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Staged Asset Deployment – Commercial and Technical Advantages of Using a Wellhead Generation Unit

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ABSTRACT

The typical geothermal development schedule for new fields may span five to ten years. Managing the cash flow for these enterprises, which demand considerable up-front exploration and drilling investments far before economical financing is available or generation can become commercial, can be challenging. Wellhead generation units can offer multiple benefits: provide an early cash flow to offset development costs, offset diesel engine fuel costs for drilling rigs, mitigate risk on the resource assessment by allowing longer-term flow tests, and set the stage for the development of larger, more efficient power plants to be operated long term. In this paper we present a financial evaluation of a standard six-year development plan, considering the insertion of a wellhead unit at the appropriate stage of development. We conduct this evaluation at a high level based on general assumptions; site-specific characteristics would require a more diligent evaluation based on local conditions such as tax implications, funding options, ownership structure(s), depreciation, resale, etc. We present a number of technical options for wellhead units, including backpressure turbines, condensing units, binary units, and surplus equipment, and compare their relative merits. The transition to the long-term power station is discussed. A number of case studies of successful implementation in countries such as Mexico, Nicaragua, and Costa Rica are presented with these dicsussions.

1. INTRODUCTION

Development of geothermal power plant projects pose a challenge to Developers due to the significant risk capital and extended duration required prior to commercial operation. This development condition requires Developers to tie up high-cost development funding for an extended period beyond the typical five-year investment return cycle historically expected in the investment market.

This is best illustrated by the Geothermal Risk and Cumulative Investment Cost Curve (Figure 1) detailed in the Geothermal Handbook recently released by the Energy Sector Management Assistance Program (ESMAP) administered by The World Bank. Figure 1 highlights the High to Moderate Risk levels that occur during the period through production drilling and prior to the date that Developers are able to access construction funding for the power plant. This period of high risk can extend to four to five years and consume nearly 50% of the project capital budget.

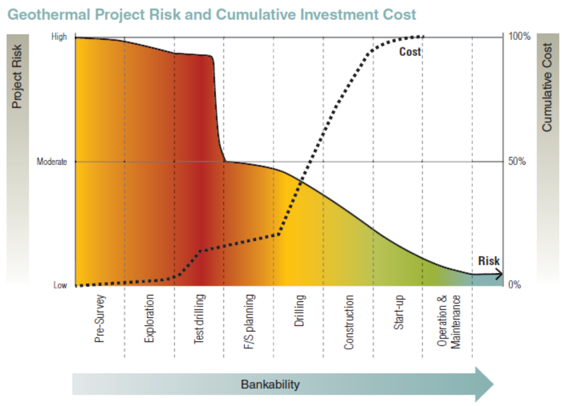

Figure 6: Project Risk Versus Cost (ESMAP, 2012)

The pressure on Developers to complete the feasibility and resource confirmation drilling can push Developers to make early long-term project decisions regarding aspects such as resource capacity, degradation, and chemistry; and power plant sizing and capital budget. This often results in power plants that have been oversized for the resource, and ultimately being in the undesirable situation where the asset cannot produce revenues sufficient to meet the financial performance requirements. The impedance of financial performance restricts the capital required to fund further make-up drilling and preventive maintenance – leading to further decline in the financial performance of the asset.

This paper will evaluate an alternative development plan of staging the deployment of assets to reduce the technical risk of development while providing early revenue returns. By installing a reduced-size wellhead generation unit during the initial stages of exploration drilling, the Developer has the ability to test the local resource conditions prior to installing a larger permanent plant. This effectively allows a continuous flow test during the development period, providing key data on production conditions, short term reservoir decline and chemistry. The staged development also provides an earlier cash flow stream which can be used to offset some of the initial development costs, and potentially provide a source of power to offset expensive fuel costs of operating diesel engine-driven drilling rigs. The staged development further provides a hedge against unexpected drilling problems which drive further delays in developing the larger project.

