DOCKETED	
Docket Number:	23-AFC-02
Project Title:	Elmore North Geothermal Project (ENGP)
TN #:	254505
Document Title:	Data Response Set 4 (Responses to Data Requests 1 to 43)
Description:	N/A
Filer:	Lindsey Xayachack
Organization:	Jacobs
Submitter Role:	Applicant Consultant
Submission Date:	2/16/2024 8:23:14 AM
Docketed Date:	2/16/2024

Data Response Set 4 (Responses to Data Requests 1 to 43)

Submitted to
California Energy Commission

Prepared by
Elmore North Geothermal LLC

With assistance from
Jacobs

Elmore North Geothermal Project
(23-AFC-02)

February 14, 2024

Introduction

Attached are Elmore North Geothermal LLC's[1] (Applicant) responses to the *California Energy Commission's (CEC) Data Requests Set 4* regarding the Application for Certification (AFC) for the Elmore North Geothermal Project (ENGP) (23-AFC-02). This submittal includes a response to Data Requests 1 through 43.

The responses are grouped by individual discipline or topic area. Within each discipline area, the responses are presented in the same order as presented *Data Requests Set 4* and are keyed to the Data Request numbers.

New or revised graphics or tables are numbered in reference to the Data Request number. For example, the first table used in response to Data Request 28 would be numbered Table DR28-1. The first figure used in response to Data Request 28 would be Figure DR28-1, and so on. Figures or tables from the ENGP AFC that have been revised have a "R" following the original number, indicating a revision.

Additional tables, figures, or documents submitted in response to a data request (for example, supporting data, stand-alone documents such as plans, folding graphics, etc.) are found at the end of each discipline-specific section and are not sequentially page numbered consistently with the remainder of the document, though they may have their own internal page numbering system.

[1] An indirect, wholly owned subsidiary of BHE Renewables, LLC ("BHER").

Contents

Appendices

Tables

Acronyms and Abbreviations

ACC	Air Cooled Condenser
ACHE	Air Cooled Heat Exchanger
AFC	Application for Certification
AFY	Acre-feet per Year
BRGP	Black Rock Geothermal Project
CEC	California Energy Commission
CPUC	California Public Utilities Commission
DOD	Department of Defense
DR	Data Request
DVCM	Desert Valley Company Monofill
EDP	Equitable Distribution Plan
ENGP	Elmore North Geothermal Project
IID	Imperial Irrigation District
IWSP	Interim Water Supply Policy
MBGP	Morton Bay Geothermal Project
NCGs	Non-condensable Gases
SCR	Selective Catalytic Reduction
TLCFP	Temporary Land Conversion Fallowing Policy
TN	Transaction Number
WSA	Water Supply Assessment

1. Alternatives (DR 1-11)

Background: Power Plant Cooling Alternative (DR 1-6)

The Elmore North Geothermal Project (ENGP) would require approximately 6,480 acre-feet per year (AFY) from the Imperial Irrigation District (IID) canal. Water taken from the IID Canal for the ENGP and the Morton Bay and Black Rock geothermal projects would total approximately 13,000 AFY.

In Data Request Set 1, staff requested an analysis of an augmented cooling system alternative for the ENGP, 140-MW baseload generating facility. In the data response, the applicant states that the alternative is infeasible "due to plant performance impacts, additional land usage required, and auxiliary power requirements" (Elmore North Geothermal 2023a, TN 252490-1). (The 63-acre plant site is located on a 140-acre parcel [APN 020-100-038] where the applicant has site control.) The applicant states that compared to a wet cooling tower, an augmented cooling system would require additional auxiliary power, causing a lower gross output and a less efficient facility. The applicant states that the alternative cooling system would greatly increase project costs.

On November 10, 2023, the applicant filed revised responses to several data requests from Data Response Set 1 for the ENGP, including an update to the Best Available Control Technology (BACT) evaluation for cooling tower particulate matter (PM) emissions. Air-cooled condensers (ACCs) with evaporative pre-cooling are among the PM abatement options in the BACT analysis update (Elmore North Geothermal 2023b, TN 253081).

The analysis states that ACC systems in higher temperature regions of California are expected to experience reduced efficiency. Heat balance case studies for the ENGP show that when temperatures are 100°F and higher, expected power output with an ACC would be 15 percent lower than with a wet cooling system. And it states that although evaporative pre-cooling could help mitigate this effect, project costs and the parasitic load of the process would increase. The three proposed geothermal projects are being designed as flash steam systems. By comparison, the analysis states that "ACCs are often implemented for binary geothermal plants, which are lower temperature systems requiring less cooling demand…." The analysis concludes that "based on the lack of demonstration of commercial ACCs on non-binary geothermal power plants, [i.e., flash systems] [an ACC with evaporative pre-cooling] is not considered technically feasible.…" The BACT proposed for cooling tower PM abatement for the three projects remains wet cooling with drift eliminators.

Data Requests:

1. *Please provide details on the effects of a pre-evaporative cooling alternative with an ACC system on power plant efficiency and net generating capacity.*

Response: Please see the Applicants Notice Pursuant to 20 C.C.R. § 1716(f) for CEC Data Requests Set 4 submitted on February 2, 2024. Without waiving its objection to this data request, the Applicant provides the following response.

Equipment Supplier Engagement

The Applicant engaged multiple vendors about specifications for available commercial products. Dry cooling supply vendors contacted include SPG Dry Cooling, EvapCo, Jord, and Hayden. The Applicant received feedback from these vendors that there are no readily available commercial air cooled condensers (ACC) with or without pre-evaporative cooling that are suitable for this project. This is due primarily to the corrosion potential of geothermal steam relative to that generated in steam boilers or the clean working fluids used in binary geothermal power plants. As such, the Applicant cannot evaluate the potential effects of the installation of pre-evaporative cooled ACC in place of the wet cooling tower system.

Prior Studies of Alternatives

In the 2011 "Air Cooling Options for Flash Plants" report prepared by Roubaix Louw, Kevin Wallace, and William Harvey (provided as Attachment DR 1A), the study highlights the history of air cooled heat rejection systems for flash plants. Key findings from the study, and further discussion of those findings, include the following:

- Only one air cooled heat rejection system had been installed at a geothermal flash plant globally at the time of publication, and the plant (Mutnovsky) consisted of three small 4 MW turbines located in a cold climate on the Kamchatka peninsula, Russia. Operating data from these facilities was not available to the authors of the study for review to give insight into how effectively these facilities operated. While not mentioned in the 2011 study (Louw 2011), an additional, larger power plant was installed at this location and the developer chose to implement a wet cooling tower at that facility.
- Fundamental challenges associated with air cooled condensers exist at geothermal flash plants that make air cooled condensers challenging to consider for implementation. Such challenges include the poor ability to separate non-condensable gases (NCGs) and the potential for poor heat exchange due to sulfur scale accumulation from the oxidation of hydrogen sulfide present in the geothermal steam.
- There was a net power reduction of 2% for the design condition of 20°C (68°F) for a Flash/ACC configuration compared to a geothermal flash plant and cooling tower (Flash/CT) configuration. While the study did not investigate the impacts at higher temperatures, the power generation discrepancy between a Flash/CT approach and a Flash/ACC approach is known to widen significantly as temperatures increase, as discussed below.
- A heat exchanger cost multiplier of 3x for a Flash/ACC configuration compared to a Flash/CT configuration.
- An air cooled heat exchanger (ACHE) with a closed circuit cooling water system serving a more traditional condenser arrangement may be considered to address some of the technical challenges associated with managing NCGs in geothermal steam; however:
  - The expected heat exchange cost multiplier would still be expected to be 2x that of the cooling tower configuration translating to an increased cost of $300-$500 per net kW in 2011 (>$50 million in 2011 for the Elmore North Geothermal Project at the midpoint in 2011 dollars), and
  - The expected net power output was calculated to be 14% (approximately 171,696,000 kwh/year) lower than the cooling tower configuration at 20°C.

Current Subject Matter Expert Commentary

One of the authors of the Louw et. al. 2011 study, Dr. William Harvey, prepared a technical memorandum, entitled "Cooling system assessment for the BHER Salton Sea Geothermal Plants", provided as Attachment DR 1B. This memorandum provides updates to the consideration and implementation of dry cooled systems globally since 2011, and the feasibility of such systems related to a large geothermal flash plant in southern California. This memorandum by Dr. Harvey supports the conclusion that ACCs and other dry cooling systems are not viable for the ENGP due to:

- The poor performance of air cooled systems generally in hot climates such as the Salton Sea;
- A flash plant being the preferred and demonstrated approach to geothermal power generation in the area where the ENGP is located; and
- ACCs and other dry cooling approaches are not being commercially demonstrated for flash plants.
- The unique characteristics of the Salton Sea geothermal fluid make utilization of an air cooled system especially challenging.

ACC Viability

Air cooled condensers are not feasible for this project due to

1. The lack of a commercially available ACC product suitable for the corrosive steam associated with the geothermal resource that will supply the ENGP; and
2. The inability to manage the NCGs associated with the steam.

ACHE (ACC Alternative) Viability

"Air Cooling Options for Flash Plants" studies a theoretical ACHE system in place of the ACC system with its known technical challenges. An ACHE based heat rejection system is deemed not feasible for this project due to:

1. The lack of a commercially demonstrated ACHE system at a flash geothermal power plant;
2. Significantly increased plant technical complexity and risk;
3. Reduced year-round baseline power production relative to a typical ACC which is already worse than a cooling tower;
4. A more exaggerated drop in power production during high ambient temperature conditions relative to a typical ACC which is already worse than a cooling tower;,
5. Increased vulnerability of steam turbine tripping in high ambient temperature conditions which is not a risk with the considered cooling tower approach;
6. Significantly increased project cost; and
7. Significantly increased area requirements.

Consideration of such complex, seasonally variable performance, and first-of-a-kind technologies that is unproven for use with geothermal flash plants in the region is not feasible, and would impede achievement of CPUC's mandate to add baseload geothermal power on a rapid timeline and is, therefore, deemed not viable for the project.

ACHE Poor Summer Performance Mitigation

DRs 1 through 6 relate to the viability of a pre-evaporative cooling system for air to be used as a heat exchange medium to mitigate poor performance of dry cooling systems in summer months.
Pre-evaporative cooling of an ACHE approach would mitigate some, but not nearly all, of the negative

impacts described in ACHE Viability Items 4 and 5 above but adds more undemonstrated technology to an already untested technology for flash plants (worsens ACHE Viability Item 1 above), adds another layer of complexity and risk (ACHE Viability Item 2 above), and increases water consumption by the project (not previously mentioned in ACHE Viability section).

Cooling Tower Water Usage Relative to Overall Site Water Usage

Finally, it is important to recognize that the water consumption associated with the wet cooling tower based heat rejection process is the minority of water expected to be used by the ENGP. Approximately 14% of the water used by the ENGP is associated with use of a cooling tower (provided in the AFC as Figure 2-5, Peak Water Balance, TN# 249737), or approximately 907 acre-feet per year.

The majority of the ENGP's water use is associated with dilution water, which is required to be added to the geothermal brine as it flashes (lowers in pressure) and cools to prevent the increasingly saline geothermal brine from precipitating solids uncontrollably and causing blockages in the plant and pipelines.

2. *Please provide the heat and mass balance diagram for a pre-evaporative cooling alternative with an ACC system for the project site for temperatures of 100°F and higher.*

Response: Please see the Applicant's Notice Pursuant to 20 C.C.R. § 1716(f) for CEC Data Requests Set 4 submitted on February 2, 2024.

