Proceedings World Geothermal Congress 2015
Melbourne, Australia, 19-25 April 2015

Modelling a Geothermal Steam Field to Evaluate Well Capacities and Assist Operational Decisions

Andrew Marsh

Mighty River Power Limited, PO Box 245, Rotorua 3040, New Zealand

Andrew.Marsh@mightyriver.co.nz

Keywords: Geothermal, Steam Field, Surface Facilities, Power Plant, Well Evaluation, Pipeline Model, Reservoir Engineering

ABSTRACT

A productive geothermal reservoir usually feeds into a network of pipelines to gather and distribute the geothermal fluid to the various connected plant equipment. By careful analysis of the measurements collected throughout the system a deeper understanding of both the geothermal reservoir and the response of the installed plant can be assembled. Regular evaluation of measurements taken from the field makes it possible to forecast plant outputs, evaluate risks emerging to the energy supply and to explore, with known accuracy, opportunities to improve the overall system. To achieve good results, certain methods have been devised based on Process and Reservoir Engineering techniques and field operating experience. This paper presents an overview of the methods employed by the author when preparing capacity evaluations and forecasts and the lessons from developing three steam field models for different fields.

1. INTRODUCTION

There are various accurate methods to test and measure a geothermal well's performance in isolation but ultimately the commercial value of the well is dependent on its ability to perform in the context of the system it is connected to. The well configuration preferences, system back-pressuring and plant behaviour are necessary inputs to discover the true nature of the system. This information is additional to that traditionally gathered about wells to determine deliverability, flowing enthalpy and responses to extraction over time.

The permanently installed above-ground production and injection system instrumentation offers the opportunity to fill in the gaps between intrusive testing on the wells. Some aspects of a well's behaviour do not change significantly between measurements points and this allows a system model to be devised to monitor the performance of the well on a real time basis. This can lead to more confidence and earlier warning of a developing problem for the production operation. Sufficient instrumentation and flexible testing intervals are the keys to being able to monitor in this way. A changing situation in the field can evolve within a matter of weeks and early warning and prediction represents significant value for modelling of this kind.

At Mighty River Power's geothermal operations in New Zealand there are currently three steam field models in operation that contribute to monitoring of the reservoirs and power plant management. The models operate standalone taking data automatically from production databases and from information generated within the reservoir engineering discipline. More accuracy can be derived by combining with other geothermal modelling tools and Mighty River Power will continue to work toward this over time. Particularly relevant is the integration of wellbore models into both three-dimensional numerical reservoir modelling and steam field models to provide the crucial relationships between production below ground and at the surface. This feedback loop between surface plant requirements and the reservoir responses with respect to pressure and temperature provides more realistic long-term management scenarios to consider.

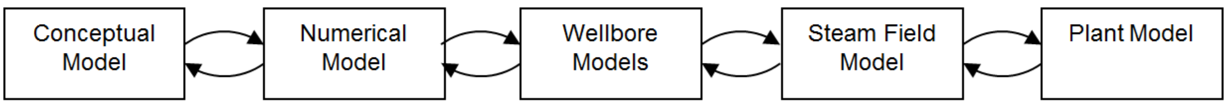

Figure 1: There are two-way information relationships between most of the various geothermal models. The steam field model interacts with plant models and well bores.

This paper will introduce the concept of steam field modelling as applied so far at Mighty River Power. It will cover what can be achieved by steam field modelling and present the basic method for building a stand-alone steam field model. It will also suggest additional areas that may be of use but have not yet been achieved.

The three steam field models so far developed are for fields that have gathering systems delivering two-phase to centralised separation sites so this paper is naturally focused towards these type of steam fields though most principals will apply universally. The models are being developed in Microsoft Excel and utilise the iterative solving functions available in the standard package but add-ins for interpolation from a table and fluid property packages are needed.

