Validation of Electricity Modelling for Energy Outlook

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for

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Energy market, pricing & risk analysts

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Definitions

The following abbreviations and acronyms are used in this report.

Capacity adequacy	The condition that there be sufficient generating plant available to run to meet demand at all times
Capacity factor	The ratio of the average (annual) output of a plant in MW to its rated output in MW
Capacity margin	The total amount (or percentage) of generating (peak MW) capacity available relative to demand
CCGT	Combined cycle gas turbine
DSR	Demand-side response (to high prices)
ECNZ	Electricity Corporation of New Zealand
Energy margin	The total amount (or percentage) of energy (GWh) available from generation over a specified period less total demand during the period.
Energy-serving	Refers to generating plant that runs in base-load or firming roles, as opposed to peaking plant which runs only during times of peak demand or system stress
GEM	Generation Expansion Model
I-Gen	Energy Link's dynamic model which calculates when and which new generation plant will be built in future years
ILR	Interruptible load reserve (provided to the market for the purposes of emergency load shedding)
Location factor	The ratio of the price at a specified grid node to the price at a specified reference node
LRMC	Long run marginal cost
MED	Ministry of Economic Development
Monte Carlo	A Monte Carlo model forecasts a time series of a parameter based on modelling an underlying random processes which follows a known distribution
MRJD	Mean reversion jump diffusion
Revenue adequacy	The condition that a generator earns sufficient revenue to cover all costs
SOO	Statement of Opportunities modelling for electricity in New Zealand
SRMC	Short run marginal cost
TOP	Take-or-pay

Contents

1 Introduction

MED currently produces and publishes the New Zealand Energy Outlook on an annual basis and includes projections of demand, energy supply and greenhouse gas emissions to 2035. In anticipation of market reforms, including publication of a Statement of Opportunities (SOO) for electricity[1], which will require MED to scale up its modelling activities, MED seeks external validation of the processes and inputs used to create the long term electricity projections.

Energy Link was engaged by MED in March 2010 to undertake "parallel modelling" of MED's Energy Outlook Reference Scenario (2009 version) and to comment on MED's approach to modelling electricity prices in the Reference Scenario.

The work undertaken by Energy Link included:

1. development, in consultation with MED, of a schedule of all inputs to MED's and Energy Link's respective (electricity) modelling processes;
2. reconciliation of the inputs to ensure that the inputs to the respective modelling processes amounted to modelling the same Reference Scenario;
3. modelling the Reference Scenario using Energy Link's entire modelling process;
4. modelling the Reference Scenario using MED's "build schedule"[2] of new generation using part of Energy Link's modelling process;
5. comparison of the outputs of the respective modelling processes and investigation of significant divergences;
6. reporting on the significant differences, comparing the two modelling approaches and commenting on MED's modelling approach in the context of its purpose of producing the Reference Scenario and other scenarios relevant to Energy Outlook and the SOO.

This report includes an Executive Summary, followed by an overview in section 3 of the purpose of the Reference Scenario within Energy Outlook.

The electricity price modelling processes followed by MED and Energy Link are briefly described in sections 4 and 5. The key inputs are described in section 6 and the results of Energy Link's parallel modelling are given in section 7. Finally, in section 8, we provide commentary on the results and offer our conclusions.

The Appendix briefly overviews aspects of the theory of electricity price modelling that are relevant to Energy Outlook.

Unless otherwise stated, all references to years are to calendar years. Prices calculated from Energy Link's modelling process actually relate to years commencing 1 April, but in the context of this report, the impacts of the timing difference are not significant when comparing Reference Scenario prices to prices calculated by Energy Link.

[1] This function is currently undertaken by the Electricity Commission.

[2] A list of new plant to be built over time, ordered by commissioning date, and including the cost and other details of each plant.

2 Executive Summary

The primary purpose of Energy Outlook is to provide information to the public to inform energy policy debate. The Reference Scenario includes projections of electricity prices which are based on the long run marginal costs (LRMC) of new plant that may be built over the period 2010 to 2035.

MED uses GEM[3] to produce the 'MED build schedule' which minimises the total cost of new generation over the forecast period, subject to constraints that ensure that an adequate capacity and energy margin is maintained year by year, taking into account (amongst other things) existing and new generation, demand growth, plant retirement and the need to provide standby reserves[4]. An Excel workbook is then used to calculate wholesale electricity prices which reflect the LRMC of the new plant contained within the build schedule.

The market simulation runs undertaken with Energy Link's *EMarket* and I-Gen models can be grouped under the two headings 'price comparison' runs and 'build comparison' runs:

1. **<u>Price Comparison</u>**
   These runs were designed to test the validity of the Reference Scenario prices, given the MED build schedule produced by GEM, with two variations:
    a. *EMarket* was run using the MED build schedule and offers consistent with observed market behaviour:
    b. *EMarket* was run using the MED build schedule and offers based on SRMC for existing large thermal plant, and based on LRMC for large new thermal plant;
2. **<u>Build Comparison</u>**
   These runs were designed to test the validity of the MED build schedule, given MED's raw inputs (consisting primarily of a list of possible plant and their respective LRMCs), to produce the I-Gen build schedule, which was then compared to the MED build schedule.

2.1 Price Comparison

The price comparison runs were set up to test the MED build schedule (produced using GEM for the Reference Scenario) in the context of the actual electricity market. In particular, the first set of price comparison runs were set up to produce market-based prices to compare with the Reference Scenario prices.

With offers set up to mirror offer structures typical of the current market, the prices produced by *EMarket* using existing plant plus the MED build schedule average \$2.5/MWh (1.1%) lower than the Reference Scenario prices over the entire forecast period (2010 to 2035). However, they sit higher from 2013 to 2023 where the MED build schedule favours peaking plant over plant which is built primarily to produce energy ("energy-serving" plant).

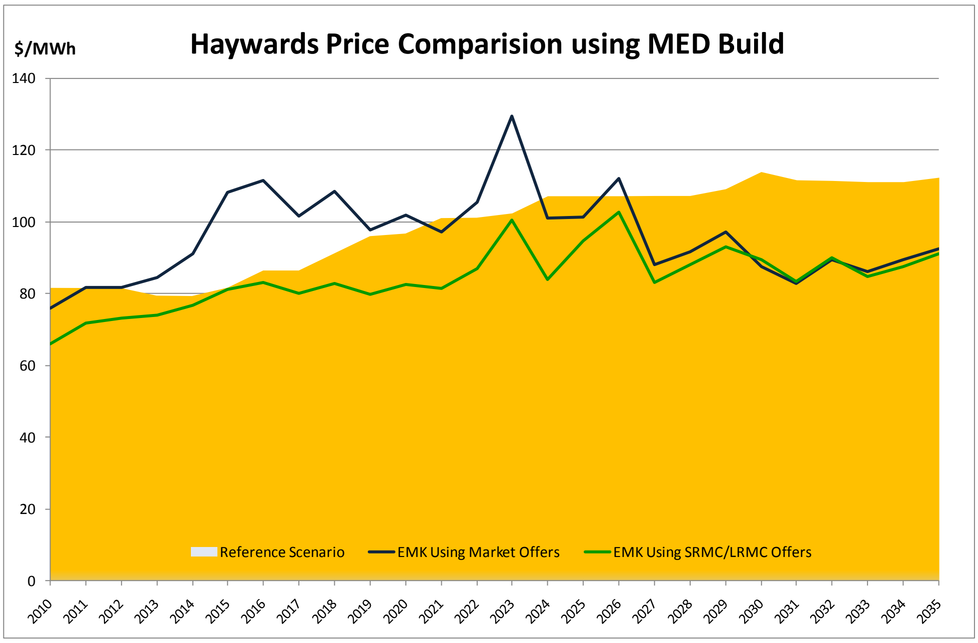
[3] Generation Expansion Model
[4] Instantaneous reserves. This can be provided by ILR or by generating plant that is synchronised with grid and available on standby.

The rate of build of energy-serving plant increases significantly from 2017 and from 2027 the total build exceeds growth in demand plus retirements. As a consequence of the higher build after 2027, much of which is renewable plant offered into the market at $0.01/MWh[5], *EMarket* produces prices which are below the Reference Scenario prices from 2027 through to 2035.

EMarket was also set to run with offers of SRMC for all large existing thermal plant, with all large new thermal plant offered at LRMC, and with all other plant offered at $0.01/MWh in line with typical offers for wind, geothermal and smaller plant. The basis for these offer structures is that large thermal plant, due to their size and high SRMCs (relative to renewable generation), tend to set price levels in the market. But the prices obtained from the *EMarket* runs are lower than the Reference Scenario prices throughout the forecast period: with so much existing and new plant offered at or well below SRMC, prices do not reach LRMC, or at least prices that will ensure that all plant recover costs.

Figure 1 shows the Reference Scenario prices in the background, along with the two series of prices from *EMarket*. Through to 2024, the two *EMarket* series more or less bracket the Reference Scenario, while from 2027 they fall consistently below the Reference Scenario. In summary then, the MED build schedule (which is produced by GEM) tends to feature peaking stations whose LRMCs are too high to allow them to run often, and so have little impact on the *EMarket* price forecast. However, in the first few years there is little energy serving plant built, which pushes up the *EMarket* prices, while more and more renewable stations are built over time which then tend to depress prices in the longer term, due to their low-price offers. While this mix of stations may ensure capacity adequacy, it does not produce prices consistent with the LRMCs of new plant when the market is simulated using offers consistent with observed behaviour.

Figure 1 – *EMarket* Prices Using MED Build



[5] Wind generation must be offered at $0.01/MWh under the market rules, geothermal tends to be offered as base-load at this price, and most smaller or embedded plant are price takers and offer either at SRMC or at $0.01/MWh.

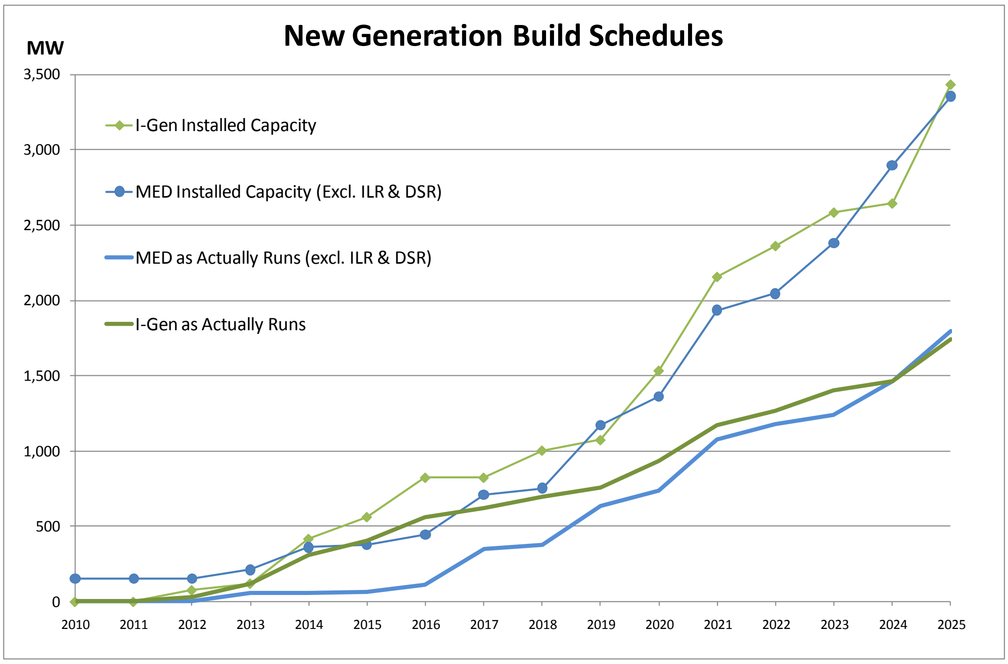
2.2 Build Comparison

The build comparison runs were set up to compare the MED build schedule directly against the build schedule from I-Gen, both using the same raw inputs, for the period 2010 to 2025. *EMarket* was then run with market-based offers using the I-Gen build schedule and the resulting prices were then compared to the Reference Scenario prices[6].

