Gas as an essential fuel in supporting the transition to a low carbon economy

A discussion paper by National Grid to support Ofgem's RPI-X@20 project.

Executive Summary

The RPI-X@20 project has benefitted from the LENS work that Ofgem completed in 2008 but no equivalent study has been undertaken for gas. As a result, the project has an incomplete view of the possible future for gas networks and is, if anything, underpinned by an assumption that gas use will decline steadily, albeit at an uncertain rate, into the future.

At National Grid, we continue to develop climate change scenarios and to assess their implications for the energy market in Great Britain. This paper sets out some of the key conclusions from our scenario work as they bear on the future of gas.

This work looks forward to 2050. The basis of the work is an assumption that policy and market structures will prioritise carbon reduction measures on the basis of: the level of reduction available; the technological challenge; and, the costs to achieve – including the degree of consumer adaptation required.

As a result we arrive at different carbon reduction profiles for different activities. Clearly reduction measures will overlap, but we generally expect progress to take the following form:

- **Energy efficiency** will start to be tackled immediately with further progress expected throughout the period.
- **Electricity generation** is also likely to be tackled early in the period without significant impact (other than cost) on end consumers.
- **Transportation**, the next most carbon intense, is likely to follow on.
- **Heat** is likely to be the most complex area to address thoroughly.

Our conclusion is that gas demand is likely to remain strong in the short-term - providing a relatively low-carbon bridge to the future - and gas is likely to continue to provide a significant level of economic support for electricity system balancing and for peak heat for many years to come.

Building on this picture, the paper also briefly sets out the main implications for the RPI-X@20 review (and subsequent gas transmission and distribution price reviews):

- Gas networks will continue to require investment to provide additional flexibility and maintain capability for the foreseeable future.
- The costs of the continued operation of gas networks are likely to be spread across a lower level of throughput, but consumers will still value the peak heat and electricity supply demand balancing services which the networks facilitate.
- The industry should pursue efforts to reduce regulatory barriers to the acceptance of wider ranges of gas quality – both to enhance supply security and to limit costs.

There is no single obviously optimal pathway to achieving the 80% reduction in CO_2 emissions sought by 2050. Technologies, markets and policies are likely to evolve in unpredictable ways but, in the short term, we should keep plausible options open to minimise the cost of the adjustment.

National Grid's Climate Change Scenarios

National Grid has developed a range of scenarios for electricity, transport and heat focusing on achieving ratified renewable energy and CO_2 targets by 2020 and 2050.

On the **gas supply side**, we believe that bio-methane is likely to make a significant and economic renewable contribution – increasingly substituting for fossil-based natural gas over the period.

On the **gas demand side**, our analysis is predicated on a series of assumptions about the way that different carbon sources will be tackled at different times in different market sectors. We recognise that the political and market framework for energy use will evolve and, in many cases, that technologies are still to be developed. However, we assume that policy and markets will move to target the most carbon intensive sectors first and that technological development will tackle the most tractable problems first.

Our modelling considers the problem of transitioning to a low-carbon economy under four broad categories: energy efficiency, electricity generation, transport and heat. The key considerations for each area are as follows:

Energy efficiency measures are often economic in their own terms and are increasingly likely to be so as real energy prices rise. They can be easy to implement on a general basis (e.g. new appliance standards and new building regulations) or can be intrusive (e.g. building insulation and heat augmentation systems such as solar thermal heating, micro generation and heat pumps). We assume that the impact of energy efficiency on demand will build up gradually over the period as the impact of policy instruments (such as grants) energy prices, smart metering, and the turn-over of appliances and building stock take effect.

