Proceedings World Geothermal Congress 2005
Antalya, Turkey, 24-29 April 2005

Overview of Production at the Mori Geothermal Field, Japan

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Keywords: Japan, Mori, production, reinjection, reservoir, tracer, caldera

ABSTRACT

Mori geothermal field is located in Hokkaido, northern part of Japan and has a liquid dominated reservoir. This field is characterized by its caldera, Nigorikawa Caldera, of an angular funnel shape. It was formed 12,000 years ago with a series of violent eruptions. Heat sources of the field are related to the volcanic activities. Also, major permeability of the reservoir is related to fractures associated with the formation of the caldera. Geothermal exploration in the caldera began in 1972. A 50 MWe double-flash power generation started in 1982, with 4 production wells and 4 reinjection wells.

Stable steam production in this field has not been very easy. This field has experienced many types of troubles since its start of operation, e.g. $CaCO_3$ and $CaSO_4$ scaling in production wells, stevensite scaling in hot water pipelines and reinjection wells, return of reinjected water to producers, down flow of shallow ground water into the reservoir, resulting enthalpy decrease of the produced fluid, and resulting decline of steam production. Some of them have been solved but some of them are still not. Reassessment of the reservoir suggests that sustainable steam production from the reservoir is about 250 t/h. Current output is 20 to 25 MWe with 10 production wells and 10 reinjection wells.

1. INTRODUCTION

The Mori geothermal field is located in the Nigorikawa Caldera in southwest Hokkaido, Japan (Fig.1). Geothermal resources in this field was first noticed when an oil exploration well was drilled in late 1910s, which produced steam and hot water from depths 60-140m (Nakamura, 1983). Later on, the basin was found to be a volcanic caldera (Sato, 1969).

The Nigorikawa Caldera was formed about 12,000 years ago, by violent pyroclastic flow eruption, fallback, and the following subsidence by compaction with degassing. The caldera is 3 km in diameter at the outer rim. Drilling data shows an angular funnel shape, with a wide upper region (3 x 2.5 km) tapering to a narrower lower region (0.7 x 0.5 km). At depth, the shear zone is rectangular with NE-SW elongation. The caldera is infilled with vent-fill material, lake and alluvial deposits, landslide deposits, and post-caldera intrusions. The vent-fill material is a gray, non-welded lapilli tuff and tuff breccia, which homogeneously includes accidental lithics and shatterd fragments, which were sheared during pyroclastic eruption, as well as accretionary lapilli occurring up to –824 m ASL. The vent-fill is intercalated with many lithic bands or lithic dominant zones that dip toward the caldera center. No large fault displacement is found around the caldera wall. Further volcanological characteristics of the Nigorikawa Caldera have been reported by Kurozumi and Doi (2003).

The Mori geothermal power station (installed capacity 50 MWe double-flash turbine system) has been in operation since 1982. However, maintaining its output has not been very easy because of several reasons. In this report, we review exploration, development and operation of geothermal power generation in this field, and lessons we learned, by updating a review by Takanohashi (2002).

Fig.1 (a): Location of the Mori geothermal field and Nigorikawa Caldera.

2. EXPLORATION AND DEVELOPMENT

Earthscientific studies by Geological Survey of Japan during 1967 and 1968 revealed that the Nigorikawa basin was a volcanic caldera of the Crater Lake type (Sato, 1969). Based on this result, Japan Metals and Chemicals Co., Ltd. (JMC) started geothermal exploration, i.e. geological survey, geochemical survey, gravity and electrical survey in 1972. In 1974, Hokkaido Electric Power Co., Inc. (HEP) and JMC agreed to develop this field for building a geothermal power station of the order of 50 MWe.

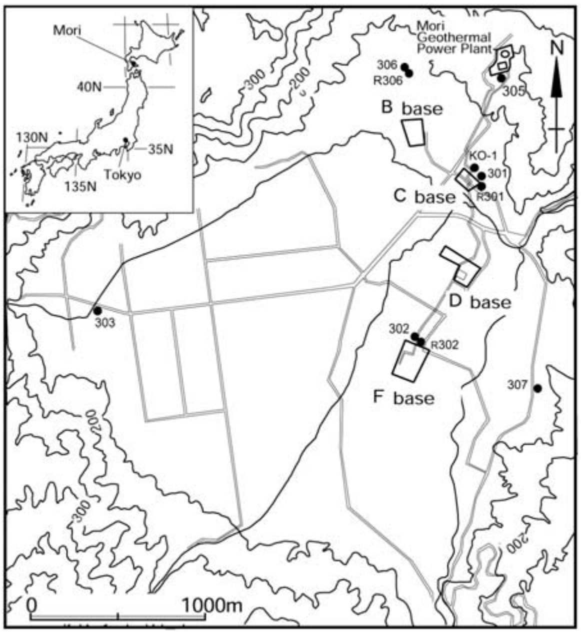
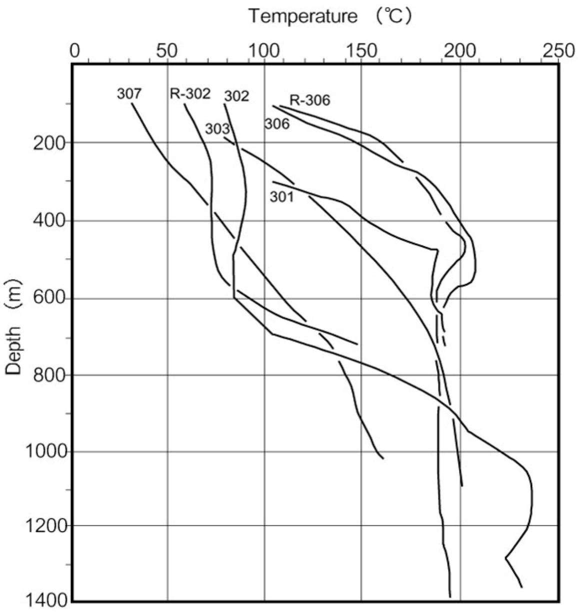


Fig.1 (b): Location of Drilling bases and exploration wells in the Mori geothermal field.