2. GOALS FOR STEAM FIELD MODELLING

Data from sensors placed throughout the steam field and plant can be used in a number of useful ways. Add to this the information collected from well testing, chemistry sampling and from wellbore and plant modelling and the list of useful outputs increases greatly. The following is a list of examples of important quantities that can be determined:

- Individual well capacities, in terms of a mass flow rate that can be developed with a wide open well control valve
- Pressures throughout the production piping network including the minimum well head pressures achievable with a wide open well control valve
- The flow rates for geothermal steam and brine delivered to the plant and how this varies with changing well configurations
- Output and performance of the plant given the steam field conditions such as maximum flows, fluid enthalpy, pressures, etc.
- Excess or shortfall in the productive fluid supply to maximise productivity of the plant
- Accurate valuation of wells in terms of their contribution to electrical or thermal output
- Injection flow rates exiting the plant that result from production
- Pressure drops throughout the injection system including back-pressuring of the plant and the level of pumping input required
- Proportions of the total injection flow into each of the injection wells for different setup scenarios
- Flow capacities for each of the injection wells if the system were to run up to a maximum delivery pressure
- Residence times in the system for injection fluid (relating to mineral deposition)

By being able to determine these values at any time, or at regular intervals, it becomes possible to monitor and manage aspects of the operational field such as:

- Historic well performance and trends
- Forecasts that accurately incorporate likely well flow and enthalpy changes
- Scenario based model runs to quantify the effects of well unavailability, plant changes and piping improvements

To define some boundaries to steam field modelling, there are natural interfaces that are simple enough to define that allow separation from the rest of the geothermal cycle and therefore simplification of the individual modelling components:

- Plant behaviour and performance can be simplified to provide the important characteristic quantities dependant on the state of the incoming fluid supply. The steam field model can represent the plant using a lookup table for fluid inlet conditions (particularly fluid enthalpy) rather than calculating a full plant model at each calculation step.
- Interaction with the wells and reservoir can be defined at the well heads by a delivery curve and enthalpy curve or an injection curve. It is necessary to interact with these curves in order to account for measured differences in performance but some aspects can be fixed and defined through reasonable assumption without compromising the accuracy of the model.

With the above goals and definitions, it is clear that a steam field will lend itself to doing some things well and will have its limitations, for instance:

- Behaviour of the geothermal reservoir remains the domain of three-dimensional numerical modelling. There is the potential to link to changes in well productivity and fluids over time as predicted by numerical modelling using a set of well bore models as a go-between but this has so far not been attempted. Predictions using stand-alone steam field modelling are therefore generally confined to the short-term (2-3 years maximum) before non-linearities in the response of the reservoir deteriorate the accuracy.
- Well behaviour can be simplified if the shape of the delivery curve is not drastically altered by intricacies such as multiple feed zone interplay, fluid temperature changes and well bore limitations. Such things will tend to affect the accuracy of predicting a well's contribution when it is shifted away from its known operating point (heavily throttled for example).
- Actual plant performance will change over time and where a plant model is based on theoretical performance the accuracy of model predictions may drift and need to be updated or calibrated.

3. BUILDING A STEAM FIELD MODEL

3.1 Describing the Production Wells

Production wells that are hot enough to be able to flow by themselves develop pressure in a dependant relationship with how much they are allowed to flow. This relationship is similar to a pump where the highest discharge pressures are developed at their outlets (in this case the well head) when at low or no flow and the discharge pressure falls off until, at atmospheric pressure, the well reaches some maximum wide-open flow rate. The relationship between the well head pressure and flow rate is close to an elliptic shape where one axis aligns with the zero pressure axis and the other axis is shifted up from the zero flow axis.

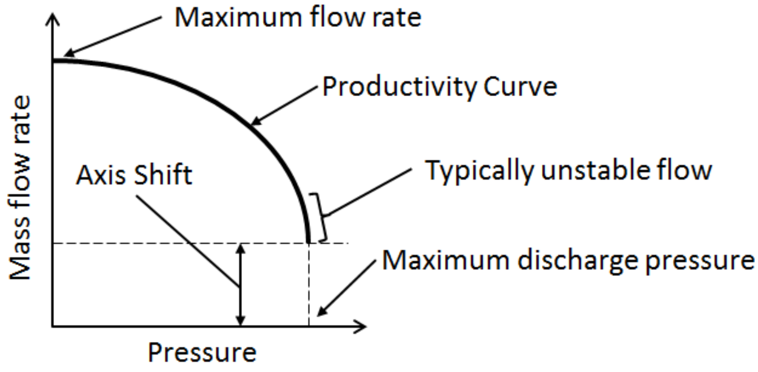

Figure 2: Typical well productivity curve

A production well can therefore often be adequately defined using an elliptic equation (Grant and Bixley, 2011) where the maximum flow rate, axis shift and maximum discharge pressure is known.

