All-Island TUoS/TLAF workshop

Dundalk March 3rd 2009

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Outline

- TUoS
  - Current RoI methodology
- TLAFs
  - Current all island methodology

TUoS – the Purpose

- To recover the costs of operating the transmission business and to provide a reasonable return on any investment made

- To design a tariff reflective of the costs imposed upon the network by participant behaviour
  – Particularly with generation tariffs to design a locational tariff which provides appropriate signals for plant location

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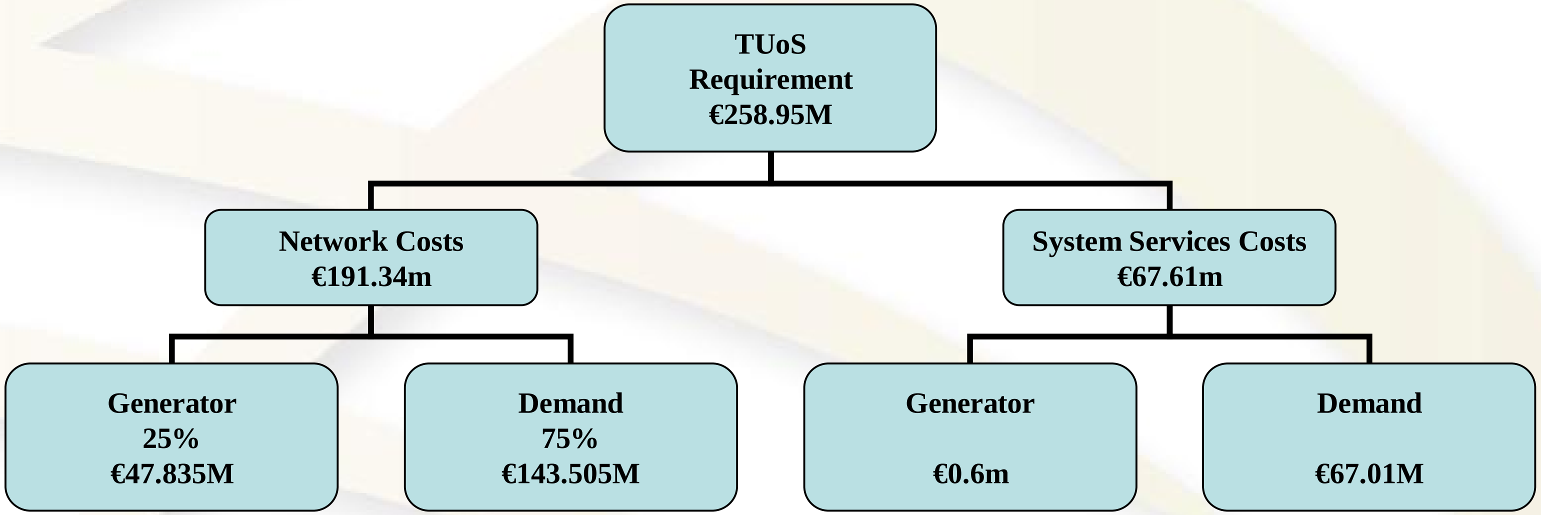
TUoS - RoI

- Shallow Connection Charging policy – since December 1999
- TUoS comprises ‘Networks’ charges and ‘System Services Charges’
- System Services Charges paid for by demand on a per MWh basis
- Networks charges split 25:75 between generation and demand
- Generation tariffs capacity based and locational on a node by node basis
  - calculated on the basis of the Reverse MW mile

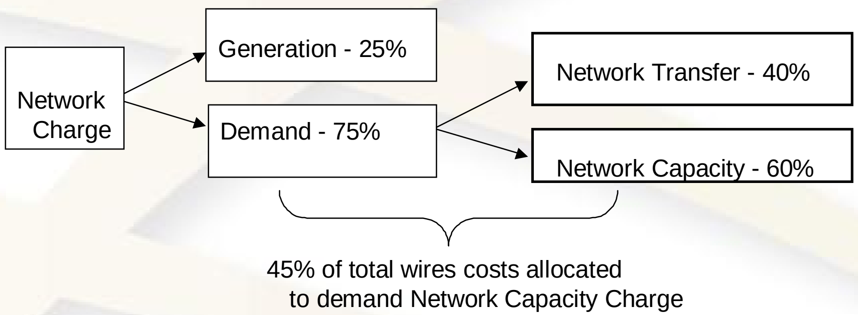
2009 Transmission Revenue Requirement



- Generators account for ~€48m
  - 25% of network costs
  - Assets, TSO costs etc.

