DELIVERING VALUE TO GEOTHERMAL OPERATORS THROUGH INNOVATIVE ENGINEERING DESIGN AND PROJECT DELIVERY

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ABSTRACT

Over the past 40 years, Jacobs has worked on more than 100 geothermal resources, over 3,000 MW of generation, in over 20 countries. The diverse nature of these projects has fostered highly innovative thinking with "whole-of-life" consideration.

This paper outlines a number of case studies showing beneficial outcomes achieved by identifying and quantifying potential opportunities for innovation which realise value, including monetary, schedule and safety benefits. This is split into two themes; excellence in engineering design leading to reductions in total installed cost (TIC) and total cost of ownership (TCO), and accelerated project delivery honed over decades of experience.

The first theme considers the reduction in cost achieved through innovation in design resulting in very high steam quality and purity. It can be demonstrated that power plant reliability is increased and this in turn reduces the TCO of the plant. Additionally, consideration of a pressure drop early in a project contributes towards a lower total cost.

The second theme considers strategies to fast track projects at various stages during project delivery to increase value. The surface exploration program for a greenfield geothermal resource typically comprises many stages to address development risk; these can represent a considerable portion of a project schedule. Significant value can be gained by combining exploration activities into a single integrated geoscience program to front end load the exploration program. Another example of fast tracking projects is through the use of Digital 3D models to improve stakeholder engagement and cohesion between design disciplines, and lead to a reduction in design changes during construction.

1. INTRODUCTION

1.1 The need for innovation

Geothermal project development is challenging, with a high up-front capital cost, significant resource and fuel supply risk, and long development timeframes. In addition in some countries the electricity market is subdued with relatively low tariffs. This is currently the case in New Zealand due to a relatively high supply capacity relative to demand.

For companies with a diversified development portfolio geothermal projects compete with conventional thermal (coal, gas) and other renewable (solar, hydro, wind) projects under consideration.

To get a project approved and for it to be both technically and financially viable there is an increasing need to be innovative in scoping and implementation. In other words the developer must be aware of innovations which can "move the needle" from a net present value (NPV) and internal rate of return (IRR) perspective. This may be a reduction in TIC or TCO, or a schedule advantage that might mean a project can be developed and available for dispatch to the market ahead of a competitor's project.

In some cases the innovation might actually be to reframe the project from the original context or even to "kill" a project in favor of a more suitable alternative.

The global geothermal industry has been innovating for more than a century since the first geothermal power plant commenced operation in 1911. Others have studied technology advancements in geothermal development, for instance Shembekar and Turaga (2011) considered drilling, well construction and stimulation, as well as power plants with a focus on Enhanced Geothermal System (EGS) developments. While similar in terms of considering innovation, the focus of this paper is to quantify potential improvements in conventional geothermal settings.

1.2 Value Plus

All project innovation can ultimately be expressed in NPV and IRR terms. We have found this a useful technique in analyzing and presenting innovation, particularly when value is not immediately obvious from a whole-of-life perspective. For instance application of safety by design techniques could be considered in terms of a reduction in lost time accidents and incidents over a project lifetime, where the cost of an accident can be quantified in terms an overall impact to both the individual and the asset owner.

Without this rigorous analysis claims of project innovation can be at risk of hyperbole and as such lack substance.

Jacobs has an existing framework for value engineering called Value Plus. Simply put it is a practice for aggregating and reporting the value added ideas generated by our project teams. A Value Plus idea or innovation is a new or different idea, innovation, or approach to add value to a specific project by providing a measurable benefit to the client's return on investment (ROI). While the scenarios presented in this paper are generic and typical, the application in practice is specific to the project context under consideration.

For appropriately sized projects we consider best practice is to hold a Value Plus workshop at project inception. Further Value Plus ideas can be generated during the project, but the initial ideas are most easily incorporated without rework.

Importantly a Value Plus idea must have the agreement of the client to be recognized.

