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An Expanded Matrix to Scope the Technical and Economic Feasibility of Waste Heat Recovery from Mature Hydrocarbon Fields

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ABSTRACT

Substantial volumes of water are co-produced with hydrocarbons during the latter stages of an oil or gas field's producing life. Such volumes require costly treatment schemes and inevitably force operators to cease field production, which leaves potentially recoverable hydrocarbons in the ground. However, the flowing temperature of these waste streams is high enough for it to be exploited for district heating and/or power generation. This opens up opportunities for mature hydrocarbon fields with the potential of extending their lifespan, improving their ultimate recovery, providing an alternative renewable low carbon energy source and reducing their operational expenditure.

With several feasibility studies and pilots supporting the feasibility of this concept, the objective of this paper is to identify key technical and economic parameters of waste heat recovery from mature and abandoned hydrocarbon fields, both onshore and offshore. These are translated into a set of indices, forming a practical screening matrix for geothermal feasibility. With reference to an existing decision matrix (Soldo and Alimonti, 2015) which was designed to select between two heat extraction technologies, the new matrix is an expanded version, with wider applicability.

The feasibility evaluation is initiated by building a database that encompasses 17 oil and gas fields in 4 countries; USA, Italy, China and Poland; making it the largest available for this type of study. Characteristic parameters for operating conditions and economic viability are extracted from the database and implemented in the matrix via 6 new indices and 2 modified indices.

Two applications of the modified matrix are presented: ranking the geothermal potential of 4 candidate oil fields in the Los Angeles Basin and selecting the best end use for the recovered heat (district heating, power generation or Combined Heat and Power) for one particular candidate, the Long Beach oilfield.

Given the novelty of this concept, the new matrix provides a baseline to assess the geothermal potential of mature hydrocarbon fields in a broader, less regional context. Furthermore, it offers a means of conducting a rapid preliminary evaluation of the technical and economic feasibility of hydrocarbon fields and deciding which of the heat extraction technologies, conversion plans and end uses of recovered heat are most appropriate. By bridging geothermal and petroleum engineering, a new outlook is established for thousands of mature hydrocarbon fields worldwide.

1. INTRODUCTION

Mature hydrocarbon fields are associated with several technical and economic challenges, such as high water cuts exceeding 90% of total liquid production, which render many fields uneconomic despite remaining hydrocarbon recovery. The costs of chemically treating co-produced water prior to surface disposal or re-injection, along with those of hydrocarbon de-watering, significantly add to the field's operational expenditure (OPEX). Given the high flowing temperature of co-produced water, which is in the range 70-160°C, heat may be recovered from the otherwise waste stream and exploited for power generation and/or district heating. Harnessing this unconventional renewable heat source onsite, or for nearby communities, can significantly increase the lifetime of hydrocarbon fields and compensate for the cost of purchased electricity. By retro-fitting existing wells for geothermal exploitation, decommissioning costs are delayed for hydrocarbon operators. Also, the installed capital expenditure (CAPEX) of drilling and infrastructure are greatly reduced for geothermal operators; these CAPEX items usually making up 50% or more of the entire geothermal project (Alimonti and Gnoni, 2013). This renders many mature oil and gas fields economically appealing for geothermal exploitation.

The concept of recovering subsurface heat includes abandoned hydrocarbon fields, as the thermal properties of the reservoir formation with subsurface water and/or steam injection during hydrocarbon production can yield significant stored heat content (Zhang et al., 2008; Cheng et al., 2013). Several field pilots and feasibility studies demonstrate the success of this approach, which was pioneered by Riney (1991), with the discussion of potential geothermal exploitation at the Pleasant Bayou field in Texas, USA. The study was followed up with research by Sanyal and Butler (2010), illustrating the potential for generating 1.6 MW from co-produced water and gas; a 22% and 78% contribution, respectively. Of the pilots tested, the Naval Petroleum Reserve No.3 (NPR-3) in Wyoming, USA, remains the longest operating geothermal project, having been established in September 2008. Although several technical challenges have had to be addressed, the project illustrates the success of a 250 kW Organic Rankine Cycle (ORC), so far yielding over 3 MW of net electrical power (Miliken, 2007; Johnson and Walker, 2010; Nordquist and Johnson, 2012). Another successful pilot is the Huabei oil field in China, where a 400 kW binary screw expander system produced a total of about 310 MWh for onsite use (Xin et al., 2012). In Europe, the Villafortuna-Trecate oil field in Italy with its high-pressure, high-temperature reservoir and strong aquifer drive, amounting to 850m^3/day of water, could potentially produce 25 GWh of thermal power over a 10-year co-production timeframe (Liu et al., 2013; Alimonti and Gnoni, 2013).

Starting from a screening analysis of past and ongoing pilots and feasibility studies, the objective of this paper is to identify key technical and economic feasibility factors of waste heat recovery from hydrocarbon fields. The identified parameters are formulated into numerical indices that can be used as part of a screening matrix. The resultant matrix is tested for two applications: ranking the success of different geothermal projects and selecting the best end use for the recovered heat at a given field. The framework and approach used here refers to a recently published matrix by Soldo and Alimonti (2015), which was developed to choose between a conventional injection-production well pair and a Wellbore Heat Exchanger (WBHX) for heat extraction at a candidate field.

To assess the feasibility of heat extraction at a candidate field, the full cycle of heat extraction, thermal power conversion and transport should be considered. This should also include the economic aspect of the application; covering costs of installation, transportation, maintenance and sale price to potential end users. One method to incorporate all relevant factors is to establish a screening matrix ranking each of the controlling parameters to give a hydrocarbon field an overall feasibility decision.

The feasibility decision is based on an average mean of nine technical, economic, environmental and social indices, referred to as the performance index (P), shown in its original version in **Equation 1.** Note that, although Equation 1 shows a simple summation, the actual calculations in the original work by Soldo and Alimonti and also in this work were performed as average mean. Each index is assigned a value between zero and one; the former being the most pessimistic. **Table 1** shows the selection range for each index. The matrix was applied to the Villafortuna-Trecate oilfield in Italy where, applying a consistent index weight, WBHX was the preferred option for heat extraction.

$$P = \sum_{j=1}^{m} I_{j.}\, w_j \qquad (1)$$

The matrix established as part of the present study offers a good starting point for the development of a framework to evaluate the geothermal potential of mature hydrocarbon fields on a global scale, and in a more detailed context. An expanded version of this matrix could be adapted to offshore and onshore fields of different scales of hydrocarbon production, with further inclusion of potential abandoned fields that could be reactivated for this application.