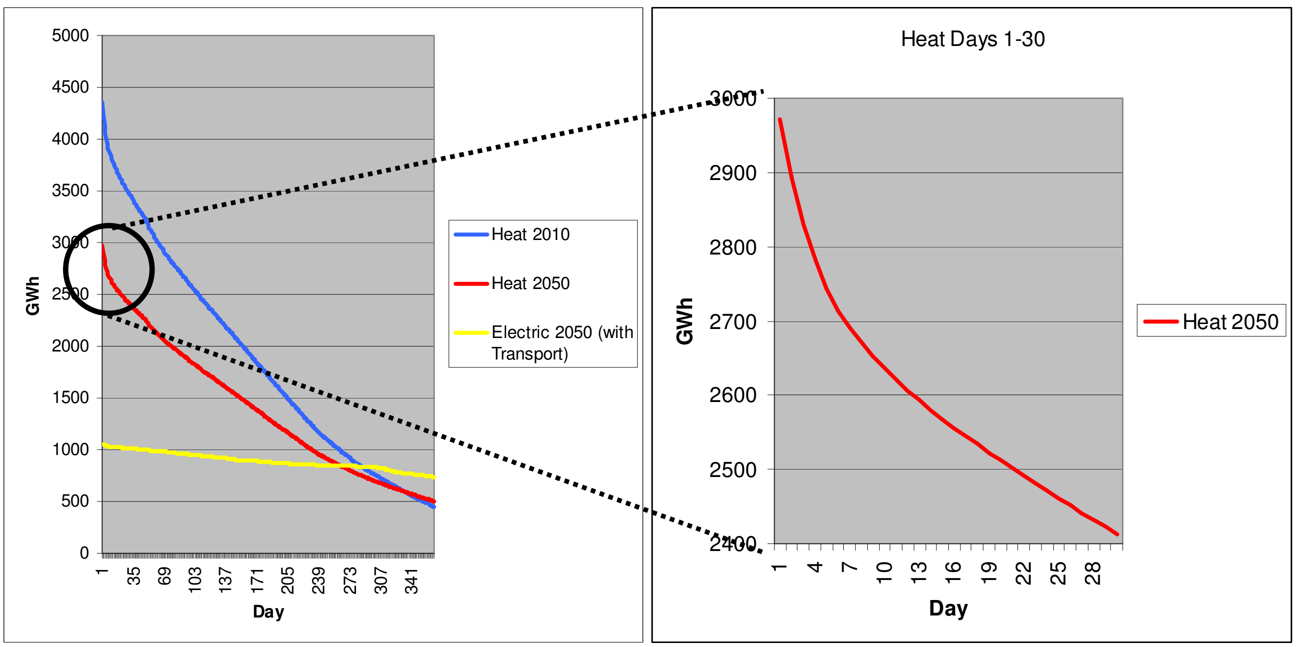
Electricity generation is likely to move towards gas in the short-term, as nuclear and coal plants close, and then increasingly towards wind, carbon capture and storage coal (and gas) and nuclear. Although we have considered the economics, more localised generation on a significant scale is not a key feature of our scenarios.

Transportation is currently dependant on oil and so less carbon intensive than generation. The transportation sector also has the opportunity to significantly enhance efficiency through electrification although this will require significant consumer adjustment. For transport, light vehicles are increasingly likely to move towards electricity but for some uses (e.g. large road vehicles and aviation) electrification is likely to be impractical and the focus of low carbon efforts is likely to be bio-fuels and natural gas.

Heat is currently dominated by gas which has evolved and expanded over a number of decades and currently serves some 22m homes, commercial and industrial premises. Gas is used to heat over 80% of homes in Great Britain with the remainder predominantly heated by oil and a smaller proportion heated by electricity, coal, and renewable fuels. The average home in Great Britain currently consumes approximately 18MWh/pa of energy for heating and current trends indicate that average consumption is declining by 2% per annum. New housing consumes approximately a third of this level as a result of tighter building regulations. Energy for hot water, rather than space heating, is a more important component of heat energy in new build houses.

These aggregate figures mask the seasonality of heat demand. In the future, despite insulation improvements and augmentation options, heat energy in residential properties will continue to be exceptionally seasonal, especially for older housing, and additional heat will continue to be required during winter months. Figure 1 shows the comparative energy requirements between electricity and heat demand on a warmest day to coldest day (average year) basis by 2050 – and for comparison the equivalent 2010 curve i.e. before energy saving measures have been implemented.

