Electricity Allocation Factor Review Background Information

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for

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Definitions

The following abbreviations and acronyms are used in this report.

AB	Allocation Baseline
EAF	Electricity Allocation Factor
EDB	Electricity distribution (lines) business
EITE	Emission-Intensive Trade-Exposed
ETS	Emissions Trading Scheme
FPVV	Fixed price variable volume
GEM	Generation Expansion Model
GIP	Grid injection point (where a generator connects to the grid)
GXP	Grid exit point (where demand is supplied from the grid)
ICCC	Interim Climate Change Committee
LA	Level of Assistance
LCOE	Levelised cost of electricity
LRMC	Long run marginal cost
Ministry	Ministry for the Environment
NZU	New Zealand Unit (under the ETS)
SRMC	Short run marginal cost

Contents

1 Introduction

The Ministry for the Environment ("the Ministry") is reviewing the Electricity Allocation Factor (EAF).

The EAF is used to calculate free allocations of NZUs to eligible activities that are emissions-intensive and export-exposed (EITE). The EAF is stated in clause 6 of the Climate Change (Eligible Industrial Activities) Regulations 2010 and currently its value is 0.537 tCO_2/MWh. This number is a key parameter used in calculating the free allocation of approximately 2.9 million NZUs to EITE industries, currently valued at around $70 million per annum.

Section 2 reviews how the EAF is used and how it is calculated, introducing some the key drivers of its actual value, and recommend a methodology for its calculation.

Section 3 works through key parameters that will be inputs to the modelling.

Section 4 provides various values for the EAF which serve either as limits to its value or contextual values against which to compare EAF estimates.

Section 5 summarises key parameters for the EAF modelling. Section 6 is a list of references to reports that are relevant to the 2019 recalculation of the EAF.

2 The EAF

The Climate Change Response Act 2002 established the framework for the ETS, and it also allows for the issue of free NZUs to EITE industries. The allocation to an industry is given by

$$\text{Allocation} = \text{Production} \times \text{Allocative Baseline (AB)} \times \text{Level of Assistance (LA)} \qquad (1)$$

The AB is a function of the sources of emissions, which may or may not include electricity, but where electricity is included then the AB is partly a function of the MWh required to produce a unit of product and the EAF, along with any other emissions sources relevant to the entity.

The LA is one of two values, depending on whether an industrial activity is moderately emissions-intensive or highly emissions-intensive. A moderately emissions-intensive activity is defined as one in which emissions from the activity are greater than or equal to 800 tonnes per $1 million of revenue from the activity, but less than 1,600 tonnes per $1 million of revenue: the level of assistance has remained at 60% since 2012.

For a highly emissions-intensive activity the threshold is 1,600 tonnes per $1 million of revenue and the LA has stayed at 90% since 2012.

For example, consider a product that has an AB of 0.2 tCO_2/tonne product and where electricity makes up 80% of the AB, to give an electricity component of 0.16 tCO_2/tonne product. This value is the product of the EAF and the energy consumption per tonne which in this case is 0.298 MWh/tonne product, i.e.

$$0.298 \text{ MWh/tonne product} \times 0.537 \text{ tCO}_2\text{/MWh} = 0.16 \text{ tCO}_2\text{/tonne product} \quad (2)$$

Given production of P tonnes of product in a year, the annual allocation of NZUs is 0.16 × P × LA. For a given amount of production and a given LA, the allocation of NZUs does not change unless the AB changes, but as the carbon price changes, so does the value of the NZUs allocated, offsetting the implied change in the electricity price.

We can see from (2) that when the EAF changes, then all ABs that are wholly or partly based on electricity consumption, will also change. As most industrial and agricultural processes require electricity, a change in the EAF will impact the majority of the ABs.

2.1 EAF Definition

The EAF is a single figure that expresses the amount by which electricity prices change with the carbon price, and has underlying units of \$/MWh per \$/tCO_2 although these are usually shortened to tCO_2/MWh. This is not to be confused with a physical value, because electricity emissions average around 100 g/kWh of generation over a typical year, which equates to 0.1 MWh/ tCO_2: the EAF is all about price and it is most affected by what happens at the margin[1], not so much by overall averages.

The definition of the EAF was originally proposed by Concept Consulting in 2011 (Concept Consulting Ltd, 2011) based on the government wishing "to partially offset the impact of the ETS on the purchase cost of electricity for certain emissions intensive, trade exposed (EITE) electricity users", and is stated as:

$$EAF = \frac{Electricity\ purchase\ cost\ with\ carbon\ charge - Electricity\ purchase\ cost\ without\ carbon\ charge}{Carbon\ charge} \quad (3)$$

where the purchase costs of electricity are in \$/MWh and the carbon charge is specified in \$/tonne CO_2.

Concept Consulting noted that "the intent of the EAF is to establish the price difference between the 'with CO_2' factual and the likely 'without CO_2' counterfactual. To establish such a counter-factual requires a modelling approach which 'turns the clock-back' and projects a schedule of generation build and retirement from before 2010 (the date of introduction of the ETS) for a world where there has never been a cost of CO_2, and no expectation of such a cost."

The approach recommended by Concept Consulting, and adopted by the 2011 contact group, was to model the period of interest (2012 – 2017) and beyond both with and without a carbon charge, with electricity prices being the key outcome of the modelling.

On the face of it, (3) suggests a modelling exercise which focuses on the purchase cost (prices) with carbon charge, then to simply remove the carbon charge component and rerun the model: the difference between the two gives the numerator in (3). However, this is not the interpretation given by Concept Consulting, and instead it is necessary to model two separate worlds, one with and one without a carbon charge, and no expectation of a carbon charge: these two worlds potentially develop in quite different ways.

[1] Because spot prices reflect the marginal cost to spot purchasers.

But the phrase "no expectation of a carbon charge" could be interpreted in two different ways:

1. there is no climate change and hence there are neither carbon-reduction policies nor shadow price(s)[2] of carbon; or
2. there is climate change, and potentially domestic carbon-reduction policies, but there is no explicit carbon charge and never will be.

Interpretation 1 above is very restrictive, and could potentially require the modelling to use higher costs for new renewable plant than has actually occurred, on the assumption that in a world without climate change there would be much less investment in renewable technology development and that it would remain relatively expensive compared to fossil-fueled thermal plant.

Interpretation 2 seems more relevant to the EAF: where we live in a world where climate change is happening, and there is huge investment in renewables offshore because of demand induced by climate change, thus bringing the cost of renewables down, and where there may be domestic carbon-reduction policies; but not an ETS.

2.2 Methodology

In principle, if one can accurately predict prices that will occur with the ETS in place, which requires an accurate prediction of the carbon price, and also accurately predict how prices would turn out without the ETS, then by definition, one has the data to make an accurate prediction of the EAF.

But predicting future prices accurately is a difficult task, with hydro inflows alone creating large uncertainties in how prices will turn out in any given year, for example. It is difficult enough to model prices for the world we are in, i.e. a world that is increasingly carbon-constrained[3] with an ETS, but (3) requires modelling prices in a world which is no longer directly relevant and, as time goes by, increasingly irrelevant and potentially increasingly divergent from the real world.

Thus, calculating a new EAF is about as difficult a modelling exercise as one can get in terms of the electricity market and price forecasting.

There are a number of methods by which future spot prices can be predicted, and none is perfect. One way of managing the challenge is to adopt a modelling approach which works across methods and which also canvasses a range of possible futures, with and without a carbon charge. If a number of approaches point to a particular value of the EAF, or a small range of values, then there can be greater confidence that the value chosen will be close to the "real" value.

The 2011 contact group decided to proceed with three methods for the EAF calculation:

1. short run marginal cost (SRMC) modelling, meant to reflect a market that is perfectly competitive, or close to it, in the short term;
2. oligopolistic market modelling using a method named after 19th century French philosopher and mathematician Antoine Cournot;

[2] The estimated price of a good or service for which no market price exists, from dictionary.com.
[3] Constrained in an economic sense, by a price being placed on carbon.

3. long run marginal cost (LRMC) modelling which produces the optimum "build schedules" in the two different worlds.

A build schedule is simply the list of new plant that will be built over a period of time to meet demand growth and make up for any retirement of existing plant. Build schedules are based on the LRMC of possible new-builds, including all fixed and variable cost over the plant's respective lifetimes, whereas SRMC includes only variable costs[4].

In economic terms, LRMC is the minimum increase in total cost associated with an increase of one unit of output when all inputs are variable, so when we talk of the LRMC of a new generator that might be built, we are really talking about its levelised cost of energy (LCOE) which is the net present value of the all-up unit cost of electricity over the lifetime of the generating asset. LCOE is often taken to mean the average price that the new generator would need to attain in order to break even over its lifetime. In effect, the LCOE of the next cheapest new generator establishes the LRMC for the market as a whole. Furthermore, if the market is well-functioning, then the next cheapest generator should be the next plant to be built, and its trigger is its LCOE meeting or exceeding its forecast realized average price.

There are some complications, however, with LCOE and LRMC, which may not be obvious, but which are important to consider. The first relates to the exercise of modelling the build schedule at a global level, as opposed to calculating LCOEs at generator project level, as would be undertaken by a company that is actually contemplating the construction of a new generating station. The company knows its project better than global modelers do, so it is highly likely that global modelling will get the build schedules wrong in terms of build order and build timing.

The second is that the LCOE is the average price required to be realised in the market, and not the same as the average price in the market. So we cannot say, for example, that "there is a ceiling of \$70/MWh on the price because wind farms can be built with an LCOE of \$70/MWh". Using windfarms as an example, existing windfarms for which there is a long history, achieve average prices which are around 10% lower than the time-weighted average price at their respective GIPs. At best, the "ceiling" imposed by our hypothetical windfarm will be \$70/0.9 ≈ \$78/MWh[5].

Even then, this ceiling applies only at the relevant GIP. Our nodal spot pricing system includes the dynamic effect of marginal transmission losses which, on average, produces lower prices close to generators and higher prices at demand centres. So if our windfarm can be justified in the lower South Is, for example, then the \$78/MWh at its GIP could co-exist with prices that are higher by several percent or more in the upper North and South islands.

Finally, when we calculate a build schedule, we need to be clear about how deterministic it is: does it perfectly anticipate demand growth and the timing of plant retirements? Does it perfectly anticipate future spot prices over its lifetime? Real markets cannot generally anticipate such things, so the modelling needs to take account

[4] Costs that vary with generation output, e.g. fuel and carbon costs.
[5] As more and more wind farms are built, the difference between time-weighted average prices and realised prices is likely to increase.

of this in some way, perhaps through the choice of scenarios, or through the way in which LRMC modelling is undertaken.

Concept Consulting recommended the LRMC approach for modelling the counterfactuals for 2013-17 by calculating a build schedule starting from 2009 (not from the plant mix in 2011) in the without-CO_2 world.

