ASSESSING COST OF PRESSURE DROP FROM A GEOTHERMAL PROJECT LIFECYCLE PERSPECTIVE

Mary Helliwell[1] and Aaron Hochwimmer[1]

[1]Jacobs, PO Box 9806, Newmarket 1149, Auckland, New Zealand

mary.helliwell@jacobs.com

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ABSTRACT

Geothermal steam fields are a key component of most geothermal projects. They provide the mechanism to transport geothermal fluid from production wells to the intended application and then on to injection wells. Along with the piping, steam fields include mechanical equipment to separate the fluid into steam and brine phases, and to clean the steam prior to admission into a power generating facility or direct use application.

Line sizing in the engineering design process considers pressure drop in the steam gathering system. Fluid velocity design criteria are applied to provide a balance between pressure drop in the lines, mitigation against internal erosion, and the capital cost of piping.

Smaller pipes incur lower initial installed capital cost compared to larger pipes. Conversely smaller pipes will result in higher pressure drop and velocity rates for a given flow. The economic impact over the project lifecycle perspective is termed the ‘cost of pressure drop’. Over time, as the reservoir responds to production, existing wells will decline requiring additional make-up drilling to provide fluid at the required interface pressures and flow rates at separation and/or power plant.

Recent trends in geothermal steam condensing power plant technology, along with advances in reservoir exploration and analysis, provide increasing confidence in higher inlet pressure machines for power generation. Higher inlet machines usually translate into better installed $/kW and resource utilisation (exergy efficiency). In this scenario a focus on reducing the ‘cost of pressure drop’ in the steam-field (in total or in part), can delay the need for de-rating the power plant and/or make-up drilling.

This paper considers the project life-cycle cost of pressure drop considerations in conjunction with existing line sizing criteria. Relevant factors that can influence decision making include drilling cost, predicted reservoir response, relative cost of piping, and the return on investment of power generation.

1. INTRODUCTION

1.1 Steamfield Layout

Geothermal reservoirs contain hot geothermal fluid that can be utilised for electricity generation at a power plant. In the majority of cases this consists of a single flash steam condensing turbine. In 2010 geothermal power generation was reported as 42% by single flash condensing from liquid dominated resources, and 24% by single flash condensing from vapour dominated (dry steam) resources. The remainder of generation comprises a balance of double flash (21%), binary (9%), and back pressure (4%) (refer Gehringer and Loksha (2012).

This paper focus on pressure drop considerations for steamfields feeding single flash condensing plant. Geothermal wells are drilled into the reservoir and fluid delivered to the surface, usually under pressure from the reservoir itself. The number of wellpads required depends on the capacity of the wells and the size of the power plant (a function of sustainable resource capacity, power demand, and project feasibility).

Once at the surface the fluid is then conveyed to the power plant, which is usually located some distance from the wellheads in a central location. The surface infrastructure installed to transport the geothermal fluid across country is commonly termed the steamfield. Every geothermal steamfield is different. The physical aspects of the field are dictated by:

- Aerial extent of the geothermal reservoir and location of production and injection target areas
- Terrain
- Consideration of geothermal hazards such potential lahar flow paths in volcanic settings
- Availability of land
- Site elevations
- Number and location of wellpads
- Location of power plant and distance from the wellpads
- Nature of geothermal fluid being transported

Geothermal projects are often to be found in magmatic settings, on the slopes of volcanoes and other geothermal active areas, with roads and wellpads built along ridges with limited access. These areas are often unstable, with landslips and seismic activity a regular occurrence. Land in steamfield locations is also often already acquired by other stakeholders for use as farmland, forestry, or is within a protected area such as a National Park. Additionally areas of cultural significance for the local population must be considered, and normally avoided, in a steamfield concept.

These factors impact on whether the best locations for pads and routes for pipelines can be acquired for development or whether less ideal solutions, from a process engineering perspective, need to be adopted.

Land requirements depend on the power plant capacity and location and number of wellpads providing net motive steam. Some steamfields are very compact, with one or two production pads located only a few hundred metres from the power plant. Others could extend over 20-30 square kilometres, with numerous production pads feeding into several separator stations which then provide steam for the power plant.