However, the productivity curve will shift over time with the drawdown of pressure from the production field and with changes in permeability in the local reservoir due to production of the fluids. To accurately assess the changing capacity of the well, the productivity curve needs to be adjusted to match the best known operating condition of the well. This can be achieved most simply by applying a percentage adjustment to the curve. How the percentage adjustment applies to the axis shift and the maximum discharge pressure will depend on indications from well bore modelling and throttling tests as to how the curve changes while varying the known conditions of interest. A Pressure Factor percentage can be applied to alter how the maximum discharge pressure moves with the overall adjustment and this seems to be reasonably consistent within a field. The Pressure Factor is usually around 50%.

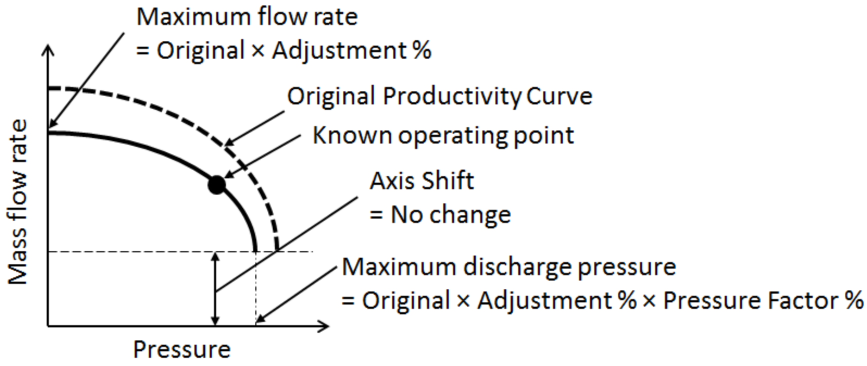

Figure 3: Shifting a production curve onto the current operating point

Wherever there is an individual measurement of the flow rate from the well (e.g. single phase orifice meters after a separator or a calibrated two-phase orifice), this can be used to adjust the curve in real time or at any interval of interest. For instance, changes can be looked at minute-by-minute as a neighbouring well is adjusted or month-by-month for long-term trending. A known operating point can also be determined from other sources of information available, for example, a control valve position or chemically determined by Tracer Flow Testing (Hirtz, et al., 1993). The latter, while usually done at a low frequency due to costs of testing, can serve as a useful check against orifice meters.

A lookup table for well flow based on the well head pressure is used to allow flexibility between using the outputs of a well bore modelling tool with a complicated curve or a simple elliptic curve fit. Likewise, a lookup table can be used to represent the flowing enthalpy of the well in terms of well head pressure (or flow).

3.2 Describing the Injection Wells

The typical injection well will operate in an open flow regime until a flow rate is reached where the application of pressure is required to drive further fluid into the well. This can be simplified to be a single sloped straight line representing the injection curve for the purposes of field modelling. A known operating point defined by a measured flow and well head pressure can be used to redefine a shifted curve by applying a adjustment multiplier to the slope and intercept of the line. If the injection well is not operating with a positive pressure above saturation at the well head then the injection curve can not be located in this way and its capacity can not be determined unless there is some downhole pressure information that can be used to assist the process.

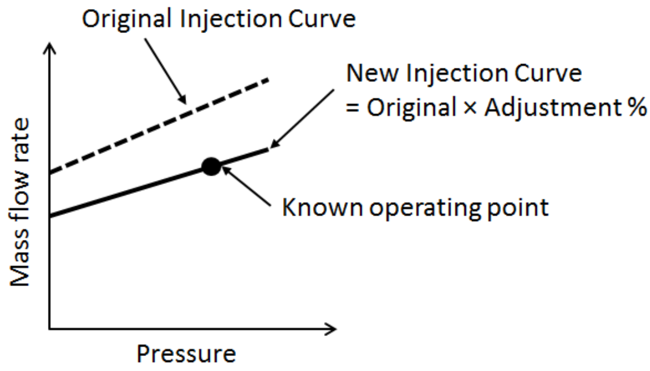

Figure 4: Typical Injection well curve and method of adjustment to a known operating point

3.3 Connecting the Wells with Piping Networks

Once the well curves have been constrained the next step is to connect the wells together so their contributions are related to one another. Some hydraulic modelling is required to establish pressure drops for various pieces of flow control equipment and lengths of pipeline. The system is best broken into sections between established pressure sensors so the sensors can be easily used to check and calibrate the theoretical pressure drops. The individual sections of pipeline are connected as a nodal network with wells at one end and plant at the other as per the real system. A known pressure at the plant is the starting point for calculation of pressure drops up the various branch lines with flow contributions from each production well and to each injection well also inputting to the calculations.