On the other hand, the 2011 contact group included a guide to preparing the EAF (EAF Contact Group, 2012) based on their experience in 2011. The key points from this guide are not entirely consistent with Concept Consulting's recommendation, specifically that an LRMC-based build schedule should be produced using the GEM model, and then the build schedule should be modelled using an SRMC model, with EAFs being estimated from the outputs of the latter. The contact group "considered that LRMC analysis excludes some insights available from the SRMC analysis such as shorter term market impacts.[6]"

NZIER was engaged in 2015 to comment on the work undertaken by Concept Consulting in 2015 (Concept Consulting, 2015) and concluded that "a complementary SRMC and LRMC approach should be considered, and econometric analysis may be viable now with more historical data available. It also recommended that "more rigour be applied to the scenario design and especially in the interpretation of results" and that "the scenario design could be done interactively by interpreting the implications on SRMC, LRMC and potential new build using a high level top-down modelling approach (which could provide a 'null hypothesis' for testing using more rigorous modelling techniques)."

The contact group also listed a number of "lessons from the first two EAF determination exercises", quoted or paraphrased below (EAF Contact Group, 2012):

- the purpose of each scenario, and how the scenario fits into the overall EAF methodology, should be clearly stated;
- assumptions ideally should be sourced from independent verifiable sources;
- assumptions consistent with each other;
- simplicity and attention to the key variables of interest should be a focus;
- the build model should be allowed to select the optimum build as far as possible without external adjustments;
- consistency across multiple time horizons is important.

Based on our long experience with modelling to predict future spot prices, we also make the following comments in respect of common traps. First, there is no such thing as the "right" answer, and no amount of additional analysis will change this: the two futures (the actual future and the counterfactual future) are fundamentally uncertain and diminishing marginal returns to modelling will be reached sooner rather than later.

Second, the aim of the modelling should not be to find "the EAF" but to produce a sample distribution of possible EAFs from which, ultimately, a probability-weighted average EAF can be calculated. This will be the best estimate of the *expected EAF*.

6 For avoidance of doubt, note that Cournot modelling was not recommended by Concept Consulting, nor by the 2011 contact group.

Third, each scenario for the actual future should have a separate counterfactual scenario, as opposed to using one counterfactual for multiple scenarios: in other words, scenarios should be paired with their respective counterfactuals. EAFs are then calculated from these pairs of scenarios, to produce the required EAF sample distribution from which the expected EAF can be calculated.

This does not mean that one counterfactual cannot be the counterfactual for multiple scenarios, but it does mean that the resulting EAFs may have different weightings in the final expected value, even though they are calculated from the same counterfactual.

Fourth, the 2011 contact group was "of the view that an EAF recommendation should apply until significant events occur that would warrant a re-assessment." One key aspect of the 2011 modelling comes up many times as causing spurious results: the change in role of the Rankine units[7] at Huntly.

In fact, the retirement of any large thermal plant will potentially create substantial issues, as borne out by our own experience, and these are described in section 3.4. We recommend that plant retirements should be avoided in the modelling, unless strongly indicated by its presence in multiple build schedules, but instead the retirement of a large generator at some future date should trigger a recalculation of the EAF.

Concept Consulting was engaged earlier this year (Concept Consulting Ltd, 2019) and reported on a number of significant deviations of key modelling inputs from the values assumed, which is to be expected given the nature of the forecasting task. Based on this, and our own experience, we strongly recommend more regular reviews of the EAF modelling which will ensure that it is kept more in sync with the latest market conditions and developments. A lot can happen in five years, and in even less for that matter. Unless triggered earlier, a review period of between three and five years is suggested. If nothing has changed significantly, then the outcome may be that no further analysis is required[8].

Recommendation: Review the EAF at least every five years and preferably every three years.

The modelling process could proceed as follows, with iterations of steps as required and where Y below is 2 and 4 (modelled period between three and five years).

Step 1. **Counterfactual 2009 to 2019**
This scenario is required only to determine the starting plant mix for future scenarios and counterfactuals. For simplicity, it could use actual costs of renewables over time, and actual fuel costs to determine the optimum build, adjusted only where it is clear that the build model has missed a key datum or constraint. However, as explained in section 3.1 it will be necessary to used expectations of demand growth which fell from around 2% per annum in 2009 to virtually nothing by 2012, then rose again after 2016.

[7] Steam turbine units of 250 MW each, commissioned in the 1980s. There were originally four units but one is now decommissioned. Two remain in service and the third is available but only if Genesis Energy can find, and justify maintaining, the human and other resources required to operate three units.
[8] Given the accelerating rate of change in the market, this seems unlikely.

Step 2. **Determine Scenarios 2020 to 202Y**
Formulate a range of scenarios which captures the potential evolution of key variables including demand growth, price of NZUs, prices of gas and coal, prices of renewables, alternative sources of income for generation plant[9], and the costs of keeping existing thermal plant in the market[10].

Step 3. **Counterfactual(s) 2020 to 202Y**
Determine the counterfactual required for each scenario formulated at Step 2.

Step 4. **Build Schedules**
For each scenario and counterfactual, produce an optimised build schedule including retirements, if any.

Step 5. **Detailed Modelling**
For each scenario with build schedule, model the market for the period 2020 to 202Y, check the actual returns for new plant match target returns within reasonable limits, and fine-tune the build schedules if required.

Step 6. **EAF Calculations**
Using the appropriate scenario-counterfactual pairs, calculate the EAFs for each year modelled. If not done already at Step 2, then assign a probability to each scenario and calculate the weighted average EAF for each year.

Step 7. **Context Checking**
The 2011 contact group recommended that "consideration should be given to any complementary analyses that would add confidence to an EAF recommendation", and the range of EAFs and the weighted average in each year should be consistent with, or at least 'make sense' in light of, any other ways of looking at EAFs that make sense. These are listed in section 4.

Step 8. **Final EAF**
Calculate the final EAF as the average over the annual EAFs calculated in Step 6 above.

Step 5 above is the detailed modelling based on the scenario build schedules. This can be thought of as the SRMC modelling, but we actually recommend a modified SRMC approach in which all renewable plant is offered into the modelled market at its respective SRMC, or price otherwise indicated by observations of the market or market rules, large hydro systems with storage offered at its water value[11], and fossil-fueled plant is offered using an offer structure consistent with what is observed in the market. This is the approach, for example, was used in the modelling undertaken recently for the Interim Climate Change Committee (ICCC) for 2035.

[9] The case in point is the swaptions written between Genesis Energy and Meridian Energy, which are known to provide dry year cover for Meridian and to cover or partly cover the fixed costs of keeping Huntly units in the market.
[10] A case in point being the $70 million mid-life of the TCC in 2022.
[11] Assuming these are competitive water values which do not assume market power, then water value is the opportunity cost of the water in storage, and hence it is correct to use it as SRMC.

For the ICCC, geothermal and solar plant was offered at $0/MWh because solar farms have virtually no marginal costs, and geothermal plant does not respond well to being ramped up or down.

Windfarms are currently offered at $0.01/MWh, if they offered at all, but from later this year they will be able to offer up to five offer bands, as other generators are able to, and we expect their offers will change over time to reflect actual marginal operating costs, which were assessed at around $12/MWh in real terms in the ICCC modelling. A recommended range of offers is included in section 3.7.

The large thermal plant[12] were offered based on observed offer strategies where most capacity is offered at SRMC or less, with high output offered at SRMC plus a margin. Peakers offered at SRMC for around one third of output, and the remainder of capacity at SRMC plus additional margins which, when dispatched during winter peaks and dry periods, have the effect of recovering fixed costs[13].

TCC and Huntly were also offered, based on observed behaviour, only when weekly average prices exceeded specified threshold values[14].

By using market modelling, there is likely to be greater consistency between the LRMC modelling and the more detailed modelling. Furthermore, the calculated EAFs are more likely to reflect the real world.

Recommendation: Use market modelling instead of pure SRMC modelling.

2.3 EAF Calculations

Halliburton and Lermit (Energy Modelling Consultants Ltd, 2011) calculated EAFs using the prices from their SRMC modelling and it appears the EAFs used average North Is prices: “only North Island model results have been used in the following analysis as the differences in prices between the two islands are generally small, following the first stage of HVDC link upgrading, commissioned in 2012.”

As already noted, New Zealand’s electricity market has a form of spot pricing known as nodal pricing[15], which includes the impact of marginal losses, transmission constraints (when these are binding), and instantaneous reserves, the latter potentially creating price differences across the HVDC link in addition to price differences due to HVDC losses.

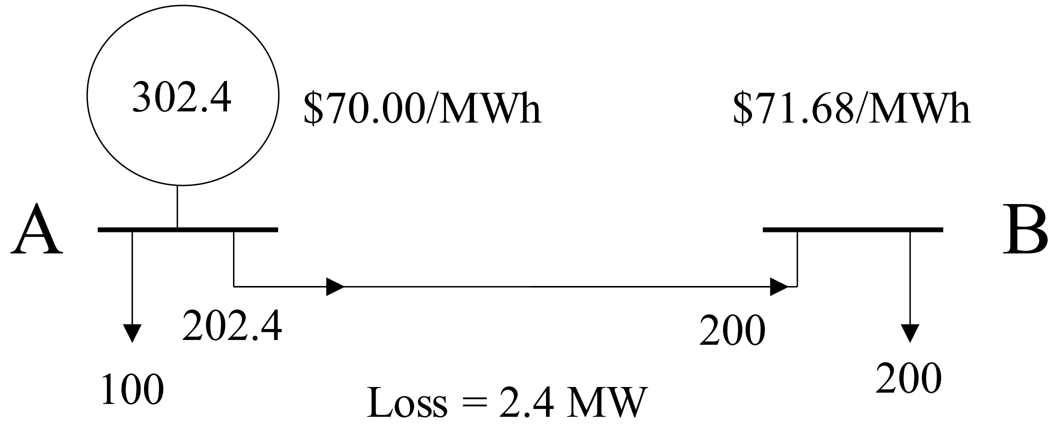
As a result of nodal pricing, combined with the location of generation and demand, there are persistent price differences across the grid. As inflows rise and fall, the relative price differences can change significantly so, for example, a dry period in the South Is can see flows southward on the HVDC link and higher prices in the south, lower in the north; and high inflows in the South Is can cause the opposite. So, when

[12] Huntly units, TCC, e3p.
[13] Short-term demand response and shortages were modelled for the ICCC at prices between $2,000/Mwh and $10,000/MWh, the latter being consistent with the scarcity pricing rules in the Code, but in the medium term the likelihood of shortage is very low, so these prices do not have sufficient influence to allow peakers to recover fixed costs.
[14] e3p appears to have adopted a similar strategy since October 2018.
[15]‘Locational marginal pricing’ in other markets.

we say "persistent" we mean on average across many years of the actual market, or across many modelled forecast scenarios.

