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The real economics of hydrogen networks: markets, mandates and money

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In this talk I am going to apply a reality check to the claims that are made for the potential role of hydrogen in meeting Net Zero targets, particularly with respect to the costs that are likely to be incurred. For simplicity and clarity I will assume that the goal is for a rapid and complete transition from natural gas to hydrogen. While this is almost certainly a straw man it provides a clear bench mark for assessing costs. Aiming to convert, say, 50% of gas usage to hydrogen will certain push up costs and cause a large number of both practical and political problems that I will return to later.

In concrete terms full conversion means replacing all final use of natural gas outside the energy sector by hydrogen by the year 2040. Based on past experience of developing networks a faster transition is patently impossible, while a slower transition will not meet the Net Zero target. Based on data for 2016-20 this will involve the replacement of 495 TWh of final gas consumption by hydrogen. The full cost will include hydrogen production and storage, network infrastructure and user equipment.

In the course of this talk I want to highlight four issues that are rarely subjected to careful engineering and economic analysis in policy or academic papers which focus on the transition to Net Zero, even though they involve huge amounts of money. These are:

(i) How will hydrogen be delivered to small and medium customers spread throughout the UK?

(ii) The Government's Net Zero path implies that initially most hydrogen will be produced by steam methane reforming (SMR) equipped with carbon capture and storage (CCS). What will this cost and does it work?

(iii) How does the expected reliance on offshore wind – or other sources of intermittent generation - affect the design and cost of plants to produce hydrogen?

(iv) Is a mandated and rapid conversion compatible with market incentives? How would the arrangements different for a partial rather than a full conversion?

Note that I will focus on full conversion from natural gas to hydrogen, not the injection of a relatively small amount of hydrogen into the natural gas network. Realising the Net Zero target requires full conversion. The injection approach is cheap and relatively easy – provided that sufficient hydrogen is available – but it is viewed as incompatible with the Net Zero target. Readers may draw their own conclusions about what this tells us about the practicality of policies that rule out low cost options for lowering carbon emissions in pursuit of the grand vision.

Some readers may feel that the tenor of this talk is relentlessly negative. There is a reason for this. I believe that a large programme to convert from natural gas to hydrogen might be feasible by the end of the current century, if technological developments are favourable and UK households are willing to bear the cost. However, scenarios of large scale conversion by 2050 are pure fantasy, involving huge costs as well as engineering difficulties.

Hydrogen networks

There is a crucial piece of background that underpins my assessment of this issue. During the period from 1991 to 2010 I worked in many countries in Eastern Europe and elsewhere on the development of gas transmission and distribution networks to serve business and households. In the Soviet period use of gas was usually restricted to large industry and energy production, so countries that wished to move away from reliance on coal needed to build new networks.

Based on this experience the notion of converting existing gas networks to hydrogen rapidly on a large scale is a complete non-starter. Quite apart from safety and operational considerations, you have to persuade every connected customer in an area to install new boilers, cookers, and fires in a narrow window **before the conversion**. No program has got close to achieving that even on a small scale. For the transition envisaged there is no reasonable alternative to developing a completely new hydrogen transmission and distribution network, which means running gas and hydrogen networks alongside each other for one or two decades. Anyone who claims otherwise is wilfully choosing to ignore both engineering and economic considerations. Even highly regulated or authoritarian regimes were or are unable to achieve this on a large scale.

The second key element in my assessment is the use of current capital and operational costs at 2020 prices for everything from customer equipment to storage and production. The literature is full of fantasy numbers about how the cost of hydrogen can be reduced by 50% or even 75% by 2035 but either (a) these are based on sleight of hand – an example assumes that the cost of electricity will be no more than $20 per MWh – or (b) they are technological snake oil without any commitment to deliver the results assumed. Anyone with practical experience of large projects such as HS2 or the Kemper County CCS project knows that the final cost is all too often more than 3 or 4 times the claimed cost before the project is approved.

