Providers of specialist cost solutions

in electricity supply and distribution

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Dear Mr Crouch

Response to Letter of 30 July 2004: Electricity Distribution Connection and Use of System Charges for Demand Customers and Generators

CoCal is pleased to have the opportunity to respond to Ofgem's open letter of 30 July 2004 on Electricity Distribution Connection and Use of System Charges for Demand Customers and Generators. Our views are based on worldwide experience of analysing distribution network costs and formulating and setting tariffs.

Divergence between methodologies

Tariffs should reflect distribution costs and formulated to avoid undue discrimination between customers or groups of customers. Some of the proposed methodologies will not achieve this.

The variation between the methodologies proposed by the DNOs will inevitably lead to disparate charging across DNOs. This could create situations where charges to domestic customers are significantly different (perhaps double) between one DNO and another simply through the way charges are constructed. (An example of this would be very different standing charges caused by different allocations of customer related costs).

Most LV network costs are neither related to the marginal cost of distributed energy nor the marginal cost of additional customers. Problems could arise where any difference is allocated to energy related charges by some DNOs and to customer related charges by others.

Demand use of system models

In modelling costs, DNOs need to derive charges on a cost reflective and robust manner. The 500 MW model most readily achieves this.

500 MW models

We would expect these models to incorporate the proposed changes to connection charge arrangements in April 2005 to reflect the network capital costs to be included in connection charges with the asset replacement and O&M costs for the remainder of the network.

This should, for example, lead to higher HV costs per kW for LV customers than for HV because HV customers will be paying for part of the HV network capital costs through connection charges, whereas LV customers will not (their connection charge normally covers only some of the LV capital costs).

Regulatory reflective method

The problems with this method are:

- It reflects the price control formula instead of underlying costs; and
- The variable element of the price control does not reflect marginal distribution costs.

Simulation model

As described, this model allocates non-demand related costs as customer related. However, non-demand related costs are much higher than marginal customer related costs.

For example, increasing the demand density (but not customer density) on a large housing estate will increase the size of feeders and the number of substations but make little difference to the amount of excavation. Increasing the customer density (but not demand density) will increase the number of services but not the amount of LV mains or number of substations. In particular, the proposed connection charge policy means that the capital cost of services in DUoS tariffs will be nil.

As described, the simulation identifies marginal demand-related costs then allocates the remaining costs as customer related.

This highlights the point that significant variations in domestic standing charges can occur through the different methodologies used to calculate yardsticks. For example, differences could occur through the different allocation of non-marginal distribution costs. Some methodologies will allocate a greater proportion of these costs as customer related compared with others. The greatest impact would be felt by small domestic customers, where standing charges form a large proportion of the electricity costs.

Prior to privatisation, all Area Boards followed Electricity Council guidance and allocated non-marginal LV network costs as customer related. This was done by defining a “minimum supply cost” comprising the proportionate costs of LV main required to supply 1.5 kW (the typical after diversity maximum demand for a domestic customer), the service joint, service cable and termination.

After privatisation, during the first Price Control period, some (but not all) RECs revised the definition of LV customer related costs to exclude the LV main. Consequently, Eastern Electricity reduced its DUoS standing charge by around 40% (we know this because one of CoCal' s Directors was Tariff Manager of Eastern Electricity at the time). The rationale for excluding the LV main was that it was neither demand nor customer related as the cost varied principally with the size of plots on a housing development.

For example, if the number of houses on a defined estate development area was increased by, say, 10%, with plot sizes correspondingly reduced, the length, amount of excavation etc. needed for the LV mains would remain the same. The 10% increase in demand would be covered by the demand related costs.

The cost of the non-demand related element of LV mains is then recovered through the reconciliation adjustment between yardstick costs and the costs allowed by the Price Control.

To summarise, we wish to draw to your attention that differences in DNOs’ standing charges may be due to differences in methodology rather than underlying costs.

Charge-setting model

The scaling of existing tariffs assumes that they are presently cost reflective. Even if they reflect costs now, they will not do so after the proposed changes to connection charges.

