CARBON NEGATIVE GEOTHERMAL: THEORETICAL COMBINED GEOTHERMAL-BECCS INJECTION CYCLE

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Keywords: *geothermal, hybrid, biomass, dissolved CO_2, BECCS, forestry waste, reinjection, non-condensable gases*

ABSTRACT

Geothermal energy is a mature and established technology in Aotearoa New Zealand. In 2019, it provided 17% of total electricity generation. However, power production from geothermal resources is often limited by heat transfer and conversion efficiencies, which are especially restrictive for low-temperature resources. For almost a century, there has been interest and research in superheating geothermal fluid with an ancillary fossil fuel boiler to improve efficiencies. Hybrid geothermal-solar and geothermal-biomass plants have been considered as carbon neutral solutions in a similar vein. The latter is of particular relevance in New Zealand due to the colocation of the Taupo Volcanic Zone (TVZ) with a large forestry industry. This work assesses the feasibility of using a biomass boiler coupled with carbon capture and storage in geothermal power generation in New Zealand. The superheating of geothermal fluid with bioenergy has been adopted in other parts of the world, and has been shown to result in an increase in energy output when retrofitting existing power stations.

Coupling bioenergy with carbon capture and storage (BECCS) technologies at geothermal plants is a pathway for net carbon negative generation. Since geothermal plants typically require reinjection wells as part of reservoir pressure management, part of the infrastructure for reinjection of CO_2 is already present. A simple systems model was constructed to explore end-member energy cycles and determine, per unit mass rate of geothermal fluid, both the biomass fuel requirements for superheating and associated CO_2 emissions. The model also quantifies the proportion of CO_2 that can be dissolved in the condensate streams for reinjection. As this CO_2 originates as atmospheric carbon that is locked in the biomass fuel during growth, the result is a carbon sequestering energy cycle (net carbon negative).

We apply the model to a theoretical geothermal doublet producing at 150 to 195 °C with a condensing turbine and optional wellhead separator. We showed that superheating the separated steam with biomass can yield electricity gains of about 50% and full emissions capture. If no wellhead separator is used and total production fluid is superheated, power output is increased two orders of magnitude, with emissions capture exceeding 30%. With only 1 kg/s of geothermal fluid flow, this energy cycle could sequester almost 2 kT of CO_2 per annum for each MWe generated. However, understanding the challenges of large-scale dissolved CO_2 injection remains a key uncertainty in determining the viability of carbon negative geothermal cycles.

1. INTRODUCTION

Geothermal energy is a mature technology in New Zealand, contributing to 17% of the country's electricity supply in 2019 (MBIE, 2020). However, the exploitation of geothermal resources for power is often limited by the significant energy losses associated with converting the thermal energy of geothermal fluid into electricity. The conversion efficiencies of geothermal power plants, ranging from 1 to 21% with a worldwide average of 12%, are considerably lower than fossil fuel and nuclear thermal plants, which can reach upwards of 40% (Zarrouk & Moon, 2014).

One particularly influential factor for these low conversion efficiencies is the enthalpy of the produced geothermal fluid. Additionally, during a traditional flash process, a significant amount of energy is rejected with brine. Since only very dry steam can be allowed to pass through a turbine, fluid from a higher enthalpy reservoir will have more heat sent to the turbine after separation. In contrast, fluid from a lower enthalpy reservoir will have a greater portion of rejected heat.

Approximately 70% of geothermal systems around the world are low to medium temperature and enthalpy systems, between 110 and 160 ºC (Franco & Villani, 2009; Hochstein, 1990; Li et al., 2020; Liu et al., 2016). Juxtaposed with the characteristically high capital costs of geothermal installations (Dickson & Fanelli, 2003), low enthalpy geothermal systems often retain high development risk, or are simply unfeasible, for flash plants.

Another drawback of geothermal energy production that has come under scrutiny in recent years is the slight carbon positive nature of resource exploitation. Whilst geothermal energy is widely considered a green energy source, there are some associated greenhouse gas emissions that originate from deep magmatic sources (Kaya & Zarrouk, 2017). The mass fraction of non-condensable gases (NCGs) in geothermal fluid can lie between 0.2 and 25% depending on the geothermal field (Özcan and Gökçen, 2010; Kaya & Zarrouk, 2017). As CO_2 is generally the most abundant NCG found in geothermal fields (Bertani and Thain, 2002; Kaya & Zarrouk, 2017), it has received particular attention. Whilst CO_2 emissions from geothermal power stations are estimated to be approximately 5% that of a traditional fossil fuel power plant (Sass & Duffield, 2003; Sigfússon et al., 2018), there has been growing interest in reinjection of magmatic origin NCGs in recent years, as evidenced by projects like Iceland's CarbFix (Gíslason et al., 2018; Kaya & Zarrouk, 2017; Sigfússon et al., 2018).