Customer premises. Let us start with the downstream end of hydrogen networks – the equipment in customer premises that currently use gas for heating and cooking. Even the basic numbers are very sketchy. There are about 28 million households in the UK plus about 6 million businesses and other establishments. Allowing for population and economic growth the total number of households and non-domestic establishments will be close to 40 million by 2040. Official statistics suggest that 87% of households rely on gas heating and we can assume that a similar proportion of non-domestic establishments use gas in some form. Thus the total number of gas customers who must be converted to hydrogen will be close to 35 million by 2040.

It is claimed that in future hydrogen boilers will cost no more than current gas boilers. An average cost of £1,500 is often cited for the cost of small to medium domestic boilers but this ignores larger properties and non-domestic establishments as well as open fires and cookers. Further, anyone who has contemplated changing their domestic heating and/or cooking equipment knows that installation costs may be a large part of the total. The average conversion cost is very unlikely to be less than £3,000 per gas connection and might realistically be as high as £5,000 per gas connection. Thus, the customer premises cost of conversion will fall in the range from £100 billion at the low end to £175 billion at the high end.

Transmission and distribution networks. My estimate of the cost of building new transmission and distribution networks is based on the modern equivalent asset (MEA) value of gas networks in the UK. British Gas (as was) published a replacement cost value for its network up to 1997, after which the rules on regulatory accounting changed. Since 1997 I have recorded the historic cost of investment in new tangible assets for the various successor companies to British Gas including National Grid Gas, the gas distribution networks (Northern Gas Networks, Scotia Gas and Wales & West Utilities) separated in 2006 and Cadent Gas separated in 2016. To these I have added expenditure on constructing new gas networks to serve Northern Ireland by Mutual Gas, Phoenix Natural Gas, Firmus and smaller companies. All historic cost figures have been converted to 2020 prices using the GDP price deflator. The resulting total MEA value of UK gas networks is about £85 billion.

This figure does not include the cost of customer connections – i.e. the pipes from the distribution mains to either the meter or equipment in the customer premises. Under current regulatory practice and bearing in mind the safety issues around hydrogen, distributors will be required to bear the cost of installing new pipework past the meter to connect customer equipment. That task alone is likely to be very demanding because of the sheer number of connections required. Based on the practical experience of rolling out fibre optic networks the average cost will be at least £1,000 per customer and may well be as high as £2,000 per customer.

Hence the total cost of building a new hydrogen network will be a minimum of £120 billion and might be as high as £150 billion at 2020 prices.

Hydrogen storage. The engineers who built the original gas networks knew that distributing a manufactured gas to customers whose demand varied greatly over time and seasons required either large amounts of storage or very flexible production capacity. Flexible production may be possible for steam methane reforming but a lot of storage is necessary if hydrogen is produced by electrolysis fed by intermittent renewables.

The easiest and cheapest form of hydrogen storage is to use salt caverns. My prediction, based on experience in dealing with the planning objections to gas storage, is that this will be strongly resisted by enough people to be politically unviable in the UK, unless the storage sites are some distance offshore. Nonetheless we can ask what would be the costs of hydrogen storage using salt caverns in the Net Zero scenario.

The scale of the storage required can be inferred by considering the numbers that drive National Grid's winter outlook planning. With SMR production the amount of storage required could reasonably be set at 7 days of average cold day demand with a more conservative level of 7 days of 1 in 20 year peak demand. This implies the capacity of hydrogen storage should be in the range 29-36 TWh. If hydrogen is primarily produced using offshore wind the amount of storage should be increased to at least 15 days demand, i.e. a storage capacity of 62-78 TWh. The capex cost of building such storage would be about £25 billion at the low end and up to £70 billion at the top end.

Summary. In purely technical terms there are no obvious reasons why a hydrogen network could not be built. It would be a huge civil works programme entailing very large amounts of disruption, so it is likely to be very unpopular. Large cost over-runs are a virtual certainty, so that the final costs will be considerably higher than the figures above.

