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Numerical Simulations and Decision Making in the Hellisheiði Geothermal Field, SW-Iceland

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Keywords

Reservoir models, Numerical Simulations, iTOUGH2, Hengill, Hellisheiði, Production, Injection, Decision Making, ROA

ABSTRACT

The Hellisheiði Power Plant is located in the southwestern part of the Hengill Area, SW-Iceland, 25 km SW of Reykjavík. The Hengill Area consists of the Hengill Central Volcano and fracture zones northeast and southwest of Mt. Hengill. The Hellisheiði Power Plant was commissioned in 2006, and expanded in 2008 and again in 2011. The current installed capacity is 303 MW electric and 133 MW thermal. Another power plant, Nesjavellir, is located in the northeastern part of the Hengill Area. That plant was commissioned in 1990 and has an installed capacity of 120 MW electric and 290 MW thermal.

Shortly after the latest units of the power plant were commissioned, problems in operating the Hellisheiði Field emerged. It was a challenge to maintain the production capacity of the power plant and to manage the reinjection. The reason for these problems was mainly the fast pace in which the Hellisheiði field was developed. All major decisions on the scale of the power production were taken before data from newly drilled wells became available. The geothermal resource turned out to be smaller and distributed differently than the conceptual model, on which the drilling strategy relied on, postulated. Due to the fast pace development of Hellisheiði it was not possible to adapt to this new reality. Consequently, the production field turned out to be too small to sustain the large capacity of the power plant.

The production density is high or approximately 250 kg/s/km² (or 40 MW/km² in electricity) within the most productive parts of the field. This high production density has caused significant pressure drawdown and decreased performance of wells. To spread the production and thus, lower the production density, a promising field called Hverahlíð located about 5 km away, in the southern part of the Hengill Area was connected to the Hellisheiði Power Plant. Moreover, reinjection has been used for maintaining the reservoir pressure, mainly on the edge of the production field. These actions have made the operation of the Hellsheiði field easier, but non-the-less make-up wells must be drilled to maintain the production capacity of the power plant.

To aid with decision making in the development and production from the Hellisheiði field, a numerical model of the entire Hengill area has been developed. It has been used to study the

feasibility and environmental impacts of different production scenarios for both Nesjavellir and Hellisheiði. The model was recently revised, and has been a key tool in the decision-making process for recent and future developments of the field. Make-up drilling schemes and different reinjection schemes have been simulated. Building on those simulations, the economic feasibility of technically sound production scenarios has been estimated.

1. Introduction

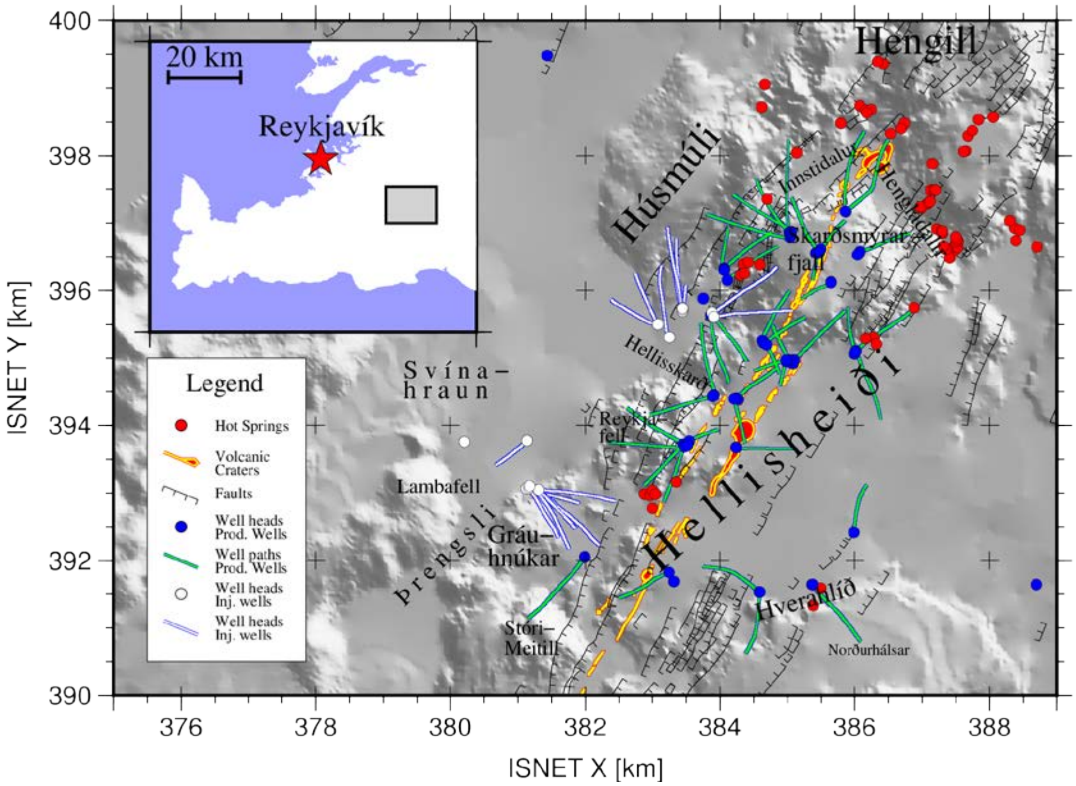

Figure 1: Map of the Hellisheiði Field showing some basic geological features and the wells drilled in the field.

The Hellisheiði Geothermal Field is located in the SW part of the Hengill Area, 25 km SW of Reykjavík. The Hengill Area consists of the Hengill Central Volcano and fracture zones northeast and southwest of Mt. Hengill. Hot springs and fumaroles are widely found in the area. Due to close proximity to Reykjavík, the geothermal fields of the Hengill Area are considered important energy resources, both for electricity and space heating. Three Holocene eruptions are known in the Hengill system, 2000, 5800, and 10,000 years ago. The eruption fissures of these events are located on the fissure swarm both north and south of the higher central part of the Hengill Volcano, but not in the central part (Sæmundsson 1967, 1992, 1995). Fig.1 is a simplified topological map of the Hellisheiði field.

The Hellisheiði Power Plant was commissioned in 2006, expanded in 2008, and again in 2011. The installed capacity is 303 MW in electricity and 133 MW in thermal energy. Fig.2 is a simplified diagram of the power plant. It is a dual flash system. The first step at 8.5 bar-a for obtaining high pressure steam for six 45 MW high pressure units. The second step is at 2 bar-a for obtaining low pressure steam for a 33 MW low pressure unit. The flashed separated water is then used to heat up fresh ground water for the district heating utility of the power plant. The heated ground water is mainly used for space heating in the Reykjavík area. The waste water coming from the heat exchangers is partly mixed with condensate water from the turbines before it is reinjected into the reservoir.