Demand TUoS Tariffs

- Not locational
- System services charge – per MWh
- 60% based upon capacity and 40% based on energy



- Unauthorised usage charge
  - Charged when MIC exceeded
- Suppliers invoiced using 3 tariff schedules
  - DTS-T, DTS-D1 & DTS-D2

Generator Tariff Objectives

- Revenue recovery
- Provide signals
  - locational signals for new generation
  - closure signals
- Tariff principles
  - simplicity & transparency
  - support shallow connection policy
  - balance stability & responsiveness

Components in Calculating Generator Charges

- Network Model
- Network Costs
- Generation Dispatch – pro rata based upon winter peak demand
  - All generators scaled equally – reflective of equal access rights for all generators
- Revenue Recovery figure – provided by CER through revenue process
- Model run gives a locational charge – this is then smoothed up or down on a postalised per kW basis to get the desired overall revenue recovery

Reverse MW-Mile

- “MW-Mile” allocation methodology
  - Establishes the extent of the network used by each generator
- “Reverse” approach
  - Rewards where a generator offsets the dominant flow on a line
  - Potential for negative tariffs
- Tariffs vary with location and over time

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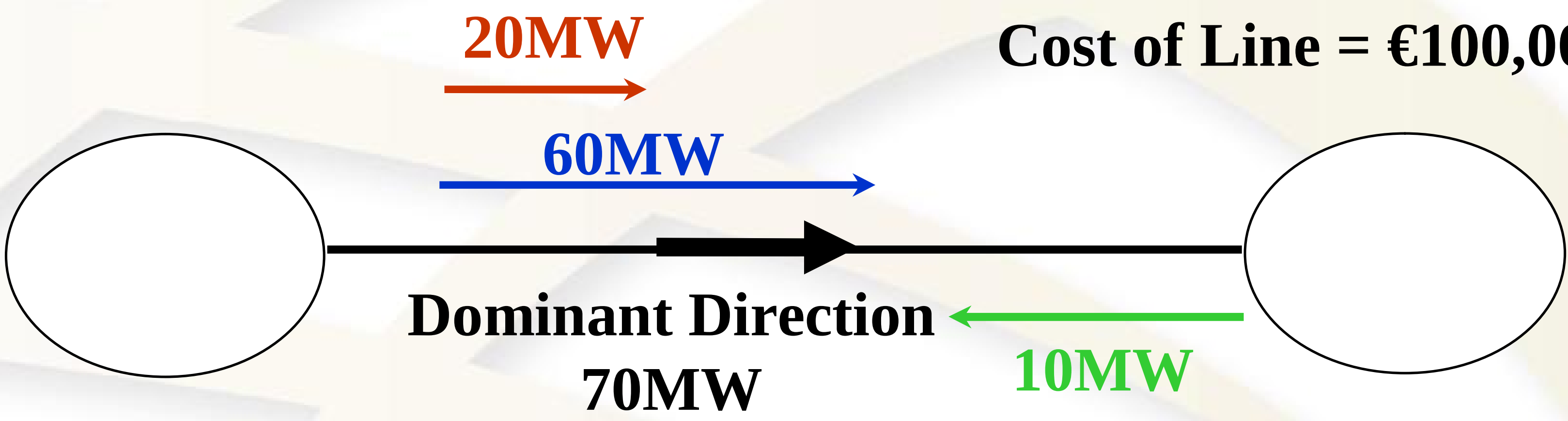
Implementation of Reverse MW-Mile

1. Base case DC load flow
   - Identifies the dominant flows
2. Set generator of interest to 0MW
3. Decrease load on a pro-rata basis
4. Re-run DC load flow
5. Compare with base case
   - Identifies usage of lines by the generator
6. Calculate generator locational payment
7. Repeat steps 2 to 6 for all generators
8. Calculate total locational revenue
9. Apply postage stamp coverage if necessary