However, the real issues are financial and institutional. Excluding the costs of converting customer premises, the infrastructure will cost a minimum of £150 billion and a figure in excess of £200 billion is more likely. That is an investment of at least £10-12 billion per year over 15 years. In 2020-21 the existing gas distribution and transmission companies had gross revenues about £5.5 billion and net cash flow of about £3.2 billion. Further, the investment will produce almost no return for at least a decade because large parts of the network must be built before large scale conversions can begin.

No matter what arrangements are made the cost of building the network will ultimately fall on the public sector, either by government borrowing or taxpayer support. That will raise all of the problems that accompany large public programmes, almost certainly inflating costs even further. In addition, it is very likely that taxpayers will bear a substantial share of the costs of converting customer premises. This will include the premises owned by public entities as well as the premises owned by households who are either unwilling or unable to cover the costs of conversion.

In summary, financing the cost of building a new hydrogen network plus associated infrastructure and converting customer premises will imply public expenditure of at least £15-20 billion per year for 15 years. There is little doubt that the money can be found for such a project but it is more uncertain as to whether taxpayers will be content with the resulting diversion of resources from other public services.

SMR production and carbon capture

There is general agreement that steam methane reforming of natural gas is currently the least expensive way of producing hydrogen in large quantities. However, conversion from natural gas to SMR-produced hydrogen will simply increase both costs and CO2 emissions unless SMR plants are fitted with carbon capture and storage (CCS). This is where the problem arises.

In my analysis of CCS published in 2017 – *The Bottomless Pit: The Economics of Carbon Capture and Storage* – I highlighted the appalling record of CCS projects with respect to cost over-runs and under-performance. Since 2017 the situation has only got worse. The one apparent success – the PetraNova project in Houston – has been mothballed because of poor performance and the loss of markets for the captured CO2. The largest attempt to capture CO2 from natural gas production – the

Gorgon LNG project in Australia – experienced huge cost over-runs and has not managed to solve problems in injecting and storing CO2 in undersea reservoirs.

So, what we have learnt to date is that CCS on a large scale is both very expensive and often doesn't work. Part of the reason is that it seems neither governments nor potential operators believe that large scale CCS is really viable. All of them want to transfer the costs of developing the technology onto someone else with the consequence that the work required to understand the costs of deploying both carbon capture for gas plants and sequestration has been delayed for nearly two decades.

I have used engineering estimates for the costs of building a large number (nearly 270) of SMR plants designed to produce 100,000 Nm3 of H2 per hour. These are equipped with 90% carbon capture, which is the target required for the Net Zero transition. Since hydrogen storage is expensive and likely to be limited by the availability of suitable sites, I have assumed that the total capacity of SMR plants must be sufficient to cover average daily winter consumption of gas. After allowing for the costs of compression and plant storage prior to injection into the transmission network, the capital cost of building SMR plants to replace non-energy gas demand would be about £105 billion with an annual operating cost of £22 billion per year. The opex cost includes an allowance for CO2 transport and storage of £50 per metric tonne of CO2. This unit cost is rather higher than I assumed in my CCS paper because the Gorgon experience suggests that undersea storage is likely to be substantially more difficult and expensive than had been assumed in the past.

The average wholesale market price of natural gas in the UK for 2015-20 was £14 per MWh. Adjusting for inflation that is about £15 per MWh at 2020 prices. At that price the wholesale cost of the gas used to meet existing non-energy consumption is about £7.5 billion per year. Using SMR plants to produce hydrogen incurs a total operating cost of about £33 billion per year even if capital costs are ignored. In terms of operating costs alone the cost for reducing CO2 emissions by substituting SMR-derived hydrogen for natural gas is over £190 per metric tonne.