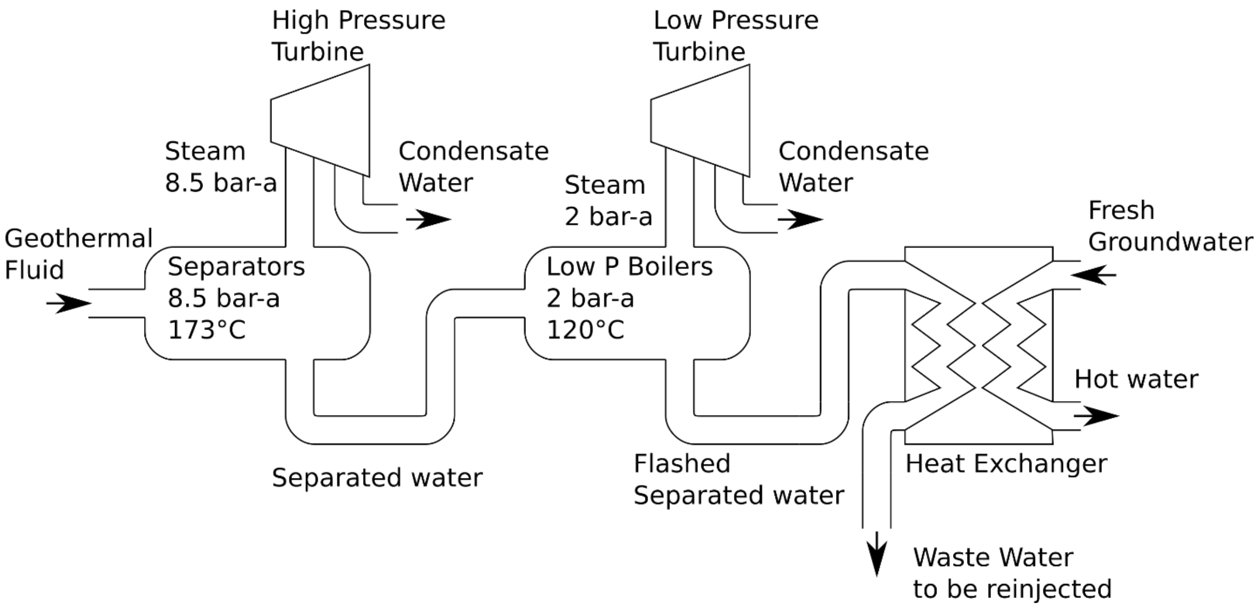

Figure 2: Simplified diagram of the Hellisheiði Power Plant. A double flash system is used for electricity generation. The flashed separated water is then used to produce hot water for direct use (space heating).

The production field lies in the fissure swarm area south of the Hengill Mountain (see map in Fig.1). The average enthalpy of produced fluid was originally ~1800 kJ/kg but has been decreasing and is now ~1500 kJ/kg. The most productive part of the Hellisheiði field is narrow resulting in high production density. Initial conceptual models, on which the development of the field relied, postulated that the energy source of the field was a large up-flow zone under the highest part of the Hengill Mountain just north of the Hellisheiði field. The geothermal field turned out to be quite different. It is characterized by narrow hot areas separated by cooler ones. Thus, the size of the geothermal resource was overestimated. All decisions on the size of the project were based on this older conceptual model and taken before any comprehensive data analysis from new wells became available and without any production history. Moreover, due to the fast pace of the project, there was no room for adapting the project to the new reality as it emerged during the drilling phase.

In Fig.3 the annual production and injection in Hellisheiði is shown with the average enthalpy of produced fluid. The production at Hellisheiði peaked in the year 2013 i.e. two years after the completion of the plant The average production density reached more than 300 $kg/s/km^2$ in the most productive parts of the system that year, which corresponds roughly to electricity generation density of 60-75 MW/km^2. It soon became evident that the power plant was too big for the size of the production field and in 2015 the annual production was considerably lower than the year before. Two steps were taken to maintain the production capacity: Reinjection was reorganized, the capacity of the reinjection wells was maximized and in-field reinjection was tested. The other step was to enlarge the production field. A new field, Hverahlíð, in the southernmost part of the Hengill Area was connected to the Hellisheiði Power Plant.

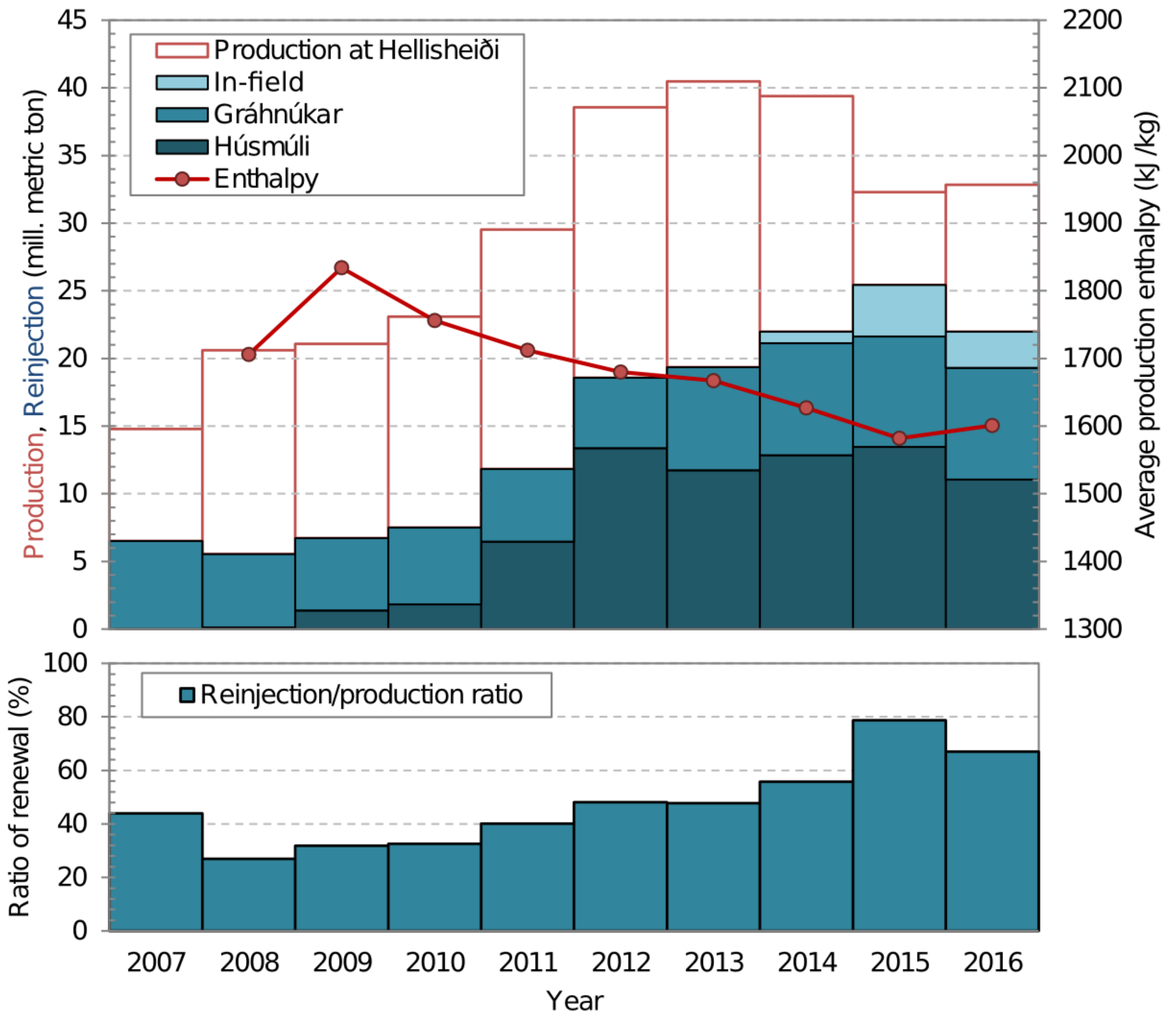

Figure 3: Total annual mass extraction and reinjection at Hellisheiði. The upper graph shows the total production in the background and the reinjection in the foreground. The amount of reinjected water into individual parts of the system are stacked. The average production enthalpy is also shown in the upper graph. The lower graph shows the ration of reinjection to production.