The prices produced by *EMarket* with market-based offers, using the I-Gen build schedule, average $7.5/MWh (7.9%) lower than the Reference Scenario prices. They remain relatively flat through to 2020 then rise sharply, exceeding the Reference Scenario prices only in 2013 and 2025.

In terms of energy-serving plant, the I-Gen build is more aggressive than the MED build through to 2016, but the MED build rate rises sharply from 2017. I-Gen was set up assuming that the energy margin evident in the market represents an "equilibrium point", and it maintains a rate of build consistent with that margin: the build schedule primarily features energy-serving plant. GEM, on the other hand, tends to maintain capacity adequacy by building peaking plant, which hardly ever run, resulting in a gap between the two build schedules when they are run in *EMarket*. Figure 2 shows the build schedules based on installed capacity, and also based on how much plant actually runs in the *EMarket* simulations.

Figure 2 – I-Gen and GEM Build Schedules as Actually Run in *EMarket*



2.3 Electricity Price Modelling

The emergence of competitive electricity markets in recent decades has spurred development of a variety of models for forecasting electricity prices. Monte Carlo models have evolved which model the tendency of electricity prices to be highly volatile around some longer term mean value. They are most suitable for use in

[6] *EMarket* was also run in half hourly mode for selected years to confirm that the I-Gen build schedule satisfied the capacity adequacy requirement

modelling price volatility rather than long term changes in the average price, and hence not suitable for use in Energy Outlook.

Cournot market models have been applied to the price forecasting problem in New Zealand, but in order to achieve realistic prices they usually require demand elasticity to be set unrealistically high and for contract levels to be set unrealistically high: if this is not done then prices tend to be much higher than one would expect. Cournot models are therefore not recommended for use in Energy Outlook.

A number of detailed simulation models are in use in New Zealand, including SPECTRA, *EMarket*, SDDP and Plexos. These models incorporate a wide range of features to model the dynamics of the market and could be employed in Energy Outlook to produce prices which are more reflective of short to medium term market dynamics.

It is widely accepted that there is a link, in the longer term, between the LRMC of new plant and electricity prices, even though the dynamics of the electricity market often mask this, especially in the short to medium term. GEM is currently used by MED and it appears to perform well, and there is strong evidence that it produces results much like Energy Link's I-Gen model under the same input assumptions and allowing for some difference in the capabilities and constraints within the two models. We support the on-going use of GEM for Energy Outlook, albeit with a recommendation for some tuning of input data to moderate the impact of GEM's tendency to build peaking plant to ensure capacity adequacy.

2.4 Conclusions

Despite divergences between the MED and I-Gen build schedules and prices, the Reference Scenario is constructed in a way which is consistent with the objective of meeting demand and maintaining security over the forecast period at least cost. The costs of new plant are also calculated using a methodology which will produce accurate LRMC values given appropriate input data. While GEM's construction may produce build schedules that favour peaking plant, adjustment of the inputs should allow this tendency to be managed, and so we agree that GEM is suitable for use in Energy Outlook. We recommend that GEM's inputs are adjusted to produce a build schedule which features a greater amount of cost-effective energy-serving plant and less peaking plant.

The price comparison runs highlighted the fact that the Reference Scenario prices, which are constructed from the LRMCs of the new plant built in the MED build schedule, do not necessarily reflect market prices because they ignore short to medium term market dynamics. Given that the Reference Scenario prices are published as 'prices', this could be misleading to some readers.

There are two approaches to this issue that might be considered:

1. the modeling process could be changed to factor short to medium term market dynamics into the calculation of the Reference Scenario prices; or
2. given that Energy Outlook is intended to inform policy debate (as opposed to supporting investment, hedging and other market-related decisions), the description of the Reference Scenario prices in Energy Outlook could be modified to more accurately reflect their construction, and thus reduce the possibility of the prices being used for purposes for which they were not intended.

The short to medium term market price dynamics of the electricity market are important in many applications but energy policy is the realm of Energy Outlook, and this is concerned with the societal, political and wider economic environment which provides context for the electricity market in the longer term. Given the practicalities of the wider economic modeling required for Energy Outlook, and its purpose of "informing New Zealand's energy policy debate", we recommend the second approach above. In particular, it should be made explicit that the Reference Scenario prices refer to the total cost of providing electricity at the wholesale level, regardless of how the market is structured in future, ignoring short to medium term market dynamics.

The differences between the Reference Scenario and *EMarket* prices in the later years of the forecast period, in particular, raise interesting and potentially important issues for debate in the context of energy policy and market structure. For example, will the current market structure allow peaking plant to recover all costs, and therefore ensure capacity adequacy, as the proportion of renewable generation grows? Or, how might generating technology evolve to allow new plant to recover its costs through a combination of efficient base-load generation and peaking? We suggest that some discussion of these wider issues in Energy Outlook might contribute significantly to the energy policy debate, and further assist readers put the Reference Scenario prices into context.

3 The Purpose of the Reference Scenario

The stated purpose of the Energy Outlook is to "be a starting point for anyone wanting to become more informed about the energy choices New Zealand faces. It includes 25 year projections of New Zealand's energy future under a variety of assumptions"[7] and according to the 2009 Reference Scenario publication the projections are "principally aimed at informing New Zealand's energy policy debate." Energy Outlook includes a range of scenarios which investigate the sensitivity of the Reference Scenario to key "macroeconomic parameters".

According to the ninth edition of the Concise Oxford Dictionary a projection in the context of Energy Outlook is "a forecast or estimate based on present trends" and a forecast is "a calculation or estimate of something future", so there is a technical distinction between a projection and a forecast. Projections are undertaken by MED for the Reference Scenario based on "business as usual continuing" (BAU) whereas, by contrast, forecasts of electricity market prices undertaken by Energy Link and others attempt to capture the potential impact of future market scenarios in a much wider sense. While these forecasts may inform the policy debate from time to time, their primary purpose is usually to support decision making in respect of major investment, hedging decisions or market strategy.

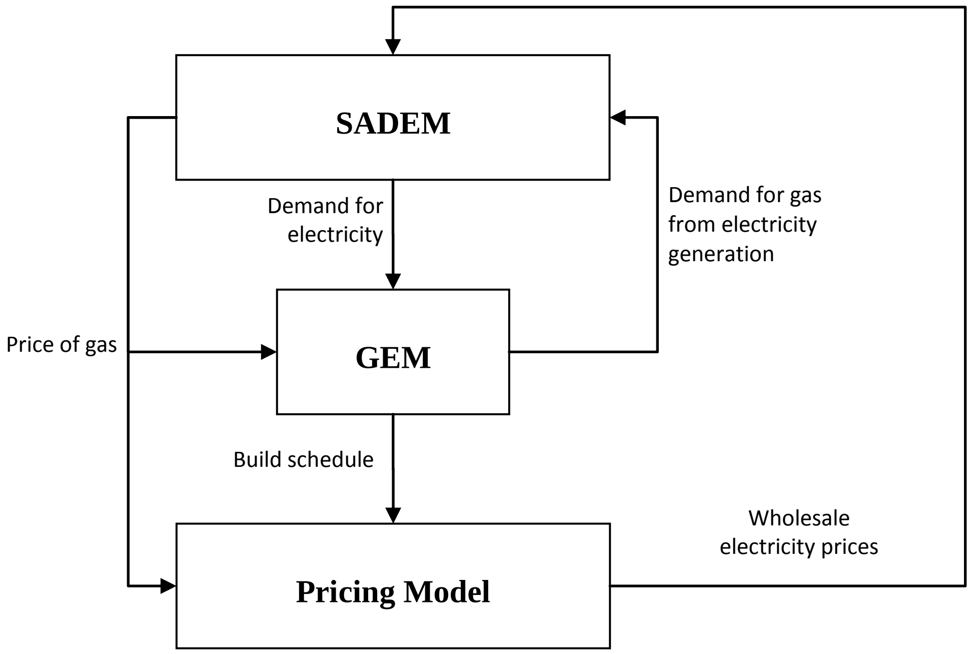
However, the Reference Scenario does not simply extrapolate recent trends in wholesale electricity prices into the future. Instead, it works with BAU projections of parameters which are believed to drive electricity prices at a fundamental level, including demand for electricity, and the costs of building new generation to match increments in demand.

[7] From Energy Outlook pages on MED's web site.

4 MED's Modelling Process

The modelling process for Energy Outlook, as it relates to electricity price projections, is shown in Figure 3, while the Appendix includes further information on the models themselves. SADEM is a partial equilibrium model of the energy sector of the New Zealand economy which interacts with the GEM model and an Excel workbook (shown as the 'Pricing Model' in the figure). The wholesale electricity price projections are produced by the Pricing Model which accepts the build schedule from the GEM model, and assumes an average year for generation[8].

Figure 3 – MED's Modelling Process



The build schedule is a time-ordered list of new generating plant that will be built over the horizon of the Reference Scenario: it includes plant capacity, LRMC, and the GWh dispatch of each plant over nine load blocks per quarter across multiple inflow years. The Pricing Model then calculates a time series of prices over load blocks and quarters, for a selected inflow year (which is a slightly drier year than average). The resulting prices are then calculated so that market participants earn at least the LRMC on their new plant. The quarterly prices are then averaged to give annual prices at Haywards. The Pricing Model takes no account of the details of the electricity market such as nodal dispatch and pricing, the grid, and the dynamics of the market.

SADEM calculates the demand for electricity, and the price of gas. Demand for electricity is influenced within SADEM by the wholesale price of electricity. The gas price is influenced within SADEM by the supply and demand for gas (including the gas used in electricity generation). In the long run it is assumed that the gas price is capped by the opportunity cost of alternative energy sources – primarily renewable electricity generation.

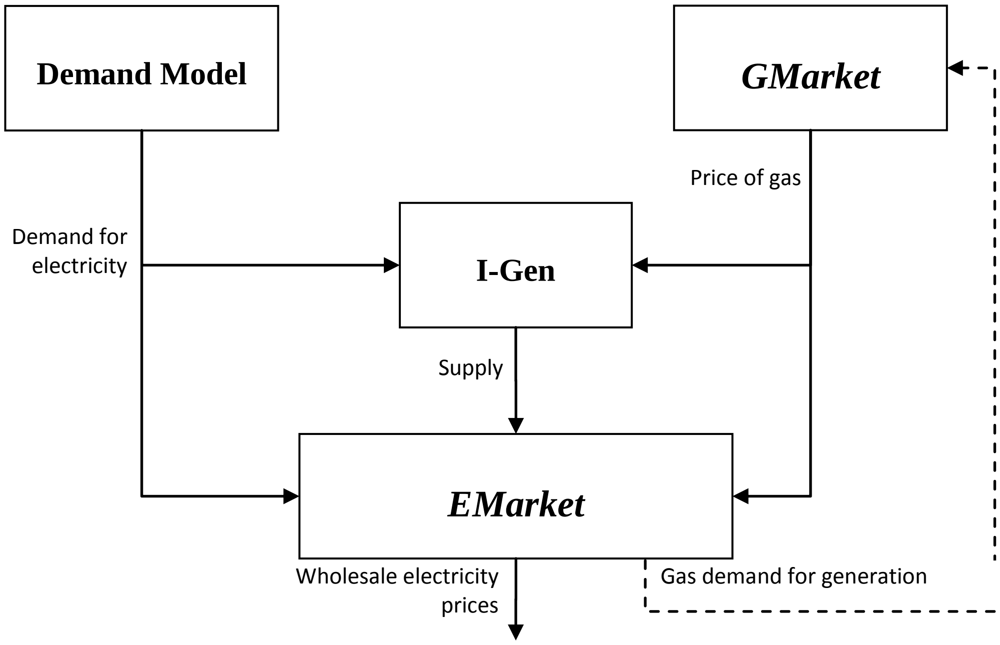
[8] Which actually means that the pricing schedule is based on inflows which are slightly less than average.

