Future Geothermal Generation Stack

A report for the Ministry of Business, Innovation and Employment

Authored by: Lawless Geo-Consulting

(Jim Lawless, Bart van Campen, Jim Randle)

Revision D

March 2020

Cover page: The 14 MW (net) binary bottoming plant at Wairakei. Original A and B Stations in the background. A good example of recent incremental brownfield development.

Table of Contents

List of Figures

List of Tables

Disclaimer

While every effort has been taken to ensure the information in this report is correct, the study has involved a degree of subjective judgement as to future events, which has included in some cases the weighing of the balance of probabilities of future events. Therefore, neither Lawless Geo-Consulting nor the individual authors take responsibility for future investment decisions which may be taken on the basis of results presented herein.

List of abbreviations

BOPRC	Bay of Plenty Regional Council
CCS	Carbon Capture and Storage
CMA	Crown Minerals Act (2010)
COD	Commercial Operation Date (date when a power plant is fully commissioned)
EDGS	Electricity Demand and Generation Scenarios (published on a regular basis by MBIE to inform electricity market and facilitate planning)
GDL	Geothermal Developments Ltd
GHG	Greenhouse gases
IRR	Internal rate of return
KGL	Kawerau Geothermal Limited (Kawerau Power Station owned by Mercury)
MBIE	Ministry of Business, Innovation and Employment
Mercury/MRP	Mercury NZ Limited (formerly Mighty River Power)
MWe	Net Megawatts of electrical energy generated from a power station
NCG	Non-condensable gases (like CO_2, CH_4 and H_2S)
NPS	National Policy Statement
NST	Norske Skog Tasman
NTGA(L)	Ngāti Tuwharetoa Geothermal Assets Limited
NTST	Ngati Tūwharetoa (BOP) Settlement Trust
NTEL	Ngati Tūwharetoa Electricity Limited
NZGA	New Zealand Geothermal Association
NZU	New Zealand carbon emissions trading unit
PRP	Peer Review Panel
RMA	Resource Management Act 1991
RPS	Regional Policy Statements
SAGS	Steamfield above ground system
TAOM	Te Ahi O Māui Partnership
TN2T	Tauhara North No. 2 Trust
TPC	Tuaropaki Power Company
TVZ	Taupō Volcanic Zone
WACC	Weighted average cost of capital

Executive Summary

This review was commissioned by the Ministry for Business, Innovation and Employment (MBIE) in consultation with Transpower. The principal objective of this work is to present estimations about the possible timing and cost of future geothermal projects in New Zealand over a 40-year horizon.

The pace of geothermal development in New Zealand has been modest over the past five years, after a period of rapid growth in response to declining gas reserves. There is now a more positive mood in the industry following the government setting objectives for greatly reduced GHG emissions by 2050. Direct use of geothermal heat can also make a significant contribution to reducing fossil fuel use, though that is not the subject of the present study. The industry foresees on-going growth in the geothermal generation sector, albeit at a modest pace.

Access to resources is more likely to constrain the pace of development than project cost and electricity price. Around half of New Zealand's high-temperature geothermal resources are currently fully or partially protected. Regulatory and consenting difficulties may lead to delays for future projects. For the present study, it is assumed that the current regulatory regime will remain more or less as is, but it is conceivable that more permissive or more restrictive approaches are possible in the future. The current draft NPS on Biodiversity, which is open for consultation at present, is an example of regulation that in its initial draft form could limit future geothermal development if that is not taken into account. It should not be assumed that all existing projects will automatically be re-consented, and the consents for all existing projects expire within the 40-year horizon. On the other hand, a more enabling regime and policy at the national level would accelerate the pace of geothermal development, but would also presumably make it easier to consent new wind and solar and possibly even small hydro projects so would not necessarily favour geothermal over other renewable sources.

It is not expected that new technology will greatly reduce the cost of future geothermal generation nor, within what is likely to be economic in New Zealand, significantly extend the geographical spread of its coverage to much lower-temperature resources. Thus, future large-scale development is likely to be within the Taupō Volcanic Zone and at Ngāwhā in Northland. Some modest cost reductions and gains in efficiency can be expected within the existing project areas, but to a lesser extent than the less mature renewable industries such as solar, wind and storage.

From a technical perspective, geothermal generation can be made to run in a load-following manner, but the most economic use of geothermal generation will remain as base load. It is conceivable that government initiatives to minimise carbon emissions might lead to geothermal becoming more important for load following, although the generators concerned would probably insist on a take-or-pay or capacity charge type of compensation to take account of the very high proportion of fixed costs of geothermal project operation. New geothermal has the potential to largely substitute for existing thermal plant as baseload firming for other renewables.

Geothermal power projects do emit GHG, albeit in most cases at significantly lower rates per MWh than fossil fuel plants. Previous studies in New Zealand have over-stated the emissions of existing and future geothermal plants, in part because emissions have actually dropped over time in some cases. More specific figures have been presented here for each prospect to a semi-quantitative level, based on actual recent data. The present MW-weighted average emissions intensity for existing geothermal projects is 76 g CO_2eq/kWh (2018), which has been steadily declining (91 g CO_2eq/kWh in 2015) and is expected to continue to do so in the future. If much higher carbon prices eventuate in the future, the pressure on geothermal plants will increase and the expected emissions intensity would likely drop faster. In general, that would disadvantage new, higher emitting geothermal projects relative to other renewables (but much less than fossil-fuelled plants). The CCS technology does exist for removal of

GHG from geothermal plants and reinjection into nearby reservoirs, and likely at a lower cost than for fossil fuel projects.

Greater future direct use of geothermal energy is generally expected to be complementary rather than competitive to electricity generation or to be based on lower-temperature resources. A notable exception to that could be at Kawerau where there is scope for expansion but the balance between future industrial use and electricity generation is unclear. Another possible future "direct use" is mineral recovery provided certain technical challenges can be overcome. Preservation of geothermal activity for tourism is a form of "direct use" which precludes generation at Rotorua and some of the protected systems in particular.

To derive capital costs of projects, scaling factors based on enthalpy and project size have been applied to the power plant portion of the project cost, which is taken to be 40% of the total. On this basis capital costs range from $4,734 to $9,767/kW with a weighted average of $5,782/kW. It is expected that at least 50% of the project capital costs will be in New Zealand currency.

No significant net reduction in existing production is anticipated due to decommissioning over the next 40 years (assuming any retirement of plant at Wairakei is met by an increase at Te Mihi), provided all existing plants can be re-consented for the existing quantities of fluid take.

.

Taking likely earliest dates of COD into account yields an estimated sequence of future geothermal projects as summarised in Table 6 (section 5.4). The total estimated available future geothermal generation stack by 2060 is 1035 MW.

This total new geothermal generation stack is slightly higher than previously presented by MBIE (2016), but it is likely that many projects will be commissioned later than previously assumed, for reasons other than cost.

1. Introduction

1.1. Scope of work

This review was commissioned by the Ministry for Business, Innovation and Employment (MBIE) in consultation with Transpower. The scope of work is presented in Annex 3. The principal objective of this work is to present estimations about the possible timing and cost of future geothermal projects in New Zealand over a 40-year horizon. The resulting 'future geothermal generation stack' should assist MBIE in updating its 2016 Electricity Demand and Generation Scenarios for New Zealand, and planning/modelling for future transmission requirements.

Differences between this review and that underlying the 2016 version include:

- Greater attention to the issue of timing and consenting of geothermal projects, which will inevitably lead to delays for some projects beyond the point that a simple LRMC comparison would indicate;
- More quantification of greenhouse gas emissions (GHG) from geothermal projects, based on recent data from existing projects;
- More consideration of the effects of scale and likely technology of projects on their capital cost;
- The split of CAPEX between local and overseas components.

The process has involved extensive consultation with the geothermal industry and relevant regulators and well as review of published information. The willing participation of many people from the industry and regulators is gratefully acknowledged (see Annex 1). However, the opinions and assumptions expressed herein are entirely those of the authors.

This report has been authored by:
Jim Lawless (Lawless Geo-Consulting Limited)
Jim Randle (GT Management)
Bart van Campen (Geothermal Institute, University of Auckland)

1.2. Background

As part of the 2016 Electricity Demand and Generation Scenarios (EDGS), MBIE produced a likely geothermal generation stack as follows:

Project	Type	Status	MW	Typical GWh pa	Capital cost $m	Variable O&M, $/MWh	Fixed O&M, $/kW	LRMC $/MWh
TikitereTaheke_generic2	Geo	Generic	80	631	409	0.00	105.00	95.37
Tauhara_stage_2	Geo	Fully Consented	250	1971	1184	0.00	105.00	97.65
Rotokawa_generic1	Geo	Generic	130	1025	620	0.00	105.00	98.09
Ngatamariki_generic1	Geo	Generic	100	788	479	0.00	105.00	98.32
Tauhara_generic1	Geo	Generic	80	631	409	0.00	105.00	102.70
Tikitere_LakeRotoiti	Geo	Proposed	45	355	299	0.00	105.00	114.47
Kawerau_generic2	Geo	Generic	30	237	219	0.00	105.00	122.56
Ngawha2_stage_1	Geo	Fully Consented	25	197	183	0.00	105.00	122.76
Ngawha2_stage_2	Geo	Fully Consented	25	197	183	0.00	105.00	122.76
Rotoma_LakeRotoma	Geo	Applied for Consent	35	276	256	0.00	105.00	123.05
Kawerau_TeAhiOMaui _KA22	Geo	Fully Consented	20	158	147	0.00	105.00	123.08
Wairakei_generic1	Geo	Generic	45	355	327	0.00	105.00	131.61
Mangakino_generic1	Geo	Generic	40	315	291	0.00	105.00	131.70
Ohaaki_generic1	Geo	Generic	40	315	291	0.00	105.00	131.70
Total			**945**					

Table 1: EDGS-2016 geothermal generation stack (source: MBIE, 2016)

The MBIE's EDGS models supposedly build the lowest LRMC plants first (many of which are geothermal – see Figure 1 below), but from the above geothermal generation stack, it can be seen that some of the fully consented plants (several now built or under construction) actually have higher LRMC than some of the other projects, still under consideration. It is therefore apparent that for geothermal plants in New Zealand cost is not the only criterion as to when projects actually get built.

The above geothermal project list adds up to around 945 MWe of new geothermal projects (including Ngāwhā, Kawerau-TAOM and Tauhara-II presently built or under construction). Many of the long-term New Zealand electricity modelling scenarios (e.g. Productivity Commission (2018), ICCC (2019), BEC2060 (2019), include much higher MWe of geothermal in their long-term (2050, 2060) scenarios, which to the present authors appear unrealistic.

Most of these modelling exercises (including MBIE-EDGS, 2016) have used uniform, average emission intensities (115 – 130 g CO_2 eq./kWh) for historic, as well as future, new geothermal investment plant. These figures are above the recent average. Recent new emissions data (McLean and Richardson 2019) and conceptual modelling (Van Campen et. al. 2020) show that varying assumptions on geothermal emissions can have significant impact on the rate, timing and location of future geothermal investment.

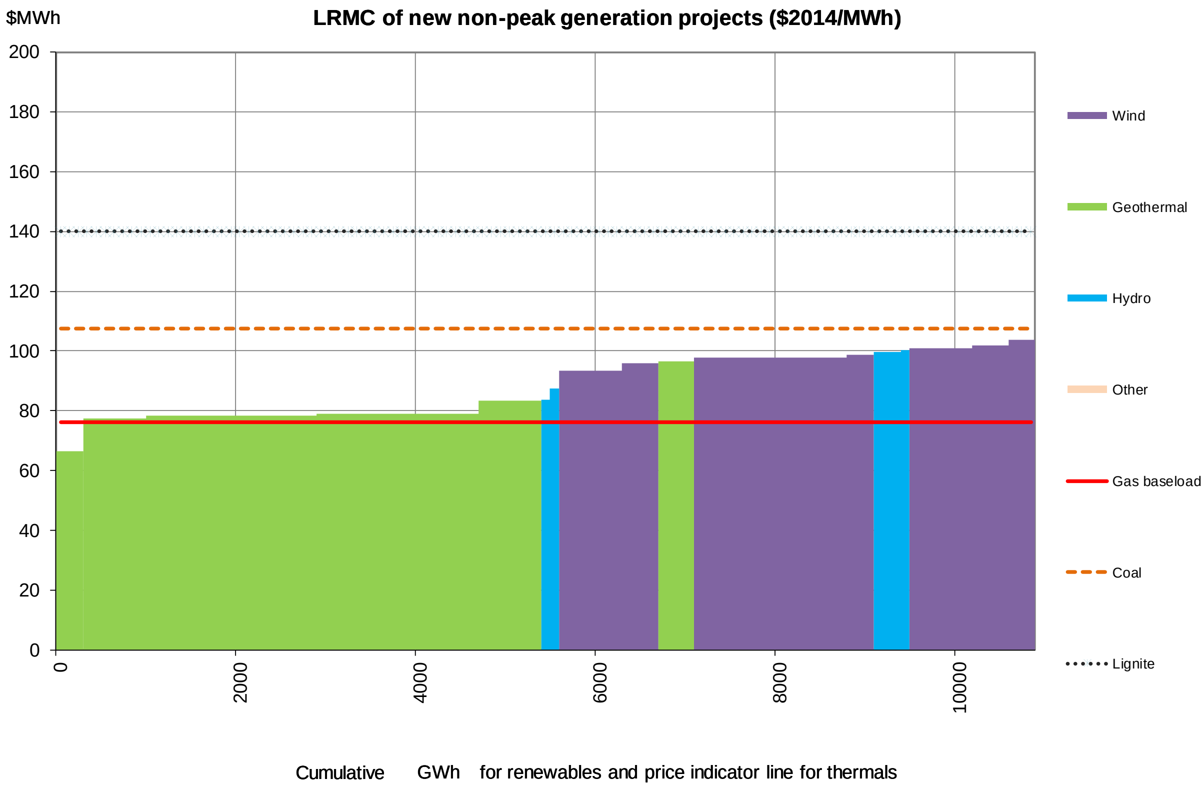

Figure 1: LRMC of new non-peak RE-generation according to EDGS-2016 (source: MBIE, 2016)

It is now timely to update the 2016 MBIE geothermal generations stack. Since then several developments have taken place:

- No large new plants have been built or retired, but one new smaller project has been built: the Te Ahi O Maui (TAOM) geothermal plant is a partnership between the Kawerau A8D Ahu Whenua Trust and Eastland Generation. It uses both an older well previously drilled by the New Zealand government, and several new dedicated wells. The plant, commissioned in September 2018, is the latest generation of Ormat binary cycle technology and is delivering 25 MWe;

- An expansion of the binary-only project at Ngāwhā in Northland by 50 MW has been consented. The first phase (25 MWe) is still at the drilling and civil works stage, but can be regarded as firmly committed, with a commercial operation date (COD) of mid-2021. The remaining, second phase is expected to be installed by 2026 at the earliest;
- The current government has introduced the Climate Change Response (Zero Carbon) Amendment Bill (2019) and presented ambitious plans to decarbonize the economy and the electricity sector, including aiming for significant electricity demand rise from electric vehicles. This is likely to significantly increase demand for renewable energy projects, including geothermal. It is important therefore to have a more updated, detailed view of the geothermal projects available.

2. Present generation, regulations and emissions

2.1. Present geothermal generation and location

Most of New Zealand's known high enthalpy geothermal resources are located in the Taupō Volcanic Zone (TVZ) in the central North Island, apart from the single occurrence in Northland at Ngāwhā near Kaikohe (Figure 2). Because of the decentralized nature of the geothermal regulatory regime under the Resource Management Act (RMA 1991), these high enthalpy systems fall under three different regional regulatory regimes: Waikato Regional Council (with around 70% of the geothermal resources), Bay of Plenty Regional Council (around 25%) and Northland Regional Council (Ngāwhā only).

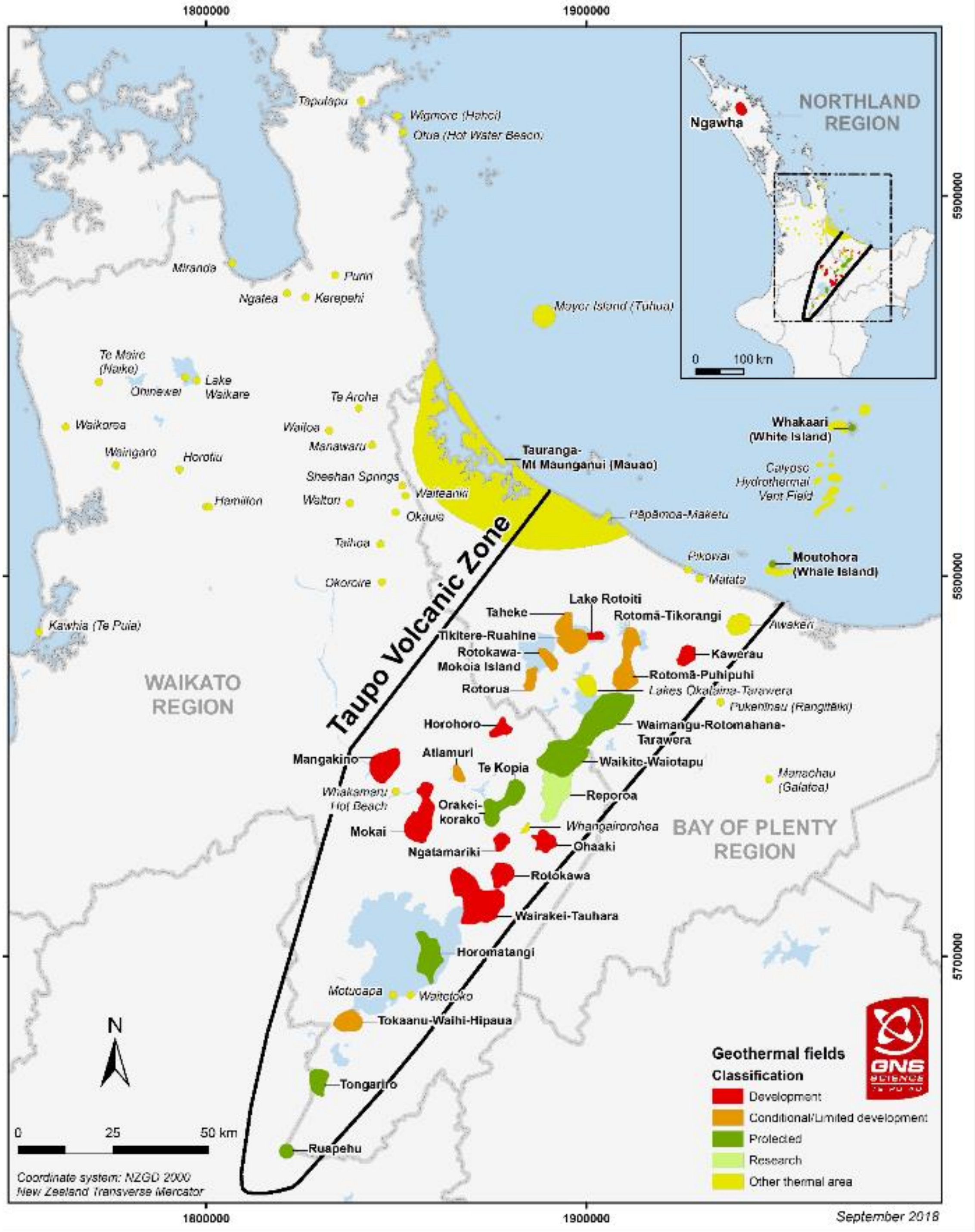

Figure 2: Map of New Zealand's high temperature geothermal resources (source: NZGA/GNS, 2019)

Geothermal generation in New Zealand started in the late 1950s and has grown over the decades, with a strong new surge since the mid-2000s (see Table 2 below) to a total of 1,010 MWe after the commissioning of the most recent Te Ahi o Maui plant in 2018. More plants are under construction.