2. OVERVIEW

The thermal power acquired from waste water streams is a direct function of the produced fluid rate, temperature, density and specific heat capacity, as shown in **Equations 2 and 3** (Soldo and Alimonti, 2015).

$$Q = (c_{pw}\, \rho_w\, q_w + C_{po} \rho_o q_o).\, (T_i - T_o), \text{ during the co-production stage} \qquad (2)$$

$$Q = c_{pw}\, \rho_w\, q_w\, (T_i - T_o), \text{ at abandonment} \qquad (3)$$

To transform this gross power to energy, a conversion plant should be used, the choice of which corresponds to the fluid temperature; while the size of installed power relies on that of evaluated gross power. For the low-to-medium temperature range, at which co-produced water is usually available, a binary ORC is suitable for power conversion. As its name suggests, a secondary organic fluid of lower boiling temperature than water is used to transfer the thermal content in the form of vapor to a turbine; these are commonly isopentane or isobutene (Xin et al., 2012). Similarly, for district heating, heat is transferred from the heat carrier to a secondary fluid at a heat exchanging unit. Combining heat and power in a single project is possible by connecting the conversion plant to another heat exchanger, where residual thermal power is extracted for district heating.

Table 1: Soldo and Alimonti matrix

Index	Controlling factors	Index selection range/corresponding value					
Thermo-energy production index (I_P)	Evaluated thermal power (P) Reference power (Pr) [1]	$P/Pr < 0.1$	$0.1 \leq P/Pr < 0.2$	$0.2 \leq P/Pr < 0.4$	$0.4 \leq P/Pr < 0.6$	$0.6 \leq P/Pr < 1$	$P/Pr \geq 1$
		0	0.2	0.4	0.6	0.8	1
Temperature-flow rate index (I_{qT})	Well head temperature (T) & flowing rate (q) [2]	$q/T \leq 0.055$	$0.055 < q/T \leq 0.125$	$0.125 < q/T \leq 0.55$	$0.55 < q/T \leq 12.5$	$q/T > 12.5$	
		1	0.75	0.5	0.25	0	
Outlet temperature index (I_{Texit})	Well head outlet temperature (Ti) Plant minimum operating temperature (T_{min}) [3]	$T_i/(2T_{min}) < 1$	$T_i/(2T_{min}) \geq 1$				
		0	1				
Pumping aided production index (I_{PE})	Fraction of pumping power (E_p) from the available energy (E)	$E_p/E > 15\%$	$E_p/E \leq 15\%$				
		0	1				
Re-injection index (I_I)	Sub-indices (qualitative) [4]: 1. Injection costs (I_{IC}) [5] 2. Corrosion and scaling (I_{ISC}) 3. Re-injection fluid interference (I_{IT}) 4. Formation damage due to permeability decrease (I_{IK}). 5. Injection location (I_{ID})	Average mean of sub-indices (Range: 0- 1)					
Scale-Corrosion index (I_{SC})	Langelier Saturation Index (LSI)	LSI = 0	0<LSI≤0.5	0.5<LSI≤1	1< LSI ≤ 1.5	1< LSI < 2	LSI = 2
		1	0.8	0.6	0.4	0.2	0
Environmental impact index (I_{ENV})	Sub-indices (qualitative): 1. Sustainably index (I_{SR}) 2. Soil Index (I_G) 3. Landscape index (I_L) 4. Subsidence index (I_S) 5. Potential seismicity index (I_{PH}) 6. Noise index (I_N) 7. Gas Emissions in Atmosphere (I_{AIR}) 8. Water contamination (I_{WATER}) 9. Radioactivity index (I_R)	Average mean of sub-indices (Range: 0-1)					
Social impact index (I_{SI})	Social perception (qualitative)	(Range: 0 or 1)					
Cost index (I_C)	Payback period (t_{pb}) in years	$t_{pb} \leq 3$	$3 < t_{pb} \leq 4$	$4 < t_{pb} \leq 5$	$5 < t_{pb} \leq 6$	$6 < t_{pb} \leq 7$	$t_{pb} > 7$
		1	0.8	0.6	0.4	0.2	0

[1] The reference power is set based on the size of the installed power plant; about 20 MW for steam plants and 1-5MW for ORC plants.

[2] The range is based on the operating conditions for a conventional ORC plant; 0-100 m^3/h and 80-160 °C.

[3] The minimum operating temperature for an ORC plant is approximately 80°C.

[4] All sub-indices are qualitatively assessed, except for I_{IC}. The assessment is based on the presence/absence of the phenomenon.

[5] Injection costs are given as a percentage of the total costs; if less than 15%, they are assigned a value of 0, otherwise, 1.

3. METHODOLOGY

3.1 Building a database of potential geothermal projects

In order to broaden the applicability of the Soldo and Alimonti matrix and to improve its geothermal evaluation of candidate projects, a database of past and ongoing field geothermal pilots and feasibility studies is required. This is to capture elements that are considered vital in these projects, but which are not included in the Soldo and Alimonti matrix. A numerical approach for such a dataset will help to constrain the range of any modified or added indices, giving them a practical representation.

The database compiles 4 feasibility studies and 5 projects, looking at 17 different oil and gas fields in 4 countries, namely the USA, Italy, China, and Poland. This makes it the largest data source available for this type of thermal heat recovery. Certain fields are studied through different recovery approaches, such as the Villafortuna-Trecate oil field in Italy and those on the Gulf Coast, USA. All data are taken from the available literature in the public domain. **Table 2** shows the hydrocarbon fields used in the survey along with their associated data sources.

Table 2: Hydrocarbon fields covered in the database, with their related literature sources

Case study / Project	*Literature Source*
1-Villafortuna-Trecate oil field, Northern Italy	• Soldo and Alimonti, 2015 • Liu, Falcone and Alimonti, 2013 • Alimonti and Gnogni, 2013
2- Grobla oil field, Poland	• Barbacki, 2000
3- LB reservoir, Huabei oil field, China	• Xin, Liang, Hu, and Li, 2012
4- Gulf Coast, USA	• Sanyal and Butler, 2010
5- Pleasant Bayou (PB-2), USA	• Riney, 1991 • Sanyal and Butler, 2010 • Erdlac et al., 2007
6- Naval Petroleum Reserve, USA	• Miliken, 2007 • Johnson and Walker, 2010 • Nordquist and Johnson, 2012
7- Los Angeles Basin, USA (A) Wilmington oil field (B) Inglewood oil field (C) Long Beach oil field (D) Santa Fe Springs oil field (E) Beverly Hills oil field	• Bennett, Horne and Li, 2012
8- Mississippi oil field, USA	• Clark, 2012
9- Texas, USA (A) East Texas oil field (B) Gulf Coast oil field (C) Delaware-Val Verde Basins oil field (D) Maverick Basin oil field (E) Trans-Pecos oil field	• Erdlac et al., 2007

Each field above is screened for a list of 52 technical and economic factors, illustrated in **Table 3**. The gathered data are studied to evaluate where new indices should be modified, added, or replaced in the Soldo and Alimonti matrix in order to assess the geothermal potential of hydrocarbon fields more thoroughly. One difficulty in constructing the database is the lack of some data reported for each field; especially data relating to the conversion plant design and the project's economic evaluation.

