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James Koenig

LECTURES ON GEOTHERMAL RESOURCES AND THEIR DEVELOPMENT

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LECTURES ON GEOTHERMAL RESOURCES AND THEIR DEVELOPMENT

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PREFACE

The UNU Visiting Lecturer for 2016 was the American geologist and geothermal specialist Mr. James Koenig. He holds advanced degrees in geology and meteorology and has worked in the geothermal industry for more than 45 years. His geothermal work started when he became a geothermal specialist for the State of California, which he served for nearly a decade. In 1973, James left the state‘s service to establish the geothermal consultancy firm GeothermEx, Inc. He served as its chairman and chief scientist until retirement in 1995. During that period, James led exploration projects that resulted a.o. in the discovery of the Miravalles, Costa Rica; Dixie Valley, Nevada; and Batong Buhay, Philippines geothermal fields. He has also worked at various times in Djibouti, Ethiopia, Indonesia, El Salvador, Honduras, Japan, Kenya, Turkey and Vietnam, for the UN, the World Bank and a large number of private developers and financiers.

After retirement, James served as a volunteer for the International Geothermal Association, concluding this as General Manager of the 2005 World Geothermal Congress in Antalya, Turkey. He continues to work as a part-time consultant, most recently to projects in Kenya, Slovakia, Turkey and the United States. James and his wife Deborah live near San Francisco, California.

Since the foundation of the UNU-GTP in 1979, it has been customary to invite annually one internationally renowned geothermal expert to come to Iceland as the UNU Visiting Lecturer. This has been in addition to various foreign lecturers who have given lectures at the Training Programme from year to year. It is the good fortune of the UNU Geothermal Training Programme that so many distinguished geothermal specialists have found time to visit us. Following is a list of the UNU Visiting Lecturers during 1979-2015:

1979 Donald E. White	United States	1998 Agnes G. Reyes	Philippines/N.Z.
1980 Christopher Armstead	United Kingdom	1999 Philip M. Wright	United States
1981 Derek H. Freeston	New Zealand	2000 Trevor M. Hunt	New Zealand
1982 Stanley H. Ward	United States	2001 Hilel Legmann	Israel
1983 Patrick Browne	New Zealand	2002 Karsten Pruess	United States
1984 Enrico Barbier	Italy	2003 Beata Kepinska	Poland
1985 Bernardo Tolentino	Philippines	2004 Peter Seibt	Germany
1986 C. Russel James	New Zealand	2005 Martin N. Mwangi	Kenya
1987 Robert Harrison	United Kingdom	2006 Hagen M. Hole	New Zealand
1988 Robert O. Fournier	United States	2007 José Antonio Rodríguez	El Salvador
1989 Peter Ottlik	Hungary	2008 Wang Kun	China
1990 Andre Menjoz	France	2009 Wilfred A. Elders	United States
1991 Wang Ji-yang	China	2010 Roland N. Horne	United States
1992 Patrick Muffler	United States	2011 Ernst Huenges	Germany
1993 Zosimo F. Sarmiento	Philippines	2012 Cornel Ofwona	Kenya
1994 Ladislaus Rybach	Switzerland	2013 Kevin Brown	New Zealand
1995 Gudmundur Bödvarsson	United States	2014 Malcolm Grant	New Zealand
1996 John Lund	United States	2015 Meseret Teklemariam Z.	Ethiopia
1997 Toshihiro Uchida	Japan		

With warmest greetings from Iceland

Lúdvík S. Georgsson, director, UNU-GTP

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LECTURE 1

A TIMELINE FOR DEVELOPING GEOTHERMAL ENERGY

Every geothermal field is unique, with regard to the resource, its physical and cultural environment, and the cost and complexity of development. Despite this uniqueness, it is possible to list the steps required in the exploration, wellfield development, and design and construction of power plants, and to estimate the time in months needed to accomplish this.

Figure 1 shows the assumptions underlying this process, based on a 30 MW power plant. It is assumed that authorization has been received to begin work, along with funding for the preliminary stages. It is further assumed that trained staff are available for the project, and that contracts can be awarded without undue delays. Changes from any of these assumptions can add considerable amounts of time to the project.

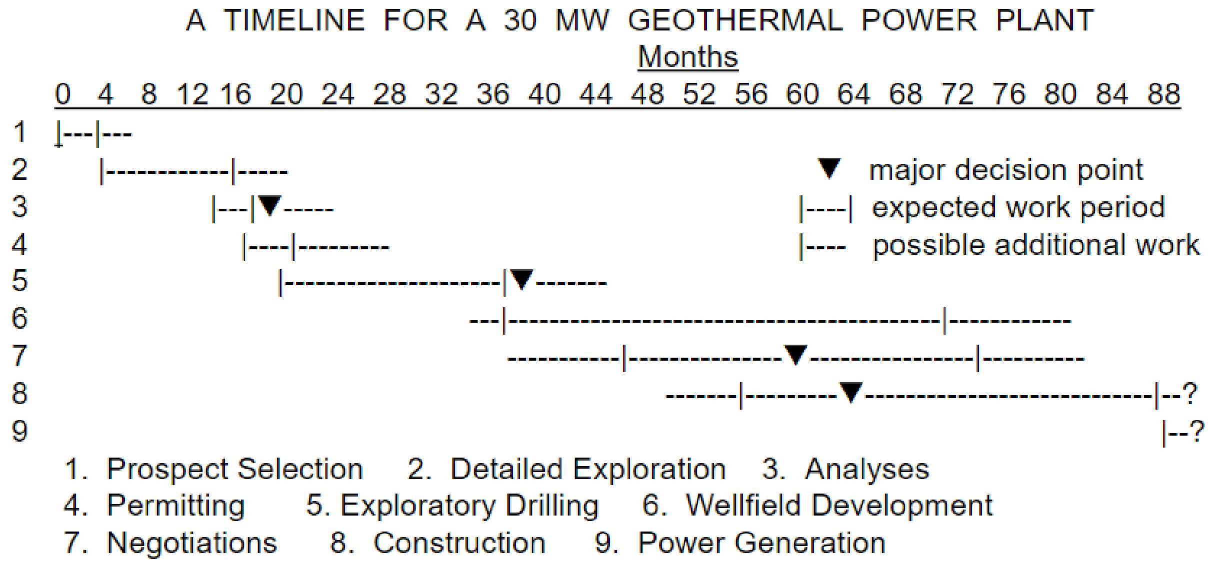

FIGURE 1: Timeline for a 30 MW geothermal power plant

Very few projects have gone from inception to delivery of electricity in less than 90 months – 7-1/2 years. Many have taken considerably longer. Reasons for lengthy delays will be explained in the following paragraphs.

The major elements in the process are grouped into 9 stages, representing broadly similar sets of activities. Many other groupings are possible, reflecting local practice.

*1. Project selection: R*eview of prior work...establishment of team...initial permitting...reconnaissance of prospect...design of exploration programme. Time: 3 months.

<u>Possible delays</u>: other commitments for trained staff; issues in permitting surface exploration

2. Detailed exploration of prospect. Some or all of the following: geological mapping...logging existing holes...fluid geochemistry...gravimetry...electrical resistivity...magnetotellurics...passive seismicity ...seismic reflection profiling...shallow temperature gradients...conceptual model. Time: 12 months (cumulative 15 months).

<u>Possible delays</u>: need to perform all of above; need to resurvey part or all of target area; problems of contracting with suppliers; lack of sufficient manpower, field vehicles or equipment

3. Analysis and decision point: Analysis of exploration data...market analysis...budgeting and preliminary economic calculations...discussions with financiers...decision whether to proceed. Time: 3 months, in small part simultaneous with stage 2 (cumulative 17 months).

> Possible delays: insufficient or ambiguous data; need to repeat prior work; ambivalent results from market or economic analysis

4. Permitting of next stage: Preliminary environmental studies...land access...mezzanine financing of drilling...permitting of drilling. Time: 4 months, beginning in final month of stage 3 (cumulative 20 months).

> Possible delays: discovery of serious environmental hazards; need for more, or more definitive, data; difficulty in arranging financing; problems with permitting; land access issues

5. Exploratory drilling: Well design...negotiations with drilling contractor...mobilization to drilling site...drilling exploratory wells 1, 2, 3...logging and short-term testing...long-term testing...numerical simulation of reservoir...decision to proceed. Time: 18 months (cumulative 38 months).

> Possible delays: delayed mobilization of drilling rig; unexpected drilling problems; ambiguous or marginal results after drilling 3 wells; need to finance additional wells

6.Wellfield development: Wellfield design…drilling of production and injection wells...testing of production and injection wells...design of surface piping system...initial injection testing...final environmental studies...preliminary power plant design. Time: 34 months, beginning upon favourable decision in stage 5 (cumulative 71 months).

> Possible delays: insufficient success in drilling production wells; difficulties in finding suitable aquifer for injection; ambiguous or disappointing well test data; problems with financing additional wells

7. Analyses and negotiations: Financial and economic analysis...prepare feasibility document... negotiate transmission access...negotiate power sale agreement...permitting of construction...financing of power plant...final power plant designs...selection of EPC contractor. Time: 27 months, in large part simultaneous with stage 6 (cumulative 74 months).

> Possible delays: disappointing financial analyses; difficulties in negotiating power sales contract; difficulties in obtaining long-term financing; lengthy negotiation over transmission line access, or with selection of EPC contractor

8. Power plant construction: Tendering and negotiations for power train...construction of civil works... construction of electric switching yard and intertie...construction and shipping of power train...erection of turbine-generator-condenser set. Time: 29 months, in large part simultaneous with stage 7 (cumulative 87 months).

> Possible delays: slow and difficult negotiations with turbine manufacturer; delays in construction of civil works or electric interconnection; delays in shipping power train; need for additional financing; problems in installing power train components

9. Operational: Acceptance testing...permit to operate..start delivery of electricity. Time: 3 months (cumulative 90 months).

> Possible delays: flaws or other problems found during acceptance testing; extended delay in obtaining permit to operate

It is possible to perform the entire process in less than 90 months, but this requires the coming-together of one or more favourable factors:

> Existence of valuable data from prior exploration, possibly including results of earlier drilling: this is not unusual: Dieng, Indonesia is an example
> Unexpected ease in permitting: rare, but has happened, for example in Turkey
> Lack of environmental issues: rare but occasionally happens: again, recently in Turkey

Ease of obtaining financing: formerly very rare; increasingly, funding is attainable without unexpected problems: the case presently in East Africa
Better-than-expected results of drilling and well testing: occasionally happens, as in Salton Sea, California
Faster contract negotiations with suppliers: rare, but not unheard of
Faster-than-forecast construction of facilities: occasionally happens, especially with ORC plants

However, the reverse is more likely.

The major sources of unexpected delays, from the lists shown for each stage, are:

Permitting, for which the only remedy is to try to anticipate all requirements before submitting permit applications
Resource quality or quantity, for which the best remedy is careful exploration and modelling in advance of drilling and provision of adequate funding for new wells
Environmental issues, which usually can be anticipated and mitigated through careful project design and coordination with environmental groups and local residents
Financing, for which there is no full remedy, but which can be mitigated by full disclosure of project risks, and honest budgeting and financial projections.
Contracting, which can be mitigated by realism in expectations, and by employing skilled and knowledgeable persons in all negotiations
Construction, mitigated and even controlled by proper supervision, and by inclusion and implementation of penalty clauses for failure to perform to contract

A few examples of unexpected delays follow:

Unit 3 at Olkaria II power plant in Kenya was delayed for over two years by an unexpected last-minute demand by a financier that a new study and numerical simulation be performed to determine possible impact with the earlier Units 1 and 2.

Environmental interveners have held up the construction of the first power plant at Medicine Lake, California for over a dozen years…with no resolution in sight. An environmental issue also is holding up construction of a geothermal power plant at North Negros in the Philippines.

Politically motivated – and unfounded – charges of conflict of interest delayed construction of Miravalles 1 power plant in Costa Rica for nearly a year.

Most commonly, development is delayed by problems in obtaining adequate financing. The stage most sensitive to this is number 5, Exploratory Drilling. In simple words, no one wants to assume the risk of exploratory drilling.

A final note: The timeline will vary with size and type of power (flash steam or ORC) and whether there are cascaded or additional uses to which the geothermal fluid is put, such as space heating. Construction of an ORC power plant may require less time than a flash steam plant, at least in small sizes (<10 MW). A space heating system may require construction of additional pipelines and a central distribution facility, all of which will change the time requirements. However, there are economies of scale to be found in building a power plant larger than 30 MW. For example, geophysical surveys, road construction, environmental surveys, building transmission lines and constructing office facilities may take no longer for a 50 MW plant than for 30 MW; and more than one drilling rig may be used for larger developments.

As stated at the outset, each project must develop its own timeline; and it must always reflect actual conditions.

LECTURE 2

REDUCING NON-RESOURCE RISK IN A GEOTHERMAL PROJECT

1. INTRODUCTION

The single riskiest step in the development of a geothermal field is the drilling of the initial suite of exploration wells. Let us assume that the existence of a sizeable geothermal resource has been proven, thereby eliminating resource risk. However, in our assumed case, instead of being able to proceed with the project, unexpected risks threaten to prevent development. What are these risks, and what – if anything – can be done about them?

The principal non-resource risks (Table 1) are:

- Opposition from local communities
- Lack of a guaranteed market and price for energy
- Financing issues
- Government interference and/or corruption
- Environmental hazards and intervention by NGOs
- Ineffective project management
- Unrealistic expectations

These risks apply whether the project is government owned or privately owned. Many projects have failed – or at least have been delayed significantly – through a failure to appreciate their importance.

TABLE 1: Mitigating non-resource risk in geothermal projects

Types of risk: Causes and possible mitigation

Opposition from local communities:
- Failure by developer to communicate honestly or effectively
- Broken promises
- Spread of false or hostile or misinformed rumours
- Unrealistic expectations by communities
- Outside agitation

Mitigation:
- Immediately form project-community (‘stakeholder’) working committees
- Honour all commitments
- Make effective use of educational tools, site visits
- Involvement of communities in major decision-making

Lack of market guarantee or adequate tariff:
- Inability to compete for market share with other energy sources
- Preferential treatment for other energy sources
- Price for energy too low for profit

Mitigation:
- Enlisting public support through education and effective use of media
- Working with legislators to obtain equality or preferences
- Careful and persistent negotiation with electric utilities and regulators

Financing issues:
- Inability to obtain financing
- Onerous or costly financial terms
- Interruption in Flow of Funds
- Cancellation of funding

Mitigation:
- Honest and complete financial requirements and budget plans

TABLE 1: Continued

Careful fulfilment of all financial terms and conditions
Negotiation of emergency or back-up line of credit
Obtaining support of legislators and media

Government interference or corruption:
Excessive bureaucratic ‘red tape’ and delays
Failure by government to provide agreed support
Unexpected changes in governmental rules and regulations
Breaking of contract terms or cancellation of agreement
Demand for bribes
Mitigation: Persistent negotiation
Enlistment of support from developer’s government
Obtaining support from local communities
Presenting case through media
Bringing case to International Arbitration tribunal
Refusal to pay bribes

Environmental hazards and intervention by NGOs:
Land-use and occupation issues
Seismic and volcanic hazards, and slope-stability issues
Air, water and soil pollution
Increased noise and traffic
Increased demand on schools, health facilities, other facilities
Destruction of wildlife habitat and threat to endangered species
Special local religious, historical, cultural issues
Mitigation: Thorough environmental surveys
Collection of baseline database on water, air quality, land use, habitats, etc.
Continual meetings with community groups and interveners
Modification of original plans to accommodate issues of hazards
Appeal to national government over unreasonable demands
Careful training of employees, contractors, suppliers regarding compliance
Prompt remediation of damages caused by project

Ineffective project management:
Lack of undivided attention to project needs
Poorly informed or politically motivated decisions
Poor use of project funds
Failure to recognize or act on opportunities
Nepotism, theft, bribery, other corrupt acts
Mitigation: Provision of special training in geothermal operations for managers
Provision of back-up staff as support for managers
Private discussions with managers regarding actions or inaction
Reports to project financiers about concerns
Reports to legislators, high government officials regarding corrupt acts

Unrealistic expectations:
Issuance of unrealistic claims by developer or government
Denial of problems, or pretence of resolving problem
False accusations over errors or problems
Mitigation: Periodic press conferences with open question and answer sessions
Careful review and editing of all press releases, other documents
Documentation of false claims and accusations, dismissal of liars
Careful and honest briefing of government officials
Issuance of retractions of claims, when or as needed

2. OPPOSITION FROM LOCAL COMMUNITIES

The local communities will look for benefits from the project. These can range from increased land values and the creation of jobs, to improvement in roads and better and cheaper access to electricity.

However, if benefits do not materialize, or if the communities are not fully informed about the project, the hoped-for support can turn to opposition. Opposition can be so strong, and can generate such political support, that project stops. One example is at El Tatio, Chile, where the initial wells were drilled in the late 1970s, and where successive efforts at development of geothermal electricity have failed, largely because of local opposition. One basis for the opposition was a fear that the impressive fumaroles and steaming ground would be destroyed. Another is a traditional belief in the sacredness of the area. It is unlikely that the project will resume in the near future.

To avoid opposition, or perhaps more realistically to minimize it, it is necessary to give the community a voice in the design and implementation of the project. This begins even before work starts, with the establishment of a joint community-developer ('stakeholder') committee. The committee should include representatives of all opinions, not just those who are most likely to benefit. This may lead to mitigation measures, perhaps resulting in the partial re-location or re-design of the project. It may not be an ideal answer, but as with many projects some compromise is necessary for the project to succeed.

Stakeholders should be given the opportunity to express their doubts or questions freely and openly. Otherwise, doubts will take the form of rumours, rumours that grow larger and more frightening as they pass from mouth to mouth. In extreme cases, the project might be picketed or even vandalized. This happened, for example, at Batong Buhay (Kalinga) in the Philippines.

Educational efforts always are useful: visits to operating fields, and films as well as talks by independent experts. But there should never be the payment of money to 'buy' support. Such payments almost always become public knowledge, are almost always assumed to be 'bribes', and typically create more opposition. It is alleged that there were illegal payments to win support for a project on the Philippine island of Negros, and this has continued to complicate efforts for development.

Another thing to try to avoid is the sudden rise in the price of land in or adjacent to the project. For example, in the Salton Sea, California area, the price of geothermal leases rose very sharply after the first project was successful. This can be protected against at the very beginning of the project by paying fair market prices for the purchase of land or for long-term leases, and not waiting until drilling has proven the resource. Remember, the cost of land is relatively minor compared to total project cost.

But the good news is that once a community comes to accept the project as necessary and as a source of future benefits, the community becomes the defenders of the project against all future opponents: make the project 'theirs' and you win valuable support. This is an enormous benefit.

3. LACK OF A GUARANTEED MARKET AND PRICE FOR ENERGY

Geothermal power has become popular as a 'renewable' or 'green' source of energy, along with wind, solar, biomass, low-head hydro, and even gas turbines. In many countries, preference is given to those 'renewables', causing coal, oil and even nuclear power lose market share. However, popularity doesn't always translate into an assured market or a favourable price for the electricity. In Kenya and Indonesia, for example, the government insists that geothermal development brings down the price of electricity to the consumer. This isn't always possible. It has led, in the Philippines and Indonesia, to government efforts to force the sale of geothermal electricity below cost.

By contrast, in some countries there is an agreement that the 'renewables', including g geothermal power, are guaranteed s price for selling electricity that is much higher than the market price. This is arranged through legislation or by government order. This ‘feed-in tariff, or FIT is in effect in Turkey, Germany and Slovakia. (In recent weeks, Indonesia has begun considering an FIT for geothermal energy.) Similarly, electric utilities are required to give a preference to renewables when buying electricity from independent power producers (IPPs). California requires 33% of all power sales to be from ‘renewables’ by year 2020, and 50% by 2030 (a ‘market set-aside’).

Such requirements often create opposition from the developers of the non-‘renewables’. And if electricity costs go up because of a generous FIT, consumer groups may join the opposition. Despite this, in Turkey, the result has been the increase from less than 20 MW of geothermal to over 500 MW in the course of a decade, based on a guarantee that a government energy agency will purchase the power at a price nearly twice that for conventional sources. Another example: In Japan, during the decade of the 1980s, very generous government support for the geothermal industry raised the generation capacity (almost entirely by private companies) from 81 to 505 MW. After the subsidies were stopped, development essentially stopped: 25 years later, geothermal generating capacity had increased only to 536 MW.