3. *Please provide justification for why reducing generating capacity is an infeasible alternative for this project when considering this alternative cooling system.*

Response: Please see the Applicant's Notice Pursuant to 20 C.C.R. § 1716(f) for CEC Data Requests Set 4 submitted on February 2, 2024.

4. *Please provide details on how the equipment requirements and the projected loss in efficiency and net generating capacity for this alternative cooling system would impact project costs and profitability.*

Response: Please see the Applicant's Notice Pursuant to 20 C.C.R. § 1716(f) for CEC Data Requests Set 4 submitted on February 2, 2024, and the response to DR 1 above. As discussed in DR 1, as there is no commercially available ACC product, use of ACC, whether with or without pre-evaporative cooling, it is not a feasible option for the ENGP.

5. *Please provide details on the acreage requirement for this alternative cooling system and how the additional equipment might be configured on the project's 140-acre parcel. Please explain the specific impacts of a larger footprint to accommodate the alternative cooling system.*

Response: Please see the Applicant's Notice Pursuant to 20 C.C.R. § 1716(f) for CEC Data Requests Set 4 submitted on February 2, 2024, and the response to DR 1 above. As discussed in DR 1, as there is no commercially available ACC product, use of ACC, whether with or without pre-evaporative cooling, it is not a feasible option for the ENGP.

6. *Please estimate the operational water use requirements for this alternative cooling system.*

Response: Please see the Applicant's Notice Pursuant to 20 C.C.R. § 1716(f) for CEC Data Requests Set 4 submitted on February 2, 2024, and the response to DR 1 above. As discussed in DRR 1, as there is no commercially available ACC product, whether with or without pre-evaporative cooling, therefore it is not a feasible option for the ENGP.

Further, it is important to recognize that the water consumption associated with the wet cooling tower based heat rejection process is the minority of water expected to be used by the ENGP. Approximately 15% of the water used by the ENGP is associated with use of a cooling tower (provided in the AFC as Figure 2-5, Peak Water Balance, TN# 249737). The majority of the ENGP's water use is associated with dilution water, which is required to be added to the brine as it cools to prevent the increasingly saline brine from precipitating solids and causing blockages in the plant.

Background: Increased Efficiency of Water Consumption as a Potential Alternative (DR 7-9)

During the August 31, 2023, CEC Joint Environmental Scoping Meeting and Informational Hearing for the *three proposed geothermal projects, Chair David Hochschild asked the applicant's representative, Jon Trujillo, about improvements in water use efficiency. Trujillo described the challenge of controlling the dilution water required to manage the dissolved solids and salts in the geothermal fluid. Trujillo stated that the applicant is looking at alternative methods and every viable efficiency. Commissioner Andrew McAllister asked whether there is value in the mineral resources dissolved in the brine, and if so, would exploiting those resources decrease power plant water requirements. Trujillo responded that it depends on the technology developed to recover the minerals and suggested that without more information on the selected technology, it is too speculative to determine the impact on water use (CEC 2023, TN 252499).*

Chair Hochschild asked Alicia Knapp, CEO of BHE Renewables, about the prospect of eventually co-locating lithium production at the three geothermal power plant facilities. Knapp responded that separate from the geothermal projects, the applicant is testing technology to recover lithium from the brine. Knapp explained that a lot of work remains before the applicant knows whether lithium extraction can be done in an environmentally sustainable manner while being economically feasible.

Data Requests:

7. *Please explain any work being done to evaluate methods to increase efficiency of water consumption in the geothermal fluid production cycle for the proposed project. If such work is occurring, please estimate when preliminary results will be available.*

Response: The Applicant's corporate philosophy is to minimize environmental impacts and conserve natural resources to the greatest extent possible. Recognizing the importance of water conservation in California in general and arid environments like southeastern California, ENGP has already been designed for optimal water efficiency given site specific characteristics, such as average ambient temperature and the nature of the geothermal resource, over 30 years of operational history in the region, and operational requirements for this specific facility. The requested water allocation is in line with best water management practices developed over decades of operation in the region.

The single largest source of fresh-water consumption by the ENGP is for dilution water purposes. The highly saline brine becomes supersaturated with chloride salts as it flashes and cools and therefore, dilution water must be added to prevent spontaneous precipitation of chloride salts under these conditions to avoid pipe plugging and plant shutdown. The addition of dilution water keeps the total dissolved solids below 32% and reduces the quantity of steam generated and an associated reduction in power output. The second largest source of water consumption is cooling tower evaporation. The rate of evaporation is fixed by ambient weather conditions and the heat rejected from the process steam.

Additional minor water uses include activities such as reagent preparation and cooling tower blow down. Sites in the region have previously experimented with options to reduce water consumption associated with minor uses, and optimal water management practices for these plants have been developed and incorporated into the design of the ENGP.

8. *Regarding testing technology on lithium production, please describe whether the applicant is assessing processes for increasing efficiency of water consumption and when analysis results might be available.*

Response: The Applicant is not currently testing technology to recover lithium from geothermal brine. The statement referenced in the Background to DR 8 with respect to testing technology to recover lithium from geothermal brine relates to a separate demonstration project. As stated in response to DRs 36-38, submitted as part of the Applicant's Data Response Set 1 (TN# 252490-1), lithium extraction and production are not proposed as part of the ENGP. Therefore, the Applicant is not assessing processes for increasing efficiency for water consumption at the ENGP relating to lithium production.

9. *Please provide any scientifically supported information regarding water use requirements for geothermal power production with and without lithium extraction.*

Response: Please see the Applicant's Notice Pursuant to 20 C.C.R. § 1716(f) for CEC Data Requests Set 4 submitted on February 2, 2024. The water use requirements are only for the geothermal power production without lithium extraction. Within the total water consumption, 69% is for the dilution water,14% is for cooling tower makeup and 17% is for auxiliary plant operating usage.

Background: Alternative Project Sites (DR 10-11)

In Data Request Set 1, staff requested information on other potential sites that were considered for the ENGP. In the data response, the applicant lists several properties that were evaluated as potential sites before being rejected due to greater environmental impacts and related construction challenges (Elmore North Geothermal 2023a, TN 252490-1). The ENGP property is described as "more optimal for pipeline distances and is already owned by the applicant." The applicant and its affiliates hold the mineral and geothermal interests on most of the properties that were considered for the ENGP (Elmore North Geothermal 2023c, TN 249737).

Data Requests:

10. *Please state whether the applicant owns or otherwise has an option to purchase other properties in the Salton Sea Geothermal Reservoir (except for the Black Rock and Morton Bay sites). Please provide the assessor's parcel number(s) for any such properties.*

Response: The Applicant does not own or otherwise have an option to purchase other parcels in the Salton Sea Geothermal Reservoir area. However, subsidiaries of the Applicant's parent company, BHE Renewables, LLC owns the surface rights to the following parcels in fee. Unless stated otherwise, subsidiaries of BHE Renewables, LLC also leases the mineral rights underlying the parcels. As stated in Section 1.5 of the AFC, Magma Power Company, a parent of the Applicant, owns and will operate the geothermal leasehold for the project.

In Data Response Set 1, DR 16 (TN# 252490-1), the Applicant discussed the parcels that were evaluated as potential sites for the ENGP, including siting considerations, which were ultimately deemed infeasible. Similar siting considerations have been applied to the parcels identified below in Table DRR-13, and fall into six primary categories with the following parameters:

- Minimum parcel size of 60 acres;
- Whether there are existing structures/land uses that may limit facility configurations or use of the parcel;

- Whether there is sufficient access to high heat flows to support operations;
- The environmental sensitivity of the parcel, including potential habitat or special-status species;
- Presumed tribal cultural sensitivity; and
- Accessibility, including whether the Applicant has control of the underlying mineral rights.

Table DRR-10. Evaluated Parcels for ENGP

APN	Parcel Size (Acres)	Reasons Why Parcel Is Infeasible for Power Plant Site
020-100-028	6	Parcel size is less than 60 acres.
020-010-034	7	Parcel size is less than 60 acres; Lack mineral rights.
020-110-054	14	Parcel size is less than 60 acres; Existing structures, buildings, and uses on the parcel.
020-100-014	19	Parcel size is less than 60 acres; Existing structures, buildings, and uses on the parcel.
020-100-037	20	Parcel size is less than 60 acres; Existing structures, buildings, and uses on the parcel.
020-110-038	20	Parcel size is less than 60 acres; Existing structures, buildings, and uses on the parcel.
020-100-039	20	Parcel size is less than 60 acres; Existing structures, buildings, and uses on the parcel.
020-100-029	23	Parcel size is less than 60 acres.
020-110-042	26	Parcel size is less than 60 acres; Existing structures, buildings, and uses on the parcel.
020-110-035	40	Parcel size is less than 60 acres; Existing structures, buildings, and uses on the parcel.
020-120-049	40	Parcel size is less than 60 acres.
020-110-046	41	Parcel size is less than 60 acres.
020-120-060	41	Parcel size is less than 60 acres; Existing structures, buildings, and uses on the parcel.
020-120-059	41	Parcel size is less than 60 acres; Existing structures, buildings, and uses on the parcel.
020-110-047	48	Parcel size is less than 60 acres; Existing structures, buildings, and uses on the parcel.
020-110-055	60	Existing structures, buildings, and uses on the parcel.
020-120-054	78	Existing structures, buildings, and uses on the parcel.
020-110-049	79	Existing structures, buildings, and uses on the parcel; Lacks sufficient access to high heat flows.
020-120-057	80	Lacks sufficient access to high heat flows.

APN	Parcel Size (Acres)	Reasons Why Parcel Is Infeasible for Power Plant Site
020-100-040	80	Existing powerplant, structures, buildings, and uses on the parcel.
020-120-056	82	Lacks sufficient access to high heat flows.
022-100-011	97	Lacks sufficient access to high heat flows.
020-110-019	122	Existing powerplant, structures, buildings, and uses on the parcel.
020-010-032	150	No control of mineral rights, only surface owned in fee. Also see, Data Response Set 1, Data Response 16 for further details.
021-300-002	160	No control of mineral rights, only surface owned in fee; Lacks sufficient access to high heat flows.
020-110-039	162	Existing powerplant, structures, buildings, and uses on the parcel.
020-110-056	162	Would require additional piping/conveyances/ROWs to access proposed ENGP production/injection wells; Located too far away from Elmore North Geothermal Leasehold (as depicted in AFC Figure 2-3).
021-300-001	166	No control of mineral rights, only surface owned in fee; Lacks sufficient access to high heat flows.
020-010-035	473	No control of mineral rights, only surface owned in fee. Also see, Data Response Set 1, Data Response 16 for further details.
021-200-011	486	No control of mineral rights, only surface owned in fee; Lacks sufficient access to high heat flows.
020-010-032	150	No control of mineral rights.

11. *Please explain the rights conveyed by the mineral and geothermal leases for properties in the Salton Sea Geothermal Reservoir compared to those conveyed by site ownership.*

Response: Please see the Applicant's Notice Pursuant to 20 C.C.R. § 1716(f) for CEC Data Requests Set 4 submitted on February 2, 2024. Without waiving its objection to this data request, the Applicant provides the following response.

