Electricity Allocation Factor Methodology Options

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Definitions

The following abbreviations and acronyms are used in this report.

EAF	Electricity Allocation Factor
EITE	Emission-Intensive Trade-Exposed
ETS	Emissions Trading Scheme
FPVV	Fixed price variable volume
LRMC	Long run marginal cost
Ministry	Ministry for the Environment
NZU	New Zealand Unit (under the ETS)
SEIP TAG	Stationary Energy and Industrial Processes Technical Advisory Group
SPD	Scheduling, Pricing and Dispatch model used in the electricity market to dispatch generation plant and to produce spot prices
SRMC	Short run marginal cost

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1 Introduction

In 2019, the Ministry for the Environment ("the Ministry") decided to review the Electricity Allocation Factor (EAF), currently set at 0.537 tCO_2[1]/MWh.

Detailed modelling was undertaken early in 2020 to calculate a new EAF, described in (Energy Link, 2020) using the methodology used in the two previous calculations in 2008 and 2011. The work also included the calculation of an EAF using two alternative methodologies, after concerns were expressed about the current methodology.

Other methodologies were also either adopted or trialled over the years.

The Ministry subsequently engaged Energy Link to review these methodologies in light of the latest round of modelling, listing the pros and cons of each method, and to advise on whether there should be a change in the methodology used either now or at some point in future.

This report is intended for readers who are either familiar with electricity market modelling, or with the details of the current EAF calculation methodology, and the use of the EAF in allocating NZUs to emission-intensive trade-exposed (EITE) entities. Some familiarity with the current methodology and earlier reports is assumed.

2 Summary

The methodology for calculating the EAF has evolved over time, from its genesis in 2003 when a physical emission factor was calculated for use in the Projects to Reduce Emissions.

The current methodology requires development of market forecasts, forward-looking scenarios of how the average spot price of electricity may evolve over the next five years or so, along with modelling of an alternative world (counterfactual) in which there never was a cost of carbon in respect of electricity generation, and no expectation of there ever being such a cost.

Although this methodology is by now well established, it suffers from the problem of the counterfactual being increasingly uncertain and difficult to formulate over time, while uncertainty in the market forecasts (factual) remains more-or-less constant over time. Combined with how innate biases in human cognition can unconsciously limit how much the counterfactual can differ from the factual, the current methodology is likely to become more expensive to run over time, and more open to criticism.

To provide greater certainty and transparency around the inputs into the process, the methodology could either:

- change to a backward-looking approach; or
- prescribe various elements of the counterfactual so that the allowed differences between the factual and counterfactual are limited, but accepted by stakeholders, thus facilitating development of the counterfactual.

[1] See https://www.mfe.govt.nz/publications/climate/electricity-emissions-factor-reports/index.html and (Concept Consulting, 2004).

If the current methodology is retained, for example, then the counterfactual could be prescribed to the extent that fuel prices are assumed to be the same as in the factual, and that the plant mix includes thermal plant existing in 2009 for as long as it can be expected to remain reliable and to cover its cash costs.

A number of alternative, backward-looking methodologies were trialled since 2018, and at least one is capable of accurately determining the impact of the cost of carbon on electricity prices over the evaluation period on the more limited assumption that the counterfactual is the same market as the factual, but without an explicit carbon cost.

Given that the alternative world approach will be increasingly difficult to implement and manage over time as the uncertainty in the counterfactual continues to increase, while the uncertainty in the market forecasts remains more-or-less constant, we recommend that a move to a backward-looking approach be considered sooner rather than later. This will lead to fluctuations in the allocations of NZUs in each period, which increases uncertainty for EITE firms and also fiscal risk for the government, but it is a robust and ultimately more acceptable method for the long term.

If these fluctuations are considered by stakeholders to be excessive, then a number of methods could be employed by which the fluctuations could be reduced. For example, the EAF could be a running average of the EAFs calculated in each period, with the possibility of initially including the current EAF of 0.537 tCO_2/MWh in the average. Running averages could be formulated which balance the need for the EAF to adjust each year against the impact that volatile EAFs could have on stakeholders.

3 Background

The Climate Change Response Act 2002 established the framework for the ETS, and also allows for the issue of free NZUs to specified industries to offset some of the cost that a carbon price places on them[2].