The deployment of organic Rankine cycle (ORC) binary plants provides a solution to both of these issues. Binary plants can be used for low enthalpy geothermal systems at enthalpies from 300 kJ/kg to 1050 kJ/kg, whereas flash plants are generally better suited to reservoir enthalpies above 800 kJ/kg (Zarrouk & Moon, 2014). Additionally, due to the closed loop nature of the geothermal fluid in the plant schematic, binary plants lack the emissions of magmatic NCG emissions since the total produced fluid is reinjected (Franco & Villani, 2009; Kaya & Zarrouk, 2017). However, despite the feasibility of binary plants in a greater number of geothermal fields and countries, they traditionally have lower conversion efficiencies than flash plants (Toselli et al., 2019b; Zarrouk & Moon, 2014).

In the sections below, we outline potential solutions to each of the aforementioned issues that are either already deployed or have been investigated in the literature. Following this overview, we propose a new energy cycle that involves joint coupling of geothermal energy and Bioenergy and Carbon Capture & Storage (BECCS) technology. With the debut of the Zero Carbon Amendment Act in 2019 (MBIE, 2020), we believe this innovative approach can have a beneficial impact for New Zealand's power generation and climate goals.

1.1 Hybrid Geothermal Systems

A solution to the low reservoir temperature and enthalpies of geothermal fields is to augment traditional geothermal production with heating from a secondary fuel source. These are described as 'hybrid' geothermal systems. Hybrid geothermal plants can be deployed using various strategies and plant specifications, depending on site specific conditions. In some cases, they may even be able to effectively utilize low enthalpy geothermal resources.

Fossil fuels were the first secondary fuel source considered for pairing with geothermal energy. Hybrid geothermal-fossil fuel plants have been investigated extensively in literature, dating back to 1924 (DiPippo, 2015; Thain & DiPippo, 2015). Methods of combining the two fuel sources included superheating of geothermal steam with a fossil fuel boiler or using the geothermal feed water for preheating in thermal plants (Bruhn, 2002; Liu et al., 2016). The latter approach in particular enabled use of low enthalpy fields. In fact, it was concluded that feed water preheating was the only feasible solution when trying to exploit low enthalpy geothermal systems for hybrid geothermal/fossil fuel plants (Bruhn, 2002). For hybrids of this nature, plant power output increases with geothermal resource temperature but decreases with distance from the power station (Liu et al., 2016). A feasibility study of developing a hybrid plant in the Geysers geothermal field in California determined that the proximity of the two fuel resources was the limiting factor for viability (Janes, 1984; Thain & DiPippo 2015). It is estimated that plants with geothermal heating of feedwater can increase potential power output by 60% (Khalifa et al., 1978; Liu et al., 2016), effectively requiring less fossil fuel consumption. However, this would at best reduce carbon positivity.

The concepts of increasing the heat of geothermal fluid with solar energy or using geothermal for solar storage have also been considered (Li et al., 2020). Solar superheating of geothermal fluid, with reservoir temperatures as low as 125 and 154 ^{o}C, has been accomplished in Iceland and the United States respectively. Solar hybrids have been investigated for plants that have fallen short of design capacity, where the advantages of each individual resource were found to negate the other's shortcomings (Manente et al., 2011). Unlike fossil fuel hybrids, combining solar and geothermal energy is effectively carbon neutral.

Similarly, the coupling of geothermal and bioenergy resources would be effectively carbon neutral due to the absorption of CO_2 by the biomass feedstock during its life cycle. Thain & DiPippo (2015) conducted a case study focused on introducing a biomass superheater to the Rotokawa I geothermal field. The base Rotokawa I plant consists of a 29 MW combined flash plant with binary units. The hypothetical insertion of the heat exchanger within the steam line was considered between the cyclone separator and the back-pressure steam turbine. Due to the remaining high enthalpy of the turbine exhaust steam, the case study considered using the exhaust steam condensate to provide further energy to the binary units. This resulted in an estimated additional 8.5 MWe, of which 6.9 MWe came from the back-pressure turbine. The use of exhaust steam in this way could contribute to additional power gains.

According to Thain & DiPippo, the gains in power production required 19 MWth of biomass combustion. When considering only the increase in power output from the base plant, this translated to a thermal conversion efficiency of 44.2% of the boiler. However, they cited the overall conversion efficiencies of the base case and hybrid plant as 25.6 and 25.4% respectively. Thain & DiPippo considered using forestry waste from the Kaingaroa Forest as the biomass feedstock for the boiler, noting the proximity of the forest to the TVZ could be an advantage.

An industry application of a geothermal-bioenergy cycle was tested at the Larderello geothermal field in Italy. A biomass superheater was implemented by Enel Green Power at the Cornia-2 facility (Dal Porto et al., 2016). The existing plant, designed at 20 MWe, was performing below theoretical capacity; thus, the plant was retrofitted to provide steam superheating. Steam was heated from 150 ^{o}C to 370 ^{o}C, adding 6 MWe of power with a turbine inlet pressure of 5 bar. The addition of the biomass superheater in between the separator and turbine required minimal plant modifications. The biomass feedstock was available from local suppliers. When coupled with a dedicated feed-in tariff and financial incentives from local government, the retrofitted project was financially viable. The consumption of biomass feedstock was determined by the efficiency of the boiler and superheater.