Hverahlíð was originally planned as a separate project and 6 exploration wells had already been drilled there. The premises of that project changed and further development was postponed indefinitely. Thus, the wells in Hverahlíð that had already been drilled and had turned out to be quite productive, could be connected with a 5 km long pipeline to the Hellisheiði Power Plant. After the wells in Hverahlíð were connected it has been possible to maintain production capacity of the power plant as can be seen in Fig.3. The production is lower that it was when it peaked in year 2013 but remained stable between 2015 and 2016.

There are two main challenges in operating the Hellisheiði Field and maintaining its production capacity. The first one concerns the drilling of make-up wells. The question that one needs to ask in that respect is; is it profitable to invest in enough make-up wells to maintain production capacity or should the production be allowed to decrease and if so, how much?

2. The Reservoir Model of the Hengill System

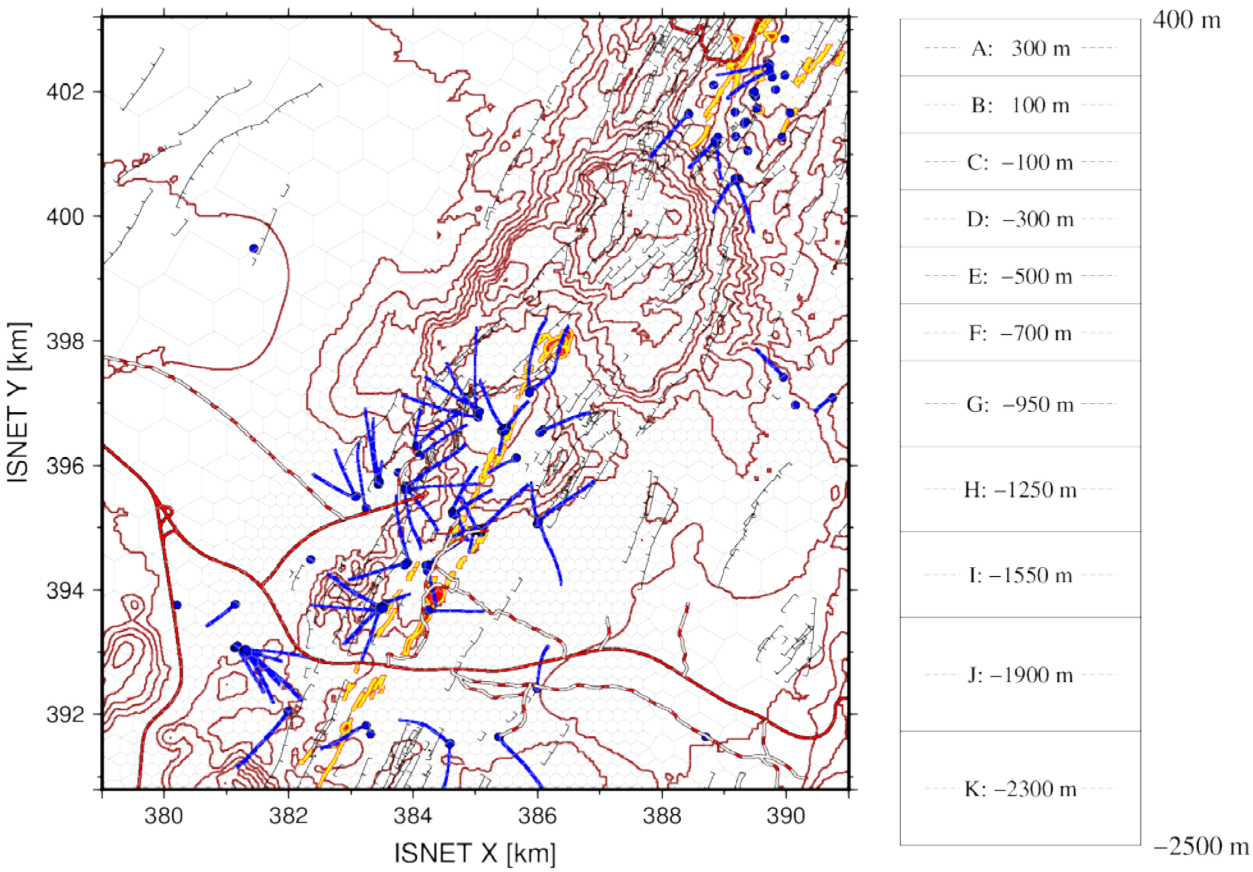

Figure 4: The segments of each layer of the model in and around the production fields in the Hengill Area (left). The layering structure of the model is shown to the right.

A reservoir model of entire Hengill Area has been constructed in the TOUGH2/iTHOUG2 software suit (Pruess et al. (1999) and Finsterle (2007)). The model consists of 11 layers each having 3,782 elements (i.e. total of 41,602 elements) and the total number of connections is 161,636. The size of the model is 50 x 50 km and the depth range is from 400 m a.s.l. to 2500 m b.s.l. Voronoid grid generated using the AMESH program (Hauwka (1998)) is used to split the layers into elements. The basic grid is hexagonal with 1600 m between centers of elements. The grid gets denser as we approach the drilling field where the distance between centers of elements is 200 m. In Fig.4 the elements of each layer of the model are shown in and around the production fields and the layering structure.

In previous modelling works of the geothermal systems in the Hengill Area the energy sources have been assumed to be below the depth range of the model. The system has been driven by choosing appropriate boundary conditions in the bottom layer of the model, which is a common practice in commercial reservoir modeling (see e.g. O'Sullivan et al (2001)). In the cases of simulation in the Hengill Area the system has been driven by sources of heat in the bottom layer and mass sources yielding small amounts of high enthalpy fluid (see e.g. Björnsson et al. (2003) and Gunnarsson et al. (2011)). In this case only mass sources yielding high enthalpy fluid, located in the hottest regions of the fields are used to drive the system. According to standard procedures in commercial reservoir modeling the heat sources drive the system to steady state (also called natural state) before production is simulated. In this case steady state means that the system is stable over a period of 10,000 years (see e.g. O'Sullivan et al (2001)).

These methods of assuming that the energy sources are below the model and that the system is in steady state before production starts have proven useful for simulating the effects of production on a geothermal system. By using the inverse part of the TOUGH2/iTHOUG2 software suit it is possible to reach a relatively good fit between measured and simulated parameters. However, there are fundamental problems with these assumptions. Firstly, geothermal systems in volcanic areas are very dynamic phenomena so assuming a steady state is a bit bold. Secondly, there are strong indications that the heat sources could be located at shallower depths, i.e. within the model depth range. And thirdly; a geothermal model avoiding the energy sources is not complete, even though it works for practical purposes (Gunnarsson and Aradóttir (2015)).