Well	The term of drilling	Outline of Well		
	Start ～ End	Depth	Vertical or Directional	Vertical depth
301	'75. 6. 5～'75. 9.20	1,000m	vertical	-
R-301	'75.10. 6～'75. 11.25	500m	vertical	-
302	'76.11. 1～'76. 12.20	1,500m	vertical	-
R-302	'75.12.15～'76. 4.30	800m	directional	776m
303	'76. 5.11～'76. 7.19	1,146m	vertical	-
305	'76. 9. 3～'76. 10.27	430m	vertical	-
306	'77. 7.12～'77. 11. 5	1,006m	vertical	-
R-306	'77. 7.12～'77. 11.20	1,500m	vertical	-
307	'77. 2. 1～'77. 9.30	1,428m	vertical	-

Fig.2: Temperature profiles and specification summary of exploration wells.

In 1975, the first geothermal exploration well KO-1 tapped a geothermal reservoir and produced steam and hot water at 469 m depth within Neogene formation. Then, 9 small diameter exploration wells were drilled (Fig. 1, 2). Well 301 encountered pre-Tertiary formation at 450 m depth. It was Kamiiso formation, which consists of limestone, chert, basaltic tuff, slate and sandstone. It was later found to distribute below 350 to 750 m depth.

Well R302 encountered the caldera wall and confirmed the existence of fractures. Well 302 tapped the geothermal reservoir at 1,100 m depth. It recorded 243 ^{o}C and produced steam and hot water. This result led an expected reservoir temperature of more than 260 ^{o}C at 1,500 to 2,000 m depth. Wells 301, 303 and 306, which were located out of the caldera wall, found that temperature exceeded 200 ^{o}C below 500 to 1,000 m depth (Fig.2).

Based on these results, characteristics of the geothermal reservoir were hypothesized as follows:

- Fractures around the boundary between the limestone of the Kamiiso formation and Neogene formation below hydrothermal alteration zone at ground surface.
- Fractures within the caldera-fill deposits at depth.
- Fractures within Kamiiso formation and Neogene formation along the caldera wall.

These exploration well confirmed that high temperature over 200 ^{o}C at 1,000 m depth distributes at least 1.5 km x 2.5 km in northern half of the basin. Based on these results, geothermal power development of the order of 50 MWe was started.

One of the most noteworthy characteristics of the Mori field is a high gas content, especially a high CO_2 gas concentration. Thus, scaling problem of $CaCO_3$ was anticipated.

A success of production tests of wells 301, 302 and 306 led to an estimation of 40 t/h steam production from a full scale production well. Also, a success of reinjection tests of wells 302 and 307 led to confidence of reinjection of 1,600 t/h hot water, which was expected to produce along with 500 t/h steam for 50 MWe power generation.

Dohnan Geothermal Energy Co., Ltd. (DGE) was established in 1976 under initiative of JMC. DGE made an agreement of the development with HEP in 1977. Thus, the steam field development was fully transferred to DGE from JMC, but JMC was still in charge of technical affairs.

Drilling of production and injection wells were started in August 1977. 17 wells were drilled between 1977 and 1981. Depths of these wells ranged from 736 m to 2,600 m; 8 of them exceeded 2,000 m.

Production fractures were first known in the caldera wall. Then the drilling was mostly targeted towards the caldera wall. However, fractures were encountered in the chert and limestone in the Kamiiso formation. Structural analysis of the fractures in the Kamiiso formation suggested the existence of 3 faults trending NE to SW (Fig.3), though these faults are not believed now.

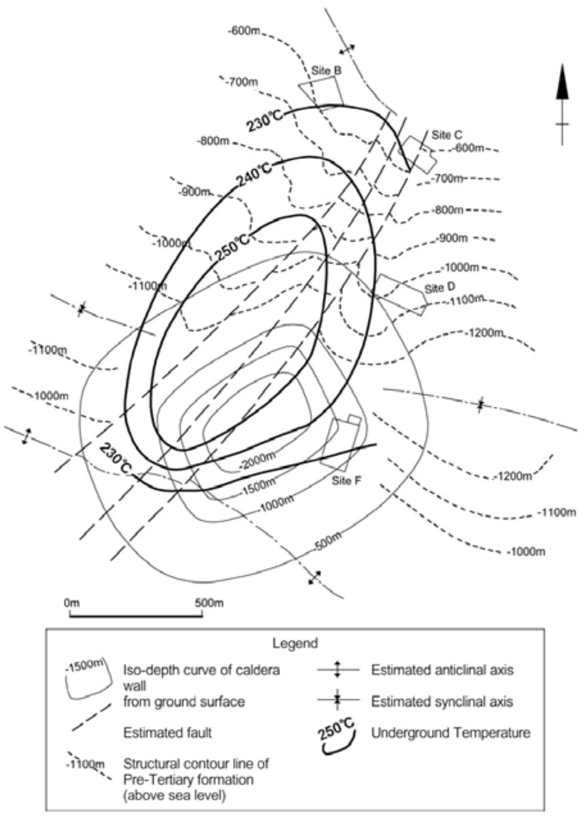


Fig.3: Three hypothesized faults in the Kamiiso formation and temperature distribution at –2,000 m depth; interpretation in early 1980s.

Based on the temperature distribution at –2,000 m ASL, a shape of the high temperature zone was thought to be affected by fault zones instead of the caldera. Then, the decision was made to produce steam from the fault zone in the Kamiiso formation and reinject separated water into the caldera wall.

10 of the wells were productive. Simple sum of the steam production was 723 t/h, and that of the reinjection rate was 2,532 t/h. Based on this result, 6 wells and 7 wells were assigned as production wells and reinjection wells, respectively (Table 1).

Table 1 Production and reinjection rates at Nov. 1982.

Site	Well	Depth (m)	Steam and Hot water: Primary Steam 7.0KSCG (ton/hr)	Steam and Hot water: Secondary Steam 1.7KSCG (ton/hr)	Steam and Hot water: Secondary Hot water (ton/hr)	Well	Depth (m)	Injected hot water: Pressure (KSCG)	Injected hot water: Flow rate (ton/hr)
Site B						B-2	1,792	5.5	98
Site C						C-1	1,773	5.5	116
Site D	D-1	2,400	60.9	22.7	262				
	D-3	2,320	132.4	42.7	492				
	D-5	736	78.2	54.2	624				
	D-6	2,205	56.2	13.1	151				
Site F	F-1	2,464	132.4	35	402	F-2	2,025	5.5	414
	F-9	2,340	67.9	25.4	293	F-5	998	5.5	428
						F-6	2,383	5.5	95
						F-7	1,464	5.5	370
						F-8	1,785	5.5	196

Though, average production rate from a well was about 100 t/h of steam and 400 t/h of hot water, success rate of wells was not high. This was because of maldistribution of permeability in the target zones, i.e. the caldera wall and the fault zone. To improve productivity and injectivity, massive hydraulic-fracturing jobs were tried and resulted in good results (e.g. Katagiri et al., 1980). Along with the fracturing jobs, Acoustic Emission monitoring and fracture mechanics analysis were also tried (e.g. Sato et al., 1983; Niitsuma et al., 1985).