2. FINANCIAL EVALUATION AND OPTIONS

A planning-level financial analysis was performed to assess the impact of early deployment of a wellhead generation unit. The purpose of this analysis was to compare the financial attributes of a base case development of a 30 MW condensing steam turbine geothermal plant versus the same development program with a 5 MW wellhead unit installed during the initial production drilling stage of the project. This analysis is not intended to be an exhaustive financial analysis of the investment, but rather a planning look at the impact of early stage generation for illustration purposes.

The key assumption to the analysis was that the 30 MW base case was assumed to carry the full cost of the development and drilling program. The 30 MW plant was assumed to take six years from initial surface exploration to commercial operation. The 5 MW wellhead unit was assumed to come on line two years prior to the commercial operation of the 30 MW plant and then operate for 10 years. This 10-year operation duration could be at the current project area or moved to another development area. At the end of the 10-year period the wellhead unit would be sold for an assumed 40% of installed value. The analysis assumed the same tariff rate for both options and did not consider the value in offsetting the purchase of diesel-based power during the production drilling phase.

The drilling program assumed a total of six production wells, three injection wells and two non-producing wells. The financial analysis assumed a make-up well would be installed every seven years.

The 30 MW plant was leveraged at an equity/debt ratio to correspond to a debt service ratio average = 1.5. The drilling and installation of the 5 MW wellhead unit were assumed to be equity funded. It was assumed that the costs for the wellhead unit would be modest; perhaps a backpressure turbine or used binary or condensing unit; technologies which will be discussed later. Table 1 shows key parameters used in the financial analysis.

Table 1: Financial Analysis Assumptions

PARAMETER	**VALUE – US$**
Total Investment of 30 MW project (1)	$134,550,000
Development and Drilling Cost (11 wells)	$57,000,000
Plant Construction Cost	$63,000,000
Financing Cost (IDC, Fees, Closing, Reserves)	$14,550,000
Total Investment of 5 MW wellhead (2)	$7,500,000
Construction Period Financing Rate	6.5% for 29 months
Term Loan Financing Rate	8% for 15 years
Assumed Average Debt Service Coverage	1.5
Discount Factor	10%
Debt/Equity Ratio	70/30
Tariff Rate	$80/MWh + 2% escalation/year
30 MW Plant Operating Duration	25 years
5 MW Wellhead Unit Operating Duration	10 years
Operating Cost – 30 MW Plant	$16/MWh + 2% escalation/year
Operating Cost – 5 MW Backpressure Unit	$6/MWh + 2% escalation/year

(1) Total capital cost of debt, equity and financing
(2) Capital cost of equity investment

The results of the planning analysis reveal that the early addition of the 5 MW wellhead unit provides an incremental improvement to the Internal Rate of Return (IRR) of the project and an increase in the Net Present Value of the project, assuming a discount factor of 10%. The financial projection was modeled on a net earnings before tax assessment and depreciation and amortization (EBITDA) basis. Table 2 summarizes these results. As noted above, these financial results do not factor in the potential added value of offsetting the cost of diesel fuel required for drilling rigs, the value of extended testing of the resource, and the value of production data in properly sizing the final project development.

Table 2: Financial Analysis Summary Results

PARAMETER	**VALUE – US$**
30 MW net Base Case	
IRR – Standalone 30 MW Development	12.03%
NPV @ 10% Discount Factor	$9,750,000
30 MW net Case with 5 MW Wellhead Unit	No added wells
IRR – 30 MW Development with Wellhead Unit	13.82%
NPV @ 10% Discount Factor	$18,380,000

30 MWnet Case with 5 MW Wellhead Unit	added wells
IRR – 30 MW Development with Wellhead Unit	12.80%
NPV @ 10% Discount Factor	$14,053,382

A series of sensitivity analyses were performed to evaluate the impact on changing parameters for the operating duration of the wellhead unit and the capital cost of the wellhead unit. Figures 2 and 3 provide illustrations of the impact of the overall financial performance based on changes to the well head unit installation.

