TNUoS Charging Tutorial

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Introductions & housekeeping

- Fire procedure – planned fire alarm test at 10am.
- Toilets

- Who am I?
- What’s my interest in TNUoS?
- I learnt a memorable lesson when...

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Agenda

09:45	Refreshments & Setup
10:00	Introductions and housekeeping
10:15	An overview of TNUoS
10:50	Transport model introduction
11:30	Break
11:45	Expansion Factors
12:00	Tariff model introduction
12:30	Lunch
13:00	CMP213
14:30	Break
14:45	Sensitivity Analysis
15:55	Closing Summary

Objectives

- To aid understanding of:
  - the TNUoS Charging Methodology;
  - how National Grid sets TNUoS tariffs;
  - the key drivers behind TNUoS tariffs; and
  - how a sensitivity analysis of TNUoS tariffs can be undertaken.

An overview of TNUoS

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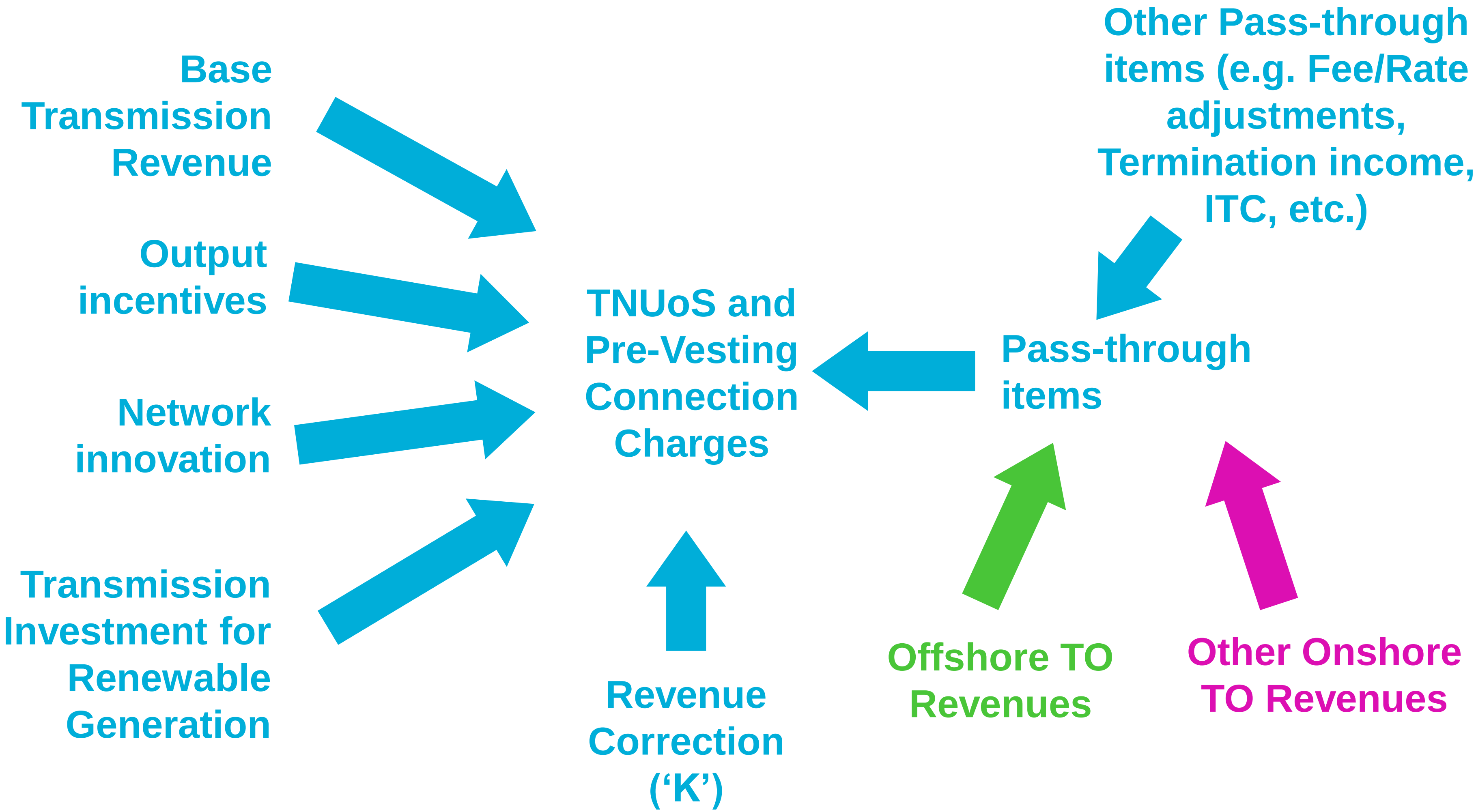
What is TNUoS?

- *“Transmission Network Use of System charges reflect the cost of installing, operating and maintaining the transmission system for the Transmission Owner (TO) Activity function of the Transmission Businesses of each Transmission Licensee”.*
- Recovers TO revenues set under the Price Controls (RIIO) and Offshore Tender Process.
- In 2014/15 TNUoS is expected to recover £2.5bn.

NGET TO Revenue Allowance



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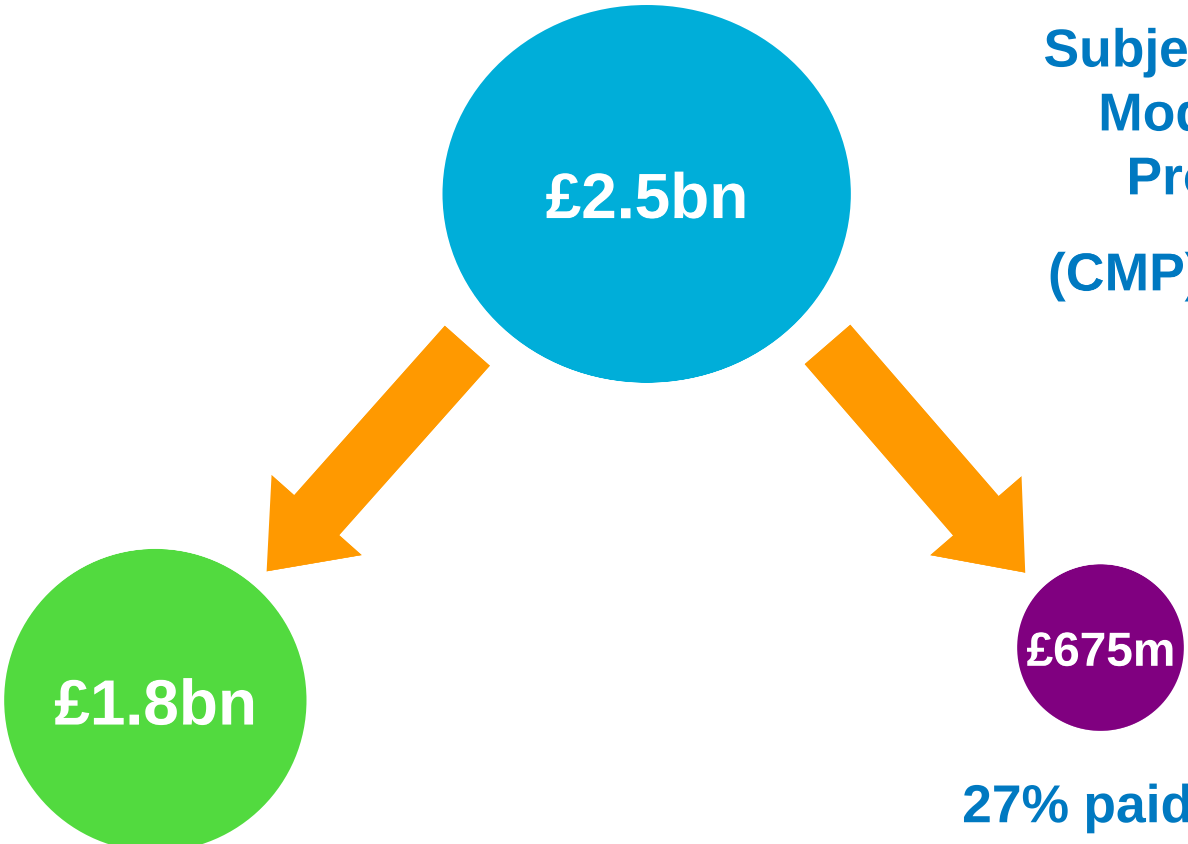
Who Pays TNUoS?



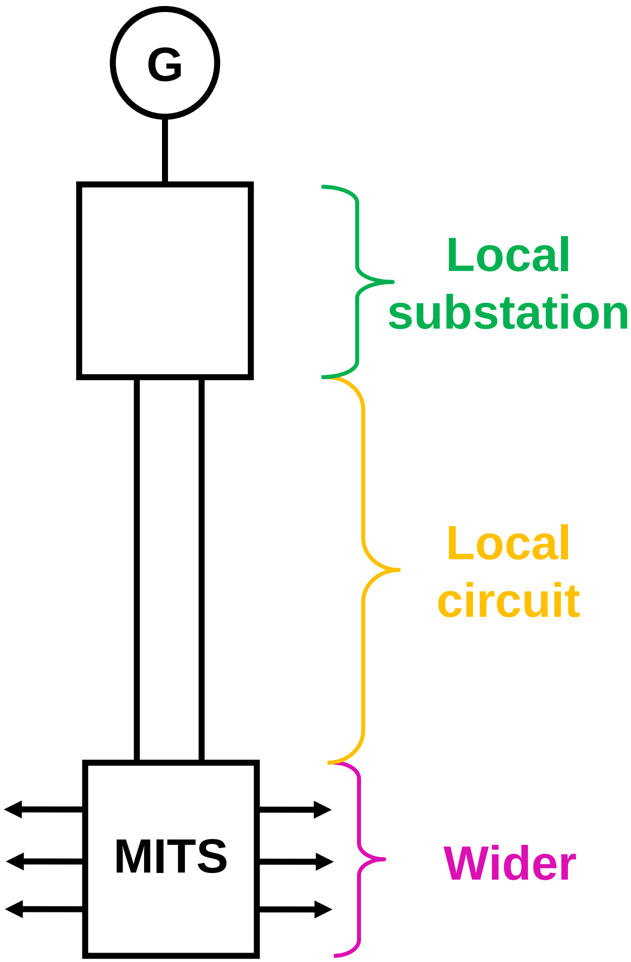
Subject to CUSC Modification Proposals

(CMP) 224 & 227

73% paid by Demand (Suppliers)

27% paid by Generators

Structure of TNUoS Charges



Illustrative only

		G	D
Locational	Substation	✓	
	Circuit	✓	
	Wider	✓	✓
Non Locational	Residual	✓	✓

Small Generators Discount (expiry 2016?)

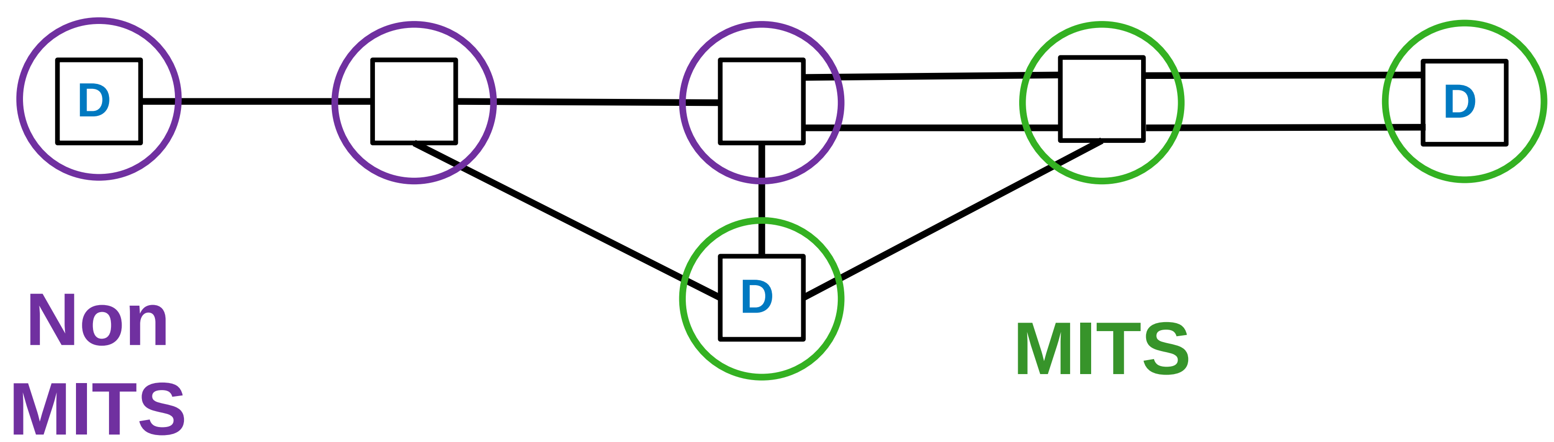
ETUoS

Generation TNUoS Charges

- Reflect the incremental cost of facilitating generation on the transmission network:
  - Higher network requirement - higher charge
- Charged to all Directly Connected generation
- Zonal element also paid by Non-Licence Exemptible Embedded Generation
- Annual Chargeable Capacity:
  - Max TEC
  - Average output of three “proving runs” (-ve local circuit and zonal TNUoS tariffs).

The Main Integrated Transmission System

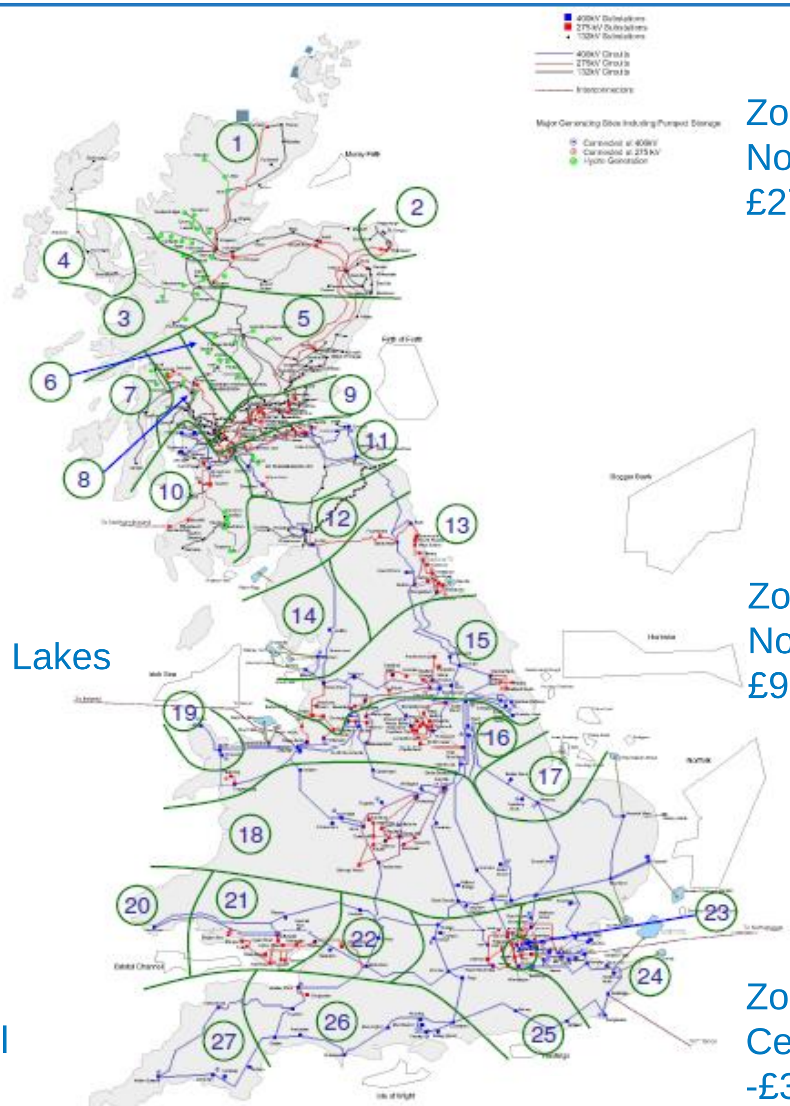
- The MITS is the part of the Tx system that facilitates bulk power flows.
- Wider generation charges represent the cost of facilitating generation on the MITS.
- Local generation charges represent the cost of local infrastructure between a generator and the MITS.
- MITS substations are those which are:
  - Grid Supply Points with two or more transmission circuits; and
  - Non-Grid Supply Points with five or more transmission circuits.



Zonal Generation Tariffs

Zone 4:
Skye and Lochalsh
£33.79/kW

Zone 1:
North Scotland
£27.68/kW



Zone 14:
North Lancashire & The Lakes
£9.15/kW

Zone 13:
North East England
£9.87/kW

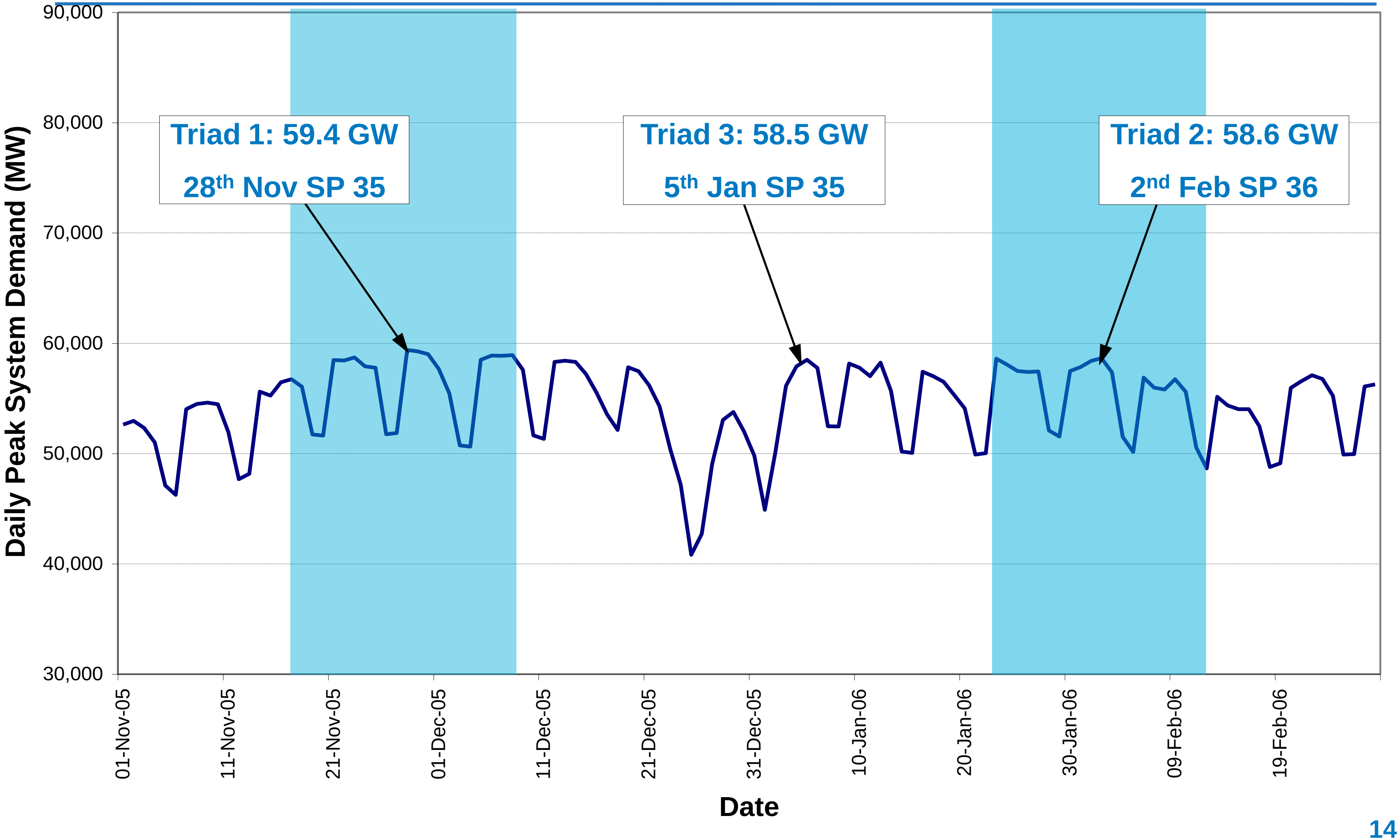
Zone 27:
West Devon and Cornwall
-£4.70/kW

Zone 23:
Central London
-£3.77/kW

Demand TNUoS Charges

- Reflect the incremental cost of facilitating demand on the transmission network.
- Half-hourly (HH) metered demand:
  - Zonal Demand Tariff (Locational + Residual, £/kW);
  - Charges based on average demand over the three “triad” periods.
  - Provides economic signal to avoid taking demand at peak.
  - Embedded Benefit paid to Licence Exemptible Dx connected generation
- Non-half-hourly (NHH) metered demand:
  - Zonal Energy Consumption Tariff (p/kWh);
  - Based on total annual consumption taken between 16:00-19:00
  - Provides gradual economic signal.

