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Success of High Temperature Geothermal Wells in Iceland

Björn Már Sveinbjörnsson

Prepared for Orkustofnun

ÍSOR-2014/053

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Abstract

This report presents data on 213 geothermal production wells and 21 injection wells drilled in seven high temperature fields in Iceland. The data was classified using the same criteria as in the International Finance Corporation (IFC) 2013 Report on the success of geothermal wells from 14 countries. A production well was deemed successful when it had sufficient capacity to be connected and utilized in the respective power plant. Injection wells that have shown a good injectivity or have been used for reinjection were deemed to be successful. Of the 213 production wells analyzed, 158 or 74% were deemed to be successful. None of the fields has a success rate below 50%. About 6% of the total wells failed because of drilling problems, 4% found inadequate temperatures, 10% could not be operated at high enough static pressure, 3% had too low permeability and 3% were so shallow that they did not reach the reservoir. The average success rate improves from 43% for the first well to 60% for the first five wells and reaches a plateau of 74% after well number 15. The first 5 wells drilled in a field are classified as Exploration Phase, the next 25 as Development Phase and wells drilled thereafter as Operation Phase. The Exploration Phase has the most variable well success rates, which has though improved in recent decades. The probability of successful wells in the Development Phase is nearly 80%. It increases until the year 2000 but declines after that. The same trend is observed for wells drilled during the Operation Phase. The reduction in the success rate may reflect step-out wells or rapid development where adequate results did not arrive in time to impact the drilling plan. The average capacity of all 213 drilled production wells is 4.9 MW_e but 6.7 MW_e for the 158 productive wells. The capacity has a lognormal distribution with a mean and most likely value of 4.8 MW_e and a standard deviation of 2.3 MW_e. The cumulative average capacity increases from 2.5 to 4.8 MW_e during the Development Phase, and reaches 4.9 MW_e during the Operation Phase. The five main operating geothermal power plants in Iceland have a ratio of installed capacity divided by number of drilled production wells ranging from 1.3 to 5.3 MW_e/well and a weighted average of 3.5 MW_e/well. Wells of 2,000–2,500 m drilled depth have the highest average capacity of 5.8 MW_e followed by wells of 1,500-2,000 m with an average capacity of 5.5 MW_e. Wells with a regular production casing diameter of 200–250 mm have an average capacity of 5.5 MW_e whereas wells with a large casing diameter of 300–350 mm have a capacity of 8.9 MW_e. The average capacity of directionally drilled wells is 6.1 MW_e compared to 4.0 MW_e in vertical wells. There is a clear increase in capacity with increased enthalpy. Wells drilled into steam caps above two-phase reservoirs at 230–240°C have the highest capacity of 11.0 MW_e and a 100% success rate. Wells in two phase reservoirs with T>300°C are with an average of 6.2 MW_e and 86% success rate.

Key words	ISBN-number
High temperature wells, success rate, well capacity, lognormal distribution, vertical and directional wells, casing size	
	Project manager's signature
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Ágrip

Í þessari skýrslu er fjallað um 213 vinnsluholur og 21 niðurdælingarholu á sjö háhitasvæðum hér á landi. Gögnin voru valin og flokkuð á sama hátt og í skýrslu International Finance Corporation (IFC, 2013) þar sem fjallað var um háhitaholur í 14 löndum. Gögnin byggjast á Borholuskrá Orkustofnunar og skýrslum sem aðgengilegar voru um árangur og afl borholna. Hliðsjón var höfð af eldri úttekt Orkustofnunar frá árinu 1992 á borárangri víða um heim, þ.m.t. á sex íslenskum háhitasvæðum.

Til þess að tryggja að gögnin í skýrslunni væru sambærileg við gögnin í skýrslu IFC voru þau valin og flokkuð á sama hátt þar. Borhola var talin hafa borið árangur ef hún skilaði nægilegu afli til að vera tengd og notuð af rafstöð á staðnum. Öll háhitasvæði á Íslandi eru innan eða nærri virkum gosbeltum og í berglögum frá nútíma eða kvartertíma í jarðfræði. Jarðhitageymar háhitasvæðanna eru því í nýlegu gosbergi sem flokkað er í „Geology Code 3“ í IFC-skýrslunni. Lekt bergsins er yfirleitt lítil en sprungur, berggangar og innskot bæta oft lektina.

Af 213 vinnsluholum sem fjallað var um eru 158, eða 74%, taldar hafa borið árangur. Ekkert háhitasvæðanna var undir 50% í borárangri. Um 6% af heildinni bar ekki árangur vegna vandamála í borun, 4% vegna lágs berghita, 10% vegna lágs toppþrýstings, 3% vegna lélegrar lektar og 3% vegna þess að holurnar náðu ekki niður í jarðhitageyminn. Hlutfall árangurs jókst frá 43% í fyrstu borholu í 60% í fyrstu 5 holunum og varð stöðugt um 74% eftir 15 holur á svæðum.

Borárangur í niðurdælingarholum var svipaður og í vinnsluholum en ekki er fjallað nánar um þær í þessari skýrslu.

Við þessa greiningu voru fyrstu 5 holur á hverju svæði taldar tilheyra könnunaráfanga, næstu 25 þróunaráfanga og borholur umfram það rekstraráfanga svæðisins. Könnunaráfanginn hefur mestan breytileika í árangri og það veldur erfiðleikum í spám um árangur. Þegar komið er í þróunaráfanga verða líkur á árangri allt að 80%. Hlutfall árangurs innan þessa áfanga virðist vaxa fram til ársins 2000 en minnka eftir það. Svipuð þróun í árangri með tíma virðist vera í borholum innan rekstraráfangans. Skýring á því gæti falist í könnunarholum á jöðrum svæðanna eða ófullnægjandi úrvinnslu á niðurstöðum fyrri borunar þegar stutt líður á milli borunar holna.

Meðalafl í öllum 213 boruðum vinnsluholum í gagnasafninu er 4,9 MW_e en 6,7 MW_e í þeim 158 holum sem skiluðu árangri. Mesta afl í borholu í safninu er 35 MW_e. Dreifing gilda á afli er “log-normal” með miðgildi og líklegasta gildi 4,8 MW_e og staðalfráviki 2,3 MW_e. Uppsafnað meðalafl allra háhitasvæða í gagnasafninu vex frá 2,5 MW_e í 4,8 MW_e innan þróunaráfangans og hækkar enn upp að 4,9 MW_e innan rekstraráfangans. Í fimm helstu jarðhitarafstöðvum hér á landi er hlutfall uppsetts afls og fjölda boraðra vinnsluholna á bilinu 1,3–5,3 MW_e/holu og að meðaltali 3,5 MW_e/holu. Borholur með boraða lengd 2000–2500 m hafa mest meðalafl 5,8 MW_e. Næstar þeim koma holur með boraða lengd 1500–2000 m og meðalafl 5,5 MW_e. Hlutfall árangurs er hæst fyrir þessar lengdir, 83%. Það er markverður munur á borholum með þvermál vinnslufóðringar 200–250 mm og meðalafl 5,5 MW_e og borholum með 300–350 mm þvermál og meðalafl 8,9 MW_e. Hlutfall árangurs er svipað í lóðréttum holum og stefnuboruðum, hallandi holum. Meðalafl í lóðréttum holum er hins vegar 4,0 MW_e borið saman við 6,1 MW_e í stefnuboruðum holum.

Það er greinileg aukning í afli með hækkandi vermi jarðhitageymis. Borholur, sem boraðar eru í gufupúða ofan við tvífasa geymi með 230–240°C hita, eru með mesta aflið um 11,0 MW_e og 100% árangur. Borholur í tvífasa geyma með hita yfir 300°C koma næstar með meðalafl 6,2 MW_e og 86% árangur.

Niðurstöður greiningar á íslenskum háhitaholum eru í flestu tilliti svipaðar þeim sem fengust við greiningu á stærra gagnasafni í IFC-skýrslunni. Markverð frávik eru þó í áhrifum stærra þvermáls vinnslufóðringar sem gefur 60% meira afl í íslenskum holum, og í vaxandi afli í holum eftir því sem fleiri eru boraðar á viðkomandi svæði. Borholur með boraða lengd 1500–2500 m skila meira afli en grynnri eða dýpri holur. Hér eru lóðréttar og stefnuboraðar holur með mismunandi víddir fóðringa bornar saman en í IFC-skýrslunni var aðeins litið til mismunandi vídda.

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1 Introduction

In June 2013 the International Finance Corporation (IFC) of the World Bank Group published the report *Success of Geothermal Wells: A Global Study* (IFC, 2013). The report analyzed data of 2,613 wells from 57 geothermal fields in 14 countries, with a total generating capacity of 7,575 MW_e, which at that time was estimated to be about 71 percent of global installed geothermal power capacity. No data on geothermal wells in Iceland were included in this report.

Orkustofnun (the National Energy Authority of Iceland) maintains a database covering all drilled wells in Iceland. It was considered desirable to contribute a selection from this database of high temperature wells drilled with the aim of electric generation in Iceland. In addition to the standard documentation in the database, data on success and capacity of wells were collected from available reports. Reference was also taken of a former analysis of Orkustofnun of success and learning curves in 30 geothermal fields worldwide, including data from six Icelandic fields up to 1990.

This report presents data on 213 high temperature production wells and 21 injection wells drilled in seven geothermal fields in Iceland. These wells serve six geothermal power plants with an aggregate installed capacity of 661 MW_e. Two further plants of 45 MW_e and 90 MW_e are in preparation.

To make the data in this report comparable to that in the IFC 2013 Report it was decided to apply the same criteria as in that report. All high temperature geothermal fields in Iceland are located within or near to the active volcanic zones and dominated by postglacial and quaternary formations. The geology type for all the fields thus corresponds to younger volcanic/volcanoclastic reservoir rocks classified as Geology Code 3 in the IFC Report. The primary formation permeability is generally low but favorable secondary permeability is found in fractures, dikes and at intrusion contacts.

A well was deemed to have been successful when it had a capacity to be connected and utilized in the respective power plant. Of the 213 production wells analyzed, 158 or 74% were deemed to be successful. None of the seven fields has a success rate below 50%. About 6% of the total wells failed because of drilling problems, 4% found inadequate temperatures, 10% could not be operated at high enough static pressure, 3% had too low permeability and 3% were so shallow that they did not reach the reservoir.

The success rate improves from 43% of the first well drilled, to 60% over the first five wells and reaches a plateau of 74% after well number 15.

The success rate for injection wells was similar to that of production wells but the following analysis is limited to production wells.

For the purposes of this study, the first five wells drilled in a field are deemed to belong to an Exploration Phase, the next 25 to a Development Phase and wells drilled thereafter to an Operation Phase. The Exploration Phase has the most variable success rates, making forecasting of likely success difficult. The success rate for this phase has though improved in recent decades. Once a project enters the Development Phase the probability of successful wells being achieved is nearly 80%. Success rates in that phase appear to increase until the year 2000 but decline after that. The same trend is observed for wells drilled during the Operation Phase. This reduction in the success rate for wells drilled during the Development Phase and the Operation Phase may reflect step-out wells or rapid development where adequate results did not arrive in time to impact the plan of drilling.

The average capacity of all 213 drilled production wells in the dataset is 4.9 MW_e but 6.7 MW_e for the 158 productive wells. The maximum capacity of a single well in the dataset is 35 MW_e. The capacity has a lognormal distribution with a mean and most likely value of 4.8 MW_e and a standard deviation of 2.3 MW_e.

The cumulative average capacity across all fields in the dataset increases from 2.5 MW_e to 4.8 MW_e during the Development Phase, and continues rising up to 4.9 MW_e during the Operation Phase. The five main operating power plants in Iceland have a ratio of installed capacity divided by the respective number of drilled production wells ranging from 1.3 to 5.3 MW_e/well and a weighted average of 3.5 MW_e/well.

Wells of 2,000–2,500 m drilled depth have the highest average capacity of 5.8 MW_e, followed by wells of 1,500–2,000 m with an average capacity of 5.5 MW_e. The success rate is highest, 83%, for these ranges. There is a significant difference between wells with a production casing diameter of 200–250 mm having an average capacity of 5.5 MW_e and a casing of 300–350 mm with an average capacity of 8.9 MW_e. The success rate in vertical wells was similar to that in directionally drilled wells, but the average capacity of directionally drilled wells is 6.1 MW_e compared to 4.0 MW_e in vertical wells.

There is a clear increase in capacity with increased enthalpy (higher steam/water ratio). Wells in one field drilled into a steam cap above two-phase reservoirs at 230–240°C have the highest capacity of 11.0 MW_e and a 100% success rate. Wells in two-phase reservoirs with temperatures higher than 300°C are next with an average capacity of 6.2 MW_e and a success rate of 86%.

The results of the output analysis of wells drilled in Iceland are in most aspects similar to those obtained for the larger dataset in the IFC Report. Significant deviations are, however, found in the impact of a larger casing diameter, yielding 60% higher capacity in Iceland, and in the increased capacity as more wells are drilled in a field. Wells with a drilled depth of 1,500–2,500 m yield higher capacity than shallower and deeper wells.

Our analysis compared vertically and directionally drilled wells of various casing sizes but that was not done in the IFC Report.

2 Overview

2.1 Project background

In June 2013 the International Finance Corporation (IFC) of the World Bank Group published the report *Success of Geothermal Wells: A Global Study* (IFC, 2013). The report was compiled for IFC by GeothermEx, Inc. in partnership with the Government of Japan and the Global Environment Facility (GEF). The dataset on which the report is based covers 2,613 wells throughout 57 fields in 14 countries. These fields together have a total capacity of 7,575 MW_e which at that time was estimated to be about 71 percent of global installed geothermal power capacity. No data on geothermal wells in Iceland were included in this report.

