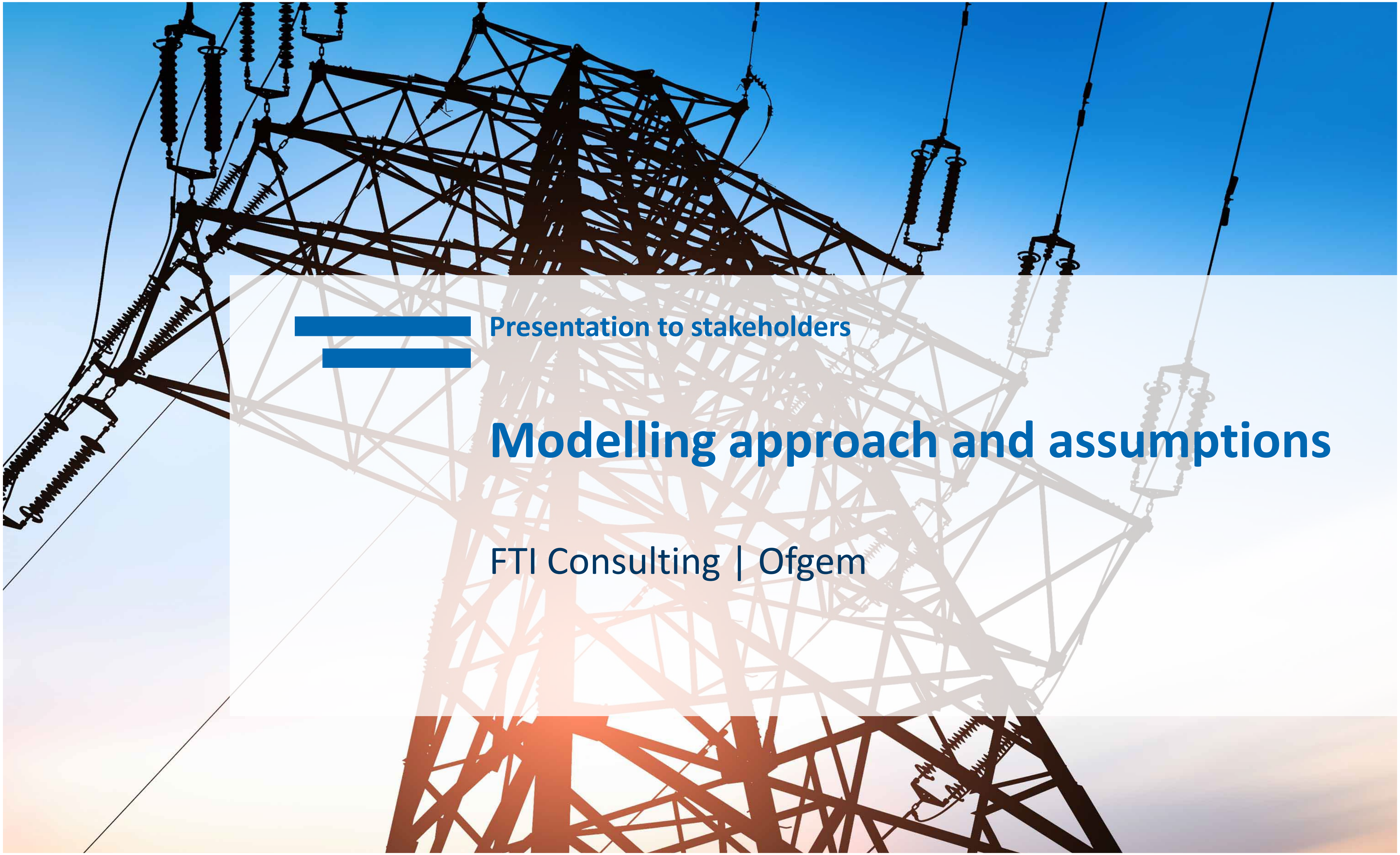


Presentation to stakeholders

Modelling approach and assumptions

FTI Consulting | Ofgem

26 May 2022

Agenda for today's workshop

Session	Item	Time	Duration	Lead
	Welcome, purpose of session	14:00 – 14:05	5 mins	ofgem
	Overview of project scope, objectives	14:05 – 14:15	10 mins	ofgem
Session 1	Session 1: Overview of our modelling approach	14:15 – 14:45	30 mins	FTI Consulting
Session 1	• Facilitated break-out group to discuss modelling approach • Summary of the discussions	14:45 – 15:00	15 mins	FTI Consulting, ofgem
	BREAK	15:00 – 15:10	10 mins	
Session 2	Session 2: Key assumptions	15:10 – 15:40	30 mins	FTI Consulting
Session 2	• Facilitated break-out group to discuss modelling approach • Summary of the discussions	15:40 – 16:00	20 mins	FTI Consulting, ofgem
Session 3	Potential policy interactions and impacts	16:00 – 16:05	5 mins	ofgem
Session 3	• Facilitated break-out group to discuss policy interactions	16:05 – 16:20	15 mins	FTI Consulting, ofgem
	Wrap up, thanks and next steps	16:20 – 16:25	5 mins	ofgem

Welcome

Regular stakeholder engagement will be used to inform the assessment and test work-in-progress

Approach

- Facilitate small group discussions with a range of stakeholder interests – use **detailed group discussion to inform** and **test** critical elements of the assessment

- Publish all workshop materials and a short overview of key discussions points for **transparency**

- Opportunity for **all interested stakeholders** to submit written feedback after each session

Housekeeping

- Today's focus is on the **modelling** and **policy impacts** – points more relevant to later workshops will be parked
- **Chatham House Rule** – we will publish an overview of key discussion points but views will not be attributed
- Encourage use of **cameras in break-out rooms** and make use of the **chat function**
- Use chat function for **clarification questions** during the presentations
- **Break** at 15:00 for 10 mins

Today's workshop will be delivered by Ofgem's Wholesale Market Reform Team supported by FTI Consulting and ES Catapult

ofgem

Heather Stewart
Team Leader

Mark Carolan
Leading LMP Project

Francisco Celis-Andrade
Leading LMP Modelling

Phoebe Finn
Leading Governance and Stakeholder Engagement

Kelly Gavin
Leading BEIS engagement and Investment Support

Matthias Noebels
Leading Costs and Implementation

FTI Consulting / **Catapult Energy Systems**

Jason Mann
Project Director

Joe Perkins
GB policy expert

Martina Lindovska
Modelling expert

Ljubo Mitrasevic
Project manager

George Day
Project Partner

Objectives and scope of the project

ofgem

Energy Systems Management and Security(ESMS) directorate - Ofgem

ESMS

Market Operation & Signals
- Cross border arrangements
- Energy Security of Supply
- Domestic market management
- Core electricity charging
- Core electricity connections
- Core gas charging & access
- TNUOS Task Force

Market Design
- Net Zero charging reform
- Distribution charging reform
- Wholesale market reform
- LLES

