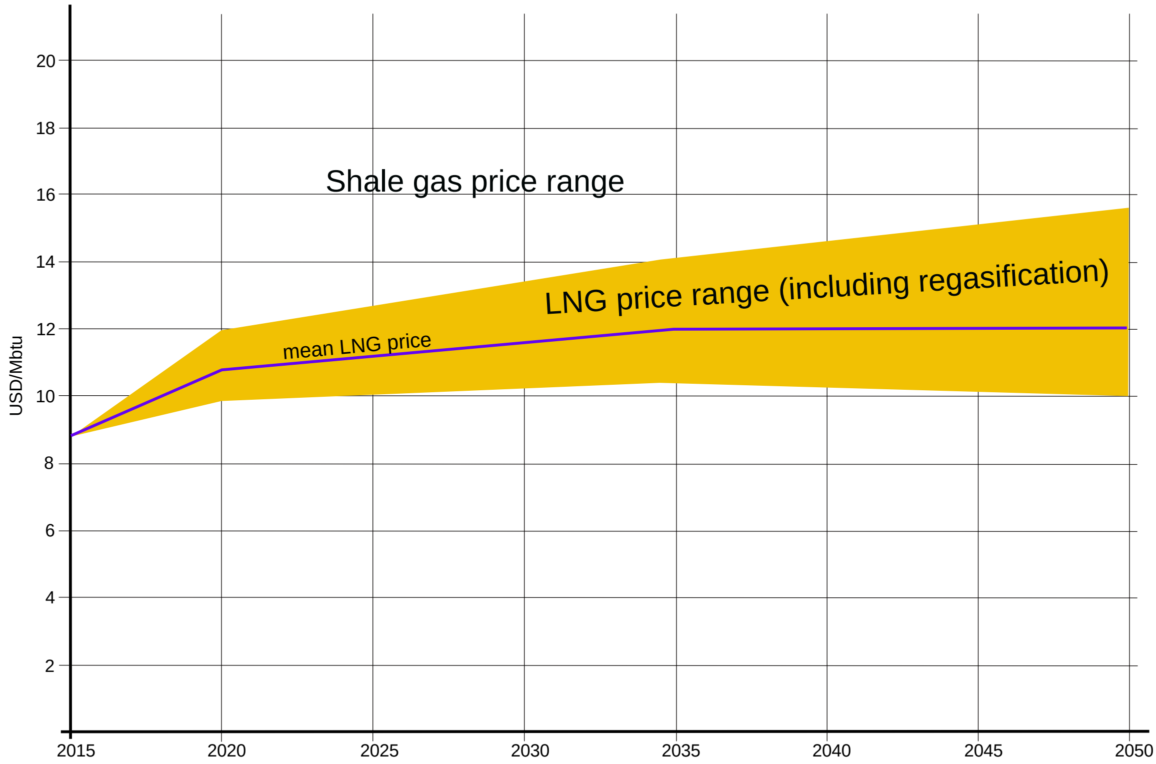

Figure 5: Gas price ranges for LNG and shale gas

Although natural gas prices (like oil prices) are notoriously hard to predict, these ranges were identified through the literature and a process of expert elicitation. The wide band for shale gas is a result of little information being available on the costs of shale gas extraction in South Africa.

4.3 Time period

The modelling period is from 2006 (the base year) to 2050, and solves on a five-year basis (i.e. for 2010, 2015, 2020, etc). This is ideal for efficiently solving large numbers of model runs and provides adequate long-term resolution, but it needs to be emphasised that the modelling framework used here is primarily geared to the long term, and does not provide sufficient resolution to address short-term challenges, such as what the optimal investment sequence for natural gas infrastructure would be for the next ten years.

4.4 GDP

The range of the GDP growth rate in the model varies between 2–4% over the modelling period (80% confidence interval) with outliers ranging between 1% and 6%. The uncertainty approach used to model the GDP growth rate is specified in detail in UNEP (2016).

4.5 Leakage rate assumption for natural gas fracking

In order to account for emissions which would be associated with domestic production of shale gas, a leakage rate is used which is the mean of the leakage rates found in the 15 studies indicated in Figure 6 – 2.86%. The total footprint of natural gas produced in South Africa from shale is thus a result of combustion (CO_2) and leakage (CH_4).

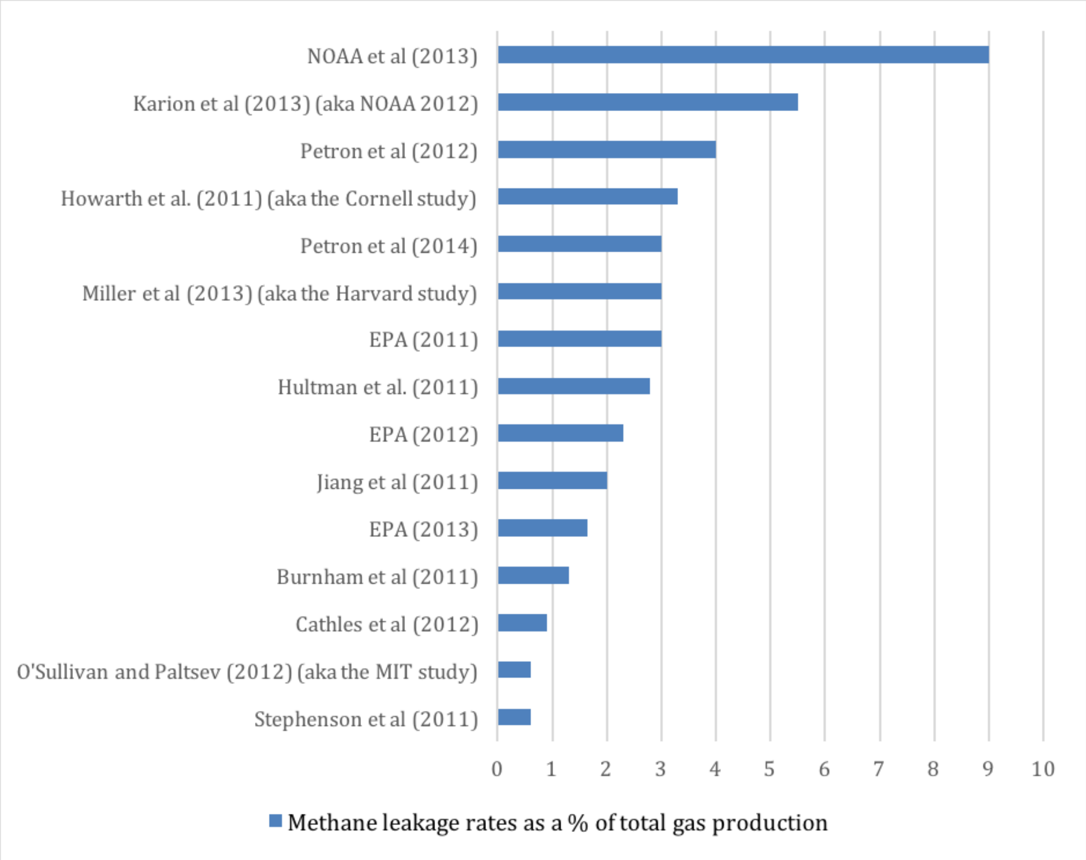

Figure 6: Methane leakage rates[4] from 15 studies

4.6 A note on presentation of results

4.6.1 Indicators

The following indicators are used in the figures below to present results:

Gas price

Figures which report the gas price against another variable, are reporting an *average* gas price, from both shale gas and LNG, calculated as a weighted average. In each case, the two gas prices are set separately, and the model then decides how much of each type of gas to use.

Primary energy supply

- TPES gas – Total primary energy supply of gas, which comprises shale gas, plus LNG, plus pipeline gas (from Southern Mozambique).
- Gas supply (all) – equivalent to TPES gas.

Emissions

- GHG emissions total in CO_2-eq – all combustion emissions plus process emissions and fugitive emissions from coal and gas extraction and processing, and also from gas transportation, calculated using standard global warming potentials for CH_4 and N_20.
- CO_2-eq from power sector – GHGs from centralised generation plants, excluding emissions from cogen and trigen (which are accounted for in the sectors in which the generation takes place).
- CO_2-eq from refineries/liquid fuels manufacture – Combustion, process and fugitive emissions from liquid fuels manufacture from crude oil, natural gas and coal, excluding cogeneration.

4 The authors are indebted to their colleague Dr Katye Altieri for this review and synthesis of literature on methane leakage rates in US shale gas production.

- CO_2-eq industry – Combustion, process and fugitive emissions, including those from Co-gen, in the industrial sector.
- Gas use in industry – including cogeneration.

The power sector

- Gas use in the power sector – all gas used in centralised power plants. Gas used by trigeneration in new commercial buildings is included everywhere except in the charts showing baseload, vs mid-merit vs peak.
- Electricity generated by gas – electricity generated by central gas plants, and commercial trigeneration, not cogeneration in industry.
- Total electricity supply – sent-out electricity by all centralised plants, and on-site generation including cogeneration and trigeneration, and rooftop PV.
- Power geneneration capacity – all centralised plants and rooftop PV, excluding trigeneration/cogeneration
- Share of electricity production by technology – share of electricity generated including cogeneration/trigeneration (in gas) rooftop PV.

Industry

- Gas use in industry – all gas used in industry including gas used in cogeneration.
- Final energy in industry – including cogeneration gas, excluding electricity generated by cogeneration.
- Industry gas consumption shares – including cogeneration
- Electricity in industry – centralised electricity.

Commerce

- Gas use in commerce – all gas used in commerce including all gas used in trigeneration.
- Final energy in commerce – all gas including trigeneration, central electricity, PV but *not* electricity from trigeneration.
- Commerce electricity – central electricity plus rooftop PV but *not* trigeneration.

Transport

- Gas used in transport – all gas combusted in vehicles.

4.6.2 Graphical presentation of results

Four types of figure are used for representing results. Each type represents 1000 model runs, either in a time series or for a specific year, as described below.

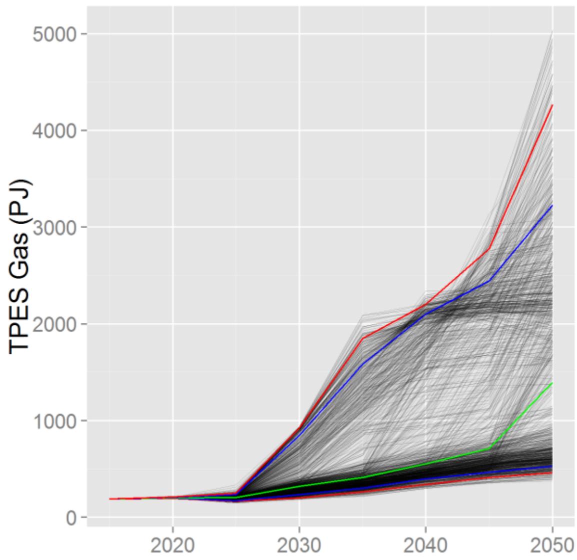

Figure 7: Type 1: time series

Type 1 (see Figure 7) are line graphs, with each very thin black line representing one model run, over the time period 2015–2050. The green line is the median for each year, the blue lines are the 10^{th} and 90^{th} percentiles, and the red lines are the 2.5^{th} and 97.5^{th} percentiles respectively. None of the coloured lines represents a specific model run.

Figure 8: Type 2: scatterplot with isopleths and colour-coded data points

Type 2 (Figure 8) represents 1000 model runs in a scatterplot for one year (in this case 2045), and the x and y axes are two possibly correlated indicators. Each dot can also be colour-coded to represent a third quantity (in this case, the predominant source of the gas – more than 60% from LNG, more than 60% from shale, or somewhere between the 60/40 range for both). The isopleths (contour lines) delineate areas of equal probability.

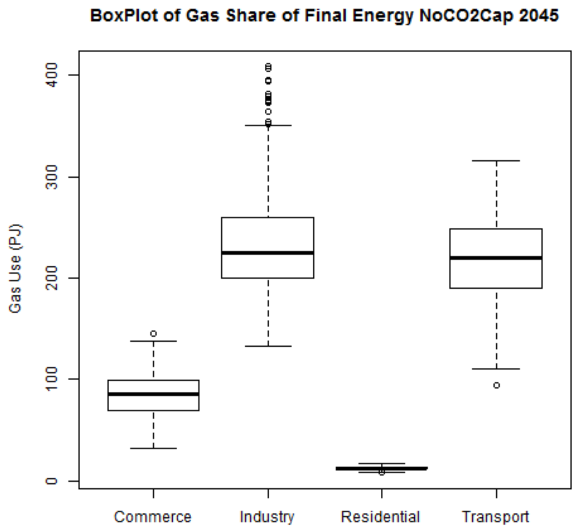

Figure 9: Type 3: boxplot

Type 3 (Figure 9) are boxplots, which plot the distribution of one variable for 1000 runs. The solid bar is the median, the 'boxes' are the 25th/75th percentiles, and the 'whiskers' are approximately a 95% confidence interval. Single points outside these are outliers.

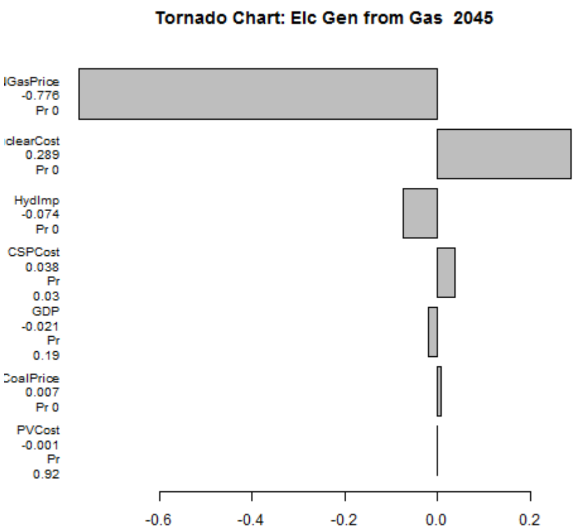

Figure 10: Type 4: tornado chart

Type 4 is a 'tornado chart' (Figure 10), which are the regression coefficients of a 'normalised' dependent variable (in this case: Elc Gen from Gas) and independent variables (GasPrice, etc…). A -0.776 coefficient for Gas implies that an increase in gas price of 1% would result in a decrease in Elc Gen from Gas by 0.776%. A 0.289 for Nuclear Cost implies an increase in Nuclear cost by 1% results in an increase of Elc Gen from gas of 0.289%. These numbers should not be interpreted too literally. Determining the exactness of the relationship would require a linear model, everything else staying at the mean. However, it shows direction and strength of the relationship between each of the independent variables that affect the variable of interest the most.

Results are presented in increasing detail – first for the overall use of gas in the economy, followed by an overview of the sectors in which gas is used, and then followed by a more detailed account of key sectors in which there is gas uptake.

4.7 Gas in the primary energy supply

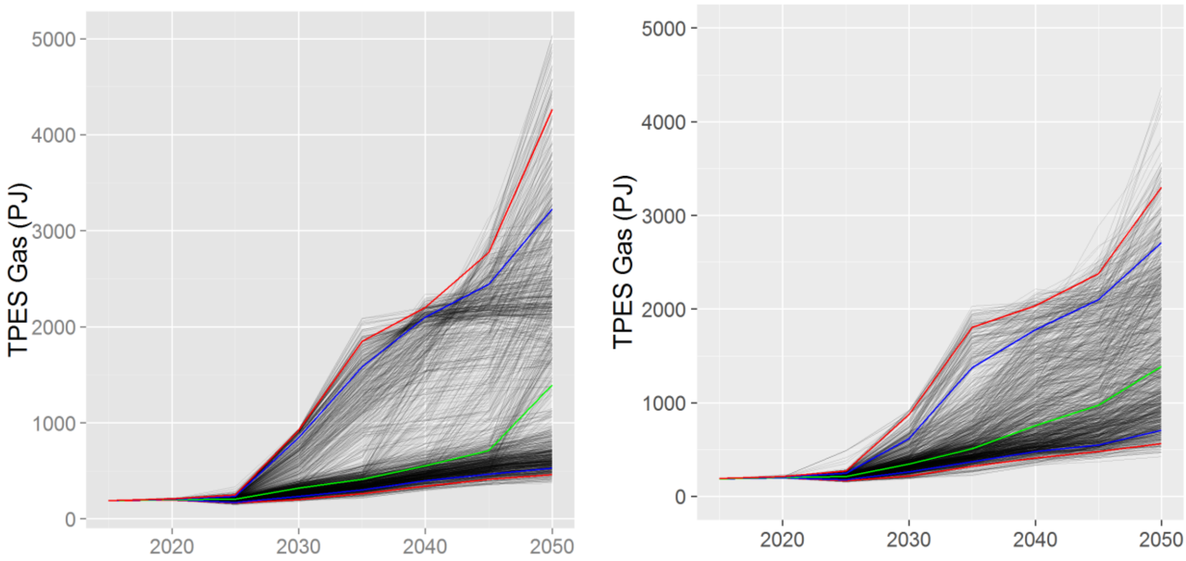

Figure 11: Total primary energy supply of gas – GHG unconstrained (left) and constrained (right)

For each of the sets of runs (with and without a GHG constraint), Figure 11 plots the total primary energy supply provided by natural gas in the South African energy system. Median uptake (the green line) is relatively low compared to the full range, and the interesting contrast between the cases with the GHG constraint, and without, is the faster uptake in the median level before 2040, combined with lower overall uptake.

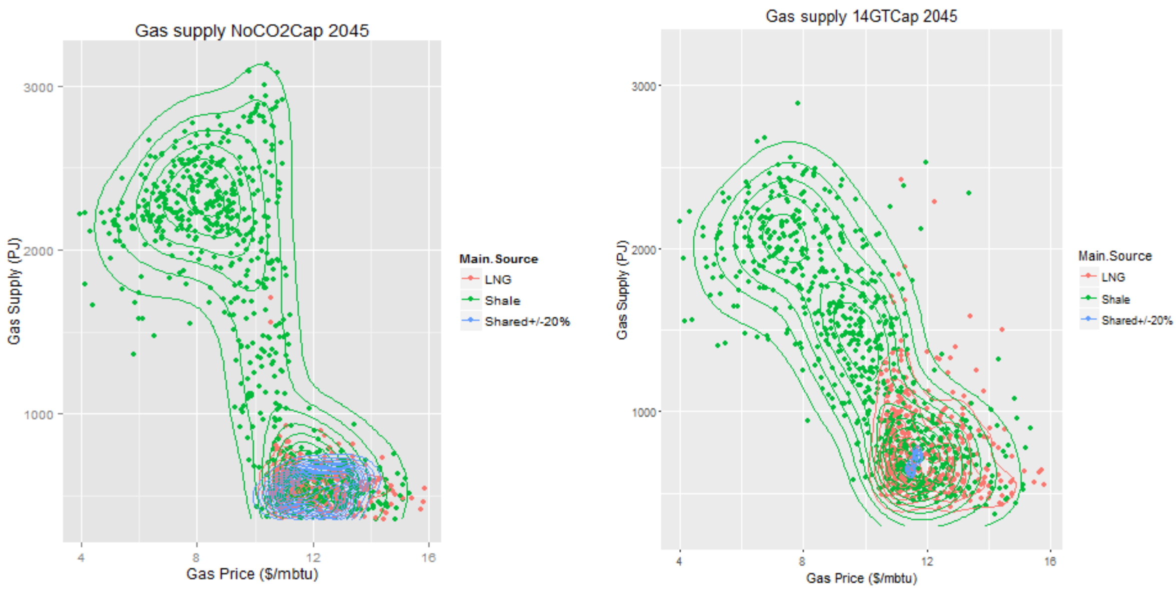

Figure 12: Gas supply vs gas price – GHG unconstrained (left) and constrained (right)

In the GHG-constrained cases, median uptake is fairly even over the period, whereas in the unconstrained cases there is a major inflection point after 2045. Below, we will explore the drivers in the overall economy, and then focus on specific sectors to understand in more detail what is driving this expansion in each of the sets of cases.