Orkustofnun (the National Energy Authority of Iceland) maintains a database covering all drilled wells in Iceland. The database contains information on over 1,200 geothermal wells drilled in Iceland since 1928. About 900 wells were drilled to recover low enthalpy water for space heating but over 300 wells were drilled in high temperature geothermal fields to obtain steam for electric generation, co-generation of heat for space heating and electricity, and industrial uses. Orkustofnun considered it desirable to contribute a selection from this database of high temperature wells drilled with the aim of electric generation in Iceland. In addition to the standard documentation in the database, data on success and capacity of wells were collected from available reports. To make the data comparable to that in the IFC 2013 Report it was decided to apply the same criteria as in that report.

Stefánsson (1992), discussed success in geothermal development based on the drilling history in 30 geothermal fields worldwide. His analysis included data on wells drilled in several high temperature fields in Iceland up to the year 1990.

This report presents data up to the year 2014 on 213 high temperature production wells and 21 injection wells drilled in seven fields. These wells serve six geothermal power plants with an aggregate installed capacity of 661MW_e, and two further plants of 45 MW_e and 90 MW_e that are in preparation. Table 1 shows installed capacity of power plants in six fields and planned development in two of the seven fields analyzed in this report.

Table 1. *Installed and planned capacity of power plants in Iceland.*

Field	Power	
	Installed (MW_E)	Planned (MW_E)
Bjarnarflag	3.2	45
Hellisheiði	303	
Krafla	60	
Nesjavellir	120	
Reykjanes	100	
Svartsengi	74.4	
Theistareykir		90
Sum	**660.6**	**135**

2.2 Aims of the IFC Report and this report

The core objective of the IFC Report was to develop a sufficiently large dataset to allow statistically significant conclusions to be drawn on the success rates of geothermal wells worldwide (expressed as the number of successful wells developed as a proportion of total wells drilled in any given field). The report determined and analyzed that overall success rate, as well as those factors that potentially affect success – including geology, resource enthalpy, and well depth. It sought to assess the extent of any improvements in well success rates, and how far the likelihood of success increases as developers learn more about any specific resource. Since the success of a well is usually determined by its power capacity (MW_e), the report also analyzed the power capacity of geothermal wells drilled and the factors affecting such capacity.

The present report has the same objective as the IFC Report, and uses the same criteria to evaluate the success.

2.3 Exploration, development, and operation wells

For the purposes of comparing the success of wells in different fields, it is necessary to divide the drilling program into three development phases. The first several wells drilled in a field are usually to confirm the existence and potential of a reservoir. Then, sufficient numbers of wells are drilled to prove enough steam and to reach the desired or optimal power output of the field. Once sufficient wells are drilled and the power plant is operational, subsequent wells are drilled in order to replace those old wells whose output has diminished. These phases of drilling can be described respectively as Exploration, Development, and Operation.

For the purposes of this study, the first five production wells drilled in a field are classified as exploration wells, the next 25 as development wells, and wells drilled thereafter operational wells. The actual number of development wells in a field will vary significantly, depending on the characteristics of the reservoir, the size of the planned power plant, and the success rate in drilling.

2.4 Defining well success

For those wells for which capacity was either available or estimated, a well was deemed successful when it had a capacity to be connected and utilized in the respective power plant. The threshold of the power plant varies between fields and depends on the steam line pressure, and the operating pressure of separators. Injection wells that have shown good injectivity or have been used for reinjection were deemed to be successful.

A geothermal well may be deemed unsuccessful for one or more reasons (IFC, 2013), for example if:

(a) unexpected mechanical problems are encountered during drilling, and the well is partly filled or bridged by drill cutting and/or casing collapse;

(b) it has an inadequate temperature;

(c) it has too low a reservoir pressure;

(d) it encounters a reservoir that is too "tight" (i.e., the Productivity Index (PI) is low); or

(e) it has unacceptable chemical problems (such as gassy, corrosive, or scaling-prone fluids).

Category (e) does not apply for Icelandic reservoirs. Acid steam has occurred in one of the fields but the chemical problems are not considered to prohibit exploitation of wells. On the other hand we have added the category "Does not reach the reservoir". This applies especially to exploration wells which are often shallow.

The success rate for the total of the dataset is defined as the number of successful production and injection wells in proportion of the total number of wells drilled. The success rate within a field is calculated on the basis of production wells alone. The same applies to phases of projects.

2.5 Difficulties encountered

A number of difficulties were encountered in the preparation of the IFC Report. The same difficulties were met in preparing this report.

1. There is no universal basis for defining the success of a geothermal well.
2. A well's power capacity is derived from the measured production rate and enthalpy ("heat content") of the produced fluid for a given power conversion scheme. Therefore, the power capacity discussed in this report is based on a calculated gross electrical power output, in the unit "MW_e". It should also be noted that the capacity of a well may change over time. The capacities cited in this report are generally based on the most recent data on production rate and enthalpy as these are considered more reliable than data on initial discharge which is often obtained shortly after completion and before the well may have fully recovered after drilling.
3. In the seven fields of the dataset, the number of wells varies from 10 to 74. Defining the first five wells as exploration wells and the next 25 as development wells, only three of the fields reach the number of wells to be defined as operational wells. This suggests that the dataset is weighted towards wells belonging to the Development Phase.
4. The oldest well in this set of data is from the year 1956 but the dataset contains all high-temperature wells drilled since 1960. Some of the techniques used in the surveying and drilling of older wells may now be antiquated, with the result that the analysis reflects historical data and not, necessarily, current trends. The development of new surveying techniques, the adoption of directional drilling, and improvements in drilling techniques may have boosted average well success and capacity. This report attempts to analyze this effect by examining well success by decade in section 4.5.

3 Overview of the Dataset

The dataset on which this report is based covers 213 production wells and 21 injection wells in seven fields in Iceland. Nine wells have been redrilled. They are counted as new wells. The production wells in these fields together have an aggregate capacity of 1,051.9 MW_e.

To the extent verifiable data are available, the assembled dataset includes the following parameters for each well:

(a) Well Code;

(b) Geology Code;

(c) Resource Code;

(d) Completion date;

(e) Initial and current status of the well;

(f) Gross power capacity (MW_e)

(g) Total depth;

(h) Production casing outer diameter;

(i) Whether a well was successful;

(j) Whether a well has been re-drilled.

3.1 Wells and fields

In order to preserve confidential data, each well cited in this report has been assigned a three-digit "Well Code," constructed as follows: an initial digit X denoting the country Iceland in which the well is located; a second digit representing the geothermal field; and a third digit representing the well number within that field. A sample code would thus appear as "X.2.5." The well number refers to the completion date. Table 2 presents the number of production- and injection wells in the seven fields analyzed in this report.

The total number is 234 and divides into 35 wells belonging to the Exploration Phase, 137 to the Development Phase and 62 in the Operation Phase.

Table 2. *Breakdown of number of wells analyzed.*

Field	Project Phases						Total
	Exploration		Development		Operation		
	Production	Injection	Production	Injection	Production	Injection	
1	5	0	25	0	5	2	**37**
2	5	0	17	2	0	0	**24**
3	5	0	23	0	0	0	**28**
4	5	0	25	5	27	12	**74**
5	5	0	10	0	0	0	**15**
6	5	0	25	0	16	0	**46**
7	5	0	5	0	0	0	**10**
Sum	**35**	**0**	**130**	**7**	**48**	**14**	**234**

3.2 Geology Code

The Geology Code as cited in the IFC Report (and the categorizations below) refers to rock type rather than geologic structure and might, arguably, be better described as a "lithology code". Table 3 shows the following categorizations denoted for the under-lying reservoir rock.

Table 3. *Definition of the IFC Geology Code.*

Geology Code	Definition
1	granitic/higher-grade metamorphic
2	tertiary and older volcanic/volcanoclastic (large-scale volcanic structures absent)
3	younger volcanic/volcanoclastic (large-scale volcanic structures (volcanoes, calderas) preserved)
4	sedimentary basin (clastic, drilled above basement)
5	sedimentary basin (clastic, drilled into basement)

These geologic categories reflect generic hydraulic rather than chemical or mineralogical properties. The reason for emphasizing hydraulic properties rather than the mineralogy of a geologic category is that the productivity of a well is predominantly a function of the following parameters:

(a) the hydraulic properties of the reservoir;
(b) the diameter and skin factor (an index of well-bore flow efficiency) of the well; and
(c) the enthalpy of the produced fluid.

In Iceland nearly all wells are drilled into younger volcanic/volcanoclastic rocks, i.e. category 3.

A well's hydraulic properties are therefore primarily dependent on the porosity and permeability of the reservoir; in particular, the presence of fissures in the rock (caused by stresses) will dramatically increase its permeability. In Iceland the matrix formation permeability is generally low but favorable secondary permeability is found in fractures, dikes and at intrusion contacts. Seismic activity aids fracturing the rock and maintaining fracture permeability.

3.3 Resource Code

Each production well cited in this report has been allocated a "Resource Code," ranging from one to seven, as shown in Table 4, indicating the approximate enthalpy of the fluid produced from the well. This code follows the classification scheme for geothermal reservoirs proposed by Sanyal (2005).

Table 4. *Definition of the IFC Resource Code.*

Resource Code	Definition	Temperature (°C)	Number of Production Wells
1	non-electrical grade	< 100°C	2
2	very low temperature	100°C ≤ 150°C	4
3	low temperature	150°C ≤ 190°C	1
4	moderate temperature	190°C ≤ 230°C	13
5	high temperature	230°C ≤ 300°C	125
6	ultra-high temperature	300°C+	62
7	steam field	230°C – 240°C	6

The Resource Code is useful in checking the correlation between the enthalpy and the capacity of a well and, therefore, the success rate of drilling. The Resource Code reflects the reservoir fluid enthalpy.

3.4 Completion date

The completion date of a well is the date on which all drilling activities are completed.

3.5 Well status

The dataset refers to both the initial and current status of all wells, in order to give an indication of the state of the well immediately after completion of drilling, and its most recent state. A definition of each of the statuses used in the dataset is given in Table 5.

Table 5. *Well status – Definitions as per the IFC Report criteria.*

Well Status	Definition
Abandoned/plugged	Well is closed with a concrete plug, not to be opened
Blow-out	Steam pressure is too high and may not be controllable: well may be shut-in
Discovery well/exploration	Early-stage well used to prove existence and size of geothermal reservoir
Dry hole	No fluid in the well, usually due to low permeability of the reservoir
Gradient	Slim-bore hole used to measure changes in temperature with depth
Idle	Well currently surplus to requirements and closed (although can be reopened if necessary)
Injector	Used to re-inject geothermal fluids into reservoir
Marginal	Low permeability of reservoir or high skin factor of bore make the well of low value
Marginal producer	Low productivity but still used to generate power
Monitoring well/observation	Well used to monitor reservoir conditions: not suitable for production or injection
Never produced	Not economically useful
Non-commercial	Purpose of drilling was not for commercial reasons, may be exploratory
Not productive	Not economically useful
Not tested	Unknown status
Production	Well used to generate power
Re-drilled	Well has been partially re-drilled due to low initial productivity
Replaced	Closed and re-drilled elsewhere, usually due to reduced output of original well
Shut-in	Well is closed to prevent blow-out or unrequired discharge
Stand-by injector	Well not needed, but can be used as injector if required
Suspended/not completed	Well not completed, due to mechanical problems while drilling
Unknown	Status cannot be determined from available data

3.6 Well capacity

Where cited in this report, the capacity of a well represents its gross electrical power capacity (MW_e). In most cases such data are based on the most recent available flow test of the well but for a number of cases the initial capacity is shown. Generally the wells retain their output performance well over the medium term and thus this is not expected to skew the data.

3.7 Well depth

"Well depth" refers to the measured depth (MD) or the length of the wellbore from the ground surface (actually from the drilling platform 3–8 m above ground) to the bottom. The true vertical depth (TVD) is less for directionally drilled wells. Most fields have a range of well depths (as shown in Figure 1) suggesting that most fields have multiple feeders, at different depths. The shortest wells, less than 350 m, are generally exploration wells that did not reach the production reservoir. The average drilled depth for all wells is 1,844 m.

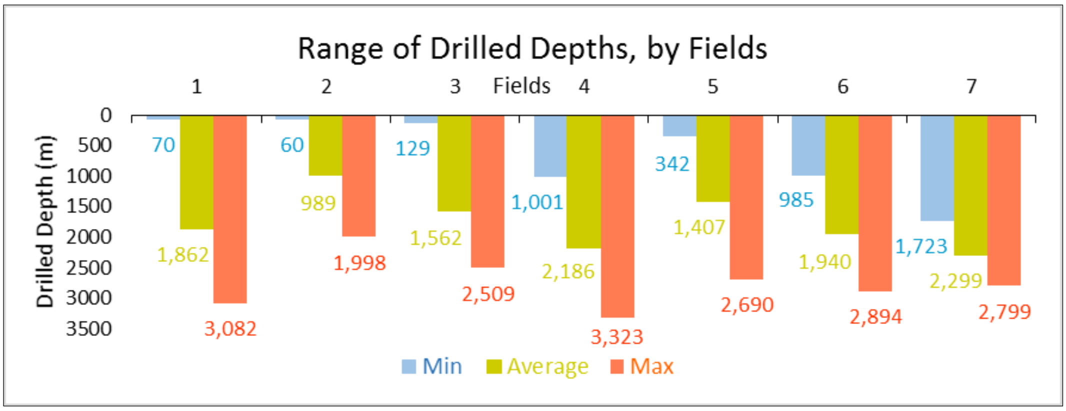

Figure 1. *Average and range of all well depths (MD), by field.*

Figure 2 illustrates the relative frequency of production well depths in accordance with project phase (Exploration, Development and Operation).