Table 3: Screened parameters for each case study

Screened parameters		
Background	***Field status***	***Heat recovery***
Information about the field's location, geology and reservoir properties: • Study approach (field pilot/feasibility study) • Location (onshore/offshore) • Reservoir geology (porosity, permeability, pay thickness) • Presence of active aquifer/natural recharge • Reservoir properties: A. Depth (D, m) B. Average temperature (T_{avg}, °C) C. Temperature gradient (T_g, °C/ 100 m) D. Ambient temperature (T_{Amb}, °C) E. Static reservoir pressure (P_{as}, bar) F. Oil specific heat capacity (c_{po}, J/kg °C) G. Rock specific heat capacity (c_{pr}, J/kg °C) H. Oil density (ρ_o, kg/m3) I. Rock density (ρ_o, kg/m3)	Information related to production and injection: • Pressure/Temperature (high/low) • Target fluid (oil/gas) • Field condition (abandoned/mature) • Water cut (%) • Total no. of wells • No. of producing wells • No. of injection wells • Total production rate (barrels/day) • Production temperature (°C) • Injection rate (barrels/day) • Injection temperature (°C) • Well diameter (feet)	Information on heat extraction and conversion: • Heat recovery type • Heat extraction method • Conversion plant type ***Thermo-energy production*** Information on conversion plant conditions: • Ti (°C) • To (°C) • Installed power (MW) • Gross power (MW) • Net power (MW) • Plant efficiency (η, %) • Pumping power (Ep, kW) ***Well head conditions*** • Flow rate (q, m^3/h) • Temperature (T_{wh}, °C) • Pressure (P_{wh}, bar)
Economic parameters	***End user coverage***	***Results***
• Project lifespan (years) • Down time (%) • Net electrical power (MW) • District heating power (MW) • Total power recovery (MWh) • Sale price ($/kWh) • Capital cost ($) • Operation & Maintenance (O&M $/kWh) • Net Present Value (NPV, $) • Payback period (years)	• Distance to served community (km) • No. of houses served • Unit-volume served (m^3) • No. of inhabitants served	• Summary of findings/results for each case study from available literature

3.2 Modifying the existing matrix

With reference to the compiled data and available literature, 6 new indices are introduced to the existing matrix, 2 indices are modified, and 2 indices are replaced. These are discussed below. The basis of the change is to add new aspects of geothermal evaluation, with a considerable level of detail and make the indices self-evident for the best end use/application of heat recovery. The following analysis is based on average technical/economic values of projects considered for waste heat recovery, without taking into account the impact of time on such indices throughout the project's lifetime.

3.2.1 Additional indices

In its technical analysis, the Soldo and Alimonti matrix focuses primarily on the performance of the conversion plant, without mentioning key geological factors that should set a starting point for the feasibility analysis. These factors, which include the primary heat source, i.e. the thermal properties of the reservoir formation, the availability of a geothermal carrier and the process of heat transfer to fluids in the wellbore, are introduced to the matrix via the simple application of 2 indices, as explained below.

- *Geothermal gradient index (I_{Tg})*

One of the controls on the efficiency of heat transfer from the reservoir to the surface is the reservoir's initial temperature, which is a function of well depth. A second constraint is that a high thermal conductivity is required to transfer stored heat to the wellbore fluids. These two factors control the rate of heat transfer to the surface and can be collectively combined in the geothermal gradient, which intervenes in Fourier's law. The latter states that the heat flux resulting from thermal conduction is proportional to the magnitude of the temperature gradient and opposite to it in sign. Hence, the geothermal gradient can be used as a proxy for the available recharge heat and for approximate projection of the temperature profile along the wellbore.

To measure the subsurface thermal conditions at a candidate field, a geothermal gradient index is suggested below. The index selection range is directly reflective of the database (**Tables 4 and 5**).

Table 4: Geothermal gradient for several analyzed oil fields

Case study (oil field)	T_g (°C/ 100 m)
Villafortuna-Trecate	2.8
LB oil reservoir, Huabei	3.5
Naval Petroleum Reserve No. 3	0.8
Wilmington	6.2
Inglewood	5.4
Long Beach	3.9
Santa Fe Springs	3.3
Beverly Hills	3.6
Maverick Basin	5.5
The Trans-Pecos	2.8

Table 5: The geothermal gradient index

Range	T_g <0.5	$0.5 \le T_g < 2$	$2 \le T_g <4$	$4 \le T_g <6$	$T_g \le 6$
I_{Tg}	0	0.3	0.6	0.9	1

- *Active aquifer index (I_{Aq})*

Besides being a driving mechanism for oil production, the presence of an active aquifer helps maintain a high water flux to the conversion plant, throughout the project's lifetime. Such flow yields large extracted heat and generated power, as illustrated in **Equations 1 and 2**. This effect is evident from several case studies, such as the oil fields of Grobla, NPR-3 and Villafortuna-Trecate. For the latter, a constant pressure is maintained throughout the entire project's lifetime, solely due to the aquifer influx. For other hydrocarbon fields, the aquifers are either absent, inactive, or weak, with limited or no impact on the production flow rate.

In addition to flow rate enhancements, the presence of a continuous water flow will promote the use of water over air cooling units; the latter consume more energy and are highly susceptible to fluctuations in daily or seasonal temperature, thus affecting the performance of the conversion plant. These are used when there is a scarcity of nearby water sources (Johnson and Walker, 2010).

To thoroughly evaluate this aspect of reservoir geology, the aquifer's regional extent, the exposure of infiltration zones, and communication through structural faulting with external/deeper water should be considered (Barbacki, 2000). Since this level of detail is not usually available in the public domain for demonstration projects, the importance of this parameter is included in a qualitative index, such that the presence of an active aquifer is assigned a value of '1', while its absence is given a value of '0'.