Figure 12 is scatterplots of each of the sets of cases, of total primary energy sourced from gas vs the average gas price for the year 2045, with colour coding to indicate the dominant source of the gas (LNG or shale). As mentioned above, we have modelled two potential sources for gas – conventional (LNG) and shale gas from domestic sources, and the price of shale gas occupies a much larger range than conventional gas. The average gas price is a weighted average of both prices, which are randomly selected from within the ranges discussed above, separately. What is apparent from the scatterplots is that (i) price is a major determinant of uptake; (ii) about half of the range of potential uptake only occurs below the minimum price assumed for LNG; and (iii) a GHG constraint leads to much higher levels of uptake at higher price levels. The range of uptake is consistently lower in the GHG-constrained cases. There is a clear inflection point at a price between USD 10 and USD 11/Mbtu. This is most visible in the unconstrained cases, in which the function of gas in the energy system changes dramatically below that price, which will be explored in more detail below. The large-scale use of shale gas is related purely to the assumed availability of shale gas at lower prices, since the inflection point is below the minimum price point of LNG, thus different price range assumptions would lead to a different gas mix. Because of the GHG constraint and the additional emissions from leakage for shale gas, there is a higher proportion of LNG used at prices greater than USD 11/Mbtu.

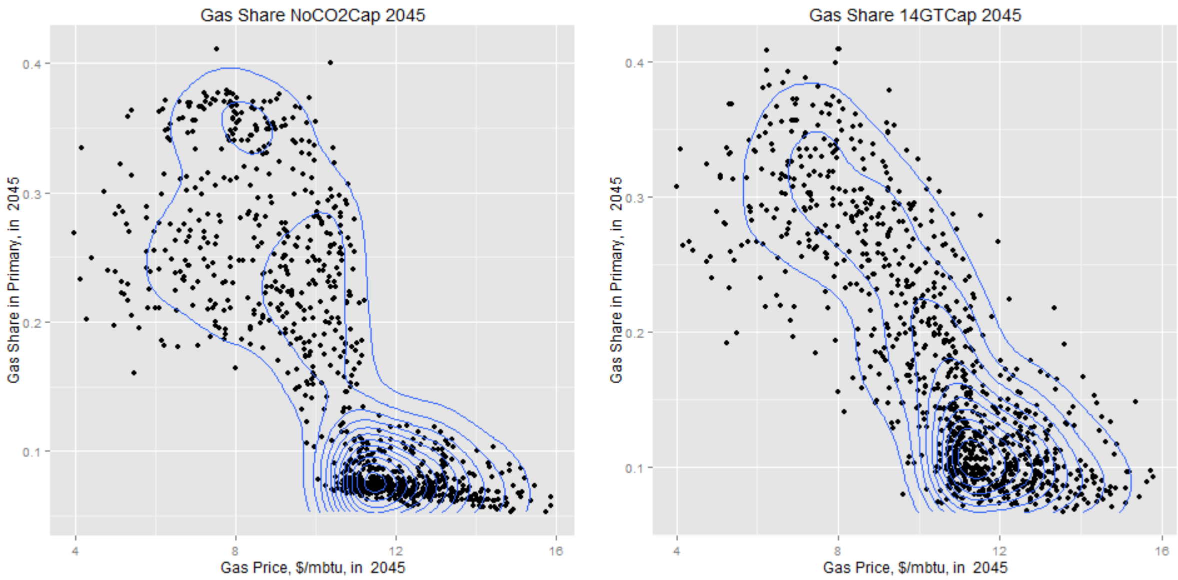

Figure 13: Gas share of primary energy vs gas price – GHG unconstrained (left) and constrained (right)

This is elucidated more clearly in Figure 13, which is scatterplots of the share of primary energy which gas occupies in 2045. In the unconstrained cases, there are clearly two clusters of cases – a ‘cheap gas’ cluster with relatively high uptake (between 15% and 40% of primary energy) and a fairly low uptake at around 5%, which are separated by a price point of between USD 10 and USD 11 per Mbtu. This is not the case in the constrained case however, where the constraint drives a much more linear distribution of shares, with a concentration above the USD 11 point between 5% and 15%.

We have explored the drivers behind this overall uptake of gas using the technique outlined above to produce tornado charts, indicating the probable impact of specific variables on the respective results, in Figure 14 and Figure 15. The key driver for gas uptake is the price of gas, although this is marginally lower in the constrained cases. GDP is a stronger driver in the constrained case since the GHG cap is absolute, which forced diversification of the energy supply where demand grows faster. Other key (but lower) sensitivities are to the cost of nuclear energy and the cost of concentrating solar power (CSP). Sensitivity to nuclear cost is much higher, as could be expected, in the GHG-constrained case, in which lower-carbon technologies compete to meet demand. GDP, and therefore increased demand, is a significant determinant of uptake of natural gas, but is *not* a significant determinant of the share of primary energy supply when considering the same sensitivity to the share of natural gas in the energy system (as opposed to the magnitude).

In Figure 15, GDP growth has a negligible impact on the *share* of gas in the energy system, the price of gas still has the largest impact, and nuclear costs are significant in the GHG constrained cases. Coal price plays a small role in determining uptake in the unconstrained cases, but the GHG constraint prevents coal price from playing a significant role in the constrained cases. The actual coal price varies with coal use, as outlined above, and is portrayed in Figure 16.

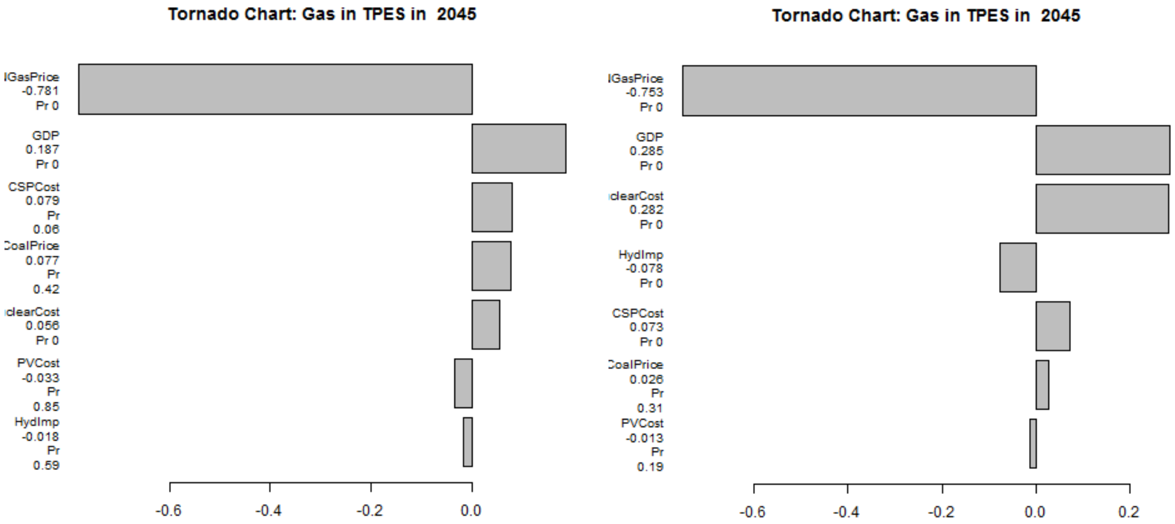

Figure 14: Factors affecting gas primary energy supply – GHG unconstrained (left) and constrained (right)

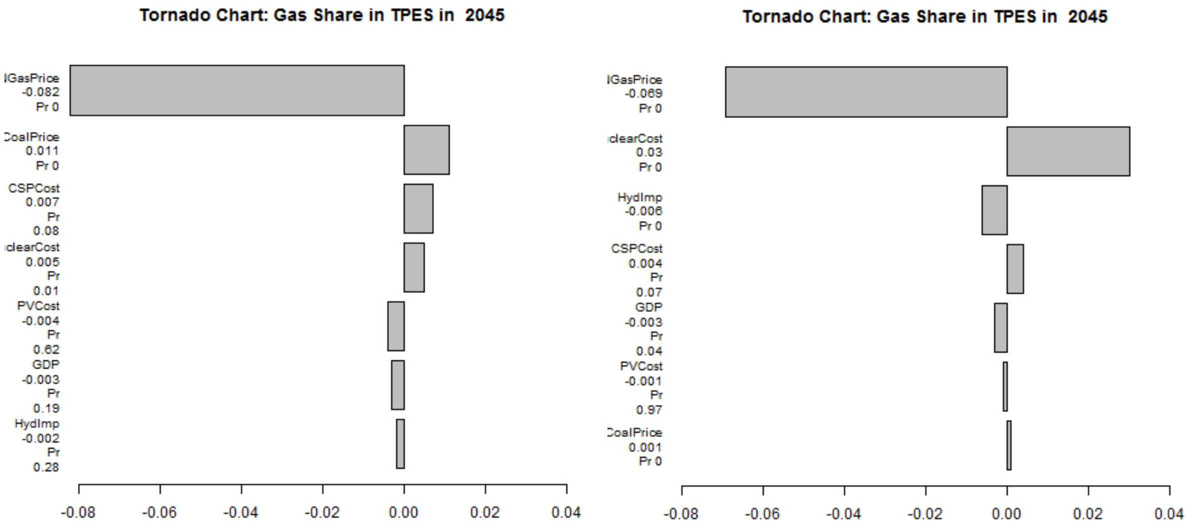

Figure 15: Factors affecting share of gas primary energy supply – GHG unconstrained (left) and constrained (right)

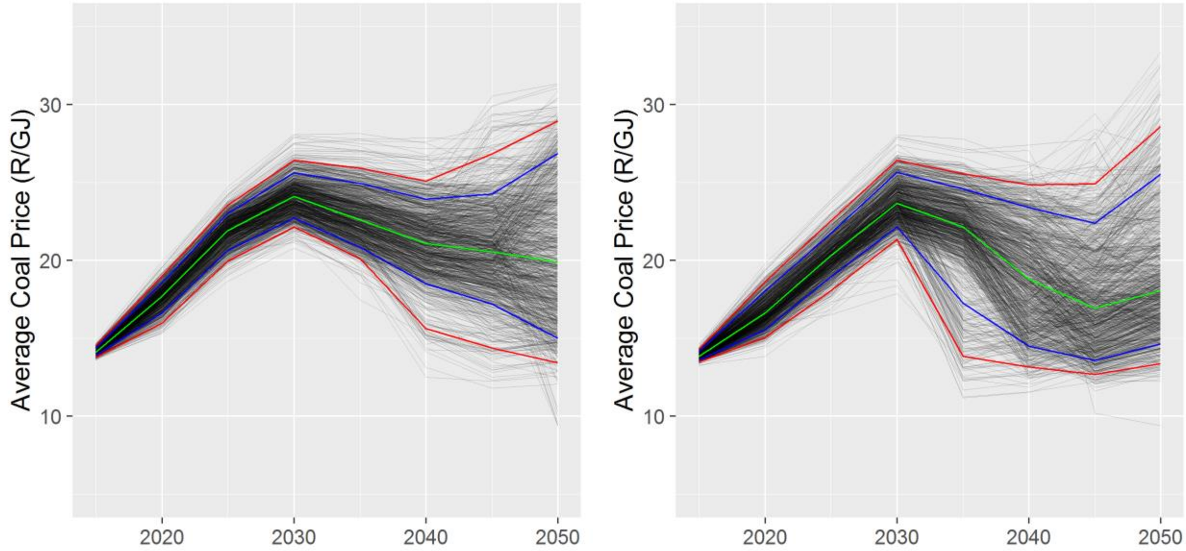

Figure 16: Average coal price – GHG unconstrained (left) and constrained (right)

GHG emissions in the two scenarios are portrayed in Figure 17. The narrow range of emissions in the constrained case is not surprising, although there is a slight difference in the timing of emissions changes and thus low-carbon investment. The range of emissions in the unconstrained cases is more surprising. Both will be explored more below.

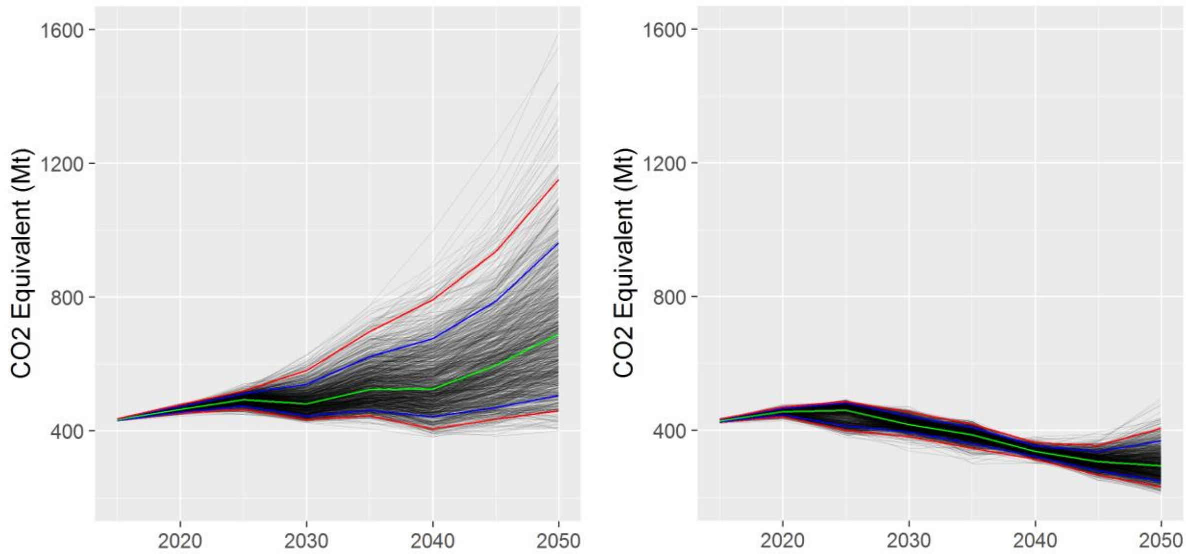

Figure 17: Total GHG emissions – GHG unconstrained (left) and constrained (right)

4.8 Use of natural gas in the energy system

Figure 18 consists of scatterplots of gas use in the energy system against the average gas price, using the same data as Figure 13, but with the scatterplots coded by colour according to which category of use dominates. Gas use is divided into transformation (electricity generation and liquid fuels production, in which gas is used to produce electricity or liquid fuels) and final energy use in other sectors (industry, transport, commercial, residential, in which gas is used directly). Blue points represent cases in which gas use is dominated by transformation (more than 60%), red points represent cases in which gas use is dominated by final energy use (more than 60%), and green points represent cases in which use is mixed (less than 20% difference between final energy use and use for transformation).

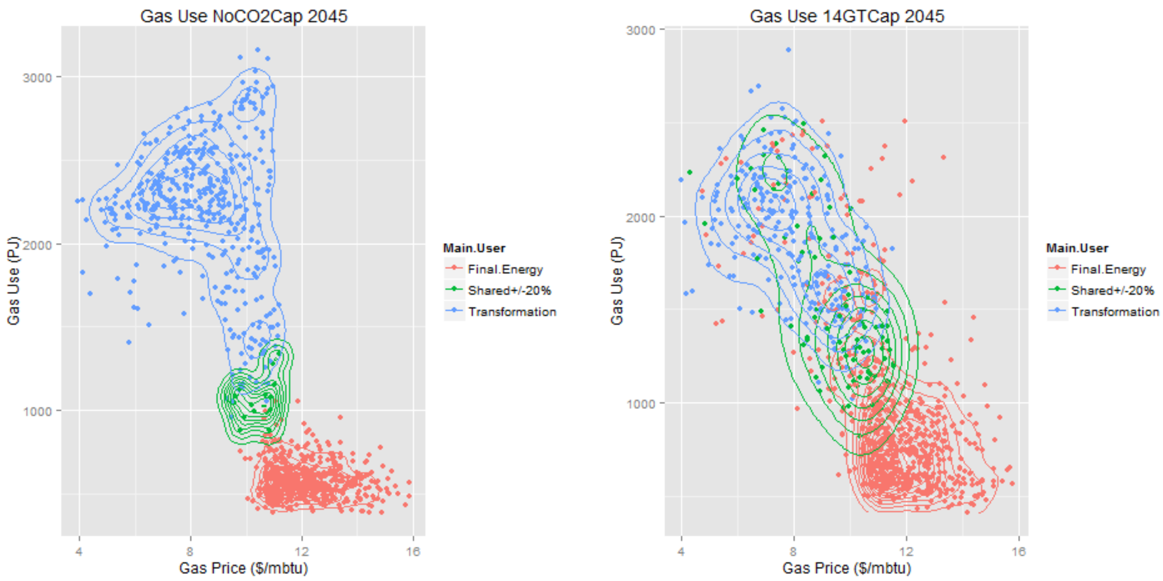

Figure 18: Gas price vs gas use, by type – GHG unconstrained (left) and constrained (right)

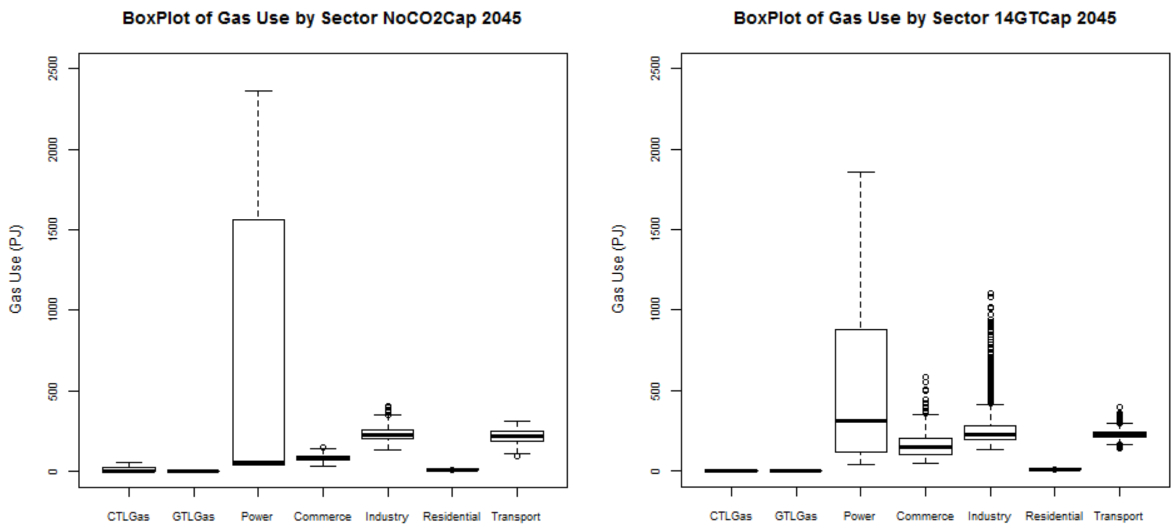

Figure 19 – Gas use by sector – GHG unconstrained (left) and constrained (right)

Since the threshold for the coloration in the figures is 60%, either red or blue coloration does not signify the *exclusion* of gas use in either transformation or final energy use. In the unconstrained cases the differentiation is quite well-defined. Use of gas as final energy dominates over USD 10/Mbtu, with transformation playing a minor role. Large-scale gas use begins at below USD 10/Mbtu, and is dominated by transformation. The GHG-constrained cases are significantly more complex. Final energy use dominates over the same price level, but dominant cases are evenly spread throughout the price range. High gas-use cases present a much more complex trend, with a spread of outliers in which final energy use dominates, at much lower prices, due to the GHG constraint driving gas use in the industry and commerce sectors.