3. Operating the Hellisheiði Field

There are two main challenges in operating the Hellisheiði Field, maintaining production capacity by drilling make-up wells and disposal of separated water by means of reinjection. As discussed the most productive parts of the field are narrow resulting in a very high production density there. With regards to reinjection, currently most of the produced fluid is reinjected into the reservoir yet it has been difficult to maintain the performance of injection wells. Moreover, it is not clear how reinjection should be managed to support the production properties of the geothermal system. Both of these issues have been addressed using model simulations.

3.1 Drilling of Make-up Wells.

One can expect the production capacity of a geothermal system such as Hellisheiði to decline with time and it is standard practice to drill make-up wells. The fundamental question for the investor is whether it is profitable to drill make-up wells. Thus, the first simulation that was run with the new numerical model was the basic scenario of no make-up wells. An example of such a simulation is shown in Fig.4. In this scenario all present wells are used and they decline as the pressure drops in the system. According to these calculations the annual decline in electricity generation is approximately 10 MW. This number is comparable to the decline that has been measured directly in annual performance measurements on production wells.

In order to maintain production capacity a make-up drilling plan has been drawn up, based on the simulated decline shown in Fig.4. All feasible targets in the area have been studied and their potential estimated. It is difficult to predict how much power a planned well is going to give. The most feasible targets where high temperature and good permeability are confirmed are all in Hverahlíð in the southernmost part of the Area. All other known hot and permeable formations are already heavily produced. In addition there are a few promising targets, where the formation temperature and permeability have not yet been confirmed. Thus, a drilling plan includes “safe” options, where the resource is confirmed, and research wells, where promising but not confirmed resources are probed. This implies uncertainty in the results of drilling the wells and therefore a financial risk.

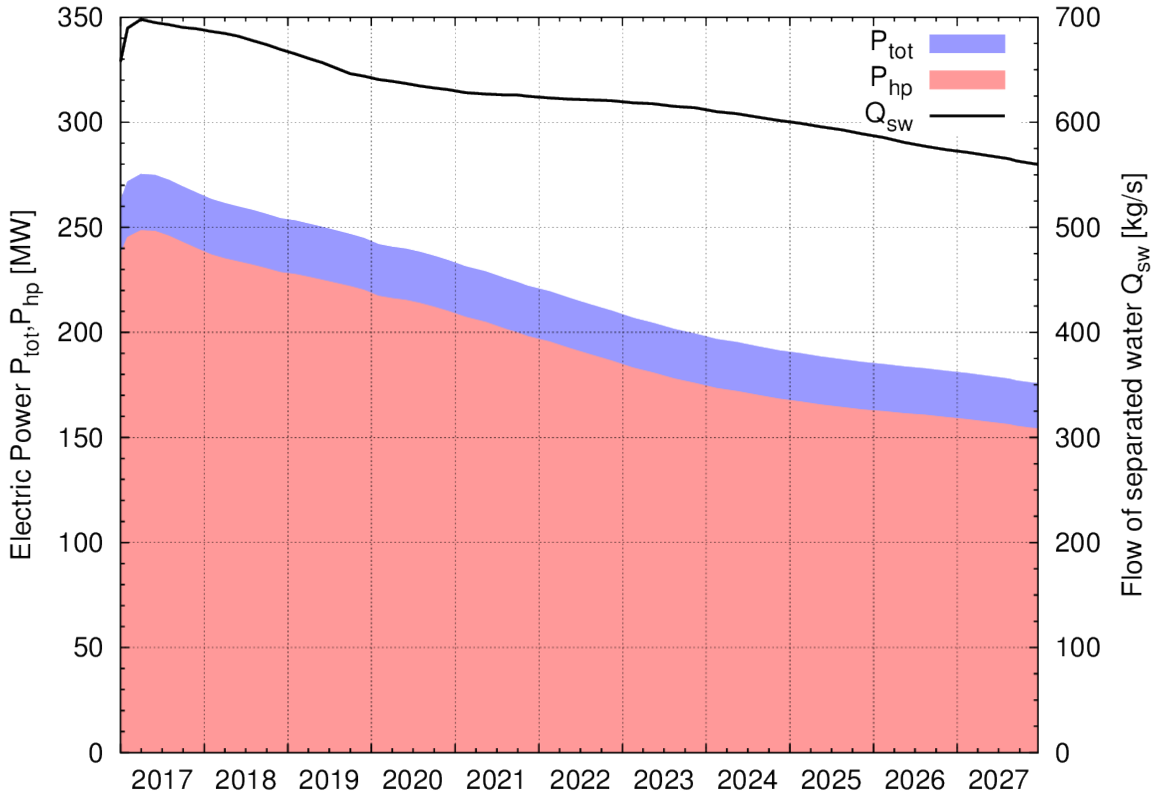

Figure 4: The evolvement of power production if no make-up wells are drilled. The electric power generation using high pressure and low pressure steam (P_{hp} and P_{lp}) is stacked. The flow of separated water (Q_{sw}) is also shown.

This uncertainty can hardly be modelled in a reservoir model; a possible resource has no meaning in numerical model. One either has a hot permeable formation or not. The model is therefore conservative; only known confirmed resources are included. However, the model was used to test the drilling plan that was drawn up. The plan calls for 15 wells to be drilled within the next 10 years. Model simulations have shown that it is possible to maintain the production capacity over the next 10 years. In Fig.5 results from such a simulation are shown. The main uncertainty in the model is the enthalpy, which has great effect on the electrical power output of the field. The enthalpy is among others dependent on the arrangement of reinjection. In this calculation a relatively simple injection scheme was followed, which is similar to the present arrangement of the reinjection system in Hellisheiði. In next section injection will be discussed in further detail. Some further work has to be done to estimate the uncertainty of the enthalpy further.