As described above, gas concentration in steam from Mori field is rather high. Most of the gas in steam in Mori is CO_2 (Table 2). At that time, scale deposition was expected to occur in pipelines, especially when flow was throttled. Thus, humic acid was considered for the scale prevention.

Construction of pipelines and the power plant started in April 1981. It was completed in August 1982, and then the trial run was started. On September 24, 1982, 50 MWe power generation was first achieved. Then, commercial power generation was started at 50 MWe on November 26, 1982, using 388 t/h 1st stage steam, 121 t/h 2nd stage steam and 1,215 t/h reinjection.

Table 2 Steam and hot water chemistry in early stages of production

(a) Steam (Vol%)

Production Well	Water/Gas ratio: H_2O	Water/Gas ratio: Gas	Component of Gas: H_2S	Component of Gas: CO_2	Component of Gas: R	Component of Residual Gas: H_2	Component of Residual Gas: N_2	Component of Residual Gas: CH_4	Sampling Date
D-1	99.47	0.53	1.2	97.3	1.5	1.1	71.2	27.7	1983/4/6
D-3	95.20	4.80	1.1	97.8	1.1	0.3	43.1	56.6	1983/11/4
D-5	97.50	2.50	2.4	97.2	0.4	1.6	59.8	38.6	1983/6/7
D-6	99.09	0.91	1.1	97.4	1.5	1.8	65.1	33.1	1983/2/11
F-1	96.01	3.99	1.2	97.7	1.1	0.2	47.9	51.9	1983/5/6
F-9	98.77	1.23	0.7	97.7	1.6	0.2	59.5	40.3	1983/3/15

(b) Condensate (mg/l)

	pH	H_2S	CO_2	Cl	SO_4	Na	K	Ca	Mg	SiO_2	Fe	Al
D-1	5.54	23	609	0.1	3.0	0.01	<0.01	0.05	<0.01	0.01	0.12	0.05
D-3	5.46	34	1,370	0.1	0.1	0.08	0.01	<0.01	<0.01	0.10	<0.01	0.01
D-5	5.53	73	1,380	0.6	6.5	0.33	0.10	0.02	<0.01	0.07	0.14	0.07
D-6	5.55	30	746	0.3	1.6	0.07	0.04	<0.01	<0.01	0.03	0.25	0.03
F-1	5.34	38	1,520	0.2	2.0	0.05	0.05	0.06	<0.01	0.03	0.06	0.03
F-9	5.32	20	1,120	0.2	2.0	0.03	0.03	<0.01	<0.01	0.04	0.18	0.03

(c) Hot water (mg/l)

	pH	H_2S	CO_2	Cl	SO_4	Na	K	Ca	Mg	SiO_2	Fe	Al
D-1	8.42	0.4	99	7,570	384	4,760	762	11.6	0.1	563	0.38	0.17
D-3	8.41	1.4	418	6,440	281	4,090	718	3.2	0.3	695	0.12	0.21
D-5	8.55	1.4	180	5,570	211	3,560	579	11.3	1.8	546	0.24	0.11
D-6	8.40	1.4	39	7,260	275	4,370	654	5.1	0.1	582	0.12	0.11
F-1	8.56	1.8	298	7,310	207	4,400	886	4.3	0.2	764	0.86	0.16
F-9	8.39	1.0	124	8,260	490	5,090	738	6.6	0.3	499	0.54	0.14

3. OUTLINE OF CHANGE OF OUTPUT AND STEAM PRODUCTION

Change of output in Mori is shown in Fig. 4. Right after the start of the commercial operation, $CaCO_3$ scale deposition in production wells had become a serious problem. It was solved by injection of a prevention chemical, but after that return of injected fluid into production wells became serious. Moreover, troubles occurred on injection tubes for the scale prevention, and then output had dropped below 10 MWe in 1989.

One of the reasons of this decline is very large local pressure draw down around a production well due to a large production from the well. This large local draw down caused an inflow of shallow ground water into the reservoir and resulted in further cooling of the reservoir.

Then, drilling of production and reinjection wells, decentralization of the production zone utilizing new target areas, and relocation of production and reinjection zones giving much larger distance considering the reservoir pressure balances, were carried out based on reassessment of the reservoir. This series of measures led to gradual recover of the production. After the drilling of well ND-11, which is the first 3 km depth well in Mori, output has been almost stable at around 25 MWe.

4. CAUSES OF PRODUCTION DECREASE AND MEASURES AGAINST THEM

4.1 $CaCO_3$ scale deposition in production wells

When the 50 MWe power generation was officially started on November 26, 1982, 4 production wells, ND-1, ND-3, ND-6 and NF-1 were used. Only 4 days after the start of the commercial power generation, steam decrease from the production wells became evident. Then, standby wells NF-9 and ND-5 were online successively. However, the 50 MWe power generation was not maintained and the output started to decrease.

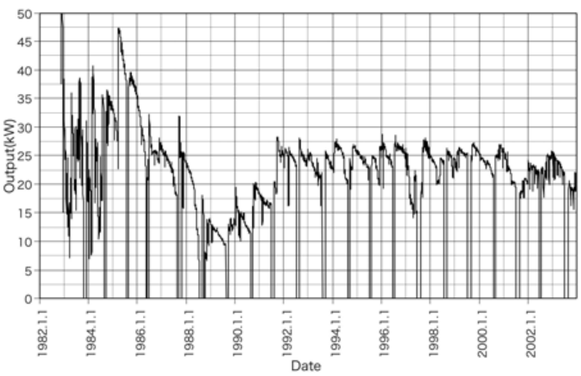


Fig.4 Output of the Mori geothermal power station

In December 1982, wellhead pressure of the production well ND-3 became too low to be online. From some measurements and inspections in the ND-3 borehole, the causes of the decline was found to be $CaCO_3$ scale deposition in the borehole. The scale deposition in boreholes became evident in wells ND-1, ND-5, NF-1, ND-6 and NF-9 successively (Fig. 5). Because of this rapid decrease in steam production caused by blockage by $CaCO_3$ scale in boreholes, output became below 15 MWe in April 1983.