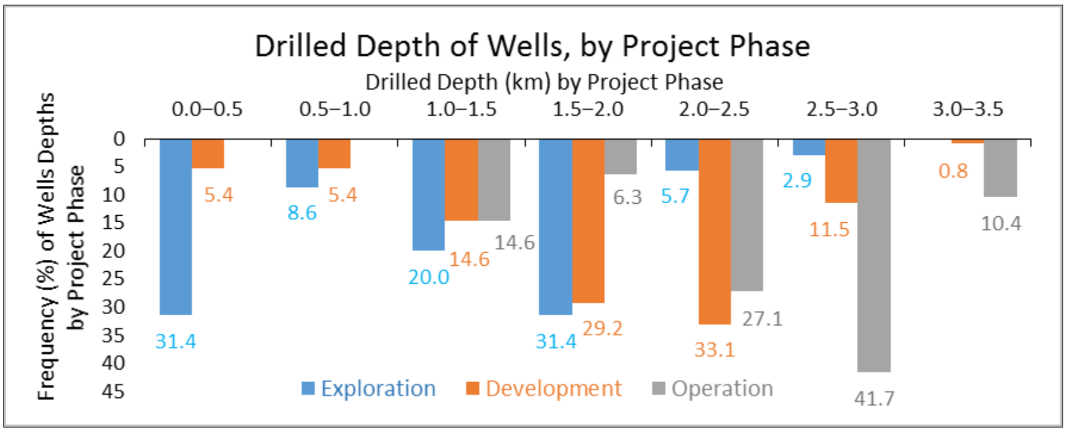

Figure 2. *Prevalence of well depths, by project phase.*

Figure 2 demonstrates that 1/3 of the exploration wells is shallow but half of the exploration wells is drilled to a depth of 1–2 km. Development wells increase in number with depth up to 2.5 km but few are deeper than that. Operational wells are preferably drilled deep, 27% to a depth of 2.0–2.5 km and 42% to a depth of 2.5–3.0 km. This indicates that developers move to exploiting deeper reservoirs in the same field as a project becomes more advanced and new rigs with greater depth capacity become available.

3.8 Casing size

Casing size in the dataset reflects the outer diameter of the production casing which is the casing string that transports the fluid to surface. This is usually measured in inches, but also in millimeters. For the dataset the diameters were converted from inches (") to millimeters (mm). The most common sizes for production casings in geothermal wells are 9⅝" or 244.5 mm and 13⅜" or 339.7 mm. The depth of the casing is shown in meters (MD).

3.9 Well success

All wells were categorized accordingly:

(a) ”N” denotes an unsuccessful well;
(b) “Y” denotes a successful well.

The criteria used for the definition of a successful well are outlined in more detail in section 2.4.

4 Presentation and Analysis of Results

4.1 Success rate and problems of unsuccessful production wells

Overall, 158 production wells (74 percent of the total) are deemed to be successful. Nine redrilled wells are counted as new wells. Seven of them were successful. Figure 3 presents a histogram of the overall success rates of wells across the seven fields analyzed in the dataset. None of the fields has a success rate for production wells below 50%.

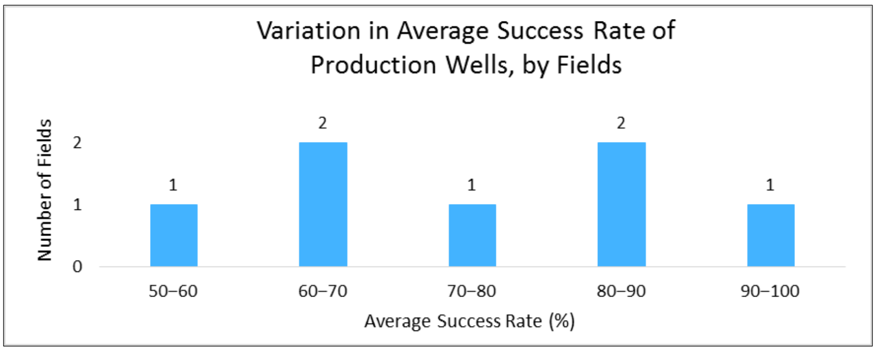

Figure 3. *Success rates of production wells across all fields.*

Reasons for deeming 55 of the 213 production wells unsuccessful are presented in figure 7 in accordance with the categories listed in chapter 2.4 above.

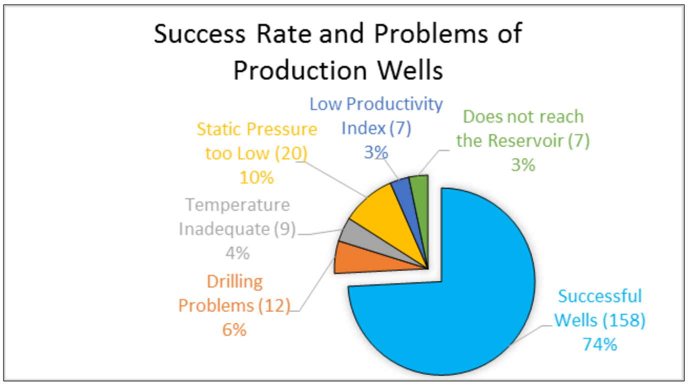

Figure 4. *Division of successful and unsuccessful production wells. Categorization of problems that prevented success.*

Figure 4 shows that 12 or 6% of the total wells failed because of drilling problems, 9 or 4% found inadequate temperatures, 20 or 10% could not be operated at high enough wellhead pressure, 7 or 3% had too low permeability and 7 or 3% were so shallow that they did not reach the reservoir.

4.2 Distribution of well capacity

Figure 5 presents a histogram of the gross capacities (MW_e) of the 158 productive wells. The figure shows that a wide range of well capacities is possible, though lower capacities are significantly more likely. The average capacity of all drilled production wells in the dataset is 4.9 MW_e whereas the average is 6.7 MW_e for the 158 productive wells. The distribution for productive wells is strongly skewed by the inclusion of several very high-capacity wells. The maximum capacity of a single well in the dataset is 35 MW_e. This well was a part of the Icelandic Deep Drilling Project (IDDP-1), drilled to reach supercritical temperatures. It hit molten lava at 2.1 km depth and produced during flow-testing superheated steam of about 380°C at the wellhead.

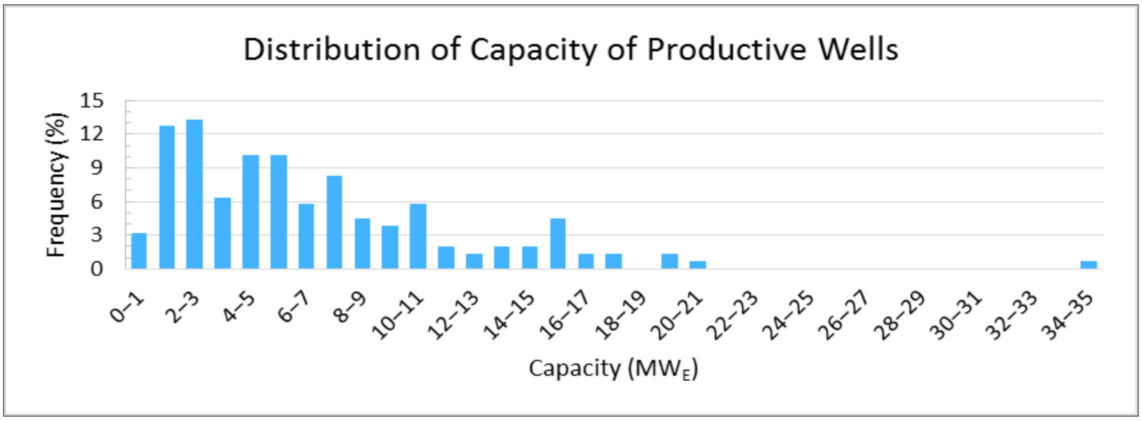

Figure 5. *Relative frequency of gross capacities of productive wells.*

Figure 6 shows the relative frequency of the logarithm of the well capacity (Q). The frequency distribution of the logarithm can be approximated by a normal distribution curve with a mean of $\log_{10}(Q) = 0.68$ and a Standard Deviation of $\log_{10}(Q) = 0.37$.

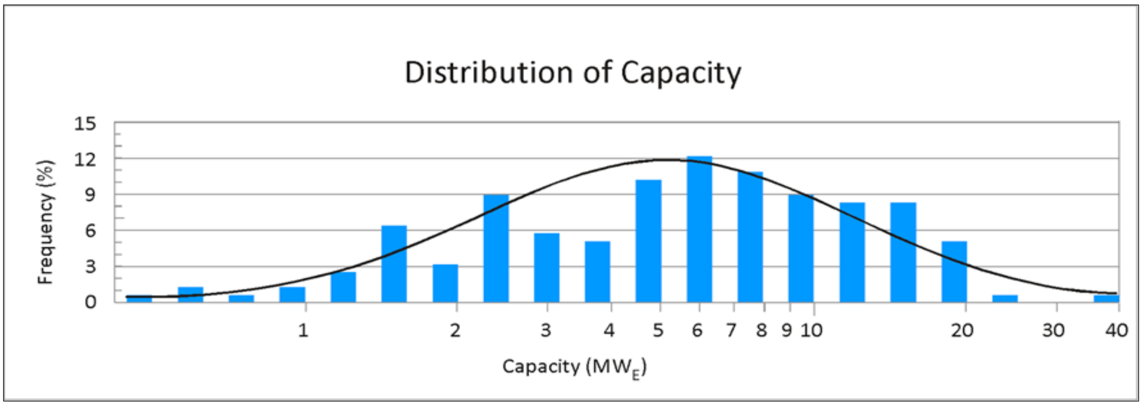

Figure 6. *Relative frequency of capacities of productive wells drawn on a logarithmic scale.*

The cumulative probability shown in Figure 7 denotes the probability that the well capacity (Q) is less or equal to the corresponding value. The mean (50%) corresponds to 4.8 MW_e, which is the most likely value for the well capacity while the average equals 6.7 MW_e. The standard deviation corresponds to 2.3 MW_e.

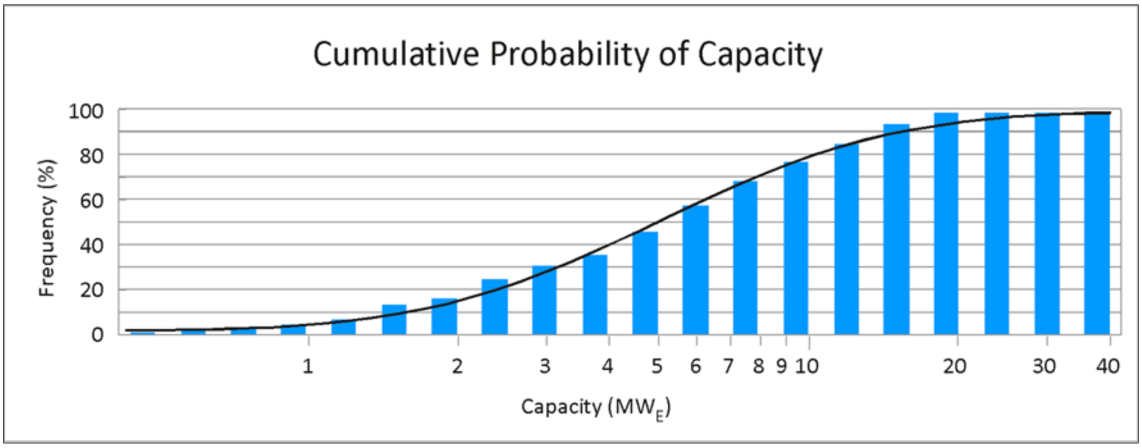

Figure 7. *Cumulative probability of the capacities of wells drawn on a logarithmic scale.*

The theoretical curve for cumulative probability fits excellently with the distribution of well capacities. The normal distribution curve also fits the data with some deficiency in the capacity values of 3–4 MW_e but excess in other values. The lognormal distribution of well capacity found here is in good agreement with the lognormal distribution of total mass flow, steam flow and Injectivity Index of geothermal wells in the Hengill Area in Iceland (Sveinbjörnsson and Þórhallsson, 2013).

In the IFC Report the distribution of well capacities was found to have the most frequent gross capacity of 3 MW_e/well with a positive skew on the distribution of 1.64. The average capacity of all productive wells in their dataset is 7.3 MW_e. We find that the capacities of wells in Iceland fit a lognormal distribution with a most likely value of 4.8 MW_e and an average capacity of 6.7 MW_e. In comparing these to datasets one must take into acount the impact of different geology and resource enthalpy as discussed below.

4.3 Learning curves

It is to be expected that the first wells drilled in a field are less likely to be successful than subsequent wells, as the developer gains a better understanding of the size, location, and dynamics of the targeted reservoir. Figure 8 shows the improvement in the cumulative average success rate of wells across all fields in the dataset.