The EAF is used in calculating the electricity portion of free allocations of NZUs to eligible activities that are 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.

The EAF was first calculated in 2008 as 0.52 tCO_2/MWh. The methodology used was based on the average SRMC of generation in electricity market forecasts with a cost put on carbon, relative to the same market forecast undertaken with no carbon cost.

In 2011 the methodology was refined by using average prices obtained from forecasts, and by developing a counterfactual based on how the electricity market might have evolved without an explicit carbon cost. The value finally agreed upon was 0.537 tCO_2/MWh, but the range of values obtained by various modelled scenarios was relatively large, and ultimately many scenarios were not included in the final averaging

[2] The allocation to an industry is explained in more detail in (Energy Link, 2019).

to obtain this value. The excluded scenarios tended to include large changes in the market such as retirement of a large thermal plant.

Early in 2020, the methodology was again applied as in 2011, but this time more extreme scenarios were excluded, including closure of the Tiwai aluminium smelter and retirement of large thermal plant. This exclusion, however, also went with a recommendation to recalculate the EAF if and when major events actually occurred. The value recommended for the EAF was 0.472 tCO_2/MWh, which is 12% lower than the current value, primarily because the more extreme scenarios were excluded.

In addition to applying the currently accepted methodology, the 2020 recalculation work also included the trialling of two alternative methodologies suggested through consultation with EITEs, both scenarios including some degree of backward-looking assessment.

3.1 Current EAF Definition

The history of the EAF extends back indirectly to 2003 when the government awarded various projects with tradeable units under the 'Projects to Reduce Emissions' scheme, though this scheme was discontinued in 2005. In 2003 Concept Consulting was engaged by the Climate Change Office to estimate an 'emission factor' for 2008 – 2012, to be used in the first round of tenders for suitable projects, and the value of this was 600 tonnes CO_2 per GWh (0.6 tCO_2/MWh). This was updated in 2004 for the second round of tenders, and the new value was set at 0.625 tCO_2/MWh.

These initial factors represented an estimate of the marginal impact of 50 MW of new baseload renewable plant on the operation of, and hence emissions from, existing thermal power stations. This original emission factor was based on the analysis of physical emission reductions and was neither explicitly related to, nor driven by expectations of price changes caused by a charge on carbon.

Nevertheless, the figure of approximately 0.625 tCO_2 per MWh was assumed by some to be the EAF that would apply to the allocation of NZUs to EITEs[3]. But in December 2007 the Stationary Energy and Industrial Processes Technical Advisory Group (SEIP TAG) was set up to examine the issue of how to estimate the expected increase in electricity price resulting from the introduction of the ETS in 2010. The SEIP TAG engaged Energy Modelling Consultants Ltd (Energy Modelling Consultants, 2008) in the second half of 2008, who defined the EAF as

$$EAF = \frac{SRMC\ with\ carbon\ cost - SRMC\ without\ carbon\ cost}{Carbon\ cost} \qquad (1)$$

where the SRMC is the average SRMC of all generation over the period considered. EAFs were calculated for all years from 2010 to 2032 and in each case the factual and counterfactual scenarios modelled were the same, except that one included carbon costs and one did not. The SEIP TAG process eventually resulted in an EAF of 0.52 tCO_2/MWh.

[3] For example, see a letter dated 5th May 2010 from the Major Electricity Users' Group to the then Minister for Climate Change Issues, Hon Dr Nick Smith.

The EAF thus calculated, expresses the amount by which electricity prices change with the carbon price, and has underlying units of \$/MWh per \$/tCO_2[4] although these are usually shortened to tCO_2/MWh. The use of these later units can create the perception that the EAF is a measure of physical emissions, however this is not the case.

In 2011 Concept Consulting (Concept Consulting, 2011) recommended the EAF be calculated using the following formula:

$$EAF = \frac{Electricity\ purchase\ cost\ with\ carbon\ charge - Electricity\ purchase\ cost\ without\ carbon\ charge}{Carbon\ charge} \qquad (2)$$

where the purchase costs of electricity are in \$/MWh, the carbon charge is specified in \$/tCO_2, and the “without carbon charge” is from a counterfactual world 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 set up to provide technical input into the process, was to model the period of interest (2012 – 2017) and beyond, both with and without a carbon charge, with electricity prices being the key output of the modelling.