- *Global efficiency index (I_{GE})*

Besides the geological settings and wellbore conditions, the supply of heat and/or power generation is directly dictated by the performance of the conversion plant. A detailed assessment of the plant design and operation is therefore necessary. Several of the indices assigned in the Soldo and Alimonti matrix (I_P, I_{qT}, I_{Texist} and I_{PE}) ignore the evaluation of the multi-stage heat loss within the conversion cycle and the impact of the ambient temperature on stored heat (**Figure 1**). While this is relevant to projects aiming for power generation, a plant performance measure for fields targeting direct use only, or combined heat and power (CHP) is similarly required. To investigate the efficiency of heat recovery, a global efficiency index is therefore introduced.

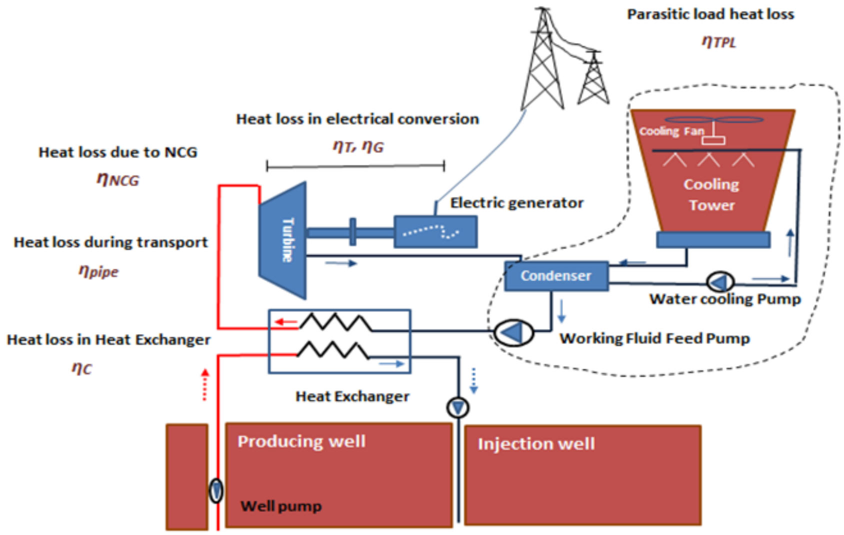

Figure 1: Heat losses at a typical conversion plant, after Moon and Zarrouk (2012)

The approach taken assigns a numerical efficiency measure to each stage of the conversion plant, in order to estimate total heat loss. This method is taken from Moon and Zarrouk (2012), who developed several equations (**Equations 4-7**) to give a particular conversion plant an overall performance evaluation.

$$\eta_c = 1 - \frac{T_o}{T_i} \quad (4)$$

$$\eta_{ncg} = 1 - 0.0059C \quad (5)$$

$$\eta_{TPL} = 1 - \frac{P_{TPL}}{P_{gross}} \quad (6)$$

$$\eta_{pipe} = 1 - 0.003\, L_p \quad (7)$$

The vast majority of case studies propose an ORC plant for power generation. This is primarily due to the low-to-medium temperature range of the produced fluids. The thermal efficiency assessed at the heat exchanger of the conversion plant in such fields is usually less than 10%, as indicated by the database in **Table 6**. However, the approach suggested here is not confined to ORC plants, but could easily be adapted to other types of conversion plants. In this instance, the thermal exchange cycle between the two fluids can be evaluated using Carnot's ideal efficiency (**Equation 4**).

Table 5: The thermal efficiencies of different oil fields in the database

Oil field	η_C
Villafortuna-Trecate	8.60
LB oil reservoir, Huabei	8.89
Wilmington	4.46
Inglewood	4.45
Long Beach	4.42
Santa Fe Springs	4.45
Beverly Hills	5.16
Mississippi	6-10

In addition to the role of geofluid temperature, its composition can largely influence the operation of a conversion plant. In particular, the presence of Non-Condensable Gases (NCG) can negatively impact the operation of the plant turbine. Once deposited in the condenser, they increase the turbine backpressure and reduce the vapor expansion work, leading to a less efficient heat transfer process

(Moon and Zarrouk, 2012). These gases are difficult to re-inject into the subsurface, unless vacuum or jet pumps are used, thus leaving less available energy (Kagel, 2008). NCG also contain toxicants, such as hydrogen sulphide and mercury, which can be included in the Soldo and Alimoniti I_{Aair} sub-index to assess environmental impact. To examine the NCG effect, **Equation 5** is used with estimates of NCG weight (C) to show that 1% of the NCG will reduce turbine efficiency by 0.59 % (Moon and Zarrouk, 2012).

Once the vapor is at the turbine, the mechanical energy is converted to electricity through a linked generator. The average efficiencies of these components range between 81-85% and 95.7-98.7%, respectively (Moon and Zarrouk, 2012). To measure the operational performance of the turbine and generator, η_T and η_G are included. The operational efficiencies of other elements can be similarly incorporated, such as using a gas heater if the conversion plant is working under its minimum required thermal power, or a gas generator for a hybrid power plant, as seen in the Gulf Coast case study.

The I_{PE} index, suggested by Soldo and Alimonti (2015), finds the proportion of energy consumption by water pumps to evaluate the available net power. A more representative measure of the power consumed for plant operation is one that takes into account the total parasitic load present, including well pumps, cooling tower and condenser. **Equation 6** is employed to find the proportion of the total parasitic load to the gross thermal power. This can further draw the difference between air and water cooling units.

During heat transport, a certain amount of heat is lost which varies according to the pipe length, size and insulation material (Moon and Zarrouk, 2012). This is also affected by the surrounding ambient temperature, such that a larger temperature difference between the stored fluids and the surrounding leads to a lager generated electric power (Sanyal and Butler, 2010). These factors are quantified in the pipe efficiency equation, **Equation 7**, where Lp is the pipe length at the conversion plant in km and the 0.03 coefficient is a function of the combined factors outlined above.