Other feasibility studies of biomass retrofits to existing geothermal systems have also been considered recently. In 2019, a techno-economic case study was conducted for retrofitting a binary plant into a hybrid biomass plant in Oberhaching, Germany (Toselli et al., 2019a; Toselli et al., 2019b). Similarly, Zhang et al. (2019) considered systems integration of ground source heat pumps with bioenergy for direct heating purposes. Hybrid plants can optimize the synergies of two different energy resources, but colocation of the resources, cost of the secondary fuel and economic incentives are vital to the success of such installations (Bruhn, 2002; Dal Porto et al., 2016; DiPippo, 2015; DiPippo & Thain; 2015; Janes, 1984, Manente et al., 2011).

1.2 Geothermal and Carbon Capture and Storage

Conventional applications of carbon capture and storage (CCS) have largely been associated with fossil fuels as a post combustion technology to minimize emissions, heavily tied to the price of carbon (Galiègue & Laude, 2017), but are limited by the buoyancy (and escape potential) of liquified supercritical CO_2 (Kervévan et al., 2013). Within this section, the distinction between liquified supercritical CO_2 and CO_2 dissolved in geothermal reinjection fluid is drawn because only the latter is considered by our model.

The omnipresence of reinjection in geothermal fields presents alternative opportunities for CO_2 storage. Reinjection is a common practice as part of resource consenting, reservoir management and pressure maintenance (Kaya & Zarrouk, 2017). The Icelandic CarbFix project makes use of reinjection apparatus to sequester CO_2 within underground basalt formations.

CarbFix was a response to combat the emissions of magmatic CO_2 in Iceland in compliance with 2040 climate goals (Berstad & Nord, 2016; Sigfússon et al., 2018). The project involved dissolution of CO_2 in water, followed by targeted reinjection into deep basalt formations deep where mineralization could occur. Mineral storage is cited to have a high capacity and be permanent (Sigfússon et al., 2018). The project has since reached industrial scale at Hellisheidi, where the sour gasses are captured through water absorption, detailed in Berstad & Nord (2016). The CO_2 charged water that is dispatched for reinjection is denser than fresh water, which mitigated the risk of CO_2 resurfacing (Gíslason et al., 2018). An in-line dissolution method was deployed, where CO_2 and H_2S are released from an interior pipe and mixes with the injection water beneath the gas inlet. The dissolution time within the vertical injection pipe is cited to take approximately five minutes (Berstad & Nord, 2016). As per Henry's Law, CO_2 solubility increases with elevated pressures (Duan & Sun, 2003; Gíslason et al., 2018), so utilization of the hydrostatic head from the reinjection well allows for dissolution at these higher pressures. Currently, 34% of CO_2 emissions and 68% of H_2S from Hellisheidi power plant are captured (Gíslason et al., 2018). According to Gíslason et al., the cost of capturing CO_2 at Hellisheidi is two to four times cheaper than conventional CCS (2018). The industrial scale application of the CarbFix program has seen 10,000 tons of CO_2 and 5,000 tons of H_2S injected in 2017.

Another case study for the capture and storage of CO_2 is the patented Pi-CO_2 method used in the CO_2-DISSOLVED project (Kervévan et al., 2013). Similar to the CarbFix program, the aim of this project was to integrate low enthalpy geothermal energy with the aqueous dissolution of CO_2 (Galiègue & Laude, 2017). The process combines geothermal energy and CCS, using the same aquifer for mining heat and storing CO_2. Unlike CarbFix however, which captures magmatic emissions from the geothermal production, CO_2-DISSOLVED involves the capture of CO_2 through separation of flue gas via aqueous technology. There are no magmatic CO_2 emissions, as the geothermal heat is extracted through a heat exchanger in a closed loop, similar to a binary plant (Kervévan et al., 2013). The carbonated reinjection brine was cited to have a higher density than the surrounding reservoir brine, allowing it to sink to deeper parts of the reservoir. This, along with the pressure maintenance afforded by reinjection, is thought to limit the ability of the CO_2 to escape from the reservoir (Galiègue & Laude, 2017; Kervévan et al., 2013).

The CO_2-DISSOLVED pilot project was conducted at a factory producing bioethanol from sugar beets in France, finding that the geothermal energy could offset some of the requirements from the natural gas boiler and that approximately 33% of CO_2 emissions could be captured. (Galiègue & Laude, 2017). Whilst conventional supercritical CO_2 capture could potentially sequester total emissions of the system, implementation of CO_2-DISSOLVED was found to be 50% cheaper for the case study.

The reinjection of dissolved CO_2, and its subsequent subsurface behaviour, has also been the subject of reservoir modelling. Numerical simulation results by Kaya & Zarrouk (2017), showed that reinjection of CO_2 (and other NCGs) when mixed with water can be a suitable sequestration tool, provided careful reservoir strategy is facilitated to avoid thermal and chemical breakthrough. Their modelling work highlighted that the majority of the CO_2 remained within the dissolved phase, mitigating the risk of cap rock leakage. However, it was also noted that a decline in pressure in the reservoir could induce the formation of a supercritical gas-like phase; gas components may subsequently rise to the surface due to buoyancy.