Liquid dominated geothermal reservoirs are most common and deliver two phase steam and brine flow to the surface. In this case, separation of the steam from the brine is required before admission to the power plant. Separation stations may be sited at individual wellpads or at central locations. This is dictated by terrain as well as capacity of and behaviour of the wells, in particular the available discharge pressure at commercial flow rates. One of the most important aspects which will influence a separator station location (when it is not located directly on the wellpad) is elevation. If possible two phase pipelines should not be routed uphill from the wellpad, but in a continuous downhill fall to the separator station. This is to reduce occurrences of fluid slugging in the lines which can occur in uphill sections. Slugging is to be avoided because it has potential to cause vibration problems to the cross country line and associated supports as the slug of brine moves through the pipe. Problems can also occur with slugging causing process upsets in the separator, especially destabilizing level control where it is used for brine pumping and disposal.

Elevation also plays a part in brine disposal. Injection of separated brine and power plant condensate is mandatory in many fields to maintain 100% injection of geothermal brine to the environment. If enough difference in pressure head is available between the fluid generation site and the injection location it may be possible to dispose of it without recourse to pumping. This has a number of advantages in that it avoids capital and operational expenditure for the pumps in addition to an increased parasitic load which reduces net power generation capacity of the project.

An ideal steamfield layout would have wellpads located at an elevation above the separation station and power plant, with the injection wellpads located at an elevation sufficiently below the power plant to allow for gravity disposal of brine and condensate.

1.2 Steamfield Design

Once the production wellpads, separator stations, power plant, injection wellpads and connecting road and pipeline routes have been identified, steamfield design may commence. Preliminary design of the steamfield is often carried out before the majority of wells, both production and injection, have been drilled. To achieve an accelerated development schedule the detailed design is also normally undertaken with only limited well data available to inform to the steamfield development.

The most important data required for steamfield design is the flow test data for both production and injection wells. For production wells it provides the following key information:

- Enthalpy of the discharge from the reservoir. The higher the enthalpy, the higher the steam content of the fluid. The ideal result from a geothermal production well is dry steam, as no brine separation is required. However, two phase flow is the more common result.
- Deliverability curve, depicting fluid mass flow as a function of pressure. As pressure increases, flowrate declines, up to the shut in pressure of the well. The curve for every well is different, even when drilled from the same pad. For a steep curve, there are significant changes in flow for small changes in wellhead pressure. For a shallow curve, little change in flow may be gained from large step changes in wellhead pressure. Examples of steep and shallow curves are presented in Figure 1 and Figure 2 respectively, below.

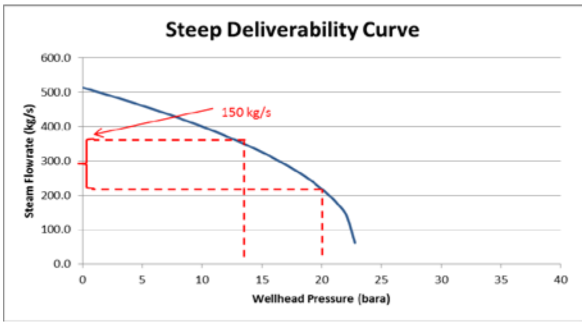

Figure 1: Typical Steep Production Well Delivery Curve

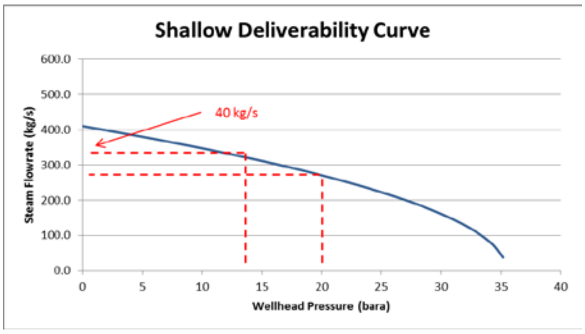

Figure 2: Typical Shallow Production Well Delivery Curve

- Decline rate of the well. All geothermal production wells suffer a decline in flow over time as the reservoir is exploited. The rate of decline will determine at which point in the future additional wells need to be added to the system to maintain adequate steam flow to the power plant. An example of well decline over time is depicted in Figure 3.