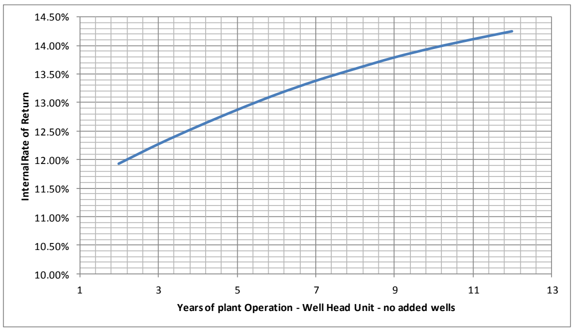

Figure 7: Case 1 - Constant CAPEX – Varied operation duration – no additional production/injection wells added

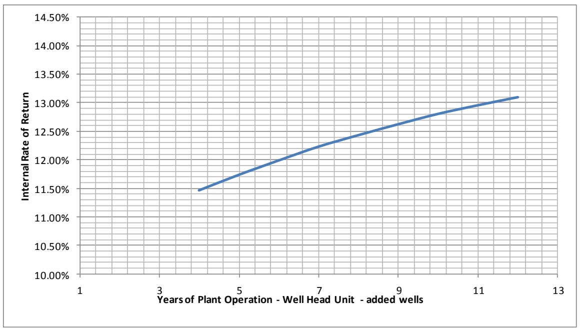

Figure 8: Case 2 - Constant CAPEX – Varied operation Duration – additional production and injection wells added in year 4

As shown in the Figures, Case 1 assumes that no added wells are required to continue operation of the well head unit. In this case, the wellhead unit would be required to operate for at least two years to match the IRR of the base case 30 MW plant. In Case 2, the assumption is made that the operation of the well head unit would require an additional production well and injection well in year four. In this case, the well head unit would be required to operate for at least six years to match the IRR of the base case 30 MW plant. The duration of operation of the wellhead unit might be at the field serving the 30 MW unit, or may reflect additional operation in a new region with the unit relocated.

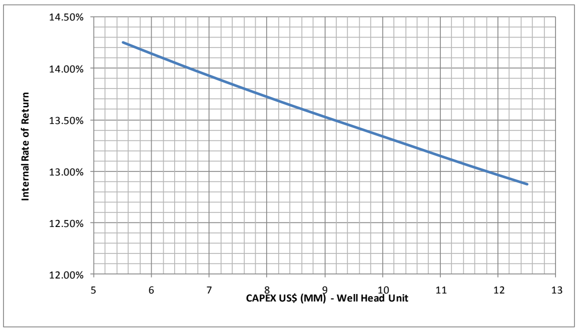

Figure 9: Constant Operating Duration – Varied CAPEX

In Figure 4, it can be seen that the well head unit capital cost does not have a major impact on the overall project IRR, as it remains greater than the base case IRR at wellhead unit costs through $12 million. The above comparison assumes that no additional wells are required for the well head unit.

3. TECHNICAL OPTIONS

The previous discussion regarding financial aspects was intended to be fairly technology-neutral. In this section we discuss a variety of equipment options available and their relative merits. It should be noted that the development strategy of a wellhead unit should discriminate between two different scenarios:

Islanded Well – in this case a well with good productivity is drilled in a region where it is unlikely that it can economically be networked together in a gathering system that could later supply a larger plant. Wellhead units such as Eburru (Mendive and Green, 2012) or Miravalles PGM-29 (Moya and DiPippo, 2010) would fall under this classification. In this scenario the wellhead unit ideally should be designed for higher efficiency and a longer lifetime, with a higher investment cost. Portability is less important in this circumstance. For fullest long-term utilization of the resource a condensing steam turbine or binary plant may be the most suitable.

Networked Well – in this case the well is intended eventually to supply fluid to a larger, higher-efficiency centralized plant. The purpose of the wellhead unit is to prove the well, generate interim cash flow, and be portable and flexible such that it can be moved to a new well at the appropriate stage. Backpressure steam turbines are ideal candidates for this application. Units used at Cerro Prieto, Los Azufres, and San Jacinto-Tizate (Randle and Ogryzlo, 2010) would fall under this classification.