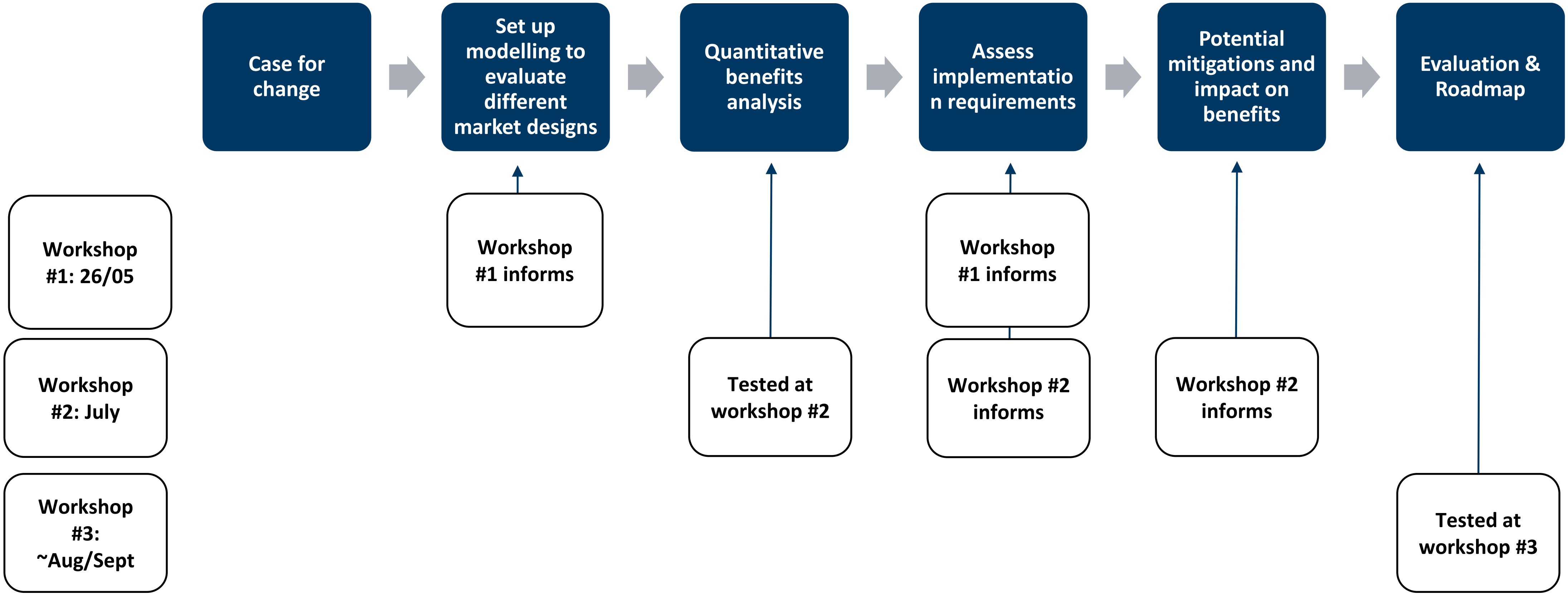
Institutions for Net Zero
- ESO regulation
- DSO regulation
- GSO regulation
- FSO
- DSO Governance

Digitalisation & Decentralisation
- Digital Vision & Architecture
- Energy Sector Data Regulation
- Distribution Flex Markets & Enablers
- Aggregator Licensing

Project overview: This project is part of our Full Chain Flexibility Strategic Change Programme

Central question	Will introducing locational granularity into the wholesale electricity market enable a fully flexible, low carbon, low-cost system?
Purpose	Produce a technical assessment of alternative wholesale market designs that considers: • the role for locational granularity in enabling power sector transformation and • the extent to which (and how) the locational granularity of electricity in the wholesale market could increase to best achieve this.
Objectives	• Identify a range of feasible market designs that vary according to how granular the locational value of electricity is (e.g. national, zonal and nodal) • Assess the potential benefits, costs and distributional impacts associated with specific models and design choices • Identify possible design choices and implementation pathways

To evaluate potential nodal design options, Ofgem and FTI have developed a six-stage workplan with regular stakeholder engagement



We expect to finalise our assessment in October.

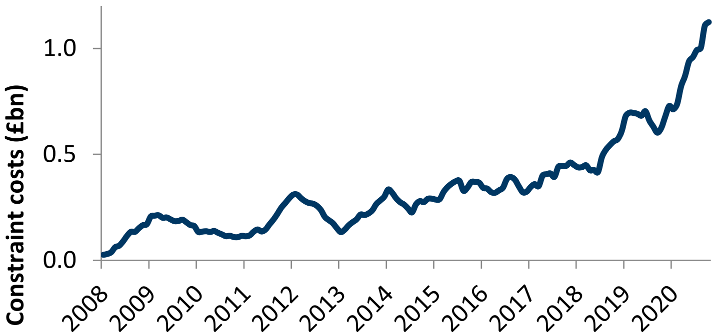
Background

ofgem

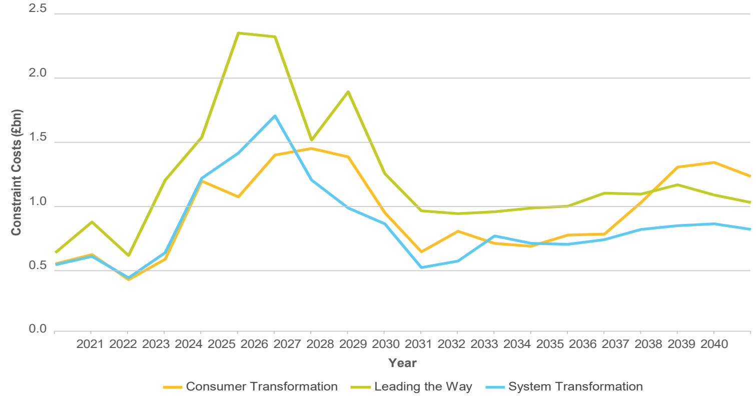
The ESO have identified several issues with the current working of energy markets which could affect GB's aim to achieve a cost-effective, secure pathway to Net Zero

1 In particular, according to the ESO, constraint costs are "*rising at a dramatic and accelerating rate*"

Congestion costs have increased 8-fold since 2010 at a cost of £7bn to customers…



… these costs are anticipated to be sustained at high levels – at a cost of c.£13bn to £19bn to 2035



2 ESO identified three other issues with market design:

Balancing role	Balancing role increasingly challenging – system operator **no longer "residual"** in market
Interconnector and storage flows	Interconnectors and storage are important sources of flexibility but at times currently **exacerbate constraints**
Flexibility resources	Current market design **does not unlock full potential** of diverse ranges of flexibility resources

3 Additionally, other potential issues are:

Siting Decisions	Locational signals provided by TNUoS may not be **sufficient to incentivise an efficient siting of generation and demand**

Session 1:
Overview of our modelling approach

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To model locational market design options, we plan to compare the status quo national market design with two locational market designs

Weaker locational signals — *Stronger locational signals*

Single national price

Uniform price clears across entire market

International examples:

No location in wholesale energy price

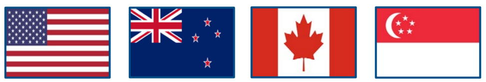
Zonal pricing

System divided into a small number of zones with individual prices

Zones typically cover large geographic areas, but wholesale energy price derived taking account of transmission between zones

Nodal pricing

System divided into many "nodes" with individual prices



Nodal wholesale energy price

The transition to more granular locational pricing have the following key impacts – these will assessed either quantitatively or qualitatively

Type	Effect	Quantitative
Short-run impact *(Operational)*	**Changes in wholesale prices** (lower in export-constrained areas and higher in import-constrained areas)	✓
	Reduced cost of congestion to be borne by consumers	✓
	More efficient dispatch across all resource types including **flexibility resources**	✓
	Surplus revenues from congestion rent and losses	✓
	Operational impacts from central dispatch system relative to the BM	
Long-run impact *(Investment)*	Greater price signals to incentivise **generation and storage to site** at more efficient locations	✓
	Greater price signals to incentivise **demand to site** at more efficient locations	✓
	Improved signals for **transmission development** (due to transparent wholesale prices between different nodes)	
Costs / Other	Changes to **CFD payments**	✓
	Other **policy interactions**	
	ESO system implementation costs	✓
	Market participant costs	✓
	Changing **risk profiles** of market participants including **financing cost**	✓

Overall approach and assumptions **are discussed in this workshop**

Qualitative assessments may include

(1) potential sensitivities
(2) international case studies
(3) interviews with third-parties

Q: What are your views on the key impacts of the locational market design we set out ?

