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High-level review of approaches for estimating a standard electricity allocation factor (EAF)

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About Concept

Concept Consulting Group Ltd (Concept) specialises in providing analysis and advice on energy-related issues. Since its formation in 1999, the firm's personnel have advised clients in New Zealand, Australia, the wider Asia-Pacific region and Europe. Clients have included energy users, regulators, energy suppliers, governments, and international agencies.

Concept has undertaken a wide range of assignments, providing advice on market design and development issues, forecasting services, technical evaluations, regulatory analysis, and expert evidence.

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1 Introduction and Overview

Concept has been asked to briefly review the 2011 modelling that was undertaken for the estimation of the 2013-2017 EAF and comment on:

- The appropriateness of the modelling; and
- What approach Concept considers would be most appropriate to estimate an EAF for any future such exercise.

Review of the 2011 modelling

Section 2 of this report discusses the approach taken for the 2011 modelling, and identifies potential issues. In particular:

- Exogenously specified fleet composition assumptions which were inconsistent with the underlying scenarios relating to fuel and CO_2 prices and electricity demand, including assumptions relating to the retirement of Huntly units;
- Inconsistent coal and CO_2 price assumptions for the scenarios;
- An inherent difficulty in maintaining consistency of assumptions for two-model approaches. i.e. having one model determine the fleet composition, and another calculate market prices. This is illustrated by some of the outputs from the SRMC modelling exercise being inconsistent with the logical framework within which they were produced. For example:
  - in some scenarios for some years, the EAF is projected to be higher than the EAF of the most fossil intensive generating station (i.e. Huntly);
  - in some scenarios for some years, the EAF is projected to be negative. i.e. it is projecting that the introduction of a cost of CO_2 results in *lower* electricity prices than would otherwise be the case; and
  - the high demand scenario having lower electricity prices than the medium demand scenarios
- The selective exclusion of some modelling approaches (particularly LRMC and Cournot), SRMC-scenarios, and modelled years, the combined effect of which was to significantly increase the calculated EAF from what it would otherwise have been.

A potential future framework to estimate a standard EAF

Section 3 sets out a conceptual framework for an approach which Concept believes is the most appropriate to estimate the EAF.

Section 3.1 describes how the ability of the generating fleet mix to change through generation entry and exit in response to changes in fuel & CO_2 prices or electricity demand will result in market prices tending, over the long-term, to the LRMC of the marginal sources of generation.

It also describes how in any given year, the 'actual' price impact is likely to be different to this LRMC-based value due to the market not being in equilibrium. However, crucially, the actual electricity price effect of a price of CO_2 will not be systematically higher or lower than the LRMC-based price effect for a market in equilibrium.

Further, attempting to consistently model the extent to which the market is in dis-equilibrium for both the factual and 'without CO_2' counterfactual 'parallel universe' becomes nigh impossible.

Accordingly, it is considered that the most appropriate framework to evaluate the electricity price effect of CO_2 should be an LRMC-based price effect for a market in equilibrium.

Section 3.2 describes how situations of market power are unlikely to alter this conclusion. Indeed, to the extent that market power existed, and was exercised on a sustained basis, it would likely have the effect of *reducing* the extent to which CO_2 prices flow through to electricity prices.

Not only is it considered that an LRMC-based approach to considering the electricity price impact of CO_2 is the most conceptually robust, but it has two other advantages:

- It is amenable to much less complex analysis than is required for so-called SRMC-type analysis, or imperfect competition analysis. This simplicity also aids transparency, auditability, and ensuring internally consistent assumptions.
- It is consistent with the frameworks used by the Electricity Authority, MBIE, and the 2010 Ministerial Review of the Electricity Market, to assess electricity prices. All these frameworks use fundamentally LRMC-based approaches to consider issues such as whether historical prices represent workably competitive outcomes, or what future prices may emerge under scenarios of different future electricity price drivers.

2 Review of 2011 modelling for development of the 2013-2017 standard EAF

2.1 Overview of 2011 modelling approach

The standard EAF currently used for industrial allocation for the period 2013-2017 was based on modelling undertaken in 2011. Three different approaches were used to estimate the EAF:

- An 'SRMC' approach, where the build schedule and consequent generation fleet composition for a given year is based on LRMC modelling[1], but plant dispatch and electricity prices are based on hourly modelling of the operation of this fleet using short run marginal cost (SRMC).[2]
- A 'Cournot' approach, where the build schedule and consequent generation fleet composition for a given year is based on LRMC modelling, but the electricity market is subsequently modelled using a Cournot (imperfect competition) model which attempts to simulate strategic bidding behaviour by generators; and
- A pure 'LRMC' approach, where the build schedule and price impacts are based purely on the impact on the LRMC of new-entrant generators.

All three approaches projected electricity price outcomes for the period 2013-2017 for a range of different scenarios. The key scenario parameters were:

- CO_2 prices (being the 'without CO_2' counterfactual with \$0/tCO_2, and \$12.5, \$25, and \$50/tCO_2 for the 'with CO_2' factual scenarios);
- electricity demand growth (Low, Medium, and High Scenarios);
- coal prices (Central, and Low);
- gas prices (Central and Low); and
- the timing of the retirement of Huntly units (various assumptions, which generally assumed progressively early retirement with progressively higher CO_2 prices).

Most of the scenarios assumed that the market would build a fleet of generation that was consistent with the underlying assumptions relating to fuel and CO_2 prices and demand – i.e. the market would be in equilibrium, with an economically efficient mix of generation. However, some scenarios were run to simulate 'shocks', namely that actual demand turned out to be different to that expected when a build schedule was determined, and similarly that gas prices turned out to be different.

This 2011 modelling acknowledged that changes in external drivers such as fuel and CO_2 prices can change the composition of the electricity fleet through altered investment and retirement decisions.

Thus for the different scenarios, the modelling attempted to simulate these altered fleet composition outcomes through the use of the Generation Expansion Model (GEM). This is an optimisation tool which is designed to determine the least-cost set of generation investments for a given set of input assumptions relating to factors such as fuel and CO_2 prices and electricity demand.