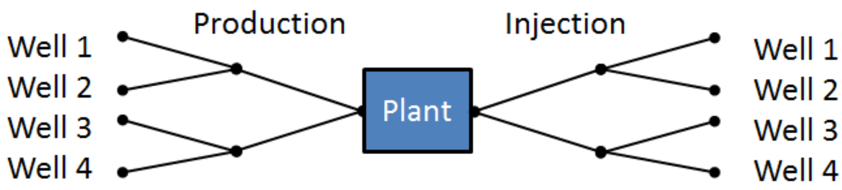

Figure 5: Example nodal network structure to represent a production gathering system and injection distribution system

Where a full hydraulic model is too onerous a first step, simpler relationships can be used to find pressure drops where actual pressure drop measurements are available to set a baseline. Such methods lump together all those parameters in the calculations which vary little over the operating range into one factor and this is calibrated to a known operating condition. The pressure drop is then proportional to the square of flow. This has proven accurate enough to obtain good results in most cases but a more complete hydraulic model would be better suited where there are significant abnormal or off-design conditions being explored.

3.4 Defining the Plant Characteristics

A full plant model is not required for the purpose of evaluating the steam field, plant and reservoir system at a high level. To be able to extract value from the steam field data, it is only necessary to characterise plant behaviour with respect to its boundary conditions. Usually the plant will have well defined interfaces to the steam field at places where the pipeline network meets the first piece of equipment within the plant boundary.

For an electricity generating station, plant behaviour will mainly vary with factors such as the ambient temperature, steam fraction (or fluid enthalpy) of the geothermal supply, non-condensable gas load and the injection pressure required at the plant boundary. Ambient temperature will vary with the day-night cycle, seasonally and with the weather but when the plant is defined at some average ambient temperature, these sorts of variations are implicit and not necessarily particularly important when examining the steam field performance. Ambient temperature can often be factored in with a simple correction where it is of interest. Non-condensable gas load and injection pressure variations will mainly affect the parasitic load and station electrical output so again can be corrected for quite easily. The main variant of interest is the fluid enthalpy as this will affect the total fluid requirements to power the station. To take into account how the plant behaviour varies with enthalpy a lookup table can be used that defines various plant parameters given the inlet enthalpy. This simplifies the plant component of the model greatly and reduces the number of iteration loops in the model.

Important values that need to be returned from a plant characteristic table are:

- 2-phase flow or steam and brine flow requirements – to then be used to define the necessary supply from the wells
- Inlet pressure to the plant – used as a starting point to define pressures in the piping network
- Injection flow – to be disposed of by injection wells
- Productive plant outputs – for power plants, this will be the electrical output

To be able to define what these quantities will be for different inlet enthalpy conditions will require some plant modelling where certain parameters are fixed and chosen (e.g. ambient temperature). These simple ‘characteristic models’ can be easily altered to test different plant scenarios by swapping out the lookup table within the steam field model.

4. CALCULATION METHODS

The components of a steam field model described in the preceding section are interdependent. They refer to each other in a circular way and therefore a solution can only be achieved by iterative calculation. Figure 6 shows the major calculation steps and the circular relationships.