Still, it remains uncertain whether such support policies will be continued indefinitely by Turkey or by any government. In Slovakia, the FIT has been reduced over the years from 19 Euro cents/kWh to 15, with the likelihood that the FIT will drop to 11 in the next few years. This has caused two planned geothermal generation projects to become marginal economically and (at least temporarily) to halt operations. In Indonesia, the national electric agency PLN has strongly contested a generous FIT, despite a government plan for geothermal to comprise up to 50% of new generation. The result is that there has been almost no new private investment in Indonesian geothermal despite there being proven reserves of several thousand MW. Almost all new development is by government-owned oil company Pertamina.

Without the guarantee of a market set-aside and FIT pricing, many geothermal projects would not be able to compete in cost against coal and natural gas, and even nuclear power. Because wind-powered generators and gas turbines can be constructed much more rapidly than a geothermal power plant, many regulatory agencies will give them preference over geothermal development. Even the price of photovoltaic solar power has come down so rapidly in recent years in the United States that solar and wind fill almost all of the market set-asides: geothermal energy is almost squeezed out of the market.

Government-owned projects fare better than private ones. This is because low-cost financing is easier to obtain, and because a government can re-arrange its development timetable to accommodate a geothermal project. Also, and very important, government ownership often allows projects to operate at a financial loss, or at least at no significant profit. Although many countries encourage geothermal energy, only in Turkey, Japan, the United States and Papua New Guinea has development largely been done privately. Private geothermal projects have added to generation in Kenya and the Philippines, and are planned for Ethiopia, Chile and possibly elsewhere.

The bottom-line is that although geothermal energy is applauded as ‘green’ and ‘renewable’, unless there are significant guarantees of market access and a favorable price, exploration and development remains a high-risk venture, especially for private investors.

4. FINANCING ISSUES

Funding for geothermal projects comes from multiple sources. This is discussed in a separate paper and is not necessary to repeat here. Risks associated with financing include:

Insufficient funding
Failure to recognize true cost of delays
Lender loss of confidence
Misuse of project funds

In order to obtain funding, project owners sometimes –and unwisely – either minimize the financial requirements, or calculate an unreasonably short length of time to achieve power generation. Underestimating costs and time requirements usually leads to inadequate start-up funding, and this in turn can result in the project shutting down for lack of funds. This happened with the Ďurkov project in Slovakia.

Project designers sometimes fail to recognize that delays associated with permitting, community issues, environmental issues, procurement, mobilization and construction add cost to a project. These contingencies should be budgeted as an additional 10 to 15% of total project cost. One example of contingency costs comes from Kenya, where mobilization by a drilling contractor once was delayed for six months because of the contractor's problems. There was no clause in the drilling contract to provide for penalties in case of delayed mobilization. Lacking compensation, the overall cost of the project rose, reflecting both the continued stand-by expenses to the project, and the loss of revenue from the resulting delay in generating and selling electricity.

Projecting an unrealistically high rate of return on investment, or overstating the ease of access to market, may initially fool the lenders or investors. But ultimately such behavior works against the developer. Even worse are attempts to conceal expenses, especially payments made to the developers or illegal payments to third parties. The net effect is that financiers lose confidence in the project.

Geothermal projects usually are financed in stages ('tranches'), with each financier setting specific terms and conditions, perhaps involving performance 'milestones'. That is, funding for the second stage is dependent upon results from the first stage. This means that there may be a pause in project activities while performance is reviewed. These delays can have major consequences, especially if one financier decides that progress hasn't matched expectations, and decides to withhold – or even withdraw from – further funding. If one financier withdraws from the project, the entire project may be at risk of collapse.

Once a project is out of money, it is increasingly hard to restart it. Bills continue to pile up while the project is stopped. Projections of cash flow become increasingly unrealistic. Financiers and investors sense an increased risk, and may refuse to resume funding.

There is no easy way to avoid these problems. However, certain steps should be taken.

The first is to be very honest when estimating all of the financial requirements and the anticipated rate of return. One fools no one but himself in "fudging" the numbers. This means that budgets should include not only the anticipated costs, but contingency funds for future price inflation, possible work interruptions, and the need for additional (unanticipated) work.

The second step is to honor all financial agreements with great care, to avoid penalties for not fulfilling performance requirements. Sometimes reports are late or inadequate, or operational problems aren't discussed adequately. If financiers learn of operational problems through other sources, this can lead to a loss of confidence in the project, and even the stopping of future tranches. An example is the geothermal project at Patua, Nevada, where facts were withheld or misrepresented by the developer, and large amounts of money were lost by investors. As a result, the private equity market is very hesitant to invest in any geothermal projects by that developer, or by anyone associated with the project.

Third, the project owner should have sufficient cash reserves – or the ability to generate additional cash – to cover delays in financing or various other contingencies. This may involve either the project owner obtaining a 'bridge' (short-term) loan, usually at higher interest rates, or the sale of other assets held by the project owner. It may also be possible to obtain project insurance, but at a high premium cost. It also may involve government-owned projects having to go hat in hand to the national legislature to ask for more funds.

The best answers, therefore, are to make sure that the project budget is sufficient, including contingency costs; to perform work closely on schedule; and to keep the financiers and investors fully informed about both progress and problems.

These may seem self-evident, but many projects – including one in India sponsored by the UN Development Programme (UNDP) in the 1960s – were stopped because of inadequate funding, leading to lengthy delays, and their ultimate abandonment. Another, a private project in Central America, was halted in the 1980s because of disagreements over the use of project funds. Several years passed before another company was able to acquire and restart the project.

5. GOVERNMENT INTERFERENCE AND/OR CORRUPTION

The classic case of government interference and mismanagement is from Indonesia in the late '90s. Because the Indonesian Rupiah was unstable, and declining in exchange value, certain private contracts to sell steam or electricity to PLN, the national electric agency, were denominated in US Dollars. A currency crisis swept across Southeast Asia in 1997-1998, and the value of the Rupiah plummeted from 2,500 to the Dollar to almost 10,000:1. PLN declared that it could not pay its bills for steam and electricity in Dollars; and following this, the government of Indonesia cancelled several existing geothermal contracts. Several major geothermal projects – Dieng, Karaha, Bratan among them – stopped.

Eventually, through international arbitration at The Hague, one American company was awarded a large amount in damages (initial capital investment, loss of future revenue, etc.). The government balked at honouring the arbitration. This effectively stopped all foreign investment in new Indonesian geothermal projects for nearly two decades. Even today, over 90% of geothermal investment is by a government agency (Pertamina) using international loans and grants. This is so despite efforts by the World Bank to encourage private investment, and despite the pledge by the Indonesian government to honour all future contracts.

Other problems involve the complex rules and regulations imposed by various governments. In effect, one agency may require a certain action, but another agency may forbid it. Rules may change repeatedly, adding another layer of complexity. And although it isn't proven, government employees have been accused of taking 'gifts' to allow a project to proceed.

Government interference in privately owned projects in various countries takes the form of investment taxes, limiting the repatriation of profits, requiring the employment of unnecessary workers, imposing special customs duties on imported equipment, and requiring that a local company own some percentage of the project. These factors have an impact on whether a project is profitable, and therefore whether it can obtain needed funding. In more than one case an international lender has refused to proceed with financing until tariffs are raised sufficiently to cover costs. Some countries do not allow any foreign investment in the geothermal industry. This often means that a government-owned project loses access to new and valuable technology. Ecuador and Bolivia have this restriction, and as a result their impressive geothermal resources remain undeveloped despite large inputs of foreign aid.

Annually, the World Bank publishes a table showing six factors affecting the quality of governance for all countries of the world. These factors include: effectiveness of the national bureaucracy, reliability of the court system, level of corrupt activity, and stability of the national government. The ratings are used by investors and lenders as guidelines when they consider whether to participate in a project.

In summary, excess and unwise government regulation, and mishandling of contracts and energy tariffs present a risk to the development of a nation's geothermal resources.

6. ENVIRONMENTAL HAZARDS AND INTERVENTION BY NGOS

There often are legitimate environmental issues, and there is a need to protect air, water, timber and soil against pollution, and as well as to safeguard agricultural lands and wildlife habitat. Non-governmental organizations (NGOs) can play a helpful role in this. In addition to these protections, there may be a need to improve existing roads, and to provide additional housing, schools and health facilities for the workers and their families. All of this must be done without impinging on the facilities already available, while at the same time offering these same benefits or improvements to the local population.

Providing environmental protections and offering additional benefits can be costly in the short time frame, but can save money in the long run by avoiding lengthy and difficult legal and regulatory conflicts.

However, occasionally there is a lack of information from the project owner. Or there may be the spread of false or misleading information, reflecting either indifference or poor communication skills by the owner, or even as a deliberate attempt by others to destroy a geothermal project. Some examples may help to explain this.

A government-sponsored geothermal project in Switzerland involved fracturing of rock under great hydraulic pressure. Although it is widely known that such 'hydrofracking' can generate small magnitude earthquakes ($M_r \sim 1 - 4.5$), the regional population was not advised in advance of this likelihood. The ensuing swarm of small earthquakes caused no measurable damage, but annoyed and even terrified the local residents. The project was forced to stop.

In Japan, the development of geothermal power is even allowed in certain national parks under specific guidelines. Despite this, the national association of spa owners routinely opposes any geothermal development, on the unproven assumption that development will destroy the thermal springs used by the spas. Geothermal developers have offered that in the event of damage to thermal springs they will supply as much hot mineral water as the spa owners want; but this offer routinely is rejected. However, at the same time, several spas and hotels have drilled their own wells to supply hot water and generate electricity for their own use. Government agencies are reluctant to intervene. This results in costly delays, and in a few cases has caused a project to stop completely. The internal contradiction of the spa owners' actions doesn't seem to matter.

Glass Mountain, California, is a sparsely settled area in a national forest. The United States and State of California governments have approved leases and permits to develop the geothermal resource. The few local residents filed no objections. However, an NGO intervened on behalf of non-resident Native Americans ('Indians') who claim some sort of ancestral right to the land. The issue has been tied up legally through a series of appeals by the NGO, even though the government has confirmed its decision to allow development.

On Bali island, the Bratan caldera was drilled with ambiguous results. When a private company attempted to restart the project, objections were raised that the project would interfere with Hindu shrines in a protected forest. All of this had been evident previously, without anyone raising objections. It was suspected that disagreements among powerful political figures over revenues to be obtained from the project had triggered the new objections. Various mitigation measures were proposed to protect the shrines and the forest. Local governments took opposing positions, nothing was resolved, and the project never restarted.

The conclusion is that true environmental risks must be addressed promptly and effectively. At the same time there must be mechanisms to protect projects against deliberate and misleading attempts to destroy them.

7. INEFFECTIVE PROJECT MANAGEMENT

This is not unique to geothermal development. It is a problem that affects all types of development projects.

What perhaps is unique to geothermal is the need for the training of managers in the specific technology and economics of geothermal energy. Professional staff usually have received this type of training – such as is given at this Iceland geothermal school or at various schools and universities in Japan, New Zealand, Italy or the United States. However, it is relatively uncommon for management officials to receive this type of training.

As a result they may not understand how important or how misleading certain actions are, or what equipment or technology is needed. They may misjudge the results of various surveys or of drilling. They may be unwilling to budget adequately. They may agree to contracts with harmful long-term effects. Any of these can add to project costs, and can even endanger a project's success. Therefore, special training courses for geothermal project managers and directors of companies or government agencies should be a part of any proposed geothermal project.

8. UNREALISTIC EXPECTATIONS

In order to obtain either government approval or project funding, projects often are oversold or 'hyped'. This may work in the short term, but usually ends up creating serious problems both for the 'hyped' project and for the entire industry.
Some examples are offered:

Efforts to develop 'enhanced geothermal systems' (EGS) involve the drilling of two adjacent wells into very hot but impermeable rock, the hydraulic fracturing of rock between the wells, the circulation of water between the wells, which becomes heated en route, followed by the production of steam or hot water for power generation. There has been extensive theoretical research, drilling and testing of wells, and a limited production of electricity from demonstration projects, in several countries.

In Australia, during the first decade of this century, over a dozen companies raised hundreds of millions of Australian Dollars on the Sydney stock exchange, and received hundreds of millions of dollars in government grants and cost-sharing contracts, to develop electricity via EGS. Unfortunately, most of the companies had no prior geothermal experience, and offered unrealistically grand estimates of geothermal electricity that they would generate. After over a dozen years, most of the companies have gone out of business, and hundreds of millions of Australian Dollars have been lost. A single demonstration plant capable of producing about 1 MW had been built. All other projects had been halted. For all practical purposes, geothermal is dead in Australia.

This has had a negative impact in other countries where EGS research is underway.

In 2008 in Kenya, the government established a wholly-owned company, GDC, with the charter to explore, drill and develop geothermal electricity either by itself or with private partners. The GDC business plan was reported as unrealistic by several independent parties; but the Government accepted GDC's promises to generate over 1,000 MW by 2018, and about 3,000 MW by 2030. Hundreds of millions of US Dollars were provided by the Kenya parliament and by international donors and lenders. To date, not a single MW of generating capacity has been installed by GDC. Its entire upper management has been removed, and it remains unlikely that more than 100 MW will be installed by 2018, about 10% of what was promised. The effects of this 'hype' are just now being felt in Kenya.

The extraordinary waste resulting from the promise by an American company that it would produce about 1,000 MW at Patua, Nevada has already been mentioned.

Estimates of tens of thousands of MW in reserves have been issued by government agencies in Indonesia, Ethiopia, the United States, the Philippines and Kenya, based on highly optimistic assumptions, and with no regard for the environmental issues and economics facing such development. Such statements can only be considered to be reckless. The long-term net effect may be to turn financing agencies against further investment in geothermal energy,

These are not the only examples of outrageous overstatement in the geothermal industry, both by government agencies and private companies, but it isn't necessary to discuss the subject further.

9. TO CONCLUDE:

Non-resource risks face government and private projects alike. By understanding the source and nature of these risks it is possible to avoid them, or at the least to mitigate them. Government projects generally have an easier time with financial risks, but may have more problems with bureaucratic mismanagement. The other issues appear to affect private and government projects about equally.

REFERENCE

World Bank: Website: *info.worldbank.org/governance/wgi/index.*
Every year the World Bank publishes an index to world governance, country by country, for 6 critical factors, rating each country for each factor. The 6 critical factors are: Control of corruption; rule of law; regulatory quality; government effectiveness; political stability and absence of terrorism; and accountability and freedom to speak openly ('voice'). It is definitely worth looking at.

LECTURE 3

SATISFYING FINANCIAL REQUIREMENTS IN GEOTHERMAL PROJECTS

1. INTRODUCTION

The ease with which geothermal projects can be financed has varied widely during the past decades. The present emphasis on ‘green’ or renewable energy sources has made it easier to obtain financing; but this is not true worldwide, and is subject to future changes in lending or investing policies.

Financing sources and requirements are different for privately owned and government-owned geothermal projects. The former typically obtain financing from a combination of company assets, joint ventures or equity investments by other parties, commercial bank loans, sale of bonds, and occasionally via grants from, or cost-sharing with, agencies of government. Government projects usually are financed by a combination of treasury funds, grants from donor agencies, and concessionary loans from international development banks and other governments (Table 2).

TABLE 2: Financing geothermal projects

Sources of finance

Government owned projects
- Treasury Funds
- Grants from donors
- Concessionary loans from development banks
- Joint ventures with private entities

Privately owned projects
- Retained earnings and other company assets
- Equity investments by private entities
- Joint ventures with private entities
- Commercial bank loans
- Sale of bonds
- Grants from government for research and development
- Cost-sharing with government agencies

Alternative types of funding
- Sale and lease-back of assets
- Rental rather than purchase of equipment
- Vendor credits at zero interest

Reducing financial risk
- Loan guarantees from government
- Project insurance or drilling insurance
- Risk-sharing with vendors and suppliers

Financing standards have evolved during the past decades, in part reflecting the emphasis on creating ‘green’ or renewable energy projects, and on the competition for market share between the various ‘green’ energy sources.

All of these differences and changes are reflected in the requirements imposed by the project financiers.

2. FINANCING PRIVATE GEOTHERMAL PROJECTS

2.1 Types of private projects

There are numerous variations possible in the process of financing geothermal projects. The following discussion, although typical, is not unique or mandatory. (The word ‘private’ is taken to mean one or more entities acting jointly in one or more phases of a project.)

There have been privately owned geothermal projects in at least a dozen countries. These include:

1. Those where a private entity does all exploration, drilling and power plant construction, and sells electricity: commonly done in the United States, Kenya, Turkey and Japan; also done in Germany, Kenya and Papua New Guinea.
2. Those where steam and hot water are supplied by a government entity and where the private company builds, owns and operates (BOO) power plants and sells electricity, perhaps ultimately transferring the plant back to the government (BOOT): previously done in Costa Rica and Indonesia, in Mexico, and anticipated in Kenya.
3. Those where a private company explores, drills and sells steam or hot water to a government-owned facility: formerly done in the United States, and presently used in the Philippines and Indonesia; in Mexico a private company has drilled on sites selected by the government agency (CFE), selling steam to that agency.
4. Those where the private company explores, drills, builds and operates a facility that either supplies its own needs, or distributes steam and/or hot water to municipal or private users: this has been done in many European countries, as well as in Japan and the United States.

2.2 Sources of funding

Only a few very wealthy oil companies, mining companies and electric utilities have been able to self-finance geothermal projects from retained earnings. Examples are Chevron Oil Company in California, Idemitsu Petroleum Company in Japan, and certain projects in Turkey. Essentially all of the other private projects have had to go to the equity and debt markets for the majority of required finance. These include stock exchanges and banks in Australia, Canada, France, Germany, Japan, Turkey and the United States, as well as private investors in those countries plus the UK, the Netherlands, New Zealand and various countries of the Middle East. Large industrial concerns from other countries, such as India’s Tata Industries, also have invested in geothermal projects

It is common for a private company to form a wholly owned subsidiary corporation that then owns the project. This protects the parent company’s other assets from claims of loss or damage in the event that the geothermal project fails. The subsidiary can sell equity in the project to individuals or other companies. It also can enter into joint ventures with other private companies, such as the Lihir Island, Papua New Guinea gold-geothermal project; or with a government owned company. The Momotombo, Nicaragua project began that way. In such a case, the private company usually has the responsibility to arrange financing.

Funds from the equity market may come from sale of stock, either on a public bourse or stock exchange, or through a private stock placement with individual investors. In some countries, there are codes or rules of disclosure that must be followed in any offering to sell stock. If the rules are violated, the stock exchange may refuse to allow transactions by that company. However, every share of new stock dilutes the value of the existing stockholders’ equity. Therefore, companies tend to limit the amount of equity financing, usually to less than 50%.

Financing the initial set of exploration wells is the hardest to arrange, because of the higher risk. Therefore, equity usually finances much – or even all – of the initial drilling.

Debt typically is in the form of project development loans, whether from a single commercial bank or a syndicate of banks. The private developer is usually required to contribute approximately 20% of the value of the loan being sought, either in cash or in other negotiable instruments. In rare cases where risk has been reduced or eliminated by earlier drilling, a company may be required to put up as little as 10%. Interest rates typically are based on LIBOR – the London Interbank Overnight Rate – plus some additional percentage. That percentage will vary with the credit rating of the company: the better the credit rating and the greater its other assets, the lower the interest asked. Three to 8% above LIBOR is not unusual; rarely is it less than 3%.

Debt also can include the issuing of bonds. These can be short- or long-term bonds, with either fixed or variable interest rates. Bond issues usually are not based on revenue from a single geothermal project. Instead, the company guarantees repayment from all of its revenue sources. This reduces risk to the lender. However, many geothermal projects are perceived as highly risky, and in order to obtain funding the company must pay 'junk bond' rates. These usually are based on LIBOR, perhaps as high as 10 to 13% above in extreme cases. For obvious reasons, companies prefer loans to issuing bonds.

2.3 Issues in financing

In all cases, there must be full disclosure of project details in advance of the loan or investment, including anticipated costs and return on investment (ROI), annual expenditure and revenue ('cash flow'), perceived risk, development timetable, management strategy, professional qualification of staff, etc. A lender may sign an interim agreement (usually called a 'terms sheet'), which is embodied in a contract once a thorough review has been conducted ('due diligence'). Banks and bond-issuing groups typically will, as part of their due diligence, hire outside experts to examine and assess the project and the private company's strengths and weaknesses. In the case where a large bond is being arranged, a bond-rating agency may issue an opinion and offer a letter grade (A, investment grade, to D, worthless junk) to the project.

Loans usually are staged. That is, successive 'tranches' (delivery of funds) are dependent upon satisfactory completion of the previous stage. To accomplish this, the lenders may establish performance milestones, such as the completion of geophysical exploration or completion of drilling and testing of exploratory wells. The lenders usually bring in outside consultants to perform the evaluation. If the milestone is completed satisfactorily, the next tranche of funds is released. However, if work is delayed or is incomplete or unsatisfactory, the next tranche may be delayed, or in extreme cases the loan may be 'called' (cancelled).