The above coefficients come together in a global efficiency equation, **Equation 8**, to allow evaluation of electricity generation. This replaces the I_{Texit} and I_{PE} indices suggested earlier by Soldo and Alimonti (2015), as they are now included in a wider context as part of the I_{GE} index.

$$\eta_E = \eta_C \times \eta_{ncg} \times \eta_T \times \eta_G \times \eta_{TPL} \times \eta_{pipe} \quad (8)$$

For CHP projects, the use of a second heat exchanger is required to exploit the remaining thermal power of water into another district heating fluid. To model this change, the global efficiency is simply modified by adding the efficiency of the second heat exchanger, **Equation 9**. With no power conversion required for district heating (DH) projects, the global efficiency equation is reduced to the product of pipeline, total parasitic load and heat exchanger efficiencies (**Equation 10**).

$$\eta_{CHP} = \eta_{C1} \times \eta_{ncg} \times \eta_T \times \eta_G \times \eta_{TPL} \times \eta_{pipe} \times \eta_{C2} \quad (9)$$

$$\eta_{DH} = \eta_{C1} \times \eta_{pipe} \times \eta_{\mathrm{TPL}} \quad (10)$$

For a comparison between the different applications, one range is used for the global efficiency index, as demonstrated below.

Table 6: The global efficiency index

Range	$\eta < 0.2$	$0.2 \leq \eta < 0.4$	$0.4 \leq \eta < 0.6$	$\eta \geq 0.6$
I_{GE}	0	0. 25	0. 5	1

- *Uptime index (I_{UP})*

The hardware availability relating to hydrocarbon production is essential for this application, even if a high I_{GE} is guaranteed. This directly influences the amount of thermal power generated and the economic value of the project. Similarly, the online percentage of the conversion plant itself is crucial, as plant operation issues can lead to a long period of shutdown, as was the case in NPR-3 (Johnson and Walker, 2010). This resulted in significant economic losses. The database shows that the field availability of the studied demonstration projects is greater than 90%, implying that common operational/maintenance issues of hydrocarbon production do no obstruct the operation of conversion plants and vice versa. Nordquist and Johnson (2012) suggest that the most successful geothermal fields are those with a total field uptime of 90-98%. To assess the overall hardware status, an uptime index is introduced (**Equation 11**). The selection range of this parameter is shown in the **Table 8** below.

$$I_{UP} = (\%\, online\ of\ hydrocarbon\ operation + \%\, online\ of\ conversion\ plant)/2 \quad (11)$$

Table 7: The uptime index

Range	$I_{UP} < 50\%$	$50\% \leq I_{UP} < 70\%$	$70\% \leq I_{UP} < 90\%$	$90\% \leq I_{UP} < 100\%$
I_{UP}	0	0.5	0.75	1

- *End user index (I_{EU})*

Of the cases with available end user information, 83% give onsite use as a favored end user of the generated power. This is largely due to the significant costs associated with energy transmission to potential nearby communities, exceeding \$1,000,000/mile (Rafferty, 20000). For remote hydrocarbon fields, in-house use is the only available option, as potential operational failures consume significant repair costs, time and labour. With the highly competitive power market in likely locations for such application, about $0.02/kWh (Rafferty, 20000), greater benefits are obtained from onsite consumption, compared to selling the generated power to a utility. However, if the generated power is in excess of the field requirements, and factors of proximity to potential communities and project lifetime are considered, external power sale can significantly increase a project's profits, as demonstrated in the evaluation of NPV for the Villafortuna-Trecate case study, which reached approximately $0.48 million at a 5% discount rate (Liu et al., 2013).

A primary concern for transmitting heat is potential loss due to transport. The insulation of pipes over long distances is not economically feasible. Although this is not a major concern for electricity transmission, setting up power lines and grid connections is significantly costly. A maximum distance of 2 miles is set to suffice both end uses. The selection range of the I_{EU} index is shown below, starting with the favoured onsite use.

Table 8: The end user index

Range	$I_{EU}=0$	$0 \le I_{EU} < 0.5$	$0.5 \le I_{EU} < 1$	$1 \le I_{EU} < 1.5$	$1.5 \le I_{EU} < 2$	$I_{EU} > 2$
I_{EU}	1	0.8	0.6	0.4	0.2	0

3.2.2 Modified indices

- *Temperature-flow rate index (I_{qT})*

This index accounts for the relationship between fluid flowing rate and wellhead temperature. To a certain extent, a high production rate can compensate for low temperatures of the produced fluid; so the most economically feasible fields are not necessarily the hottest, as proven by the omission of the hottest oil field, Newhall Potrero, in the Los Angeles feasibility study (Bennett et al., 2012). The index suggested by Soldo and Alimonti is customised for the characteristic operating flow rate and temperature range of an ORC plant: 0-100 m^3/h and 80 -160 °C, respectively. The ranges defined are incompatible with several case studies, e.g. PB-2 and NPR-3. The index is modified here to serve two purposes, depending on what the matrix is being used for. For a comparison between multiple fields, the modified index takes into account the specific operating conditions of the chosen conversion plant, without numerical restriction to a given plant type. This is to give more weight to the heat flux into the plant, which is heavily reliant on flow and temperature (**Table 10**).

Table 10: Modified temperature-flow rate index

Range	$I_{qT} \le (q_{Min}/T_{Max})$	$(q_{Min}/T_{Max}) \le I_{qT} < (q_{Av}/T_{Av})$	$(q_{Av}/T_{Av}) \le I_{qT} < (q_{Max}/T_{Min})$	$I_{qT} \ge (q_{Max}/T_{Min})$
I_{qT}	1	0.75	0.5	0

To evaluate temperature and flow conditions in the context of the targeted end use, an additional index (I_{App}) can be used, according to the optimum conditions for each. This index is also a measure of waste heat recovery viability, as candidate fields must meet the minimum required conditions for a given recovery type to be valid cases.

District heating plants can be operated seasonally or throughout the year. They can also be converted to cooling plants by reversing the heat exchanging process. The period of operation will control the network design; specifically the supply and return temperature and flow rate. The focus of the analysis here is on the minimum required conditions for a general district heating plant. The average operating conditions for each end use of waste recovered heat are shown in **Table 11**; these are used to set the limits of the I_{App} index (**Table 12**).

Table 9: Operation conditions specified for each type of heat recovery

Heat recovery	Temperature conditions ° C	Mass flow rate (m^3/h)
District Heating [1]	Plant operating conditions	
	Average minimum operating temperature for DH plant: 55	Average minimum operating flow for DH plant: 9-36 [2]
	Network Design	
Low temperature DH (LTDH)	Ts:70 Tr: 30	9-36
High temperature DH (HTDH)	Ts: 70-120 Tr: 40-70	36-99
Power generation	70-160 [3]	0-100
CHP [4]	70-160	0-100

[1] Data for DH application is from Xing et al., (2012). LTDH is usually used for the summer season and all year DH, while HTDH is for the winter season. The conditions are for an optimal DH design, assuming pipes are installed on ground with an average ground temperature of 7° C and pressure loss at 200 Pa/m.
[2] Based on the minimum of both LTDH and HTDH.
[3] Operating conditions for power generation are in line with a typical ORC plant. Ranges are quoted from Soldo and Alimonti (2015), with minimum operating temperature adjusted from 80 to 70° C, based on the compiled database.
[4] Power generation is prioritised for CHP.

