MATCHING THE FIELD TO THE PLANT

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SUMMARY - This paper deals with two aspects of "sizing" geothermal projects; the selection of turbine inlet pressure and attendant economic benefits, and the selection of project size to maximise economies of scale.
A previous paper outlined a method to quantify, before detailed design and price estimation, the capital cost implications of alternative steam supply pressures for a steam dominated system (Kamojang in Indonesia). The method considers the size or rating of a plant item or subsystem and determines the change in size or rating for a change in steam supply pressure. Cost changes are assessed from the estimated cost of the plant item or subsystem using normal rules for the cost of size changes. Separate savings or additional costs are evaluated for the steamfield and power plant parts of the project. This method is now extended to liquid dominated systems, for which a low enthalpy case is considered as well as a medium enthalpy case. For the medium enthalpy case (1600 kJ/kg), appreciable cost savings are predicted for 10 bara turbine inlet pressure compared to a value of 6.5 bara. For the low enthalpy case, the lower turbine inlet pressure will provide lower overall costs.
A strong drive for economies of scale means that the customary approach of matching the power plant to the geothermal field is not the only approach for project development. This paper examines the economies of scale which can be achieved with larger unit and plant sizes, and establishes some guiding principles for maximising such economies. Wherever possible, the approach should be to "match the field to the plant". In small geothermal fields, the standard approach of matching the plant to the field is still justified on the grounds of minimising technical and commercial risk. In very large fields economies of scale will be limited by the power density of the field and other physical limitations which will require replication of plant and equipment without economies of scale.

1.0 INTRODUCTION

One intention of this paper is to extend the ideas presented in a previous paper (Mills, 1995). These concerned a methodology for quantifying the costs and benefits which arise in selecting the steam supply pressure for a geothermal power plant. A particular steam dominated field was examined and the methodology is now extended to liquid dominated systems. As for the previous paper, a turbine inlet pressure (TIP) of 10 bars absolute (bara) is compared to a lower TIP value of 6.5 bara. Two cases of low and medium enthalpy well types are considered, being 1085 and 1600 kJ/kg. Medium levels of permeability are assumed. A project size of 60 MWe is considered, with the power plant comprising two units of 30 MWe each.

Within geothermal circles, conventional wisdom has been that the power plant should be matched to the field, rather than the other way around. This approach is taken to avoid the possibility of the field being unable to sustain the full output of the installed power plant, either from the very outset, or after a few years of operation. There have been a number of examples where this has occurred, such as the South Geysers plant in USA, Krafla in Iceland, and Ohaaki in New Zealand. Commercial advantages can be achieved in projects by seeking economies of scale from developing larger power projects and/or using larger unit sizes; both approaches can reduce the installed cost of power projects. This paper is intended in part to clarify the thinking on the way in which power plants are developed in relation to the geothermal field, and thereby to establish some general guidelines.

2.0 METHODOLOGY

Capital cost estimates are made of both the steamfield development and the power plant. Often such estimates will be prepared prior to completion of detailed design.

The effect of variations in TIP on the cost of particular plant items or subsystems is evaluated. A size rating is calculated for plant subsystems, and a new value is derived for the changed TIP. The saving or additional cost for the subsystem is then determined from the change in size rating. The separate effects for plant subsystems are then combined to determine an overall balance of cost and savings effects. Note that it is only necessary to consider those costs that are affected by changes in steam supply pressure.

3.0 STEAM USAGE

Steam consumption estimates for the plant (but excluding gas extraction system) are given in Table 1.

Table 1 - Steam Usage and Mass Flow.

TIP / bara	Steam Usage / t/h/MW	Steam Mass Flow / t/h
10	6.33	380
6.5	7.0	420

4.0 IMPLICATIONS FOR STEAMFIELD

The selection of steam pressure will impact on several aspects of the steamfield design, as discussed below.

4.1 Number of Wells

Estimates of the output of typical wells were made using the wellbore simulation software **WELLSIM.** The predicted output curves for the two enthalpy cases, 1085 kJ/kg and 1600 kJ/kg, are shown in Figures 1 and 2. Specific assumptions were made, including that the wells had standard sized casings and that the fluid feeding the well was derived from a single feed at 1500 m.