The interpretation given by Concept Consulting requires the modelling of two separate worlds, one with a carbon charge (factual) and one without a carbon charge (counterfactual), and in the latter case, there being no expectation of a carbon charge: these two worlds potentially develop in quite different ways.

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)[5] 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-fuelled 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.

[4] The unit is \$ per tonne of CO_2.
[5] The estimated price of a good or service for which no market price exists, from dictionary.com.

4 Methodologies

This section briefly reviews the methodologies trialled or used over the years back to 2003, and lists their respective pros and cons.

Table 1 below summarises the methodologies that have so far either been trialled or adopted at various times. The fields indicate the following:

- Methodology: a short name for the particular methodology being referenced;
- Year: the first year the methodology was trialled or adopted;
- Status: this has two parts; whether the methodology was adopted or only trialled, and whether the methodology is consistent with the current definition of the EAF given by formula (2) in section 3.1 above;
- Time Domain: indicates whether the methodology calculates an EAF using forecasts (forward-looking) or analysis of actual market data (backward-looking);
- Factual: the scenario which produces costs with a charge on carbon;
- Counterfactual: the scenario which produces costs without a charge on carbon
- Cost Type: the type of costs used in calculating the EAF, e.g. LRMC, SRMC, market spot prices;
- Comments: additional relevant information.

Forward-looking methodologies produce EAFs that are averaged over many forecast scenarios, including many scenarios for inflows into the hydro lakes, so these EAFs do not relate to any particular year. Thus, an EITE paying spot prices will receive allocations of NZUs which do not match the electricity prices in any given year, unless a year just happens to be "average" in some sense.

On the other hand, backward-looking methodologies produce an EAF for each year, or period within each year, which matches what happens in each year. For example, in a wet year with low prices, the EAF will tend to be lower than some average value, and EITEs will receive less NZUs. In a dry year, the opposite is likely to happen. On the other hand, EITEs on fixed price variable volume (FPVV) contracts will receive NZU allocations which may appear to bare little relationship to the electricity prices they pay.

Table 1 – Summary of Methodologies

Methodology	Year	Status	Time Domain	Factual	Counterfactual	Cost Type	Comments
Physical emissions	2003	Adopted but no longer used; not consistent	Forward-looking	Modelled physical generation with 50 MW baseload new renewables	Same market as factual but without new renewables	Not applicable – this methodology is based on physical emissions	Initially developed for use in assessing the carbon impact of Projects to Reduce Emissions
SRMC impact	2008	Adopted but no longer used; not consistent	Forward-looking	Modelled market with ETS	Same market as factual but with carbon costs removed from SRMCs	SRMC	Does not require a separate counterfactual

Methodology	Year	Status	Time Domain	Factual	Counterfactual	Cost Type	Comments
Electricity purchase cost impact - SRMC	2011	Adopted; consistent	Forward-looking	Modelled market with ETS	Modelled market as it might have evolved without ETS	SRMC	Counterfactual is an alternative evolution of the electricity market in a world with no carbon charge on emissions from generation
Electricity purchase cost impact - Cournot	2011	Trialled; not consistent	Forward-looking	Modelled market with ETS	Modelled market as it might have evolved without ETS	SRMC	Must be used with care due to the tendency to produce higher prices than observed in the actual market
New generation cost impact	2011	Trialled; consistent	Forward-looking	Modelled market with ETS	Modelled market as it might have evolved without ETS	LRMC	Market costs are calculated using the LRMC of new generation in the two worlds (factual and counterfactual)
Modified generator offers	2018	Trialled; not consistent	Backward-looking	Actual market	Actual market with carbon cost removed from thermal offers only	Spot prices	Hydro offers are not consistent with the lower thermal offer prices in the counterfactual. Uses the vSPD or similar model.
Modified generator and hydro offers	2018	Trialled; not consistent	Backward-looking	Actual market	Actual market with carbon cost removed from thermal offers, hydro offers reduced	Spot prices	Capable of estimating the actual EAF for the historical year of interest. Counterfactual water values are estimated using the reduced thermal offer prices. Uses the vSPD or similar model.
Modified generator and hydro offers with thermal quantity reduction	2018	Trialled; not consistent	Backward-looking	Actual market	Actual market with carbon cost removed from thermal offers, hydro offers reduced, low-priced thermal generation reduced	Spot prices	Capable of estimating the actual EAF for the historical year of interest. Counterfactual water values are estimated using the reduced thermal offer prices. Uses the vSPD or similar model.
Electricity purchase cost impact	2020	Adopted; consistent	Forward-looking	Modelled market with ETS	Modelled market as it might have evolved without ETS	Offer prices in line with observed and likely market behaviour	Counterfactual is an alternative evolution of the electricity market in a world with no carbon charge on emissions from generation
Actual market with and without carbon	2020	Trialled; not consistent	Backward-looking	Actual market modelled in EMarket	Actual market with carbon cost removed from generator offers	Average electricity spot price	Capable of estimating the actual EAF for the historical year of interest. The scenarios were run using the EMarket model which re-optimises water values in the counterfactual.
Actual market versus forecast counterfactual	2020	Trialled; not consistent	Backward-looking and forward-looking	Actual market	Modelled market as it might have evolved without ETS	Average electricity spot price	Inconsistencies arise from the use of the actual market as factual and a forecast counterfactual