[1] LRMC modelling considers the impact of a change in CO_2 prices (or indeed, any other factor input) on the Long Run Marginal Cost (LRMC) of potential new entrant generation to meet a growth in demand. – i.e. the LRMC includes capital and fixed costs, as well as the variable costs of operation (e.g. fuel)

[2] SRMC modelling considers the impact of a change in input prices (such as fuel and CO_2) on the short-run marginal cost of operation – i.e. only the variable costs of operation.

GEM was used to produce new generation build schedules for each of the scenarios. For example:

- In scenarios with high CO_2 prices, GEM forecast that a higher proportion of new-build generation would come from renewable generation; and
- In the counter-factual scenarios with low coal prices, GEM forecast that a significant amount of new-build generation would come from new coal-fired plant.

For a given scenario (being a composite of fuel prices, CO_2 prices, and electricity demand growth), the same *largely*-GEM-produced fleet composition scenarios were used for each of the three EAF estimation approaches (i.e. SRMC, Cournot and LRMC).

2.2 Potential issues with the 2011 modelling

2.2.1 Exogenous specification of fleet composition

As set out above, one of the key impacts of a price of CO_2 is that it will alter composition of the generation fleet through less emissions-intensive plant being built which would displace emissions intensive plant. This dynamic effect will have a major impact on electricity price outcomes.

However, one significant issue with the 2011 modelling approach is that a number of significant plant composition decisions were <u>not</u> determined via GEM optimisation, but were instead exogenously specified (hence the italicisation of the phrase "*largely*-GEM-produced fleet composition scenarios" above). For example:

- GEM was constrained so that it was not 'allowed' to build coal stations in the scenarios where a CO_2 cost is introduced, even though the assumptions used in the modelling suggested that it would still be cheaper to build new lignite stations even with CO_2 prices of \$12.50 or \$25/tCO_2. This has the potential to result in significant inconsistencies between the 'with CO_2' and 'without CO_2' prices, and would generally act to increase the computed EAF.
- Huntly unit retirement decisions were not determined through GEM determining whether it would be economic to retire units, but instead were assumptions that were specified exogenously. As is explained in section 2.2.4 below, this potentially introduces significant problems given the importance of the Huntly units (particularly the 'last' two Huntly units) at providing dry year reserve. In other words, an assumption about Huntly retiring could be inconsistent with the rest of the scenario assumptions relating to fuel and CO_2 prices. Given that early retirement was assumed to occur with an introduction of a price of CO_2, this exogenous assumption would act to increase the computed EAF.
- The so-called 'Gas' scenario which forced the building of a new CCGT in 2015 in the \$12.50/tCO_2 'with CO_2' scenario, but without an equivalent 'Gas' scenario for the 'without CO_2' counterfactuals. This would act to increase the computed EAF – although it should be noted that this Gas scenario was eventually discarded from inclusion in the sub-set of scenarios used to estimate the eventual EAF.

All of the above constraints significantly increase the likelihood that the resultant build schedule is internally <u>in</u>consistent with the underlying fuel price, CO_2 price and electricity demand assumptions, and would generally act to increase the computed EAF.

2.2.2 Consistency of coal and CO_2 prices

It is likely that in a future where global warming (and hence CO_2) is not an issue, there would be a significantly greater demand for coal – and consequently significantly greater world coal prices – than in a future where global warming is an issue.

However, the scenario framework for the 2011 modelling did not attempt to capture this dynamic.

Indeed, some of the scenarios had coal prices which were the *reverse* of this dynamic. I.e. the counterfactual 'without CO_2' scenarios had coal prices which were lower than in the factual 'with CO_2' scenarios. These assumptions seem logically inconsistent, and would act to significantly increase the computed EAF – although, as discussed below, these were eventually excluded from inclusion in the subset of scenarios which were used to estimate the eventual EAF.

2.2.3 Exclusion of some approaches and results from the eventual EAF

Excluding the Cournot and LRMC approaches

Although three modelling approaches were used, in the end the Contact Group decided not to use the Cournot and LRMC results, and instead only used a sub-set of the SRMC results to estimate the EAF.

The reasons the group gave[3] for discounting the Cournot results were: "*Additional assumptions are required for this type of modelling and a comprehensive analysis would be a significant task.*"

And the rationale given for discounting the LRMC modelling is that: *"LRMC insights would generally extend into the later years for the modelling horizon we are considering here. Further, it is considered that LRMC analysis excludes some insights available from the SRMC analysis such as shorter term market impacts."*

Given that the Cournot and LRMC results had materially lower EAFs than the SRMC approach, excluding these approaches had the effect of resulting in a higher estimated EAF.

While Concept agrees that Cournot modelling is fraught with difficulties, and often quite subjective, it disagrees with the assertion that LRMC modelling is an incorrect approach to consider these issues. This is discussed in detail in section 3.

Exclusion of scenarios and years

The eventual EAF was based on the average EAF across a limited set of scenarios and years, with some scenarios excluded:

- The cheap coal scenarios
- The cheap gas scenario
- The 'shock' scenarios
- The high and low demand scenarios
- The \$50/tCO_2 scenarios

The exclusion of the 'coal', 'gas' and 'shock' scenarios seems sensible, given the issues raised above.

The exclusion of the \$50/tCO_2 scenario seems more questionable as, at the time, \$25/tCO_2 prices seemed to be the mid-case for many projections. Its exclusion increased the eventual EAF.

Similarly, it is not clear why the high and low demand scenarios were excluded. Their exclusion also increased the eventual EAF.

Further, although the EAF was to be used for the period 2013-2017, the EAF was only estimated from the modelling results for 2013-2015 in the case of the scenarios where the Huntly decommissioning years were 'aligned' between the 'with CO_2' and 'without CO_2' scenarios, and only from the results from the 2013-2014 years for the scenarios where the Huntly decommissioning years were 'unaligned'.