We can illustrate the various technologies and how they can contribute to production from a well by using a set of simple example conditions. Consider a well drilled with a bottom hole temperature of approximately 260°C and equivalent enthalpy of 1134 kJ/kg. This might be brought to the surface and steam and water produced from the two-phase fluid in a flash separator. If the total well flow were 200 tph, 44.5 tph kg/h of steam at 6 bara and 155.5 tph of separated water at 159°C could be produced. These characteristics are similar to conditions encountered in recent flash plant projects in Nicaragua (Lawless et al, 2003) and Kenya (Mendive and Green, 2012).

We will discuss how this well could be harnessed using several technologies, some of which may operate in parallel or be added in incremental stages:

1. Backpressure steam turbine
2. Condensing steam turbine
3. Bottoming steam binary
4. Bottoming brine binary
5. Centralized plant, flash or binary

3.1 Backpressure Steam Turbine

Backpressure steam turbines are compact and relatively uncomplicated, as they do not require a condenser and supporting cooling water system including pumps, cooling tower, and non-condensable gas removal system. Figure 5 shows a Fuji backpressure turbine installed at the Svartsengi plant in Iceland. For the sample conditions used for our example, the 44.5 tph of 6 bara steam produced might generate 2.5 MW in a backpressure turbine (17.8 tph per MW). A single strong well, or two more modest wells thus might be sufficient to generate 5 MW in a backpressure wellhead unit, as was used for the financial analysis presented earlier.

Figure 10: Fuji 6 MW backpressure turbine (Yamaguchi, 2010)

Supporting equipment for the backpressure turbine would include the separator/vent station, an enclosure for the turbine, and electrical works. The proximity of transmission capacity would be a key factor for the economics of a wellhead unit. Figure 6 shows the installation at the Miravalles PGM-29 site. This turbine consumes 72 tph of steam at a 7.7 bara turbine inlet pressure to generate around 5 MW, or 14.4 tph/MW (Moya and DiPippo, 2010).

One could consider the separator station as a cost which would be incurred in any event if the larger networked gathering system is based around satellite separation stations, and not specially required for wellhead unit. One disadvantage of backpressure turbines can be seen in Figure 6 – the exhausted steam contributes a quite visible and audible plume; which also represents wasted energy.

Figure 11: Miravalles PGM-29 wellhead unit and separator station (Moya and DiPippo, 2010)

Lawless et al (2003) laid out a development strategy for San Jacinto that was followed faithfully. First, a set of productive wells was drilled between 1994 and 2001, as exploration continued in the broader field. A Stage 1 pilot plant, consisting of 2 x 5 MW backpressure turbines, was installed using backpressure turbines. These turbines had been previously used at the Berlin geothermal field from 1992-1998, but had been replaced by a condensing unit. These units were placed into service in 2005 and operated until 2012, when they were similarly replaced by the larger 2 x 38.5 MW condensing turbines. These backpressure turbines have thus seen around seven years of service at each of two sites (14 years total), and may find a future home at yet another locale to continue their contributions.

Simple, inexpensive, rugged, and portable, backpressure turbines would seem to be prime candidates for wellhead unit "hopping". The lead time for new units of this type may not be much shorter than for condensing units; therefore developers ideally would either have an existing stable of units or be able to find used or existing units in the marketplace that could be deployed more swiftly. Backpressure units may also be equipped with black start capabilities and have some ability to load follow, depending on the sophistication of the separator/vent station.

3.2 Condensing Steam Turbine

The power that can be generated from the steam can be approximately doubled with the use of a condensing turbine. In our example, 44.5 tph of steam could potentially produce 2.5 MW in a backpressure turbine and 5 MW in a condensing turbine. Condensing units are an especially appropriate choice for islanded wells, such as seen in Figure 7 at Eburru in Kenya (Mendive and Green, 2012), as this configuration harnesses the resource more efficiently. Not shown in Figure 7 is the cooling tower. The additional equipment results in a higher capital cost and more effort required for relocation than the backpressure units. The higher cost for relocation and additional lost time in generation between deployments would need to be considered in a more detailed analysis at a specific site.