Boxplots in Figure 19 portray the range of gas uptake by sector across the economy. In the unconstrained cases, by far the widest range is in the power sector, and the ranges of uptake are comparatively narrow in the demand sectors. In half the cases, there is very little gas use in the power sector. In the constrained cases, the picture is somewhat different, with a significantly smaller range of uptake in the power sector, and high uptake in the industry and commerce sectors in the upper range. This is clearer in Figure 20, which portrays the share of gas use by each sector.

This clearly indicates an incongruence between uptake in the power sector and in the other sectors, which maintain their shares when uptake in the power sector is fairly low.

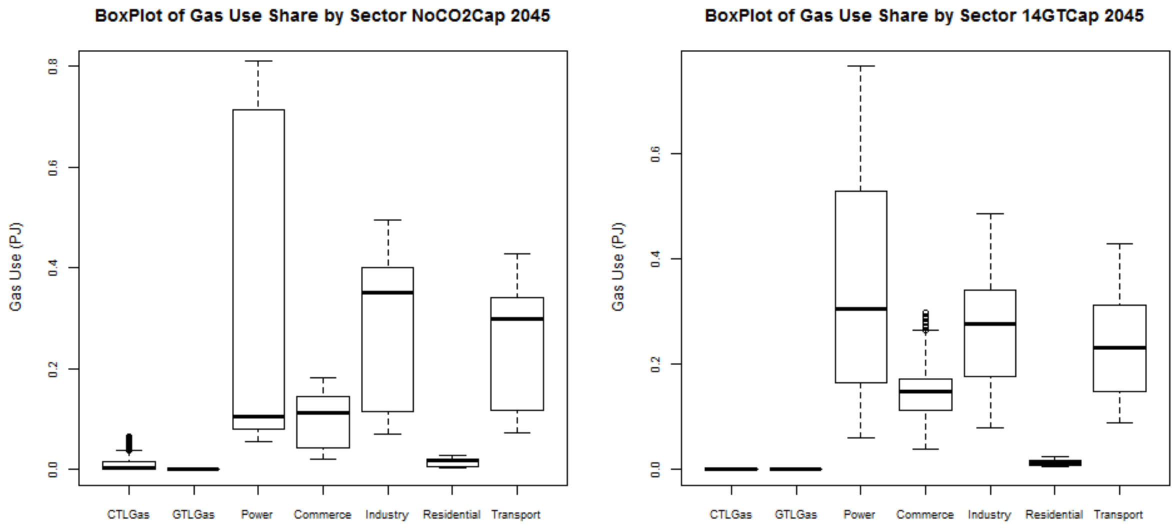

Figure 20: Share of gas use by sector – GHG unconstrained (left) and constrained (right)

Figure 21 indicates the range of GHG emissions in both sets of cases per sector in the year 2045, by which time most current coal-fired power plants would have retired, as would the current coal-to-liquids plant, and emissions from these sectors are indicative of new infrastructure. The range of emissions in the power sector is indicative of the overall electricity demand and the supply mix (between coal and gas). What is clear from the unconstrained cases is that the bulk of emissions originate from the power sector with industry, transport and liquid fuels manufacture having a far lower impact. The contrast with the constrained cases indicates where the key least-cost mitigation options are in the model: the biggest shift is in the power sector, followed by liquid fuels manufacturing, with far smaller variations in the other sectors, which is consonant with the very high GHG intensity of the liquid fuels manufacturing sector and the electricity sector in South Africa. As will be further seen below, coal power is curtailed in the constrained cases, with concomitant diversification, and at the same time gas use for power generation has a smaller range due to the GHG constraint.

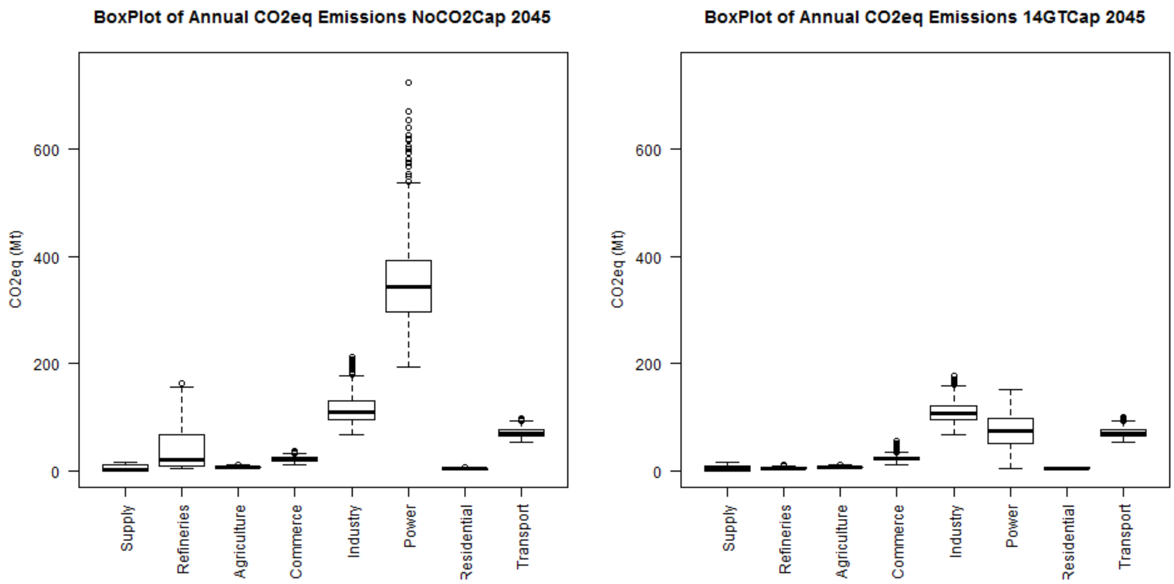

Figure 21: GHG emissions in 2045 per sector – GHG unconstrained (left) and constrained (right)

4.9 The power sector

Gas use in the power sector is portrayed in Figure 22. The median is very low in the unconstrained GHG cases until 2045, and higher uptake rates are largely correlated with the availability of low-cost gas and high levels of GDP growth. The timing of the scaling-up of gas generation is a combination of the gas price and GDP growth. With higher gas prices and/or lower GDP growth rates, gas use is largely confined to peaking plants. The GHG-constrained cases have a different growth pattern – the median growth is significant from 2040, but only at 50% of the unconstrained cases, and the outliers (with very low gas prices) grow similarly until 2035, but their growth is constrained by GHG limitations from 2040 on. The range of growth is very significantly smaller (around 50% of that of the unconstrained cases). The first factor in this difference is in the difference in demand between the constrained and unconstrained cases.

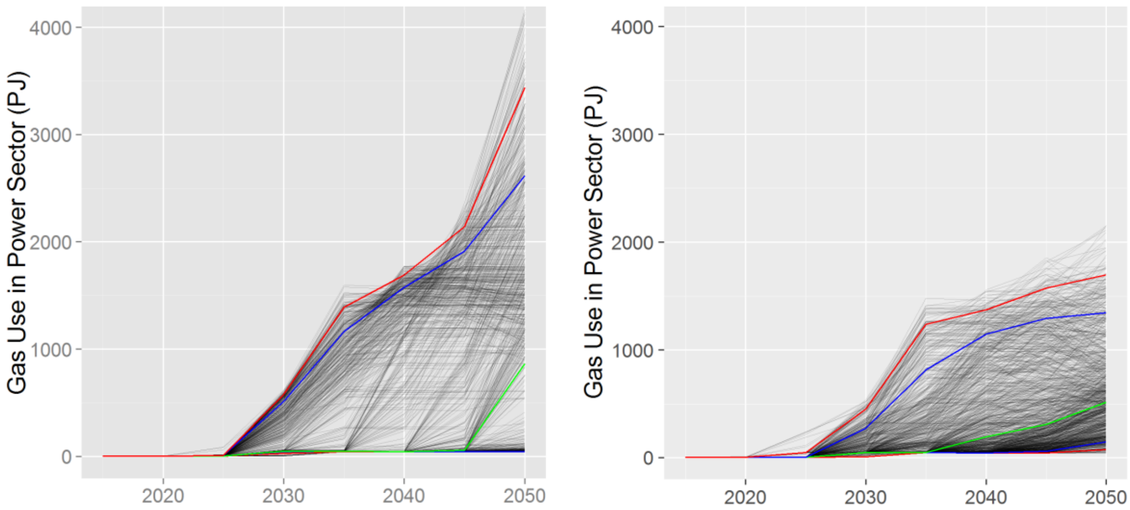

Figure 22: Gas use in the power sector – GHG unconstrained (left) and constrained (right)

Figure 23 plots the gas price against electricity generated by gas for the year 2045, and the colours indicate the average capacity factor of gas power plants in each case, and indicate the role which gas power plays in the overall electricity system. The red dots represent cases in which the capacity factor is higher than 60% – in other words, on average, gas plants approach the function of baseload plants; green dots indicate cases in which the average capacity factor is between 10% and 60%, approximating to the average function of mid-merit plants, and blue dots for capacity factors below 10%, i.e. plants are mainly used for peaking. One of the cases for large-scale gas deployment in South Africa is the balancing role that gas could potentially play if solar and wind power was deployed at a large scale, and this would typically involve a capacity factor of between 30% and 60%. The function and extent of the role of gas power in the electricity system is sharply determined in the unconstrained cases by the gas price, with a dramatic shift at a price of around USD11/Mbtu. Over a gas price of around 11 USD/Mbtu, gas use for power generation declines to extremely low levels and primarily serves the function of peaking plant within the electricity system. The GHG-constrained cases have a significantly different and more linear distribution which indicates that mid-merit plants are used at significant scale above and below that price, even though the overall distribution of gas power use is lower. This reflects both the impact of the GHG constraint as well as the more variable use of gas plants in a grid with significant levels of renewable energy uptake, which will be explored further below.

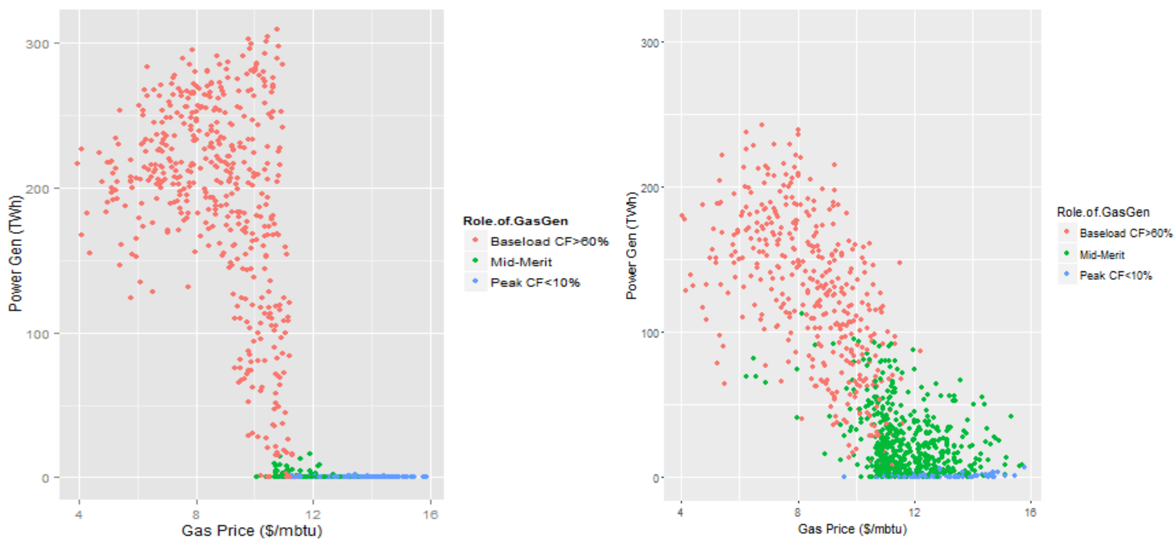

Figure 23: Electricity generated vs gas price, by capacity factor – GHG unconstrained (left) and constrained (right)

Figure 24 and Figure 25 plot the total electricity supply, including from self-generation, and the total electricity demand on the grid, respectively. The slight differences between the cases with and without a GHG constraint are due to some demand-side efficiency measures, in the commerce sector particularly, and an increased uptake of co-generation in industry, which contributes to lower power requirements for the constrained cases. The overall range of demand, resulting from the range of GDP growth rates, is large, and plays a significant role in the dynamics of the GHG-constrained cases.

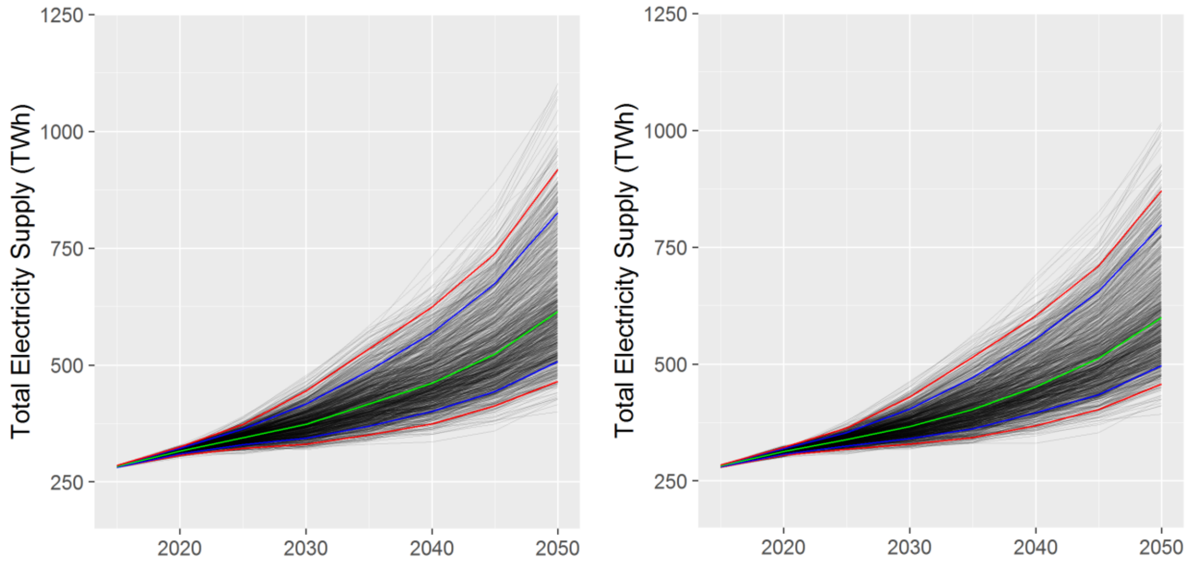

Figure 24: Total electricity supply – GHG unconstrained (left) and constrained (right)

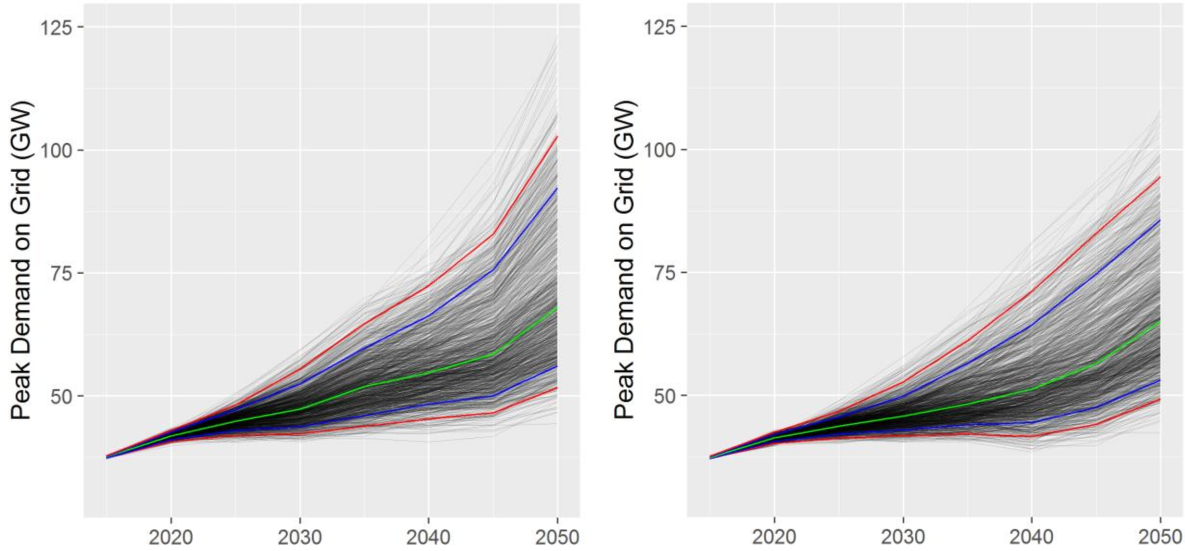

Figure 25: Peak electricity demand – GHG unconstrained (left) and constrained (right)

In the unconstrained cases, electricity generation is dominated by coal, with only half the cases having any significant quantities of gas generation, with significant outliers at higher levels. The share of coal and gas is determined by the price at which gas is available, with significant capacity only coming in below a price of USD 11 /Mbtu. Notably neither nuclear power nor renewable energy contribute significantly to the energy mix. In the GHG-constrained cases, the picture is quite different.

The range of coal generation capacity is far smaller in 2045, and represents mostly residual capacity with a small amount of new capacity in a minority of cases. The key driver for this is obviously the carbon constraint, which also drives the large investments in nuclear power and renewable energy, and caps the uptake of gas, even at very low prices. The role of gas in the electricity system, as observed above, is different – the lower capacity factors are driven by the intermittency of the PV, CSP and wind plants in the system – in other words the role of gas as a system balancer. The predominant influence on the quantity of electricity generated from gas, in Figure 28, is the gas price. In the unconstrained cases this is the only notable influence, whereas in the constrained cases the cost of nuclear technology is a significant but lesser factor. Nuclear power is almost entirely absent from the unconstrained cases, but under some conditions is adopted at large scale (the range is greater than gas). Since the capacity indicated in Figure 26 is for the year 2045, for coal capacity in both sets of cases, the bottom of the range represents the remaining residual capacity, which has largely retired by 2045. In the unconstrained cases there is an enormous range of potential coal uptake, primarily driven by the cost of gas and by variations in GDP. In the constrained cases, there is almost no new coal capacity in 2045, and the main variation is in the balance between low-carbon technologies and gas.

Plant use is indicative of the dominance of coal in the unconstrained cases. Figure 26 consists of boxplots of electricity generated by technology in 2045. The bottom of the range in both sets of cases indicates the role of residual coal capacity, which is relatively small. Figure 27 indicates the shares of electricity production per technology. The share of electricity production from coal is high – a median of around 0.6.