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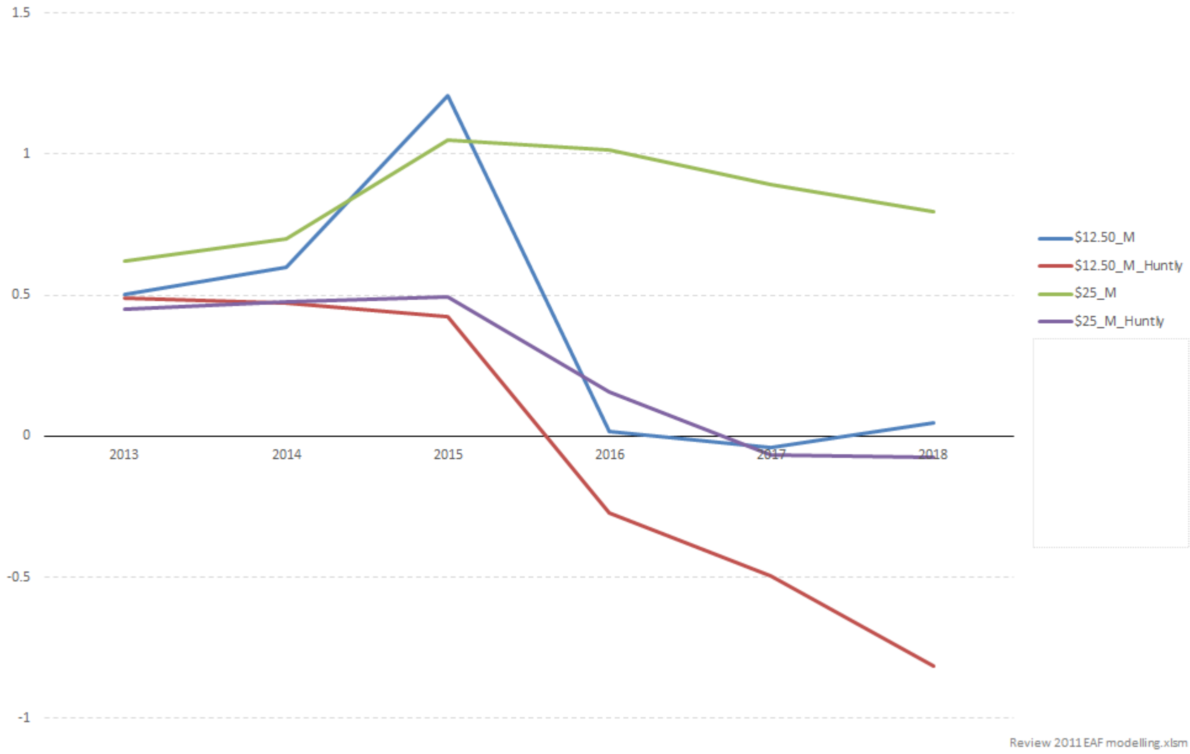
[3] "*Development of an Electricity Allocation Factor Recommendation for 2013 Onwards*", By an EAF Contact Group Assembled by Ministry for the Environment during 2011, Published June 2012

If the modelling is robust, there appears to be no first-principles basis on why the results for the full period modelled should not be used to estimate the EAF for that period. Given that the latter years' results from the modelling (as illustrated in Figure 1 below) had significantly lower EAFs than the early years, the exclusion of the latter years significantly increased the 'final' EAF from what it would have been.

Figure 1: Projected tCO_2/MWh EAFs computed using the SRMC approach for the scenarios used to eventually estimate the 'final' EAF



Potentially these latter years were excluded by the Contact Group because of their radically different nature compared with the earlier years, thereby raising questions about their robustness. (Particularly seeing as three of the four scenarios were projecting that introducing a cost of CO_2 would have *reduced* electricity prices by 2017 – a result which seems 'surprising' (as detailed further in section 2.2.5)).

However, to the extent this is the case, it would draw into question the whole modelling approach, not just these latter years, given that the same modelling approach was used throughout.

2.2.4 Huntly retirement assumptions

As mentioned above, the retirement of Huntly units is an exogenously specified assumption. Given that Huntly units have a major role to play in terms of providing dry-year reserve, the scenarios where Huntly units are retired early result in significantly higher electricity prices than where Huntly units are retired later. Indeed, for the SRMC and Cournot modelling, the scale of modelled price increase due to Huntly units retiring early suggests that this is an inconsistent assumption. i.e. in the 'real world' a Huntly unit would not be retired if its withdrawal caused prices to rise by such an amount.

In this is it notable that Genesis subsequently made a submission which stated that carbon pricing would only have a small effect on the timing of the retirement of the Huntly units. This is consistent with Concept's own modelling of the issue which suggests that for the provision of dry year reserve, CO_2 costs are a small factor in the overall economics of the different dry-year generation options.

Given that for many of the scenarios the ‘with CO_2’ world is assumed to have Huntly units retiring earlier than in the ‘without CO_2’ world, this exogenously specified assumption is resulting in significantly greater EAFs than should properly be the case. As illustrated in Figure 1 above, this explains why the EAFs for the scenarios where the Huntly retirement decision is aligned between the ‘with CO_2’ and ‘without CO_2’ scenarios (the ‘Huntly’ scenarios in Figure 1) are a lot lower than those scenarios where Huntly is exogenously assumed to retire early in the ‘without CO_2’ world.

2.2.5 Inconsistent EAF projections

Figure 2 and Figure 3 show the key projections from the SRMC modelling exercise for all the scenarios except the ‘shock’ scenarios.