2. METHODOLOGY

2.1 Model Overview

The financial model considered in this paper is a simple discounted cash flow (DCF) model considered at project conception prior to any investment being made.

All project costs are provided in USD.

The model includes project CAPEX profile, geothermal well costs and drilling success rates, along with make-up well drilling and reservoir decline. It enables NPV for a given tariff or Levelised Cost of Electricity (LCOE) for a given Weighted Average Cost of Capital (WACC) to be calculated.

2.2 Generic Development – Base Case

The opportunities for innovation described in this paper can provide real, quantifiable benefits to developers. A generic 2 x 55MW single flash steam condensing geothermal development has been hypothesized, so that the opportunities and benefits from the opportunities can be tested. This builds on work by Quinlivan et al. (2015) which describes a 2 x 55MW development in an Indonesian context with typical volcanic terrain. Such a development can provide a basis for sensible inputs through which to test the Value Plus ideas.

The plant is developed in two phases, with costs up to Final Investment Decision (FID) borne by equity holders, and costs post FID shared between lenders and project sponsors so that a total Debt:Equity ratio of 60:40 is achieved.

Typical well success rates across three stages of the project have been used. The three stages are exploration, development and injection wells, with 50%, 80% and 90% success rates respectively used in the base case model. Here we consider that the average successful well has a potential output that equates to 10 MW of generation as per Quinlivan et al. (2015).

Capital Expenditure, other than the wells, has been estimated using capacity based relationships to derive a total CAPEX of USD $547m, in 2016 dollar terms. The CAPEX is inclusive of owner's costs and estimating contingencies. The CAPEX is spread over a nominal six year development with three years to FID and three years post FID as described in Table 1.

The LCOE has been calculated for the base case, using a WACC of 8.3%, as $82.96/MWh. This cost of electricity gives the base case model an NPV of $0 by definition. The LCOE is used in all the opportunities investigated in this paper so that the NPVs of Value Plus ideas can be directly compared.

The complete financial model inputs for the generic development are listed in Table 7 presented the end of this paper. The CAPEX profile is in Table 1. While some inputs will be higher or lower in different circumstances the values used here are representative and suitable to evaluate the value of the opportunities discussed in this paper.

2.3 Model Scenarios

The value of project innovation through engineering design and project delivery has been examined relative to the base case model. The following sections explore the following innovations:

- Enhanced power plant reliability through high steam quality and purity (Section 3);
- Consideration of cost of pressure drop at project inception (Section 4);
- Integrated and front-end loaded 6G (i.e. geology, geochemistry, geophysical, geotechnical, geohazards, and GIS [LiDAR]) exploration programme (Section 5); and
- Leveraging Digital Engineering Models to reduce design changes during construction (Section 6).

It is noted that some innovations do come at an additional front end cost, involve work at risk, or introduce additional complexity to the project.

Table 1: CAPEX spend profile.

CAPEX phasing		
CAPEX Pre-FID Period		
Development duration	Year	CAPEX [$m]
Year 2016	0	1
Year 2017	1	14
Year 2018	2	38
Year 2019	3	65
Total		118
CAPEX Spread Post-FID		
Development duration	Year	
Year 2019	3	0
Year 2020	4	166
Year 2021	5	122
Year 2022	6	140
Total		428
Total Project		547
Total Development Duration	Years	6

3. IMPROVING POWER PLANT RELIABILITY – MAXIMISING THE ASSET THROUGH STEAM CONDITIONING

3.1 Summary

The assurance of suitable steam purity is a typical expectation at the inception of a geothermal power project. For instance:

- Turbine original equipment manufacturers (OEMs) and power plant developers will seek to ensure that good steam quality is available to mitigate against solids deposition, and hence prevent deterioration of efficiency and failure to meet performance guarantees; and
- An owner will seek to ensure good steam quality for the reason above but also over the longer term to protect against unplanned maintenance, and associated consequential generation loss.