Table 10: The application index

Range	T<55	0≤(q/T)<0.62	0.163≤(q/T)<0.62
I_{App}	Project geothermally unfeasible (Regardless of flow rate)	District heating / Power Generation / CHP	District Heating

- *Flow Assurance Index (I_{FA})*

Several flow assurance problems are likely to occur in the geothermal cycle; including scale and corrosion. Soldo and Alimonti's matrix accounts for this issue in two places: in the I_{ISC} sub-index of the injection index and the overall I_{SC}. Besides injection wells, these issues could occur in the production tubing and in several components of the conversion plant, such as the heat exchanger. If the composition of the co-produced water is prone to these phenomena, any of these damage locations is equally likely. Even if the sub-index is eliminated to avoid biased analysis, nearly all case studies have missing information from the water-analysis reports, which are needed to identify the Langelier Saturation Index (LSI), which is required for the I_{SC} (refer to this index in **Table 1**). The best approach is therefore to replace the existing index with a general qualitative flow assurance index, ranging from the complete absence of any flow-related issues; thus a value of '1', to a value of '0', where the presence of flow assurance issues forces hydrocarbon production and/or the heat recovery process to cease.

- *Explosive Limit Sub-Index (I_{EL})*

This is part of evaluating the environmental impact (I_{ENV}) due to waste heat recovery and/or hydrocarbon production. A gas seepage hazard is possible with heavily faulted or highly permeable reservoirs. The risk of gas migration is amplified with poorly completed wells or old abandoned wells reactivated for such application (Chilingar and Endres, 2005), which could result in large-scale explosions, if combustible gases are involved. One way to scale this hazard is to use the explosive limit, also known as the flammability limit. This sets well-defined boundaries for the weight percentage of combustible gases in the air that cause explosions in the presence of an ignition source (Nolan, 2014). The lower explosive limit (LEL) is the minimum weight percentage of a given flammable gas which can cause fire; below this limit, the gas is too lean for combustion and causes no such harm. The Upper Explosive Limit (UEL) gives the maximum concentration of these gases, possibly resulting in an explosion; above this limit, concentrations are too rich for combustion. Both limits are a function of pressure and temperature. The introduced sub-index evaluates the hazard imposed by gases at hydrocarbon sites and abandoned wells utilised for geothermal projects. If the weight percentage of these is between the LEL and UEL boundaries; it is given a value of '0'. If it falls outside this range, it has a value of '1'. **Table 13** provides the LEL and UEL for most common flammable gases; all measurements are expressed as volume percentage in at atmospheric pressure and 25°C.

Table 11 – Lower & Upper Explosive Limits of common combustible gases

Gas	LEL	UEL
Hydrogen	4.0	75.0
Hydrogen Sulphide	4.0	44.0
Carbon Monoxide	12.5	74.0
Methane	5.0	15.0
Ethane	3.0	12.4
Butane	1.8	8.4
Pentane	1.4	7.8
Hexane	1.2	7.4
Heptane	1.1	6.7
Benzene	1.3	7.9

4. ANALYSIS

In this section, two main purposes the matrix can serve are discussed. These are to rank the geothermal feasibility or success of different projects or candidate fields and choose the best end use for the recovered heat at a given field. The analysis of the approach is demonstrated here with the results of the two applications provided in the following section.

4.1 Ranking of geothermal projects for a given end use

For this application, the projects being compared should be targeting the same end use; so the comparison considers how key technical and economic factors are being utilised. For an overall comparison, all of the above indices should be assessed. By reference to the database, four fields in the Los Angeles Basin are chosen, based on the availability of data: Wilmington, Inglewood, Long Beach and Santa Fe Springs. The indices are applied to each field, in order to find the performance index, which is employed to rank the thermal feasibility of the surveyed fields.

While most indices are found through direct reference to the database, some assumptions and calculations are required to find others. For the end user index (I_{EU}), considerations of the field's location, project lifetime, and the targeted end use are required. The project is assumed to extend to the average lifetime of an ORC plant, some 30 years, with declining hydrocarbon production throughout this period (Bennett et al., 2012).

Inglewood, Long Beach and Sonata Fe Springs are highly prolific fields, located in close proximity to densely populated residential areas (Bennett et al., 2012), so exporting the generated power to nearby communities is possible. This is an essential element for building an economically sound case for projects which are aimed at continuing with waste heat recovery after hydrocarbon production ceases. For Wilmington, however, most of hydrocarbon production is offshore (Bennett et al., 2012). Due to the high costs involved in transmitting electricity offshore, onsite use is a preference for this field. Given the feasibility of this option for the other cases and its advantage of eliminating the cost of setting up transmission lines or connections to existing grids, it is set here as the base case for the targeted end user.

For the re-injection index, the cost of re-injecting is estimated at an average of \$0.03/barrel. These are compared to total energy costs; including those of conversion plant maintenance, lifting, separation, de-oiling, pumping, filtration, and injection. All relevant costs are quoted from Baily et al. (2000). Being non-pressurised fields, re-injection into the same layer of production is possible. Hence, a value of '1' is assigned to the I_{ID} index. I_{IC} is crucial for the evaluation of re-injection, as the other sub-indices, I_{IT}, I_{IK} and I_{ID}, are only sensitive to the method of heat-extraction technology. If a conventional geothermal injection-production well pair is assumed for the four cases; these indices become consistent throughout.

The environmental index is assessed by looking into the potential hazards posed by co-producing hydrocarbons and waste streams, along with those added by installing conversion plants. The data used for this index are acquired from the environmental analysis of the Los Angeles Basin by Chilingar and Endres (2005). For the L_{EI} index, the concentration of combustible gases, primarily methane, is at 5%; thus causing a potential explosion risk. Several historical cases of fire explosion in the Los Angeles Basin, due to gas seeps, demonstrate the level of risk involved, such as the Ross Department explosion incident in 1985 (Chilingar and Endres, 2005).