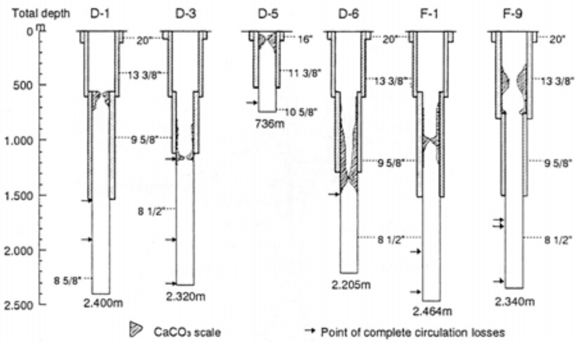


Fig.5 $CaCO_3$ Scale deposition in production wells

As one of the measures to this problem, the scale deposit was mechanically removed by drill bits at first. However, this operation was time consuming and costly. Also, this operation injected cuttings of the scale deposit into production fractures, and resulted in decrease in fracture permeability.

Then, HCl acid treatment was tried. However, there occurred another problems, i.e. damage of casing pipes by HCl and strong offensive smell after the job. Then, the mechanical removal and the acid treatment were combined. Also, hot water was injected so as to clean the inside of boreholes and dilute HCl which flowed into the reservoir, at the end of the recovery job. This combination job was successful and recovered the output to 30 MWe in September 1983.

To thoroughly overcome this scale problem, a fundamental research was carried out as a part of NEDO project from 1983. Based on the results of the study, continuous injection of polyacrylic acid soda into production wells to prevent $CaCO_3$ scale deposition in boreholes, was started from December 1983. This injects the scale prevention chemical into depths slightly below flashing depths of production wells. Because of success of the measures, the output was recovered to 35 MWe in August 1984.

The scale prevention chemical is injected into boreholes through tubing. At first, both conventional oil-field tubing and parasitic tubing were employed, but later the conventional tubing inside of boreholes was solely employed though the conventional tubing reduce production rate because of reduction in cross sectional area of open space in boreholes. This change was chosen because of difficulty of changing injection depths. That is, injection depth of the parasitic tubing was fixed, so that we could not change injection depths according to changes in flashing depth. On the other hand, conventional borehole tubing can allow us to change injection depths only by changing tubing depths.

Many troubles occurred on the tubing especially in 1987 and 1988, and caused severe damage on power production. For example, power generation was obliged to stop while fixing the tubing of NF-1 in September 1988. To overcome this problem, coiled tubing, i.e. a large diameter capillary tube, was employed instead of the conventional tubing from September 1991, to inject the scale prevention chemical (Fig.6). It can be installed and retrieved by a winch. This greatly reduced time and cost for the installation and retrieval of the apparatus. At first, stainless steel tube was employed, but it was later replaced with Incoloy tube from June 1991, which withstands in further hostile condition. Fig. 6 shows the current chemical injection apparatus.

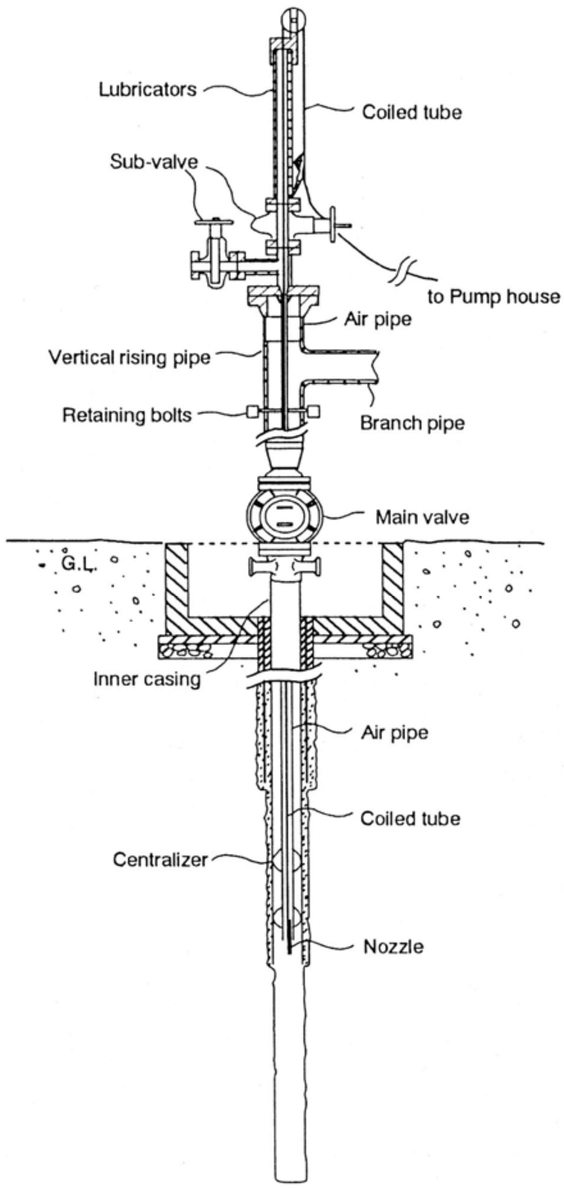


Fig.6 Chemical injection apparatus for $CaCO_3$ scale prevention

4.2 Migration of Reinjected Water

Average water to steam ratio of produced fluid in November 1982, when the 50 MWe power generation was officially started, was about 3.4. Total amount of Reinjected water was 1,200 t/h into wells NF-2, NF-5, NF-7 and NF-8 at that time.

The above mentioned scaling problem was almost solved in September 1983; the output was recovered to 30 MWe. However, the average water to steam ratio increased to 3.8. Also, increase of chlorine concentration and decrease of enthalpy of produced fluid had become notable. These indicated that return of reinjected fluid had become affecting production. Results of tracer tests in 1983 confirmed that the reinjected fluid returned to producers NF-9, ND-1 and ND-6.

