Estimating an electricity allocation factor (EAF): Technical appendices

NZIER report to the Ministry for the Environment

26 May 2015

About NZIER

NZIER is a specialist consulting firm that uses applied economic research and analysis to provide a wide range of strategic advice to clients in the public and private sectors, throughout New Zealand and Australia, and further afield.

NZIER is also known for its long-established Quarterly Survey of Business Opinion and Quarterly Predictions.

Our aim is to be the premier centre of applied economic research in New Zealand. We pride ourselves on our reputation for independence and delivering quality analysis in the right form, and at the right time, for our clients. We ensure quality through teamwork on individual projects, critical review at internal seminars, and by peer review at various stages through a project by a senior staff member otherwise not involved in the project.

Each year NZIER devotes resources to undertake and make freely available economic research and thinking aimed at promoting a better understanding of New Zealand's important economic challenges.

NZIER was established in 1958.

Authorship

This report was prepared at NZIER by Mark Dean.

1. Introduction

The Ministry for the Environment (MfE) has engaged NZIER to interpret and comment on a report by Concept Consulting "High level review of approaches for estimating a standard electricity allocation factor (EAF), 1 May 2015". The Concept report refers a process undertaken back in 2011 (and also 2008) when MfE formed a Contact group to estimate an EAF for energy intensive trade exposed (EITE) firms.

The following discussion is a technical appendices which complements a memo provided to MfE on the 26 May 2015.

2. The modelling approach chosen in 2011

Concept Consulting produced a report in April 2011 recommending a "Long Run Marginal Cost" (LRMC) approach to estimating the Electricity Allocation Factor (EAF). The industry contact group had a mix of views, with some either:

- supporting an LRMC approach
- supporting the approach but recognising the limitations, so also desiring other approaches to be considered
- rejecting the approach outright and desiring an alternative method.

The following extract from "Development of an Electricity Allocation Factor Recommendation for 2013 Onwards" (June 2012) explains the rationale at the time:

> *"Therefore, the Contact group decided to proceed with three methodologies*
>
> *the build schedule is based on LRMC and plant dispatch is based on short run marginal costs ('SRMC') , and*
>
> *the build schedule is based on LRMC and the electricity market is modelled using a Cournot (imperfect competition) model; and*
>
> *capital, fuel and carbon costs are used to calculate LRMC for potential additions to capacity and LRMC price forecasts including carbon are compared against LRMC forecasts excluding carbon to determine price uplift and implied emission factors.*
>
> *The purpose of taking this approach was to maximise access to a broad dataset and to allow the contact group to analyse and understand in greater depth the complex range of drivers across the options.*
>
> *Energy Modelling Consultants Ltd (EMC) was engaged to undertake the first two approaches outlined above. The Ministry of Economic Development (MED) provided the third and the build schedules for the EMC modelling."*

3. Concept 2015 report

MfE has subsequently received a report from Concept "High level review of approaches for estimating a standard EAF" (May 2015). This report summarises some criticisms of the 2011 modelling approach and also outlines an alternative approach based on LRMC. The following sections describe Concept's criticism, and then a response is provided for each.

3.1. Criticism of 2011 approach

> *"Exogenously specified fleet composition assumptions which were inconsistent with the underlying scenarios relating to fuel and CO2 prices and electricity demand, including assumptions relating to the retirement of Huntly units"* Concept (2015).

The building of new plant was determined using the "GEM[1]" optimisation model, whilst the 'price' impact was determined in the OCCAM[2] model. Input assumptions common to both models were aligned (e.g. fuel and carbon prices) and the resulting build schedule from GEM was used in OCCAM. There was therefore internal consistency in terms of the input assumptions.

However, because none of the assumptions were known with certainty, a range of scenarios were considered. GEM acts a bit like a central planner with perfect information of future fuel costs, capital costs, and demand and so on. But in reality the market has uncertainty to deal with. GEM also cannot assess each company's relative hedge positions (and the resulting profitability and risk for each company).

The scenarios were all discussed at length by the contact group and the overall design of the scenarios was intended to reflect the most important assumptions (that would affect an EAF).

Part of the scenario design was incorporating the Huntly retirement/storage decision. It was acknowledged that this was an important assumption, so a range of retirement dates was modelled, with some aligned to the counterfactual, and some not aligned. At the time there were 4 units (1000MW) so even if the retirement decision was endogenised, some judgement would have still been required since Genesis would not have retired all 4 units at once, even if it was the optimal 'least cost' decision.