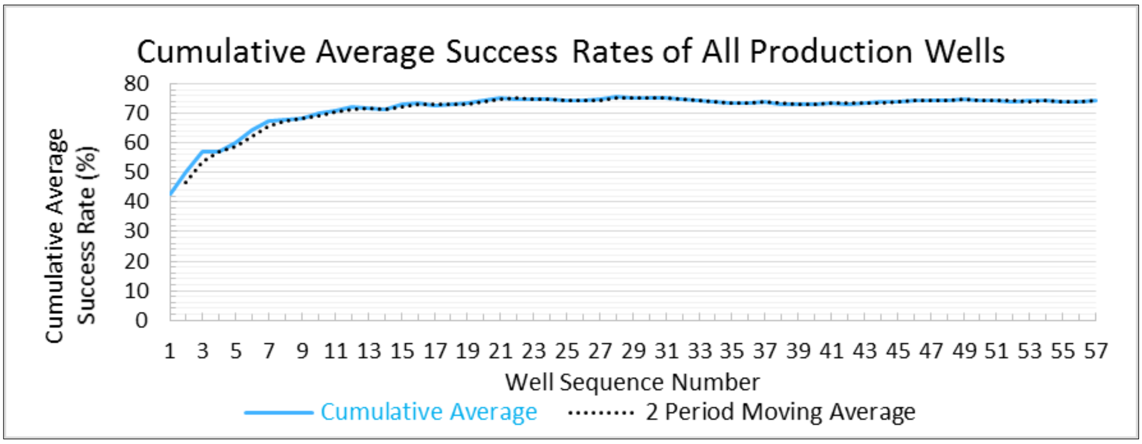

Figure 8. *Learning curve – Production well success rate. The solid line shows the cumulative average. The dotted line is a period moving average of pairs of data points. There is a good agreement between these two.*

The designation of wells as "Exploration", "Development", and "Operation" was discussed in section 2.3, above.

While the first well drilled shows an average success rate of 43%, the success rate averaged over the first five wells increases to 60%, rising to about 74% after well number 15.

Figure 9 shows how the success rate increases as a project moves from the Exploration Phase to the Development Phase where it nearly reaches 80% but does not increase further in the Operation Phase.

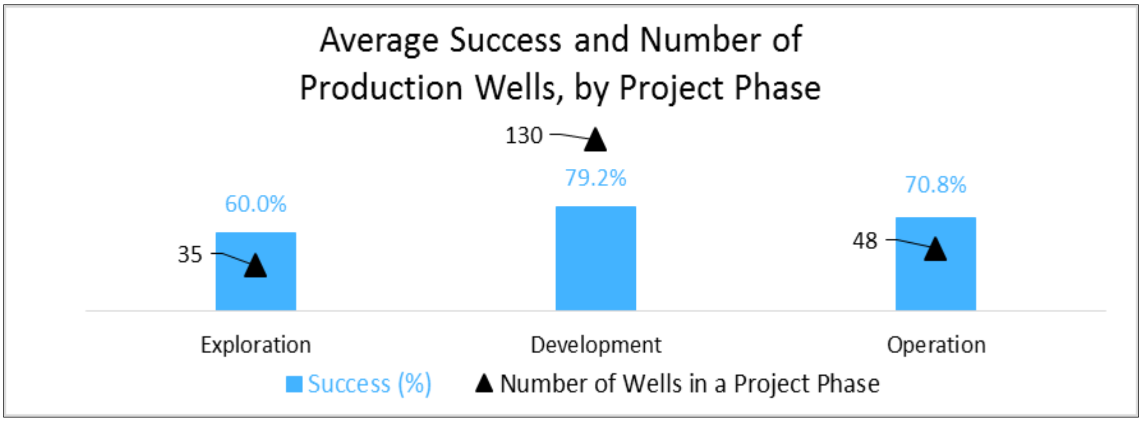

Figure 9. *Success rates of production wells, by project phase.*

Knowledge gained from early wells appears to lead to greater power capacities of new wells as field development progresses. Figure 10 shows the cumulative average capacity drawn after sequence number of wells drilled, averaged across all fields. The cumulative average capacity is the average capacity of all wells up to and including a particular well number. The average increases from 2.5 to 4.8 MW_e during the Development Phase, and continues rising up to 4.9 MW_e during the Operation Phase.

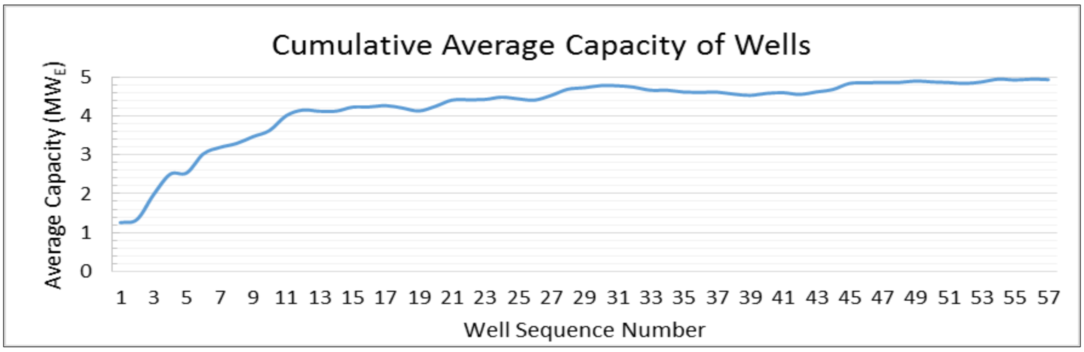

Figure 10. *Cumulative average capacity of production wells as a function of the well sequence number in all fields.*

These results are in good agreement with Stefánsson (1992), who presented learning curves for 30 geothermal fields worldwide, indicating the plateau of average well output and the number of wells drilled in each field before the average well output reached that plateau. Stefansson examined the ratio between installed capacity and the total number of production wells drilled in each field for 29 operating power plants. He found a ratio ranging between 0.3 and 4.8 MW_e/well with a weighted average of 1.9 MW_e/well. Excluding the field at Bjarnarflag where wells were drilled for other utilization than generation of electricity, we find that the five operating power plants in Iceland have a ratio ranging from 1.3 to 5.3 MW_e/well and a weighted average of 3.5 MW_e/well.

4.4 Variation in success, by project phase

An analysis of the variation in well success in each phase of field development (see Figure 11) shows that the Exploration Phase has the most variable success rates, making forecasting of likely success more difficult. The success rate lies in the range 10–20% for two fields, 50–60% for other two, 70–80% for still other two and 90–100% for one field. Once a project enters the Development Phase the probability of successful wells being achieved is above 70%. In this phase five fields with 103 wells have a weighted average of 76%, one field with 17 wells an average of 88% and one field with 10 wells a 100% success rate. In the three fields having a number of wells in the Operation Phase, success rates of 20% are obtained in 5 wells, 67% in 27 wells and 94% in 16 wells.

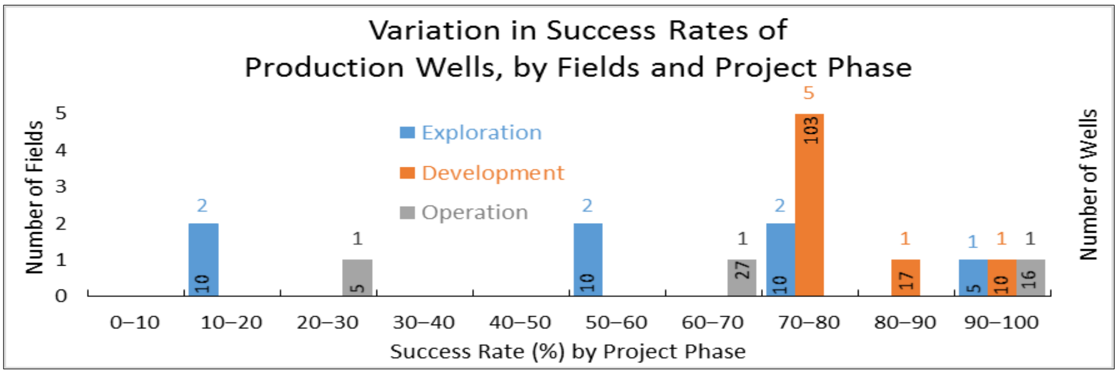

Figure 11. *Variation in success rates of production wells, by project phase.*

4.5 Improvement over time

It would be reasonable to assume that surveying and drilling techniques have improved in recent decades, and that project developers and drilling companies are becoming more adept at locating and reaching geothermal resources. Table 6 shows a breakdown of analyzed production wells in project phases by decades.

Table 6. *Production wells by decades from 1956–2014.*

Project Phases	Number of Wells in Project Phases, by Decades							Sum
	1950≤1960	1960≤1970	1970≤1980	1980≤1990	1990≤2000	2000≤2010	2010≤2014	
Exploration	1	12	12	1	1	8	0	35
Development	0	5	10	38	12	62	3	130
Operation	0	0	0	0	7	37	4	48
Sum	1	17	22	39	20	107	7	213

Figure 12 illustrates trends in the successful drilling of these wells for each decade since the 1960s.

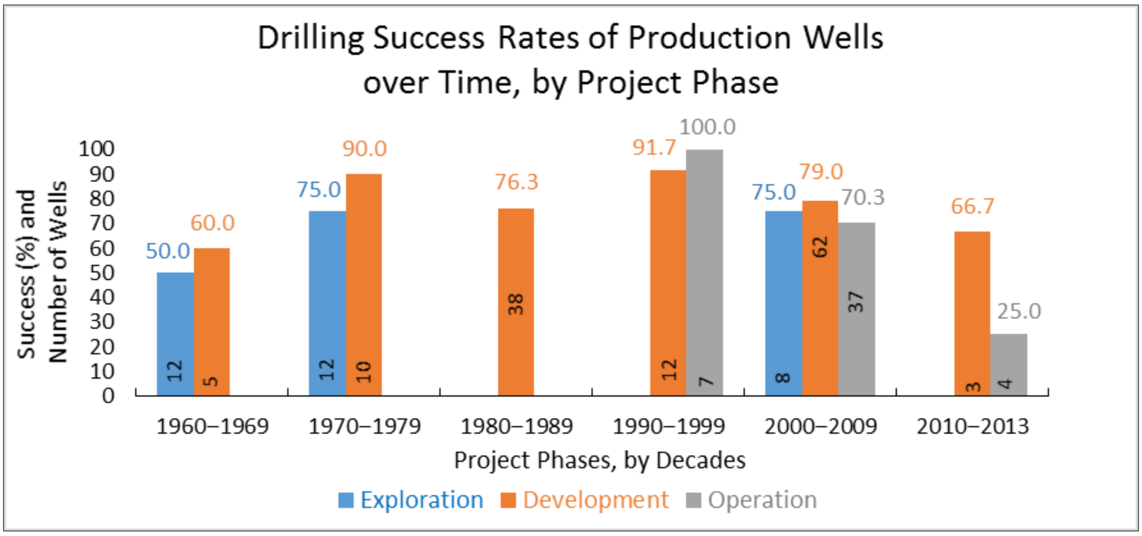

Figure 12. *Success rates of production wells for each decade since the 1960s, by project phase.*

The success rate for wells drilled during the Exploration Phase improved after the first decade. The success rate in the Development and Operation Phase generally lies between 60 and 90% but has not shown the same improvement. Success rates in the Development Phase appear to increase until the year 2000 but decline after that. The same trend is observed for wells drilled during the Operation Phase although the wells drilled in 1990–1999 and 2010–2013 are much fewer than in the decade 2000–2009. The reduction in the success rate for wells drilled during the Development Phase and the Operation Phase may reflect step-out wells or rapid development where adequate results did not arrive in time to impact the drilling plan.

4.6 Impact of well depth

Figure 13 correlates average capacity and success rate of all drilled production wells with drilled depth. Wells of 2,000–2,500 m drilled depth have the highest average capacity of 5.8 MW_e followed by wells of 1,500–2,000 m with an average capacity of 5.5 MW_e. The success rate is highest, 83%, for these ranges.

