# F Review of IES Report on Modelling of Transmission Pricing and Congestion Management Regimes

Congestion has the potential to impact economic efficiency over time through affecting investment decisions by both generators and Transmission Network Service Providers (TNSPs). On this issue, the Southern Generators made a supplementary submission[287] to the Congestion Management Review containing a modelling report undertaken by IES[288]. The IES modelling report attempted to quantify such effects through estimating the extent of dynamic inefficiencies caused by transmission investment and generation locational investment under the current regime, using a case study of a single region in the NEM, Queensland.

In the Directions Paper, the Commission stated that the assumptions and methodology applied by IES needed to be fully interrogated before any conclusions could be drawn from the work.[289] This Appendix reviews the IES modelling and sets out the Commission's position on IES findings.[290]

IES has informed the Commission that the analysis was time limited and the approach was necessarily different to that of a regulatory test application (where a range of transmission and generation investment alternatives to address a particular constraint are evaluated over a wide range of market outcomes). Hence a number of simplifying assumptions were made. The purpose of the modelling was a comparative exercise to quantify the impact of three different transmission pricing scenarios for generators using plausible data from Queensland in order to support and quantify the benefits of the Southern Generators submissions.

## F.1 Summary of IES Report and methodology

IES estimated the extent of dynamic inefficiencies caused by transmission investment and generation locational investment under the current regime, using a case study of the Queensland region for a 14 year period (2006/07 to 2020/21). The model compares the current pricing rule of a single regional reference price[291] for Queensland to two alternative cases:

- **Case 1**: of introducing eleven nodal prices for Queensland via a full regime of constraint support pricing; and

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287 Southern Generators Supplementary Submission to CMR, Modelling of future efficiency gains., 22 December 2006.

288 Intelligent Energy Systems (IES), Modelling of Transmission Pricing and Congestion Management Regimes, Report, 22 December 2006.

289 AEMC, Congestion Management Review Directions Paper, 12 March 2007, p.29.

290 The review assessed the IES model's methodology logic and assumptions and not seek to verify the accuracy of the underlying calculations (other than questions to IES where results appeared anomalous or counter-intuitive).

291 Based on price at the South Pine node.

- **Case 2**: including a congestion levy on new generators in addition to the nodal pricing regime introduced under Case 1. The congestion levy estimated the cost of transmission augmentation needed to relieve any congestion caused by each new generator location decision, in line with a causer-pays principle.

| Scenario | Settlements | Transmission costs charged for new generation capacity |
|---|---|---|
| Base Case | Regional | No |
| Case 1 | Nodal | No |
| Case 2 | Nodal | Yes |

Each case was modelled using a network model that included all material intra-regional constraints. The same physical network and constraints were used for all cases until the point in either Case 1 or Case 2 when modelling leads to a change in network investment.[292]

The modelling was not a least cost optimisation of both transmission and generation – it is an iterated two staged approach which sought to represent a competitive market expansion plan. IES noted that this approach is designed to represent least cost decision making by each new generator and results in the difference in outcomes between cases being driven by the different pricing signals to generators.

The first stage in IES modelling is to calculate a market based automated generator entry. This new entry model is an iterative process of ranking the most economical plant each year based upon a comparison of each potential generator's short run marginal cost (SRMC) to the average relevant nodal price. This assesses whether the spot market premium is sufficient to cover the generator's fixed costs.

The generator new entry assessment is only tested in the first year of the new investment, and hence there is net present value (NPV) assessment over the life of the generating plant. This means that a new generator enters the market if the relevant nodal price results in it making sufficient revenue to cover both variable and fixed costs in that year. IES considered that when load is increasing, it is a reasonable approximation to assume that if the plant is economic in the first year then it should be economic over its life.

The input list of potential new generators included known planned projects and generic new entrants spread across the network. There wasn't any detailed verification on the suitability of the location of the generic new generation projects.

After the new entry generation has been determined, the transmission response is calculated either against the reliability criteria or a market benefit assessment. The

[292] The modelling incorporates committed network upgrades, new generation plant and plant upgrades as per the 2006 SOO-ANTS and the TNSPs regional 2006 Annual Planning Reviews. Demand growth for each of the 11 Queensland nodes was modelled using published energy and demand projection from the Powerlink 2006 APR. Generators' SRMC are the same for all cases and were based on the ACIL-Tasman cost estimates used by NEMMCO for the 2006 SOO-ANTS. Only system normal conditions have been modelled.

market benefit assessment gauges whether there is a large enough difference in the nodal prices which would reflect high congestion costs to justify the expenditure.