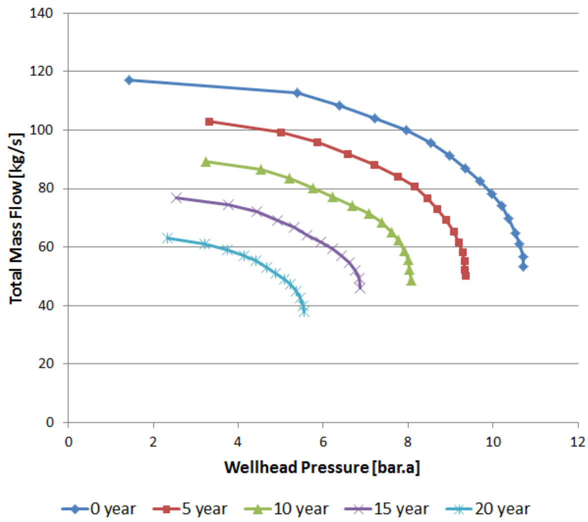

Figure 3: Typical Well Decline over 20 years

- Concentration of Non Condensable Gas (NCG) in the geothermal fluid. Most wells deliver a mixture of gases such as carbon dioxide and hydrogen sulphide with the geothermal fluid. Most plants are designed for 1 - 2% NCG content and have a gas extraction system specified to this duty. If wells deliver considerably more than this concentration of NCG the turbine efficiency could be reduced. This uncertainty can be mitigated through plant design and building in flexibility in the gas extraction system with multiple trains and/or hybrid ejector/liquid ring vacuum pump arrangements.

Injection well data also provides valuable information to the steamfield design.

- Injectivity curve, similar to a deliverability curve, illustrating fluid flow able to be injected into the well against pressure. All wells are different, even on the same pad, depending on where they have been targeted sub surface and the associated feed-zones intercepted. Ideally, fluids will be able to free drain into the well, with the operating water level below the surface. This may not always be possible. Where the well has a water level at the surface, or is slightly over-pressured, pumping will be required to dispose of fluid into the well. As with production wells, injection well curves may be steep or shallow. For a steep curve, small changes in pressure will result in large changes in flow injected into the well while for shallow curves very little additional flow change is seen, even for significant increase in pressure. Figure 4 depicts typical curves for wells requiring pumped injection.

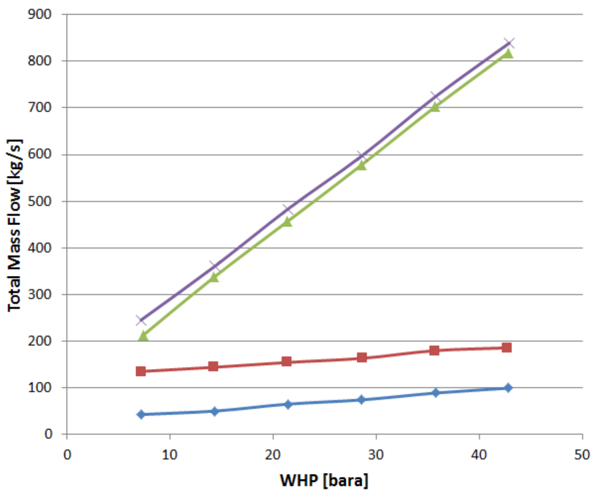

Figure 4: Typical Shallow and Steep Well Injectivity Curves

The well data, for both production and injection wells, directly affects operation of the field. At lower pressures more steam is generated by the production wells and less wells will be required to keep the field at steam-surplus, however there is also a reduction in power output from the turbine at lower inlet pressure which will impact on generation capacity of the plant.

As operating pressure is reduced, steamfield and equipment sizing increases due to increase in specific volume of the steam. This has an impact on capital outlay of the field.

If the turbine is operated at a higher interface pressure, the specific power output is increased per kg/s of steam and steamfield line and equipment sizing will be smaller, but less steam will be produced from each well and more wells may be required to keep the unit operating at capacity.

When steamfield design is undertaken before the well data has been obtained, assumptions have to be made on the best available information. This usually involves estimating enthalpy and well capacity from a small number of exploration wells and applying it throughout the field.