Most of these geothermal systems were well explored by government drilling programmes from the 1950s-1970s, before electricity markets were deregulated and privatized. Most of the geothermal power developments until recently have been in the Waikato Region, with resources/power plants generally located close to the central transmission lines. With the notable exception of Kawerau, geothermal systems in the Bay of Plenty region have been less developed, partially due to private/Iwi landownership and restrictions in access, and partly due to the protection of geothermal surface features. Hence less is known and more systems are classified as 'conditional/limited development' in Bay of Plenty (see 2.3). These systems also tend to be more remote and some transmission upgrades might be needed to integrate any developments into the main grid.

Many of the present geothermal plants were (re)consented in the 2010s for up to 35 years, and will have their consents expire around 2040-50. The first consents to expire are for Mokai (2024) and Wairakei A and B/Te Mihi in 2026. This has generally been included as a decommissioning in electricity modelling exercises like MBIE-EDGS (2016), but a different approach has been taken here. Mokai and Wairakei A&B have been assumed to continue at around the same capacity or replaced by a similar capacity. For example, in the case of Wairakei either by fully reconsenting Wairakei A and B stations, re-configuring them with a smaller output and/or adding a third unit at Te Mihi. In effect, this would cancel out the 'decommissioning' of Wairakei A and B, and is therefore not seen as a separate project. For project consents expiring in the 2040s and beyond it is very uncertain what might happen, but it has generally been assumed that projects will continue. If the requirement is to model the decommissioning of geothermal plant explicitly, then these projects need to be studied and modelled separately, but this is outside the scope of this work.

2.2. Outline of geothermal technology

Technology choices have environmental impacts that may affect the timing and feasibility of a project. There are a number of different possible plant configurations for converting geothermal heat to electricity. A range of these have been adopted in New Zealand, more so than in some other countries. The originally-installed capacity of some of the power plants was greater than at present.

The reasons for the range are partly technical, in that the applicable temperature ranges of binary plants and condensing turbines are different, but they have also been driven by regulatory issues and consideration of environmental effects, which have changed greatly over time (Lawless et al. 2016).

The biggest differences in the effects of different types of plant configurations are in the waste disposal and cooling systems adopted. The oldest plants, Wairakei and Kawerau, did not initially adopt reinjection of separated brine but rather disposed of brine to rivers, though in both cases that has since been reduced by partial reinjection (80% in the case of Wairakei). Condensing steam turbines often use water passing through evaporative cooling towers (either natural draft or mechanical draft) to maintain condenser vacuum. Therefore, a proportion of the steam condensate is lost to evaporation rather than injected. In the special case of Wairakei, the Waikato river is used for direct-contact cooling which results in contamination of the river. Binary plants usually use air cooling systems, and so conserve water for reinjection. although in some circumstances the cooler reinjected fluid and the fact that the reinjection load is increased, can produce a problem with reservoir cooling.

Plant	COD	Current MW	Steam Supply	Prime Mover	Cooling
Wairakei A&B	1958	127	Triple flash	BPT & CST	Water (river)
Kawerau	1966	8	Single flash	BPT	None *
Ohaaki	1988	57	Double flash	BPT & CST	Natural draft evaporative water
Kawerau binary	1989 &1993	4	Bottoming, retrofitted	Binary	Air
Wairakei BP	1996	19	(Topping) Triple flash	BPT	Water (river)
Poihipi	1996	50	Dry steam	CST	Mechanical evaporative water
Rotokawa + extension	1997 & 2003	35	Single flash	Combined cycle	Air
Ngāwhā	1998 & 2008	25	IP steam and brine	Binary	Air
Wairakei binary	2004-2005	14	None - bottoming	Binary	Air
Mokai	1999, 2005, 2007	112	Single flash	Combined cycle	Air
Kawerau (KGL)	2008 & 2017	107	Double flash	CST	Mechanical evaporative water
Kawerau-GDL	2008	8	None - bottoming	Binary	Air
Rotokawa - Nga Awa Purua	2010	140	Triple flash	CST	Mechanical evaporative water
Tauhara - Te Huka	2010	28	IP steam and brine	Binary	Air
Kawerau (TOPP1)	2013	21	Double flash	CST	Mechanical evaporative water
Ngatamariki	2013	82	IP steam and brine	Binary	Air
Te Mihi	2014	166	Double flash	CST	Mechanical evaporative water
Kawerau-Te Ahi O Maui	2018	25	IP steam and brine	Binary	Air
Total		**1028**			

Table 2: Geothermal plant and generation technologies in New Zealand. Capacities are installed capacity, not necessarily original capacity nor current generation e.g. Ohaaki was originally 108 MW, installed capacity is now 57 MW, currently produces around 40 MWe. (source: NZGA, 2019 and authors' input)

* Exhaust steam is used for industrial process heat

Mass loss through evaporation rather than returning it to the reservoir will generally reduce the amount of pressure support provided by reinjection (though it could avoid enthalpy decline). Thus, reservoir pressures can be expected to decline faster than would otherwise be the case. That in turn could lead to accelerated production decline (arguably lesser sustainability) and unwanted surface effects such as changes in thermal activity and subsidence.

The possibility of such effects was a significant factor in the adoption of a binary-only (i.e. no steam turbines) plant and full reinjection at the recent Ngatamariki plant. It remains to be seen whether this will be a major consideration for future power schemes, though it should be noted that the plant selection in that case was voluntary on the part of the developer and there is no suggestion that such should be in effect made mandatory through resource consent conditions. Wider consideration of this issue would favour binary-only plants over condensing steam turbines which would lead to an increased project cost per MW. On the other hand, for high enthalpy fields, combined cycle plants such as Mokai and Rotokawa with steam turbines exhausting into binary condensers can be very efficient and cost effective.

Type	Size	CAPEX/MW	Thermodynamic efficiency	Water conservation	Other issues
Back pressure turbine (BPT)	Small to mid-range	Cheapest	Low when stand-alone	Lowest	If stand alone, most applicable at remote locations (e.g. single well) and/or early stage resource testing
Condensing steam turbine (CST)	Largest turbines	Next cheapest	High, but require high grade resource	Low if using evaporative cooling	Very efficient if using multiple flash, economies of scale
Binary	Small and modular	Most expensive	Not very efficient *per se*, but can make use of lower grade resources	High	Can be used for small individual projects or larger modular combinations
Combinations	Depends on combinations, generally larger overall	Intermediate	Can be very efficient overall	High	Various configurations possible including retrofitting

Table 3: Characteristics of different plant types (source: Lawless et al, 2016)

2.3. Regulatory environment and impacts on development timing and feasibility

Classification and preservation of geothermal systems

The situation regarding regulation and classification of geothermal systems in New Zealand is complex and differs from the regime in many other countries. The discussion here does not purport to be exhaustive or definitive, but touches on a number of issues that need to be taken into account when considering the course and especially the pace of further geothermal electricity development in this country.

Geothermal resources in New Zealand are managed under the Resource Management Act 1991 (RMA). Previous analyses of the likely Generation Stack have been based principally on the long run marginal cost (LRMC). That is logical, and LRMC is a key parameter, but it does not explicitly take into account the geothermal regulatory environment in New Zealand. One of the fundamental principles of the RMA is that of sustainable management, which in the geothermal context has been variously interpreted to mean:

- A proportion of New Zealand's geothermal systems should remain undeveloped, or with limited development, in order to protect or manage their intrinsic scientific, landscape, ecological and cultural value. Other, "development" systems can be developed, although still within the context of sustainable management. This has led to the classification of all geothermal systems in the TVZ from Protection to Development, as described further below;
- Even in systems where development is provided for, the rights of future generations should be taken into account. Therefore, while extraction can exceed renewability in the short term, a proportion of the resource must remain at the end of the consent period;
- Even in systems where development is provided for, untoward surface effects should be avoided, mitigated, or remedied as for any project. That can include effects on significant surface geothermal features, but also other external effects such as subsidence and hydrothermal eruptions.

Both regional and district councils have roles and responsibilities relating to geothermal developments. Regional Councils have the function of managing the take and use of geothermal fluid and energy, and discharges to the environment, while district councils have a role managing the effects of the use of land (e.g. earthworks, infrastructure, structures etc.). Most of New Zealand's geothermal resources are managed by the Waikato and the Bay of Plenty Regional Councils. The Northland Regional Council manages the Ngāwhā geothermal system.

Since the introduction of the RMA, there has so far been little direction from central government on geothermal development. There has been a National Policy Statement on renewable electricity generation (2011), but in the view of the present authors it lacks specificity.

The RMA framework is specified by the regional councils in their Regional Policy Statements (RPS), and specific policies and rules for activities within regional plans. The Waikato and Bay of Plenty Regional Policy Statements take a broadly similar approach to sustainable management of geothermal resources through classification of systems. Both have adopted a similar classification system for geothermal areas. That for Waikato Regional Council is as follows:

> "Classification is based on ranking each system's characteristics and aims to balance development with the protection of highly valued surface features. There is a different management approach for each category.
>
> In areas classified for **Development**, large-scale uses are allowed as long as they are undertaken in a sustainable and environmentally responsible manner.
>
> In **Limited Development** systems, takes that will not damage surface features are allowed.
>
> **Research** systems are those where not enough about the system is known to classify it as either Development, Limited Development, or Protected. In these systems, only small takes and those undertaken for scientific research into the system are allowed.
>
> **Protected** systems contain vulnerable geothermal features valued for their cultural and scientific characteristics. Their protected status ensures that their underground geothermal water source cannot be extracted and that the surface features are not damaged by unsuitable land uses.
>
> **Small** systems are isolated springs or sets of springs. These can only sustain small takes and are not suitable for electricity generation" (WRC 2019).

Bay of Plenty Regional Council has a very similar classification policy with some differences in terminology.

A significant proportion of New Zealand's high temperature geothermal resources are currently fully or partially protected from development. Lawless (2005) estimated that proportion to be 40-70% depending on what assumptions are made. While some of the resource capacity estimates in that paper need to be updated, the general conclusion remains valid.

Hence, a significant portion of the remaining resources are in categories which mean in effect that only very limited development is possible pending further investigation, for example to demonstrate whether abstraction would adversely affect significant surface features. It would, however, be possible to develop a conditional or limited development system provided adverse effects on surface features are avoided, remedied or mitigated. In "Development" systems, consenting (or reconsenting) would likely be via a notified consent process, hearings and potentially appeals, and can be a protracted process.

It is possible to change the classification status of a system, most likely through a regional plan change process, for example from "Research" to "Development" or "Conditional Development" to "Development" if new information becomes available, but that has not been done so far and may turn out to be a protracted process in practice.

Thus, absent a major revision of the RMA and/or a retreat from the principles of sustainability (which seem unlikely within the time frame considered), there could be consequent delays in obtaining consents for projects, especially where a change in their status needs to be taken into account as well as their cost. There are likely to be geothermal projects which ultimately have a reasonably low LRMC but which we know will be delayed by many years by the regulatory requirements.

The cost of delay could be taken explicitly into account by considering both the probable escalation in major cost components[1] and the financial effect of delay on the Net Present Value (NPV). That is the methodology adopted in the recent work by GT Management for example (GT 2019). However, the existing MBIE EDGS/GEM-model does not work that way and so for consistency with other renewable sources which are being considered in parallel to but outside this study, the possible timing of projects due to regulatory issues has been estimated, but has not been used to determine the LRMC.

Central government policy affecting geothermal development

Although allocation and management of geothermal resources takes place at the regional level, under the RMA National Policy Statements (NPS) can provide national guidance and must be given effect by RPS and regional plans.

As well as the existing NPS on renewable electricity generation (2011), the forthcoming draft NPS on Biodiversity may be relevant to geothermal development. This is presently under development and open for consultation. As presently worded, it would require strict preservation of geothermal ecosystems and biodiversity in every geothermal system, even within geothermal systems classified for development. The regional authorities have expressed the view that if passed in its present form it could preclude all further geothermal development and/or the reconsenting of existing projects even in "Development" systems.

Another potential concern is fresh water regulation. Geothermal energy is regulated as "water" under the RMA. There is currently debate at a national level and development of policy relating to ownership and administration of natural fresh water. That could lead to some uncertainty for future geothermal development, especially around the aspect of royalties.

An area where the lack of involvement by central government is detrimental to geothermal development in the view of the present authors, concerns the collection of exploration data. The way in which access to geothermal resources, and the data resulting from geothermal exploration are handled is in contrast to how minerals and petroleum are handled in New Zealand. Access to and allocation of mineral resources is covered under the Crown Minerals Act (CMA 2010). A company can apply for a Prospecting Permit or Exploration Licence over a specific area, and for a limited time. They then have priority in terms of applying for a mining license (although not an automatic right to obtain one). To keep their exploration right they have to fulfil a minimum programme of work and file regular

[1] Escalation of the several major cost components of a geothermal project is not straightforward, as they are controlled by different factors. For example, the cost of pipelines etc. depends on world-wide steel prices, but the cost of drilling is far more dictated by the cost of oil and hence demand for drilling rigs. For the present purposes an overall figure of 2.2% has been used, being an approximation to US PPI.

reports with New Zealand Petroleum and Minerals. That information enters the public domain after an embargoed period. A very similar situation applies to petroleum, except that specific areas are more often offered for tender by the Government rather than being granted in response to exploration company initiatives.

In both those cases, the information that is collected about our natural resource endowment becomes part of our national inventory, to the benefit of the country as whole. Most countries have a generally similar regime for both mineral and geothermal resources.

In contrast, it is not possible in New Zealand to obtain priority of access during exploration to geothermal resources, since those are allocated under the Resource Management Act. The only way a company can obtain rights/consents to use geothermal energy is to obtain a resource consent to extract it from a particular area. However, to obtain a resource consent requires a thorough application which not only has to cover environmental effects, but also issues of sustainability. This means that the applicant has to have a good idea of the size of the resource and how it could be developed. This in turn, means that for a company to obtain a resource consent for geothermal development, they need to undertake a thorough investigation at a minimum cost for geophysical surveys of hundreds of thousands of dollars, and probably drilling at a cost of tens of millions of dollars, but with no right of priority or access. Since geothermal exploration carries no rights of priority, there is a strong incentive for the data collected to remain confidential. Hence, unlike petroleum and minerals exploration, New Zealand Petroleum and Minerals (nor any other central agency) does not collect information generated during the exploration phase, nor do they make any effort to collate or publish existing data to attract investment. Regional Councils collect only data generated during the exercising of a resource consent, which may come many years after exploration, by different parties, or not at all.

Other issues that arise from the legal/regulatory environment and could also affect the timing or feasibility of projects include the following.

Multiple operators

A feature of both the Waikato and Bay of Plenty regional policies is that multiple operators with separate take and discharge consents are allowed on a single geothermal resource/system, e.g. there are presently four developers on the Kawerau system. That is unusual on a world scale. It can and has led to complications and delays, although it can also lead to opportunities for collaboration and flexibility. The over-production and consequential severe decline of the Geysers geothermal resource in the USA was a consequence of multiple tapper access, which was only resolved when one single operator effectively remained in operation and took steps to recover the reservoir pressure through supplementary injection.

Status of landowners

Landowners do not own underlying geothermal resources. However, they do control access to them, so in practice, they have a considerable de-facto degree of control. That can lead to delays and complications especially where there are multiple landowners over a particular resource/system.

Maori interests

Maori are involved in geothermal projects in several different ways, some of which at times can have conflicting objectives. Some of these are:

- As landowners. In practice, the land overlying many of our geothermal resources belongs to Maori trusts. There is a range of models of engagement ranging from the Mokai project where the Tuaropaki Trust took the lead role and initially was the sole owner of the power scheme, to those where the landowners are more passive and just receive a royalty.

- As *kaitiaki* of the resource. A guardianship role for Maori is explicit in the RMA (and in some Statutory Acknowledgements), but precisely what that means and who is responsible can sometimes be unclear. In places, the local Maori landowners also are accepted as having the mandate for *kaitiakitanga*, but in other areas, arrangements may be different or more commonly overlapping.
- As claimants to be owners or users of the resource. Under the Geothermal Energy Act (1953), it was stated clearly that: "*The sole right to tap, take, use, and apply geothermal energy on or under the land shall vest in the Crown*." Ownership of some resources has however been challenged with a number of Waitangi Treaty claims, some of which are unresolved, and some of which have been brought by wider parties than the specific landowners. While in no case has actual ownership of the resource been transferred to Maori as part of a Waitangi Tribunal settlement, the Crown has in cases recognized access to the resource and ownership of assets such as wells. For example, in the case of Ngāti Tūwharetoa Geothermal Assets (NTGA) at Kawerau (a wholly owned subsidiary of Ngāti Tūwharetoa Settlement Trust), as holders of Statutory Acknowledgements by the Crown, Ngāti Tūwharetoa (Bay of Plenty) is recognised by the Crown as having particular cultural, spiritual, historical, and traditional association with, and use of, the geothermal energy and geothermal water located in the Kawerau Geothermal System.