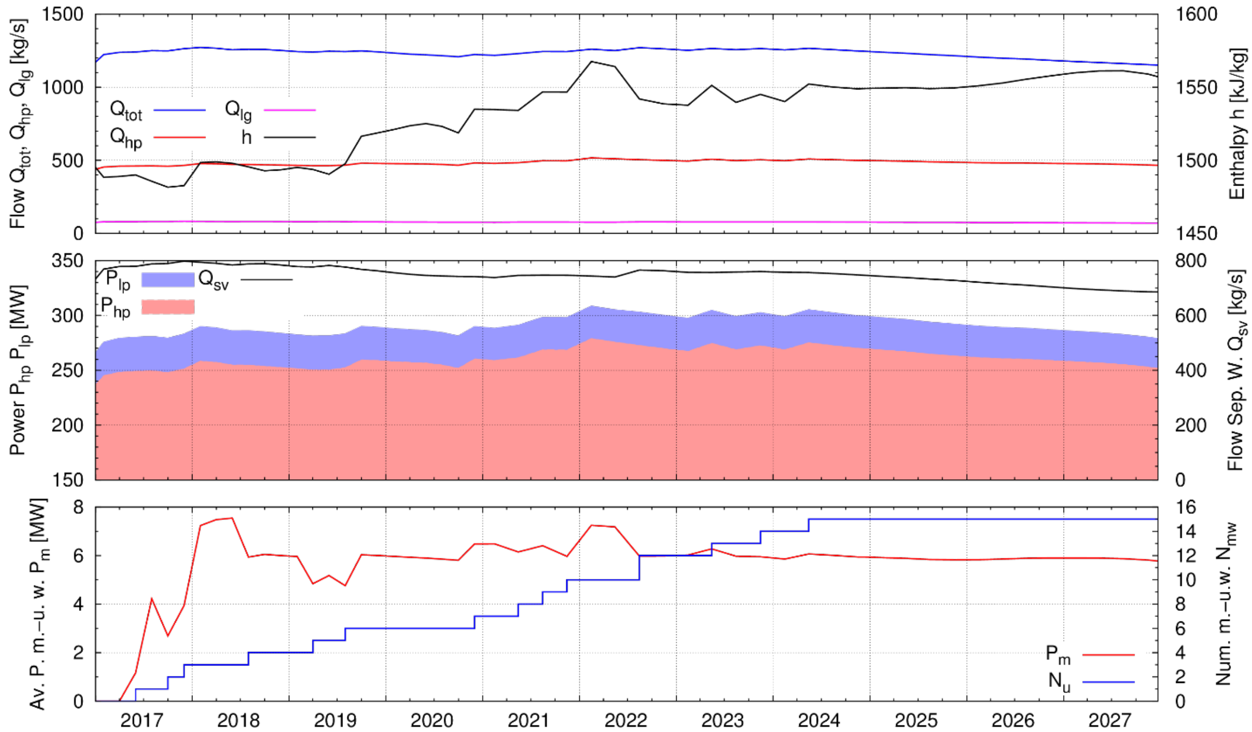

Figure 5: Model simulation where 15 make up wells are drilled. The uppermost graph shows the total flow Q_{tot}, the enthalpy of the fluid h and the resulting flow of high and low pressure steam (Q_{hp} and Q_{lp} respectively). The graph in the middle shows the electric power generated from the high and low pressure steam (P_{hp} and P_{lp} respectively) and also the flow of separated water (Q_{sv}). The lowermost graph shows the average electric power of the make-up wells (P_m) and the accumulated number of make-up wells (N_{mw}).

The profitability of the 15 well drilling plan was estimated. In Fig.6 the calculated Return on Assets (ROA) of the plan is compared to the ROA of the scenario where no make-up wells are drilled. As mentioned above there are uncertainties in that plan. Drilling operation can fail, either due to technical reasons or when a promising target turns out to be not suited for production (to cold and/or too impermeable). It can also happen that drilling turns out to be more successful than anticipated. Moreover, there are also uncertainties in the predicting decline of the production capacity. In order to deal with these uncertainties two more drilling plans were drawn up; one pessimistic where 32 wells have to be drilled in the next 10 years and another optimistic where only 6 wells had to be drilled. The cost of drilling and connecting the wells for all three scenarios was estimated and the ROA calculated (see Fig.6).

It can be clearly seen that all three drilling plans are better than the no make-up wells scenario, especially in the long run. There will be higher ROA for the no make-up wells case in the beginning, but it will then plummet as the production capacity declines further. Consequently, drilling make-up wells is profitable even if the drilling operation is relatively unsuccessful.

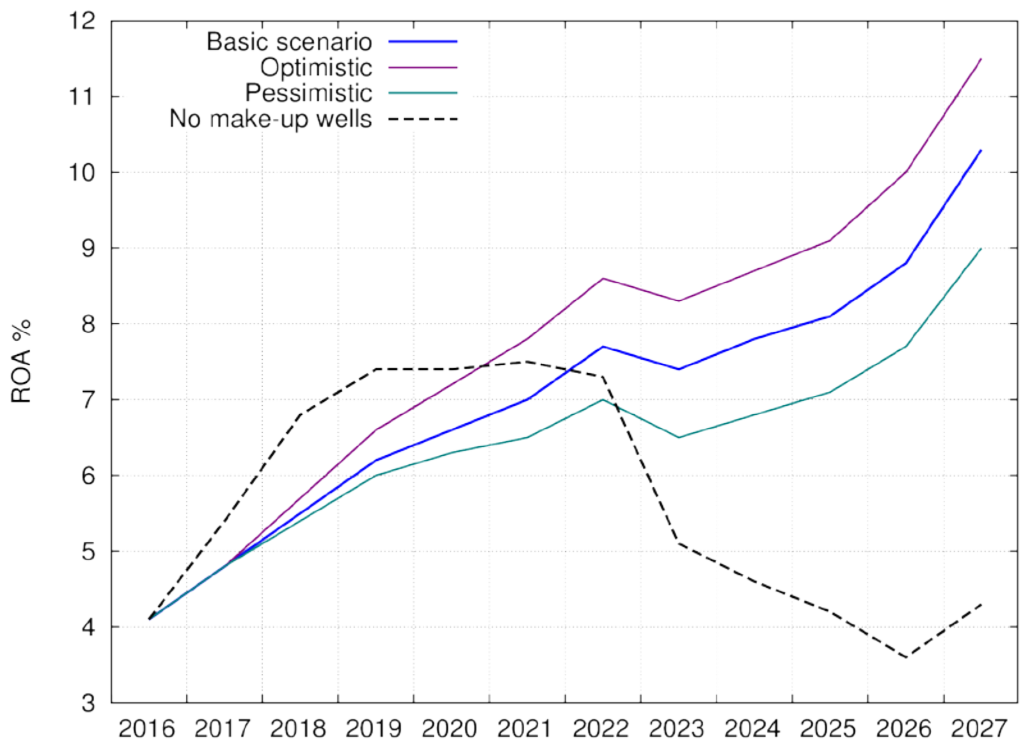

Figure 6: Return on Asset (ROA) for different operational scenarios. In the basic scenario 15 make-up wells are to be drilled. A pessimistic and optimistic scenarios with 10 and 20 make-up wells respectively are also shown. A scenario with where no make-up wells are drilled is also shown for comparison.

3.2 Managing reinjection

Managing reinjection has been a challenge since the commission of the Hellisheiði Power Plant. The original reinjection zone was in Gráuhnúkar SW of the production field. High formation temperature in wells there made it a promising field for production. In order to stop reinjection in the Gráuhnúkar Area a new reinjection zone was planned in Húsmúli on the Western edge of the Hellisheiði Field. That reinjection zone was commissioned in September 2011. Intensive induced seismicity followed the commission of the Húsmúli field which caused considerable disturbances in the neighboring community of Hveragerði, c.a. 10 km East of Hellisheiði. Induced seismicity due to injection had not been an issue before in geothermal field in Iceland (Gunnarsson 2011, 2013; Bjarnason et al. 2012). Another challenge has been the capacity of the injection zones. The injectivity of the wells in Húsmúli has never been high enough to inject all waste water from the power plant there. Thus, the Gráuhnúkar Reinjection Zone is still operated as such, despite the high formation temperature that has been observed there. Even the combined capacity of the Húsmúli and the Gráuhnúkar reinjection zones is currently not high enough to be able to inject all waste water from the power plant. This is partly due to decreasing enthalpy of the produced fluid and partly due to decreasing capacity of the reinjection zones. To solve this problem in-field reinjection has been tested. Production wells that cannot be used for production have been connected to the reinjection system (Gunnarsson and Mortensen 2016).