Universal design criteria for the field (such as minimum and maximum velocities in lines for example) are also adopted for sizing lines and equipment, which may not necessarily be ideal once real well data becomes available.

1.3 Power Plant Considerations

Higher turbine inlet pressures through a flash condensing turbine (for a given steam flow) results in increased efficiency and power output, and also permits the use of larger units.

However designing and operating a plant for higher pressures requires sufficient confidence in the sustainability of the resource at that pressure, along with the nature (slope) of well deliverability curves.

Larger plant units are expected to have a lower capital cost or a per MW basis because more power is achieved for the approximately the same balance of plant cost. The variable component is largely the power train (turbine, generator and high voltage transformer).

An assessment of lifecycle cost of a project should consider all aspects of the development including drilling, steam field, and power plant. The relative value and benefit of optimizing (reducing) the pressure drop in the steam field depends on the interplay of these factors.

2. THE IMPACT OF HIGH PRESSURE DROP IN A GEOTHERMAL STEAMFIELD

Ideally a steamfield will be designed for the minimum pressure loss possible, at acceptable cost, between production wellhead and turbine inlet. In reality, however, this may not be achieved for a number of reasons. They may include:

- Wells delivering lower enthalpy fluid than estimated at design stage, which leads to higher two phase flows being required to deliver the steam flow needed for power generation. This will also lead to increased requirements for brine disposal capacity.
- Actual flows in lines being higher than design, resulting in higher velocities (with an increase in friction losses) and possible under-sizing of equipment such as separators. This may occur when production wells have greater capacity than initially anticipated, or when additional wells are connected to existing infrastructure.
- Capital cost savings being made by reducing line sizes below the optimum, or by installing reduced bore pipe fittings such as valves which increase

pressure loss. This is especially the case for wellhead branchlines which need to be rated for high shut-in well pressures compared to the rest of the field, increasing pipe class, flange ratings, pipe wall thickness and attendant installation costs. Line sizes are restricted to reduce costs, but can result in high pressure losses being incurred by the fluid, especially when wells have higher flowing capacity than anticipated in the design stage of the project.

- Tortuous line routes leading to a high number of bends and other fittings being required. This may be the case when optimum routes are not available, when the terrain is challenging for cross country construction, or where there is congestion, especially when wellpads are extended to accommodate additional make-up wells.

High pressure losses incurred in the steamfield have the following impacts:

- High wellhead pressures required to accommodate the losses, impacting on the ability of production wells to deliver geothermal fluid at the required separation interface pressure. The steeper the deliverability curve, the greater the impact that increased wellhead pressure (WHP) will have. This will result in additional wellhead production capacity being required to meet the delivery steam flow needed to maintain generation by the turbine.
- Wells decline over time. If they are operating at a high WHP, they will drop below the pressure at which they can deliver fluid to the power plant at an earlier time in the life of the field. The impact of this can be seen in Figure 3. If the well represented in this graph is operated at 8 bara, for example, it will no longer be productive after 10 years (or will need to be de-rated into a lower pressure system if available), whereas if it were operated at 6 bara, the well would continue to be productive for another 8 years. The outcome of wells becoming unproductive will be the requirement for make-up wells to be brought online sooner than would be needed if the wells are operating at a lower WHP.
- Increase in superheat in steam lines, which leads to the potential increase in solid particulates being carried forwards to the turbine. As the steam dries out and suspended solids come out of solution this increases the possibility of damage to the turbine blades.
- Possible mechanical damage to cross country pipelines due to erosion, vibration or excessive noise, leading to wall thinning and possible early failure, especially of bends and other fittings.

3. COST OF STEAMFIELD PRESSURE DROP AND MITIGATIONS THAT CAN BE APPLIED

At design stage of a project there is often a desire to keep costs at a minimum, rather than designing for a longer term optimum, and lower lifecycle cost, for the field.

This is especially true for the cross country pipelines and wellhead branchline piping. In the early years of operation, when the field is steam-rich and pressure drop is not necessarily a major problem, this is considered to be a conscientious decision. In reality, however, in the mid to late years of operation as decline in the field begins to take effect and make-up wells are required to maintain steam demand, decisions made at design stage may result in the steamfield becoming constrained. As the industry understanding of geothermal resources becomes more advanced, developers have increasing confidence in operating a steamfield at higher overall operating pressures, and specifying higher inlet plant with the associated advantages in performance and cost (refer section 1.3). This trend creates a higher relative weighting on designing for reduced pressure drop over initial lower capital cost.