Figure 2: Projected $/MWh prices computed using the SRMC approach

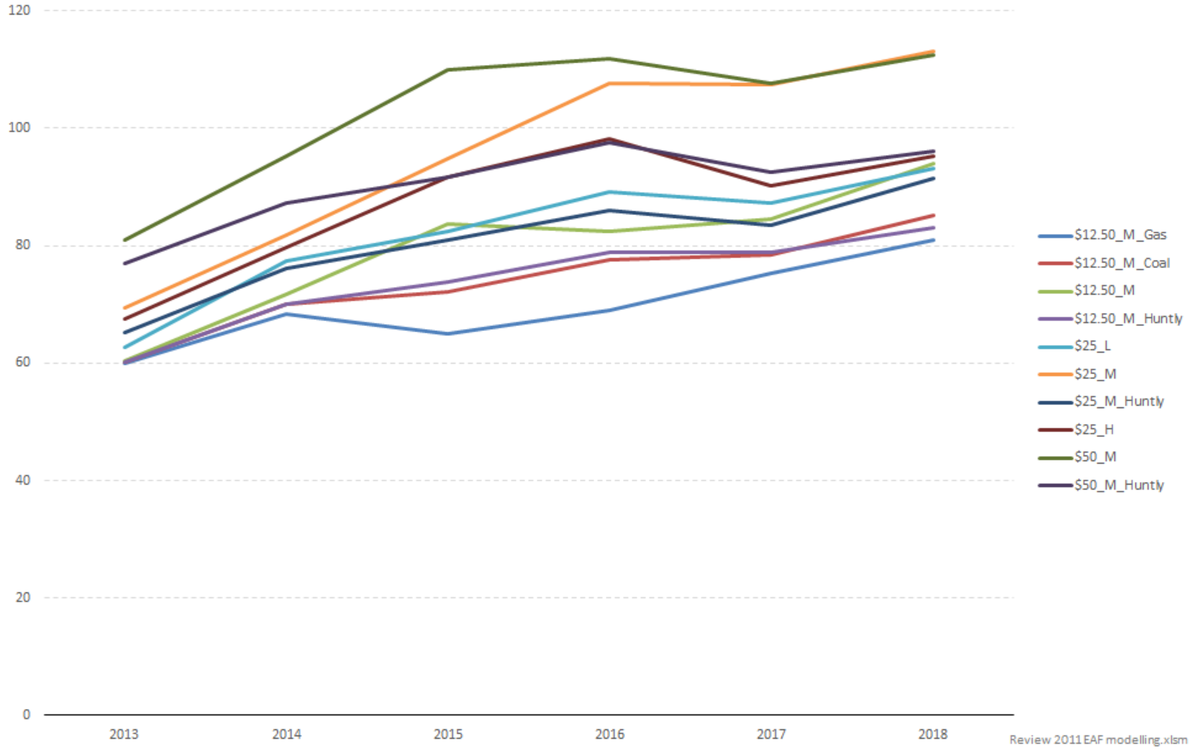
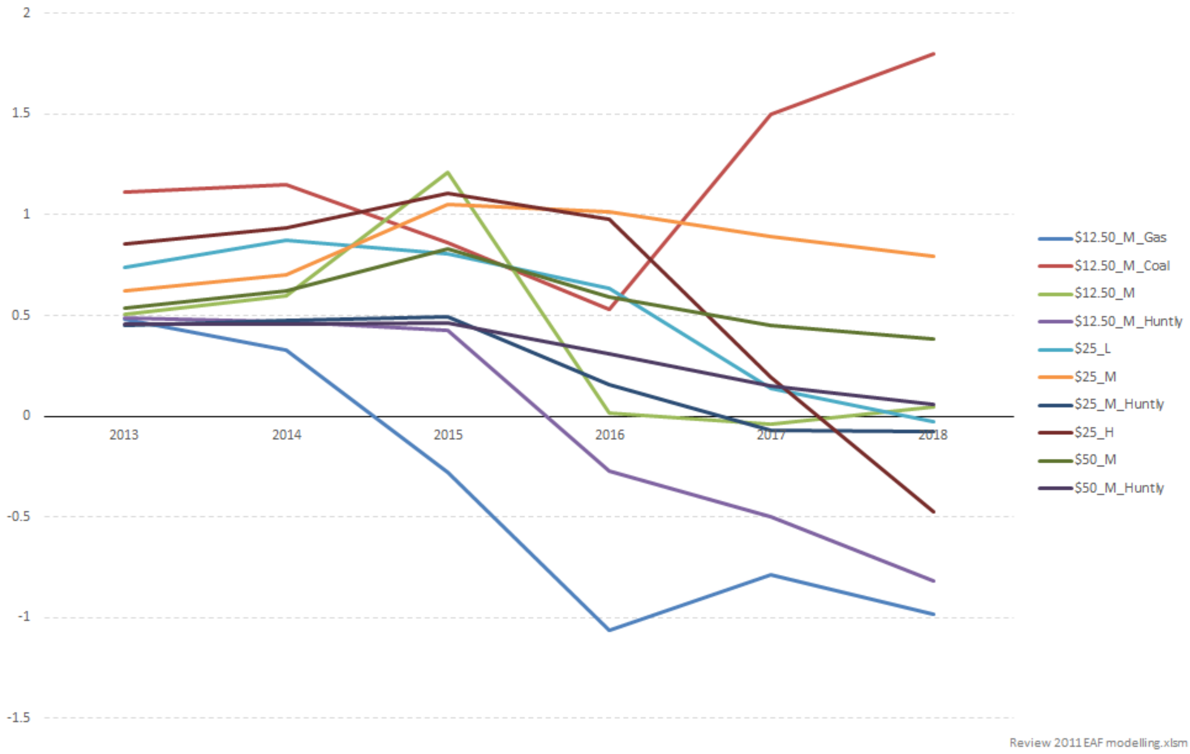


Figure 3: Projected tCO_2/MWh EAFs computed using the SRMC approach



Some of these results seem inconsistent within the logical framework within which they were produced. In particular:

- in some scenarios for some years, the EAF is projected to be *higher* than the EAF of the most fossil intensive generating station, i.e. the Huntly power station which has an EAF of 0.96 (noting that the EAF of new Lignite and Coal stations is lower than for Huntly, being 0.89 and 0.78, respectively)

- in some scenarios for some years, the EAF is projected to be *negative*. i.e. it is projecting that the introduction of a cost of CO_2 results in lower electricity prices than would otherwise be the case.

Such outcomes of EAFs being higher than the most fossil intensive station or negative can certainly occur for a market in dis-equilibrium – and was something the modelling attempted to look at through running 'shock' scenarios, although these scenarios were not included in the subset of scenarios that were used to estimate the eventual standard EAF.

However, the other scenarios explicitly assumed that the market *would be in equilibrium*. i.e. the fleet composition was determined to be the most economic given the underlying values for fuel and CO_2 prices and electricity demand, and these fuel, CO_2 and demand values were used for the SRMC modelling.