Past history has shown that Maori landowners are not averse to geothermal development in principle and have acted as a springboard in many cases, although experience suggests that Maori landowners are more likely to take a long term and holistic view of the resource than a more strictly economically-driven developer. The combination of the above factors, the tensions between them, and complexities of land ownership can lead to delays that need to be considered in the potential timing of new geothermal generation projects.

Safety Regulations

There is a general view in the industry that recent revisions in national safe working, in some cases, do not take account of the specifics of geothermal operations, and can be a hindrance to development. The leading developers are, however, working pro-actively with MBIE on rationalising these aspects and longer-term this will hopefully not lead to delays.

No attempt has been made to take all the above-mentioned issues into account for specific projects in this report, but they need to be considered as representing possible factors in lower geothermal growth/availability scenarios.

2.4. Greenhouse gas emissions

Geothermal generation is not free of Green House Gas (GHG) emissions as the produced underground fluids contain many dissolved, non-condensable gases, especially carbon dioxide (CO_2) and hydrogen sulphide (H_2S), and in some cases traces of methane (CH_4) (ESMAP, 2016). The CO_2 and CH_4 are GHGs. A large part of these GHGs will be emitted to the atmosphere, even if the majority of the produced fluids is subsequently reinjected into the ground. Geothermal power plants have to account for their GHG emissions by closely monitoring/sampling the emissions from their produced vs their reinjected fluids (e.g. under the NZ Emissions Trading Scheme - ETS).

Geothermal fluids and reservoir rocks vary considerably from field to field, as well as variations in power plant technology (low-temperature, closed loop binary systems), efficiency, reinjection, management, etc. Hence emission intensity (generally expressed as g CO_2/kWh or g CO_2eq/kWh) varies significantly, from 18-21 g CO_2eq/kWh for some Icelandic plants and Wairakei in New Zealand, to 1,640 gCO_2 /kWh in Alasehir-Kavaklidere, Turkey (Layman (2017). Bertani and Thain (2002) calculated a weighted world average of around 122 g CO_2eq/kWh.

In comparison, GHG emissions for fossil-fuel fired power plants are closely monitored and reasonably standardized/similar around the world, with around 390 g CO_2eq/kWh for CCGT and 955 g CO_2eq/kWh for coal-fired generation (McLean and Richardson 2019).

In contrast to many renewable energy plants, geothermal plants provide baseload generation, with capacity factors of 90-95% or more, particularly in New Zealand. Hence most geothermal power plants will replace much higher emitting baseload fossil-fuel generated electricity and serve to reduce emissions significantly. In terms of life-cycle emissions geothermal power plants tend to have lower life-cycle emissions (excluding direct, operational, field emissions) than solar PV, but higher than wind (IPCC 2014).

Until recently, limited geothermal field emissions data was publicly available in New Zealand. What was publicly available, were aggregated data from MBIE on fugitive emissions from the geothermal power generation sector. This resulted in an estimated average of 115-130 g CO2eq/kWh over recent years. As those were the only available, public data sources, these were the data used in several recent modelling efforts for New Zealand's future low-emission electricity/energy sector, including BEC (2015), MBIE-EDGS (2016), Vivid (2017), Sapere (2018), Productivity Commission (2018), ICCC (2019). In general, these studies acknowledged a variation of emissions between different existing plants (from 32 – 597 gCO_2/kWh), but they generally modelled (future) geothermal investments with a single constant emission intensity of 115 (BEC-2015, MBIE-2016) – 130 (ICCC, 2019) g CO_2eq/kWh.

Recently, however, the NZ Geothermal Association managed to gather confidential company emissions data and publish almost 10 years' worth of geothermal emissions data (McLean and Richardson 2019 – see Annex 2 for details). Relevant conclusions from this review include:

1. The mw-weighted average emissions intensity in 2018 was estimated at 76 g CO_2eq/kWh. This was down from 91 g CO_2eq/kWh in 2015. As a cross-check that can be compared to a figure for Indonesia (where all resources tapped are volcanic, similar to New Zealand) of 63 g CO_2eq/kWh (Yuniarto et al. 2015);
2. A large variation in emission intensities between fields: in 2018 from 21 gCO_2eq/kWh for Wairakei A&B to 341 g CO_2eq/kWh for Ohaaki;
3. All NZ geothermal field/plant emissions are considerably lower than gas- or coal-fired emissions (at 390, and 955 g CO_2/kWh respectively, see Figure 3 below);
4. A general, long-term trend towards lower emission intensities for each individual field, as well as in aggregate, weighted average (see point 1). For individual fields at times long term degassing trends might be interrupted by new wells taken into production, added capacity or operational changes;
5. Generally lower emissions intensity for newer, more efficient geothermal plants.

The NZGA data is detailed and seems accurate, but the emissions intensity averages and totals do not seem to match data from MBIE (fugitive emissions from geothermal generation going back to 1990). This would need further comparison and investigation.

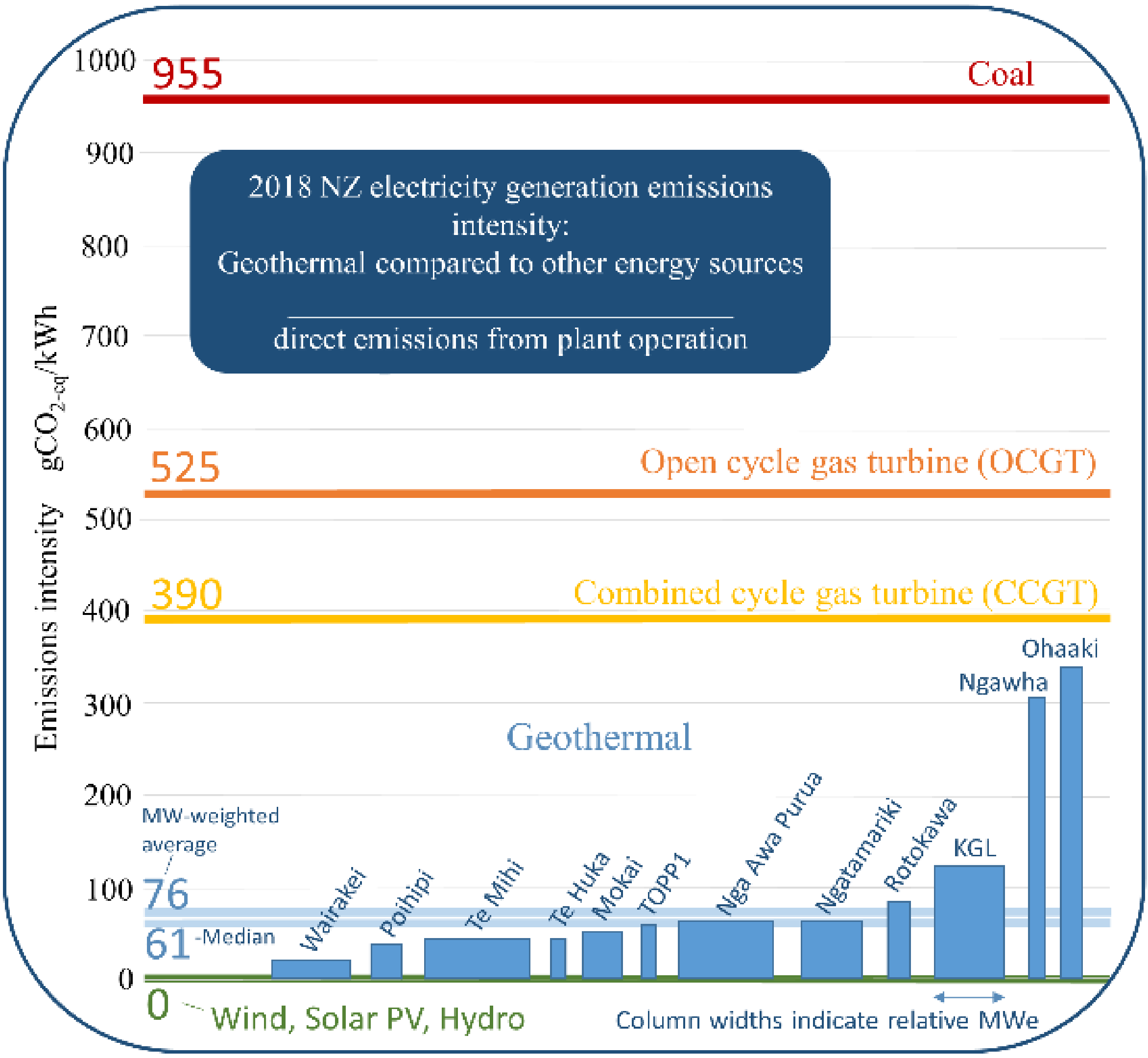

Figure 3: Graphical chart comparing the operational emissions intensity of geothermal power stations in New Zealand to other types of electricity generation (source: McLean and Richardson 2019)

For the present modelling purposes, a semi-quantitative approach is proposed, classifying (new) geothermal plants in 4 categories. The cost implications are discussed in 3.4:

- Very low emissions (< 40 g CO_2eq /kWh)
- Low emissions (40 –80 g CO_2eq/kWh)
- Medium emissions (80 –150 g CO_2eq/kWh)
- High emissions (> 150 g CO_2eq/kWh)

For the long-term future (especially under high carbon price scenarios), improved technologies, higher efficiencies, better reinjection management and even Carbon Capture and Storage (CCS) are all options to further reduce geothermal emissions. CCS for geothermal is likely to be easier/cheaper than for some power sources as the sequestration area (the geothermal reservoir that the fluid and emissions came from originally) is co-located with the power station; much more so than for most coal or gas-fired power plants. Additionally, the gas stream to be processed is predominately CO_2, rather than a nitrogen/CO^2 mix in a fossil fuelled plant.

Although a separate issue from GHG, it is noteworthy that New Zealand has some of the most permissive air emission limits for toxic geothermal gasses in the world[2], most notably H_2S. Elsewhere where tougher limits apply, geothermal plants have continued to operate economically despite H_2S removal being required (e.g. in the USA).

[2] Noting again that resource consent conditions in New Zealand are region, and project, specific, not in accordance with an overall national standard.

3. Methodology adopted for estimating CAPEX and OPEX

3.1. CAPEX

Estimating costs for future geothermal investments faces many uncertainties and the variation in capital costs (CAPEX) can easily be as much as 20-30% depending on project specifics. When using publicly declared costs of projects, project-specific issues need to be considered. CAPEX can also vary depending on the financial assumptions with regard to how sunk costs are treated. For example, some of the existing projects took over several highly productive historical wells drilled by the government decades before, but at significantly less than replacement cost. Given the very long history of some New Zealand projects before COD, the differences can be significant.

The NZ dollar exchange rate can also have a significant effect as a large portion of the project cost consists of overseas components, as discussed below. For the present study, an exchange rate of 0.65 to the US dollar is assumed (slightly higher than the rate at time of writing), but noting that this has varied by at least 15% over the past decade. Therefore, CAPEX can be reasonably accurately estimated for plants in the near future when the project is well-defined, but becomes less clear for projects in the more distant future. However, experience indicates that changes in exchange rates are to a large extent cancelled out by changes in national inflation rates, and it is therefore appropriate to undertake all long-term cost estimating in a single currency.

GT Management (2019) produced a detailed Production Cost Model, which incorporates a large number of factors to estimate geothermal CAPEX. That model has the advantage of having been based on extensive consultation with the international industry, and peer review by the World Bank. It was originally developed using funding from the New Zealand Ministry of Foreign Affairs and Trade (MFAT). While that modelling was specific to Indonesia, and some of the specific costs and financial assumptions (WACC, IRR) will differ from those in New Zealand, it included a number of useful empirical cost correlations which are used here.

As in many energy projects, there is a tension in geothermal projects between the desire by developers and regulators on the one hand to proceed cautiously in a staged or modular fashion, and the fact that the cost of geothermal power projects has significant economies of scale. That applies particularly to the power plant cost: the number and cost of wells and SAGS (steamfield above ground system) tend to be more simply, linearly dependant on the MW. The effect of size on power plant cost was quantified by GT Management (2019), based in part on earlier work by SKM (2009). That correlation was developed further with Indonesian cost data and extensive feedback from developers.

While the correlation is specific to Indonesia, it should also be applicable in New Zealand to a sufficient degree of accuracy for the purposes of this report. It has been used in developing the capital cost estimates, assuming that the power plant is roughly 40% of the total project cost.

Figure 4 shows three correlation ratios/formulas, in case multiple plants/units are ordered or built around the same time. For the present report, the single unit correlation is used unless stated otherwise. The authors have assumed that the remaining 60% CAPEX has a fixed cost per MWe, and that it scales linearly with MW capacity.

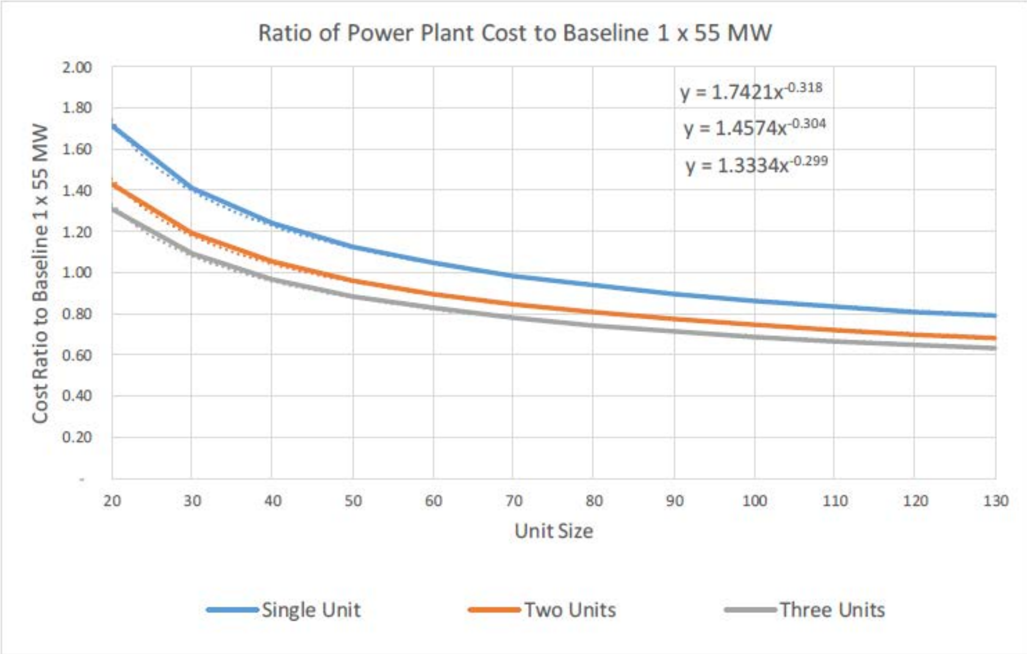

Figure 4: Variation of power plant cost with size (source: GT Management, 2019)

Reservoir enthalpy and well productivity affect the plant design and number of wells, including the production-to-reinjection-well ratio, and complexity of the SAGS. For this report a single reservoir enthalpy scaling factor will be used as follows:

Enthalpy (kJ/kg)	Multiplier on basic power plant costs
760 – 940	1.3
940 – 1450	1.0
> 1450	0.9

Table 4: Scale factors for enthalpy (source: GT Management, 2019)

In the case of retrofitted bottoming binary plants, the project CAPEX would be reduced by the lack of new wells required, but the plant cost per MW will be higher because of the low enthalpy. It has been assumed that these two factors will offset each other. As these plants will inevitably be small this assumption will make relatively little difference to the big picture. It has been observed at Kawerau that such plants are attractive to smaller developers, presumably because of low capital requirements, the low resource risk and the relative ease of getting consents to operate. Generally, the bottoming plant operations would come within the geothermal resource consents for the primary field operators, and they would only be responsible for their additional direct effects (discharge, land-use, etc).

A useful international CAPEX benchmark is 4,000 to 5,000 USD/kW for greenfield projects, with the higher number being more appropriate to small projects with low-quality resources. The 4,000 USD/kW figure is approximately 6,000 NZD/kW. There are however several reasons why CAPEX for recent projects in New Zealand may have been lower than the international benchmark:

- The mature and competitive nature of the New Zealand geothermal industry.
- Many of the projects in New Zealand were brownfield, rather than greenfield projects (e.g. Ngāwhā, Te Mihi);

- Even in projects which have not previously had power plants, the level of risk is lower than in most overseas project because of the large legacy of resource data;
- In some cases, previously drilled wells would have been purchased at less than replacement cost, or taken into the project at a discounted sunk cost;
- Access and infrastructure costs are generally low in the TVZ;
- Drilling costs per metre in NZ are lower than in some countries and in some cases, wells are shallower;
- Some projects may have taken advantage of a higher NZ/US dollar exchange rate at the time.

The publicly available data from projects in the past decade bears this out:

- The Eastland annual report 2019 reported the cost of TAOM at NZ $149 million for 26 MW net, i.e. NZ$5,730 per kW. This would appear to be a reasonable benchmark for projects of this size. Larger brownfield projects should have slightly lower unit costs;
- At final notice to proceed, Top Energy's CEO reported the cost of Ngāwhā-3 will be NZ $182 million for 28 MW net, or NZ $6,500 per kW. It is understood that the civil costs for this project will be high and the enthalpy is low, so the CAPEX will be higher than average. Ngāwhā-3 is presently under construction, with an expected COD of mid-2021;
- In its annual report, MRP/Mercury reported the cost of greenfield Ngatamariki A (82 MW net, 2013) was NZ 466 million, i.e. NZ$5,682 per kW. This project is now almost 7 years old, so some cost escalation would be necessary for reference. On the other hand, the pure binary plant configuration will have been more expensive than a combined cycle plant.
- Contact Energy reported the Te Mihi project cost at NZ $633M for 166 MW, or $3,753 per kW. However, that was for the power plant only. It was completed in 2014 and could be expected to have lower than average CAPEX due to the large size, high enthalpy, and the fact that it will have made use of some of the existing Wairakei infrastructure, probably including previously drilled wells. For that reason, it is difficult to decide what the full cost including steamfield infrastructure "should" be, but it could be expected that would add at least 20% to the power plant cost.