In January 1984, the output returned to 32.8 MWe, and then it was recovered to 47.3 MWe in March 1985 owing to the success of a new production well ND-7 (T.D. 2,733 m, initial steam production rate 109 t/h). However, rapid decline still continued. Then, another tracer tests were done and found that reinjected fluid into NF-6, NF-7 and NF-8 was affecting production badly and causing serious temperature decrease. To overcome this problem, 500 t/h of reinjected fluid into NF wells was started to be relocated into wells in the C base from July 1986 (Fig.7).

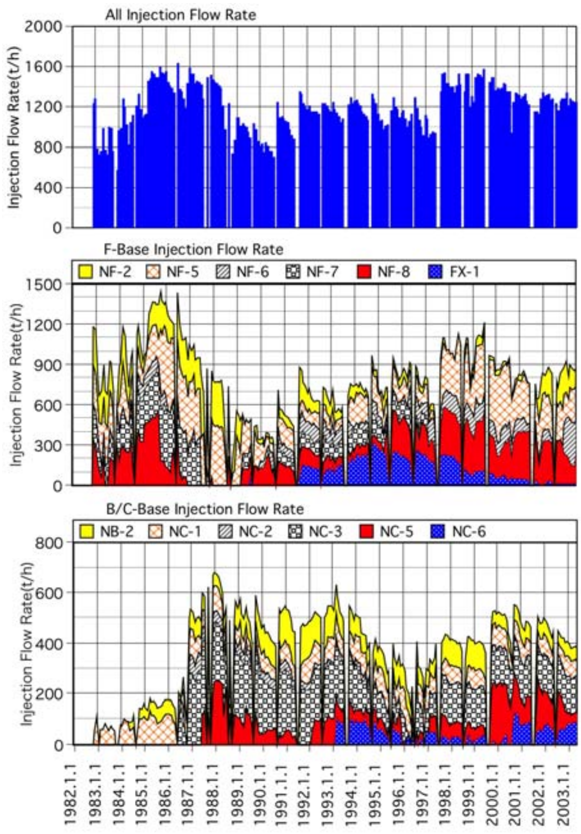


Fig.7 Changes in reinjection in total and of wells

This action reduced the rate of return of reinjected water into producers, but accelerated the reservoir pressure decline. Due to the accelerated reservoir pressure decline, the shallow ground water, which has low chlorine concentration, started to flow into producers through the caldera wall. This phenomenon continued to decrease enthalpy of produced fluid. Due to the enthalpy decline, wells NF-9, ND-6 and ND-3 stopped production in July 1987, September 1987 and June 1988, respectively.

To overcome this problem, balances of production and reinjection rates of all the wells were reexamined and reassigned. Along with this reexamination, production well ND-6 was sidetracked in 1989, and new production wells ND-9 and ND-11 were drilled in 1990 and 1991, respectively. As a result, 228 t/h of steam was produced from 8 production wells. Also, reinjection rate was distributed as many wells as possible to reinject in wider area instead of a single zone. By the end of 2004, 42 tracer tests have been conducted since February 1983.

Produced fluid in Mori field is characterized by 3 components; 1) original geothermal fluid from depth, 2) reinjected water, 3) low chlorine shallow ground water (e.g. Yoshida, 1991). Contributions of these 3 components between 1985 and 2003 are shown in Fig.8.

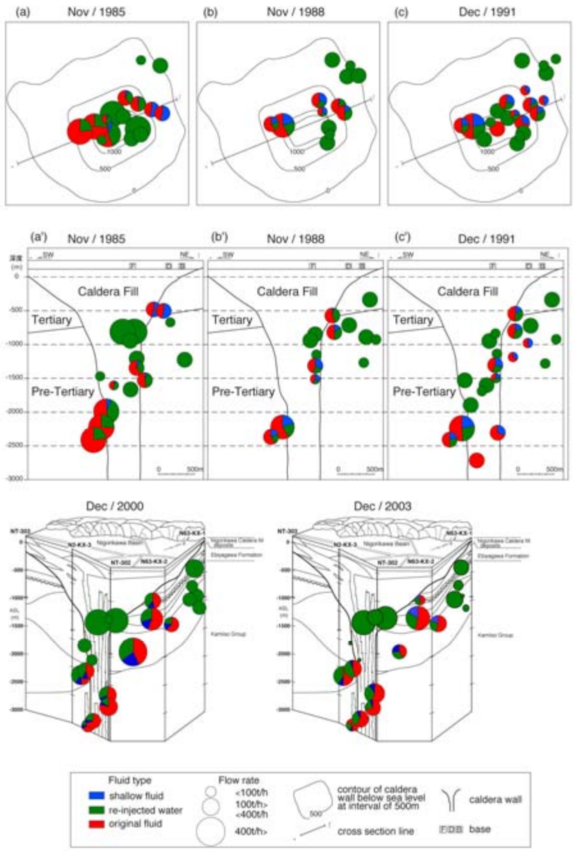


Fig.8 Changes in distribution of production and reinjection and proportion of three component fluids in produced fluid

4.3 Scale Deposition in Line Pipes and Reinjection Wells

Besides the above mentioned $CaCO_3$ scale deposition in production wells, stevensite deposition was found in well ND-1 and some line pipes for reinjection water in October 1988 (e.g. Muramatsu and Akazawa, 2000). Magnesium plays an important role for the formation of the stevensite. Studies on fluid temperature and Mg concentration of well ND-1 suggested that Mg in dolomite in the Kamiiso formation dissolved into geothermal fluid due to the temperature decrease caused by the return of reinjected water, and then it formed the stevensite.

In the upper reaches of the reinjection pipeline, in which water temperature is still rather high, coupling of Mg and SiO_2 easily forms the stevensite with high crystallinity. On the other hand, in the lower reaches of the reinjection pipeline, Mg/SiO_2 ratio becomes lower resulting in lower crystallinity. Based on observations using an electron microscope, there are so many different shapes of the stevensite scales reflecting different formation conditions even in the same location of pipelines.

Scale deposits in pipelines have been removed by high-pressure water jet during the annual inspection of the power plant. Shapes of them are bedded, platy, flexuous, flaky and muddy. Also, their hardness and strength are all different. Sometimes, flakes of scales peeled from pipelines flow into reinjection wells and reduce their reinjectivity. For example, there occurred a serious decrease in reinjectivity in well NF-2 in 1989. Since there occurred the stevensite scale problem, work over of reinjection wells had become important to maintain their reinjectivity.