5 Energy Link's Modelling Process

Energy Link's long term modelling process is shown in Figure 4. Demand is calculated by the Demand model which projects demand growth based on historic trends[9].

The *GMarket* model indirectly uses demand for gas for electricity generation in its forecasts, and it outputs an expected gas price, along with high and low range gas prices, which are used in calculating LRMC's in I-Gen and generator offers in *EMarket*.

Figure 4 – Energy Link's Modelling Process



The market-driven build schedule of new plant from I-Gen is used within *EMarket* for longer term price forecasts. However, in Energy Link's modelling, generator offers are not simply a function of plant LRMC. Instead, offers are sculpted to reflect a number of constraints and limitations on offers, which mimics observed behaviour. For example, a typical offer strategy for a large new gas-fired thermal plant might include:

1. a 'must-run' offer band priced at zero: this reflects the need for a large thermal plant to run at an output at least as large as its minimum safe output, which for CCGT plant, for example, can be around 40% of maximum rated output;
2. one or more offer bands priced at SRMC: these might reflect a take-or-pay gas contract, or perhaps to the need to generate enough to at least match a market participant's total contract (hedge plus retail load) commitments;
3. higher priced offer bands: these might reflect the plant's LRMC, or perhaps higher fuel costs when contract limits are exceeded.

For most of Energy Link's purposes, prices are required at a much finer level of resolution than annually, so it is important that generator offers provide a realistic

[9] Since 1974 demand has grown at a more or less constant annual increment of around 90 MW excluding losses.

degree of variation in prices between periods of low and high demand, for example, or between wet and dry periods.

All other generators are offered at realistic market prices: for example, wind farms, embedded generation (which is typically smaller scale than grid-connected generation) and geothermal plant are offered at or near zero. Peaking plant is offered using an offer strategy that is consistent with their need to recover fixed costs from the market over the course of their relatively short and unpredictable operating regimes.

6 Inputs to the Modelling

The price comparison runs used MED's build schedule within *EMarket* and covered the period 2010 to 2035, while the build comparison runs covered the shorter period from 2010 to 2025.

6.1 MED's Build Schedule

The new generating plant shown in Table 1 were taken from the Pricing Model workbook provided by MED and used in *EMarket* with the parameters shown[10]. All wind farms, small hydro, geothermal and other small plant was offered at or near zero[11]. Gas and diesel-fired plant was offered using the offer strategy described in section 5.

Table 1 – MED Build Schedule to 2035

Station	LRMC (MED)	Capacity	Node	Commission Date	Type
Generic OCGT NI 1	341.52	150	ALB	1/01/2010	Thermal Diesel Peaking
Te Mihi	75.29	60	WRK	1/01/2013	Geothermal
Generic OCGT SI 1	405.63	150	ISL	1/01/2014	Thermal Diesel Peaking
Hawea Control Gate Retrofit	81.40	17	CML	1/01/2015	Hydro
Mokai 4	83.78	40	WIR	1/01/2016	Geothermal
Toaroha	86.56	25	HKK	1/01/2016	Hydro
Kawerau stage 2	83.71	67	KAW	1/01/2017	Geothermal
Tauhara stage 2	86.48	200	WRK	1/01/2017	Geothermal
Mohaka	83.76	44	TUI	1/01/2018	Hydro
Clarence to Waiau Diversions	93.65	70	ARG	1/01/2019	Hydro
Clutha River Queensberry	102.96	180	CML	1/01/2019	Hydro
Kakapotahi	112.91	17	HKK	1/01/2019	Hydro
Ngatamariki	92.11	67	WRK	1/01/2019	Geothermal
Otoi Waiau	92.59	16.5	TUI	1/01/2019	Hydro
Rotokawa 3	91.66	67	NAP	1/01/2019	Geothermal
Clutha River Beaumont	91.80	190	ROX	1/01/2020	Hydro
Clutha River Luggate	115.14	100	CML	1/01/2021	Hydro
Generic geo 1	95.69	75	KAW	1/01/2021	Geothermal

[10] Three plant from the MED build schedule are not shown above because they were already assumed in Energy Link's modelling as being built in the near future: Contact Energy's Stratford gas-fired peaking (200 MW) and Tahuara I geothermal (23 MW) plants, and Mighty River Power's Nga Awa Parua geothermal plant (140 MW). Note that the MED build schedule was determined in 2009 and so does not reflect recent announcements (eg. Meridian's Te Uku windfarm).
[11] In the real market generation can normally only offer as low as $0.01/MWh but for the purposes of the modelling the difference between zero and 0.01 is immaterial.

Station	LRMC (MED)	Capacity	Node	Commission Date	Type
Generic geo 3	102.56	110	WRK	1/01/2021	Geothermal
Mangawhero to Wanganui Div	103.98	60	BRK	1/01/2021	Hydro
Motorimu	98.13	80	TWC	1/01/2021	Wind
Turitea	97.41	150	TWC	1/01/2021	Wind
Generic geo 2	102.56	110	WRK	1/01/2022	Geothermal
Gas fired OCGT 3	257.02	200	SFD	1/01/2023	Thermal Gas Peaking
Long Gully	98.10	70	CPK	1/01/2023	Wind
Lower Clarence River	113.54	35	CUL	1/01/2023	Hydro
Tarawera at Lake Outlet	105.64	14	OWH	1/01/2023	Hydro
Whakapapanui Papamanuka	120.50	16	WKM	1/01/2023	Hydro
Arahura	107.69	18	HKK	1/01/2024	Hydro
Arawata River	107.64	62	HKK	1/01/2024	Hydro
Lake Mahinerangi	104.55	200	HWB	1/01/2024	Wind
Nevis River	139.19	45	FKN	1/01/2024	Hydro
Puketiro	101.71	120	MST	1/01/2024	Wind
Wairau	108.69	73	BLN	1/01/2024	Hydro
Otahuhu C	114.76	407	OTA	1/01/2025	Thermal Gas Baseload
Coal seam gas plant	80.63	50	WMG	1/01/2025	Thermal Gas Baseload
Marsden Point Refinery	137.08	85	MDN	1/01/2027	Thermal Gas Baseload
Pouto	101.29	300	HEN	1/01/2027	Wind
Generic OCGT NI 2	344.33	150	SDN	1/01/2028	Thermal Diesel Peaking
Belmont Hills	106.49	80	HAY	1/01/2029	Wind
Borland Monowai Canal	125.11	12	MAN	1/01/2030	Hydro
Gas fired OCGT 2	239.51	200	HLY	1/01/2030	Thermal Gas Peaking
Glenbrook upgrade	48.04	80	GLN	1/01/2030	Thermal Gas Baseload
Generic wind Wairarapa 1	108.45	100	TWC	1/01/2030	Wind
Kaituna Low Level	113.33	37.5	KMO	1/01/2030	Hydro
Mokairau	103.37	16	GIS	1/01/2030	Wind
Ohariu Valley	107.19	70	UHT	1/01/2030	Wind
Rototuna Forest	101.59	250	MDN	1/01/2030	Wind
Rough River	110.70	11.1	HKK	1/01/2030	Hydro
Taipo	113.25	33	HKK	1/01/2030	Hydro
Tenergy NZ Wind Farm	109.78	10	SFD	1/01/2030	Wind
Waitangi Falls Ruakiteri	123.40	16	RDF	1/01/2030	Hydro
Waverley	109.78	100	WGN	1/01/2030	Wind
Whangaehu	128.21	19.6	TNG	1/01/2030	Hydro
Project Hayes stage 1	116.07	150	NSY	1/01/2031	Wind
Project Hayes stage 2	117.62	160	NSY	1/01/2031	Wind
Red Hill	105.78	20	DAR	1/01/2031	Wind
Wainui Hills	115.81	30	GFD	1/01/2031	Wind
Generic wind Wairarapa 2	110.10	100	WDV	1/01/2032	Wind
Hawkes Bay Wind Farm	106.07	225	WHI	1/01/2033	Wind
Biomass Cogen, Kawerau	110.20	30	KAW	1/01/2034	Thermal Gas Baseload
Project Hayes stage 3	119.86	160	NSY	1/01/2035	Wind

All other inputs into *EMarket* were taken from the list of Reference Scenario inputs in section 6.2.

6.2 Reference Scenario Inputs

The following tables summarise the key input data used in the full parallel modelling process which put inputs for the Reference Scenario into I-Gen. I-Gen produced its own build schedule which was then input into *EMarket* and runs undertaken over the period 2010 to 2025 using all inflows as part of the build comparison.

A significant amount of plant may be retired over the projection period and the Reference Scenario includes a schedule of retirement for the 1,000 MW Huntly power station, TCC and Otahuhu B CCGT power stations, as shown in Table 2. This retirement schedule was also used in the build comparison as input to both I-Gen and *EMarket*.

Table 2 – MED Retirement Schedule

Station	Capacity	Node	Decommission Date
Huntly - Unit 1 (dry year reserve)	226	HLY	1/01/2015
Huntly - Unit 2 (dry year reserve)	226	HLY	1/01/2017
Huntly - Unit 3	226	HLY	1/01/2019
Huntly gas	66	HLY	1/01/2019
Huntly - Unit 4	226	HLY	1/01/2021
TCC	365	SFD	1/01/2025
OTAB	370	OTA	1/01/2030

Figure 5 shows a diagrammatic summary of the offers for Huntly, as used in *EMarket* for both full and partial modelling runs. The offers are colour-coded by price in the bands shown, and the profile of offers reflects the staged retirement of the plant. As units are moved to more of a standby role their offer prices increase accordingly.

Figure 5 – Summary of Huntly Offers

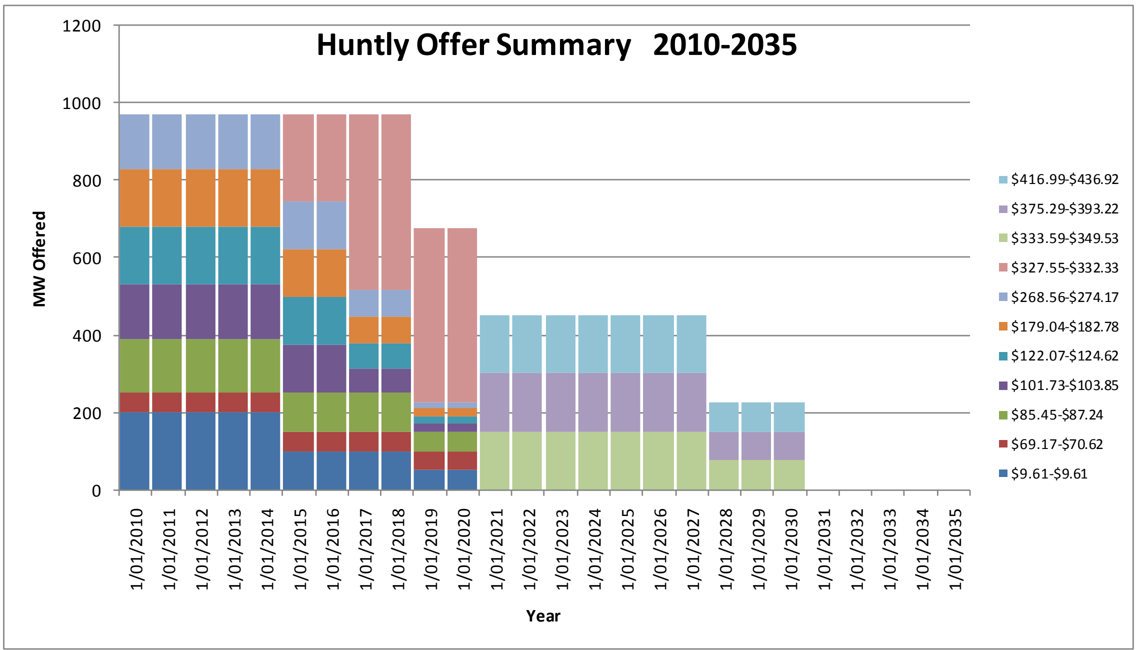


Table 3 shows the demand used in all modelling in I-Gen and in *EMarket*. It differs slightly to the Reference Scenario demand because the embedded generation shown in Table 4 is not modeled in *EMarket*. This adjustment ensured that Energy Link's modelling matched the demand in MED's modelling.