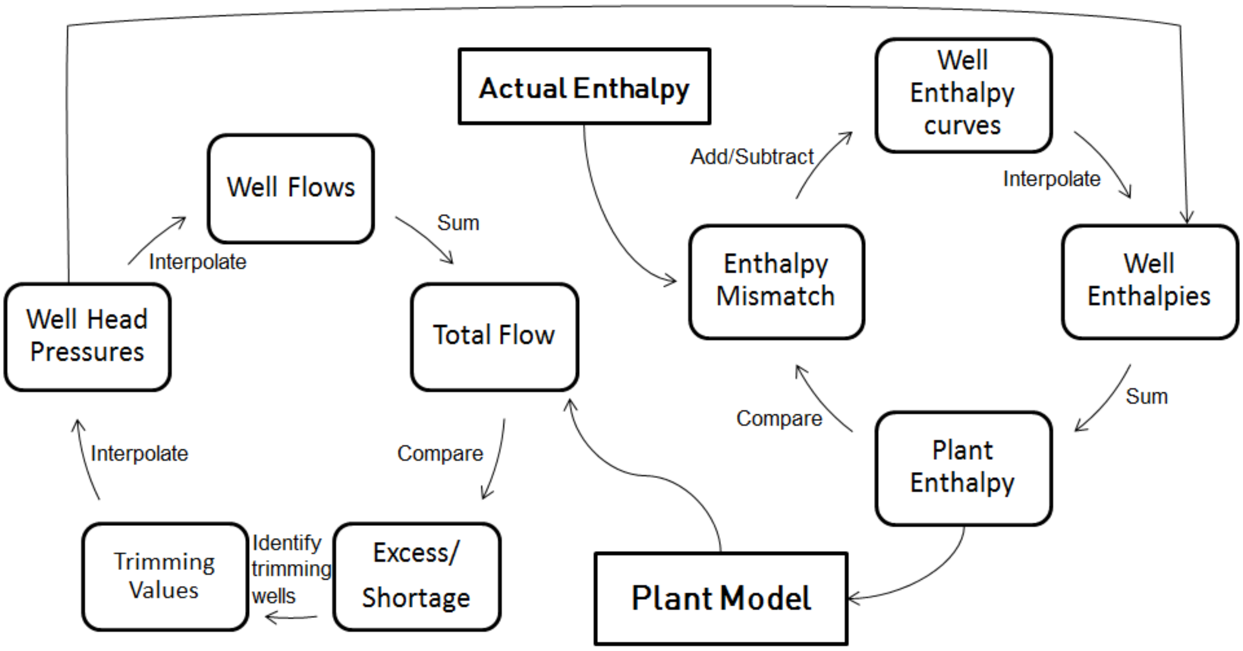

Figure 6: Overview of steps in an iterative solving method for steam field modelling

A measured enthalpy of the fluid passing into the plant is usually available since the first step is to separate the vapour and liquid phases and the flow rates of these can be accurately measured as a single phase. This summed enthalpy product from all of the wells coupled with a best estimate of the enthalpy of each individual well (from measurements such as those from Tracer Flow Testing) allows a corrected estimate of the enthalpy from each well. Once the well enthalpies are established, a new resultant fluid enthalpy at the plant given different combinations of the wells can be calculated and the nominal plant flow can be determined using the plant characteristic model. The nominal fluid flow will be drawn from individual wells by a set of rules based on the operating status of each well. The flow contribution of each well then determines the weighted enthalpy given to the plant completing the circular reference. Following this method it is possible to converge on a complete description of how the steam field will operate in the particular scenario that has been set up.

4.1 Defining the Well Configurations

It is necessary to define each well’s role in supplying the system as this will set the well’s contribution based on the rules that apply to each well status. Wells on a geothermal field will usually fit into one of the following categories:

- Inoperative – Not able to be flowed due to a problem with the well or due to testing underway
- Closed – Able to be flowed but currently not being utilised
- Fixed Opening – Flowing at a rate determined by opening a throttling control valve to some partial opening
- Fully Open – The control valve is 100% open and only back-pressuring through the system is limiting the flow rate
- Controlling (or trimming) – The control valve is operating on a feedback loop to control something downstream such as a pressure or productive output from the plant

The contribution of an inoperative or closed well is zero and the flow from a well with fixed opening is based on achieving a fixed flow rate and so the contribution of this well is also definable. A fully open well will be operating at the minimum well head pressure from the network of pressure drops back to the well head. A controlling well will supply the remaining difference between the plant requirement and the flow from all other wells (or some biased proportion if there are multiple controlling wells).

4.2 Finding a Well Capacity

The pressures in the piping network are calculated at each iteration step of the steam field calculation loop shown in Figure 6. The flow from wells that are fully open will depend on these calculated pressures since there is no intervening throttling action between the plant and the well head. These wells can be said to be operating at their full capacity for that particular scenario. To determine the flow capacity for a well, the intersection of the well deliverability curve and the backpressuring curve must be found. The capacity of the well will be converged upon as each iteration alters the contribution of each well and the backpressuring.