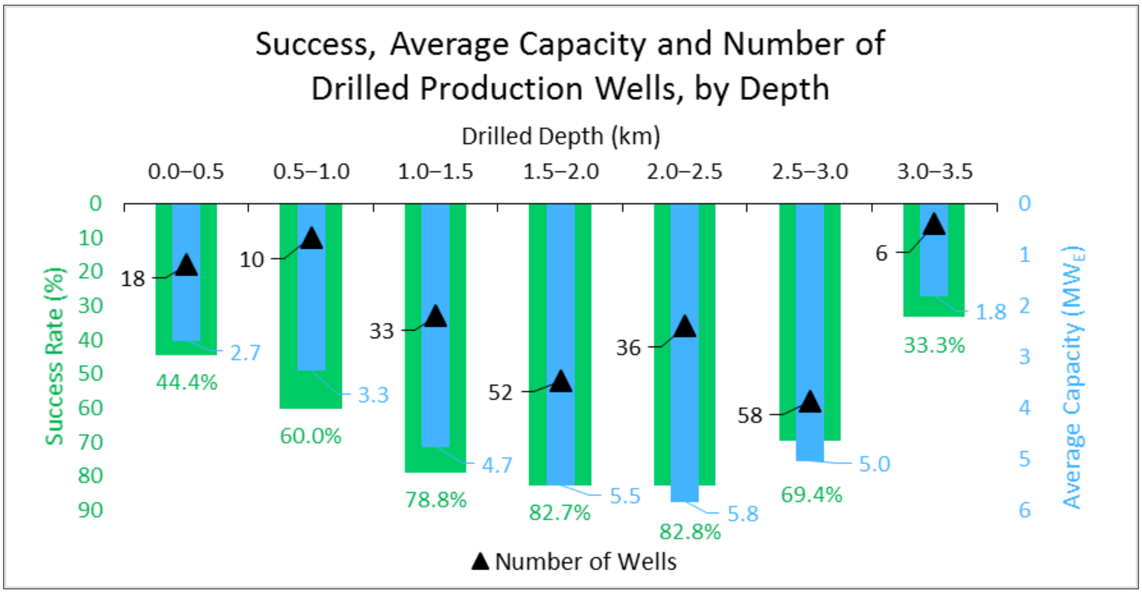

Figure 13. *Success and average capacity per drilled production well, by depth.*

4.7 Impact of casing size

It might be assumed that the larger the diameter of a production casing, the greater the flow rate of geothermal fluid and, consequently, the greater the well capacity (MW_e). The scale-up factor for very permeable wells, where the output is limited by diameter, is often assumed to be proportional to the cross sectional area of the casing. The double area of 339.7 mm vs. 244.5 mm diameter casing offers thus a factor of two in potential output improvement. Figure 14 illustrates the average capacity of wells by various casing sizes. There is a significant difference between 85 wells with a casing diameter of 200–250 mm and an average capacity of 5.5 MW_e and 63 wells with a casing of 300–350 mm and a 60% higher capacity of 8.9 MW_e,

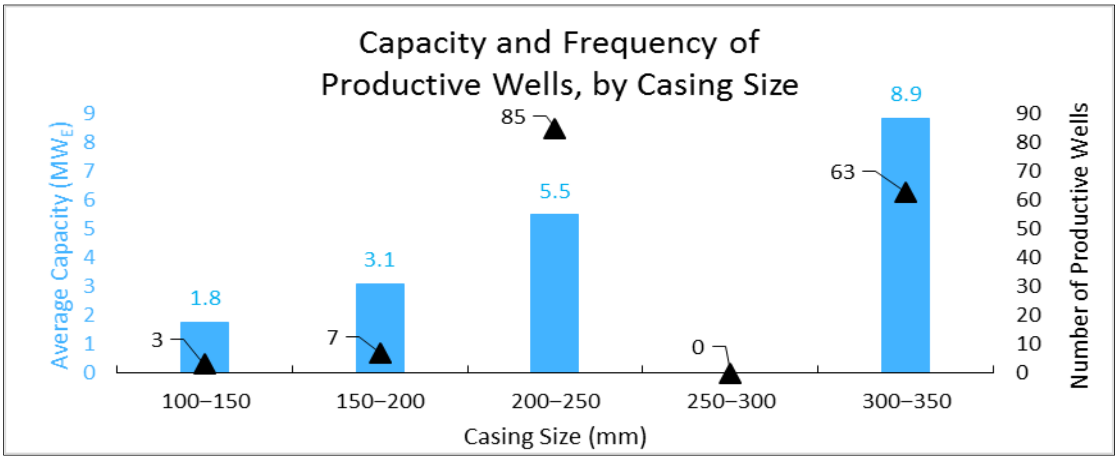

Figure 14. *Frequency and capacity of productive wells, by casing size.*

Sveinbjörnsson and Þórhallsson (2014) found in the Hellisheiði field in Iceland that the cost of drilling a production well with a production casing diameter of 340 mm (13⅜") was only 10% higher than that of a 245 mm (9⅝") diameter. Larger diameters yielding 60% higher capacity may thus be of definite advantage.

4.8 Impact of directional drilling

Improvements in drilling technology have made it possible to drill directionally inclined wells. The inclination is generally built up when drilling for the production casing, usually beneath 300 m. The inclination is increased by 2–3° every 30 meters until 20–40° are achieved. The inclination is then kept locked until final depth is reached. Inclined drilling may have the advantage of intersecting vertical permeable fractures. It also gives the opportunity to drill multiple wells from the same drillpad and reach under areas of difficult terrain. Table 7 shows a breakdown of both directionally and vertically drilled production wells.

Table 7. *Success and average capacity of all vertically- and directionally drilled production wells, by casings.*

All Production Wells	Production Casing Diameter (mm)						Total/ Weighted Average
	None	100≤150	150≤200	200≤250	250≤300	300≤350	
Vertically Drilled Wells							
Number of Wells	2	4	10	68	1	35	**120**
Average Capacity (MW_E)	0	1.3	2.2	3.5	0	5.9	**4.0**
Average Depth (m)	232	72	169	1,677	262	1,647	**1,548**
Successful Wells	0	3	7	49	0	26	**85**
Success Rate (%)	0	75	70	72	0	74	**71**
Directionally Drilled Wells							
Number of Wells				43		50	**93**
Average Capacity (MW_E)				5.3		6.8	**6.1**
Average Depth (m)				2,256		2,135	**2,191**
Successful Wells				36		37	**73**
Success Rate (%)				84		74	**79**

In vertically drilled wells the success rate ranges from 70 to 75% and the average capacity of all drilled wells increases with casing diameter, reaching 3.5 MW_e for 200–250 mm production casing and 5.9 MW_e, or 50% more, for 300–350 mm casing. Figure 15 shows success rate, average capacity and the number of vertical wells for varying casing size.

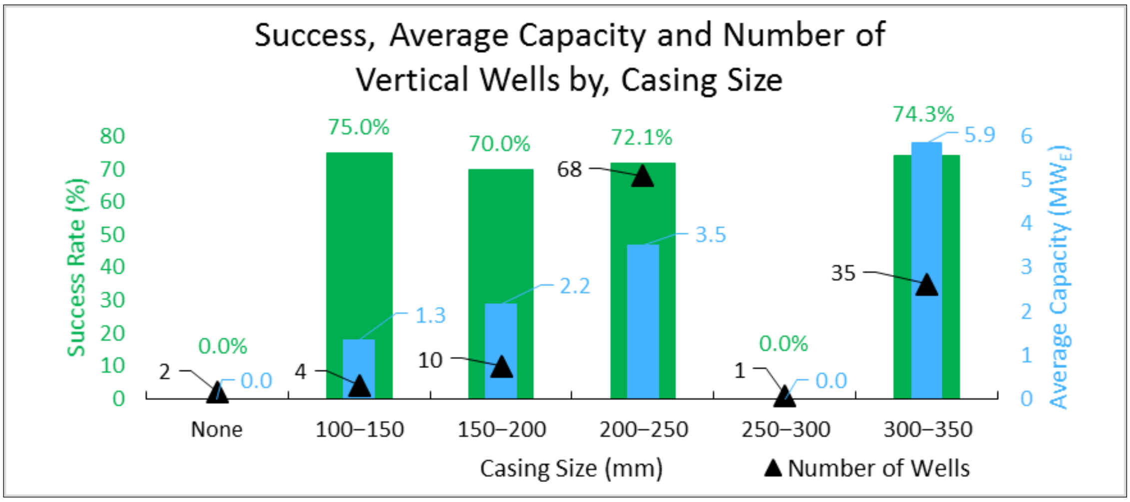

Figure 15. *Success, average capacity and number of vertically drilled wells, by casing size.*

In directionally drilled wells there are only two groups of casing sizes. For the 200–250 mm production casing the success rate is 84% and the average capacity is 5.3 MW_e but for the wider casing of 300–350 mm the success rate is 74% and the average capacity 28% higher or 6.8 MW_e (see Figure 16).

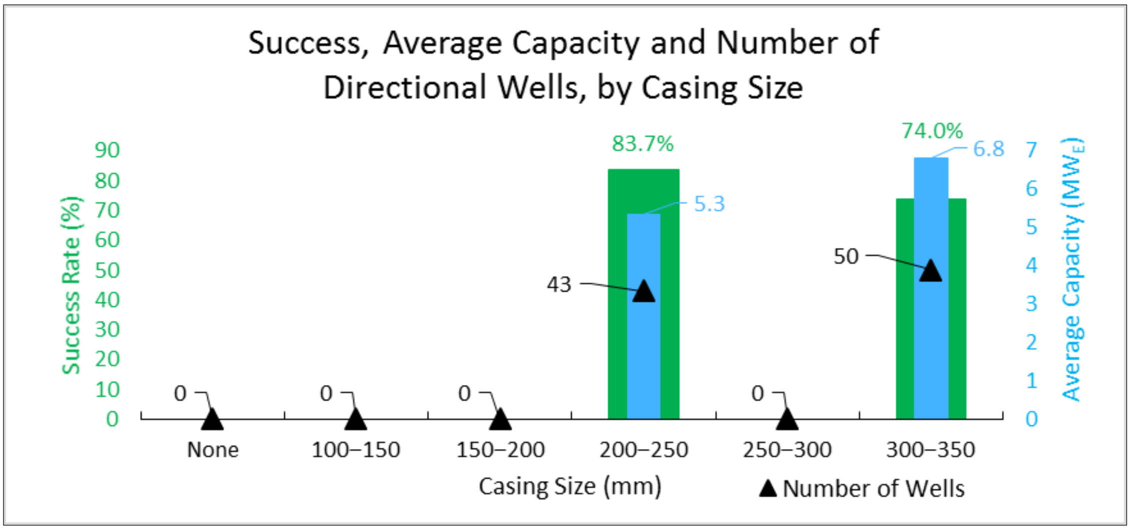

Figure 16. *Success, average capacity and number of directionally drilled wells, by casing size.*

Figure 17 compares success rate, capacity and number of vertically- and directionally drilled wells of the two most common sizes of production casing. For the narrower casing the directional wells have slightly higher success rate but 50% higher capacity.

There is insignificant difference in success rate of vertically and directionally drilled wells with the wider casing but the capacity is high for both types of wells, 6.8 MW_e for the directionally drilled and 5.9 MW_e for the vertically drilled wells, compared to the slimmer type of wells.

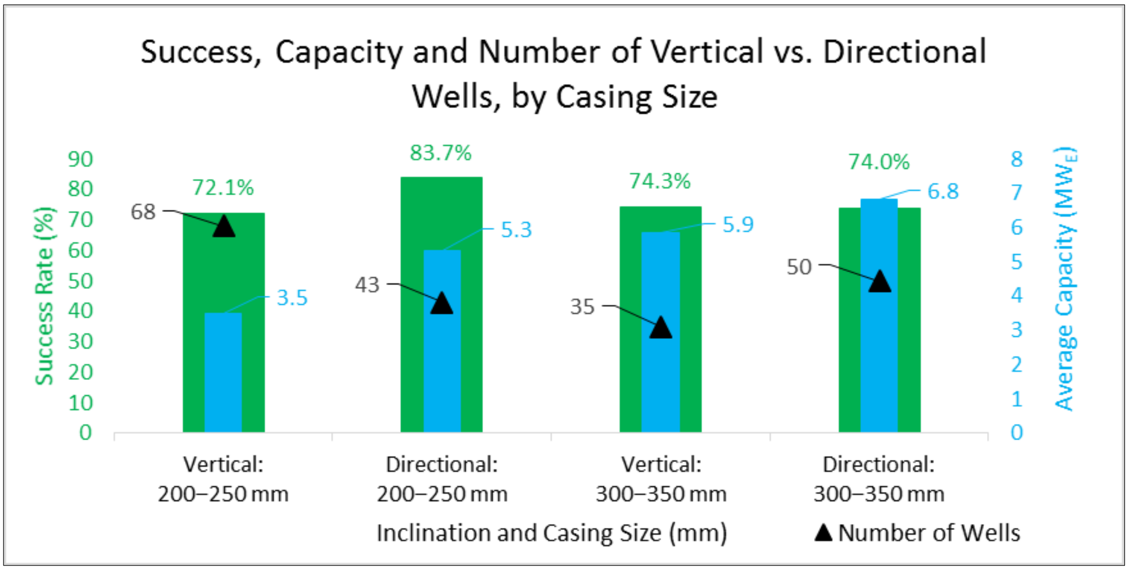

Figure 17. *Comparison of success rate, average capacity and number of vertically- and directionally drilled wells of the two most common sizes of production casing.*

4.9 Impact of geology

The IFC Report found that fields meeting Geology Code 2 (tertiary older volcanics) tended to have higher capacity in comparison with fields of Geology Code 3 (younger volcanics).

All high temperature geothermal fields in Iceland are located within or near the active volcanic zones and dominated by postglacial and quaternary formations. The geology type for all the fields thus corresponds to Geology Code 3 in the IFC Report. The primary formation permeability is generally low but favorable secondary permeability is found in fractures, dikes and at intrusion contacts. Variations in capacity do not depend on the rock type, but on resource temperature, fluid enthalpy and permeability.

4.10 Impact of resource enthalpy

It might be reasonable to assume that higher enthalpy resources would result in higher capacity wells. Figure 18 compares average capacity and success rate in different resource codes. There are 125 production wells in Resource Code 5 (230–300°C), 62 wells in Code 6 (300°C+), and 6 wells in Code 7 (steam 230–240°C). It should, however, be noted that the wells in Code 7 are not drilled into pre-existing steam reservoirs but steam caps that have developed above two phase reservoirs due to drawdown in the liquid dominated reservoir. The wells of Code 7 are few but have the highest capacity of 11.0 MW_e and a 100% success rate. The wells of Code 6 are next with an average capacity of 6.2 MW_e and a success rate of 85.5%. There is a clear increase in success rate and capacity with increased enthalpy.

Comparing these results with results obtained in the IFC Report one must note that most of the Icelandic reservoirs are classified with a Resource Code 5 or 6. In Geology Code 3 the IFC Report found an average capacity of 5.4 MW_e for Resource Code 5, 7.6 MW_e for Resource Code 6 and 6.9 MW_e for Resource Code 7.