Table 3 – Demand Schedule in GWh p.a.

Year	NI	SI	NZ
2010	25,511	14,859	40,370
2011	25,867	14,995	40,862
2012	26,292	15,154	41,446
2013	26,777	15,320	42,098
2014	27,296	15,469	42,765
2015	27,807	15,574	43,381
2016	28,264	15,621	43,885
2017	28,728	15,657	44,385
2018	29,132	15,657	44,789
2019	29,635	15,718	45,354
2020	30,427	15,939	46,366
2021	31,208	16,172	47,381
2022	32,038	16,438	48,476
2023	32,872	16,709	49,582
2024	33,555	16,904	50,459
2025	34,042	17,000	51,042
2026	34,503	17,092	51,594
2027	34,955	17,182	52,137
2028	35,414	17,275	52,689
2029	35,820	17,342	53,162

Year	NI	SI	NZ
2030	36,172	17,383	53,555
2031	36,579	17,449	54,028
2032	36,979	17,509	54,488
2033	37,369	17,565	54,934
2034	37,752	17,615	55,367
2035	38,111	17,655	55,766

Table 4 – Embedded generation removed from demand schedule

Embedded Generation not modelled	Demand reduction (MW)
Te Rapa	26.4
Rotokawa	30.6
Tararua 1&2	13.6
BOPhydro (est)	47.5
OtagoHydro (est)	61.75

All modelling assumed a carbon charge of NZD $25 per tonne of CO_2 and real prices were produced, i.e. general inflation was ignored.

Table 5 shows the fuel prices assumed in all modelling in I-Gen and in *EMarket* in both the partial and full modelling process. Fuel prices are given in real terms excluding carbon charge[12].

Table 5 – Input fuel prices in $/GJ

Date	Gas	Coal	Diesel
1/04/2010	6.53	4.5	35.53
1/04/2011	6.57	4.5	36.24
1/04/2012	6.63	4.5	36.74
1/04/2013	6.70	4.5	36.66
1/04/2014	6.79	4.5	36.47
1/04/2015	6.89	4.5	36.41
1/04/2016	7.01	4.5	36.35
1/04/2017	7.15	4.5	36.06
1/04/2018	7.30	4.5	36.57
1/04/2019	7.47	4.5	37.06
1/04/2020	7.65	4.5	38.13
1/04/2021	7.85	4.5	39.2
1/04/2022	8.07	4.5	40.28
1/04/2023	8.30	4.5	41.35
1/04/2024	8.55	4.5	42.42
1/04/2025	8.82	4.5	43.5
1/04/2026	9.10	4.5	44.57
1/04/2027	9.39	4.5	45.64

[12] Carbon prices were applied to fuel prices in all modelling in GEM, I-Gen and *EMarket*.

Date	Gas	Coal	Diesel
1/04/2028	9.70	4.5	46.72
1/04/2029	10.03	4.5	47.79
1/04/2030	10.38	4.5	47.79
1/04/2031	10.74	4.5	47.79
1/04/2032	11.11	4.5	47.79
1/04/2033	11.51	4.5	47.79
1/04/2034	11.92	4.5	47.79
1/04/2035	11.92	4.5	47.79

6.3 Limitations on Data Matching

Both GEM and I-Gen include limited modelling of the impact of the grid on prices. For example, I-Gen calculates location factors by region around the grid so that as more generation is built in a region its location factor relative to the rest of the grid falls, and vice versa. Due to the way that I-Gen works it was not possible to fully duplicate the location factors used in GEM. However, we do not believe that this significantly influenced difference between the build schedules produced.

7 Results of the Parallel Modelling

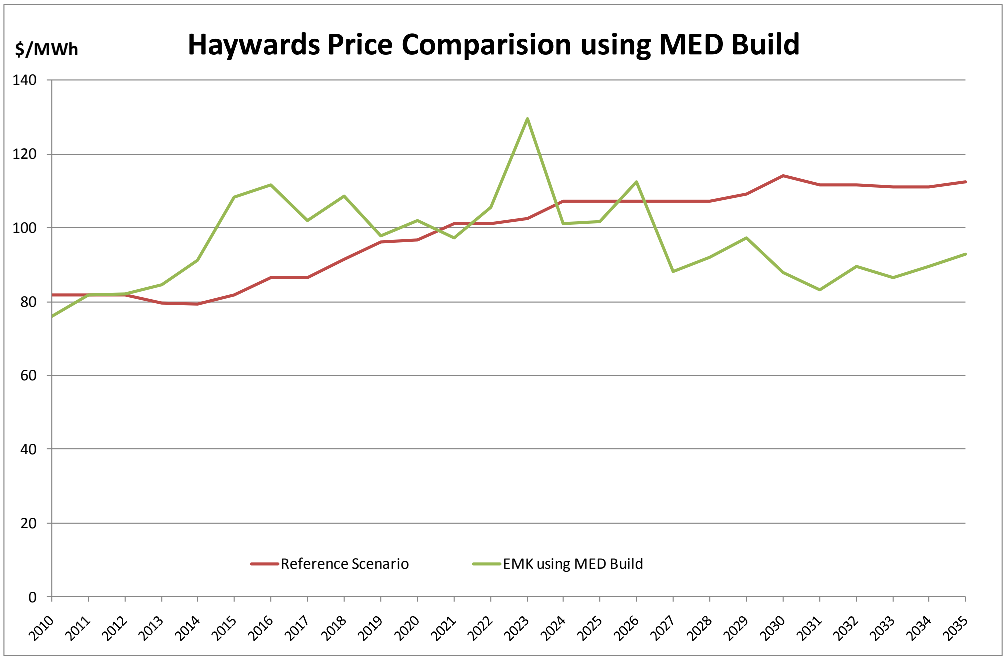
This section reviews the key outputs from both the full and partial parallel modelling exercises. Only a small selection of the output data produced by I-Gen and *EMarket* are presented here and more data is available if it is required.

Unless otherwise stated, all LRMC values and prices in this section are referenced to the Haywards grid node in Upper Hutt.

7.1 Price Comparison: Results Using MED's Build Schedule

Figure 6 shows the prices from the Reference Scenario compared directly with the all-inflows Haywards prices from *EMarket* using MED's build schedule. In all simulation runs *EMarket* was run through market simulations for the last 79 years of hydrological inflows, so the prices shown are the average over all available historical inflows.

Figure 6 – *EMarket* versus Reference Scenario Prices



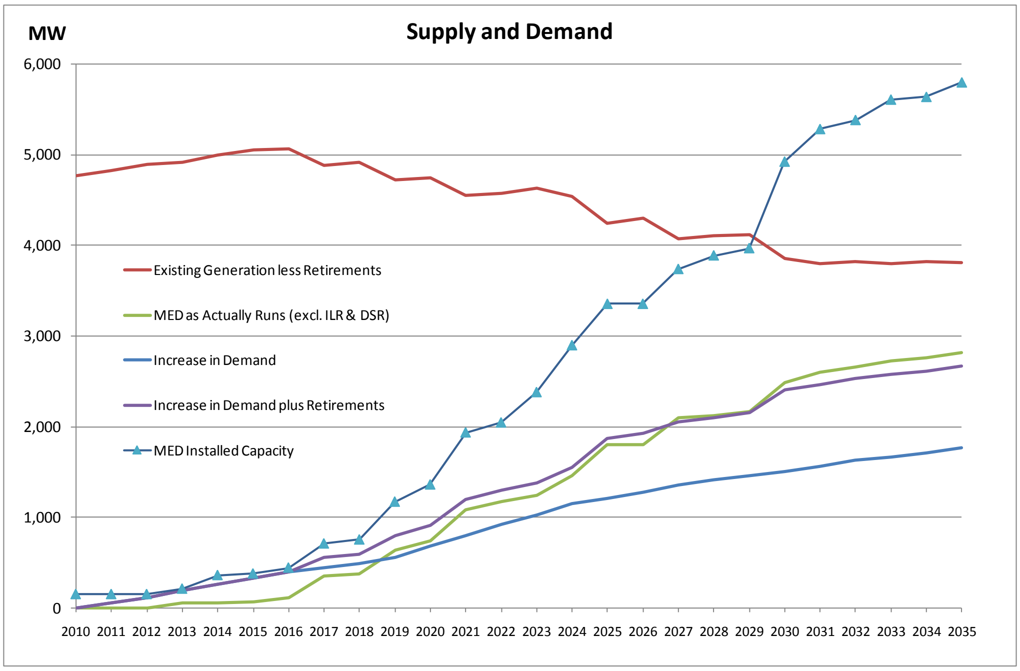
EMarket's prices are lower than MED prices by $2.5/MWh on average over the entire period, an average percentage difference of -1.1%, but they were generally higher in the first half of the forecast period and lower in the second half.

Figure 7 shows the net impact of increasing demand plus the retirement of existing plant on the supply-demand gap (shown as the 'Increase in Demand plus Retirements' curve) which can be seen running above the MED build schedule right through to 2029, after which accumulated build slightly exceeds the increase in demand plus retirements. This chart shows supply which is based on the amount that plant actually runs in *EMarket*, as well as the installed capacities in the MED build schedule. The MED build schedule shown also excludes interruptible load reserve (ILR) and demand-side reductions (DSR): these dummy generators represent additional load which is assumed to be available to be shed either in grid emergencies (ILR) or when prices are very high (DSR), hence both contribute to the ability to meet short term peak demand.

The MED build schedule includes diesel and gas-fired peaking plant which ensure sufficient capacity to meet the security constraints within GEM. However this peaking plant is priced sufficiently high that it virtually never runs in *EMarket* and so does not appear in the "as actually runs" schedule.

Thus, the supply-demand gap is a gap in terms of cost-effective energy supply, and not in pure capacity terms, and is a function of GEM's construction which satisfies security constraints without regard to market prices - this is discussed further in section 7.2.

Figure 7 – Supply and Demand using MED Build Schedule



The gap is particularly evident through to early next decade, which primarily explains the difference between the Reference Scenario and the *EMarket* prices up until around 2025. While the low rate of build of energy-serving plant in the front years may be sustainable in the physical sense, *EMarket* models a market response to the narrowing gap between supply and demand, resulting in higher prices. When the rate of build picks up after 2016, *EMarket's* prices ramp down accordingly.

From 2027 *EMarket's* prices remain below the Reference Scenario prices. From around this year, GEM builds additional gas and diesel-fired peaking stations to ensure that there is sufficient generation to meet peak demand. The LRMC calculations in GEM assume peaking stations operate at a capacity factor of 5%, but the stations were modeled in *EMarket* as offering their full output using offers priced at SRMC and upward (refer to the offer structure outlined section 5). In the *EMarket* runs, the peaking stations operated at an average of just over 3% capacity factor in four selected dry years[13], which translates into a capacity factor of less than 1% on average over all historical inflow sequences.

From 2027 there is also a substantial, and growing amount of new renewable plant which all is offered at zero, which is the primary reason that *EMarket's* prices fall below the Reference Scenario prices.