1.3 BECCS Technologies

Bioenergy and carbon capture and storage (BECCS) is a developmental technology where the associated emissions from bioenergy use are captured and sequestered. The combustion of biomass is considered a carbon neutral process, thus BECCS has the potential for negative emissions (Fridahl & Lehtveer, 2018; Kemper, 2015; Kervévan et al., 2017). The global potential of sequestration through BECCS is estimated to be 3.3 - 7.5 $GtCO_2$/year (Kemper, 2015; Woolf et al., 2010).

The 5th assessment report (AR5) presented by the Intergovernmental Panel on Climate Change (IPCC) stated that most scenarios cannot achieve a decline in CO_2 presence in the atmosphere to below 450ppm by the year 2100 without suitable deployment of BECCS applications (Kemper, 2015). In addition to AR5, the Shared Socioeconomic Pathways (SSP) framework indicates that BECCS is a key technology to reduce global greenhouse gas emissions. (Fridahl & Lehtveer, 2018). These scenarios typically assume that the carbon neutral production of biomass will allow for BECCS technologies to compensate for industries where emissions reductions could prove significantly challenging. Median scenarios of the SSP framework showcase BECCS technologies to account for roughly 20% of the total energy production by 2100 in order to achieve global climate goals.

The combination of geothermal and BECCS could be considered a carbon negative energy technology, due to the development of an artificial carbon sink. The bioenergy may assist in superheating geothermal fluid for maximum power output, whilst intrinsic reinjection infrastructure could provide the means for CO_2 injection into geothermal reservoirs. Rather than focus on the reinjection of solely magmatic NCGs, such as in CarbFix, or specifically target existing low-CO_2 industrial emitters, geothermal/BECCS could expand on applications of conventional geothermal systems whilst assisting in the pursuit of ambitious climate targets.

This study presents the methodology and results of a systems model showcasing a theoretical geothermal/BECCS hybrid doublet. The mass and energy balances allow for the determination of power production for different schematic arrangements. Additionally, sequestration limitations due to CO_2 solubility in water are tested for given reinjection conditions. Figure 1 illustrates the main heat and mass transfers envisioned for a geothermal/BECCS hybrid.

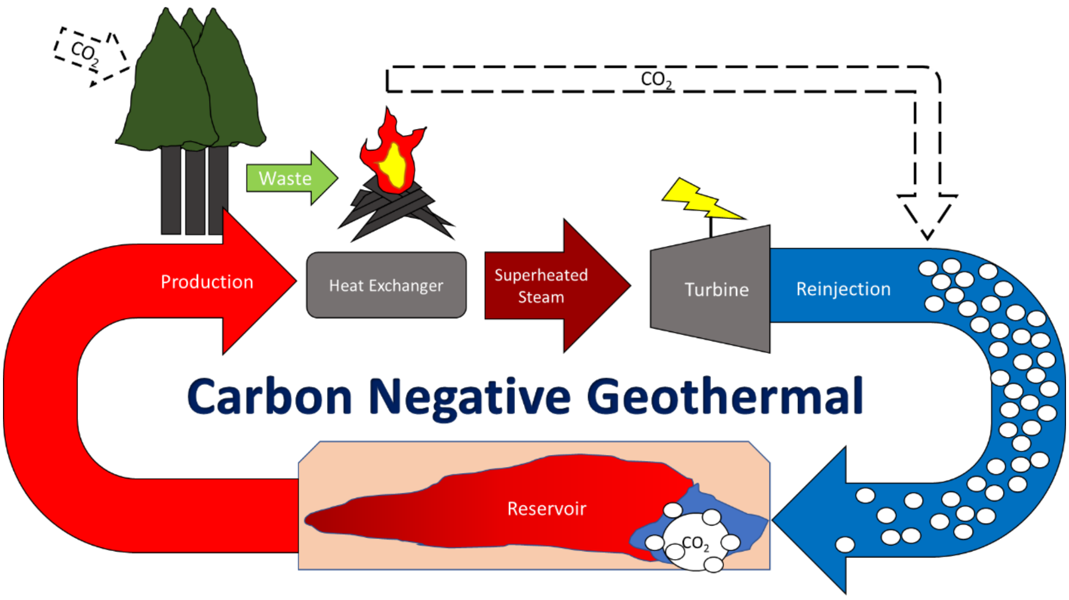

Figure 1: Illustrated life cycle of carbon negative geothermal systems.

2. METHODOLOGY

To evaluate the performance of a combined geothermal plant with biomass boiler, a systems model of a condensing turbine doublet system was constructed. The model is representative of the above-ground thermodynamic phenomena that occur as geofluid is produced from a production well, passes through a separator (in applicable scenarios), undergoes superheating from a biomass boiler (in applicable scenarios), expands in the turbine, is cooled in the condenser, and is finally dispatched for reinjection. Developing a model for the energy and mass balances of a hybrid geothermal/BECCS system is useful because it can inform on the usable geothermal heat, biomass feedstock burn rate, associated CO_2 emissions from the feedstock, power potential and maximum emissions capture for an array of initial conditions. Additionally, comparative analysis of the efficiencies of different scenarios and plant strategies can determine the strengths, weaknesses and risks of the respective approach. By identifying the desired fluid temperature after superheating, we can determine the corresponding biomass burn rate. This then allows us to calculate the CO_2 emissions of the boiler.

