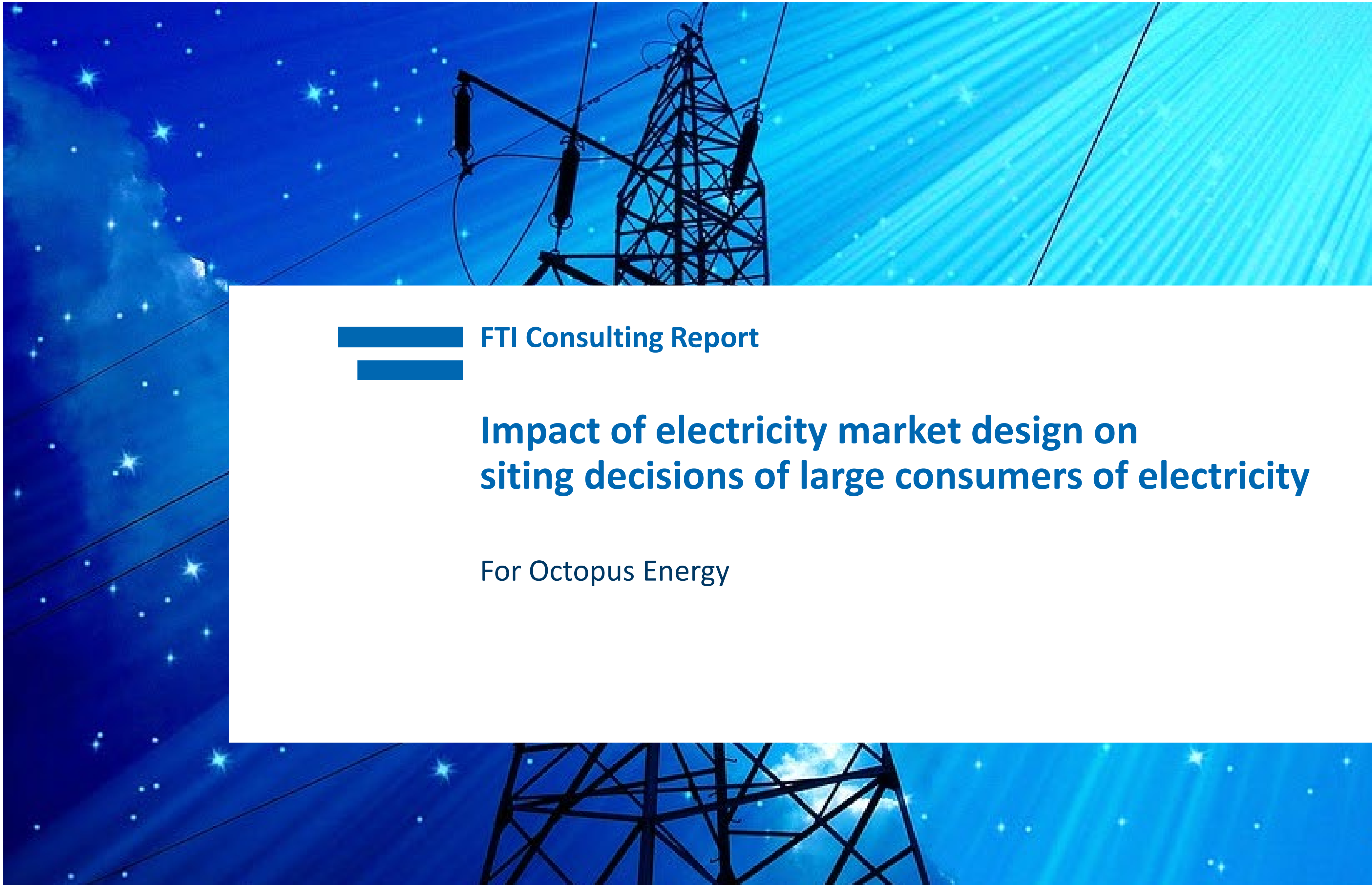

FTI Consulting Report

Impact of electricity market design on siting decisions of large consumers of electricity

For Octopus Energy

FTI CONSULTING

October 2023

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Contents

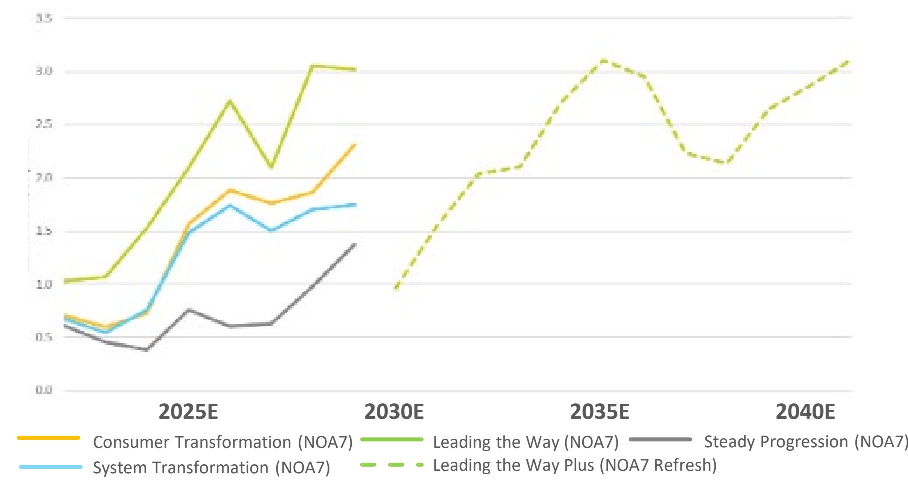
Executive summary

Ofgem is considering the benefits of alternative power market designs as part of the Government's wider review of electricity market arrangements in GB

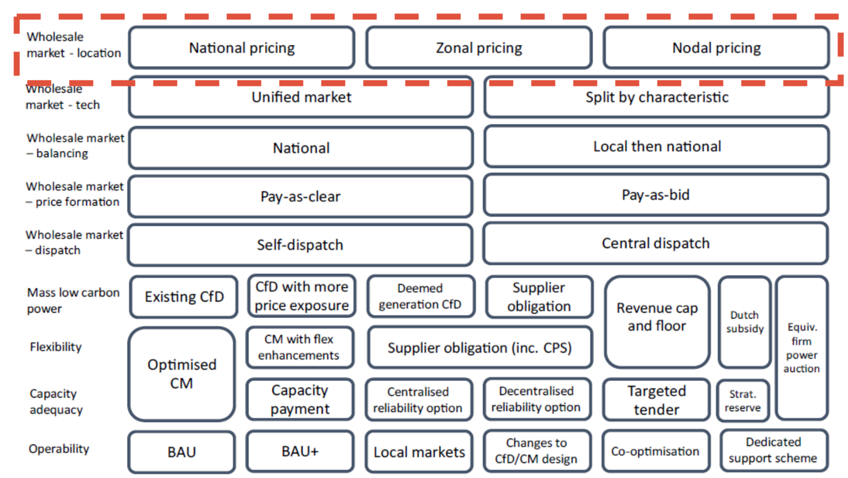
Market design is an important element in achieving Net Zero targets in Great Britain (GB) while managing costs to consumers