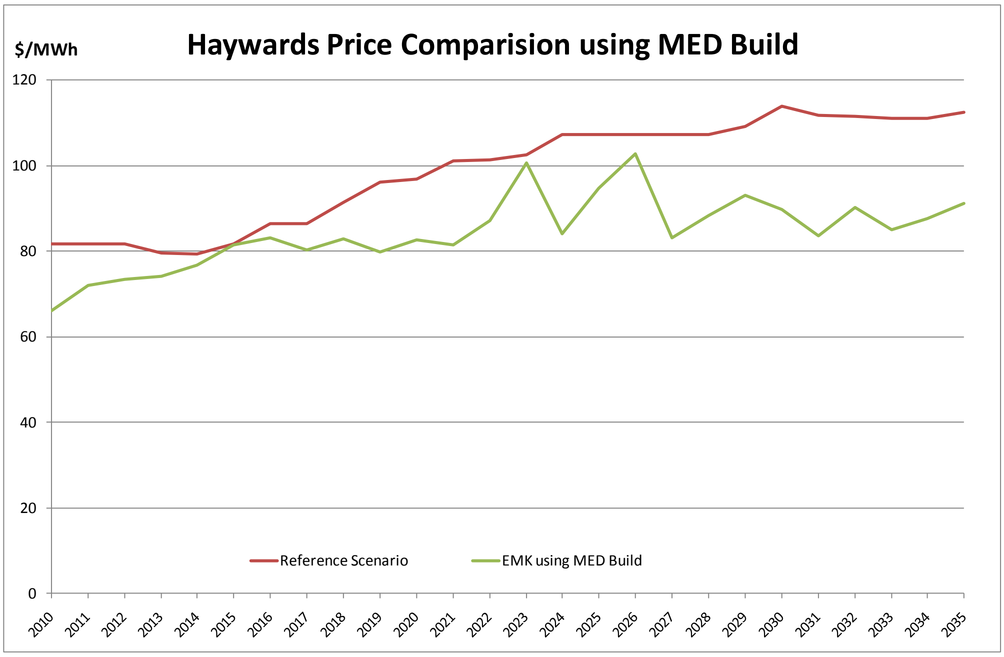
A second set of *EMarket* runs were undertaken, this time using an alternative offer structure for large thermal plant:

- existing thermal plant at SRMC; and
- all new thermal plant at LRMC.

[13] 1932, 1937, 1976 and 2008. The *EMarket* runs were undertaken in day-night mode, but the capacity factors were cross-checked using half hourly runs.

The objective of these runs was to test the sensitivity of the prices produced by *EMarket* to offer strategies, this time using offers more closely aligned to the LRMC's used for new plant in GEM. The results are shown in Figure 8.

Figure 8 - *EMarket* Prices using SRMC/LRMC offers, versus Reference Scenario



The second set of prices produced by *EMarket* are consistently lower than the Reference Scenario prices, the latter based on the assumption that prices will follow LRMC. What is evident in Figure 8, and from 2027 in Figure 7, is that prices are not guaranteed to reach LRMC in the context of the actual market, when there is so much plant that is offered at or well below SRMC, for example, must-run hydro and thermal plant, wind and geothermal.

The significant number of peaking stations featured in the Reference Scenario build schedule from the middle of next decade, while required to retain capacity adequacy, seldom run on average and therefore hardly ever directly influence prices. This issue is discussed in greater depth in section 8.1 covering the comparison of the Reference Scenario prices and the prices produced by *EMarket*.

7.2 Build Comparison: Results Using Raw Inputs to the Reference Scenario

This section overviews the modelling results when MED's assumptions were used in the I-Gen model to produce the build schedule, then modelled in *EMarket*. Because of the current limitations on I-Gen, and given the time available, the forecast end-point was moved back from 2035 to 2025.

Figure 9 shows the all-inflows average price obtained from *EMarket* at Haywards which sits on average $7.5/MWh (7.9%) below the Reference Scenario prices.

Figure 9 – *EMarket* Prices using I-Gen Build versus Reference Scenario Prices

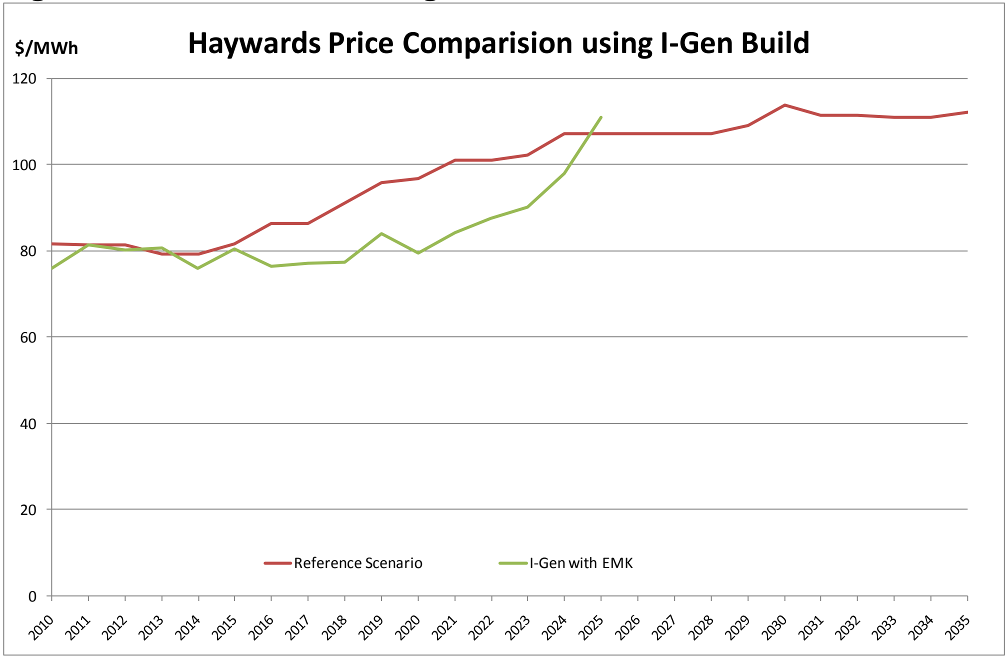


Figure 10 shows the cumulative impact of the build schedule from I-Gen combined with the retirements to 2025.

Figure 10 - Supply and Demand using I-Gen Build Schedule

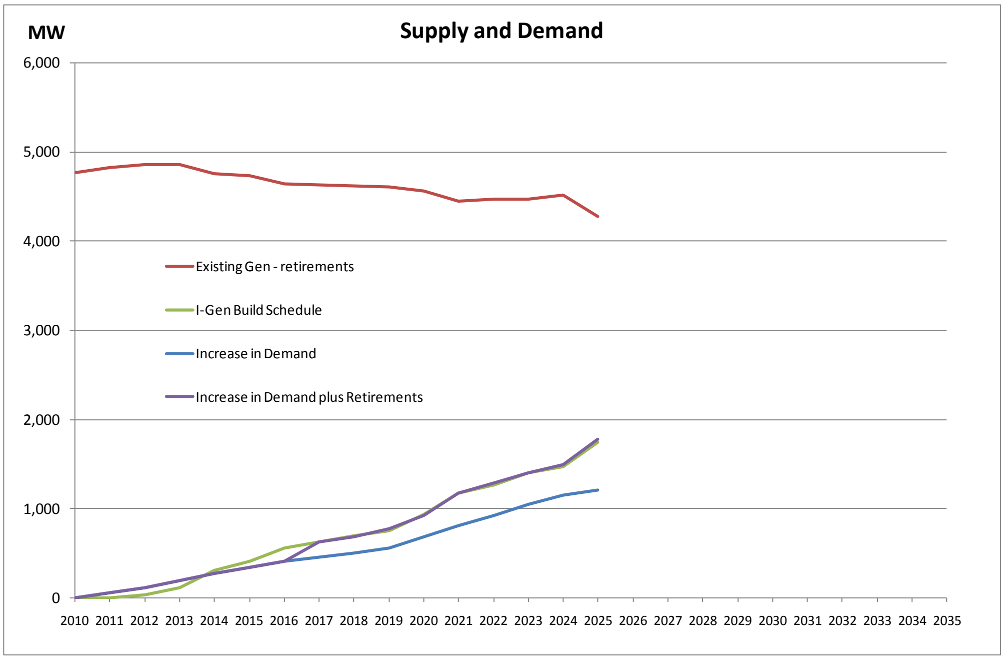
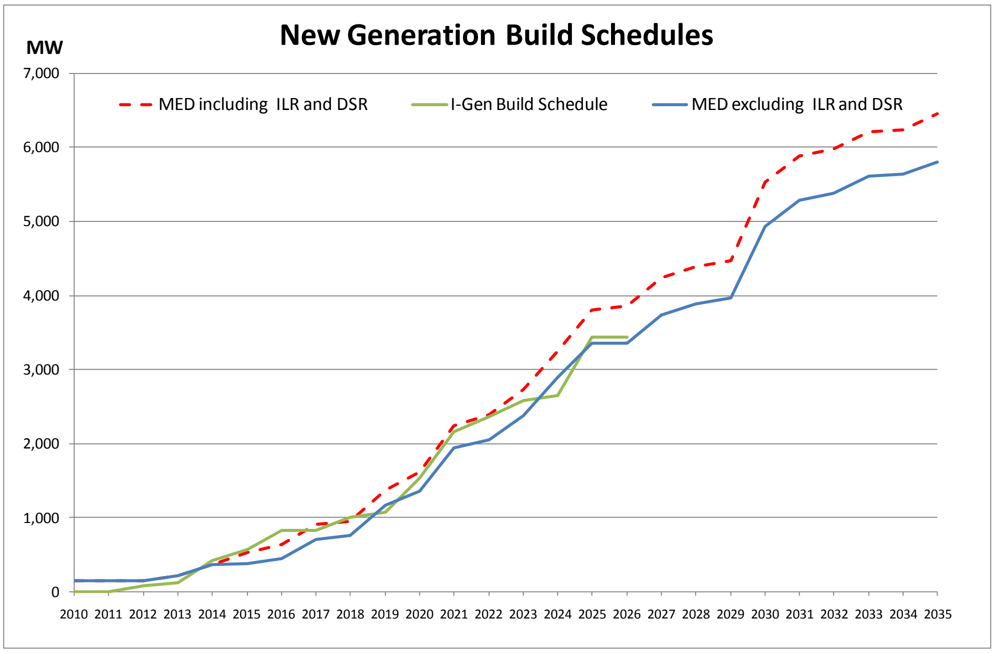


Figure 11 compares the build schedule from I-Gen to the MED build schedule, based on using the same inputs and on installed capacity. The solid MED build curve excludes the dummy generators included in GEM that represent ILR and DSR, i.e. it represents the addition of capacity that is available to serve energy. The dashed curve is the MED build schedule including additional ILR and DSR.

Figure 11 – Build Schedules as Installed Capacities



A different picture is presented in Figure 12 which compares the I-Gen and MED build schedules (ignoring ILR and DSR) based on the amount that the plant actually ran in the *EMarket* simulations.