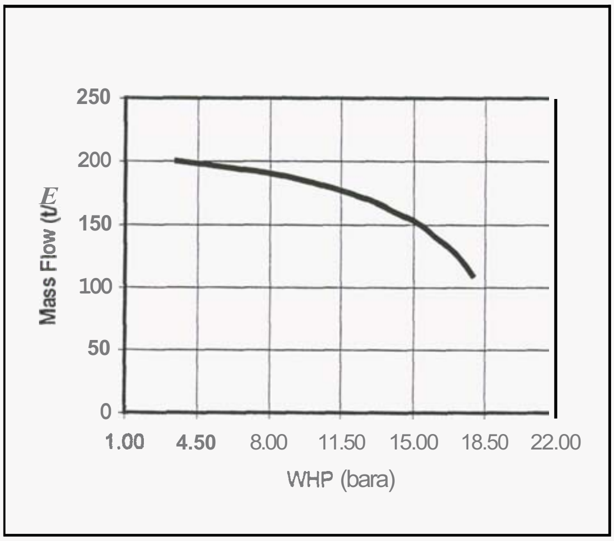

Figure 1 - Average Well Output Curve - 1085 kJ/kg Case.

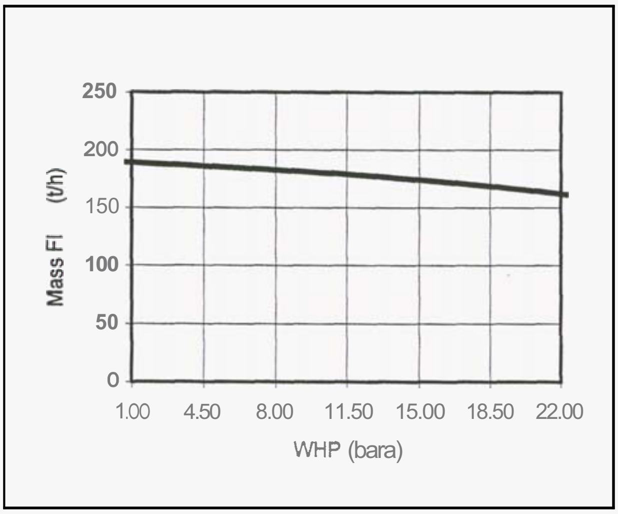

Figure 2 - Average Well Output Curve - 1600 kJ/kg Case.

From this information, the number of wells required for the 60 MWe project (2 x 30 MWe units) can be estimated for each TIP, and these are shown in Tables 2 and 3 (which assume that the pressure drop between wellhead and separator, and also between separator and turbine inlet, is 0.75 bar).

Table 2 - Required Number of Wells 1085 kJ/kg Case.

TIP / bara	Well Total Flow / t/h	Well Steam Flow / t/h	Exact Well Numbers	Whole Wells & MW Output
10	178	27.4	13.9	15 ≡ 65 MW
6.5	189	35.0	12.0	13 ≡ 65 MW

Table 3 - Required Number of Wells 1600 kJ/kg Case.

TIP / bara	Well Total Flow / t/h	Well Steam Flow / t/h	Exact Well Numbers	Whole Wells & MW Output
10	179	60.1	6.3	7 ≡ 66 MW
6.5	183	66.4	6.3-	7 ≡ 66 MW

For the 1085 kJ/kg case, two less wells are required for 6.5 bara TIP, compared to 10 bara. The cost of a well is assumed to be USD 2,250,000.

For the 1600 kJ/kg case, the same number of wells are required for 6.5 bara TIP and 10 bara.

It should be noted that the well output curves in Figures 1 and 2 are those expected at the outset of field operation. The decline in well output over the operating life of the field will determine the number of make-up wells required, and there may be significant differences in the response of the lower enthalpy (liquid dominated) field compared to the higher enthalpy field. This analysis takes no account of such decline, but consideration would need to be given to the way in which well output declines over the life of the project. The differences in make-up well burden (to maintain plant output at the initial value) between TIP values of 6.5 bara and 10 bara would need to be compared, and capitalised values included in the economic balance.

The total mass withdrawal rate from the field can be calculated from the data in Tables 2 and 3, and is shown in Table 4.

Table 4 - Total Mass Flow Rates.