These assessments will inform us of the impact of locational pricing market designs on different stakeholder groups (by type and location)

Effect	Consumers	Generators	Storage / ICs	Network owners	ESO
Changes in wholesale prices (lower in export-constrained areas and higher in import-constrained areas)					
Reduced cost of congestion to be borne by consumers					
More efficient dispatch across all resource types including **flexibility resources**					
Surplus revenues from congestion rent and losses					
Operational benefits from central dispatch system relative to the BM					
Greater price signals to incentivise **generation and storage to site** at more efficient locations					
Greater price signals to incentivise **demand to site** at more efficient locations					
Improved signals for **transmission development** (due to transparent wholesale prices between different nodes)					
Changes to **CFD payments**					
Other **policy interactions**					
ESO system implementation costs					
Market participant costs					
Changing **risk profiles** of market participants					

Modelled impact will be assessed by stakeholder groups <u>and</u> by location

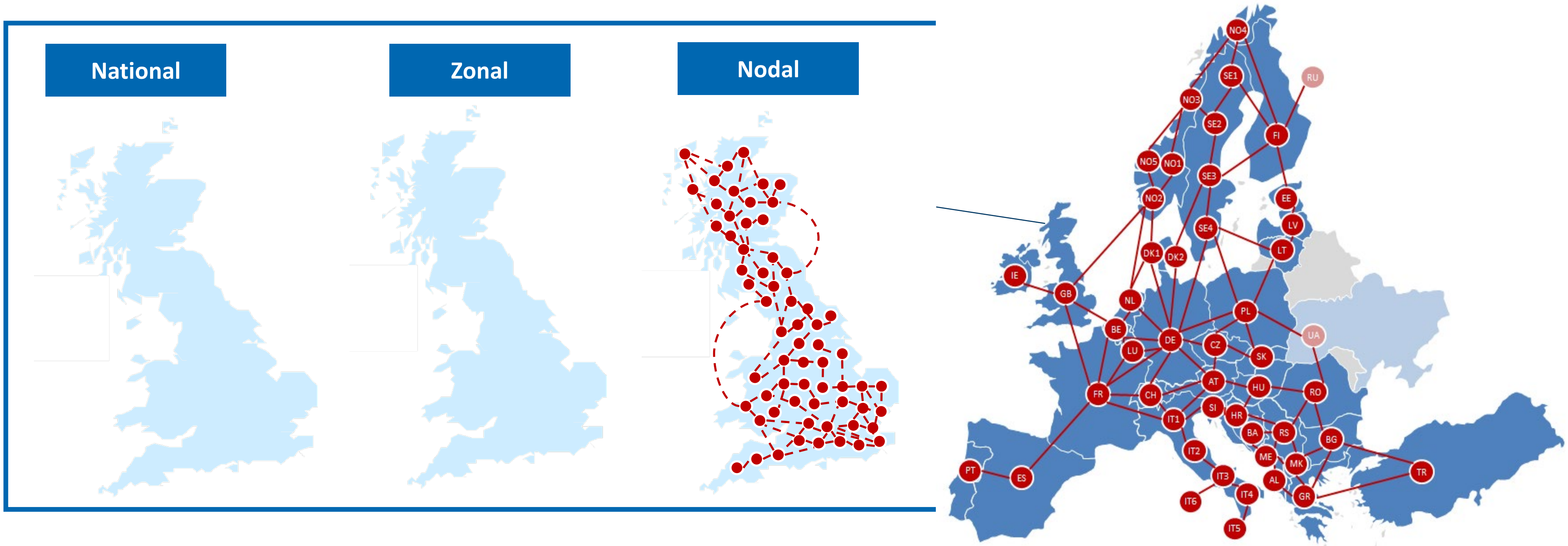
A range of sensitivities will be tested which could inform the impact on a particular stakeholder group (e.g. changing generator assumptions)

Some non-modelled areas will only affect specific stakeholder groups

Q: What are your views on the stakeholder categories considered?

Overarching approach is to divide GB market into a number of zones or nodes, overlaid on European market model to assess price and stakeholder impact

Baseline geographical set-up of FTI's power market model



Our modelling is based on the Plexos Integrated Energy Model platform, which forecasts the optimal evolution of capacity and generation dispatch

Locational granularity

National market | Zonal market | Nodal market

Proposed modelling scenarios

Scenario 1: Leading the Way

Scenario 2: System Transformation

Key inputs

1 **Transmission capacity**

Includes current & future network topology, and seasonal availability assumptions

2 **Demand**

Includes annual demand, profile and flexibility assumptions by type and location

3 **Generation capacity**

Includes build-out assumptions, plant technical characteristics and renewable capacity profiles

4 **Commodity prices**

Includes price projections for a set of commodities (CO_2, gas etc)

Power Market Model PLEXOS

Long Term Capacity Expansion model

For the zonal and nodal market designs only – the LT model determines the optimal evolution of generation capacity (GW):

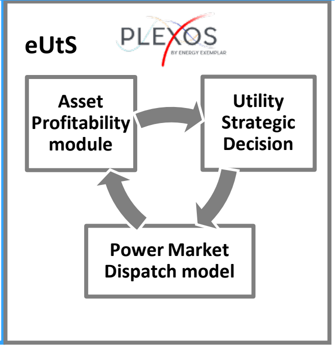
- Finds the lowest-cost combination of generation plants (of all technologies)…
- …that meets the minimum capacity margin,…
- …constraints on CO_2 and other emissions…
- …for each price zone

For the national market design, we will align total capacity and location with the FES scenarios

Short Term Dispatch Model

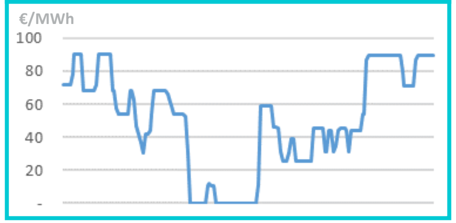
Takes capacity from the Long Term model as given and determines the optimal output of generation (GWh):

- Finds the least-cost dispatch profile of generation…
- …that meets demand…
- …on an hourly basis…
- …for each generating plant…
- …for each price zone

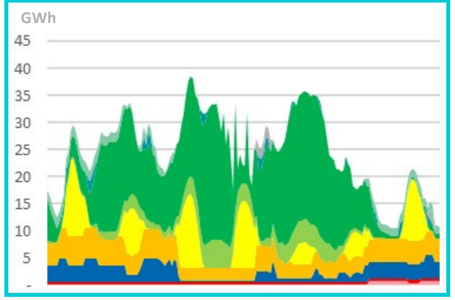


Hourly outputs for each modelled year

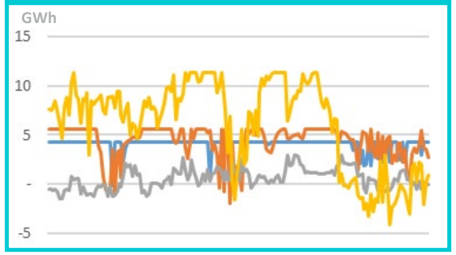
Wholesale power prices



Generation



Flows between zones



Etc.

For the remainder of the first session, we will discuss a range of options for locational granularity and identify a plausible range of modelling scenarios

Locational granularity

National market | Zonal market | Nodal market

Proposed Modelling scenarios

Scenario 1: Leading the Way

Scenario 2: System Transformation

Key inputs

1 **Transmission capacity**

Includes current & future network topology, and seasonal availability assumptions

2 **Demand**

Includes annual demand, profile and flexibility assumptions by type and location

3 **Generation capacity**

Includes build-out assumptions, plant technical characteristics and renewable capacity profiles

3 **Commodity prices**

Includes price projections for a set of commodities (CO2, gas etc)

3a

- Present the spectrum of locational market design options…
- And discuss preferred options to model

For the zonal and nodal market designs only – the LT model determ…

- Find… tech…
- …
- …co…
- …for each price zone

- Present the range of energy scenarios…
- And consider which are the best suited for modelling

For the national market design, we will align total capacity and location with the FES scenarios

4 **Short Term Dispatch Model**

Takes capacity from the Long Term model as given and determines the optimal output of generation (GWh):

- Finds the least-cost dispatch profile of generation…
- …that meets demand…
- …on an hourly basis…
- …for each generating plant…
- …for each price zone

PLEXOS

Asset Profitability module

Utility Strategic Decision

Power Market Dispatch model

Hourly outputs for each modelled year

Wholesale power prices

Generation

Flows between zones

Etc.