The above CAPEX for historic NZ geothermal projects will be subject to cost escalation, and some scaling due to size and enthalpy. The authors therefore propose to use a reference CAPEX figure of 5,500 NZD/kW for a single unit, 55 MW development, medium enthalpy. This will be scaled for the various prospects being proposed (see chapter 5), using the above-mentioned scaling factors.

3.2. Foreign/USD and local cost shares

One difference between New Zealand and international projects in terms of the breakdown into local and overseas cost components, is that drilling rigs in New Zealand are usually contracted on a NZ$ day rate basis, whereas overseas it is more likely to be in US$. Drilling costs in New Zealand are sometimes slightly lower than in some other countries because there is a mature and competitive local drilling industry and some of the resources are shallower. However, it is likely that such items as casings and well heads will be sourced internationally.

The power plant cost will have a higher overseas cost component as there are no manufacturers in New Zealand for the major plant components (turbines, generators etc.), although physical installation can be carried out by competent local sub-contractor firms and some smaller components (e.g. switchboards) and construction materials can be sourced in New Zealand. Similarly, steam field costs will require mostly overseas currency for steel pipe material, but minor fabricated components, construction materials and labour can be sourced in New Zealand.

Given that drilling costs make up typically 30% to 40% of a project in New Zealand, these factors mean that the overseas cost proportion of a New Zealand geothermal project can be expected to be rather lower than the international average in less developed countries (such as Indonesia, Kenya and the Philippines). Overall, it might be expected that at least 50% of the project capital costs will be in New Zealand currency, and this may rise on a case-by-case basis to 60% or even more.

It is likely that a much higher contribution of local currency would be found for operating costs, including major plant overhauls and make-up and replacement well drilling costs. In practice, the only overseas currency component of operating costs will be for spare parts sourced from original equipment manufacturers, and this, taken over the life of the project, may be less than 20% or even 10% of the whole life cost.

3.3. OPEX

Operation and Maintenance costs/expenditures (OPEX) for geothermal power plant, as for solar and wind, are virtually all constant per MW installed capacity, rather than being variable on a per MWh delivered energy basis (which is used by the fossil industry because of the impact of fuel cost and machine maintenance based on effective full-power hours), especially if carbon/GHG costs are excluded. There will be some variation between plants depending on technology, fluid characteristics and age of the plant, but within a limited range. Accounting practices can also make a difference depending on how OPEX is treated.

For simplicity's sake, in this report all fixed O&M costs apart from make-up drilling are clustered together and summarized in one factor, starting with Contact Energy's recent Tauhara estimate (Contact, 2018) at NZ$ 20/ MWh (ex carbon cost), which results in NZ$ 157,680 per MW per annum (90% CF).

For individual projects, variations in resource run-down rate will also play a role in terms of make-up drilling, which can also be treated as fixed O&M. The rate of decline of individual geothermal wells, and of geothermal resources as a whole, varies significantly. For the present study, the authors have used an estimate of 3% annual run down. This is at the lower end of the possible range, but consistent with the conservative approach taken to sustainability in New Zealand (though it would be too low for Ohaaki for example, and too high for Kawerau). For a 55MW project, with wells producing on average 9MW each, that would result in around one well every 5.5 years. At NZ$10M per well, that would cost NZ$1.8/annum or $33,000/MW as fixed O&M. In this analysis those costs will be evenly spread per year, though in practice especially on larger projects they would be drilled in batches every few years to save on rig mobilisation costs.

Combining the above factors, the authors therefore estimate fixed OPEX for all projects at NZ$ 190,000/MW p.a. (NZ$ 190/kW).

Note that this figure includes all O&M costs, including replacement wells. For modelling purposes this is appropriate, although from a strict accounting perspective replacement wells are normally regarded as capital asset additions rather than being expensed.

3.4. Greenhouse gas emission costs

For this study, the authors have developed a semi-quantitative approach, using four emissions categories to classify each project/field: from very low – low – medium – high (see chapter 2.3), without an attempt at calculating the specific potential cost/impact on LRMC for each project, as MBIE modelling with the produced 'future geothermal generation stack' is expected to calculate the GHG emission costs under various carbon market price scenarios, and incorporate these in LRMC-calculations accordingly. To put that in perspective though, at a "NZU" carbon price of $25 per tonne, even the highest emitting geothermal stations (Ngāwhā and Ohaaki) would incur a penalty of less than

NZ$10/MWh ($7.6 and $8.5 respectively) and most plants would be much less. At a 95 % capacity factor, Ohaaki would have an additional variable OPEX of $70,000 per MW p.a. The majority of stations, using a MW-weighted average of 75 gCO_2eq/MWh would cost $15,600 per MW p.a.

4. Other potential future developments

4.1. Potential for new technology to increase existing geothermal generation capacity

Geothermal generation is a mature technology with a history of over 100 years. The original Wairakei plant in New Zealand, which was the first large-scale plant in the world, has been operating for over 60 years. There have been some major changes over the last 25 years, especially with regard to steam turbine technology, where the "standard" large size geothermal unit has increased from 55 MW to 110 MW and larger, and now allows a higher inlet steam pressure. Drilling for geothermal wells is very much an offshoot of the oil drilling industry, so radical changes in geothermal drilling technology are not expected, although there are some areas for further research and such work is continuing in the USA. Therefore, while there is some scope for technical improvements in geothermal generation projects, it can be expected that the gains will be small and incremental. More significantly, the rate of cost reduction for geothermal generation due to technical improvements is likely to be significantly less than for solar, and to a lesser extent wind. That will disadvantage geothermal generation relative to the other newer sources as time progresses.

Geothermal generation projects in New Zealand are already efficient on a world scale (Lawless et al. 2016). There is some potential to take up existing technology which has not been widely used to date in New Zealand, but whether that happens will be driven by costs and the regulatory environment. For example, a high carbon tax would make CCS feasible, but it would also further disadvantage geothermal plants (especially those with higher emission intensities) relative to other renewables such as wind, which are free of operational GHG emissions.

Some possible changes in geothermal technology over the coming decades include:

- Greater use of digital technology to improve resource investigation, drilling, operations and maintenance. Geothermal operators are reporting small but steady improvements in this regard;
- Greater use of low-temperature binary plants. For reasons given in the next section, this is likely to be mainly restricted to retrofitting as bottoming plant utilising brine from existing condensing power schemes (with limited opportunities) rather than as stand-alone projects;
- Use of pumped wells in conjunction with binary plants on lower temperature resources (Febrianto 2017). Similarly, for economic reasons, this is likely to be restricted to un-tapped areas of already developed resources rather than moving into wholly new areas;
- Carbon capture of carbon dioxide for industrial or agricultural use. This is already being done, for example for many years at Kizildere in Turkey. For most uses it requires removal of the hydrogen sulphide content of the total non-condensable gases (NCG), which is possible but at significant cost. This may be forced on geothermal projects in the more distant future if carbon prices rise significantly. It has also been suggested that geothermal reservoirs could be used for CCS not only of their own emissions, but also of carbon dioxide emissions from other sources, possibly with (injected) carbon dioxide eventually replacing steam as the working fluid in geothermal power plants. Some theoretical modelling has been carried out on this concept showing that the thermodynamics are favourable, and some small-scale trials in Iceland, but the practical challenges are formidable, especially in terms of scaling and corrosion and guaranteeing the GHG remain underground;
- Improvements in controlling deposition of silica and other deleterious minerals in the waste stream. This is an area where there *are* new developments, with New Zealand taking a leading role. This includes the Geo40 process, which produces a commercial silica product and is being trialled in several areas including NZ and Japan[3]. Apart from extracting minerals, it

[3] https://geo40.com/projects/

creates an opportunity to extract more energy from the brine fraction of geothermal fluid by allowing for a lower reinjection temperature. It is most applicable to high temperature resources, where it could make a modest contribution to the output of new plants. It is unlikely existing plant will be re-configured and retrofitted to any significant extent. It also provides the opportunity to extract other minerals from the geothermal waste streams. For example, lithium is a valuable minor component of geothermal brine, but recovering it means either inhibiting the co-deposition of silica or removing the silica first. That could provide a valuable additional revenue streams for future geothermal projects as well as helping to meet sustainability criteria;

- Deeper drilling in known high temperature areas to tap super-critical fluid. This has been proposed in several countries including New Zealand as a means of sourcing geothermal fluids with much higher enthalpy, hence much greater well productivity, than in conventional projects. Some trials of this have been conducted in Iceland and Japan with mixed results. There are significant practical difficulties, not only with the drilling and well design but also with corrosion and mineral deposition by these fluids. Even if the practical difficulties can be solved this is considered by the present authors likely to be too expensive to be included in the Generation Stack over the time period considered;
- Creation of artificial geothermal resources by hydraulic stimulation in hot impermeable rocks at depth (Hot Dry Rock, HDR or EGS projects). This is superficially an attractive proposition, as hot rocks, especially granites, exist in many parts of the world, including New Zealand, outside of the naturally convective magmatic-related geothermal systems. Experimental schemes have been developed in several parts of the World including Europe and Australia. However, the flow rates achieved and the cost of drilling to such depths has meant that the economics of such schemes are unfavourable. It is very unlikely that such projects would become economically feasible in New Zealand within the time frame considered;
- Possible use of production from deep sedimentary systems. This is again a relatively new approach being considered in Australia and parts of Europe (especially where lower temperature fluids can be used directly for district heating) and its application to New Zealand will be limited;
- More economical methods of resource exploration, especially by the use of deep slimhole wells. This will have limited application in New Zealand, where most initial exploration drilling has already been undertaken;
- Expanded use of improved general drilling techniques, e.g. the use of aerated drilling to minimise down-hole problems, possibly the use of hammer rather than rotary drilling for certain types of formations, improved bit technology to allow holes to be drilled for longer without the need to trip-out-of-hole for bit changes. These can be expected to have some incremental cost advantages in New Zealand but a resulting radical drop in costs is not expected.

4.2. Potential for geothermal generation to be extended to areas outside the existing Rotorua-Taupō and Ngāwhā areas

High temperature geothermal resources in New Zealand are confined to the Taupō Volcanic Zone (TVZ) and a single occurrence at Ngāwhā in Northland. It is geologically improbable that any other undetected high temperature naturally convective resources exist at economically drillable depth in New Zealand. Hot dry rock projects are excluded for the reasons given under 4.1. Therefore, any expansion of geothermal generation on a significant scale outside these regions will require the use of lower temperature resources, which inevitably means binary power plants and probably the use of pumped wells, as lower temperature wells cannot self-discharge by two-phase flashing.

Geothermal power projects of this type have been successfully developed in many countries as summarised in Figure 5. They *can* be economic provided some of the following special circumstances exist:

- Relatively high power prices e.g. Germany, where prices for electricity from renewable sources can be more than 5 times the average price in New Zealand. Febrianto et al. (2017) estimated a base case LEC (Levelized electricity cost) of 9.52c US/kWh (NZc 14.6/kWh) for low enthalpy plants with pumped wells in favourable circumstances in Indonesia, considerably above the current average cost in New Zealand;
- Extensive shallow geothermal reservoirs with high pressures/water levels. This is the case in parts of the USA and Turkey;
- High permeability near-surface geological formations such as terrestrial sediments, to provide an extensive reservoir for geothermal resources to accumulate;
- Extensive high permeability deep sedimentary reservoirs that have been explored by oil wells, preferably with numerous existing but abandoned wells that can be converted.

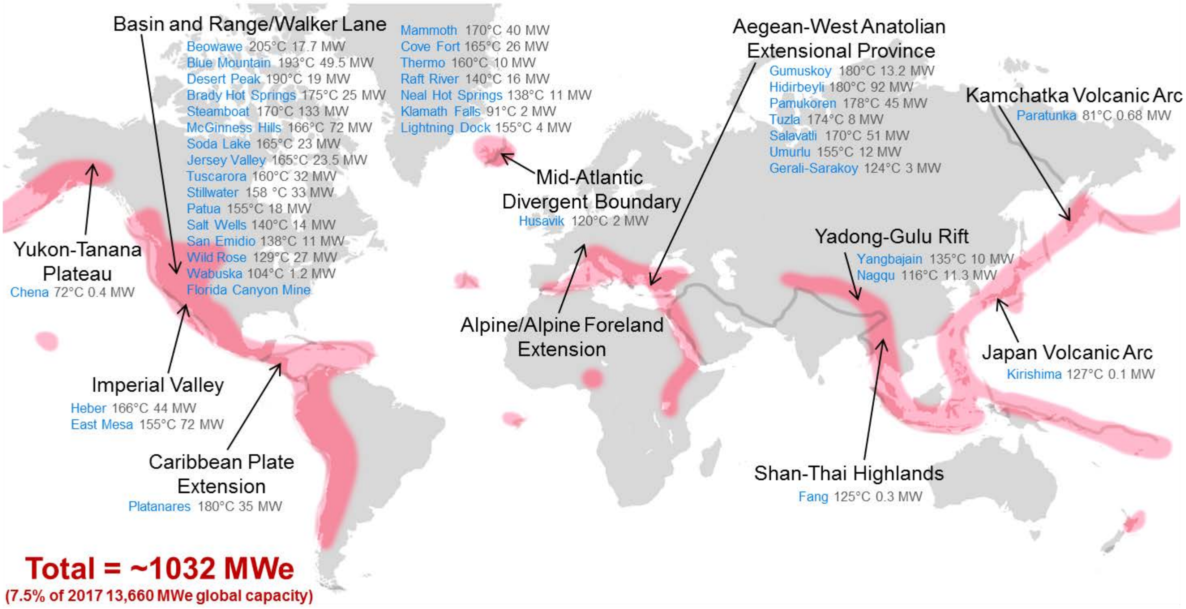

Figure 5: Regions where <210°C geothermal reservoirs have been developed for power generation. Showing average reservoir temperature and net installed capacity (source: Febrianto 2017)

In New Zealand, there are no extensive areas of high permeability near-surface sediments to provide a reservoir, except possibly the Canterbury Plains, where no significant geothermal heat has been discovered. Therefore, any geothermal resources associated with isolated tectonic hot springs are likely to be small. In the absence of such circumstances, such projects, while technically possible, will be sufficiently expensive that they are likely to be more expensive than other renewable sources especially wind and to a lesser extent solar.

There are two situations where that may not apply:

- Energy recovery from hot water produced by oil wells. There are oil wells in Taranaki which produce water hot enough to generate electricity in a binary plant, albeit at significant cost because of the modest temperature. Those opportunities are sufficiently limited and small scale at present that they can be ignored for the present purposes. Reyes (2019) has observed that there are only four abandoned oil wells with temperatures over 150 °C in Taranaki, and these are scattered rather than grouped to provide a larger project. The potential is perhaps

5 MW in total, and it is unlikely that there will be a large expansion of the oil industry in the foreseeable future;

- Water at around 200 °C in the outflow zones of some TVZ high temperature geothermal systems, such as at Mokai. That has the advantages that the permeability is high in some of the near-surface pyroclastic formations, the outflows are shallow and represent a significant volume of resource, and in most cases the extent of the resource has been well defined by geophysics and previous drilling. These also have the advantage that, unlike the separated brine steam from high-temperature projects, the silica content of the water has re-equilibrated underground and so does not pose such a risk of deposition in the surface pipework as would the use of a bottoming plant on a high temperature resource. However, given that such occurrences are all in the TVZ, they can be regarded as "second tier" additions to known high temperature projects.

It is concluded therefore that the potential for projects outside the known high temperature areas in New Zealand is very limited.

4.3. Potential for geothermal to generate in a load-following manner, to compensate for intermittency of other electricity sources

Geothermal power plants, having high CAPEX and low OPEX, are usually operated in as close to base-load operation as possible. They achieve higher capacity factors than any other type of power plant, often over 95%.

From a technical perspective, it is possible to operate geothermal power plants in a load following manner. Generally, this is achieved as the load is reduced by diverting steam to a silenced atmospheric vent (usually a rock muffler) because the original steam source (the wells) cannot respond as quickly as conventional boilers. Steam venting can easily occur as quickly as the load change on the turbine. Obviously, the vented steam represents a loss of energy and hence a potentially significant decrease in overall thermal efficiency. The loss of steam can be minimised by partial throttling of one or more production wells, but fully 'shutting in' of individual wells is highly undesirable because of the potential for thermal cycling problems. Therefore, depending on the degree of load reduction, there may still be some residual steam venting. Following a load reduction, load increase may be slightly slower if production wells have been throttled as they will take longer to re-open without causing flow instability problems in the steam supply system (wells and separators), although if the load increase is programmed (e.g. to correspond to an expected diurnal increase in the early morning) then the throttled wells can be opened in advance of requirement.

Note that steam venting in this manner may be considered environmentally or socially problematic in some areas, especially if the project is located close to a population centre. It may also in New Zealand be regarded as "unsustainable" (not efficient use) under the RMA, although the amount of steam venting may actually be very small, especially if undertaken in support of predictable diurnal load variations. For binary plants using brine, load following is more easily achieved by simply bypassing the brine flow directly to injection. As this hotter brine is then being reintroduced into the sub-surface system there should be no issues regarding unsustainability.

One example is the Tongonan I power plant in the Philippines. It had a 3 x 37.5 MW condensing steam turbine configuration. The number of units was partially because spinning reserve was required for a nearby copper smelter. When it was built it was the only power source on the island of Leyte, so it had to operate in a completely load-following manner. It was a technical success (Minson et al, 1985). However, it would be unlikely to be acceptable in New Zealand because it achieved load shedding by discharging surplus steam to the atmosphere.

Closer to home, when first built what is now the Poihipi plant operated in a load/cost-following manner. The owner, Geotherm Energy, had a daily resource consent allocation which would not support the full output for 24 hours. Rather than run the station at part load (which would have been physically and economically inefficient), the station was run at the full 55MW output during the day, when spot power prices were highest, and then reduced to about 3 MW overnight. It was not shut down completely to avoid thermal cycling. This was also technically successful. However, the station is no longer run in that way as it is now inter-connected to the Te Mihi/Wairakei steam supply system which has much larger consents.