2.1 Model Construction

The input parameters for the model are designed to be representative of measurable or design values of a given hybrid geothermal/BECCS system. For this study, theoretical values are used that were found in literature or otherwise determined to be characteristic and plausible for geothermal systems.

The model accounts for the mass and energy balances in the following components of a doublet production-reinjection system:

- Production well
- Wellhead separator
- Biomass heat exchanger
- Condensing turbine

Additionally, the model determines:

- Magmatic NCG and boiler flue gas mass rate (CO_2-eq kg/s)
- Maximum solubility of CO_2 at various reinjection conditions (kg per kg of water)

2.1.2 Model Assumptions and Limitations

The initial model condition is characterised by the properties of the geothermal reservoir: temperature (T), pressure (P) and enthalpy (h), shown as point 1 on Figure 2. These parameters are integral to resource estimation in conventional geothermal fields. When considering fluid flow at a given flow rate through the production well, flashing in the wellbore can be treated as isenthalpic (DiPippo, 2015; DiPippo, 2015) Thus, the enthalpy at point 2, the wellhead, can be equated as such:

$$h_1 = h_2 \qquad (1)$$

If flashing in the wellbore is suspected to contribute to 'the excess enthalpy effect', as outlined by Thain & DiPippo (2015), then wellbore measurements or wellbore simulations are required to determine h_2.

If the geothermal fluid passes through a wellhead separator (point 3 on Figure 2), then induced flashing will occur and geothermal steam will separate from brine. The process is governed by conservation of mass and energy:

$$\dot{m}_t = \dot{m}_s + \dot{m}_b \qquad (2)$$

$$\dot{Q}_t = \dot{Q}_s + \dot{Q}_b \qquad (3)$$

Where the subscripts t, s and b denote total, steam and brine components. Energy rates, Q_i, can be expressed in terms of mass rate, $\dot{m}_i$, and specific enthalpies, h_t:

$$\dot{m}_t h_t = \dot{m}_s h_s + \dot{m}_b h_b \qquad (4)$$

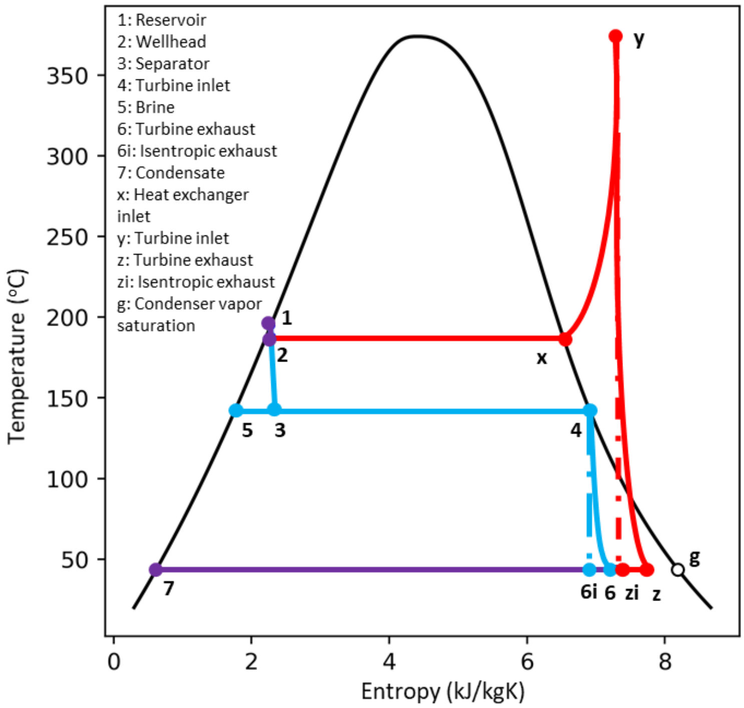

Figure 2: TS-Diagram of doublet process for a base geothermal system (blue line) and a hybrid geothermal/BECCS system without separator (red line). The purple line indicates the processes where the two systems overlap.

The mass fraction of separated steam is determined by solving Eqs. (2) and (4) for a given total flow of geothermal fluid (DiPippo, 2015). Component enthalpies h_s and h_b are computed via steam tables for known separator pressures. The enthalpy of steam and brine at the separator conditions can be derived from point 4 and point 5 (Figure 2), respectively. In a base case geothermal system, the steam would enter the turbine inlet at the pressure conditions at point 4. Wet expansion would occur within the turbine, characterized by the Bauman rule (DiPippo, 2015):

$$h_6 = \frac{h_4 - A\left[1 - \left(\frac{h_8}{h_7 - h_8}\right)\right]}{1 + A(h_7 - \ h_8)} \qquad (5)$$