Locational granularity | Modelling scenarios

To model zonal market design options, we propose to use seven zones following the most constrained boundaries as defined by the ESO

Options	Number Zones / Nodes	Pros	Cons
1 *Pre-BETTA split*	2	• Splits along a boundary with the most significant constraint costs • Might address stakeholder concerns regarding liquidity	• Unlikely to be meaningful given planned Tx reinforcements and evolving electricity system
2 *Main constraint zones (currently observed)*	7	• Based on the set of most significant constraint boundaries • Defined by the ESO – objective • Might address stakeholder concerns regarding liquidity	• Historically-observed and hence may not be reflective of the future as the Tx network continues to evolve
3 *NOA & ETYS zones (currently identified)*	20[1]	• Boundaries developed based on SQSS requirements • Identifies additional, less critical, network bottlenecks	• Some boundary zones overlap or represent the subset of larger constraint boundary • Highly fragmented
4 *BID3 model zones*	60[2]	• Consistent with the approach used in FES market modelling (may vary over time depending on generation fleet)	• Zones are not fixed and vary for different technologies • Zones do not reflect constraint boundaries

Q: What are your views on the zonal market design options we should model?

Notes: (1) NOA defines 18 active constraint zones in the latest NOA7; the ETYS defines 23 zones
(2) Based on NG's Long-term Market and Network Constraint Modelling

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To model nodal wholesale market design, we propose to use transmission substations to better reflect the network topology

Options	Number Zones / Nodes	Pros	Cons
1 *GSPs only (i.e. interface between Tx and Dx network)*	500+	• Based on the number of GSPs which are well defined and well understood within the industry • Likely to be sufficient to capture majority of the transmission constraints	• Does not fully align with transmission network topology • Calculation of the losses will deviate from actual observed values
2 *Transmission substations[1]*	750+	• Better reflects generation location (e.g. includes generation-only nodes) • More accurate representation/calculation of the overall network losses	• More computationally challenging than option above
3 *All nodes identified in PowerFactory model*	1800+	• Representation of the ESO network model as used for system planning (and not necessarily for market modelling)	• A large number of nodes are defined historically and may not be relevant as it does not represent the actual system configuration
4 *Include all the Distribution level nodes*	10,000+	• More accurate representation of the combined transmission and distribution network	• ESO has no visibility over distribution level nodes • Not aligned with SoW of being "transmission-first" • No evidence of a 'needs case' to introduce dynamic locational price signals at the distribution level • No international precedent for distribution LMPs

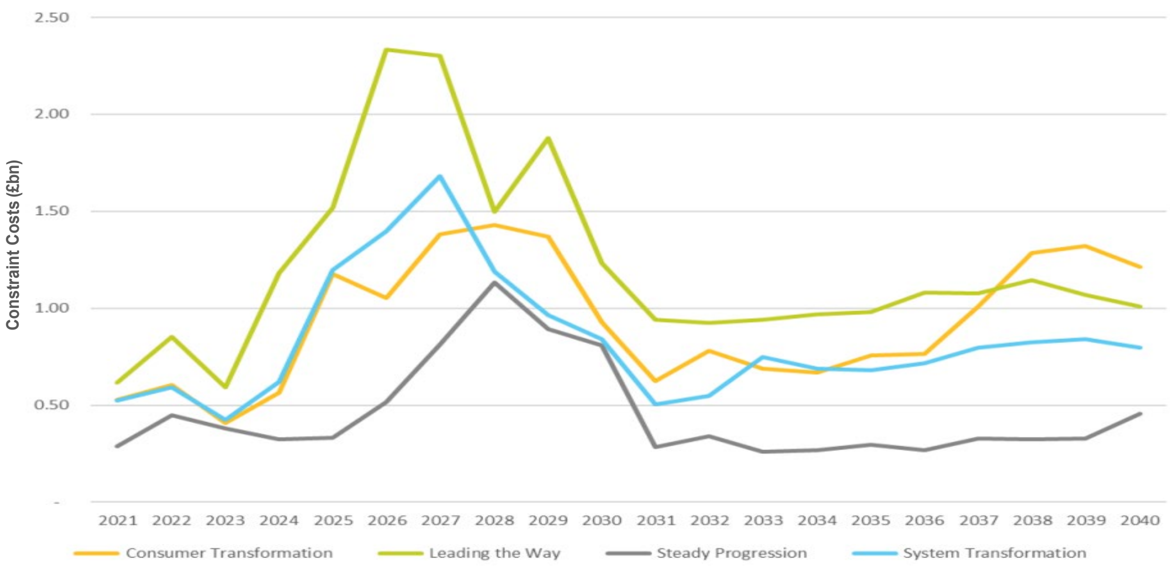
Q: What are your views on the nodal market design options we should model?

Notes: (1) Transmission substation includes any point on transmission network where two or more circuits connect (TX/DX, TX/Generator, Tx/Tx interface).

We intend model two FES scenarios which would map out a wide range of possible outcomes from the model

- Propose to select **two FES 2021 scenarios** that provide the widest range of total system constraint costs, in order to capture the range of system constraint outcomes.
- In addition, these scenarios should be **Net Zero compliant** and, ideally, at least one CB6 compliant.
- Based on ESO's NOA6 publication, we recommend using the **Leading the Way** and **System Transformation** scenarios.

NOA 6, constraint costs by FES scenario, 2021 to 2041



Scenario 1: **"Leading the Way"**
- ✓ Corresponds to the most constrained GB system (i.e. **'upper bound' scenario**)
- ✓ CB6 compliant
- ✓ Based on ESO's initial data provided

Scenario 2: **"Consumer Transformation"** vs **"System Transformation"**
- **CT** is CB6 compliant…
- …while **ST** misses the CB6 target by a small margin
- **ST** has lower constraint costs than **CT** and would be a **better 'lower bound' scenario** on the basis of NOA6…
- …and **ST** is expected to lead to materially lower constraint costs than **CT** under NOA7.
- Propose to **model System Transformation** to capture a wider range of constraint outcomes.

Note: We will be running the model ahead of FES 2022 publication

Q: What are your views on the scenarios we should model?

- Note: **Steady Progression** is currently seen as less preferred as it does not meet Net Zero by 2050

Session 1: Breakout group discussions

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Breakout group 1: discussion structure

Split stakeholders into smaller breakout groups and discuss the proposed modelling approach and gather their views on locational granularity and scenario selection

Discuss modelling Approach	1. What are your views on the **key impacts** of the locational market design we set out (slides 15)? 2. What are your views on the stakeholder categories considered (slide 16)?
Discuss locational granularity and scenario selection	3. What are your views on the **locational disaggregation** we should model (i.e. number of zones and nodes to model) (slides 20-21)? 4. What are your views on the **scenarios** we should model (slide 22)?

Session 2:
Key assumptions

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Session 2: Breakout group discussions

Step 1: Define transmission capacity (and associated parameters) between each zone / node and country over time

Q: What are your views on transmission post-2041?