Figure 12 – Build Schedules as Actually Run in *EMarket*

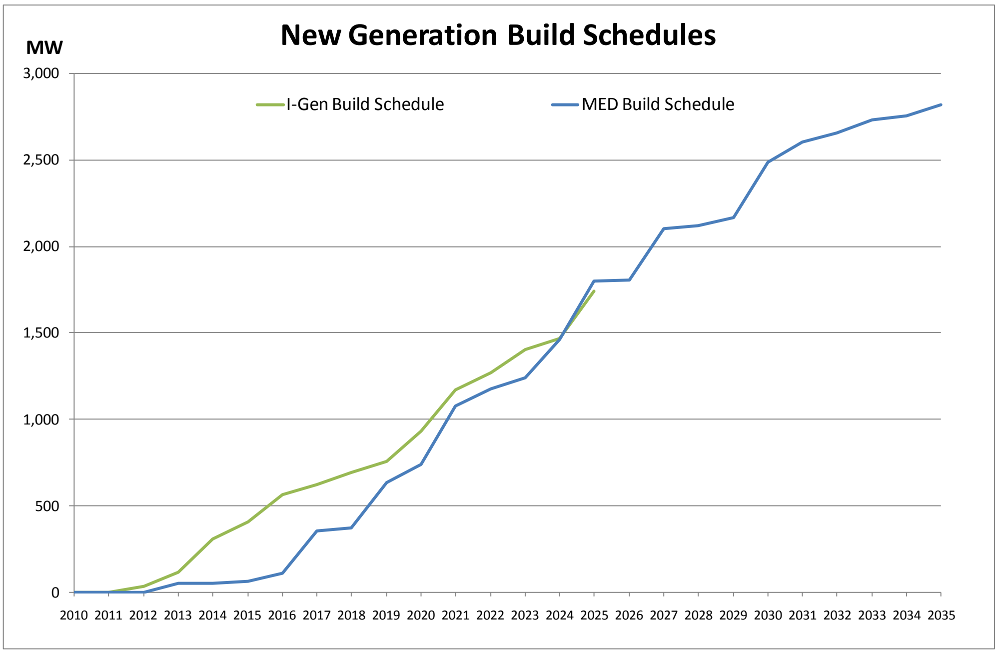


Figure 11 shows the two build schedules containing similar amounts of new plant in capacity terms, but Figure 12 highlights the fact that GEM builds more peaking plant than I-Gen. GEM builds peaking plant to satisfy its security constraints, but ignores the interaction of supply and demand in the context of the market, and tends to under-build energy-serving plant relative to I-Gen. The additional peaking plant built by GEM hardly ever runs because it is too expensive, and so has virtually no impact on the market.

Table 6 shows the detailed build schedule produced by I-Gen. The 'Timing Difference' column shows the difference in years between the commissioning date in I-Gen's build schedule and the commissioning date in the MED build schedule, a negative timing difference indicating that the plant was commissioned earlier in I-Gen. The average timing difference in the table is -2.9 years, which is to say that the plant built by I-Gen, on average, is built almost 3 years earlier than it is in GEM. What the table does not show, is that GEM builds a substantial amount of peaking plant which I-Gen does not build: in simple terms, I-Gen builds energy-serving plant in favour of peaking plant.

Table 6 – Build Schedule from I-Gen

Station	LRMC (I-Gen)	Capacity	Node	Commission Date	Timing Difference
Te Mihi	75.80	60	WRK	1/12/2012	-0.3
Hawea Control Gate Retrofit	78.46	17	CML	1/12/2012	-2.3
Mohaka	90.05	44	TUI	1/06/2013	-4.8
Motorimu	117.15	80	LTN	1/04/2014	-7.0
Tauhara stage 2	87.57	200	WRK	1/06/2014	-2.8
Otoi Waiau	99.55	16.5	WRA	1/08/2014	-4.7
Taranaki Cogen	100.12	50	SFD	1/05/2015	Not in MED Build
Clarence to Waiau Diversions	98.80	70	CUL	1/06/2015	-3.8
Toaroha	94.77	25	HKK	1/06/2015	-0.8
Kawerau stage 2	91.42	67	KAW	1/06/2016	-0.8
Ngatamariki	93.49	67	OKI	1/06/2016	-2.8
Rotokawa 3	93.01	67	WRK	1/06/2016	-2.8
Mangawhero to Wanganui Div	106.59	60	BPE	1/11/2016	-4.4
Clutha River Queensberry	99.30	180	ROX	1/08/2018	-0.7
Long Gully	108.57	70	CPK	1/03/2019	-4.1
Turitea	109.99	150	LTN	1/04/2020	-1.0
Clutha River Beaumont	88.53	190	ROX	1/06/2020	0.2
Marsden Point Refinery	104.29	85	MDN	1/06/2020	-6.8
Lower Clarence River	119.76	35	CUL	1/11/2020	-2.4
Pouto	123.59	300	MPE	1/01/2021	-6.2
Puketiro	112.63	120	PNI	1/04/2021	-3.0
Kakapotahi	123.60	17	HKK	1/08/2021	2.3
Mt Cass	127.03	50	WPR	1/08/2021	Not in MED Build
Taipo	124.01	33	KUM	1/09/2021	-8.6
Belmont Hills	118.03	80	TKR	1/12/2021	-7.3
Butler River	124.38	22.5	IGH	1/12/2021	Not in MED Build
Ohariu Valley	118.82	70	TKR	1/06/2022	-7.8
Upper Grey	127.69	35	IGH	1/07/2022	Not in MED Build
Clutha River Luggate	111.05	100	ROX	1/11/2022	1.6
Lake Mahinerangi	110.33	200	HWB	1/06/2023	-0.8
Waimangaroa River	132.89	22.2	IGH	1/06/2023	Not in MED Build
Arnold	134.42	46	DOB	1/06/2024	Not in MED Build

Station	LRMC (I-Gen)	Capacity	Node	Commission Date	Timing Difference
Tarawera at Lake Outlet	118.84	14	TRK	1/06/2024	1.2
Otahuhu C	95.61	407	OTA	1/06/2025	0.2
Whakapapanui Papamanuka	123.46	16	BPE	1/08/2025	2.3
Waverley	121.74	100	SFD	1/09/2025	-4.6
Mokairau	122.66	16	GIS	1/11/2025	-4.4
Rototuna Forest	123.96	250	MPE	1/11/2025	-4.4

Figure 13 shows the energy margin by year[14], relative to the 1992 dry year: the total excess energy available from generation in each year assuming 1992 inflows, relative to the demand in each year. Once Contact Energy's 200 MW Stratford peaking plant is commissioned mid 2010, the energy margin will sit at 25.7%, which is below the average since 1996 (the first year of the electricity market). It is also slightly below the average since 2003 of 26.3% when the energy margin took a step downward due to strong demand growth.

Figure 13 – Dry Year Energy Margin

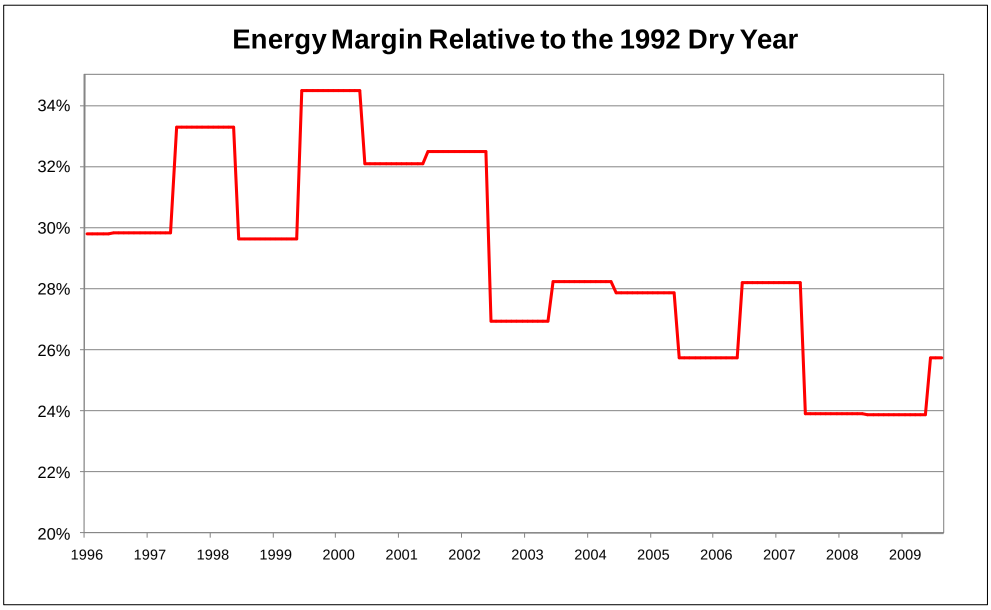
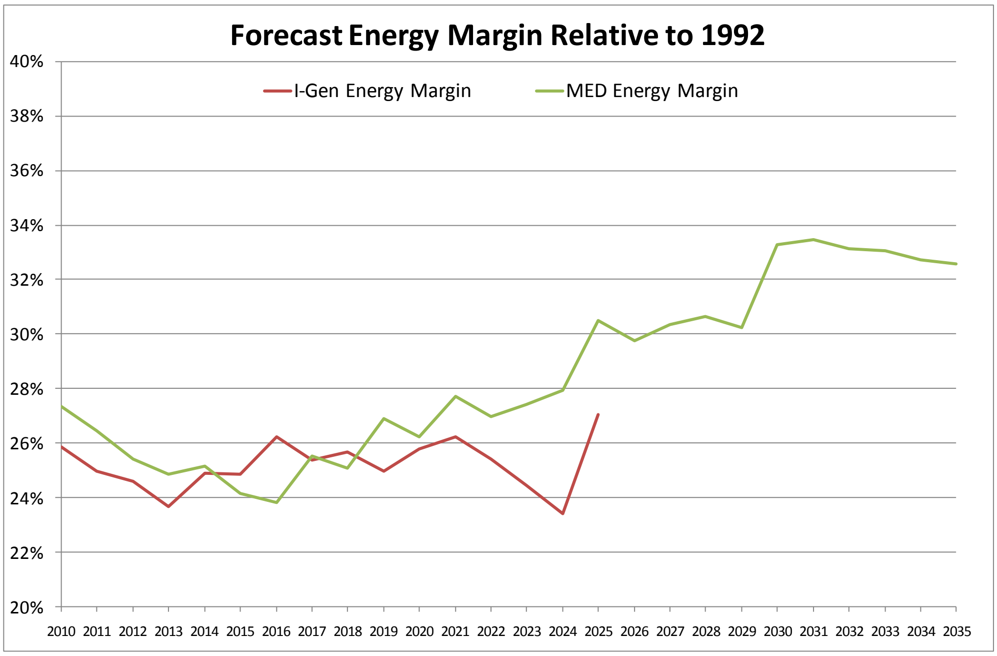


Figure 14 shows the energy margin projected ahead for both the MED and I-Gen build schedules. GEM's emphasis on building wind farms later in the forecast period, which also requires additional peaking stations to maintain security, sees the projected energy margin from GEM climb from a low point in 2016 to a high in 2031, after which it falls only slightly.

[14] Note that the energy margin shown is not calculated on the same basis as the Electricity Commission's Winter Energy Margin.

Figure 14 - Forecast Dry Year Energy Margins



8 Discussion and Conclusions

Nothing in this section should be construed as being critical of Energy Outlook, which clearly does help to inform the policy debate. The discussion and our conclusions are directed at the finer points of electricity price modeling, and at how the Reference Scenario prices are portrayed within Energy Outlook.

At this point it is useful to restate our classification of the two modelling exercises according to two key questions, as follows:

1. **Price comparison**: given the MED build schedule, what are the prices that result from a dynamic simulation of the electricity market using *EMarket* and how do these compare to the Reference Scenario prices?
2. **Build comparison**: given the same input assumptions as those used in producing MED's build schedule, what is I-Gen's build schedule and how does this translate into prices in *EMarket*?

8.1 Price Comparison

In the price comparison, there is significant variation between the prices calculated by MED and those calculated by Energy Link using *EMarket* and offer strategies reflective of market behaviour, both using the same build schedule (refer Figure 7). The MED build schedule initially features mainly peaking plant at high LRMC (ensuring they virtually never run) and little baseload plant which results in sharply rising prices in *EMarket*: this rise is not exhibited in the Reference Scenario prices, which actually fall slightly. In referring to this fall, the commentary in Energy Outlook 2009 states that "we could see a flattening in prices over the next 5 years".