Where points 6, 7 and g represent the actual turbine exhaust conditions, the properties of steam at condenser pressure and the properties of water at condenser pressure, respectively (Figure 2). The coefficient A, derived at the ideal turbine exhaust conditions, point 6i, is given by:

$$A = 0.5\, \eta_{TD}(h_4 - h_{6i}) \qquad (6)$$

Where the dry turbine expansion efficiency, η_{TD}, is set at the maximum theoretical value of 85%. Once the real exhaust conditions of the turbine are known, the generated power output, $\dot{W}_{gen}$, is determined (in MWe):

$$\dot{W}_{gen} = \dot{m}_s(h_4 - h_6) \qquad (7)$$

In order to determine the total saleable power, $\dot{W}_{net}$, parasitic loads, $\dot{W}_P$, must be deducted from this total:

$$\dot{W}_{net} = \ \dot{W}_g - \dot{W}_p \qquad (8)$$

If the plant was a hybrid with a separator, then following Eq. (4), the geothermal fluid would instead enter a heat exchanger for superheating, denoted with the subscript SHS. In this case, the mass rate of steam is unchanged:

$$\dot{m}_s = \dot{m}_{shs} \tag{9}$$

If there is no separator, then the total geothermal fluid will be dispatched for superheating. This is displayed by the red line on Figure 2, going from point 2 to point x. The mass rate of superheated steam shall be:

$$\dot{m}_t = \dot{m}_{shs} \tag{10}$$

Based on the design temperature for superheating, the enthalpy of superheated steam is determined, as showcased by point 4' on Figure 2. Thus, the heat required for superheating, $\dot{Q}_{SH}$, is determined from (Thain & DiPippo, 2015):

$$\dot{Q}_{SH} = \dot{m}_{shs}(h_y - h_x) \tag{11}$$

The biomass burn rate, $\dot{m}_{biomass}$, can then be calculated:

$$\dot{m}_{biomass} = \dot{m}_{shs}\frac{h_y - h_x}{\eta_{Boiler}HHV} \tag{12}$$

Where HHV is the higher heating value of the biomass feedstock and η_{Boiler} is the boiler efficiency (assumed or measured), reflecting a non-ideal boiler with some degree of heat loss during heat exchange. Because the residual enthalpy of steam condensate at the turbine exhaust is likely to be high, the equations for dry expansion are more appropriate in the hybrid case (Janes, 1984):

$$h_z = h_y - \eta_{TD}(h_y - h_{zi}) \tag{13}$$

For this study, if turbine expansion was mostly dry (above 90%), it was considered completely dry. Generated and net power would then be determined in the same way as in Eqs. (7) and (8) respectively, but with superheated steam conditions. Finally, the conversion efficiency, η_c, for the base geothermal plant could be determined by:

$$\eta_c = \frac{\dot{W}_{net}}{\dot{m}_t h_t} \times 100 \tag{14}$$

And for the hybrid plant:

$$\eta_c = \frac{\dot{W}_{net}}{\dot{m}_t h_t + \frac{\dot{Q}_{shs}}{\eta_{\mathrm{Boiler}}}} \times 100 \tag{15}$$

The model is designed to be modular and scalable, with the ability to add or remove certain geothermal apparatus for given scenarios. The solubility of CO_2 was integrated into the model by implementing the modelling work of Duan & Sun (2003).

2.1.2 Model Assumptions and Limitations

Whilst the process equations laid out in section 2.1.1 are representative of the primary thermodynamic phenomena of the doublet system, minor losses of pressure and temperature (and thus energy) have been neglected. These losses would occur at the previously described geothermal apparatus, scrubbing, gas extraction, insulation, valves, bends and orifice plates. The model assumes that the geothermal well will flow unassisted, and that no scaling or corrosion will occur within the above ground equipment. Several assumptions made regarding biomass feedstock were derived from a case study of Rotokawa I (Thain & DiPippo, 2015). This included the use of Kaingaroa forestry waste, values for higher heating value of monetary pine, and a moisture content of 25% in the feedstock. The model requires adjustments for non-wood-based biomass implementation. The model currently does not optimize the design conditions of the geothermal apparatus. Further, while the model has the capability of determining the solubility of CO_2 at various saline conditions, a pure water model was selected for simplicity of presenting scenario results. Finally, the model treats other commonly found NCGs from magmatic origin or flue gas as equivalent to CO_2. We assume that complete capture of magmatic NCGs, through engineering and design techniques, occurs. This can, for example, include the use of liquid ring vacuum pumps or surface condensers. Flue gas emissions capture would thus also be limited by the presence of these magmatic NCGs. For the scenarios outlined in Section 2.3, no attempt was made to quantify or assume a theoretical parasitic load. Thus, only generated power is presented in Section 3. This will result in a larger conversion efficiency value than in practice. Other engineering constraints involving the superheating of steam and managing of carbonated water are determined solvable (Dal Porto et al., 2016; Sigfússon et al., 2018; Thain & DiPippo, 2015).

2.3 Scenario Setup

In this study, we modelled eight different scenarios representing a range of end-member configurations for a unit mass flow of 1 kg/s (Table 1). The initial conditions for scenarios 1-4 were set to a theoretical geothermal reservoir temperature of 150 °C, which was considered by Hochstein (1990) to be on the boundary of low and medium temperature geothermal systems. Magmatic NCGs were considered at 2% by weight, based on a similar assumption by Kaya & Zarrouk (2017). At the assumed reservoir pressure of 50 bar, the enthalpy of the reservoir fluid was determined to be 635 kJ/kg, well below the saturation enthalpy of water at that pressure. Traditionally, a binary ORC plant would be more suitable than a condensing turbine for this reservoir enthalpy, with a likely estimated conversion efficiency below 6% (Zarrouk & Moon, 2014). These conditions were deliberately chosen to compare theoretical exploitation of a flash plant and three combinations of hybrid plants.