In a market in equilibrium it is not credible to assume that electricity prices would rise by an amount greater than that equivalent to the most fossil-intensive plant operating at the margin for 100% of the time. (Indeed, that outcome in itself would appear to stretch credibility). Instead, an increase in the cost of CO_2 and the resultant increase in generation from renewable plant would be expected to displace some fossil-intensive plant from the margin for at least some of the time. Thus, for a market assumed to be in equilibrium, the EAF equivalent to the most fossil intensive plant should be considered to be an absolute upper-limit.

Similarly, in a market in equilibrium, it is not credible to assume that an increase in cost inputs for some plant would lead to a decrease in electricity prices. At the limit, it could be the case that an increase in cost inputs for some plant would have no impact on electricity prices, and thus a zero EAF could be considered to be a lower bound.

These results of the computed EAF from the SRMC exercise being outside these credible upper and lower bound are considered to be a function of:

- the inconsistency of assumptions highlighted in the previous sub-sections; and
- the inherent difficulty in achieving internal consistency using a two-model approach. i.e. where the build-schedule from a planting model is fed into another, completely separate model to calculate the prices. This is because of the many complex 'moving parts' of the different models and large number of different assumptions used by the models for factors beyond annual assumptions relating to fuel and CO_2 prices and demand. As such, the margin of error from such approaches is likely to be materially greater.

Other 'unusual' price outcomes from this SRMC modelling process further illustrate this point:

- For the scenarios with \$25/tCO_2 prices, electricity prices in the high demand scenario are forecast to be *lower* than the medium demand scenario
- Electricity prices in some scenarios being materially higher than the LRMCs of the new-entrant generation that is assumed to be built to meet demand and respond to changing fuel and CO_2 prices.[4] For such outcomes to occur it would have to be assumed that the wholesale electricity generation market was subject to a high degree of market power that was being exercised on a sustained basis. Not only is this inconsistent with the conceptual framework for the SRMC modelling (noting that the Cournot modelling attempted to address such factors), this is

[4] From examination of the MED paper on the LRMC modelling, it appears that the first tranche of geothermal and wind plant have LRMCs of approximately $88/MWh, and the second tranche appear to have LRMCs of approximately $98/MWh.

contrary to analysis undertaken by the Electricity Authority, and the Ministerial Review which concluded this did not appear to be the case

3 Discussion on how CO_2 prices are likely to flow through to electricity prices

3.1 How market prices will be driven, in the long-run, by the LRMC of marginal sources of generation

The introduction of a cost of CO_2 will increase the variable (or short-run) costs of all generating stations that emit CO_2.

In a competitive market, all such stations will increase their \$/MWh offers into the spot market by an amount equivalent to the \$/tCO_2 price of CO_2 multiplied by the tCO_2/MWh emissions intensity of their generation. (This latter factor being a function of the fossil-intensity of their fuel, and the efficiency of their generation).

If a CO_2-emitting station happens to be the marginal plant called to operate in any given half-hour, this will increase the market price of electricity for that half hour by the increase in the marginal plant's offer price. This is because the marginal plant called to operate in a given half-hour sets the price for the whole market.

For a fixed fleet of generation, the introduction of a price of CO_2 will likely be significant, because CO_2-emitting stations are operationally marginal across a significant proportion of the year.

However, New Zealand's generation fleet is not fixed. New generation can be built to meet a growth in demand or to displace expensive generation. Old generation can be retired – either due to age, or due to becoming more expensive than new generation.

Introducing a price of CO_2 can have a significant impact on this 'dynamic' aspect of how the electricity fleet changes over time to meet changing circumstances. And this dynamic aspect will strongly influence how a price of CO_2 will flow through to electricity prices.

A simple example will illustrate this:

Consider a market in equilibrium where the average spot market price across all half-hours is \$70/MWh. This \$70/MWh figure will be the average of the prices of the marginal resource to be selected for each of the 17,520 half-hours:[5]

- At times of surplus (e.g. summer nights, and/or very wet periods) a renewable generator may be the marginal plant, so the half-hourly spot price will be very low;
- At other times, a fossil-generator will be marginal, so the spot price will be a function of their fuel and other variable operating & maintenance costs;
- And for a few periods of extreme scarcity (e.g. periods of significant peak demand, and/or very dry periods, or other factors driving significant plant outages), prices will rise to extreme levels, with the price reflecting some level of demand curtailment – with such curtailment being the marginal 'resource' to meet requirements. These scarcity prices are critical to cover the capital and fixed costs of the marginal source of infrequently-used 'peaking' generation.

If a \$25/tCO_2 price of CO_2 were introduced, this will increase the short-run costs of all the CO_2-emitting stations, and increase the price of electricity for all the periods where CO_2-emitting stations are the marginal resource. In a market where these marginal stations are a mix of coal- and gas-fired plant, the average electricity price rise across all time periods could be approximately

[5] It should note that this description is a simplification for the purposes of this discussion. Accordingly, it ignores some aspects of hydro offers, network effects, and thermal unit-commitment. However, such complications won't affect the fundamentals of how CO_2 prices will flow through to electricity prices.

$10/MWh, making the overall electricity price $80/MWh. This price rise is the 'static' increase that would be experienced if the fleet of generating stations were fixed.

However, in a dynamic world, this static price increase may take electricity prices above the price required to make a *new* generating station profitable. In this respect, the price required by a new generating station should not just be greater than its variable (i.e. short-run) costs of operation. In addition, it needs to cover its fixed annual operating & maintenance costs (e.g. labour, rates, etc.), plus it needs to recover an annual amount to pay for the capital costs of building the plant in the first place.

In our hypothetical example, the cheapest source of new generation are geothermal stations. Their only variable costs relate to the emissions of CO_2, at a rate of 0.15 tCO_2/MWh. At a price of $25/$tCO_2$, this gives a variable cost of $3.75/MWh. Their fixed operating & maintenance costs are equivalent to $6.25/MWh. They also have a capital recovery factor equivalent to $65/MWh. In total, the sum of these costs – being the 'long-run marginal cost' (LRMC) of such new generation – equals $75/MWh.