4.1 Physical emissions

This methodology was used to estimate the marginal emission reductions caused by new generation that might be allocated tradeable carbon units under the Projects to Reduce Emissions. The market is modelled with and without a project in 50 MW 'chunks' (438 GWh per annum) and the difference in emissions in tonnes between the with and the without scenarios is divided by 438 GWh to give the marginal impact in units of tCO_2 per GWh. The values adopted in 2003 and again in 2004 were 600 tCO_2 per GWh and 625 tCO_2 per GWh, respectively, which can be written as 0.6 tCO_2/MWh and 0.625 tCO2/MWh.

These units are the same as those of the current EAF which suggests that the 2003 and 2004 values are equivalent to the current EAF. However, the earlier values were expressions of the physical impact on emissions whereas the current EAF expresses the cost impact of the ETS and has underlying units of \$/MWh per \$/tCO_2 which can be shortened to tCO_2/MWh.

The earlier values thus appear to be EAFs because of the units used, but in reality they are not EAFs as currently defined. As a result, we must assume that once the SEIP TAG took up the issue, the emphasis was changed from assessing the physical impact of new renewable generation to the impact on the cost of electricity paid by consumers. The fact that the values of 0.6 and 0.625 tCO2/MWh are relatively close to the current value of the EAF (0.537 tCO_2/MWh) is a result of the fact that spot prices in the electricity market are set based on the marginal cost of electricity to consumers purchasing at spot prices, which tend to be either set by, or influenced by the marginal cost of operating thermal generation.

Pros	Cons
• Requires fewer assumptions about the future market than methodologies based on costs	• Not based on changes in costs to consumers

4.2 SRMC impact

In the years leading up to the commencement of the obligations[6] on electricity generators to surrender NZUs into the ETS to cover their emissions, the SEIP TAG developed the concept of basing an EAF on the impact of the ETS on electricity prices, rather than using physical emissions as outlined in 4.1.

The method adopted in 2008 forecast market prices over the period from 2010 to 2032 using five scenarios of carbon costs from \$0 to \$80/tCO_2. The carbon costs were then simply removed from the modelled generator costs, and the market model rerun, to produce the without-carbon counterfactual.

The costs used in formula (1) to calculate the EAF were the average SRMCs of generators in each scenario modelled.

The SEIP TAG process eventually resulted in an EAF of 0.52 tCO_2/MWh.

Pros	Cons
• Does not require an alternative evolution of the electricity market without a carbon cost	• Using SRMCs may miss some of the dynamic pricing impacts in the spot market

4.3 Electricity purchase cost impact – SRMC

Late in 2011 further modelling was undertaken to calculate an EAF for the years 2013 to 2017, but this time the counterfactual changed to an alternative evolution of the electricity market without an explicit cost on carbon. Three methodologies were trialled, including this one, along with 'Electricity purchase cost impact – Cournot' outlined in section 4.4 and 'New generation cost impact' outlined in section 4.5.

The costs used in formula (1) to calculate the EAF were the average prices in each scenario.

[6] Generators are not required to become ETS participants, but those of any size have opted in so that they have the maximum degree of control over their carbon costs.