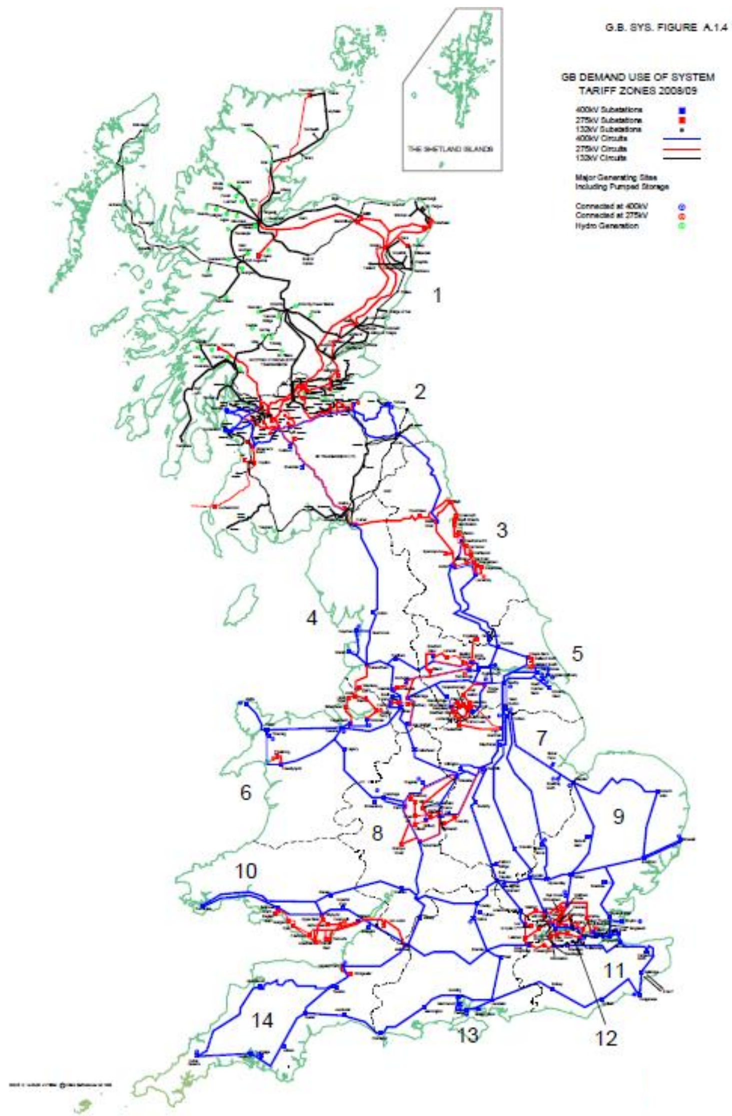
Triad determination example – 2005-06



Zonal Demand Tariffs

Zone 4:
North West
HH: £29.64 /kW
NHH: 4.24 p/kWh

Zone 14:
South Western
HH: £38.70 /kW
NHH: 5.23 p/kWh



Zone 1:
Northern Scotland
HH: £16.17 /kW
NHH: 2.19 p/kWh

Zone 9:
Eastern
HH: £34.63 /kW
NHH: 4.75 p/kWh

Zone 12:
London
HH: £38.55 /kW
NHH: 5.14 p/kWh

Calculating TNUoS tariffs

- Transport Model
  - used to calculated the locational investment signals (wider and local)
  - if you add 1MW of generation what impact does it have?
  - the impact is measured in terms of additional flows
  - proxy for level of investment at each location

- Tariff Model
  - used to ensure correct revenue recovery
  - also ensures that revenue recovered in desired G / D proportions

The Transport Model



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What is the Transport Model?

- A simplified model of the transmission system which contains
  - generation at each power station location (TEC at each node)
  - demand at each demand location (demand at each node)
    - Grid Supply Points (GSP) to DNOs
    - Direct Connects e.g. interconnectors, railways
  - the network that connects these (e.g. OHL / cable circuits)

- Models power flows on the transmission system at system peak
  - designed to represent conditions that drive transmission investment

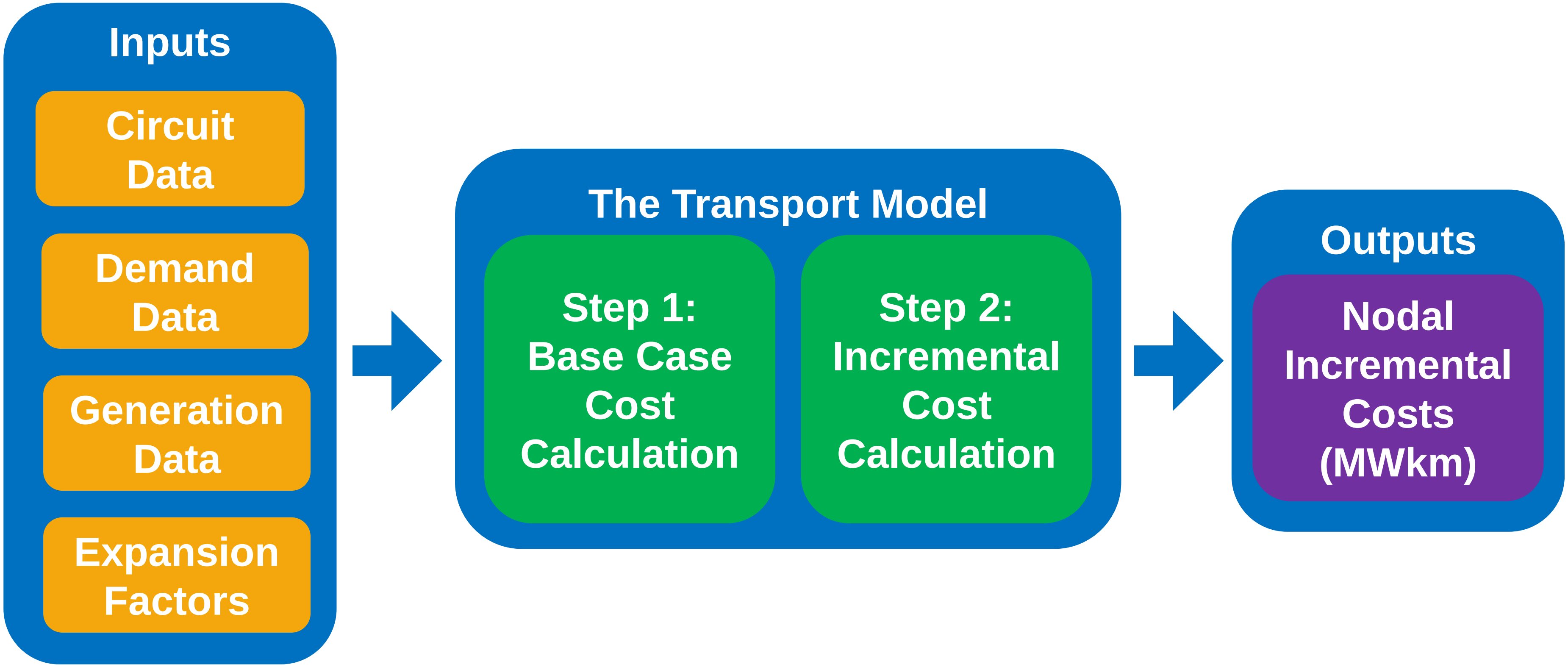
The Transport Model

What does it do?

- Model power flows at system peak (the base case)
- Inject an additional MW at each node
- Look how power flows change compared to the base case
- Measure length of network that the additional MW flows on
- This length represents the investment required for additional generation connecting at this node

Length of network is the measure of investment cost

Transport Model Overview



Transport Model

- Please open File 1.

Transport Model

Node Data Inputs

Node **Dem** **Gen** **Node-to-Zone Mapping**

DC Load Flow

Nodal Input

Bus ID	Bus Name	Voltage	Demand	Cat A Gen	Cat B Gen	Cat C Gen	Gen Zone	Dem Zone
1	ANDE10	132	0	45	0	0	7	2
2	ANSU10	132	0	21	0	0	5	1
3	AUCC10	132	0	0	0	0	7	2
4	AUCW10	132	0	0	0	0	7	2
5	BLYT4A	400	0	0	0	0	10	3
6	BLYT4B	400	0	0	0	0	10	3
7	CLEV40	400	0	0	0	0	17	11
8	CLYN2Q	275	0	0	0	0	7	2
9	CLYS2R	275	0	0	0	0	7	2
10	EHAU10	132	0	108	0	0	7	2
11	ERRO1T	132	0	0	0	0	4	1
12	ESST1Q	132	0	0	0	0	5	2
13	ESST1R	132	0	0	0	0	5	2
14	FIDF20_ENW	275	12	0	0	0	9	4
15	FIDF20_SPM	275	256	1,987	0	0	9	6
16	GRIF1S	132	0	102	0	0	4	1
17	GRIF1T	132	0	102	0	0	4	1
18	INNE10	132	0	0	0	0	1	1
19	KAIM10	132	0	0	0	0	7	2
20	KNOC10	132	0	0	0	0	1	1
21	KNOC20	275	0	0	0	0	1	1
22	MOFF10	132	0	0	0	0	7	2
23	MOFF40	400	0	0	0	0	7	2

Transport Model

Circuit Data Inputs

Start / End **Elec Parameters** **Length**

Network Input Data

TO Region	Bus 1	Bus 2	R	X	OHL Lengtl	Cable Lenç	Link Limit	Code	Link Type	pare-Cap	Outaged
NGC	ABHA4A	EXET40	0.1	1.0	48.9	-	1390	A833	OHL	No	No
NGC	ABHA4A	LANG40	0.1	0.5	24.6	-	1390	A83D	OHL	No	No
NGC	ABHA4B	EXET40	0.1	1.0	49.2	-	1390	A879	OHL	No	No
NGC	ABHA4B	LANG40	0.1	0.5	24.6	-	1390	A87F	OHL	No	No
NGC	ABTH20	COWB2A	0.0	0.5	12.0	-	1350	B82J	OHL	No	No
NGC	ABTH20	PYLE20	0.2	1.4	34.6	-	1140	B829	OHL	No	No
NGC	ABTH20	TREM20	0.3	2.1	47.0	-	625	B854	OHL	No	No
NGC	ABTH20	UPPB20	0.1	1.1	27.4	0.5	770	B821	COMPOSIT	No	No
NGC	ABTH20	UPPB20	0.1	1.1	27.8	-	955	B820	OHL	No	No
NGC	ALDW20	BRIN20	0.1	0.7	17.9	-	625	B339	OHL	No	No
NGC	ALDW20	WMEL20	0.0	0.4	9.1	-	955	B338	OHL	No	No
NGC	ALVE4A	INDQ40	0.2	2.0	97.5	-	1390	A876	OHL	No	No
NGC	ALVE4A	TAUN4A	0.2	1.5	72.9	-	1390	A834	OHL	No	No
NGC	ALVE4B	INDQ40	0.2	2.0	97.5	-	1390	A829	OHL	No	No
NGC	ALVE4B	TAUN4B	0.2	1.5	72.9	-	1390	A877	OHL	No	No
NGC	AMEM4A_EPN	AMEM4A_SEP	0.0	0.1	-	-	0	None	CONSTRUC	No	No
NGC	AMEM4A_EPN	ECLA40_AQUL	0.1	0.7	35.7	-	2010	A696	OHL	No	No
NGC	AMEM4A_EPN	IVER4A	0.0	0.4	20.3	-	2010	A609	OHL	No	No
NGC	AMEM4B_EPN	AMEM4B_SEP	0.0	0.1	-	-	0	None	CONSTRUC	No	No
NGC	AMEM4B_EPN	ECLA40_AQUL	0.1	0.7	35.7	-	1390	A697	OHL	No	No
NGC	AMEM4B_EPN	IVER4B	0.0	0.4	20.3	-	1390	A610	OHL	No	No
NGC	AXMI40_SEP	AXMI40_SWEB	0.0	0.1	-	-	0	None	CONSTRUC	No	No
NGC	AXMI40_SEP	CHIC40	0.0	0.6	39.7	-	2780	A84F	OHL	No	No
NGC	AXMI40_SEP	EXET40	0.0	0.6	36.3	-	2780	A852	OHL	No	No
NGC	BAGB20	MAGA20	0.1	0.5	12.3	0.5	860	B82F	COMPOSIT	No	No
NGC	BAGB20	SWAN20_SPM	0.1	0.8	18.7	0.5	860	B82E	COMPOSIT	No	No

Transport Model

Nodal outputs

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DC Load Flow | **Nodal Input** | Hidden columns | **Nodal Calculations** | Hidden columns

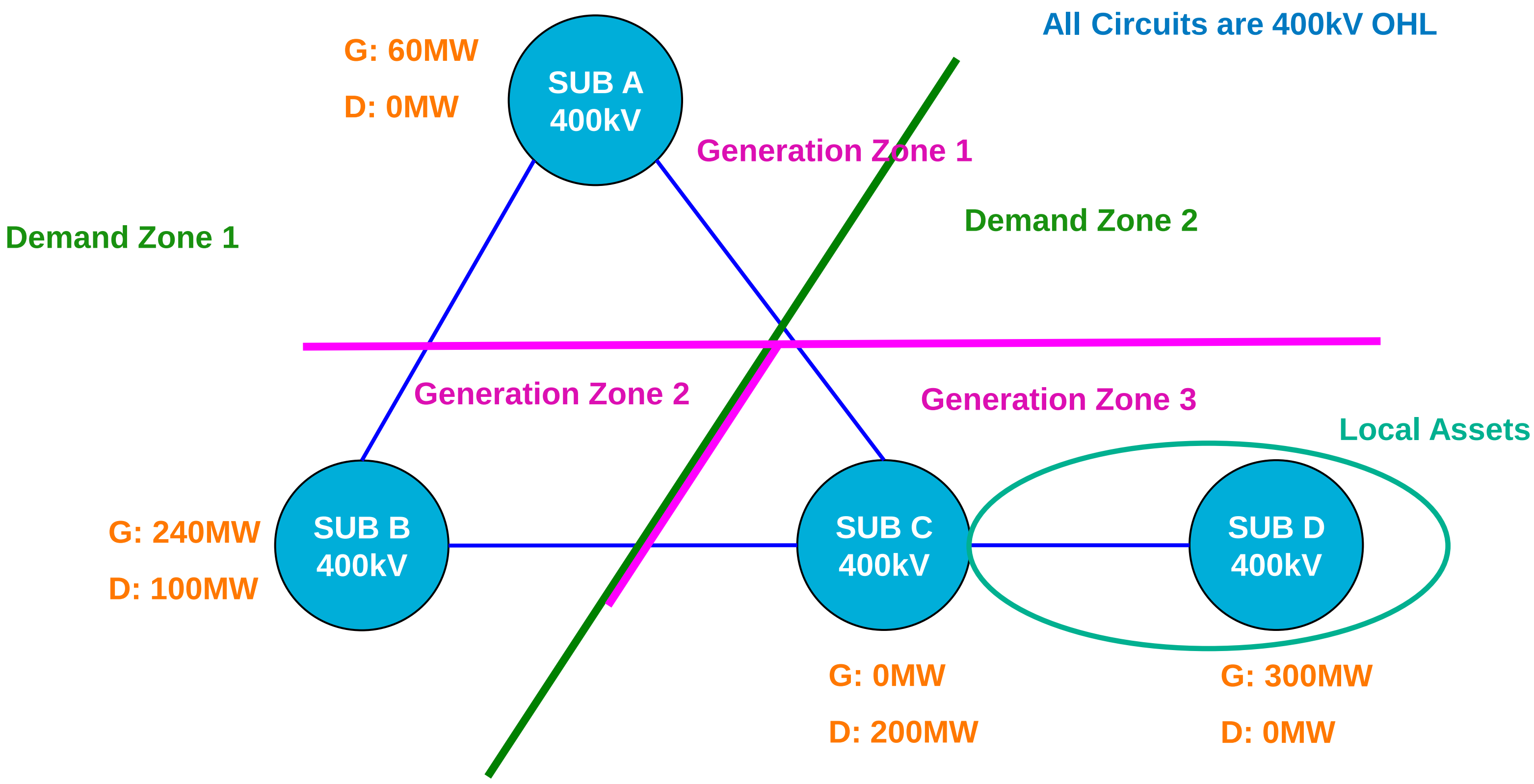
Bus ID	Bus Name	Voltage	Bus Order	BusTransf	BusVang	Scenario 1 Demand	Scenario 1 Wider	Scenario 1 Local
1	ANDE10	132	1	32.6	0.5	657.5	555.9	207.4
2	ANSU10	132	209	15.0	0.7	817.5	792.7	92.3
3	AUCC10	132	2	-	0.6	230.1	230.1	-
4	AUCW10	132	3	-	0.5	709.1	709.1	-
5	BLYT4A	400	408	-	0.5	455.6	455.6	-
6	BLYT4B	400	432	-	0.5	455.6	455.6	-
7	CLEV40	400	351	-	0.1	52.7	52.7	-
8	CLYN2Q	275	4	-	0.5	540.0	540.0	-
9	CLYS2R	275	5	-	0.5	540.2	540.2	-
10	EHAU10	132	6	78.1	0.5	649.8	495.5	202.1
11	ERRO1T	132	460	-	0.7	966.6	966.6	-
12	ESST1Q	132	203	-	0.6	453.8	[illegible]	-
13	ESST1R	132	143	-	0.6	529.0	529.0	-
14	FIDF20_ENW	275	7	- 12.0	0.3	295.0	[illegible]	-
15	FIDF20_SPM	275	533	1,181.5	0.3	295.0	295	-
16	GRIF1S	132	388	73.8	0.7	941.3	960	71.0
17	GRIF1T	132	389	73.8	0.7	1,024.1	949	277.2
18	INNE10	132	8	-	0.9	1,135.2	1,135	-
19	KAIM10	132	9	-	0.6	668.3	668	-
20	KNOC10	132	10	-	0.9			-
21	KNOC20	275	483	-	0.9			
22	MOFF10	132	11	-	0.5			
23	MOFF40	400	472	-	0.5			
24	RAIN20_ENW	275	12	- 91.6	0.3			
25	RAIN20_SPM	275	478	- 445.0	0.3			
26	SBAR40	400	495	-	0.2			
27	STEW4C	400	735	-	0.5			
28	STEW4D	400	647	-	0.5			
29	STLE10_SHEPD	132	516	- 9.1	0.6	[illegible]	[illegible]	-
30	STLE10_SPD	132	515	- 67.6	0.6	610.8	610.8	-
31	STRB20	275	555	34.4	0.9	1,140.9	1,043.6	97.3
32	TILB40	400	816	-	0.1	38.8	38.8	-
33	WTHU41	400	308	- 20.5	0.0	8.3	8.3	-
34	WTHU42	400	650	- 20.5	0.0	32.7	32.7	-
35	WTHU4A	400	320	-	0.0	34.5	34.5	-

Each MW from FIDF increases flow on 529km of 400kV OHL (equivalent) network

Example 1: A Simple Transport Model

- Please open File 2.