	1085 kJ/kg	1600 kJ/kg
TIP 10 bara	2470 t/h	1130 t/h
TIP 6.5 bara	2265 t/h	1160 t/h

For the low enthalpy case, total mass flow decreases by about 9% for 6.5 bara TIP compared to 10 bara. For 1600 kJ/kg case, total mass flow increases at the lower pressure by about 2.5%. The resource could decline slightly more rapidly due to any increase in mass withdrawal rate.

4.2 Costs of Pipelines, Separators & Reinjection System

The actual layout of the field can depend on many factors including field area (assumed to be 6 km^2), field shape (assumed circular with power plant near the centre), well output (hence number of wells per km^2 and resultant well spacing) and location of separator plants.

Pipeline Diameter- As discussed in the previous paper, the overall impact on the pipelines of increasing TIP is to reduce the DIF value by 10%. This is assumed to apply to steam lines and two phase lines (on the basis that a two phase line would have a similar size to a steam line carrying the resultant steam). For 1085 kJ/kg, the cost of pipelines would be about USD 8,000,000, and the saving from raising pressure to 10 bara would be about USD 800,000. For 1600 kJ/kg, the cost of pipelines would be about USD 6,000,000, and the saving from raising pressure to 10 bara would be about USD 600,000.

The above figures ignore the cost of connecting any extra wells that need to be connected. The cost of connecting a single well is taken as USD 500,000.

Separator Sizing-

Separators are essentially volumetric devices; a separator sized for 50 t/h at 6.5 bara, would operate quite satisfactorily with 75 t/h at 10 bara. Furthermore separators are usually made to standard designs, so they come in discrete blocks of capacity, such as 50 t/h or 100 t/h (at say 6.5 bara). The numbers and costs of separator stations have been estimated and are shown in Table 5 for the two enthalpy cases and the two operating pressures.

Table 5 - Required Number and Cost of Separators.

	6.5 bara TIP		10 bara TIP	
1085 kJ/kg	**5 x 100 t/h 1 x 50 t/h**	USD 2.3 M	3 x 100 t/h	USD 1.2 M
1600 kJ/kg	**100 t/h 2 x 50 t/h**	USD 2.2 M	3 x 100 t/h	USD 1.2 M

Reiniection System-

The estimated quantities of water for disposal in each case are given in Table 6.

Table 6 - Reinjection System Parameters.

	6.5 bara TIP	10 bara TIP
1085 kJkg	1845 t/h	**2090 t/h**
1600 kJ/kg	740 t/h	750 t/h

It can be seen that there is little difference due to steam supply pressure in the amount of water for reinjection for the 1600 kJ/kg case. At lower enthalpies, the quantity of separated water increases appreciably. Adopting the higher steam supply pressure has a significant effect at lower enthalpies on the quantity of water for reinjection.

In any real field there will be other factors which need to be considered, including physical layout (where possible making use of topographical differences to reduce the need for pumping), the actual capability of the injection wells, etc.

The variation in cost of reinjection pipes can be easily quantified by estimating the cost of the reinjection lines at 6.5 bara supply pressure, and adjusting the diameter by the square root of the increased volumetric flow (this assumes constant liquid velocity). Assuming the same pipeline lengths, from an estimated cost of reinjection pipelines of USD 2,000,000 for 6.5 bara, the 10 bara case would show a price increase of about USD 130,000.

It is assumed that the variation in cost of reinjection pumps follows a two thirds power law relationship with the flow rate ratio; this equates to a 9% increase. From a basis of USD 1,800,000, the extra cost for 10 bara TIP would be about USD 160,000.

The power demand for reinjection pumps is assumed to be increased by the increase in flow (about 13%). (No allowance is made for higher pump suction pressure which will probably be off-set by the higher required reinjection wellhead pressure due to fixed injectivity but higher flow rate.) This will result in an increased power demand of about 200 kW, assuming the reinjection system uses a total of 1500 kW. This power increase can be capitalised; for a power price of 7.5 c/kWh, and assuming 80% capacity factor, the extra annual cost is about USD 105,000. The capitalised value, using 15% discount rate and 25 years, is taken as USD 675,000.

4.3 Steamfield Balance

The overall implications for the steamfield of using 10 bara TIP over 6.5 bara TIP are very strongly enthalpy dependent, as shown in Tables 7 and 8:

Table 7 - Cost Savings for 10 bara TIP - 1085 kJ/kg.