Scenario 1 consists of base-case geothermal flash plant with a production well, wellhead separator, condensing turbine, and reinjection well. The only CO_2 emissions would be of magmatic origin. Scenario 2 consists of a hybrid geothermal/BECCS system with a production well, wellhead separator, biomass heat exchanger, condensing turbine, and reinjection well. There would be CO_2 emissions from the flue gas in addition to magmatic NCGs. The steam from the separator would be heated to a final temperature of 375 °C in the heat exchanger. Scenario 3 has the same setup as Scenario 2, except that the steam from the separator would be heated to a final temperature of 425 °C in the heat exchanger. Scenario 4 consists of a hybrid geothermal/BECCS system with the biomass heat exchanger but no separator, with a final steam temperature of 375 °C. There would be CO_2 emissions from the flue gas in addition to magmatic NCGs. Scenarios 5-8 follow the same structure as Scenarios 1-4 but for an initial reservoir temperature of 195 °C, based on a survey of Tauhara domestic boreholes (Lebe, 2020). For the same pressure (50 bar), this corresponds to a reservoir enthalpy of approximately 831 kJ/kg. This reservoir enthalpy approaches the threshold suggested for exploitation with a flash plant with a low conversion efficiency (Zarrouk & Moon, 2014). The initial conditions for scenarios 1-8 are given in Table 1.

Table 1: Initial conditions for scenarios 1-8

Input	Scenarios 1-4	Scenarios 5-8	Units
Reservoir Temperature	150	195	° C
Reservoir Enthalpy	635	831	kJ/kg
Reservoir Pressure	50		bar (atm)
Geothermal Mass Rate	1		kg/s
Magmatic NCGS	0.0204		kg/s
Wellhead Pressure	12		bar (atm)
Separator Pressure	4		bar (atm)
Condenser Pressure	0.09		bar (atm)
Generator Efficiency	95		%
Dry Turbine Efficiency	85		%
Superheater Efficiency[1]	75		%
Bioenergy CO_2 Emissions	0.862		kg/kg-wood
Other NCG emissions (CO_2-Eq)[2]	0.015		kg/kg-wood
Higher Heating Value[1]	15350		kJ/kg

[1] (Thain & DiPippo, 2015)
[2] (Bioenergy Association, 2019)

3. MODEL RESULTS

For Scenarios 1-3, only a very small amount of steam, 0.0142 kg/s, is flashed out of the separator. The base case geothermal system generated 6.1 KWe and yielded a conversion efficiency of approximately 1%. For Scenarios 2 and 3, the biomass burn rate required to heat the steam from 150 °C to 375 °C or 425 °C was only 0.0006 kg/s and 0.0007 kg/s, respectively. The conversion efficiencies in Scenarios 2 and 3 were mildly improved from the base case, generating 8.7 KWe at 1.34% and 9.3 KWe at 1.4% efficiency, respectively. It was found that reinjection pressures less than 5 bar could facilitate total emissions capture. This would result in a 100% degree of carbon negativity. However, in Scenarios 2 and 3, the vast majority of the energy in the geothermal fluid was rejected by the separator as brine. The increase in the final superheating value from 375 °C to 425 °C only improved power production by 0.6 KWe (16%). The power gains between Scenarios 2 and 3 with regards to Scenario 1 can be described as 43% and 52% increase respectively. Because no separator was used in Scenario 4, the mass rate was thus considerably higher, and the enthalpy difference between the heat exchanger inlet and outlet was larger than Scenarios 2 and 3. Subsequently, the biomass burn rate to achieve superheating is substantially increased, to approximately 0.22 kg/s. The generated power in this scenario, 734 KWe, is over a hundred times the output of the base geothermal case. The conversion efficiency is substantially increased to 14.09%. This process results in greater total CO_2 emissions dissolved in the reinjection fluid, despite the requirement to increase the dissolution pressure threshold.

For Scenarios 5-7, the increase in reservoir enthalpy, from 635 kJ/kg to 831 kJ/kg allowed a higher mass fraction of steam to flash in the separator, 0.1 kg/s. The efficiency of the base geothermal plant improved to 5.5%, whilst Scenarios 6 and 7 saw an increase to 7.04% and 7.34%, respectively. This corresponded in a power gain of 20 KWe (42%) between Scenarios 5 and

Scenarios 6 and 24 KWe (52%) between Scenarios 5 and 7. Similar to Scenarios 2 and 3, total CO_2 reinjection is possible for low reinjection pressures for both Scenario 6 and 7 as the reinjection fluid would be undersaturated due to the small emissions.