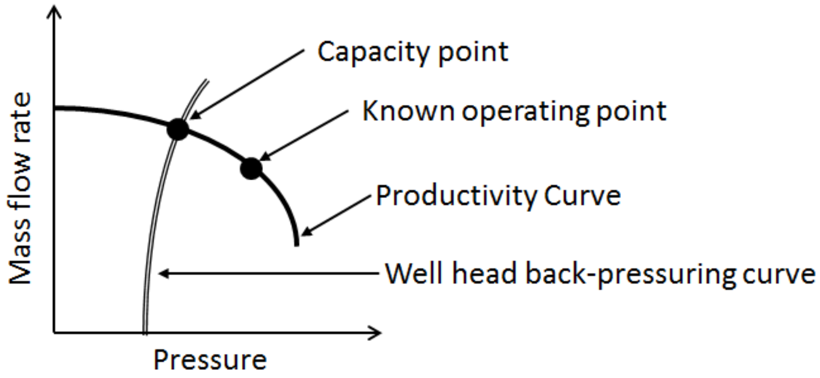

Figure 7: Well capacity is determined by finding the intersection of the productivity curve and well head back-pressuring curve

The well head back-pressuring curve is the sum of the interface pressure from the plant lookup table and the pressure drops in pipework leading up to the well head as a function of the flow from this well. All the other wells (which also affect the pressure drops) can be assumed to be flowing at the values as determined by the rules of their operating status. Capacity evaluated in this way informs of the flow that would result if all other well flows are fixed and this particular well is opened to 100%. If the well status is Fully Open, then capacity and current flow will be one and the same.

4.3 Calibration of the Model

A productivity curve for a well can be shifted to match a known operating point (refer to Figure 3). Where centralised separation is used and multiple wells are combined in two-phase it is often difficult to be accurate about the known operating flow and enthalpy for an individual well. Since accuracy is a potential problem, it is best to use as many sources of information as possible to construct a best guess. In the case of a steam field model it is possible to incorporate information from two-phase orifice measurements, plant enthalpy and well testing such as Tracer Flow Testing (TFT) and downhole sensor runs.

For enthalpy, the best guess of current enthalpy from each of the wells can be compared and corrected to the plant enthalpy and a correction applied to all wells to bring them into alignment. Since this correction is usually small (usually less than 10kJ/kg) and fairly stable over time this simple approach would seem to be valid.

In a similar way, the orifice flow calculations from the wells can be compared to the total throughput of the plant and corrected to the plant by using a common multiplier for each of the individual well results. These multipliers tend to be in the order of 5-10% of the total flow and are again fairly stable over time suggesting the two-phase orifice calculations require further refinement. While the accuracy of the raw two-phase orifice flow calculations is a potential source of significant error, comparison with results of TFT and other measures have shown that the errors, once corrected to the plant, are most likely less than 5%.

Productivity, enthalpy and injectivity curves for wells are calibrated to the model time when the operating measurement points are available. The model time can be taken back into the past to other measurement points to see how the curves change over time or it can be fixed to define a set of baseline curves for forecasting purposes.

The pressure drops for the piping network could also undergo calibrations from time to time since there is an empirical element where sensors are used in conjunction with hydraulic modelling methods to account for unknown parameters such as a friction factor and scaling.

4.4 Developing a Production History and Forecasting

Wherever there is a known operating point for each well (flow rate and well head pressure) a well flow capacity can be determined for that time. If there is continuous information from which the operating point can be determined, such as orifice plate measurements, then capacity can be calculated at any regular interval to produce a trend over time. Such a trend is very useful to compliment more traditional well testing since it will independently confirm productivity trends and pick up subtle changes that may correspond to various events and changes throughout the field. It is most useful to evaluate well capacity in each case rather than flow because there are often changes in flow due to control inputs to the well. A capacity will change primarily due to productivity changes in the well but may also change when the status of other wells change because the back-pressuring of the system will change. The latter is typically a step change while the former changes slowly over time. Periods of stable well configuration provide the clearest indication of decline in well productivity.

With a clear indication of current well decline and with other reservoir modelling techniques to understand the longer-term consequences of production, accurate future predictions of outputs from the field are very possible. Moreover, the steam field modelling incorporates the limitations of the above-ground facilities into future predictions to understand how and when production changes will need to occur. By altering parts of the model such as well statuses, the plant characteristic and steam field limitations, the relative benefits of each modification can be quantified which leads to the enhancement of a production strategy.