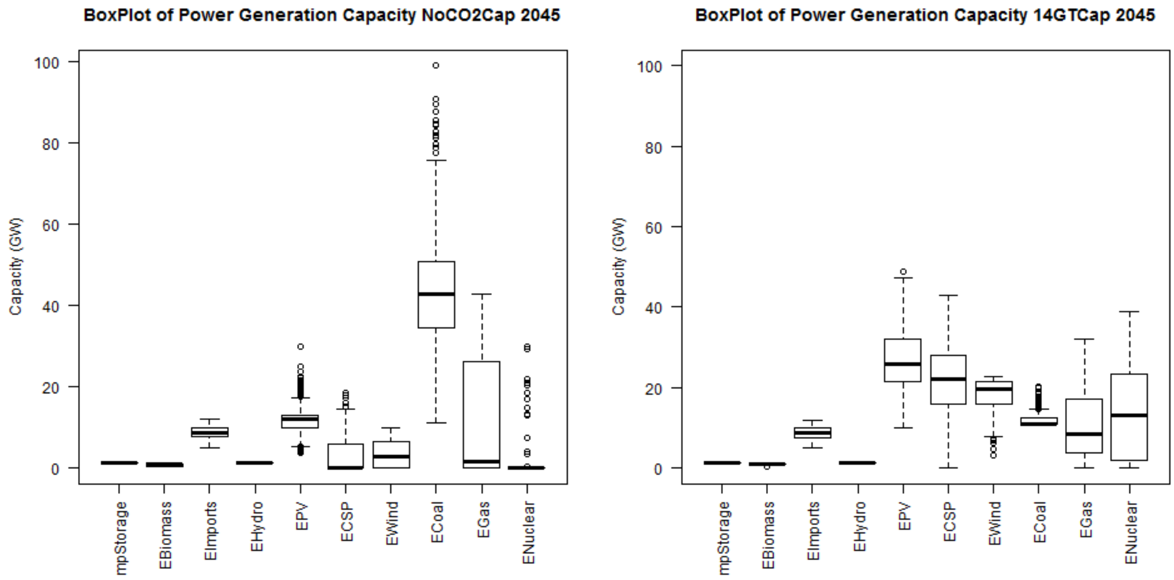

Figure 26: Power generation capacity by technology – GHG unconstrained (left) and constrained (right)

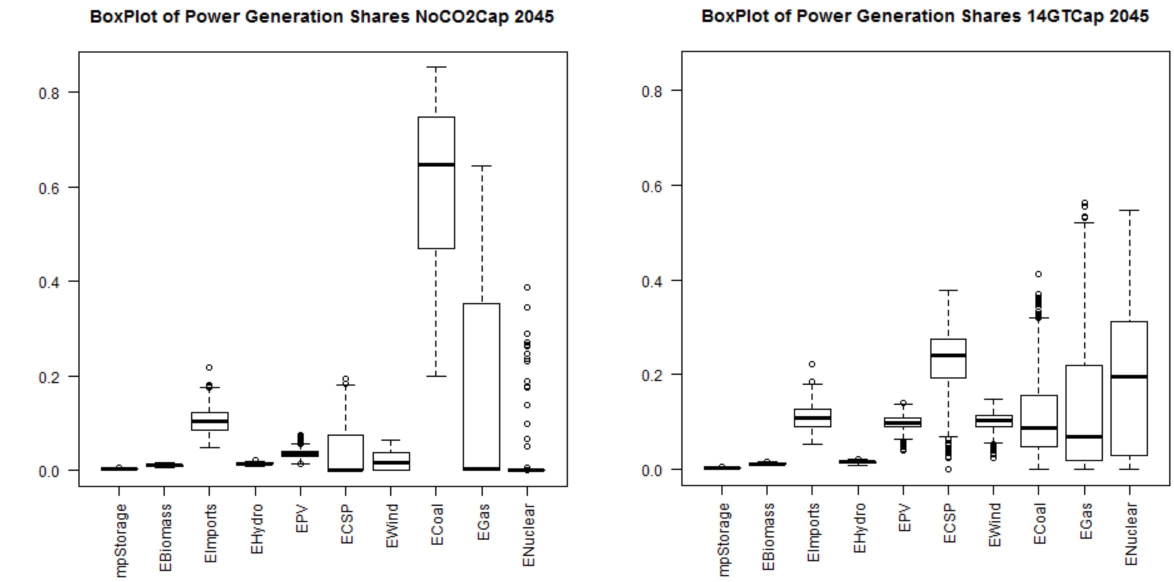

Figure 27: Share of electricity production by technology – GHG unconstrained (left) and constrained (right)

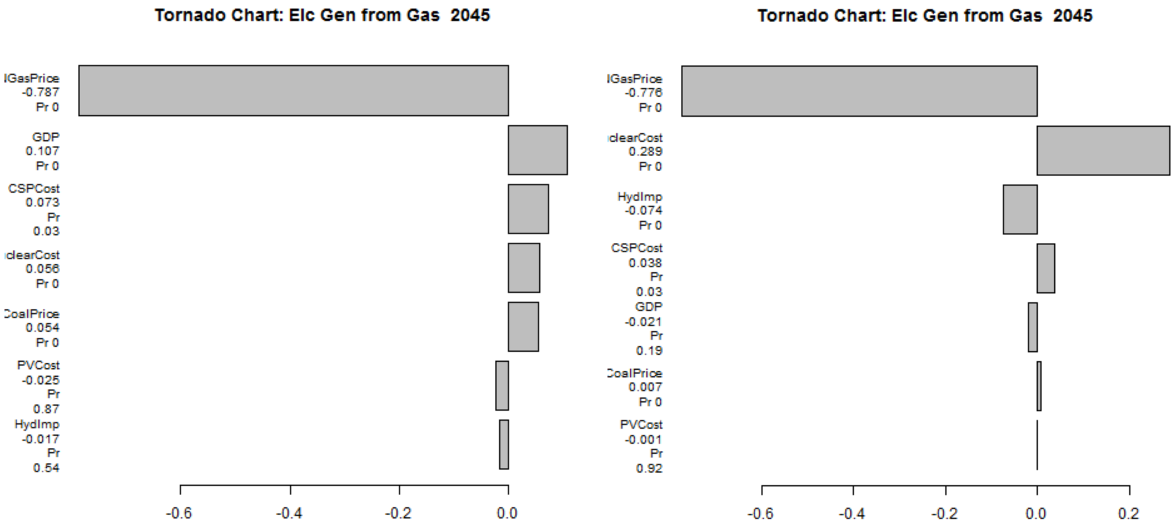

Figure 28: Factors influencing gas power generation – GHG unconstrained (left) and constrained (right)

Gas power occupies a 25–75% percentile range of zero to around 30%, with a median close to zero. In almost all unconstrained cases, there are no new nuclear plants. In the constrained cases, the residual coal capacity still plays a significant role in electricity production, and the variation is explained primarily by trade-offs in the overall energy system of the remaining emissions space, given the GHG constraint. Nuclear, CSP and wind and solar play a dominant role in the majority of cases, followed by gas. CSP, compared to other technologies, is less sensitive to key variables, and lacks the sensitivity that gas power has to fuel price. As will be discussed further below, since there is significant path dependency resulting from the GHG constraint, there are trade-offs between decarbonisation in the liquid fuels sector (specifically synthetic fuels) and decarbonisation in the electricity sector. Given the lack of new coal capacity in the constrained cases, the variation in output is driven by the timing of the reduction of emissions from the liquid fuels sector. In Figure 28, it is evident that the key variable influencing the scale of gas power generation is the gas price in the unconstrained cases; in the constrained cases, the cost of nuclear power has an important secondary effect. In terms of the share of gas power, in Figure 29, GDP has no discernible impact on the share of gas power in the unconstrained cases, but in the constrained cases, it has a mildly negative effect because of the carbon constraint, which limits the over-deployment of gas.

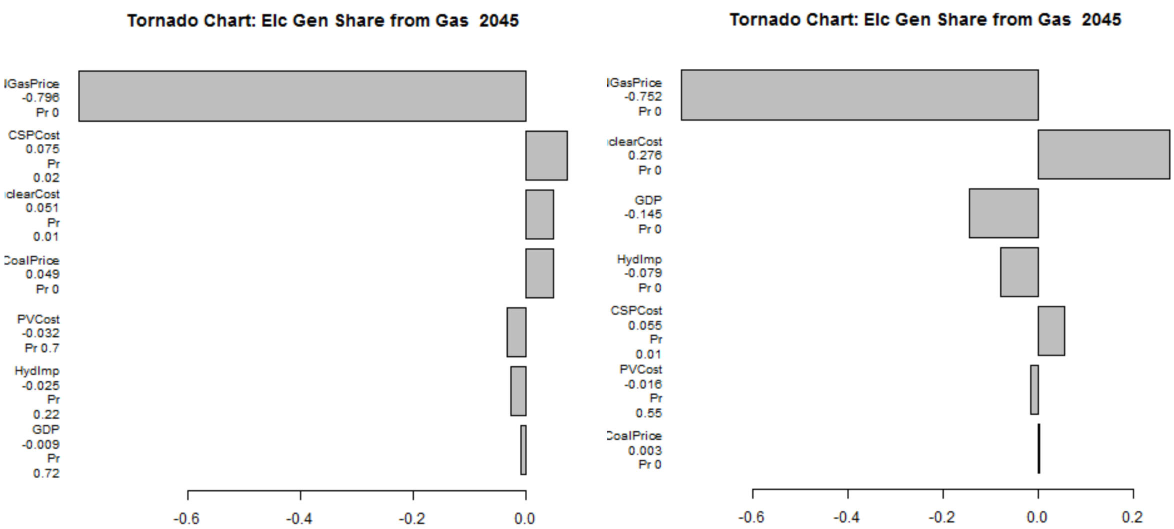

Figure 29: Factors influencing share of gas power generation – GHG unconstrained (left) and constrained (right)

Figure 30 to Figure 34 plot the relationship between electricity generated from gas and electricity generated by other technologies, and also indicate the role which gas plants play in the electricity system by the colour of each point – red indicates an average capacity factor of over 60% (akin to baseload), green indicates a capacity factor of between 10% and 60% (mid-merit) and blue indicates a capacity factor of below 10% (peaking). Figure 30 plots electricity generated from gas against electricity generated from coal, and the dynamic between these two electricity sources in the unconstrained cases is based on demand and the gas price – very high levels of coal-fired electricity are accompanied by very little gas power. In the middle of the coal range, the range of gas generation is large, depending on demand and the gas price, and at lower levels of coal generation, in all the cases capacity factors of gas plants are high, corresponding to low gas prices. There is a more limited but still pronounced trade-off between coal and gas in the constrained cases, but as can be seen from the figures which follow, the persistence of lower capacity factors at higher levels is due to other factors. Figure 31 plots electricity generated from gas against electricity generated by nuclear power. Within the range of costs for nuclear plants modelled, nuclear power is not competitive with either gas or coal, except at very high gas prices. As indicated in Figure 27, significant levels of nuclear power are absent in the unconstrained cases apart from a few outliers. In the constrained cases however, there is a trade-off between electricity generated from gas and electricity generated from nuclear power, since both gas and (even more) coal are constrained by the GHG constraint, and the trade-off hinges on the cost of nuclear technology and the gas price.

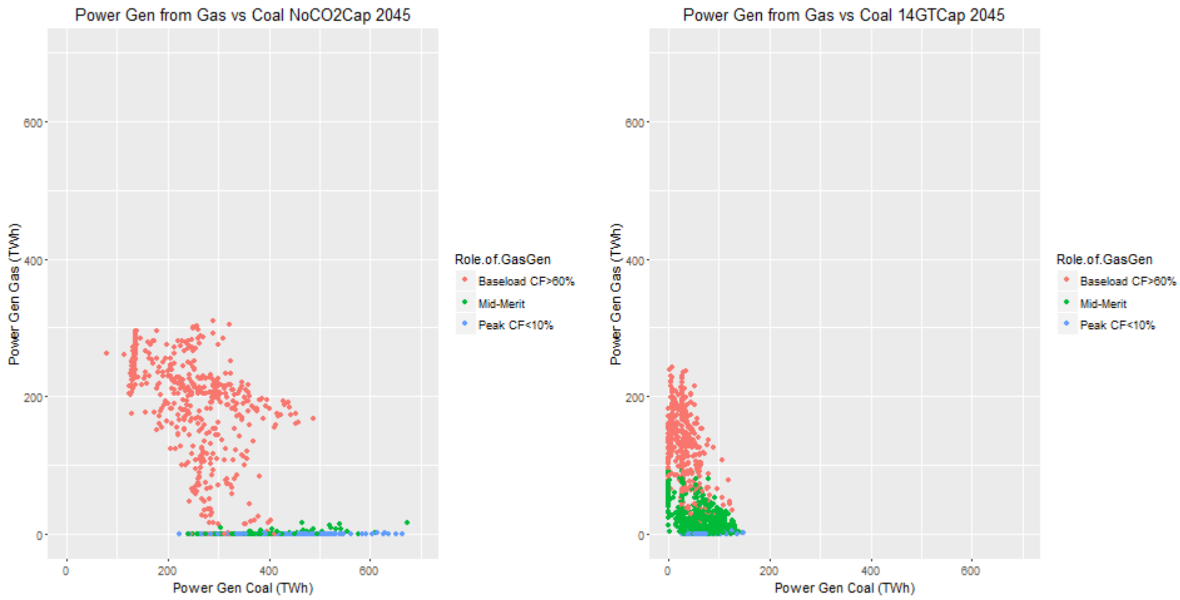

Figure 30: Electricity generated from coal vs electricity generated from gas – GHG unconstrained (left) and constrained (right)

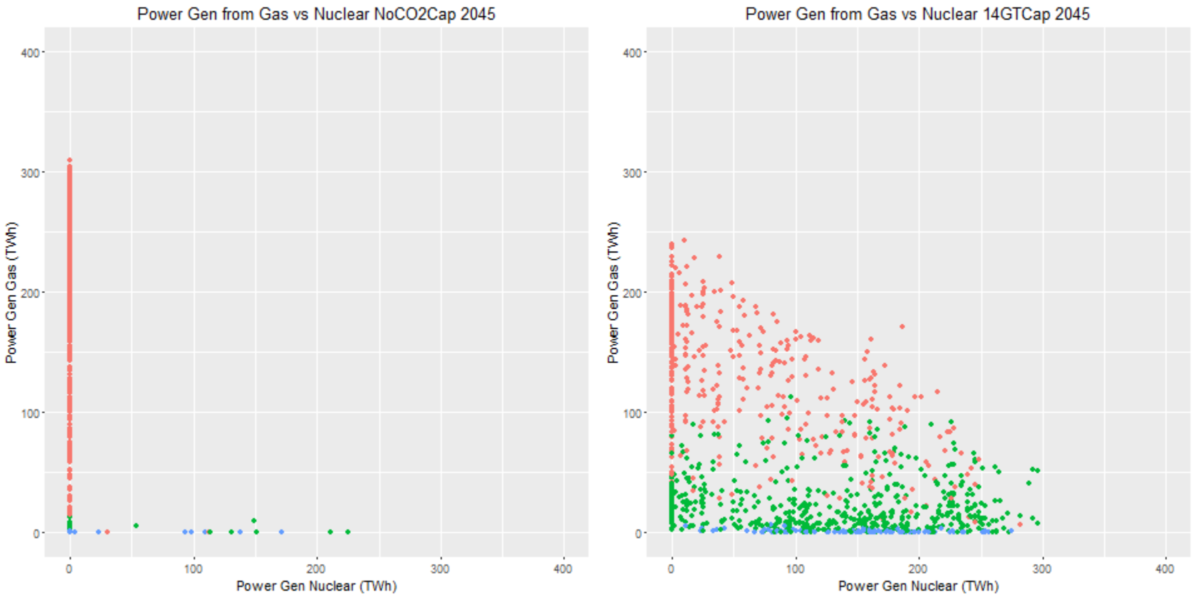

Figure 31: Electricity generated from nuclear power vs electricity generated from gas – GHG unconstrained (left) and constrained (right)

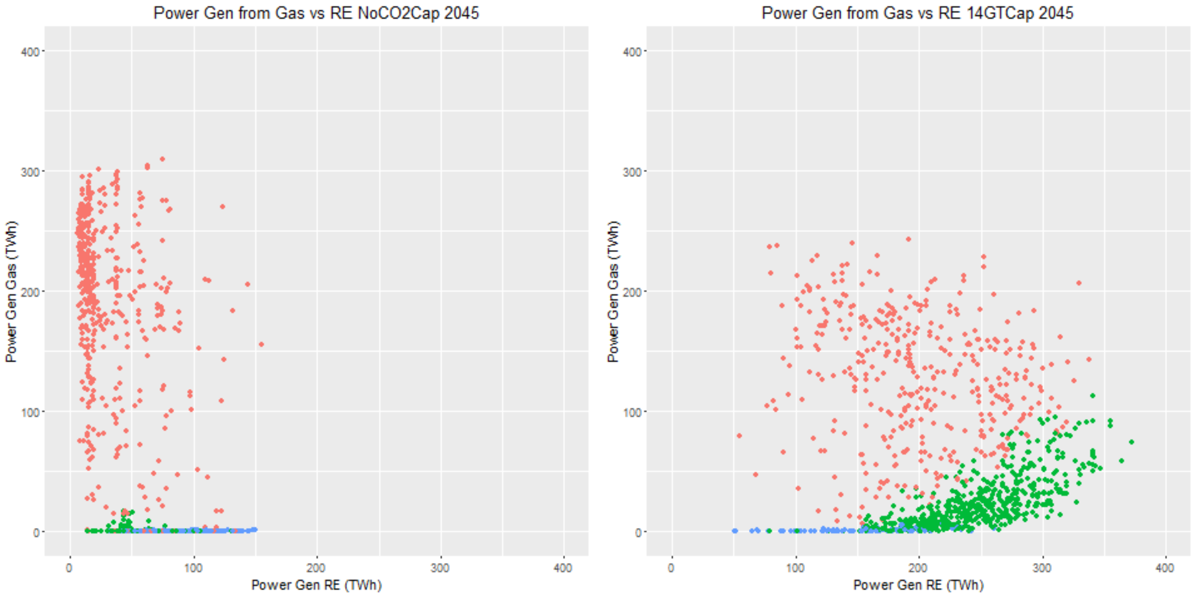

Figure 32: Electricity generated from renewable energy (solar thermal, solar PV, wind) vs electricity generated from gas – GHG unconstrained (left) and constrained (right)