In 2015 almost 80% of produced fluid was reinjected into the system (see Fig.3). Such intensive injection, especially when part of the reinjected water is injected in-field, poses a risk of thermal break-through. Extensive tracer tests have been undertaken to estimate that risk. Preliminary results show that there is some risk of thermal breakthrough (Kristjánsson et al 2016). Monitoring of the wells, in which the risk of thermal break through is believed to be highest, has not shown any sign of cooling. There have, however, been some changes in the flow and enthalpy of wells in the vicinity of injection wells. On one hand, the injection has had positive effects on wells that have low enthalpy (<1500 kJ/kg), the flow from them has increased but the enthalpy has not changed significantly. On the other hand, the injection has had negative effect on wells with higher enthalpies, especially on medium enthalpy wells (1500 - 2000 kJ/kg). Injection seems to cause the enthalpy in such wells to decrease. The reservoir is initially water dominated. Higher enthalpies are caused by boiling in the formation due to pressure drawdown. Higher pressures due to reinjection will stop such boiling and thus, lower the enthalpy of the produced fluid (Gunnarsson and Mortensen 2016). This effect has also been seen in wells in the Nesjavellir Field in the Northern part of the Hengill Area.

Thus, injection is a double edge sword, even though the risk of thermal breakthrough is low. The pressure increase caused by it will enhance the flow from low enthalpy wells but the same pressure increase will lower the enthalpy of the produced fluid from medium to high enthalpy wells. This effect can be seen in model simulations.

As mentioned above the capacity of injection zones has barely been enough to be able to sustain full reinjection of all waste water. Considerable amount of work is now being invested in to enhance the capacity of the reinjection system. Injection into the reservoir as well as disposal of waste water outside the reservoir are considered. Fig.7 shows a map with present and planned reinjection zones. Currently a new partly in-field zone is being tested in Skarðsmýrarfjall in the northern part of the field. Another zone is being connected at the northern edge of the field. These new reinjection wells were all drilled as production wells but cannot be used as such. The capacity of the reinjection system should be sufficient when these new zones have been connected. The question is how the reinjection will affect the production properties of the geothermal system.

The reservoir model is being used to estimate the effects of different injection scenarios on the geothermal reservoir. Six scenarios are shown here all using the same drilling plan of 15 make-up wells as discussed in previous section. In Table 1 these injection scenarios are defined. There the maximum flow of water into each reinjection zone and mixing ratio vs. time are listed. In some of the reinjection zones; Gráuhnúkar, Húsmúli and the present in-field wells the separated water is mixed with condensate water. This is done to prevent scaling and to cool the water. The injectivity of the reinjection wells is highly dependent of temperature and is much higher for colder water. Adding condensate water to the separated water cools it down and the net effect is that more separated water can be injected. The temperature dependence is so high that more separated water can be injected when ~30% of the total amount is condensate water (Gunnarsson 2011b, Sigfússon and Gunnarsson 2011). In Fig.8 the total flow of injected waste water is shown and how it is divided between different injection zones (the same zones as are shown in Fig.7). The total amount of injected water comes from the simulation. The total flow and calculated enthalpy is used to estimate the amount of separated water.

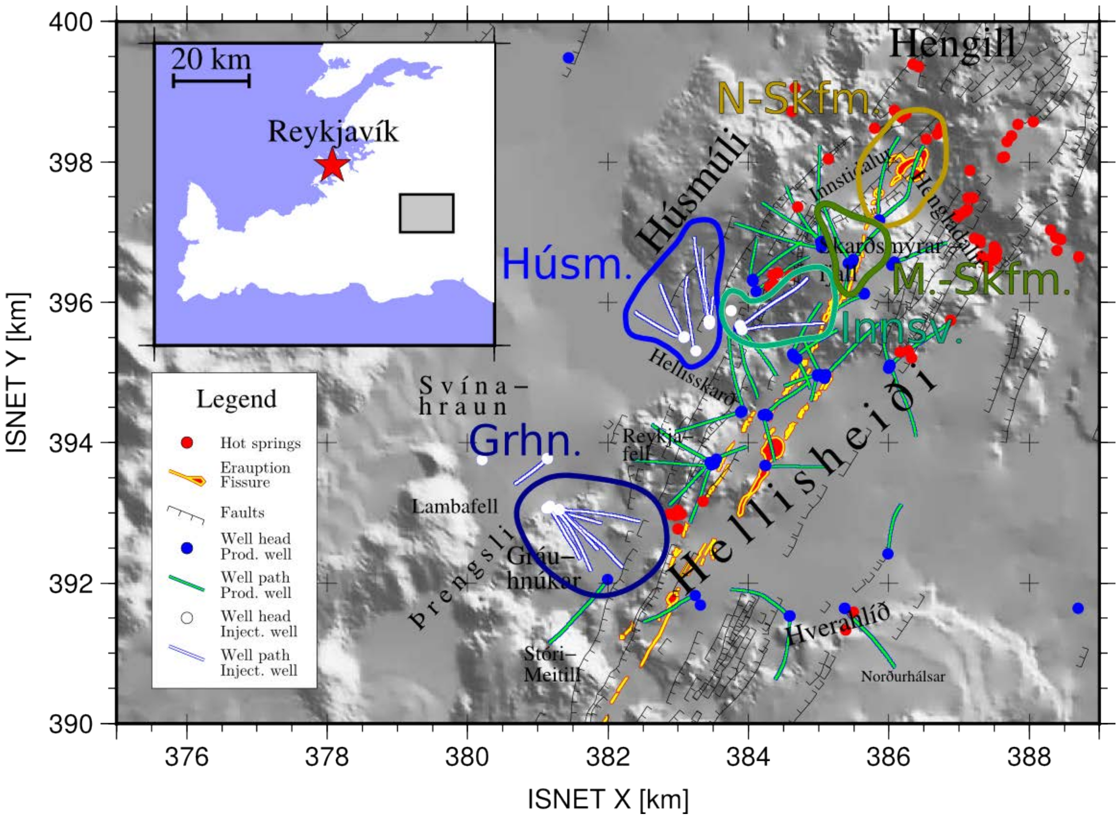

Figure 7: Map showing present and planned reinjection zones in Hellisheiði. Gráuhnúkar (Grhn.) and Húsmúli (Húsm.) are the original zones. Then there are the in-field reinjection well (Innsv.). Currently a new injection zone in Skarðsmýrarfjall (M.-Skmf.) is being tested and a new one in the northern edge of the field (N-Skmf.) will be tested soon.

The total flow and temperature of the injected water is thus estimated using the calculated total flow of produced fluid, its enthalpy, and the preferred mixing ratio. This is done in an iterative way and the enthalpy and flow converge rather quickly (in approximately 5 iterations). In the six scenarios shown in Fig.8 the maximum flow (in some cases time dependent) and thinning ratio for each zone was defined. In two of the scenarios (no. 3 and 4) the defined maximum flow is not sufficient to inject all the separated water. It those cases the residual water is expected to be disposed of outside the reservoir. Disposing of waste water outside the reservoir is something that is being considered. Two methods are mainly being discussed; injection into lower groundwater layers above the impermeable cap rock that covers the geothermal reservoir and to build a pipeline to the coast and dispose of the water into the ocean

As can be seen in Fig.8 the amount of separated water is dependent on the arrangement of the injection. This can be clearly seen in Fig.9 where the average enthalpy of the produced fluid and resulting flow of high pressure steam is plotted for these scenarios. The enthalpy of produced fluid is highly dependent on how the injection is managed. According to the model the in-field injection has a significant impact on the enthalpy as can be seen in scenario 3. This effect has been seen in operation data from the power plant and has, as mentioned above, been interpreted as an effect of higher pressures in the reservoir. The reservoir is originally water dominated and higher enthalpies are due to boiling in the formation. Higher formation pressure prevents that

Table 1: Different injection scenarios that were simulated using the numerical model. The table shows how the separated water was distributed on reinjection zones from left to right until all separated water had been reinjected (or as in scearios 3 and 4 the residual water has to be disposed of outside the reservoir). Maximal total flow (Q_{max}) and the ration of condensate water; mixing ratio, (p) is listed vs. time for each of the reinjection zones.