It should also be noted that these retirement decisions would apply to any model method employed. Concept make a valid point however, that in Genesis's own submission they stated that carbon pricing had only a small effect on retirement decisions. Since 2011, Genesis has retired one unit and put another in storage, despite carbon prices sitting around $5 per tonne in recent years.

GEM was also constrained so that coal stations would not be built in any of the scenarios with a coal price. This is similar to the group's approach to the Huntly decisions, where judgement was preferred over the default model outcomes. Recalling that GEM makes decisions based purely on minimising a set of costs, which

[1] GEM

[2] OCCAM

in reality are unknown. The fact was, at that time, in a world with (some level) of carbon pricing and an intention to reduce New Zealand emissions, not one company was publicly proposing a coal fired power station. Even if the economics worked, the PR consequences (e.g. MRP's failed attempt to restart Marsden B coal plant in 2004) and also the risk of exposure to future carbon prices would be enough to deter a potential investor. Potential nuclear stations were also not considered even if they were economic (again, it would be a PR disaster for the company and political suicide for the government). However, coal stations were 'allowed' to be built in the counterfactual scenarios, since these were parallel universes where carbon emissions were not a concern to the public.

The lack of a 'gas' scenario in the counterfactual was discussed by the Contact group. Some members were also critical of this, especially since there was a coal counterfactual scenario. This was perhaps one area of the scenario design where there wasn't complete consensus.

> *"Inconsistent coal and CO2 price assumptions for the scenarios."*

Concept's assertion that in a world with higher coal demand the price should increase is a sound deduction. The scenario design again reflected uncertainty in the coal price, whether it should be \$4.50 or \$5.50, so both counterfactual scenarios were included (in the \$5.50 scenario coal was not built because of relative economics, but with \$4.50 prices the coal plant was built).

> *"An inherent difficulty in maintaining consistency of assumptions for two-model approaches. i.e. having one model determine the fleet composition, and another calculate market prices. This is illustrated by some of the outputs from the SRMC modelling exercise being inconsistent with the logical framework within which they were produced. For example:*
>
> *in some scenarios for some years, the EAF is projected to be higher than the EAF of the most fossil intensive generating station (i.e. Huntly);*
>
> *in some scenarios for some years, the EAF is projected to be negative. i.e. it is projecting that the introduction of a cost of CO2 results in lower electricity prices than would otherwise be the case; and*
>
> *the high demand scenario having lower electricity prices than the medium demand scenarios."*

These results did appear to be odd, but made sense once we dig a bit deeper into the dynamic changes happening within each scenario. Figure 1 shows an extract from a high level, simplified dispatch and build model, where hydro volatility is ignored (i.e. assumes 'mean' hydrology each year). This is illustrative only and is intended to show how a market in short run equilibrium moves towards a long run equilibrium.

The red SRMC line, where there is no carbon price, starts at a relatively low price, and as demand grows each year, more expensive thermals are dispatched which increases the SRMC clearing price. Eventually prices rise beyond LRMC (point 4) and a new plant is built. We assume a renewable (\$0 SRMC) plant is built which supresses SRMC prices (as expensive thermals are marginalised). However, as demand continues to grow so do SRMC prices, and so the process cycles on over time. This is a dynamic which Concept also discusses in their report (Section 3.1)

When a carbon price is introduced (blue line) the SRMC price rises as the thermal stations setting the price will face an increase in their own SRMC. This means that the signal to build new plant is accelerated (point 2). Note the LRMC line doesn't change since the new plant is renewable (nil emissions in this example). Prices fall as they did in the counterfactual, however at this point in time the counterfactual SRMC price is rising, so is higher than the carbon price scenario. This is what causes a negative EAF.

The key point is that once the two scenarios start to diverge on different build profiles, it becomes very difficult to make comparisons between the SRMC outcomes in any given year. Some years will be positive and some will be negative, but over time the average EAF for the carbon scenario should be positive.