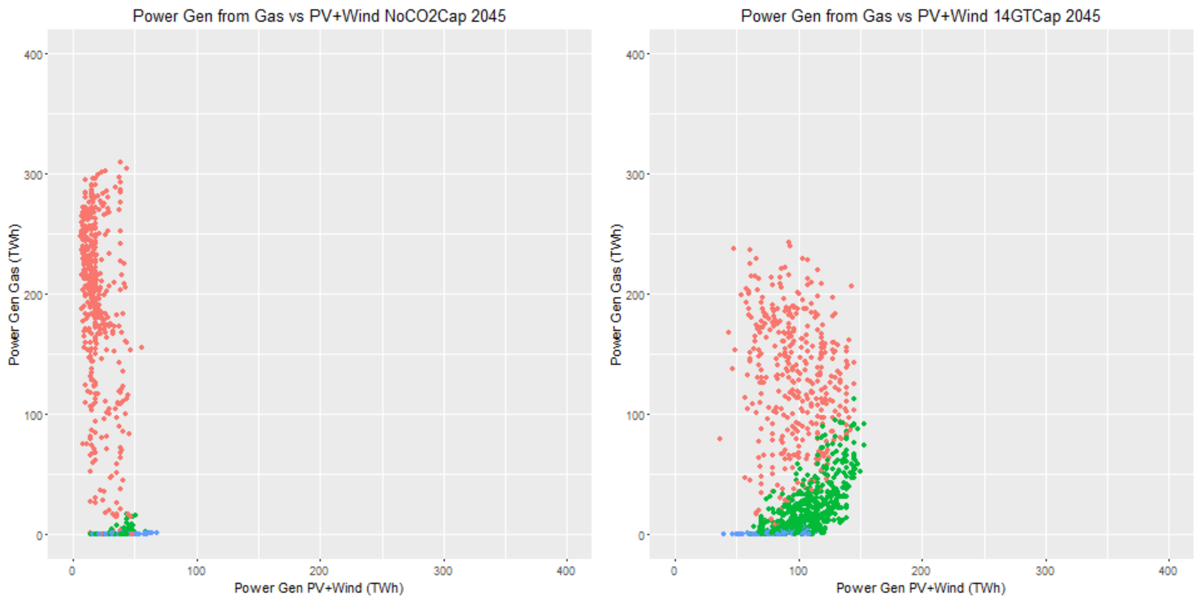

Figure 33: Electricity generated from solar PV and wind vs electricity generated from gas – GHG unconstrained (left) and constrained (right)

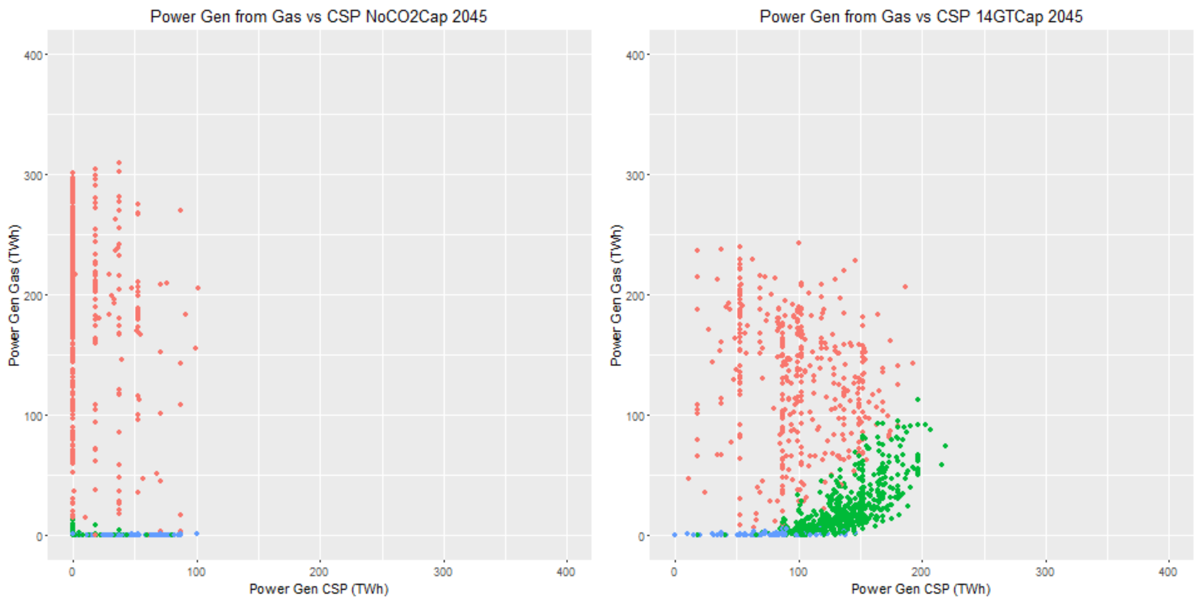

Figure 34: Electricity generated from solar thermal vs electricity generated from gas – GHG unconstrained (left) and constrained (right)

A more interesting pattern emerges when one compares electricity generated by wind and solar plants to electricity generated from gas, in Figure 32. In the unconstrained cases, electricity generation from renewable energy sources is limited to 150 TWh, and the function of gas in the electricity system is not clearly related to the extent of renewable energy deployment. Gas has a limited role in balancing the system (the green points) at very low gas deployment levels – otherwise the role that gas may play in this regard is obscured by the relative scale of electricity generation between the technologies. This small balancing role is visible more clearly in Figure 33 and Figure 34, and it is clear that this is correlated with PV and wind, but not CSP. The distribution of gas uptake in relation to PV and wind is also considerably different in relation to CSP, where there is relatively little uptake of gas in cases where there is significant CSP uptake. In the constrained cases, the outcome is somewhat different. Beyond a certain level of renewable energy uptake, there is far great uptake of gas power at lower load factors, which suggests that gas power is playing a major role in balancing the system at higher renewable energy penetration levels. As with the unconstrained cases, there is evidently a trade-off between CSP and gas penetration at higher load factors.

GHG emissions from the electricity sector, in Figure 35, have a wide range in the unconstrained cases, which is driven by variable growth in demand and the proportion of coal generation in the overall mix. The key drivers for this very significant variation are economic growth and emissions intensity of electricity generation. From Figure 27, it is clear that this is partly a function of the relative shares of coal and gas, which is largely driven by the gas price; other technologies play a marginal role. Given the similarly large variation in electricity supply in Figure 24, which is a function primarily of economic growth, GDP growth in individual cases is also a major determinant of GHG emissions.

The increasing variation towards 2050 in the GHG emissions from the constrained cases in the electricity sector is driven by two factors: i) GHG emissions elsewhere, i.e. the relative costs of mitigation across different sectors, and ii) the relative costs of low-carbon and gas technologies and fuel within the electricity sector. Earlier mitigation elsewhere allows more scope for using residual coal capacity later in the period, and the nuclear/gas tradeoff also has an impact on mitigation elsewhere, as well as on residual coal capacity use, since the model is allocating GHG emissions space to the electricity and other sectors on the basis of the overall cost of mitigation across the economy.

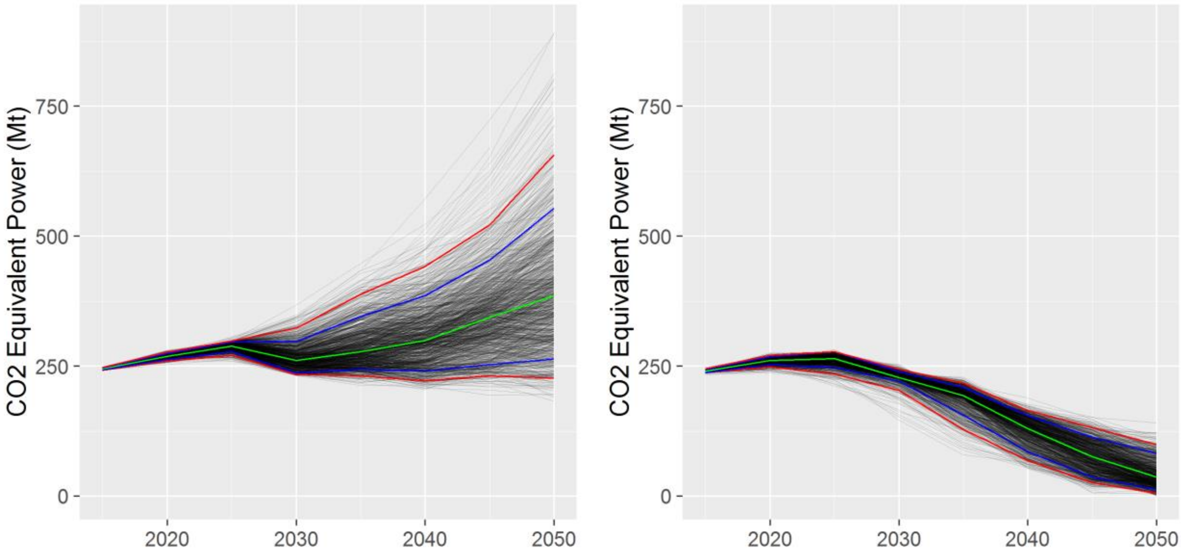

Figure 35: GHG emissions from the power sector – GHG unconstrained (left) and constrained (right)

4.9.1 Limitations

It is worth noting that the annual build limits on PV (1 GW) and wind (1.28 GW) are very conservative in this study and that this would be a very productive area for further work. Given the rapid changes in technology and costs in the electricity sector, and specifically in renewable energy technologies, it would also be worth re-evaluating the ranges for technology costs.

4.10 Liquid fuels

South Africa currently produces liquid fuels from crude oil, coal and natural gas (in small quantities). Key features of the modelling results respond to the questions: a) what is the future of CTL technology in South Africa? and b) what is the role of natural gas as a transport fuel, directly or in the form of future gas-to-liquids plants? Most emissions originate from the coal-to-liquids process, with a small share from crude oil refineries. Since (as can be seen in Figure 45) the share of liquid fuels as transport fuels varies very little between cases, emissions in the GHG constrained cases indicate in Figure 36 that after 2040 the only emissions remaining are from crude oil refineries, and these are an insignificant proportion of the overall range for the sector. In both the unconstrained and constrained GHG cases, the extent of the emissions range above 12 Mt is thus an indicator of CTL capacity. Existing CTL capacity is assumed to retire in 2040. Remaining emissions at this point are as a result of either crude oil-refining, or additional coal-to-liquids capacity being added, depending on the crude oil price, economic growth and the coal price. One of the major outcomes of this analysis is that there is no new gas-to-liquids capacity, since natural gas is used directly in the transport system as a vehicle fuel, rendering its further processing pointless. This outcome is the result of the model's ability to assess the overall cost of the whole energy system. The range of CTL capacity in the unconstrained cases is linked to economic growth rates and the relative prices of coal and crude oil.

In the GHG-constrained cases, since existing CTL capacity takes up a significant proportion of the remaining carbon space, it is retired prematurely in some cases, and no new capacity is built. The point at which this capacity is retired in the time period 2025–2035 depends on available carbon space elsewhere and specifically the speed at which the electricity sector decarbonises. There is thus a complex interrelationship between decarbonisation in the liquid fuels supply sector and in the electricity sector, depending on the mitigation cost implied by variations in technologies and fuel costs.

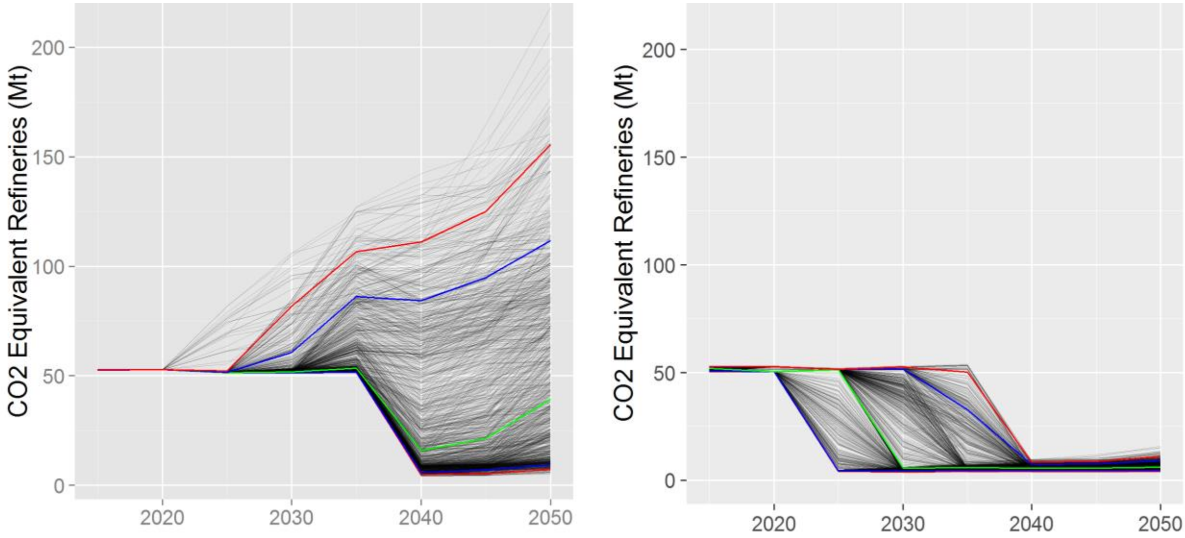

Figure 36: GHG emissions from the liquid fuels supply sector – GHG unconstrained (left) and constrained (right)

4.11 Industry

As can be seen in Figure 37, the median cases are fairly similar in the constrained and unconstrained cases, with significant departures in the outlying cases when GHGs are constrained, reaching very high levels of uptake in cases where GDP growth is high and more displacement of coal use in industry by gas is necessary. In Figure 38, in the constrained cases, in cases where there is high GDP growth and low gas prices, there is significantly higher uptake of gas due to the carbon constraint. In the unconstrained cases, there is some uptake of gas, but as is portrayed in Figure 40, the variation in 2045 in the share of energy in industry taken up by gas is pretty constant over all cases at a low level of just under 10%. A carbon constraint raises the range of variability a little, but leads to a cluster of outliers with much higher shares.

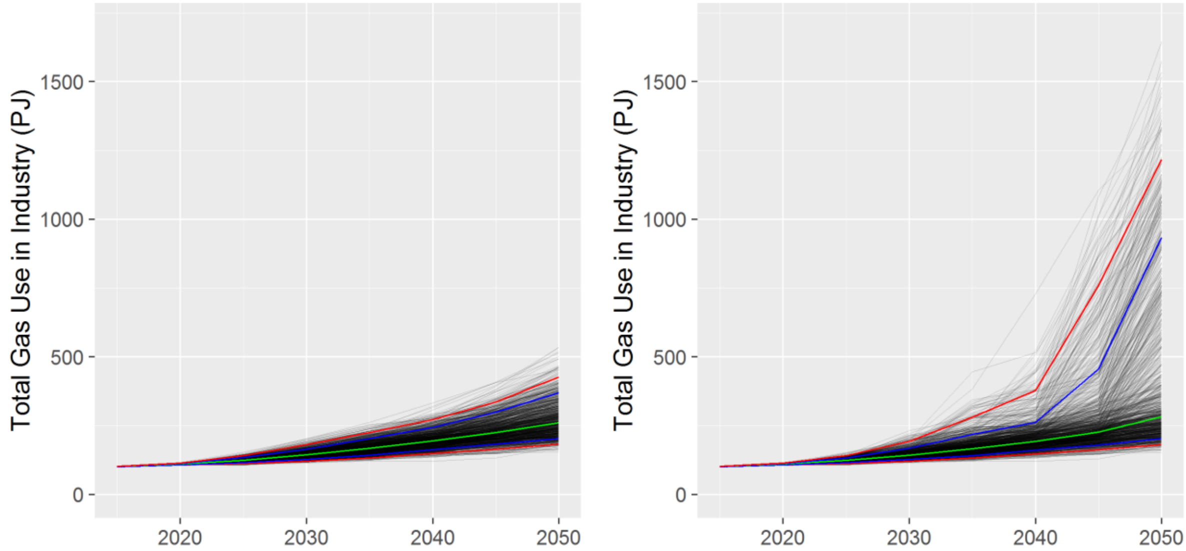

Figure 37: Gas use in the industry sector – GHG unconstrained (left) and constrained (right)

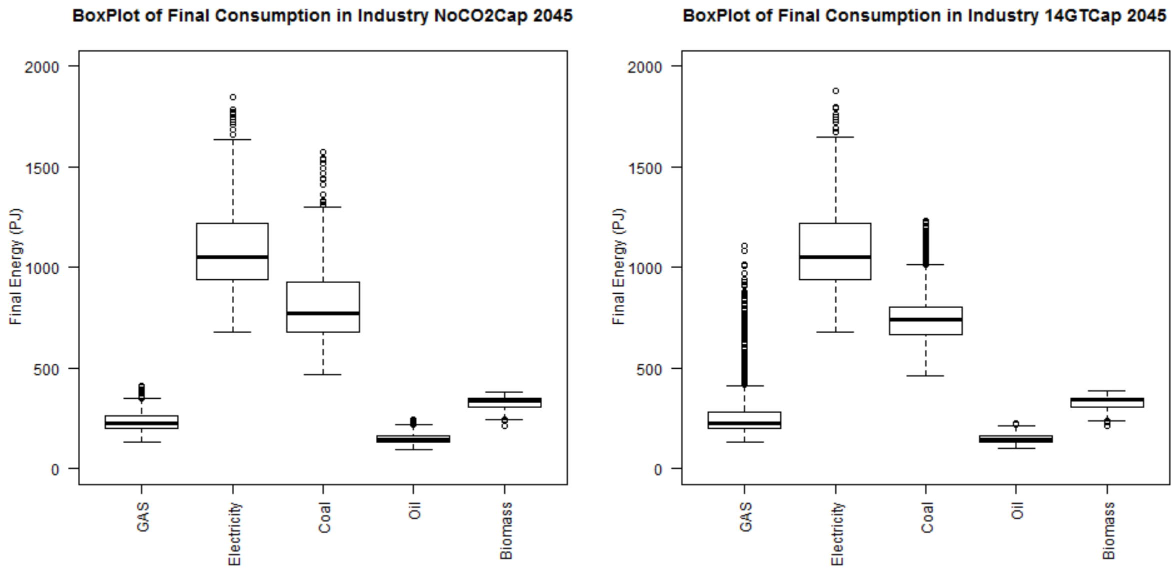

Figure 38: Final energy in industry by energy carrier – GHG unconstrained (left) and constrained (right)

The variation in uptake by 2045 in the unconstrained cases depends primarily on the GDP growth rate, and to a lesser extent on the coal price, as portrayed in Figure 39. In Figure 40, the share of gas in industry varies very little, and most of the variation is between coal and biomass (which includes waste), and the uptake of gas is primarily driven by overall increased energy demand. In Figure 41, two of the most significant factors affecting the share of gas (to the extent to which it varies) are the coal price (slightly more gas) and GDP (coal use grows slightly faster).