<u>Yardsticks</u>

Split of customers between yardsticks

The need for customer categories should be dictated by the capability of tariff structures to reflect the significant differences of costs imposed by the different customer groups. We would expect to see the following categories:

- Public Lighting – because load characteristics are very different from any other category;
- Domestic single rate – because domestic customers peak in the evening;
- Non-domestic single rate – because non-domestic customers peak in the day;
- Two rate tariffs for both domestic and non-domestic – because the day and night rates should reflect both day and evening costs;
- Tariffs for larger LV supplies fed from the LV network;

- Tariffs for larger LV supplies fed from HV/LV substations – because the capital cost of the feeder from the substation will be paid in the connection charge. (All DNOs should have "substation" tariffs but only a few do);

- Tariffs for HV supplies fed from the HV network; and

- Tariffs for HV supplies fed from EHV/HV substations – because the capital cost of the feeder from the substation will be paid in the connection charge.

Calculation of yardsticks

There is no accepted method of allocating HV system costs between HV and LV customers and there is no reconciliation between coincidence and diversity factors. Many countries achieve such a reconciliation using a system load model, calibrated by the input quantities to the system, losses and the quantities distributed to customers. The Appendix shows an example of how this can be achieved.

Treatment of EHV

Yardstick costs are scaled to reconcile with the price control for lower voltages. The same scaling should apply to EHV.

The allocation of joint asset costs often assumes a coincidence of unity between the EHV customer and the remaining system. This coincidence should be lower than unity, especially when the system is distributing more domestic load than non-domestic.

Availability of Statements

Statements should be available for free download from the company websites although a charge is reasonable when a printed copy is provided as an alternative.

O&M charges

It would be helpful and aid transparency of charging if overall O&M costs were identified in the regulatory accounts along with a valuation of the distribution system on a MEAV basis. This would produce a value for the percentage O&M that should be charged for the provision of additional connection assets.

I hope you find our comments helpful. If you would like further detail on any of the above, then please let me know.

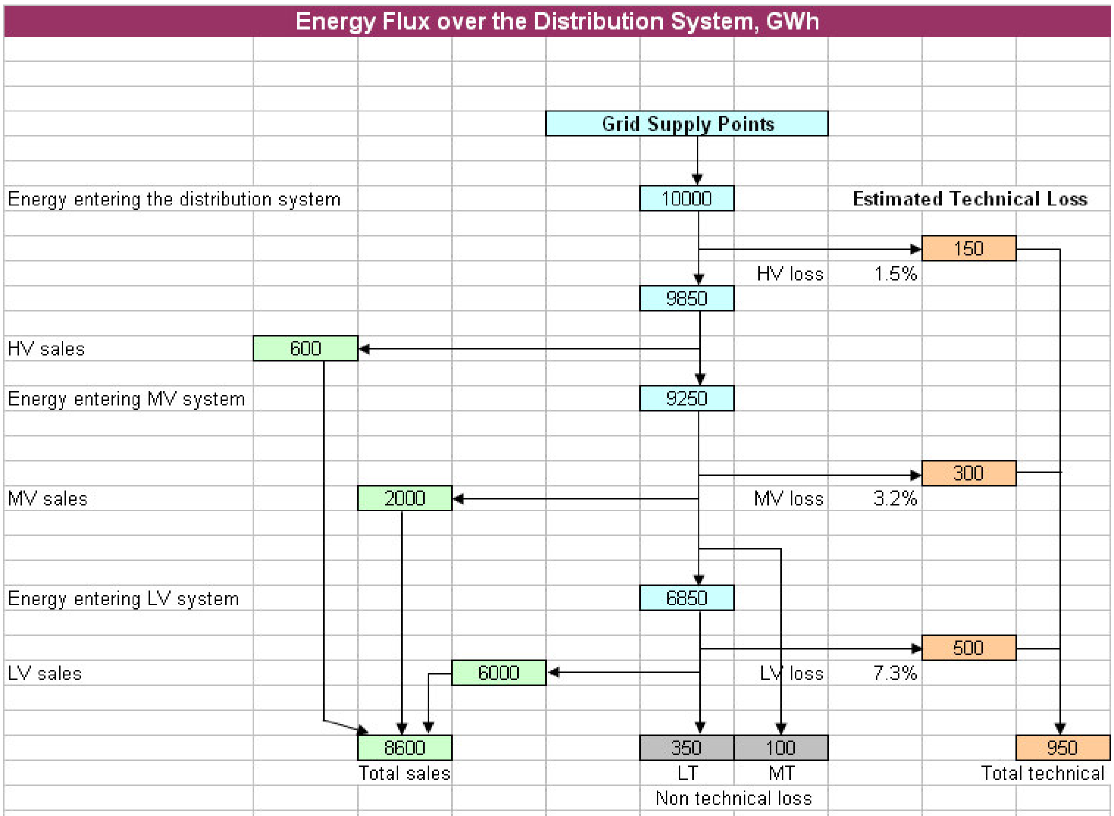
Yours sincerely

Adrian Callaby
Director

Appendix

Example showing the first step of reconciling energy, power and losses.