California law provides that ownership of real property grants a person the right "to possess it and use it to the exclusion of others." Cal. Civ. Code §§ 654, 658. The right to possess and use the real property to the exclusion of others "includes free or occupied space for an indefinite distance upwards as well as downwards". Cal. Civ. Code § 659. Ownership of, or interests in, the surface and subsurface can be separated in a variety of ways, including a mineral lease. (See, *Howard v. County of Amador,* 220 Cal.App.3d 962, 972), oil and gas lease, or a geothermal lease. *(*See generally, *Kenncott Corp. V. Union Oil Co.*, 196 Cal.App.3d 1179.) In general, a mineral lease typically grants the holder a limited right to enter and remove resources covered by the lease, in addition to a limited right to use the surface as "necessary and convenient" to remove the resource, which in some cases may involve the entirety of the surface. (See, for example, *Wall v. Shell Oil Co., 209 Cal.App.2d 504).*

2. Air Quality (DR 12-14)

Background: Project Lifespan (DR 12-14)

The Elmore North Geothermal Project Data Request Response Set 1 (Revised Responses to Data Requests 3, 4, 7, 10 to 13, and 73 to 77) (TN 253081) states that the project would use one Tier 3-certified fire pump and three Tier 4-certified emergency generators (collectively, the Units). In the emission estimation and impacts analysis, the applicant used vendor data for the Tier 3 fire pump and assumed Tier 4 emissions for the emergency generators. However, based on experience analyzing data center projects, staff understands that normally the selective catalytic reduction (SCR) for the Units needs time to warm up before it can reach full NOx control effectiveness. Therefore, worst-case hourly NOx emissions would include uncontrolled emissions during the warm-up period and controlled emissions for the rest of the hour. Staff needs engine manufacturer and emissions control device specifications sheets to verify the emission rates used by the applicant. Staff also needs clarification on whether the applicant would test the engines concurrently or only one engine at a time during a single hour.

Data Requests:

12. *For the Units, please provide up-to-date manufacturer specification sheets showing engine and emissions control system performance specifications. This information should identify uncontrolled and controlled emissions and the warm-up time for the SCR to reach full effectiveness.*

Response: The Applicant is working to secure up-to-date manufacturer specification sheets showing engine and emission control system performance. These specification sheets will be submitted along with the revised modeling requested in DR 13 below.

13. *For the Units, please update the NOx emissions estimation and NO_2 impacts modeling analysis to account for uncontrolled emissions during the SCR warm-up period and controlled emission for the rest of the hour.*

Response: Consistent with the request for additional time requested in filing on February 2, 2024 (TN# 254297), the requested modeling results will be provided on or before March 11, 2024.

14. *Please clarify whether the engines used by the Units would be test concurrently or only one at a time during a single hour.*

Response: Engines used by the units would be tested one at a time during a single hour.

3. Biological Resources (DR 15-17)

Background: Production Wells and Pads (DR 15-17)

Per the AFC and the November 17, 2023 General Area Refinement (TN249737 and TN 253187, respectively), proposed construction of Elmore North would include nine production wells on five well pads, plus one additional well pad for resource support. As shown on Figure 1-4 (TN249737) and Figure 1-4R (TN 253187), the production wells and pads are located north and northwest of the project site. Four of these well pads occur in areas within the Sonny Bono Salton Sea National Wildlife Refuge. The location of proposed well pads within the refuge have historically and episodically been inundated with water long enough to support the growth of emergent wetland vegetation. Based on a review of Google Earth Pro images from 1985 to present, one or more of these well pads were at least partially inundated for the following months and years: Dec. 1985; Sep. 1992; June 1996; May 2002; Jan. 2003; June 2005; Aug. 2005; Dec. 2005; Jan. 2006; Aug. 2006; Feb. 2008; June 2009; Sep. 2010; May 2012; June 2012; and Mar. 2014. Based on a review of Google Earth Pro images, the refuge in the area of these 4 well pads began drying (i.e., had less inundation) in June 2012, Mar. 2014, and Mar. 2015; and was dry or had minimal inundation in Oct. 2016, Feb. 2019, Apr. 2020, and Feb. 2023.

CEC biological resources staff, the U.S. Fish and Wildlife Service, and the California Department of Fish and Wildlife are concerned with characterizing and managing the changing conditions of these areas where the production wells and pads are proposed to occur. Listed species such as the desert pupfish (state and federally endangered) and Yuma Ridgeway's rail (federally endangered, state threatened, and state Fully Protected species) are known to occur in the area where these structures are proposed to be located. "Fully Protected" species are those for which no incidental take may be authorized (Fish and Game Code Sections 3511, 4700, 5050 and 5515). It is our understanding that the source of the water for these areas is primarily the Imperial Irrigation District canals and drains, which convey rain and agricultural runoff. Staff is concerned that if/when these areas become inundated, listed species may be present, and experience incidental take. This may necessitate a Section 7 Incidental Take Permit, if there is a federal nexus, or a Section 10 Habitat Conservation Plan, if there is not a federal nexus, under the Endangered Species Act. If Yuma Ridgeway's rail are present, avoidance of the area or an application for appropriate take permits pursuant to SB147 may be required. Staff recommends that the applicant begin the time consuming federal permit process early, if necessary.

Data Requests:

15. *Please provide background on the reasoning for the placement of the production wells in the Salton Sea National Wildlife Refuge. Are there alternative location(s) for these four production wells outside the Refuge and areas of historic inundation? Were alternative locations considered, and if so, why were they dismissed?*

Response: As discussed in DRR 10 above as well as DR Set 1, DR 16 (TN# 252490-1), several parcels were considered for alternative plant locations as well as well pads. Key components for the selected well pad locations the proximity to the geothermal resource with high heat flows, ability to access to the location, and distance to ENGP. Parcels were rejected if they would have caused greater impacts on special status species habitat and wetlands as well as potential construction challenges. The ENGP well pad locations were ultimately chosen to sustain sufficient production and injection capacity for the project life while reducing potential environmental impacts.

Furthermore, the concerns about historic inundation should be balanced against the fact that flooding is not a reasonably foreseeable event and that the Salton Sea shoreline has receded approximately 0.5 mile over the last decade, substantial reducing the risk of inundation of ENGP site and well pads.

16. *Please provide measures that will be implemented if the areas for the production wells are inundated at the onset of construction.*

Response: At the onset of construction, if the production well pads are inundated construction will occur at other well pad locations that are dry and commence again after the areas are dried out. Standard SWPPP best management practices would be put in place during construction to prevent stormwater flowing outside the construction area as well as prevent stormwater flowing into the project. In addition, even with the recent 2023-2024 storms (current and historic rainfall provided below in Tables DRR-16A and DRR-16B) the project and well pad areas have not been inundated due to rain.

Table DRR-16A. Historic Rainfall in Niland, CA

Niland					
	Sep 2023	Oct 2023	Nov 2023	Dec 2023	Jan 2024
Monthly data	0.52	0.00	0.17	0.00	1.16
Normal range*	0.00-0.18	0.00-0.19	0.00-0.12	0.00-0.32	0.12-0.44

*30% chance precipitation a given month will fall outside of the range based on historic data (1971-2000)
Values are in inches
Source: ACIS WETS tables https://agacis.rcc-acis.org/?fips=06025

Table DRR-16B. Historic Rainfall at Imperial County Airport, CA

Imperial County Airport					
	Sep 2023	Oct 2023	Nov 2023	Dec 2023	Jan 2024
Monthly data	0.52	0.00	0.23	trace	trace
Normal range*	0.00-0.15	0.00-0.04	0.00-0.12	0.00-0.19	0.00-0.22

*30% chance precipitation a given month will fall outside of the range based on historic data
Values are in inches
ACIS WETS tables https://agacis.rcc-acis.org/?fips=06025

17. *Are there physical or engineering structures that would/could be constructed to prevent inundation of the production wells in the future, after completion of construction?*

Response: Developing engineering structures for a reasonably unforeseeable and hypothetical inundation are inappropriate at this time. The Project will be built to the appropriate building codes and requirements appropriate for this location.

4. Land Use (DR 18-19)

Background: Consultation with United States Department of Defense (DR 18-19)

Review of the California Military Land Use Compatibility Analyst (CMLUCA) mapping tool maintained by the Governor's Office of Planning and Research (OPR) indicates the proposed project is in an area designated as Military Special Use Airspace – Military Operation Area (MOA). The CMLUCA mapping tool and notification list can be accessed via OPR's Military Affairs webpages here: https://opr.ca.gov/planning/land-use/military-affairs/

Additional geospatial information for U.S. Military Installations, Ranges, and Training Areas (MIRTA) can be accessed at the Defense Installations Spatial Data Infrastructure webpage: https://www.acq.osd.mil/eie/bsi/bei_disdi.html

Review of the MIRTA Map Viewer (site managed by U.S. Army Corps of Engineers) shows, like the CMLUCA, the project site is within Special Use Airspace – Low Altitude – MOA, in addition to being beneath Military Training Route – Visual and Military Training Route corridor – Visual.

The following is excerpted from the Warren-Alquist Act, Public Resources Code, section 25519.5:

a. *If the site and related facilities specified in the application are proposed to be located within 1,000 feet of a military installation or lie within special use airspace or beneath a low-level flight path, as defined in Section 21098, the applicant shall inform the United States Department of Defense of the proposed project and that an application will be filed with the commission.*

b. *If provided by the United States Department of Defense, the applicant shall include within the application a description of its consultation with the department, with regard to potential impacts upon national security, including potential impacts on the land, sea, and airspace identified by the United States Department of Defense and its impacted service components, for conducting operations and training, or for the research, development, testing, and evaluation of weapons, sensors, and tactics. If the information is provided after the application is filed, the applicant shall forward the information upon receipt.*

Data Requests:

18. *Please provide confirmation that the applicant has informed the United States Department of Defense (DOD) of the proposed project because the project appears to lie within special use airspace and beneath low-level flight path. DOD contact information and request form for project review is available at: https://www.dodclearinghouse.osd.mil/*

Response: Letters were sent to the US Department of Defense (DOD) on February 12, 2024 and docketed on February 12, 2024 (TN# 254410).

19. *If provided by the DOD, please file upon receipt a description of the applicant's consultation with the DOD, with regard to potential impacts upon national security, including potential impacts on the land, sea, and airspace identified by the DOD and its impacted service components, for conducting operations and training, or for the research, development, testing, and evaluation of weapons, sensors, and tactics.*

Response: As of the time of filing no communications have been received from the DOD.

5. Solid Waste (DR 20-21)

Background: Schedule of Desert Valley Company Monofill Cell 4 Expansion (DR 20-21)

According to the Solid Waste Information System (SWIS) website (CalRecyle 2023, https://www2.calrecycle.ca.gov/SolidWaste/SiteActivity/Details/4194?siteID=606), the Desert Valley Company Monofill (DVCM) has a remaining capacity of 789,644 cubic yards (cy) and is permitted through January 31, 2025. According to the applications for the Elmore North, Morton Bay, and Black Rock geothermal projects, an estimated 62,000 tons of filter cake produced from geothermal brine would be generated annually from these facilities. Using a filter cake density of 2.0 grams per cubic centimeter (Own et al. 1979, https://www.osti.gov/servlets/purl/5696613), the 62,000 tons per year would convert to approximately 36,783 cy per year. Over the anticipated 30-year project period, the estimated total filter cake (1,103,490 cy) would represent 140 percent of the remaining reported DVCM capacity. In addition, the facility is due to close in January 2025 without the proposed DVCM Cell 4 expansion (BRG Consulting 2021, https://www.icpds.com/assets/GPA18-0004-ZC18-0005-CUP18-0025-DVC-Draft-EIR-.pdf). As the DVCM facility is local and uniquely permitted to receive filter cake waste, its continued operation would benefit the proposed geothermal projects.