Figure 1 Load Duration Curves for Electricity Generation

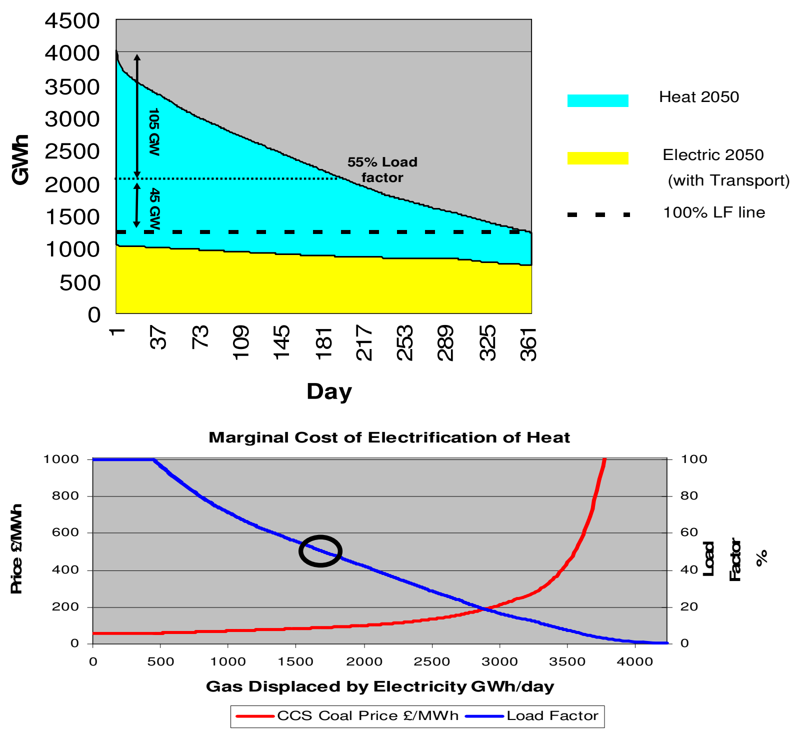


Whilst electricity demand remains relatively flat throughout the year, heat increases significantly such that on a peak day there would be roughly three times the energy required for heat (~3000GWh) than electricity and transport combined (~1000GWh). Accordingly, the full electrification of heat would range from approximately 1200GWH on the warmest day to 4000GWh on the peak coldest day.

Such a variable load duration curve would in practice require significant addition generation plant and network capacity operating at low load factors on average over the year. Put another way, generation plant will be required to meet the peak day demand and so would need the capability of flexing supply from 25% to 100% capacity on average. Given that nuclear and wind will provide a base load a significant number of coal and CCGT CCS generation assets would remain idle for long periods during the year escalating the costs for energy. The cost of electrifying heat is likely to be uneconomic without either heat storage or, more plausibly, the peak demand capability already provided by the existing gas network. Figure 2 shows the modelled cost for electricity per

MWh against generation plant load factors alongside the combined electricity (including heat and transport) load duration profile. Figure 2 shows that a 100% load factor (all generation plant operates at maximum output) would provide the cheapest price for energy but would only be operational for a handful of days per year.

Figure 2 Cost of Electrifying Heat



Clearly generation plant doesn't currently operate at 100% load factors, but the analysis indicates that the price of energy starts to increase exponentially as load factors fall below 50%. Electrifying heat starts to become less economic than bio-methane and natural gas as electricity load factors fall below 55% (even assuming that gas (either bio-methane or natural gas) costs in excess of £100/MWh). Consequently, a balanced approach may be appropriate where a typical property uses electricity, renewable heat where available, and a blend of bio-methane and natural gas for peak demand shaving.