The input and output GWh are known. Estimated losses are then adjusted to achieve reconciliation between input and output.

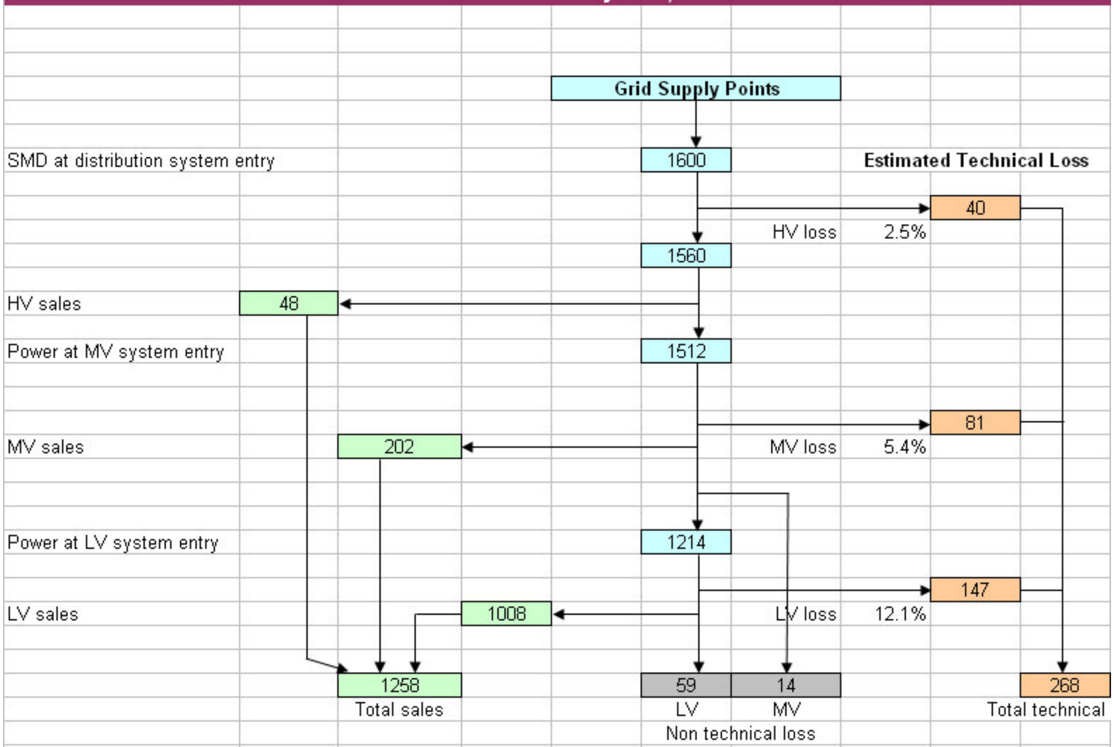


Technical loss as a percentage of sales

	Loss on Sales	Sales GWh	T loss GWh	Purchases GWh
HV	1.5%	600	9	609
MV	4.9%	2,000	99	2,099
LV	13.2%	6,000	791	6,791
Non tech loss MV	4.9%		5	105
Non tech loss LV	13.2%		46	396
Total		8,600	950	10,000

From the energy flow reconciliation it is possible to obtain the power flows at the time of System Maximum Demand. Note that percentage power losses are much greater than the GWh losses.

Power Flux over the Distribution System, MW at time of SMD



Technical loss as a percentage of sales

	Loss on Sales	Sales MW	T loss MW	Purchases MW
HV	2.6%	48	1	49
MV	8.4%	202	17	219
LV	23.3%	1,008	235	1,244
Non tech loss MV	8.4%		1	16
Non tech loss LV	23.3%		14	73
Total		1,258	268	1,600