Data Requests:

20. *Please provide information regarding the estimated completion of the DVCM Cell 4 expansion and whether and how this would affect geothermal filter cake disposal for the proposed geothermal project.*

Response: The DVCM Cell 4A phase 1 expansion is estimated to be completed by the second quarter of 2026. The existing DVCM cell is projected to reach its capacity by October 2027 and the five-year Solid Waste Facility Permit renewal review is due September 18, 2025. Construction of Cell 4A in conjunction with existing operating cells provide operational flexibility to accommodate geothermal filter cake disposal from the proposed geothermal project.

21. *Please identify an alternate disposal option for the geothermal filter cake from each location if the DVCM Cell 4 expansion is not completed or remains inadequate in time for project operation.*

Response: Copper Mountain Landfill operated by Republic Services, Inc. in Yuma, Arizona will be designated as an alternate disposal option for the geothermal filter cake from each location.

6. Water Resources (DR 21-43)

Water Supply Assessment

In response to Data Request Set 1, Data Request 99, the applicant submitted a draft Water Supply Assessment (WSA) in accordance with Senate Bill (SB) 610. CEC staff is concerned about the Imperial Irrigation District's (IID's) ability to provide reliable water supply to the MBGP as well as the Elmore North and Black Rock geothermal projects during normal periods, as well as single and multiple-year dry periods, throughout the life of the projects. This is due to the combined annual operational water demand for the three proposed geothermal projects of approximately 13,165 AFY, which comprises approximately two-thirds of the remaining 19,620 AFY available non-agricultural set- aside under IID's Interim Water Supply Policy (IWSP) (IID 2009).

Background: WSA – Lead Agency Designation (DR 22)

The first section of the WSA, Purpose of Water Supply Assessment, identifies the lead agency as Imperial County Planning & Development Services.

Data Requests:

22. Please revise the WSA to identify the CEC as the lead agency under the California Environmental Quality Act (CEQA).

Response: The draft of the Water Supply Assessment reviewed by the CEC staff was a preliminary draft submitted to the Imperial Irrigation District (IID) for their review and comment. This draft is undergoing revisions based on IID's comments and will be re-issued as a draft final version. In this draft final version, the Applicant will add text to note that the CEC is the lead agency under the California Environmental Quality Act.

Background: WSA – Impact of Project Water Demand to IID (DR 23)

The Executive Summary of the WSA (Page iii) states; "Thus, the proposed Project's estimated water demand, combined with other development anticipated in the area is likely to adversely affect IID's ability to provide water to other users in IID's water service area."

Data Requests:

23. Please explain how this observation would be mitigated by IID to ensure water supply to the proposed geothermal projects and existing agricultural users would be provided.

Response: Fees are paid by the developer for the procurement of water or a program that will generate conserved water. The developer pays a fee for IID to secure a quantity of water sufficient to satisfy the project's water needs similar to other in lieu fees collected by any other state/local agency.

Background: WSA – Impact of Voluntary Water Conservation (DR 24-25)

The Executive Summary of the WSA (Page iv, paragraph 2) states; "IID has gone on record that its share of the California proposal under a voluntary plan would not exceed 250,000 AFY as long as there are no obligatory reductions imposed."

Data Requests:

24. *Please explain how and to what extent potential water reduction and the voluntary conservation measure would impact water supply to the proposed geothermal projects.*

Response: The reductions are applicable through calendar year 2026 and the Project is not expected to be operational in 2026. Therefore, these potential water reductions are not expected to impact the project.

25. *Please explain how possible delivery reductions that could result from revisions to the Colorado River Interim Guidelines for Lower Basin Shortages and Coordinated Operations for Lake Powell and Lake Mead (2007 Interim Guidelines) would be addressed and what impact this could have on the proposed geothermal projects' water supply.*

Response: If a request for an "X" percentage of water reductions is issued to IID by a governmental authority having appropriate jurisdiction, then each water user within IID's service territory will see an "X" percentage reduction in their water supply.

Background: WSA – Efficient Water Use (DR 26-28)

Section 1, Project Description of the WSA (paragraph 4, Page 1-2) describes proposed Best Management Practices (BMPs) for water use efficiency such as: use of fresh water supplied by IID shall not exceed the agreed-upon amount. In addition, it states that the project will comply with California Water Code (CWC) Section 461.

Data Requests:

26. *Please explain how not exceeding the agreed-upon amount of fresh water will result in water use efficiency. Please discuss alternate BMPS that would result in verifiable water use efficiency.*

Response: ENGP has been designed for optimal water efficiency given site specific characteristics, such as average ambient temperature and the nature of the geothermal resource, over 30 years of operational history in the region, and operational requirements for this specific facility. The requested water allocation is in line with best management practices developed over decades of operation in the region. These best management practices include optimizing the amount of dilution water injection that is necessary to stabilize the chlorides within the fluid and prohibit precipitation, optimizing cooling tower blowdown at nightshift during the summer season, optimizing the cooling water treatment with vendor to maintain the water quality, and monitoring the cooling water quality through biweekly internal lab sampling and testing to keep the freshwater usage under the agreed-upon amount.

27. *Please correct the link and URL included in Section A5 of Appendix A directing the user to the WikiHome, Bathroom Home Improvement webpage, not the California Urban Water Conservation Council BMPs. The California Urban Water Conservation Council BMPs have been archived at the following URL: https://calwep.org/our-work/conservation/bmp-guidebooks/*

Response: The WSA will be updated to correct the hyperlink.

28. *Please provide information on how the project would use reclaimed water to satisfy beneficial water use per CWC Section 461.*

Response: The Applicant evaluated using IID drain water and effluent from the town of Calipatria's water treatment system. The IID drain water contains higher levels of total dissolved solids content than the Project can accept and withdrawal of drain water would impact Desert pupfish within the drains. Further the use of IID drain water would reduce agricultural drain flows into the Salton Sea, resulting in further reduction in the sea's elevation. The quantity of effluent from Calipatria's water treatment system is insufficient to support the project. The Applicant is unaware of any reclaimed water sources in the Project area with sufficient supply to support the project's water demand.

Background: WSA – Proportionate Water Demand Reduction (DR 29)

Section 1 of the WSA (paragraph 5, Page 1-2) states; "the MBGP may be required to reduce its water supply demand by a proportionate reduction of the total volume of water available to IID."

Data Requests:

29. *Please explain how the proportionate reduction would be determined for water users and how this could specifically impact the proposed geothermal projects' water supply.*

Response: As noted above, proportionate reduction means that if an "X" percent reduction in IID's water supply is issued, then all IID water users would experience an "X" percentage reduction.

Background: WSA – Contradictory Statements Concerning Future Water Demand (DR 30)

Section 1.4 of the WSA (Page 1-11) states: "long term water supply augmentation is not anticipated to be necessary to meet proposed project demands." However, Section 6.1 of the WSA (Page 6-2) states: "Given the prolonged drought conditions and recent communication from the Department of the Interior, reductions to all basin contractors, including IID, are increasingly likely. These two statements seem to contradict each other. Also, the second statement indicates that the likelihood of water supply reduction in the future is high."

Data Requests:

30. *Please describe how the project would manage water supply reductions and what measures would be taken to address delivery shortages over the life of the project.*

Response: Please see the response to DR 26.

Background: WSA – IWSP Conservation Measures (DR 31)

Section 1.5 IID Interim Water Supply Policy [IWSP] for Non-Agricultural Projects (September 2009) of the WSA (first paragraph, Page 1-13) describes how the IWSP designates up to 25,000 AFY to be conserved from IID's annual Colorado River supply. Based on the explanation in Section 1.6, part of this designation is achieved through the Temporary Land Conversion Fallowing Policy (TLCFP). However, other conservation measures that contribute to the 25,000 AF annual designation are not specified in the IWSP.

Data Requests:

31. *Please describe the other means of water conservation that account for the 25,000 AF annual designation.*

Response: Developers pay IID an in lieu fee commensurate with their water needs and IID implements conservation projects to generate the needed water supply. A current example is IID has a system conservation project, a reservoir, that once constructed will conserve an estimated 10,000 acre-feet of water per year (AFY). In addition, IID's programs include farm fallowing, canal lining projects, and a water system conservation program. The water system conservation program includes a Discharge Reduction Program consisting of:[2]

- Communication upgrades
  - Installation of automated lateral headings
  - Design and installation of monitored discharge sites
  - Laptop computers for Zanjeros.
  - SCADA integration and monitoring
- Large operational reservoirs
- Mid-Lateral off-line operational reservoirs
- Existing operational reservoir up grades
- Main canal and lateral interties
- Main canal seepage recovery projects

Background: WSA – Availability of Non-Agricultural Project Set-Aside (DR 32)

The last paragraph of Section 1.5 of the WSA (Page 1-14) states: "As of May 2023, IID has issued two water supply agreements under the IWSP that total 5,380 AFY, leaving a balance of 19,620 AFY of potential water supply available for additional contracting under the IWSP." Therefore, the estimated operation water demand for all three proposed geothermal projects of 13,165 AFY constitutes about 67 percent, or two-thirds, of the non-agricultural project water supply available in the IWSP program.

Data Requests:

32. Please explain how IID would provide water demand if other competing projects demand more than the remaining 33 percent of the available IWSP water supply prior to the project possibly being certified.

Response: The 25,000 AFY is identified in the 2009 (Interim Water Supply Policy for Non-Agricultural Projects (IWSP)[3]. If IID needs to increase the industrial water supply above this amount, they would need to complete another environmental document to effect this change.

Background: WSA – Clarification of the IWSP Fee Schedule (DR 33)

In Table 8 of the WSA (Section 1.5, Page 1-14) the highest tier included in the IWSP fee schedule is defined as customers with a demand between 2,501 and 5,000 AFY. The annual estimated water demand for both the Elmore North and Morton Bay geothermal projects (6,480 AF and 5,560 AF, respectively) exceed the upper limit of the highest tier.

Data Requests:

33. Please clarify if these projects would be included in the highest tier of Table 8 or if a new tier would be created.

[2] https://www.iid.com/water/water-conservation/system-conservation

[3] https://www.iid.com/water/water-conservation/fallowing/temporary-land-conversion-fallowing-policy-tlcfp

Response: The Applicant understands that when IID receives a water supply agreement request for more than 5,000 AFY, the IID Board of Directors will establish additional rate tiers as necessary.

Background: WSA – Association of Water Conservation with IWSP (DR 34)

Section 2.2.6 of the WSA (paragraph 4, Page 2-3) states that IID will receive billions of dollars for the water they conserve as part of the Quantification Settlement Agreement (QSA) and Transfer Agreements.

Data Requests:

34. *Does the water conservation that IID will receive payment for include the conservation to support the IWSP program?*

Response: No, Section 2.2.6 states that payments are for the transfer of water. The Quantification Settlement Agreement pays for the transfer water. The IWSP pays for the water conservation projects by private development at a local level on a case by case basis.

Background: WSA – Analysis of Dry Year Water Availability (DR 35-36)

Section 3 of the WSA (Page 3-1) states that analysis for multiple dry years required for SB 610 is not applicable since water availability from IID is not dependent on local rainfall and would not differ between normal and dry years. However, the lack of regional precipitation over the greater Colorado River basin could affect the Colorado River flows and as a result IID's allocation of water supply.