Simple 4-Node Model

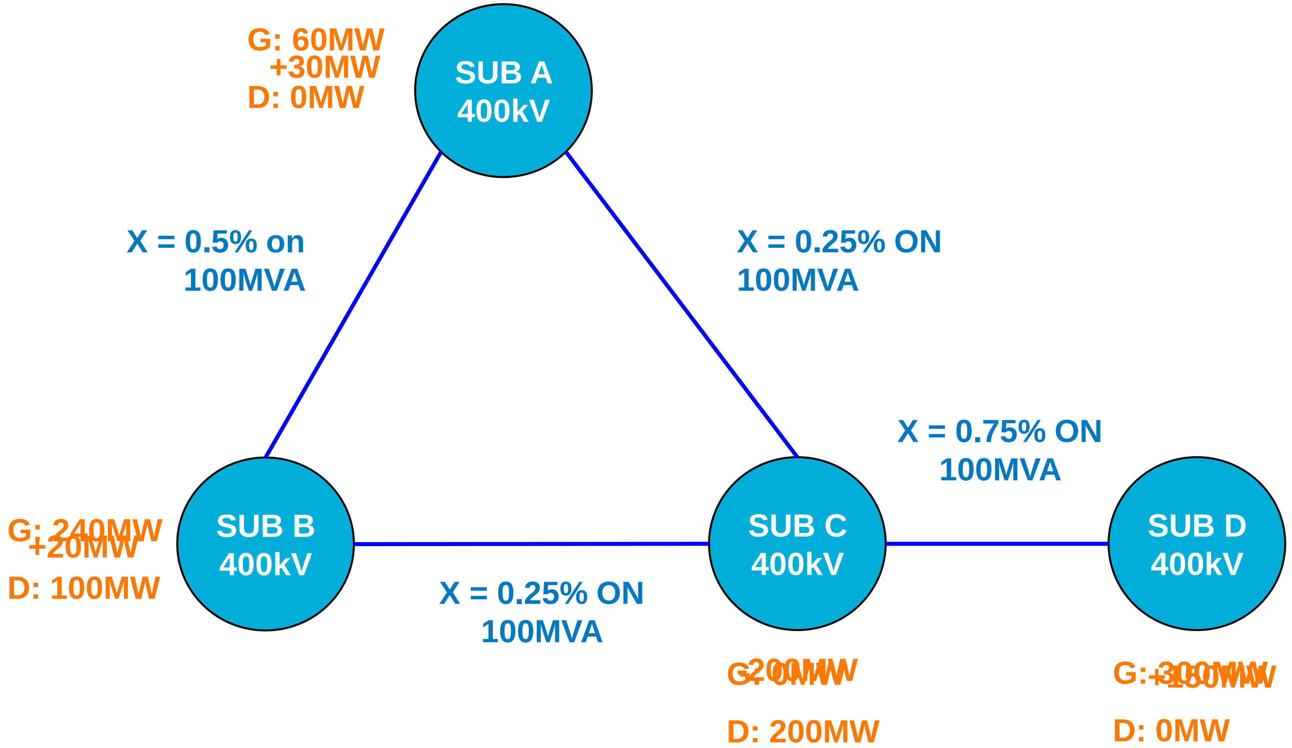


Total Demand: 300MW

Total Generation Capacity: 600MW

=> 50% Scaling Factor

Power Flows (Base Case)

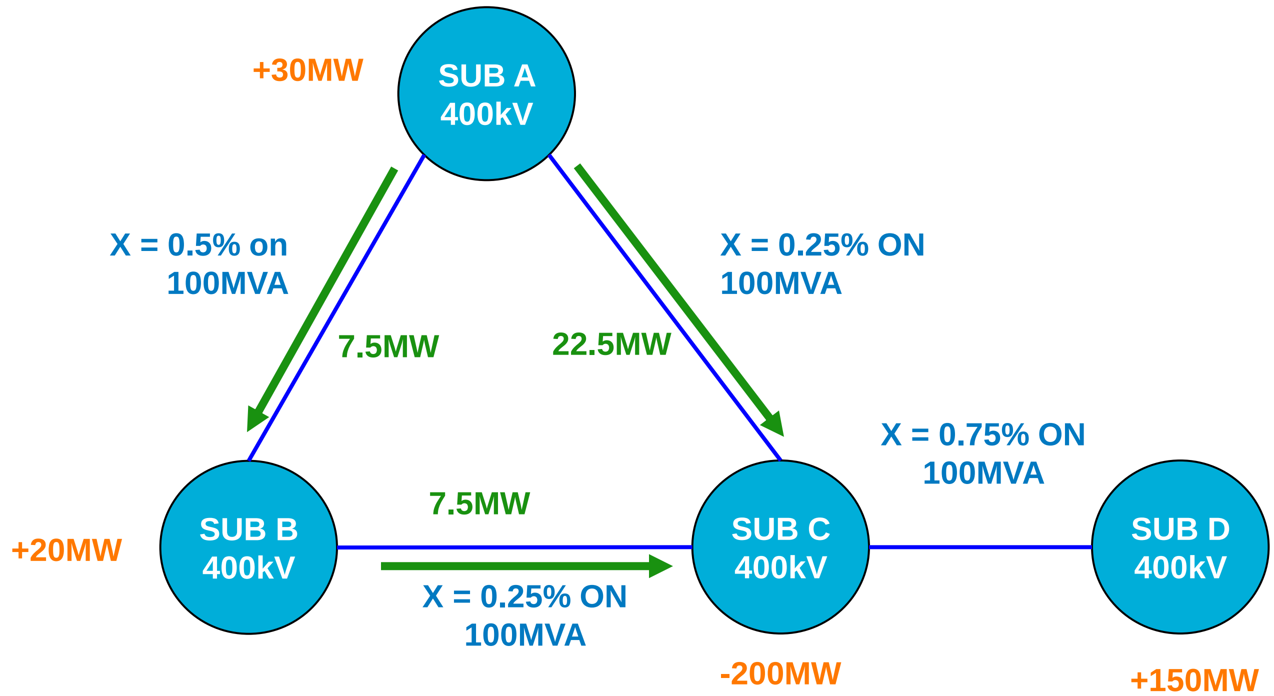


Total Demand: 300MW

Total Generation Capacity: 600MW

=> 50% Scaling Factor

Power Flows (Base Case)



Node A has an export of 30MW:

There are two possible routes for this to take:

A-C and A-B-C

Power flows will be inversely proportional to the sum of the impedances across both routes.

A-C flow:

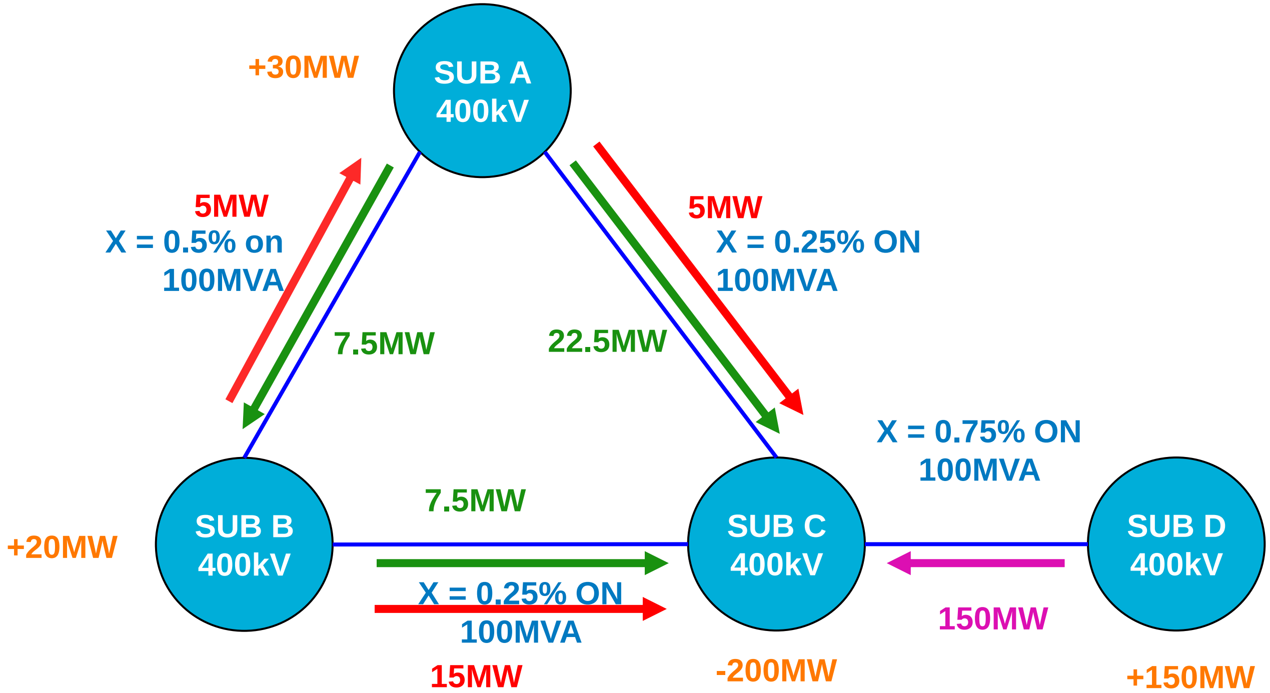
30 * (0.25 + 0.5 + 0.25 - 0.25) / (0.25 + 0.5 + 0.25)

= 30 * 0.75 = 22.5MW

A-B-C flow:

30 * (1 - 0.5 – 0.25) / (1) = 7.5MW

Power Flows (Base Case)



Two possible routes for Node B:

B-C and B-A-C

B-C Flow:

20 * (0.25 + 0.5 + 0.25 - 0.25) / (0.25 + 0.5 + 0.25)

= 20 * 0.75 = 15MW

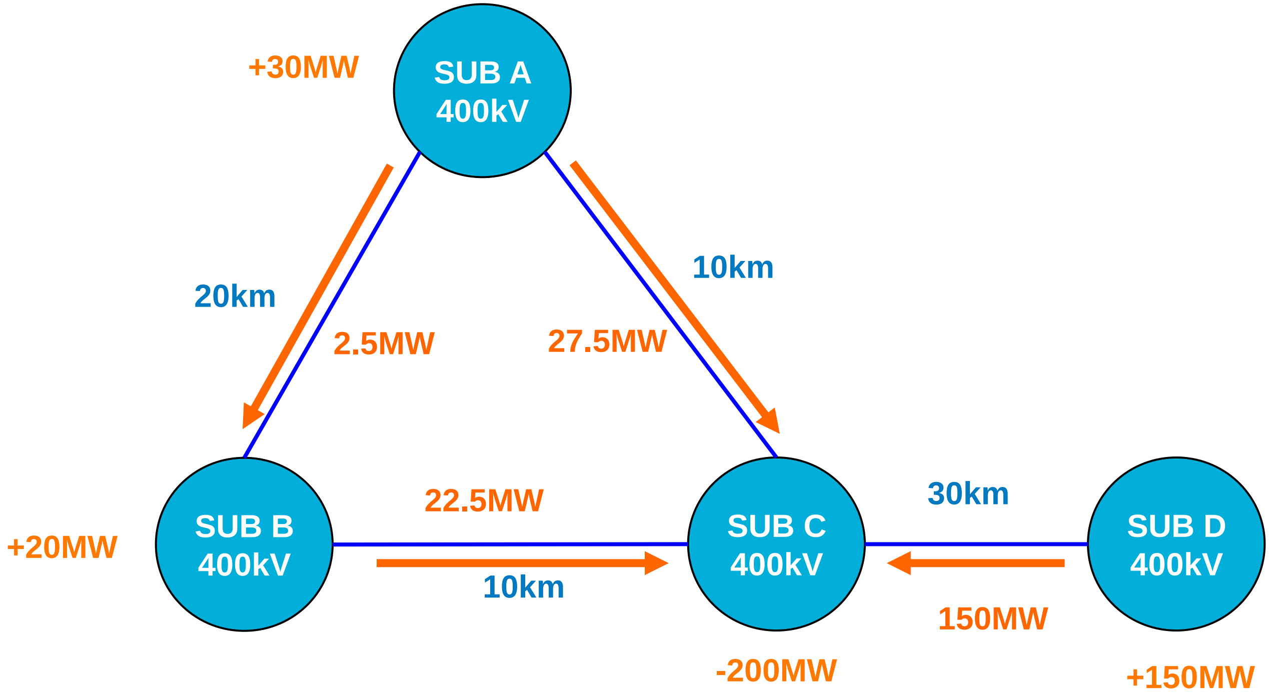
B-A-C Flow:

20 * (1 - 0.5 - 0.25) / (1) = 20 * 0.25 = 5MW

One possible route for Node D:

D-C: 150MW

Power Flows (Base Case)



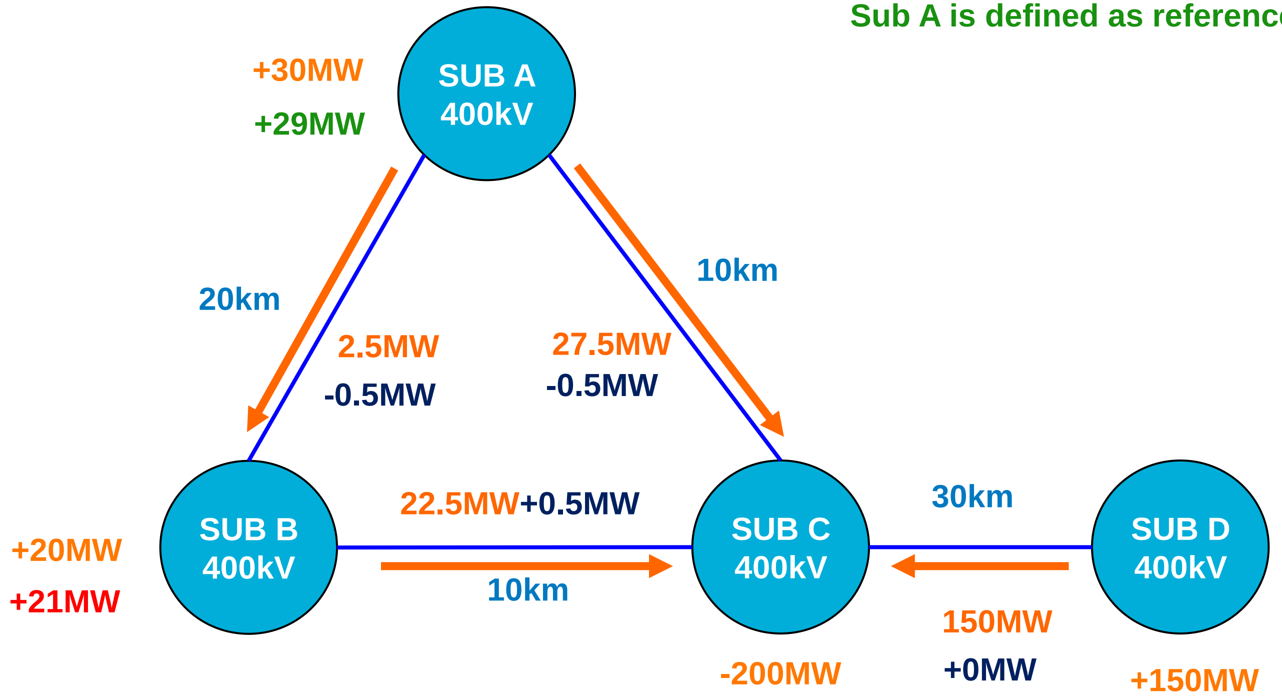
Total Base Case "Cost":

2.5*20 + 27.5*10 + 22.5*10 + 150*30 = 5050 MWkm

Local Cost: 4500 MWkm

Nodal MWkm Cost – Node B

Sub A is defined as reference node



Nodal Cost calculated by adding an additional 1MW generation to each node in turn to feed 1MW of additional demand at the reference node.

Revised flows from Node A:

A-C = 0.75 * 29 = 21.75MW; A-B-C = 0.25 * 29 = 7.25MW

Revised flows from Node B:

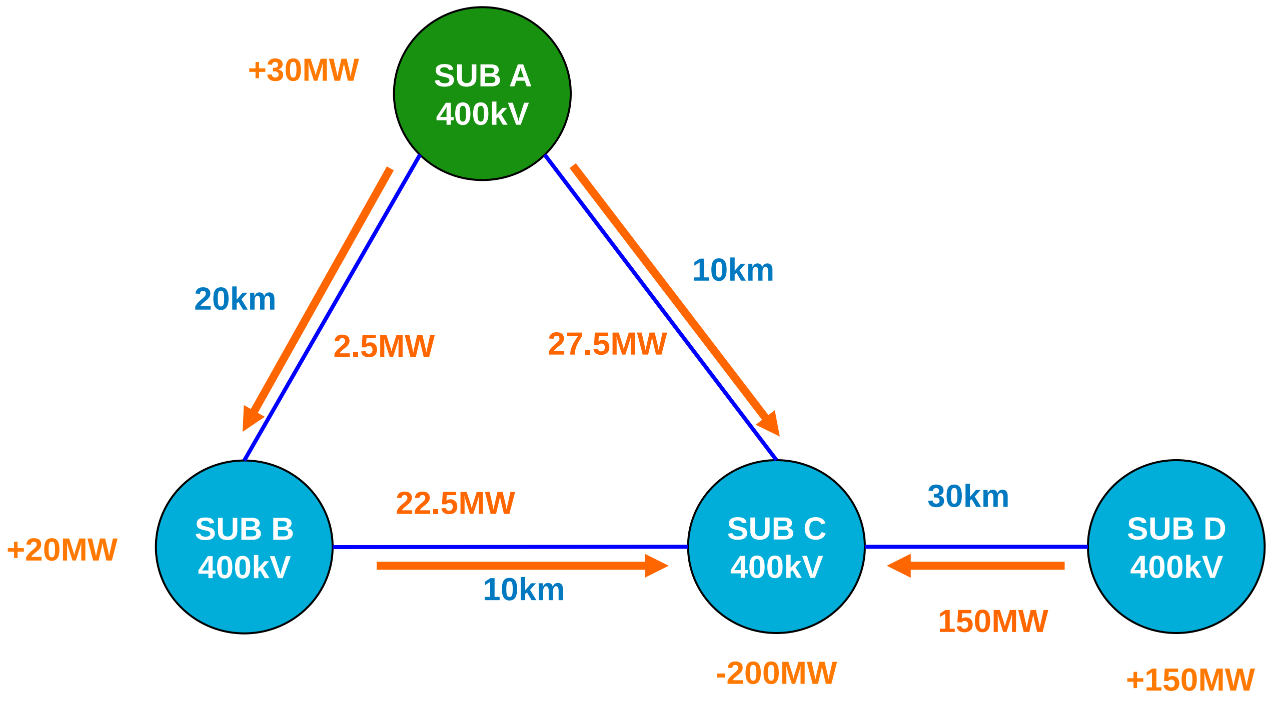
B-C = 0.75 * 21 = 15.75MW; B-A-C = 0.25 * 21 = 5.25MW

Node D flows unchanged

Node B Nodal cost = -0.5 * 20 -0.5 * 10 + 0.5 * 10

= -10MWkm

Nodal MWkm Costs

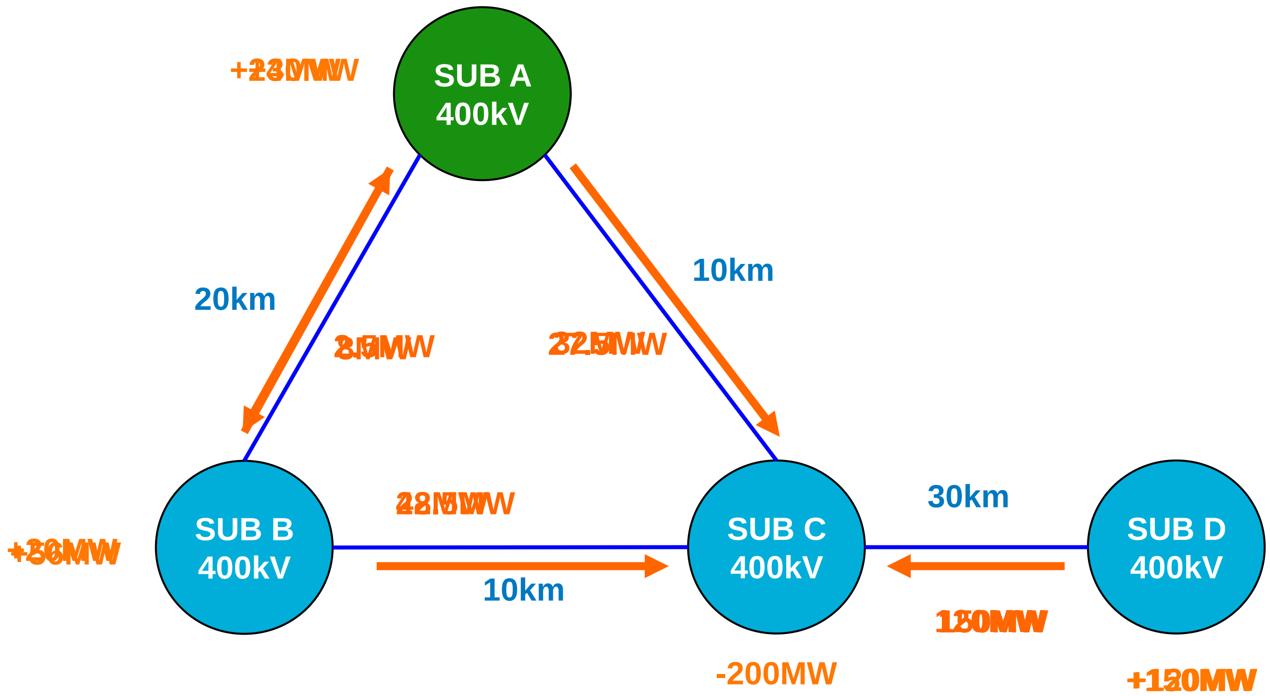


Node	Wider	Local	Total
SUB A	0	0	0
SUB B	-10	0	-10
SUB C	-15	0	-15
SUB D	-15	30	15

Exercise 1

- Unprotect the Transport Sheet
- Add 150MW of generation to node B and run the model.
  - Please do not re-order busbars (this resets the reference node).
  - How do the nodal costs change?
  - If you add more or less generation (5MW, 200MW) do the results change?