If this happens, a company might urgently look for a bridge loan (also called a mezzanine loan), to finance the project until the original lenders are satisfied that the milestone has been completed successfully. Sometimes, a bridge loan or even a line of credit is arranged in advance, to be activated only in time of emergency, so that there is no interruption of activity.

If, based on drilling and well testing, the project is successful, the holders of bonds – or in some cases the banks making the loan – may have the option to convert debt into equity. That is, they are allowed to cancel the remaining debt in return for shares in the project or in the parent company. There may even be arrangements by which stockholders have the right to purchase more shares in the successful company (an 'option to buy'), sometimes at a pre-determined (favorable) price. This provides additional working capital for subsequent activities.

If, on the other hand, the project is failing, equity holders may try to sell their stock, usually at a loss. There are often two broad classes of stock: common and preferred. In a forced liquidation of a company, the holders of preferred shares are paid before the holders of common stock (this is not universal, as laws vary from country to country). If a project fails, the holders of the debt must be repaid to the best extent possible, before the shareholders receive anything. This may involve selling all project assets (equipment, etc.), and even selling other assets held by the private company, assets that have nothing to do with the geothermal project. However, in most countries, the 'corporate shield' protects the personal wealth of the company owners from seizure.

Many times project assets are insufficient to repay all debts. In that case, there usually are contract terms that govern who receives payment first. 'Senior debt' is that debt having the highest priority for repayment. Lenders typically insist on a contract clause that makes their loan senior debt. 'Secured debt' is backed by other assets of the company, assets that can be seized in the event of a loan default. Lenders not holding senior or secured debt may end up losing money. This discourages future lending by the financial community for geothermal projects. Bankruptcy laws in the United States and other countries may allow a company to avoid full repayment by protecting certain classes of assets from seizure. But declaring bankruptcy usually ruins the possibility of obtaining future loans.

2.4 Government aid to private projects

Partial funding has been provided to private projects by government agencies in several cases. Australia and Japan have been the primary examples. Assistance may take the form of research grants, wherein a company tests a new state-of-the-art technique, instrumentation, or process, with financing provided by the government and with results made available to all future users. Alternatively, the government may pay part of the costs of exploration or drilling (cost sharing) in return for access to all of the results. This type of government support was used successfully in Japan in the 1980s. The government paid for all surface exploration, then paid 50% of the cost of exploratory wells, and 25% of the cost of development wells. This was highly popular with private investors, and led to a rapid growth in geothermal generating capacity. Less-generous grants had some success in the United States; but results in Australia were poor, possibly because the Australian government and the private developers badly misunderstood the risks and costs.

Another form of government support is a 'loan guarantee', in which the government agrees to guarantee repayment of a commercial loan in the event that the private company is unable to make repayment. A loan guarantee is granted only after careful appraisal of the chance of success of the project.

Another technique is to provide project insurance. (Insurance may be offered by commercial insurance companies as well as by the government.) In this, the insurer participates in the assessment of risk, and even in the actual siting and design of wells, to further reduce risk. The private company pays an annual cash premium, equal perhaps to 2 to 10% of project cost, for the insurance. If the project is not successful, the private company collects the face value of the insurance policy, often several million dollars. Rather than insuring the entire project, insurance may be limited to just the success or failure of a single well. Insurance by a government agency was attempted in the United States with minimal success, because of the high cost of annual premiums. In Germany private insurance companies have offered such insurance.

A government agency may also support a geothermal project by guaranteeing a market for the electricity, and by authorizing a very high price for electricity. The former is called a 'market set-aside' and the latter is known as a 'feed-in tariff (FIT) and is paid to producers of 'green' or 'renewable' energy in many countries. Very high FITs are offered by Germany and Slovakia; slightly less generous FIT offers are available in Turkey, and on a few islands in Indonesia and the Caribbean. Market guarantees are offered in Turkey and the United States for all 'renewables'. As a renewable, geothermal must compete against solar and wind power for market share. This rewards only the most efficient and least costly projects.

2.5 Financial reporting

During the life of a project there are many reporting requirements imposed by lenders and donors. Project milestones have been mentioned. Another requirement for private companies and some government agencies is the annual report, which deals mainly with financial aspects but also provides technical information about project activities and plans. Lenders may also require semi-annual or quarterly or even monthly technical and financial reports in addition to milestone reporting. If a company chooses to issue press releases whenever something of significance has happened, and especially if the company is listed on a stock exchange, the press releases have to specify which statements are factual and which are speculation. If a company issues false press releases, often they will be sued by unhappy investors; they may also be de-listed by the stock exchange.

In addition to reporting requirements set by lenders, it is essential that the company collect a comprehensive suite of project data on a regular basis, and maintain complete files of those records. This documentation is especially valuable when dealing with claims of environmental damage by the project, or when making claims against suppliers for inferior merchandise, or in cases of claims of fraud by investors or lenders.

3. FINANCING GOVERNMENT-OWNED GEOTHERMAL PROJECTS

In certain countries, only an arm of the government is allowed to conduct geothermal exploration and development for electricity. These include: Armenia, Bolivia, China, Djibouti, Ecuador, Iran, until very recently Portugal (the Azores), and certain island nations of the Caribbean. In earlier years this was the requirement in Chile, El Salvador, Ethiopia, France, Guatemala, Hungary, Iceland, Italy, Mexico, New Zealand, Nicaragua, Peru, Russia and Vietnam, but laws have been changed to allow various types of private investment, with or without government participation. (Non-electric projects generally have been allowed in almost all countries.)

Where the government is the sole or dominant participant, a project to develop geothermal resource areas often follows this path:

3.1 Reconnaissance

Data on thermal or volcanic features are compiled by either a national geological survey, or by some interested private party. This is followed by limited reconnaissance studies; the results are brought to the attention of the government with a recommendation that further work be done. The government requests and is given either technical assistance or a grant of money from an international agency, such as the United Nations Development Programme (UNDP), or from a foreign government (perhaps Iceland, Italy, Japan) to confirm and amplify those earlier findings.

Favourable results from that additional reconnaissance causes the government to design a project whose ultimate aim is power generation. Financial support is provided for pre-feasibility studies by an international donor, such as the UNDP or the Global Environmental Fund of the World Bank, or a foreign government. Typically, the studies are carried out by a major consulting firm chosen by the government under rules of International Competitive Bidding (IFCB), or by a group supplied by the donor government (such as the UK, the US or Norway). Usually there is a training component in the funding, under which local staff receive training in geothermal science.

3.2 Exploratory activities

If pre-feasibility studies yield encouraging results, the government then decides to request financing for a detailed exploration program. Financing, through the drilling of an initial suite of exploration wells, may come from an international development bank, such as the World Bank, Japan's JICA or the German KfW, or from a group of development banks. The government typically is asked to fund up to 50% pf the total budget. This usually is in the form of such things as vehicles for in-country transportation, living expenses and housing for expatriate experts, and the provision of technical and support personnel.

If the funding is in the form of a loan, a sovereign guarantee may be required as a condition. This obligates the national government to repay the loan from its general revenues, and not specifically from income from the geothermal project. Often a portion of the funding is in the form of non-refundable grants that serve to lower the cost of borrowing for the risky step of exploratory drilling.

3.3 Development

If results are favourable and a discovery suitable for power generation is made, the government has several options. It can go to a single financier, such as the World Bank, KfW or JICA; or a consortium can be formed of international lenders, involving regional development banks (the Asian Development Bank or the Inter-American Development Bank) and the development agencies of several countries (for example, France, Spain, the Netherlands).

Alternatively, it can find a joint venture partner, either a private company or an agency of some foreign government. The former might include a Japanese turbine manufacturer or a major trading company. The joint venture partner could include a partially privatized state entity. ENEL of Italy, for example, has participated in both government-owned and privately owned geothermal projects abroad. Sovereign wealth funds, such as from Norway or Singapore or Qatar, have considered participating, with the opportunity to earn revenues from the sale of electricity.

The point is that there are many possible avenues for financing development; and with today's enthusiasm for 'renewable' energy and low CO_2 emissions, the opportunities have never been greater.

In any event, a loan package is obtained, probably with more than one lender. Each participant might decide to finance a specific phase or part of the project. This could be the drilling of development wells (done in Kenya through the China Import-Export Bank), or the construction of power transmission lines, or the financing of a turbine-generator set. In earlier years, lender and donor nations often required that all goods and services provided under their financing come from companies in their country. However, both the World Bank and United Nations try to discourage and avoid that practice.

Loan terms generally are concessional. The annual percentage interest is set far below LIBOR, repayment often to begin only after 3 to 5 years. However, as in exploration drilling, the borrowing country is asked to provide up to 50% of the total cost. The loan most often is made to the national government, rather than to a national electric utility or some other government agency; and in return the national government is required to give a sovereign guarantee. That means that even if the project is unsuccessful, the national treasury will repay the lenders. Some loans carry generous forgiveness clauses if the project fails.

Not surprisingly, a country can at any one time have several loans for a wide variety of projects in the energy, health, housing, education, and/or transportation sectors, all under sovereign guarantee of repayment. But because interest rates are set very low, and because typically there are no penalty clauses for late or missed repayment, repayment usually is not a problem, and national development is aided.

4. PRIVATIZATION OF NATIONAL ENTITIES

In recent years, many national agencies that have been active in geothermal projects have been privatized, either wholly or in some degree. These include ENEL of Italy, the developer and operator of the Larderello field; Kenya's KenGen, developer and operator of Olkaria field; and the former national electric utility of New Zealand, among others. Shares of equity are sold either through the bourse or by special private placement with a large private entity (a so-called 'strategic investor'). In a varying degree, this has modified their access to financing. However, even with the combination of private equity and strategic investors, often there remains the need for government grants, and loans from international development banks and foreign governments.

There is also a form of 'privatization' in which no shares are sold to private entities. Instead, the government retains full ownership, but provides no financial support. Sometimes this is referred to as a 'parastatal company'. The parastatal is expected to earn sufficient money through sale of goods (electricity, hot water) and services (consulting, analytical laboratory services, etc.) to support itself. This doesn't always happen. Government financial support may continue to be needed. A geothermal parastatal also might be given preference in the selection of the most-favourable prospects for development. This can inadvertently reduce or even eliminate private interest in investing in geothermal projects.

What is highly variable is the amount of government intervention on behalf of a partially privatized entity. Many electric utilities, such as in Indonesia and the Philippines, have in the past been urged by the government to sell electricity below cost, in an attempt to stimulate economic growth. This caused National Power Company of the Philippines to go bankrupt; and has caused Indonesia's PLN to run annual deficits that require financial support from the government. Financiers resist this money-losing process, in part fearing that it will impede repayment of loans, and in part on the premise that government subsidiaries have negative long-term effect on development.

5. OTHER ASPECTS OF FINANCING

5.1 Estimating project cost

The two most-costly items in a geothermal project are the drilling of geothermal wells, and the design, manufacture and erection of the power plant.

No one is eager to finance the high-risk stage of exploratory drilling. It is common for the initial exploratory suite to consist of 2-5 wells, from 2 to over 3 km in depth. The cost per meter for such an operation, including mobilization and movement between sites, averages US$ 1,500-2,000 even in this (temporary) period of increased rig availability. Therefore, the exploration risk will range in cost from a low of US$ 10 million (as recently seen in Turkey) to a high of US$28 million (Germany or France).

If one of the initial exploration wells is truly productive, exploration usually is considered a success. Success rates in the development drilling stage rarely run above 70-75%, with one disposal well needed for every 1.5 or 2 production wells. Recent estimates are that drilling, well testing and construction of separator stations and steam-gathering lines cost in the range of US$ 1-2 million per MW developed.

Power plants, including not only the turbine-generator power train, but also the electrical switching yard, cooling facilities, civil works and transmission intertie, cost between US$ 1.5 and 3 million per MW. The cost of Organic Rankine Cycle (ORC or binary) generating systems has come down significantly, largely as a result of improved efficiency in energy conversion. Lower cost can be viewed as lower financial exposure and therefore lower financial risk. This may favor the development of moderate temperature geothermal fields (120-180°C).

Based on all of this, an initial 30 MW power plant, including exploration and development wellfield and intertie to the distribution grid, will cost between US$ 75 and 150 million. A private company will have to fund all of these costs, and therefore will demand a high FIT. For a government project, donor grants and loan forgiveness might cover 10-15% of the cost. The national government will be responsible for up to half of the remainder in the form of in-country support, with the rest as loans covered by sovereign guarantees. For small or poor countries, this represents a major commitment, especially if other development loans are in effect at the same time.

5.2 Hidden cost factors

The development banks and agencies of other governments impose the rules of International Competitive Bidding (ICB) on all procurement. This means that any contract for goods or services (greater than some small US$ value) must go through a complex process of tendering, qualification of bidders, evaluation of bids, selection from the top qualified list, review by lender, and finally contract negotiation. Privately owned projects may go through a slightly shorter process, and usually are able to act more quickly, with equal or better results. It is widely agreed that ICB adds from 6 months to 2 years to a geothermal power project funded by international development banks. Where the need for electricity is urgent, the lost time can be very costly.

Also, a private company usually employs a team of professionals and management with prior experience in geothermal projects. They are able to hire experienced consultants and contractors without extensive searches or application of ICB rules. This provides faster and more professional exploration and development, and therefore can be more attractive to financiers.

Some government organizations – national geological surveys, for example – might have similar in-house skills. However, for its first geothermal project, the government often lacks sufficient trained personnel. Geothermal training schools, as in Iceland, and on-site training courses as have been done for over two decades in Kenya, help greatly. However, some government projects are plagued by poorly trained staff, or by management whose attention is divided. Training and education allowances in loan agreements definitely help, but can result in delays – and therefore costs – while staff are trained. Long-term use of consultants in place of trained staff may be necessary, but also adds to costs.

Training of both staff and management should begin before any geothermal project is started. However, trained staff occasionally are ‘poached’ away by projects in other countries. Employee education contracts, therefore, should include clauses requiring the employee to return home and work for a fixed number of years, to safeguard the project. Every trained employee who leaves the project increases the project cost.

In some countries, there is a mandatory retirement age – usually at 60. This deprives the project of its most experienced personnel, and in turn can increase costs for recruitment and training. Alternatively, the retired employee may be hired as a consultant to the project, again at a higher cost.

5.3 Other financing mechanisms

Ways have been devised to reduce costs in both private and government projects. As mentioned above, donor grants and loan forgiveness are possible for government projects. Vendors of major equipment often are asked to supply very costly items on interest-free long-term credit (“vendor credit”). The vendor, in turn, may get financial assistance from its government (for example, the Chinese Export-Import Bank helped support the Chinese drilling contract in Kenya). A national (or even a regional) government may provide a loan guarantee, in which a private developer is protected against claims for repayment if a project fails or cannot generate sufficient revenue to repay debts. The government loan guarantor assumes that responsibility. Project insurance also has been mentioned, as has cost sharing between a private developer and the national (or regional) government.

New financial instruments have been developed in recent years. These include 'sell-lease back' arrangements in which project assets are sold and then leased back from the buyer. The seller gets cash to pay off debts (including loans) and to replenish the company treasury. The buyer gets an income stream at a higher rate of return than bank interest. Alternatively, companies can lease major equipment rather than having to borrow money for purchases. These mechanisms increase long-term cost while lowering the need for immediate financing. Still another mechanism is risk sharing. In this, a private developer asks a contractor or supplier to forgive the debt if a project is unsuccessful; but if the project succeeds, he is to be given a cash bonus or a share of profits. This sometimes is referred to as "Islamic financing".

Finally, vendors may underwrite the cost of specialized training for project staff.

6. A PEEK INTO THE FUTURE

The geothermal industry is cyclical. In past decades, the availability of funding has varied with the price of oil and natural gas. Today, despite very low oil and gas prices, the emphasis on 'clean, green' energy has favoured geothermal. But, in many countries, other clean, green sources – solar, wind, biomass, even hydro – are absorbing much of the available funding.

High feed-in tariffs (FIT) have always been controversial. Developers love them, and even demand them; most consumers don't like them. In some countries they are losing favour, in Germany and Slovakia for example, because the additional costs are passed on to consumers. Despite the advantage to the developer of feed-in tariffs, the risk involved in drilling, the long 'lead time' to completion of geothermal projects, and the remoteness of many fields from load centres, continues to discourage some lenders. All of these work to make financing geothermal projects more difficult than for solar or wind. Taxation benefits are provided by some governments for 'green' energy. In the United States these subsidies have benefited solar and wind far more the geothermal power.

Solar and wind resources are being used extensively in China, Spain, Germany, the United States, Austria and elsewhere. Those resources usually are available only during daylight hours. A result is an excess power supply at off-peak hours, seen in certain fields in the United States, Germany and Kenya, and possibly elsewhere. This leads to pressure on geothermal firms to agree to be curtailed (reduced in power output) during hours of high supply and low demand. This reduces revenue, which can discourage investors and lenders. Many geothermal contracts now are written with 'take or pay' clauses: the buyer must pay for the electricity whether it is needed or not.

Despite the disfavour in which oil is viewed in western countries, oil – and coal – still are regarded favourably in many developing countries. In Uganda, oil has been discovered – up to 5 or 6 billion barrels in reserves – and the geothermal potential is only moderate and not that well understood. Which resource do you think will be developed first?

All of this means that in order to remain competitive and successful, geothermal projects must more carefully control costs and design contracts for finance and for sale of power with great skill. These must not be 'cut-and-paste' jobs, where financial agreements are copied from other countries without care for specific local conditions. Costly delays in financing must be avoided, through careful observance of milestone requirements, and perhaps by better procurement practices. Above all, geothermal developers must learn to develop new markets, such as KenGen's geothermal spa and its plans for a geothermal energy park in Kenya. Direct use, for space heating, has grown in popularity in the West, partly because of shorter lead times to production, and partly because capital outlay is smaller and thus easier to finance.

One possibility is that space heating utilizing shallow holes and heat pumps in regimes of normal temperature gradients, rather than generation of electricity, may be the geothermal wave of the future.

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LECTURE 4

THE IMPORTANT ROLE OF WATER IN GEOTHERMAL PROJECTS

1. INTRODUCTION

Water is the heart of every geothermal system. It is the fluid carrying heat to surface. It is the cooled fluid injected back into the reservoir or evaporated into the atmosphere. It is the fluid needed in drilling wells, and in supporting the community of project workers. It has many additional or alternative uses. Its absence or shortage can doom a geothermal project; and its misuse can create enormous environmental problems.

2. THE HYDROLOGIC CYCLE

The hydrologic cycle (Figure 2) is a convenient means of describing the sources of surface and subsurface water. In simplest form, evaporation of water occurs at the surface of oceans, lakes, ponds and streams, the rate of evaporation usually a function of air and water temperature. The invisible warm moisture rises into the atmosphere until the 'lifting condensation level' (LCL) is reached. At the LCL, the water vapour condenses as clouds. Air masses rise when passing over warmer land masses, or when forced to flow over mountains. As they rise, the air masses cool, becoming over-saturated with moisture. When liquid saturation levels are exceeded, precipitation results, in the form of rain, fog or snow.