Drilling cost of two wells	-4,500,000
Connection cost of two wells	- 1,000,000
Reduced pipeline diameter	800,000
Separator costs	1,100,000
Reinjection costs	**- 290,000**
Increased pumping power	**- 675,000**
Increased mass extraction rate - 9% more than 6.5 bara, no monetary value assigned	
TOTAL USD Cost Saving	**- 4,565,000**

Table 8 - Costs Savings for 10 bara TIP - 1600 kJ/kg.

Drilling cost of wells	same number of wells
Connection cost of wells	same number of wells
Reduced pipeline diameter	600,000
Separator costs	1,000,000
Reinjection costs	no difference
Increased pumping power	no difference
TOTAL USD Cost Saving	**1,600,000**

5.0 IMPLICATIONS FOR POWER PLANT

These are unchanged from the original paper and were found to be as given in Table 9 for 10 bara compared to 6.5 bara.:

Table 9 - Costs Savings for 10 bara TIP.

Steam supply piping	200,000
Condenser and gas extraction	420,000
Cooling tower	420,000
MCW and Aux. CW piping	170,000
MCW pumps/motors	200,000
Reduced parasitic power demand	450,000
TOTAL USD Cost Saving	1,860,000

6.0 CONCLUSIONS ABOUT STEAM SUPPLY PRESSURE

Adopting a high steam supply pressure of 10 bara at the turbine inlet compared to the case of 6.5 bara TIP is expected to increase or decrease the cost of the steamfield depending on fluid enthalpy. Irrespective of fluid enthalpy (because steam separation effectively decouples the power plant from fluid enthalpy considerations), there will be a decrease in the cost of the power plant parts of the project.

The change in steamfield capital cost depends on the enthalpy case. For 1085 kJ/kg, there will be an extra cost of about USD 4.6 million. The 1600 kJ/kg case shows a saving of USD 1.6 million. Generally savings arise from the higher pressure because of smaller pipelines and fewer separators. But at low enthalpy values there are significant penalties which arise from the need for additional wells (drilling and connecting), extra reinjection pumping and reinjection pipeline size, as well as the parasitic power demand of reinjection pumps.

Of note is the fact that total mass extraction rates can increase or decrease for the two pressures considered depending on the field enthalpy.

The difference in power plant costs may be nearly USD 2 million, which includes the capitalised value of reduced auxiliary power usage for 10 bara TIP. Cost savings, all favouring 10 bara TIP, occur for the condensing and gas extraction system, the cooling systems, including the cooling tower, and various piping subsystems.

The preference for higher or lower steam supply pressure will thus depend on the fluid enthalpy (as this affects significantly the behaviour of the wells). For 1085 kJ/kg, the nett extra cost for 10 bara TIP is about USD 2.8 million. For 1600 kJ/kg, the expected cost saving for 10 bara TIP is about USD 3.5 million.

Linear interpolation suggests that the cost cross-over point is at an enthalpy of about 1300 kJ/kg, but it would be useful to check an intermediate TIP value to confirm whether the relationship is linear.

These conclusions were derived using the methodology outlined, and the results depend on the validity of that methodology. As opposed to making a detailed evaluation of all facets of the project, the methodology evaluates the cost changes in components of the steamfield and power plant developments that would be expected to be significantly affected by the selection of steam supply pressure. The approach can be applied quickly and easily before full optimisation or detailed design is undertaken.

7.0 ECONOMIES OF SCALE

This section deals with the issue of how much capital can be saved by seeking economies of scale. There are a number of ways that economies of scale can be achieved, including the following (which often would be found in combination):

Steamfield

- Multiple well pads (to concentrate production and to reduce per well civil engineering costs for access and drill site construction);
- Large diameter wells (to maximise well output and reduce the number of wells for any given project size);
- Special drilling techniques (to improve well output);
- Two phase fluid transmission (to reduce numbers of pipes);
- Large and/or centralised separator stations (to reduce civil costs and use fewer but larger pressure vessels and thereby obtain economies in the cost of separator stations);
- Maximise flow in lines (thereby reducing number of lines)
- Higher fluid flow velocity (thereby reducing line size, but pressure drop works against this).