- The past decade has seen a **fundamental shift** in both **how** and **where electricity is generated** on the GB electricity system.
- Increasing mismatches between where electricity is generated and where it is consumed have **significantly increased the costs of managing transmission congestion**, forecast to reach £3bn a year by 2035.
- To **help GB reach its Net Zero commitments at an acceptable cost to consumers**, BEIS launched the Review of Energy Market Arrangements (**REMA**) consultation in 2021, exploring a wide range of market reforms. [2,3]
- Options for introducing more **locationally-granular pricing in the wholesale electricity market** have been one of the **more prominent reforms** that have been examined.
- FTI has recently supported Ofgem on a **technical assessment of locational pricing** options, which is due to feed into the REMA process. [4]

ESO constraint cost forecasts, NOA7+HND, 2022-2041, £bn[1]



Market reform options under consideration in REMA[5]



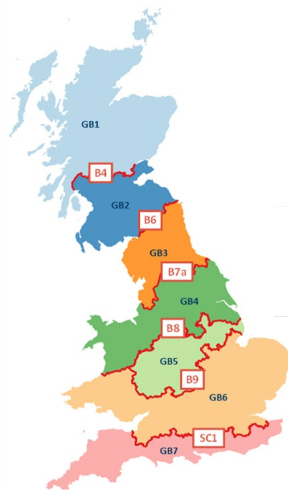
Merits of locational wholesale market design are a key focus of REMA…

…and Ofgem has been providing technical input into the policy debate

1. ESO (2022) Modelled Constraint Costs – August 2022 (link) 2. UK Government (2021), Net Zero Strategy; page 101. 3. Gov.UK, UK launches biggest electricity market reform in a generation. 4 Ofgem, Locational Pricing Assessment. 5. BEIS (2022), Review of Electricity Market Arrangements - Consultation Document; page 49.

This report builds upon FTI's assessment for Ofgem by considering the impact of locational pricing on the siting decisions of new large consumers

National | **Zonal** | **Nodal**



Uniform price clears across entire market

GB Germany

GB System divided into ***seven zones*** *with individual prices*

Australia Sweden
Norway Italy

GB system divided into ***c.850 "nodes"*** *with individual prices*

USA New Zealand
Canada (Ontario) Singapore

Considered Zonal and Nodal locational pricing market designs against the status quo of national

FTI's assessment commissioned by Ofgem showed that:[1]

1. Locational pricing would likely deliver **significant consumer benefits** across the period from 2025 to 2040 (between £28bn and £51bn under a nodal pricing regime).
2. **Consumers in all GB regions would benefit from a transition to locational pricing**, although some cohorts would benefit more than others.
3. Moving to locational pricing would likely reduce emissions faster. Applying **DESNZ's carbon values, environmental benefits could amount to a further £4.3bn to £17.9bn.**
4. **Flexibility resources** (particularly interconnectors, but also batteries and electric vehicle charging) would be utilised more effectively under Zonal or Nodal pricing, recognising constraints on the network.
5. There would be **significant potential reductions in the need for transmission investment,** as locational pricing would deliver market signals that would improve operational and siting decisions of large generators, reducing the need for additional transmission investment.

FTI's previous assessment considered the impact of locational pricing on the siting decisions of large generators, while taking demand's siting decisions as fixed.[2]

This report augments previous analysis by considering the extent to which locational pricing could also encourage large consumers of electricity to site in alternative locations and the associated benefits.[3,4]

1. Ofgem, Locational Pricing Assessment. 2. Holding demand's siting decisions as fixed was an assumption agreed with Ofgem based on stakeholder engagement. 3. In this assessment, we hold the size and location of generators constant across all modelled market designs to isolate the societal impacts of the siting decisions of large consumers. 4. Improved locational investment signals to demand assets was raised as a key potential advantage of nodal or zonal pricing in the REMA consultation; BEIS (2022), Review of Electricity Market Arrangements - Consultation Document; page 49.

Specifically, Octopus has asked FTI to test whether nodal pricing could deliver additional benefits by improving siting signals to new demand

- Building on the previous assessment for Ofgem, Octopus is now seeking to understand whether locational pricing could deliver additional benefits beyond those captured in the Ofgem assessment.[1] Specifically, we have examined:
  1. the extent to which locational pricing could provide a **meaningful incentive** for large consumers of electricity to **site in areas** with **lower wholesale prices** due to large amounts of **excess renewable generation capacity**.
  2. the extent to which improved siting decisions of large demand, in turn, could deliver **wider benefits to GB consumers**.

- In this context, FTI has been commissioned to test the impact of **new incremental demand** entering the market **under national and nodal pricing regimes**. Specifically, we have been asked to consider the impact of the siting decisions of new demand on the following variables:

Wholesale cost of electricity paid by new demand	• ***How does the siting decision of new demand impact the private electricity costs of the new demand?***
Wholesale cost of electricity paid by other market participants	• ***How does the siting decision of new demand impact the wholesale electricity price paid by other market participants?***
Dispatch of available resources and carbon emissions	• ***How does the siting decision of new demand affect the GB generation/ import dispatch and power sector carbon emissions?***
Need for (and benefit of) new transmission infrastructure	• ***How does the siting decision of new demand affect the need for new transmission infrastructure in GB?***

1. Unlike the Ofgem assessment, we hold the size and location of generators constant to the FES 2022 Leading the Way scenario, to isolate the impact of demand siting decisions.

To estimate benefits, we model the change in key variables following the entry of new demand under the two different market designs (relative to baseline)

- To estimate the **impact of new demand on the wholesale cost of electricity**, we compare the wholesale prices + rebalancing costs that market participants would pay following the entry of new demand under the two different market designs (national pricing vs. nodal pricing), holding generator size and location constant. Note that there are no rebalancing costs under nodal pricing.
  - For national pricing, we consider costs based both on prices in the wholesale electricity market and 'redispatch' outcomes in the Balancing Mechanism. Importantly, **we assume that the new demand sites in the South, close to hubs of demand, under the current national pricing** market design, with the single national wholesale price failing to provide sufficient incentives to consider siting elsewhere. We do not consider that new demand would site in the North under national pricing, since there is no strong pricing signal to do so.[1,2]
  - For nodal pricing, we consider the possibility of new demand siting (a) in the South and (b) in the North (closer to renewable generation).
- We consider the change in wholesale prices following the entry of new demand *relative* to a baseline level of demand under each market design, as set out in the diagram below.
- To estimate the **impact of the new demand on generation/ import dispatch and emissions**, we compare the change in the generation mix following the entry of new demand at each location relative to the baseline, as well as a comparison between the two locations under nodal pricing.
- To estimate the impact on **transmission infrastructure requirements**, we compare the socio-economic welfare impact of additional transmission capacity under nodal pricing with baseline demand, new southern demand, and new northern demand.