Data sources for network topology

2020 2025 2030 2035 2040 2045 2050

	2022	2023-2030	2031-2041	2042-2050
Network topology[1]	nationalgridESO ETYS **Available years:** 2023, 2025, 2027, 2030		nationalgridESO NOA[1] **Available years:** 2035, 2040	To be confirmed
Seasonal availability	nationalgridESO ETYS		nationalgridESO, ofgem, FTI Consulting Develop assumptions based on 2022-2030 data	

ESO's ETYS includes detailed information on substations, transmission circuits and transformers and their technical characteristics in summer, winter and autumn/spring

No public data on transmission development post-NOA

Option 1: Model period ends in 2041

Option 2: Split out modelling into:

- Periods up to 2041 (as per Option 1) and
- Period 2042-2050 for which transmission assumption required (e.g. endogenous build-out by model or no change in assumptions)

1) Circuit characteristic (e.g. seasonal ratings and impedances) for the reinforcement proposed by NOA will be based on standard parameters for Transmission assets based on type (e.g. OHL, Cable, Transformer) length, and nominal capacity.

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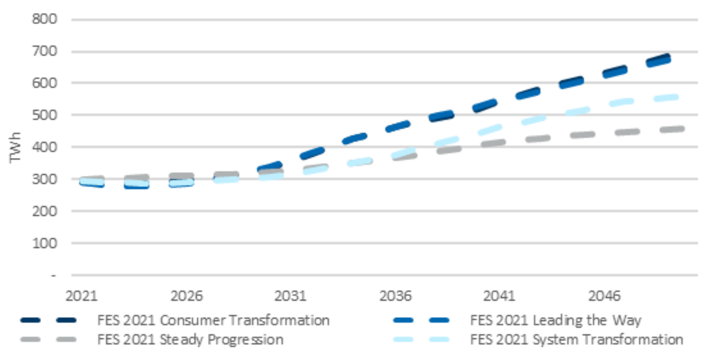
Step 2: Define the evolution of demand levels for each node, together with an hourly demand pattern, and flexibility assumptions by demand type

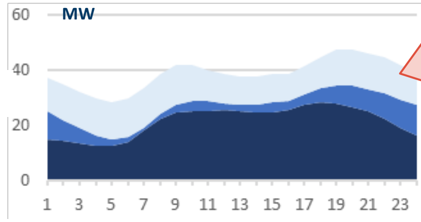
A Define **annual demand** by node, by year and by demand type

Total GB demand evolution according to FES 2021



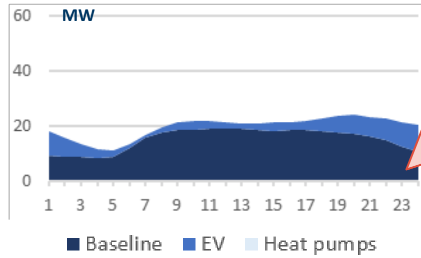
B Define **hourly demand profiles** by demand type (where possible)

Total GB demand on 9th January 2030



Note: EVs, heat pumps are further optimised in each zone according to prices

Total GB demand on 15th June 2030



Note: We use the same pattern for baseline demand in all zones to reflect ESO's approach

C Define **flexibility assumptions** (i.e. price responsiveness) by demand type

Sum of demand type = total demand

Demand type	Flexibility assumption
Baseline demand	▪ Demand side response at given £/MWh
Industry electrification	▪ Optimised to reach 75% yearly load factor
Electric vehicles	▪ Certain % of demand is flexible ▪ Fixed units follow exogeneous pattern ▪ Flexible unit are optimised endogenously
Heat pumps	(as above)
P2G	▪ All demand is optimised endogenously by the model
Storage	(as above)

D Assess impact of **demand portability** (i.e. energy-intensive consumers decide to relocate/site to different locations)

Demand relocation between the zones/nodes is not modelled endogenously

Option to model benefits from demand portability with exogenously-defined sensitivities

Note: more detail provided in the Appendix

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The ESO's FES is the primary source for annual demand data while demand patterns and flexibility assumptions come from a range of sources

Data sources for demand

	Baseline	EV	Heat pump	Industry Electrification	Storage	P2G
Annual level	nationalgridESO **FES 2021**				nationalgridESO/ofgem FTI CONSULTING Demand level depends on the installed capacity, which is determined by FES and modelling (see slide [x])	
Hourly profile	entsoe/nationalgridESO We are reviewing the ESO profiles to ensure consistency with profiles for other European countries published by ENTSO-E		entsoe ESO cannot provide heat pump profiles	ofgem FTI CONSULTING Demand pattern is optimised endogenously by the model		
Flexibility	DSR activated when prices are very high (c.300/MWh, increasing each year) up to 40 hours a year	nationalgridESO/ofgem FTI CONSULTING Proportion of flexible units is calibrated to reflect demand under flexible categories in ESO FES modelling		Industrial electrolysers have a 75% load factor, consumption is optimised over the year	Full flexibility (i.e. storage assets choose to consume and discharge power with reference to the opportunity cost of storage vs consumption)	

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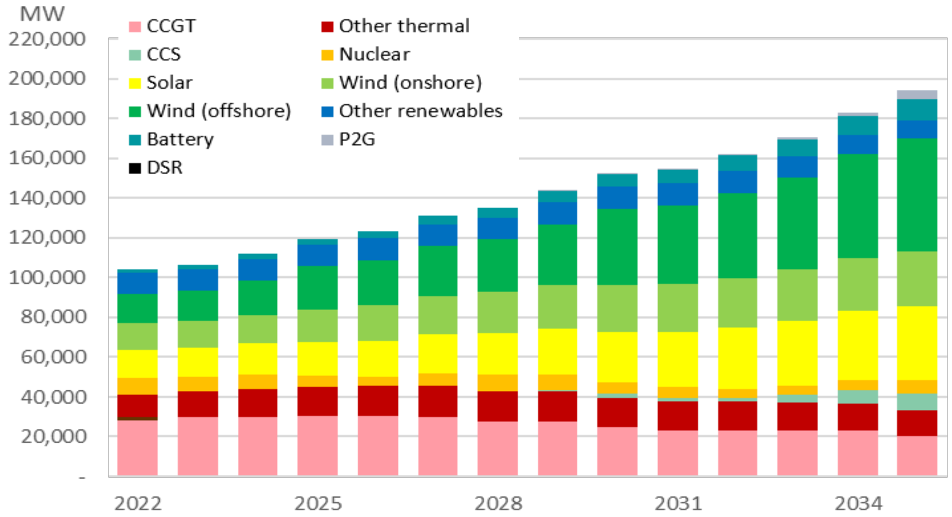
Step 3: Develop generation capacity (including storage) build-out under each of the locational market designs

A For the **national** market design, use the **total generation capacity** rollout as set out by the FES…

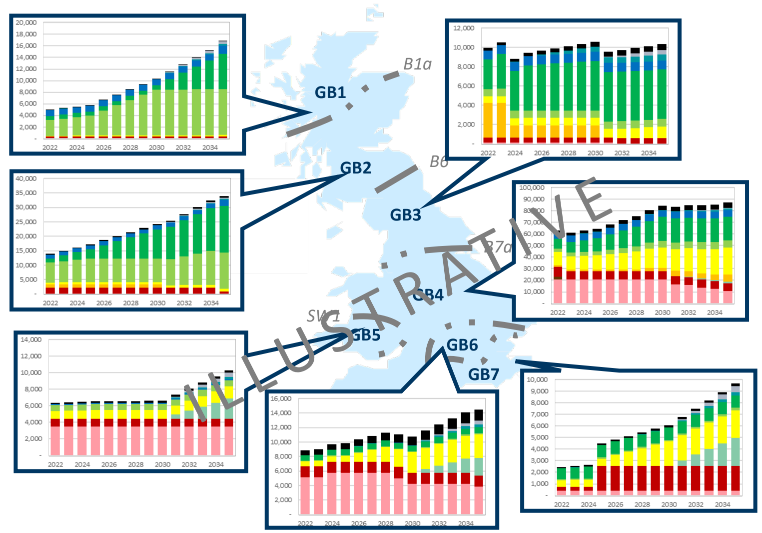
B **… as well as generation capacity at each location (GSP-level)** which is also provided by the FES

Total GB capacity (MW), FES System Transformation



Source: *National Grid ESO: Future Energy Scenarios 2021*

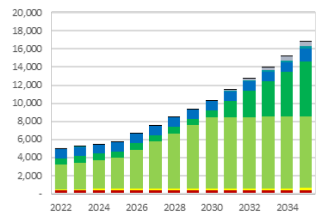
GB capacity by zone (MW), FES System Transformation



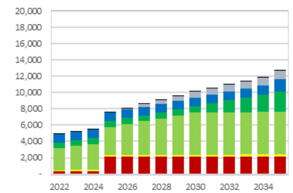
C **In Zonal and Nodal markets we would expect a generation to locate differently given different greater locational price signals**

	Total Capacity	New Capacity
Zonal	▪ **Exogenously** (FES) with dispatchable gen. & storage **optimised using the LT model**	▪ Allocated to different locations **endogenously using the LT model**
Nodal		

Illustrative example



***National:** FES System Transformation in North Scotland*



***Zonal / nodal:** Optimised based on locational pricing – some capacity relocates due to wholesale price signals*

Q: What are your views on how generation capacity should be forecasted?