Data Requests:

35. *Please consider a revision to Section 3 to recognize that regional weather patterns could impact IID's water supply.*

Response: Section 3 of water supply assessment will be revised to acknowledge that regional weather patterns could impact IID's water supply.

36. *Please revise Section 3 to note that this topic is also addressed in Section 5.*

Response: Section 3 of the WSA will be revised to include a reference to Section 5 as appropriate.

Background: WSA – Clarification of EDP Clearinghouse (DR 37-38)

Section 5.1 of the WSA (Page 5-4) states: "The Revised 2022 EDP also establishes a water exchange clearinghouse to facilitate the movement of water supply between all water users and water user categories. Water user categories identified in the Equitable Distribution Plan (EDP) are 1) agricultural, 2) potable water, and 3) industrial/commercial (IID 2023, https://www.iid.com/home/showpublisheddocument/20254/638313266942930000)."

Data Requests:

37. *Please describe the types of projects in the industrial/commercial water user category.*

Response: The Industrial/Commercial water user category applies to a user receiving district nonpotable water for anything other than agricultural production. It can be agriculture related (i.e., a packing shed), but if it is not agricultural production related it is categorized as Industrial/Commercial.

38. *Please clarify how movement of water supply will be conducted through the clearinghouse, and how these measures will address potential delivery shortages over the life of the project.*

Response: Every user will get apportioned water based on their projected need. There are three water user categories – IID system needs, agricultural uses, and municipal/potable/industrial/commercial uses. IID removes the quantity of water required to operate their system and then divides the remaining water as follows: 96% for agriculture and 3% for municipal, potable water, and industrial/commercial water uses. Water is then distributed to each customer based on a three year average use. At the commencement of operation of the ENGP, the Applicant will request water based on projected use through the clearinghouse and will be supplied as available.

In addition, there is a set aside that each categories have access to, called reserve water. More information can be found in The Revised 2023 Equitable Distribution Plan (EDP) approved and adopted by the IID Board on July 26, 2023.[4]

Background: WSA – Water Reduction Impact to Project Operations (DR 39-40)

Section 6.1 of the WSA (paragraph 3, Page 6-2) states; Given the prolonged drought conditions and recent communication from the Department of the Interior, reductions to all basin contractors, including IID, are increasingly likely. If such obligatory reductions were to come into effect within the 20-year project life, the applicants are to work with IID to ensure any anticipated reduction can be managed.

Data Requests:

39. *While it is reassuring that IID would work with the applicant if drastic water conservation measures were enacted, please explain how such obligatory reductions would impact the operational water supply to the proposed geothermal projects.*

Response: Please see the response to Data Request 26.

40. *A planned operational life of a 40-year project is identified in numerous passages in the applications for the three proposed geothermal projects (Jacobs 2023a, Jacobs 2023b & Jacobs 2023c, TN 249724 and TN 249752). Please correct the project life to 40 years throughout the document and ensure that the water availability analysis reflects a 40-year operational period.*

Response: The planning period for the WSA, as stipulated in Senate Bill 610, is 20 years. A water supply agreement will be executed between IID and the Applicant which will be tied to Imperial County's issuance of a Conditional Use Permit (CUP) for the well field facilities (well pads and conveyance pipelines).

Background: WSA – Impact of Combined Water Demand (DR 41)

Section 7 (Page 7-1) of the WSA lists the construction and operational water demand for MBGP in Table 14 (150 AFY & 5,560 AFY, respectively). However, the water demand of all three proposed geothermal projects (BRGP, ENGP & MBGP) should be considered together, especially with respect to the limitations of the IWSP set-aside.

[4] https://www.iid.com/home/showpublisheddocument/20254/638313266942930000

Data Requests:

41. *Please include in the WSA an analysis of how the water demand of all three proposed geothermal projects impacts the regional water supply.*

Response: The WSA is project specific, and Table 14 (within the WSA) presents the amount of water needed for this specific Project. Table 5 of the WSA provides a cumulative summary of the non-agricultural water demand and includes the BRGP and MBGP, in addition to the ENGP.

Background: WSA – Comparison of Project and Agricultural Water Use (DR 42)

Section 8 of the WSA (Page 8-3) states: "In any case, the proposed project will use less water than the historical agricultural demand of proposed project site, so the proposed project will ease rather than exacerbate overall IID water demands." This statement is erroneous. The rates based on estimated water demand for all three proposed geothermal projects (Black Rock GP: 7.03 AF/acre, Elmore North GP: 40.50 AF/acre and Morton Bay GP: 34.75 AF/acre) are significantly higher than the historic use of 5.1 AF/acre used for comparison.

Data Requests:

42. *Please correct the statement referenced above.*

Response: The referenced statement will be removed from the final draft of the WSA.

Background: WSA – Non-Agricultural Water Delivery Without IWSP (DR 43)

The WSA (Page 8-3) states: "In the event that IID has issued water supply agreements that exhaust the 25 KAFY [thousand acre feet per year] IWSP set aside, and it becomes apparent that IID delivery demands due to non-agriculture use are going to cause the district to exceed its quantified 3.1 MAFY [million acre feet per year] entitlement less QSA/Transfer Agreements obligations, IID has identified options to meet these new non-agricultural demands. These options include (1) tracking water yield from temporary land conversion from agricultural to non-agricultural land uses (renewable solar energy); and (2) only if necessary, developing conservation projects to expand the size of the district's water supply portfolio."

Data Requests:

43. Please clarify how tracking yield from land conversion and developing conservation projects in the future will address the likely immediate delivery shortfall. Include actual measures proposed and resulting expansion of the district's water supply portfolio.

Response: Section 8.1 of the WSA presents how land conversion tracking and water conservation measures are achieved annually. Based on discussions with IID, there have been substantial water savings due to recent solar developments within IID's service territory.

Additional information on IID's The Temporary Land Conversion Fallowing Policy (TLCFP) can be viewed at https://www.iid.com/water/water-conservation/fallowing/temporary-land-conversion-fallowing-policy-tlcfp .

Attachment DR 1A
Air Cooling Options for Flash Plants

Air Cooling Options for Flash Plants

Roubaix Louw[1], Kevin Wallace[1], and William Harvey[2]

[1]POWER Engineers
[2] Reykjavik University

Keywords

Air cooling, air cooled condenser, flash plant, hybrid cooling, surface condenser, water consumption

ABSTRACT

Flash steam power plants commonly use evaporative cooling with wet cooling towers, with cooling tower makeup provided by the condensed steam. These units are often preferred over binary units for high temperature resources for thermodynamic and economic reasons. However, at locations where near 100% reinjection of the produced geofluid is required, binary or combined cycle units with air-cooled condensers are generally applied. There are certain limitations in applying air-cooled condensers for flash units, and we discuss these considerations.

The purpose of this paper is to explore the opportunities and challenges of coupling a flash cycle, for harnessing high temperature resources, with air cooling to allow complete reinjection. The performances of air cooled flash plants are investigated and compared to a conventional water cooled flash plant configuration, as well as to an air cooled binary plant. The plants are compared in terms of gross, parasitic, and net power consumption. A number of heat exchanger configuration options for an air-cooled flash steam plant are investigated and described in terms of capital cost, material selections and non-condensible gas handling capability. A configuration with a steam turbine, surface condenser, and air-cooled heat exchanger, circulating water in a closed loop, is presented as a viable air-cooled flash alternative, with modest performance and capital cost penalties compared to a plant equipped with a wet cooling tower or air-cooled binary unit. Avenues for future improvements of the various cycles are presented.

Introduction

Although there has been a recent expansion of binary cycle suppliers, spanning a range of working fluids, turbine types, and packaging methods, for fundamental thermodynamic and commercial methods the flash plant, utilizing steam admitted directly through the turbine, remains the preferred option for higher temperature resources. Flash plants also have the benefit of supplying themselves with a supply of clean condensate, which can be used as makeup water for a wet cooling tower. Of the steam in a flash plant that passes through the turbine and condenser, approximately 75% of this flow is subsequently evaporated in a wet cooling tower, with the balance sent to reinjection.

There are some locations where the reservoir conditions or permitting considerations restrict the net withdrawal of fluid from the reservoir. Full reinjection may help avoid subsidence, such as has been encountered at Wairakei (Brockbank et al, 2011). There may be a desire to minimize impact on nearby thermal features which may have recreational or cultural value. There may be conditions which limit reservoir recharge or external injection water supplies. Or there may be a permitting environment where the evaporation and drift from a wet cooling tower are viewed as undesirable. With potential future EGS applications in especially arid locations, water conservation measures may be doubly important to conserve fluid for the reservoir. In circumstances such as these binary plants are generally used, coupled to air cooled condensers (ACCs). While air cooled condensers are generally more sizeable, costly, and less efficient than wet cooling towers, when the constraints require their use they are a widely used and proven option.

In this paper we explore the possibility of using a flash plant with a variety of cycle configurations to allow the use of air-cooled condensers. Currently there is only a single air-cooled flash plant operating; the Mutnovsky project in Russia (DiPippo, 2008). We discuss why there are few of these plants operating currently, and evaluate the impact on plant performance and cost by moving to air cooling. We discuss some limitations that future research might be able to overcome, and posit that an air-cooled flash option might be a competitor to binary units for high-temperature resources with water use limitations.

Cycle Configurations

We set out here a level basis of resource and ambient conditions for comparisons of the different configurations, as shown in Table 1.

Table 1. Design criteria for comparisons.

Design Condition	Assumption	**Comments**
Site Elevation	Sea level	-
Design Dry Bulb Temperature	20	Assuming a design based on summer conditions
Design relative humidity	50%	For comparison with water-cooled options
Geofluid conditions	Geofluid enthalpy of 1200 kJ/kg	Moderately energetic; lower than higher grade resources such as in New Zealand or the Salton Sea
Geofluid flowrate	1.2 million kg/h	-

The various cycles are compared on a basis of constant geofluid flowrate, with the impact on gross and net generation evaluated. The size of the plant for these resource conditions and flow rate is around 50 MW gross; a reasonably modest-sized plant at a high-temperature resource. A double flash cycle is used for all flash cases, with the flash pressures tuned to increase net power output for each cycle.

Figure 1. Germencik flash plant with wet cooling tower.

Flash/CT

We start by considering the typical performance of a conventional water-cooled flash unit equipped with a cooling tower, similar to the Germencik plant shown in Figure 1. A single steam turbine accepts the high and low pressure steam and exhausts to the direct contact condenser. Hotwell pumps transfer the mixture of condenser cooling water and condensate to the cooling tower. We assume this plant has no H_2S abatement system, for simplicity in comparison.

Binary/ACC

A typical binary plant operating with isopentane as a working fluid, an air-cooled condenser, recuperation, and other features commonly associated with these cycles is considered next. The Ormat plant at Olkaria III, shown in Figure 2, would be analogous to this plant choice. These are generally constructed of several modules of <15 MW each, each turbine exhausting to a dedicated ACC section, although the several ACC sections are generally grouped into larger banks.