An increase in the offer prices at one or more thermal stations, due to the cost of carbon under the ETS, for example, is transmitted to other grid nodes in proportion to these persistent price differences. A simple example is shown below in Figure 1 in which the marginal generator at node A offers generation at $70/MWh, and this is the nodal price at A, but the nodal price at B is $1.68/MWh higher due to marginal losses.

Figure 1 – Nodal Pricing Example with Marginal Losses



The point here is that if the marginal offer price at A were to increase by $1 then the price at B would increase by $1.024/MWh due to losses on the interconnecting line.

These persistent differences in spot prices also lead to differences in the prices of FPVV contracts[16], which the vast majority of consumers are on. The prices of ASX quarterly baseload futures contracts at Benmore and Otahuhu are often used as references for pricing hedges and FPVV contracts for larger consumers, and for the period from October 2015 to May 2019 the Otahuhu price for the third year[17] along the ASX forward curve[18] averaged 8.5% higher than the equivalent Benmore price, with a low of 4.1% and a high of 14.1%.

Recommendation: Consider whether the EAF should have multiple values to reflect regional differences in prices.

As originally recommended by Concept Consulting, we also agree that the EAF should be calculated on the assumption that all EITE consumers have flat load profiles. While some consumers will differ from this, for example dairy factories which tend to have load profiles which peak early in summer and which are lower over winter, the task of assessing all load profiles would be non-trivial for a relatively small benefit.

Recommendation: The EAF should reflect a baseload consumption profile.

[16] Prices are fixed at time of signing, but volumes transacted at these prices can vary in accordance with the consumer's actual consumption.

[17] The third year was chosen so as to reduce the impact of spot prices on ASX prices. For example, in October 2015 the prices used were the average of the four quarters in 2018.

[18] A forward curve is just a graph of the settlement prices of forward contracts, in this case futures.

3 Key Inputs to the Modelling

In this section we review key inputs into the modelling and related matters, and suggest likely ranges for inputs. We also refer to work done by Concept Consulting earlier this year (Concept Consulting Ltd, 2019) when the firm reviewed key EAF assumptions, their key conclusion being that actual outturns of key inputs would have produced an EAF lower than 0.537 tCO_2/MWh. It is, of course, very unlikely that the actual EAF, even if it can be observed with any accuracy, would turn out as forecast, but it is nevertheless instructive to review actual outcomes to determine, at the very least, if there are any lessons that can be learned for the current EAF review.

3.1 Demand Growth

Concept noted that demand was almost flat since 2011, remaining close to 40,000 GWh per annum, whereas the 2011 scenarios used 1.5%, 2% and 2.5% growth per annum.

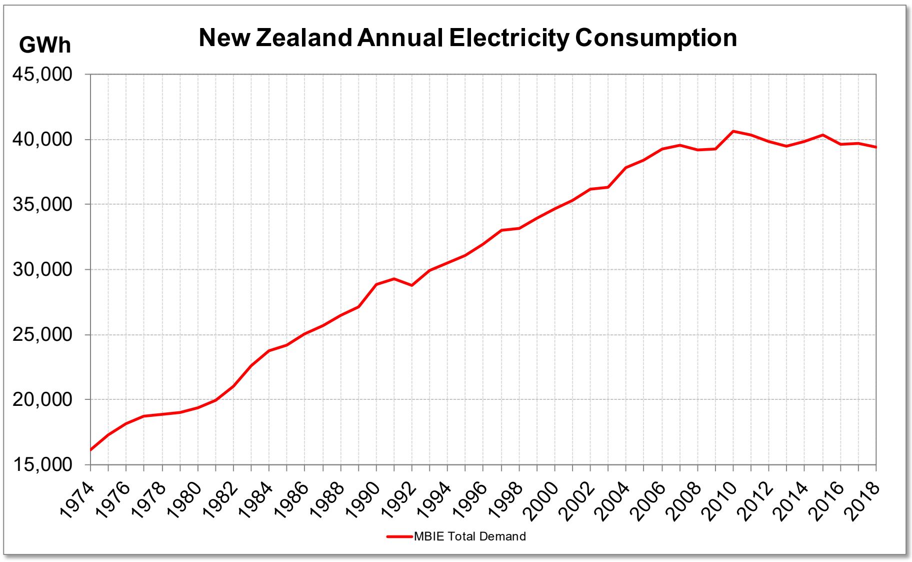
Concept's conclusions appear to be based on data published annually by MBIE in Energy in New Zealand, and currently available to calendar 2017[19]. This is the same data that Energy Link has referenced for many years, but we have recently become aware of a potential issue with the data, with the effect of understating demand growth.

The MBIE data is sourced from returns from retailers and therefore based on sales data, but the latest releases note that the data "does not include data for smaller retailers whose market share has increased in recent years. The Ministry is currently investigating increasing the coverage of this data." We do not know how many smaller retailers' data are missing, but the scale of the potential issue is likely to be significant given that at the end of 2018, the latest year for which MBIE data is available, independent retailers[20] had 178,485 ICPs. Of these, not all would have missed providing data to MBIE, but it is quite possible that a few hundred GWh of demand is missing.

The MBIE data extends from 2004 as shown below, with the change in average growth rate apparent after 2006.

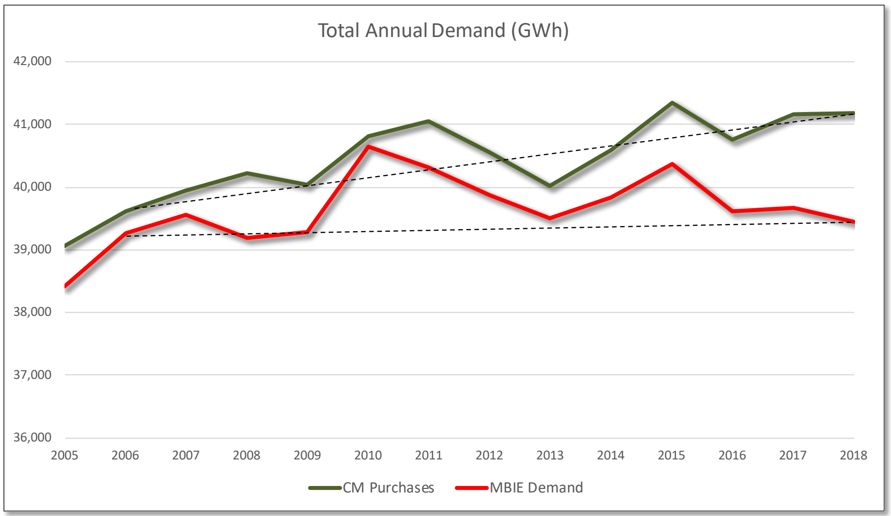
[19] Refer to Figure 5 in (Concept Consulting Ltd, 2019).
[20] Retailers not partly owned by the five largest gentailers.

Figure 2 – MBIE Demand



An alternative reference for demand are the total purchases in the spot market, from the Clearing Manager[21], which is shown below against the MBIE data. MBIE's demand has barely changed since 2006, while Clearing Manager purchases have trended up since 2006.

Figure 3 – MBIE Demand and Clearing Manager Purchases

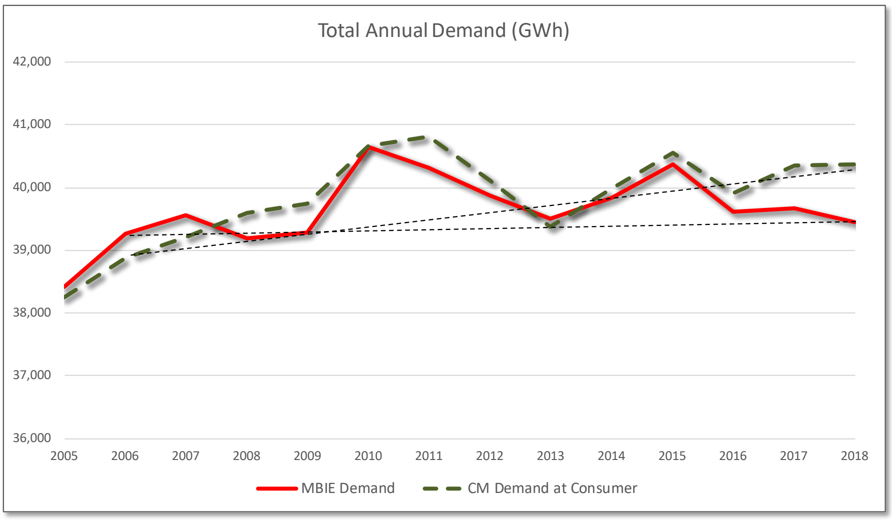


Purchases from the Clearing Managers, however, are reconciled to GXPs and so do not include local losses incurred on distribution networks. The following chart shows our attempt to roughly reference the Clearing Manager data to consumers' meters by removing local losses of 4%[22] and adding in onsite generation, including solar, and otherwise unallocated demand from MBIE's tables.

[21] NZX.

[22] This gives total losses of just over 7%, which is close to MBIE's long-run average value of just under 7%.

Figure 4 – MBIE Demand and Estimated Demand



Demand analysis is complicated these days by irrigation demand, which could be as high as 1,350 GWh per annum[23] and which swings around from year to year. The gap between MBIE and the estimated consumption in 2018 is 930 GWh, which is likely to be on the low side due to high spot prices at the end of 2018, resulting in a substantial demand response.

Growth in demand based on the estimates above has averaged 0.32% per annum since 2006 with the Tiwai smelter included, or 0.37% per annum with Tiwai excluded. Despite the fact that our estimates are quite rough, we believe there is evidence of demand growth of around 0.4% per annum excluding Tiwai.

Recommendation: Engage with MBIE to determine if a better estimate of actual demand can be made for the last few years, given the data missing from smaller retailers.

There is still some uncertainty about the future of the Tiwai smelter, but if the smelter were to close, or even to downsize significantly, then this would be such a large change to demand that it should trigger a recalculation of the EAF. The smelter has hedge contracts in place for 572 MW through to 2030 and for an additional 50 MW through to 2022, so Tiwai should be modelled as operating at its normal demand with four pot-lines in service.