Power Plant

- Single larger units compared to multiple units (to reduce powerhouse footprint and hence lower installed costs, reduce maintenance and operating costs);
- Large units compared to smaller units (to lower installed costs);
- Purchasing more than one unit (to obtain volume discount);
- Adopting price efficient contractual bases (to control margins).

Electrical and Transmission

- Single units compared to multiple units (to reduce number of switchyard bays, number of transformers, and other equipment);
- Large transformer sizes (for economies of scale);
- Maximise transmission voltage (to limit conductor size and reduce line losses);
- Use large conductor size / high line capacity (to reduce losses, and carry more power on the same towers);

The following discussion focuses on power plant factors in particular. This is done for two (related) reasons. The power plant comprises perhaps 60% of the project cost which makes any ratio savings greater in absolute terms. Also, very appreciable savings can be made in the cost of the main generating plant, which are major cost items.

A typical range of power plant costs is given in Table 10. The data are indicative, but have appropriate relativity between single and twin unit cases.

Table 10a - indicative Power Plant Costs (Million USD).

Plant Size / MWe	1 x 55	1 x 75	1 x 110
Site Dev / Civil / Struct	7	7.75	8
Mechanical	22	27	35
Electrical	17	21	27
Cooling Tower / Other	15	17	22
Develop & Engineer	5	6	7
TOTALS	66	78.75	99
Installed Cost / $/kW	1,200	1,050	900

Table 10b - Indicative Power Plant Costs (Million USD).

Plant Size / MWe	2 x 55	2 x 75	2 x 110
Site Dev / Civil / Struct	8	8.5	9.5
Mechanical	42	52	67
Electrical	33	40	52
Cooling Tower / Other	27	33	43
Develop & Engineer	8	9	10
TOTALS	118	142.5	181.5
Installed Cost / $/kW	1,075	950	825

In the case of a field that may have reserves sufficient for around 100 to 150 MWe, but with only about 50 MWe proven, a commitment could be made to a 55 MWe unit. Extra effort taken to prove 110 MWe would provide two principal benefits; capital cost savings of as much as USD 19 million (1 x 110 MWe case compared to an eventual 2 x 55 MWe project), plus earlier generation of the additional 55 MWe of capacity (along with earlier capital expenditure). Note that there are various permutations for developing 110 MWe of plant (1 x 110; 2 x 55 in a single location; or, less likely, 1 x 55 in each of two locations).

In the case of a much larger field that may have reserves sufficient for 200 to 250 MWe, but with only about 100 MWe proven, a commitment could be made to a 110 MWe unit. Extra effort taken to prove about 200 MWe would provide capital cost savings of about USD 17 million (2 x 110 MWe case compared to an eventual project with 2 separate plants of 1 x 110), plus earlier generation of the additional 110 MWe of capacity. As before, there are various permutations for developing 220 MWe of plant, such as 2 x 110 in a single location; 2 x 110 in each of two locations; 3 x 75 MWe in one or two locations, etc. Another variation would be two separate plants each of 2 x 55 MWe, which is the worst permutation of those listed in Table 10. The saving between 2 x 110 in a single location and 2 separate plants of 2 x 55 could be in excess of USD 50 million.

For smaller fields, the classical approach of matching the plant to the field is more appropriate. This is because of the risks that arise from over-sizing the plant, either at the outset or during the mid-life of the project. Mid-life risk (i.e. after the first few years of operation) can arise from the need to drill make-up wells. Intuitively, if the plant is a large proportion of the field capacity then the make-up well burden should be high, and may prove to be uneconomic. Effort must be made to quantify the make-up well needs, and the financial consequences incorporated into a complete analysis.

It is expected that for large steamfield developments no special economies of scale are available beyond a certain point; i.e. a law of diminishing returns applies. This will be due to two factors.

The first is that individual pieces of equipment can only be made so big before duplication is required; this applies to pump/motor units, separator stations, and pipelines (which typically are up to 1000 mm in diameter).