Flash/ACC

The next cycle examined is an air-cooled flash unit, with the turbine exhausting directly to an air-cooled condenser. This

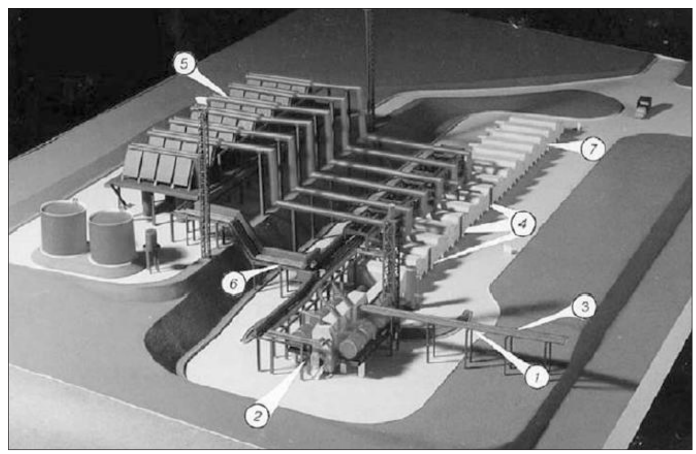

Figure 3. Mutnovsky air-cooled flash plant (DiPippo, 2008).

Figure 2. Olkaria III binary plant with air cooled condensers (Ormat).

ACC may be in either a horizontal or A-frame configuration. Figure 3 shows the Mutnovsky project; which is a single flash plant consisting of three 4 MW turbines (#4) exhausting to A-frame ACCs (#5).

Although the authors have not reviewed detailed performance or O&M data from the Mutnovsky plant, we can envision that for a large geothermal flash plant, such as the one under consideration, operating with an ACC would have several complications. The first is collecting the non-condensible gases (NCG) that are present in the geothermal steam. This would be very difficult in a horizontal-type ACC with little opportunity for separation of the gases and liquid. Some manufacturers have proposed means to accomplish this in an A-frame ACC, as shown in Figure 4. It is not clear how efficiently this is accomplished at Mutnovsky with their A-frame ACCs. Additional pilot testing of these techniques in a geothermal environment would be advisable before wider commercial implementation. Secondary air-cooled exchanger loops would be required for cooling of components such as gas removal system intercondensers, vacuum pump seal water, or lubrication oil coolers.

The second consideration that gives one pause for applying an ACC as a geothermal steam condenser would be the potential for deposition of solids. The large area of the ACC and operation at subatmospheric pressure would inevitably permit some air inleakage. In cases where the steam contains hydrogen sulfide, it is possible that sulfur formed from its oxidation would build up within the tubes. There may be other impurities in the steam such as silica that would deposit in the tubes, depending on the efficiency of steam washing. It is not clear how easily the A-frame ACC could be cleaned if tube fouling were indeed to occur. Better cleaning options for a geothermal ACC could also be a candidate for research and development, if the Flash/ACC option were appealing.

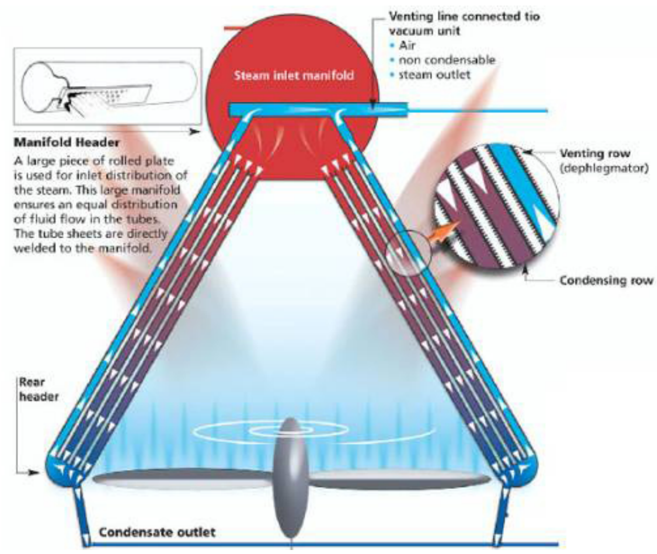

Figure 4. NCG venting in an A-frame ACC (GEA).

Flash/ACHE

The final cycle examined is a flash plant with a surface condenser. The surface condenser is cooled by circulating water. This circulating water is cooled in a separate air-cooled heat exchanger, or ACHE. Water with a corrosion inhibitor would be used as the circulating fluid. While both the Flash/ACC and Flash/ACHE cycles would have some minor losses of water carried as humidity out with the venting of non-condensible gases, these would be small (hundreds of kg per hour), and minimal evaporative losses would occur from the cooling cycle. While this cycle adds another level of heat transfer resistance and complexity, it avoids the difficulties inherent in the scaling and NCG buildup that one might encounter in an ACC applied for a flash unit. Figure 5 shows a process flow diagram of the Flash/ACHE configuration. No geothermal plants with this configuration are currently operating, although surface condensers are commonplace in the geothermal industry, and water-to-air heat exchangers are relatively uncomplicated.

Comparisons

Table 2 shows a summary of gross and net output for the various cycles. It should be noted that detailed thermodynamic and commercial tuning centered around the turbine exhaust pressure and heat exchanger approaches can result in many potential

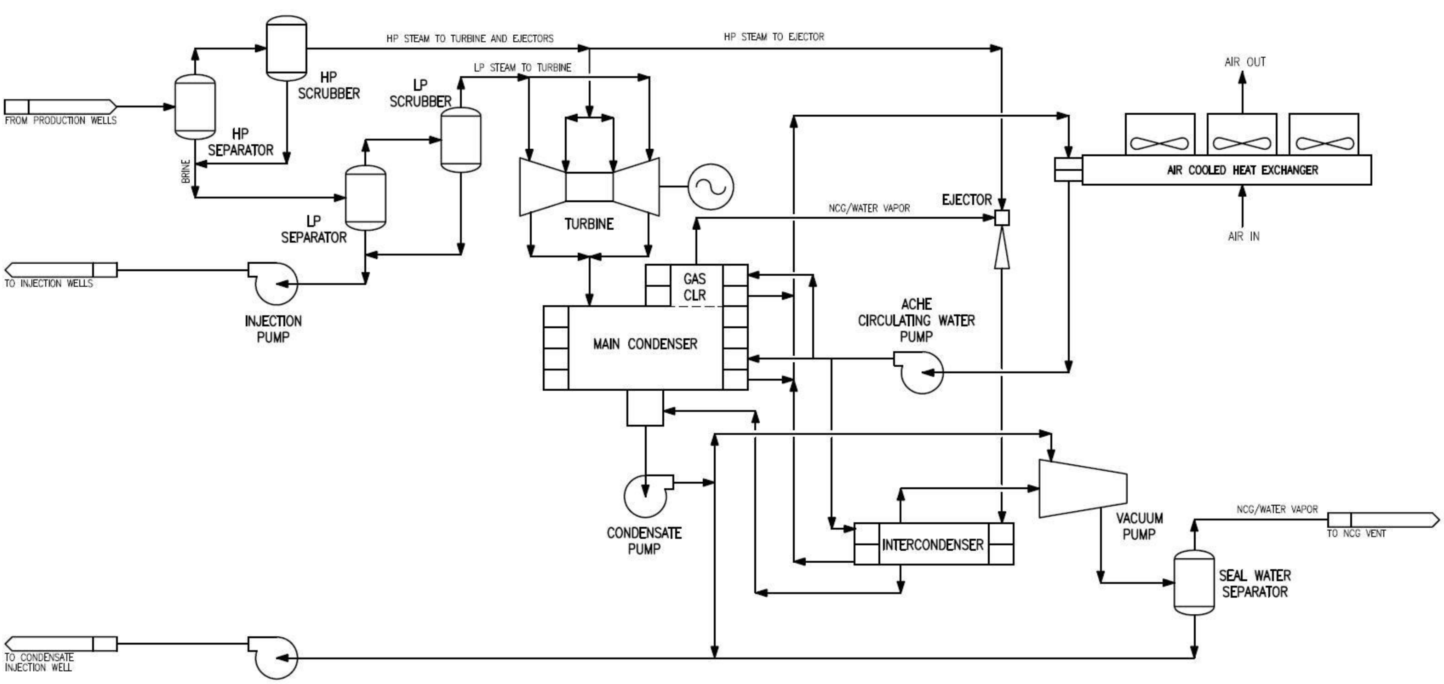

Figure 5. Process schematic of the Flash/ACHE cycle.

combinations of gross, parasitic, and net output. For this study we have selected typical midrange values encountered in plants to obtain the values shown in the table, but others are certainly possible. As one might expect, for the high-temperature resource under consideration, the water-cooled flash plant has an edge in net output over the air-cooled binary unit, despite comparable gross output, due to the lower parasitic loads. Thermodynamically, there would be an advantage in cooling the turbine exhaust directly using an ACC compared to indirectly through an ACHE, however practical limitations in the application of a Flash/ACC cycle as discussed might make it less attractive.

Table 2. Summary output for cycles.

Cycle Configuration	Gross Power (kW)	Parasitic Load (kW)	Net Power (kW)
Flash/CT	51,935	3,303	48,632
Binary/ACC	50,886	5,988	44,898
Flash/ACC	51,219	3,500	47,718
Flash/ACHE	48,103	6,420	41,683

Table 3 indicates the distribution of the major parasitic loads related to the cooling systems at various plants. None of the air-cooled options rely on wet cooling tower fans. The Flash/ACHE requires an additional investment of over 1 MW of circulating water loads over the Flash/ACC option. Considerable effort is generally expended in tuning the condenser pressure, cooling tower range and approach, and circulating water flow of a flash plant using wet cooling. Tuning a Flash/ACHE cycle for commercial and technical performance would require a similar effort to maximize the project net power and present value. Driving down the cost and parasitic consumption of the ACC or ACHE, while limiting turbine backpressure increases, would be key.

Table 3. Sample distribution of major parasitic loads.

Cycle Configuration	Circulating Water Pumps	Cooling Tower Fans	Air-Cooled Condenser or Heat Exchanger Fans
Flash/CT	880	893	-
Binary/ACC	-	-	1760
Flash/ACC	-	-	1657
Flash/ACHE	1400	-	3478

Table 4 shows some commercial considerations concerning the ACC or ACHE. Heat exchanger areas and cost multipliers were estimated using the Hudson software program ACHE v2.0. We have found this a bit conservative for the larger ACC/ACHEs, but reasonable for making qualitative comparisons between similar options. The Binary/ACC and Flash/ACHE approaches have the significant advantage of being able to use carbon steel tubes for the air coolers, due to the non-corrosive cooling fluid. The base equipment cost for the ACC for the Binary/ACC cycle might be in the $8-10 million range. In contrast, the Flash/ACC approach will require stainless steel or similar corrosion resistant tube material to resist the effects of handling the geothermal steam/NCG mixture, with possible air inleakage as well, due to operation at subatmospheric pressure. For the approaches selected, the overall required heat transfer area for the Flash/ACC is approximately double compared to the Binary/ACC. Although rejecting a similar heat duty, the ACC for the flash plant thus is estimated to cost an additional $10-15 million compared to the ACC for the binary plant, not considering the technical improvements required to deal with the NCG removal and scaling issues.

In contrast, the Flash/ACHE may be constructed of carbon steel wetted materials, as it can handle a water/glycol coolant. The ACHE is not required to operate at subatmospheric pressure, and air inleakage is restricted to the surface condenser. Duty is comparable to the other cycles, and heat transfer area is comparable to the Flash/ACC. As a result the ACHE cost would fall between the ACCs for the Binary/ACC and Flash/ACC.

Table 4. Heat Exchanger Considerations.