As can be seen, if these plant had been built in the market prior to the introduction of a cost of CO_2 (i.e. where prices average $70/MWh) they would not have been profitable. However, after the introduction of a cost of CO_2, the static market price of $80/MWh will be high enough to make such new plant profitable.

In a competitive market, this should encourage new entry by such geothermal generators.

However, as new geothermal generation enters the market, it will act to displace some fossil-generators who were at the margin for some periods. This will give rise to a greater number of periods where renewable generators are at the margin – with the associated very low prices. Further, with new capacity entering the market, the market will move into a situation of relative surplus capacity, with the result that there will be fewer periods of extreme scarcity, and thus fewer periods of extremely high prices.

These two effects will act to lower the overall CO_2-related market price increase across all periods such that it will no-longer be $80/MWh.

In a competitive market, this process of new-entry should continue to occur – with the associated reduction in market prices – until it is no-longer profitable for a new generator to be built. In our example, this will happen when the market price reaches $75/MWh – i.e. the LRMC of the new-entrant generation.

This dynamic may also result in some stations retiring. In particular, some older-fossil plant may no longer be called to operate for as much of the year, plus will not receive the same level of extreme scarcity prices due to the relative situation of surplus capacity. If the prices it receives are no longer sufficient to cover its fixed O&M costs associated with keeping the plant operational, it will retire. This will act to reduce the situation of surplus capacity, and once again result in some periods of extreme scarcity.

Importantly, it should be appreciated that, given the two to five year lead-time for new generation investment[6], it is the *expectation* of future prices that drives these generation entry and exit decisions.

As can be seen, the process of entry and exit is driven by the extent to which market prices cover the LRMC of the marginal source of generation. i.e.:

- Variable + fixed O&M + capital costs, in the case of potential new-entry; and

[6] Some stations are relatively quick to build (e.g. a new OCGT could take no more than eighteen months), whereas others, such as a new hydro scheme, can take many years to build.

- Variable + fixed O&M, in the case of potential retirement.[7]

Further, as illustrated above, the competitive market dynamics are such that prices should equilibriate in the long-term to the LRMC of the marginal economic source of generation.

- For baseload prices, this should equal the LRMC of the marginal new-entrant baseload generator;
- For peaking prices, this should equal the LRMC of the marginal source of peaking generation. This will either be an existing older fossil generator (in which case the LRMC will be the variable + fixed O&M costs necessary to stop it being retired), or a new peaking fossil generator such as an open-cycle gas turbine (in which case capital costs also need to be included) – whichever is cheaper.

Accordingly, the appropriate framework to consider the impact of CO_2 prices on electricity prices should be an LRMC-based framework.

In this it should be noted that the 'actual' price impact of CO_2 will differ from this LRMC-based approach for years where the market is not in equilibrium. I.e. the mix of generation is not least-cost, given the underlying fuel, CO_2 and electricity demand drivers. There may be too much or too little generation overall, and/or there may be too much higher-cost generation, and not enough lower-cost generation.

Over time, the market should move into a situation of equilibrium through generation entry and exit as participants respond to the price signals.

However, at any moment in time it is likely that the market will not be in equilibrium. This will primarily be due to two factors:

- The inevitability that market expectations will be wrong for fuel and CO_2 prices and electricity demand for two to five years hence (the timeframe for new-entrant decisions, given the lead time in building a power station). i.e. fuel and/or CO_2 prices and/or electricity demand may turn out to be higher or lower than were expected.[8]
- The 'lumpy' nature of power station investment. i.e. rather than being built in neat 1 MW increments, power stations can be several hundred MW in size, which is large for the New Zealand market.

Accordingly, the market may be in situations of relative surplus or scarcity, and/or have too much or too little fossil stations given the underlying fuel and CO_2 prices. Therefore, for a given year, the electricity price effect of a price of CO_2 will likely be different to the LRMC-based price effect for a market in equilibrium. Sometimes it will be higher, and at other times it will be lower.

For example, if market expectations are for high CO_2 prices, it is likely that this would encourage a significantly greater amount of new renewable generation entry than if expectations are for low CO_2 prices. However, if actual CO_2 prices turned out to be lower than were expected, the extent of new renewable entry will turn out to be 'too much' with a consequent suppressive effect on market prices such that prices for a while will be lower than the LRMC of new generation. The reverse is true if CO_2 prices turn out to be higher than were expected at the time generators were making new investment decisions.

[7] For an existing generating station, the capital costs are sunk and should not be included in consideration of its future long-run marginal cost.

[8] This is not a function of electricity markets per se, as centrally planned systems will find it equally difficult to predict the future for these key drivers. Indeed, one of the key successes of electricity markets relative to centrally planned systems, is being able to adjust to changes in these key drivers more quickly and at lower cost.

Accordingly, the actual price effect for a given year of a \$25/tCO_2 price will depend on whether this price was higher or lower than was expected several years previously. This will be further compounded by whether other market drivers such as fuel prices and electricity demand turn out to be different to what was expected.

Crucially, the actual price effect of a price of CO_2 will not be systematically higher or lower than the LRMC-based price effect for a market in equilibrium.

Accordingly, it is considered that the most appropriate framework to evaluate the electricity price effect of CO_2 should be an LRMC-based price effect for a market in equilibrium.

Attempting to model the year-on-year 'actual' price impact of a cost of CO_2, including the extent to which the market is in dis-equilibrium will become a nigh impossible exercise. This is because the appropriate counter-factual is modelling electricity prices in a world where a cost of CO_2 has never (and will never) be a factor of electricity prices, and which will consequently result in significant differences in the generation mix for the two 'parallel universes' through different entry and exit decisions. Attempting to model periods of dis-equilibrium for these two 'parallel universes' over a sustained period of time, requires significant subjective judgements on frankly unknowable factors as to how the counter-factual 'without CO_2' universe would have moved over time, including its own periods of dis-equilibrium. The extent of subjectivity required will invalidate this approach.

3.2 Might market power alter this outcome?

The structure of the NZ market is such that, at times, some generators could be considered to have market power – particularly at times of scarcity.