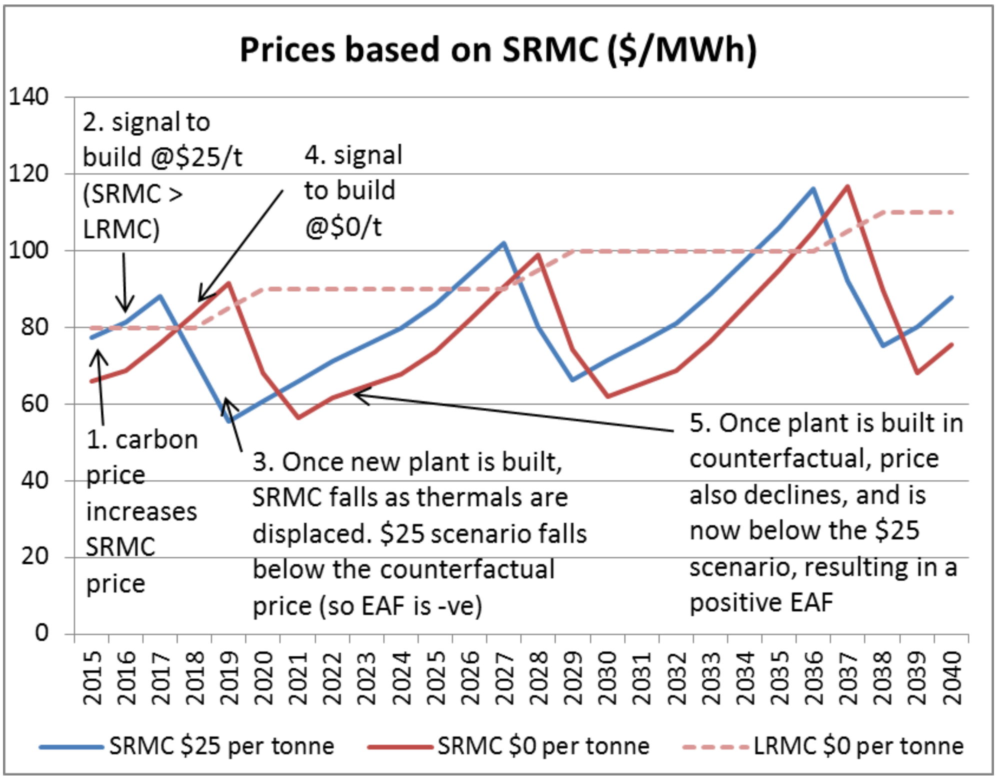
The same case can be made when comparing medium versus high demand growth scenarios, where the high growth scenario may build more $0 SRMC renewables up front (and so supress the SRMC price earlier than in the medium growth scenario).

This is a dynamic which wasn't obvious to the Contact group at the time of commissioning the modelling work. If it had been known perhaps a slightly different approach to scenario design, modelling and/or output interpretation would have been considered.

I don't believe this dynamic calls into question the entire modelling approach as Concept suggests.

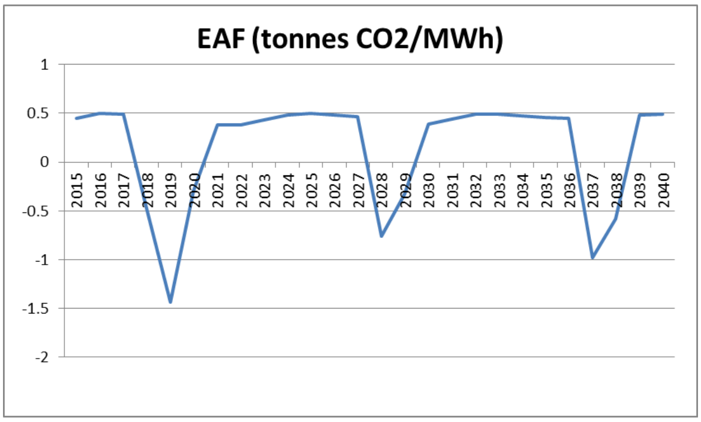
GEM will be determining least cost build schedules to ensure that there will be equilibrium between demand and supply, in any given year. OCCAM will be determining short run market outcomes, given the build schedules provided by GEM (maintaining consistency of assumptions between the two modelling approaches). The cyclical pattern in figure 1 is not unlike what will be implicitly occurring in the GEM and OCCAM modelling (if the "noise" of hydrology could be neutralised).

Figure 1 SRMC dynamics when LRMC driven by new renewables



Source: NZIER simplified dispatch model

Figure 2 EAF when LRMC driven by new renewables



Source: NZIER simplified dispatch model

> *"The selective exclusion of some modelling approaches (particularly LRMC and Cournot), SRMC-scenarios, and modelled years, the combined effect of which was to significantly increase the calculated EAF from what it would otherwise have been."*

The modelling revealed results which seemed counterintuitive and unexpected, for example, negative EAF's in some years. The group consensus was to exclude modelled years which appeared to be 'outliers', which typically occurred after the Huntly units retired. The previous section discussed how these negative EAF's could come about. Next time the EAF is updated these sorts of outcomes should be expected and considered explicitly when deciding on a modelling approach and the scenario design.