Example: Reverse MW-Mile Approach

Line Capacity =100MW

Cost of Line = €100,000



Generator 1: 20/100 = €20,000

Generator 2: 60/100 = €60,000

Generator 3: -10/100 = -€10,000

Locational recovery for this line = €70,000

Remainder to Postage Stamp recovery

TLAFs – all island

TLAFs – The Purpose

- Losses are incurred on the transmission system
  - These need to be accounted for in the energy market
  - Loss factors applied to generator output

- Locational loss factors
  - determined ex-ante annually
  - applied to both transmission and distribution generators
  - some generators responsible for more than others
  - marginal approach used

- TLAFs support efficient real-time dispatch of the system
- TLAFs help to promote efficient location of generating plant
- If loss factors reflected reality in real time then implicitly losses would be optimised on the system

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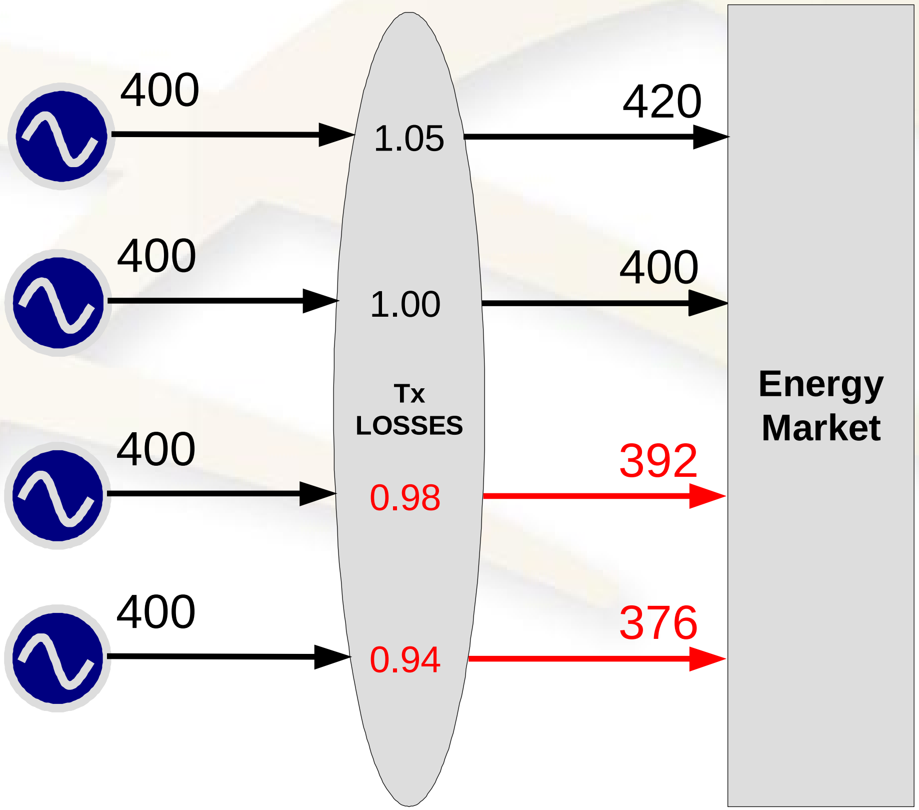
TLAF Adjusted Settlement Quantities



TLAFs – The Structure

- SEM
  - Monthly – day (7am – 10pm)/ night
  - SEM systems capable of using trading period TLAFs
  - Provision for losses for suppliers also exists

Methodology

- Dispatch (average)
- System Model (single all island model)
- Calculating Marginal Loss Factors, **MLFs**
- Convert from MLF to Transmission Loss Adjustment Factor