	National pricing	Nodal pricing
a Baseline demand	Wholesale prices (+ rebalancing costs)	Wholesale prices
b New demand siting in South	Wholesale prices (+ rebalancing costs) ↑	Wholesale prices ↑
c New demand siting in North *(closer to generation)*		Wholesale prices ↑

Change from Baseline

Change from Baseline

Incremental demand, all else equal, results in higher electricity prices under both market designs and all siting decisions

We then compare the differences in changes from Baseline

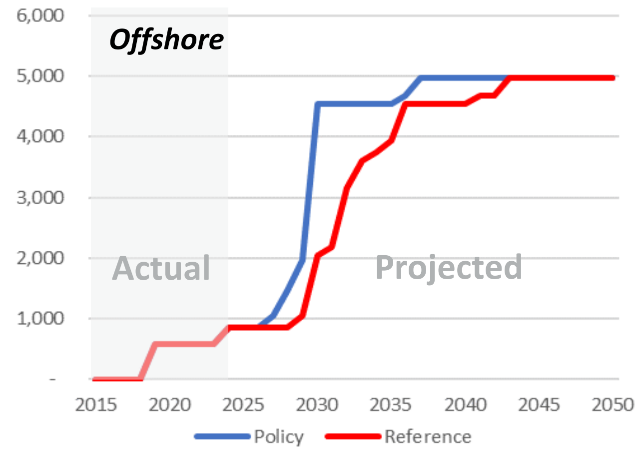
1. We note the regional difference in the TNUoS charges paid by consumers under the current market design. However, TNUoS charges represent only a small proportion of wholesale electricity costs paid by consumers (with regional unit charge savings around 57% (link) but representing only approximately 3-5% of consumer bills (link)). Other factors (such as the availability of skilled labour and/or the cost of transporting outputs) therefore may outweigh the (weak) incentive for consumers to site in regions with relatively lower TNUoS charges.
2. Energy intensive consumers often spend a large portion of total costs on electricity. For example, electricity costs form a significant portion of the total operating costs of an electrolyser, between 58-90% when consuming in the wholesale market (BEIS, Hydrogen Production Costs, 2021; page 29 and Annex.).

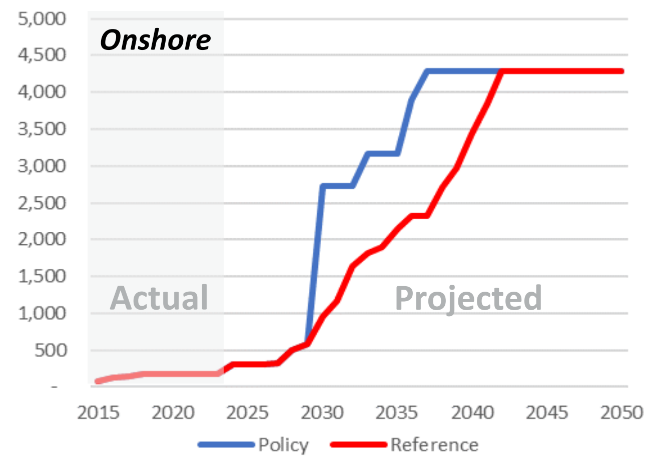
We also estimate the benefits of accelerating transmission network build-out under national and nodal designs

Pace of new transmission development

- The latest plans published by NG ESO[1] forecast that a significant deployment of large-scale transmission investments is completed between 2025 and 2030, including new onshore links connecting Scotland and England and offshore links connecting windfarms around GB. Some further transmission investment is expected to become operational between 2030 and 2040.
- To reflect the uncertainty in the speed of transmission network build, we test two different assumptions:
  - Our central scenario uses the **FTI Reference transmission scenario,** which includes all the transmission projects anticipated by NG ESO but assumes a slower pace of new transmission build. This is slightly more aligned with the completion dates anticipated by transmission owners, historical development times for comparable projects, and likely supply chain constraints. Overall, Reference transmission assumes a steadier build-out of new transmission infrastructure from 2025 to 2040.
  - We use the NG ESO **Policy transmission scenario** as a sensitivity in our analysis. Policy transmission represents a faster transmission build out than Reference transmission with both scenarios delivering the same projects by the mid 2040s.
- These two sets of transmission build assumptions are shown on the right, separately for offshore and onshore networks.
- We use these two transmission build-out scenarios to assess the benefits of incremental transmission capacity in the Policy Scenario, relative to the Reference Scenario.

Cumulative new networks from 2015 onwards (km)





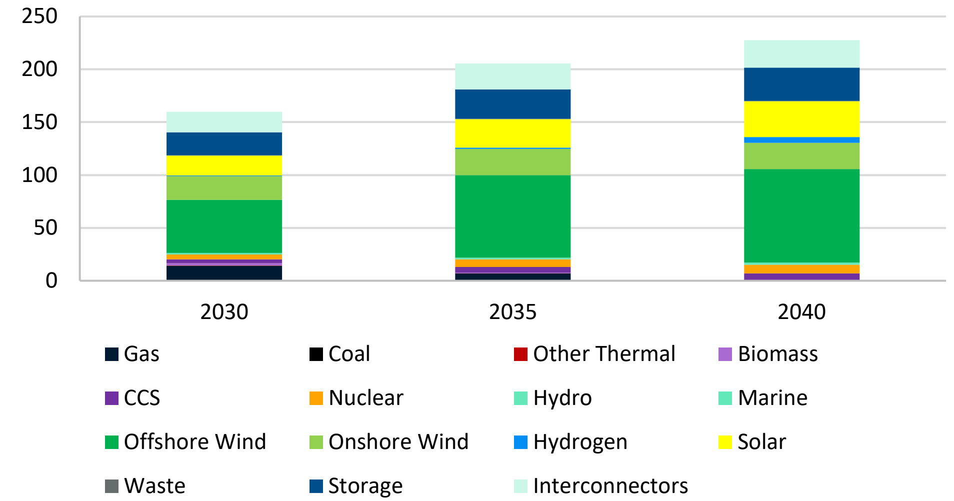
1. *Holistic Network Design, NG ESO, 2023*

Taking generation as fixed to FES 2022 Leading the Way, we see varying prices across GB under nodal pricing

We take generation capacity and location as fixed to the NG ESO, FES 2022 Leading the Way scenario.

- The Leading the Way scenario predicts significant growth in domestic wind generation, with capacity forecast to grow to 73 GW in 2030 and 113 GW by 2040.
- Conversely, fossil fuel capacity is projected to be completely phased out by 2040, with just 14 GW remaining in 2030.
- With fixed Leading the Way generation capacity and Reference transmission, we see an average single national wholesale price of £44.62 in 2030, and £31.53 in 2040 under national pricing.
- Under nodal pricing, the wholesale varies across GB as shown in the maps below.