It is worth considering whether this may impact the extent to which CO_2 prices feed through to electricity prices generally – as was considered by the 2011 EAF Contact Group that considered the appropriate 'standard' EAF for the 2013 to 2017 period.

However, there are two factors which suggest that this is unlikely to alter the conclusion about the CO_2 price impact being driven by the LRMC price impact.

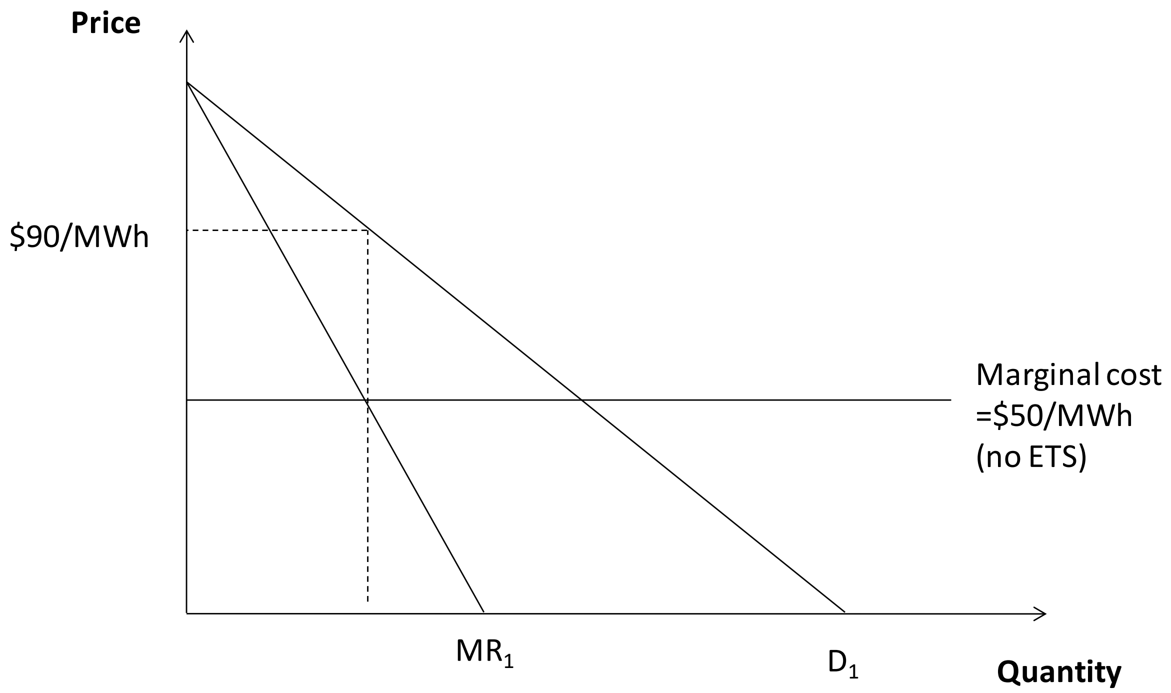
- Firstly, there are two countervailing factors which will act to counter the sustained exercise of market power by generators:
  - If existing generators push prices above the LRMC of new generators for a sustained period, it is likely they will encourage new generators to enter the market to capture such rents. This threat of the loss of market share (and a reduction in market prices) should incentivise existing generators not to exercise market power to raise prices significantly above competitive levels.
  - The exercise of market power is likely to invite a regulatory / political response, the effect of which could negatively impact on profitability more than the potential excess profits which a generator could earn by exercising market power.
- Secondly, even if a generator had market power and was inclined to use it, it is not considered that CO_2 prices would systematically exaggerate or ameliorate such a generator's ability or inclination to exercise market power. Indeed, as the analysis below illustrates, a general case can be made that if a generator were to exercise market power it would *reduce* the extent to which a CO_2 price would flow through to electricity prices.

In a perfectly competitive market, any generator which raises its price will lose all its sales volume. As a result, generator offers will be driven down to their avoidable costs.

However, in the real world, generators can influence spot prices at times through their supply offers. In technical terms, these generators face a downward sloping residual demand curve for *their* output[9] in the relevant time period. As a result, their decisions can be expected to reflect a price/volume trade-off, and prices will not necessarily be driven to their avoidable costs.

A simplified example can help to illustrate this. Rather than perfect competition, imagine the industry is supplied by a single monopoly firm[10]. The downward sloping demand curve faced by the supplier is denoted by D_1 in Figure 4.

Figure 4: Illustrative difference between prices and costs (monopoly supplier)



The marginal cost of supply is assumed to be $50/MWh prior to introduction of an ETS. The seller is assumed to wish to maximise its profits. Furthermore, it is assumed that there are no other factors which would restrain prices (e.g. the effect that higher prices might have in encouraging subsequent new entry).

Standard economic theory indicates that profit maximisation will occur at the level of output where marginal cost equates to marginal revenue[11]. For the linear demand curve D_1, the marginal revenue curve will have the same vertical intercept and twice the slope, and is shown as MR_1. The point where marginal cost = marginal revenue is shown by the vertical dotted line. This represents the volume of electricity that will be produced and consumed, and the spot price will be $90/MWh.

This example illustrates how the spot price is expected to rise above the level of marginal cost where a supplier can restrict output and raise prices *without any competitive response*. Clearly in this instance, the use of cost data would by itself not provide reliable guidance on prices.

It is also useful to take this example one step further and consider the effect of introducing an ETS, assuming all other things are unchanged. The ETS will raise the marginal cost of supply for the monopoly supplier. The supplier will no longer be profit maximising at the old level of output. As shown in Figure 5, the profit maximising output will reduce (denoted by the dotted red vertical line).