The benefits of developing a history and forecast are clear and the methods quite simple. To develop a history, the model needs to be automated to calibrate and recalculate at time steps into the past and to record the important outputs. By setting up a macro or looping piece of code, the model time can be stepped back at regular intervals to build a table of values. Since the sum of the well capacities should at least fulfil the plant requirements, it is useful to plot the surplus well capacity over time.

To develop a forecast requires some way other than actual well measurements to define how a well's productivity and enthalpy will change with time. This can be as advanced as feeding directly from other connected models or as simple as a linear or exponential extrapolation. The steam field model then works out how these changes will be expressed in the capacity of the wells and ultimately the productive outputs of the plant. Using the steam field model to make these conclusions is particularly important when a well's maximum discharge pressure is not significantly higher than the plant inlet pressure (less than perhaps 2 or 3 times higher) since changes in productivity are amplified in the more vertical part of the productivity curve. Ultimately, as pressure draws down in a field, wells are more at risk of becoming unstable and unproductive. Management of the fluid supply in this scenario would be difficult without a means of accurately evaluating the ability to satisfy plant requirements from the available wells.

5. OUTPUTS OF THE MODEL

The steam field model is aimed at assisting key operational decisions. It attempts to accurately represent the ability of the productive reservoir to develop productive outputs and differentiate between slight reductions and increases in revenue for any number of options that are presented. For this reason, the outputs of a steam field model are often used to evaluate anything from short-term removal of a well for testing purposes through to a major plant modification. Moreover, when looking at long-term asset management, the risks and opportunities presented by various scenarios can be considered and the model outputs offer a route to prioritisation.

5.1 Current Situation

At the current or optimised condition (which should be one in the same with the benefits of this model) it is useful to consider the capacity of each well and sometimes the corresponding minimum well pressures achievable. It is also useful to understand, from a risk perspective, the impact of a well not being available – the N-1 well scenarios. The impact of a well not being available is often a loss of productive output (for electrical generation this will be a reduction in power output in megawatts). Also of interest is the current rate of decline (or growth) in well capacity. The most appropriate way to represent decline as a single measure is usually an exponential rate such as percent per annum.

This information can be represented in a table such as in the fictional example below:

Table 1: Example of a table that could be used to describe the current situation of productive capacity within a steam field

	Capacity (t/h)	**Minimum WHP** (barg)	**Enthalpy** (kJ/kg)	**N-1 output reduction** (MWe)	**Current Decline Rate** (% mass flow p.a.)
Well 1	100	11.0	1300	2	3
Well 2	150	12.5	1240	4	5
Well 3	200	13.0	1350	5	10
Well 4	120	11.2	1180	3	6
Total	**570**		**1276**		
Required for Plant	500				

A similar table is useful to summarise the injection situation.

5.2 Productive Contributions of a Well

The capacity of a well is most simply represented as a mass flow rate but a well can also be valued for its productive contribution (e.g. electrical or thermal megawatts) by looking at the current fluid conversion rate in the plant. Where a simplistic conversion rate is applied (e.g. a mass flow conversion with units of tonnes/hour per megawatt) the resultant output becomes dependent on a further set of assumptions and variables. To get those assumptions and variables right, a steam field model will evaluate the following dependencies to value the well more accurately:

- The maximum output of steam and brine from a well are dependent on the operating configuration the steam field wells since this affects the minimum well head pressure for the well
- The steam and brine conversion rates (t/h/MW) used to calculate the maximum MW contribution from a well are dependent on the weighted enthalpy being supplied to the plant
- The enthalpy being supplied to the plant is dependent on the steam field configuration which will be biased to achieve the optimum enthalpy within the limitations of the steam field and reservoir management strategies
- The fluid supply requirement for the plant (which determines the surplus well capacity) is also dependent on the weighted enthalpy being supplied

5.3 Process Flow Diagrams

A process flow diagram is simple to construct from the information in a steam field model since flows, pressures and other fluid state information have to be known throughout the steam field network. Arranging the information schematically is both useful to understanding the setup of the model and to display the results of a scenario in a visual way. The curves deriving the well performance and operating points of each well (refer to Figure 7) can be displayed alongside a flow diagram to add another simple way of understanding a production scenario.

5.4 History and Forecasting Charts

A table of historical and forecasted values is best charted as a time series for visualisation purposes. This allows easy evaluation of imminent risks to the fluid supply and injection capability. While individual well trends are of interest, it is the total supply that is of primary importance. For this reason it is often useful to stack up the individual well contributions and evaluate the total supply capacity against the plant requirement.