Although this methodology uses SRMCs in modelled generator offers, the 'build schedules' of new generation plant used in the factual and counterfactual scenarios are calculated using LRMCs. The assumption here is that new plant will be built as demand increases, or as existing plant retires, in order of LRMC, with the lowest cost plant being the next to be built. The resulting build schedule is then added to existing plant in the detailed market modelling.

A contact group was set up prior to this modelling taking place, and it ultimately chose this methodology to calculate the current value of the EAF, 0.537 tCO_2/MWh.

However, a wide range of scenarios were modelled, including some in which large thermal plant either retired or changed operating status[7], and these produced a wide range of EAFs. Ultimately, the contact group had to come to a consensus over which scenarios to include in the averaging to obtain the new EAF, and some were simply ignored.

Pros	Cons
• The modelling approach used SRMC in generator costs but was explicit in using the current definition of the EAF and average prices	• Requires an alternative evolution of the electricity market without a carbon cost

4.4 Electricity purchase cost impact – Cournot

As in section 4.3, this methodology required a forecast of market prices as the factual, and a counterfactual in which the electricity market evolved without a carbon cost.

This methodology produced higher prices overall than the SRMC method, but lower price differences between the factual and counterfactual prices, resulting in a lower EAF. Cournot models of market behaviour assume market participants will make use of any market power they may have, which is not necessarily consistent with the behaviour actually observed in electricity markets.

Pros	Cons
• Based on a relatively simple theoretical model of market behaviour in oligopoly markets[8]	• Requires an alternative evolution of the electricity market without a carbon cost • Cournot modelling is based on a model of the oligopolistic electricity market which may not reflect actual market behaviour, leading to overestimates of prices

4.5 New generation cost impact

This methodology uses only the LRMCs to calculate factual and counterfactual build schedules. It is then assumed that electricity prices will be driven directly by the LRMCs of new plant, and the difference between the average LRMC of new plant in the factual and counterfactual captures the impact of carbon on electricity prices.

[7] For example, Huntly changing to a 'dry year reserve' plant.
[8] An oligopoly market is one which is dominated by a small group of large suppliers, in this case the four largest gentailers.

Pros	Cons
• Does not require detailed modelling of spot prices	• Misses dynamic market effects caused by interactions between market participants or delays in building new plant

4.6 Modified generator offers

The Electricity Authority's vSPD[9] model was used to recalculate half-hourly spot prices for 2016 and 2017 after removing the actual effective carbon costs from the actual offers of thermal generators. The effective carbon costs were calculated using the actual prices of NZUs and the subsidies[10] applying in each year. No other adjustments were made to generator offer prices.

As a result, hydro generators held prices higher than would be expected in the counterfactual[11], so this methodology produced an unrealistically low EAF of 0.1 tCO_2/MWh.

Pros	Cons
• Does not require an alternative evolution of the electricity market without a carbon cost	• Does not take account of the impact on water values of lower thermal generator offers, resulting in unrealistically high offer prices for hydro generators

4.7 Modified generator and hydro offers

The methodology in section 4.6 was modified by adjusting hydro offers in the counterfactual scenario without carbon costs, and produced a more realistic EAF of 0.48 tCO_2/MWh. The hydro adjustment was in proportion to the reduction in the offer prices of thermal generation that was likely to be marginal in any given vSPD solve.

Pros	Cons
• Does not require an alternative evolution of the electricity market without a carbon cost • Makes an adjustment to hydro offer prices in the counterfactual in line with lower offers from marginal thermal generators	• The hydro adjustment is not a re-optimisation of the value of water in storage lakes.

4.8 Modified generator and hydro offers with thermal quantity reduction

The methodology in section 4.7 was modified by reducing the quantity of low-priced thermal generation offered into the market, which was based on observations of historical market behaviour, and produced an EAF of 0.42 tCO_2/MWh.

Pros	Cons
• Does not require an alternative evolution of the electricity market without a carbon cost	• The hydro adjustment is not a re-optimisation of the value of water in storage lakes.

[9] vSPD is an implementation of the SPD dispatch and pricing model used in the electricity market to dispatch generation and calculate spot prices.
[10] In 2016 one NZU covered two tonnes of CO_2 emissions and in 2017 one NZU covered 1.5 tonnes of CO_2 emissions.
[11] Higher water values would also result in excessive spill from hydro lakes during periods of higher inflows.