Finally, there is a larger issue. The impression given by official documents is that "blue hydrogen" produced by steam reforming is no more than a stopgap until the costs of "green hydrogen" have fallen low enough. One may have doubts about whether that will ever happen, but private investors are unlikely to punt more than £100 billion on the vagaries of future government policy in this area. The most cost-effective option would be the government to offer PPA-type contracts for 25 or 30 years with a fixed annual payment plus a variable price per unit of hydrogen linked to the natural gas price. The implication is that most risk is transferred to the government, which would be committed to large payments of up to £20 billion per year to 2070 or beyond. Inevitably, the costs of such an arrangement would likely fall on hydrogen customers. They might be less than pleased with the large increase in their heating bills.

Green hydrogen production

Hydrogen enthusiasts are enamoured of the idea that the cost of green hydrogen can be reduced below $2 per kg using electrolysis fuelled by offshore wind. However, it appears that they have no appreciation that cost calculations look entirely different when electrolysis is powered by intermittent renewables rather than a nuclear power plant. The issue is best understood by comparing the designs of an electrolysis plant powered by (a) a 1000 MW nuclear plant with an expected 95% availability factor, and (b) a 1000 MW offshore wind farm with an expected load factor of, say, 55%. In the first scenario you would build an electrolysis plant with a capacity of 1000 MW and run it at capacity except when the nuclear plant is offline for refuelling or maintenance. In the second scenario one faces a difficult optimisation decision which depends on the range of load factors over which the electrolysis plant can operate efficiently – i.e. at close to the design conversion level which is currently about 65%..

Figure 1 shows a simplified version of the trade-offs involved. The lowest orange curve shows the average electricity usage over 40 years in MW using the distribution of wind speeds for offshore sites for plants of different sizes that only operate efficiently at between 90% and 100% (full capacity). The calculations use average offshore wind speeds and generation for all offshore sites in the UK for the period from 1981 to 2020 for the months from October to March to cover winter demand for heating. A 1000 MW electrolysis plant will only use an average of 100 MW because most the time the electricity output from the wind farm is below 900 MW and the plant has to be switched. At the other end of the distribution a 200 MW plant will produce an average of 182 MW because most of the time the wind farm will produce more than 200 MW, meaning that surplus power will have to be curtailed or sold to the grid at a very low price. For such a plant the maximum average yield will be 303 MW for an electrolysis plant with a capacity of 500 MW. The figure shows that the maximum average yield increases for more flexible plants with a large efficient operating. For a plant with an efficient operating range of 50% to 100% the average yield is about 439 MW for a plant with a capacity of 800 MW. However, there is a cost penalty for building and operating larger plants so that the optimal plant is likely to be lower – perhaps 600 MW with an average yield of 420 MW.

It may be argued that electrolyser plants can buy in power, but where from? The calculations already assume that offshore wind from all parts of the UK is pooled. The scale of the capacity required – over 300 GW - rules out any significant role for solar, onshore wind or interconnectors. The only realistic alternative source of supply is nuclear power, in which case it would be better to design a system based entirely on nuclear. In addition, the optimistic economics of electrolysis based on very low electricity costs will be completely undermined by the need to buy electricity at high prices when offshore generation is low.

There is, in any case, an even more serious design issue. How should we allow the significant variability across years in the average wind speed in winter. Averages are rather misleading. No operator can accept the risk that there might be insufficient hydrogen production to meet demand in 1 year out of 2 or even 1 year out of 10. Figure 2 shows the 10th percentile, lower quartile (25th percentile) and median of the annual distributions averaged for Figure 1 for a flexible plant with an operating range of 50% to 100%. National Grid works to a 1 in 20 year reliability standard which may be too strict in this case. A 1 in 10 year standard would mean that the optimal electrolysis plant size is 550 MW – rather than 800 MW for the average yield – and the expected yield would be about 320 MW from a 1000 MW wind farm.

The total capex cost for electrolysis relying on nuclear power would be about £625 billion and slightly more than double this figure for electrolysis relying on offshore wind generation on the assumption that flexible plants allow operation in the range from 50% to 100% of capacity. These are optimistic estimates of capital costs based on current claims about the unit costs of developing nuclear and offshore wind plants.