Cycle Configuration	Tube Materials	Heat Exchanger Cost Multiplier
Flash/CT	N/A	N/A
Binary/ACC	Carbon steel	1x
Flash/ACC	Stainless steel	3x
Flash/ACHE	Carbon steel	2x

The Flash/ACHE requires a circulating water system, including circulating water pumps and surface condenser, which would not be required for the Flash/ACC option. For a 50 MW plant these installed costs might be in the $10-$15 million range. The total capital cost of the Flash/ACHE thus might be comparable or a bit higher than the Flash/ACC option, despite the lower heat exchanger cost.

The Flash/ACHE thus suffers several penalties, most notable when compared to the Flash/CT option. It may have a performance penalty of approximately 15% of net output. It may have a cost penalty in the range of $300-500 per net kW. Where cooling tower makeup water is available, the Flash/CT option will remain the favored choice.

Bombarda and Macchi (2000) indicated that water-cooled flash units operating in this geofluid enthalpy range around 1200 kJ/kg may have a cost advantage ($200-500/kW) over binary units, with the advantage widening at higher temperatures. It is thus possible that for circumstances where air cooling is required, the Flash/ACHE may be competitive compared to the Binary/ACC option. Although not covered in this study, it would be insightful to compare the performance of the Flash/ACHE and the Binary/ACC for operations during the extreme hot and cold ambient conditions.

One option that has not been discussed in this study, but that may be another feasible alternative for water-constrained locations, is an air-cooled combined cycle. The performance of these units is generally similar than binary units at high-temperature resources, although there may be some cost advantages in exchange for additional operational complexity. Another option which may deserve additional study in the future is the potential for using hybrid cooling on the ACHE, if there may be limited supplies of fresh water that can be used during the hottest periods.

The Flash/ACC would potentially have significant performance benefits over the Flash/ACHE; around 10% in net power. However, several commercial and technical challenges would require innovative solutions in order for this to be a favored alternative. Useful information might be obtained if a small pilot ACC could be operated at an existing unit, handling a limited quantity of turbine exhaust steam, in order to test NCG removal efficiency and cleaning strategies.

Conclusions

Water-cooled flash plants will continue to be the mainstay of the industry for higher temperature resources where water can be obtained for cooling tower makeup, either through condensed steam or from external sources.

The Binary/ACC configuration will continue to be a primary choice where temperatures are lower or where water extraction is limited. Air-cooled combined cycles may also be an alternative for water conservation for higher temperature resources.

The Flash/ACC approach, while simpler from a thermodynamic perspective, does not seem appealing unless improved techniques for cleaning the internals and removing NCGs are developed. In addition, higher grade materials required for the ACC tubes might render it an uneconomical alternative to a conventional Binary/ACC approach, which is well proven. If these issues could be overcome, the Flash/ACC may be competitive, but this effort would require research and pilot studies.

The Flash/ACHE approach may be a feasible and currently deployable alternative to the Binary/ACC plant. The Flash/ACHE configuration relies on proven components that are widely used in geothermal and other industries, uses an ACHE without costly exchanger materials, and could be applied as a complete or partial retrofit at existing units with surface condensers that wished to reduce water consumption. Depending on the commercial considerations at an individual project, the Flash/ACHE plant may be a competitive option.

References

Bombarda P, Macchi E. 2000. Optimum cycles for geothermal power plants. Proceedings World Geothermal Congress. 2000 28 May- 10 June; Kyushu, Japan.

Brockbank K, Bromley C, Glynn-Morris T. 2011. Overview of the Wairakei-Tauhara subsidence investigation program. Proceedings of the Thirty-Sixth Workshop on Geothermal Reservoir Engineering. 2011 31 Jan-2 Feb; Stanford, California.

DiPippo R. 2008. Geothermal Power Plants: Principles, Applications, Case Studies and Environmental Impact. Oxford (UK): Elsevier.

Attachment DR 1B
Cooling System Assessment for the BHER Salton Sea Geothermal Plants

Memorandum

To: Jaclyn Urbank
Jacobs
Project Manager, Geothermal

From: William Harvey
Metis Renewables
Technical Advisor, Geothermal

Date: January 31, 2024

Re: Cooling system assessment for the BHER Salton Sea Geothermal Plants

Dear Engineer Urbank,

This memorandum provides technical background on a set of design questions posed by the California Energy Commission (CEC), regarding the Black Rock Geothermal Project (BRGP), Elmore North Geothermal Project (ENGP), and Morton Bay Geothermal Project (MBGP). These projects are currently under development by BHE Renewables (BHER). The request posed by the CEC is to assess the ability and effects of applying air-cooled condensers (ACC) to the BRGP, ENGP and MBGP power plant designs.

Metis Renewables is a third party and is not directly involved in the design of the facilities or the CEC process. This memorandum provides a technical view on the suitability of ACC technologies to the BRGP, ENGP and MBGP designs, and the design review is based on publicly available data from BHER's permit applications. In the informed view of this author, ACCs are unsuitable and not commercially proven for the BRGP, ENGP and MBGP applications. The following memo describes this statement in more detail.

CEC's requests are understandable, as air-cooled condenser technology is used at geothermal binary power plants such as the Casa Diablo 4 unit at the Mammoth complex, many geothermal projects in northern Nevada, and other binary geothermal projects worldwide. In principle ACCs can significantly reduce the plant water consumption by reducing the water required for cooling towers, which rely on evaporation to drive heat transfer. ACCs may be the only option for binary plants in settings where there is little makeup water available. ACCs may be desired in circumstances where 100% of the produced geothermal fluid must be reinjected to avoid reservoir depletion. ACCs are also a reasonable selection for binary plants in extremely cold climates to avoid the use of freeze protection equipment for circulating water systems. These three constraints are not applicable to the BRGP, ENGP and MBGP developments.

The author has encountered similar questions from stakeholders at other projects worldwide that inquired about the relative merits of water- versus air-cooled plants. In response to those inquiries, Louw, Wallace and Harvey (the author of this memo) explored these requests with the geothermal project owners and made selected findings available in the public domain by publishing the paper *Air cooling options for flash plants* for the 2011 Geothermal Resources Council conference (see attachment). This memo builds on those findings with commentary on recent industry trends, the Salton Sea Geothermal Resource, and Imperial County project specific considerations.

BHER proposed plant design

BRGP, ENGP and MBGP are designed for triple steam flashes. The power generation facility (PGF) includes steam turbines, surface condensers, wet cooling towers, sparger based non-condensable gas (NCG) abatement systems and condensate bio-oxidation abatement systems. The two abatement systems rely on interactions with the water in the cooling tower.

Makeup water for evaporation in the cooling tower is primarily provided by the condensation of the flashed steam of the geothermal process. CEC along with the California Department of Conservation – Geologic Energy Management Division determined that the projects have adequate geothermal resource for their project lives. This is also demonstrated by BHER's long operational experience with the reservoir and operating geothermal power plants nearby.

The produced Salton Sea Geothermal Reservoir geothermal fluid has extremely high total dissolved solids (TDS) content of over 20% of total mass, with the primary constituent of the TDS being chloride. The TDS in the geothermal fluid remaining in separated liquid after flashes must be processed by a commercially proven system, such as the proposed crystallizer-reactor-clarifier (CRC) processes, which is also used by nearby geothermal power plants, as part of the overall resource production facility (RPF). The CRC system precipitates and separates out iron-silicate solids from the geothermal fluid before the liquid is injected to the reservoir. This solids removal process minimizes plugging and scaling in downstream equipment, piping, and the injection wells.

These particular combinations of PGF and RPF elements are unique to the geothermal power plants at the Salton Sea Geothermal Reservoir, with geothermal fluid known for its high temperature (>400 °F), corrosivity, and high TDS. Geothermal power plant technology used elsewhere is not necessarily suitable for Salton Sea Geothermal Reservoir applications.

Key considerations

ACCs are unsuitable for the proposed BHER projects due to three key considerations:

1. Air cooling which relies on ACCs is less suitable than water cooling for hot climates such as those found within the Imperial Valley, California, where summer temperatures can exceed 120 °F. Power plants in these hot environments incur performance limitations, resulting in significant reductions in energy capacity (also known as resource adequacy), which is the primary benefit to ratepayers in the western United States seeking renewable, firm resources like geothermal energy.
2. Geothermal flash plants are the best and only known commercially proven technology for the unique resource conditions at this Salton Sea Geothermal Reservoir. Binary equipment for geothermal power plants would scale up in a short period of time if exposed to the geothermal fluid from the Salton Sea Geothermal Reservoir.

3. ACCs and other air-cooling configurations are not commercially proven nor technically effective solutions for geothermal flash plants, and ACC systems even if available commercially would be especially unsuitable at this location.

This memo is not intended as a condemnation of binary geothermal power plants using ACCs. Such plants exist widely throughout the world and are reasonable designs at the locations where they are suitable. Rather, this memo focuses on geothermal power plants located at the Salton Sea Geothermal Reservoir.

Air cooling is generally less suitable than water cooling for hot climates

A site-specific consideration driving the geothermal power plant and cooling system designs is the high ambient dry bulb temperature, relative to a lower wet bulb temperature. Power generating units with ACCs reject heat from the process by transferring energy through the ACC from the condensing turbine exhaust vapor to air at its dry bulb temperature. As air has relatively poorer heat transfer characteristics than water, large heat exchange areas must be provided, and large quantities of air must be moved.

Units with water-cooling first transfer energy from the condensing turbine exhaust vapor to circulating water in a water-cooled condenser. Then a portion of that water is subsequently evaporated directly into the air in a cooling tower, providing a cooling effect analogous to sweating which drives the temperature differential of the circulating water relative to the turbine exhaust temperature. As a result of this more effective heat transfer in a cooling tower, less air needs to be moved for the same cooling effect for a water-cooled unit. The water-cooled condenser can operate at a lower temperature/pressure, improving plant efficiency. The overall design impacts of water cooling versus air cooling are significant reductions in equipment size, including water-cooled condensers and cooling towers, and parasitic power reductions due to fewer fans with less power required for air movement.

Real-world examples illustrate how ACCs require more materials, land and parasitic power than water-cooled cycles. Consider the layouts of two geothermal power plants with similar power outputs and similar climate conditions at the Olkaria field in Kenya. The footprint of these plants displayed on the same map scales are shown in Figure 1:

- Olkaria III (or OrPower 4), a 139 MW air-cooled binary geothermal power plant
- Olkaria IV, a 140 MW water-cooled flash geothermal power plant

The site area consumed by the air-cooled binary project is dominated by the ACCs and its many fans, being around 400-600% larger than the site area of the water-cooled flash project with its two eight-cell cooling towers. Considerably more air movement is required for air cooling (usually a similar ratio as to extra acreage consumed) than water cooling, due to air’s lower specific heat. The cooling system design has significant impact on capital costs through additional equipment, material, land, and parasitic power for the fans.

Figure 1. Olkaria III (air-cooled, left) and Olkaria IV (water-cooled, right) geothermal plants. Map scale is same for both images. (Google Earth)

Based on publicly available historical temperature data from the National Oceanic and Atmospheric Administration, dry bulb temperatures around the Imperial Valley routinely reach daily averages at and above 80 °F (26.7 °C) from June-September, and over 90 °F (32.2 °C) through July-August, with maximums reaching over 110 °F (43.3 °C). Anecdotally from having visited the general project area, one would describe the summer heat for hourly peak periods as “searing.”