As these examples show, it is quite possible to run a geothermal power plant at variable load. It is however very economically unattractive (except in the special case where it is consent limited and cost following), since the economics of geothermal power project are designed around continuous operation. In effect the last few percent of operation represent the profit margin.

In general, the efficiency of geothermal plants drops off at part load, as with any thermal plant, so there is an incentive to maximise their output given that the limiting factor is usually consented fluid take, not MW. On a small scale, in recent years there has been a move to adapt resource consent wording to average fluid take over longer than a daily period to allow for some make-up of outages.

Summarizing the above, the authors see little potential for geothermal power plants in New Zealand, which will be mainly located near the central part of the grid system, to firm up the intermittency of other power plants and load to any large degree by being load-following. However, if the use of solar and wind power increases there may be an increased demand for the geothermal plants to be able to respond to those plants' very variable inputs to the grid. That is feasible. On the basis of scenarios presented in the report, if all of the new geothermal generation postulated here was in fact developed over the next 40 years, it would be more than sufficient to provide baseload to replace all remaining thermal plant, because of the high capacity factors of the geothermal plant. In 2018 existing geothermal plant produced 7,510 GWh of generation, and all thermal stations 6,895 GWh. This report suggests slightly more than a doubling of New Zealand's installed geothermal capacity by 206 (Section 5), so the figures match quite closely.

4.4. Extent to which non-electric uses of geothermal energy will compete with, or complement generation

In most cases geothermal direct use will be complementary to electricity generation and can provide a valuable additional revenue stream. Many direct uses require only lower temperature heat than is suitable for regular condensing steam geothermal turbines, so cascaded uses are common, as in the case of the Prawn Farm at Wairakei, which heats river water to around 25-30°C using geothermal brine from the Wairakei power plant discharges.

Generally speaking, large geothermal power schemes produce a vast surplus of low-grade heat which can be readily utilised provided silica deposition issues can be overcome. In some cases, it may be possible to make use of individual high temperature wells which are either marginal for production for power generation or in an inconvenient location to connect. Although from a technical perspective direct use of geothermal heat may be more efficient than conversion to electricity, the economic value of electricity is generally greater than that of the equivalent amount of heat. One of the biggest hurdles to overcome is obtaining a load of sufficient size to justify well drilling. As a stand-alone proposition there are very few industrial operations with enough scale to make it worthwhile, which is why these operations stand alongside electricity generation. Furthermore, in many cases the availability or cost of transport of raw materials to the geothermal site makes stand-alone direct use less attractive than generation.

There are some exceptions to these generalisations, as follows:

- The very large dedicated industrial site at Kawerau uses a portion of the high-temperature resource for industrial direct heat use and will undoubtedly continue to do so;
- It is possible that re-powering the existing dairy factory at Reporoa which uses natural gas may take precedence over generation, though a complementary scheme is more likely;
- In some cases, such as Rotorua, preservation of the thermal activity for tourism logically takes precedence over power generation. This can also be considered a non-extractive "use".

5. Review of individual prospects

Because of the importance of regulatory issues, the prospects and projects are presented in this chapter organised by region. Minor hot spring occurrences that are unlikely to lead to economic projects are not included. Prospects that are currently protected from development are included, but covered only briefly to identify key issues and give an approximate estimate of potential resource capacity.

As well as estimates of the capacity of individual resources, as cited with each prospect below, there have been several studies intended to assess all of New Zealand's geothermal resources on a consistent basis. These include:

- A paper by Lawless and Lovelock (2002), which underwent several revisions, the most recent being Lawless (2005). This used a simplistic but consistent volumetric stored heat method to estimate the potential generation capacity for all of New Zealand's high temperature geothermal resources. Although the individual resource estimates which make it up should, and in some cases have been updated, it remains a useful assessment of what proportion of our total geothermal resource capacity is available and what proportion is protected from development. In some cases, it still has the best estimates available, and in a common framework. It is probably the source of the oft-quoted figure that our total capacity is 3,600MW, but it is often overlooked that Lawless's (2005) estimates were based on total resource depletion over 50 years, because of perceived conservatism over sustainability. On the one hand, that period may be too short given the tenor of recent resource consent litigation, but on the other it would be more usual in the international industry to use a figure of 30 years, which would increase the 3600 MW to 6000MW. The SKM/WRC (2002) report produced separate estimates for 30, 100, 200 and 300 years so the results can only be compared by scaling accordingly. It also is often overlooked that Lawless's (2005) paper included a large proportion of protected fields. Given that 1,000MW has already been developed, the true remaining available quantity is undoubtedly much less than 2,600 MW.
- A comprehensive assessment by SKM/WRC (2002) of all of the geothermal resources in the Waikato region using a similar methodology to that of Lawless (2005). This study produced a range of probabilistic results (P10, P50 and P90) as well as a range of depletion timeframes (including recharge) for 30, 100, 200 and 300 years. For the area it covers, and where no more specific information is available, this is still regarded as the best available estimate for the present study.

In general, it is important to distinguish between total resource capacity and project capacity. The above estimates referred to total resource capacity, that is to say what could be expected to be economically extracted while running the resource to depletion, albeit over a longer time scale than resource consents will be available for. In the scenarios presented below, what is estimated is what a prudent developer might be prepared to undertake within the next 40 years, having regard to resource uncertainty and the requirement for sustainable management under the RMA, which will generally require some of the resource to remain un-depleted. Thus, the projects included in the 'future geothermal generation stack' here are generally less than the ultimate resource capacity.

Decommissioning

Decommission of existing projects could occur for one of three reasons:

1. Resource depletion. The only project where this applies to a significant degree is Ohaaki, which has already been de-rated from 108 MW to 57 MW and is currently producing about 40 MW. Even in that case it is not expected that there will be further retirement of plant. This is discussed in more detail below.

2. Mechanical degradation of plant. The only plant where this is expected to be a major issue over the next few decades is Wairakei, which has already been operating for over 65 years. It cannot operate much longer in its present form, both for that reason and because it does not meet modern environmental expectations. It is not yet clear what will happen at Wairakei: it may be overhauled, re-configured or retired, but as discussed below in either event any decrease in output will be made up from Te Mihi.
3. Failure to obtain new resource consents. As the longest period resource consents can be issued for is 35 years, all plants will require reconsenting within the 40-year horizon. For reasons discussed above, it should not be assumed that new consents will automatically be granted for the same quantities nor under the same conditions. The possible implications of this are discussed in Section 5.4 below.

In summary therefore, no significant net reduction in existing capacity due to decommissioning should occur within the next 40 years for resource or operational reasons. Some reduction is possible if the consenting regime is applied more rigorously.

5.1. Northland

Ngāwhā

Ngāwhā is the only high temperature prospect in the Northland region, and the only one known outside the TVZ. It is located near Kaikohe. The geology differs from that in the TVZ, with the geothermal resource being wholly hosted in Mesozoic greywackes, capped by impermeable Tertiary sediments. That means that while the resource volume is large, storage capacity for fluids is small and disturbances in reservoir pressures propagate rapidly through the reservoir. Careful management of the resource is required.

A number of wells were drilled using central government funding in the late 1970s to early 1980s. The project was later taken up by Top Energy and local and regional Maori interests to form a company now called Ngāwhā Generation Limited. The field was developed in several stages, with initially a 10 MW power plant (1998), another 15 MW in 2008. At present a further expansion is underway. In 2017 resource consent was granted to expand the project with another ~50 MW, the first stage of which (~28 MW) is presently under construction, with an expected COD of mid-2021. The second stage is expected to follow after lengthy observation of the impacts of the previous phase, indicated for 2026 at the earliest: a minimum gap of 3 years is required by the new consents (Consent Decision Report, 2015). All developments are pure binary plants because of the lower reservoir temperatures than typical in the TVZ.

Part of the reason for the slow staged development has been the conservative resource consent conditions. Certain small hot springs at Ngāwhā are regarded as being highly culturally significant. As these are of low flow rates, they are potentially very sensitive to changes in reservoir pressure. Hence development can only proceed on the condition, accepted by the developers, that reservoir pressures must remain fixed within a narrow band. That has led to the unusual situation where over 100% reinjection is practiced by using meteoric water to make up any loss of mass due to gas emissions, and to compensate for thermal effects on pressures. So far this strategy appears to have been successful.

Another unusual feature of the Ngāwhā project is the large NCG quantity emitted per MW: 304 g CO_2eq/kWh in 2018 (McLean and Richardson 2019). This is partially due to a moderately high gas content in the deep fluid, but has more to do with the fact that the productive reservoir has a temperature of only about 220°C, less than any other geothermal power scheme in New Zealand (not including bottoming binary plants, which run on separated (de-gassed) brine and so have very low emissions). This means that considerably more fluid is required for each MW generated, and hence more GHGs per MWh emitted.

There are however some reasons to suppose that future expansion of the drilled area could produce less NCG per MWh, namely:

- The gas content in the reservoir has been depleting with time. Emissions per kWh have declined by 18% in the past 8 years, gas content of the three main production wells has fallen to almost half its original value according to Bromley et al. (2014);
- While the currently productive part of the reservoir is at a temperature of 200 -230°C, this is because good permeability is so far localised in a shallow zone at the top of the greywacke, where gas has accumulated. An earlier deep well reached a temperature of 300°C but failed to encounter significant permeability. If during future drilling, a hot and permeable zone is located (and there are some geological reasons to suppose that such might exist), then a future scheme could have significantly less NCG/MWh.

The strategic location of Ngāwhā, north of the transmission bottleneck at Auckland and being the furthest north power plant in the country, means that from a grid perspective there will be a strong incentive to further increase production there, even if the project suffers economically from high GHG emissions.

There appears little doubt that the resource capacity is potentially large. Lawless (2005) gave an optimistic estimate of 120 MW over 50 years and there is reason to believe even that figure may be conservative. Burnell and Weir (2014) presented numerical reservoir modelling demonstrating that the current management regime could sustain production to 2050 at 75 MW capacity, with insignificant change in reservoir pressure and only a small decline in enthalpy. However, it is probable that further development will proceed cautiously by stages with the effects of each expansion considered before further consents are granted.

Accordingly, three future projects each of 25 MW capacity are projected (on top of the Ngāwhā-3 expansion presently under construction) at long intervals in 2031, 2041 and 2051 to take the total capacity to 125 MW. Higher than average CAPEX costs should be anticipated, because of the small size of the project stages, the low resource quality (temperature and gas content) and the need for supplementary injection. Some upside is however possible.

5.2. Waikato Region

Atiamuri

The Atiamuri system is classified for limited development. It is located between Atiamuri and Mangakino. Some geoscientific surveys have been carried out and one shallow well drilled to 600m (Risk, 2000a). The gas content is unknown, but as silica sinters have been deposited rather than carbonate travertine (which would imply a high bicarbonate content) it may not be extremely high. The resource does not appear large and may be of relatively low temperature compared to others in the TVZ. SKM/WRC (2002) gave a median estimate of 6 MW over a 30-year project life. As far as is known no developer has expressed an interest in applying for resource consents to develop Atiamuri.

Because of the probable small size, limited development classification and possible low temperature, it is assumed that no more than 5 MW would be developed, not before 2040. The small size of the project and possible lower enthalpy will increase the CAPEX.

The gas content at Atiamuri is unknown, but because of the possible lower temperatures may be higher per MWh than the average for the TVZ. It is assumed to be "medium" according to the classification adopted in this study.

Horohoro

The Horohoro system is classified for development. It is situated near the north-eastern boundary of the Waikato region, close to the road from Atiamuri to Rotorua. Some geoscientific surveys have been carried out and several shallow wells drilled to a maximum of 593m (Risk 2000b).

Despite a promising geophysical anomaly and signs of past activity, drilling encountered only modest temperature (80 °C) and it appears the system is waning. SKM/WRC (2002) gave the median capacity as 5 MW over a 30-year project life.

Because of the probable small size and possible low temperature, it is assumed that no more than 5 MW would be developed, not before 2040, and at relatively high cost.

The gas content at Horohoro is unknown, but because of the possible lower temperatures may be higher per MWh than the average for the TVZ. Emission intensity is therefore assumed to be "medium".

Ketetahi/Tongariro

A geothermal system which is at least in part steam-dominated exists under Mt. Tongariro with its surface expression at Ketetahi Springs. The resource is undoubtedly large. SKM/WRC (2002) gave a median estimate of 100 MW based on a 30-year project life. This prospect is totally enclosed by a National Park and it has protected status by Waikato Regional Council. Also, recent eruptions from Te Maire Craters on Tongariro have demonstrated significant volcanic risk. Ketetahi/Tongariro is therefore not considered further in this study for potential geothermal generation.

Lake Taupō/Horomatangi

A geothermal system exists under Lake Taupō. SKM/WRC (2002) estimated this at 380 MW over a 30-year project life. The system is classified as protected. The environmental effects of disturbing the system are unpredictable and possibly severe. Development is not practical and hence this prospect is not considered further.

Mangakino

The Magakino system is classified for development. It is located between Atiamuri and Mangakino on the north bank of the Waikato river, and lies north-west of Mokai.

Mercury Energy previously held resource consents for drilling, and drilled 4 deep wells covering the central part of the supposed resource, supplementing an earlier shallow well (607 m with a maximum temperature of 185 °C) drilled to the west during government-funded exploration. Comprehensive geoscientific studies have been carried out, though not all of that information, nor all of the results of deep drilling have been made public.

SKM/WRC (2002) estimated the median capacity as 47 MW over 30-year project life. That estimate was done before the detailed exploration by Mercury Energy, being based only on the results of the original shallow well in the west. Although no details are available it would be reasonable to assume from the level of commitment and the area drilled that Mercury Energy were hoping for a larger resource than that. However, in the event, deep drilling was largely unsuccessful in terms of locating a large, hot and permeable resource. Post-drilling, Rustandi et al. (2016) estimated the generation capacity to be between 10 and 26 MW, provided adequate permeability could be located.

It is clear that at least some hot resource exists based on the original shallow well and chemical geothermometry, but it may not be very large. Further scientific work would be required to better understand the geothermal system, though that is complicated by the fact that the original thermal features and part of the resource area have now been flooded by hydro development. It is assumed therefore that a 25 MW project is possible, but not before 2030 and because of the scale, at higher than average cost.

The gas content at Mangakino is unknown but is probably low.

Mokai

The Mokai system is classified for development. It is located north-west of Taupō, to the south of the Waikato river downstream of Atiamuri. Extensive scientific surveys have been carried out and a number of deep wells drilled during the government exploration phase. These were then taken over by the Tuaropaki Power Company, of which the local land-owning Tuaropaki Trust remains the major shareholder, and further drilling was undertaken.

A combined cycle steam turbine/binary plant was installed in three stages with a total capacity now of 112 MW. Two significant direct use projects have also been installed: a large area of geothermally-heated greenhouses, and a milk-processing plant.

SKM/WRC estimated the median resource capacity as 140 MW. The plant has been maintaining close to full output. The main resource fluid take consent expires in 2024. A small expansion was applied for in 2016, to maintain production from the existing plant. It is therefore considered unlikely that further expansion of that plant would be undertaken.

Furthermore, Tuaropaki previously stated (Brian Jones, pers. comm. 2007) that a factor in deciding to install the direct use projects was the greater opportunities these gave for providing employment. It therefore seems probable that further direct use projects and/or expansion of the existing ones may occur in preference to greater power generation at the Mokai plant.

However, there may be a significant un-tapped resource contained in the outflow zone of the Mokai field, which still lies within the same land ownership. The 'Mokai outflow' resource would be at lower temperatures than the upflow zone, but could be tapped with shallower wells and without having much impact on the current production zone (though reinjection may have to be shifted). It is therefore considered possible that an additional 25 MW of binary plant could be installed there, possibly in association with future direct use projects. This is unlikely to occur before 2030.

The GHG emissions intensity from such a plant may be lower than for most geothermal projects in New Zealand, as the outflow would have been de-gassed already. Because of the lower enthalpy in that zone and the small scale, the CAPEX would be higher than average.

Ngatamariki

The Ngatamariki system is classified for development. It is located north of Taupō, north of Rotokawa and south of Orakei Korako. Extensive scientific surveys have been carried out and 4 deep wells were drilled during the government exploration phase. These were then taken over by Mercury Energy and further drilling undertaken.

As discussed in section 2.2, the plant selection was in part dictated by concerns over maintaining reservoir pressures to avoid any effects on the adjacent Orakei Korako field. However, there is no direct evidence that any connection exists, nor to the Rotokawa field to the south. Cold water incursion from above was also a concern. Hence, despite the high field enthalpy, an 82 MW binary plant was built and commissioned in 2013 (Legmann, 2015). The main consents expire in 2045.

SKM/WRC (2002) gave the median resource capacity as 120 MW over a 30-year project life. More recent estimates based on numerical simulation modelling indicated a median value of 83 MW (Quinao and Zarrouk, 2015). Modelling demonstrated that the existing project can continue to perform for 50 years with relatively little change in well performance and total production. Under operation, production has been lost due to unanticipated calcite deposition (Quinao et al, 2017) which is now being managed. Pressure change has been relatively small.

It seems probable that further development of the Ngatamariki field could occur, but in view of the perceived sensitivity of the area it would be difficult to obtain further consents until a significant period of operation and observation has occurred. It is also likely that any future power plant would have to have the same configuration as the present one. Therefore, it is assumed that a further 50 MW binary plant could be installed, but not before 2030 and with above average CAPEX.

The gas content at Ngatamariki is low. Future developments can be assumed to have similar emissions.

Ohaaki

The Ohaaki system is classified for development and the Ohaaki development is one of the oldest in New Zealand. Government-led exploration started in the 1960s, but it was deemed small and problematic to develop, until the oil crisis and Brundtland report of the 1970s spurred the government to re-ignite developing indigenous, non-hydro and non-fossil power plants.