Scenario 1	Gráuhnúkar		Húsmúli		In-Field		N.-Skmf		M-Skmf	
	Q_{max}	p	Q_{max}	p	Q_{max}	p	Q_{max}	p	Q_{max}	p
2017-01-01	300	0.1	250	0.4	150	0.4	0	0	0	0
2017-02-01	300	0.1	250	0.4	150	0.4	0	0	150	0
2040-01-01	300	0.1	250	0.4	150	0.4	0	0	150	0
Scenario 2	Gráuhnúkar		Húsmúli		In-Field		N.-Skmf		M-Skmf	
	Q_{max}	p	Q_{max}	p	Q_{max}	p	Q_{max}	p	Q_{max}	p
2017-01-01	300	0.1	250	0.4	150	0.4	0	0	0	0
2017-02-01	300	0.1	250	0.4	150	0.4	0	0	150	0
2017-08-01	300	0.1	250	0.4	150	0.4	140	0	150	0
2040-01-01	300	0.1	250	0.4	150	0.4	140	0	150	0
Scenario 3	Gráuhnúkar		Húsmúli		In-Field		N.-Skmf		M-Skmf	
	Q_{max}	p	Q_{max}	p	Q_{max}	p	Q_{max}	p	Q_{max}	p
2017-01-01	300	0.1	250	0.4	150	0.4	0	0	0	0
2017-02-01	300	0.1	250	0.4	150	0.4	0	0	150	0
2017-12-01	300	0.1	250	0.4	150	0.4	0	0	150	0
2018-01-01	300	0.1	250	0.4	0	0	0	0	0	0
2040-01-01	300	0.1	250	0.4	0	0	0	0	0	0
Scenario 4	Gráuhnúkar		Húsmúli		In-Field		N.-Skmf		M-Skmf	
	Q_{max}	p	Q_{max}	p	Q_{max}	p	Q_{max}	p	Q_{max}	p
2017-01-01	300	0.1	250	0.4	150	0.4	0	0	0	0
2017-02-01	300	0.1	250	0.4	150	0.4	0	0	150	0
2017-12-01	300	0.1	250	0.4	150	0.4	0	0	150	0
2018-01-01	150	0.1	125	0.4	0	0.4	0	0	0	0
2040-01-01	150	0.1	125	0.4	0	0.4	0	0	0	0
Scenario 5	Gráuhnúkar		Húsmúli		In-Field		N.-Skmf		M-Skmf	
	Q_{max}	p	Q_{max}	p	Q_{max}	p	Q_{max}	p	Q_{max}	p
2017-01-01	300	0.1	250	0.4	150	0.4	0	0	0	0
2017-02-01	300	0.1	250	0.4	150	0.4	0	0	150	0
2017-08-01	300	0.1	250	0.4	150	0.4	0	0	150	0
2017-09-01	300	0.1	250	0.2	150	0.2	0	0	150	0
2040-01-01	300	0.1	250	0.2	150	0.2	0	0	150	0
Scenario 6	Gráuhnúkar		Húsmúli		In-Field		N.-Skmf		M-Skmf	
	Q_{max}	p	Q_{max}	p	Q_{max}	p	Q_{max}	P	Q_{max}	p
2017-01-01	300	0.1	250	0.4	150	0.4	0	0	0	0
2017-02-01	300	0.1	250	0.4	150	0.4	0	0	150	0
2017-08-01	300	0.1	250	0.4	150	0.4	0	0	150	0
2017-09-01	370	0.1	300	0.4	150	0.4	140	0	150	0
2040-01-01	370	0.1	300	0.4	150	0.4	140	0	150	0

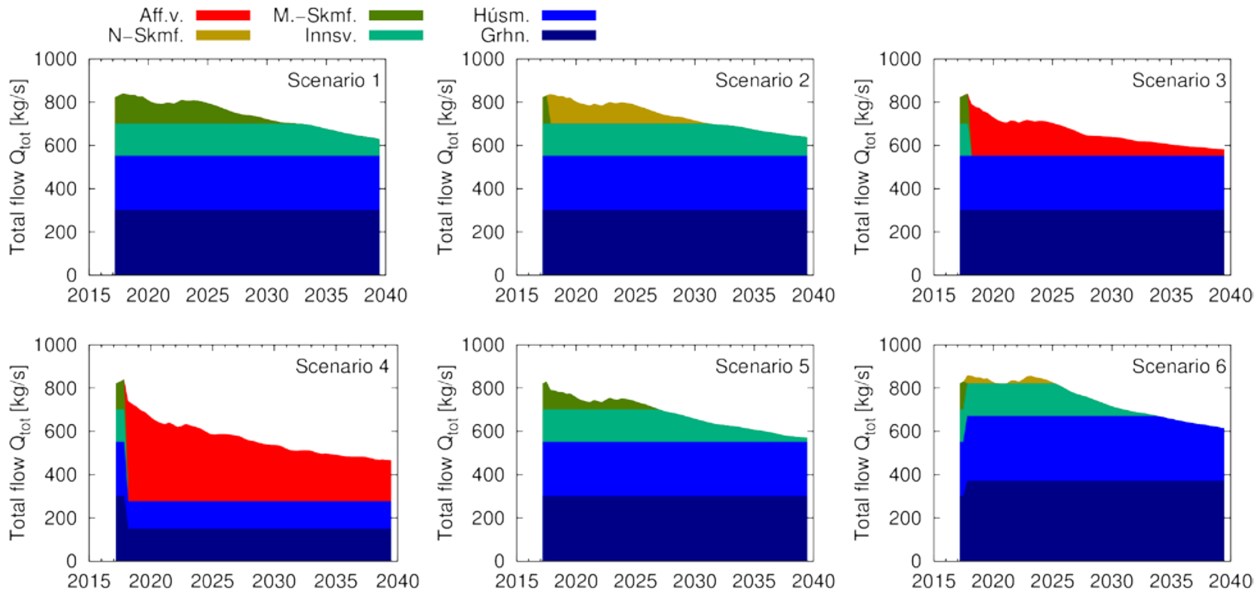

Figure 8: Total flow of injected water for different injection scenarios. In two cases (no. 3 and 4) part of the waste water is disposed of outside the geothermal reservoir (Aff.v.)