Nodal MWkm Costs



Total Demand: 300MW

Total Generation Capacity: 750MW

=> 40% Scaling Factor

Node	Wider	Local	Total
SUB A	0	0	0
SUB B	10	0	10
SUB C	-5	0	-5
SUB D	-5	30	25

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Observations

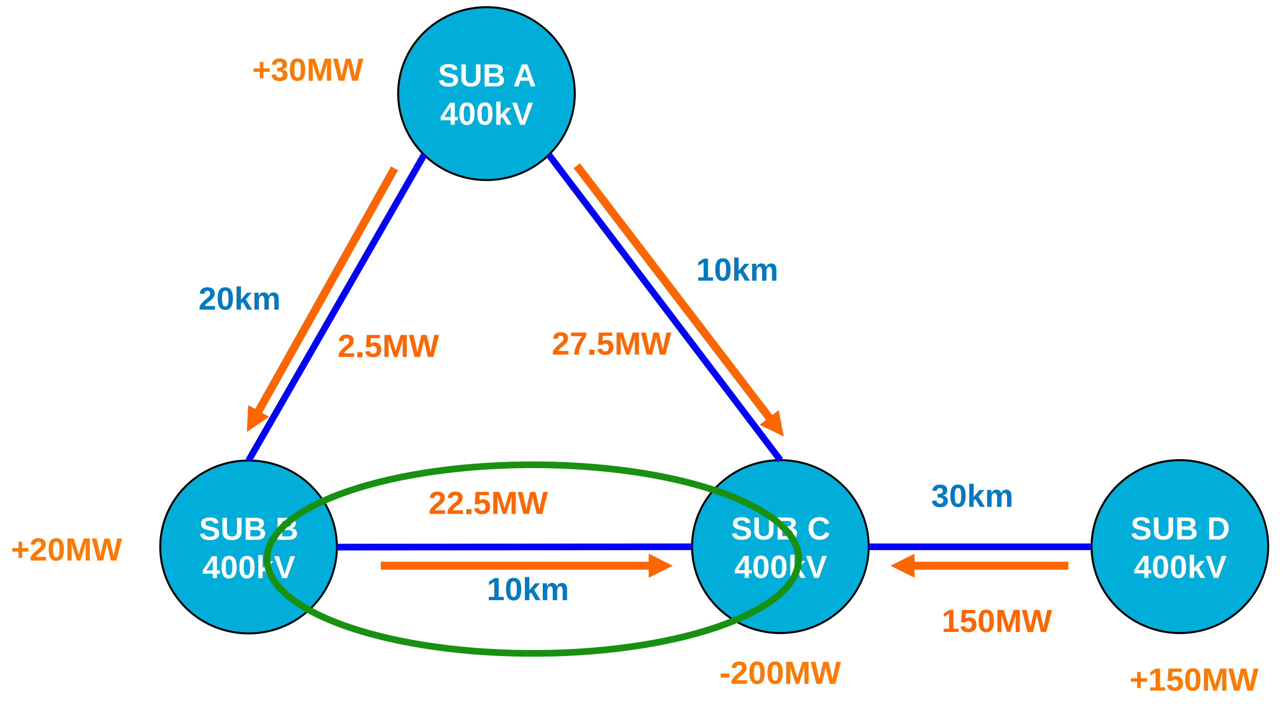
- The model assumes that:
  - If additional generation requires additional on a circuit then it will drive investment on that circuit.
  - If additional generation reduces flows on a circuit then it will reduce the need for investment.
- Changes in flow direction drive changes in locational tariffs:
  - Generation;
  - Demand; and
  - Circuit impedance.
- What else can drive changes in locational tariffs?
  - Circuit length/technology/voltage.

Circuit Technology

- TNUoS tariffs calculated based on cost of 1MWkm of 400kV Overhead Line OHL
- Need to consider:
  - Other Voltages (275/132kV)
  - Underground Cables
  - Offshore Transmission

- Expansion factors are used by the model to “stretch” these types of circuit so the equivalent cost is modelled.
- For example if the cost of 275kV OHL is twice that of 400kV OHL per MWkm:
  - A factor of 2 would be applied to the length of any 275kV OHL when calculating the MWkm cost.

275kV OHL example

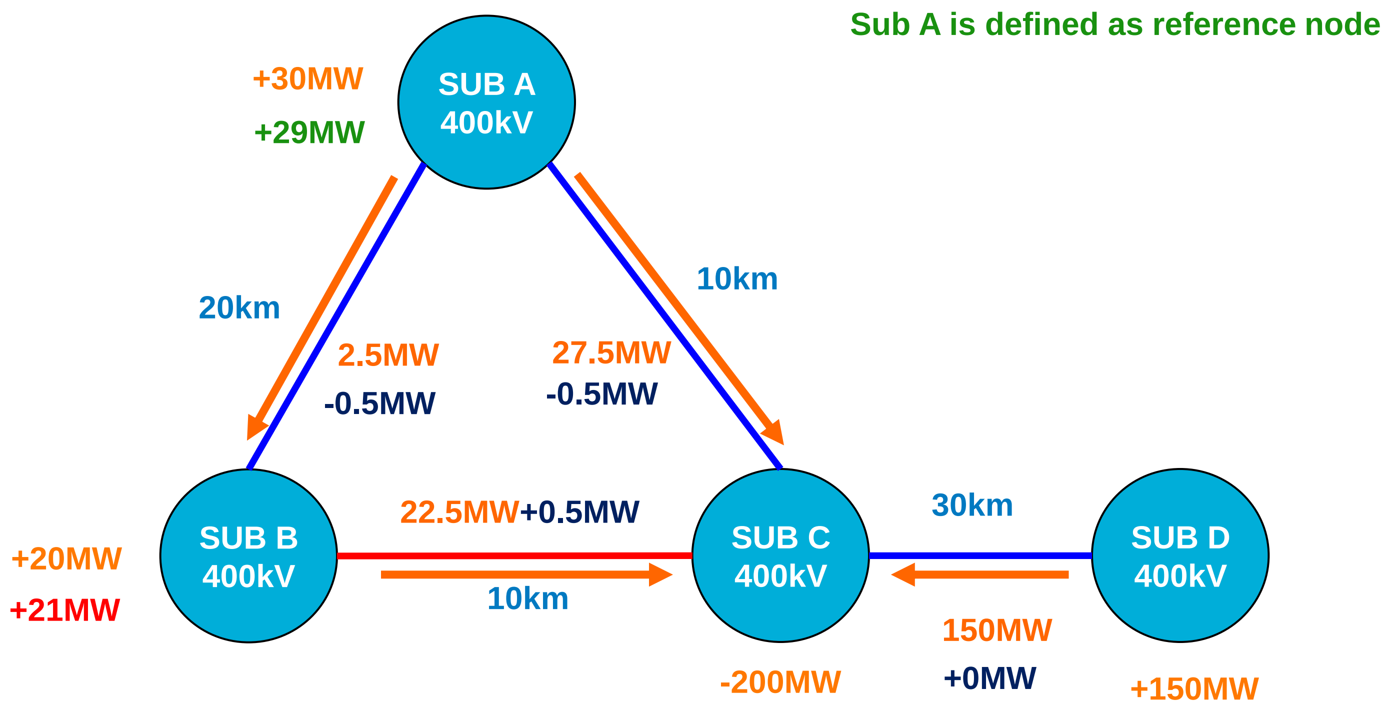


Total Base Case "Cost":

2.5*20 + 27.5*10 + 22.5*10*2 + 150*30 = 5275 MWkm

Local Cost: 4500 MWkm

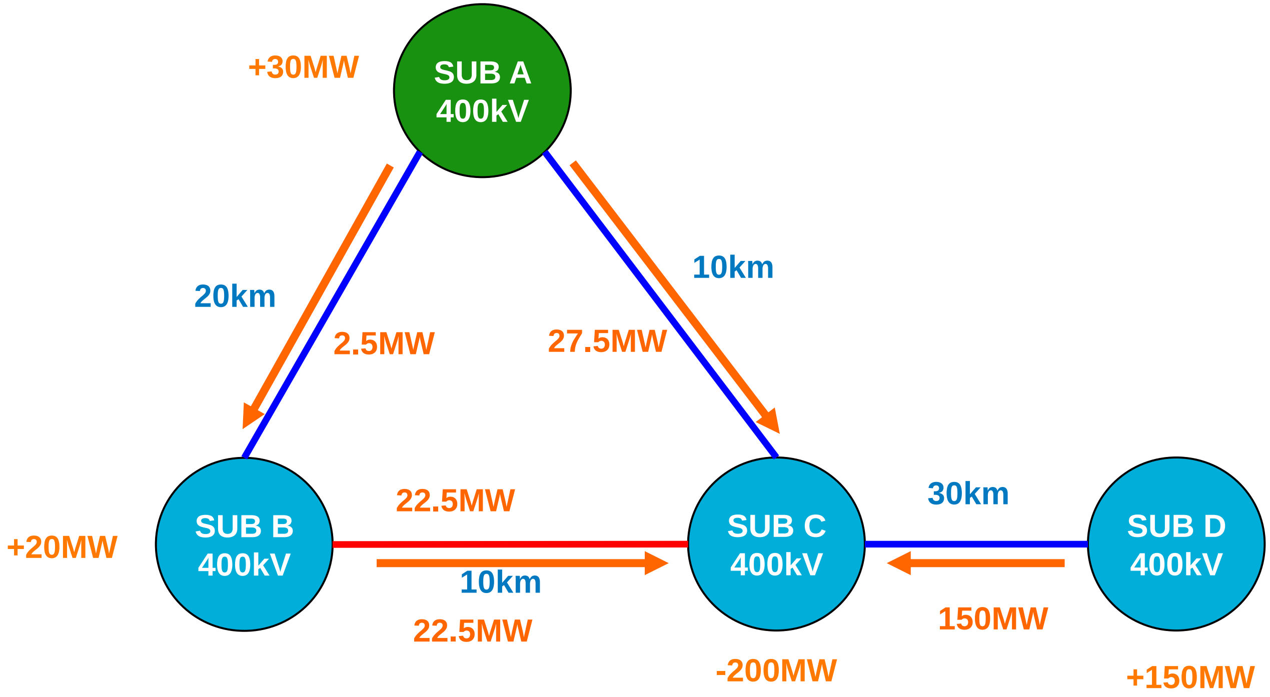
Nodal MWkm Cost – Node B



Node B Nodal cost = -0.5 * 20 -0.5 * 10 + 0.5 * 10 * 2

= -5MWkm

Nodal MWkm Costs



Node	Wider	Local	Total
SUB A	0	0	0
SUB B	-5	0	-5
SUB C	-17.5	0	-17.5
SUB D	-17.5	30	12.5

Example 2

- Please open File 3.

Offshore Expansion Factor Calculation

- Onshore expansion factors are based upon generic costs by TO and technology type:
  - High level of historic data; and
  - Limited cost variation between projects.
- Offshore expansion factors are project specific:
  - Based upon proportion of OFTO Revenue associated with assets;
  - OFTO Revenue pro-rated by cost; and
  - £/MWkm cost determined from circuit length and rating.
- For radial solutions observed to date, tariffs have been calculated outside of the Transport model.
  - Incremental MW limited to flow in one direction.

The Tariff Model

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Tariff Model

- Please open File 8.

What is the Tariff Model?

- Nodal Transport Model output converted into tariffs
  - length per MW converted to £ per MW (raw tariffs)
  - groups nodes into zones
    - generation zones set once each price control
    - demand zones fixed to DNO network areas

- Makes key adjustments to raw tariffs to
  - ensure revenue recovery
  - achieve desired proportion of revenue is recovered from generation
  - no negative demand tariffs
  - small gens adjustment

Tariff Model

General Input Data (shown in blue)

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Proportion of revenue to be collected from demand customers

Key Inputs Table	
Re-referencing Quantity (km)	-205.03
Demand Recovery Percentage	73.000000%
Required Demand Recovery Percentage	73.000000%
Expansion Constant (£/MWkm)	11.142856
Global Locational Security Factor	1.80
Total Infrastructure Revenue (£m)	1724.28
Proportion from Generation (£m)	465.56
Proportion from Demand (£m)	1258.72
Substation and Offshore Local Asset Charge Revenue (£m)	95.74
Residual Charge for Generation(£/kW)	3.608
Residual Charge for Demand (£/kW)	19.708

Converts km to £
(the annual cost of 1km of 400kV OHL)

Security Factor

Target Revenue from all TNUoS tariffs
(MAR less pre-Vesting connection charges)

Revenue from other locational charges
(and therefore not recovered through residual)

Tariff Model

Nodal Data from Transport Model

64	Derivation of Zonal Generation Tariffs - Wider Tariff			
65–68	Zone	Zone Name	Generation Charge Base: TEC Net Stn 83.15831	Unadjusted Transport Zonal Wtd Marginal (km)
69	1	North Scotland	0.607	1096.74
70	2	Peterhead	1.180	1010.87
71	3	Western Highland & Skye	0.327	1168.53
72	4	Central Highlands	0.404	931.59
73	5	Argyll	0.556	725.51
74	6	Stirlingshire	2.648	734.77
75	7	South Scotland	4.100	651.51
76	8	Auchencrosh	0.176	637.52
77	9	Humber & Lancashire	18.561	303.43
78	10	North East England	3.181	466.94
79	11	Anglesey	0.960	345.56
80	12	Dinorwig	1.644	310.34
81	13	South Yorks & North Wales	13.708	220.06
82	14	Midlands	7.903	111.02
83	15	South Wales & Gloucester	6.644	59.65
84	16	Central London	0.135	-316.17
85	17	South East	12.922	58.49
86	18	Oxon & South Coast	3.381	-68.68
87	19	Wessex	3.087	-157.73
88	20	Peninsula	1.035	-325.98
89			83.158	

This is produced automatically by the model when the tariff model is run.

Each green number is the weighted average of the nodal information from the Transport Model.

Weighted according to TEC or demand

Tariff Model

Output Data

Automatically Calculated

Unadjusted Transport Zonal Wtd Marginal (km)	Unadjusted Transport Zonal Tariff (£/kW)	Unadjusted Transport Zonal 394.23	Re-referenced Transport Zonal Wtd Marginal (km)	Re-referenced Transport Tariff (£/kW)	Re-referenced Transport Zonal 52.25	Residual Zonal 300.03	Final Zonal Tariff (£/kW)	Final Zonal Revenue 352.28
1096.74	22.00	13.36	891.70	17.88	10.86	2.19	**21.493**	13.05
1010.87	20.28	23.92	805.83	16.16	19.07	4.26	**19.771**	23.33
1168.53	23.44	7.67	963.49	19.32	6.33	1.18	**22.933**	7.51
931.59	18.68	7.54	726.55	14.57	5.88	1.46	**18.181**	7.34
725.51	14.55	8.09	520.47	10.44	5.80	2.00	**14.047**	7.81
734.77	14.74	39.02	529.74	10.63	28.14	9.55	**14.233**	37.69
651.51	13.07	53.57	446.47	8.95	36.71	14.79	**12.563**	51.51
637.52	12.79	2.25	432.48	8.67	1.53	0.63	**12.282**	2.16
303.43	6.09	112.96	98.40	1.97	36.63	66.97	**5.581**	103.60
466.94	9.37	29.79	261.90	5.25	16.71	11.48	**8.861**	28.19
345.56	6.93	6.65	140.53	2.82	2.71	3.46	**6.426**	6.17
310.34	6.22	10.23	105.31	2.11	3.47	5.93	**5.720**	9.40
220.06	4.41	60.50	15.02	0.30	4.13	49.46	**3.909**	53.59
111.02	2.23	17.60	-94.02	-1.89	-14.90	28.51	**1.722**	13.61
59.65	1.20	7.95	-145.39	-2.92	-19.37	23.97	**0.692**	4.60
-316.17	-6.34	-0.86	-521.20	-10.45	-1.41	0.49	**-6.846**	-0.92
58.49	1.17	15.16	-146.55	-2.94	-37.98	46.62	**0.669**	8.64
-68.68	-1.38	-4.66	-273.71	-5.49	-18.56	12.20	**-1.882**	-6.36
-157.73	-3.16	-9.77	-362.76	-7.28	-22.46	11.14	**-3.668**	-11.32
-325.98	-6.54	-6.77	-531.01	-10.65	-11.02	3.73	**-7.043**	-7.29
		394.23			**52.25**	**300.03**		**352.28**

Revenue from wider tariff

Final Tariffs (Wider + Residual)

Tariff Model

- So what happens to the Nodal MWkm Costs from the Transport Model?
  - A weighted average MWkm cost for each generation/demand zone is calculated.
  - This is converted into a locational tariff by applying:
    - The Global Locational Security Factor; and
    - The expansion constant.
  - Each nodal Local MWkm cost is converted into a local circuit tariff by applying:
    - The nodal Local Security Factor; and
    - The expansion constant.

Zonal Tariff Calculations

- "Raw" Locational Tariffs:

  Gen Tariff = Zonal MWkm * Security Factor * Expansion Constant

  Dem Tariff = -Zonal MWkm * Security Factor * Expansion Constant

- Re-referenced tariffs (scalar adjustment to set G:D split):

  RR Gen Tariff = (Zonal MWkm + ReRefQnty) * Sec. Factor * Exp. Const.

  RR Dem Tariff = (-Zonal MWkm – ReRefQnty) * Sec. Factor * Exp. Const.

- Final Zonal tariffs (addition of residual amounts):

  Gen Tariff = RR Gen Tariff + Gen Residual

  Dem Tariff = RR Dem Tariff + Dem Residual

Exercise 2

- Using the File 8:
  - Increase the TO Infrastructure Revenue by £200m
  - Run the model – what do you notice?
  - Increase the generation charging base by 10% & run the model.
  - How do the tariffs change this time?
  - Alter the balance between HH and NHH demand in a zone.
  - How does this affect demand tariffs?

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Exercise 2 - Review

- Revenue changes affect the generation and demand residuals.
- Changing the generation or total demand alters each residual:
  - Charge is spread over larger/smaller MW base.
- Altering HH:NHH balance in a demand in a zone affects NHH tariffs.