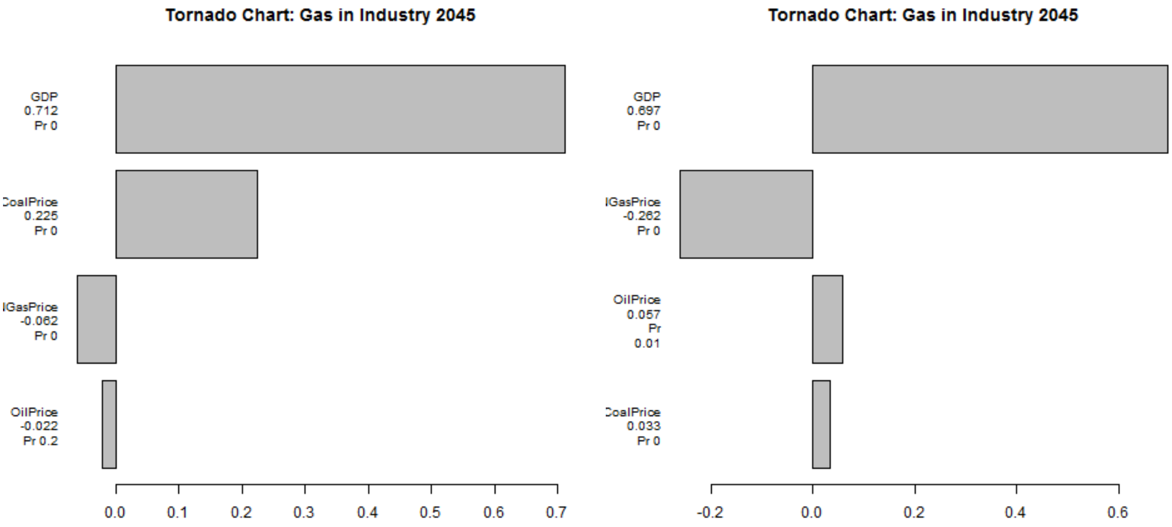

Figure 39: Factors affecting the uptake of natural gas in the industry sector

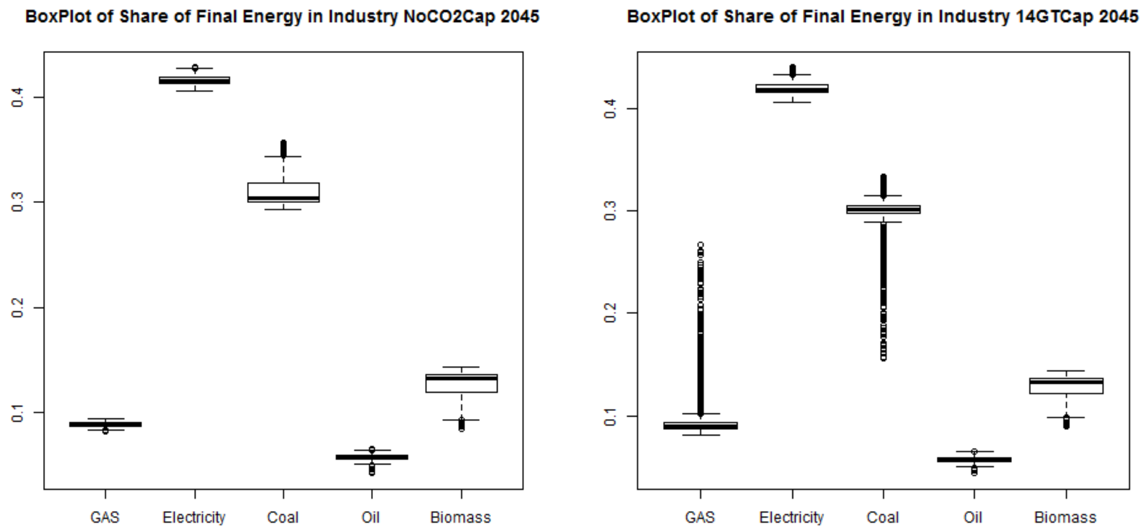

Figure 40: Share of final energy in industry by energy carrier – GHG unconstrained (left) and constrained (right)

The GHG-constrained cases are somewhat more interesting. In Figure 39, GDP and the gas price are the key factors which affect gas uptake, whereas in Figure 41 GDP affects the share of gas positively and the gas price is another key factor. Interestingly, in Figure 42, in the unconstrained cases there is practically no variation in the share of gas used in each industry subsector, whereas there is significant variation in these shares. It is evident from the overall GHG emissions from the industry sector (Figure 43) and from the shares of renewable energy vs fossil fuels used in the industry sector (Figure 40) that the only driver for mitigation in the industry sectors is fuel-switching.

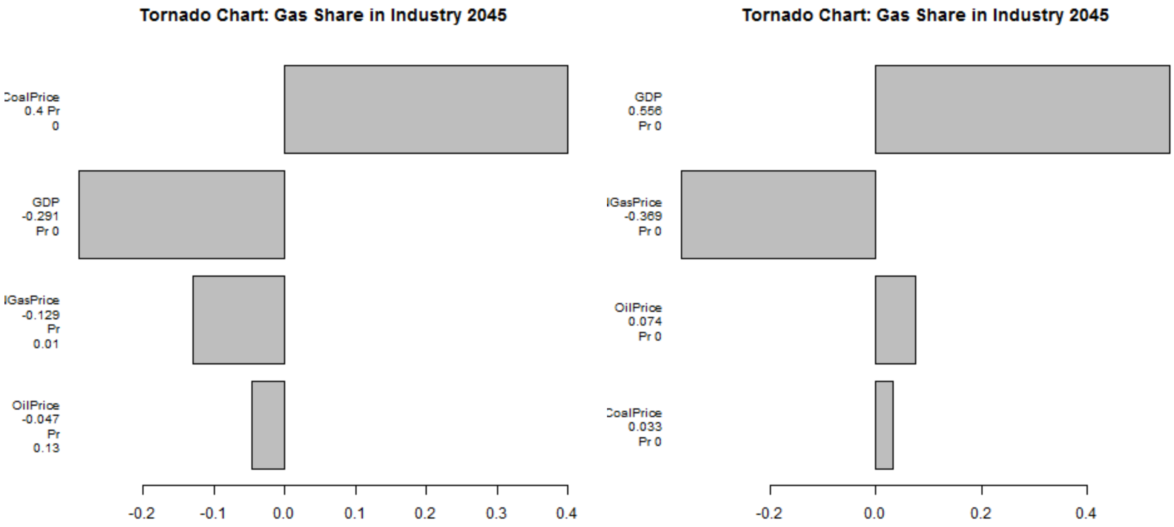

Figure 41: Factors affecting the share of gas use in the industrial sector – GHG unconstrained (left) and constrained (right)

Although there are energy efficiency improvements over the modelling period, these occur in both the constrained and unconstrained cases. This fuel-switching from coal to gas results in the lower range of emissions in the GHG-constrained cases. With higher GDP growth rates, there is more pressure to restrict GHG emissions across the economy. Since there are cheaper options elsewhere, this only becomes a significant driver for gas use in industry at higher GDP growth rates.

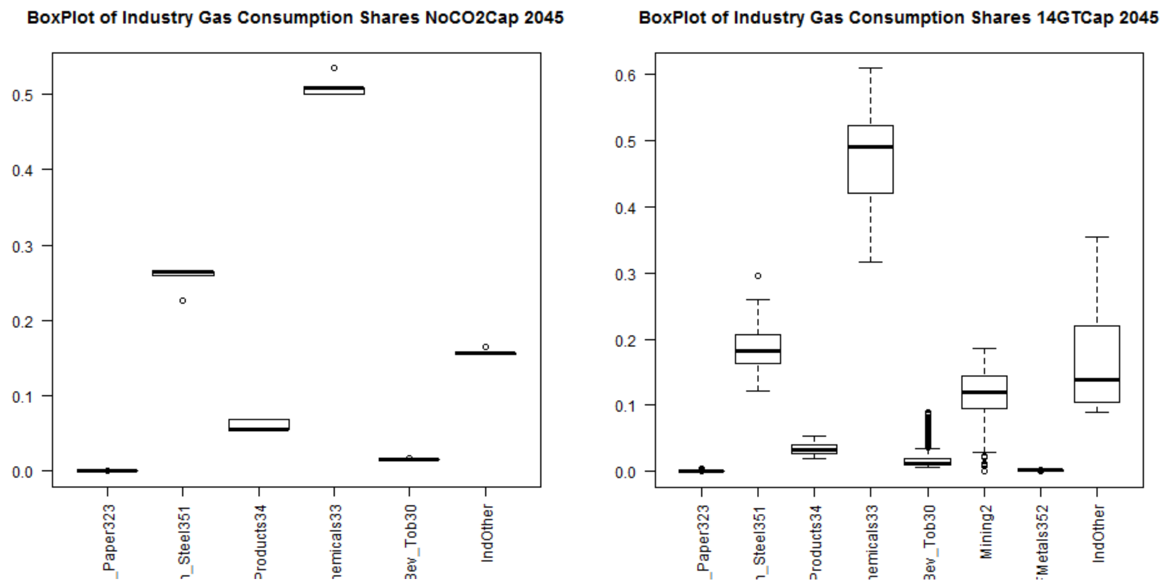

Figure 42: Share of gas used per industry subsector – GHG unconstrained (left) and constrained (right)

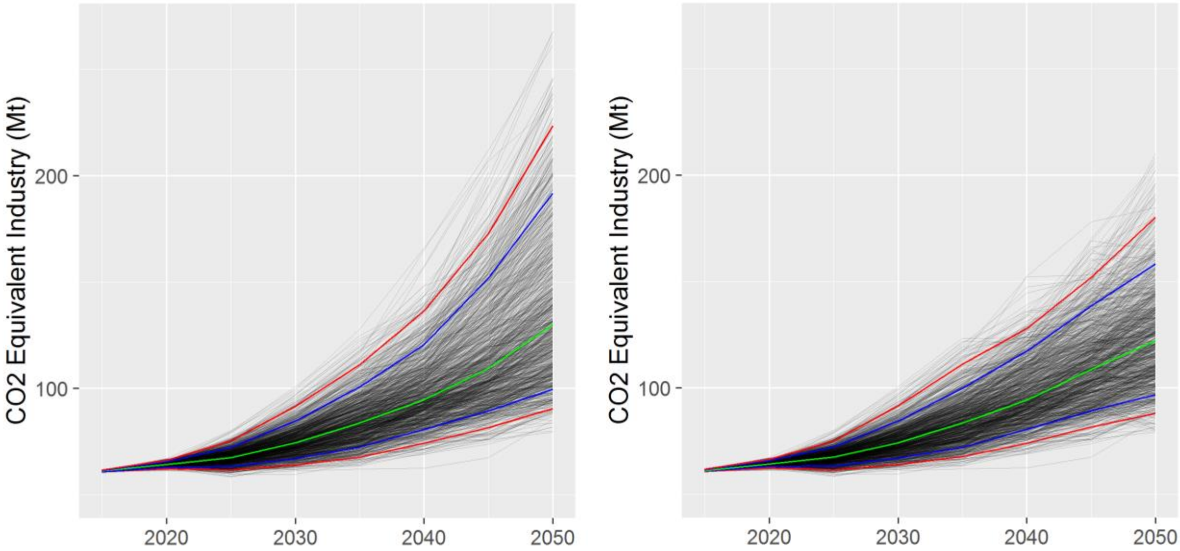

Figure 43: GHG emissions from the industry sector – GHG unconstrained (left) and constrained (right)

4.12 Transport

One of the most significant results of this analysis is the potential role of natural gas as a transport fuel – although compressed natural gas is increasingly being used internationally in the transport sector, primarily to combat air pollution in urban areas and, depending on the oil price, for cost reasons, but this has not been given much consideration in South Africa. The share of transport fuel taken up by natural gas in 2045 in the analysis is around 20%, a share which does not vary widely between the constrained and the unconstrained cases. Other than a niche role for electric and hydrogen vehicles, fossil-derived liquid fuels still play a dominant role in transport, with a share of just under 80%. Most natural gas goes into freight and private passenger vehicles, with a far smaller share going into public transport. Due to the constrained nature of the transport sector, emissions are only marginally lower in the constrained cases.

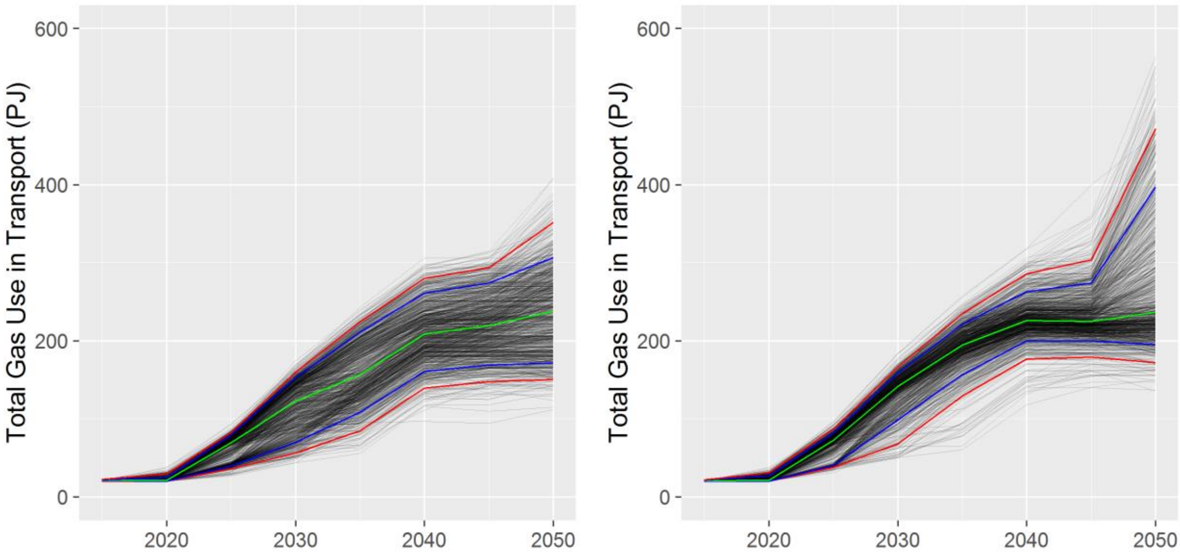

Figure 44: Gas use in the transport sector – GHG unconstrained (left) and constrained (right)

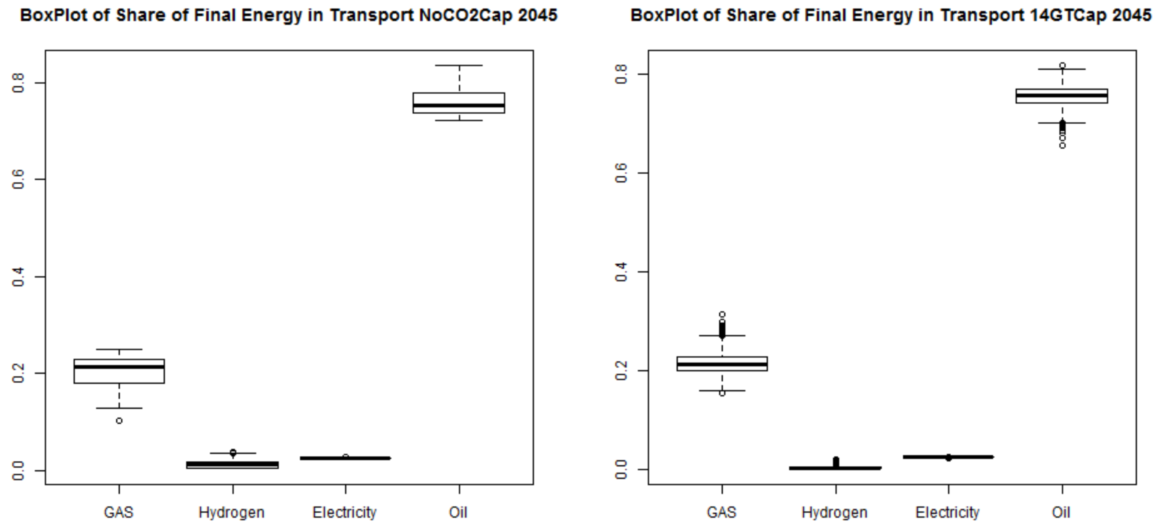

Figure 45: Share of final energy for transport – GHG unconstrained (left) and GHG constrained (right)

The GHG constraint drives a slightly faster uptake of CNG in the transport sector, and as observed above, direct use of natural gas in the transport sector displaces GTL completely. Fuel switching does not result in significantly lower GHG emissions, but would result in other co-benefits, especially local air pollution.

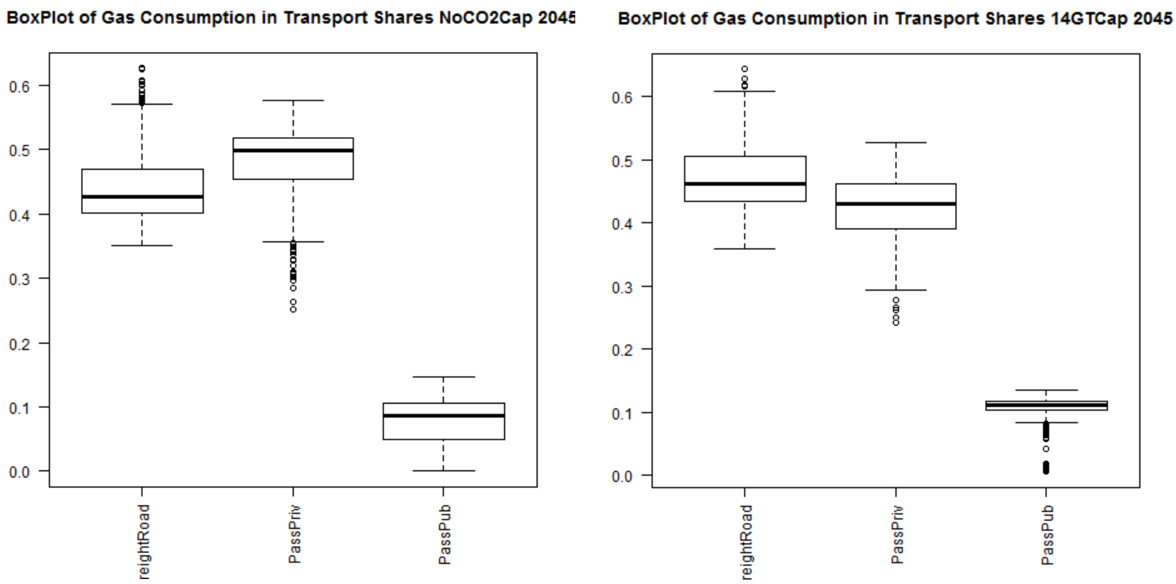

Figure 46: Share of gas used per transport mode – GHG unconstrained (left) and constrained (right)

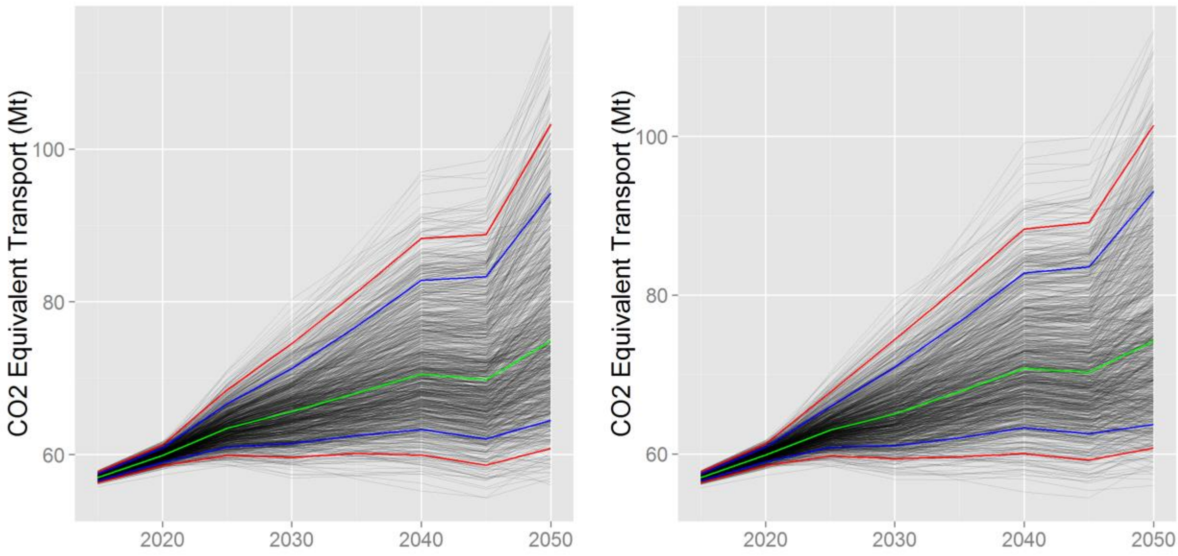

Figure 47: GHG emissions in the transport sector – GHG unconstrained (left) and constrained (right)

4.12.1 Limitations

Note that assumptions around electric and hydrogen vehicles (cost and potential uptake rates) are extremely conservative, and should probably be considered with a range of uncertainty as well in future work.