Dispatch and System Model

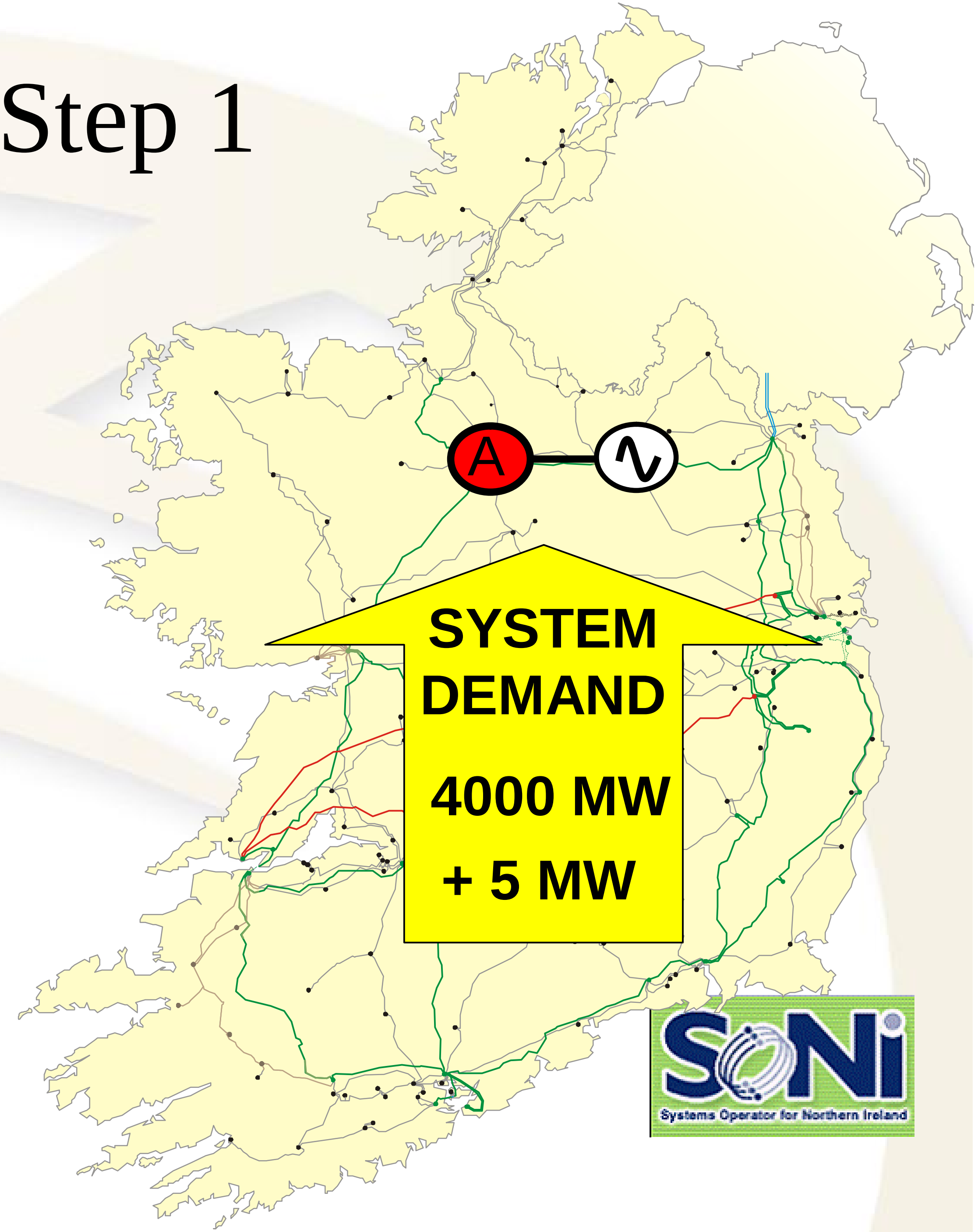
- Plexos Dispatch:
  - Forecast Demand
  - Fuel Forecast
  - Planned Outage Schedule
  - System Constraints
- The most up to date system model is used for the analysis
  - Planned network developments
  - Planned generation and loads

Example – Step 1

- Take Node A as the study bus
- Make Node A the system swing/slack bus
- **Increase** the system demand by 5 MW