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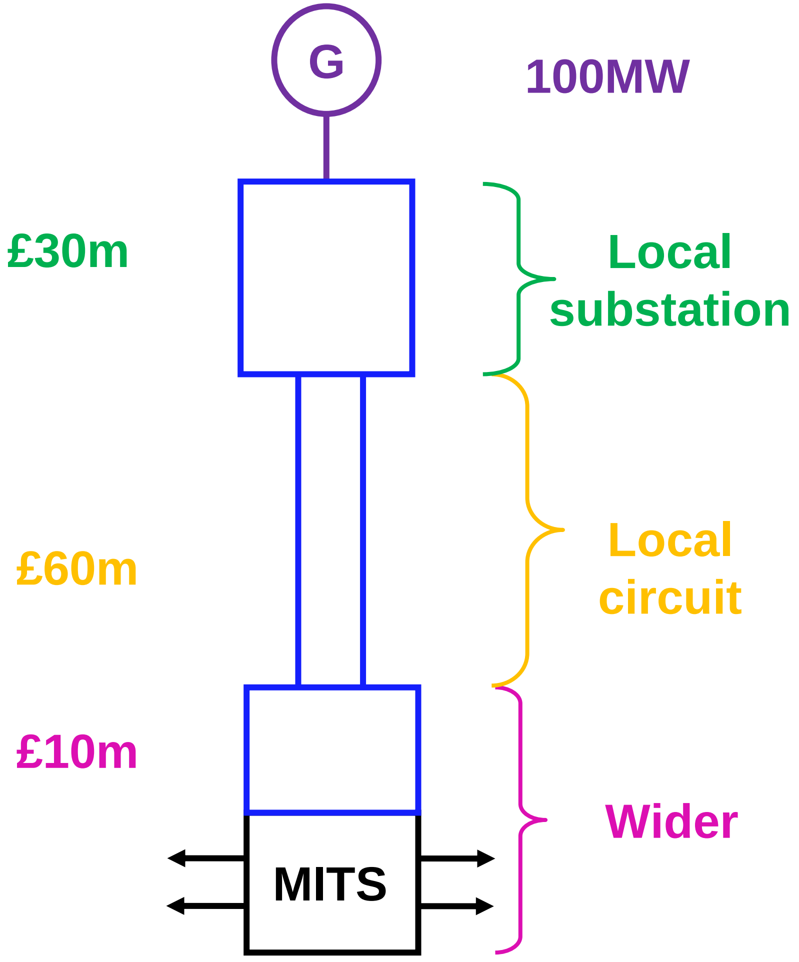
Offshore Tariff Example

Wayne Mullins

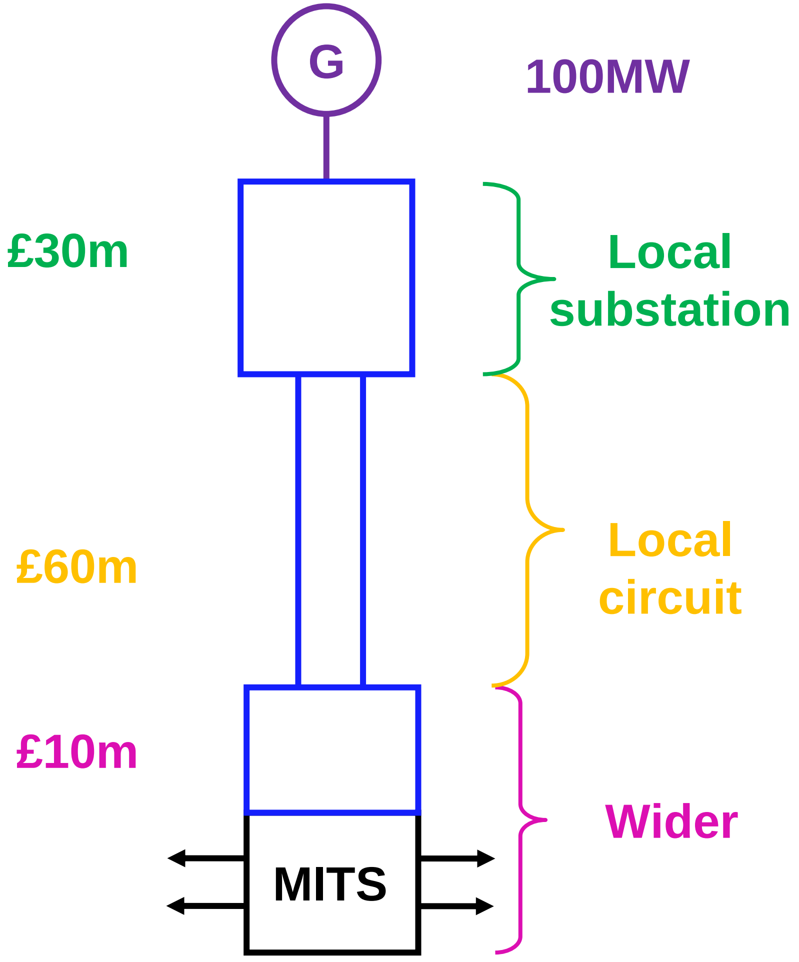
Offshore Tariff Calculation Example

- Total asset value = £100m
- Annual Revenue = £10m
- Local Substation:
  - Transformer: £18m, 120MW
  - Switchgear: £2m, 400MW
  - Platform: £10m, 120MW
  - Civils Discount = 35p/kW
  - Tariff = £1.8m/120MW + £0.2m/400MW + £1m/120MW – £0.35/kW = £23.48/kW
  - 100MW generator pays 78.3% of substation assets



Offshore Tariff Calculation Example

- Total asset value = £100m
- Annual Revenue = £10m
- Local Circuit:
  - Length: 100km, Rating: 60MW
  - Assumed Expansion Constant: £10/MWkm
  - Unit cost = £3m/6000MWkm = £500/MWkm
  - Expansion Factor = 50
  - Security factor = 2*60/100 = 1.2
  - Tariff = 1.2 * 50 * 100km * £10/MWkm = £60/kW
  - Generator pays 100% of cable assets



CMP213



Wayne Mullins

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Issues with the current charging regime

- No account for different generation using the network at different times (network sharing):
  - Assumes 1MW of generation requires 1MW of capacity
  - Equal scaling of generation provides flows that are inconsistent with network design
- Methodology changes required to deal with HVDC and Island connections

CMP213

- Raised by NGET in June 2012, following Ofgem's Project TransmiT SCR.
- Workgroup process resulted in 27 different options…
- Ofgem approved WACM 2 on 11th July 2014:
  - 1st April 2016 Implementation
  - Decision subject to Judicial Review

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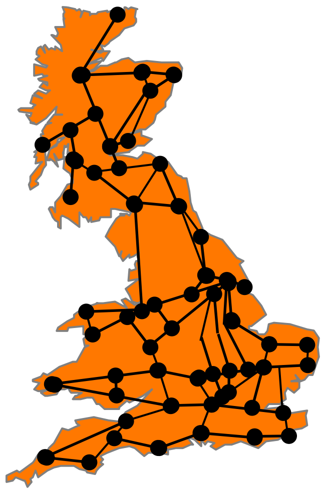
CMP213 – Sharing (1)

Peak Security Requirements



- Investment traditionally peak driven.
- More recently increasing level of investment based upon cost-benefit

Year Round Requirements

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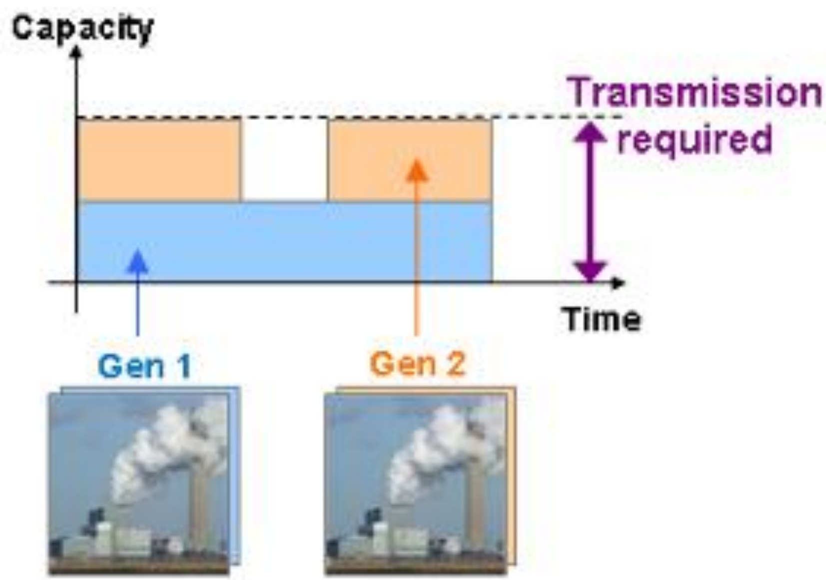
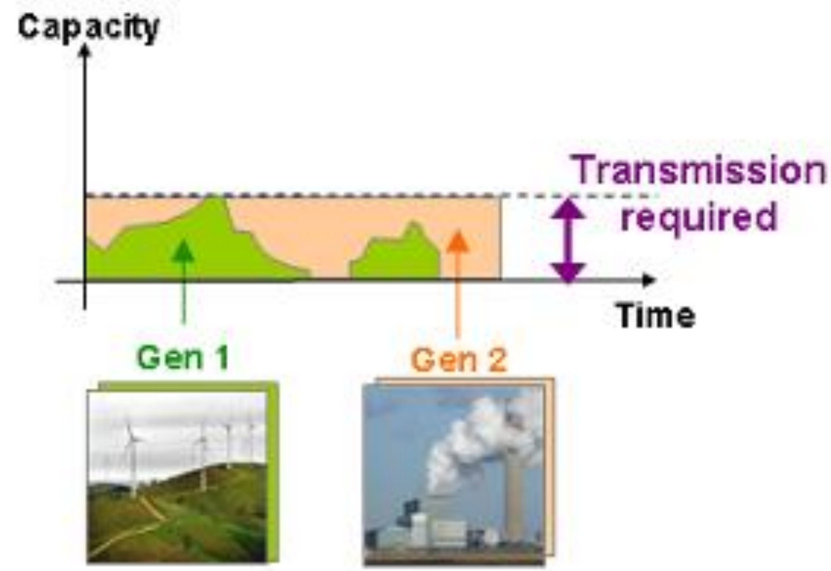
CMP213 – Sharing (2)





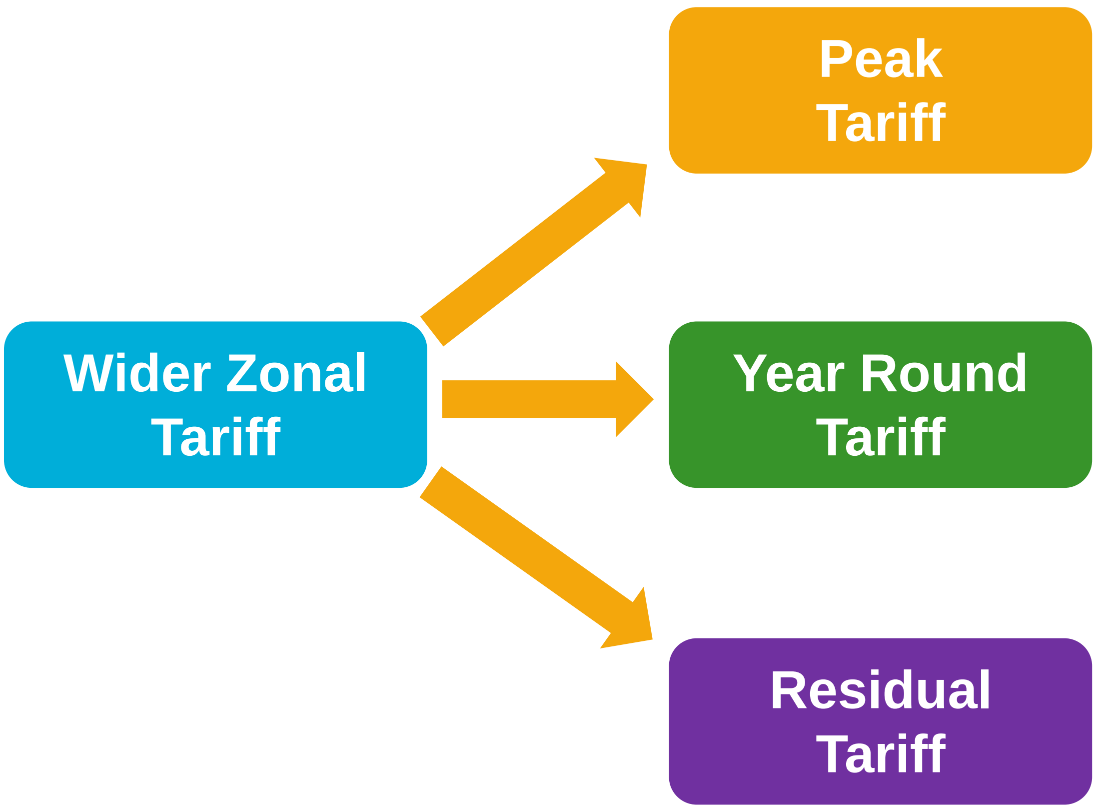
- Current Methodology assumes 1MW generation implies 1MW of transmission – still holds for peak requirement.
- Year round requirement includes some network sharing.

  => Load Factor based Year Round charges

  - Only applies where sufficient plant diversity (sharing) exists

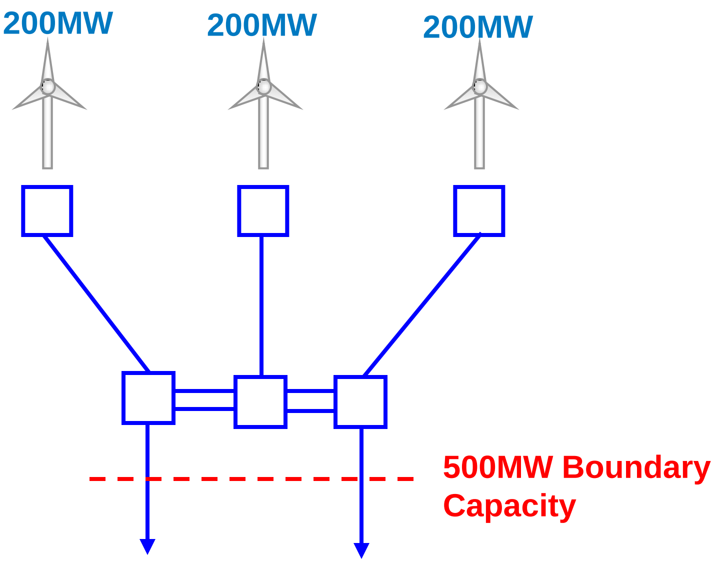
CMP213 – Wider Tariff Structure

Status Quo **CMP213**



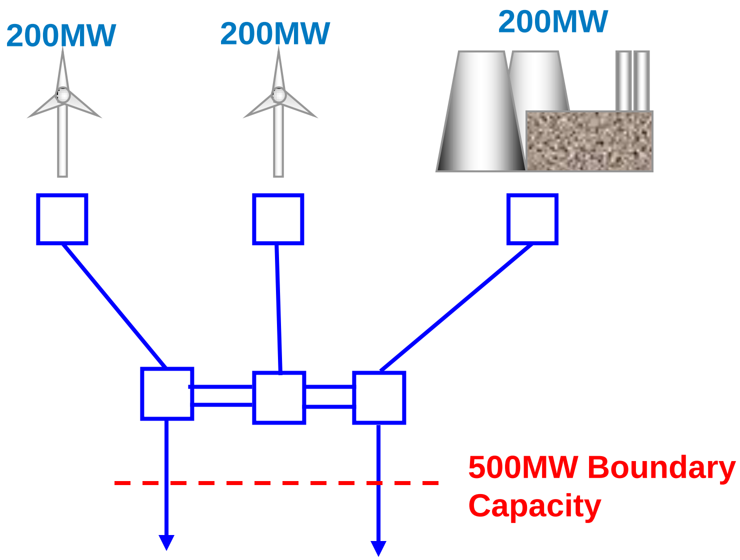
CMP213 - Low/High Plant Diversity Scenarios

- Low Diversity:



- 100MW wind constrained off
- Expensive bid price to make up for lost subsidy
- **CBA results in more investment per MW of generation**

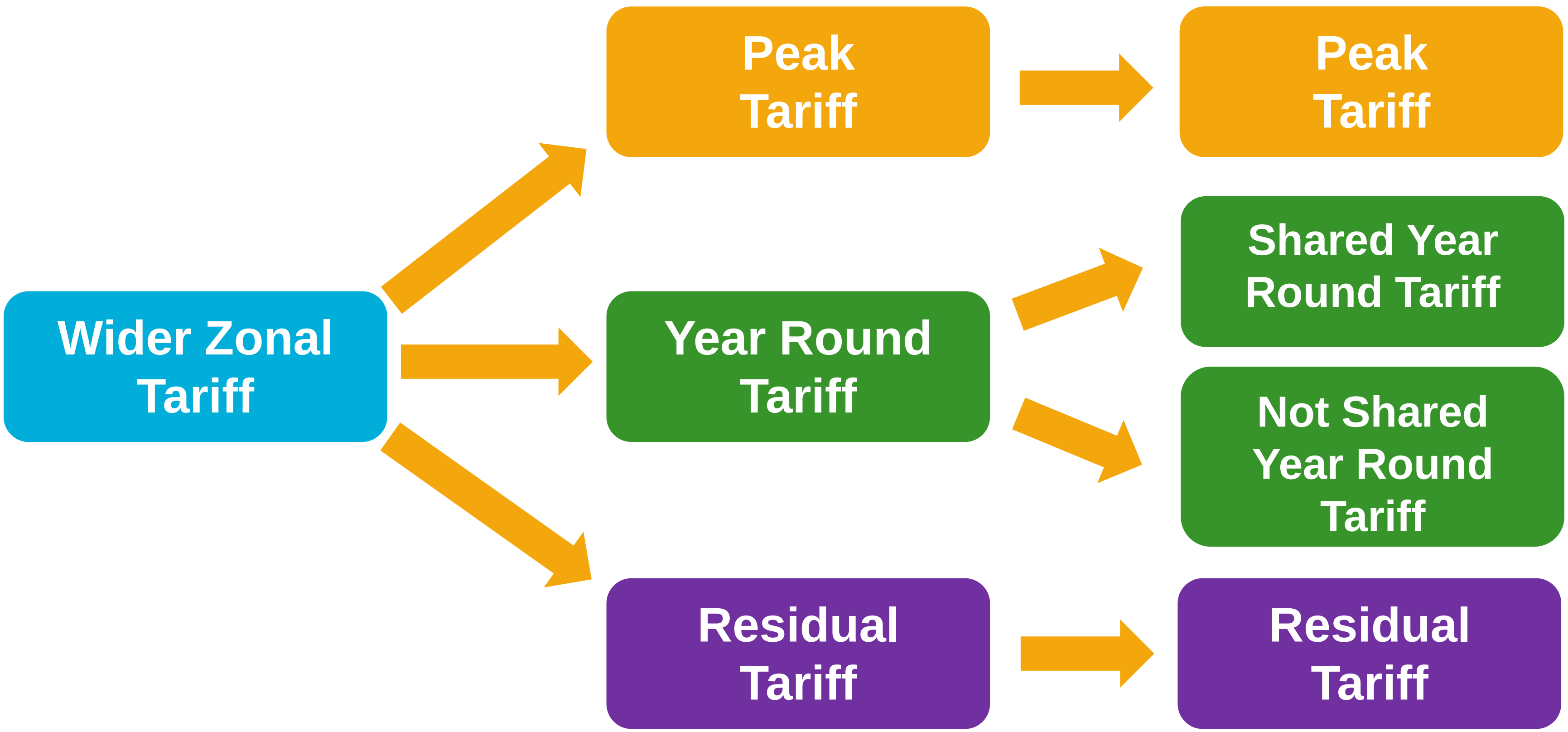
- High Diversity:



- 100MW conventional generation constrained off
- Cheaper bid price due to fuel saving

CMP213 – Wider Tariff Structure

Status Quo | CMP213 | WACM2



CMP213 – HVDC and Islands

- Current mainland onshore Tx assets costs based upon generic levels for each technology.
  - Limited cost variability
- Offshore Tx asset costs are based upon project specific costs
  - Increased cost variability
- HVDC/Island costs expected to be similar to offshore
  - Circuit expansion factors include HVDC converter costs
- Mechanism to determine HVDC flows