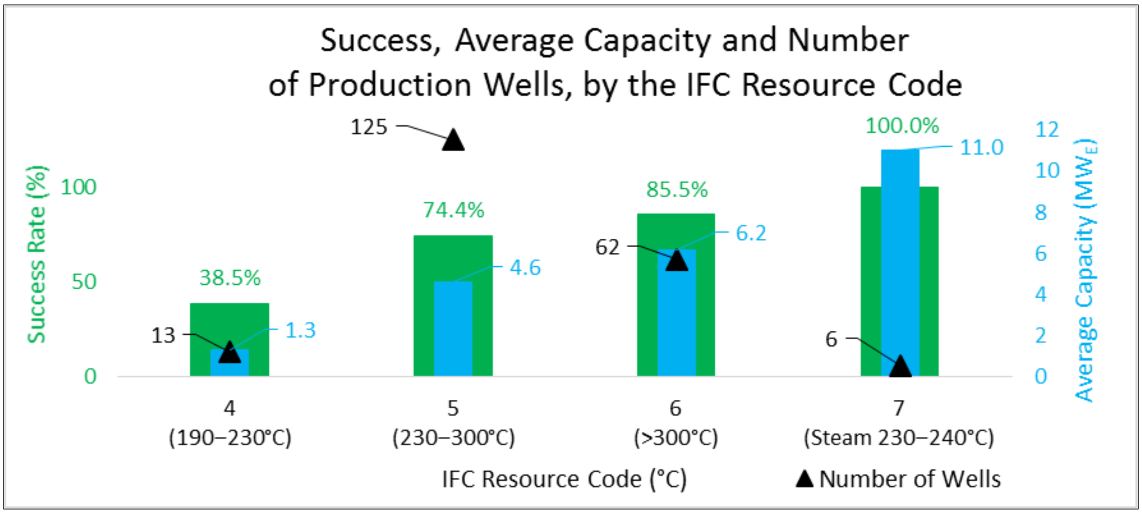

Figure 18. *Success and capacity of production wells, by the IFC Resource Code.*

5 Conclusions

5.1 Geology

All high temperature geothermal fields in Iceland are located within or near to the active volcanic zones and dominated by postglacial and quaternary formations. The geology type for all the fields thus corresponds to the Geology Code 3 in the IFC Report. The matrix formation permeability is generally low but favourable secondary permeability is found in fractures, dikes and at intrusion contacts.

5.2 Key findings

1. Of the 213 production wells analyzed, 158 or 74% were deemed to be successful. None of the fields has a success rate below 50%. About 6% of the total wells failed because of drilling problems, 4% found inadequate temperatures, 10% could not be operated at high enough static pressure, 3% had too low permeability and 3% were so shallow that they did not reach the reservoir.
2. While the first well drilled shows an average success rate of 43%, the success rate averaged over the first five wells increases to 60%, and reaches a plateau about 74% after well number 15 in a field.

3. The Exploration Phase has the most variable well success rates, making forecasting of likely success more difficult. The success rate for this phase has though improved in recent decades. Once a project enters the Development Phase the probability of successful wells being achieved is above 70%. Success rates in that phase appear to increase until the year 2000 but decline after that. The same trend is observed for wells drilled during the Operation Phase. The reduction in the success rate for wells drilled during the Development Phase and the Operation Phase may reflect step-out wells or rapid development where adequate results did not arrive in time to impact the drilling plan.
4. The cumulative average capacity of all wells increases from 2.5 to 4.8 MW_e during the Development Phase, and continues rising up to 4.9 MW_e during the Operation Phase.
5. The five main operating power plants in Iceland have a ratio of installed capacity divided by number of drilled production wells ranging from 1.3 to 5.3 MW_e/well and a weighted average of 3.5 MW_e/well.
6. The average capacity of all productive wells in the dataset is 6.7 MW_e, though the distribution is strongly skewed by the inclusion of several very high-capacity wells. The maximum capacity of a single well in the dataset is 35 MW_e.
7. The capacity has a lognormal distribution with a mean and most likely value of 4.8 MW_e and a standard deviation of 2.3 MW_e.
8. Wells of 2,000–2,500 m drilled depth have the highest average capacity of 5.8 MW_e followed by wells of 1,500–2,000 m with an average capacity of 5.5 MW_e. The success rate is highest, 83%, for these ranges.
9. There is a significant difference between productive wells with a production casing diameter of 200–250 mm and an average capacity of 5.5 MW_e and a casing of 300–350 mm with an average capacity of 8.9 MW_e.
10. The success rate in vertically drilled wells was similar to that in directionally drilled wells, but the average capacity of directionally drilled wells was 6.1 MW_e compared to 4.0 MW_e in vertical wells.
11. In vertically drilled wells the success rate ranges from 70 to 75% and the average capacity of all drilled wells increases with casing diameter, reaching 3.5 MW_e for 200–250 mm production casing and 5.9 MW_e for 300–350 mm casing.
12. In directionally drilled wells there are only two groups of casing sizes. For the 200–250 mm production casing the success rate is 84% and the average capacity is 5.3 MW_e but for the wider casing of 300–350 mm the success rate is 74% and the average capacity 6.8 MW_e.
13. There is a clear increase in capacity with increased enthalpy. Wells drilled into steam caps above a liquid dominated reservoir at 230–240°C have the highest capacity of 11.0 MW_e and a 100% success rate. Wells in two-phase reservoirs with temperatures higher than 300°C come next with an average capacity of 6.2 MW_e and a success rate of 86%.

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Appendix A – Dataset of 234 High Temperature Wells in Iceland

IFC Well Code	IFC Geology Code	IFC Resource Code	Completion Date	Initial Status	Last Known Status	Gross Capacity	Date	Total depth	Production Casing Diameter	Production Casing Depth	Success-ful	Re-drilled	Pumped
	(1–5)	(1–7)	(yyyy.mm.dd)			(MW_e)	(yyyy.mm.dd)	(m)	(mm)	(m)	(Y/N)	(Y/N)	(Y/N)
X.1.1	3	5	1956-07-03	Exploration	Abandoned			162.0	203.2	12.0	N	N	N
X.1.2	3	4	1968-09-05	Exploration	Abandoned	2.3	1970-07-16	301.4	152.4	43.0	Y	N	N
X.1.3	3	5	1968-11-22	Exploration	Abandoned			1,166.0	244.5	242.0	N	N	N
X.1.4	3	5	1968-12-20	Exploration	Abandoned			1,036.0	244.5	246.0	N	N	N
X.1.5	3	1	1969-02-14	Suspended	Abandoned			127.3	339.7	40.0	N	N	N
X.1.6	3	5	1969-07-30	Exploration	Abandoned			572.0	127.0	222.0	N	N	N
X.1.7	3	1	1969-09-06	Exploration	Abandoned			69.8	203.2	38.0	N	N	N
X.1.8	3	5	1969-11-28	Production	Abandoned	5.5	1987-05-18	1,754.0	244.5	297.0	Y	N	N
X.1.9	3	5	1983-05-06	Production	Abandoned	10.7	1992-11-16	1,445.0	339.7	524.6	Y	N	N
X.1.10	3	6	1999-02-26	Production	Production	15.8	2003-09-16	2,046.0	339.7	691.1	Y	N	N
X.1.11	3	5	2002-05-04	Production	Production	15.2	2013-05-14	2,248.0	339.7	688.6	Y	N	N
X.1.12	3	6	2002-12-17	Production	Production	10.9	2013-05-27	2,506.4	339.7	841.7	Y	N	N
X.1.13	3	5	2003-05-17	Not productive	Abandoned			2,457.0	339.7	817.6	N	N	N
X.1.14	3	5	2004-01-30	Not productive	Abandoned			2,306.0	339.7	795.5	N	N	N
X.1.15	3	5	2004-03-26	Production	Production	15.2	2005-02-03	2,507.0	339.7	792.0	Y	N	N
X.1.16	3	5	2004-05-07	Not productive	Monitoring			2,627.4	339.7	878.6	N	N	N
X.1.17	3	5	2005-01-18	Production	Production	5.0	2013-05-07	1,814.7	339.7	749.5	Y	N	N
X.1.18	3	6	2005-04-14	Production	Production	4.7	2012-10-05	2,247.9	339.7	742.0	Y	N	N
X.1.19	3	5	2005-05-18	Not productive	Abandoned			2,126.0	339.7	728.3	N	N	N
X.1.20	3	5	2005-11-19	Production	Production	5.1	2013-05-15	1,713.0	339.7	609.0	Y	N	N
X.1.21	3	5	2006-01-04	Production	Marginal producer	2.8	2011-03-17	1,680.3	339.7	719.9	Y	N	N

IFC Well Code	IFC Geology Code	IFC Resource Code	Completion Date	Initial Status	Last Known Status	Gross Capacity	Date	Total depth	Production Casing Diameter	Production Casing Depth	Success-ful	Re-drilled	Pumped
	(1–5)	(1–7)	(yyyy.mm.dd)			(MW_e)	(yyyy.mm.dd)	(m)	(mm)	(m)	(Y/N)	(Y/N)	(Y/N)
X.1.22	3	5	2006-02-27	Not productive	Abandoned			3,082.4	339.7	900.2	N	N	N
X.1.23	3	5	2006-02-05	Production	Production	6.5	2013-05-16	2,114.0	339.7	697.3	Y	N	N
X.1.24	3	6	2006-03-23	Production	Production	9.2	2013-05-14	1,923.8	339.7	692.7	Y	N	N
X.1.25	3	6	2007-01-14	Production	Production	7.1	2013-05-27	2,426.0	339.7	795.5	Y	Y	N
X.1.26	3	6	2007-02-22	Production	Production	9.9	2007-10-11	2,531.0	339.7	703.0	Y	Y	N
X.1.27	3	6	2007-04-01	Production	Production	14.3	2008-04-30	2,180.0	339.7	706.7	Y	N	N
X.1.28	3	6	2007-05-20	Production	Production	11.7	2008-08-20	2,200.0	339.7	690.0	Y	N	N
X.1.29	3	5	2008-03-13	Production	Production	14.9	2013-05-16	1,503.0	339.7	751.3	Y	N	N
X.1.30	3	7	2008-04-28	Production	Production	19.0	2008-10-27	1,119.0	339.7	765.0	Y	N	N
X.1.31	3	5	2008-07-23	Injector	Injector			3,009.0	339.7	728.3	Y	Y	N
X.1.32	3	6	2008-12-04	Not productive	Not productive			3,077.0	339.7	900.2	N	Y	N
X.1.33	3	6	2010-06-08	Not productive	Monitoring			2,837.0	339.7	900.7	N	N	N
X.1.34	3	6	2011-06-03	Not productive	Monitoring			2,869.0	339.7	1,213.0	N	N	N
X.1.35	3	5	2013-01-15	Production	Idle	10.8	2013-04-15	1,222.6	339.7	748.5	Y	N	N
X.1.36	3	5	2013-04-16	Not productive	Not productive			1,202.0	339.7	1,067.7	N	N	N
X.1.37	3	6	2013-11-04	Injector	Injector			2,695.0	339.7	946.7	Y	N	N
X.2.1	3	1	1971-12-02	Exploration	Abandoned			261.9	273.1	0.0	N	N	N
X.2.2	3	4	1972-12-03	Production	Abandoned	5.0	1972-04-27	239.3	203.2	103.6	Y	N	N
X.2.3	3	4	1972-02-10	Production	Abandoned	7.0	1972-04-27	402.0	203.2	143.0	Y	N	N
X.2.4	3	5	1974-05-11	Production	Abandoned	7.5	1974-07-22	1,713.0	244.5	394.0	Y	N	N
X.2.5	3	5	1974-06-08	Production	Abandoned	7.3	1974-07-16	1,519.0	244.5	395.0	Y	N	N
X.2.6	3	5	1979-09-28	Production	Production	5.2	2005-12-31	1,438.0	339.7	600.0	Y	N	N
X.2.7	3	5	1980-01-15	Production	Production	4.2	2005-12-31	1,603.5	339.7	622.0	Y	N	N

IFC Well Code	IFC Geology Code	IFC Resource Code	Completion Date	Initial Status	Last Known Status	Gross Capacity	Date	Total depth	Production Casing Diameter	Production Casing Depth	Success-ful	Re-drilled	Pumped
	(1–5)	(1–7)	(yyyy.mm.dd)			(MW_e)	(yyyy.mm.dd)	(m)	(mm)	(m)	(Y/N)	(Y/N)	(Y/N)
X.2.8	3	7	1980-02-05	Production	Production	13.1	2005-12-31	425.0	339.7	226.0	Y	N	N
X.2.9	3	5	1980-06-09	Production	Production	4.3	2005-12-31	994.0	339.7	588.0	Y	N	N
X.2.10	3	5	1980-07-11	Production	Production	6.6	2005-12-31	1,141.0	339.7	582.0	Y	N	N
X.2.11	3	1	1981-11-03	Exploration	Abandoned			60.0	None	None	N	N	N
X.2.12	3	5	1982-03-31	Production	Monitoring	2.6	1998-04-20	1,488.0	339.7	606.6	Y	N	N
X.2.13	3	5	1982-04-19	Production	Abandoned	3.1	1990-06-26	1,998.0	244.5	612.0	Y	N	N
X.2.14	3	4	1992-12-16	Exploration	Monitoring			140.6	219.1	95.0	N	N	N
X.2.15	3	7	1993-02-22	Production	Marginal producer	2.1	2005-12-31	612.4	244.5	195.0	Y	N	N
X.2.16	3	5	1998-05-13	Injector	Injector			1,260.0	339.7	789.0	Y	N	N
X.2.17	3	7	1998-06-08	Production	Production	12.7	2005-12-31	440.0	339.7	246.0	Y	N	N
X.2.18	3	5	1998-08-04	Production	Marginal producer	2.1	2005-12-31	1,600.0	339.7	715.0	Y	N	N
X.2.19	3	5	1998-11-17	Production	Marginal producer	2.8	2005-12-31	1,837.0	339.7	764.3	Y	N	N
X.2.20	3	7	2000-12-12	Production	Production	5.5	2005-12-31	430.5	339.7	236.7	Y	N	N
X.2.21	3	5	2001-03-31	Production	Production	4.7	2009	1,475.0	339.7	844.0	Y	N	N
X.2.22	3	5	2008-02-08	Production	Production	10.0	2008-03-17	862.0	339.7	385.0	Y	N	N
X.2.23	3	7	2008-05-15	Production	Production	13.6	2008-11-13	700.0	339.7	483.4	Y	N	N
X.2.24	3	5	2008-05-25	Injector	Injector			1,086.0	None	None	Y	N	N
X.3.1	3	2	1965-08-20	Exploration	Abandoned			129.1	152.4	74.0	N	N	N
X.3.2	3	2	1965-10-04	Exploration	Abandoned			393.0	152.4	84.0	N	N	N
X.3.3	3	5	1966-08-22	Exploration	Abandoned			836.0	152.4	92.5	N	N	N
X.3.4	3	5	1970-11-04	Exploration	Abandoned			426.0	244.5	310.0	N	N	N
X.3.5	3	5	1972-10-11	Production	Production	3.6	2011-07-15	1,804.0	244.5	447.0	Y	N	N
X.3.6	3	5	1982-11-01	Production	Production	8.2	2011-07-15	1,144.0	244.5	638.0	Y	N	N