To overcome this problem, pH control of reinjected water has been applied since 1997, based on results of field experiments since 1994 (Kasai et al., 2000). This treatment has been very successful and reduced cost of the annual inspection greatly. Also, reinjectivity of wells recovered to the level before 1988.

5. MORI GEOTHERMAL RESERVOIR AND CURRENT OPERATION STATUS

5.1 Mori Geothermal Reservoir

The heat source of the Mori geothermal field was first estimated to be a magma chamber, which caused the eruption of the Nigorikawa Caldera about 12,000 years ago. This idea has not been changed basically to date. However, detailed studies on skarn minerals in the Kamiiso formation indicated that the heat source consists of the following two members; deeper parts of andesitic intrusions which intruded almost the same period as the caldera eruption, and conductive heat from solidified magmas intruded before the caldera eruption.

The Nigorikawa Caldera is characterized by its angular funnel shape (Figs 9 and 10). Over 40 wells has been drilled in the caldera; 4 of them exceed 3,000 m depth. These wells revealed the following fundamental characteristics of the caldera; 1) shape of the shallow part of the caldera is controlled by shallow tectonic conditions, 2) an inclination of the caldera ranges between 60 to 70 degrees, and 3) inside of the caldera down to –1,600 to –1,700 m ASL is infilled by fallback from the caldera (e.g. Ando et al., 1992). Based on these characteristics, Aramaki (1984) selected this caldera as the typical example of funnel shaped calderas, and named it “Nigorikawa type caldera”.

Later, scientific core holes, e.g. N2-KX-3, were drilled by NEDO. Detailed inspection of cores from these wells revealed formation processes of the caldera and associated fractures (Kurozumi and Doi, 2003). Schematic cross section of the caldera and isobaths of the subsurface caldera wall are shown in Figs 9 and 10, respectively.

By these core holes, 39 clastic veins, 13 altered andesitic dikes were confirmed within basement rock in the vicinity of the caldera wall. Distribution of these veins and dikes indicates extent of the shear zone around the caldera wall; horizontal extent is about 500 m in northeast, about 150 m in northwest, more than 250 m in southwest, and about 130 m in southeast (Kurozumi and Doi, 2003).

In the early stage of the development, faults and associated fractures in the Kamiiso formation were assumed to be permeability of the reservoir, as described above. However, this idea is not valid now.

Fractures are also found in zones about 150 m inside of the caldera wall. They are formed by degassing and subsequent compaction process after the caldera eruption. They cause lost circulations and give permeability for production. Also, fractures are confirmed around post caldera intrusions (Kurozumi and Doi, 2003).

Clay minerals were used for zoning of altered minerals in the caldera fill, in the early stages of the development. However, garnet was later found in the caldera fill. Then, detailed zoning was tried again using calcium silicate minerals, e.g. garnet, epidote, wollastonite, amphibole and clinopyroxene. Based on this study and minimum homogenization temperature distribution of quartz, calcite and anhydrite, initial temperature distribution was estimated again and confirmed that the caldera wall is the hot up-flow region of the reservoir (Arai and Komatsu, 1998).

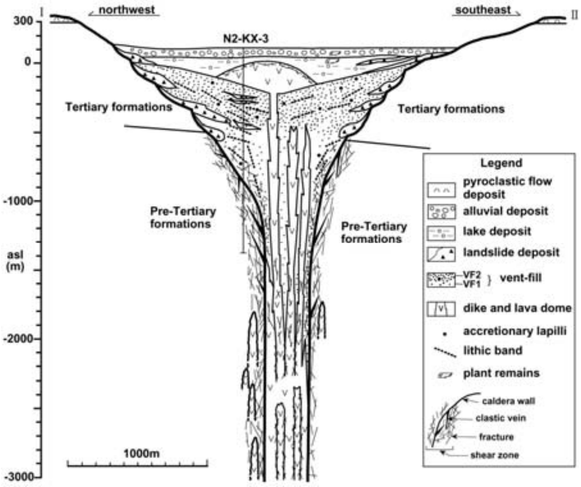


Fig.9 Schematic cross section of Nigorikawa Caldera (Kurozumi and Doi, 2003)

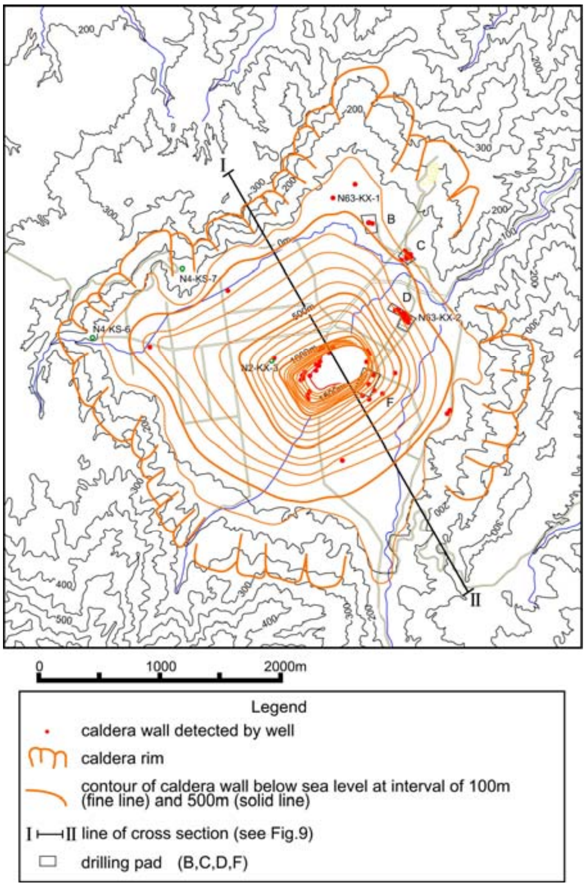


Fig.10 Isobaths of the caldera wall (Kurozumi and Doi, 2003)

Fluid in this field is basically a mixture of meteoric water and seawater. It is classified into 4 types based on SO_4 concentration and SO_4/Cl. Gas composition of the geothermal fluid suggests that some magmatic fluid mixes into the geothermal fluid. Hot springs in the caldera basin are mixtures of shallow ground water and the geothermal fluid, based on analyses of their chemical composition and isotopic composition (e.g. Yoshida, 1991).