The Cournot approach also produced some unexpected results. Given more time and budget some of these issues could have been analysed through further research. However, given the complexity of the Cournot modelling and the 'rabbit hole' we could have ended down, the Contact group decided to park these results and focus on the SRMC (and LRMC) results.

My interpretation of the Contact group's feeling about the LRMC modelling was that it was a useful insight, especially when considering medium to longer term trends. However, given that spot prices are usually set by a marginal thermal generator that will face an increase in its costs (due to carbon) the group felt it was important to firstly understand this short run dynamic.

3.2. Concept's proposed approach

In Section 3.1 of Concept's report, they describe the nature of short run versus long run equilibrium, which is not too different from Figure 1. They admit that at any moment in time the market probably won't be in equilibrium due to the lumpy nature on plant investment and also the inevitability that market expectations (which drive decisions made today) will be wrong. This then means that the actual electricity price impact will be different to the LRMC based effect.

Concept explains that there is an inherent difficulty in trying to predict a market disequilibrium because an unknown counterfactual scenario needs to produced …

> *"the extent of subjectivity required will invalidate this approach".*

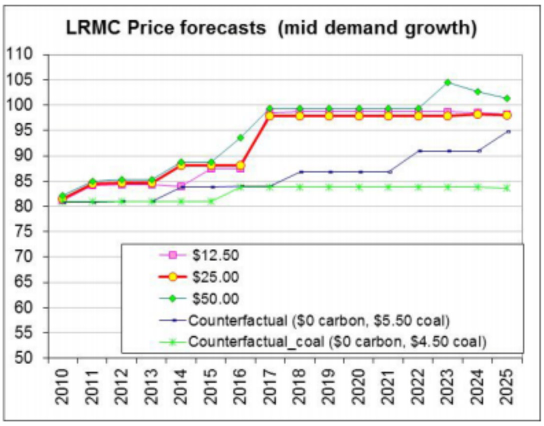
Concept argues that this problem disappears if the CO2 price impact is based on an LRMC approach.

I agree that the market will rarely be in a *long run* equilibrium and that estimating an appropriate counterfactual is extremely subjective, but do not reach the same conclusion that this necessarily favours one approach over another.

Counterfactual scenario

A counterfactual scenario is required for *any* method employed, including an LRMC analysis. For example, in 2011 the Ministry of Economic Development (MED) produced LRMC based EAF's for the Contact group. In Figure 3, the LRMC's for the two counterfactual scenarios diverge from 2020, with the $25/tonne EAF 0.568 under one counterfactual and 0.282 under another.

Figure 3 MED's LRMC price forecasts (2011)

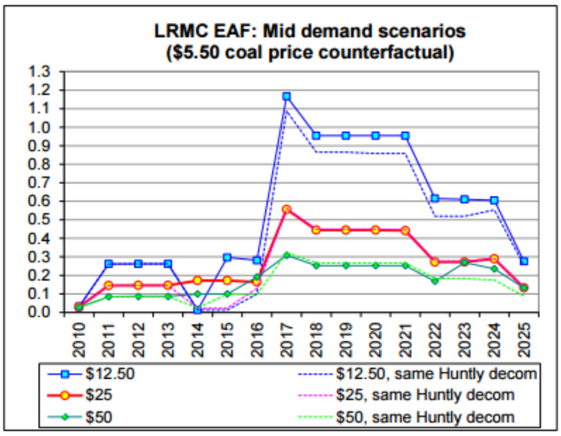


Source: MED

EAF volatility due to carbon price uncertainty

An LRMC approach is also subject to an additional source of volatility if the cheapest LRMC plant is typically renewable. In this case the LRMC profiles are largely unchanged across the different carbon price scenarios because the EAF = change in electricity price/carbon price, so the numerator is relatively constant. This can be seen in Figure 4 post 2017. Therefore, the carbon price assumption becomes even more critical under an LRMC approach (as opposed to an SRMC approach where in the short run cost increases would be passed through into spot prices).