IFC Well Code	IFC Geology Code	IFC Resource Code	Completion Date	Initial Status	Last Known Status	Gross Capacity	Date	Total depth	Production Casing Diameter	Production Casing Depth	Success-ful	Re-drilled	Pumped
	(1–5)	(1–7)	(yyyy.mm.dd)			(MW_e)	(yyyy.mm.dd)	(m)	(mm)	(m)	(Y/N)	(Y/N)	(Y/N)
X.3.7	3	5	1983-11-17	Production	Marginal producer	1.7	2008-07-29	2,001.0	244.5	585.7	Y	N	N
X.3.8	3	4	1984-07-10	Exploration	Abandoned			403.0	None	None	N	N	N
X.3.9	3	5	1984-09-22	Production	Production	8.5	2011-05-10	1,055.0	244.5	820.8	Y	N	N
X.3.10	3	5	1984-11-06	Production	Production	3.2	2008-07-03	1,798.0	244.5	593.5	Y	N	N
X.3.11	3	5	1985-06-02	Production	Production	10.3	2011-08-10	2,265.0	244.5	557.7	Y	N	N
X.3.12	3	6	1985-07-16	Production	Monitoring			1,856.0	244.5	782.5	N	N	N
X.3.13	3	5	1985-08-22	Production	Production	10.4	2006-08-16	1,609.0	244.5	816.9	Y	N	N
X.3.14	3	5	1985-09-16	Production	Production	5.8	2007-08-28	1,304.0	244.5	770.0	Y	N	N
X.3.15	3	6	1985-10-23	Production	Monitoring	4.8	2011-05-19	1,748.0	244.5	784.0	Y	N	N
X.3.16	3	5	1985-11-27	Production	Production	4.6	2011-05-10	2,024.0	244.5	790.3	Y	N	N
X.3.17	3	5	1986-08-29	Not productive	Monitoring			2,100.0	244.5	773.0	N	N	N
X.3.18	3	5	1986-10-23	Marginal	Monitoring			2,136.0	244.5	941.1	N	N	N
X.3.19	3	5	1999-05-12	Production	Marginal producer	2.3	2001-01-04	1,800.0	244.5	761.1	Y	N	N
X.3.20	3	5	1999-06-20	Production	Production	16.1	2006-08-14	1,700.0	244.5	793.0	Y	N	N
X.3.21	3	5	2000-07-22	Production	Production	7.1	2011-06-01	1,771.0	244.5	798.5	Y	N	N
X.3.22	3	5	2000-11-04	Production	Production	8.5	2011-06-01	1,805.0	244.5	797.0	Y	N	N
X.3.23	3	6	2003-11-08	Production	Production	9.6	2011-07-15	1,750.8	244.5	714.0	Y	N	N
X.3.24	3	5	2005-06-30	Production	Production	9.0	2011-08-10	1,928.6	244.5	735.0	Y	N	N
X.3.25	3	5	2007-01-29	Marginal	Abandoned			836.5	244.5	835.3	N	N	N
X.3.26	3	5	2007-12-15	Marginal	Marginal			2,509.0	339.7	1,087.0	N	N	N
X.3.27	3	5	2008-02-22	Not productive	Idle	3.4	2008-09-25	2,503.0	339.7	762.0	Y	N	N
X.3.28	3	5	2008-12-01	Production	Production	17.5	2011-08-10	2,098.0	244.5	753.0	Y	Y	N
X.4.1	3	5	1985-11-20	Exploration	Monitoring			1,816.0	244.5	793.9	N	N	N

IFC Well Code	IFC Geology Code	IFC Resource Code	Completion Date	Initial Status	Last Known Status	Gross Capacity	Date	Total depth	Production Casing Diameter	Production Casing Depth	Success-ful	Re-drilled	Pumped
	(1–5)	(1–7)	(yyyy.mm.dd)			(MW_e)	(yyyy.mm.dd)	(m)	(mm)	(m)	(Y/N)	(Y/N)	(Y/N)
X.4.2	3	4	1995-01-25	Exploration	Monitoring			1,035.0	244.5	777.0	N	N	N
X.4.3	3	5	2001-08-20	Production	Production	2.7	2002-06-14	1,887.0	244.5	801.0	Y	N	N
X.4.4	3	5	2001-10-14	Production	Production	4.0	2002-06-14	2,008.0	244.5	786.5	Y	N	N
X.4.5	3	5	2002-06-24	Production	Production	4.3	2009-09-01	2,000.0	244.5	799.0	Y	N	N
X.4.6	3	5	2002-08-08	Production	Production	7.9	2011-05-03	2,013.0	244.5	800.8	Y	N	N
X.4.7	3	5	2002-10-14	Production	Production	10.7	2008-05-22	2,270.0	244.5	800.4	Y	N	N
X.4.8	3	5	2003-06-23	Production	Production	3.8	2011-06-22	1,604.0	339.7	750.0	Y	N	N
X.4.9	3	5	2003-08-08	Not productive	Injector			2,808.0	244.5	931.5	N	N	N
X.4.10	3	4	2004-06-19	Marginal	Monitoring			2,209.0	339.7	775.0	N	N	N
X.4.11	3	5	2004-08-01	Production	Production	15.6	2011-06-30	1,652.0	339.7	765.0	Y	N	N
X.4.12	3	3	2004-08-06	Injector	Not productive			1,306.0	339.7	400.0	N	N	N
X.4.13	3	5	2004-09-12	Production	Production	15.3	2007-09-20	1,863.0	339.7	731.0	Y	N	N
X.4.14	3	5	2004-09-30	Not productive	Not productive			2,397.3	244.5	782.0	N	N	N
X.4.15	3	5	2004-11-05	Production	Marginal producer	1.8	2005	2,008.0	339.7	702.0	Y	N	N
X.4.16	3	5	2004-11-25	Production	Production	9.2	2011-06-22	1,806.7	339.7	631.0	Y	N	N
X.4.17	3	5	2005-05-29	Injector	Abandoned			1,997.0	339.7	399.2	N	N	N
X.4.18	3	5	2005-08-09	Production	Production	2.4	2006-05-09	1,902.0	339.7	697.5	Y	N	N
X.4.19	3	5	2005-09-18	Production	Production	17.9	2011-06-30	1,500.0	339.7	806.0	Y	N	N
X.4.20	3	5	2005-10-06	Production	Production	6.3	2007-06-07	1,668.0	339.7	666.3	Y	N	N
X.4.21	3	5	2005-12-11	Exploration	Idle	1.9	2006-10-30	2,002.0	244.5	693.0	Y	N	N
X.4.22	3	6	2006-02-08	Production	Idle	5.5	2006-08-30	2,165.0	244.5	902.5	Y	N	N
X.4.23	3	3	2006-03-17	Injector	Injector			1,864.0	339.7	532.4	Y	N	N
X.4.24	3	5	2006-04-10	Production	Production	19.4	2011-06-22	1,554.6	339.7	651.0	Y	N	N

IFC Well Code	IFC Geology Code	IFC Resource Code	Completion Date	Initial Status	Last Known Status	Gross Capacity	Date	Total depth	Production Casing Diameter	Production Casing Depth	Success-ful	Re-drilled	Pumped
	(1–5)	(1–7)	(yyyy.mm.dd)			(MW_e)	(yyyy.mm.dd)	(m)	(mm)	(m)	(Y/N)	(Y/N)	(Y/N)
X.4.25	3	3	2006-04-18	Injector	Abandoned			1,204.0	339.7	399.0	N	N	N
X.4.26	3	4	2006-07-19	Production	Idle	1.3	2006-01-12	2,104.0	339.7	1,062.8	Y	N	N
X.4.27	3	3	2006-08-21	Injector	Injector			2,121.0	339.7	828.0	Y	N	N
X.4.28	3	6	2006-09-01	Injector	Injector			2,211.0	339.7	849.0	Y	N	N
X.4.29	3	5	2006-09-15	Not productive	Not productive			1,968.0	339.7	754.6	N	N	N
X.4.30	3	5	2006-09-29	Injector	Injector			2,076.0	244.5	860.0	Y	N	N
X.4.31	3	5	2006-10-24	Production	Production	7.9	2007-06-19	2,587.0	339.7	708.2	Y	N	N
X.4.32	3	5	2006-11-18	Production	Production	4.7	2007-06-26	2,115.0	339.7	751.2	Y	N	N
X.4.33	3	5	2006-12-08	Not productive	Not productive	0.8	2011-05-03	2,155.0	339.7	708.5	Y	N	N
X.4.34	3	5	2007-02-14	Production	Production	7.5	2009-06-23	2,502.0	339.7	952.0	Y	N	N
X.4.35	3	6	2007-04-04	Production	Production	10.9	2011-08-04	2,318.5	339.7	705.0	Y	N	N
X.4.36	3	6	2007-05-17	Marginal	Marginal			2,688.0	244.5	970.0	N	N	N
X.4.37	3	5	2007-07-01	Abandoned	Abandoned			1,473.0	339.7	655.0	N	N	N
X.4.38	3	5	2007-07-01	Injector	Injector			2,580.0	339.7	964.5	Y	N	N
X.4.39	3	5	2007-07-28	Production	Production	4.9	2011-11-09	2,702.8	339.7	724.0	Y	N	N
X.4.40	3	5	2007-08-09	Production	Production	7.6	2008-01-10	2,465.6	339.7	752.0	Y	N	N
X.4.41	3	5	2007-08-29	Not productive	Not productive			1,394.0	339.7	722.0	N	N	N
X.4.42	3	6	2007-09-23	Marginal	Marginal			2,450.0	339.7	1,038.0	N	N	N
X.4.43	3	5	2007-09-24	Marginal	Marginal			2,325.0	244.5	835.0	N	N	N
X.4.44	3	5	2007-10-23	Production	Idle	5.9	2008-06-03	2,808.0	244.5	1,102.7	Y	N	N
X.4.45	3	5	2007-11-08	Production	Production	2.4	2008-07-15	2,726.0	339.7	766.8	Y	N	N
X.4.46	3	5	2007-11-09	Injector	Injector			2,302.0	339.7	1,122.5	Y	N	N
X.4.47	3	5	2007-12-22	Not productive	Not productive			2,820.0	339.7	845.5	N	N	N

IFC Well Code	IFC Geology Code	IFC Resource Code	Completion Date	Initial Status	Last Known Status	Gross Capacity	Date	Total depth	Production Casing Diameter	Production Casing Depth	Success-ful	Re-drilled	Pumped
	(1–5)	(1–7)	(yyyy.mm.dd)			(MW_e)	(yyyy.mm.dd)	(m)	(mm)	(m)	(Y/N)	(Y/N)	(Y/N)
X.4.48	3	5	2008-01-23	Injector	Injector			3,011.6	339.7	782.7	Y	N	N
X.4.49	3	5	2008-03-05	Marginal	Marginal			3,111.5	339.7	780.0	N	N	N
X.4.50	3	5	2008-03-16	Production	Production	11.0	2008-08-19	2,843.0	339.7	782.0	Y	N	N
X.4.51	3	6	2008-04-14	Production	Production	8.4	2008-08-25	3,322.9	339.7	919.2	Y	N	N
X.4.52	3	5	2008-04-15	Marginal	Marginal			3,055.5	339.7	780.0	N	N	N
X.4.53	3	5	2008-05-23	Production	Production	15.1	2008-08-13	2,415.0	339.7	771.5	Y	N	N
X.4.54	3	6	2008-06-24	Production	Production	16.2	2011-08-04	2,514.0	339.7	774.0	Y	N	N
X.4.55	3	5	2008-06-26	Production	Production	5.7	2011-05-02	2,744.0	339.7	1,031.5	Y	N	N
X.4.56	3	5	2008-07-16	Production	Production	4.9	2011-11-09	2,606.0	339.7	836.5	Y	N	N
X.4.57	3	6	2008-07-19	Production	Production	7.5	2011-08-04	2,400.0	339.7	868.1	Y	N	N
X.4.58	3	5	2008-09-05	Production	Production	4.3	2011-11-09	2,288.0	339.7	829.0	Y	N	N
X.4.59	3	6	2008-10-11	Production	Production	12.6	2010-01-28	2,000.0	339.7	694.0	Y	N	N
X.4.60	3	5	2008-10-19	Not productive	Monitoring			1,454.0	339.7	800.0	N	N	N
X.4.61	3	6	2008-10-25	Production	Idle	1.5	2009-09-11	2,620.0	244.5	736.0	Y	N	N
X.4.62	3	6	2008-11-22	Injector	Injector			2,703.0	339.7	702.5	Y	N	N
X.4.63	3	5	2009-03-23	Injector	Injector			1,945.0	339.7	654.0	Y	N	N
X.4.64	3	5	2009-04-29	Not productive	Not productive			2,516.0	339.7	896.0	N	N	N
X.4.65	3	6	2009-06-15	Production	Idle	13.1	2011-02-16	2,507.0	244.5	965.7	Y	N	N
X.4.66	3	6	2009-06-17	Production	Idle	20.2	2009-11-11	2,436.0	244.5	758.5	Y	N	N
X.4.67	3	4	2009-07-29	Exploration	Not productive			2,783.0	244.5	809.0	N	N	N
X.4.68	3	4	2009-07-29	Injector	Monitoring			1,000.5	339.7	457.6	N	N	N
X.4.69	3	5	2009-09-13	Production	Production	9.3	2011-08-25	1,467.0	339.7	656.0	Y	N	N
X.4.70	3	5	2009-09-22	Production	Idle	2.4	2010-09-23	3,111.3	244.5	1,040.8	Y	N	N