The wet bulb temperature design basis for the cooling towers stated in the project applications is 80 °F. Wet bulb temperature generally rise less than the dry bulb temperatures during the day or extreme weather events, making a water-cooled system more resilient to circumstances such as heat waves and not significantly affected by weather. Based on the 2005 American Society of Heating, Refrigeration and Air-Conditioning Engineers Handbook design data, monthly mean coincident wet bulb temperatures in the Imperial Valley are below 80 °F even in the hottest months of July and August.

Most geothermal projects suffer reduced output during hot periods, but air-cooled binary power output especially suffers at elevated ambient temperatures. Analysis was conducted by the author and their team through the Electric Power Research Institute (EPRI 2014) on the indicative impacts of elevated wet or dry bulb temperatures on flash and binary geothermal projects. These studies showed water-cooled flash plant output typically drops by 5-10% as wet bulb temperature rises by tens of degrees above the plant design point. In contrast, air-cooled binary plants can lose over 50% of design output as dry bulb temperatures rise over 100 °F. Similar analysis was presented by Hance (2005), with Figure 2 showing the deep declines of a typical air-cooled binary geothermal plant output during the hotter months. This illustrative project is likely located in a cooler climate such as Northern Nevada. Hotter environments such as Imperial County would experience more severe net output reductions.

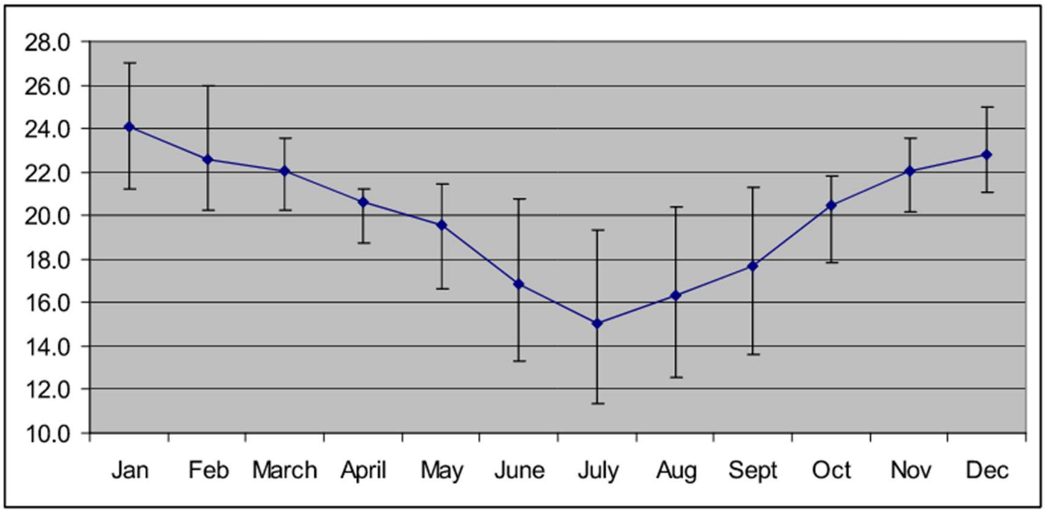

Figure 2. Estimated average monthly power output variation from a 20 MW air cooled binary geothermal power plant (Hance 2005)

An air-cooled geothermal plant in the Imperial Valley could experience severe power output reductions at the same time as peak energy demands occur because of air conditioning load on those hot days. This scenario with an ACC design reduces the availability of firm, clean power under peak demand situations. Water cooling provides a more sustained hourly output and better aids California's grid in peak load conditions, which complements intermittent generation from solar and wind during hot evenings and during heat waves.

Flash versus binary for the proposed projects

A flash steam design using a steam turbine handling steam coupled with a CRC solids separating process handling the liquid is the only proven technology for the geothermal power plants in the Salton Sea Geothermal Reservoir due to the unique geothermal fluid. This is demonstrated by the operating flash power plants at the reservoir (e.g. BHER's existing ten plants and Hudson Ranch).

Theoretically the only competing option would be binary cycle technology, which accepts both steam and liquid to heat exchangers to transfer the thermal energy to a separate working fluid for a Rankine cycle. Handling such high-temperature, corrosive, and scale-prone geothermal fluids in binary heat exchangers would be unsustainable, costly and challenging to operate due to the scaling that would occur. These results were demonstrated by the *Geothermal Loop Experimental Facility: Final Report* study, conducted by San Diego Gas & Electric (SDGE 1980) for the Department of Energy. Since the report and to our knowledge there are no binary plants that operate at comparable high temperatures and TDS concentrations of geothermal fluids from the Salton Sea Geothermal Reservoir.

The decision to design the proposed geothermal power plants with the multiple steam flashes and solids separation processing similar to commercially proven installations in the area is logical to reduce technology and operational risks.

Limitations of air cooling for flash plants

For a more extensive description of the options for and limitations of air-cooled geothermal flash plants, please refer to Louw et al. (2011). Using the terminology of that paper, the commercially proven design for the proposed projects could be designated a "flash/CT" arrangement, with a water-cooled condenser and cooling tower.

In theory it would be possible to condense the steam turbine exhaust either in an ACC ("flash/ACC"), or in a water-cooled condenser coupled to an air-cooled heat exchanger ("flash/ACHE"). These two approaches would require minimal makeup water from the flashed steam and return some additional condensate to the reservoir.

A summary of practical challenges with the flash/ACC or flash/ACHE configurations, which is covered in more detail in the paper, include:

- **Unavailable components**: ACCs are a proven and commercially valid alternative for fossil power plants such as natural gas combined cycles, where the relatively pure steam from a heat recovery steam generator, with few impurities such as chlorides and non-condensable gases (NCGs), can be condensed in an ACC. Binary geothermal plants also have relatively clean, noncorrosive working fluid vapor at the turbine exhaust that can readily be condensed in an ACC.
  However, geothermal flashed turbine exhaust steam contains higher quantities of impurities such as chlorides and NCGs. These impurities such as chloride salts and hydrogen sulfide can be corrosive. Hydrogen sulfide can also mix with oxygen to form solid sulfur. The geothermal steam may also contain volatile solids from the steam separation process. Such gases or solids in the turbine exhaust, at concentrations far above those seen in a conventional fossil plant or geothermal binary plant, would build up (NCGs) or deposit (solids) in the internal tubes of an ACC. The wetted materials of such an ACC (e.g. tubes/tubesheets) would need to be upgraded from typical carbon steels to corrosion resistant alloys, such as 316L stainless steel or duplex stainless steel for corrosion resistance and routine descaling maintenance. A proven and commercially available geothermal steam condensing ACC that is designed to address these higher quantities of natural geothermal steam impurities and associated scaling/corrosion issues is ***not*** available in the market as of 2024.
- **Unproven systems**: There are very few examples of flash/ACC configurations operating successfully worldwide. The only example to our knowledge is the first 12 MW phase of the Mutnovsky geothermal power plant in Kamchatka, Russia, which was commissioned in 1999 (DiPippo 2008). Kamchatka's harsh winter climate is the complete opposite of the conditions in the Imperial Valley. Its operating status is unknown and little data are available. A 50 MW unit was later added to Mutnovsky and commissioned in 2002. This is a conventional flash/CT cycle, and likely indicates issues the operator had with the air-cooled design. The authors are not aware of any flash/ACHE geothermal plants worldwide, historical or operating.
- **Costly/less efficient**: The increased heat exchange area, size, number of components, parasitic load, and costs for a flash/ACC or flash/ACHE configuration would increase cooling system costs significantly (likely by several multiples) over the flash/CT arrangement. Notable impacts include:

  - Significant capital costs and process pressure drops would result from the ducting required to distribute the turbine exhaust steam over the extent of the far larger ACC system. Water-cooled condensers are more closely coupled to the turbine exhaust and thus have small ducting pressure drops.
  - ACCs would induce a performance output reduction, even at the rated design point ambient temperature, of around 15-20% of net output, due to the higher condensing temperature and backpressure of the ACC, and the additional pressure drop from the crossover ducting.
  - To reach a comparable firm power output with a theoretical air-cooling system an increased consumption of geothermal fluid would be required, for which ENGP and MBGP would require further dilution water and conflict with the water conservation goal.
- **Severe hot weather impacts**: As noted earlier, the reduction in output during hot periods in the Imperial Valley for flash/ACC or flash/ACHE configurations would be similar to those experienced for an air-cooled binary system; a potential reduction of over 50% in net output. Compare that impact with a conventional flash/CT that would be moderately impacted by up to a 10% reduction in firm output during extreme, summer hot weather. Peak load in California typically occurs during high heat events. ACCs for the proposed projects, even if feasible, would reduce the resilience and reliability on California's grid system.

Other considerations

Land use: as noted earlier, air cooling would require significantly more land.

Market's judgement: there are other research papers that address the potential for air-cooled flash plants in theory (e.g. Kitz 2018), yet no geothermal projects save Mutnovsky have been built with ACC technology, which leaves the ACC technology for high TDS geothermal applications requiring demonstrated proof of concept. More studies and small-scale pilot plants would be required before attempting ACC systems commercially at the Salton Sea Geothermal Reservoir.

NCG abatement: The abatement systems designed within the proposed projects rely on spargers and bio-oxidation of hydrogen sulfide in the steam condensate using cooling tower water. These are proven abatement technologies used in other projects in the area that minimize technology risk and meet permit conditions. A move to air cooling would require different techniques to handle these NCGs. These issues may be solvable but would represent a shift in approach and permitting away from proven methods applied to similar projects at the Salton Sea Geothermal Reservoir.

Infeasibility of ACC evaporative precooling: it is true that for some air-cooled binary plants, some water can be used for evaporative precooling of the air, which can offer limited performance benefit during high ambient temperatures. There are pros and cons with this approach. However, logically since the flash/ACC or flash/ACHE cycle options are inherently infeasible/unavailable as of January 2024, including precooling is also infeasible.

Summary

In summary we judge the proposed projects' design using water-cooled flash with traditional RPF solids separations to be a proven, technically appropriate choice for their specific Salton Sea Geothermal Reservoir geothermal fluid conditions along with the Imperial Valley's summer weather conditions.

A switch to an unproven, more costly, less efficient air-cooled cycle with no comparable operating precedents under these conditions or market availability of components would introduce significant technology risks and is inadvisable. These observations are backed by our research into ACC technology from sites with less severe conditions than those that will be encountered by the proposed projects. Furthermore, these observations are drawn on our firsthand experience with other water- and air-cooled geothermal projects worldwide. Selected references are listed at the end of this memo.

Respectfully,

William Harvey, PE, PhD
Metis Renewables LLC

References

DiPippo R. 2008. Geothermal Power Plants: Principles, Applications, Case Studies and Environmental Impact. Oxford (UK): Elsevier.

Gunderson J, Harvey W. 2014. Adaptive designs for geothermal plants. Palo Alto (CA): Electric Power Research Institute. Report 3002002939.

Hance C. 2005. Factors affecting costs of geothermal power development. Washington (DC): Geothermal Energy Association.

Kitz K. 2018. A new air-cooled condensing system for both geothermal steam and conventional steam power plants. GRC Transactions, Vol. 42, 2018.

Louw R, Wallace K, Harvey W. 2011. Air cooling options for flash plants. GRC Transactions, Vol. 35, 2010.

SDGE. 1980. Geothermal loop experimental facility: final report. San Diego Gas and Electric. Prepared for the Department of Energy: Report DOE/ET/28443-T1.