4.13 The commerce sector

There is considerably greater uptake of gas in the commercial sector under a GHG constraint (Figure 48). The interplay between gas, electricity and coal use is complex – electricity supplied to the sector includes electricity generated centrally, rooftop PV and electricity generated by trigeneration on-site (combined onsite heat, cooling and power generation). Figure 49 and Figure 50 are boxplots of final energy use in the commercial sector. 'Electricity' includes centralised electricity supply and rooftop PV, but excludes trigeneration (Since there is significant uptake of gas-fired trigeneration, gas consumed by trigeneration is included, but electricity generated by trigeneration is excluded so as not to account for energy use in the sector twice). Investment in trigeneration is determined thus by the economics of both alternative electricity supply (PV / centralised) and alternatives for generating heat (coal, electricity, thermal only use of gas, liquid fuels).

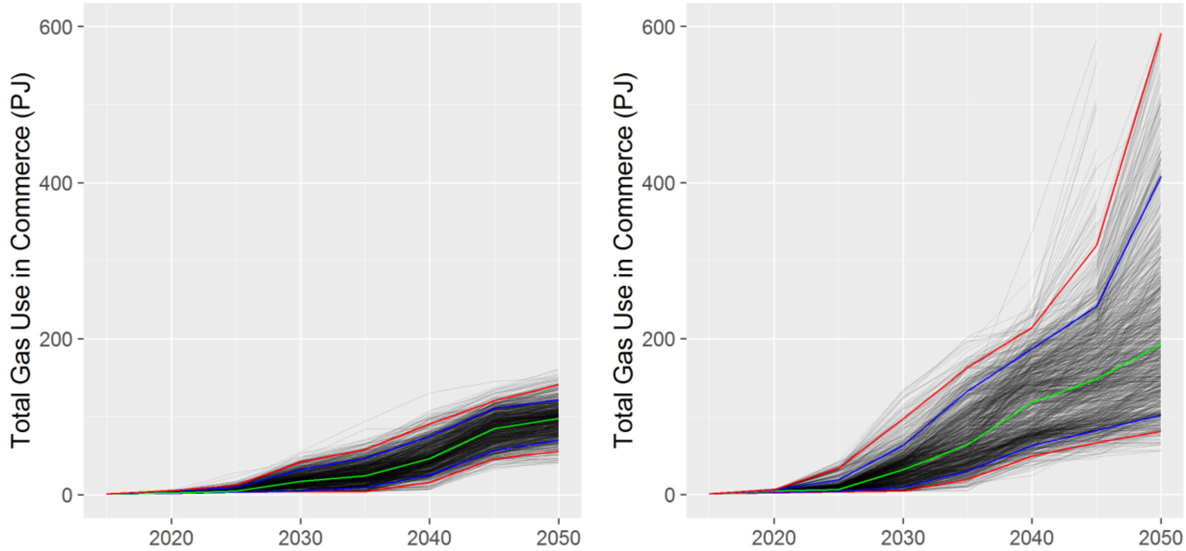

Figure 48: Gas use in the commerce sector – GHG unconstrained (left) and constrained (right)

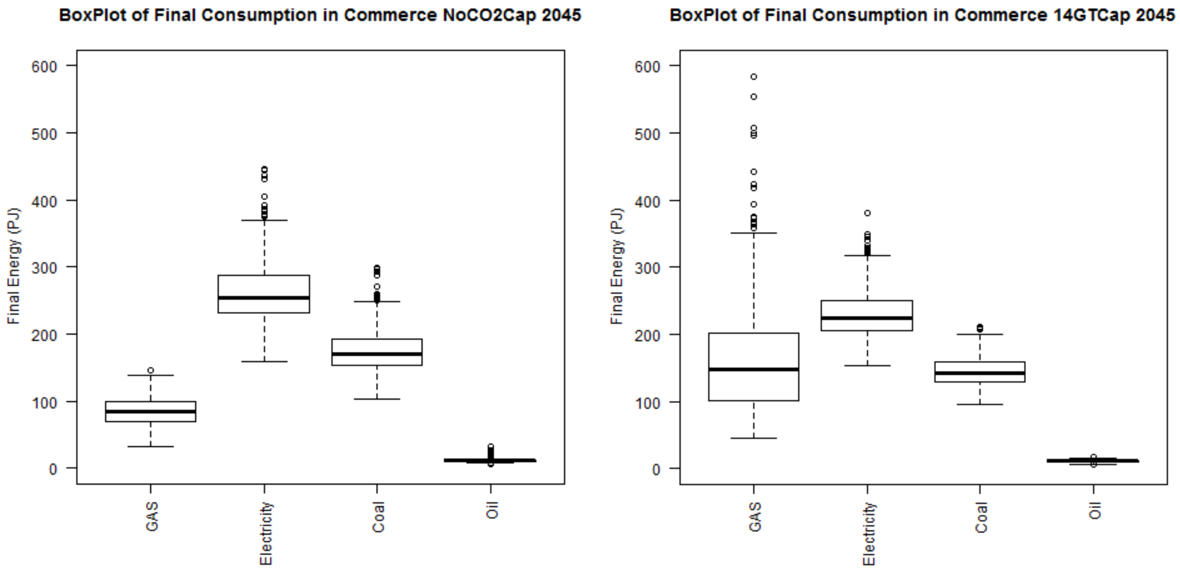

Figure 49: Final energy consumption in the commerce sector – GHG unconstrained (left) and constrained (right)

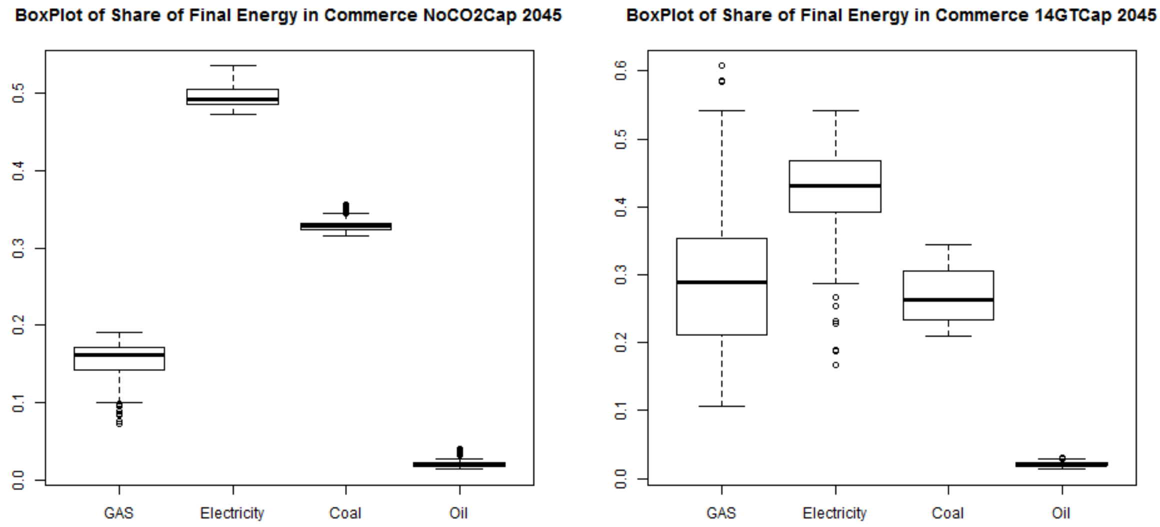

Figure 50: Shares of final energy consumption in the commerce sector – GHG unconstrained (left) and constrained (right)

In the unconstrained cases, there are quite wide ranges for use of all three energy carriers (Figure 49), but the shares of each carrier (Figure 50) vary over a much smaller range. The variations in use of energy carriers is thus primarily driven by different GDP growth rates, with limited substitution between coal and centralised electricity on the one hand, and gas/trigeneration on the other. In the GHG-constrained cases, on the other hand, the much higher uptake is driven by the relatively low cost and efficiency of trigeneration. Since the heat from thermal electricity generation, which is wasted in centralised plants, is utilised from trigeneration, overall final energy consumption in the sector is lower, and also far less carbon-intensive. There is a small tradeoff between gas and rooftop PV in the sector. Shares of energy carriers in the constrained cases varies widely, by contrast to the unconstrained cases, since variations in the cost of technology and fuel change the relative mitigation costs of shifts to lower-carbon technology in different sectors.

Drivers for uptake of natural gas (Figure 51) are GDP in both constrained and unconstrained cases – the slightly greater correlation with GDP in the constrained cases is due to the constraint on greater use of coal and the efficiency of trigeneration as a mitigation option. There is also greater sensitivity to the gas price due to the far greater range of natural gas uptake. The influence of PV is interesting – there is a slight trade-off between PV and trigeneration in the sector. Interestingly, the *share* of gas use is affected to a significant extent by the GDP growth rate (Figure 52), unlike the electricity sector

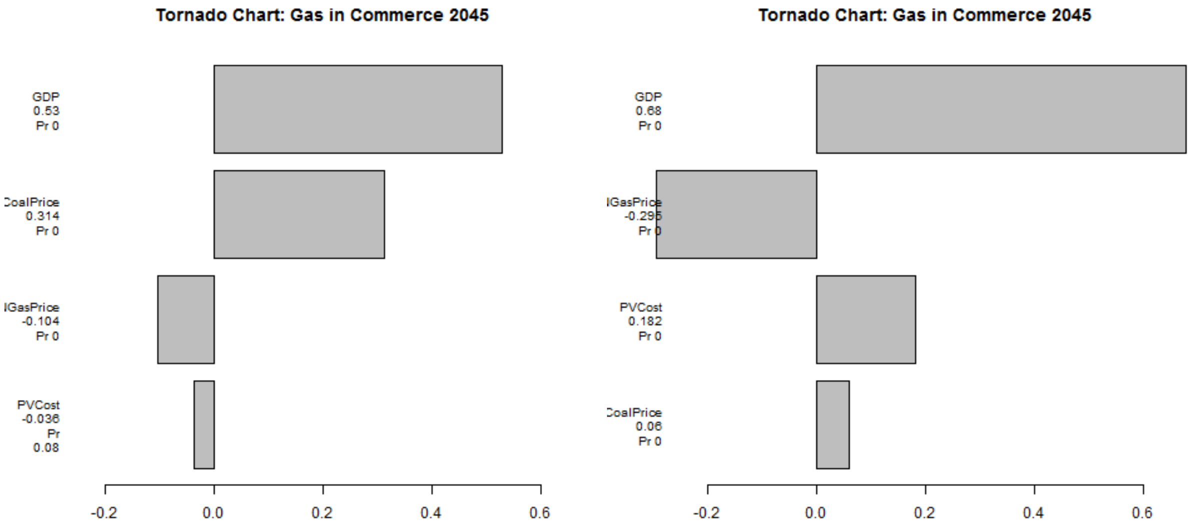

Figure 51: Factors affecting gas use in the commerce sector – GHG unconstrained (left) and constrained (right)

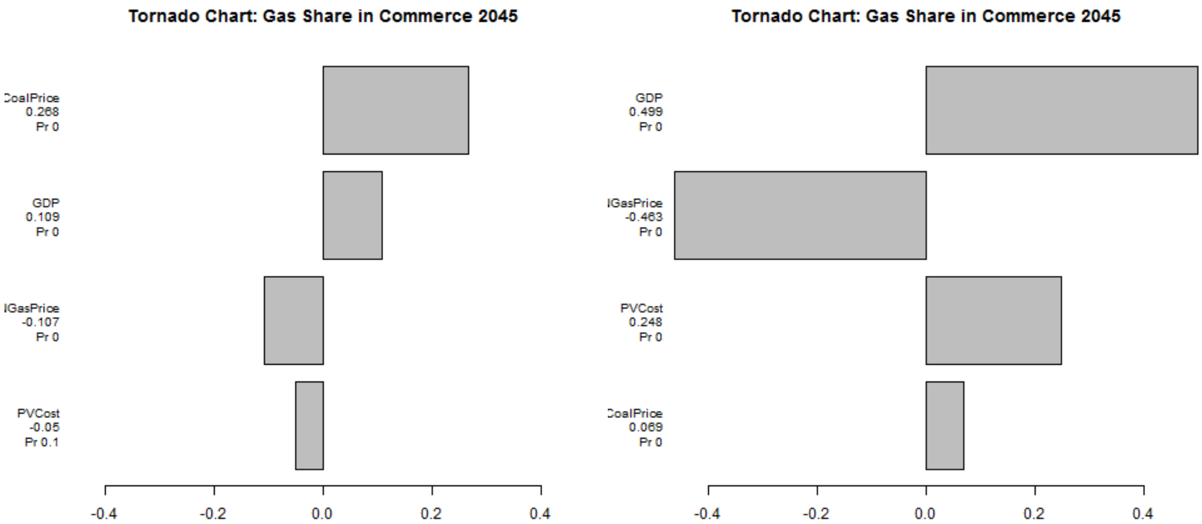

Figure 52: Factors affecting the gas share of final energy in the commerce sector – GHG unconstrained (left) and constrained (right)

4.14 Sensitivity to high leakage rates from fracking

In this section we explore the impact of far higher natural gas leakage rates from shale gas production on the GHG constrained case, to gain insight into shale gas uptake in a GHG-constrained energy system. In the results above a leakage rate of 2.86% is assumed, whereas in this sensitivity analysis the assumed leakage rate is 9%, based on Karion et al (2013). The figures in this section portray both the sets of GHG constrained cases – in each one, the figure on the left portrays GHG constrained cases with a high leakage rate, and the figure on the right portrays GHG-constrained cases with the leakage rate we used for the rest of the study. The figures on the right have all been included above in previous sections, and we include them here again for easy comparison.

In Figure 53, use of gas is clearly more constrained with a much smaller distribution, and later uptake. In Figure 54, it is evident that shale gas predominates only at much lower gas prices, and gas does not play as large a role in the energy system. The drivers for this are more evident in Figure 55 and Figure 56. Whereas in the original constrained cases the key driver for gas uptake is the price of gas, in the high leakage cases GDP growth is the main driver. The gas share of primary energy is driven not primarily by the gas price (as it is in the original constrained cases) but by the cost of nuclear power technology. The dominant role of gas in the energy system changes with high leakage rates, which is more evident in Figure 57: there is a shift in the profile of gas uptake, and there is a significant difference in the extent to which gas is used for electricity generation.

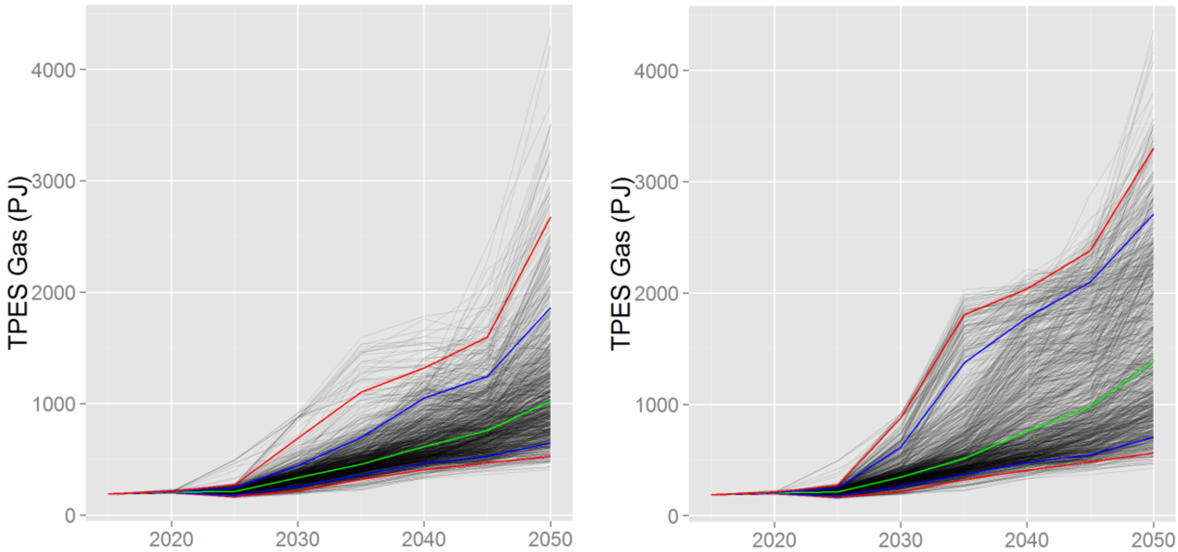

Figure 53: Total primary energy supply from natural gas – high leakage on the left