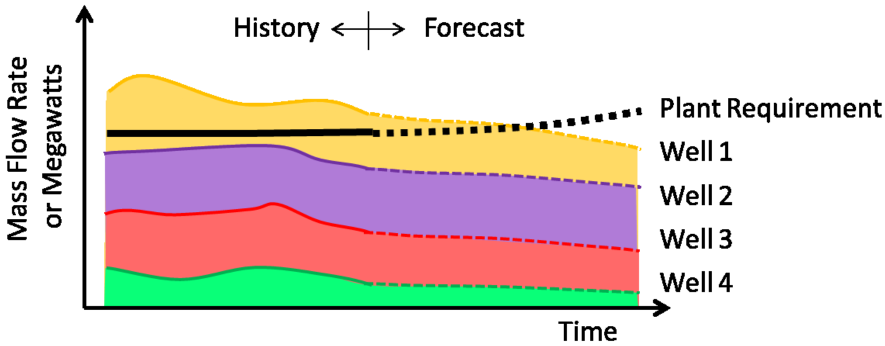

Figure 8: A time series history and forecast chart can easily summarise the current situation and highlight the level of risk for the future

In addition to capacity, it is often useful to plot the actual well flows (or utilisation of a well's capacity) to understand how the field is being produced or will have to be produced in the future and where the spare capacity is concentrated. The actual flow predictions have the potential to provide a useful feedback to reservoir numerical modelling by providing realistic production flows rather than making assumptions such as spreading production equally across all the wells.

6. FURTHER DEVELOPMENT POTENTIAL

There are many opportunities remaining to improve steam field modelling at Mighty River Power that would seem justified in terms of time and effort. The major areas of interest are listed below:

- The user interface of the current models is poor and only really workable by those familiar with the model. There have been requests by plant operators, operations management team and financial analysts to use the model for various purposes but since the model is still under development, this has not really been practical.

- Most wells have some level of interference with the productivity of other wells in the vicinity by way of a fluid connection through the reservoir. This is most clearly evident and measurable when production changes are made and quick changes in well productivity occur. Since it is a measurable phenomenon it ought to be possible to split productivity changes due to interference from changes due to permeability and other reservoir pressure changes. These can be treated differently when forecasting and therefore further improve longer-term accuracies.

- Taken one step further, a well-calibrated reservoir numerical model coupled to a well bore model accounts more naturally for all those factors affecting well productivity, including interference. Ideally the numerical model would provide the well productivity, enthalpy and injection curves to the steam filed model through the well bore model. In return, the steam field model would provide how the wells will be produced and injected into over time. The additional iteration loop this creates at every time step adds another dimension of processing and complexity but this is likely manageable.

- Incorporation of more sophisticated plant characteristic modelling where more factors than just enthalpy can be varied (for instance NCG content) will allow more scenarios to be explored.

- Understanding of two-phase steam and water flow regimes and pressure drops in large pipelines is still a work in progress. Phenomena such as surging and slugging can present limitations to steam field performance and are sometimes difficult to predict and explain. Pressure drops through tees, orifice plates and other fittings are not always easy to account for through modelling. Improvements to the understanding of why pressure drops and flow regimes occur will lend further accuracy to field modelling and prediction of risks to the fluid supply.

7. CONCLUSIONS

Through this paper I have attempted to present the subject of field modelling as it has naturally developed during process engineering activities within Mighty River Power's geothermal operations. A steam field model that simulates the connections between the wells and the plant has been proven to promote a more holistic understanding of the system and this has benefited management of the operations. Difficulties that have arisen while trying to solve what tends to be a complex system have been successfully overcome and the modelling concepts have been proven valid over several years of successful operation. As with all models there are ongoing improvements to the methods and assumptions to consider investing further time and effort into. In the longer term, the desire to integrate the steam field model with other geothermal models will undoubtedly be borne out due to the value of the outputs.

REFERENCES

Grant, M., and Bixley, P.: Geothermal Reservoir Engineering, Second Edition, Academic Press, (2011)

P. Hirtz, J. Lovekin, J. Copp, C. Buck, and M. Adams: Enthalpy and Mass Flowrate Measurements for Two-Phase Geothermal Production by Tracer Dilution Techniques, *Proceedings,* Stanford Geothermal Workshop (1993)