The power plant was consented (water rights granted) for 20-year production in 1978 at 80-90 MWe for phase-1 (a second phase up to 150 MWe had been listed as an option after several years of operation). During detailed design, two additional high-pressure turbines (ex-Wairakei) were added to the design to make use of the excess steam expected in the first 10 years of operation, bringing net capacity to 108 MWe. The plant was finally commissioned in 1989, by which time 49 wells had been drilled. During exploration and extensive well testing, significant pressure drops had been foreseen, and as many as three new wells per annum were planned to maintain steam pressure. The plant ran at full capacity until 1993, but very few new wells were drilled as market circumstances had changed significantly. The power station was re-consented for lower production levels in 1998 (15 years) and again in 2013 (for 35 years; consents expire in 2048).

Ohaaki has high temperature areas, but suffers from zones of limited permeability (in deeper areas) and cold-water inflows into some of the intermediate production zones. Given the long and not totally successful operational history, stored heat estimates such as have been carried out at other fields are less relevant than the actual reservoir responses. GHG emissions are high. The fluids are high in silica, creating scaling issues and relatively high operational costs.

The 2013 resource consent allows Ohaaki production at 40,000 tonnes per day (tpd), which could produce around 55 MWe using one HP and one IP turbine. During the consenting process, specific mention was made of the option to convert one of the IP-turbines to low pressure, to potentially generate an additional 20 MWe from the same fluid take, depending on market circumstances and solution of technical issues, especially silica deposition. In the present market circumstances Ohaaki runs at 40-45 MWe-net and Contact has indicated in their System Management Plans they expect to maintain this in the coming 5 years. This would notionally leave around 25-30 MWe of additional generation available within the same consent, on medium investment.

In the meantime, after extensive pilot testing, GEO-40 has constructed a commercial silica-removal plant on the Ohaaki field. This both resolves the silica issue, and produces sellable silica. The next step is to remove lithium for sale as well. Future plans might include upscaling volumes.

The costs and gas emissions for any future development would depend very much on the configuration. If it was done by converting one of the turbines to lower pressure operation, that would be at lower than typical cost as far as the power plant is concerned (since much of it already exists), but significant additional drilling would be required, perhaps at lower than a typical success ratio based on results to date, and the silica removal system (which is also energy intensive) would add cost. If it was done by retrofitting bottoming binary plant, the CAPEX would be higher per MW but the drilling cost would be less, as would the gas emission per MW as it would be utilising already de-gassed brine.

For the present study, after discussion with Contact Energy, it is assumed that no additional output will be produced at Ohaaki above present output within the time period considered. If some additional generation did take place, that would come within the original total installed capacity so presumably would have no impact on the transmission connection, which must be over-sized for the current operation.

Orakei Korako

The Orakei Korako system is classified as protected and is a significant tourist destination. It is located to the north-west of Ohaaki, straddling the Waikato river. Detailed surface surveys were carried out there before part of the field was flooded by hydro development. Four wells were drilled to over 1000m during previous government-funded exploration, encountering temperatures over 200 °C (Risk 2000b).

Orakei Korako is close to the Ngatamariki field. There is no evidence that these fields are connected, and the scientific data suggests they are not (Risk 2000b), but concern that the development of Ngatamariki could possibly affect Orakei Korako has led to stringent monitoring conditions at Ngatamariki, including shallow monitoring wells between the two fields, and choice of a binary plant at Ngatamariki to conserve fluid for reinjection.

The median capacity of the Orakei Korako field was estimated by SKM/WRC (2002) as 110 MW over a 30-year project life. There is no doubt it is one of the larger un-tapped fields in the region, but because of the protected status, no generation is anticipated there within the 40-year horizon.

Reporoa

The Reporoa system is classified as a ‘Research system’. It is located to the south west of the larger Waiotapu field and south of the Waikite field. Scientific investigations have been carried out and one well was drilled to about 1300 m during government exploration, which encountered moderate temperatures around 225 °C (Risk, 2000b).

Reporoa was estimated by SKM/WRC (2002) to have a median capacity of 42 MW over a 30-year project life. They commented that the area for the estimate was downgraded on the basis that the system may be waning and the low-resistivity zone represents an older, larger system (Bibby et al., 1994). If that is not the case, the resource would be larger. Lawless (2005) estimated a median capacity of 42 MW over a 50-year project life.

There is a large dairy factory at Reporoa currently fuelled by natural gas. So it is possible some direct use of geothermal energy could take place there rather than electricity generation. It is more likely, though, that cascaded dual use would be favoured.

The principal reason Reporoa has been classed as a "research" system is that there are concerns over a possible hydrological connection to the protected Waiotapu geothermal system to the north east, or even the further outlying Waimangu and Waikite systems. A connection between Waimangu and Waiotapu appears unlikely. The Waimangu system underwent major changes following the 1886 Tarawera eruption, without that affecting Waiotapu, so a connection even further to the south to Reporoa seems very unlikely. The concept of a connection between Reporoa and Waiotapu and Waikite was based mainly on earlier Schlumberger DC resistivity surveys, which have been superseded by later MT methods, and no longer seems very likely.

Recent numerical simulation modelling by Pauline and Kaya (2019) demonstrated that a 25 MW development at Reporoa should be possible without affecting Waiotapu, provided the reinjection was appropriately sited. Nevertheless, any development at Reporoa will require a cautious approach and adjustment of the current classification, based on new data and the on-going operational history. Accordingly, it is expected that an initial 25 MW development could occur, but not before 2030, with subsequent 25 MW stages in 2040 and 2050. The scale of the project and possibly only moderate temperatures mean that it will be of above average cost.

The NCG content appears to be medium, based on well chemistry reported by Bignall (1990).

Rotokawa

The Rotokawa system is classified for development. Despite close proximity to the Tauhara field there does not appear to be a hydrological connection. Extensive scientific surveys have been carried out and a number of deep wells drilled during the government exploration phase. These were then taken over by a joint venture between what is now Mercury Energy and the local landowning trust, the Tauhara North No. 2 Trust, and further drilling undertaken.

Development took place in two stages. The first stage was a combined cycle back pressure steam turbine and binary plant, very similar to that at Mokai, and commissioned in the same year (1997), but of smaller capacity. It was expanded in 2003 and now has a capacity of 35 MW. The second stage, called Nga Awa Purua, was the 2010 commissioning of a triple-flash condensing steam plant of 140 MW. Consents for the Rotokawa Nga Awa Purua plants expire in 2053.

The capacity of the Rotokawa field is large. It was estimated as 300 MW by SKM/WRC (2002) over a 30-year project life. The response to production is however now more informative. The field has shown a response to the current level of production in terms of enthalpy and pressure declines, (Clearwater 2015), but recent numerical modelling indicates 50+ years of production can be sustained by appropriate management (Hernandez 2015).

Further development of the Rotokawa field seems possible, but the size and nature of the plant is not clear. Previous development was on the south side of the Waikato river, but the field extends to the north of the river and has been confirmed by two early exploratory wells, albeit possibly at somewhat lower temperature. Under the newest consent (20/6/2018), an increased amount of fluid can be taken from the south as well as the north western side of the river. The consents expire in 2053.

It is therefore expected that there could be a further 100 MW expansion at Rotokawa, but in two 50 MW stages, with the first not before 2030 and the second 10 years after that. CAPEX would be average as the field has high temperatures.

The GHG emissions at Rotokawa were originally in the medium category, but McLean and Richardson (2019) pointed out that they have declined substantially with production. Future developments can be assumed to have low emissions.

Tauhara & Wairakei

The Tauhara field is classified for development, jointly with Wairakei. Tauhara and Wairakei need to be considered together. They are adjacent fields each side of the Waikato river, with Tauhara in part underlying Taupō township. They occupy separate areas, have separate hot upflows, power plants and resource consents, but are hydrologically linked. More than 40 years of operation at Wairakei without reinjection caused a large pressure decline at Tauhara, leading to significant environmental effects in both areas including loss of thermal features, changes in thermal activity, hydrothermal eruptions and subsidence. As production at Wairakei without full reinjection continues, albeit a much smaller proportion than in the past, the cumulative effects on Tauhara still need to be considered and will be an issue in any new consents. Cumulative effects of discharge to the Waikato river will also need to be taken into account in the future.

There are several power plants and direct use projects on the Wairakei field:

- Wairakei (A and B stations) was the first grid-connected geothermal power plant in New Zealand, in 1958. Its output peaked at 192 MW. The configuration is complex, with many small condensing and back pressure steam turbines. Contact Energy commented that: "Wairakei output is primarily constrained by resource consent limits. Permitted mass take is 245,000t/d and the resource is quite capable of supplying this. Fluid utilisation within the permitted take is prioritised to Te Mihi and Poihipi, as they are the most efficient and have lower environmental impact. Wairakei utilises the balance and ramps up during outrages on other plants. It is unusual for Wairakei to be loaded over 120MW these days and often operates at 80-90MW."
- A series of bottoming binary plants (19 MW total) operating on some of the separated brine were added near to the Wairakei power plant site in 1996 and 2005. Their production falls under the Wairakei A&B consents;
- The Poihipi 55 MW condensing steam turbine plant lies to the west, also tapping the Wairakei resource. It was originally built by Geotherm Energy Ltd. but was later taken over by Contact Energy and is run jointly with the other Wairakei power plants, with an interconnected steam supply system;
- The Te Mihi station is a modern double flash condensing steam plant of 166 MW capacity with two units, commissioned in 2014. It is in the northern part of the Wairakei field.

The main fluid take consents for all the above stations on the Wairakei field expire in 2026.

At Tauhara, Contact Energy received consent for up to 250 MWe of geothermal generation (plus direct, cascade use) in 2010, but due to subdued electricity demand growth the main plant has not been built yet. The consents expire in 2045. At present Tauhara supports:

- The Te Huka plant is a binary power plant of 24 MW capacity. It was commissioned in 2010; The direct use system supplying Tenon and Natures Flame is a separate stand-alone system, not interconnected to Te Huka. The systems are physically close together and may be connected at some time in the future. Consents for both come under the main Tauhara consents and expire in 2048.

- A number of deep wells have been drilled, and the lapse period for Contact's Tauhara-2 plant has been extended to 2025. Contact has indicated work on the plant is restarting, with the plant likely to be built in 2 stages in the norther part of the Tauhara area. It seems that the only thing holding up construction of that plant is Contact Energy waiting until they are sure it is economically justified, given the current low growth in national power demand and the uncertainties over the future of the Tiwai Point/ Manapouri scheme.

Additionally, there are a large number (several hundred) shallow wells which are used for domestic purposes or small-scale industrial use. These tap a shallow part of the resource, so do not directly compete with the larger power schemes, but the potential for the power schemes to affect the shallow wells may affect the social licence for future expansion, along with other environmental effects. These include a recent acceleration in subsidence rates, leading to some damage[4], in the Crown Rd area, which will inevitably raise public awareness of possible effects.

There is no doubt the Wairakei and Tauhara fields have a large physical capacity. SKM/WRC (2002) estimated the median capacities of Wairakei and Tauhara respectively as 510 and 320 MW over a 30-year project life. Those figures are interesting for comparison with the other fields in the region, but they are not very relevant to predicting future production because:

- A large amount of energy has already been extracted (not considered by SKM/WRC, 2002), including a large sub-surface transfer from Tauhara to Wairakei. There has also been a significant amount of recharge from depth.
- The physical capacity of the fields is not the main driver of what future development is likely to be possible. It has far more to do with environmental effects and consenting.
- More sophisticated methods are now available using actual production and monitoring data and numerical reservoir modelling. For example, the most recent modelling reported (Contact Energy 2019) drew the following conclusions:
    - The target total mass flow of 245,000 tonnes per day at Wairakei is maintained until almost 2050.
    - The total steam flow for Tauhara II is maintained at the target of 47,300 tonnes per day up to 2036 and then fell slowly to 40,000 tonnes per day by 2060. This showed a revision is required to the allocation of production to areas of the model to meet the target as opposed to an indication that the field overall cannot sustain the target.
    - The model is able to accept all the injected/reinjected condensate and separated geothermal water at Wairakei.

Contact Energy have presented a number of scenarios for how Wairakei-Tauhara may be developed in the future (Contact, 2018). For the present study, it is assumed that:

- The 250 MW Tauhara plant goes ahead by 2025. It will probably in practice be installed in multiple stages. Here it is assumed that it will be a single plant with identical two units installed sequentially;
- Reconsenting of the Wairakei plant as it currently stands in 2026 should not be taken as given. There are features of the Wairakei plant which would be environmentally unacceptable in a new plant/consent. Re-configuring it to meet modern expectations would be expensive;
- If the Wairakei A and B stations were to close, there would be a surplus of steam available which could not be fully accommodated by the existing Poihipi and Te Mihi plants;
- Therefore, it is assumed that there will be no net loss or gain of capacity at the Wairakei field, whether that is achieved by fully reconsenting Wairakei A and B stations, re-configuring them with a smaller output and/or adding a third unit at Te Mihi;

Further generation is possible at Tauhara, but it is unlikely to be consented until some years of experience are gained in operating the new 250 MW plant and observing any effects. It has been somewhat arbitrarily assumed that an additional 30 MW may be possible in 2035.

[4] Though so far only to property owned by Contact Energy, or for which repairs have been paid for by Contact Energy

The gas content at Wairakei varies from plant to plant as they have different configurations and tap different resource sectors. The emissions at the original A and B stations (and the binary) are very low in part because the field has become de-gassed by many years of operation, and because they tap a de-gassed outflow zone. They are slightly higher at Te Mihi/Poihipi as they draw on the reservoir closer to the upflow. It can be expected that the new Tauhara plant will have emissions similar to the Te Mihi plant. All are low using the present classification.

Te Kopia

The system is classified as protected. It is adjacent to the Orakei Korako field, to the northeast, but appears to be separate. There have been extensive scientific surveys and two deep drillholes to around 1000 m with a maximum temperature of 240 °C (Risk 2000b).

The median capacity of the Te Kopia field was estimated by SKM/WRC (2002) as 96 MW over a 30-year project life.

Because of the protected status, no generation there is anticipated within the 40-year horizon.

Tokaanu (+ Hipaua-Waihi)

The system is classified for limited development. It is located at the south end of Lake Taupō. The geology of this field is somewhat different from most in the TVZ, being associated with an elevated andesitic stratovolcano. That means that it is more likely to have an extensive outflow zone than most.

There have been extensive scientific surveys, though not all of the data have been made public. No wells have been drilled apart from some very shallow ones for early exploration and to supply the thermal pools at Tokaanu, which are clearly on an outflow zone.

SKM/WRC (2002) estimated the median capacity as 200 MW over 30 years. This is probably the largest untapped and not fully protected field in the region. It is understood that developers have previously been in discussions with the major landowner for some years though no announcements have been made as to an agreement being reached.

It is conjectured that a large development here is possible, but it would be a protracted process whereby wells would have to be drilled at risk, within the context of the current limited development status, then an application made to change the status to allow greater development on the basis of the results. That is to say, to confirm the nature of the larger resource, the developer would have to drill more wells than would be economically justified by the limited development currently permitted. Consenting may not be straightforward because of existing direct use, land stability issues (there were two historical destructive landslides from the thermal ground, one of which caused multiple fatalities) and proximity to Lake Taupō which could lead to flooding if subsidence occurred.

Accordingly, it is suggested that a 20 MW project may be possible by 2030, followed by a 100 MW development 10 years later. Development beyond that may be possible but at the present it is too uncertain to include. There is evidence for high temperatures so CAPEX will be average.

The gas content at Tokaanu is probably medium based on data from Severne (1999).

Waimangu, Waiotapu and Waikite

These three systems are lumped together by Waikato Regional Council, and are classified as protected, but it is likely that they are all separate systems, and a large part of Waimangu lies within the Bay of Plenty region (with an agreement for joint management and an alignment in protected status). Seven wells were drilled at Waiotapu as part of earlier government exploration, encountering high temperatures (295 °C) but limited permeability.

SKM/WRC (2002) gave the median capacity of Waimangu as 280 MW over a 30-year project life and Waikite - Waiotapu as 340 MW. There is no doubt they are of large capacity. Waiotapu has the largest surface heat flow of any geothermal field in the TVZ.

Because of the protected status, no development is anticipated at these fields. However, because of the reputed possible connection between Waiotapu and Reporoa, more scientific work at Waiotapu would possibly be needed before the status of Reporoa as a "research" system could be changed.

5.3. Bay of Plenty Region

Kawerau

Kawerau is the furthest north-east of the high temperature geothermal systems on-shore within the TVZ[5]. It is classified as for development.

Kawerau was extensively drilled in the late 1950s and was the first large geothermal project commissioned in New Zealand as it started supplying steam to the local pulp and paper mills in 1957. For many years the focus was on industrial use of the steam. Although about 10 MW of electricity was internally generated (and still is, at around 8MWe) within the industrial complex, that was not connected to the national grid. Total steam taken was equivalent to about 40 MW electrical capacity. Ngāti Tūwharetoa Geothermal Assets Limited (NTGA) is a 100 % wholly owned subsidiary of Ngāti Tūwharetoa Settlement Trust (NTST). At the time of its formation (2005), NTGA purchased the Crown assets including take, injection and monitoring wells, supporting infrastructure and the historical supply contracts and consents relating to the Kawerau Geothermal System (Kawerau SMP, 2018). Industrial use remains a major emphasis at Kawerau with currently 6 principal industrial users.

In the 2000s, attention was focussed on the potential for more electricity generation. Mighty River Power (now Mercury) carried out drilling, including in the eastern part of the resource, which lies under land owned by the Putauaki Trust and which had not been previously drilled. That led to Mercury commissioning a 100 MW condensing steam power plant in 2008 (in 2017 rerated to 117 MW).

Further small power plants in various ownership were added. Some of those were bottoming binary plants (so are dependent on the fluid provided by the upstream schemes). The latest project has been the 25 MW Te Ahi o Maui binary high-enthalpy plant which is a partnership between the Kawerau A8D Ahu Whenua Trust and Eastland Generation.

The main consents and expiry dates are as follows:

[5] Geothermal systems occur on White and Whale Islands, which are geologically part of the TVZ, but these are fully protected and not considered further.