IFC Well Code	IFC Geology Code	IFC Resource Code	Completion Date	Initial Status	Last Known Status	Gross Capacity	Date	Total depth	Production Casing Diameter	Production Casing Depth	Success-ful	Re-drilled	Pumped
	(1–5)	(1–7)	(yyyy.mm.dd)			(MW_e)	(yyyy.mm.dd)	(m)	(mm)	(m)	(Y/N)	(Y/N)	(Y/N)
X.4.71	3	5	2009-11-14	Injector	Injector			2,039.0	339.7	689.8	Y	N	N
X.4.72	3	3	2009-12-14	Injector	Abandoned			1,024.0	339.7	405.0	N	N	N
X.4.73	3	6	2010-07-11	Injector	Injector			2,204.0	339.7	659.5	Y	N	N
X.4.74	3	5	2011-02-26	Injector	Injector			2,192.0	339.7	628.0	Y	N	N
X.5.1	3	4	1965-07-29	Exploration	Abandoned	1.1	1965-09-03	342.4	177.8	107.0	Y	N	N
X.5.2	3	5	1965-07-29	Exploration	Monitoring	1.4	1965-09-03	492.0	130.2	207.0	Y	N	N
X.5.3	3	5	1966-10-16	Exploration	Abandoned	1.0	1968-05-01	683.2	127.0	596.0	Y	N	N
X.5.4	3	5	1968-09-17	Production	Abandoned	2.9	1969-07-30	1,138.2	127.0	625.0	Y	N	N
X.5.5	3	5	1969-03-15	Production	Abandoned	1.5		637.7	177.8	478.0	Y	N	N
X.5.6	3	5	1969-09-02	Production	Abandoned	4.3		1,193.0	193.7	577.5	Y	N	N
X.5.7	3	5	1969-12-05	Production	Abandoned	6.1	1977-05-01	1,205.9	193.7	582.0	Y	N	N
X.5.8	3	5	1970-10-29	Production	Production	1.9	2012-08-01	1,311.7	152.4	819.0	Y	N	N
X.5.9	3	5	1970-11-09	Production	Abandoned	4.3		1,311.6	187.3	532.5	Y	N	N
X.5.10	3	5	1979-07-13	Production	Abandoned	6.5	1992-06-01	1,923.0	244.5	619.6	Y	N	N
X.5.11	3	5	1980-08-06	Production	Abandoned	8.3	1977	1,519.0	244.5	597.8	Y	N	N
X.5.12	3	5	1980-11-15	Production	Abandoned	5.8	1992-06-01	1,996.0	244.5	686.1	Y	N	N
X.5.13	3	6	2006-06-03	Production	Idle	7.5	2010	2,155.0	244.5	852.2	Y	N	N
X.5.14	3	6	2008-04-05	Production	Idle	15.7	2010	2,505.8	244.5	840.0	Y	N	N
X.5.15	3	6	2008-05-13	Production	Idle	2.4	2010	2,690.4	244.5	846.6	Y	N	N
X.6.1	3	5	1974-10-13	Exploration	Abandoned	1.7	1974-10-31	1,138.0	222.3	296.0	Y	N	N
X.6.2	3	5	1974-12-02	Exploration	Abandoned	1.2	1977-08-19	1,204.5	222.3	298.0	Y	N	N
X.6.3	3	5	1975-07-25	Exploration	Abandoned	6.2	1975-11-01	1,720.0	244.5	600.0	Y	N	N
X.6.4	3	6	1975-09-12	Production	Abandoned			2,000.0	244.5	593.6	N	N	N

IFC Well Code	IFC Geology Code	IFC Resource Code	Completion Date	Initial Status	Last Known Status	Gross Capacity	Date	Total depth	Production Casing Diameter	Production Casing Depth	Success-ful	Re-drilled	Pumped
	(1–5)	**(1–7)**	**(yyyy.mm.dd)**			**(MW_e)**	**(yyyy.mm.dd)**	**(m)**	**(mm)**	**(m)**	**(Y/N)**	**(Y/N)**	**(Y/N)**
X.6.5	3	6	1975-10-29	Production	Marginal producer	2.0	2012-08-01	1,299.0	244.5	642.9	Y	N	N
X.6.6	3	5	1976-08-03	Production	Monitoring	2.3		2,000.0	244.5	576.2	Y	N	N
X.6.7	3	5	1976-10-01	Production	Monitoring	1.0	1987-09-03	2,165.0	244.5	808.9	Y	N	N
X.6.8	3	6	1976-10-03	Marginal	Abandoned			1,658.0	244.5	537.0	N	N	N
X.6.9	3	3	1976-11-16	Production	Monitoring	6.3	1977-01-18	2,082.0	244.5	805.5	Y	N	N
X.6.10	3	6	1976-11-20	Not productive	Monitoring	1.4	1997-01-21	2,217.0	244.5	788.4	Y	N	N
X.6.11	3	6	1978-11-08	Production	Abandoned	1.1	1997-07-21	2,222.0	244.5	985.3	Y	N	N
X.6.12	3	6	1980-07-12	Abandoned	Abandoned	1.5		2,050.0	244.5	1,057.9	Y	N	N
X.6.13	3	6	1980-08-30	Production	Production	1.4	2012-08-13	2,107.0	244.5	699.1	Y	N	N
X.6.14	3	6	1980-10-23	Production	Idle	1.5	1997-07-21	2,097.0	244.5	1,086.6	Y	N	N
X.6.15	3	5	1981-06-22	Production	Abandoned	1.4	1981-08-09	1,981.0	244.5	662.1	Y	N	N
X.6.16	3	5	1981-08-13	Production	Production	2.1	2012-07-03	2,190.0	244.5	685.3	Y	N	N
X.6.17	3	4	1981-10-22	Marginal	Monitoring			2,215.0	244.5	662.6	N	N	N
X.6.18	3	5	1982-07-01	Production	Production	0.7	2012-08-14	2,150.0	244.5	642.1	Y	N	N
X.6.19	3	5	1982-08-22	Production	Production	2.1	2012-08-14	1,823.0	244.5	641.3	Y	N	N
X.6.20	3	5	1982-09-15	Production	Production	3.8	2012-07-31	1,200.0	244.5	1,035.7	Y	N	N
X.6.21	3	5	1982-11-01	Production	Idle	2.9	1997-07-21	1,280.0	339.7	285.0	Y	N	N
X.6.22	3	5	1983-07-16	Not productive	Not productive			1,876.0	244.5	558.6	N	N	N
X.6.23	3	5	1983-08-14	Production	Production	2.6	2012-07-31	1,780.0	244.5	878.0	Y	Y	N
X.6.24	3	5	1983-09-23	Marginal	Marginal			1,968.0	244.5	529.7	N	N	N
X.6.25	3	5	1983-10-10	Exploration	Not productive			985.0	339.7	329.2	N	Y	N
X.6.26	3	6	1988-09-05	Production	Marginal producer	2.0	2012-08-01	1,400.0	244.5	404.5	Y	N	N
X.6.27	3	5	1990-09-05	Production	Abandoned	11.2		2,105.0	244.5	1,141.5	Y	N	N

IFC Well Code	IFC Geology Code	IFC Resource Code	Completion Date	Initial Status	Last Known Status	Gross Capacity	Date	Total depth	Production Casing Diameter	Production Casing Depth	Success-ful	Re-drilled	Pumped
	(1–5)	(1–7)	(yyyy.mm.dd)			(MW_e)	(yyyy.mm.dd)	(m)	(mm)	(m)	(Y/N)	(Y/N)	(Y/N)
X.6.28	3	6	1991-12-17	Production	Injector	3.2	1993-07-05	2,127.0	244.5	1,197.8	Y	N	N
X.6.29	3	5	1996-11-25	Production	Not productive	5.7		1,003.0	339.7	376.2	Y	N	N
X.6.30	3	6	1997-06-13	Production	Idle	4.3		2,103.0	244.5	992.7	Y	N	N
X.6.31	3	6	1997-07-29	Production	Production	8.6	2012-08-01	2,054.0	244.5	804.6	Y	N	N
X.6.32	3	6	1997-08-27	Marginal	Marginal producer	0.6	2011-01-05	2,191.0	244.5	662.1	Y	Y	N
X.6.33	3	6	1997-10-09	Production	Production	0.4	2012-08-01	1,440.0	244.5	790.0	Y	N	N
X.6.34	3	6	1997-11-09	Production	Production	3.2	2012-07-31	1,771.0	244.5	1,093.8	Y	N	N
X.6.35	3	6	1998-09-14	Production	Production	5.5	2012-08-01	1,875.0	244.5	1,069.5	Y	N	N
X.6.36	3	6	1999-08-09	Production	Production	1.3	2012-08-14	2,011.0	244.5	1,103.3	Y	N	N
X.6.37	3	6	1999-09-14	Production	Production	8.5	2012-08-15	2,002.0	244.5	1,021.0	Y	N	N
X.6.38	3	4	2006-08-07	Exploration	Marginal			2,894.0	244.5	795.9	N	N	N
X.6.39	3	6	2007-05-28	Exploration	Idle	3.0	2007	2,502.0	244.5	891.7	Y	N	N
X.6.40	3	6	2007-07-06	Production	Monitoring	7.5		2,507.8	244.5	1,286.1	Y	N	N
X.6.41	3	6	2007-11-18	Production	Production	4.5	2012-08-02	2,501.0	244.5	1,102.9	Y	N	N
X.6.42	3	6	2008-01-18	Marginal	Production	0.5	2012-08-15	2,194.0	244.5	759.4	Y	N	N
X.6.43	3	6	2008-07-21	Production	Idle	6.4	2008	2,700.1	244.5	1,038.4	Y	N	N
X.6.44	3	6	2008-11-01	Production	Idle	5.5	2008	2,865.0	244.5	967.2	Y	N	N
X.6.45	3	6	2009-07-07	Production	Idle	35.0		2,104.0	339.7	1,958.2	Y	N	N
X.6.46	3	6	2009-08-28	Production	Production	7.7	2012-08-02	1,468.0	244.5	993.5	Y	N	N
X.7.1	3	6	2002-09-09	Exploration	Idle	6.0		1,953.2	244.5	609.5	Y	N	N
X.7.2	3	5	2003-12-13	Exploration	Not productive			1,723.0	244.5	611.1	N	N	N
X.7.3	3	6	2006-09-28	Exploration	Idle	5.9		2,659.0	244.5	756.0	Y	N	N
X.7.4	3	6	2007-08-25	Production	Idle	14.1		2,239.5	244.5	824.7	Y	N	N

IFC Well Code	IFC Geology Code	IFC Resource Code	Completion Date	Initial Status	Last Known Status	Gross Capacity	Date	Total depth	Production Casing Diameter	Production Casing Depth	Success-ful	Re-drilled	Pumped
	(1–5)	(1–7)	(yyyy.mm.dd)			(MW_e)	(yyyy.mm.dd)	(m)	(mm)	(m)	(Y/N)	(Y/N)	(Y/N)
X.7.5	3	6	2007-10-05	Abandoned	Abandoned			1,909.7	244.5	846.5	N	N	N
X.7.6	3	6	2008-08-19	Production	Idle	10.4		2,499.0	244.5	812.7	Y	Y	N
X.7.7	3	6	2008-09-17	Production	Idle	5.6		2,798.9	244.5	846.0	Y	N	N
X.7.8	3	6	2011-09-17	Production	Idle	3.6		2,509.0	244.5	768.8	Y	N	N
X.7.9	3	4	2011-11-09	Exploration	Monitoring			2,503.0	244.5	1,493.5	N	N	N
X.7.10	3	6	2012-12-15	Production	Idle	2.0		2,194.3	244.5	824.9	Y	N	N

Appendix B – CD with Data Analyzed etc. (closed distribution)

Excel-table: Dataset of 234 high temperature geothermal wells in Iceland

Excel workbook (in Icelandic)

Sheet 1: Extended dataset of 234 high temperature geothermal wells.

Sheet 2: List of all comments in Sheet 1.

Sheet 3: Discrepancies between databases.

List of references for the tables (in Icelandic)