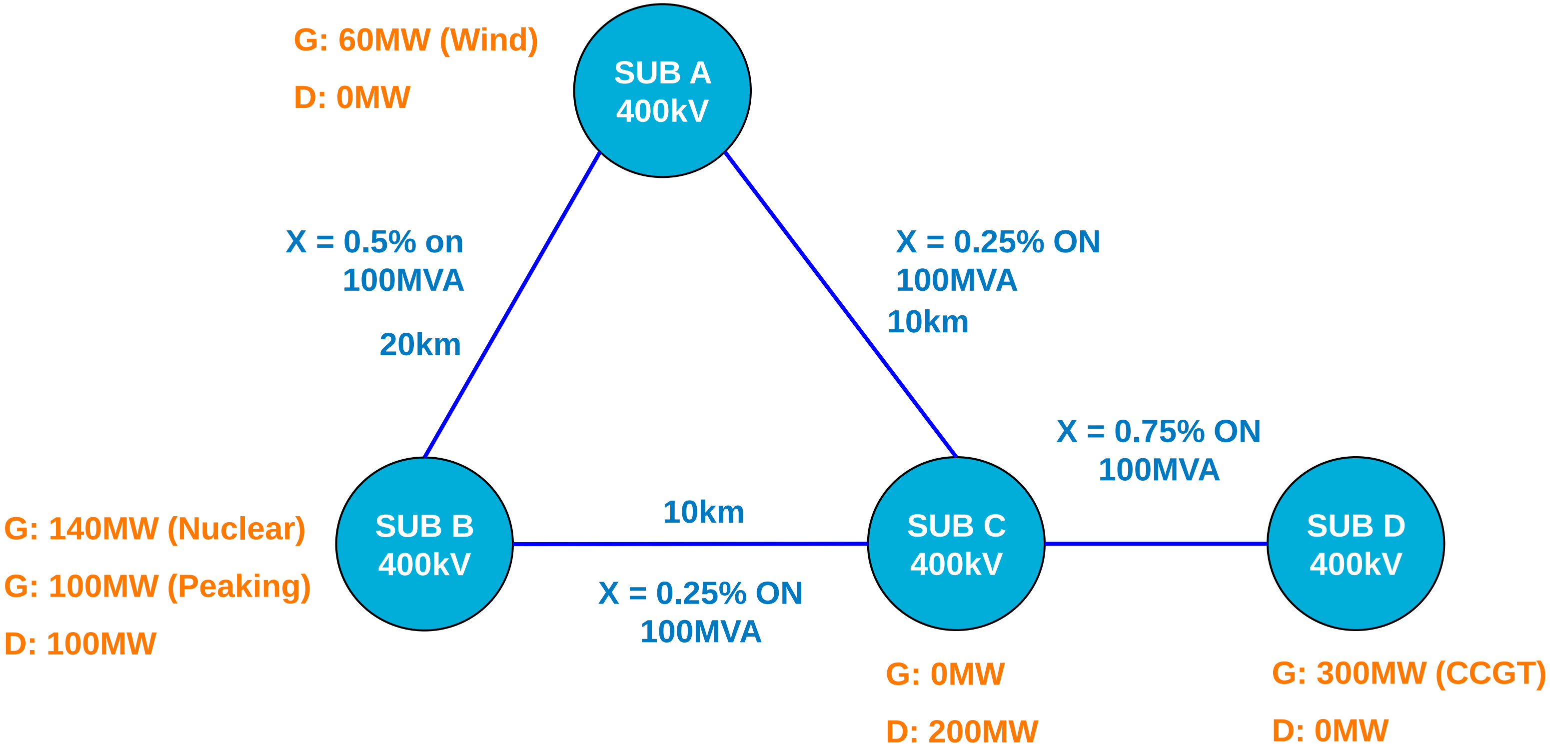
Charges under CMP213 WACM2

- Demand – relatively unchanged.
- Generation:
  - Wider zonal tariff split into 4 components:
    - Peak Security (Zero for intermittent plant)
    - Year Round Shared (Load Factor)
    - Year Round Not Shared
    - Residual
  - Local Circuit Charges based upon Year Round background.
  - Chargeable Capacity as previous

Example 3

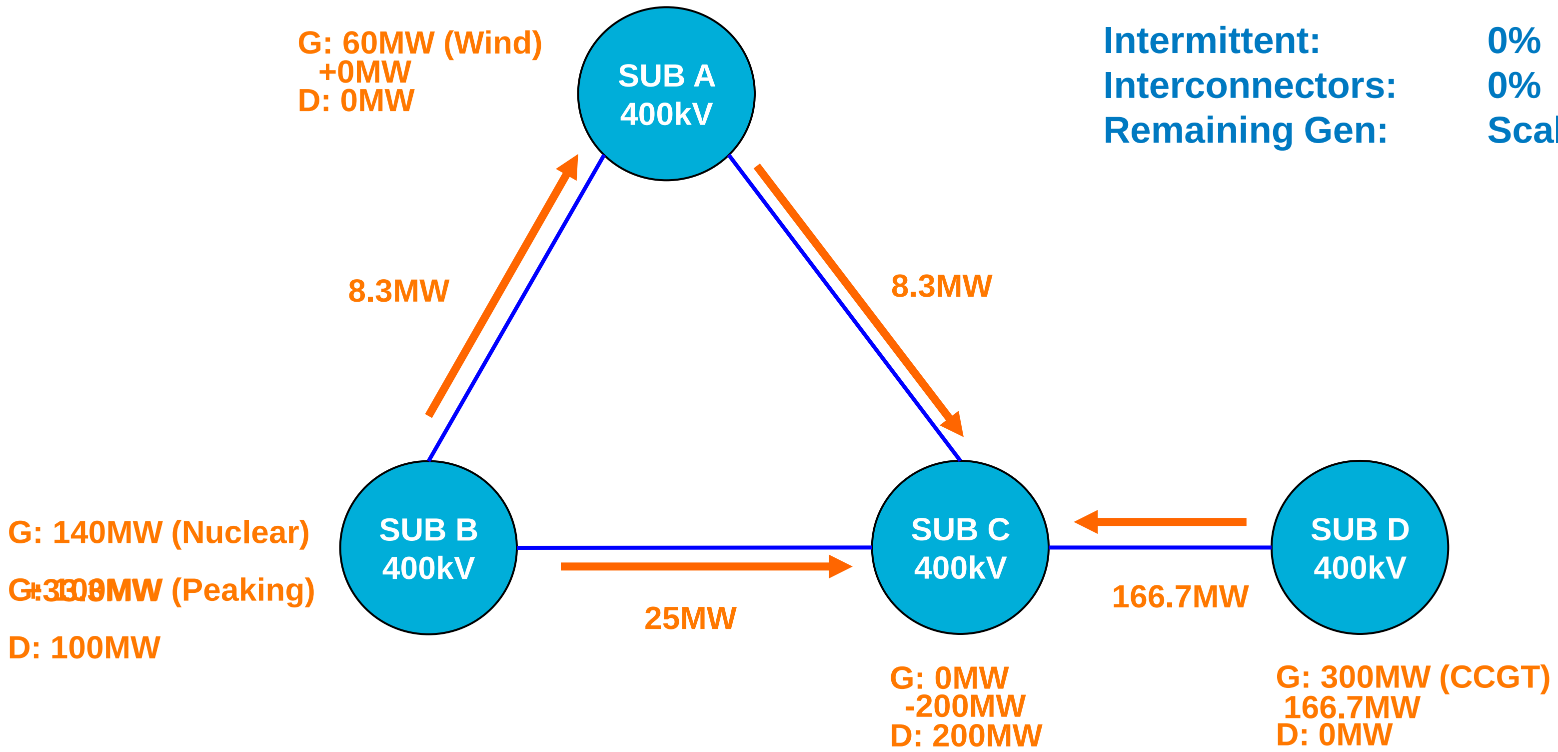
- Please open File 5.

Four Node Model



Peak Security Background

Intermittent: 0%
Interconnectors: 0%
Remaining Gen: Scaled



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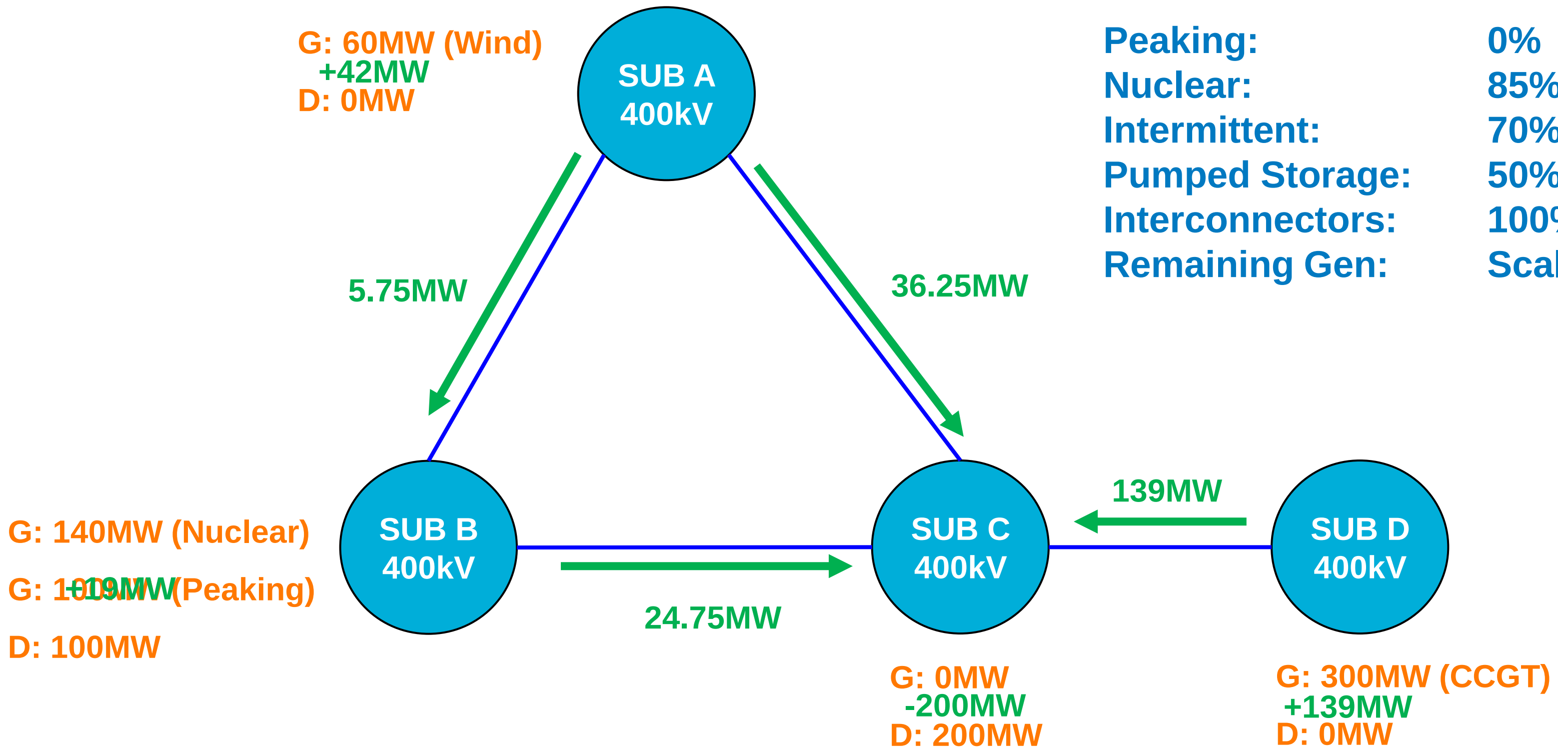
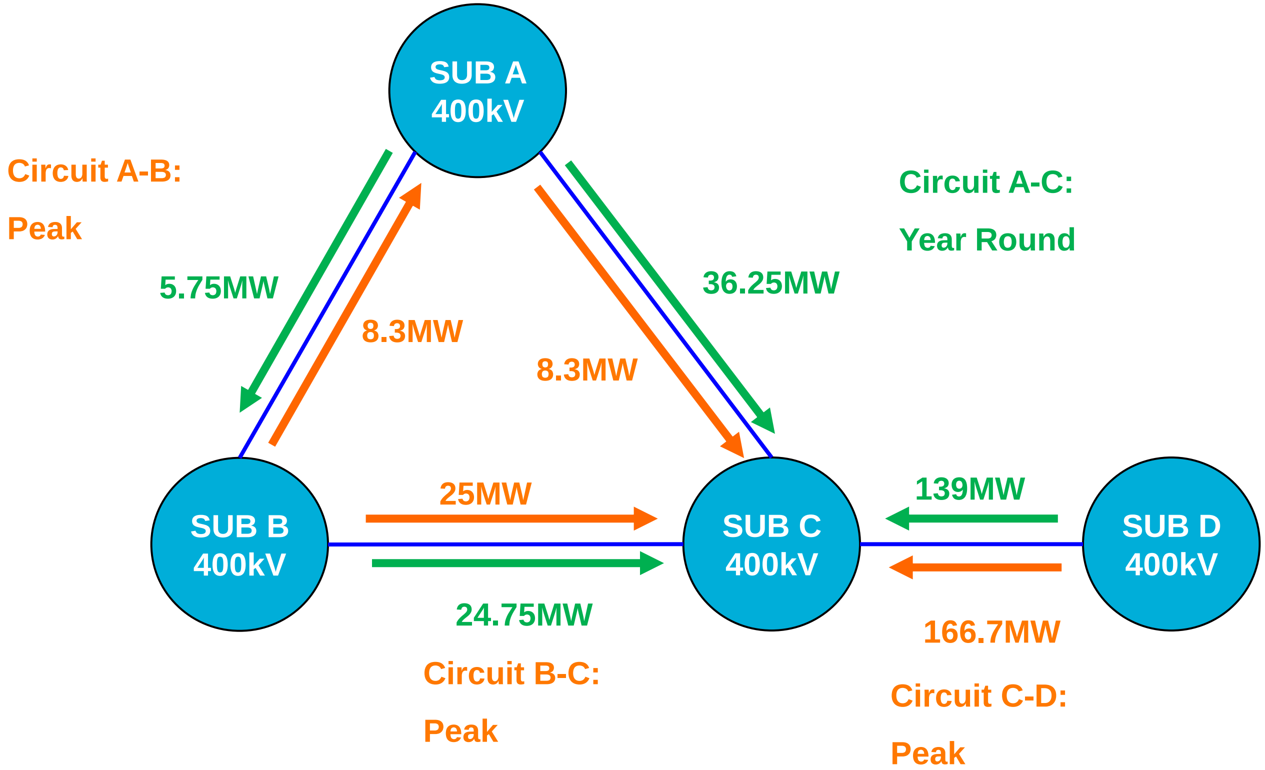
Year Round Background



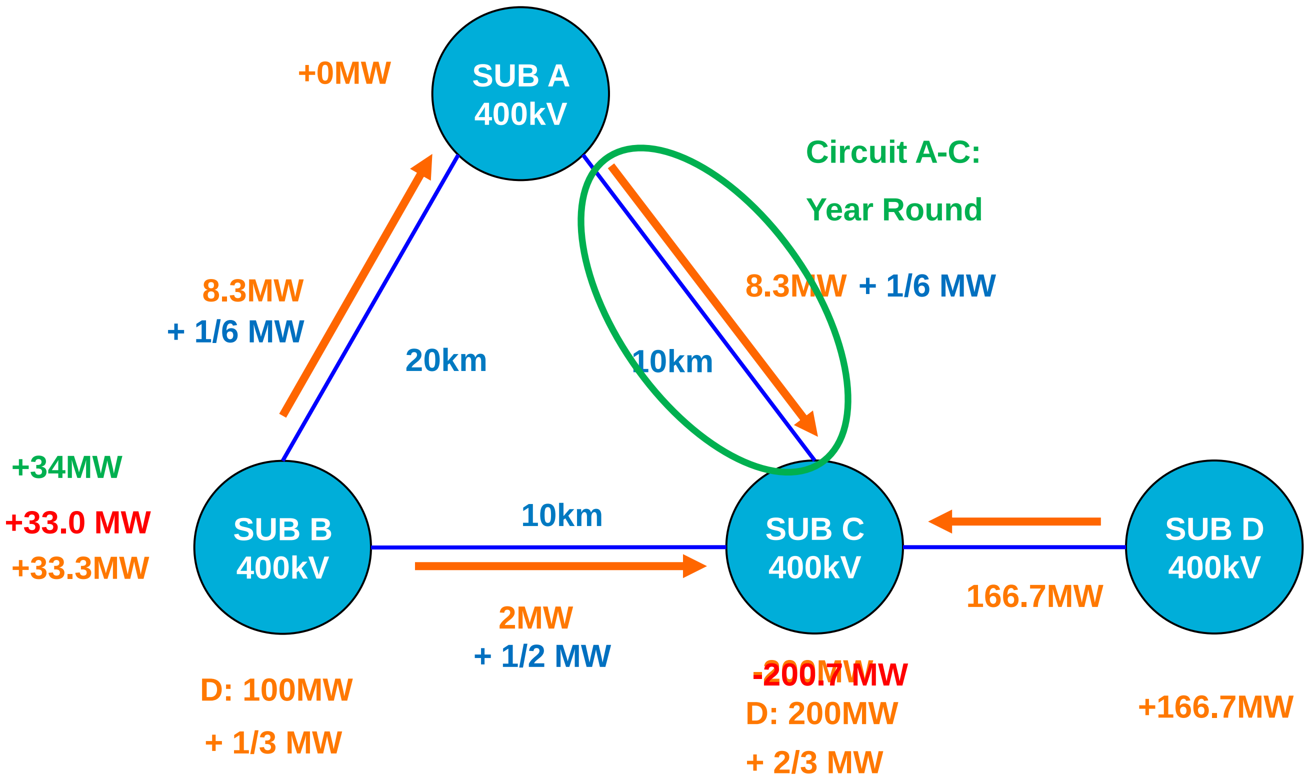
Peaking:	**0%**
Nuclear:	**85%**
Intermittent:	**70%**
Pumped Storage:	**50%**
Interconnectors:	**100%**
Remaining Gen:	**Scaled**

Driver of Investment



Local circuit tariffs are YR based

Peak Security Nodal MWkm



Node B Nodal Peak Security cost = 20 / 6 + 10 / 2

= 8.3 MWkm

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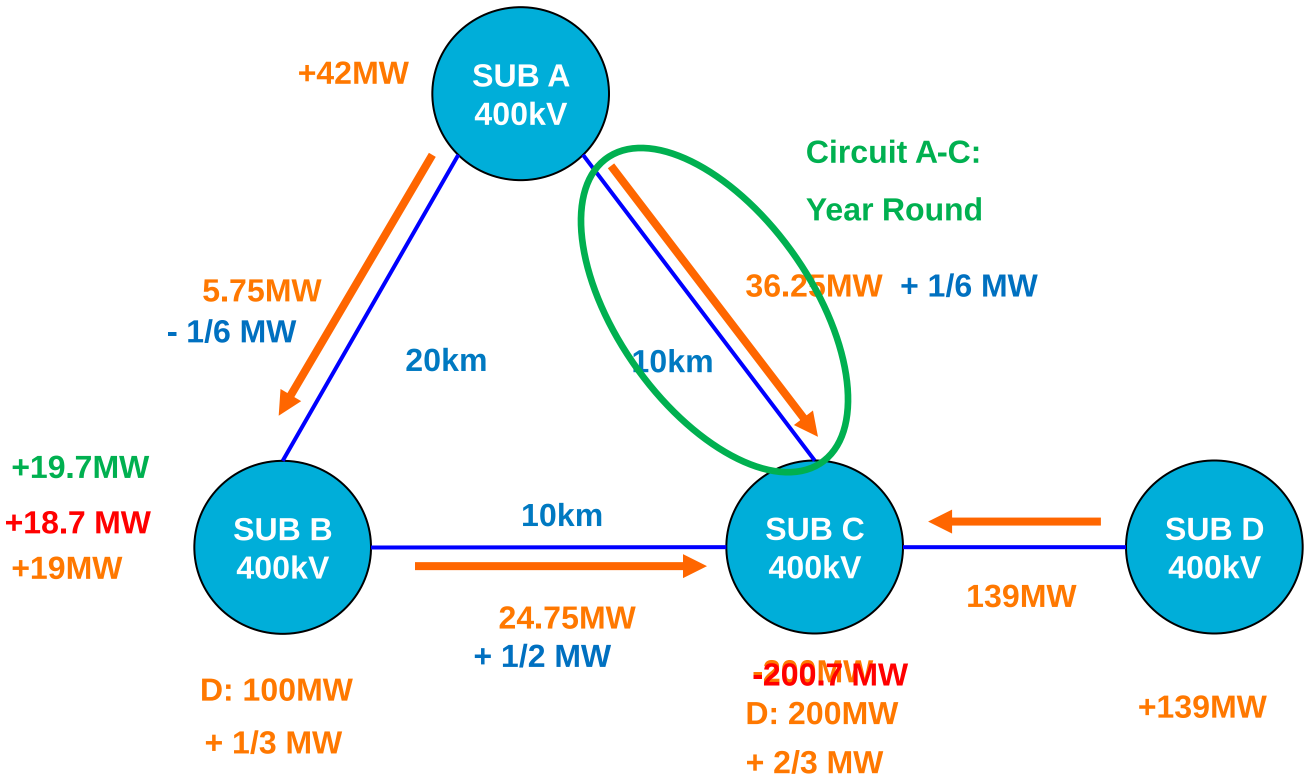
Year Round Nodal MWkm