Capacity input data is based on the FES 2021, while inputs for our long-term model are based on European benchmarks

Data sources for generation capacity

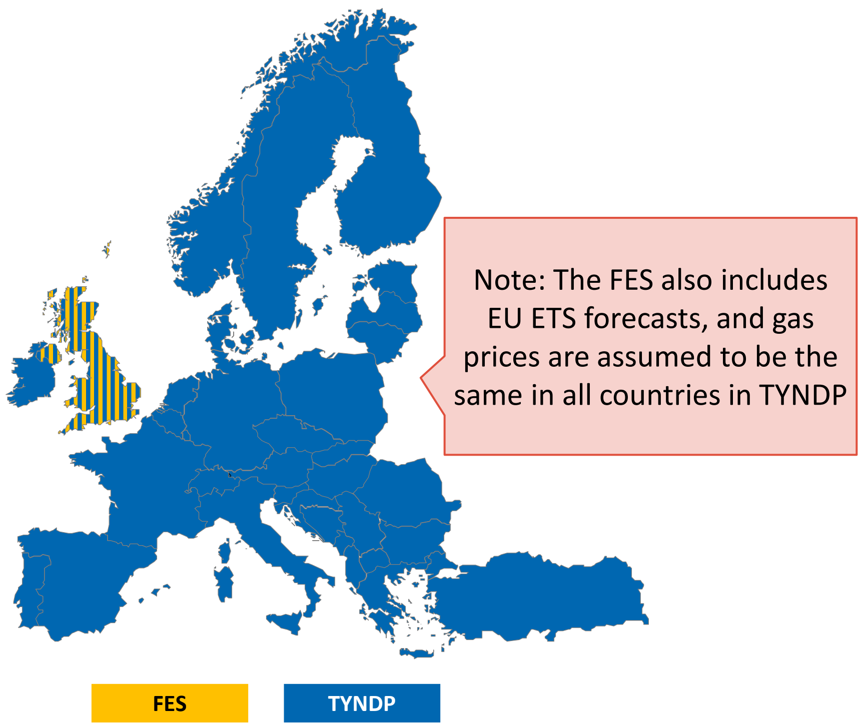
	Nuclear	Thermal	Renewable	P2G	Storage
Capacity build-out input	nationalgridESO Future Energy Scenarios 2021				
CAPEX	European Commission EC Technology Pathways: 2020 Reference scenario				Bloomberg NEW ENERGY FINANCE
Efficiency of new units	entsoe TYNDP 2022			entsoe / FTI Consulting Battery: 90% P2G: 45%	
Max capacity per technology in zones/nodes	To be confirmed – some sites are fixed (e.g. nuclear), and some sites are limited (e.g. offshore wind)				

Commodity price forecasts are based on future curves and long-term projections in the World Economic Outlook

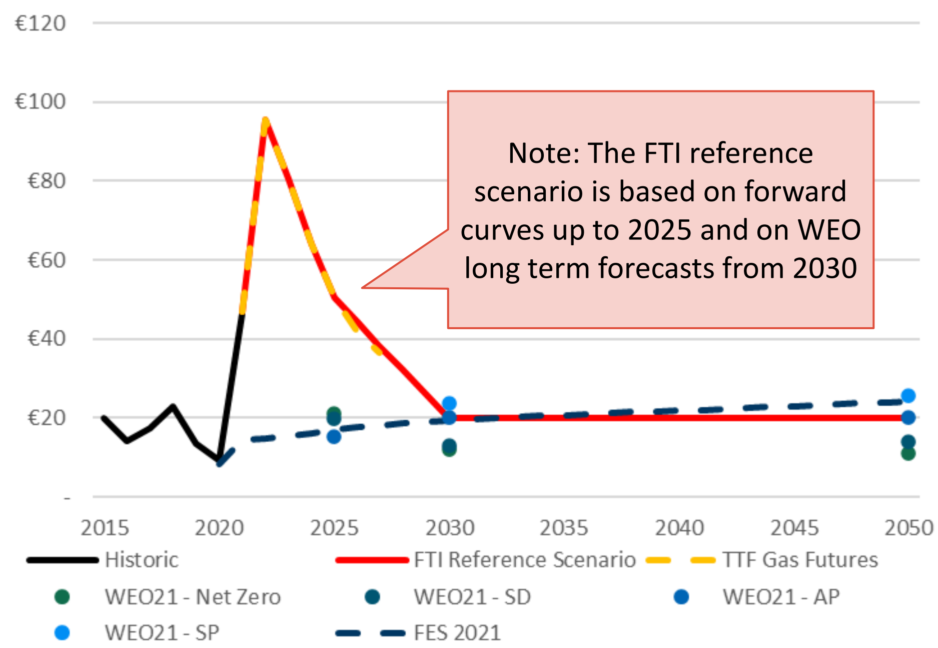
- Commodity prices (mainly **CO2 and gas**) are the main determinant of the Short Run Marginal Cost (SRMCs) of thermal power generators, and thus a primary driver of wholesale power prices
- We can calibrate commodity price forecasts using different forecasts:

1. TYNDP (ENTSO-E): Provides commodity price forecasts for the **whole of Europe, up to 2050**. Long-term forecast are based on the IEA's Word Economic Outlook (2021) scenarios, while short-term forecasts follow future curves if they differ from the WEO significantly;
2. FES (NG ESO): Provides forecasts for each commodity in **GB, up to 2050.**
3. Future curves + long term benchmarks: To reflect recent market development, we often combine long-term benchmarks with future curves

Geographical scope of long-term forecasts



Gas price forecasts (€/tCO2)



Transmission capacity | Electricity demand | Generation capacity build-out | Commodity prices | **Run dispatch model** | Additional quant. analysis

Once transmission, demand and generation parameters are defined, we **(4) run the dispatch model** with **(5) additional analysis** on the outputs

Locational granularity

National market | Zonal market | Nodal market

Proposed Modelling scenarios

Scenario 1: Leading the Way

Scenario 2: System Transformation

Key inputs

1 **Transmission capacity**

Includes current & future network topology, and seasonal availability assumptions

2 **Demand**

Includes annual demand, profile and flexibility assumptions by type and location

3 **Generation capacity**

Includes build-out assumptions, plant technical characteristics and renewable capacity profiles

4 **Commodity prices**

Includes price projections for a set of commodities (CO2, gas etc)

Power Market Model PLEXOS

Long Term Capacity Expansion model

For the zonal and nodal market designs only – the LT model determines the optimal evolution of generation capacity (GW):

- Finds the lowest-cost combination of generation plants (of all technologies)…
- …that meets the minimum capacity margin,…
- …constraints on CO2 and other emissions…
- …for each price zone

For the national market design, we will align total capacity and location with the FES scenarios