Like the generator new entry modelling, the transmission response is modelled as an annual iterative process. However, the modelling uses Powerlink's 2006 Annual Planning Review[293] forecasts of transmission expenditure for all three Cases for the first 10 years. This meant that only in the last 5 years was it necessary for IES to determine the optimal transmission response to new generation entry.

IES thought that this approach was similar to how the current market operates with Transmission Network Service Providers (TNSP) making investment decisions in response to committed generation projects and reliability criteria for loads.

Generators bids are determined in a manner that attempts to maximise profits given contract revenues and the applicable spot price (i.e., either the RRN price or the nodal price). The allocation of contracts to generators portfolios is consistent across all cases ensuring that contract allocation doesn't bias the results.[294]

The study estimated an overall net present value benefit (NPV) benefit of $194.65m in efficiency savings from introducing nodal pricing to the Queensland region of the NEM through a comprehensive CSP regime. Although the results for Case 1 show an increase in the overall dispatch costs caused by increased generation from a relatively more expansive plant, this is more than offset by significant reductions in transmission and generation capital costs. IES modelling found that nodal pricing in Queensland would result in generation replacing transmission upgrades. IES estimates that benefit would increase to $222m (NPV) with the addition of congestion levies on new generation in Queensland.

**Table F.1: Results from IES modelling on the comparison of total savings of introducing locational pricing and congestion levies, Queensland region ($m NPV for 2006/07 to 2020/21)**

| | | Net Present Value ($m) | | | |
|---|---|---|---|---|---|
| Case | | Dispatch cost savings | Generator capital cost savings | Transmission expenditure savings | Total savings |
| 1 | Locational pricing | -58.06 | 130.8 | 121.91 | **194.5** |
| 2 | Locational pricing with congestion levy | -365.52 | 464.06 | 123.98 | **222.5** |

293 Powerlink, Annual Planning Report, 2006.

294 The bidding is based upon the regional/nodal price clearing the market. Effectively each generator has one shot to respond to the pre-dispatch price and price sensitivities. The generator's response is based upon profit maximising behaviour with generators determining their optimal bid based on a price volume trade off considering their contract level. IES considered this to reasonably represent actual bidding behaviour.

The introduction of a congestion levy in Case 2, dramatically changes the dispatch costs and the savings in generation capital costs compared to Case 1 results. There is a substantial increase in the dispatch costs which is, however, more than offset by the reduction in generator capital costs.

The congestion levy acts as a barrier to entry, making remote generation more expensive and encouraging generation closer to the load. Under Case 2, remote generation (which is generally coal) is heavily discouraged. This process results in less total plant capacity in Case 2 than Case 1. Also Case 2 has a slightly higher unserved energy amount (although still at a level well below the reliability standard). Effectively, under Case 2 the system is run a bit tighter, i.e. there is a closer match of the supply and demand than in Case 1.

There is variation in the fuel type and location of new entry generation between the three cases. The Base Case estimated that there will be an extra 2,500MW in built in Queensland in addition to the planned projects. 1500MW of this 2,500 extra generic investment is coal-fired plant located in the South West. The remaining new plant is gas fired located in Gladstone and Moreton is primarily required to meet shoulder and peak requirements.

Compared to the Base Case, an extra 500MW is estimated to enter the market in Case 1. Also there is different in the generation mix with more gas fired and less coal plant and location is different with more new entry generation in Moreton South, Gold Coast (Tweed) and WideBay.

The congestion levy in Case 2 results in significantly less new generation entry. IES estimated that 900 MW less generic new entry will occur. As noted above, the congestion levy results in remote coal fired generation being replaced by gas fired generation closer to load.

IES applied a discount rate of 9% for its calculations. The Commission has calculated that adjusting the discount rate by one percentage results in approximately a $20m adjustment to the NPV gains either way (i.e., a 10% discount rate decreases the gains by $20m and an 8% rate would increase the benefit by $20m). For the modelling, IES didn't use terminal values but instead apply an annual equivalent cost approach which accounts for terminal values of any new assets through spreading it over the life of asset in the annual capital cost.