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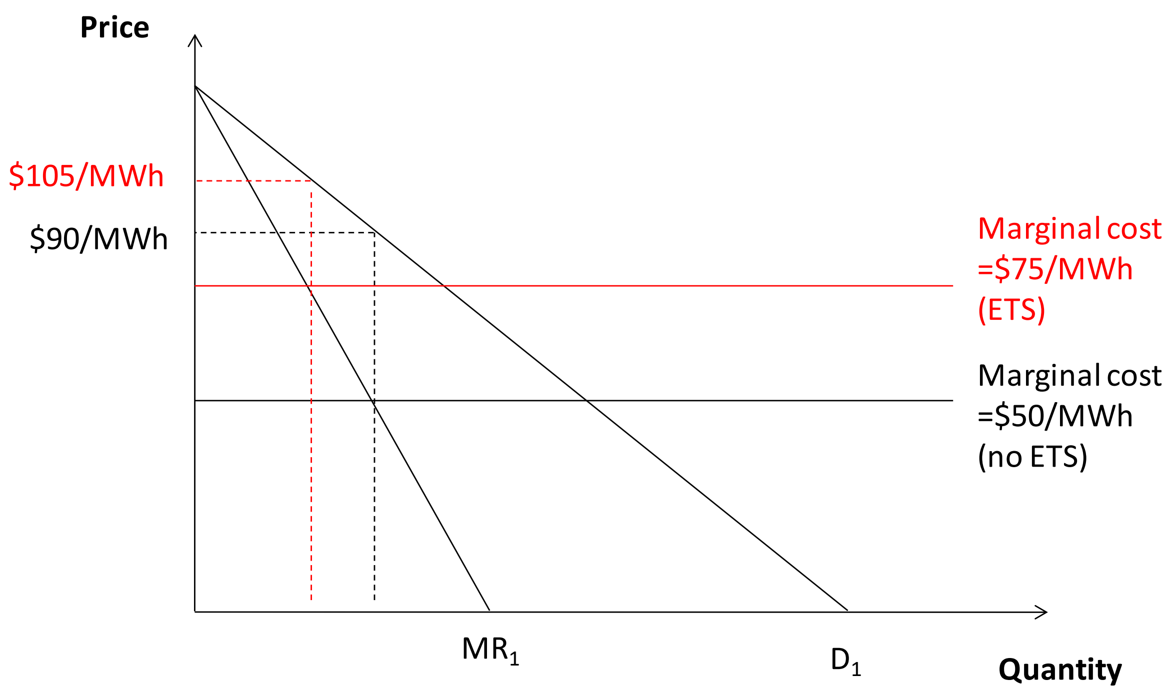
9 The so-called residual demand curve represents the portion of industry demand that is not met by other suppliers.

10 Again, this example is illustrative. In reality, the spot market is likely to be somewhere between perfect competition and a monopoly supplier.

11 Other simplifying assumptions have also been made such as no forward contract sales or inter-temporal effects, a homogeneous product, no externalities, and perfect information.

This will raise the price to $105/MWh. Again, this price is significantly higher than the new marginal cost of supply ($75/MWh), and again shows that cost data by itself would not be a reliable indicator of expected prices where suppliers have significant market power.

Figure 5: Illustrative effect of ETS on prices (monopoly supplier)



This example also illustrates another *general* point about the incidence of any additional cost. In a perfectly competitive market, the cost increase is expected to be borne entirely by purchasers because prices are always driven to the level of a supplier's avoidable costs.

However, absent perfect competition, prices would be expected to be above avoidable costs. As a result, any subsequent cost increase may be shared by purchasers (via higher prices) and sellers (via lower margins).

In the simple illustrative case shown, the ETS raised generator costs by $25/MWh. This was shared by a rise in the price paid by consumers ($15/MWh) and a reduction in generator margins ($10/MWh). This illustrates how the relative incidence of the ETS cost on purchasers and producers will be determined by the elasticities of demand and supply.

While the model is based on a monopoly example the more general point is that where a seller has market power (i.e. the price falls as sales increase or vice versa) and exercises it, some sharing of any cost increase would be expected. The basic intuition is that marginal revenue will be less than price (average revenue) if the seller has market power[12]. The profit maximising condition remains MR= MC. Given that the slope of the marginal revenue curve is steeper than the demand curve, the price effect would be expected to be smaller than the cost increase.

[12] Recall the marginal revenue is the change in total revenue if one more unit of output is sold. Because goods are sold at a uniform price, production of one more unit will reduce the price for all sales if the demand curve is sloped downwards.   Alternatively, Marginal Revenue = Price * (1 + 1/Price elasticity of demand). Given that price elasticity is a negative term when market power exists, marginal revenue will be lower than price (see Perloff, J., 2008, Microeconomics: Theory & Applications with Calculus, Pearson).

3.3 Summary

Section 3.1 describes how the ability of the generating fleet mix to change through generation entry and exit in response to changes in fuel & CO_2 prices or electricity demand will result in market prices tending, over the long-term, to the LRMC of the marginal sources of generation.

It also describes how in any given year, the 'actual' price impact is likely to be different to this LRMC-based value due to the market not being in equilibrium. However, crucially, the actual electricity price effect of a price of CO_2 will not be systematically higher or lower than the LRMC-based price effect for a market in equilibrium.

Further, attempting to consistently model the extent to which the market is in dis-equilibrium for both the factual and 'without CO_2' counterfactual 'parallel universe' becomes nigh impossible.

Accordingly, it is considered that the most appropriate framework to evaluate the electricity price effect of CO_2 should be an LRMC-based price effect for a market in equilibrium.

Section 3.2 describes how situations of market power are unlikely to alter this conclusion. Indeed, to the extent that market power existed, and was exercised on a sustained basis, it would likely have the effect of *reducing* the extent to which CO_2 prices flow through to electricity prices.

Not only is it considered that an LRMC-based approach to considering the electricity price impact of CO_2 is the most conceptually robust, but it has two other advantages:

- It is amenable to much less complex analysis than is required for so-called SRMC-type analysis, or imperfect competition analysis. This simplicity also aids transparency, auditability, and ensuring internally consistent assumptions.
- It is consistent with the frameworks used by the Electricity Authority, MBIE, and the 2010 Ministerial Review of the Electricity Market, to assess electricity prices. All these frameworks use fundamentally LRMC-based approaches to consider issues such as whether historical prices represent workably competitive outcomes, or what future prices may emerge under scenarios of different future electricity price drivers.