Table 2: Model Results for Scenarios 1-8

	Mass of Steam (kg/s)	Biomass Burn Rate (kg/s)	Mass of Flue Gas (kg/s)	Superheater Heat Flow (KWth)	Generated Power (KWe)	Conversion Efficiency (%)
1	0.014	0.0000	0.0000	0.0	6.1	0.96
2	0.014	0.0006	0.0005	12.2	8.7	1.34
3	0.014	0.0007	0.0006	14.9	9.3	1.44
4	1.000	0.2235	0.1960	4573.5	733.8	14.09
5	0.106	0.0000	0.0000	0.0	45.7	5.49
6	0.106	0.0045	0.0039	91.4	65.0	7.04
7	0.106	0.0054	0.0048	111.2	69.7	7.34
8	1.000	0.2064	0.1810	4224.3	733.8	14.51

With the only change between Scenarios 4 and 8 being the increased reservoir temperature of the latter, the generated power outputs of the hybrid plants were identical. However, the decrease in the enthalpy difference between the heat exchanger inlet and outlet for Scenario 8 results in a slightly lower biomass burn rate of 0.206 kg/s, corresponding to a decrease in flue gas emissions and thermal requirement from the boiler. This allows for a lower pressure of reinjection fluid to reach saturation of CO_2. There is also an increase in conversion efficiency, at 14.51%, when compared to Scenario 4. To quantify the capacity of emissions capture for Scenario 8, at reinjection conditions at 1 kg/s and roughly 25 bar and 45 ^oC, 0.046 kg/s of flue gas emissions could be captured, which would be equivalent to 1.98 kTs/annum/MWe carbon negative. Flue gas emissions beyond dissolution capacity would be discarded.

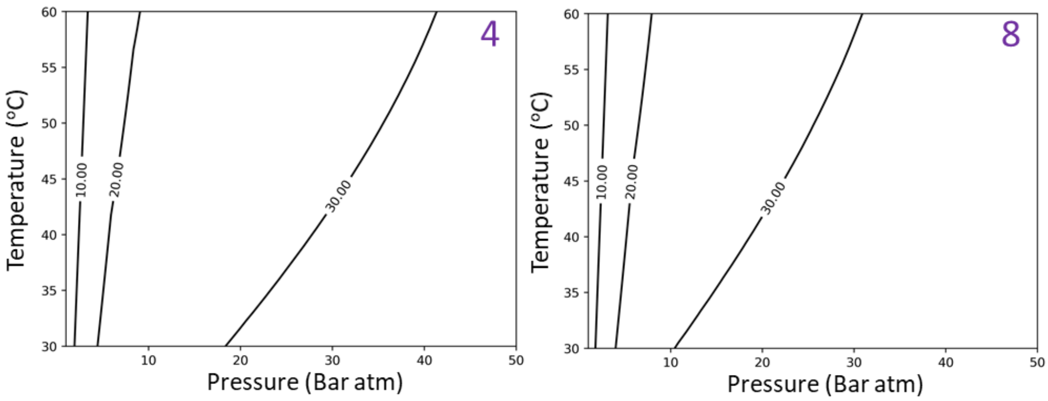

Figure 3: Total Emissions Capture for Scenarios 4 and 8.

4. DISCUSSION AND FUTURE WORK

This initial work showed the potential energy gains for superheating geothermal fluid with biomass, as well as the capacity to dissolve both magmatic NCGs (carbon neutral) and some amount of flue gas emissions (carbon negative) in reinjection flows. Our model results show that the choice to superheat total flow in a theoretical hybrid system can have a significant impact on power production, conversion efficiency and CO_2 emissions. Scenarios 4 and 8 had a significantly higher power output than all other scenarios, even displaying conversion efficiencies greater than the world-wide average for geothermal plants. However, it is possible that having no separator would limit the hybrid plant's load factor to that of the biomass boiler. For the hybrid scenarios including wellhead separators, an increase in the superheating target from 375 ^oC to 425 ^oC resulted in only a small increase in power production, conversion efficiency, and emissions requiring sequestration. The increase in reservoir enthalpy between the first four and the last four scenarios generally yielded greater power generation, except for Scenarios 4 and 8, where the final generated power output was equivalent. However, the greater reservoir enthalpy for Scenario 8 allowed for a lower biomass burn rate and thus lowered the threshold for emissions capture, which can already be limited by the presence of magmatic NCGs. For all counterpart scenarios, the conversion efficiency was higher, when the reservoir enthalpy was higher.

This first model iteration can currently be run for any given reservoir pressure, temperature and enthalpy. Further analysis is ongoing to add modular systems for base and hybrid binary schematics to the model. Additionally, economic analysis will be integrated to better characterize the opportunity costs of different configurations. This economic analysis is especially important when considering the cost of biomass and hypothetical price of carbon. Once the thermodynamic and economic model is complete, optimization and sensitivity analysis can be used to determine the feasibility of potential new hybrid systems, retrofits to existing plants, and analyse alternative biomass feedstocks. Acquisition of data from existing geothermal fields can assist in calibrating and improving the model. Quantifying the potential of carbon negative geothermal systems could expand the role of geothermal power production in meeting New Zealand's climate goals. This work is a first step towards making a business case for a pilot project to further test geothermal/BECCS technologies.

ACKNOWLEDGEMENTS

The authors of this study would like to acknowledge Prof. Rosalind Archer for her contribution in reviewing this work and providing expert advice.

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