Generation capacity by type, FES 2022 Leading the Way, GW[1]

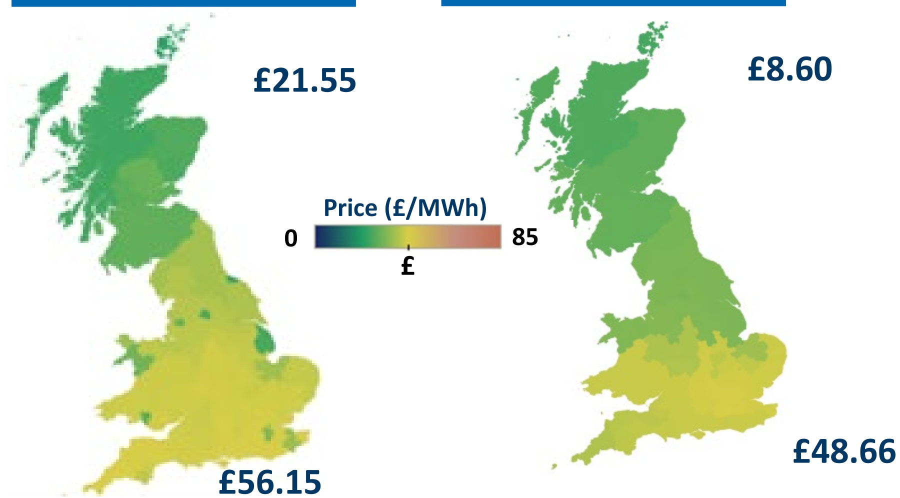


National pricing

2030 | **2040**

Nodal pricing

2030 | **2040**



1. NG ESO, FES 2022 Data workbook

To evaluate the impact of demand-siting decisions, we test both fixed (baseload) and flexible sources of demand

Type of new demand

- Based on discussions with Octopus, our expectation is that the impact of new demand could vary depending on whether the demand is fixed (and hence consumes power at all times, including peak hours), or whether the demand is flexible (and hence is able to avoid peak hours, and, conversely, fill the "troughs").
- As a result, we modelled the following two types of demand:

A **datacentre cluster** to illustrate the impact of a new **fixed load**. That is, the load of the datacentre is defined (and fixed) in each hour across the year according to the typical consumption patterns of a datacentre.

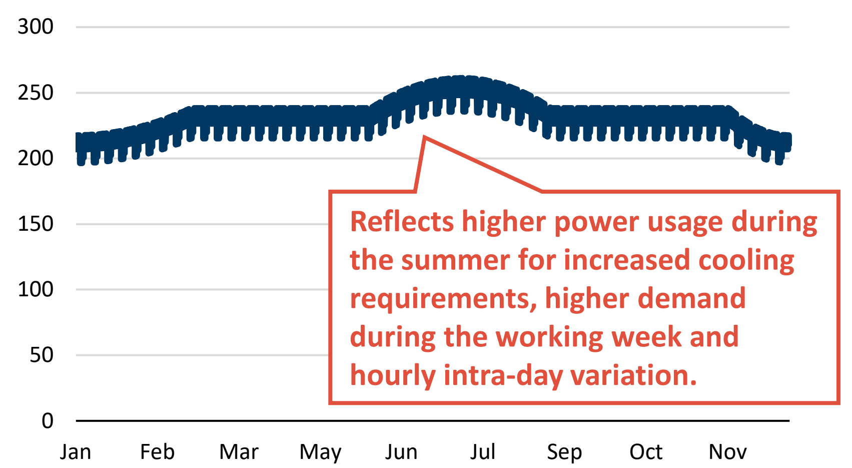
For modelling purposes, we assume that a new data centre would locate near Slough in England or near Aberdeen in Scotland, close to large hubs of demand.

An **electrolyser cluster**[1] to illustrate the impact of a new **flexible load**. That is, the electrolyser has some flexibility in when it consumes throughout the year, and optimises its consumption on electricity prices, subject to a target level of annual consumption and maximum hourly consumption.

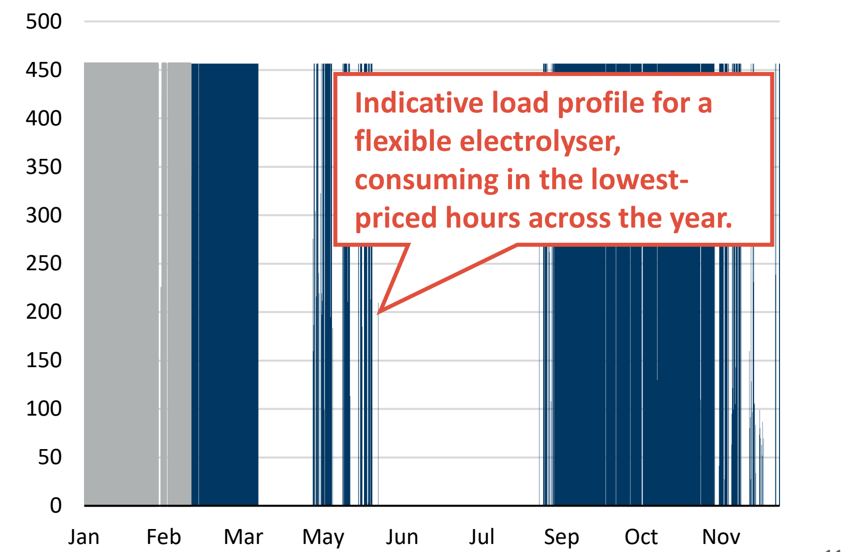
We assume that a new electrolyser would locate by the Grain LNG terminal in England and near the St Fergus gas terminal in Peterhead in Scotland for proximity to potential future hydrogen networks.

- We assume that both types of demand would become operational in 2030 and require 2TWh of power annually – but that the electrolyser **would only consume during the cheapest c.50% of hours** in the wholesale market. Importantly, we assume that the electrolyser would not participate in the BM under the current market design, due to uncertain market outcomes.
- A new 2TWh electrolyser represents a 6% increase in total electricity demand for hydrogen production in 2030, whilst the 2TWh datacentre is a 2% increase in 2030 commercial demand.[2]

Indicative hourly fixed datacentre load, MW



Indicative hourly flexible electrolyser load, MW



1. An electrolyser is a device used to split water molecules into hydrogen and oxygen. Hydrogen can in turn be used as a source of energy in, for example, power generation, industrial processes or transportation. 2. NG ESO, FES2022, LtW.

We assume that the electrolyser cluster would site close to potential future hydrogen networks, and the datacentre cluster close to key demand centres

We place electrolysers at key sites of potential future hydrogen networks

- Since electrolysers are used in the production of hydrogen, we place them at sites that will **likely be connected to future hydrogen networks**.
- For example:
  - In **the North**, we place the electrolyser at **Peterhead** due to its proximity to the **St Fergus gas terminal**, site of the proposed Acorn Hydrogen Project and associated gas transmission infrastructure.[1]
  - In **the South**, we place the electrolyser at the **Isle of Grain** due to the proximity with the **Grain LNG terminal**, a potential site for future hydrogen storage.[2]

Datacentres are placed near sites of concentrated demand

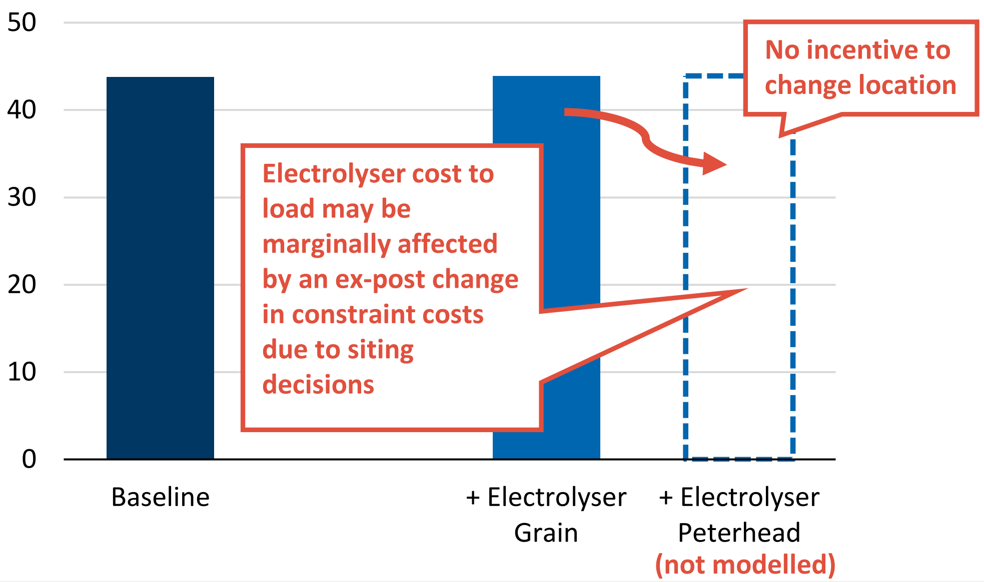
- We understand that datacentres are generally built near centres of demand. We therefore place the datacentres **close to large cities.**
- For example:
  - In **the North**, we place the datacentre next to **Aberdeen**.
  - In **the South**, the datacentre is placed near **Slough**, next to London.