Good steam purity, 'good' being defined in specification from both the OEM and owner, is determined by the design and operation of the steamfield and steam separation system. This section considers steam purity in the context of lifecycle costs for a geothermal generation asset.

Good steam purity is affected by the following processes:

- Separation efficiency – the performance of the bulk liquid/ steam separation process;
- Pipeline "scrubbing" – the ability of the process pipework to remove particles from separated steam in transmission to the power plant. This is a function of length of line, turbulence and heat loss (condensation); long cross-country steam pipelines (assuming not operated at high velocities) naturally promote pipeline "scrubbing";
- Steam scrubbing – the efficiency of the final steam separation (polishing) stage;
- Steam washing – artificial injection of cold condensate to facilitate some condensation of the steam, itself "nucleating" on free solid particles and hence removing these from the steam flow; and
- Stable operation – whilst geothermal steam separators can be designed to handle specified liquid slug volumes, any avoided turbulence in the steam separator will logically sustain good performance. Separation systems should ideally be operated at constant (or very steadily changing) separation pressures. Upstream liquid slugging effects and cycling or unstable production wells can lead to unstable inlet flows to steam separators. Liquid slugging effects can also be minimised through good design practice.

These effects and mechanisms, and incorporation of these considerations in the engineering design, represent minor incremental cost increases to the overall development and operation costs of a geothermal power plant when considered during system design. The contention of this argument is that they represent a significant overall saving when considered on a TCO basis.

3.2 Analysis

In order to test the impact upon lifecycle cost of steam purity, the 'good' steam quality base case model (described and incorporated in Section 2.2) was tuned with sensitivities to represent 'poor' steam purity.

Steam purity refers to the amount of solid, liquid or vaporous contamination in the steam, where high-purity steam contains very little contamination. Steam quality is a measure of the amount of moisture in the steam.

The difference between the base case and the poor steam purity case is that the major maintenance frequency increases from 14 days every four years to 14 days annually. In addition forced outages are doubled to 1%. The overall plant availability is consequentially reduced. With the increased major maintenance and forced outages the availability reduces to 95.16%; this is considered somewhat conservative with many examples of plants internationally achieving less than this owing to reliability impacts of poor steam quality. The base case availability of 98.54% is taken to represent modern plants with good steam quality and modern refinements in engineering design (Pointon et. al., 2009).

In parallel with decreasing the availability the operations and maintenance (O&M) costs have been increased from \$14.5/MWh to \$16.5/MWh to fund the additional major maintenance. A major overhaul of the turbine could typically cost \$2m, excluding lost generation. Based on an annual generation of 880 GWh the additional maintenance equates to approximately \$1.5/MWh of additional O&M cost (10%).

A "Steam Purity" case has been run with changes to the base case as presented in Table 2.

Table 1: Steam Purity Financial Model Assumptions.

	Base Case	Poor Steam Purity
Major Maintenance Frequency	1 in 4 years	annually
Forced Outages	0.5%	1%
O&M cost	\$14.5/MWh	\$16.0/MWh

3.3 Results

The changes above, once applied to the base case development parameters, resulted in a decrease to the NPV of the project of -\$22.6m and decreased the IRR from 8.3% to 7.8%.

The reduction can be attributable to the reduced generation in this scenario (-\$14m) and the increased O&M costs (\$9m).

3.4 Conclusions

There is clearly a large financial detriment if steam purity is not given sufficient focus during the engineering design and construction stage of a project. Comparatively small 'savings' in construction cost can have a very large impact on the TCO of the project if reduced steam purity increases maintenance and reduces generation.

4. COST OF PRESSURE DROP – REDUCING TOTAL COST OF OWNERSHP

4.1 Summary

The location of steamfield infrastructure, including wellpads, separator stations (for liquid dominated systems) and the power plant drive the initial hydraulic design of the steamfield. Typically, the steamfield will be operated at a target power plant interface pressure. Pressure losses between the production wells and the power plant are dependent upon the length of cross country line, the sizing of that line and fluid properties. Accordingly, lowering steamfield pressure loss allows the well to operate at lower well head pressure (WHP) for a given target interface pressure.