4.9 Electricity purchase cost impact

This methodology is based on the methodology outlined in section 4.3 and also uses an LRMC-based model to produce build schedules for new plant, which are then added to existing plant. The market is modelled using thermal offers with offer structures observed over many years in the market: these are not purely based on generator SRMC[12].

This was the methodology used early in 2020 and described in (Energy Link, 2020), producing a final recommendation of 0.472 tCO_2/MWh, although this value has not yet been adopted.

The range of scenarios was limited relative to the modelling undertaken in 2011 (see section 4.3) to avoid having an excessively wide range of EAFs contributing to the final average EAF. However, this was done with the recommendation that if any major event occurred, such as retirement of a large thermal plant or closure of the Tiwai Pt aluminium smelter, this would trigger a recalculation of the EAF.

The counterfactual was developed by running an alternative build schedule from 2009 to the end of 2019, thus producing the starting plant mix.

Pros	Cons
• Capable of capturing both the impact of LRMC on build schedules and the dynamic behaviour of spot market participants	• Requires a fully developed alternative evolution of the electricity market without a carbon cost, dating back to 2009

4.10 Actual market with and without carbon

In principle, this methodology is similar to the methodology trialled in 2018 and outlined in section 4.7 and it was trialled early in 2020 (Energy Link, 2020). However, it was run in Energy Link's *EMarket* model which does the market dispatch, and produces spot prices using the same methodology as in the SPD model, but also fully optimises water values for stored water, and uses these in modelled offers for hydro generators, along with the impact of the physical structure of the large hydro river chains[13].

Actual market prices could have been used as the factual, but *EMarket* was initially set up to model what actually happened in the market, then carbon costs were removed and *EMarket* was rerun as the counterfactual. In principle, it would be possible to set *EMarket* up to model the actual market and to produce spot prices which match actual prices almost perfectly, but this would require a larger effort subject to diminishing returns. Using modelled actual prices reduces the effort required to remove carbon

[12] Generators tend to offer enough generation from their portfolio at SRMC, or adjusted SRMC, to cover their exposure to spot purchases (as a retailer) plus hedge contracts. Quantities offered beyond the total required to cover retail plus hedges may be offered at prices higher than SRMC, for example in an attempt to also cover fixed costs.

[13] This structure also impacts on hydro offers due to constraints within each river chain, and the fact that the value of water reduces as it flows downstream and passes through generators in the chain.

costs from generators' offers in *EMarket*, and ensures that differences between actual market prices, and modelled actual market prices, did not distort the final result.

This methodology was trialled on four years from 2016 to 2019 and produced EAFs from 0.312 (2017) to 0.557 (2019).

Pros	Cons
• Does not require an alternative evolution of the electricity market without a carbon cost • Consistent approach to modelling the actual and counterfactual markets	• Lacks a counterfactual in which there is no carbon cost and never was, and never will be

4.11 Actual market versus forecast counterfactual

This methodology was also trialled early in 2020 (Energy Link, 2020). It used actual market prices as the factual for the years 2016 to 2019, but the counterfactual data was taken from the counterfactual developed under the 'Electricity purchase cost impact' methodology outlined in section 4.9.

However, it produced EAFs from -0.1 up to 1.9, and this wide range was significantly influenced by the choice of a counterfactual that was developed under an entirely different set of assumptions, and the two scenarios were so widely different in their construction that this resulted in large errors in the calculated EAFs.

Pros	Cons
• Lack of consistency between factual and counterfactual is likely to introduce large errors, and diverse EAFs, that do not necessarily represent actual EAFs	• Requires an alternative evolution of the electricity market without a carbon cost

5 Discussion and Conclusions

The choice of methodology ultimately comes down to two key considerations:

1. should the EAF be forward or backward-looking?
2. should the EAF reflect the difference between the actual world and a world in which "there has never been a cost of CO_2, and no expectation of such a cost"?

5.1 Forward versus Backward-Looking

A forward-looking EAF is based on forecasts, none of which can be certain about a range of factors including inflows into hydro systems, fuel prices, demand, plant mix, and of course carbon prices. The EAFs produced using forward-looking methodologies inevitably cover a wide range of scenarios which are then averaged to give an EAF.