We have leveraged Octopus's experience in, and understanding of, the retail market and **validated these assumptions** with them.

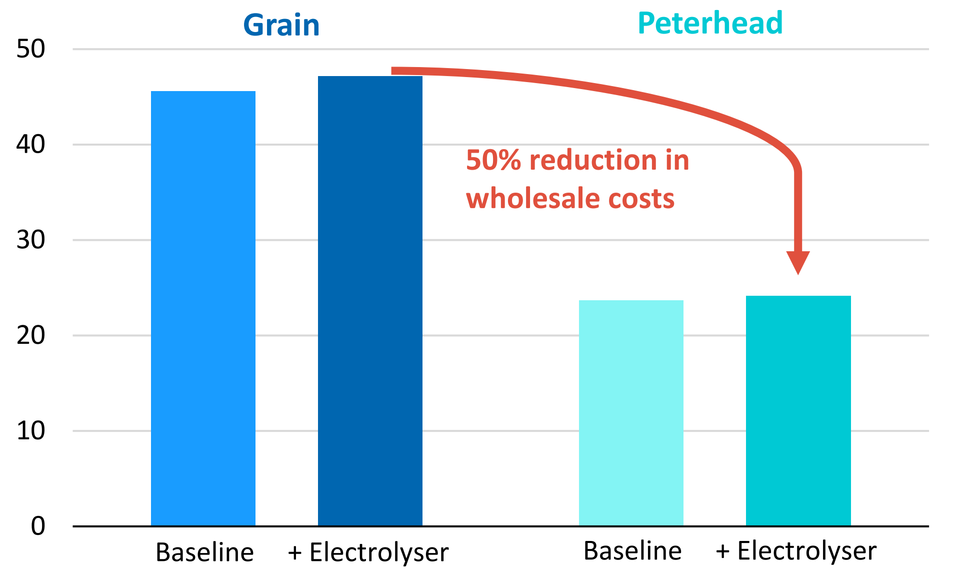
Note: (1) Acorn Hydrogen Project Summary Report, 2021 (link); (2) Uniper, 2022 (link).

Under nodal pricing, large consumers have potentially stronger incentives to site in the North due to lower wholesale electricity costs in the North…

Average electricity price (wholesale + balancing costs), Baseline demand and Grain electrolyser
National pricing, Reference transmission, 2030, £/MWh



Average electricity price, Baseline demand and Grain and Peterhead electrolysers[2]
Nodal pricing, Reference transmission, 2030, £/MWh



Note: Figures do not account for the impact of intra-GB congestion rents or CfD top-ups

- **Under national pricing, there is little wholesale price incentive for large consumers of electricity to site in the North**, with consumers across GB facing a single wholesale price in all regions…[1]
- … meaning siting decisions are instead heavily focused on broader considerations such as proximity to labour, infrastructure and demand.
- The siting decision of the electrolyser may impact total GB constraint costs, but as these costs are spread across GB consumers, the price impact faced by the asset itself is assumed to be minimal.

- With nodal pricing, prices vary between nodes across GB, with electricity prices in the North generally lower than those in the South.
- Therefore, there is often a **significant price incentive for large consumers of power to site in the North**.
- For example, wholesale **electricity costs are c.50% lower in Peterhead compared to Grain**, after adding the additional electrolyser demand.

1. See FN1, slide 8. 2. As previously explained, we find that electricity prices increase when new demand enters the market. This is in part because we have taken generator location and size as fixed.

…and this incentive exists in all modelled years, and is particularly pronounced for demand that is flexible and can respond to price fluctuations

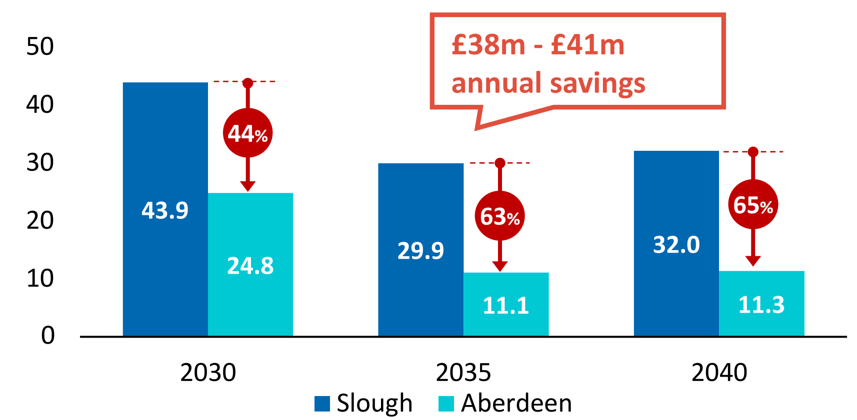
- Our analysis shows that, under the FES 2022 LtW scenario, there is a significant difference in the wholesale electricity price that a large consumer of electricity would pay in different locations in GB under nodal pricing.

For example, we estimate that a **new fixed load datacentre** could **save up to 65%** on its wholesale electricity costs in a given year by locating in Aberdeen rather than in Slough under Reference transmission. Under Policy transmission, the datacentre could see similar savings of up to 60% on its wholesale electricity costs.

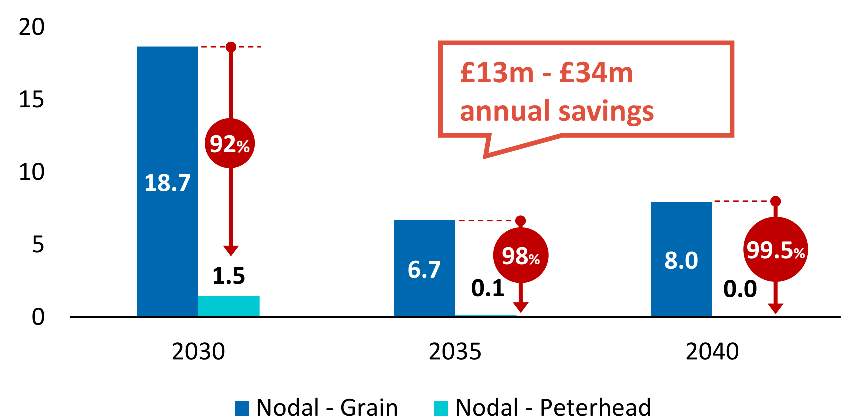
When the **new flexible load electrolyser** sites in the North, it consumes in the windiest (and therefore often cheapest) hours across the year, avoiding the most expensive hours in Peterhead. In fact, it almost always consumes low-cost wind generation that otherwise would have been curtailed. It may therefore pay over **99%** less overall on its wholesale electricity costs by siting in Peterhead rather than in Grain, under both Reference and Policy transmission.