Pipeline size selection for cross country lines is dependent on the following items:

- Fluid in the line
- Mass flow of the fluid
- Distance the fluid is to be transported
- Acceptable wellhead pressure (for two phase and dry steam lines)

From a process perspective the lower the pressure drop across the steamfield, the better. Pressure at the plant interface equates to energy and revenue. Reduced pressure drop can be leveraged in two ways: wellhead pressures can be reduced which allows wells to remain productive for longer, or the turbine can be operated at a higher pressure, producing a higher specific power output per kg/s of steam supplied to the power plant. Another benefit is the potential opportunity for future expansion of steam capacity at wellpads before major new infrastructure needs to be added to the field.

Where well curves are steep (Figure 1), small changes in pressure result in significant changes in flow. In this case, pressure drop should be reduced as far as possible (mainly by installing optimum diameter cross country pipework and equipment). Where wells are operating on a shallow curve, however (Figure 2), there is minimal gain to be seen for reducing pressure loss, therefore savings can be made by sizing lines with a smaller diameter, as long as maximum velocity criteria (to protect against premature wear due to erosion) is not exceeded.

Another driving force impacting on steamfield cost is the lengths of lines required. Where wellpads are sited close to the power plant, there are limited savings to be gained in construction and procurement costs by reducing line size. When lines are required to cover long distances (several kilometres for example) or across difficult terrain, construction and procurement costs will become much more significant within the overall cost of the steamfield, and significant savings can be made by reducing pipeline size. To give an indication of costs of cross country lines during concept design a “Dollar/Inch/Foot” (DIF) rule is often applied (US$ per inch diameter of line multiplied by length of line to be installed).

An indicative installed value used in current projects is US$20 per DIF (Hochwimmer et. al. 2013) which includes allowance for pipe procurement and civil/structural/mechanical/C&I design and construction. The installed cost will vary depending on factors such as terrain, location, material supplier, and other requirements of the design.

At this rate, 100 ft of line would incur the following costs:

Pipe Diameter	Installed Capital Cost [USD/100 ft]
16”	$32,000
20”	$40,000
24”	$48,000
30”	$60,000
36”	$72,000
42”	$84,000

The attraction of installing smaller diameter lines, especially over long distance, can easily be appreciated when this is taken into account.

3.1 Lifecycle Cost Considerations

One point that is often forgotten during initial design and construction however is the longer term impact of making line size reductions at design stage.

The cost of drilling and connecting a typical make-up well is currently about US$7 million (Hole (2013)), an order of magnitude increase in spending required when compared to the additional cost incurred for installing a 24” diameter line instead of a 20” diameter line, for instance (26.5 km of the lower diameter line would need to be installed before a saving of US$7 million is achieved).

If connection of one well over the lifetime of the field can be deferred by savings due to minimizing pressure losses the additional costs incurred at installation would be recouped. If two or more wells are deferred, then there are significant savings to be made over the operating life of the plant.

A rigorous analysis of the savings over the life of a project, from a net present value, need to be assessed in a financial model. This has not been presented in this paper but is a recommended step in the assessment of any new steam field development to take a holistic view of the project which informs decisions around sizing of a steamfield. As discussed the cost of drilling, and cost/performance of power plant technology as a function of inlet pressure has an increasing influence in considering life cycle cost up front in steam field design

3.2 Additional Design Considerations to Minimize Pressure Drop

Where an increase to optimum line size is resisted, such as well head branchline piping, due to consideration of costs of construction and procurement of pipe and fittings pressure drop savings can still be made through good design practice.