Figure 12: Eburru wellhead power plant with condensing turbine (Mendive and Green, 2012)

3.3 Bottoming Steam Binary

In some locations, such as Bjarnaflag in Iceland (operational since 1969) or well PGM-29 in Miravalles (operational since 2007), backpressure units have been operating for long periods with no plans for relocation or modification to condensing type. In these cases, it would seem possible to harness the exhaust steam for some additional power generation using bottoming steam binary units, with no or few modifications to the backpressure turbine. Recent years have seen an expansion in the binary marketplace, with suppliers such as Ormat, TAS, Atlas Copco, Pratt & Whitney, and Cryostar, among others, able to provide packaged solutions. In our sample configuration a bottoming steam binary may be able to generate around an additional 2 MW from the 44.5 tph of wet exhaust steam from the backpressure turbine. These packaged binary units might be installed permanently at an islanded well. Alternatively, if these are packaged in such a way that they can be relocated with little difficulty, they could serve as similar "flying" units of ~1-2 MW modules that could hop with the backpressure units to new wells, as mature wells are networked into the larger gathering system for centralized plants.

3.4 Bottoming Brine Binary

Mature steamfields such as at Olkaria or Coso may have satellite two-phase, single-flash separator stations that might accommodate bottoming binary systems harnessing the geothermal brine. This is generally constrained by an injection temperature lower limit on the reinjected brine to prevent precipitation of solids. For our sample configuration, a flash pressure of 6 bara and corresponding saturation temperature might be expected to be close to the lower allowable limit. However if individual well chemistry and anticipated precipitation kinetics is evaluated during the longer term operation of the steam turbine, one might discover that it would be possible to extract additional heat from the injectate without fear of scaling. An extraction of energy from the brine sufficient to cause a 20-25 ^{o}C incremental reduction in temperature might allow binary generation of around 500 kW. A difference from the bottoming brine binary option is that this plant might stay operational even after the steam from the well is linked to the gathering system, if the gathering system will be only harnessing single-phase steam such as at Olkaria. This configuration thus might more reliably be planned on to operate for a longer period before it might be relocated to another well, which would improve its IRR. The design points for a plant such as this should be evaluated after the brine flow and chemistry is well characterized to assess the appropriate size and avoid scaling. Thus it might be appropriate to add a module of this sort after a steam-side wellhead unit had been operating for some time.

3.4 Centralized Plant

In most cases, the most economical long-term scenario for a developer will not be multiple wellhead units operating indefinitely, but rather a networked gathering system where steam and brine can be used by one or several larger units in the 50-100+ MW range. Larger units generally offer lower installed costs and lower O&M costs on a per MWh basis, while offering better flexibility to accommodate changes in individual well characteristics (due to averaging over the entire steamfield), higher plant efficiency, and control simplicity due to the lower number of units. However, larger flash units may take many years to construct.

Some propose that the industry might inevitably move away from centralized units. In theory wellhead units could be tailored to the individual characteristics of each well, and thus offer greater overall field utilization efficiency. They also might be constructed in a shorter time period. However, there are insufficient data yet on the long-term O&M costs or performance on such dedicated units, especially with the large degrees of productivity variations that can be experienced at individual wells, so we feel it would be premature to assume that centralized units are not the preferred long-term economical solution.

At San Jacinto, the wellhead backpressure steam turbine was married fairly seamlessly with the centralized plant approach. The wellhead backpressure turbines generated 10 MW from 150 tph of steam (15 tph/MW) and operated from 2005-2012. The original concept for San Jacinto (Long, 2010) was to install 72 MW of net capacity in the form of three reconditioned turbines, using 678 tph of steam (9.4 tph/MW). However, this strategy was modified to use two more efficient and newer turbines to generate 70.8 MW net from 582 tph (8.2 tph/MW). Higher drilling costs have put a priority on more efficient plant designs; while the backpressure turbines served their intended purpose, the centralized plant will be the more appropriate long-term strategy.