Of probably greater importance is the fact that at some point extra capacity must be sought from new areas of the field to avoid increasing the power extraction density beyond normal limits (say in the range 10 to 15 MWe/km^2). At that point field facilities need to be replicated into the new areas. This may be as simple as extending two phase lines, but the high pressure drops needed for two phase flow will require that separator stations and steam lines also be replicated into the new field areas. In the extreme, establishing a new power plant location may be justified rather than transporting fluids over very long distances. In some cases, physical conditions may simply require this, rather than being based on a balance of costs and benefits.

For electricity transmission, there are will also be constraints on economies of scale. Significant factors are expected to be limits on the load that individual transmission lines can carry, the desirability of having more than a single circuit for export of large power flows, demand for power on the system and the extent of the system (integrated or regional network), system conditions (such as low voltage) that arise from load flows, and power production from other new projects that will also require transmission capacity. These factors require site-specific examination.

8.0 FAST-TRACK FIELD PROVING AND EXPENDITURE TIMING

Rapid field proving and development of adequate steam at wellhead is needed to allow the largest possible development to be committed at the outset. Doubling steam production would be expected to approximately double the capital expenditure on field drilling, but clearly this will depend on a whole range of factors. Some improvement in drilling success might be expected in drilling for an expanded power plant, but only if the expansion occurs by means of in-fill drilling in the already explored parts of the field.

It is important to note that the extra expenditure would eventually be required to expand the field, even without fast-tracking the field proving.

A key determinant of project profitability is the timing between capital expenditure and earning revenue from the project. Therefore, if the time delay between spending the capital and commencing operation is the same (i.e. same delay for expansion as for the initial plant), there will be no effect on profitability. This assumes expenditure is the same, power price is the same, and the relative timing (of expenditures and revenues) is also unchanged.

An alternative, more conservative, approach would be to consider the financing cost of bringing the expenditure forward.

For the sake of quantifying amounts, it is assumed here that drilling for an extra steam supply of 55 MWe (in addition to a base of 55 MWe) is advanced by two years, and the finance rate is 10%. It is further assumed that wells provide 10 MWe and cost USD 2.5 million each, drilling success is 80%, and reinjection wells are required one for every four successful production wells. The drilling for 55 MWe would thus have a expected cost of USD 25 million [(60/10x1.25+0.5)+2)x2.5].

The corresponding financing cost, allowing for compounding over the two year period, would thus be USD 5.5 million. There is no justification to charge additional interest for carrying the drilling cost through (part of) the power plant construction period. This is because the drilling costs would in any case have to be so carried during the construction of the assumed expansion.

As noted above, the expanded generation becomes available sooner than would otherwise be the case, but this is largely offset by advancing the capital expenditure for the new plant. For this reason, the appropriate economic measure is the difference between the capital cost savings and the extra cost of bringing the drilling forward. For the above example of a 55 MWe increment on a base of 55 MWe, the capital saving is USD 19 million versus a cost (for interest) of USD 5.5 million. The nett benefit is thus about USD 13.5 million, for the 110 MWe project. Assuming an annualised worth of USD 2.2 million (15%, 25 years), for 90% capacity factor and 7% parasitic loads, this is equivalent to almost 0.3 c/kWh.

9.0 CONCLUSIONS ABOUT FIELD PROVING

While there are limits to the economies of scale that can be achieved for steamfield and electricity transmission parts of a project, there are appreciable economies that can be achieved for the power plant part. These arise from the cost reductions that are provided by larger unit sizes, and also from using multiple units at a single site.

Acceleration of field proving allows the capital savings to be realised. A conservative measure of the cost of advancing the drilling is the cost of financing the earlier expenditure, rather than the actual drilling cost. Accordingly the potential savings can be significant. If the power plant expansion has the same relative timing of capital expenditure with commencement of operation (and thus ability to earn revenue), advancing the drilling simply advances the capacity expansion and the cost of power production would be reduced because of the capital savings that the expansion would allow.

For large geothermal fields, minimal increase in resource risk arises from committing large power plants as early as possible. Such large power plants allow economies of scale to be maximised, so the approach should be to prove as large as possible field capacity, and thereby match the field to the plant. Economies of scale will be limited by the need to locate the expansion power plant in a new location because of the simple inability of a field to deliver ever-higher power density. Usual power levels of 10 to 15 MWe/km^2 apply.

For smaller geothermal fields, the risk of "over-installing" generating plant requires that the plant be matched to the field. This is the more traditional school of thought.

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