Consent holder	Consent no.	Date excised	Expiry date	Purpose	Maximum take volume (t/day)	Maximum discharge volume (t/day)
Mercury/KGL	63295	29 Sept 2006	30 Nov 2040	Take and discharge	45,000[1]	45,000[1]
	67335	30 Nov 2040	30 Nov 2040	Take and discharge	20,000	20,000
NTGA	24598	2 May 2006	30 Sept 2030	Take and discharge	44,400[2]	24,000[3]
	67151	1 June 2016	31 Dec 2050	Discharge (to Tarawera River)	-	20,880
	66862	17 Feb 2014	35 yrs post commencement	Take and discharge	45,000	45,000
GDL	67161	24 Jan 2014	35 yrs post commencement	Take and discharge	5,280[4]	5,280
TAOM	67340	12 Sept 2016	35 yrs post commencement	Take and discharge	15,000[5]	15,000
Total take and discharge volumes					**174,680**	**175,160**

Table 5: Summary of Kawerau production consents (source: Kawerau-SMP 2018)

The current situation is therefore complex, with resource consents held by four groups and several projects, some of which are interconnected. There is a joint reservoir management committee and plan (Kawerau SMP, 2018). The BOPRC peer review panel publishes a public community report on the status of the system based on the separate consent holder reports, but consent holders currently have their own responsibilities and report details separately – and not publicly. Bay of Plenty Regional Council are currently rationalising the situation but full details of the reservoir response are not currently available for the purposes of this review.

The capacity of the Kawerau resource is large. Lawless (2005) estimated it at 450 MW, but more recent work has superseded that. The latest publicly available summary report from BOPRC (2017) states that *"In 2017 the pressure drops field wide were comparable to recent years and well within modelled limits."* but notes some enthalpy decline. The 2018 SMP stated that declines in the deep reservoir pressure have been in the range of 2-5 bar. It is certainly the case that the effects on the reservoir have been much less than at Wairakei (up to 25 bar), despite Kawerau having been similarly operated for many years without reinjection, albeit at a smaller scale. There have been on-going issues with calcite scaling and more recently in controlling silica deposition, but those are amenable to management. There is currently some unused capacity within the resource consents held by the various parties, of the order of 40,000 tpd though some of that may be used for further industrial direct use rather than electricity generation.

Because of the complex situation, it is difficult to make detailed estimates of what may occur over the next 40 years, and what proportion of further development may be for direct use rather than electricity generation. Accordingly, it is assumed that a further 50 MW of electricity generation is possible, but not before 2030. Further development is possible but cannot be quantified at this time. The resource is high temperature so costs for condensing steam plant should be average, but smaller binary plants will be more expensive.

The gas content in the deep reservoir at Kawerau is higher than most in the TVZ, but because of the diverse plant configurations, the emissions per MWh vary. The bottoming binary plants for example, produce virtually no emission. It is estimated that overall for future developments, the gas emissions will be the same as the current average, which is at a medium level.

Rotoma

The Rotoma field lies near Lake Rotoma, north east of Rotorua. It is classified in part for development and in part for limited development. It has little surface expression and is somewhat enigmatic, with the chemistry being less informative than at most NZ fields.

Preliminary investigation works were undertaken in the early 1990s with the drilling of one well. Few details are available, but it is believed that the well discharged at a sub-commercial rate but did prove moderate temperatures. In 2010 Rotoma No. 1 made application for a 35 MWe station with supplementary use for process heat applications. This was declined but exploration consents were granted to construct up to ten wells for investigation and monitoring and taking and discharge of fluid to better understand the Rotoma-Tikorangi Field and potential effects on Waitangi Soda Springs. However, no further exploration has taken place to date. Further geoscientific work would be needed before development could proceed.

Lawless (2005) estimated the resource capacity over a 50-year project life as 35 MW. This is one case where resource uncertainty is more significant than regulatory impediments, and there are relatively few surface features or geothermal ecosystems to be affected. It has been assumed that a 25 MW development using binary plant (because high temperatures have not been confirmed) would be possible by 2030, with possibly further extensions beyond that, but they are too uncertain to include at this stage. CAPEX would be higher than average because of the scale and possibly low enthalpy.

The gas content at Rotoma appears to be higher than most in the TVZ. For the present purposes it is assumed to be medium.

Rotorua

The Rotorua geothermal system underlies the town of Rotorua and extends into the lake. There is extensive surface activity, which is the focus of much tourist activity. It has a special classification status and management plan which would probably preclude any large-scale generation.

No deep wells have been drilled. Many hundred independently-owned shallow wells have been drilled and used for bathing, domestic and commercial purposes, although many wells were closed by Government action in the 1980s after the significant tourist features were observed to be affected.

Lawless (2005) estimated the electrical generation capacity to be 35 MW over 50 years. No electrical generation is likely to occur though because of the requirement to preserve the thermal activity. It has been estimated that tourism related to geothermal activity brings about 5 times the income to Rotorua than would be possible using the field for electricity generation, quite apart from its cultural significance. Accordingly, it is not considered further for power generation purposes in this report.

Taheke and Tikitere

Taheke and Tikitere are geothermal fields which lie north and south of Lake Rotoiti respectively. Geophysics shows that the Tikitere system extends under the lake and hot springs occur on the Lake bed. It is not known if this provides a connection between Tikitere and the Taheke field, though it appears unlikely. Tikitere and Taheke are classed for conditional development, though Lake Rotoiti itself appears to be separately classed as being for development. Separate development under the lake would have considerable practical difficulties so is not taken into account here.

There are significant geothermal features at the Hells Gate area of Tikitere. Several shallow wells were previously drilled at Tikitere (also known as Ruahine Springs) during government-funded exploration. They discovered a shallow dry steam resource, which is probably not characteristic of the deeper reservoir. More recently 4 deep wells were drilled at Taheke: no details are publicly available.

Three Maori land trusts including Paehinahina Mourea (60 %), Manupirua (30 %) and Tikitere (5%) Trusts own the land over the Tikitere resource and as such, joined forces to jointly develop the geothermal resource. Consent applications have been lodged but not progressed for exploration investigations.

At Taheke, the resource area is split between two different Maori trusts, who have separately entered into agreements with Mercury Energy and Contact Energy. Mighty River Power Limited (Mercury) was granted consent for exploration wells at Taheke (with permission from Okere 1B3C3 and Adjoining Blocks Incorporated and Ruahine & Kuharua Incorporation) in 2013. It has not been exercised. Exploration consents were granted to Taheke 8C and Contact, for up to 10 wells. Contact has drilled 4 wells.

Lawless (2005) estimated the resource capacity over 50 years to be 240 MW for the two fields (and possibly Lake Rotoiti) combined. Because of the complicated land ownership, as far as projects go they need to be treated separately. Tikitere is a good example of an area on which a reasonably large and low-cost development is possible, but which is likely to be delayed by consenting, especially with regard to significant geothermal features, and commercial factors. We have assumed a 50 MW development would be possible, but not until 2030, with possibly a further 50 MW in 2040. There is some possibility that the first stage development would make use of the shallow steam zone, so costs would be lower than average based on the high enthalpy. That would probably not apply to any second stage development which would have to tap the deeper reservoir.

At Taheke, it would be most logical for there to be a single development but that does not appear to be likely based on the history to date. Therefore 25 MW developments are predicted in 2030, 2040 and 2050, without specifying which landowners and generators will carry them out. The small size of the projects will make them more expensive than the average.

The gas content at Tikitere based on previous well testing result was high. However, those shallow wells tapped a steam zone where gas can be expected to have accumulated. Tapping the deeper, hotter liquid may lead to lower gas emission per MWh. At Taheke no data are publicly available. It is assumed that both areas will have medium emissions.

5.4. Summary future geothermal generation stack

The following table summarises the individual assessments discussed above, to produce the basis for an overall future geothermal generation stack. Note that unlike the previous 'MBIE stack', this is arranged by anticipated earliest date of commercial operation, which is largely driven by non-economic issues rather than LRMC.

The estimated total additional geothermal generation available by 2060 is 1035 MW. There are considerable uncertainties in that estimate, mainly to do with regulatory and consenting issues rather than cost, although an increase in carbon emission cost is also potentially a significant factor which has not been taken into account (apart from classifying each prospect in a semi-quantitative manner).

Producing a range of scenarios is outside the scope of this report, but it is perhaps worthwhile to estimate what the impact would be if the assumptions made as to the mutability of geothermal systems classification prove to be incorrect. That would eliminate any significant development at Atiamuri, Tokaanu and Reporoa, thus reducing the total to 835 MW.

If it proves more difficult than anticipated to obtain consents for further expansion in existing development systems, then longer delays may occur, or in the worst case no further increase in generation would be possible. It is even conceivable that reconsenting of the existing projects, all of which have consents that expire within the next 40 years (Wairakei for example as early as 2026) may prove to be difficult or impossible, leading to an actual reduction in capacity.

These uncertainties, and a comparison with the possible total economically developable quantity under a much more permissive regulatory regime, are further quantified in Figure 6 below. The possible tranches of MW used to build up this figure are as follow:

1. Already installed capacity as in Table2: 1028 MW.
2. Already consented additions as in Table 6 (Tauhara, Ngāwhā 3 & 4): 300 MW.
3. Possible additions as in Table 6 that would require consents, but are within development fields (Ngāwhā 5 & 6, Mangakino, Mokai4, Ngatamariki 2, Rotokawa 3 & 4, Kawerau 2, Rotoma, Tauhara 3, Horohoro, Rotokawa 4): 360 MW.
4. Possible additions as in Table 6 within research or limited development fields, that would therefor require a change of status (Tokaanu, Tikitere, Taheke, Reporoa, Atiamuri): 375 MW.
5. Other fields that are currently classified as protected, and so cannot be developed under the current regulatory regime. Note that the present authors do not advocate a change of the status of these fields, but have included them for the sake of completeness. Field capacities are taken from the estimates quoted in Sections 5.1 - 5.3 above, where necessary converting to a 50-year project life (Ketetahi, Orakei Korako, Te Kopia, Waikite, Waimangu, Waiotapu): 556 MW. Not included in that are fields on offshore islands (e.g. White Island), the field under Lake Taupō, and Rotorua, at all of which development of power generation is considered impractical.

Not explicitly taken into account are the fact that currently Wairakei and Ohaaki generation is typically below their maximum installed capacity and there is unused capacity within the existing Kawerau consents, since it is not clear whether the latter would be used for electricity generation or direct industrial use.

Project	Location	Status	Enthalpy	MW	Capital cost NZD/kW	Capital cost NZ$M	Earliest date	GHG emissions category	Variable O&M, $/MWh	Fixed O&M, $/kW
Ngawha-3	Northland	Consented	Low	25	NZD 7,802	195	2021	High	0	190
Tauhara-2a	Waikato	Consented	Medium	125	NZD 4,734	592	2021	Low	0	190
Tauhara-2b	Waikato	Consented	Medium	125	NZD 4,734	592	2026	Low	0	190
Ngawha-4	Northland	Consented	Low	25	NZD 7,802	195	2031	High	0	190
Mangakino	Waikato	Generic-Greenfield	Medium	25	NZD 6,127	153	2030	Low	0	190
Mokai-4	Waikato	Generic-brownfield	Low	25	NZD 7,802	195	2030	Low	0	190
Ngatamariki-2	Waikato	Generic-brownfield	Medium	50	NZD 5,568	278	2030	Low	0	190
Rotokawa-3	Waikato	Generic-brownfield	Medium	50	NZD 5,568	278	2030	Low	0	190
Kawerau-2	Bay of Plenty	Generic-with-restrictions	Medium	50	NZD 5,568	278	2030	Medium	0	190
Rotoma-1	Bay of Plenty	Generic-Greenfield	Low	25	NZD 7,802	195	2030	Medium	0	190
Tokaanu-1	Waikato	Generic-with-restrictions	Medium	20	NZD 6,335	127	2030	Medium	0	190
Tikitere-1	Bay of Plenty	Generic-with-restrictions	High	50	NZD 5,023	251	2030	Medium	0	190
Taheke-1	Bay of Plenty	Generic-with-restrictions	Medium	25	NZD 6,127	153	2030	Medium	0	190
Reporoa-1	Waikato	Generic-with-restrictions	Medium	25	NZD 6,127	153	2030	Medium	0	190
Tauhara-3	Waikato	Generic-brownfield	Medium	30	NZD 5,968	179	2035	Low	0	190
Horohoro	Waikato	Generic-Greenfield	Low	5	NZD 9,767	49	2040	Medium	0	190
Atiamuri	Waikato	Generic-with-restrictions	Low	5	NZD 9,767	49	2040	Medium	0	190
Rotokawa-4	Waikato	Generic-brownfield	Medium	50	NZD 5,568	278	2040	Low	0	190
Tokaanu-2	Waikato	restrictions	Medium	100	NZD 5,119	512	2040	Medium	0	190
Tikitere-2	Bay of Plenty	restrictions	Medium	50	NZD 5,568	278	2040	Medium	0	190
Taheke-2	Bay of Plenty	Generic-with-restrictions	Medium	25	NZD 6,127	153	2040	Medium	0	190
Reporoa-2	Waikato	Generic-with-restrictions	Medium	25	NZD 6,127	153	2040	Medium	0	190
Ngawha-5	Northland	Generic-brownfield	Low	25	NZD 7,802	195	2041	High	0	190
Taheke-3	Bay of Plenty	Generic-with-restrictions	Medium	25	NZD 6,127	153	2050	Medium	0	190
Reporoa-3	Waikato	Generic-with-restrictions	Medium	25	NZD 6,127	153	2050	Medium	0	190
Ngawha-6	Northland	Generic-brownfield	Low	25	NZD 7,802	195	2051	High	0	190

Table 6: Summary table 'Future geothermal generation stack' (figures in 2019-NZD)

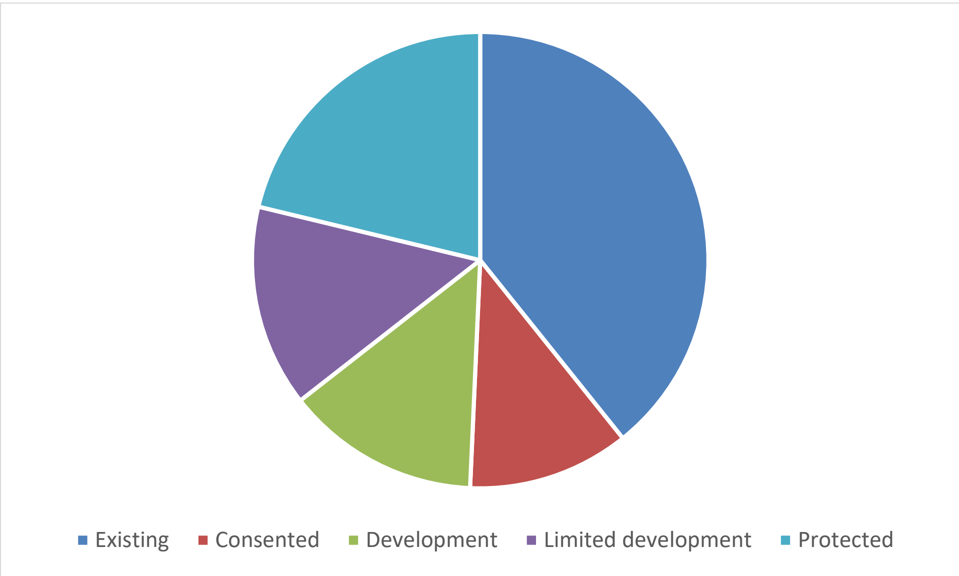

Figure 6: Breakdown of possible total geothermal generation by category

6. Conclusions

The pace of geothermal development in New Zealand has been modest over the past five years, after a period of rapid growth in response to declining gas reserves. The recent slow-down is mainly due to a flat power demand and the possible contribution to the grid of the Manapouri power scheme if the Tiwai Point aluminium smelter were to close.

There is now a more positive mood in the industry following the government setting objectives for greatly reduce GHG emissions by 2050. The generators have pointed out that there is limited scope for further de-carbonisation of the existing electricity grid because of our already-large degree of renewables generation and the practical advantages of maintaining some gas generation for load trimming. There are however significant opportunities for renewable electricity to substitute for other existing fossil-fuel usage in the transport and industrial sectors, which make up 18% and 11% of our total emissions respectively. Direct use of geothermal heat can also make a significant contribution to reducing fossil fuel use, though that is not the subject of the present study. The industry foresees on-going growth in the geothermal generation sector, albeit at a modest pace.

Access to resources is more likely to constrain the pace of development than project cost and electricity price. Around half of New Zealand's high-temperature geothermal resources are currently fully or partially protected. Regulatory and consenting difficulties may lead to delays for future projects. For the present study, it is assumed that the current regulatory regime will remain more or less as is, but it is conceivable that more permissive or more restrictive approaches are possible in the future. The current draft NPS on Biodiversity, which is open for consultation at present, is an example of regulation that in its initial draft form could limit future geothermal development if that is not taken into account. It should not be assumed that all existing projects will automatically be re-consented, and the consents for all existing projects expire within the 40-year horizon. A more enabling regime and policy at the national level would accelerate the pace of geothermal development, but would also presumably make it easier to consent new wind, solar and hydro projects so would not necessarily favour geothermal relative to other renewable sources.

It is not expected that new technology will greatly reduce the cost of future geothermal generation nor, within what is likely to be economic in New Zealand, significantly extend the geographical spread of its coverage to much lower-temperature resources. Thus, future large-scale development is likely to only be within the Taupō Volcanic Zone and at Ngāwhā in Northland. Some modest cost reductions and gains in efficiency can be expected within the existing project areas, but to a lesser extent than the less mature renewable industries such as solar, wind and storage.

There is considerable scope for new geothermal plant to replace existing thermal plant, whether that be in a baseload or load following mode. From a technical perspective, geothermal generation can be made to run in a load-following manner, but the most economic use of geothermal generation will remain as base load, and since it is not anticipated that geothermal generation will extend to new geographical areas or remote parts of the grid, the scope for this to occur is limited, except possibly at Ngāwhā. It is conceivable that government initiatives to minimise carbon emissions might lead to geothermal becoming more important for load following, although the generators concerned would probably insist on a take-or-pay or capacity charge type of compensation to take account of the very high proportion of fixed costs of geothermal project operation.