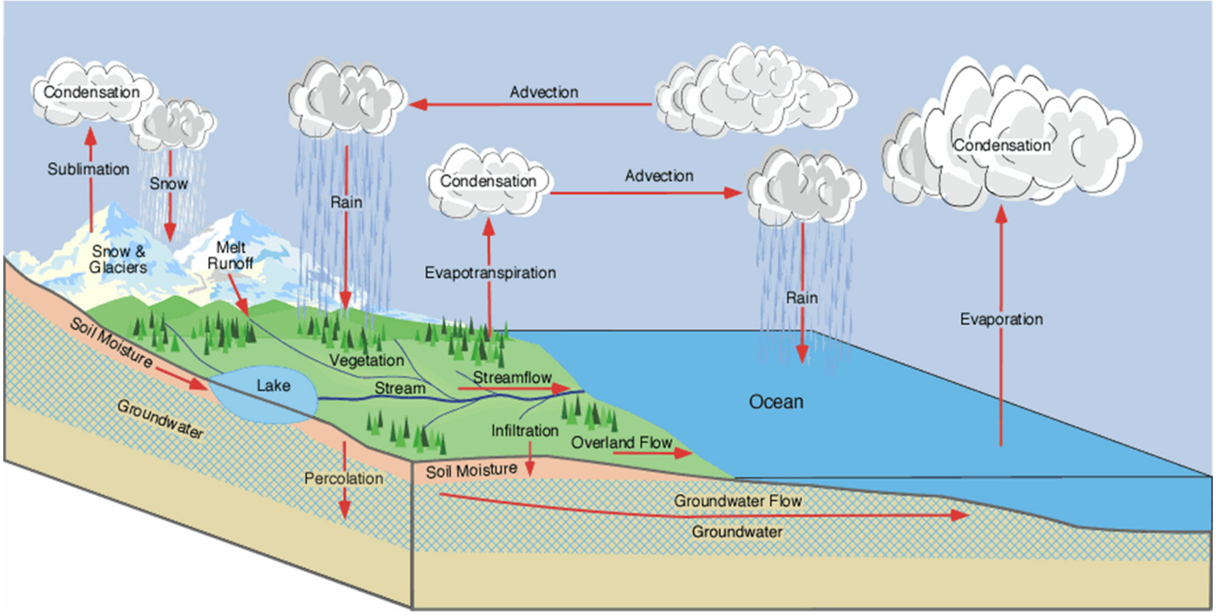

FIGURE 2: The hydrologic cycle

When it reaches the ground, the precipitation can re-evaporate into the atmosphere, or be absorbed by plants as part of their growth process. Some precipitation will be collected in streams and rivers, eventually reaching the ocean or becoming ponded in lake basins with no surface outflow (Figure 3). A small fraction of the precipitation percolates downward through soil and rock under the influence of gravity, until reaching the permanent water table. The water table is the zone below which all rock pores or fractures contain water. Some of this underground water remains stored for millennia in aquifers. Where the water table is intersected by lows in the surface topography, the underground water emerges as springs or feeds into rivers, and eventually re-enters the sea. The underground water gradually

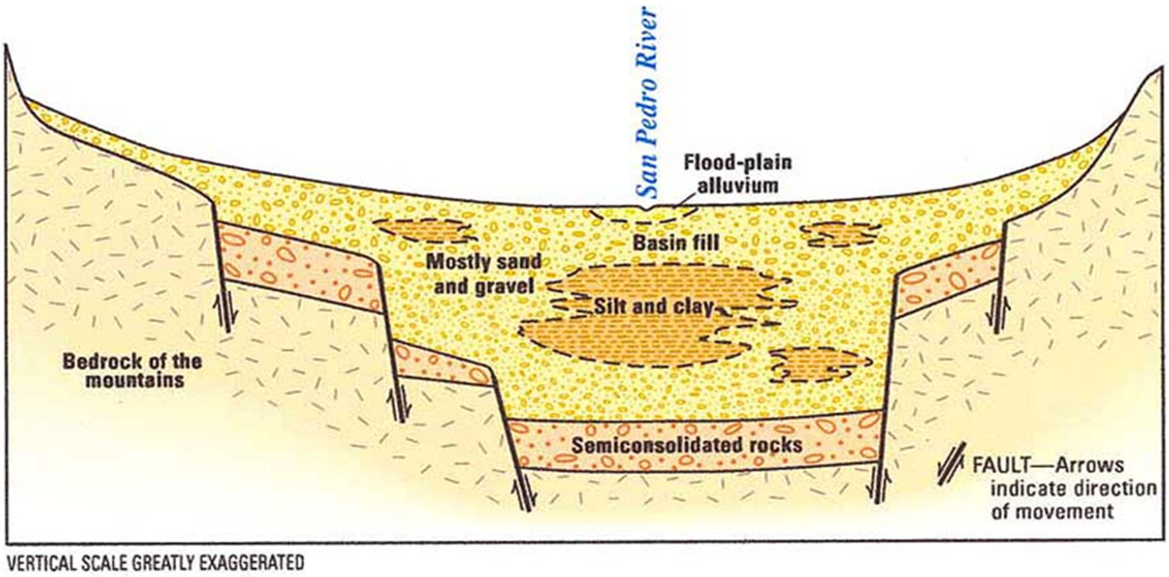

FIGURE 3: Typical Basin and Range faulting, showing step faults,
a result of Tertiary rifting and basin filling with sediment

becomes warmed by the natural heat of the Earth, becomes less dense, and is displaced upward.by the denser descending cold water. This can be considered a convective cycle.

Many factors can modify or interrupt this cycle, causing feedback loops. These include rainfall directly onto the ocean surface, ponding in man-made dams, or diversion through canals or from wells for human use or consumption. Rivers may change their course, lakes may evaporate to dryness, and springs may cease or start as depth to the water table varies, or as permeable pathways close or open.

3. COOL-WATER CHEMISTRY

Cool, surface or near-surface waters usually exhibit a chemical composition in which calcium (Ca) is the most abundant cation, followed in abundance closely by magnesium (Mg), and at a distance by sodium (Na) and potassium (K). This can be expressed as Ca>Mg>Na>>K or Ca~Mg>>Na>>K. Lithium (Li), boron (B), fluoride (F) and iron (Fe) are trace constituents. Silica (SiO_2) usually is present as well, in relatively small amounts (<50 mg/l). Among the anions, carbonate ($HCO_{)}$) is dominant, with lesser amounts of sulphate (SO_4) and chloride. However, SO_4 can be as abundant as HCO_3 in certain young volcanic terrains. This can be expressed as HCO_3>>SO_4>Cl; or HCO_3~SO_4>>Cl. Compounds of nitrogen (N_2) also may be present, resulting from decay of organic matter.

Total dissolved solids – cations plus anions – range from a few tens of mg/l to perhaps 1,000 mg/l. Mountain streams usually are at the lower end, while cool mineral springs often are – as their name indicates – more mineralized. Most cool waters are neutral or near neutral (pH = 6 to 7.5); and thus, unless polluted with chemical or bacterial toxins, are drinkable. Changes in fluid pH affect chemical solubility. For example, silica (SiO_2) solubility increases significantly in both strongly acidic (pH < 2.5) and strongly basic (pH > 10) waters. By contrast, calcite ($CaCO_3$) becomes less soluble as pH becomes more basic.

4. GEOTHERMAL RESERVOIR FLUID

The geothermal resource basically is hot water, with a varying composition of dissolved solids and non-condensable gases. The possible contribution of water from magma has been debated for decades, with the general agreement that any magmatic contribution is small – less than 5% at most. The dissolved solids in produced geothermal waters range from a few mg/l in those systems that produce steam and essentially no liquid water ('vapour-dominated systems'), to as high as 250 or 270 g/l (250,000 to 270,000 mg/l) in certain superheated brines. Examples of the former are Kamojang, Indonesia and Larderello, Italy, whereas the Salton Sea, California and Asal, Djibouti are the most saline geothermal systems known to date.

With increasing temperature and/or residence time underground, the groundwater evolves in composition. Hot water is a great solvent, the solvency of most species doubling with every added 10ºC of temperature, but with certain important exceptions. Two important exceptions are calcium and magnesium carbonate, which decrease in solubility with increasing temperature. Therefore, as temperature increases, calcium and magnesium carbonate become supersaturated and are deposited, while the abundance of the other cations and anions increases.

This simplified view of water evolution, with variations in temperature, residence time and pH, allows us to classify very hot waters as typically Na>K>Ca>>Mg and $Cl>SO_4>HCO_3$, or even $Cl{\sim}SO_4>>HCO_3$ in waters derived from subsurface volcanic terrain. Conversely, in carbonate terrain, the trend may be $Cl{\sim}HCO_3>>SO_4$. These trends are useful in attempts to identify the lithology of a geothermal reservoir.

Similarly, the temperature at which the geothermal fluid was in equilibrium with its lithologic host can be determined from the abundance ratios between Ca, Mg, Na, and K, and from the absolute concentration of SiO_2. This helps in forecasting the temperature of the geothermal resource. It is probably the most widely used tool in exploration of geothermal systems. Another important tool comes from calculating the ratios of isotopes of hydrogen and oxygen in geothermal fluids. They tell us about travel paths and residence time in the reservoir. Ratios of the isotopes of helium (He) also are useful in identifying a possible magmatic source for the gas, and by extension for the geothermal water.

Non-condensable gases (NCG) dissolved in geothermal fluids range from much less than 1% by weight to over 8%. An example of the latter is at the southern end of the Dieng, Indonesia field. Another example is the Monte Amiata field in Italy. The principal gas almost always is carbon dioxide (CO_2), usually comprising in excess of 90% or even 98% of the gas by weight. Other gases, present generally in decreasing order of abundance, are hydrogen sulphide (H_2S), nitrogen (N_2) and argon (Ar). Rarely there are measurable amounts of hydrochloric acid (HCl), hydrogen fluoride (HF), sulphur dioxide (SO_2), and other species. The latter typically are associated with active magmatic systems, such as at Tatun, Taiwan and Tiwi, the Philippines.

5. USES, APPLICATIONS AND ISSUES

The purpose here is not to discuss details of power generation, but to show the paths that water follows (Figure 4).

After the geothermal fluid is brought to the surface, it can be used to generate electricity, or to provide heat directly to structures or used in various mechanical and chemical processes. In power generation, steam may be separated ('flashed') from water and sent to the turbine; or the fluid may go through a heat-exchanging process in which another working fluid is sent to the turbine (binary or Organic Rankine Cycle - ORC). For process and heating applications, the geothermal fluid may be put through a heat exchanger, or may be used directly.

In the 'flashed-steam process', gases most commonly are ejected into the atmosphere, where they are diluted by air. An exception is H_2S, which many countries require to be neutralized to water (H_2O) and sulphate ion (SO_4), or even to native sulphur (S_2). If this is not done, the H_2S may become oxidized at or near the surface to create sulphuric acid (H_2SO_4). That, and the less-common HCl, are extremely corrosive and will damage casings and surface facilities unless treated ('scrubbed').

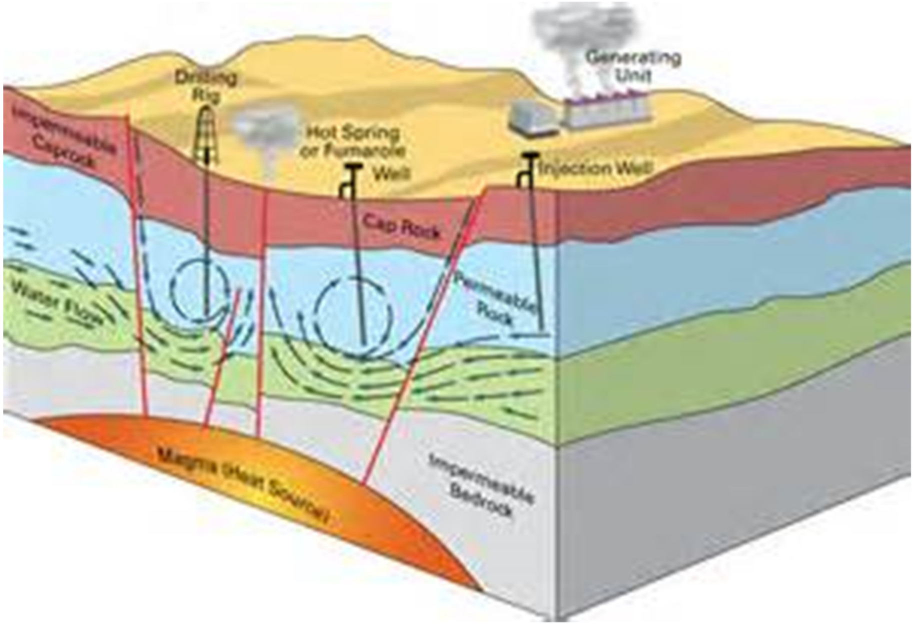

FIGURE 4: Idealized downward circulation of cool meteoric water, heating at depth of several km, followed by upwelling, and storage in aquifer at shallow depth. Local flow to surface as thermal springs in the subsurface, groundwater movement is toward zone of lower pressure, surrounding wells

By contrast, in geothermal power generation by ORC or binary cycle processes, there is no separation of steam from water, and the entire fluid mass is injected back into the reservoir. Because the ORC process is a closed loop, the NCGs also are injected along with the brine. Similarly, because the pressure drop is small from wellhead to heat exchangers and then to injection well, deposition of scale usually is trivial.

In flashed-steam systems, there is usually a significant drop in fluid pressure from the well through to the turbine. As steam separates from water, the concentration of various species increases in the water. If the pressure drop exceeds saturation limits, the result may be super-saturation of certain species, followed by the deposition of scale at some location within the well, the wellhead, pipelines or even the turbine. The principal species subject to scaling are silica and calcium-magnesium carbonate, although iron-based compounds form scale in certain fields. Scale deposition is a function not only of species concentration and fluid pressure, but also of system temperature and pH. (Examples of fields of different environment with carbonate scaling are Kizildere, Turkey; Beppu, Japan; and Sao Miguel, Azores, Portugal. Silica scaling has recently been reported at Ahuachapán, El Salvador and Olkaria, Kenya; and scaling by compounds of iron is known at Salton Sea, California).

The major flashing of steam takes place in a vessel called the separator. If the separator is improperly designed or is too small to handle the mass of geothermal fluid, separation may be incomplete. In that case there is a carryover of liquid water with the steam. This can increase the risk of scale deposition near or in the turbine because of increased concentration.

Carbonate scale can be removed by scraping, or prevented by modification of the fluid pH by injection of a neutralizing agent into the well. If not done, carbonate scale can plug a well in a matter of days. Silica and iron scale, although slower to deposit, are far more difficult to remove. It is best, therefore, to prevent super-saturation of silica by limiting the pressure drop and thus reducing the percentage of fluid flashing to steam.

6. COOLING AND INJECTION OPERATIONS

As mentioned, vapour-dominated (also called 'dry steam') systems send steam directly to the turbine after ejecting NCGs. However, most geothermal systems produce a hot brine. Separated steam is sent to the turbine. The brine, representing from about 10% to over 70% of the produced mass, remains available for possible other uses, or for disposal. Uses can include power generation via a 'bottoming cycle' ORC turbine, space heating or (through the reverse Carnot cycle) cooling of structures. In both Iceland and Kenya, the cooled residual geothermal brine is delivered to a spa for recreational use. However, in most geothermal power plants, the brine is not used further and is injected underground.

Typically, after leaving the turbine-generator, the steam is condensed to liquid water and cooled. Cooling of this condensate usually is by evaporation in large cooling towers. Evaporative cooling on average results in the loss to the atmosphere of 70% or more of the mass of condensed steam. In many geothermal fields this is an unacceptable waste of water, especially in countries where population – and water demands – are growing. But even more important, recoverable energy is being wasted through evaporative cooling.

As mentioned earlier, where the fluid temperature is too low to support the flashing of steam at an acceptable pressure, the ORC process often is used for power generation. In that process, the entire fluid mass is sent to heat-exchanging tubes. After heat has been transferred to a working fluid, the cooled geothermal fluid is available for disposal. Because cooling is non-evaporative, all of the produced fluid is preserved, usually including any dissolved NCG.

There are additional forms of non-evaporative cooling, by air, with essentially no evaporative loss; and by hybrid systems involving a varying degree of evaporation. These may add approximately 10 to 15% to the cost of cooling, and this has been used as an argument against their use. Thus, for ORC generation and for vapor-dominated systems, essentially all of the geothermal fluid is available for disposal. For most flashed-steam plants, the percentage available for post-cooling disposal may be as low as 30%.

Disposal in almost all fields is by injection back into the geothermal reservoir or into some adjacent aquifer. One requirement of all injection is that there be no leakage and no deliberate disposal into aquifers supplying potable water, or onto the ground or into surface waters. This is not always easy to monitor. Short-term disposal, for example during initial testing, typically is into a lined sump, where the fluid ultimately is diluted by rainwater and/or evaporates to dryness. In Turkey, if there is no disposal well available, disposal of the geothermal fluid is permitted into large streams during certain test periods – but not during commercial production. It is allowed during the rainy season, when rivers are at maximum flow, and dilution also is maximum. At this time it is unclear whether there has been significant environmental damage from occasional use of this means of disposal.

In earlier years at the Wairakei, New Zealand field, the brine and steam condensate were re-combined and disposed of into the large and rapid Waikato River. Not surprisingly, environmentalists objected to the practice. Moreover, this loss of mass led to both a rapid and unacceptable decline of pressure within the reservoir, and a subsidence of ground surface across nearly 30 km^2, to a local maximum of nearly one meter. After a serious review, the surface discharge was stopped and disposal is now entirely by injection.

In the Ahuachapán, El Salvador field, the original design in the mid-1970s rejected the use of injection on the basis that it was unproven and therefore overly risky. Instead, a concrete canal of about 100 km length was constructed in 1978 from power plant to the Pacific Ocean at a significant additional cost. However, lacking injection, there was quickly a decline of about 7 bars in field pressure. Power output dropped from 95 MW to under 60 MW. In 2004 the canal was abandoned, and full injection was instituted. After some experimentation, disposal wells were drilled at a distance of several km at Chipilapa, and these have proven successful. Pressure has been stabilized, new wells have been drilled, and production has returned to over 80 MW, while avoiding significant temperature declines.

At the Tiwi geothermal field in the Philippines, brine and condensate were discharged via a short pipeline into the Pacific Ocean from 1979 to 1983. Partly through the loss of mass, field pressure declined sharply. Production was reduced from 330 MW to under 200 MW, and injection instituted at the field margin. This was accompanied by a localized production of highly acidic (possibly magmatic) water, and elsewhere by scale deposition and by ground subsidence. Despite these issues, and problems with cold-water infiltration into the reservoir, the combination of careful placement of production wells and injection wells has stabilized production at over 200 MW.

These examples point out both the uncertainties and the costs associated with finding the correct location for injection. The objectives are to restore mass and pressure to the geothermal system, while not causing excessive cooling. Experience tells us not to inject directly into the production horizon, but at some distance outside, below or even above the reservoir. Without properly designed injection, there have been excessive declines in pressure or temperature in many fields, leading to a reduction in power output. The injected fluid generates three fronts of movement. These move at unequal speed, and with direction of movement controlled preferentially by fractures in the rock and to a lesser degree by conduction through unfractured rock. The fronts are pressure, temperature and chemistry (if less than 100% of produced mass is injected, the chemistry of the injectate differs from that of the reservoir fluid). To ensure that the injected fluid does its job of pressure maintenance, is necessary to monitor these fronts. This often is done by use of a chemical tracer injected with the brine, as well as by chemical sampling and measurement of temperature. Various chemical tracers are available commercially; it is not the place to discuss them here. It is common for there to be one injection well for every two or three production wells. Careful monitoring, either via tracers, or via a regular program of P and T measurements and chemical sampling, helps in the selection of the best sites for injection wells.

When done properly, there are several advantages to injection, with the benefits generally proportional to the percentage of produced mass that is injected. The advantages are the maintenance of mass and pressure in the reservoir; minimizing the potential for scale deposition; a reduced need to drill additional production wells; and the avoidance of environmental damage at surface disposal sites. All of these tend to extend the life of a geothermal field and to reduce long-term financial costs.

At The Geysers field in California, disposal initially was into a surface stream. However, in 1968 a State agency mandated injection, principally to avoid destroying habitat for fish. This led to injection of perhaps 25% of the produced steam. The rest, some 75%, was lost to the atmosphere by evaporation via cooling towers. Not surprisingly, with time there were severe pressure drops within the reservoir. Output of electricity declined sharply, from almost 2,000 MW to under 1,000. Finally, in the 1990s, agreements were signed with neighbouring communities to inject treated municipal waste water into selected wells. This has worked even better than anticipated. Presently, water equal to 85 to 95% of produced mass is injected. Pressure declines have stabilized and some wells have not a pressure increase. The field operators estimate that about 50 MW have been added to field reserves. This, in effect, has lengthened the productive life of the field. All parties have benefited.

7. PROTECTING FRESH WATER AND OTHER ENVIRONMENTAL QUESTIONS

Water is needed for use in drilling, sometimes several thousand tons, as the base for drilling mud and to compensate for lost circulation. There is also the additional demand for water by the resident project staff, and by any businesses or industries arising near the development site. The demand may reach several hundred cubic meters per day for large developments.

In areas of high rainfall, it may be relatively easy and inexpensive to obtain additional water, via springs, rivers, lakes or water wells. In arid, or even semi-arid, terrain, or in areas with seasonal or unreliable rainfall, it becomes increasingly hard to find the needed additional water supplies. This has caused disputes between local residents – sometimes nomadic herdsmen, other times farmers and villagers. As an example, the planned development of Asal field in Djibouti will require amounts of fresh water that presently aren't available. Nomadic Adal herdsmen already have made it clear that nothing is to interfere with their very limited water sources. Even in the highly industrialized United States there have been serious disputes between local residents and geothermal developers over water usage. This has included charges of pollution of municipal aquifers, raised at both Steamboat Springs and Casa Diablo (Long Valley) fields. Although the charge of contamination was disproved at Steamboat Springs, and remains unproven at Casa Diablo, bitter feelings linger.