Produced fluid is classified into 3 groups from chlorine concentration and specific enthalpy; 1) deep geothermal water which is high enthalpy and high Cl concentration, 2) ground water which is low enthalpy and low Cl concentration, and 3) reinjected water which is high Cl concentration. Wells ND-11, NF-10, NF-11, NF-12 produce high enthalpy fluid which does not contain a lot of reinjected water and ground water, suggesting that the deep geothermal water ascends northern to northwestern side of the caldera wall.

Isotopic study shows that ground water flows into the center of the hot spring reservoir from the outer side of the caldera; it is a relatively slow flow. Also, the ground water flows into the geothermal reservoir through the high permeability part of the caldera wall; it is a rather fast flow. The current reservoir model is shown in Fig.11.

5.2 Numerical Modeling and Reevaluation of Sustainable Output

As described above, about 400 t/h steam was produced from 4 production wells and 1,200 t/h hot water was reinjected through 4 reinjection well at the first stage of the power production. However, capacity of the reservoir was later found not to be large enough for 50 MWe power generation. Thus, reassessment of the reservoir capacity based on numerical modeling was tried later.

In 1988, 3 dimensional numerical modeling of the reservoir using the GEOTHER code was carried out. It covered area of 1,500 m X 1,700 m and 2.350 m depth with 648 grids. The study consists of a history matching to reservoir pressures, borehole temperatures and geochemical temperatures between November 1982 to October 1987, and some performance predictions. The results indicated that sustainable steam production was about 250 t/h.

In 1989, Central Research Institute of Electric Power Industry carried out a third party study. Their results indicated that sustainable steam production was at most 240 t/h.

From 1988 to 1993, 3 dimensional numerical modeling was carried out again using SING and FIGS codes, as a part of a NEDO project. It covered area of 11.4 km in northeast to southwest with 14 grids and 11.3 km in northwest to southeast with 14 grids, and from +100 m ASL to –3,800 m ASL in depth-wise with 19 layers; 3,724 grids in total excluding outer cells. The study consists of a natural state modeling, a history matching to reservoir pressures, borehole temperatures, geochemical temperatures and chlorine concentrations, and some performance predictions (Sakagawa et al., 1994). The results gave valuable insights for better allocation of production and reinjection to each well.

Based on these results, new strategy for operating the field was established as follows; 1) allocate production in wider area than before, so as not to cause too much local reservoir pressure draw down in a particular area, 2) further separate production and reinjection zones so as to reduce rate and speed of the migration of the reinjected water, 3) make efforts to reduce rate of the down flow of the ground water into the reservoir through the caldera wall by controlled reinjection in shallow part of the caldera, and 4) target to stabilize output at 20 to 25 MWe.

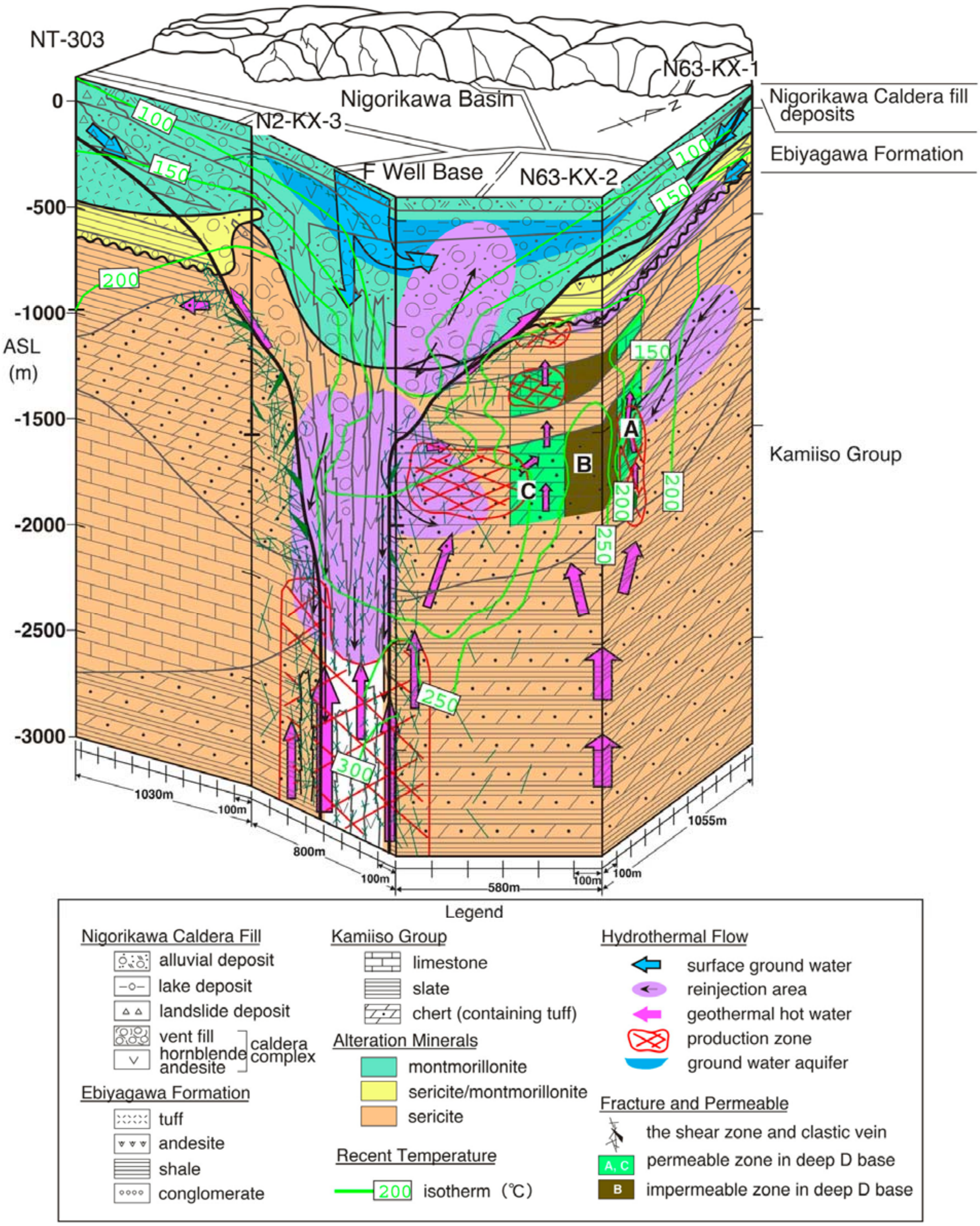


Fig.11 Schematic conceptual model of the current state of the Mori geothermal reservoir

5.3 Current Operation Status

Only 4 production wells were used when commercial power generation started at 50 MWe in 1982. Large average steam production from one well reduces necessary number of wells, and leads to lower development cost. However, initial decline is generally very large, and a very large production drop will occur if a well stops production. Also, this causes a large reservoir pressure draw down in the vicinity of the wells. Thus, being a large average steam production per well sometimes has a higher risk in operation of a geothermal field.