  => 4005 MW
- Record the increase at the study node

  => 5.1 MW



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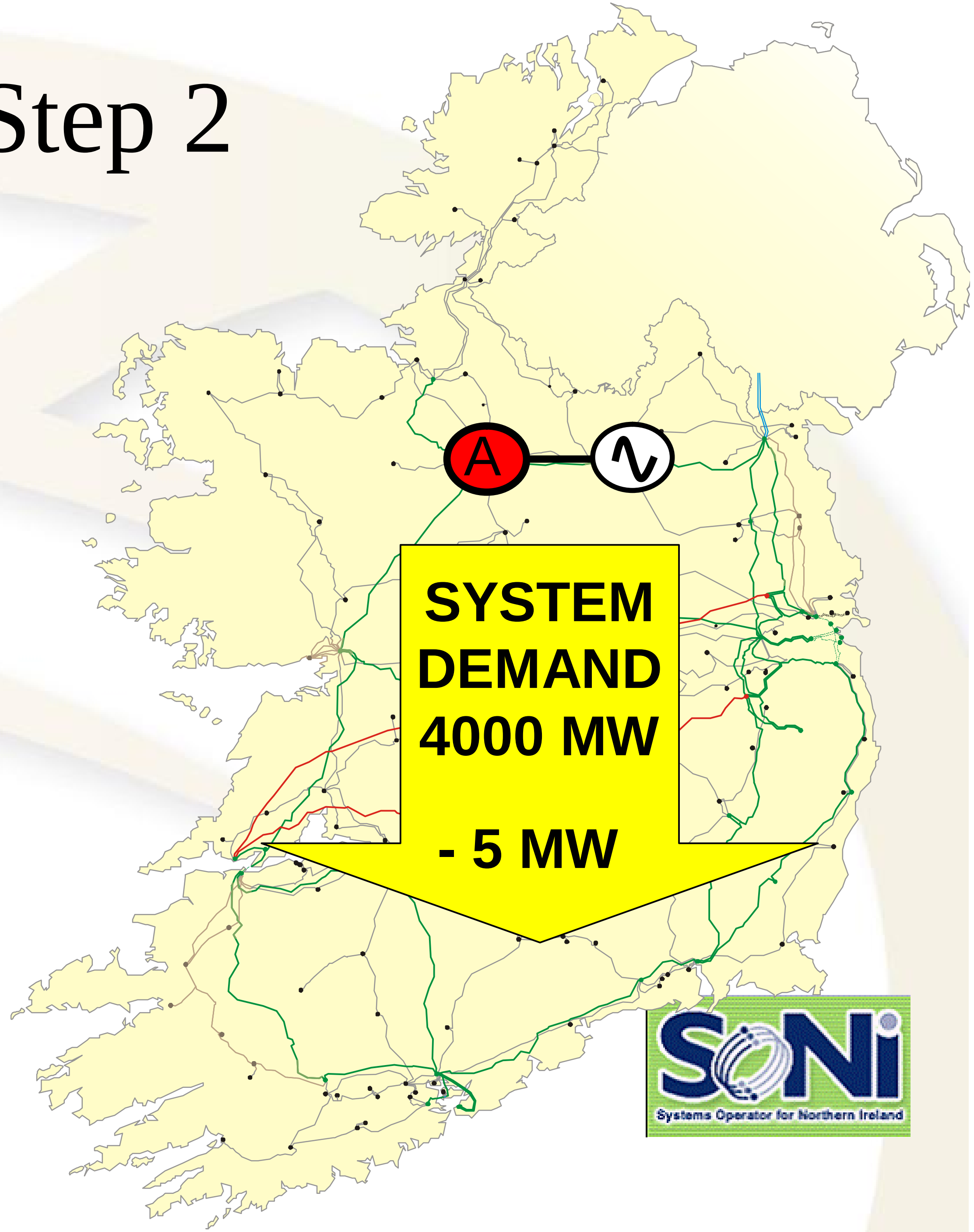
Example – Step 2

- **Decrease** the system demand by 5 MW

  => 3995 MW

- Record the decrease at the study node

  => -5.2 MW



Example – Step 3

$$MLF_{NODE\ A} = \frac{5}{Avg\ (5.1,\ 5.2)} = 0.971$$

- The program does this for all the transmission nodes in the system model

Station	Export Generation	+5MW	-5MW	MLF
Node A	0.0	5.1	-5.2	0.971
Node B	90.0	5.2	-5.1	0.979
Node C	40.0	5.2	-5.1	0.971
Node D	470.0	5.1	-5.1	0.972
Node E	10.0	5.1	-5.0	0.991
Node F	0.0	5.2	-5.1	0.970
Node G	5.0	5.2	-5.2	0.968
Node H	0.0	4.8	-4.8	1.047
Node I	25.0	5.1	-5.1	0.985
Node J	0.0	5.1	-5.1	0.986

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Example – Step 4

- Marginal loss methods create an over recovery of losses
  - need to be scaled to reflect the system model (PSSE) losses
- Scaling of the derived marginal loss factors to meet the modelled system losses is performed using the shift method

Example –Step 4 contd.