At Eburru geothermal field in Kenya, an intricate system of pipes and condensers gathers the steam discharged from the small fumaroles. Traditionally, this was the sole reliable fresh-water source. In the middle 1980s, as part of the geothermal drilling programme, a 10 km pipeline was constructed to deliver water from Lake Naivasha, and store it at the site. This was done at a cost of several million US Dollars, and required energy-consuming pumping to raise the water 600 meters in elevation from the lake to Eburru. The pipeline now is used only a few days each month, whereas the steam condensate continues to be harvested carefully.

The potential for pollution of groundwater or land surface becomes more acute in regions where there is insufficient rainfall to dilute accidental (or in some cases deliberate) discharges of geothermal brine, drilling mud or other contaminants. However, this is a hazard even in humid regions. A case in point was the early stage of development of the Langano geothermal field in Ethiopia in the 1980s, where there were numerous potentially toxic discharges of geothermal fluids and other materials onto the ground surface. Similarly, fruit orchards along the Rio Paz, between El Salvador and Guatemala may have been damaged by discharges of boron- and chloride-rich brines into tributary drainages during testing of the original Ahuachapán wells.

On the island of Nisyros in the Greek Neocene volcanic arc, a high-temperature, high-salinity geothermal field was discovered through exploratory drilling. Fluid salinity probably exceeded 150 gm/l (150,000 mg/l). Local residents became alarmed about potential toxicity and possible pollution; and although their concerns were not the principal reason for stopping the project, it might ultimately have done so.

The owners and operators of Japanese thermal spas (onsen) routinely oppose geothermal developments within several km of their propertied, fearing that the natural hot springs either will be reduced in flow or contaminated by leakages. Geothermal developers have offered to make up any loss in spring flow rate from produced geothermal steam, but this offer generally has met with refusal. This has helped to delay the development of geothermal electricity in Japan.

However, geothermal development is allowed in designated areas within Japanese national parks. Similarly, in Costa Rica, geothermal development is allowed within carefully selected sections of the Las Pailas volcanic national park.

By contrast, in the United States, not only is drilling forbidden within Yellowstone National Park, but a 3 km zone surrounding the park also is off-limits for any geothermal exploration, to protect the famous geysers and boiling springs from possible drainage through outflow zones. This may have been a reaction to the situation that prevailed in the Rotorua, New Zealand thermal park. Over a period of several years, flows from thermal springs ceased, and discharges from the famous geysers stopped or were severely curtailed. Investigation showed that private landowners in the area illegally had drilled thermal-water wells; and that this resulted in the drawdown of the shallow hot-water aquifer that supplied the geysers. The government seized and destroyed the illegal wells. A strict policy of controlled use and monitoring was established, with the happy result that the geysers once again are returning to their former glory.

To put it simply, it is the responsibility of the geothermal developer, whether private or government, to conserve water; to make available additional or replacement water supplies; to protect existing thermal features; and to ensure that pollution is avoided.

8. OPPORTUNITIES FOR BENEFICIAL USE

The most beneficial use is the supply of fresh water to inhabitants of desert or other water-deficit areas. This can be done in two ways: first, by saving the condensed steam after power generation; and second, by using geothermal electricity to desalinate non-potable waters. Such a scheme has been proposed for the Salton Sea geothermal field, in a desert region of California that receives on average 5 cm annually of precipitation. This proposal has received funding for feasibility studies. Still another method is the condensation of fumarole steam – essentially pure water – for domestic and agricultural use.
An important beneficial use is the supply of hot water for space heating, and in some areas for air cooling. Iceland is the prime example of this, with over 90% of the population receiving heating from geothermal wells. This also is done in such diverse countries as Hungary, Japan and the United States, and continually is increasing in application. Geothermal steam is used at Kawerau, New Zealand in the processing of wood pulp for paper. Hot water heating also is used very extensively in greenhouses in Turkey. In Kenya, both hot water and CO_2 gas are supplied from Olkaria field to a major flower-growing greenhouse complex. The inflow of CO_2 reportedly increases flower growth by up to 30%.

There are many other uses for the heat, the steam condensate, the carbon dioxide gas, and for other constituents of the geothermal brines, such as the recovery of native sulfur, lithium and zinc. Although the principal benefit may be the generation of electricity, the additional value of value of the geothermal fluid should never be overlooked.

9. A CONCLUDING REMARK

Geothermal brines, although composed principally of waters too hot and too saline for ordinary domestic or agricultural use, are a valuable commodity with many alternative uses; commodity too valuable to be wasted or misused. Understanding the chemistry and physical characteristics of the geothermal waters pays off both financially in improved reliability of production, and in fewer environmental issues.

LECTURE 5

GEOTHERMAL RESOURCES OF THE BASIN-AND-RANGE GEOLOGICAL PROVINCE, USA

1. LOCATION AND GENERAL CHARACTERISTICS

The northern arm of the Basin-and-Range province is an area of over 600,000 km^2 characterized by fault-bounded horsts and flat-floored grabens, mostly trending N-S. It extends about 800 km E-W from the States of Utah to California, and is cantered in the State of Nevada (Figure 5). Its eastern boundary in Utah is the Wasatch Range of mountains; in California, its western boundary is the Sierra Nevada. The northern edge of the province in Oregon and Idaho partly is formed by the Snake River Plain, and on the south, its border is a major NE-trending linear feature, the Las Vegas Shear Zone. The southern arm of the province, which extends from southernmost Nevada into the States of Arizona and New Mexico and beyond into Mexico, is not discussed in this paper.

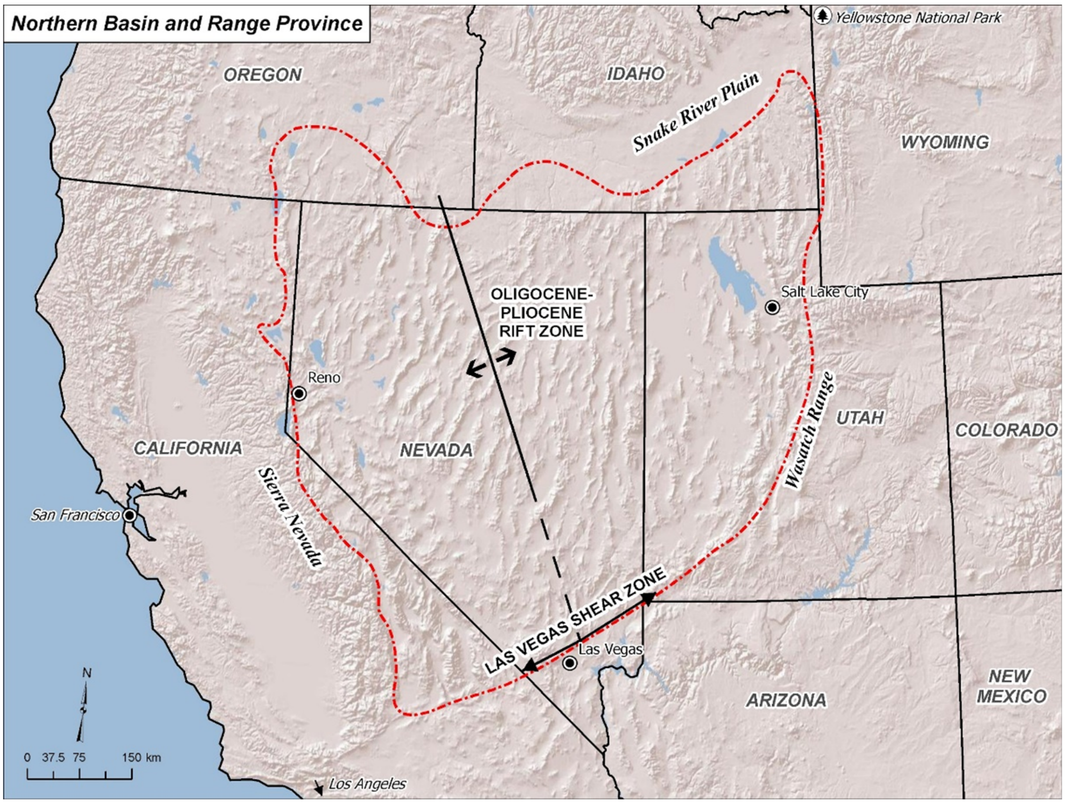

FIGURE 5: Northern Basin and Range province

The principal population centres are along the eastern and western margins of the province, specifically the Reno, Nevada and Salt Lake City, Utah areas. A few smaller cities are present to the north or south of these; and there are a few small towns scattered along the major highways of the province interior. Las Vegas and associated town are farther to the south of the southern boundary. However, it is one of the most sparsely inhabited areas of the United States. Tourism, cattle ranching, farming and government operations are the major economic activities.

Topographically, elevations in the interior range from about 1.3 km in the lower basins, to over 3.2 km in the higher mountain ranges, with an average elevation about 1.5 km above sea level. Topographic relief is greatest along the province's western and eastern boundaries, exceeding 3 km in places along the Sierra Nevada front, and reaching 2.4 km locally along the Wasatch front. Relief is less within the interior of the province, the maximum being just over 2 km. The region is semi-arid, with occasional winter snowstorms and rare summer thunderstorms. There is a great spread of temperatures between the summer highs (38 to 40ºC) and the winter lows (-15 to -25ºC), with a year around average being about 18ºC. Although a few important rivers are fed by runoff from the bordering Sierra Nevada and other mountain ranges, the entire area is characterized by internal drainage. Rivers evaporate in desert playas, or feed into permanent but closed lake basins. This wide area of internal drainage is also known as the Great Basin.

2. STRUCTURAL SETTING

The Great Basin is a region of crustal extension and thinning, the failed northern arm of a major N-S-trending intra-continental rift. By some interpretations, the rift is the landward projection of the East Pacific Rise, displaced eastward along multiple faults and spreading centers in the Gulf of California and the State of California into central Nevada. East-west rifting began late in Oligocene Epoch, accompanied by extensive volcanism. As rifting continued, progressively younger volcanic rocks were extruded. However, by the beginning of Pleistocene Epoch volcanism was waning. The youngest volcanic rocks are found along the eastern and western margins of the Great Basin, and along the eastern end of the Snake River Plain to the north. The most extensive zone of Quaternary volcanism extends intermittently for several hundred km along the front of the Sierra Nevada (Figure 6).

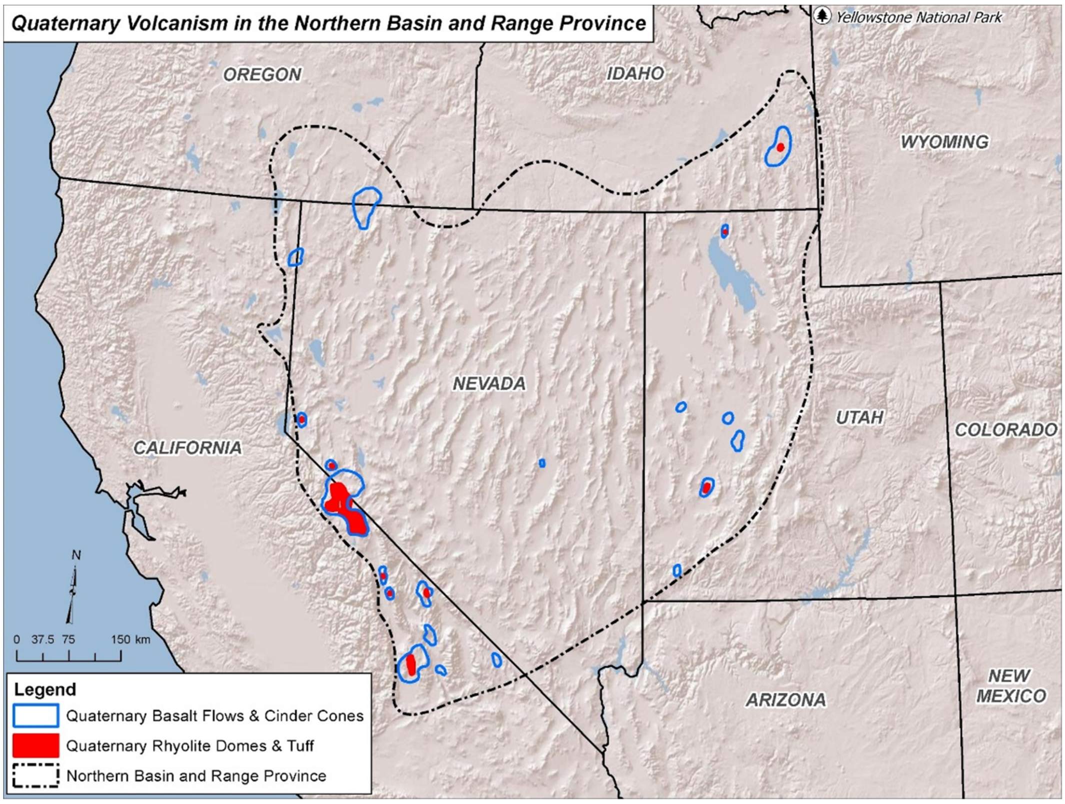

FIGURE 6: Quaternary volcanism in the Northern Basin and Range province

The Snake River Plain is an area of crustal down-warping and massive middle and late Cenozoic volcanic activity. Volcanism, in this case, is the product not of crustal rifting, but of the westward movement of the North American tectonic plate over a semi-stationary mantle hot-spot. The oldest volcanic rocks, of Miocene age, are at the western end of the Plain. They become progressively younger until the Quaternary Yellowstone caldera in the northwestern corner of the State of Wyoming. Basin and Range structure continues for some distance north of the Plain. This suggests that emergence of the mantle hot-spot some 16-17 million years ago, and thus the formation of the Snake River downwarp, post-date the start of N-S rifting and crustal extension.

Quaternary volcanism is essentially bi-modal. Basaltic flows and cinder cones are present both as large fields and as isolated eruptions, the latter more commonly at a distance from the margins of the Basin. Quaternary rhyolite domes, obsidian flows and massive ash-flow tuffs are most abundant along the Sierra Nevada front, and of course at Yellowstone on the northeast, and are present in smaller numbers along the Wasatch Range front in Utah.

Within the Great Basin, the oldest rocks ('basement') exposed in the horsts are Proterozoic, Paleozoic and Early Mesozoic sedimentary and lesser volcanic rocks, cut locally by granitic intrusions. Metamorphic core complexes are exposed in the eastern part of the province. Basement has been offset internally by major thrust faults of Mesozoic age, with both duplication and elimination of parts of the stratigraphic column. The thrust faults are indicative of crustal shortening and thickening during the period before rifting and crustal expansion began. Overlying the basement are Tertiary tuffs and lavas of varying composition. These are intruded in places by small dikes and stocks of Middle to Late Tertiary age. The flat-floored basins are filled to depths of 500 to over 2,000 meters with Quaternary and later Tertiary lacustrine, alluvial and fluviatile sediment. Induration and hydrothermal alteration increase with depth. Underlying the basin fill are the same Late Tertiary volcanics and Paleozoic and Mesozoic formations that form the horsts. Basement rocks often exhibit hydrothermal alteration and low-grade metamorphism.

There are several centres of metallic mineralization regionally, principally silver and copper. The best known of these are the Comstock Lode (silver) in western Nevada, the Austin silver deposits of central Nevada, copper mines at Ely and Ruth in eastern Nevada, and the Bingham copper deposit of western Utah. In addition to these, there are several gold deposits of large tonnage but very low grade (perhaps 3 to 20 parts per million) in central Nevada (Carlin-type ore bodies), often found in geographic association with a major thrust fault. Mercury, antimony and sulphur mineralization are present at certain volcanic centres, thermal springs and fumaroles.

Most of the range-front faults have experienced episodic activity. This often creates new fault scarps in a stair-step pattern. Many of the older fault segments do not cut the most recent deposits and therefore are not exposed at the surface. The range-front faults in general strike N-S, although strike varies across a 60° arc, from NNW-SSE to NNE-SSW. This probably reflects changes in the direction of plate movements and crustal extension since Miocene Epoch. Crustal extension presently is measured at approximately one cm annually across the width of the Basin and Range, but has varied through time. Thus, cumulative extension during the past 20 million years has resulted in approximately a doubling of E-W length, although this varies locally from 50% to over 200% total extension. Basically, the North American Plate has moved westward, completely overriding the subducted Farallon Plate and part of the Pacific Plate. One result is that at depths of several km some of the east-dipping range-front faults flatten from their initial high-angle dip, to become listric in form.

The province is seismically active, with the most earthquake activity in the western area (Figure 7). The most seismically active zone is along the Sierra Nevada front. Another important earthquake zone runs N-S from Death Valley in California through Dixie Valley, Nevada, near the rift centre. The Wasatch front also is active, but slightly less so. Earthquake magnitude in each of these regions can exceed 7.0 on the Richter scale. Occasional swarms of lower magnitude, such as a swarm lasting several weeks outside of Reno about 10 years ago, may be related to intrusion of dikes at a few km depth. By contrast the Snake River Plain is essentially aseismic.

Seismic reflection profiles indicate a major increase in wave velocity at about 30 km depth within the Great Basin, as opposed to over 50 km depth beneath the Sierra Nevada and Wasatch blocks (Figure 8). This suggests significant thinning of the crust. However, earthquake waves become attenuated at depths of only 12 to 15 km beneath the northern Basin and Range. This indicates that plastic flow rather than

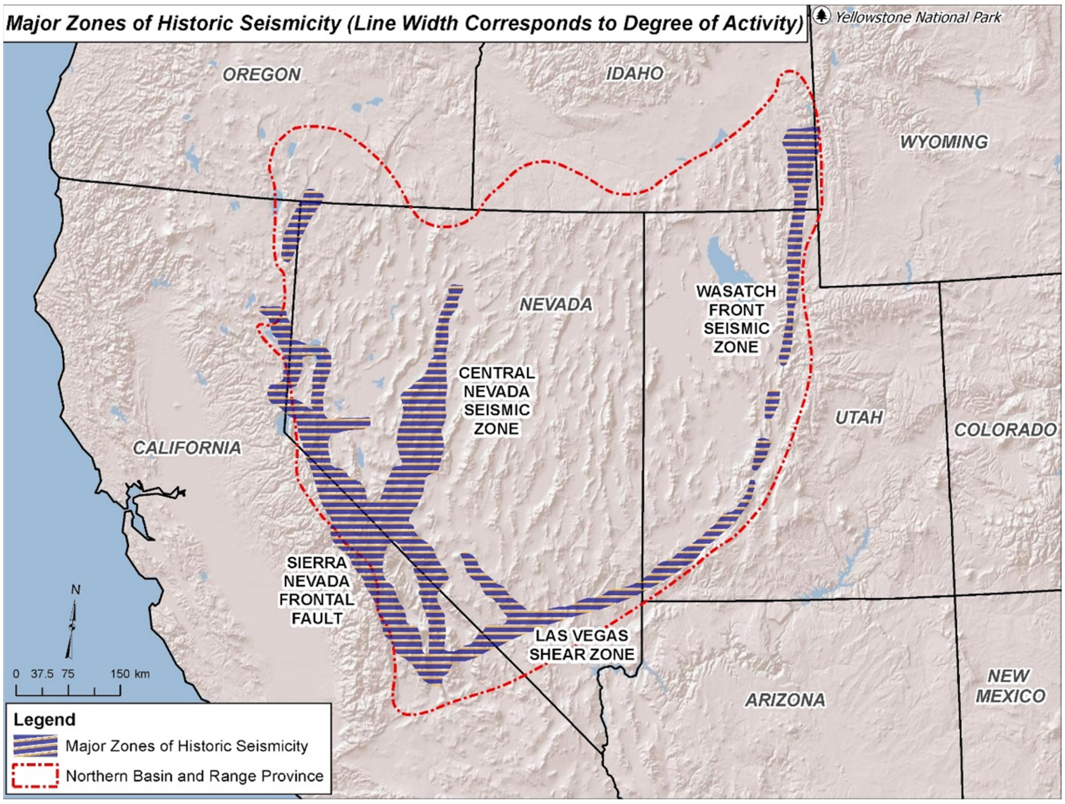

FIGURE 7: Major zones of historic seismic activity in the Northern Basin and Range province

brittle fracture starts to occur at these depths. In turn this indicates elevated temperatures, perhaps 950 to 1100°C (incipient melting).