In should also be noted that in 2004, IES did a similar modelling study for the ACCC which formed part of its submission to the MCE on the CRA report on NEM regional structure review.[295] That report considered the magnitude and materiality of the costs and benefits of implementing either a full nodal pricing regime for generators and consumers or nodal pricing for generation only. IES concluded that a nodal pricing regime is likely to induce different generator behaviour and this may have material benefits in terms of the NEM dispatch costs – mainly through fuel costs. Also that a change from regional pricing to nodal pricing would yield as much benefit to the market as the amount of transmission investment that would be

[295] IES, Regional Boundaries and Nodal Pricing, an analysis of the potential impact of nodal pricing and market efficiency, Report to ACCC, 12 December 2004.

required to eliminate half the dispatch costs due to intra-regional transmission constraints in Queensland.

## F.2 Submissions on IES Report

Powerlink[296] and Stanwell[297] submissions to the Commission contained comments on the IES modelling of transmission pricing regimes.

Powerlink considered that some of the assumptions used in the 2006 IES report are unrealistic, especially the assumption that there are no constraints on fuel availability or other key factors which affect generation location. Powerlink stated that this led to projections of significant amounts of new generation in the South East Queensland load centre, where it noted that there are well-known constraints on fuel availability and cost, water, and environmental acceptability. Powerlink considered that if the modelling reflected real world constraints on generation location decisions, generation would be located outside the load centre which would result in more transmission infrastructure. Powerlink stated that it considers that nodal pricing would not solve the real world constraints on generator location.

Stanwell's submission concurs with Powerlink's view. Stanwell considered that generation investment decisions extend beyond pool prices considerations as modelled by IES and other issues such as competitively priced fuel and water and incentives associated with greenhouse policies influence generators decisions. Also Stanwell had a number of concerns about the new entry plant selected for the Base Case and in particular the dominance of new coal plant over gas plant. Stanwell believed that the impact of the current state and proposed national environmental regulation and the recently announced increase and extension of the Queensland Gas Incentive Scheme (to 18% by 2020) plus the abundant supply of the low cost gas means that gas will become the dominant fuel choice for new entry generators. Stanwell stated that making the Base Case more reflective of these realities may result in a significant reduction in the benefits estimated by IES. Stanwell considered that carbon pricing is likely to change the expected pattern of generation investment.

Stanwell also stated that IES modelling does not consider other effects of nodal prices, for example the costs of implementation and flow-on impacts to the contract market and liquidity. In addition, Stanwell noted that in IES modelling the application of locational pricing does not deliver new generation in North Queensland, but that it is generally accepted that this area would benefit from further generation investment.

## F.3 Review of IES Modelling Approach

Following an assessment of the IES methodology[298] and reviewing submissions from market participants, the Commission considers that the following observations present limitations with the modelling.

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[296] Powerlink submission to AEMC Directions Paper, 12 April 2007, p.4.

[297] Stanwell letter to the Commission, 11 July 2007, Congestion Management Review.

### F.3.1 No consideration of the risk implications of introducing nodal pricing.

Nodal pricing will create a different set of risks for generators compared with the current regional structure and this will have implications for the trading and contract position of market participants. None of these issues were factored into the modelling plus no risk management instrument (e.g. constraint support contracts) was included.

Therefore the Commission considers that modelling does not fully reflect the full effect and implications of moving from a regional structure to a nodal prices structure. The Commission understands the model did not do so because IES considered that this would have required a subjective judgement on quantifying the risks under the different pricing rules. Noting the difficulties of doing this, the Commission considers that the modelling is limited by not assessing the risk implications of nodal pricing.

### F.3.2 Model limited to Queensland with simplistic modelling of other NEM regions

Except for flows on QNI, the rest of the NEM was modelled in this analysis on a regional basis with no intra-regional constraints. Any interactions between the Queensland and other regions were ignored (i.e. a higher Queensland price may lead to a higher NSW price). Hence the modelling in this regard was very simplistic and do not fully reflect all the implications of changing from the current regional pricing structure.[299]

### F.3.3 No sensitivity analysis performed on results

The Commission consider that sensitivity analysis would help to improve the quantification of costs. IES informed the Commission that this was not performed due to time limitations.

It is important to understand the degree of dependence the results have on the key assumptions. One example would be generator costs estimates which are based on ACIL-Tasman long term estimates. These figures do not reflect the current short term facing generators –for example higher costs for gas turbines caused by high world demand, or higher construction costs caused by shortages of skilled labour.