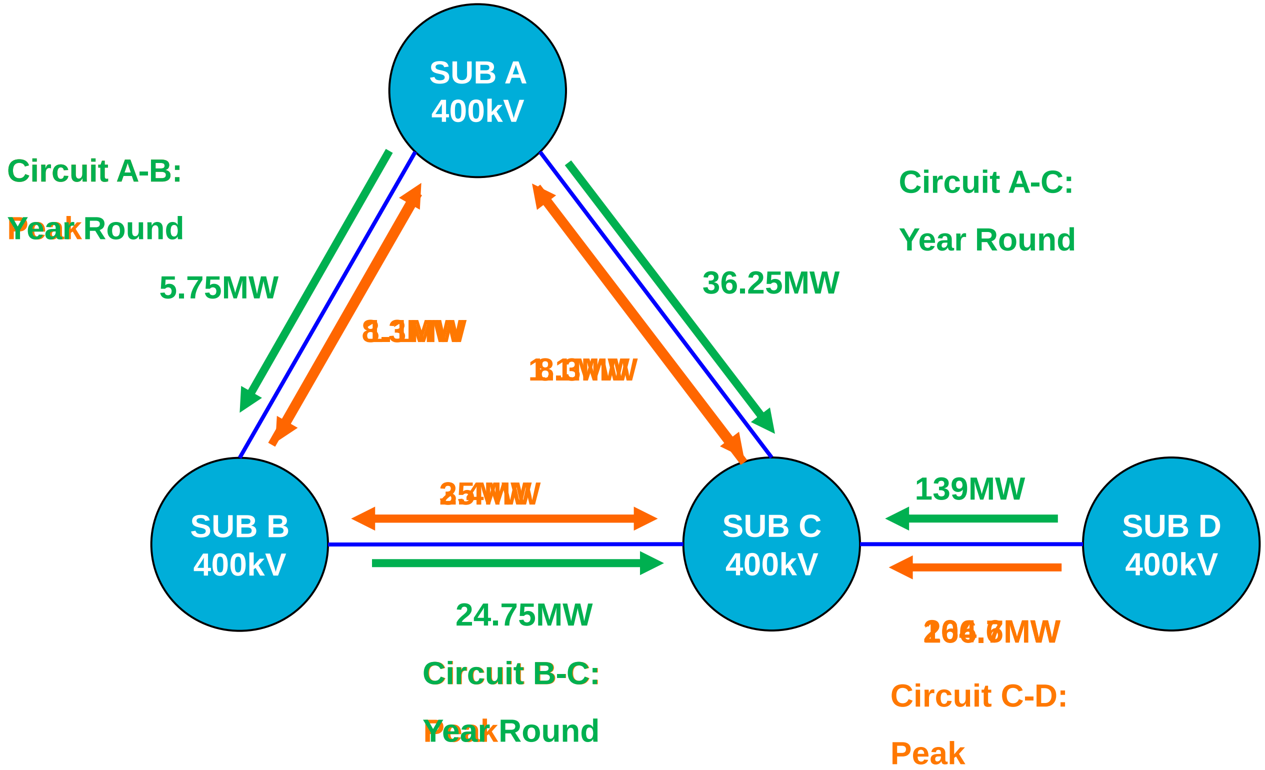
Node B Nodal Year Round cost = 10 / 6

= 1.7 MWkm

Exercise 3

- What happens if the 100MW of peaking generation at Node B closes:
  - Peaking plant only runs in the Peak Security Background
  - There is also 140MW of nuclear at node B
  - Both are scaled to demand in the Peak Security Background
  - Run the model – what do you notice?

Exercise 3 - Driver of Investment



Local circuit tariffs are YR based

Exercise 3 - Review

- Generation background changes can alter the driver of investment on a circuit in the model.
  - This means that generation connecting and retiring can alter the balance between Year Round and Peak Security Tariffs.
  - The relative geographic location of peaking plant and intermittent generation should limit this affect.

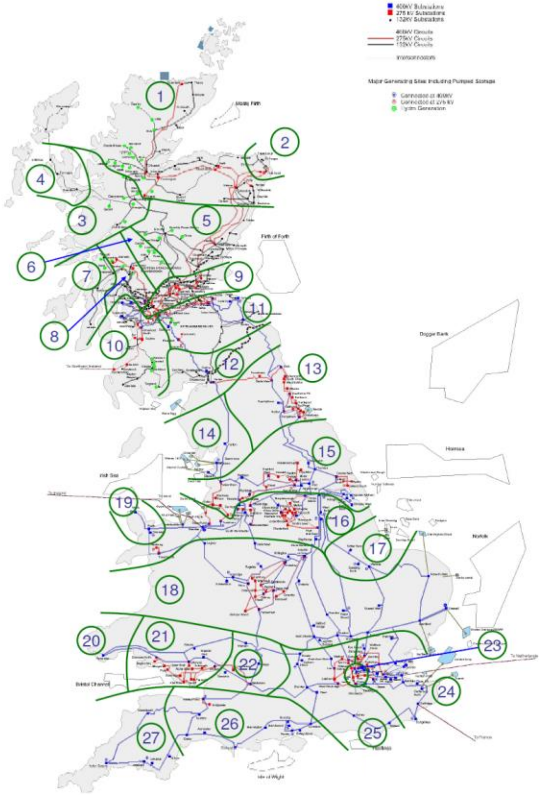
Diversity - Carbon/Low Carbon Generation

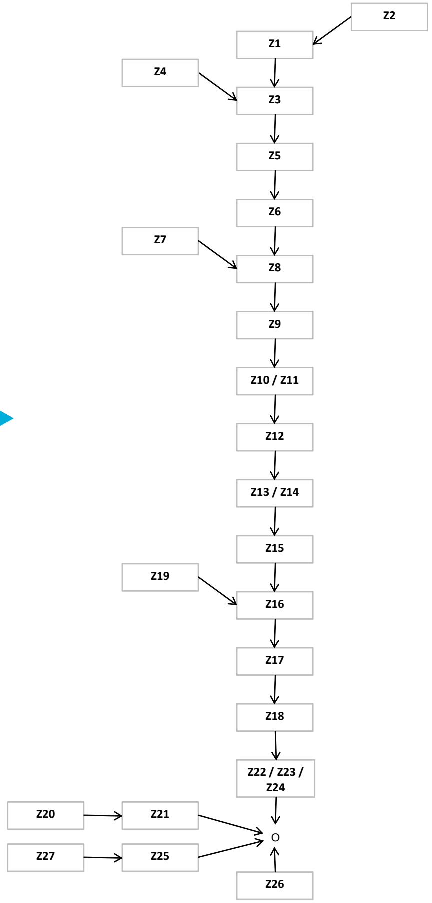
- For the purposes of the Shared & Non-Shared Year Round tariff calculation, each generator is classified as either Carbon or Low Carbon.
- This is used to reflect the higher cost of constraining off Low Carbon plant (due to subsidy loss or technical inflexibility).
- Each fuel type is classified as follows:

Carbon	**Low Carbon**
Coal	Wind
Gas	Hydro (excl. Pumped Storage)
Biomass	Nuclear
Oil	Marine
Pumped Storage	Tidal
Interconnectors	

Network Connectivity

- As part of the diversity 1 methodology, the network is converted into simplified network connectivity diagram, depicting the flow of energy through the network to the main demand centre
- For example:





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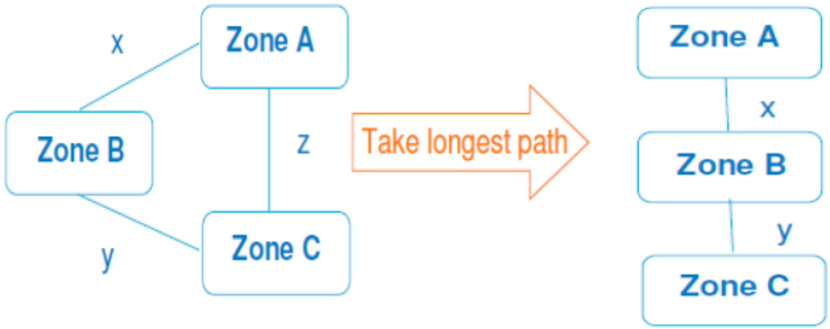
Network Connectivity (2)

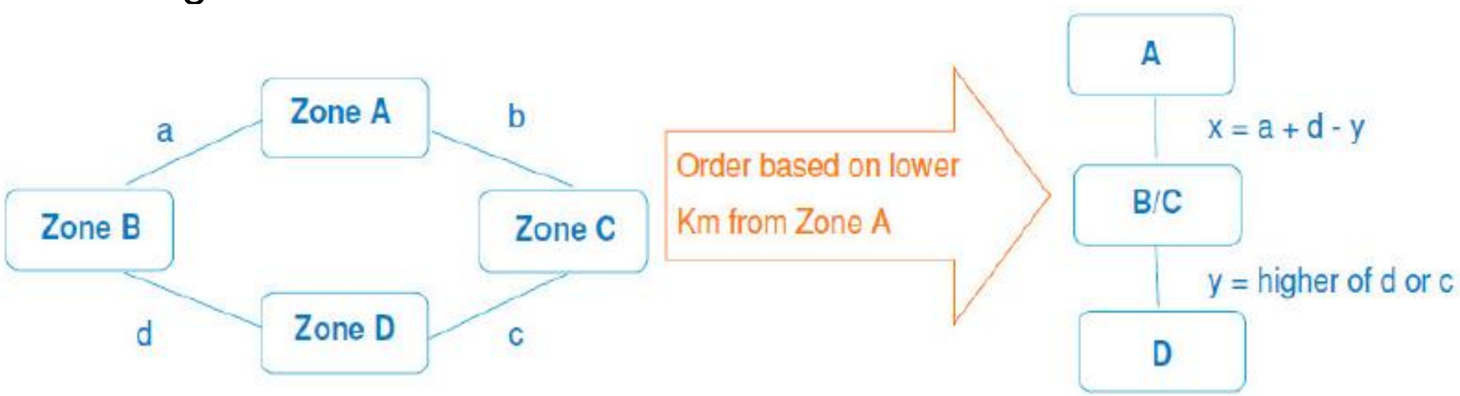
- MWkm length of boundary between two zones is defined as difference between zonal MWkm

$$BIkm_{ab} = ZIkm_b - ZIkm_a$$

- Each zone should have a single entry/exit point based upon electrical connectivity
- Longest route used for parallel circuits

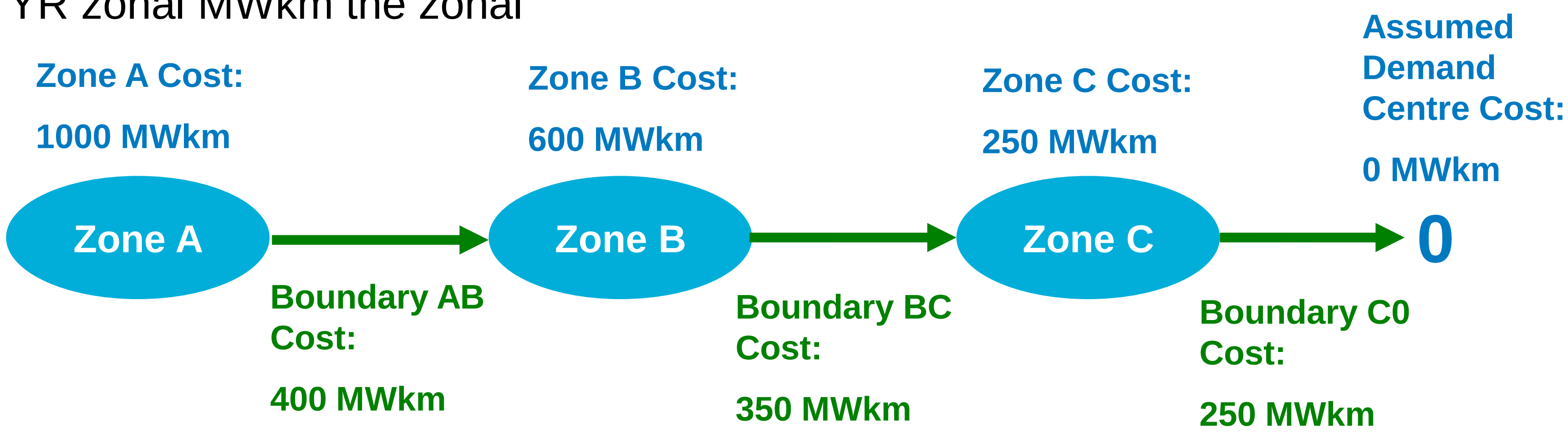


- Parallel zones are amalgamated with incremental MWkm immediately beyond the amalgamated zone being set to the largest of those existing prior to the amalgamation:



Splitting Zonal MWkm by Boundary

- MWkm length of boundary between two zones defined as difference between YR zonal MWkm the zonal

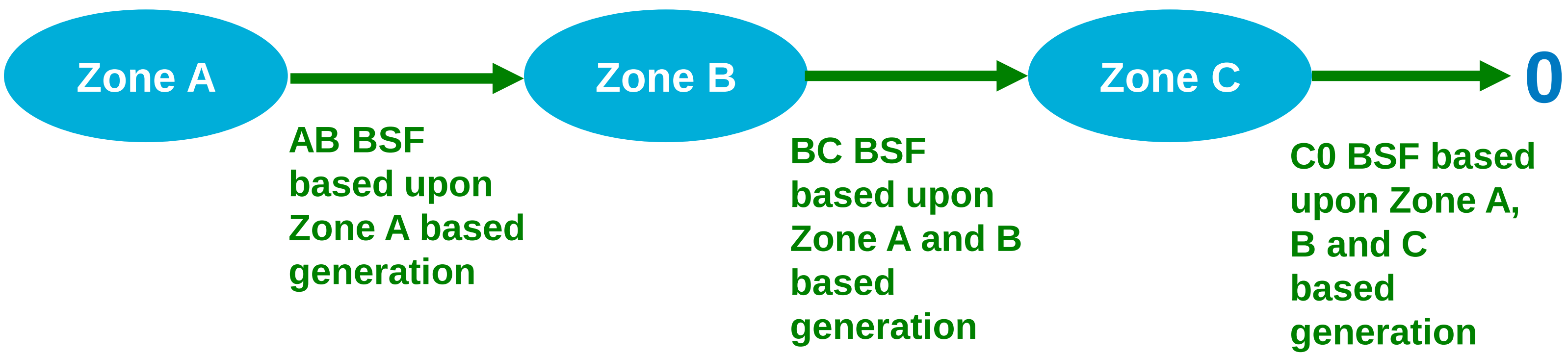


- Conversely the YR MWkm for a zone can be determined as the sum of all of the boundary constraints between the zone and the demand centre:

Zone A MWkm = AB MWkm + BC MWkm + C0 MWkm

Boundary Sharing Factors (1)

- A sharing factor is defined for each boundary, based upon the level of Carbon and Low Carbon generation in each preceding zone



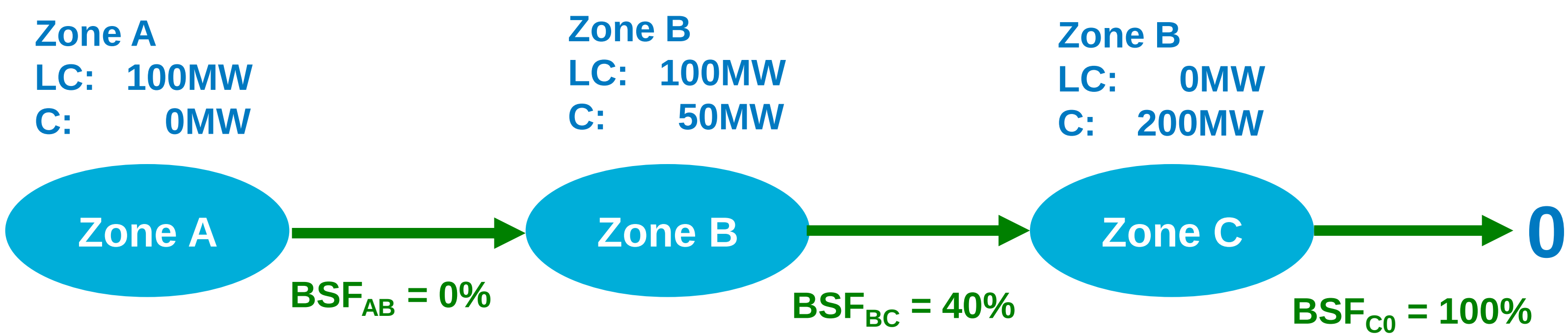
- Under diversity option 1, if the capacity of Carbon generation affecting a boundary is greater than or equal to the capacity of Low Carbon generation affecting the boundary then the Boundary Sharing Factor is set to 100%

$$\text{If } (LC_{XY}/(LC_{XY}+C_{XY})) \leq 0.5 \text{ then } BSF_{XY} = 100\%$$

Boundary Sharing Factors (2)

- If there is less Carbon based generation than Low Carbon Generation affecting a boundary then the Boundary Sharing factor is determined as follows:

$$BSF_{XY} = 2 - 2\left(\frac{LC_{XY}}{LC_{XY} + C_{XY}}\right)$$



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Zonal Shared/Not Shared MWkm

- Boundary shared MWkm is equal to the product of the boundary cost and the boundary sharing factor.
- Zonal shared MWkm is equal to the sum of the shared MWkm across affected boundaries.
- Zonal non-shared MWkm is equal to the difference between the total YR zonal MWkm cost and the shared MWkm cost

Zonal Shared/Not Shared MWkm

Zone A → Zone B → Zone C → 0

BSF_{AB} = 0%

Boundary AB Cost:

400 MWkm

BSF_{BC} = 40%

Boundary BC Cost:

350 MWkm

BSF_{C0} = 100%

Boundary C0 Cost:

250 MWkm

Zone A Total Cost:

1000 MWkm

Shared Cost:

390 MWkm
(100%* 250
+ 40% * 350
+ 0% * 400)

Not Shared Cost:

610 MWkm
(1000 - 390)

Zone B Total Cost:

600 MWkm

Shared Cost:

390 MWkm
(100%* 250
+ 40% * 350)

Not Shared Cost:

210 MWkm
(600 - 390)

Zone C Total Cost:

250 MWkm

Shared Cost:

250 MWkm
(100%*250)

Not Shared Cost:

0 MWkm
(250 - 250)

Assumed Demand Centre Cost:

0 MWkm

Year Round Tariffs

- Zonal Year Round Shared tariffs are calculated by multiplying the zonal shared MWkm costs by the Locational Security Factor and the Expansion Constant.
- Zonal Year Round Not Shared tariffs are calculated by multiplying the zonal not shared MWkm costs by the Locational Security Factor and the Expansion Constant.
- Balance of Low Carbon to Carbon generation will affect the balance between Year Round Shared and Not Shared Tariffs.