An origin for this situation has been proposed: Melting of the low-temperature elements of the subducted Farallon Plate resulted in bowing or uplift of the heated crustal segment directly above the melt. Bowing was accompanied by stretching or extension, with subsequent fracturing and collapse into a basin-and-range topography. Melt ascended major fractures, in part reaching the surface as extrusive rocks, and in part remaining in the subsurface as intrusive necks, dike swarms, and small plutons. The ascending

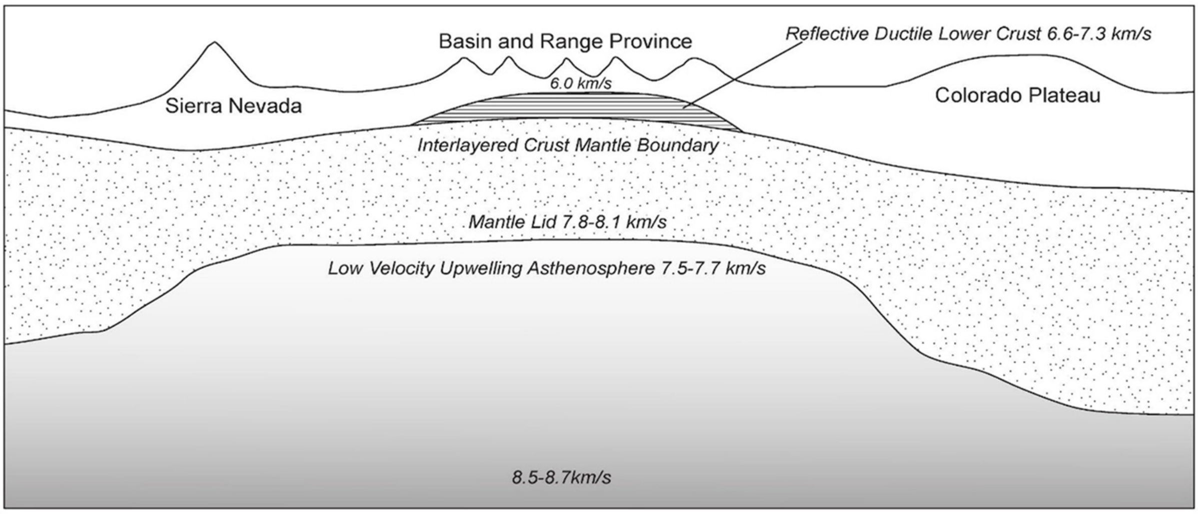

FIGURE 8: Interpretive lithospheric cross-section of the Northern Basin and Range province. The crust of the Basin and Range is thinner (30-35 km) than the adjacent Sierra Nevada and Colorado Plateau provinces (40-45 km), and a portion of the lower crust is highly reflective, possibly a result of ductile deformation and magmatic intrusions

magma in turn melted the low-temperature crustal rocks, resulting in a highly fractionated volcanic and intrusive rock suite. Igneous underplating of the region by crystallization of the residual melt probably is occurring at depths of about 12-15 km. (This model – melting of a subducted wedge, followed by heating, arching and fracturing - may have application in the assessment of the East African and Red Sea rifts, as well as the grabens of south-western Turkey, the Lake Baikal region and elsewhere.)

Gravity surveys have revealed two major Bouguer lows (-200 - > -240 mgals) in central Nevada, comparable in size and intensity to the Bouguer negatives of the Sierra Nevada and Wasatch Range. The latter have crustal thicknesses of 50 to 60 km, and their gravity lows reflect the buoyant, low-density granitic crust. By contrast, central Nevada has a thin crust and shallow depth to higher-density rock. Therefore, the gravity lows probably represent low-density melt or plastic flowage…part of the igneous underplating process.

Maps of heat flow (Figure 9) show a major linear high (>105 µW/m^2) in northern Nevada ('the Battle Mountain high'), extending north-eastward and ending in the Yellowstone area. This is more than twice the world average of heat flow. In area, the anomaly corresponds largely with the zone of high-temperature thermal features and NE-SW linear zones described in the following paragraphs.

Along with the obvious N-S fault pattern, there are several zones of NE-SW-trending faults and topographic alignments in the northern Basin and Range (Ekren, 1976) (Figure 10). These may be – at least in part – controlled by structural trends of the Paleozoic-Mesozoic rocks, or even of Precambrian age. One important alignment of small NE-SW faults and topographic lows extends from north of Reno to the Idaho border, where it appears to merge with the southern boundary of the eastern Snake River Plain, and from there extends to Yellowstone. Another such zone runs from Lake Tahoe on the California border, through Nevada's Carson Sink, across the northwestern corner of Utah. A third zone, less-well defined, extends from Mono Lake Basin in California an indeterminate distance into central Nevada. Another extends in disconnected segments from Honey Lake, California into northwestern Nevada. Other NE-SW topographic and structural trends are present, usually shorter in length or less obvious topographically.

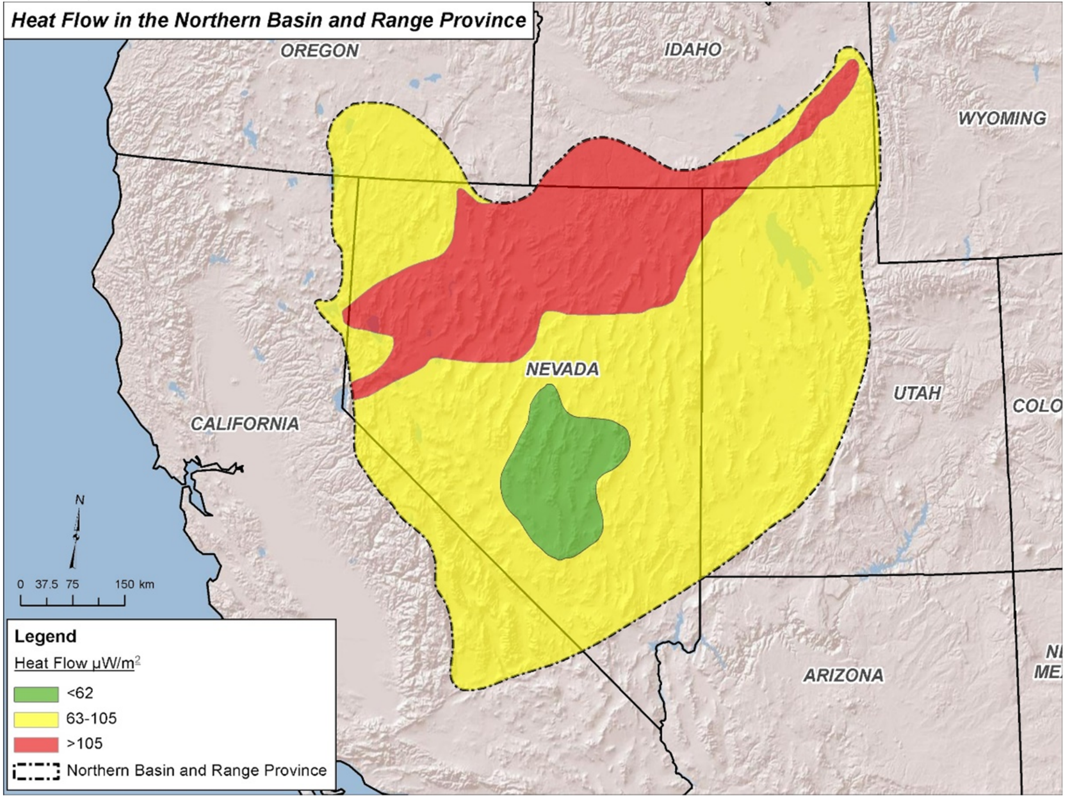

FIGURE 9: Heat flow in the Northern Basin and Range province

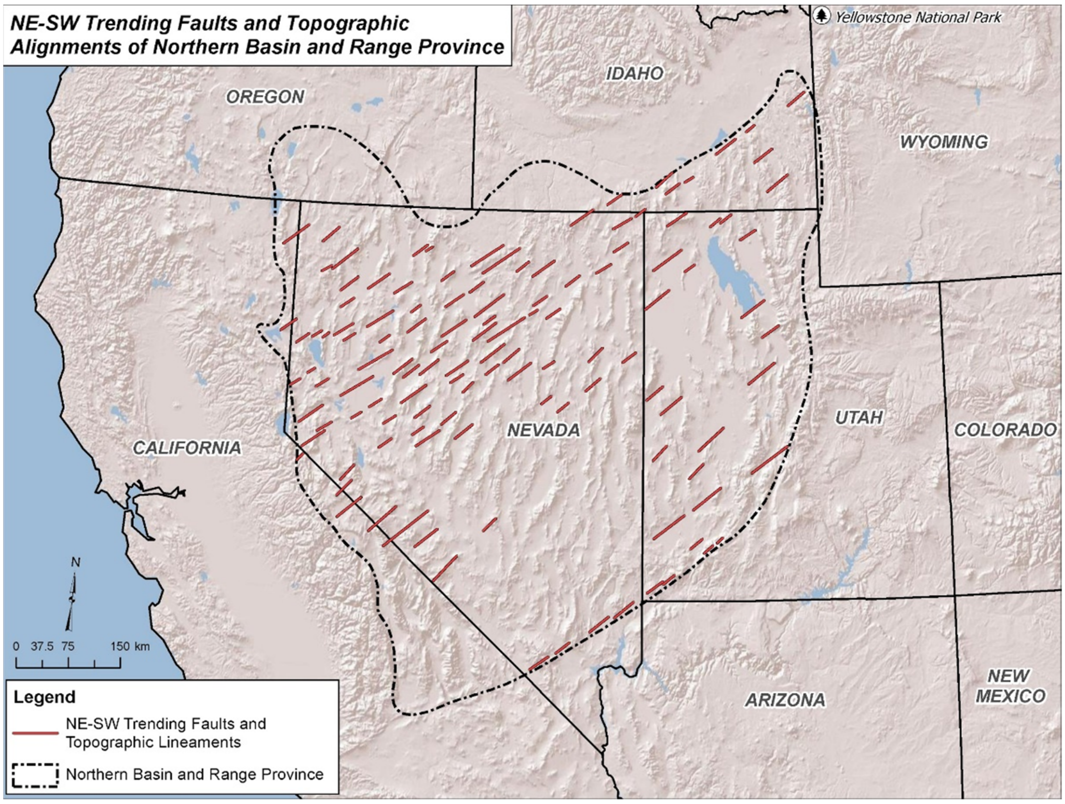

FIGURE 10: NE-SW trending faults and topographic alignments of the Northern Basin and Range province

To the south, the zone of NE-SW features ends with the NE-SW Las Vegas Shear Zone. Interestingly, the several linear zones serve to confine the major geothermal fields of the northern Basin and Range province. Equally interesting, topographic surfaces in the region to the south average about 1 km lower in elevation; and the strongly negative Bouguer gravity anomalies end there. This may reflect less bowing of the crust, less heating, and therefore fewer major geothermal features in the southern Basin and Range province.

3. GEOTHERMAL FEATURES

The northern Basin and Range contains the largest concentration of boiling or near-boiling springs, warm ground and fumaroles of any area in North America (Trexler et al., 1983) (Figure 11). Table 2 lists 18 geothermal systems that have been drilled to depths between 1 and 2.5 km and that have temperatures above 170°C (Figure 12). Most are clustered in northern and western Nevada and adjacent California; but some are in western Utah along the Wasatch front.

Some high-temperature springs clearly are associated with Quaternary silicic volcanism: Coso, Paoha Island (in Mono Lake) and Long Valley in California; Steamboat Springs in Nevada; and Roosevelt in Utah (Luedke and Smith, 1981). The only manifestation at the China Hat, Idaho, rhyolite dome is that snow melts almost instantly in a small area. Minor basalt eruptive centres are associated with thermal waters or warm ground at Soda Lake and Chimney Spring, Nevada; and Abraham (Crater), and Cove Fort, Utah; and possibly elsewhere. (Lassen volcano and the Medicine Lake Highlands, although magmatic, usually are considered to be outliers of the Cascade Range volcanics. Although Basin and Range structures extend past Yellowstone, that magmatic system is a product of the Snake River mantle hot-spot.)

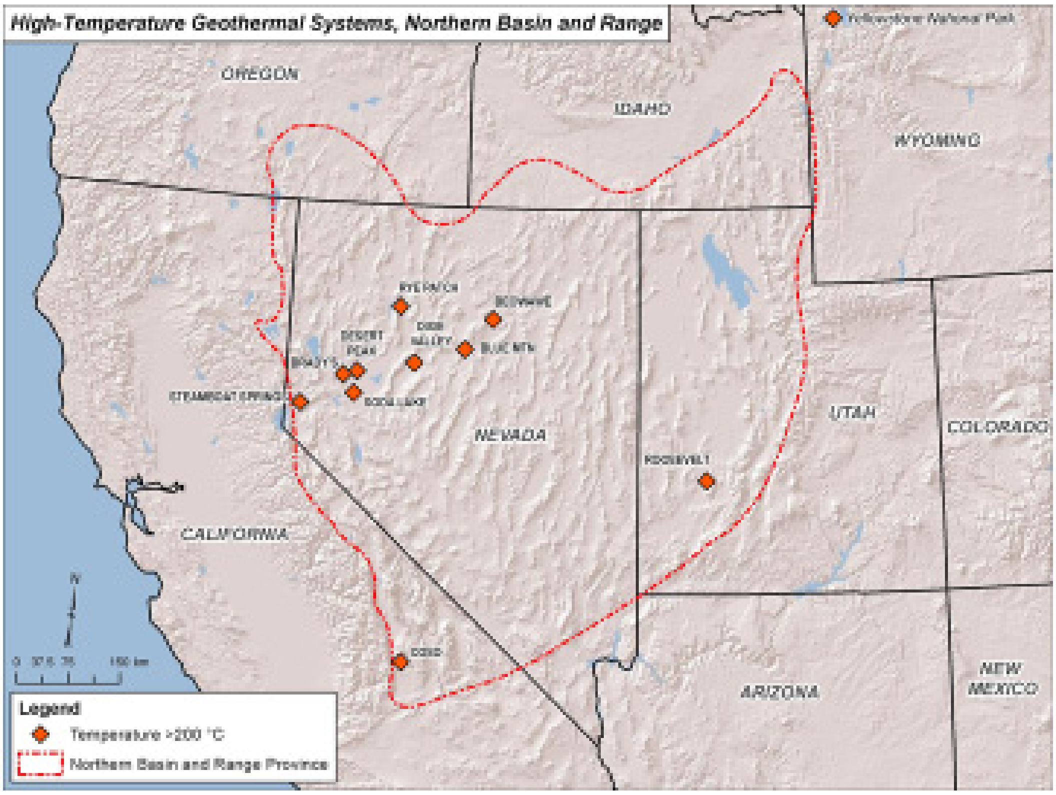

FIGURE 11: High-temperature geothermal systems in the Northern Basin and Range province

But most thermal manifestations are found in non-magmatic environments. Many are present along N-S range-front faults. Others are present along NE-SW-trending faults. Two of the most important of

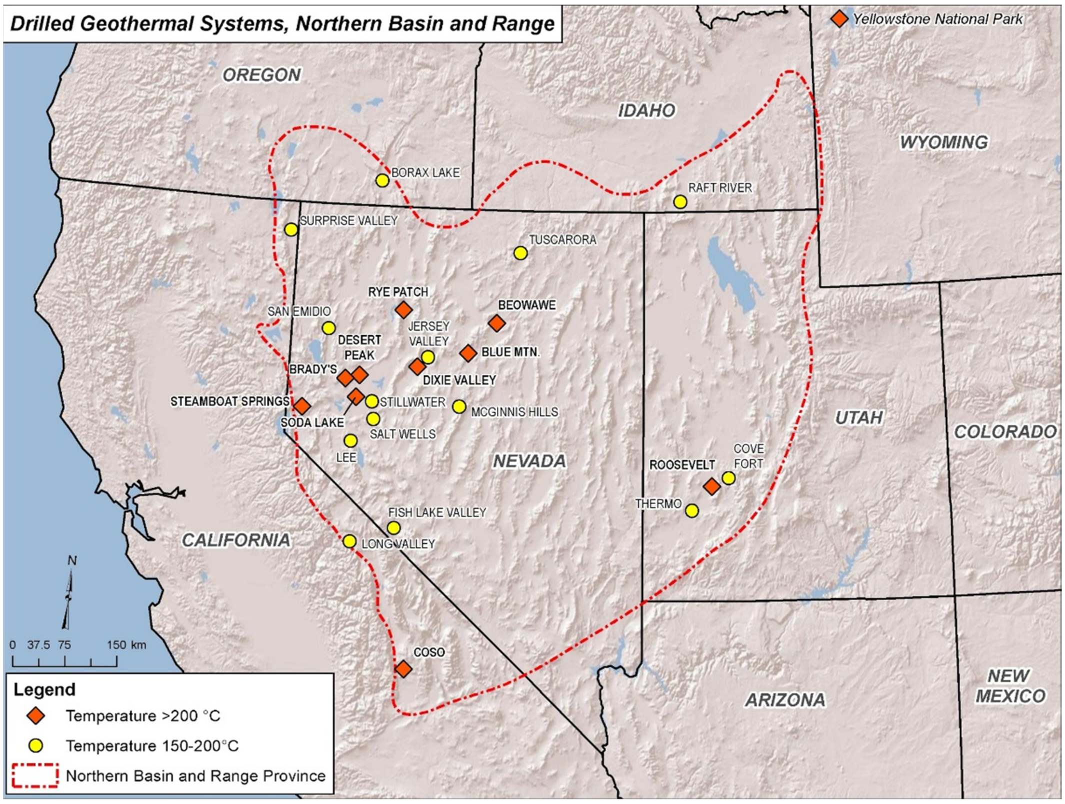

FIGURE 12: High-temperature and intermediate geothermal systems drilled into in the Northern Basin and Range province

these are Beowawe and Crescent Valley, in central Nevada (Trexler et al., 1983). Some – again possibly a very large percentage – are present at intersections of N-S and NE-SW faults or fracture zones. Among these, Dixie Valley in central Nevada and Bradys in western Nevada are the best known. However, there are several that have not had deep exploratory drilling.

Additionally, there are several areas without thermal springs or fumaroles, but which instead are marked by mounds or linear zones of siliceous sinter, opalite or travertine, mercury and sulphur mineralization, and emanations of sulphurous gases. These include Desert Peak, San Emidio, and Rye Patch, Nevada, and Cove Fort, Utah. When drilled, they were found to be active geothermal systems. The absence of surface springs reflects a deepening of the local water table, or the sealing of fractures that once leaked hot water to the surface. Several other boiling-water systems have been found through the accident of drilling water wells, test holes for mercury or other minerals, and exploration for oil. Examples are Newcastle, Utah and, Fly Ranch, Nevada (water wells for livestock), Fish Lake, Nevada (oil exploration), Hawthorne, Nevada (mineral exploration), and the Huffaker Hills, Nevada (domestic wells). Most of these accidental discoveries were at depths much less than 1 km; some experienced temperature reversals with additional depth. This suggests horizontal flow from a vertical fracture at some unknown direction.

It has been projected that temperatures of 950 to 1100°C are present at 12 to 15 km depth. This equates to an overall gradient of about 60 to over 80°C/km. In turn, this suggests that any hole drilled to 3 km depth will encounter rock temperatures of 180 to perhaps 240°C. Where permeability is sufficient at that depth, fluids with such temperatures are found. However, intergranular porosity becomes very small at these depths in the Paleozoic-Mesozoic and underlying crystalline rocks. Permeability depends, therefore, on the presence of through-going fracture networks; and these most often are the range-bounding faults and associated smaller fractures.

Cold rain and snow melt percolate downward along fractures, becoming warmer as they descend. Hot waters are less dense than cold water; therefore, the heated waters are displaced upward, cooling conductively, and often descending again, forming a convective loop. Because of active seismicity and crustal extension, faults may be "open" to several km depths, with descending water becoming heated to the rock temperatures at those depths. If the ascending heated waters encounter a permeable rock unit, the waters will move horizontally, thereby forming a geothermal reservoir. This creates a dual porosity system: high porosity and permeability in the main range-bounding faults; and lower porosity and permeability, but much greater volume, in the fractured reservoir formation. If the permeable aquifer is found at shallow depths, the water temperature will be higher than the regional temperature gradient would suggest. However, at depths below that thermal aquifer there usually will be either isothermal conditions, or a reversal of temperature with greater depth until the depth is reached that matches the regional temperature gradient (60-80°C/km).