Over time, in our base scenario, the overall picture develops as follows:

Up to 2020

Generation and gas supply

To achieve the 15% renewable energy target by 2020 there will be significant development in wind generation capacity. Over the same period, we expect additional CCGT generation plant to be developed to off-set the closure of ageing nuclear plant and coal-fired power stations subject to the large combustion plant directive.

The total electricity generation output is likely to be developed to meet traditional electricity demand as we do not anticipate material increases in electricity demand in transport or heat sectors.

It is likely that aggregate natural gas consumption will increase to meet the increase in CCGT plant. With UKCS production in decline there will be a greater reliance on imported natural gas and further expansion in pipeline and LNG importation capacity. It is also likely that additional gas storage capacity will be developed to aid balancing and mitigate security of supply risks (in both electricity and heat supply). By 2020 bio-methane will start to be injected into distribution networks but this will be primarily used for heating.

Transport

We expect transport efficiency to continue to improve combined with a shift towards hybrid petrol or natural gas vehicles, some electrification of smaller road vehicles and the use of bio-fuels and natural gas in some HGVs.

Heat

It seems likely that non-generation gas aggregate demand will continue to decline as a result of efficiency improvements such as: non-invasive property insulation (loft and cavity wall insulation); industrial process improvements; greater heat control (aided by smart meters); and, replacement of ageing heating appliances by more efficient plant. Augmentation of heat energy by solar thermal is likely to become more prevalent as installation costs reduce and energy prices provide an additional incentive. Electrified heat (by heat pumps or economy 7 systems) is also likely to be widely employed on new housing developments as the carbon-neutral homes policy take effect in 2016.

2020 to 2030

Generation

Low CO_2 electricity generation capacity will increase through to 2030 with a significant contribution made by new nuclear plant and CCS coal-fired and CCGT plant. At that time, it is likely that existing CCGT plant will increasingly operate as electricity system balancing plant rather than base load, as new CCS and nuclear plant will be relatively inflexible and wind generation intermittent.

Between 2020 and 2030 it is likely that electricity will become less carbon-intensive than either oil or gas and, as a result, we expect a gradual transition towards electricity in both transport and heat sectors. Until that point is reached, electricity for transport or heat on a large scale would actually increase CO_2 emissions as the marginal generating plant is likely to be the most carbon-intensive.

Transport

As oil is more carbon intensive than natural gas, we expect quicker electrification of transport than heat over this period. The average petrol engine converts up to 25% of the fuel energy into motion; this can increase with hybrid technology to around 40% and upwards of 70% with electricity, thus providing a significant reduction in energy per mile driven.

Furthermore, the asset lives of road vehicles are typically shorter than home heating systems or distribution and transmission networks and upstream assets, and as such it is likely that electrification of transport will be easier and more economical to roll out. However, the current shortcomings in electrified road transport need to be remedied and, in particular, improvements in battery technology will be essential. Transport electrification along with additional demand from new housing and commercial developments employing electricity for heat, possibly through heat pumps, is likely to take any additional electricity capacity, providing the economic incentives (price of carbon) and legislation are in place. Electrification may not be suitable for all vehicles and we have assumed that aviation remains fuelled by oil and HGVs (20% of road vehicles) make use of oil, biofuels and natural gas.

Heat

It is possible that existing home heating via oil is replaced by bio-fuels / biomass, gas or electricity (heat pumps) dependant on costs and government incentives over this time period. We anticipate some migration from existing gas consuming properties onto electricity (with and without heat pumps), but do not expect the levels to be significant. A mass roll out of ground or air source heat pumps seems unlikely given that ~70% of existing housing is either flats, terraced, or small to medium sized bungalow/semi-detached housing. Existing housing is therefore likely to find it challenging to find either the space internally or externally to be adopted technically let alone economically (assuming replacement of existing heat delivery systems as well as central heating). However, we do expect retail fuel prices to increase over time encouraging further efficiency measures where practicable. As such, it is plausible that the uptake of solar thermal heating will increase during this time period. Such systems appear relatively simple to retro-fit to existing properties as well as new build.