From 2027, *EMarket's* prices fall below the Reference Scenario prices due to the significant number of renewable and peaking plant built in the latter part of the forecast period. As the peaking plant LRMCs are relatively high, these plant do not run sufficiently often to drive prices up to the level of the Reference Scenario price, or to recover their total costs, when they employ market-based offers.

When *EMarket* was run again using SRMC offers for existing large thermal plant, and LRMC offers for new large thermal plant, prices fell below the Reference Scenario prices through virtually the entire forecast period.

Over the first few years the Reference Scenario is bracketed by the two Emarket price forecasts. The two Emarket prices display how sensitive prices are to offer strategies, with a large difference in the two price trends until about 2025. By 2030 Huntly coal, TCC and Otahuhu B have all been decomissioned, leaving just E3P and Otahuhu C as the major thermal baseload stations. It is interesting that from 2030 the offer strategy has little effect on final prices which is probably due to the smaller tranches of thermal stations setting prices.

GEM minimises the total cost of new capacity over the forecast period, while maintaining capacity adequacy year by year, and the build schedule results along with the corresponding LRMCs. While there is good evidence that prices in the longer term tend to follow LRMC, this does not necessarily follow in the short to medium term.[15] Prices can rise well above LRMC before new plant is built, or fall below LRMC when new plant is built, and when there is a relative surplus of plant for a period.

Constructing a price projection purely from LRMCs means that the significant impact of supply-demand dynamics in the electricity market may be missed. If the current approach is retained then MED should consider whether it would be more appropriate if Reference Scenario prices are no longer referred to as being any sort of market price projection or forecast. For example, they might usefully be referred to as "marginal costs of new generation", or "price indicator/drivers", or "price trend markers". While this might be considered a finer point, given MED's high degree of credibility and influence, using the word 'price' creates an expectation of a certain level of accuracy year-by-year which could be misleading to some of Energy Outlook's readers.

The low prices obtained from *EMarket* in the latter part of the forecast period are a function of the large amount of plant in the MED build schedule. Chattopadhyay and Westergaard[16] noted that "the incremental peaking constraint" in GEM "creates a bias towards building new capacity to meet the peak and therefore generally bias[es] the new entry mix towards peaking units". The documentation on GEM on the Electricity Commission's web site is incomplete and in many cases out of date, but it appears that the incremental constraint on peaking capacity is no longer in GEM. Nevertheless, the behavior predicted by Chattopadhyay and Westergaard does appear to be occurring in the latter part of the forecast period: this is most likely a function of the remaining capacity adequacy constraints within GEM, and of the amount of renewable generation that is built.

Irrespective of whether peaking plant is over-built or not, there is potentially a more subtle issue at play in the latter part of the forecast period, which is highlighted by the gap between the Reference Scenario prices and prices produced by *EMarket* assuming

[15] This is discussed further in the Appendix.
[16] D Chattopadhyay and E Westergaard, *Generation Expansion Model: A High Level Review*, a report prepared by CRA International for Transpower, May 2007.

offers reflective of current market behavior: how will the market function as the proportion of renewable, wind energy in particular, increases as a percentage of total generation?

An assumption under-pinning the design of our "energy-only" electricity market, is that generators will, over the long term, recover all of their costs of generation (i.e. their LRMC) through revenue based on spot prices. Although additional revenue is available to some generators (depending on their technical capability) through the provision of ancillary services including instantaneous reserve and frequency keeping[17], the lion's share of revenue comes from the market for energy.

With a higher proportion of renewable generation supplying demand, we can expect there to be longer periods when spot prices are low, e.g. when inflows are high and the wind is blowing across the country. This translates into shorter periods when new peaking plant, for example, can run to recover their total costs, and hence greater risk attached to earning those revenues. To obtain prices closer to the Reference Scenario prices, and for peaking plant to recover costs, the modelling runs suggest that peaking plant offers in *EMarket* (and indeed the offers of other large thermal plant) would need to be considerably higher than they currently are. In terms of the actual market, when we get to 2025 and beyond, pure peaking plant may not be viable, given the risks associated with their dispatch and the risks that this creates for generator revenues.

One way to manage these risks is to build peaking plant that could be quite different to that which is modelled in the MED build schedule: for example, technology developments may provide plant that is capable of efficient base-load operation and cost-effective peaking. Another way is for the market to develop a mechanism that explicitly rewards the provision of capacity, as a separate product to energy, i.e. a 'capacity market' with similar characteristics to those in overseas markets. Read[18] notes that "it seems likely … that the way in which capacity requirements have been modelled [in GEM] corresponds to an implicit assumption that the current 'energy-only' market will be supplemented by a capacity market, in which capacity payments are made to all (new) capacity".

The further into the future one attempts to forecast prices, the greater the uncertainty around all of the variables which either do or may affect prices, including the structure of the market itself. GEM appears to make implicit assumptions about the structure of the market in respect of capacity adequacy, which raises questions about the ability of market prices to rise to the point where future peaking capacity can recover costs.

In addition, Bishop and Bull[19] acknowledge that "GEM makes no attempt to forecast electricity prices or to assess revenue adequacy". But it is certainly conceivable that the Reference Scenario prices could represent the total average price received for generation from a combination of the energy market and a future capacity market, for

[17] Another possibility is that peaking plant will offer option contracts to other market participants which will help fund the plant's fixed costs, as happened in 2009 when Genesis and Meridian entered into an option contract which has the effect of paying some of Huntly's fixed costs.

[18] E G Read, *Using GEM to Produce SOO Scenarios: A Preliminary Conceptual Guide*, a report prepared for Meridian Energy, July 2007.

[19] P Bishop and B Bull, *GEM: An explanation of the equations in version 1.2.0*, Electricity Commission, July 2007.

example, which might suggest that if the energy-only market cannot deliver these prices, then perhaps the market design should be changed. Nonetheless, this discussion further reinforces our earlier point that MED should consider whether the Reference Scenario prices should indeed be called 'prices' at all, at least not in the context of our existing market.

8.2 Build Comparison

In the price comparison, it became evident in the second half of the forecast period that the MED build included large amounts of renewable generation and a corresponding number of peaking stations, whereas prior to 2025 the MED build appears to include too little cost-effective energy-serving capacity relative to the build produced by I-Gen. In terms of how much plant actually runs in *EMarket*, the two build schedules initially diverge, but then slowly converge until they meet in 2024. The fact that they do eventually meet is somewhat surprising, but also encouraging, given that one model (GEM) is predicated on a set of physical constraints and the other (I-Gen) is predicated on the dynamics of the market.

GEM includes a number of inputs and constraints which are intended to ensure capacity adequacy year by year. We believe it would be worthwhile investigating how input data could be modified to achieve a build schedule that retains a realistic energy margin over the entire forecast period, but which places greater emphasis on building plant that is cost-effective in market terms, i.e. that is not just present to ensure that demand is met in a small handful of hours in any given year.

8.3 Conclusions

GEM has a tendency to produce build schedules which satisfy relatively narrow security constraints which ensure capacity adequacy, without considering whether all plant would be cost-effective to build. Without actually modifying GEM, it would be worthwhile investigating how the GEM input data could be modified or adjusted to produce a build schedule which maintains an energy margin, in particular, in line with the margin currently delivered by the market, using plant which might actually be profitable to build.

That said, the value in modelling is obtained not just by getting results which appear to be correct in some sense (for example, in line with conventional wisdom), but also in understanding why results sometimes diverge from what is the currently accepted norm. This is particularly so for the far future where there is a much greater chance the norm of tomorrow will be different to the norm of today. Our recommendations in respect of GEM should therefore be seen as fine tuning, rather than as any criticism or major concern about the MED build schedule. If anything, a greater level of discussion concerning issues such as peak capacity versus energy margin, and energy and capacity markets, would be valuable for informing the policy debate.

However, the process of fitting prices to the build schedule using LRMCs misses important market dynamics which also significantly influence prices in both the short and the medium term. Given that Energy Outlook's purpose is to inform the energy policy debate, (as opposed to supporting investment, hedging and other market decisions), we recommend that the description of the derived prices in Energy Outlook be modified to more accurately reflect their construction and thus reduce the possibility of the prices being used for purposes for which they were not intended or are not suitable.

9 Appendix – Theory of Electricity Price Modelling

By working at a more fundamental level with trends in the underlying variables that drive electricity prices, actually producing electricity price projections (or forecasts) requires a model of how prices derive from these fundamental drivers.

The field of electricity price modelling using computers has received a great deal of attention in the past two decades as many jurisdictions have restructured centrally controlled electricity supply industries as electricity markets, in which prices are notoriously volatile. A variety of approaches to price modelling have evolved for both short and long term horizons.

We briefly review the main types of models in the following sections and include a comment on whether each type of model would be appropriate for use in Energy Outlook.

9.1 Monte Carlo Models

Because of their widespread use in the analysis of financial markets, Monte Carlo models have received an enormous amount of attention in the literature. Financial models work on the assumption that price behaviour can be described by 'Wiener processes', more commonly known as Brownian motion or random walks[20]: under this assumption asset prices are driven by a series of small random shocks.

The classic financial market Wiener process works on the basis that the relative change in the price in some time interval Δt is a function of the price at the start of the interval, an underlying trend (or drift rate) in the price, to which is added normally distributed noise, as shown in (1) below:

$$\frac{\Delta S_t}{S_t} = \mu \Delta t + \sigma \varepsilon \sqrt{\Delta t} \quad \text{.......} (1)$$

where S_t is the spot price at some time t,

ΔS_t is the change in S that we want to calculate for the time interval Δt,

μ is the rate at which the spot price returns to the mean,

σ is the volatility (standard deviation) of S,

ε is a random number drawn from a standard normal distribution[21].

Electricity prices in the short to medium term exhibit a tendency to revert to some mean value so the financial models have been extended to accommodate mean reversion, and also the tendency for electricity prices to take large jumps (or spikes) well beyond the limits of the normal distribution[22]:

[20] *Options, futures and other derivative securities*, John C Hull, Prentice Hall, is a widely used text book in this field.

[21] The standard normal distribution has mean of zero and standard deviation equal to one.

[22] Mean reversion was added initially for the analysis of interest rates. Jump processes were added more recently, principally for the modelling of electricity prices.

$$\frac{\Delta S_t}{S_t} = \alpha(\bar{S} - S_0)\Delta t + \sigma\varepsilon\sqrt{\Delta t} + \kappa dq \quad (2)$$

where $\bar{S}$ is the mean value of S,
α is the rate at which the spot price returns to the mean,
κ is the proportional jump size,
dq is a random variable that is mostly zero but is occasionally equal to one when a jump occurs.

Models of the nature of (2) above are often called "Mean Reversion Jump Diffusion" models, or simply MRJD. In electricity prices, jumps occur both on the short and longer term time scales. For example, a line constraint can cause the price in a region of the grid to spike for as little as one half hour, whereas dry years cause the price to spike above otherwise 'normal' levels over a period of weeks or months.

The MRJD parameters $\bar{S}$, α, σ and κ can be estimated from historical price data. But this begs the question: how do these parameters evolve over time? In the longer term, which is the concern of Energy Outlook, the underlying mean price, $\bar{S}$, is highly likely to change, as it has over the history of the spot market. MRJD models do not tell us anything about price trends and so their application has been limited in New Zealand. Where they are used in the long term, other models provide the core parameters which are expected to change over the horizon of the projection or forecast.

Alternatively, some models use MRJD components for specific purposes, particularly where an additional degree of volatility in forecasts is sought. The *EMarket* model, for example, includes an MRJD function which is often used to model the physical output of wind farms, and which has been applied to short and medium term modelling of gas and oil prices relevant to the Singapore electricity market.

The implicit assumption in Monte Carlo modeling is that the parameters of the underlying distributions can be estimated with accuracy that is sufficient for purpose, including their evolution over time. While the parameters needed for Monte Carlo models could be estimated from historical data, which could be described as BAU, a mean price parameter is required: the mean price, of course, varies over time, possibly deviating from historical trends.