4. DEVELOPMENT OF GEOTHERMAL RESOURCES

The first major wave of exploration devoted to development of geothermal electricity in the northern Basin and Range was in the late 1950s and 1960s. Almost all work was done at or near thermal springs or fumaroles, especially where privately owned land was available for leasing. Relatively little geophysical – or even geological – exploration was carried out, except for research by the U.S. Geological Survey (mainly at Steamboat Springs). However, numerous wells were drilled, almost all significantly less than 1 km in depth, at Beowawe, Bradys, Crescent Valley, Darroughs Hot Spring, Fernley, Genoa, Great Boiling Spring (Gerlach), Pyramid Lake, Smith Valley, Steamboat Springs, Stillwater, and Wabuska in Nevada; and at Amedee and Wendel (together known as Honey Lake), Bridgeport, Mono Lake, Coso, Casa Diablo (Long Valley), Kelley's Hot Spring, and Surprise Valley in California; and at Lakeview and Crump (Adel) in Oregon (Koenig, 1970). Most sites were abandoned without further work. However, some of these along with other prospects were explored further in subsequent years.

The early round of drilling did encounter two systems above 200°C:

Beowawe	212°C at 622 m
Bradys	215°C at 1,540 m

Both of these fields have been utilized for power generation.

Several others were found to be above 150°C:

Steamboat Springs	187°C at 558 m
Casa Diablo	178°C at 323 m
Surprise Valley	160°C at 655 m
Coso	151°C at 114 m

Beowawe, Bradys and Surprise Valley have no associated Quaternary volcanism. Of this group, only Surprise Valley has not been developed for power generation (Table 3).

TABLE 3: Geothermal power generation, Northern Basin and Range Province

Field	Installed capacity, MW	Plant type	Maximum temperature, °C	Notes
California				
Coso	270	Flash	213	Insuffic. resources; partly curtailed
Honey Lake	30	Hybrid	110	Wood waste heated by geothe. fluid
Long Valley (Casa Diablo)	40	Binary	178	Being rebuilt after decommissioning
Idaho				
Raft River	13	Binary	151	Output to be increased
Nevada				
Beowawe	17	Flash & Binary	212	
Blue Mountain	49	Binary	213	Resource probably not sufficient
Bradys	26	Hybrid	215	Facility also for drying vegetables
Desert Peak	23	Binary	210	Rebuilt after decommissioning
Dixie Valley	65	Flash	238	
Jersey Valley	23	Binary	165	
McGinnis Hills	72	Binary	170	Recently expanded
Patua	30	Hybrid	184	Solar being added; resource limited
Salt Wells	24	Binary	181	
San Emidio	12	Binary	159	Plans to expand
Soda Lake	16	Binary	204	
Steamboat Springs	137	Binary & flash	235	Recently expanded
Stillwater	47	Hybrid	177	22 MW solar added; resource insuff.
Tuscarora	32	Binary	173	
Wabuska	5	Binary	107	Still in operation after 30 years
Wild Rose	22	Binary	127	Plans for expansion at a later date
Utah				
Cove Fort	25	Binary	175	Plans for expansion to over 60 MW
Roosevelt	34	Flash	270	
Thermo	10	Binary	171	Permeabil. inadequate; being rebuilt
Total	**1,024 MW installed**			

NB: Resource size and/or sustainability was misjudged at several fields, including: Blue Mountain, Coso, Patua, Stillwater, Thermo.

Several fields have changed ownership over the decades, with changes in operating strategy and development plans.

Two others prospects – both non-volcanic – had temperatures above 120ºC (assumed to be the economic lower limit for generation by ORC processes):

Darroughs	130ºC at 253 m
Crump	121ºC at 513 m

Neither has had commercial development of geothermal electricity.

The reported temperatures at these fields yield gradients that are vastly above the 60-80ºC/km range forecast in a prior paragraph. Also, some of the wells reported temperature reversals in their deeper sections. Together, this means that thermal fluids are rising convectively and are being stored in shallow aquifers. It also means that in many cases the upwelling is at some distance horizontally from the drilled site.

Continued drilling in subsequent years confirmed the important discoveries at Beowawe, Bradys, and Casa Diablo (Long Valley), and has found higher-temperature aquifers at Coso (215ºC) and Steamboat Spring (228ºC). Flash-steam power plants were designed and constructed at Beowawe, Bradys and Coso. Hybrid flash-ORC facilities were built at Steamboat Springs and Casa Diablo. Of the many other areas drilled in that early episode, both Stillwater and Wabuska also had ORC geothermal power plants installed.

A second wave, in the mid-70s and early '80s, was based on more-detailed exploration prior to drilling. Exploration utilized geologic mapping, geochemistry of thermal fluids, regional gravimetry, and in some fields electrical resistivity soundings. These were supplemented by extensive sets of temperature gradient holes, in which the initial holes were drilled to perhaps 50 to 150 m, and then supplemented with holes to perhaps 500 or even 1,000 m at the most attractive sites. Together, these techniques provided a useful picture to about 1 km in depth or slightly deeper, and were incorporated into conceptual models of the prospects, along with Monte Carlo probability projections of reserves. This led to deeper drilling, in the depth range of 1.5 - 2.5 km, at several sites. Several 'blind' fields – those having no surface manifestations – were discovered in this manner (Edmiston and Benoit, 1984).

With data from deeper reservoirs, the use of numerical simulation to calculate reserves, plan wellfield development, and estimate field life became a standard industry practice. It is almost impossible to obtain financing for development without presentation of a numerical simulation based on a sound conceptual model.

Significant discoveries were made at Roosevelt, Utah (270ºC); Desert Peak (210ºC), Dixie Valley (238ºC) and Soda Lake (204ºC), Nevada. Flash steam plants were built at each. Desert Peak was a true "blind" discovery whose only surface indication was siliceous sinter and traces of mercury mineralization. A patch of weakly steaming ground guided exploration at Dixie Valley. At several other prospects, the results were marginal or ambiguous in terms of temperature or sustainability of flow. These include Tuscarora, Rye Patch, Salt Wells, Pumpernickel Valley, Lee Hot Spring, Blue Mountain, and Fish Lake Valley, all in Nevada; Borax Lake, Oregon; Preston, and Raft River, Idaho; and Thermo, and Cove Fort, Utah. Attempts were made to install ORC power plants at certain of these (Table1, and McNitt, oral communication, 2016).

The 1990s to the present are characterized by the extensive use of magnetotelluric soundings in exploration, along with continued drilling of temperature gradient holes to 1 km or deeper, and the wider use of ORC generation. This has enabled the development and utilization of some of the lower-temperature systems, such as Raft River, Idaho (150ºC); Cove Fort, Utah (175ºC); and Tuscarora (173ºC), Salt Wells (181ºC), Jersey Valley (165ºC), San Emidio (159ºC); and more recently McGinnis Hills (170ºC) and Wild Rose (135ºC)., all in Nevada .Desert Peak has been converted to ORC from flashed steam; a very small ORC bottoming unit has been added to Beowawe; and a flashed-steam turbine has been added to the assemblage of ORC units at Steamboat Springs. The small ORC at Wabuska has been expanded to four times its original 1.3 MW size, utilizing water at 108°C.

The highest-temperature fields are arranged along a relatively narrow zone that trends NE-SW. Outward from that zone are other NE-SW lineaments along which the lower-temperature fields are aligned. The significance of this is still under discussion. Additionally, the hottest thermal springs in these zones discharge from fractures in the oldest rocks exposed locally. All of this suggests a regional strain pattern with greatest (or youngest) extension in the NW-SE direction.

The period also witnessed two interesting hybrid developments: at Honey Lake, California, wood chips are used as power plant fuel, dehydrated by low-temperature (107ºC) geothermal steam; and at Bradys, a facility was built to dehydrate onions using geothermal steam. Most recently, at both Stillwater and Patua (previously known as Hazen or Fernley), Nevada, there has been the combined use of solar and geothermal power, partly because the geothermal resource has proven insufficient or too costly to develop.

Table 1 (in part from Shevenell, 2015 and from McNitt, oral communications, 2016) lists the operating geothermal power plants in the northern Basin and Range. Of these, Coso, Casa Diablo (Long Valley), and Honey Lake are in California; Raft River is in Idaho; and Roosevelt and Cove Fort are in Utah. All of the others are in the northwestern quarter of Nevada. The total installed generating capacity at the 22 producing geothermal fields is an astonishing 1,024 MW. Even more astonishing, many of these had no surface discharge of hot water. San Emidio was found by temperature gradient drilling along a zone of siliceous sinter and warm ground. Desert Peak also was found by exploratory drilling into a mineralized zone. McGinnis Hills and Wild Rose were found initially during drilling for metallic minerals. Cove Fort discharged toxic gases, but without thermal waters.

Temperatures are highest at Roosevelt, Dixie Valley, and at an extension of Steamboat Springs (Steamboat Hills) – all exceeding 235ºC – followed by several clustering between about 184 and 215ºC: Beowawe, Blue Mountain, Bradys, Casa Diablo (Long Valley), Coso, Patua, and Desert Peak. Several of these, however, have either been down-rated in size or decommissioned because of cooling, pressure declines and/or a shortage of geothermal fluid. A few fields have been developed, sold to other developers or even abandoned, and then developed further. Cove Fort, Utah; and Stillwater and San Emidio, Nevada are examples (Table 4).

There are unconfirmed reports that other drilled sites have had temperatures above 150ºC, or even 170ºC. These include a hole to over 1 km at Lee Hot Spring (itself a shallow, flowing well drilled 80 years ago for irrigation water), and to about 1.2 km at Ruby Valley, Nevada. A hole drilled near Lund, in south-western Utah, and another at Colado, Nevada, may have had bottom-hole temperature of 150ºC. Other drilled sites with temperatures over 150ºC include the previously mentioned Surprise Valley, California, plus Borax Lake, Oregon (160ºC) and Fish Lake Valley, Nevada (157ºC). None of these has been developed for electricity. Many others are known or estimated to be between 120 and 150ºC.

The point is that exploration and development has been episodic, driven not just by characteristics of the resource, but also by the increasing efficiency of ORC generation, and the market and economics of power sales. This has not been a steady progression.

Exploration is continuing on a reduced basis, not because of a lack or prospects, but because the market for geothermal electricity is limited, and many of the fields are believed to be too small for economic development. Shallow wells continue to be drilled for domestic and commercial use in the Reno metropolitan area., Deep exploratory drilling is planned at Crescent Valley, Nevada, and reportedly at Crump, Oregon, and Surprise Valley, California. However, several interesting prospects remain only partly explored. Geochemical thermometers for many thermal springs suggest that reservoir temperatures above 150ºC are waiting to be found.

TABLE 4: High-temperature systems of the Northern Basin and Range Province
(showing maximum temperature and summary of major defining features)

Over 200°C		
Roosevelt, UT	270	Quaternary rhyolite domes; near Wasatch Range front; opalite mound
Dixie Valley, NV	238	Intersection of historically active N-S and NE-SW faults; weak fumarole
Steamboat Springs, NV	236	Quaternary rhyolite volcanism; steaming ground; near Sierra Nevada front
Bradys, NV	215	Boiling spring; N-S and NE-SW fault intersection
Coso, CA	213	Quaternary rhyolite domes; fumaroles; along active fault; Sierra Nevada front
Blue Mountain, NV	213	"Blind" system; intersection of NE-SW and N-S faults; found by drilling
Beowawe, NV	212	Along NE-SW fault near N-S fault intersection; fumarole
Desert Peak, NV	210	"Blind" system; hydrothermal mineralization; may connect to Bradys at depth
Rye Patch, NY	205	"Blind" system; N-S range-front fault; found by gradient drilling
Soda Lake, NV	204	Quaternary basalt flows; warm ground
Over 170°C		
Patua, NV	184	Boiling springs; mineralization; fault intersections of many directions
Salt Wells, NV	181	Thermal springs; siliceous sinter; NE-SW & N-S faulting
Long Valley (Casa Diablo), CA	178	Quaternary rhyolite domes & caldera; steaming ground; Sierra Nevada front
Stillwater, NV	177	"Blind" system; found by drilling; along range-front faults
Cove Fort, UT	175	Mineralized zone; Quaternary basalt flow; N-S Wasatch Range front
Tuscarora, NV	173	Boiling springs; intersection of N-S and NE-SW faults
Thermo, UT	171	Hot spring; N-S and NE-SW faults
McGinnis Hills, NV	170	"Blind" system; mineralized; found by drilling

The depth at which these temperatures were measured varies from about 150 to over 1,500 m. Geochemical thermometers for many of these fields indicate systems over 200°C. Data for additional areas indicate subsurface temperature regimes in excess of 170°C.

5. CONCLUSIONS AND CONCERNS

The first conclusion is that the northern Basin and Range is a giant bowl of hot water (Figure 13). Holes drilled almost at random encounter rock temperatures corresponding to gradients of 60°C/km or higher. However, once an aquifer is encountered, temperatures tend to become isothermal, or even reverse with continued depth. (In these characteristics, the Basin and Range exhibits an interesting similarity to the Menderes Graben of Turkey.)

Heat flow is abnormally high in the northern Basin and Range – over 100 $\mu W/m^2$ – reflective of a thin crustal layer (<30 km) and a very shallow depth to the layer of plastic deformation (12-15 km). Thermal springs and fumaroles are structurally controlled along range-front faults, with the intersection of N-S and NE-SW faults being especially significant. These factors result in the northern Basin and Range having the greatest areal density of high-temperature springs in North America.

The thin crust and horst-and-graben structure result from the westward-moving North American Plate overriding the Farallon Plate, with resulting melting of the low-temperature subducted limb, followed by crustal heating, arching, extension, thinning and fracturing. This allows cool meteoric water to descend along fractures to several km, become heated, rise convectively, cool conductively, and descend again in a convective loop. As part of this process, heated waters may be stored in aquifers at relatively shallow depth.

System temperatures are highest at the Quaternary rhyolite domes and calderas along or near the eastern and western margins of the northern Basin and Range…with one exception. That exception is the non-magmatic Dixie Valley field of north-central Nevada. It is assumed, for lack of strong evidence to the contrary, that the relatively shallow depth to the layer of plastic deformation and very deep circulation

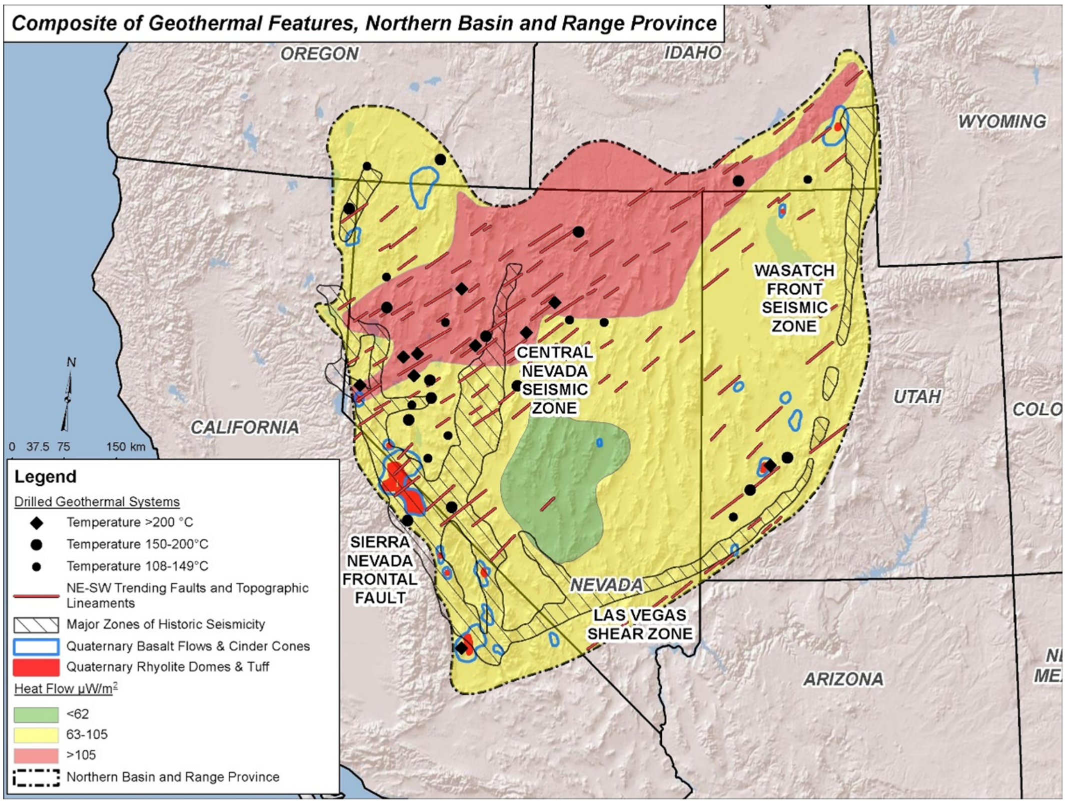

FIGURE 13: Composite of geothermal features, Northern Basin and Range province

of meteoric water along the seismically active Dixie Valley frontal fault, are the principal control mechanisms.

Many of the discovered fields are ‘blind’, lacking surface manifestations. Some have been found accidentally, in the course of drilling for oil, water or metallic minerals. Others have been found through a combination of slim-hole temperature gradient drilling and magnetotelluric soundings, with supplementary geochemistry of soil gases. This exploration methodology essentially is unique to the Basin and Range. The highest temperature systems are found along a relatively narrow zone that extends NE-SW across Nevada. Installed geothermal generating capacity of the northern Basin and Range province is 1,024 MW.

Although the Basin and Range is a generous supplier of hot water, it can be a demanding and even a treacherous host. Injection has been a problem in many fields, there either being a shortage of accessible injection sites, or there being a sudden cooling of the field as a result of poorly chosen sites. The size of many fields and prospects is small, with several being less than 20 MW in capacity. Small fields can – and do – exhibit rapid pressure declines.

All of the fields have been discovered by private entities, with little or no government support. Financing has come from sale of corporate stock, investment by private groups, and commercial bank loans. The need to show an attractive rate of return has led some companies to greatly overstate the size of their discovery or its sustainability. This has resulted in an overbuilding at some fields, with, as a result, the occasional decommissioning of power plants or even failure of the venture. In turn, this has made banks and investment groups less willing to take on geothermal projects.

However, the ever-increasing efficiency of ORC generating units has been a spur to development. An advantage of ORC is that units can be added in small modules when warranted, and at much less time than for a flash steam plant. Electricity has been generated from fluids with temperatures as low as 108^{0}C. This has enabled geothermal to compete with wind and solar power.

The electricity market is limited in the sparsely populated Basin and Range. There is essentially no transmission line access to the San Francisco Bay Area market. While there is access to the giant Los Angeles market, northern Nevada is at a disadvantage to solar and wind power in terms of distance. Prices for 'renewable' energy, including geothermal, rarely reach US$ 100/MWh, and often are US$ 60-80/MWh. Government subsidies in the form of tax credits and grants for R&D do not favor geothermal energy relative to wind and solar. As a result, wind power and solar energy increasingly are capturing the available markets.

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LECTURE 6

SALTON SEA, CALIFORNIA, CASE HISTORY, 1927-2016

1. LOCATION AND TECTONIC SETTING

The Imperial Valley of Southern California is an extremely arid desert, having an average annual precipitation of about 5 cm, and a mean annual air temperature of approximately 26°C. Winters are mild, but summers get extremely hot (to 45°C). The Valley represents the northern end of the active Gulf of California Rift, and is known locally as the Salton Trough (Figure 14). Within the Trough is the Salton Sea, a large lake with no surface outflow. Much of the Trough is below sea level, separated from the Gulf of California (in Spanish, the Mar de Cortez) by an alluvial ridge that averages about 9 meters above sea level. However, the surface of the Salton Sea is at -72 meters, and its bottom is perhaps 10 meters deeper, making it the second lowest land surface in North America (after Death Valley).