Station	Export Generation	+5MW	-5MW	MLF	Marginal Losses Allocation	Scaled MLF	Scaled Marginal Loss Allocation
Node A	0.0	5.1	-5.2	0.971	0.000	0.981	0.000
Node B	90.0	5.2	-5.1	0.979	1.884	0.989	0.984
Node C	40.0	5.2	-5.1	0.971	1.167	0.981	0.767
Node D	470.0	5.1	-5.1	0.972	13.150	0.982	8.450
Node E	10.0	5.1	-5.0	0.991	-0.006	1.001	-0.012
Node F	0.0	5.2	-5.1	0.970	0.000	0.980	0.000
Node G	5.0	5.2	-5.2	0.968	0.162	0.978	0.112
Node H	0.0	4.8	-4.8	1.047	0.000	1.057	0.000
Node I	25.0	5.1	-5.1	0.985	0.382	0.995	0.132
Node J	0.0	5.1	-5.1	0.986	0.000	0.996	0.000

Total = 17 MW

Total = 10 MW

Base case losses = 10 MW

Scaling Factor = 0.01

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Step 5

- System model losses (from PSSE) ≠ real system losses
  - a **final scaling** needs to be carried out

- **K Factor**

K = System Model Losses – Target Loss Projection

TLAF = Scaled MLF - K

TLAFs – by Node

ALL-ISLAND TRANSMISSION LOSS ADJUSTMENT FACTORS 2007					
Transmission Station	Bus Voltage kV	Month			
		November		December	
		Day	Night	Day	Night
Ardnacrusha	110	1.019	1.024	1.018	1.019
Aghada	110	1.049	1.051	1.046	1.052
Aghada	220	1.047	1.05	1.044	1.051
Arigna	110	0.995	0.988	0.995	0.988
Agannygal	110	0.995	0.988	0.996	0.99
Ahane	110	1.021	1.022	1.02	1.021
Arklow	110	0.999	1.016	1.001	1.014
Arklow	220	1.003	1.019	1.004	1.017
Athea	110	0.992	0.997	0.991	1
Athlone	110	1.008	0.993	1.009	0.996
Aughinish	110	0.983	0.982	0.981	0.981
Arva	110	1.012	1	1.012	1.001
Athy	110	1.009	1.009	1.008	1.005
Ballywater	110	1.045	1.042	1.044	1.043
Ballycummin	110	0	0	1.016	1.016
Booltiagh	110	1.016	1.017	1.014	1.017
Baltrasna	110	0	0	0.99	1.003

TLAFs – by Market Participant

ROI Transmission Loss Adjustment Factors 2007 [All-Island Market]						
Transmission-Connected Generation Station	Unit Identifier	Connected at	Month			
			November		December	
			Day	Night	Day	Night
Aghada (ESB)	AD1, AT1, AT2, AT4	Aghada 220 kV	1.047	1.050	1.044	1.051
Aghada PCP (ESB)	AP5	Aghada 110 kV	1.049	1.051	1.046	1.052
Ardnacrusha (ESB)	AA1, AA2, AA3, AA4	Ardnacrusha 110 kV	1.019	1.024	1.018	1.019
Ballywater (Ballywater Windfarms Ltd.)	BW1	Crane 110 kV	1.045	1.043	1.045	1.044
Booltiagh (Booltiagh Windfarm Ltd.)	BT1	Booltiagh 110 kV	1.016	1.017	1.014	1.017
Coomagearlahy (SWS Kilgarvan Windfarm Ltd.)	CG1	Coomagearlahy 110 kV	1.018	1.016	1.015	1.018
Derrybrien (Gort Windfarms Ltd.)	DY1	Agannygal 110 kV	0.995	0.988	0.996	0.990
Dublin Bay Power (Synergen)	DB1	Irishtown 220 kV	0.982	1.003	0.983	1.000
Edenderry (Edenderry Power Ltd.)	ED1	Cushaling 110 kV	0.945	0.935	0.953	0.937
Erne (ESB)	ER1, ER2	Cliff 110 kV	0.981	0.974	0.976	0.964

TLAFs – RAs & SEMO

- Prepared in accordance with the statutory and licensing arrangements pertaining in each jurisdiction
- Timeline
  - Draft all island TLAFs to RAs, end August
  - RAs' Consultation, September
  - RAs' Decision, October
- Submitted to the SEMO in accordance with the T&SC
  - Applied in settlement from 1^{st} Jan

Thank you

Any questions?