Electricity market modelling typically includes some or all of the 89 historical inflow sequences commonly available to modellers[14], so inflows alone produce this number of scenarios. Add in some variations on demand, fuel prices, and so on, and one ends up with hundreds of scenarios. In principle then, if these scenarios cover a representative

[14] Dating back to April 1931. One dataset extends back to 1928.

range of future scenarios, then the resulting averaged EAF[15] should be the actual EAF obtained by averaging the actual annual EAFs from the next hundreds of years. The calculated EAF is therefore only an expectation value.

On the other hand, a backward-looking methodology is based on what actually happened versus some counterfactual that is assumed would have happened without a carbon cost. The EAF that results from each calculation, be it annually or quarterly, for example, should reflect the impact of a carbon cost during that period. As noted above, if all other things are equal, a wet year will produce a lower EAF and a dry year will produce a higher EAF. Ignoring the issue of whether or not an EITE is paying spot price or not, this produces a better match, period-by-period, between the cost of carbon and its underlying effect on electricity prices, and the allocation of NZUs.

In the electricity market, EITEs can choose whether to pay spot prices, or to contract out of paying spot prices by contracting under FPVV arrangements. If they choose to pay spot prices, they can also hedge their spot price risk by buying electricity hedge contracts. The same choice is not present for them in respect of the EAF, which partly determines their allocation of NZUs each year. The monetary risk associated with a backward-looking EAF may be able to be hedged, or partially hedged, using a combination of hedge contracts that are already traded, e.g. electricity and NZU hedges, but as this is a small market it is difficult to predict whether such a hedge market would develop if a backward-looking approach were adopted.

On the other hand, backward-looking EAFs have the advantage, for EITEs paying the spot price, of being a partial hedge for electricity spot prices. This being the case, and given that EAFs are calculated using spot prices, moving to using backward-looking EAFs is a viable alternative to the current methodology using forward-looking EAFs.

5.2 Choice of Counterfactual

This requires modelling of two separate worlds which potentially develop in quite different ways. But just because there is no carbon charge, and “no expectation of a carbon charge” in the counterfactual scenarios, it does not mean that there is no climate change. If New Zealand did not have an ETS, nor any expectation of ever having an ETS (or equivalent explicit carbon charge such as a carbon tax), we nevertheless live in a world where climate change is happening and, as a result, there is huge investment offshore in renewables because of the demand induced by climate change, thus bringing the cost of renewables down over time.

There are also domestic carbon-reduction policies which are not based on the ETS. Because of this, the counterfactual is not isolated from the transition to renewables, it just happens at a lower rate in respect of the electricity market. Thus, even the counterfactual represents a world in which climate change has an impact on the electricity market, which means that some of the assumptions used in the factual can also be used in the counterfactual, in particular the cost of building new generation where that cost is heavily influenced by developments offshore.

From a conceptual standpoint, this approach has obvious appeal, because it can capture changes in prices which move far beyond the direct impact of carbon costs on electricity

[15] The ‘averaged EAF’ is the probability-weighted average over all scenarios in each future year.

generation. For example, if we expected gas prices to remain much lower in the counterfactual than in the factual, for whatever reason, then the resulting EAF would be larger than if it were only calculated with respect to the direct impact of carbon costs.

But there are a range of issues with this approach which make it not only difficult to implement successfully, but increasingly problematic over time. The most obvious and most important issue is that the uncertainty over how the counterfactual world evolves increases over time, whereas the uncertainty in the factual, while significant, remains relatively constant over time.

For example, consider the next two decades, and suppose that we recalculate the EAF once every five years starting in 2025. Then in 2025 we will forecast the electricity market for around five years from 2026 through to 2030. At this point, the uncertainty in the factual remains the uncertainty associated with five years of forecast electricity market operation, as it is today. But the uncertainty in the counterfactual increases from the current level of uncertainty inherent in an 11 year forecast (2009 to 2019) to the uncertainty in a 16 year forecast (2009 to 2024.

Then in 2030 the uncertainty in the factual will be that which is associated with a five year forecast, from 2031 to 2035, but the uncertainty in the counterfactual will rise in relation to a 21 year forecast. Every five years the disparity in uncertainties between the factual and counterfactual will increase until, by 2040, the counterfactual period is 31 years while the factual period is still five years.

This growing uncertainty difference between the factual and counterfactual could translate into confidence in the value of the EAF falling over time. In other words, there could come a point when the counterfactual is simply viewed as being irrelevant to the present day.