Figure 4 MED's LRMC based EAF's (2011)



Source: MED

Demand growth uncertainty

If demand growth is flat this will limit the need to build new generation, and hence an LRMC price path would be flat for some time. Perhaps LRMC becomes less relevant for contract pricing decisions made over the short to medium term. In Figure 1 this would be represented by a horizontal SRMC price over time, since there would be no demand growth to engage the more expensive thermal stations. If thermals are decommissioned then the SRMC will decline over time and EAF will tend towards zero (the emissions intensity of renewables). If the flat or declining demand is due to increasing quantities of local generation, such as solar PV, then perhaps a completely new modelling approach needs to be considered for that scenario.

Existence of long run versus short run equilibriums

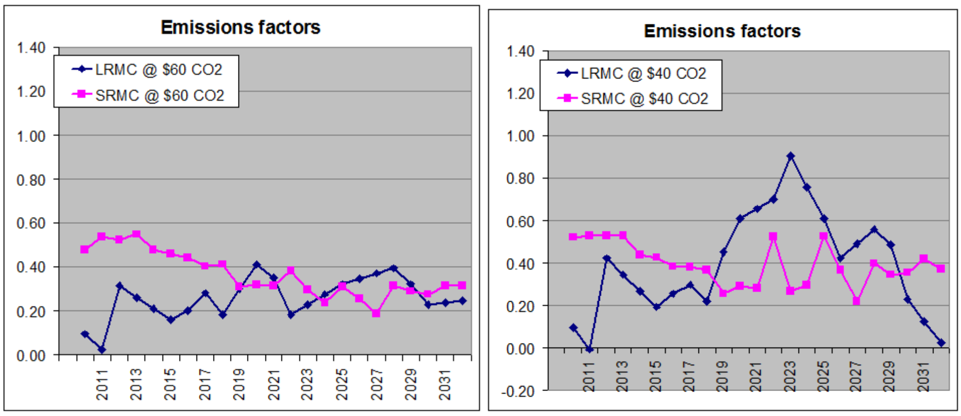
The electricity market is always in a short run equilibrium, with market prices reflecting the relative demand and supply conditions (the exception being demand curtailment due to plant or transmission outages). However, it is difficult to assess whether the market is ever in a long run equilibrium, because of the impact of hydrology on spot prices and the tendency for markets to cycle through various states of surplus and deficit capacity. So it is difficult to test whether the economic theory (that short run prices tend towards LRMC) holds. The price of hedge contracts is a sensible indicator of whether prices are tending towards LRMC.

The importance of time frames

How do we reconcile short run (instantaneous) carbon price impacts on the SRMC of thermals to LRMC outcomes? In 2008 for example, the LRMC EAF for the first few years was very low since it reflected geothermal LRMC, and then got very high due to changing build schedule dynamics (Figure 5). In the long run it seemed to converge on the SRMC forecast. Given the current uncertainty around demand growth it may take some years for the market to converge on a theoretical LRMC price, so there could be some nervousness from stakeholders about relying completely on an LRMC approach.

Figure 5 2008 study EAF

LRMC vs SRMC approaches



Source: MED

4. Other feedback on the 2011 EAF

Most of the feedback from stakeholders back in 2011 supported the overall modelling approach, but there was not consensus on how the scenarios should be interpreted (and so what the resulting EAF should be).

Table 1 Feedback from stakeholders (2011)

Support for approach and EAF of 0.537	Support for approach but higher EAF of 0.606	Support alternative approach
Genesis Balance Holcim	MEUG Business NZ Pacific Aluminium CHH	Norske Skog (SOL's 2010 Cournot modelling results of 0.613 to 0.689)

Source: NZIER

MEUG:

"MEUG places great emphasis on the asymmetric social costs described by NZIER as

"… the potential social costs from setting the EAF too low compared with the social costs of setting it too high. In our opinion, this should have been a key consideration; the objective of the ETS is presumably to provide a positive net benefit to New Zealand and the world."

Only option c (.606 factor) takes this social cost into account"

BusinessNZ:

"BusinessNZ supports the higher EAF of 0.606 tCO2/MWh. BusinessNZ's support of this higher factor rests principally on the need to correct the fact that the 2008 sub-group did not give appropriate consideration to the impact of a price of carbon on the initial new generation build schedules, but instead, assumed the same schedule. Doing so understated the initial EAF, making an upward adjustment now seem larger than it should be. Business NZ also considers that a higher EAF is justified on the basis of the asymmetric risks to investment arising from under, rather than over-estimating the EAF."