Subsidence due to hydrocarbon extraction is strongly present in all oil fields in the Los Angeles Basin. The Wilmington field has experienced significant subsidence, reaching about 8.5 m, before a water-injection scheme was implemented to overcome this issue. However, subsidence at Inglewood was directly responsible for the Baldwin Hills disaster in 1963 (Chilingar and Endres, 2005). Therefore, the flow assurance index (I_{FA}) is '0' for all. The social impact (I_{SI}) is inferred to be positive, as the use of already disturbed terrain is being transformed into a sustainable, environmentally friendly, and locally beneficial project.

4.2 Choosing the best heat recovery application for a given project/field

The choice of end use for the recovered heat is directly controlled by several factors illustrated in **Figure 2**. Out of the 13 indices discussed, 5 of them are most sensitive to the technical and economic aspects of the chosen application. Even without the remaining indices, these 5 indices give a reliable indication of the most suitable end use of heat fit for a given field. The key indices are: I_{App}, I_{GE}, I_C, I_{UP} and I_{EU} indices, which can be collectively combined under a new performance index to be used for this purpose: the P_{App} index. This approach is later demonstrated on an oil field chosen from the previous section.

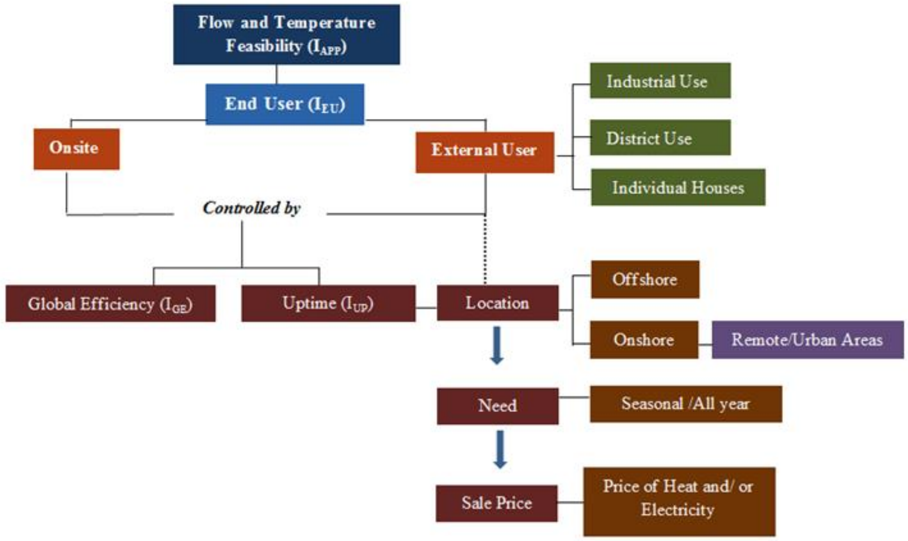

Figure 2: Controls for selecting the end use of waste heat recovery

5. RESULTS AND DISCUSSION

The results of running the modified matrix on the 4 selected fields to rank their feasibility for geothermal exploitation are illustrated in **Table 14**, while the data used to find the indices are provided in AL-Mahrouqi (2015). Based on the performance index (P), the Wilmington oil field is the most feasible for heat recovery, followed by Long Beach, Inglewood and finally, Santa Fe Springs. The results are a reflection of data reliability and accuracy of assumption. One reason for the proximity between the results is the fact that these fields lie in the same geological setting and hence, subsurface controls of heat recharge availability are not that different. As mentioned above, the fields also share the same methodology of heat extraction and therefore, the I_{ENV} index is not as influential for this comparison as it could be for other fields. Figures relating to plant performance do differ between the fields (AL-Mahrouqi, 2015); however the difference is not large enough to fall into different selection ranges of their corresponding I_{GE} index. Overall, I_{Tg}, I_p and I_C show the most significant differences between the fields.

Table 12 - Ranking of geothermal projects in oil fields in Los Angeles Basin

Index	Wilmington	Inglewood	Long Beach	Santa Fe Springs
I_{Aq}	0	0	0	0
I_{Tg}	1	0.9	0.6	0.6
I_P	0.6	0	0.6	0.4
I_{GE}	0.5	0.5	0.5	0.5
I_{qT}	1	1	1	1
I_I	0.75	0.75	0.75	0.75
I_{FA}	0	0	0	0
I_{UP}	1	1	1	1
I_{ENV}	0.3	0.3	0.3	0.3
I_{SI}	1	1	1	1
I_C	0.4	0.4	0.4	0.2
I_{EU}	1	1	1	1
P	0.62	0.56	0.59	0.55

For choosing the best end use for recovered heat, an external end user is usually a priority for fields implanting DH or CHP projects on a commercial scale. Given the offshore location of the Wilmington oilfield, it is best to consider fields lying onshore within a few hundreds of meters from residential areas. Therefore, the second most feasible project (the Long Beach oilfield) is used here to illustrate this application. The information required for finding the $P_{App.}$ index is shown in **Table 15**; a dataset of payback period calculation is given by AL-Mahrouqi (2015). Power generation data is the same as that used for ranking geothermal projects, as discussed above.

Table 15 - Long Beach oil field: application performance index (P_{App}) data

Parameter	DH[1]	CHP [5]
Available thermal power	1273 kW	1273 kW
Heat exchanger efficiency	57%; based on 70 °C T_i and 40 °C T_o	First heat exchanger efficiency = Second heat exchanger efficiency (assuming a consistent temperature differential and manufacturer) = 57%
Global efficiency	19% [2]	2.5%
Uptime	>90%	≥90%
Total installed cost [3]	$470,000	$ 2,419,623
O&M	$0.01- $0.03/kWh	0.034/kWh
Sale price	$0.05/kWh	Consecutive co-generation: • Heat sale price: $0.05/kWh • Electricity sale price: $0.11/kWh All-year co-production: • Heat & power sale price: 0.16/kWh
Discount rate	5%	5%
Payback period (years)	All-year DH: 10.84 Seasonal DH: Unfeasible [4]	All-year production: 6.03 6-months consecutive co-generation: 14.6 All-year power & seasonal district heating: 6.49

[1] Figures are quoted as values per kWh from the US Department of Energy (2015).
[2] Heat losses due to transportation and total parasitic load are estimated to be 2/3 of the available heat (Rafferty, 2000).
[3] The cost of setting up transmission lines to the end user and customer connections are not considered.
[4] The application gives a negative discounted cash flow throughout the project's lifetime (AL-Mahrouqi, 2015).
[5] Figures are found by adding those from DH and power generation.