- Overall, we estimate that, under Reference transmission, the decision to site in the North leads to **c.44-65% savings** for the new fixed load datacentre, and **c.92-99.5% savings** for the new flexible load electrolyser (which can flexibly target its consumption to the lowest-priced hours in a year). The level of savings is driven by the rate of deployment of renewable generation and transmission capacity.
- Under Policy transmission, siting North would generate **c.14-63% savings** for the new fixed load datacentre and **54-99.7% savings** for the new flexible load electrolyser in annual wholesale electricity costs.
- Electricity costs form a significant portion of the total operating costs of an **electrolyser**, between **58-90%** when consuming in the wholesale market.[1]
- This suggests that there is a **significant incentive** for large consumers to site closer to generation under nodal pricing.

Average annual wholesale price paid by new fixed load datacentre
Reference transmission, £/MWh



Average annual wholesale price paid by new flexible load electrolyser
Reference transmission, £/MWh

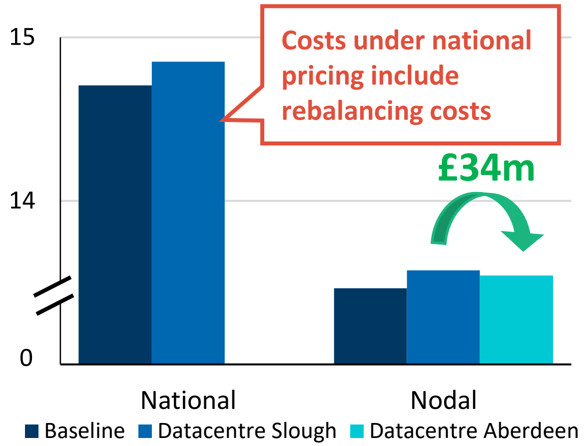


Note: Figures do not account for the impact of intra-GB congestion rents or CfD top-ups.

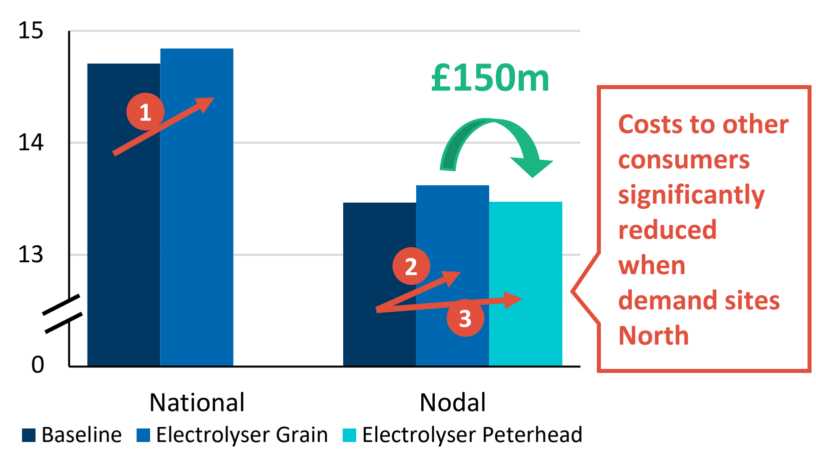
1.BEIS, Hydrogen Production Costs, 2021; page 29 and Annex.

Under nodal pricing, GB consumers face lower total wholesale electricity costs when demand is incentivised (and chooses) to site in the North…

Consumer wholesale costs[1], new datacentre demand, 2030
Reference transmission, £bn



Consumer wholesale costs, new electrolyser demand, 2030
Reference transmission, £bn



Legend

Cost impact of new demand — Benefit of siting North

Total power costs to GB consumers are lower under nodal pricing when demand sites in the North, relative to siting in the South

- To estimate the impact of the new demand on wholesale costs faced by other consumers, we consider the increase in electricity costs for other GB market participants following the entry of new demand.
- As expected, incremental demand (holding all other factors equal) increases total costs of electricity to GB consumers (i.e. regardless of where a new source of demand is located, the aggregate electricity costs increase).
  - Under **national pricing**, we do not consider the option of new demand siting in the North of GB given there is no pricing signal in the wholesale market to do so.[2]
  - Under **nodal pricing**, demand has a price incentive to site in the North, which reduces the impact the new demand has on wholesale costs for other GB market participants.

- For example, in 2030 with Reference transmission and new flexible electrolyser demand:
  1. Total costs to other GB consumers would have increased by £137m in the national design (as prices are generally higher due to increased demand).
  2. Total costs to other GB consumers would have also increased by £155m in the nodal design had the electrolyser sited itself in Grain.
  3. However, crucially, the electrolyser has the incentive of siting itself in Peterhead instead, and in those circumstances the total costs to other GB consumers would have increased by only £5m.

  → This means that nodal pricing, by incentivising the **electrolyser** to site in Peterhead, reduces the total **costs to other GB consumers by c.£150m** in 2030.

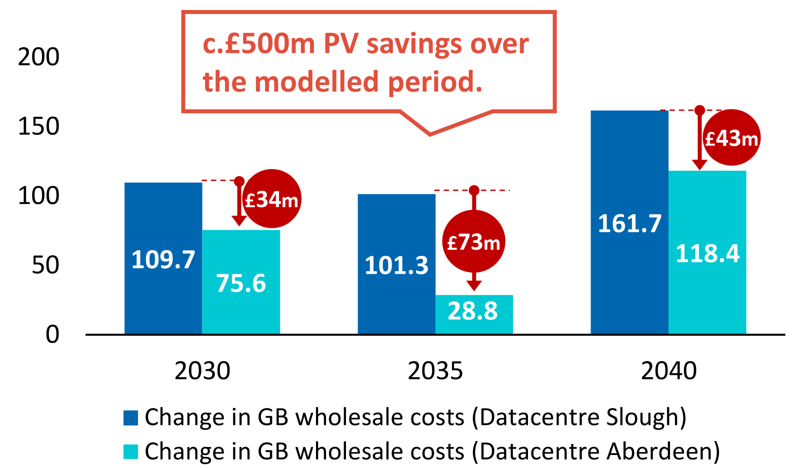
  → Similarly, nodal pricing, by incentivising the fixed load **datacentre** to site in Aberdeen, reduces the total costs to other GB consumers by **c.£34m**.

1. For national pricing, we estimate costs based on prices in the wholesale electricity market and the balancing market. 2. See FN1, slide 8.