Genesis:

"Option b based on more credible assumptions on the effects of the ETS on the future role of the Huntly Power Station

Option b is based on more credible assumptions about the effect of the ETS on the future role of the Huntly Power Station. Option c assumes emissions prices will have a "substantial effect"1 on when the Huntly Power Station is shifted into dry-year reserve status. We do not consider this is a correct assumption to make. We assess the operational viability of the Huntly Power units on the basis of their age, technology and the availability of new generation coming on-line. While we incorporate carbon pricing into this assessment, it is unlikely that this would be the substantial driver behind a decision to retire these units."

Pacific Aluminium:

"We note the material prepared for MEUG by NZIER in 2010 and in particular the discussion around asymmetric social costs of getting the EAF wrong2. Critically, it is clearly preferable to err on the side of caution rather than set an EAF that may be too low."

Norske Skog:

"We don't support any option. We believe that option c at best represents a lower bound for the EAF. Our reasons are explained in the body of this submission. In a nutshell the options provided have been estimated using a central planning paradigm and ignore competitive behaviour and risk aversion. Therefore they can really only be expected to represent a lower bound for the EAF."

Norske were also critical of Concept's LRMC approach:

"Model accuracy is much more important than simplicity. Many SRMC models have wide acceptance in the industry – despite involving very complicated algorithms."

"...according to the LRMC model investors can make a perfect investment for each modelling scenario. Then the probability weighted average of all of the perfect solutions is computed to provide an answer. This answer is fundamentally biased and unrealistic. In practice investors do not possess perfect knowledge about the future. Investors must make decisions at a point of time, with no ability to anticipate the future. Non-anticipativity of exogenous parameters must be included in any realistic modelling of future investment."

"We did not find any empirical evidence in Concept's report to support an assertion that LRMC = spot price. Concept instead relied on a general argument that investors would not invest unless expected revenues matched the LRMC of their plant. This argument is generally sound, but falls short in the NZEM context due to a number of other factors. Firstly generation investment is lumpy, and for reasons of economies of scale often large in comparison with system demand. Thus after a large investment spot prices are likely to be suppressed for a considerable length of

time. We agree with Concept3 that over time contract prices and spot prices should equal each other. However we do not agree with Concept that contract prices (and therefore spot prices) will equal LRMC. We tested this hypothesis by extracting the LRMC of a CCGT from figure 5 and plotting this with the final spot price at HAY2201 as well as a two year moving average of the HAY2201 final price. It can be observed that there is no observable relationship between monthly spot price and the CCGT cost. Neither is there any relationship between the moving average spot price and CCGT cost. Our assertion is that due to the NZEM being dominated by renewable generation the effects of hydrology swamp out all other factors. Thus we believe that any useful estimation of spot prices and changes to spot prices due to the ETS must take into account expectations of hydrological variation. LRMC models cannot do this."

[3] Section 1.3.4 of Concept report.

5. What has changed since 2011?

Table 2 Developments since 2011

Assumption	2008 report	2011 report	Current
Method	SDDP & GEM, LRMC	OCCAM & GEM, LRMC	? … need to consider 'disruptive' scenarios also
Huntly units	All 4 units in storage 2013, 2015, 2018, 2020. In all scenarios same years	Counter_M: Unit 1 storage 2016, unit 2 storage 2020 $25 = 2013 & 2017 $50 = 2012 & 2016	Unit 1 decommissioned, unit 2 moved to 90 day storage in 2013
Gas market	$6.50	80PJ max, 55% ToP contracts, $7.30/GJ excl carbon	ToP% probably needs to be lower (e.g. Contact)
Coal price	$4	$4.50 - $5.50/GJ`	?
Demand	~1.5%?	2%pa growth 2010-2017 (+6300GWh). Low scenario 1.5%pa	Flat growth in recent years to continue?
Carbon prices	$0, $20, $40,, $60, $80	$0, $12.50, $25, $50	around $2 to $5 per tonne since 2013
Counterfactual	Same	Base + cheap coal	?
Etc.			

Source: NZIER

The 2011 Contact group report noted that the recommended EAF should be enduring until "significant events occur warranting a re-assessment". The sorts of factors mentioned were:

- emissions price
- fuel prices
- major plant changes
- market structure changes.

The report also noted that "officials should actively monitor these key variables through time and periodically consider whether a re-assessment is justified". There have been a number of developments since 2011 which may warrant a revision of the EAF.