Several possible scenarios of implementing heat recovery applications are evaluated here for a thorough assessment. These include all year/seasonal DH; all-year power generation; all-year CHP; CHP of 6-months consecutive heat and power generation, and CHP of all-year power and seasonal DH. The above data are used to find the P_{APP} per each application, as shown in **Table 16.**

Table 13 – Application Performance Index of each end use for the recovered heat, Long Beach oil field, Los Angeles Basin

Index	District Heating	Power Generation	Combined Heat and Power		
Period	All-year	All-year	All-year	Seasonal	All-year power & Seasonal DH
I_{App}	1	1	1	1	1
I_{GE}	0	0.25	0.5	0.5	0.5
I_C	0	0.2	0.4	0	0.4
I_{UP}	1	1	1	1	1
$I_{EU[1]}$	0.8	0.8	0.8	0.8	0.8
P_{App}	0.56	0.65	0.74	0.66	0.74

[1] The Long Beach oil field lies underneath two densely populated cities: Long Beach and Signal Hill, California, where there are houses within 0.5 miles of the field site.

Seasonal DH is an invalid business case, as the project will fail to pay back the installation costs within the 30-year lifespan of the project (AL-Mahrouqi, 2015). Although an all-year DH option gives a reasonable $P_{App.}$, it is still the least appealing of the options. This is largely due to the low-to-medium temperature the plant operates at and the consequently low global efficiency (about 19%), along with the considerably lower heat sale price. A seasonal CHP option is nearly as efficient as an all-year power generation scenario, with only 0.01 difference in the $P_{App.,}$ which is due to the seasonal, heat-sale contribution. The two outstanding options are the all-year CHP and CHP with all-year power generation and seasonal DH. The marginal contribution of district heating makes the two projects equally valid, according to the $P_{App.}$ index. Nevertheless, two factors could highlight a considerable difference between the two options. One is the uptime index (I_{UP}); as project and network maintenance increase proportionally with the project operating hours. This factor also relates to district heating demands from the external end user. In Los Angeles, California, the average daily temperature is about 20 °C (Chilingar and Endres, 2005) and therefore; there is less need for an all-year district heating scheme. The plant, however, could adapt to the need for cooling, by reversing its heat exchanger. To confirm the viability of either option, a cost-benefit analysis is required, incorporating a heat and power associated maintenance, distribution network and purchasing agreements, which are outside the scope of this work.

6. CONCLUSIONS

This study is focused on identifying key technical and economic parameters of waste heat recovery from mature and abandoned hydrocarbon fields. The approach taken was to build a database of past and ongoing geothermal projects and feasibility studies, where each case study was surveyed for a list of 52 parameters. Those found to be significant were incorporated into an existing matrix by Soldo and Alimonti (2015); originally developed to choose between two extraction technologies of subsurface heat. The modified matrix in its wider format considers more aspects, including an evaluation of the availability of heat recharge and geothermal fluid; detailed conversion plant performance; hardware availability; end user economic and technical considerations, and temperature and flow feasibility, which are variable according to the type of end use for the recovered heat. Each parameter was translated into a numerical index, either qualitative or quantitative. For the latter, both the established database and available literature were used to set the range for each index. Two applications for which the modified matrix can be employed for are demonstrated. These are ranking geothermal projects for a given end use and selecting the best recovery application for a candidate field. For the first application, geological, environmental, and social aspects can be strong controls over the feasibility of subsurface thermal recovery. For the second, major controls over the selection of an end use for the recovered heat were gathered in an application performance index ($P_{App.}$). This index assesses temperature and flow feasibility for a particular application, as well as considering location, need, and sale price related to the targeted end user.

Looking at the novelty of this concept and the paucity of data in the related literature, the database provided is a valuable reference when considering such heat recovery applications, as it provides rough estimates of the required operating conditions and expected economics for candidate fields.

Moreover, the modified matrix is a straightforward, reliable tool to evaluate the success of geothermal projects and compare various technical and economic aspects between them and within a given field. Recovering waste heat from hydrocarbon fields could positively alter the management cycle of many mature hydrocarbon sites and give new life to many abandoned oil fields worldwide.

7. RECOMMENDATIONS FOR FUTURE WORK

- All parameters discussed are assessed at the initial time of considering waste heat recovery. A time varying property implanted for these parameters can draw a continuous image of the project geothermal performance throughout its lifetime. This can be aided by conducting reservoir and wellbore simulations to extract an approximate subsurface temperature profile at the production and injection wells and link that with the conversion plant performance.

- For gas fields considered for waste heat recovery, several factors should be introduced to the modified matrix; as these strongly affect the content of heat recovered from the produced gas. These are water salinity, dissolved gas content and initial gas saturation (Sanyal and Butler, 2010). Besides the thermal content, chemical and mechanical (hydraulic) energy should be also included for an overall feasibility assessment.

- Investigation into other applications of heat recovery onsite for hydrocarbon fields should be conducted. These include using the recovered heat for hydrocarbon separation.

NOMENCLATURE

Roman

C	Weight fraction of NCG in produced hydrocarbon [Fraction]
C_{po}	Oil specific heat [W/kg K]
C_{pw}	Water specific heat [W/kg K]
I	An index in the evaluation matrix [Dimensionless]
j	An individual index in the evaluating matrix [Dimensionless]
L_p	Pipe length of conversion plant [km]
m	Total Number of indices [Dimensionless]
P	Performance index [Dimensionless]
P_{gross}	Gross power [KW]
P_{TPL}	Power consumption by total parasitic load [KW]
Q	Evaluated thermal power from co-production [KW]
q_o	Oil flowrate [m^3/s]
q_w	Water flow rate [m^3/s]
T_i	Plant inlet temperature [°C]
T_o	Plant outlet temperature [°C]
w	Index weight [Dimensionless]

Greek

ρ_o	Oil density [kg/m^3]
ρ_w	Water density [kg/m^3]
η_c	Thermal cycle efficiency [Fraction]
η_{C1}	Efficiency of first heat exchanger [Fraction]
η_{C2}	Efficiency of second heat exchanger [Fraction]
η_{CHP}	Efficiency of combined heat and power plant [Fraction]
η_{DH}	Efficiency of district heating plant [Fraction]
η_E	Efficiency of electricity generating plant [Fraction]
η_G	Efficiency of generator [Fraction]
η_{ncg}	Efficiency due to non-condensable gases [Fraction]
η_{pipe}	Efficiency due to pipe length [Fraction]
η_T	Efficiency of turbine [Fraction]
η_{TPL}	Efficiency of total parasitic load [Fraction]

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