The second most important issue is that we live in the factual world, and not in the counterfactual world, and this leads to cognitive biases that influence the development of the counterfactual, albeit unconsciously. Even with the best intentions in the world, the 'anchoring effect'[16] and 'availability bias'[17], for example, will both tend to lead to a counterfactual that resembles the factual more than it theoretically should. These tendencies can be overcome to an extent by expert forecasters who have the experience and processes designed to overcome them, and by adding additional resources to the process, e.g. by using a panel of experts so that a wider range of views can be obtained in respect of the counterfactual. But because of this, the cost of developing the counterfactual is likely to increase substantially over time.

Anchoring, in particular, also has the unfortunate effect of making it difficult for stakeholders to accept alternative realities that might be markedly different to the world we live in. This will lead to increasing debate over the EAF each time it is recalculated, also causing the cost of the process to increase over time. In many ways, the anchoring effect makes it almost inevitable that at some point the use of an alternative world as

[16] The anchoring effect occurs when initial pieces of information (the factual world in which we live) is relied too heavily when making subsequent judgments, e.g. about the counterfactual world.
[17] Availability bias is a mental shortcut that relies on immediate examples that come to a given person's mind when evaluating a specific topic, concept, method or decision.

counterfactual, will be abandoned in favour of a methodology that is more believable and more acceptable to a wider range of stakeholders.

There are ‘halfway house’ approaches which could allow the current methodology to function for some years yet, but they rely on limiting the set of alternative worlds that are allowed in the counterfactual, relative to the factual. For example, in the modelling undertaken early in 2020 it was, after consideration of a range of alternatives, assumed that all thermal plant operating in 2009, or commissioned since, would be kept in the market indefinitely, i.e. it would be run until maintenance and reliability issues forced it out of the market, unless prices fell to the extent that they no longer covered cash costs. It was also assumed that the impact of this on the gas market, i.e. the quantities of gas demanded, would be insufficient to cause a significant movement in the price of gas away from the prices in the factual. These two assumptions made the development of a counterfactual significantly more straightforward than having to completely reimagine the evolution of the electricity market since 2009.

5.3 Conclusions

Looking ahead, it is likely (perhaps inevitable) that the current methodology will become more expensive to maintain, and come under increasing scrutiny, and the call for change will rise. At some point in the future, it may therefore be necessary to provide greater certainty and transparency around the inputs into the process, by either:

- moving to a backward-looking methodology; or
- prescribing various elements of the forward-looking counterfactual (alternative world) so that the allowed differences between the factual and counterfactual are limited, thus facilitating development of the counterfactual, in particular.

Of the backward-looking methodologies trialled to-date, the ‘Actual market with and without carbon’ described in section 4.10 will capture changes in thermal offers when carbon costs are removed, and the impact on water values. Using *EMarket*, for example, it can also be run down to the half-hourly level if required, although sufficiently accurate answers will be able to be obtained significantly faster using a higher resolution, e.g. three-hourly.

The process could be run monthly, quarterly or annually, for example, using a method that could be prescribed to the extent required to make it both repeatable and transparent, requiring relatively few judgements about model settings, and no judgements about an alternative world.

The disadvantage would be that EAFs would move around from period to period, in line with volatility in electricity prices.

The methodology used early in 2020 is based on the methodologies used in 2008 and 2011, so by now is well established. But it could be refined by prescribing key elements of the alternative world, and by basing each recalculation on an extension of the counterfactual used in the previous recalculation, thus ensuring continuity in plant mix and other key elements of the alternative world.

Given that the alternative world approach will be increasingly difficult to implement and manage over time, however, we recommend that a move to a backward-looking approach, as recommended above, be considered sooner rather than later. This will lead to fluctuations in the allocations of NZUs in each period, which increases uncertainty for EITEs and also fiscal risk for the government, but it will also be a more robust and ultimately more acceptable method for the long term.

If these fluctuations are considered by stakeholders to be excessive, then a number of methods could be employed by which the fluctuations could be reduced. For example, the EAF could be a running average of the EAFs calculated in each period, with the possibility of initially including the current EAF of 0.537 tCO_2/MWh in the average. Running averages could be formulated which balance the need for the EAF to adjust each year against the impact that volatile EAFs could have on stakeholders.

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