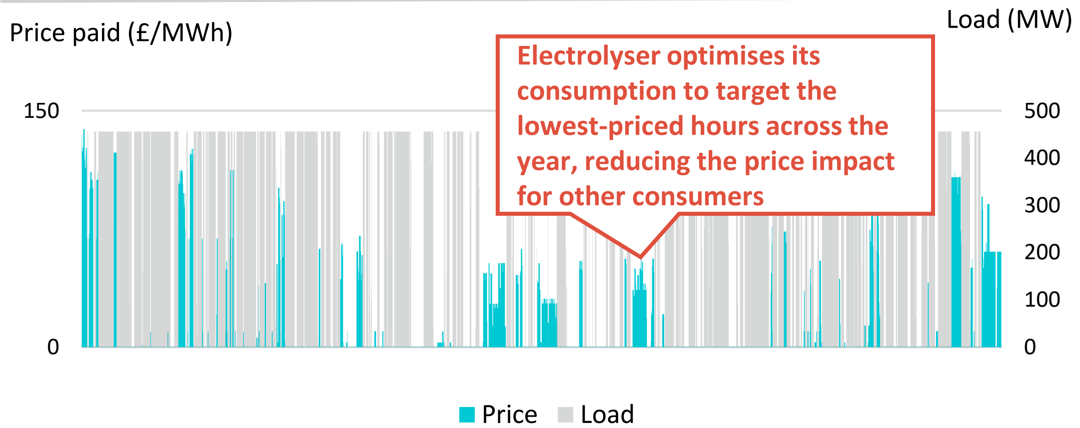
…and this benefit of nodal pricing is consistently observed for both types of demand (although more pronounced for flexible demand)

- With new fixed load datacentre demand, the increase in **consumer wholesale costs is reduced by £34m-£73m when the datacentre sites in the North,** under **Reference transmission**, and **£44m-£89m** under **Policy transmission**.
- The reduced impact on wholesale costs for other consumers from new demand siting in the North is particularly significant with flexible electrolyser demand, with the **increase in consumer costs reduced by between £67m-£150m** under Reference transmission and **£46m-£76m** under **Policy transmission**, relative to demand siting in the South.
- This is because, when siting in the North, the flexible demand can target its consumption to **low-priced hours when there is an excess of domestic wind generation** that would otherwise be curtailed, meaning the new demand has little to no impact on prices for other consumers.

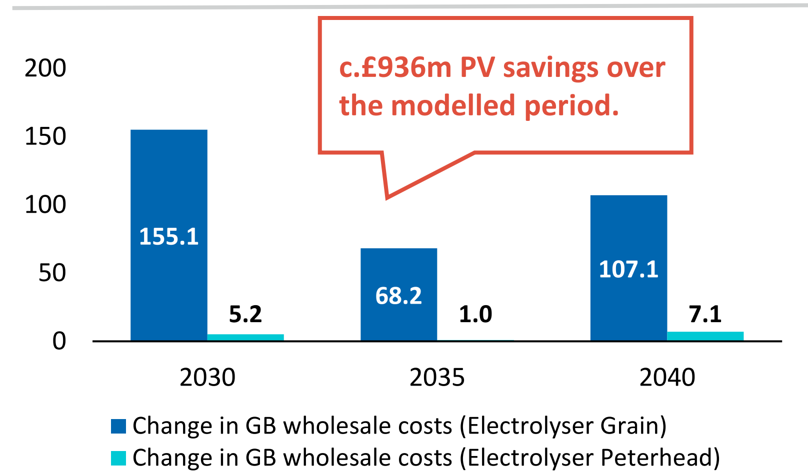
Change in consumer wholesale costs, new datacentre demand
Reference transmission, £m



Hourly load and price paid, Electrolyser siting in Peterhead, Scotland
Reference transmission, 2040



Change in consumer wholesale costs, new electrolyser demand
Reference transmission, £m



1. For national pricing, we estimate costs based on prices in the wholesale electricity market and the balancing market.
2. See FN1, slide 8

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By making better use of domestic wind generation, GB imports less power from Europe when demand sites in the North under nodal pricing

- Relative to national pricing, the new demand in the South under nodal pricing is generally met by less thermal generation (primarily driven by the earlier years) and more cheap domestic wind generation. For example, across the modelling period and under Reference transmission, the new fixed load datacentre demand is partially met by an extra **2,256 GWh of thermal generation under national pricing**, and 1,352 TWh under nodal pricing.
- Under national pricing, there is a significant increase in imports from Europe and, under Reference transmission, an average of 33% of the additional imports are met through balancing market flow reversals. That is, the single national wholesale price, by failing to account for intra-GB transmission constraints, leads to an insufficient quantity of interconnector imports into GB, requiring the ESO to source additional interconnector imports at short notice, typically at a higher cost.
- When the demand sites in the North, curtailment of low-cost domestic wind is significantly reduced, with Scottish wind generation often displacing imports from Europe via interconnectors. Between 2030 and 2040, **20,102 GWh of domestic wind generation**[1] is used to meet the new flexible load electrolyser demand when sited in Peterhead, compared to just 4,134 GWh when sited in Grain.

Changes in generation and imports dispatch (relative to baseline demand)

Reference transmission, GWh, 2030-2040

	GWh	Thermal gen	Curtailed domestic wind	Imports
Datacentre (fixed demand)	National Slough (relative to national baseline)	↑↑↑ 2,256	↓ -2,019	↑↑↑ 14,989
	Nodal Slough (relative to nodal baseline)	↑↑ 1,352	↓↓ -4,160	↑↑↑ 14,278
	Nodal Aberdeen (relative to nodal baseline)	↑↑ 1,334	↓↓↓ -13,624	↑↑ 6,163
Electrolyser (flexible demand)	National Grain (relative to national baseline)	↑↑ 856	↓ -1,165	↑↑↑ 17,152
	Nodal Grain (relative to nodal baseline)	↑ 57	↓↓ -4,134	↑↑↑ 14,176
	Nodal Peterhead (relative to nodal baseline)	↑ 38	↓↓↓ -20,102	↑ 1,576

1. Total reduction in curtailment of 20 TWh equates to 32% of the expected output of Dogger Bank Wind Farm A over the modelled period (the first phase of the world's largest offshore wind farm which started producing electricity on 10th Oct 2023, with typical 55% offshore wind load factor and installed capacity of 1.2 GW (link)).

We assess the benefits of Policy transmission as the change in socio-economic welfare caused by the additional capacity over Reference transmission