We note that the efficiency levels of small scale electricity production that typically consume biogas operate at lower efficiency levels than residential boilers and as such, incentives should promote a more efficient usage by injecting the gas into existing networks where economic to do so. In some of our scenarios we assume that a significant amount of bio-methane would be introduced into distribution networks. Given the potential for demand reductions, bio-methane could make a sizeable contribution (50-100TWh/a) towards existing natural gas heated homes by 2030. We have assumed the majority of bio-methane is produced from waste products with low levels of bio-fuel crop production.

2030 to 2050

Whilst it becomes increasingly difficult to model long term scenarios as far out as 2050 it seems logical to assume that electricity growth will continue and electricity networks will be geared towards providing electricity at sufficient levels to accommodate the smaller vehicle road transport fleet. It is also possible that between 2030 and 2050 existing gas heated homes will start to employ some electricity for heating. However, the full electrification of heat has, and will continue to face, the major economic barrier of peak heat provision.

Consequences for the Gas Sector

Our modelling and analysis has identified a number of key priorities which apply across a range of scenarios in the way the climate change targets may be achieved.

It seems likely that gas will continue to play an important role in meeting climate change targets and security of energy supply even if overall demand levels reduce. Specifically gas will:

- ***Remain a vital component in electricity generation*** in the short-term as a bridge to a low carbon generation mix and then as a flexible and diverse supply of energy for balancing electricity supply and demand.
- ***Provide an economic solution to peak heat demand*** by utilising an efficient existing public infrastructure (with largely sunk costs) and continuing to utilise existing private consumer infrastructure build into the fabric of existing buildings.
- ***Play a part in transport as a backup fuel for smaller vehicles and a major fuel for HGVs*** by providing a relatively benign transport fuel where the technical barriers to electrification remain.
- ***Allow existing fossil fuels to be substituted with renewably sourced bio-methane.***

These conclusions have a number of implications for gas networks which RPI-X@20 ought to take into account:

Widespread gas usage but reduced annual throughput
At the transmission level, annual and peak demand for gas may climb in the short-term as gas generation continues to substitute for nuclear and coal. In the longer-term, annual demand may reduce but peak demand is likely to remain strong as gas generation continues to be used to balance the electricity system.

Gas distribution networks are expected to experience a continued reduction in the level of annual gas demand over the short to medium term as efficiency measures take effect and as those buildings that can use electricity for heating leave the network. Thereafter, annual demand is likely to reach a floor as demand becomes focussed on meeting peak heat requirements during winter months. The number of connected customers is likely to remain stable even as annual demand reduces.

More flexible gas networks
The gas transmission system is expected to serve CCGT plant and CCS connected consumers. Accordingly, there is likely to be a requirement to enhance import capability (LNG terminals and inter-connectors with Europe) and cope with additional storage as UKCS production declines. Over the short term, it is expected that that gas flows will change further as LNG terminals and inter-connectors become the main gas entry points. This will require a review of capacity and compression utilisation and investment needs to be made fit for both the short and long-term low carbon future.

At the distribution level, bio-methane connections are likely to increase through a combination of smaller scale anaerobic digestion and larger gasification plant connecting onto a range of pressure tiers. Natural gas is expected to continue to flow from the transmission system and bridge any gap between bio-methane supply and gas demand. We assume that the majority of bio-methane production will be continuous and so some investment may be required for storage and compression systems into the future

Making full use of smart metering to create smart gas grids may make a significant contribution towards delivering these more flexible networks.

A wider variety of gas specifications

The range of supplies connected to gas networks is expected to change. At the transmission level, further importation capacity (LNG and pipeline) is likely to be required, while at the distribution level bio-methane is expected to make inroads into supply.

The current gas quality requirements need to be reviewed to ensure that they do not impose unnecessary costs on gas producers/deliverers and to ensure the UK has access to the widest possible range of supplies at the cheapest cost. Similar considerations apply to the calorific value and billing regulations.