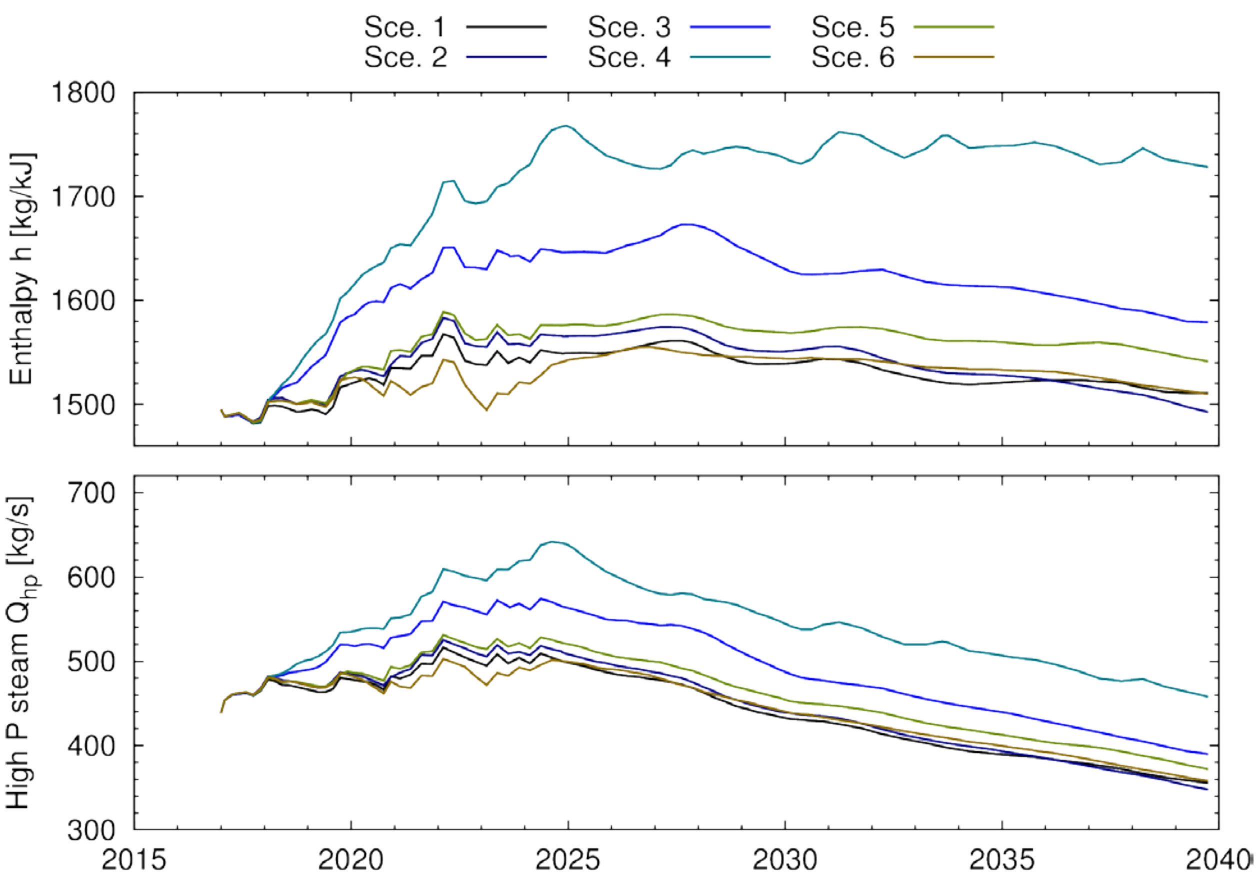

Figure 9: Enthalpy (h) of produced fluid for different injection scenarios and resulting flow of high pressure steam (Q_{hp}).

boiling and thus, decreases the enthalpy (Gunnarsson and Mortensen 2016). Decreasing the amount of injected water further as in scenario 4 increases the enthalpy further (see Fig.8 and 9).

For the electricity generation, it is tempting to dispose of a considerable amount of the separated water outside the reservoir. There are however two issues that need be considered before that decision is made. Firstly, the cost of either pumping that water toward the ocean or into groundwater layers. A potential buyer of waste water – for instance industry that could use warm water – could make that option feasible. Secondly, is that the separated water is needed for producing hot water in the district heating utility of the power plant. The market for hot water is steadily growing and one has to take that into account when planning the field management.

4. Summary and Conclusion

The Hellisheiði Geothermal Field was developed at a very fast pace. The power plant was commissioned in few steps from 2006-2011. Due to this fast pace, all decisions on the size of the project were taken before data from new wells became available. Thus, it was impossible to adapt the project to the reality that emerged when down-hole data and production history data became available. That reality is that the temperature anomaly in Hellisheiði is smaller and distributed differently than previous conceptual models assumed. Therefor the power plant is too big for the original production field.

This problem has partly been solved by connecting the neighboring Hverahlíð Field to the Hellisheiði Power Plant. By that means, it was possible to maintain the production capacity of the power plant and ensure the future practical feasibility of the project. However, it will still be a challenge to maintain the production capacity of the combined Hellisheiði-Hverahlíð Field. For that purpose make-up wells have to be drilled. The production density of the original drilling field is very high, but in Hverahlíð it is still relatively low. Thus, the drilling of make-up wells will focus mainly on the Hverahlíð field. However, the edges of the system, where they are not completely known, will also be probed by drilling into them.

Numerical modelling has been used to estimate the production properties of the geothermal field. A 3D numerical model using the TOUGH2/iTOUGH2 software has been calibrated using field data and production history matching. That model has then been used to estimate the decline in the field production capacity and to estimate different production scenarios. If no make-up wells are to be drilled the production capacity would, according to the model, drop approximately 10 MW annually. Direct power estimates on production wells have given similar values on the decline of production capacity. A plan for drilling make-up wells was drawn based on these estimates. According to this plan 15 make-up wells have to be drilled over the next 10 years to maintain the production capacity. Further model simulations have confirmed that this plan is sufficient to maintain the production capacity of the field. For estimating the cost and risk of the drilling plan two more drilling plans were drawn; one pessimistic where 32 wells have to be drilled to maintain the production capacity and one optimistic where only 6 wells are needed. The cost of all these plans was estimated and the return on asset (ROA) or profitability calculated. The result is that all the drilling plans, even the pessimistic one, are more profitable that not drilling make-up wells and letting the production capacity decline.

The main uncertainties in these estimates are the predicted enthalpies and the drilling operations. The risk of the drilling operations is included by drawing up these three different drilling plans (the most likely one, the pessimistic and the optimistic one). More work is however needed to estimate the uncertainty of the calculated enthalpy of produced fluid. The enthalpy is very dependent on the arrangement of the reinjection. Simulations of different reinjection scenarios have shown significant differences in the calculated enthalpy. It has also been observed in the operation of the power plant that injection affects the enthalpy in the vicinity of the injection wells. These effects are dependent on the enthalpy of the wells. Low enthalpy wells benefit from the higher pressure caused by reinjection. For medium and high enthalpy wells higher pressure can be harmful because it can slow down boiling in the vicinity of the wells where the formation temperature is at boiling point curve. That will cause the decreasing enthalpy and thus, decreasing steam flow.

The arrangement of reinjection is currently being reviewed. The numerical model will play a key role in analyzing different injection scenarios and supporting decisions on field development. The question is how much to reinject and where. After the geologically most feasible option have been mapped their practical (fiscal) feasibility also have to be estimated.

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