Short Term Dispatch Model

Takes capacity from the Long Term model as given and determines the optimal output of generation (GWh):

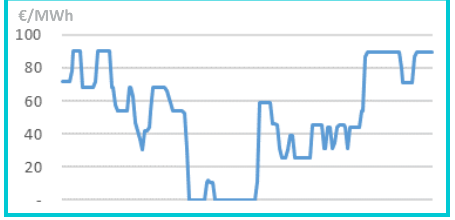
- Finds the least-cost dispatch profile of generation…
- …that meets demand…
- …on an hourly basis…
- …for each generating plant…
- …for each price zone

PLEXOS

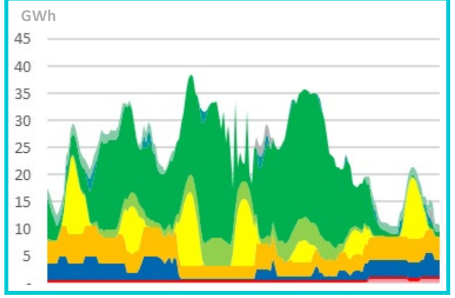
Asset Profitability module → Utility Strategic Decision → Power Market Dispatch model → Asset Profitability module

Hourly outputs for each modelled year

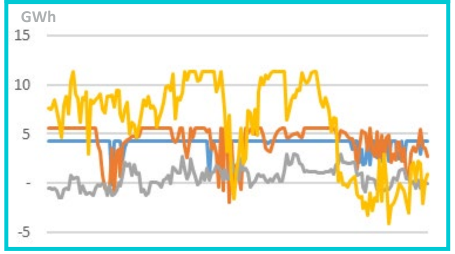
Wholesale power prices



Generation



Flows between zones

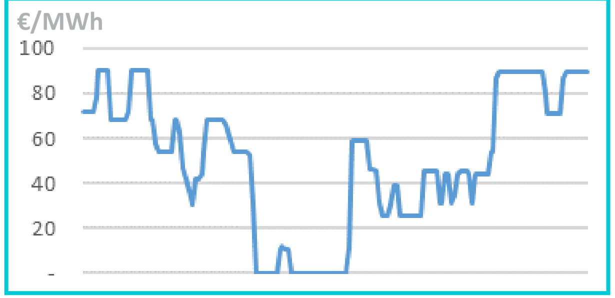


5 ***Additional quantitative analysis***

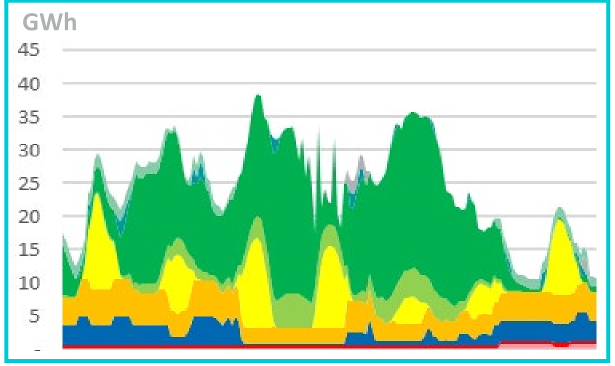
Step 4: Run dispatch model in each year to produce hourly outputs for each modelled year and each zone/node

Hourly outputs for each modelled year

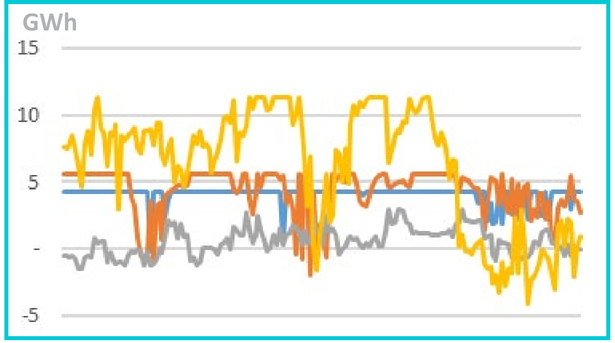
Wholesale power prices



Generation



Flows between zones



Dispatch approach

- The model uses the capacity build-out and determines the least-cost dispatch to meet hourly demand (generator bids are priced on an SRMC basis).
- This is applied to each granular location simultaneously within GB (and across Europe).

Expected outputs

- **Generation / consumption** by each resource on the system on an hourly basis
- Associated **wholesale prices** at each node/zone.
- **Flows** between each zone / node / countries (this would cover curtailment of renewables, Interconnector flows, storage operations and transmission losses among others).
- **Congestion and losses rent** are calculated using the outputs determined by the model

- For the national / zonal markets, the short-term (ST) dispatch model is run twice – with and without intra-national / intra-zonal constraints. This will provide congestion volumes.

Renewable profiles and thermal plant characteristics are based on ENTSO-E data to ensure consistency across all of Europe

Data sources used:

Renewable capacity profile	entsoe **Pan-European Climate Database**
Thermal plant operating characteristics	entsoe **Pan-European Market Modelling Database**
Generation, demand and interconnector assumptions for Europe	entsoe **TYNDP 2022**

- The Pan European Climate Database ("PECD") includes climate data for 5 different onshore GB regions (UK01-UK05 on the map)
- Each node/zone would be assigned to one of these regions or a combination of them
- Renewable profiles will be based on the **2013 climate year**, in line with ESO assumptions for the FES and NOA

- Choice of scenario **to be determined**; these assumptions will be kept consistent across Europe

Step 5: The approach to assessing the impact of CFDs to inform our modelling will vary across market designs depending on whether CFD generators are existing or new.

- Our modelling assumes an **efficient dispatch and siting of CFD-based generation**, responding to locational wholesale electricity prices
- New generators with CFDs will be **allocated to different locations endogenously**, based on expected future wholesale electricity prices subject to other real-world constraints (e.g. no onshore wind in England)
- We recognise that the **existing CFD regime** would need to be **adapted to be compatible** with locational pricing

Q: What are your views on our approach to modelling CFD contract holders?

Key principles for CFD regime design

Existing (legacy) CFD contracts	New CFD arrangements
▪ Honour existing contracts and obligations ▪ Likely to include a continuation of existing strike prices, and risk exposure (e.g. through 'tail risk')	▪ Continued competitive allocation of contracts based on CFD strike price auction ▪ Efficient allocation of risks between generators and consumers ▪ Efficient siting incentives for new generation, reflecting transmission network / locational prices (currently absent from the existing CFD regime)

Step 5: Stakeholders have raised concerns regarding the potential impact of locational wholesale pricing on the cost of capital

- **Locational pricing** could **change the risks** faced by market participants…
- …with potential implications for the **cost of capital**.
- Overall **balance of risks** needs to be assessed in light of full spectrum of policies (e.g. including CfDs)

Higher risks	No change in risks	Lower risks
'Tail end' revenues (post 15 year CFDs) under zonal/nodal	Nodal price volatility (managed via FTRs; FTR liquidity via hubs)	TNUoS volatility (driver of higher WACC) removed

Case studies:

- Nodal markets remain **attractive to investors**, despite the perceived volatility of LMPs (and indeed lack of CMs) – e.g. New Zealand and ERCOT.
- Zonal markets can also be attractive to both thermal and wind capacity investors – e.g. Sweden.

Further international evidence will be examined, to evaluate investors' perceptions…

..while taking into account other supporting mechanisms in place at the time

Risk assessment

International evidence

Stakeholder input

Potential **mitigation / transitional measures** to be discussed at a later stakeholder workshop

Q: What are your views on the potential impacts of locational pricing on the cost of capital?