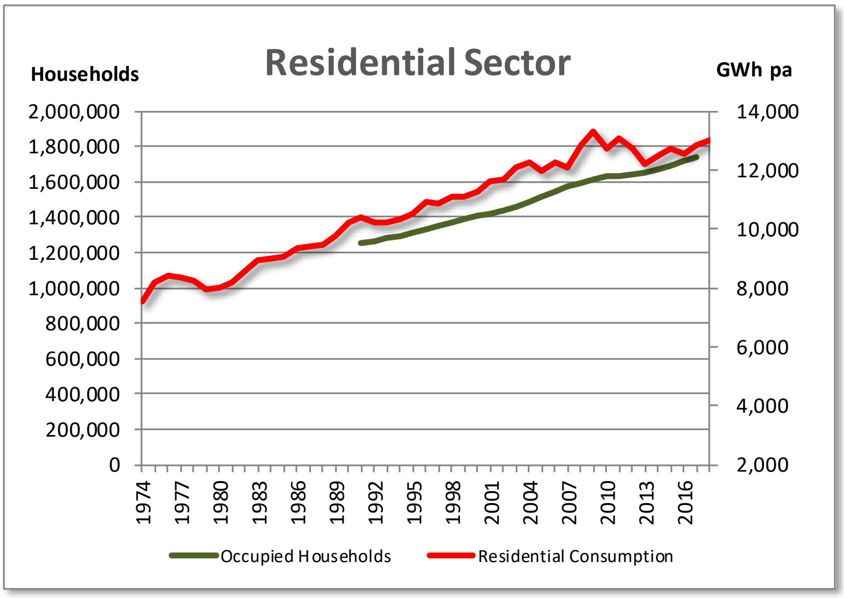
MBIE's demand data is split out into sectors, but the missing data issue discussed above means that the estimated total consumption, minus Tiwai, must be split out between the MBIE sectors. Small retailers are most likely to supply residential consumers, but some may supply a small number of commercial customers. If we assume that 100% of small

[23] Energy Link estimate based on 747,000 ha of irrigated land in New Zealand ins 2017 (Stats NZ) and *Energy Use and Efficiency Measures for the New Zealand Arable and Outdoor Vegetable Industry*, AgriLink NZ Ltd, October 2005, and *Submission: Electricity Price Review*, Irrigation New Zealand, 2018. There is 120 MW of irrigation at ASB GXP alone, with the potential for up to 518 GWh over a six-month season at full output.

retailers supply residential customers, then the sectorial demand is as shown in the following charts.

Residential demand took a pause from 2007 to 2013 but is on the rise again as population increases.

Figure 5 – Residential Demand Estimates



The average consumption per household has fallen 2009, as shown below, even as the number of occupants per household increased as shown in Figure 7. Anecdotal evidence suggests that wealthier households have invested in energy efficient lighting, appliances, and added insulation, but that this trend has slowed, so that the fall in household consumption has run its course for the time being.

Figure 6 – Residential Consumption per Household

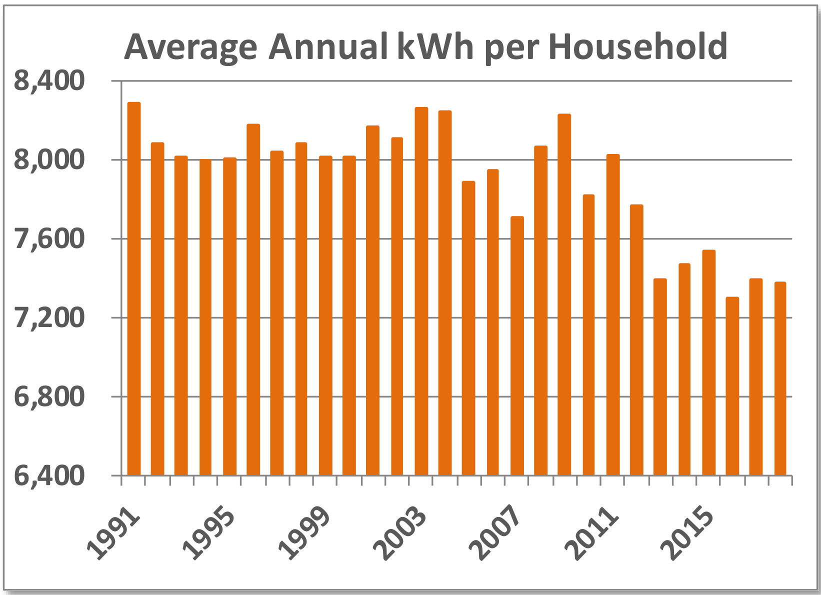
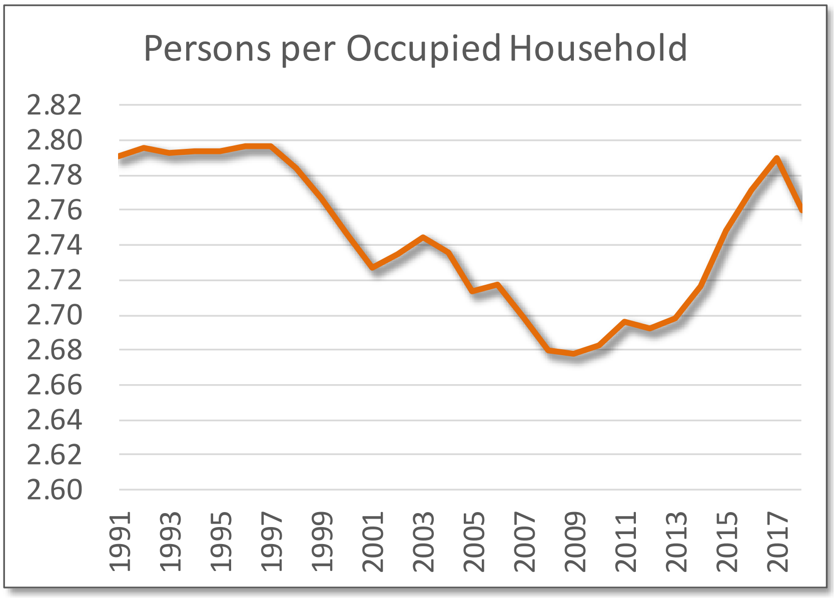


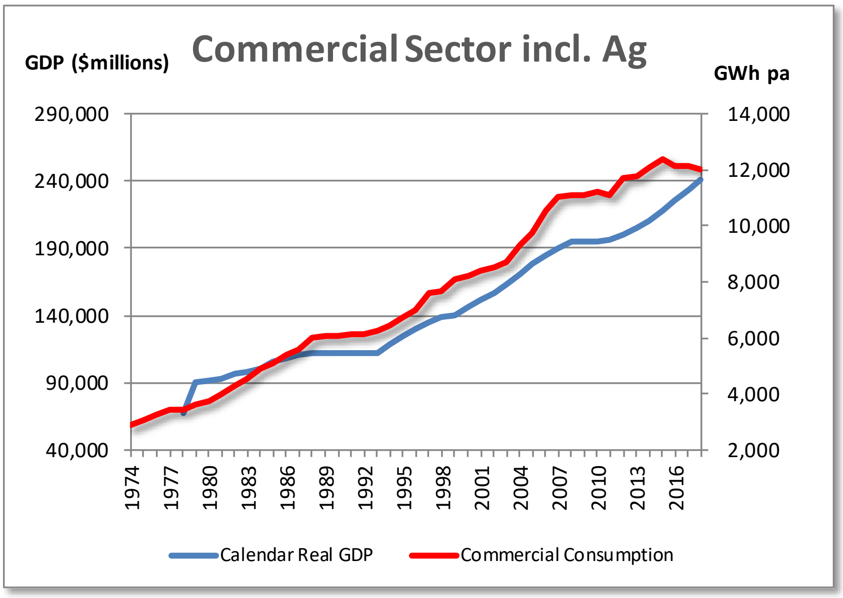
Figure 7 – Occupancy Rate



Continued strong population growth[24], therefore suggests that residential demand growth will continue at its current rate for some time yet.

On the other hand, growth in the commercial and ag sectors has halted in the last three years, partly driven by a slow-down in the rate at which new dairy farms and irrigation are developed. Demand in the non-ag commercial sector may be driven by increasing energy efficiency, e.g. lighting and heating, but possibly also by the increase in online shopping versus visiting stores, hence static or reducing commercial space.

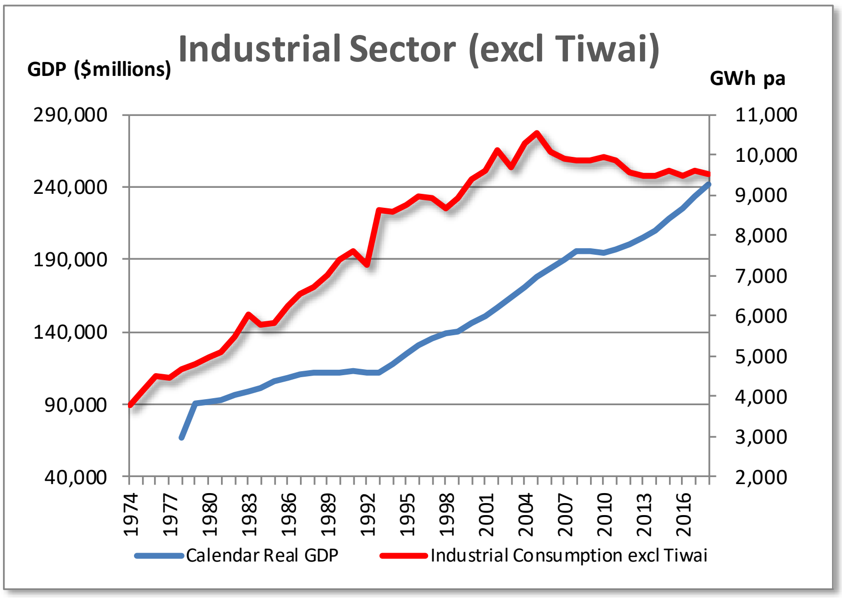
Figure 8 – Commercial-Ag Demand Estimates



[24] Stats NZ data for the year ending April 2019 is 55,834 for net migration, 11% up on the same month last year.

MBIE's industrial data is broken down into sub-sectors. The restart of Tiwai's fourth pot-line will reverse the trend in the basic metals sub-sector, but 1,564 GWh per annum has gone from the Wood, Pulp, Paper and Printing sub-sector since 2004, and nothing seems likely to reverse this trend.

Figure 9 – Industrial Demand



Based on the last two to three years, demand growth is only present in the residential sector at the rate of around 240 GWh per annum. If this rate is applied to the market as a whole it equates to 0.6% per annum.

The ICCC's base case assumed demand growth of 0.5% per annum, with additional growth from EVs and electrification of industry at a low rate, and this would be consistent with the latest estimates provided above.

It is possible that demand could grow at a lower rate if, for example, population growth were to slow significantly, or if the nation were to move into recession. Or solar installations could increase in frequency or in size[25].

A factor that has only recently become significant in our modelling of sectorial demand, and then only in the residential sector, is the average temperature for the year: recent years have seen record temperatures, particularly in the colder months, which could signal more impact on electricity demand in future. The potential impact is difficult to assess because it is only since 2016 that we have observed this effect, combined with the limited length of MBIE's quarterly sector data which has only been available from June 2013.