When looking at Cost of Pressure Drop (COPD) there are a number of different ways the benefit of the reduced pressure drop could be realised, including:

- For a given number of wells sufficient to meet the power plant design capacity, a larger pipeline and reduced pressure drop would provide the owner with excess steam available under the wellhead. The wells will initially be throttled, however as the field declines the throttle is opened up until the point where the well is fully open and production is at maximum. At this point, further production is required and this is provided through make-up drilling;
- The reduced pressure drop between wellhead and turbine could be utilized to run the power plant at a higher inlet pressure for a number of years, providing increased efficiency and output before de-rating the plant in the future. The initial make-up well drilling is postponed and the frequency reduced thereafter; and
- If considered early enough in a project lifecycle, lower steamfield pressure drop could mean wells are operated at lower pressure, and correspondingly higher flows, providing additional capacity per well. Overall this would mean that fewer wells are required during the initial development and the make-up well drilling frequency is reduced.

The third scenario is the approach we have taken to model COPD in this paper.

4.2 Analysis

In this case, the interface pressure has been selected as 8 bara. If a typical steamfield has a pressure drop of 2 bar from the production wells we have a WHP of 10bara. Figure 1 shows a generic well deliverability curve, with a flow rate of 145 kg/s for a well at 10 bara WHP.

If the steamfield pressure drop were to halve to 1 bar, then the WHP decreases to 9 bara with a corresponding flow rate increase to 176 kg/s, as shown in Figure 1.

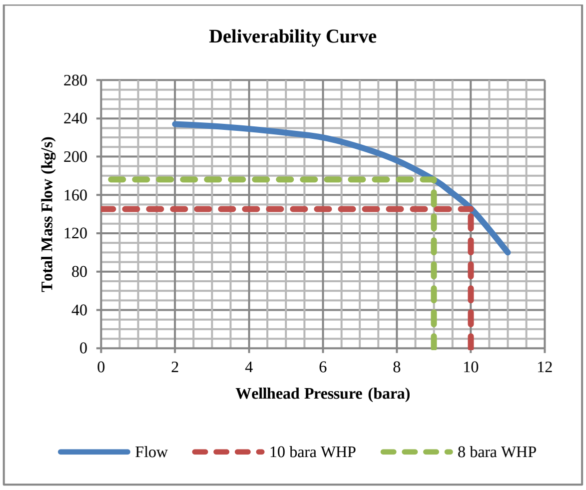

Figure 1: Generic Wellhead Deliverability Curve.

This equates to an approximate 20% increase in mass flow rate, so assuming constant enthalpy the 10 MW well can now deliver 12 MW.

Assuming that the higher delivery flow rate is sustainable, an increase in the output per well is likely to decrease the number of wells required in a field, all things being equal. It will also increase the capacity achieved from each make-up well and therefore reduce make-up well drilling costs through the life of the project.

A larger pipe size is one way to decrease the pressure drop. If the pressure drop for the same flow rate is to halve, a 30% lower velocity is required, which requires a larger area, or a 19% larger pipe diameter. There is a fourth power relationship between diameter and pressure drop. If our pipeline was originally a 30" pipe, a 36" pipe will reduce our pressure drop from 2 bar to 1 bar. If we assume that 18 production wells are spread across six well pads, each with 2.5km of cross country pipelines, then we have 15km of pipeline that will need to be increased in size. An indicative installed value used in current projects is approximately US$20 per Dollar/Inch/Foot (DIF) (Helliwell and Hochwimmer, 2013). To increase 15km of 30" pipeline to 36" there is an increase in capital cost of $5.9m USD.

The increase in well output and the corresponding increase in steamfield capital cost have been run against the generic 2 x 55MW development described earlier. A "Cost of Pressure Drop" case has been run with changes to the base case as presented in Table 3.