Methodology

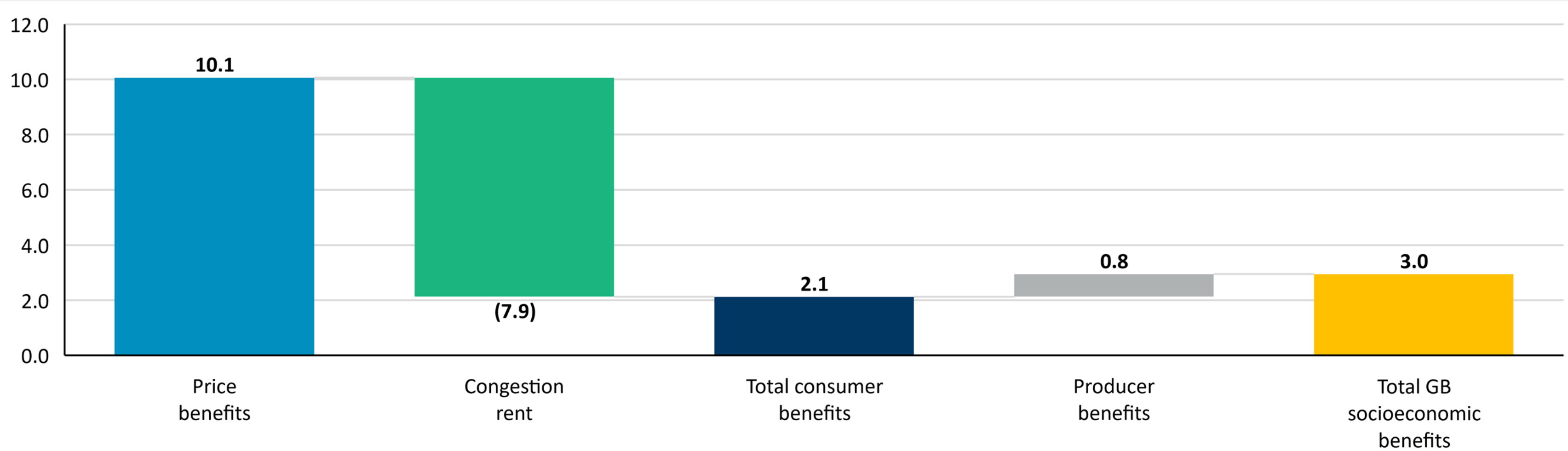
- To estimate the need for additional transmission under nodal pricing, we assess the **increase in total socio-economic welfare** when adding the **incremental transmission** capacity in the **Policy Scenario** (HND), relative to the **Reference Scenario** (HND with a delayed build out). We interpret a greater **benefit** of **additional transmission** to imply a greater **need** for **transmission upgrades**.
- The total **consumer** benefits delivered by Policy transmission are:
  - — The reduction in wholesale electricity costs and
  - — The change in intra-GB congestion rents due to the incremental transmission capacity which may be positive or negative
- We assess the change in producer surplus as the increase in total producer revenues, less any increase in producer costs.
- Changes in consumer and producer benefits are modelled in 2030, 2035 and 2040. The changes are interpolated between the years and discounted at 3.5%

Key mechanisms observed

- Policy transmission increases the transmission capacity, particularly between Scotland and England relative to Reference transmission. Therefore, **more low-marginal-cost Scottish wind power** can supply demand in England and thus **reduce overall electricity costs** (as shown in the light blue bar below).
- However, prices increase in the North due to the additional demand, meaning that **nodal prices converge somewhat across the country**, and therefore **intra-GB congestion rents decrease** (as shown in the green bar below).
- The increase in **producer benefits** (shown in light grey bar below) is driven by **reduced curtailment of Scottish wind** due to the extra demand from the South, and **increased rents earned by interconnectors** due to lower prices in the South. These two effects **offset the reduction in average wholesale electricity costs** (which would generally reduce producer surplus).

Change in GB socio-economic welfare between Reference and Policy transmission scenario

£bn, Present Value, 2030-2040



Our analysis suggests that nodal pricing incentivising fixed demand to site in the North can reduce the need for additional transmission investment

- Nodal pricing can provide clearer signals for where transmission network reinforcement is required, with wholesale (and Financial Transmission Right) market outcomes revealing where persistent congestion is observed on the existing transmission network. We find that, under nodal pricing, the siting decision of new demand can also impact the underlying 'needs case' for additional transmission.

With incremental fixed datacentre demand, when the datacentre sites in the South, the benefit of (and therefore need for) additional transmission investment increases, while the opposite happens when the datacentre sites in the North.

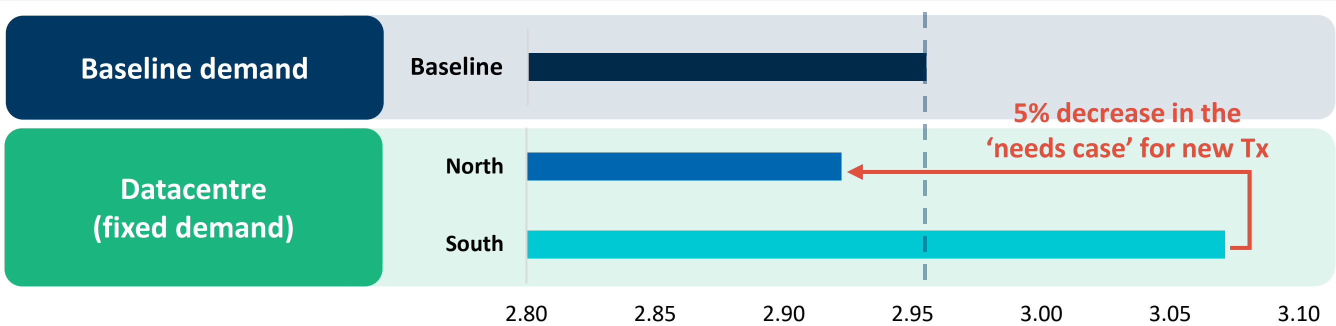
Since the datacentre has a fixed load, it often consumes in high-price hours, particularly when located in the South. The additional transmission capacity of Policy transmission allows the Southern datacentre to consume more low-cost wind generation from Scotland, reducing its impact on wholesale prices for other consumers in the South. This means that, with a Southern datacentre, Policy transmission delivers a greater socio-economic benefit.

When the datacentre is located in the North, it is close to, and often consumes, domestic wind generation that in many hours would have otherwise been curtailed. Siting in the North therefore reduces the benefit of additional transmission as there is less of a need for North-South flows.

With incremental flexible electrolyser demand, there is little impact (< 2%) from the siting decision on the need for additional transmission investments. By design, the electrolyser consumes in the cheapest hours across the year, meaning that when sited in the South it avoids the most congested hours where increased transmission capacity would be most valuable.

- If we considered the impact of generation siting decisions these results may change. The FTI/Ofgem assessment, which considered generation, but not demand, siting decisions, showed a reduction in the need for transmission investment.

Needs case for Policy transmission investment (total GB socio-economic benefits derived from additional transmission capacity)
£bn



Nodal pricing enables large consumers to choose to site in the North, and thus deliver further benefits to GB, compared to previous FTI/Ofgem assessment

Demand siting in the North under nodal pricing, relative to siting in the South, would have significant potential benefits in addition to those shown in the previous FTI assessment of locational design options:

	Datacentre (fixed load) siting in Aberdeen (rather than in Slough)	**Electrolyser (flexible load) siting in Peterhead** (rather than in Grain)
Wholesale cost of electricity paid by new demand	↓ **Reduced by £38m-£41m** under Reference and **£10m-£39m** under Policy transmission[1]	↓↓ **Reduced by £13m-£34m** under Reference and **£5m-£15m** under Policy transmission[2]
Wholesale cost of electricity paid by other market participants	↓↓ **Impact reduced by £34m-£73m** under Reference and **£44m-£89m** under Policy transmission[3]	↓↓ **Impact reduced by £67m-£150m** under Reference and **£46m-£74m** under Policy transmission[4]
Generation mix	↓ **7-9 TWh** less domestic wind curtailed between 2030-2040 by re-siting North	↓↓ **13-17 TWh** less domestic wind curtailed between 2030-2040 by re-siting North
Need for (and benefit of) new transmission infrastructure	↓ **5%** reduction in the societal benefits of Policy transmission between 2030-2040, implying reduced need for transmission investment	↔ Minimal impact on the need for Policy transmission

1,2,3,4. Range across modelled years