Carbon prices have been extremely low since 2013, so one could argue that of all the alternate scenarios considered in 2011, the world we have experienced since 2013 is in fact closer to the counterfactual. In which case the counterfactual scenario could be simplified to a world pretty similar to where we are now.

Major plant changes would include the decommissioning of Huntly, and 2 units have already been stood down (in the counterfactual this was 2016 and 2020). The 2011 report noted the importance of the Huntly decommissioning dates to the analysis. Also in 2011, the units were decommissioned in different years depending on the carbon price scenario. Genesis have decommissioned units 1 and 2 with carbon prices at very low levels, which supports their 2011 submission that carbon prices would not materially affect their decommissioning decision.

Demand growth has also been non-existent, leading to surplus capacity and delaying potential new build.

6. Approaches to consider for next EAF

Different modelling approaches all have pros and cons, but the critical issue is how will the prices that consumers face be affected, particularly the EITE firms. We can be sure that spot prices will be affected if the SRMC of thermal generators changes, but it is also true that few consumers face the spot price directly. Most industrial consumers will hedge their consumption, so the question then is to what extent will spot prices affect hedge contract values. Over time there should be consistency between spot and hedge prices, otherwise there are arbitrage opportunities. Furthermore, if demand increases and new plant is required to be built, the LRMC of new generation is also a sensible indicator of where hedge prices should sit, since a potential investor in a power station would only invest in that plant if convinced that generation could be hedged at a price equivalent to LRMC. Therefore, the theory suggests that over time either an SRMC or LRMC approach to forecasting an EAF should yield consistent results.

However, there will be sustained periods when the market is in a long disequilibrium (Figure 1) and it is possible that hedge contracts will be written for values higher or lower than LRMC. This is evident with the ASX futures contracts which are probably influenced by hydrology over the first couple of quarters. Furthermore, the last few years has seen no demand growth resulting in a relative over supply of capacity, and what if demand remains flat for another 5 years? A pure LRMC approach would struggle to cater for this type of scenario since it is unlikely that any new plant would be planned before 2020 in this case.

An SRMC approach would be able to model these short run imbalances more explicitly. However, it does require layers of assumptions, more complex modelling techniques, and as we have seen, the design of the scenarios is also a critical component in the analysis.

The optimisation techniques used in OCCAM and GEM assume perfect information, and risk neutral behaviour by firms. Although hydro inflows are modelled as a stochastic variable, the alternative values of those variables are known at the outset, so the OCCAM model can make the best 'least cost' decision. GEM it is like a central planner with knowledge of the costs of all plant, and who can forecast demand with 100% accuracy. If either of these highly stochastic variables turn out to be different than forecast, it is unlikely that the results will be 'optimal'.

In reality, consumption and investment decisions will be made with the best available market information to hand, which of course will be incomplete. The result is that markets will rarely be in a perfect long run equilibrium, with some level of either over or under supply.

So it is clear that both SRMC and LRMC techniques have their deficiencies. SRMC has the timing issues highlighted in Figure 1 which result in negative EAF's in some years, as well as the 'least cost' perfect solution which can never be attained in reality. LRMC is a theoretically sound approach however because of short run imbalances, consumers may not be convinced that the EAF calculated from this method will ever reflect a "real world" (as opposed to a theoretical) outcome.

In 2011, the Contact group also explored imperfect competition via Cournot modelling. This resulted in an EAF lower than the SRMC modelling, because as prices increased (in response to a carbon price) demand reduced. The demand reduction put some downward pressure on prices, hence limiting the potential price increase (compared to a pure SRMC world). This result was perhaps unexpected by the contact group. In fact, in 2008 Tom Haliburton's report stated:

> *"Market gaming will increase market prices above SRMC …… consequently, if SDDP predicts a company will gain additional revenue from CO2 charges, it is likely that a lower bound on this increase will be estimated by SDDP."*

This shows the learnings that have evolved between 2008 and 2011. Concept in their 2015 report (Section 3.2) describe that under conditions of imperfect competition, it is quite reasonable for a cost increase to not be fully passed on in final prices (if the demand function is downward sloping as opposed to vertical).