In well head piping in particular the following aspects of design can assist in keeping pressure losses to a minimum:

- Ensure that branchlines are designed with minimum of bends and fittings (while maintaining compliance to mechanical design codes and requirements). Thought to future well requirements at initial wellpad layout can also help significantly with future development as new make-up wells are added to the system. This would ensure that initial and future branchlines are ergonomically designed, rather than having to squeeze future pipework around existing layouts. This thinking also forms part of broader safety by design considerations.
- Ensure that all valves installed in the line are full bore, reducing pressure losses through the valve. Control valves on production wells (and sometimes injection wells) do not act in the usual manner, in that they do not continually modulate on a level or flow parameter. These valves are used to throttle flow, with the desired valve position being 100% open, allowing the well to discharge at full capacity. When throttling does take place, minor adjustments are made over days or weeks rather than the usual modulating time of a typical control valve. In this case, the reduced bore normally installed with conventional control valves to assist in accurate control is not required so the valves may be full bore which will reduce pressure losses in the branchline.
- Select valve types, instrumentation and fittings for minimal pressure loss, rather than initial capital cost. In a dry steam line, for example, a vortex meter incurs lower pressure losses than a less expensive orifice plate meter.
- Pressure losses in two phase lines are significantly higher than in single phase lines. Freeston, Lee & Hole (1983) recommend that a loss of at least twice that seen in single phase flow should be adopted. Any savings that can be made, then, by eliminating bends and other fittings will make material contributions to pressure reductions.
- Where space allows make use of swept bends rather than 90 degree tees. Tees exert higher pressure losses than wye bends, therefore they should be avoided if possible if enough space is available to incorporate swept bends into branchline design, with as shallow an angle as can be accommodated. The diagrams and the attendant charts (Figure 5, Figure 6, Figure 7), from Crane (2010), depict the pressure losses for both fittings. The hydraulic resistance of a pipe (K) can be expressed in the terms of a resistance coefficient using friction factor f, pipe length, L and pipe diameter, D.

$$K = f \times L/D \qquad - (1)$$

The figures below show the K factors for straight run and branch components for a tee and a wye fitting. The graphs show how the K factor is reduced as the angle reduces from 90^o, with attendant reduction in friction losses.

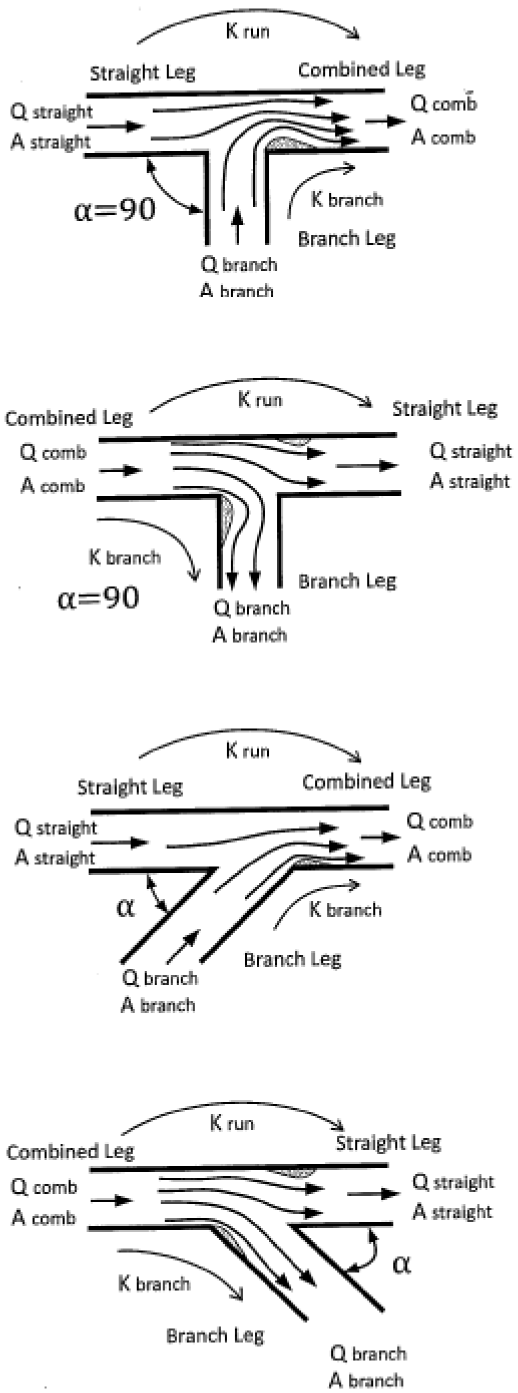

Figure 5: Schematics of Various Tees and Wyes for Convergent and Divergent Flow (from Crane (2010))