Demand could grow at a higher rate if, for example, growth picks up in the commercial and industrial sectors (excluding Tiwai) after several years of consolidation. It is also possible that a large new industrial load could locate in New Zealand[26] due to, for

[25] Based on reports in Energy News, Refining NZ and others are evaluating large solar farm projects. Only time will tell if large scale solar is currently economic in New Zealand.
[26] Based on queries over the years.

example, our high percentage of renewables and the marketing benefits this might create. In the longer run, there is greater potential for higher demand growth rates once the conversion to EVs really kicks in, and also driven by the increasing electrification of industry. But over the shorter horizon of the EAF modelling, recently observed growth rates are probably more relevant.

Recommendation: Base Case demand growth of 0.5% with a low growth scenario of 0.3% and a high growth rate scenario of 0.8% per annum. To these rates, add EV and solar uptake based on recent trends.

Recommendation: Assume the Tiwai smelter continues to operate at close to full capacity in all scenarios.

Each of the three demand scenarios needs to be paired with a relevant counterfactual scenario, which raises the question of how demand would have grown since 2009 without a price on CO_2.

The charts above show that demand growth had already changed by 2009 from what it was up until 2006[27], so there does not appear to be any reason to make large adjustments from the three demand scenarios recommended above, except to the extent that the price impact of the ETS may have caused electricity demand to have reduced (assuming the introduction of ETS led to higher prices) of switching away from other fuels to electricity.

We observe statistically significant demand elasticity in the residential demand sector, when using real electricity prices, suggesting that residential could now be around 1,000 GWh per annum lower in 2018 than it would have been if the real electricity price had not risen since 2009. The actual change in price, however, cannot all be blamed on the ETS, because the ETS does not impact the component of the price which reflects retailers' non-energy costs and line charges. Any demand reduction associated with the ETS, therefore will be much less than 1,000 GWh.

Recommendation: Base Case counterfactual demand growth of 0.5% with a low growth counter of 0.3% and a high growth rate counter of 0.8% per annum, plus EV and solar uptake based on recent trends, with a small correction for demand elasticity from 2009 to 2019 if indicated by the price difference between scenario and counterfactual.

3.2 Carbon Prices

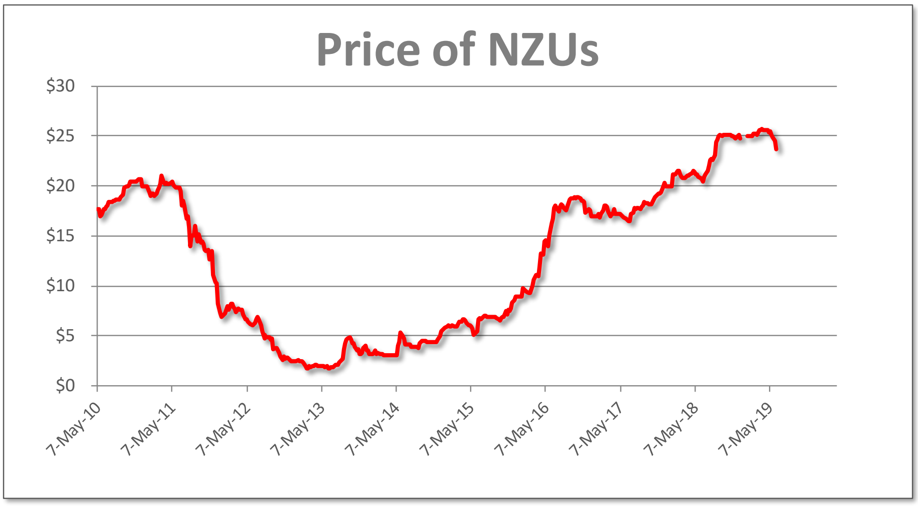
Concept Consulting showed that NZU prices turned out lower than forecast for the 2013-17 period, based on the actual prices and after allowing for the two emissions for one emission unit policy under the ETS, which finished at the end of 2018. Concept Consulting concluded that the EAF would have turned out lower than 0.537 tCO_2/MWh had the lower carbon costs been anticipated.

Emitters have had the option to buy NZUs from the government for $25 each (fixed price option, FPO) and spot prices[28] reached this value late last year, in the expectation that the FPO would increase this year. However, NZU prices have fallen to close to

[27] From 1974 through to 2006 demand growth averaged just under 700 GWh per annum.
[28] We source prices weekly from OM Financial's Commtrade system.

$23, as shown below, since recent ETS announcements delayed any change to the $25 FPO until the introduction of cost-containment reserve auctions probably late in 2020, but no later than December 2022.

Figure 10 – NZU Prices



Forecasting NZU prices is fraught with difficulty. It is easy to show, for example, that even if the EAF is as low as 0.1 tCO_2/MWh, it would take an NZU price of almost $400 per tonne for electricity and gas to produce heat at the same marginal fuel cost in common process heat applications if a gas boiler were replaced with an electrode boiler[29]. But this would cause a 290% increase in the cost of gas and a 50% increase in the cost of electricity for larger consumers, with significant rises in the cost of electricity for all consumers.

The adverse reaction from consumers, and the political consequences of the very high NZU prices that might need to be reached in order to trigger mass switching of gas to electricity, are obvious. The ICCC assumed $50 per tonne price by 2035, in real terms, which could be applied to the EAF modelling by scaling the NZU price linearly up from its current level toward $50. Lower and higher prices can be included in scenarios with their respective probability weightings applied: given the relatively short term recommended, price deviations from the linear price path should be modest, say no more than $10 each way.

A complication, however, is that not all generators face the same carbon prices, as some have hedged their carbon exposure through to 2024, in the case of Genesis Energy for example. Genesis and Contact Energy have also established the Dryland Forestry Partnership along with Air New Zealand and Z Energy, for the purpose of reducing their respective exposures to carbon prices and, ultimately, to generate NZUs at lower-than-market prices. Estimates of these prices need to be made, and included in the scenarios.

There is an economic argument that carbon costs should be factored in at prevailing market rates, however Genesis and Contact have plant which runs in baseload-firming

[29] This is perhaps an extreme example, as significantly lower NZU prices might cause switching to high temperature heat pump technology, all other things being equal.

modes, so the threat of new entry of renewables is likely to constrain carbon costs to actual values.

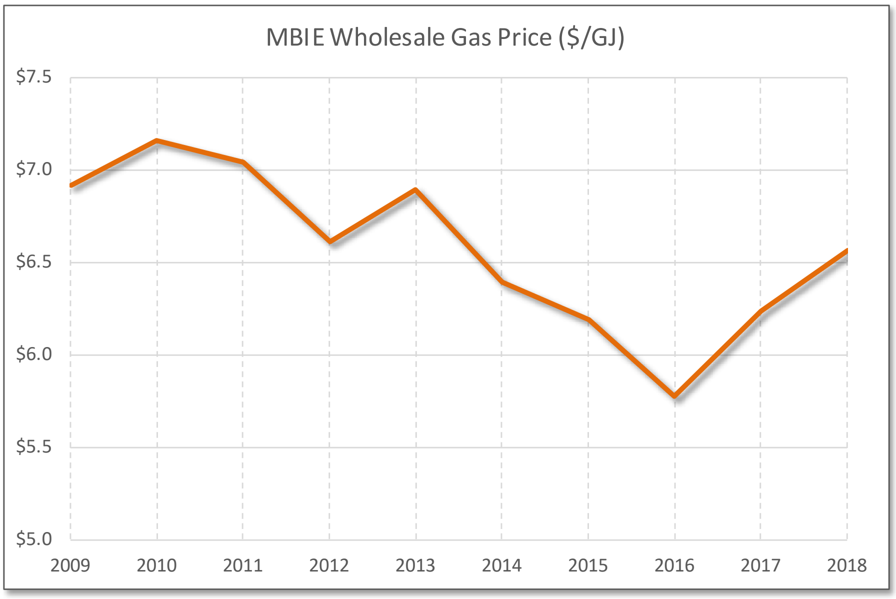
Recommendation: Include carbon prices for Genesis and Contact plant on a cost basis.

Recommendation: Form carbon price scenarios which take into account the political-economic environment in which the ETS exists, including the likely introduction of a cost-containment reserve in 2021 and the influence of other emissions-reductions measures that reduce reliance on the ETS as the sole driver of incentives to reduce emissions[30].

3.3 Fuel Prices

Concept Consulting noted that gas prices were below the 2011 EAF forecast of $7.28/GJ (in 2009 dollars) and the following chart shows the annual average wholesale gas price updated to include 2018.

Figure 11 – Wholesale Gas Price



The chart shows just how soft the gas market was after 2011, but it has tightened up since 2016. The latest reserves data for January 2019 were published by MBIE on 13th June and show an increase of 71 PJ (3.6%) over the January 2018 data. In the longer term, however, the reserves have fallen from 2,642 PJ in 2014 to the latest figure of 2,037 PJ.

Despite a high level of exploration activity[31] through to 2014 there have been no significant new fields discovered since the early 2000s, and then exploration activity ground to a halt from 2015 to 2017[32]. As a result, virtually all new reserves are from

[30] For example, the announcement on 9th July of the government's intention to introduce a Clean Car Standard and Clean Car Discount scheme.
[31] Exploration refers to drilling that is targeting new gas fields.
[32] 2018 activity data is due to be released by MBIE in September.

development drilling in existing fields, and with the ban on new offshore exploration, we are now almost totally reliant on existing fields[33]. Even if new discoveries are made in existing offshore permits, not all of these permits are within pipeline distance of the existing gas transmission system, which means that these discoveries may not provide additional gas for generation.

Methanex recently announced it had secured half of its gas requirements through to 2029 and is working on the other half, potentially locking up 45% of total gas production through to the end of next decade, at the same time as the ratio of reserves to production is now less than 11 years.

Assuming demand for gas continues at current rates, the latest MBIE data shows the Maui field being totally exhausted some time in 2021. But OMV has announced plans to extend the lives of the Pohokura and Maui fields, and on 14th June Contact Energy announced that it has secured 40 TJ/day from OMV for this winter and "supply of Maui gas at the same price for 2020 to 2024, with volumes subject to field deliverability."[34] This announcement confirms the OMV announcement and although the price was not disclosed, based on this and other recent announcements by Contact, the price seems likely to be close to $7/GJ. This tends to indicate that supply is relatively tight and that there is upward pressure on prices, in line with the generally tight supply-demand balance and the ban on new offshore exploration.

The only bright note in the latest MBIE reserves data is an increase of 438 PJ (23%) in the 2C contingent reserves, which is the best estimate of potential reserves not currently considered to be commercial due to one or more contingencies including, for example, where there are currently no viable markets, or where the resource is only viable using new technology under development, or where evaluation the data is insufficient to allow a full commercial assessment to be made. This increase came primarily from a large increase for the Todd-owned Maganhewa field, whereas there was a significant reduction for OMV's Pohokura field.