The design of a centralized station would benefit from more mature resource data which could be collected from long term operation of a wellhead unit, that allows better selection of the design point. An improvement of 0.1 bar in the selection of appropriate turbine inlet steam pressure, versus excess wellhead or governor valve throttling if not optimal, might result in the generation of several thousand additional MWh annually for a nominal 50 MW plant. The application of the wellhead unit thus could provide a benefit to the output or efficiency of the centralized plant for 20-30+ years.

One possible alternative for wellhead units that has not yet been widely deployed is a biphase turbine, which can accept a two-phase fluid at the inlet. This could provide a higher output and less need for separation equipment. A pilot unit of this type was installed at Cerro Prieto and operated intermittently between 1997 and 2000, generating around 800 kW (Hays and Velasco, 2003). We view this as a technology still under development, but if more mature, larger, and economical units became available, biphase turbines could become another attractive option for wellhead units in the future.

4. COMPARING DEVELOPMENT STRATEGIES

The various technologies for wellhead units have several advantages and disadvantages, as summarized in Table 3. The developer must balance the desire for utilization efficiency with constraints on capital cost and portability.

Table 3: Comparison of wellhead unit technologies

	Back pressure Steam	**Condensing Steam**	**Bottoming Binary – Steam**	**Bottoming Binary - Brine**
Capital cost	Lower	Medium	Higher	Higher
Efficiency	Lower	Higher	Harvesting an otherwise lost resource, if using backpressure exhaust	Harvesting an otherwise lost resource, if using unutilized brine
Portable	High. Few supporting facilities.	Lower. Cooling tower relocation and basin reconstruction more difficult.	Medium. ACCs are large structures, but generally modular.	Medium. ACCs are large structures, but generally modular.
Best suited for?	“Hopping” on wells that are intended to be eventually networked	Dedicated operation on an islanded well	“Hopping” along with backpressure turbines	Later stages of installation on islanded wells, or networked wells with unused brine

Development of a field that will incorporate wellhead generators should include the following considerations:

- Identification of wells as likely “islanded” or “networked” resources.
- Placing a priority on the fast-track development of the large, centralized plants, which will likely be the most efficient and economical over the long term.
- During exploration and drilling, scouring the market for available wellhead units that can be obtained within a short lead time, be installed soon after promising well completion, and operate commercially for several years to improve cash flows.
- In some cases for developers this might warrant owning a “pool” of wellhead units, or an agreement with other developers where units can be shared or resold.
- Developing a management plan to smoothly install, operate, phase out, and relocate wellhead units as the overall project progress demands.

5. CONCLUSIONS

In this paper we have reviewed typical wellhead generator economics, performance, and technologies available. Key barriers to implementation of wellhead units are generally not technical issues, but rather the availability of affordable machines, and time in developing the proper structures to manage the installation and operations.

We feel that deployment of small modular units can have a positive influence on project economics, if the deployment of these units is planned well in advance, as was done for several projects we have discussed. Developers may reap further benefits in niche areas by using techniques such as bottoming steam or brine binary units, also installed using a staged deployment strategy.

We feel there are some pitfalls in wellhead units, but ones that can be managed. Regardless of the small size of the units, lead times can be considerable for new equipment, so planning for deployment of these should be done far in advance. The small size of units and infrequent demand might also not be as appealing a market for the conventional suppliers of the highest-grade geothermal turbines; ideally increased demands for these units could expand the marketplace. The energy and focus of a developer should rightly reside in a largest centralized plant development; to some extent wellhead units - if not properly managed - can be viewed as a bit of a distraction even if they can contribute to greater project success. The biphase turbine might be a long-range research opportunity that could pay dividends in the future, but likely is not currently a commercially mature technology.

Overall, we feel that wellhead generators offer several new niches for product development and deployment, both along technical and commercial lines. Sutter et al (2012) outline several other potential benefits of wellhead generation and small power plants, such as the social benefits of increased and more rapid electrification, and integration of agribusiness and tourism with the projects. We anticipate that, especially for developers of larger fields, different project development models will emerge and more units of these types will be constructed.

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