From 1991, 4 deep production wells of the order of 3,000 m depth and a reinjection well NC-6 has been drilled to disperse production and reinjection in wider area. Currently, 80 to 100 t/h steam is produced from 4 production wells (500 to 1,500 m depth) in the outside of the caldera, 40 to 50 t/h is from 2 production wells (about 2,000 m depth) in the vicinity of the caldera, and about 100 t/h is from 4 production wells (depths deeper than 2,500 m) in the deep part of the caldera, resulting in 220 to 240 t/h 1st stage steam in total (Fig.12). At the same time, 700 to 800 t/h water is reinjected into 5 reinjection wells within the caldera, and 400 to 500 t/h water is reinjected into 4 reinjection wells out of the caldera. Based on this production and reinjection, 20 to 25 MWe power generation has been continued.

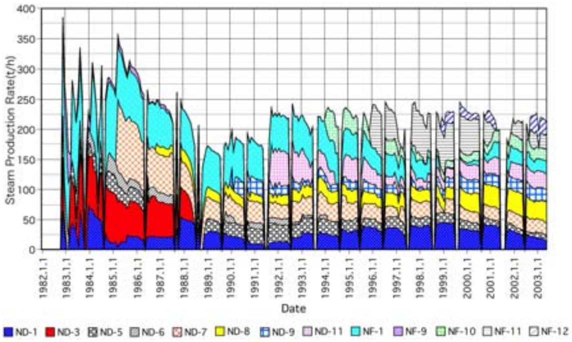


Fig.12 Changes of 1st stage steam from wells

As a reservoir monitoring, 4 wells of the order of 1,000 m depth, which are located in the production zone, reinjection zone and their peripheries, have been used for continuous monitoring of the reservoir pressure decline. Wellhead pressure, line temperature, and line steam and water rates have been continuously monitored. Steam and water rate of each production well has been measured once a month, by a tracer dilution method. Also, Ca, Cl and SiO_2 concentration of produced water have been monitored once every 10 days, and detailed steam and water chemistry have been monitored once a month. Based on results of these monitoring, reinjection rates of wells are adjusted so as not to give too much damage on production wells.

In general, initial decline of steam production of a well lasts for 5 years after the start of production of the well. After that, the steam production rate can be stabilized at about 20 to 30 t/h at a well, if the return of reinjected water is adequately controlled. In some cases, steam production could be increased slightly, owing to recovery of fluid temperature; e.g. the case of ND-8 in Fig.13. In this case, fluid temperature recovered from 206 ^{o}C (1992) to 224 ^{o}C (2000).

There still remains the return of reinjected water to all the production wells. The reinjected water, which returns to production wells with thermal recovery, is now estimated to be about 110 t/h, based on results of the tracer tests. However, the tracer test may not detect return of reinjected water, which returns after a very long period of time. Thus, there must be such reinjected water, which is returning to producers after a very long travel time.

$CaSO_4$ scale deposition occurred in the well bore of NF-10, after two years' operation. This led to decline of wellhead pressure and steam production rate (Fig.14). This was resulted from mixture of shallow and deep fluid in the well bore. This problem was fixed by installing a casing pipe to the shallow feed. $CaSO_4$ scale can also be removed by injecting cold water into a production well. This operation is sometimes very effective at some production wells. Thus, it is routinely done before the scaling in the wellbore becomes very serious.

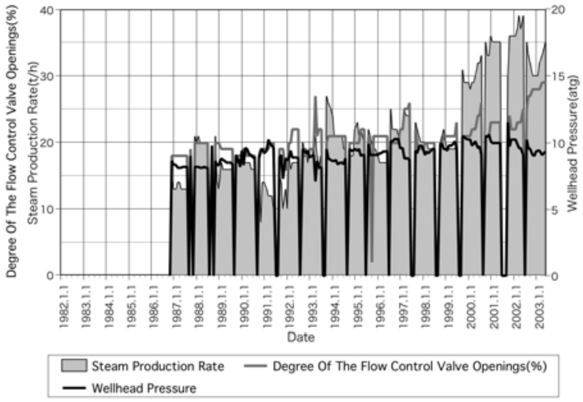


Fig.13 Steam production from ND-8

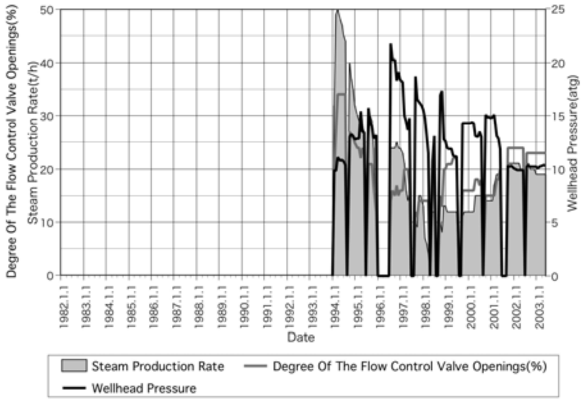


Fig.14 Steam production from NF-10

6. CONCLUDING REMARKS

Mori field has experienced many types of troubles since its start of operation, e.g. $CaCO_3$ and $CaSO_4$ scaling in production wells, stevensite scaling in pipelines and reinjection wells, return of reinjected water to producers, down flow of shallow ground water into the reservoir, resulting enthalpy decrease of the produced fluid, and resulting decline of steam production. Some of them have been solved but some of them are still not. In February 2004, the field was transferred to HEP from DGE. However, JMC is still engaged in reservoir management of the field, and thus hopes to contribute for better operation of the field.

ACKNOWLEDGMENTS

We would like to thank management of JMC, DGE and HEP for their permission to publish this paper. We also would like to thank our colleagues at JMC and JMC Geothermal Engineering Co., Ltd. for their stimulating discussions.

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