Step 5: We will provide an indicative estimate of a range of implementation costs, triangulating from several sources

One-off implementation costs predominantly consists of the two items below

ESO system implementation costs — One-off costs to enhance the processes, new IT & software systems and capabilities

Market participant implementation costs — One-off costs to update system and capabilities of market participants

Approaches

- **International case studies**, including recent (IESO) and older examples (ERCOT, CAISO)
- **Direct conversations** with system vendors & market participants
- **Conversations** with ESO to understand cost of running existing systems

Assumptions

TBD on approach to estimating **zonal implementation costs**

IESO case study on system costs (Ontario, Canada)
IESO (2019) MRP Business Case – Market Renewal Program Update Meeting

Installed capacity (GW)	**38**
Target LMP go-live date	**2023**
Labour costs *(mix of design, IT, project management & support, shared services, market rules and IT roles (FTE = 60 to 70))*	**CAD $58m**
IT (Hardware & Software) *(dispatch systems = $31m)*	**CAD $53m**
Professional & consulting (legal, consulting and contract services)	**CAD $34m**
Contingency (mostly contingency for IT provisions	**CAD $16m**
Other (interest & rent)	**CAD $9m**
Total (Central Estimate)* **30% of the Central estimate cost are actuals (already incurred)*	**CAD $170m**
Cost estimate uncertainty	*-$18m CAD +$23m*

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We anticipate we will need to run the following types of sensitivities, but the precise assumptions will be decided at a later date and limited by the amount of time available/computational complexity

A. Market design & policy sensitivities

Locational price exposure to demand	Vary the extent of **locational price exposure to demand** and to **generation / storage / interconnectors…** **…**e.g. load to face national price for a period of time (at the cost of efficiency loss)
Impact of nodal pricing on dispatch	**Isolate the impact of locational pricing on dispatch** - for given level of transmission and capacity build out… …to separate out the role played by Tx build-out and siting decisions

Q: What are your views on (1) our proposed sensitivities; (2) other sensitivities we should include; and (3) which one do you see as a high priority?

B. Generation, transmission & demand sensitivities

Generation and transmission sensitivities	Test the **sensitivity of the CBA to key variables, e.g.:** ○ GB nuclear capacity ○ Interconnector capacities ○ Transmission build-out sensitivities
Demand portability	• Test the sensitivity of the CBA to demand portability: allowing some **demand to relocate in response to wholesale power price signals** (e.g. data centres, electrolysers)
Alternative scenarios	• Test the sensitivity of the CBA to using other (non-FES) scenarios… • …for example, **BEIS's demand and supply scenarios**

Breakout group 2: discussion structure

Split stakeholders into smaller breakout groups and discuss the proposed modelling approach and gather their views on locational granularity and scenario selection

Discuss key inputs into modelling	1. What are your views on **transmission post-2041**? (slide 27) 2. What are your views on how **generation capacity** should be forecasted(slides 30-31)?
Discuss additional quant. analysis	3. What are your views on our approach to **modelling CFD contract** holders (slides 36)? 4. What are your views on the potential impacts of locational pricing on the **cost of capital**? (slide 37)
Discuss sensitivities	6. What are your views on **proposed sensitivities**? (slide 39) 7. Any **other sensitivities** we should include? 8. Which one do you see as **a high priority?**

Potential policy interactions and impacts

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A potential introduction of greater locational pricing could have a range of implications for different policies & regulations

Policy Area	Arrangement	Initial Priority	Initial Comments
Network development and charging	TNUoS		Would need to be restructured - likely to be greatly simplified for nodal, still some complexity for zonal
	DUoS		No change, but would need to consider how local price is used in any future regulatory framework
	Network planning		No impact on the current arrangements, but there could be a change in the outcomes (mainly long term)
	Connect and manage		Nodal pricing would likely require a change in this policy, as access rights in nodal are generally non-firm (only provide access to the local node)
Investment support schemes	Capacity Market		Could stay with the status quo or if wished, or develop a CM that was more locational
	CFDs		Could be operable with locational pricing, though expect amendment to maintain efficacy
	Cap and Floor		Initial view is that no change would be required, though change to IC rents to be assessed quantitatively
	Low Carbon RAB		Initial view is that no change would be required, though change to participant revenues to be quant. assessed
Balancing Market	Ancillary Services		Under a nodal system, dispatch can co-optimise energy and AS with potential for significant efficiencies
	Balancing Mechanism		Role of BM significantly reduced with some changes in processes and systems required
	BSUoS		No change expected and BSUoS would be much lower (or positive) if benefits redistributed to customers
Wider market arrangements	Retail market		Price cap determination process might change. More creative retail business models might emerge
	Cross-border arrangements		Extent to which changes needed to ensure effective XB trading to be assessed
	Distribution flexibility		Might impact the operation and procurement of flexibility providers. It might also trigger different consumption behaviour
	UK ETS		Extent to which changes needed to ensure effective ETS to be assessed

Key: Low · Medium · Medium/High · High

NB: This slide intends to capture initial thinking that has been done so far on the extent to which current policies & market arrangements could be impacted, should more granular locational pricing be introduced to the GB wholesale electricity market. It is presented for discussion and does not represent Ofgem's view on the future of these policies or arrangements.

Breakout group 3: Discussion structure

Discuss mapping of the policy areas

1. Have we **missed any policies** that would likely be impacted by the introduction of more granular locational pricing?
2. Which are **the priorities to explore** as part of this assessment?

Discuss assessment of the policy interactions

3. Do you **agree with our initial assessment** of likely policy impacts?
4. Which are you most concerned about?

Wrap up and next steps

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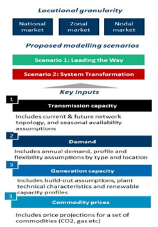
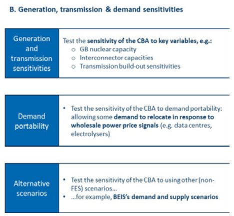
Next steps and plans for the next workshop

Consolidate key assumptions and sensitivities

Key Assumptions



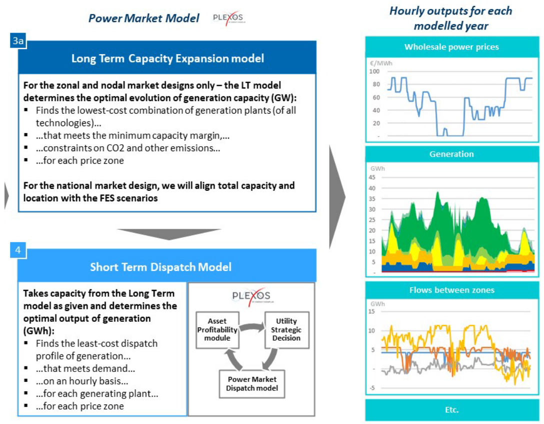
Sensitivities



Evidence from stakeholders

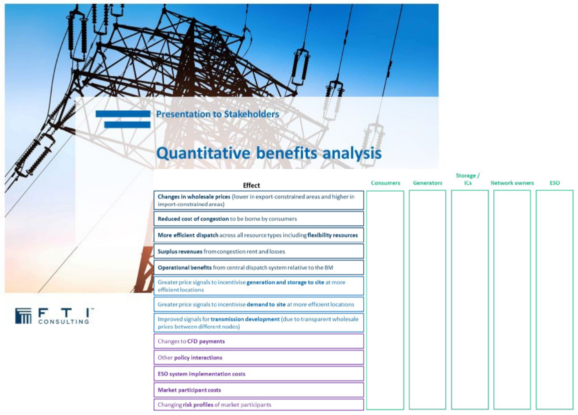
- **Publish a short summary** of discussions and **workshop materials** – ask **all interested stakeholders for written feedback**
- **Incorporate feedback** from today's session

Conduct Quantitative benefits analysis



- Conduct **qualitative and quantitative assessments** of key impacts
- Identify the **impact** of locational pricing market designs **on different stakeholder groups**

Next workshop



- **Present initial results** of the cost-benefit analysis
- Discuss with stakeholders (1) potential **mitigations**, range of transitional measures and impact on benefits and (2) **implementation requirements**

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