With a background of tight supply, the ICCC used Energy Link's central gas price forecast for uncontracted wellhead gas in 2035. However, in the shorter term, which is the domain of the EAF modelling, it would be prudent to base gas prices on what is known about gas that is already contracted using the latest announcement from Contact and disclosures from Genesis, with PPI escalation where relevant. Todd's gas[35] prices are not in the public domain but may be inferred from the spot prices at which the McKee peaker runs, when it runs, after making an allowance for carbon costs.

Recommendation: Scenario gas prices should be based on disclosed prices of gas, or prices that can reasonably be inferred from spot market behaviour, with escalation where appropriate.

The counterfactuals do not include a price on carbon, but nevertheless there might have been carbon-reduction policies such as the ban on new offshore oil and gas exploration, which is not directly related to the ETS, but which can apply even in the counterfactuals.

[33] OMV has announced their intention to drill in existing offshore permits.
[34] https://www.nzx.com/announcements/336046
[35] Used to fuel the McKee peaker and the new Junction Rd peaker due to be commissioned in 2020.

With no carbon price on gas and coal, however, the outlook for existing thermal generation and for new thermal plant is potentially quite different, even if the gas price evolves in the same way, which suggests that the only fuel price difference between the gas scenarios and their respective counterfactuals should be the direct impact of the carbon price.

Recommendation: Counterfactual fuel prices should be the same as the relevant scenario fuel prices, with PPI escalation if deemed appropriate.

The only station left burning coal is Huntly, and then only a mix of gas and coal, the ratios depending on the availability and cost of each fuel at the time. The events of the last year[36] have shown that the presence of a diversified fuel mix, gas and coal, has substantial value in ensuring security of supply during unexpected events. Genesis Energy purchases some coal locally but late last year resumed imports of coal from Indonesia, to supplement the 150,000 tonnes per annum of domestic coal that it has under contract with BT Mining.

Genesis has run the coal stockpile down in recent years, so the average price of coal in the stockpile has moved closer to the average of the locally contracted coal price and the price of short to medium term contracts for imported coal. There is little or no information in the public domain concerning the price of locally contracted coal so we recommend using a forecast of the term price of Indonesian coal of the correct specification.

The global price of coal is almost certainly independent of demand for coal exports to New Zealand, so we also recommend using the same coal price in the counterfactuals.

Recommendation: Coal prices in scenarios and counterfactuals should reflect forecasts of short to medium term contracts for imported coal.

3.4 Plant Retirements

The retirements, or partial retirements, of key thermal plant are potentially highly disruptive events with significant impacts on spot prices. Concept Consulting pointed out that two units at Huntly were retired earlier than any of the dates assumed in the 2011 modelling. Unit 3 was permanently retired in 2015 and one further unit is in storage, leaving only two operational units[37].

Southdown and Otahuhu B were also retired in 2015, the former being announced in February 2015 and the latter announced on 17th August 2015 for closure in September 2015[38]. This is an important point, as it tells us that we cannot assume plant closures will be signaled well in advance.

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[36] Two major outages of the Pohokura gas field which had the effect of restricting total gas consumption by 22 PJ.

[37] Genesis announced earlier this year that it is looking at making a third unit available over winter, but this is dependent on being able to secure the human and other resources required to operate three units.

[38] Contact later claimed this was well signalled, but this is at odds with perceptions of other markets observers and participants that we have talked to.

Contact has publicly stated that there is a "reasonable chance"[39] that the TCC will close in 2021 if the $70 million cost of its mid-life refurbishment is not justified in economic terms. Given that Contact is not a participant in the upstream gas market, it is likely to face greater fuel price and availability risk than Todd Energy and Genesis who are upstream participants. TCC is designed as a baseload CCGT but for some years it has operated intermittently, only when prices are high enough to warrant its presence in the generation mix, so it is now effectively in a firming-peaking role. It is not designed as a peaker, and given the fuel risks, retirement in 2021 seems likely.

It is well known that the continued presence of two Huntly units is underwritten by the large swaptions[40] agreed between Genesis and Meridian Energy since 2010, with the current swaption expiring at the end of 2022. But recent announcements from these two gentailers strongly suggest that both are looking at alternatives. If this source of funding for Huntly's fixed costs were to reduce significantly, then the continued operation of Huntly would be called into question.

The retirement of large thermal plant is highly significant for two reasons:

1. if a retirement is not unambiguously signaled years in advance, which is unlikely given past history, then there will be delays in building replacement plant, leading to squeezes on supply and price increases[41], i.e. the market will be in disequilibrium;
2. the units are likely to be replaced by a mix of renewables and thermal plant, e.g. wind farms, geothermal, peaker: this may make up for the retired capacity on average, but there will be periods when there is more capacity than required, and periods when there is less than required, with the consequence that price volatility is likely to increase[42] after the retirement.

In theory, one can use an LRMC model to determine the optimal dates for retirement, but in practice it is impossible to predict the outcome of future events which can be binary in nature, e.g. a new swaption between Genesis and Meridian is signed in 2022, or it is not signed, combined with the difficulty in determining how market participants view the risks of retaining or not retaining certain plant, e.g. does Contact view being reliant on upstream gas participants as an excessive risk for its business, or is it confident that fuel will be contracted reliably and economically in the long term?

Retirement events are potentially so significant and so disruptive, combined with being difficult to predict, that we recommend the modelling assume these do not happen during the EAF modelling period. Instead, a major retirement event should be a trigger for another EAF calculation.

Recommendation: Ignore the possibility of plant retirement and assume existing plant continues to operate through to the end of the EAF modelling period.

[39] As reported by Scoop on 13th February 2019.
[40] A swaption is an option to call on a predefined hedge contract. In this case, Meridian is the buyer, Genesis the seller.
[41] There is good evidence to suggest that we are in such a period right now.
[42] In other words, a large amount of firm capacity is replaced with a smaller amount of firm capacity (perhaps none if no peaker and geothermal is built) and a significant amount of non-firm capacity.

3.5 Build Schedules and the LCOE

The LCOE of a project is a key determinant of whether it might proceed or not. However, it is difficult to predict the LCOE of any particular project unless one has very detailed knowledge, usually more than is available for modelling exercises such as this.

Instead, the modeler needs to have a range of projects available for which LCOEs can be calculated which are "reasonably accurate" in the sense of providing an indicative range for each type of generating technology. Put another way, the objective is not to predict which plant will be built next, but at what price level it will be built.

It can be dangerous to take international experience and translate it directly to New Zealand because we are a small market which is located at a great distance from the countries where we source most of our generating plant. Our civil costs, a significant component of any project, are higher than in larger countries closer to suppliers, and we lack depth in the energy EPC[43] sector.

At the New Zealand Wind Energy Conference held in May 2019, Vestas presented on the latest turbine technology which could be applied in this country and claimed that "with taller towers and more advanced turbine technologies [including much greater tip heights], a typical New Zealand wind power plant may produce 83% more energy annually comparing to the current best solution"[44] but at the same event Tilt Renewables' presentation stated that "significantly larger WTGs are not necessarily the solution at every potential NZ site due to access/topography/visual amenity/wind conditions etc"[45].

The best indication of the forecast cost of building new plant in New Zealand, therefore, is the cost of actually building new plant in New Zealand, i.e. using data from recent projects. Trends in prices are certainly important, but any that are taken from overseas must be calibrated to our conditions.

The ICCC modelling included BAU assumptions around trends in LCOE of 0.5% annual decrease for wind and 4.5% decrease for solar to 2025 then 2.0% per annum to 2035, both in real terms.

A key issue for LRMC modelling to produce build schedules is that in the real world LCOEs are compared to forecast prices when making the decision to build. Modelling this process means that it is not valid to assume that prices are known in advance, and some account of this uncertainty should be included, either in the LRMC model itself, or in the range of scenarios that are run. Alternately, LRMC models that work on demand growth assumptions need to take into account the uncertainty in future demand.

The conterfactuals will all need a 2019 plant mix as a starting point for producing a build schedule for each scenario. Back in 2009, the EAF modelling assumed demand growth of 1.5%, 2.0% and 2.5% per annum which was a commonly used range back then. Over time, the market came to realise that demand growth was not likely to return

[43] Companies that specialise in engineering, procurement and construction for energy projects.
[44] http://www.windenergy.org.nz/store/doc/Next-generation-of-wind-turbines-and-the-future-of-NZ-wind-energy_Peter-Cowling-Vestas.pdf
[45] http://www.windenergy.org.nz/store/doc/NZs-energy-transition-and-innovation_Clayton-Delmarter-Tilt-Renewables.pdf

to its historic rate of growth prior to 2006, and expectations adjusted downward, so that by 2012 plans to keep building new plant at historic rates had more less been shelved. Due to the time it takes to construct new plant, however, the last plant to be commissioned as a result of the old demand assumptions, was probably Te Mihi in 2014.

But as a consequence of the multi-year downward adjustment in expectations of demand growth, the counterfactual build through to 2019 needs to be undertaken on the same basis as the real market, with a major assumption change from around 2012, which should result in an over-build of new plant relative to demand, less any retirements, just has actually happened.

3.6 Contracts

The discussion of the EAF thus far, and the modelling in 2011, was only concerned with the impact on spot prices. However, most consumers, even the larger ones, either avoid spot price risks by contracting FPVV, or hedge spot price risks, which means their exposure directly to spot prices is low, and their costs are driven by fixed price contracts. As noted in section 4.4 above, historical contract prices exhibit a significant premium over actual spot prices, so we can expect that consumers will pay more than spot prices in future.

An adjustment to the EAF should be considered to reflect premiums evident in FPVV and hedge contracts, for which there is enough historical data to make reasonable estimates. This could add of the order of 10% to the EAF, so it would be a material change to the EAF calculation methodology.

Recommendation: Consider whether the EAF should include an adjustment reflecting premiums in the fixed price contracts typically transacted with larger consumers.

The spot market, the domain of the EAF modelling, does not exist in isolation from the market for FPVV contracts and hedges. In fact, the existence of contracts between market participants modifies their offering behavior, to varying degrees, with the large gentailers typically offering plant at SRMC or less to cover the total of their FPVV sales plus hedges. Plant offered beyond the amount required to cover sales and contracts is offered at prices which will set spot prices higher than SRMC, if and when dispatched, and therefore increase the chance of recovering the fixed costs of plant.

There is limited information available about the total sales and hedges contracted to market participants, although some can be inferred from disclosures by listed companies, for example. But a typical approach would be to assume that behavior observed over the longer term is reflective of future behavior, e.g. the total quantities offered at SRMC versus quantities at SRMC plus a margin.