Table 2: Cost of Pressure Drop Financial Model Assumptions.

	Base Case	COPD
Average Successful Well Output	10 MW/well	12 MW/well
Steamfield CAPEX		+$5.9m

4.3 Results

The changes above, once applied to the base case development, resulted in an increase to the NPV of the project of $18.56m and increased the IRR from 8.3% to 8.7%.

The increase can be attributed to the increased well output which allows the number of production wells drilled to reduce from 18 to 15. In the base case model the discounted make-up well drilling CAPEX over the life of the project is $12.4m, and drops to $10.6m once the pressure drop is reduced. These benefits are offset by a modest 1% increase in capital cost for the larger pipe.

4.4 Conclusions

Cost of pressure drop is a factor that should be thoroughly reviewed during the development of a new plant. A seemingly significant increase in steamfield construction costs due to the selection of a larger pipe size can be outweighed by the increase in output from each well in the right circumstances. In an actual project development there will be a point where a larger pipe size does not produce a net benefit to the project for a number of reasons, either the reservoir cannot sustain production at the higher flow rate, the pipe is already so large or the field is spread out and the pipelines are so long that the reduced well costs are outweighed by the increase in steamfield costs. Each project should be assessed on its own merits, utilizing project specific input data.

5. FAST TRACKING EXPLORATION – THE VALUE OF INFORMATION

5.1 Summary

The geothermal project delivery process for a new greenfield project is inherently time consuming as the resource potential gets progressively firmed up and informs the development strategy.

Fast tracking this process can lead to significant value for a project although it does mean some early investment is required at risk.

5.2 Analysis

The surface exploration program for a greenfield geothermal resource typically comprises an initial phase of preliminary scientific reconnaissance, surface surveys and exploration well drilling. Information required for exploration drilling includes topographical, geotechnical and environmental reviews which are typically completed only following confirmation of the presence, quality and capacity of a resource.

Each stage of exploration as outlined above has greater cost and therefore a staged approach is often utilised with decision gates to manage risk. In addition to environmental and other permitting requirements, this can add substantially to the schedule.

As discussed by Ussher and Hochwimmer (2015), an integrated geoscience program comprising geology, geochemistry, thermal mapping and geophysics can provide exploration and interpretation on par with a staged approach while saving time and cost. The requirement for only one field program can have advantages in reducing HSE risk and stakeholder requirements.

The integrated information allows for early commencement of lengthy environmental and permitting processes, as well as providing sufficient information to progress civil works associated with exploration drilling.

A "front end loaded" program including full 6G survey completed and then assessed in an integrated way could be justified where early indications show a potentially commercial resource.

From a developer's point of view, it is generally desirable to get to FID as soon as possible to reduce off balance sheet costs and bring in cash flow. It also reduces project risk by allowing stakeholders to make informed decisions as early as possible. These benefits must be traded off against additional work done at risk.

Applying the front end loading to our financial model reduces the timeframe by six months, and can allow the long lead activities of permitting and land access to commence earlier. It can also be argued that the well targeting is improved by virtue of having integrated information and therefore probability of success increases.

The Pre-FID development time has been reduced by six months to 2.5 years, while at the same time the exploration and development drilling success rates have increased as can be seen in Table 4. Table 5 presents the CAPEX spend profile used to model this scenario.

Table 3: Fast Tracked Exploration Financial Model Assumptions.

	Base Case	Fast Tracked Exploration
Pre-FID development time	3 years	2.5 years
Exploration Drilling Success rate	50%	60%
Development Drilling Success rate	80%	85%

Table 4: CAPEX spend profile (fast tracked exploration case).