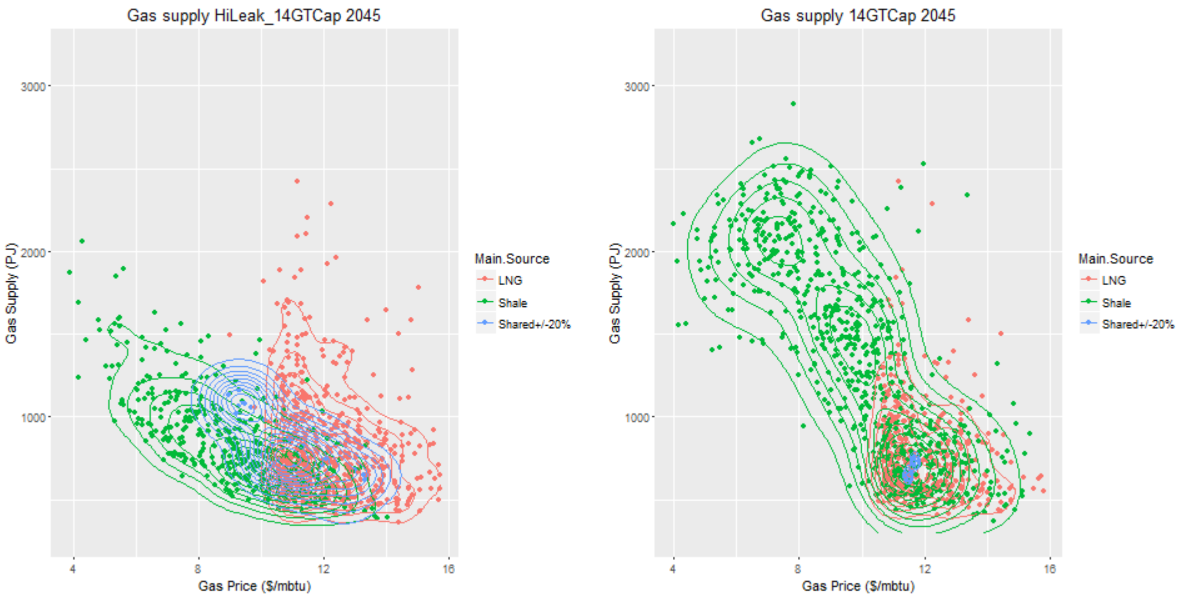

Figure 54: Gas supply vs gas price, by source – high leakage on the left

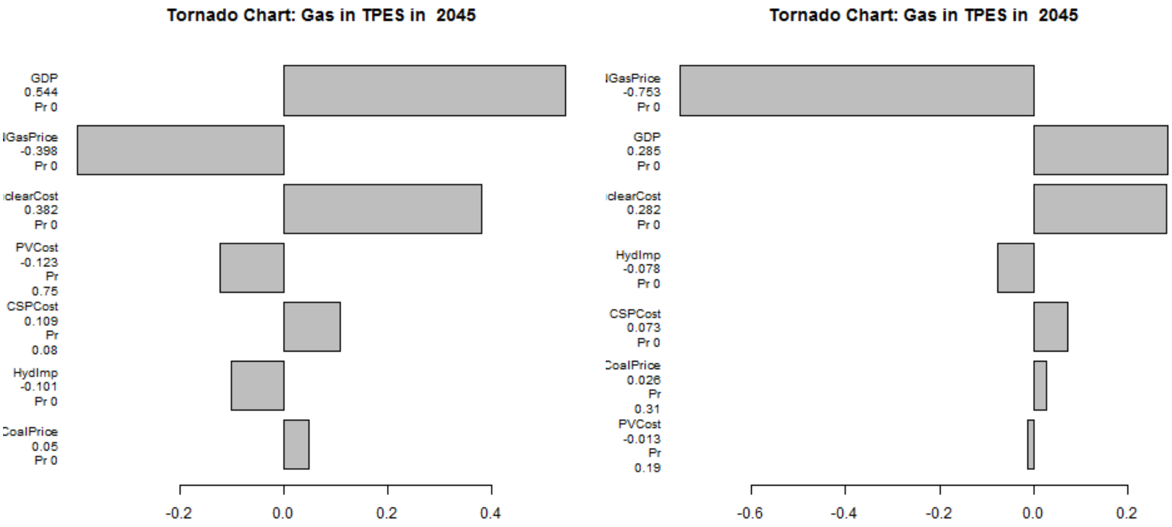

Figure 55: Factors affecting total primary energy supply from natural gas in 2045 – high leakage on the left

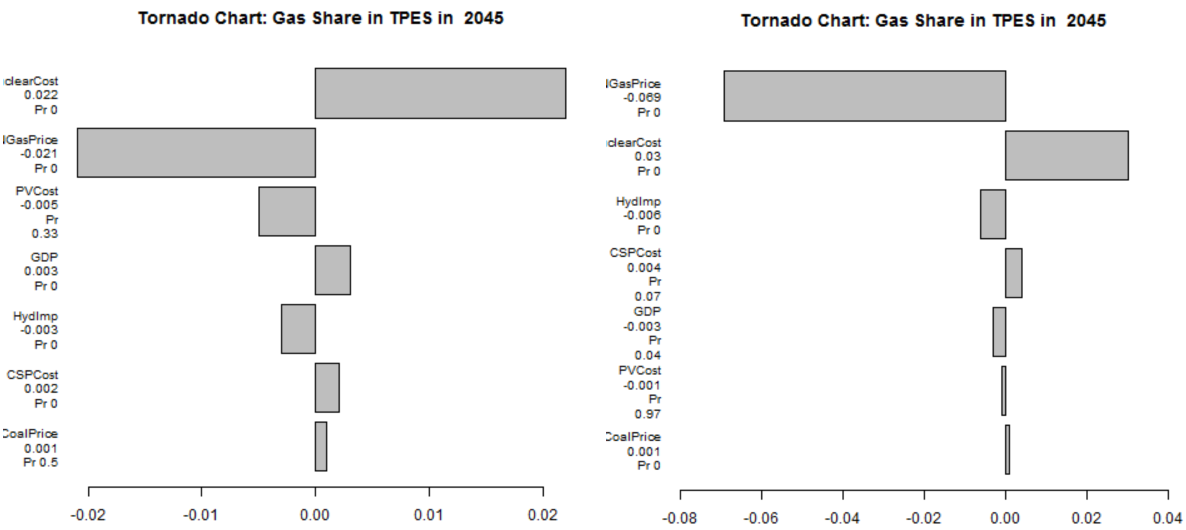

Figure 56: Factors affecting the share of total primary energy supply from natural gas in 2045 – high leakage on the left

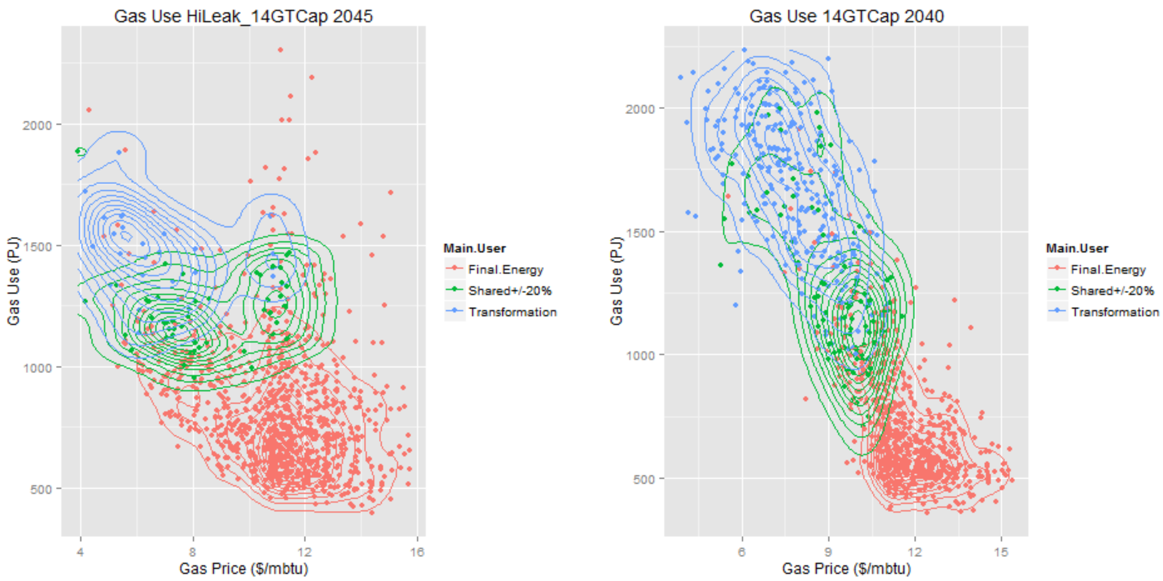

Figure 57: Gas price vs gas use, by type – high leakage on the left

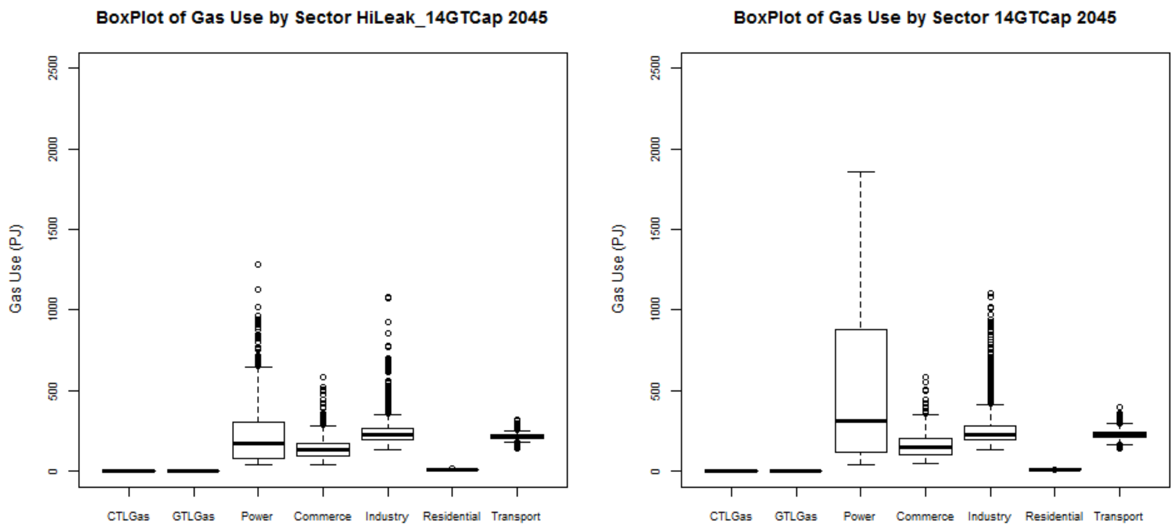

Figure 58: Gas use by sector – high leakage on the left

This is clearer in the sectoral disaggregation in Figure 58 – there are small changes to gas use in other sectors, but a major change in the range of gas uptake in the electricity sector. The increased efficiency and effective cost of mitigation of on-site generation in the commercial and industrial sectors result in a lesser impact on uptake than in the electricity sector. The role of gas power in the electricity system changes as well; as can be seen from Figure 59, gas plant in most cases does not run at a load factor of about 60%, whereas in the low leakage rate cases, when the average gas price drops below around USD 10/Mbtu, there is large-scale use of gas in the electricity sector, at load factors of above 60%; in other words, gas is used as baseload. This does not occur in the high-leakage cases. The winners in the high-leakage case are nuclear power, with marginal increases in the shares of coal and CSP.

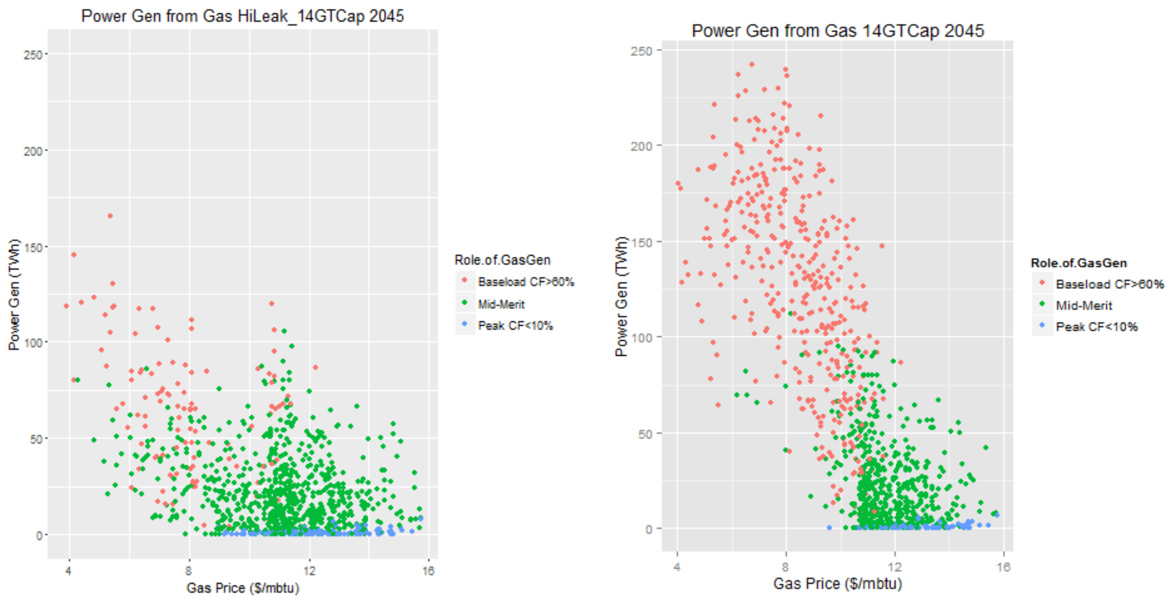

Figure 59: Gas use vs gas price in the power sector by average load factor – high leakage on the left

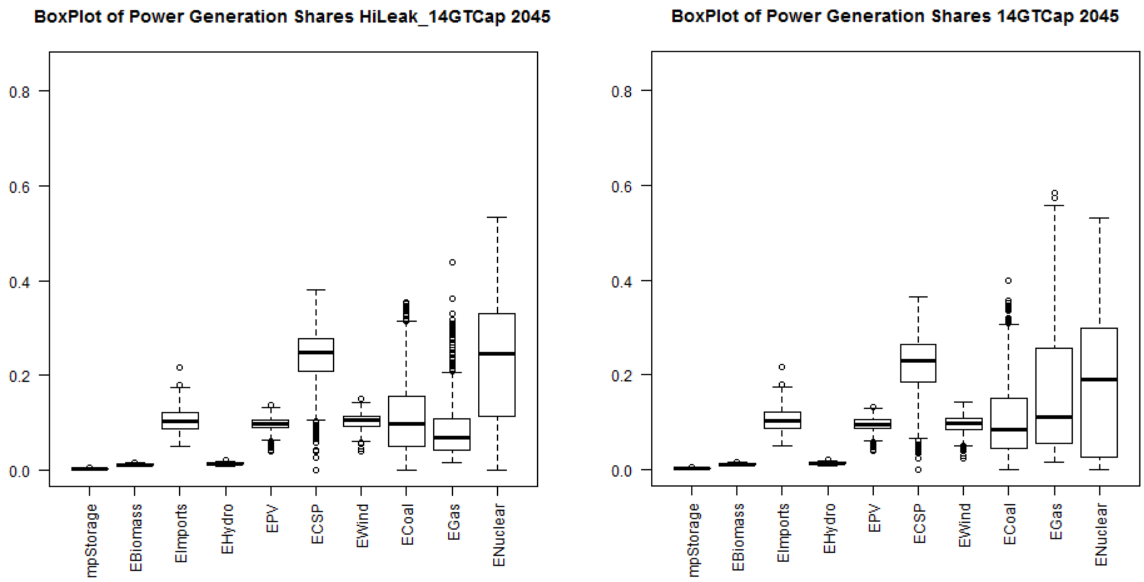

Figure 60: Shares of power generation by technology – high leakage on the left

5. Conclusions and policy implications

The three groups of modelled cases analysed above provide some key insights into the role which natural gas might play in the South African economy to 2050. Gas is taken up by the model primarily for electricity generation, for transport, and in the industrial and commercial sectors, including in cogeneration and trigeneration. Interestingly, there is no further development of gas-to-liquids infrastructure, because there is significant direct use of natural gas (in the form of compressed natural gas) in the transport sector, which would render further GTL capacity pointless (because it would be less efficient and more costly). There is not a lot of contrast between the constrained cases and the unconstrained cases with regard to transport, with a higher range of uptake in 2050, mostly because of modelled constraints.

For the rest of the economy, however, the GHG constraint has a complex systemic effect on the energy system, and the extent to which gas is taken up depends on what the most cost-effective allocation of the available GHG emissions space is across the economy. This in turn depends on the relative cost of gas, coal, low-carbon technologies such as solar and nuclear, and on when existing CTL infrastructure is retired, the latter being dependent on the relative price of coal, crude oil and the relative price of mitigation elsewhere.

There is a clear distinction in the results between the way in which gas is used in the electricity sector, and elsewhere. For the commerce and industry sectors, in the unconstrained cases gas uptake is relatively stable and depends primarily on GDP growth and the coal price, whereas in the constrained cases, uptake depends on GDP growth and the gas price, and is relatively indifferent to the coal price, because of the GHG constraint; i.e. the limit to coal use is not cost but the GHG constraint. When GDP growth is high, the GHG constraint results in very high uptake of gas, but only if leakage rates associated with gas produced from unconventional sources are low enough.

The electricity sector is considerably more complex. Where there is no GHG constraint, uptake of natural gas is primarily dependent on the gas price. Below around USD 10/Mbtu, uptake is very high, and gas displaces coal generation to a significant extent, as baseload power. Above this price, gas plays only a minor role in the electricity system. With a GHG constraint, however, gas plays a far greater role at higher gas prices than it does in the unconstrained cases, primarily as mid-merit plant, and there is a strong correlation between higher uptake of renewable energy and gas use. With high leakage rates, gas use is limited to this role even at low prices on account of its large GHG footprint. As elucidated above and below, the model used in this study does not account for spatial dimensions of either potential demand for gas or for the optimal locations of required infrastructure; nor is it an accurate tool for tackling policy problems concerning the short-term dilemmas which currently confront government, and specifically the Independent Power Producer office, in procuring the first round of gas-fired power plants.

There are some significant implications for policy, and specifically for energy and gas policy and for climate mitigation policy. The approach used in this study, with its emphasis on the uncertainty of key model parameters (economic growth, technology costs, fuel costs), provides a more nuanced approach to understanding complex energy systems problems than the usual scenario-based approach, but gives rise to its own problems of interpretation. Further work could profitably be done in focusing the uncertainty analysis more specifically and carefully on key inflection points in the planning horizon.

By comparison to a more limited analysis based in a specific sector only (for instance, electricity), or using a more limited methodology which does not fully capture cross-sectoral interactions, the analysis in this project provides some key insights for policymakers, which may be invisible in less integrated approaches. The first key group of insights concerns the role of gas in meeting future electricity demand, and particularly in a GHG-constrained system, both in terms of the electricity system itself and in terms of the overall economically efficient package of mitigation measures chosen by the model given the ranges of uncertainty. There are two policy-relevant insights in particular concerning electricity supply. The first is that the potential role for gas in a GHG-constrained future is closely related to the other technology options available, and specifically the uptake of renewable energy technologies, and therefore investment in gas infrastructure should be closely connected with investment in large-scale renewable energy. The second is that gas-fired cogeneration and trigeneration are an important option in a GHG-constrained future, and that these offer very significant efficiency gains, especially in cases where there is large-scale use of coal for heat generation. The potential roles for these technologies are underestimated in conventional electricity planning (because modelling is generally limited to the supply side), and this is an area for significant further research. Options for cogeneration and trigeneration depend on the development of an appropriate gas pipeline network. The key policy lesson in the transport sector is that it does not make sense to plan to develop further gas-to-liquids infrastructure, since natural gas can be used more effectively directly in vehicles, which also has significant air pollution benefits.

It is worth highlighting some of the risks which were not assessed in this study, which policymakers will have to take into account. The first set of risks is associated with environmental impacts of fossil fuel use, since neither the potential risks to local water supply arising from the production of shale gas in the Karoo nor the very significant externalities of coal production were estimated, and are not included in this analysis. The second set of risks which were not assessed are the potential macro-economic risks to the South African economy of importing large quantities of natural gas, which would mostly replace domestically-sourced coal. This would potentially have a very significant effect on South Africa's trade balance, and also expose the South African economy to further price risk (from international gas prices, in addition to the price risk from crude oil faced by the economy). On the other hand, gas sourced in the region could provide a counterweight to current trade imbalances between South Africa and its neighbours.

5.1 A note on limitations of this study

It is worth noting the following limitations, which suggest areas for further work. The first is GDP growth, which in the short term has proved to be overoptimistic. The second is in the power sector, in which the pace of technology development and deployment is currently extremely fast, and the ranges of uncertainty employed in this study of costs, as well as assumptions about build rates, are probably far too conservative. Globally, wind and PV investment and cost forecasts have consistently been too low, whereas solar thermal technology has still to fully realise its promise, and global deployment remains at relatively low levels. The third area is in the transport sector. More recent work indicates a much greater potential for electric vehicles than this study assumes, and also potential for hydrogen fuel cell vehicles (reformed from natural gas).

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