The swaption between Genesis and Meridian can be modelled by modifying the offers of one unit at Huntly under conditions in which the swaption might be called, i.e. periods of low storage in, and low inflows into, Meridian's storage lakes.

3.7 Policy and Market Structure

There are a number of policy and regulatory developments that need to be considered, including:

1. transmission pricing;
2. distribution pricing;
3. changes to how windfarms offer into the market;
4. changes to the ETS;
5. "100% renewables by 2035 (in a normal hydrological year)" coalition clause;
6. Climate Change Response (Zero Carbon) Amendment Bill.

The Zero Carbon Bill includes a Climate Change Commission which would make recommendations for changes to the ETS (see section 3.2).

The Climate Change Commission might make other recommendations relevant to the EAF, but there is nothing in the bill which suggests what these might be or when they might occur.

The confidence and supply agreement between the Labour and Green parties includes a goal to "request the Climate [Change] Commission to plan the transition to 100% renewable electricity by 2035 (which includes geothermal) in a normal hydrological year". The ICCC's report is currently with the government and it recommends, in simple terms, that priority should be given to electrifying transport and industry rather than meeting an arbitrary renewables target for electricity. This is based on detailed modelling which shows that the cost of getting to very high renewable levels rises exponentially, but also on the difficulty of defining a "normal hydrological year". Even during wet years, capacity is required to meet peak demand in winter, and this is most economically provided by including gas-fired peakers in the plant mix. If the price is right, this could also include coal-firing at Huntly, however, the ICCC also assumed that Huntly (and TCC) would be retired well before 2035.

Without knowing how the government will react to the ICCC's recommendation, it is difficult to know if the request to the Climate Change Commission will be made in a modified form, or if it will be made at all. As a result, we recommend ignoring the possibility for policy changes, other than those already signaled for the ETS. If policy announcements are made in the future, these might be triggers for EAF recalculations.

The Electricity Authority is about to announce a new proposal for the TPM, the third since late 2012. We can be reasonably certain that this will include the abolition of the HVDC charge, which currently imposes a cost on South Is generators of around $8.60/MWh which is not borne by North Is generators. The original rationale for levying South Is generators for the costs of the HVDC link was that it primarily benefited these parties by giving them access to higher prices in the North Is. While this is still true, the HVDC link also benefits North Is generators by giving them access to higher prices during dry periods, and South Is and North Is consumers by lowering prices and improving security of supply.

The proposal may introduce new charges on North Is generators, but these are harder to predict.

There may also be a period over which the existing charges are phased out and new charges are phased in.

Although we cannot be certain that the new proposal will be adopted in the short term, the ICCC's modelling demonstrated that in the longer term the nation will become more reliant on wind generation, and that correlations in the output of wind farms will become very important. As a result, locational charges made to generators, such as the HVDC charges, could create very significant distortions in the mix of new plant, and impose higher costs on consumers.

We therefore recommend assuming that the HVDC charge will be phased out over the new few years, and that the HVDC charge be scaled down over the EAF modelling period.

The Electricity Authority has also put pressure on distributors to move away from line tariffs that use simple variable (per-kWh) charges to recover the majority of EDBs' revenues from residential and SME consumers. One driver for this is that the status quo artificially incents the installation of solar power. As the process is well underway, we recommend that behind-the-meter solar uptake assumes that the value of solar power is the forecast daytime spot price so that behind-the-meter solar power competes for market share on the same basis as grid-scale generation.

Recommendation: Assume the HVDC charge of around $8.6/MW of South Is injection is phased out over the next few years.

Recommendation: Assume the per-kWh value of behind-the-meter solar power is the relevant forecast daytime spot price.

Windfarms are obliged to offer into the spot market at $0.01/MWh, if they offer at all, but from later this year they will be able to offer up to five price-quantity bands just like other generators. This introduces the possibility of windfarms offering their actual SRMCs, which could include variable costs of repair and maintenance, royalties or land rentals, for example.

Estimates of total SRMC are available for offshore windfarms, but data for New Zealand is harder to obtain, and the current offering rules have caused these to be hidden from the market. Offshore estimates suggest the SRMC may be of the order of $8/MWh to $25/MWh, the latter for older turbines. Some windfarm operators have long term fixed price contracts for O&M so their effective SRMC may be much lower.

The windfarm SRMC value used in the ICCC modelling was $12/MWh[46], which is at the lower end of the above range. We recommend that a range of values is used for windfarms with older wind farms offered at up to $20/MWh and new windfarms offered at prices lower than $5/MWh for their first few years, reflecting technology improvements and the likelihood of windfarm owners having fixed price O&M contracts for at least the first few years of operation.

Recommendation: SRMC modelled offers for windfarms to be set between $20/MWh for the older windfarms and $5/MWh or less for new wind farms.

[46] In ICCC scenarios for 2035, with very high renewables and very high wind penetration, this value also determined the spill order, i.e. wind spilled first, then hydro. However, this is not so relevant to the shorter term EAF modelling.

While the basic structure of the spot market, including nodal pricing, remains largely unchanged since October 1996, it is also constantly being refined by the Electricity Authority and by various reviews that have occurred over the years[47]. It is easy to imagine substantial changes to market structure that might occur in the longer term, for example the introduction of a capacity market or enhanced scarcity pricing, but predicting if or when this might occur is regarded as a pointless in the context of the EAF. Furthermore, there are few major changes in the wind, except as noted above.

Recommendation: Assume the electricity market structure remains unchanged.

3.8 Miscellaneous Parameters

This section briefly lists the recommended values or setting for a range of other parameters.

3.8.1 Inflows

Market modelling for New Zealand which forecast expected prices typically runs all historical inflows through each scenario, which go back around 90 years. It is impossible to predict inflows with any accuracy more than a week or so ahead, so all inflows should be run and the results averaged to give expected values of key outputs including spot prices.

There is some evidence that inflow patterns are changing due to climate change, with the South Is becoming drier from February to April and wetter over winter, but even within this trend there is still a high degree of volatility.

3.8.2 River chains and Lakes

A higher degree of detail in modelling the structure of the major hydro systems can provide additional insights if required, but the key criteria for modelling is that the chosen model, its inputs and setup, calculate water values for the major hydro lakes which are consistent with the actual operation of the market, both in terms of average values and management of security of supply.

3.8.3 Wind Profiles

Even with the modest degree of wind penetration present in the market and possible over the next few years, correlations between wind farms, both in terms of location and output, can and do produce short term volatility in spot prices. For the three to five years recommended as the EAF forecast horizon, these correlations are not likely to produce major distortions in the EAF calculations. If higher accuracy can be achieved, as it was for the ICCC for example, then this ensures that all effects are captured, but this level of accuracy is not considered to be essential; moderate accuracy will suffice.

3.8.4 Solar Profiles

The penetration of solar is not currently high and is not likely to surge over the next few years, so the solar output profiles need not be highly accurate, provided that they capture the basic solar output profile.

[47] Ministerial review of 2009, for example.

3.8.5 Demand Profiles and Time Resolution

Different models may use different approaches to demand, with some using demand time-series and others using load duration curves. Monthly or weekly demand is considered too coarse to capture peak effects, but a demand profile which captures basic peak and off-peak dynamics within each week in the year should suffice.

Higher time resolution modelling can be useful but is not considered to be essential while wind and solar penetration is relatively modest. Higher resolution modelling will produce more output data which can be useful for diagnostic purposes, but it will slow the modelling process. An approach which does 90% of the modelling work in a coarser mode, but which can then be checked or refined by running final scenarios at a finer resolution, would be useful but may not be essential.

3.8.6 Demand Response, Official Conservation Campaigns and Tiwai Triggers

In addition to the longer term elasticity which may modify demand slightly in the counterfactuals in 2019, the key demand response that needs to be modelled is that which occurs when spot prices reach extreme levels, e.g. in dry years.

In extreme cases, an Official Conservation Campaign may be declared and modelled demand response needs to reach levels that are consistent with observed historical levels, e.g. 10% to 15% in an extreme event. Failure to model this response will result in spot prices that are too high during extreme dry years and too high on average.

The hedge agreement between Meridian Energy and the Tiwai smelter includes "trigger" storage values which, when storage falls below them, could trigger a demand reduction at the smelter. The algorithm basic trigger setting and protocols are included in the agreement which is also in the public domain, but it is relatively complex to model. Actual triggers should also occur no more than Official Conservation Campaigns, and neither should occur more than a few times at most across the full range of historical inflows.

3.8.7 Outages

All plant has planned outages and these can and do have an impact on spot prices when they remove significant amounts of capacity from the market. All known and reasonably expected outages should be included in the modelling.

3.8.8 Transmission Grid

The grid was substantially upgraded over the last decade, so the impact of transmission constraints is expected to be minimal for the next few years. If a model has more grid detail than this allows checking for constraints, but this is not considered essential for the current EAF calculation period.

On the other hand, if it is considered important to consider regional differences in the EAF, then the models will require grid detail sufficient to calculate nodal prices which accurately reflect the impact of marginal losses on spot prices across the grid.

3.8.9 Inflation

The EAF must be calculated in the context of the real world and so inflation may have an impact on its value. As a result, the market modelling should be undertaken using nominal prices. The Producers Price Index (PPI) is the most relevant measure of inflation for industries such as generation construction and gas supply, and the PPI has averaged 2.3% per annum since 1990. It is currently common to use a PPI assumption of 2% per annum and this is recommended for the EAF market modelling.

4 Context Checking

Calculating the EAF is a complex and potentially large undertaking requiring modelling of many scenarios and counterfactuals. In this section, we outline a number of data points that can be used to define a range of the EAF and to help keep the scenario modelling in context.

4.1 Upper Bounds: EAFs of Thermal Stations

Concept Consulting (Concept Consulting, 2015) noted that a market in disequilibrium could achieve an EAF that is greater than that of the most "fossil intensive" plant but that this is not credible in a market that is in equilibrium or close to it, and recommended that "the EAF equivalent to the most fossil intensive plant should be considered to be an absolute upper-limit".

Table 1 shows the EAFs for existing thermal plant and the highest value is that of the Rankine units running entirely on coal: 0.92 tCO_2/MWh[48].

Table 1 – EAFs for Existing Thermal Plant

Thermal Stations	Efficiency	Heat Rate	Emission Factor - Fuel tCO2/GJ	Emission Factor - Output gCO2/kWh	EAF tCO2/MWh
Huntly - Coal	35%	10,315	0.089	922	0.92
Whirinaki Peaker	33%	11,000	0.069	758	0.76
Huntly - Gas	34%	10,500	0.053	557	0.56
P40 (Huntly Unit 6)	38%	9,500	0.053	504	0.50
Stratford Peaker	40%	9,000	0.053	477	0.48
McKee Peaker	40%	9,000	0.053	477	0.48
TCC	49%	7,300	0.053	387	0.39
e3p (Huntly Unit 5)	50%	7,200	0.053	382	0.38

4.2 Base Case Internal EAF

A middle of the road indication of the EAF can be achieved by running a counterfactual for the base case which is just the base case with all carbon-based components of offers set to zero. Essentially, by comparing this with the base case, the computed EAF is the impact of the ETS, all other things being equal. We'll call this the 'base case internal EAF'.