Geothermal power projects do emit GHG, albeit in most cases at significantly lower rates per MWh than fossil fuel plants. Previous studies in New Zealand have over-stated the emissions of existing and future geothermal plants. More specific figures have been presented here for each prospect to a semi-quantitative level, based on actual recent data. The present weighted average emissions intensity for existing geothermal projects is 76 g CO_2eq/kWh (2018), which has been steadily declining (91 g

CO_2eq/kWh in 2015) and is expected to continue to do so in the future. If much higher carbon prices eventuate in the future, the pressure on geothermal plants will increase and the expected emissions intensity would likely drop faster. In general, that would disadvantage new, higher emitting geothermal projects relative to other renewables (but much less than fossil-fuelled plants). The CCS technology does exist for removal of GHG from geothermal plants and reinjection in nearby reservoirs, and likely at a lower cost than for fossil fuel projects.

Greater future direct use of geothermal energy is generally expected to be complementary rather than competitive to electricity generation or be based on lower-temperature resources. A notable exception to that could be at Kawerau where there is scope for expansion but the balance between future industrial use and electricity generation is unclear. Another possible future “direct use” is mineral recovery provided certain technical challenges can be overcome. Preservation of geothermal activity for tourism is a form of “direct use” which precludes generation at Rotorua and some of the protected systems in particular.

Taking likely earliest dates of COD into account yields an estimated sequence of future geothermal projects as summarised in Table 6 (section 5.4). The total estimated available future geothermal generation stack by 2060 is 1035 MW. Capital costs range from $4,734 to $9,767/kW with a weighted average of $5,782/kW. It is expected that at least 50% of the project capital costs will be in New Zealand currency.

This total new geothermal generation stack is slightly higher than previously presented by MBIE (2016), but it is likely that many projects will be commissioned later than previously assumed.

References

- BEC (2015); Business NZ Energy Council; World Energy Council; *New Zealand Energy Scenarios Navigating energy futures to 2050*; Auckland, 2016;
- BEC2060 (2019); Business NZ Energy Council; World Energy Council; *New Zealand energy scenarios. Navigating our flight path to 2060*; Auckland, 2019; Retrieved from (Dec 2019): https://www.bec2060.org.nz/
- Bertani, R., Thain, I.; 2002: *Geothermal power generating plant CO2 emission survey*; IGA News, (49), 1–16;
- Bignall G. 1990: ; *Hydrology and hydrothermal alteration, Reporoa well;* Proc 12th New Zealand Geothermal Workshop, Reporoa, 1990;
- Bibby, H.M., Caldwell, T.G., Risk, G.F. 1994: *Resistivity evidence for an independent geothermal field at Reporoa.* Proc. 16th N.Z. Geothermal Workshop, 1994, 16, 133-138.
- Bromley, C.J., Burnell, J., Mroczek, E., Simpson, M.; 2014: 2014 Ngāwhā conceptual model. GNS Consultancy report 2014/181.
- Burnell, J and Weir, G: 2014: 2014 Ngāwhā numerical reservoir model: GNS Consultancy report 2014/143.
- Clearwater J. Hernandez D., Sewell S., Addison S.; *Model-based decision making to manage production in the western compartment at Rotokawa*; Proceedings of the 38th New Zealand Geothermal Workshop, 2015;
- Climate Works Australia (2014); *Pathways to Deep Decarbonisation in 2050*; (September), pp.1–49; https://www.climateworksaustralia.org/project/national-projects/pathways-deep-decarbonisation-2050 ;
- Consent Decision Report, 2015: Ngāwhā Generation Limited's Resource Consent Applications to the Northland Regional Council and the Far North District Council and Top Energy Limited's Notice of Requirement to the Far North District Council
- Contact Energy; 2019: Wairakei – Tauhara geothermal system Annual Monitoring Report for 2018.
- Contact Energy; 2018; Contact Energy Investor Presentation; Published via NZX, November 2018; http://nzx-prod-s7fsd7f98s.s3-website-ap-southeast-2.amazonaws.com/attachments/CEN/326341/289918.pdf ;
- ESMAP (016; *Greenhouse gases from geothermal power production*; Washington, 2019; Retrieved from (Dec 2019): https://www.esmap.org/node/57064 ;
- Febrianto, R., Bydder, J., Hochwimmer, A., Ussher, G.:2017; *Pumped Well Geothermal Power Generation in the Indonesian Context*; Proceedings of the 5th Indonesia International Geothermal Convention & Exhibition (IIGCE) 2017
- GT Management 2019; GT Management, *Cost of Production from Geothermal Power Projects in Indonesia*; Revision 4; Unpublished report, for PT SMI December, 2019;
- ICCC 2019; Interim Climate Change Committee; *Accelerated Electrification: Evidence, Analysis and Recommendations*; Wellington, 2019;
- Hernandez D., Clearwater J., Burnell J., Franz P., Azwar L., Marsh A.; *Update on the Modeling of the Rotokawa Geothermal System: 2010 – 2014*; in: Proceedings World Geothermal Congress, 2015;
- IPCC 2014; Bruckner, T., Fulton, L., Hertwich, E., McKinnon, A., Perczyk, D., Roy, J., Wiser, R.; *Annex III: Technology-specific cost and performance parameters*; In: O. Edenhofer, R. Pichs-Madruga, Y., Sokona, E. Farahani, S. Kadner, K. Seyboth, J. C. Minx (Eds.), Climate Change 2014: Mitigation of Climate Change. Retrieved from (Dec 2019): https://www.ipcc.ch/pdf/assessmentreport/ar5/wg3/ipcc_wg3_ar5_annex-iii.pdf
- Kawerau SMP: 2018; Bay of Plenty Regional Council; Kawerau geothermal system management plan; Whakatane, February 2018;
- Lawless, J.V; 2002: *New Zealand's geothermal resource base revisited*; 7th Annual Seminar, New Zealand Geothermal Association, Taupō, 2002;

- Lawless, J.V: 2005; *Maintaining Leadership in Geothermal Energy Generation in New Zealand*; National Power Conference, Auckland 2015;
- Lawless, J. V., Darma, S., van Campen, B., Randle, J.B.; 2016: *Can geothermal regulation enhance (technical) innovation – Evidence and - case studies from NZ and Indonesia*; New Zealand Geothermal Workshop, 2016;
- Lawless, J.V., Lovelock, B.G.; 2001: *New Zealand's geothermal resource base*. 6th Annual Seminar, New Zealand Geothermal Association, Taupō;
- Legmann, Hilel.;2015: *The 100-MW Ngatamariki geothermal power station a purpose-built plant for high temperature, high enthalpy resource;* in: Proceedings of the World Geothermal Congress 2015, Melbourne, Australia, 19-25 April 2015
- MBIE 2016; Ministry of Business, Innovation and Employment; *GEM 2016 LRMC model*; Wellington, 2016;
- McLean and Richardson, I. 2019; *New Zealand Geothermal Power Generation in Context*; in: Proceedings of the 41st New Zealand Geothermal Workshop, 25-27 November 2019, Auckland, New Zealand;
- Minson, A.A.C., Kivell, J.A., .Fry, T.J.; 1985: *Tongonan I geothermal power development, Philippines*; in: Geothermics Volume 14, Issues 2–3, 1985, Pages 353-370;
- Pauline, R, Kaya, E; 2019: *Modelling geothermal power generation from the Waiotapu-Waikite-Reporoa geothermal fields* in: Proceedings of the 41st New Zealand Geothermal Workshop, 25-27 November 2019, Auckland, New Zealand p.62;
- PB Power; 2012; *Generation Data Update*; Parson Brinkerhoff report for Ministry of Economic Development; NZ Wellington, January 2012;
- Quinao J., Zarrouk, S.; 2015: *Probabilistic resource assessment using the Ngatamariki numerical model through experimental design and response surface methods (ED and RSM)*; in: Proceedings of the 37th New Zealand Geothermal Workshop, 2015;
- Quinao, J., Buscarlet, E., & Siega, F.; 2017: *Early identification and management of calcite deposition in the Ngatamariki geothermal field, New Zealand (2017)*; in: Proceedings of the 42nd Workshop on Geothermal Reservoir Engineering, Stanford University;
- Reyes, A; 2019: *Geothermal energy from petroleum wells in New Zealand – benefits and barriers*; Proceedings of the NZ Geothermal Workshop, 2019;
- Risk, G.F. 2000a; *Boundaries of Horomatangi, Tokaanu-Waihi-Hipaua, Waiotapu-Waikite, Waimangu and Atiamuri Geothermal Fields*; GNS report 2000/22 for Environment Waikato;
- Risk, G.F. 2000b; *Boundaries of Horohoro, Te Kopia, Orakei Korako, Ngatamariki and Reporoa geothermal fields*; GNS report 2000/131 for Environment Waikato;
- Rustandi, D., Sadiq. J. Zarrouk, S.J., Luketina, K.M.; 2016: *The Mangakino geothermal system: resource evaluation*; Proceedings of the 38th New Zealand Geothermal Workshop 23-25 November 2016, Auckland;
- Stevenson, T., Batstone, S., Reeve, D., Poynton, M., Comendant, C.; 2018: Transitioning to zero net emissions by 2050: moving to a very low-emissions electricity system in New Zealand; Prepared for the New Zealand Productivity Commission; April 2018;
- Severne, C.; 1999: Recent geophysical and geochemical studies from the Tokaanu-Waihi hydrothermal system (Taupō Volcanic Zone New Zealand); in: Proceedings of the 24th Workshop on Geothermal Reservoir Engineering, Stanford University;
- SKM 2009; Assessment of Current Cost of Geothermal Power Generation in New Zealand (2007 basis); Sinclair Knight Merz, Auckland, 2009;
- SKM/WRC 2002; Sinclair Knight Merz Report for Waikato Regional Council; *Resource capacity Estimates for High-Temperature Geothermal Systems in the Waikato Region*; Hamilton, 2002;
- Van Campen, B., Archer, R., Grinlinton, D.; 2019: Ohaaki resource assessment in UNFC framework and proposal: Proceedings of the 41st New Zealand Geothermal Workshop, 25-27 November 2019, Auckland, New Zealand;

- Van Campen, B., Suomalainen, K.; 2020: *Changing geothermal GHG emissions and impact on future low carbon power systems - the case of New Zealand's decarbonisation plan*; in: 7th IAEE Asia-Oceania Conference 2020; Energy Centre/International Association for Energy Economics; Auckland, February, 2020 (in press);
- WRC 2019; Waikato Regional Council; *Classifying geothermal systems*; Retrieved from (Dec 2019): https://www.waikatoregion.govt.nz/environment/natural-resources/geothermal/classifying-geothermal-systems/
- Yuniarto, Soesilo, T.E.B., Heviati, E.; 2015: *Geothermal Power Plan Emissions in Indonesia;* in: Proceedings of the World Geothermal Congress 2015, Melbourne, Australia.

Annex 1: List of persons consulted

Simon Addison	Ormat
Rosalind Archer	Director, Geothermal Institute
Phil Bishop	Electricity Authority
Sam Brown	Tuaropaki Power Company (review only)
John Burnell	GNS Science
Jane Bydder	Mercury Energy
Aroha Campbell	Tauhara North No. 2 Trust
Nick Clarke	Mercury Energy
Gilad Cohen	Ormat
Bruce Cole	Ormat
Penny Doorman	Bay of Plenty Regional Council
Mike Dunstall	Contact Energy
Ben Lee	Northland Regional Council
Hilel Legmann	Ormat
Katherine Luketina	WRC
Katie McLean	Contact Energy
Jim McLeod	Waikato Regional Council
Ted Montague	Contact Energy
Michael O'Sullivan	University of Auckland
Jaime Quinao	Ngāti Tūwharetoa Geothermal Assets
Paul Quinlivan	Jacobs
Agnes Reyes	GNS Science
Greg Ussher	Jacobs
Patrick Walsh	Ormat
Sadiq Zarrouk	Geothermal Institute

Annex 2: GHG emissions from NZ producing fields

Source: McLean and Richardson 2019)

Emissions intensity and source data for Mercury power stations

Station	Year	Emissions factor [tCO_2(eq)/t steam]	# sample sets	Mass steam [kt]	Generation [GWh (net)]	Emissions intensity [gCO_2(eq)/ kWh(net)]
Mokai	2011	0.0058	*	*	*	35
	2013	0.004356	6	5,555	815	30
	2014	0.004033	6	5,722	876	26
	2015	0.0036	8	6,159	851	26
	2016	0.004599	8	6,215	852	34
	2017	0.004155	8	5,910	848	29
	2018	0.0046	12	5,616	492	52
Ngatamariki	2014	0.016062	8	3,220	629	82
	2015	0.01805	8	3,792	733	93
	2016	0.015	8	3,716	699	80
	2017	0.01342	10	3,873	801	65
	2018	0.013352	12	3,765	785	64
Nga Awa Purua (NAP)	2011	0.019449	*	*	*	130
	2012	0.016329	12	8,076	1145	115
	2013	0.015633	12	7,449	1106	105
	2014	0.013356	12	7,369	1063	93
	2015	0.014663	12	7,359	1083	100
	2016	0.01309	12	7,915	1170	88
	2017	0.011181	12	7,576	1170	73
	2018	0.009947	12	7,798	1239	63
Rotokawa	2011	0.024004	*	*	*	150
	2012	0.02174	6	1,614	284	123
	2013	0.01829	6	1,636	284	105
	2014	0.018994	6	1,603	256	119
	2015	0.018205	6	1,581	273	105
	2016	0.015991	8	1,620	280	93
	2017	0.014966	8	1,551	289	80
	2018	0.01454	12	1,684	292	84
Kawerau (KGL)	2011	0.017358	*	*	*	136
	2012	0.020443	12	6,647	842	161
	2013	0.018352	12	6,231	813	141
	2014	0.019471	10	6,857	901	123
	2015	0.02226	12	7,001	902	173
	2016	0.019153	12	6,676	853	150
	2017	0.017288	12	6,947	961	125
	2018	0.017082	12	6,558	912	123

*Source data for some of the Mercury power stations was not readily available for 2011, only the final results

Emissions intensity and source data for Top Energy (Ngāwhā) and NTGA (TOPP1) power stations.

Station	Year	Emissions factor [tCO_2(eq)/t steam]	# sample sets	Mass steam [kt]	Generation [GWh (net)]	Emissions intensity [gCO_2(eq)/ kWh(net)]
TOPP1	2017	0.0122	15	920	187	60
	2018	0.0121	12	929	187	60
Ngāwhā	2010	0.09700	26	361	101	348
	2011	0.09252	4	683	193	328
	2012	0.08902	4	735	203	322
	2013	0.08839	6	769	197	345
	2014	0.08640	10	783	194	348
	2015	0.08119	4	784	192	332
	2016	0.08490	12	770	203	322
	2017	0.08314	6	726	198	306
	2018	0.08395	4	735	203	304

Emissions intensity and source data for Contact Energy power stations

Station	Year	Emissions factor [tCO_2(eq)/t steam]	# sample sets	Mass steam [kt]	Generation [GWh (net)]	Emissions intensity [gCO_2(eq)/ kWh(net)]
Wairakei	2010	0.0048	1	13,105	1,359	46
	2012	0.0065	2	13,202	1,324	65
	2013	0.0062	1	13,018	1,262	64
	2014	0.002	1	11,630	1,156	20
	2015	0.0022	1	11,540	1,113	23
	2016	0.0026	13	10,387	1,119	24
	2017	0.0026	12	9,581	1,045	24
	2018	0.0023	8	9,287	1,017	21
Te Mihi	2014	0.0059	12	6,107	756	48
	2015	0.005	8	10,627	1,262	42
	2016	0.0048	8	10,169	1,188	41
	2017	0.0052	10	12,121	1,410	45
	2018	0.0051	9	11,704	1,376	43
Poihipi	2010	0.006	1	3,208	385	50
	2012	0.0014	2	3,651	448	11
	2013	0.0013	1	3,471	450	10
	2014	0.0019	1	3,136	394	15
	2015	0.0020	1	2,464	322	15
	2016	0.0020	1	3,069	398	15
	2017	0.0041	3	3,215	413	32
	2018	0.0048	11	3,209	403	38
Te Huka	2010	0.0087	1	1,254	210	52
	2011	0.0079	1	779	133	46
	2012	0.0046	12	1,216	210	27
	2013	0.0047	6	1,020	176	27
	2014	0.0057	1	1,373	213	37
	2015	0.0059	10	1,221	195	37
	2016	0.0059	9	1,210	191	37
	2017	0.0055	10	1,188	207	32
	2018	0.007	8	1,240	193	45
Ohaaki	2010	0.0555	1	3,892	411	525
	2011	0.0493	1	3,480	392	438
	2012	0.04875	2	3,077	346	434
	2014	0.0463	1	2,597	272	443
	2015	0.0411	1	2,982	326	376
	2016	0.0494	12	3,103	331	463
	2017	0.0392	10	3,230	338	375
	2018	0.0363	9	2,552	272	341

Annex 3: Scope of work

The primary task is to produce a list of geothermal generation projects which could be commissioned in New Zealand over the next 40 years, giving:

- Location
- Probable capacity
- Probable capital cost
    - Split of capital cost into local and foreign components
- Likely timing
- GHG emissions to a semi-quantitative level
- Estimated operating cost

These will be used as input to the existing MBIE Long run marginal cost model to produce a predicted generation stack. The model will be run by MBIE.

A written report will be produced explaining the reasoning behind the parameters selected, noting that non-economic issues, particularly regulatory, are likely to drive the timing of many projects. Comments will be made on other geothermal resources which have considerable generation potential, but which are likely to be unavailable in the foreseeable future because of regulatory classifications for preservation. It is believed this could comprise about 50% of the total.

To this end it will be necessary to consult with the major geothermal developers, and the regulatory authorities concerned.

With regard to predicted capital costs, reference will be made to recent economic modelling studies in Indonesia which produced correlation curves for geothermal costs vs. project size and resource quality.

Other matters to be addressed are:

- Potential for new technology to increase existing geothermal generation capacity
- Potential for geothermal generation to be extended to areas outside the existing Rotorua-Taupō and Ngāwhā areas.
- Potential for geothermal to generate in a load-following manner, to compensate for intermittency of other electricity sources.
- Extent to which non-electric uses of geothermal energy will compete with, or complement, generation.