CAPEX phasing		Base Case [$m]	Fast Track [$m]
CAPEX Pre-FID			
Development duration	Years	3	2.5
Year 2016	0	1	1
Year 2017	1	14	15
Year 2018	2	38	55
Year 2019	3	65	38
Total		118	109
CAPEX Post-FID			
Development duration	Years	3	3
Year 2019	3	0	75
Year 2020	4	166	145
Year 2021	5	122	144
Year 2022	6	140	64
Total		428	428
Total Project		547	538
Total Duration	Years	6	5.5

5.3 Results

The changes above, once applied to the base case development, resulted in an increase to the NPV of the project of $9.2m and increased the IRR from 8.3% to 8.5%.

The increased exploration and development drilling success rates mean that the number of production wells required reduces from 18 to 17, saving $8.9m from the CAPEX. In addition, bringing forward the development timeline by six months provides a benefit of $1.8m.

5.4 Conclusions

There is clearly financial benefit in reducing the schedule for a commercially viable resource. The potential gains should be considered against work which must be completed at risk for resources which are less attractive in terms of known quality and capacity and should be progressively de-risked through the exploration work.

This approach of optimizing the project schedule and paralleling some activities can also occur beyond exploration leading to a number of benefits including reduced financing and overhead costs.

6. DIGITAL ENGINEERING 3D MODELS – COMMUNICATION SAVES CONSTRUCTION TIME AND COST

6.1 Summary

A second example of innovation in the development process is through the use of Digital 3D models. Geographical Information Systems (GIS) integrated with relational databases allow data to be manipulated visually using a mapping interface.

Such models can be utilised to contextualize the overall development and improve alignment of the multiple facets of a complex project.

6.2 Analysis

Digital models are justified in terms of their ability to communicate complex information visually and as such improve stakeholder engagement (Sinclair, 2015).

Along with constraint verification (interference detection) and aligning boundary conditions, for example topography settings, the use of digital models can improve cohesion between design disciplines, significantly reducing rework and duplication.

Such models can enhance wellsite targeting and help to optimise plant configuration, access and transmission options. Decisions can be made quickly and misinterpretations minimised.

It is difficult to quantify potential value-add savings in generic terms. The use of the building information modelling (BIM) approach can yield construction cost savings up to 20% for buildings and general structures. Here we will represent savings in planning, design and construction time of 10%. We have modelled a reduction of the Post-FID construction period from 3 to 2.7 years as noted in Table 6.

Table 5: Digital Modelling Financial Model Assumptions.

	Base Case	3D Models
Pre-FID development time	3 years	2.7 years

6.3 Results

The changes above, once applied to the base case development, resulted in an increase to the NPV of the project of $5.0m and increased the IRR from 8.3% to 8.4%.

Compressing the Post-FID construction timeline by 10% provides the full $5.0m benefit.

6.4 Conclusion

Digital 3D models allow digital representations of physical and functional characteristics. Their use in geothermal development is justified in terms of savings related to consistency of design.

7. OTHER INNOVATIONS

7.1 Thinking Laterally – Developing outflows

In some settings there may be alternative ways to utilize a resource or supplement a conventional development.

Lateral outflow zones are found in many fields and in some cases are extensive, with good permeability and prolific flow rates. Tapping these outflows at circa 200-300m may produce relatively hot fluid through the use of line shaft or electrical submersible pumps at moderate parasitic costs.

Electricity can be produced using the Organic Rankine Cycle (ORC) process in a binary power plant as shown in Figure 2, and reinjected to minimise environmental impact.

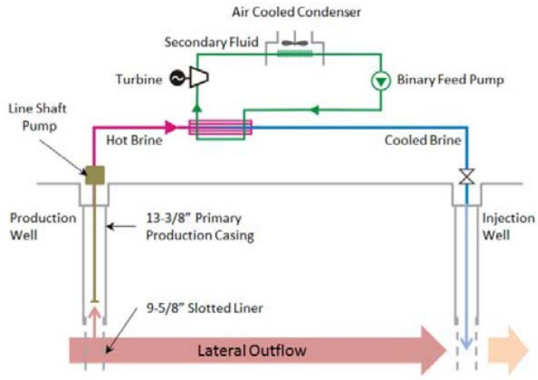

Figure 2: Schematic of a Simple Hot Water Binary ORC Power Plant, pumped from a Lateral Outflow. Figure not to scale. (Source: Hochwimmer et al., 2013).