To the best of our knowledge, Monte Carlo models have primarily been employed in this country in applications where modelling price volatility is the primary aim, and therefore they are not particularly suitable for use in Energy Outlook.

9.2 Cournot Models

Cournot models have been applied in New Zealand to the problem of forecasting electricity prices and other electricity data. The basic Cournot market assumes that each player in the market treats the output level of its competitors as fixed and then decides how much to produce. The Cournot model is appealing for electricity market modelling because these markets are often oligopolies, where there is a lot of evidence to suggest that maintaining market share is a prime consideration of the large market participants, as they formulate their operating strategies and tactics.

However, the Cournot model is highly reliant on demand elasticity, which is defined as the responsiveness of the quantity demanded of a product to a change in its price. Without a significant degree of demand elasticity, Cournot models are known to push prices unrealistically high.

In the short to medium term demand for electricity is known to be highly inelastic. To achieve realistic prices, Cournot models therefore require their demand elasticity parameters to be set at values well in excess of the actual elasticity. This is often passed off as being a surrogate for the downward pressure that the threat of new entry places on prices in the real electricity market.

Some Cournot models also incorporate the players' total contract positions (the total over all hedges and fixed price variable volume contracts) to further constrain prices[23]. There is considerable debate over whether these models are valuable in modelling electricity prices at all, apart from limited applications in the study of the potential for excessive gaming[24].

In the longer term there is evidence that electricity demand is elastic, at least in certain sectors. But for the purposes of Energy Outlook, prices are set on an annual basis, so the time horizon of a Cournot model would be one year, again requiring unrealistically high demand elasticity for each annual simulation. Therefore, in our opinion, Cournot models are not suitable for use in Energy Outlook.

9.3 Simulation Models

The models most often applied in New Zealand to the calculation of prices and other quantities over the longer term are simulation models which model the underlying assets, systems and processes operating in the real electricity market. The models vary in their construction and granularity, but the processes modeled in some or all models include nodal dispatch and pricing, the transmission grid, hydro generator offering strategies based on the calculation of the marginal water values[25] (commonly just called water values), thermal and other generator offer strategies, hydrology (inflows into, releases from and flows down hydro systems), hydro storage, plant outages and instanteous reserves[26]. The most well known available simulation models in use in New Zealand are SPECTRA, *EMarket*, SDDP and Plexos[27].

1. **SPECTRA**
   Originally developed by ECNZ in the late 1980's to minimise the use of fuel for generation at the Huntly and New Plymouth power stations, and the first model to apply stochastic optimisation (optimisation under uncertainty) of water values in an

[23] Although in the instances we have seen the contract position's also had to be set unrealistically high in order to constrain prices.
[24] Gaming is a natural activity for players to undertake in any market, as they continually experiment with improving their total returns. However, excessive gaming may amount to the abuse of market power which, if sustained, may ultimately lead to a reduction the economic welfare of electricity consumers.
[25] The marginal water value of a storage lake in a hydro-electricity system, at any given time, is the expected future value of the next cubic meter of water released for generation.
[26] These are required in case of an unexpected plant outage and can be provided by partly loaded generators, unloaded generating units in hydro stations, and by interruptible load.
[27] Energy Link only has direct experience of the *EMarket* model, and is reliant on third party documentation in respect of the other three models.

operational context in this country. SPECTRA's water values are 'tried and true' and the model is still in use, although exactly how much it is used in an operational sense is unknown. It is a fast model working on a weekly time step, but many simplifications are made in its modelling of the grid and of the major hydro reservoirs, so it is lacking in detail for some applications. One or two market participants are known to have SPECTRA and it appears that the EC also has access to SPECTRA.

2. ***EMarket***
   This model was developed in 1997/98 by Energy Link in conjunction with Mercury Energy and is used by Energy Link and two market participants. *EMarket* includes stochastic water values using a proprietary algorithm and has a great deal of detail in its modelling of the grid, hydro systems and thermal generators. *EMarket* is unique among the four models in that dry year security of supply is built in to the water value algorithm rather than being a function of an exogenous shortage cost. Two of its strengths are that it does full nodal dispatch and pricing on a large grid and it can model instantaneous reserves. It is also a fast model which can be set to work on a time step from monthly down to half hourly, which provides it with a great deal of flexibility in application.
3. **SDDP**
   SDDP was developed in South America and is used in a number of countries, but it has a reputation for being rather slow when run in the New Zealand context. While its hydro system modelling is stochastic and can be set up to be quite detailed, the published results that we have seen from its simulations show a high occurrence of zero storage events in hydro lakes. SDDP's main strength appears to be that it can be configured in an arbitrary way and to model a wide variety of assets and constraints. EC and Transpower both use SDDP but we are unsure of how many others may use it in New Zealand.
4. **Plexos**
   Plexos was developed in Australia and is sold around the world. It is highly configurable and detailed and, as far as we know, reasonably fast. In the past, its water values were deterministic and hence not suitable for calculating realistic water values in the New Zealand context, but the Plexos web site now claims that it includes optimisation of releases with uncertain inflows. We believe it has achieved limited penetration in the New Zealand market.

All four models above are discrete time simulation models, which is to say that they split each modeled period up into discrete time periods, not necessarily of equal length, and some of the results of the simulation in each period are carried over to be starting values in the next period.

To the best of our knowledge, only Plexos includes processes for selecting new generation over longer term horizons (known as a "capacity expansion module"). Since demand is normally modeled to grow over time, to ensure the balance between supply and demand is maintained, new generation must be built at discrete intervals. Hence, to a greater or lesser degree, these models require models or processes which determine which new plant is built and when: GEM and Energy Link's I-Gen models are two examples.

9.4 LRMC Models

Some models, including MED's modelling for Energy Outlook, base prices on LRMC values for new plant that will or might be built in future. In a competitive market it is expected that prices will reflect the cost of supply. For example, in 2007 the EC concluded that "actual wholesale electricity contract prices appear to have followed a similar track to LRMC" and that "there does not appear to be evidence that wholesale contract prices have been persistently overshooting LRMC"[28]. However, the apparent relationship between prices and the costs of supply is influenced by the time frame over which the prices are measured, and by the structure of the market.

In a perfectly competitive market it is expected that prices in the short term will reflect the short run marginal cost of supply (SRMC) and in the longer term the long run marginal cost of supply (LRMC).

In fact, because of the large size of individual generating assets, and because generator's short run costs are less than their total costs, it can be shown that even in the short term prices will not always reflect SRMC. In our spot market, prices are sometimes reflective of SRMC and sometimes not, depending on a range of factors.

Generators' costs in the short term are dominated by two factors: for thermal generators it is the cost of fuel[29], and for hydro generators it is the opportunity cost of water (which equates to the water value at any particular time). Fixed costs include capital costs, fixed operations and maintenance costs, and administrative overheads.

It is often stated that in the long run spot prices will rise to the LRMC of new generation. Since in the long run all costs are variable, LRMC includes both the variable and fixed costs of new generation projects. In a competitive market, all other things being equal, rational investors will build new generation only when they expect prices[30] over the life of their new generation plant to at least equal their project's LRMC.

This market process, however, (contrary to popular belief) does not guarantee that spot prices will rise in future, or even that prices will reflect LRMC. Investors in new generation capacity are all too aware that if too much new plant is built, or if LRMC falls (perhaps due to new technology, falls in the prices of generating plant or in fuel costs), then spot prices may not continue to rise, and could even fall.

New generation may also be able to be built even when general expectations of prices are below its LRMC, for example if it will only run during periods when prices are higher than the average price, or if it can earn revenues from sources other than the spot market (including from the reserves market, from frequency keeping, or in the case of embedded generation from avoided transmission costs[31]). Or if, because of the

[28] Refer *Issues Paper – Survey of Market Performance, Market Design Review*, 2007.
[29] If the fuel supply is limited then there may also be an opportunity cost to consider. This has potentially always been a consideration (from time-to-time) for the coal stock pile at Huntly, depending on its size and the rate at which coal can be either mined or imported. But in future it will be an on-going consideration for the gas stored in Contact Energy's Ahuroa gas storage facility.
[30] Strictly speaking, it is the generation-weighted price that is of prime concern.
[31] Transmission costs are incurred by lines companies, but the presence of embedded generation may reduce these costs, resulting in a payment from a lines company to the embedded generator.

characteristics of a particular project, an investor can build generation at a cost lower than what the rest of the market perceives to be the LRMC of that particular type of generation.

Furthermore, spot prices are set by the offers of generation that is 'on the margin'[32] in each half hour of market operation. If, for example, a new generator is built then it may or may not be on the margin, and hence in a position to actually set the price. Wind farms are a case in point because they must, under the market's rules, offer their output at $0.01/MWh, and so are unlikely to set the spot price (except on rare occasions of massive over-supply). All other things being equal, the addition of more wind generation actually tends to reduce spot prices rather than increasing them. The same applies to geothermal plant which is relatively inflexible and tends to offer all output at values at or near $0.01/MWh.

From careful observation of the spot market since 1996, Energy Link has concluded that most new generation will initially offer low prices and thus seek to be dispatched to a high level. This is particularly so when the investors in new generation (shareholders, banks, and financial institutions) have invested on the basis of the highest level of return possible from the plant and wish to see the plant return steady revenue streams.

Some new plant, however, does not continue to offer most of its output at low prices, the prime example being new gas-fired thermal plant, and especially when this is owned by a market participant with a diversified portfolio of generation assets.

Assuming that the LRMC of new generation is actually rising, the implication for spot prices is that if either some new or existing plant does not raise its offer prices as new generation is built, then prices will actually fall over time regardless of LRMC.

From the discussion above, we can see that LRMC modelling has a grounding in the empirical data which shows that in the long term prices seem to follow LRMC, but pure LRMC modelling fails to take into account the dynamics of offering strategies, grid constraints and hydro inflows, all of which will continue to impact significantly on spot prices in the future.

LRMC models, however, have an important role to play within larger forecasting processes, such as the processes developed by Energy Link and by MED.

MED uses the GEM model, developed for the EC. GEM is a mixed integer optimisation model which accepts a list of potential new generation projects, and has the objective of minimising the total fixed and variable costs of building and operating new generation over time. The optimisation is subject to a number of constraints including the need to build new plant to ensure capacity adequacy. GEM's primary output is a schedule of new plant including when and where they are built.

Energy Link's I-Gen model, on the other hand, simulates the way in which investors (including existing players and potential new entrants) plan and undertake investment in new generation. The fundamental assumption is that investors will invest in new

[32] A plant is said to be on the margin when its output is varied up or down by the System Operator in response to changes in demand. Typically one generator is on the margin for energy in each half hour, but when lines reach their maximum limit then at least one more generator comes on to the margin.

generation when the expected revenue stream from the wholesale electricity market is at least as large as the new plant's total costs, i.e. when the expected generation-weighted price path over the life of the plant is greater than or equal to the plant's LRMC.

Just as is the case in the real electricity market, in I-Gen there is no hard constraint on the pace at which new generation is built[33], regardless of demand growth, so investment is driven purely by economics. Instead, I-Gen models the response of price to changes in the balance between supply and demand changes over time: as the price increases with a reduction in spare capacity, new plant is more likely to be built, and vice versa.

I-Gen works with a list of possible new projects, restricted in Energy Link's modelling to known projects and potential projects, of which there is an abundance. A project is built when the forecast price at decision time exceeds the project's LRMC. Project LRMC's include a small random element to simulate the variability in the LRMCs of real projects. The model is run over the forecast period a number of times, and the forecast price in each run is calculated directly from the price series produced in the previous run. After a number of iterations the price series converges to within a narrow band. I-Gen's output is a project build schedule which is selected from the build schedules produced in the last few converged runs.

[33] This is in contrast to GEM which does include security constraints designed to ensure capacity adequacy.