If EAFs from any of the other scenarios are a long way from the base case internal EAF then the question should be asked: is there a good reason? A good reason must be

[48] Concept Consulting's value for Huntly on coal is 0.96 and the reason for the small difference is not known, but could be accounted for by a small difference in heat rate or in the emission factor of the fuel used in the calculations.

associated with counterfactual builds that are significantly different to what has actually occurred.

4.3 Lower Bounds

At the other end of the range, Concept Consulting also recommended a lower bound of zero, which is consistent with the premise that the ETS is more likely to raise prices than to lower them.

Scientia Consulting (Scientia Consulting, 2018) undertook modelling of the spot market for 2016 and 2017 to estimate EAFs under three scenarios[49], and in each case the counterfactual was the actual spot price:

1. Scenario 1: thermal offers were adjusted downward assuming the NZU price was zero: EAF calculated as 0.1 tCO_2/MWh;
2. Scenario 2: thermal offers adjusted as above and hydro offers were also adjusted down to reflect the impact on water values: EAF calculated as 0.48 tCO_2/MWh;
3. Scenario 3: as for 2 above except that "the assumption that thermal generators respond to lower spot prices and reduce their amount of lower-priced generation": EAF calculated as 0.42 tCO_2/MWh.

It is unrealistic to think that water values would not adjust in response to a significant change in thermal offers, otherwise lakes would keep filling until they spilled excessively, so Scenario 1 is not directly relevant to the EAF calculation.

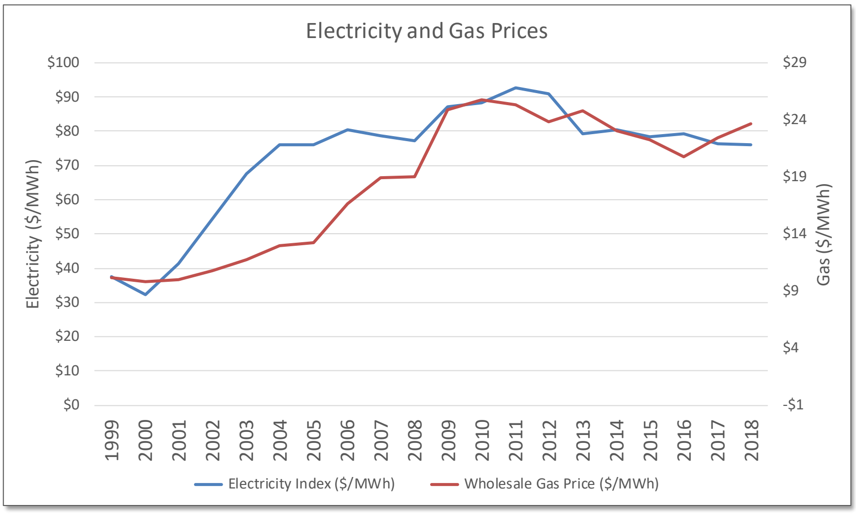
Scenario 2 and three are more realistic, and are similar in concept to the base case internal EAF, except that they are based on key parameters, including inflows and demand, which are peculiar to 2016 and 2017. The base case internal EAF on the other hand, includes the impact on the EAF of the full range of inflows.

4.4 Electricity-Gas Contract Ratio

Electricity contract prices reflect expectations of future spot prices, and while the thermal sector remains significant, gas prices are a key driver of future spot prices[50]. There is an index of the price of larger electricity contracts, including FPVV and hedge contracts, extending back to 1996 which is referenced to the Haywards node in Upper Hutt. MBIE also publishes the average price of wholesale gas going back to 1999, and the two series are shown below, where the electricity contract prices are averaged by year.

[49] The EAFs were calculated using load-weighted average spot prices.
[50] For a simple explanation, see https://www.energylink.co.nz/news/blog/what-drives-electricity-prices

Figure 12 – Electricity and Gas Price Indexes



The two price indexes are plotted against different vertical axes to show that they are well correlated[51], except for the period from 2001 to 2008. In 2001 the market experienced its first major dry period, and in 2003 the Maui reserves redetermination triggered an increase in the price of wholesale gas, and these two events led to a rapid rise in the electricity index. However, it took several years for the gas price to rise to the same proportionate extent, which is likely due to two factors: the longer term of gas contracts, combined with the fact that electricity generation makes up only a minor portion of demand for wholesale gas[52].

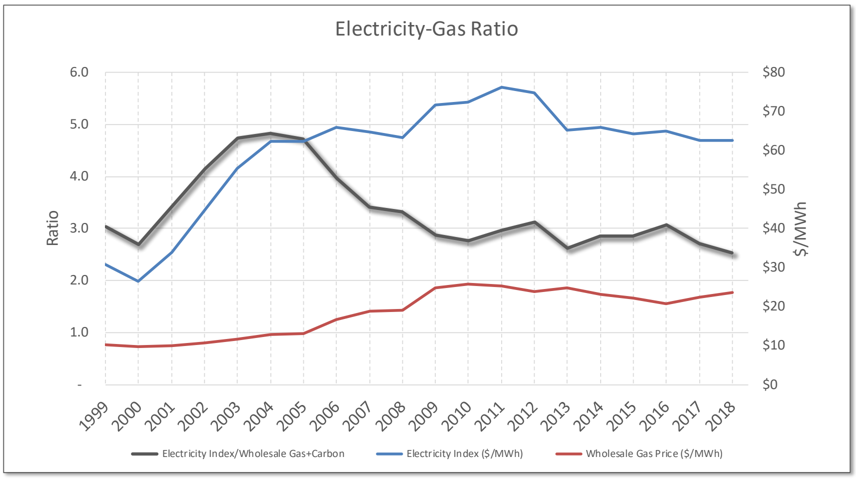
We can take the ratio of the electricity index to the gas index, after making two adjustments:

- add in the price of carbon using the ETS subsidy rate and the annual average prices of NZUs;
- reducing the electricity index by 18%, which is the average amount by which the index over-estimated the actual spot price from 1999 to 2018.

Figure 13 shows the two indexes, including carbon in the gas price, and the electricity-gas ratio.

[51] The correlation from 1999 to 2018 is 0.82.
[52] 32% in 1999, rising to 46% in 2007 as production at Methanex fell, and between 19% and 24% from 2014 to 2018.

Figure 13 – Electricity-Gas Ratio



Ignoring the period where the gas index was "adjusting" to the new gas pricing regime post-Maui redetermination, we can calculate the average index value and it is 2.8: effectively, this value gives us the ratio for the period where the two markets are in equilibrium, or close to it, in terms of gas prices.

The ratio appears to be falling, but this is the result of 2017 and 2018 being years of significantly higher electricity prices.

The change in the electricity price given a $1/tonne change in carbon price, can then be inferred using a ratio of 2.8, and this gives us the change in the electricity price per unit change in the gas price. The carbon price adds to the gas price, but in proportion to the emission factor of gas, which is 0.53 tonne/GJ.

The apparent impact on the electricity contract price of a $1/tonne change in carbon price is therefore given by $2.8 \times 0.053 \times 3.6 = 10.8 \times 0.053 \approx$ $0.53/MWh per $/tonne[53].

It is probably no coincidence that this value, estimated somewhat crudely from price indexes, is close to the current EAF value of 0.53 tCO_2/MWh, on the assumption that the electricity market is workably competitive (to borrow a phrase from the Electricity Authority) and prices largely reflect costs. This being the case, this value provides additional context and suggests that a significant move away from the current EAF value would be at odds with market expectations. That is not to say that market expectations correctly take account of the EAF counterfactual scenarios: we have no way of knowing if that is the case.

Recommendation: Absolute lower and upper bounds for the EAF are zero and the EAF of the most emission-intensive thermal station, respectively. Additional context is attained by reference to the base case internal EAF and to market expectations of an EAF close to 0.53 tCO_2/MWh

[53] If coal were the dominant thermal fuel then with coal at 0.89 tonne/GJ, the impact on electricity contract prices would be $.90/MWh per $/tonne.

5 Scenarios

Having more scenarios does not guarantee a better result. Using the probability-weighted approach that we recommend means that there should be a realistic range of scenarios, along with their respective counterfactuals, which gives a realistic range of EAFs. A fair degree of judgement will be required in setting the probability of each scenario, from which will automatically come the final EAF as the probability-weighted average across all scenarios and all years modelled.

Based on earlier sections, the following is a summary of all key parameters.

Table 2 – Key Parameter Summary

Parameter	Recommended Values
Demand	0.3%, 0.5%, 0.8% p.a.
Carbon	Rising linearly to $50, along with a low and a high scenario
Gas	Disclosed prices plus PPI where appropriate
Coal	Indonesian coal price forecast for the correct coal, plus domestic transport costs
HVDC Charges	Phase out over the next few years
Solar	Value of behind-the-meter solar is the relevant forecast daytime spot price
Wind farm offers	Newer windfarms $5/MWh through to the oldest windfarms at $20/MWh
Genesis-Meridian swaption	Renewed in 2023
Tiwai Pt smelter	Operates at its current normal operational load unless turned down during an extreme dry year
Retirements	All plant remains in the market at current capacity
Inflows	Market modelling include all historical inflows available back to around 1930
River chains and lakes	Water values consistent with market
Wind profiles	Moderate accuracy in terms of correlations between wind farms, high accuracy not required
Solar profiles	Basic solar output profile for behind-the-meter solar
Demand profiles	Detailed enough to capture peak, off-peak dynamics within each week of the year
Time resolution	High resolution may be useful, e.g. particularly for finalising scenarios, but is not considered essential provide that the demand profile shape is captured at the required minimum level
Demand response	Demand response would capture the likely response during an Official Conservation Campaign and also the possibility of Tiwai load being reduced when storage falls below trigger levels in the Meridian-Tiwai hedge agreement
Outages	Known outages and expected planned outages of major plant to be modelled
Transmission grid	If decided, sufficient detail is required in the grid model to allow the impact of marginal losses on the EAF to be assessed accurately
Inflation	PPI 2% per annum
Wind LCOEs	Calibrate to actual market data and deflate by 0.5% per annum in real terms
Solar LCOEs	Calibrate to actual market data and deflate by 4.5% per annum in real terms

The minimum number of permutations that can be formed from the table above is nine: three demand scenarios paired with three carbon scenarios, on the assumption that demand growth and carbon prices are parameters which are independent or close to it. Each scenario may require its own counterfactual, but some counterfactuals may serve the purpose with more than one scenario.

6 References

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