The Contact group felt there was more work to do to fully understand the Cournot modelling and so parked the results at the time. Additional assumptions are required to estimate firm hedge levels and demand elasticities. Often these variables will be adjusted to calibrate the model to historical price outcomes, so the modeller's judgement may end up having a large bearing on the results. Tom Haliburton in his response to the 2011 EAF submissions (14 August 2012) made comments:

> *"While least cost, or SRMC modelling, is widely used throughout the world, market modelling is not attempted so often."…."There is no clear consensus on the best approach to modelling strategic bidding in electricity markets. A factor in this lack of consensus may be that bidding strategies and their effects are specific to each market" …."So in addition to more complex modelling, the process is dependent on further assumptions and these assumptions may need to change over the time horizon being studied as the electricity industry evolves."*

If this approach were to be considered in future EAF rounds, then more thorough research would be required than in 2011.

Overall, the final approach taken in 2011, with SRMC and LRMC price paths both considered, seems like a sensible method to continue with. However, the deficiencies identified need to be addressed.

One option would be to devise a "smoothed contract price path" which indicates the price level required by firms, over time, in order to support the SRMC of existing thermals, and also support the LRMC of new build. This would essentially be the hedge prices that energy firms would use in their business plans, and the implicit assumption would be that any cost increases faced would be passed on in a way that would be NPV neutral (i.e. current share price valuations would be maintained[4]). By calculating a smoothed price this would avoid the potential negative EAF's in some years. Also, by bringing the metric back to NPV (or share price) there would be a

[4] The outputs from SRMC and LRMC modelling would be required for this approach. It would take the raw model outputs and devise a method for interpreting the results within the context of contract markets and how it may change firms pricing strategies.

consideration of how the time value of money will play out if the building of renewables is brought forward (in order to displace more costly thermals).

Scenario design is also crucial, as was observed in 2011 with the Huntly decommissioning dates. With two units now already out of service, there are just two more units left to decide on. Aligning these dates across scenarios would make sense from several perspectives:

- Genesis stated in their submission that carbon prices have no significant bearing on their decommissioning decision;
- Genesis have already decommissioned two units despite a very low (one could say non-existent) carbon price, which supports the claims they made in their submission ;
- Interpretation of model results will be simpler.

Figure 6 shows how each assumption change affected the $25 per tonne EAF. The first row shows the EAF when build schedules are aligned in both the counterfactual and the $25 scenarios. These are the sorts of numbers you would expect to see in response to an instantaneous change in costs, with no long run adjustments possible. However, once the build schedules start to diverge and different decisions on decommissioning are made there are adjustments to the EAF which are difficult to interpret (without the help of a diagram like Figure 1). For SRMC results to be accepted then the moving parts in Figure 6 would need to be identified and understood. The scenario design needs to consider these complexities and identify opportunities to simplify the analysis.

Figure 6 2011 EAF decompostion

Table 24: Components of the $25_M Scenario EAF

Case	2013	2014	2015	2016	2017	2018
EAF for $25_M_Huntly relative to $25_M_Huntly_$0 case	0.532	0.524	0.604	0.676	0.64	0.70
Effect of build schedule change due to carbon price	-0.080	-0.048	-0.112	-0.520	-0.708	-0.776
Effect of change to Huntly switch to reserve shutdown status assumptions	0.172	0.224	0.548	0.852	0.944	0.876
EAF for $25_M relative to Counter_M	0.624	0.7	1.04	1.008	0.876	0.80

Source: Tom Haliburton 2011 report

Because the scenario design was the focus of some criticism, as well as causing some (previously) unexpected results, perhaps a more iterative approach could be considered next time. Once the scenarios have been mapped out, a simple ‘top down’ model (such as that used in Figure 1) could be used interactively to help understand how the different scenarios would play out in terms of:

- the LRMC supply stack
- the SRMC of each station
- how thermal utilisations (and therefore spot prices) may react in response to demand growth

- how this would affect the signals to build new plant (i.e. when will SRMC > LRMC).

The modelling framework also needs to consider disruptive technologies such as solar PV. The modelling in 2008 and 2011 only considered the building of large scale grid connected plant. The addition of solar PV and potential demand side efficiencies will show up as reduced grid demand (and so less need for grid connected supply). As discussed, this may lead to spot prices falling and the EAF falling too. However, industrial consumers could see their transmission and distribution costs rise if there is less traffic on the network (and the utilities still attempt to recover the same sunk cost). It is a natural extension to want to understand how carbon pricing would affect the uptake of solar PV, and whether the EAF method should be augmented to capture these potential effects.

An econometric approach could also now be considered. This was discarded back in 2011 because of insufficient data. However, with several years of data this is now a feasible avenue to explore.