Since such a programme would involve the construction of nearly 130 GW of nuclear capacity or 380 GW of offshore wind capacity in 15 years I think that we can safely discard the idea. Neither the money nor the resources are available for construction on such a scale. The whole green hydrogen story is simply absurd if it is intended as a route to decarbonisation before 2050. It should be parked in the category of fairy tales while engineers think seriously about other strategies.

Overall assessment

Table 1 shows the estimates of the capex and opex costs that might be incurred to convert from natural gas to hydrogen within the time scale required to achieve Net Zero. I do not present these figures because I think that this is a serious option. What the figures show is that the notion of relying on large scale hydrogen to achieve Net Zero is implausible in the extreme. In aggregate terms the issue need not be financial. A total capital expenditure of £350 billion over 15 years is roughly 1% of 2020 GDP at current prices per year. Historically the UK has spent 16-18% of GDP on gross fixed capital formation, so this cost would be about 6% of total investment over the period.

However, pre-emption of net capital formation is another matter. Such a program would amount to almost one-third of net capital formation over 15 years. In other words, the UK would have to sacrifice a substantial part of the capital accumulation required to maintain or increase living standards for a growing population in order for a period of a decade and a half. This is only part of the effect. The programme will involve the diversion of all kinds of skills as well as finance from other productive activities to sustain the construction of networks, storage facilities and SMR plants as well as the conversion of homes for what is essentially a less efficient and less secure form of energy use. A government whose current PR claims that Net Zero can be attained without any sacrifices will never sustain such a programme.

What about conversion on a smaller scale? The current pilots are little more than either hydrogen mixing or hot air with no relevance to the real engineering problems of full conversion. The real challenge arises when the goal is to convert 20,000 or more premises in a medium-sized town. If hydrogen is priced to cover full capital and operating costs for steam reforming and the network, it will be at least twice the cost of natural gas on a heat-equivalent basis. The number of voluntary conversions will be small, while mandatory conversion will be highly unpopular. Practical experience tells us that a new fuel must be either cheaper and/or more convenient to use if it is be accepted quickly.

It is almost inevitable that the government will be forced to subsidise both conversions and the hydrogen price for domestic customers with finance raised by levies on natural gas consumption. However, unless the price of natural gas reverts to 2020 levels this is not a viable strategy for a large growth in hydrogen use because public tolerance for higher energy prices driven by green levies is very limited.

The cost issue is fundamental to both institutional and financial arrangements. Mandating conversion from natural gas to hydrogen for a significant part of the UK would be “very brave” step in Sir Humphrey’s terminology – i.e. politically suicidal – unless almost all of the cost is borne by the Exchequer and/or the finance is covered by government guarantees. Existing gas companies might lobby to be given the job of building the network, but the gas distribution networks don’t have the scale or financial resources required while National Grid Gas is compromised by National Grid’s primary focus on electricity. Further, construction of hydrogen production plants will only be possible at the outset when backed by HPA’s (hydrogen purchase agreements) similar to PPAs with a single buyer.

Under these circumstances, it is almost inevitable that the network plus storage would be owned and operated by a public company, what we might call British Hydrogen. Competition might be possible for hydrogen production but the uncertainty about demand will strongly favour contracts with a single buyer. Even other arrangements are adopted to preserve the fiction of private ownership and operator, the reality will be a market controlled and substantially financed by the Exchequer.

Figure 1 - The effect of wind intermittency and plant flexibility on electrolysis plant design