The Commission considers that no sensitivity analysis weakens the validity of IES results.

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[298] The Commission also held discussions with IES and Southern Generators.

[299] For all three Cases the South-West Queensland nodal prices were fairly equal. This is the price that influences NSW, so therefore IES doubt that the impact on NSW of the different scenarios in QLD would differ significantly.

### F.3.4 No verification of whether the location of the additional generation was plausible

As noted above, the modelling assumes no constraints on fuel availability, water or other factors which affect generation location. Both Powerlink and Stanwell in their submissions to the Commission argued that this results in unrealistic new entry generation scenarios.

Powerlink argued that this assumption leads to the projection of significant amounts of new generation in the SEQ/Brisbane load centre, where there are constraints on fuel availability and cost, water and environmental acceptability. Powerlink argued that these real world constraints would cause most new generation to locate at more favourable locations which would ultimately mean more transmission investment. Stanwell considered that gas fired generation will become the dominant fuel choice of the new entry generators in Queensland irrespective of the pricing regime.

In response to this, IES noted its assumptions on locations were the assumptions calculated by ACIL-Tasman and used by NEMMCO for their reliability modelling for the SOO. Also it considered the new generation locations to be plausible.

### F.3.5 Generic transmission costs estimates used for congestion levies

IES used a very simple transmission pricing model that assumes that transmission costs are based on distance to load. It has noted that the transmission costs estimates used to determine the congestion levies for new generation were simplistic and that better cost estimates from the TNSPs would help to qualify the results. IES recognised that there is difficulty in modelling individual causer pay congestion levies for new generators because each transmission augmentation will be highly dependent upon the exact circumstances. IES did informe the Commission that better estimates of congestion levy would improve the model.

### F.3.6 Transaction costs and implementation costs of introducing new pricing regimes not included

There will be significant transaction and implementation costs of changing the current regional pricing structure to a nodal pricing system, for example IT and administrative costs.

None of these costs were included in the modelling and hence the Commission considers that IES results may overstate the benefits of introducing different pricing structures.

In previous work done for the ACCC, IES have attempted to quantify the costs associated with implementing nodal pricing.[300] In that report, IES estimated that the generator nodal prices results in approximately $7.2m to $14.9m IT capital costs with ongoing operational costs of up to $2.4m (2004 prices).

[300] IES, Regional Boundaries and Nodal Pricing, an analysis of the potential impact of nodal pricing and market efficiency, Report to ACCC, 12 December 2004.

## F.4 Conclusion

The Commission recognises that the dynamic efficiency aspect of congestion could have the largest effect on economic efficiency. Furthermore, with significant investment planned in the energy sector over the next 5 to 15 years, there will be considerable potential dynamic efficiency effects for the NEM.

However estimating such effects is extremely difficult. The IES report represents an important, useful attempt at quantifying such effects under various pricing regimes. However with the limitations and observations on the report discussed in this Appendix, the Commission does not consider that the estimates of the costs incurred under the current regional pricing regime contained in IES report are realistic.

The Commission agrees strongly with the point made in Stanwell and Powerlink submissions that there are the other important factors beside price signals that determine generation location and hence transmission investment. These factors include portfolio risk; carbon risk; fuel source; water source; environmental restrictions (air shed, water, noise, etc). Furthermore, the risk management implications of nodal pricing will be substantial and will need to be reflected in any assessment of different pricing regimes. These two issues have to be properly evaluated for any assessment of the efficiency under various pricing regimes to be comprehensive.

The approach IES applied to model generation and transmission decision making is not sophisticated and does not accord in total with current regulatory arrangements for transmission investment in the NEM. Under the current Rules, every significant transmission investment needs to go through the Regulatory Test, which works out the least-cost or most net beneficial solution. Transmission is not built simply in response to, or to accommodate, generation location. Furthermore IES models generator entry based upon being profitable only in the first year. The risk of being constrained off in the future by additional new generation is not taken into consideration.

The Commission understands that incorporating such effects into the modelling could be quite complicated. However not doing so makes the model less realistic and hence weakens the validity of the results. The Commission does recognise that that in the future, work will be required to develop a more robust framework for modelling of dynamic efficiency impacts especially for regional boundary assessments.