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Sensitivity Analysis

Wayne Mullins

TNUoS – Drivers of tariff changes

- Transport model data changes
  - Generation (flow)
  - Demand (flow)
  - Circuit Data (flow/locational cost)

- Tariff model data changes
  - Allowed Revenue (residual)
  - G:D Split (residual)
  - Generation base (gen residual)
  - Demand base (dem residual)
  - NHH:HH split at peak (NHH tariffs)

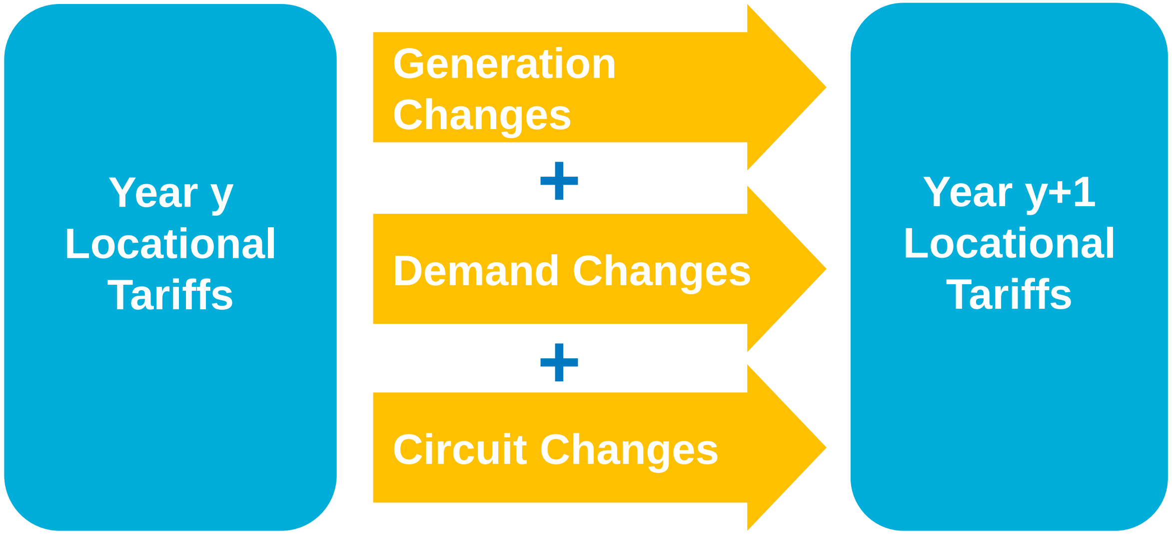
Tariff Sensitivities

- National Grid produces a number of TNUoS forecasts:
  - Quarterly for the following charging year
  - Annual 5 year forecast

- These forecasts are based upon a particular view
  - Customers may wish to model their own view or a range of views:
    - Timings of generation changing
    - Different demand growth scenarios
    - Revenue changes
  - The impact of simple framework changes can also be modelled.

Year on year locational tariff changes

- Annual changes in tariffs are driven by a combination of events.
  - The effect of each event can be looked at in isolation to highlight the driving factors behind zonal tariff changes.
  - Sometimes it is the combination of events which lead to individual changes.
    - This can be via a cumulative or netted effect.



Example 4

- File 6 shows a fictitious transport model with the following changes from scenario in File 4:
  - +2GW at Peterhead (PEHE20)
  - +2GW at Tees Renewable Energy Plant (GRST20)
  - 10% reduction in transport model demand
  - Removal of HVDC link

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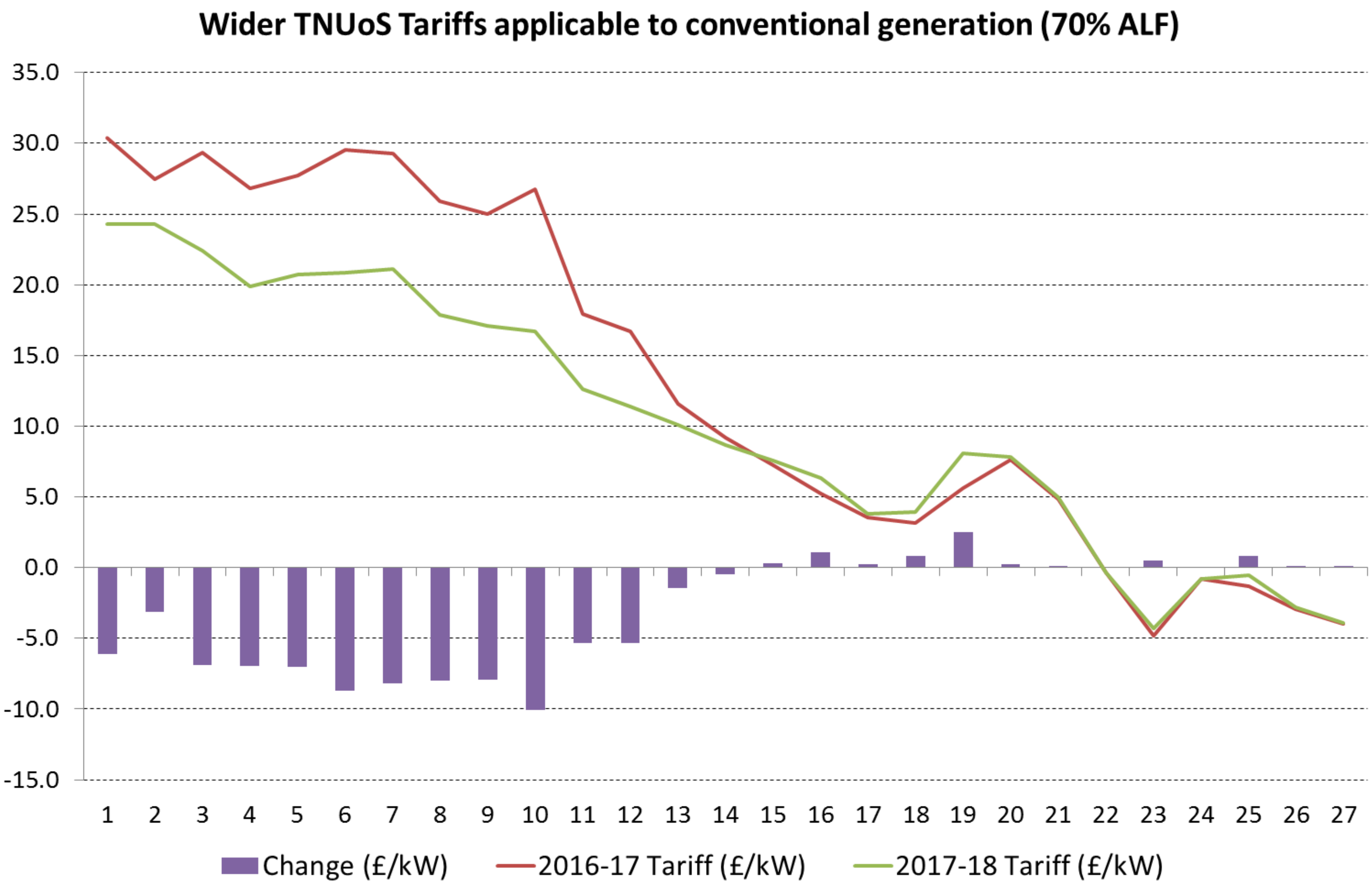
Example 4 – Tariff Changes (1)



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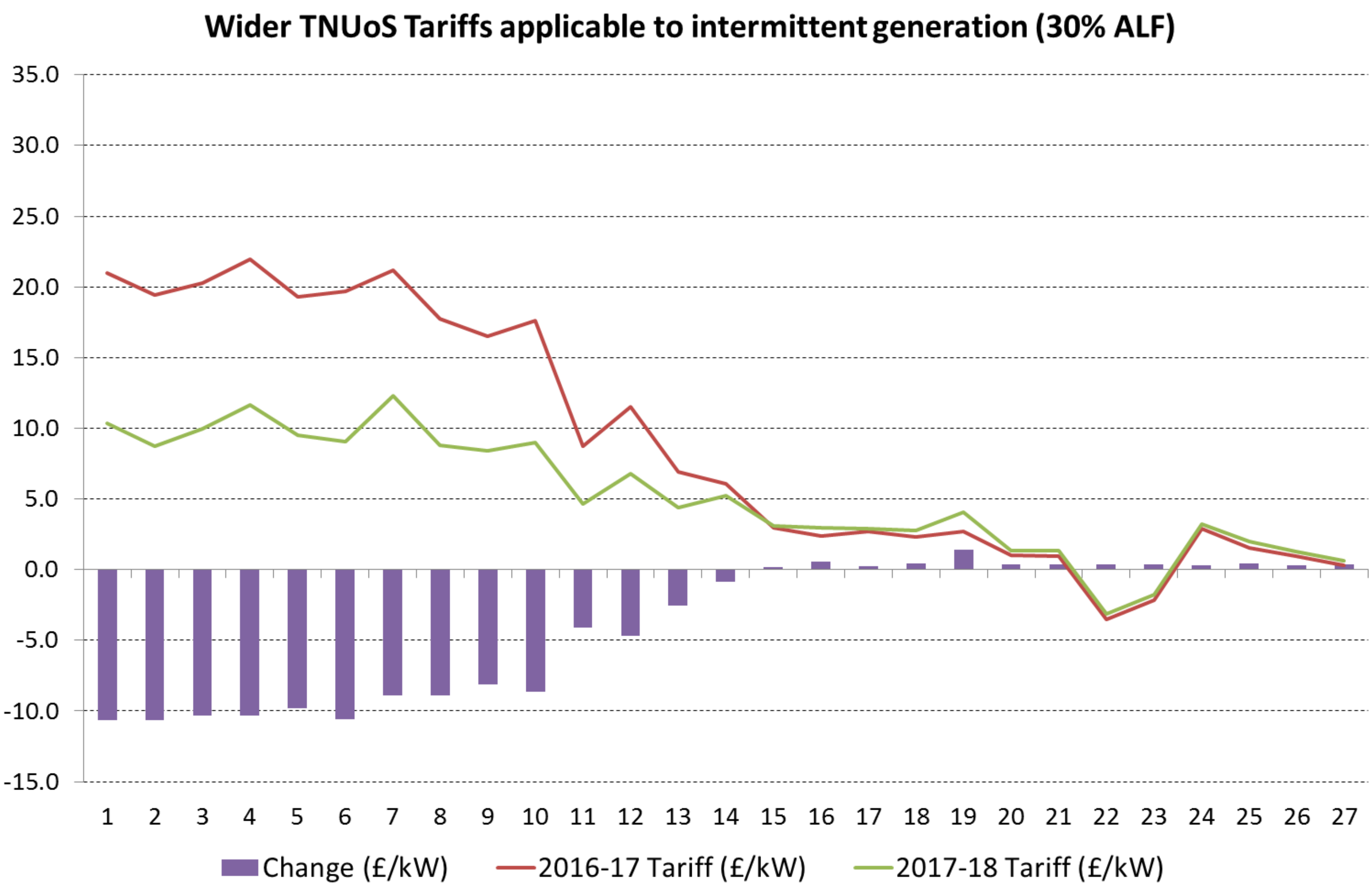
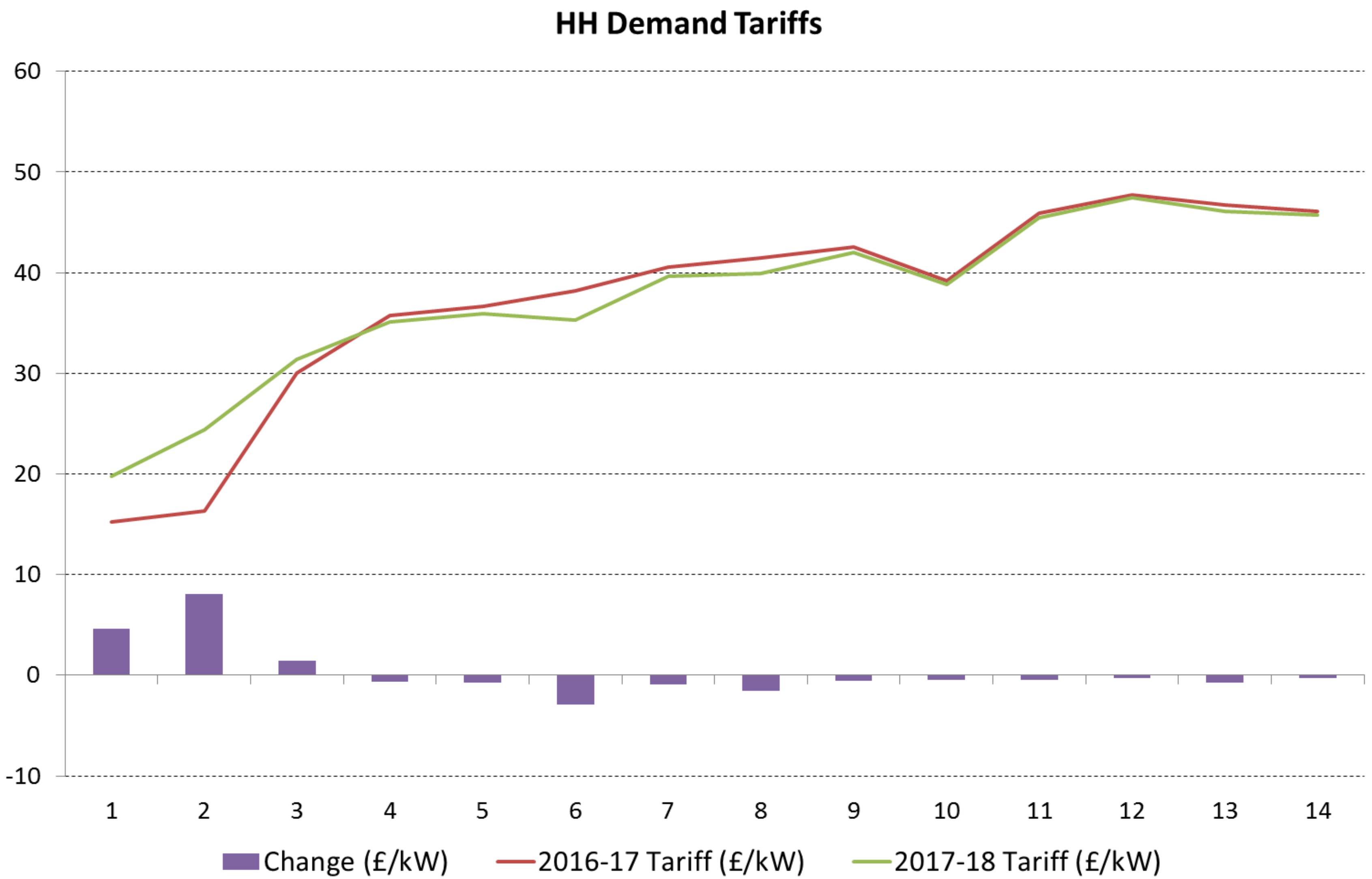
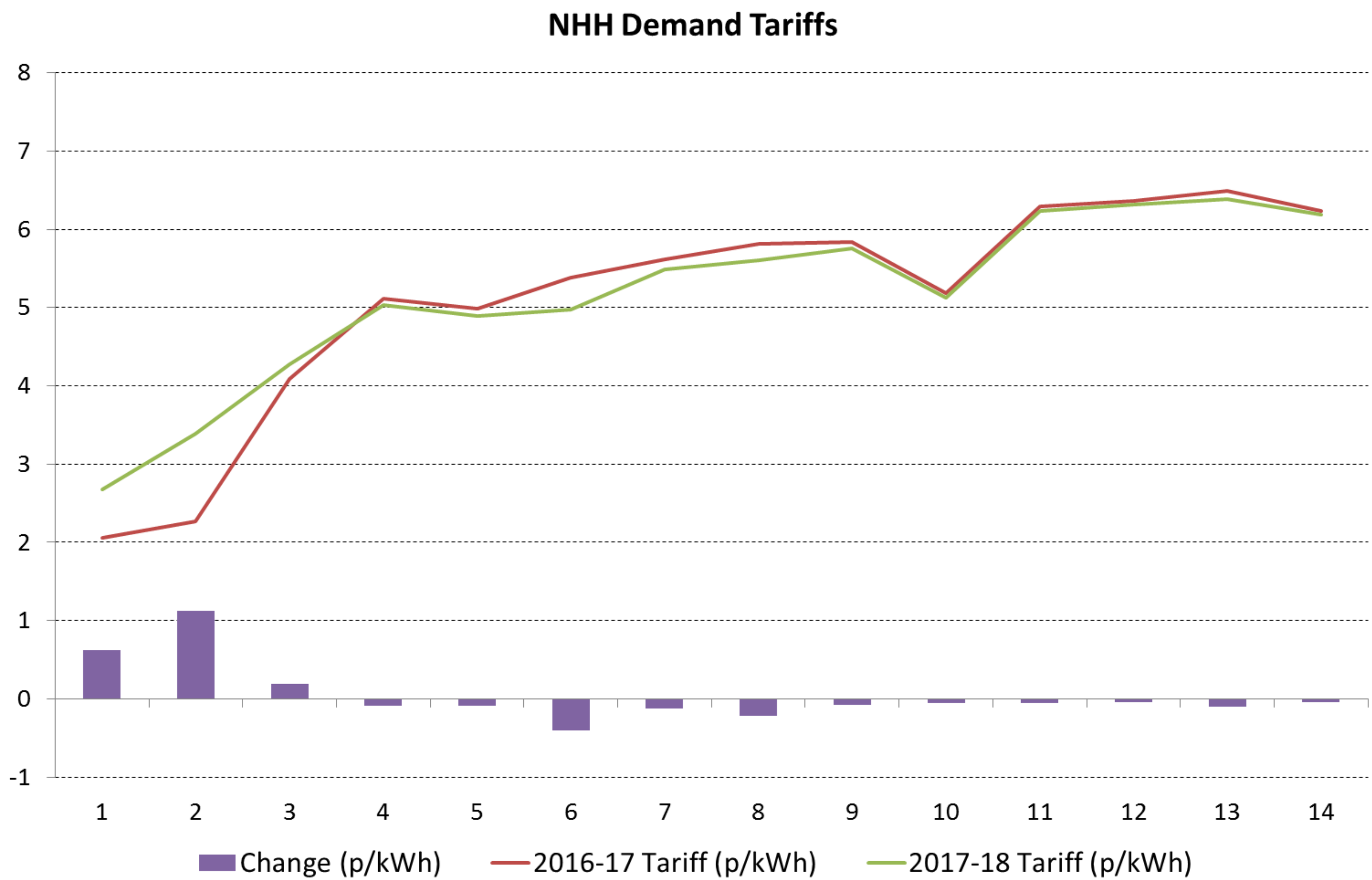
Example 4 – Tariff Changes (2)



Example 4 – Tariff Changes (3)



Example 4 – Tariff Changes (4)



Exercise 4

- In a copy of File 4 make one of the following changes to the transport model sheet and run the model:
  - +2GW at Peterhead (PEHE20) – Use the Gen Input sheet
  - +2GW at Tees Renewable Energy Plant (GRST20) – As above
  - 10% reduction in demand – Edit data on Transport Sheet
  - Removal of HVDC link – Remember to reorder busbars
- Copy the resulting generation tariffs from the “Final Tariffs sheet” into the “Results” sheet in file 7.
- Do the same with the final demand tariffs from the Tariff sheet.
- How much difference does each change make?

Residual Changes

- Changes in revenue
  - RIIO – (Revenue = Incentives + Innovation + Outputs)
  - Changes in Pass through items
  - Offshore timings
- Changes in generation and demand charging bases
- G:D Split changes
  - E.g. as a result of CMP224 & CMP227

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G:D Split

- Currently 73% of TNUoS is recovered through demand charges; and
- 27% is recovered through generation charges.

- Arrangements introduced under CMP224 will apply a cap to generation recovery going forwards to ensure that this stays with limits set by the EC

- CMP227 may alter the current G:D split, reducing the recovery from generation (e.g. 15:85 instead of 27:73)

Offshore timings

- An OFTO's revenue applies to the total TNUoS revenue following:
  - Asset transfer in the Offshore Transmission tender process (developer build); or
  - The associated offshore transmission assets commissioning.
- Similarly an offshore generator (connecting via a radial spur) becomes liable for local TNUoS upon the later of:
  - The OFTO's revenue becoming "live"; or
  - The generator's TEC becoming applicable
- Local TNUoS charges may not recover 100% of the OFTO's revenue

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Exercise 5

- In a copy of File 4 change the demand recovery % to 85%:
  - What do you notice?

- In another copy of File 4 model the effect of a £100m of OFTO revenue being delayed:
  - Assume that this would have resulted in £80m being recovered from Local Offshore and substation charges,
  - If charges are set assuming the OFTO is appointed, but it subsequently delays to a later year what does this mean?

End

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