This can be a relatively low risk, low cost project development option. A financial analysis is not included here, however further details are provided in Hochwimmer et al. (2013) and Hochwimmer et al. (2015).

This type of system will be most appropriate where power prices are high and/or specific feed-in tariffs exist for renewable energy.

This type of project innovation can be explored separately to the Value Plus ideas described above to yield additional commercial revenue stream and commercial 'upside' to the project.

8. CONCLUSION

Geothermal project development can be challenging compared with other types of energy, with significant capital expenditure (tied to significant risk) and long timeframes.

Innovation should be considered for all stages in a development in order to reduce TIC or TCO, or reduce the development programme. Even seemingly small changes can have a significant effect on NPV and IRR.

The Value Plus framework is presented and this provides a mechanism to compare and contrast innovation and get concurrence from the client on the value of the innovation prior to implementation.

This paper has outlined a number of ideas for incorporating innovation to add value to a geothermal project development.

When applied to a generic 2 x 55MW single flash steam condensing geothermal development, significant savings can be realised.

We have modelled four specific cases where savings (or reduction of cost in the case of improving steam purity) of up to $22m are available as shown in Figure 3, generally at modest additional costs.

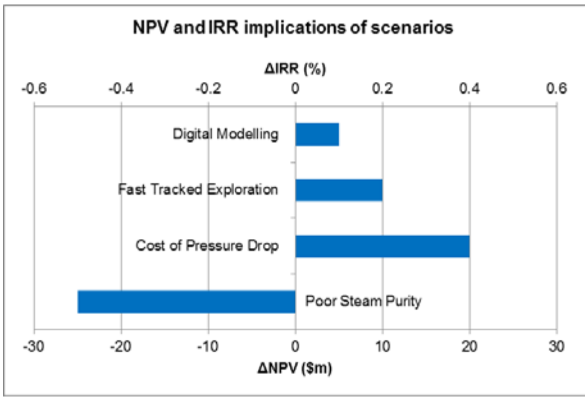

Figure 3: Implications on NPV and IRR for various scenarios.

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FINANICAL MODEL INPUTS

Base case inputs for the generic geothermal development financial model are presented in Table 7 below.

Table 6: Model Inputs – Base Parameters.

	Unit	Base
Plant type		
Location		Indonesia
Power Production		
Gross capacity	MW_e gross	122.22
Parasitic load	%	10%
Net capacity	MW net	110
Units	no.	2
Utilisation Rate	%	92.65%
Minor Maintenance		Assume no downtime required
Major Maintenance	days/unit	14
Major Maintenance Frequency	year	4
Forced Outages	%	0.50%
Availability	%	98.54%
Development Phase Conditions & Assumptions		
Generation per Successful Well	MW_e net	10
Well Success Factors		
Exploration drilling success rate	%	50%
Development drilling success rate	%	80%
Injection well drilling success rate	%	90%
Re-injection Wells	#	7
Total production wells	#	18
Total Wells (inc. injection)	#	25
Power OPEX		
Basic plant operating cost	$/MWh	14.5
Sustaining CAPEX		
Make-up well Costs	$m/well	8
Mobilisation for make-up wells	$m	1
DEVELOPMENT TIMINGS & CAPEX PHASING		
Exploration Programme CAPEX		
Standard size wells	$m/well	7
Development Programme CAPEX		
Additional standard size wells	$m/well	6
Injection well costs	$m/well	5
Phase 1 - Geoscience and Project Prep	$m	1
Phase 2 - Exploration	$m	37
Phase 3 - Development	$m	155
Phase 4 - Power Plant Construction	$m	304
Sub-total	$m	497
Estimating margin @10%	$m	50
Total cost (excluding IDC, Owner's Costs, Financing Costs, Insurance)	$m	547