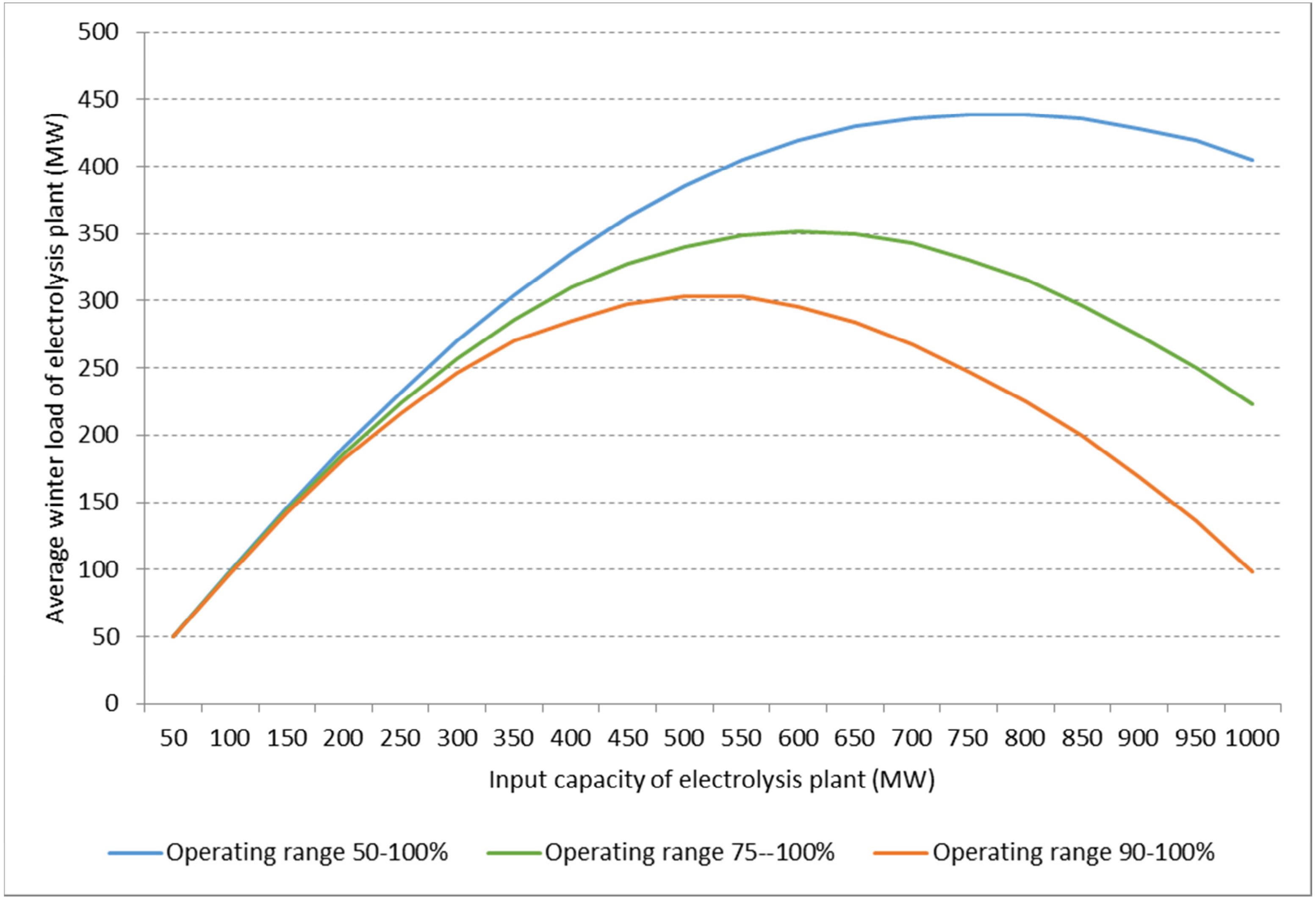

Figure 2 - The effect of annual wind variability on electrolysis plant design

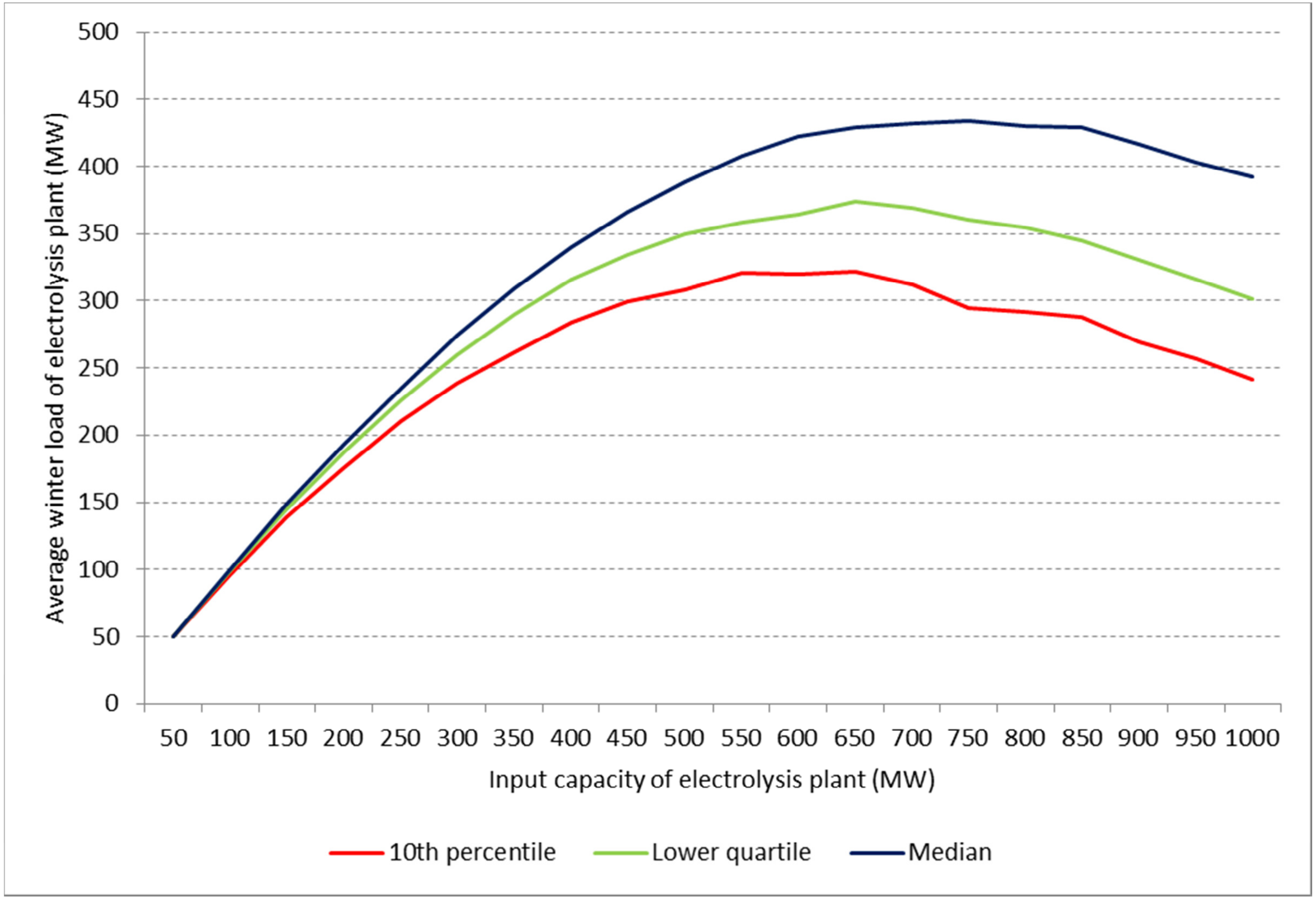

Table 1 – Summary table of capex and opex costs

	Capex cost (£ billion)		Opex cost (£ billion per year)		Operating life	Note
	Low	High	Low	High	Years	
Customer premises conversion	100	175	0	0	15	No increase on current expenditure
Transmission & distribution	120	150	2	3	40	Similar to current expenditure
Hydrogen storage	25	70	3	7	50	
Hydrogen production						
Steam methane reforming	105	150	33	45	25	Including natural gas
Electrolysis using nuclear power	625	850	42	60	50	No allowance for waste disposal
Electrolysis using offshore wind	1450	2000	145	200	25	