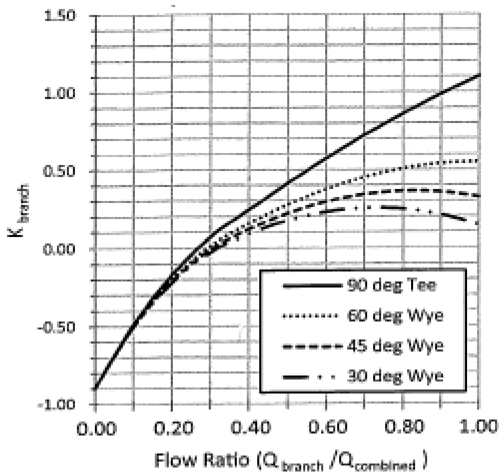

Figure 6: Branch Hydraulic Resistance for Converging flow in tees and wyes with area ratio of 1 (from Crane (2010), Figure 2-14)

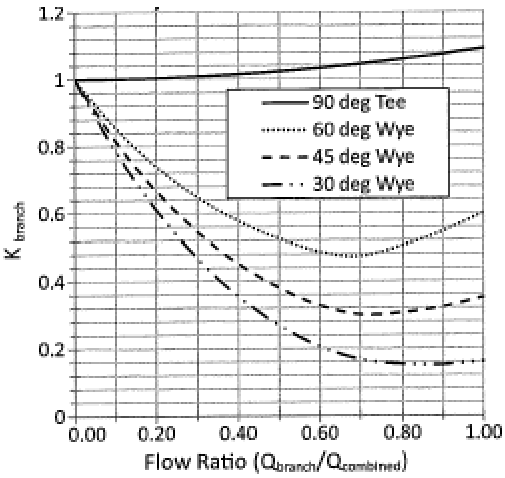

Figure 7: Branch Hydraulic Resistance for Diverging flow in tees and wyes with area ratio of 1 (from Crane (2010), Figure 2-16)

4. CONCLUSIONS

This paper has discussed steamfield design and layout, and established the criteria that need to be supplied before the design can be completed. It has also been established that often this data is not available at critical stages of design process, and the fact that this may result in steamfield operation at less than optimum conditions for the field.

High pressure loss in the system has an adverse effect on a project performance. For a set interface parameter this means that wells will need to operate at higher WHP to accommodate the pressure drop. The knock-on effects of this can be felt in two ways. The steam turbine is operated at a lower interface pressure than could be achieved, with lower specific power output per kg/s of steam. Another impact which has significant influence on capital expenditure is the point when the field is no longer able to sustain steam flow to the turbine to maintain generation capacity. This is the time when make-up wells need to be drilled, at an average cost of about US$7 million per well. Wells will become sub-commercial at an earlier time when operated at a higher WHP (as depicted in Figure 3).

It has been established that the steamfield may be undersized in later life for a number of reasons, including being a conscious decision at design stage. This is often seen as a cost saving measure at the time of construction, when the field is in steam surplus, especially when pipelines need to be constructed over long distances, or difficult terrain. While cost savings appear to be significant and attractive at this early stage, as the field becomes steam constrained, make-up wells will be required, which will incur major costs. The initial perceived savings will be dwarfed by an order of magnitude of additional costs if even one additional make-up well is required due to higher than necessary pressure losses incurred in the steamfield. There is also an increasing drive to higher pressure inlet machines as developers gain more confidence in the ability to predict and manage reservoir behaviour at higher operating pressures. This creates a higher relative weighting on designing for reduced pressure drop over initial capital cost.

While steam lines are often sized with sufficient capacity, wellhead branchline sizing is most often the part of the steamfield where greatest resistance will occur to size the lines for optimum pressure losses. This is due to the relatively high installation and procurement costs associated with the high specifications required to protect against high shut in wellhead pressures. Even here, though, significant savings may be made by informed design of the branchlines, incorporating allowance for future expansion, specifying pipe fittings that incur the least pressure loss rather than lowest cost, installing full bore valves and making use of swept bends instead of 90 degree tees.

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