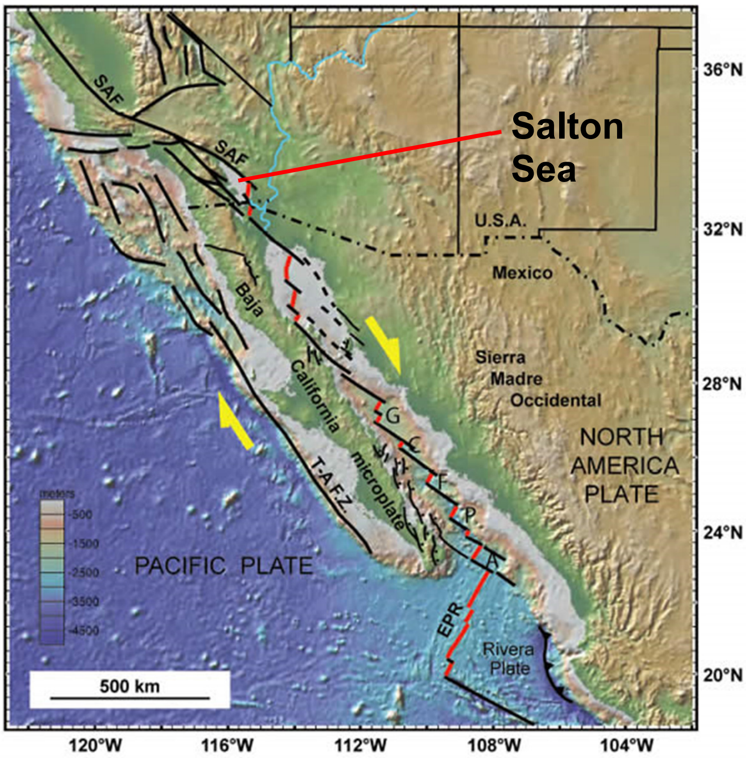

FIGURE 14: The Gulf of California Rift Zone

Rifting began probably in Miocene epoch, progressing northward, first splitting Baja California from the mainland of Mexico and then continuing into California (Figure 15). In California, the southern end of the NW-SE-trending San Andreas Fault and its subsidiary extensions form the eastern Rift boundary;

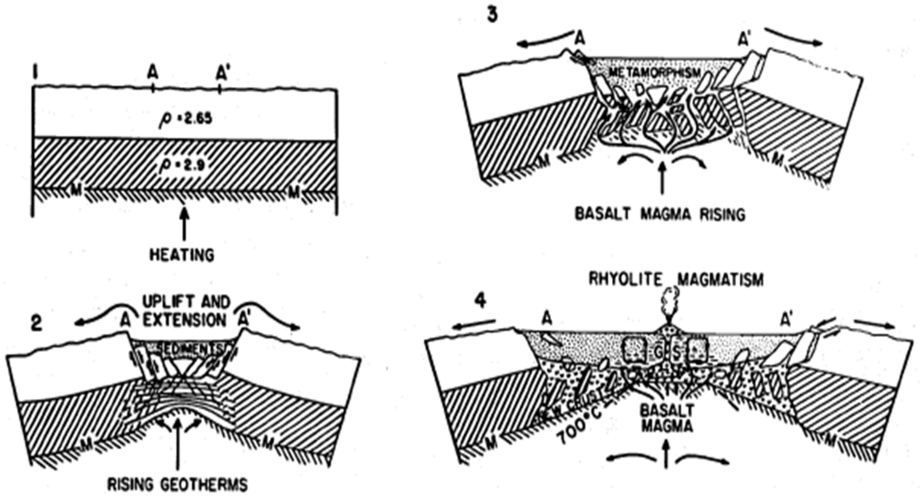

FIGURE 15: Four stages in the development of the Salton Trough Rift; 1) Pre-rifting conditions; 2) Extension and uplift; 3. Magma injection and metamorphism; and 4) Rhyolite extrusion (Elders and Cohen, 1983)

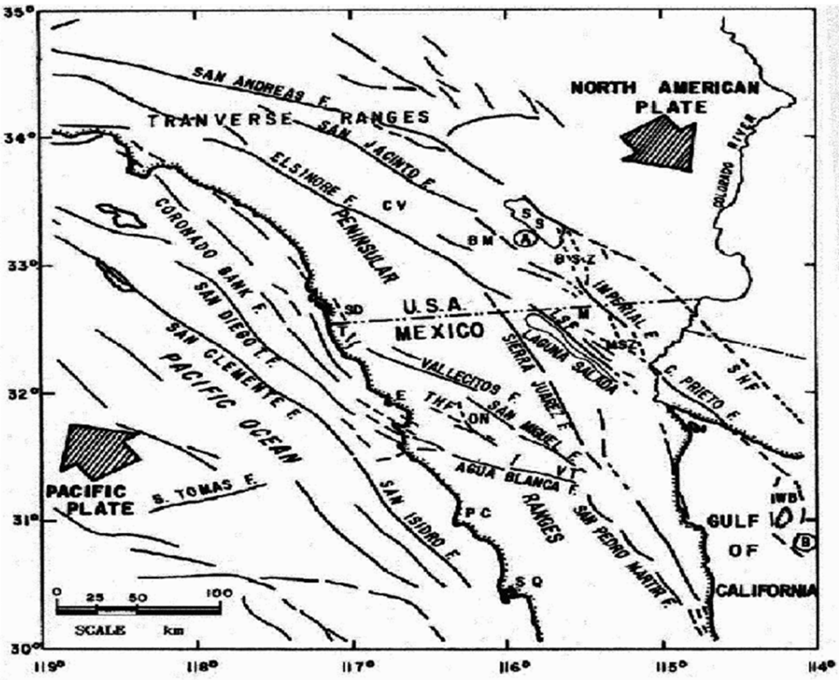

FIGURE 16: Detailed pattern of active or potentially active faults in and surrounding the Salton Trough

whereas branches of the San Jacinto Fault form its western boundary (Figure 16). All are dominated by right-lateral horizontal offset. The Rift is very active seismically, with numerous earthquakes along both boundary fault sets, and especially along the Imperial Fault, part of a transform fault system that runs N-S through the centre of the Rift. A major swarm of tremors at the northern end of the Imperial Fault denotes a spreading centre, referred to as the Brawley Fault or Brawley Seismic Zone. It is one of many pull-apart centres along the entire Rift. They serve to transfer extension stepwise to the right from one fault to another. They also tend to localize magmatic upwelling from the mantle into the shallow lithosphere.

North of Salton Sea, another series of faults and major shears (the Eastern California Shear Zone) transfers the zone of extension eastward to the Death Valley depression, and beyond that into central Nevada. (The Central Nevada Rift is discussed in a separate paper.)

In California, the Salton Trough (Figure 17) is filled to a depth of 4 to over 6 km with a mixture of silt, clay, sand and evaporates, poorly to moderately indurated, and in the deeper section metamorphosed to

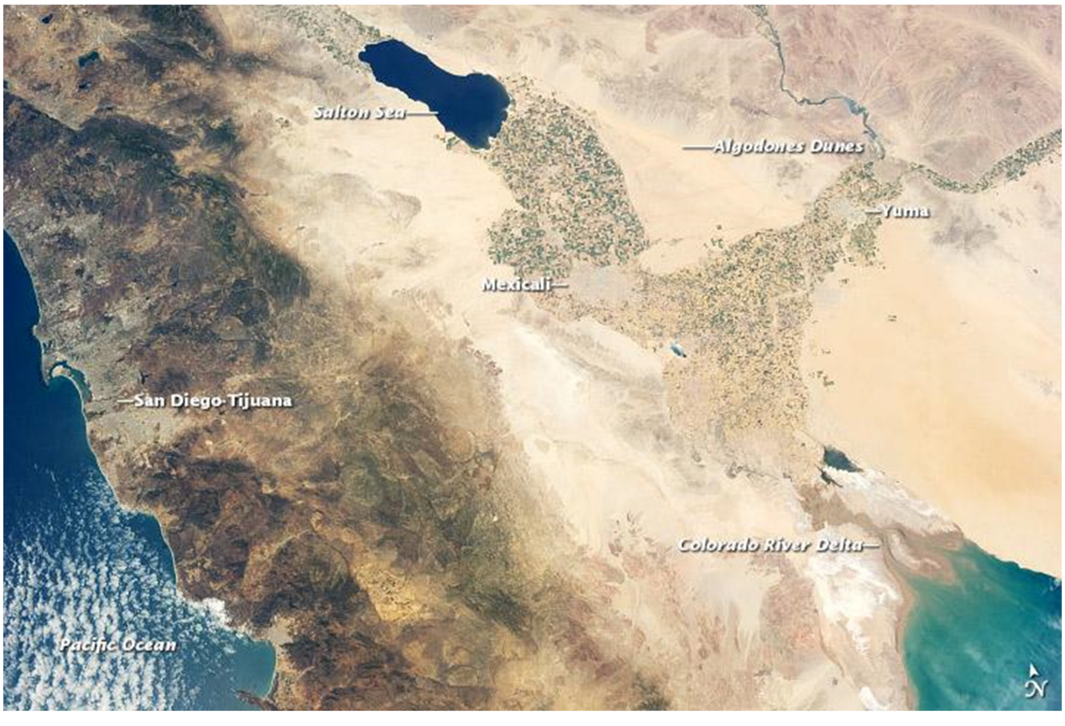

FIGURE 17: Aerial view of the Salton Trough

the greenschist facies. The sediments formed as part of the delta of the ancestral Colorado River, accompanied by episodes of lacustrine and aeolian activity. The focal depth of microseismic swarms generally is not greater than 8 km, suggesting that there is a phase change in that depth range. It is assumed that diabase sills and remnants of the pre-rifting granitic batholith – hot, plastic, but not molten – underlie the basin fill.

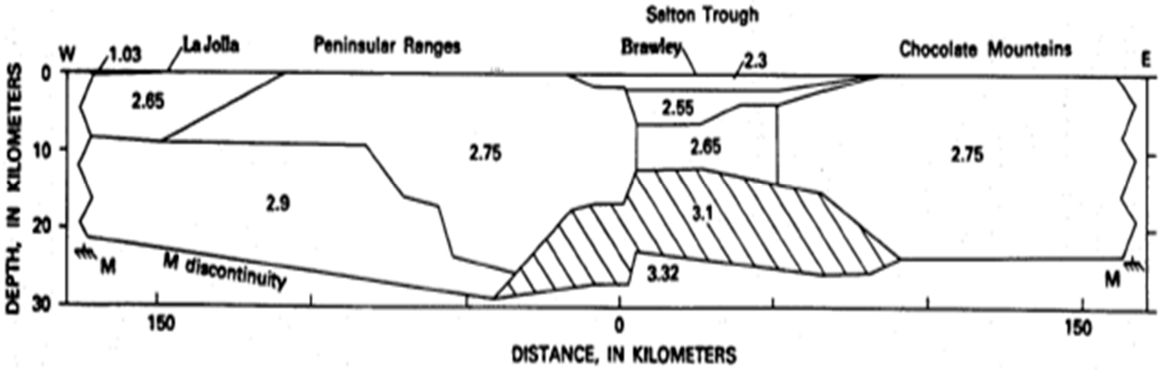

FIGURE 18: Cross-section from seismic reflection profiles: high-velocity body (striped area) with upper surface at about 10 km is interpreted as mafic intrusive complex, the ultimate heat source for the Salton Sea geothermal field

Several important geothermal fields are present in both the Mexican and American sections of the Rift, located mostly at the spreading centres. The two most important fields are Salton Sea in California, and Cerro Prieto in Mexico, about 80 km apart. Quaternary volcanic rocks are exposed at both fields. Five small rhyolite domes (the Salton Buttes) at the southeast corner of the Sea have been dated radiometrically to range in age from about 16,000 years before present (ka) to as young as 1,800 ka. Seismic studies suggest that there are numerous channels for the upward ascent of a highly differentiated magma from a zone of melting that begins at 18-20 km depth (Figure 18). The Salton Buttes are the only surface manifestation of igneous activity in the Salton Trough. A strong positive Bouguer anomaly around the domes extends northward a few km beneath the lake (Figure 19). This suggests either (or both) densification by metamorphism or widening of the intrusive body at depth.

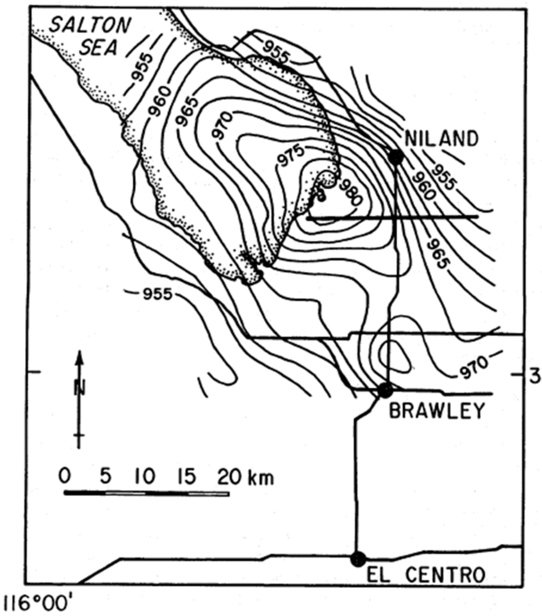

FIGURE 19: Complete Bouguer gravity map of the Salton Trough

2. WHAT IS THE SALTON SEA?

There have been ephemeral lakes in the central depression of the Salton Trough throughout later Tertiary and Quaternary time, each evaporating to dryness. Water for some of these lakes may have originated as underflow from the Colorado River some 60 km to the east, through permeable units of the basin fill. However, the most recent lakes, in the 19th Century, formed from natural overflow of the Colorado River following winters of high precipitation. Each had disappeared within a dozen years. However, the present lake was created by a man-made accident. At the beginning of the 20th century, water from the Colorado River was diverted through lengthy canals to support an irrigated system of agriculture in the Imperial and Coachella Valleys. In 1905-1906, the river burst through the control gates on the canals,

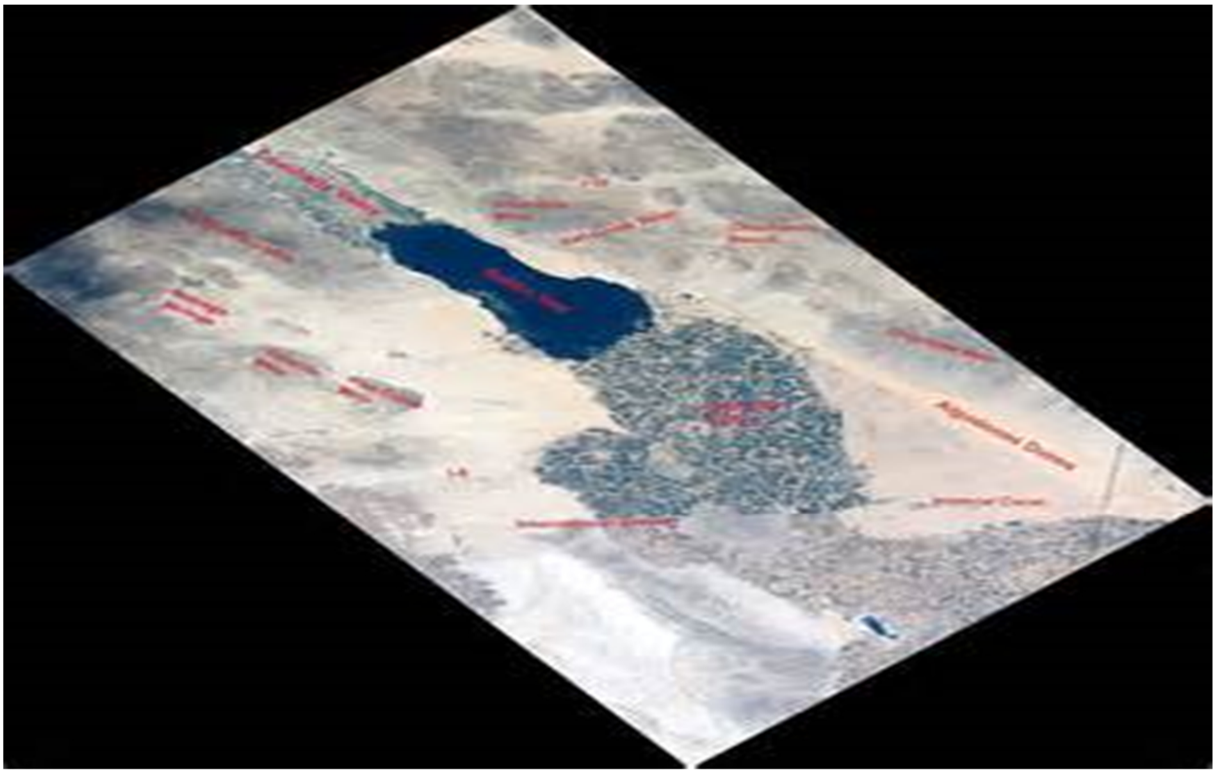

FIGURE 20: Irrigation is intensive in the US part of the Salton See Trough and less intense in Mexico, reflecting the relative availability of Colorado River water

pouring into the below-sea-level depression and thereby forming the largest lake within California (over 900 km^2). However, within a decade the lake had lost half its mass through evaporation.

A highly organized system of irrigation and drainage canals supports the extremely important and valuable agriculture industry of Imperial Valley (Figure 20). The incoming irrigation water from the Colorado River is of high quality, probably with not over 500 mg/l of total dissolved solids (TDS). But because the relatively high salinity of the desert soils requires intensive irrigation to flush away salts, the irrigation discharge carries a few thousand mg/l of TDS. By an Executive Order of the United States government, the irrigation discharge is allowed to flow into the Salton Sea. There is a lesser amount of inflow from irrigation in the Coachella Valley, north of the lake, and seasonally as rainfall runoff from nearby mountains. The lake would have evaporated to dryness by now, except for these inflows. In addition to the moderately saline irrigation discharge, there is probably solution of saline beds beneath the lake. Because the lake has no surface outlet, and because of the high rate of evaporation, salinity of lake water has increased to over 43,000 mg/l, significantly greater than that of sea water (36,000-37,000 mg/l).

In the late 1940s, the State of California began experimentation to create a fishing industry in Salton Sea. A food chain was developed successfully by the mid-'50s. Salt-water fish were introduced, and tilapia now flourish, supported by a nutrient food chain partly derived from algae and other micro-organisms present in the irrigation runoff. A fishing and recreation industry has been developed. The lake has become a major stopping place for thousands of migratory birds. Several small communities dot the shore of the lake, with many visitors during the mild winter months.

The lake level varies with the amount of irrigation runoff that it receives. During the 1940s and early 1950s, the level rose. In recent years the level has dropped despite heavy irrigation inflow, possibly because of a regional drought. This has resulted in exposing lands around the Salton Buttes that previously were under water.

The intricate system of canals and ditches must remain at existing grade in order to carry water to the fields and then to the Salton Sea. Subsidence of the ground surface therefore is a matter of concern. Subsidence has several possible causes. One is tectonic movement, uplift or rotation of fault blocks, and settlement resulting from earthquakes or crustal extension. A second is compaction of the upper layers of soil if there is less irrigation and subsequent drying of the surface. A possible third cause is the withdrawal of vast quantities of brine from the geothermal reservoir and subsequent injection back into the deep subsurface. These are monitored periodically, to allow re-grading of ditches, if necessary.

Because the Colorado River is shared by several states and Mexico, treaties have been signed that regulate how much water each state can withdraw from the river, and how much must remain when the river enters Mexico. As population and demands for fresh water have increased, pressure has been exerted on the Imperial Irrigation District (IID) to curtail usage. The originally generous allocation to Imperial Valley now is being reduced. This will mean less irrigated agriculture, and less water for the Salton Sea, beginning in 2017-2018. The lake is projected to shrink in size by up to one-third over the following decade, exposing a saline bed and leaving lakeside communities several kilometres from the water. Increasing water salinity of a smaller lake may destroy the fishing industry and reduce habitat for migratory birds.

Maintaining constant salinity and a constant water level – and thus protecting the fishing and recreation activities and property values – has become a major political issue. Plans have been drawn up to either desalinize lake water, or to dike off portions of the lake as fresh water habitat, while allowing the rest of the lake to 'die' (eutrophy). Already there are episodes in which large numbers of tilapia die, probably from a lack of oxygen during major periods of algal blooms (Figure 21). Unfortunately, schemes to rehabilitate the lake require enormous amounts of money, electrical energy, and political cooperation between farming and recreation groups and the IID, the local electric utility. While plans are debated, the lake level – and residential property values – continue to drop.

FIGURE 21: Mass death of tilapia caused by depletion of oxygen, a result of rising temperatures and falling lake levels. Increasing lake salinity (over 42,000 mg/l) helps support massive algal blooms. Plans to revive the lake involve desalination of brine and construction of dikes and barriers, using geothermal energy from additional power plants

Many people now look to geothermal energy as a potential solution to the complex issues.

3. THE SALTON SEA GEOTHERMAL SYSTEM

The Salton Buttes consist of 5 separate extrusive features, 4 having names – Mullet Island, Rock Hill, Red Hill and Obsidian Butte, with the latter two being double or coalesced domes. They extend NE-SW along a zone 7 km in length that parallels the spreading centre, and are composed of rhyolite flows, pumice and obsidian. The presence of small fumaroles, bubbling warm muds pots and CO_2 seeps was recognized at Mullet Island dome and the adjacent terrain long before irrigation began in Imperial Valley. The area of major CO_2 seeps is immediately to ENE of Mullet Island. Figure 22 shows the Salton Sea geothermal field, Figure 23 the volcanic islands and Figure 24 steaming mud pots.

In 1927, three holes were drilled into Mullet Island to a maximum depth of 450 m. Although temperatures in excess of 110°C were encountered, the discharge mainly was CO_2 gas, along with

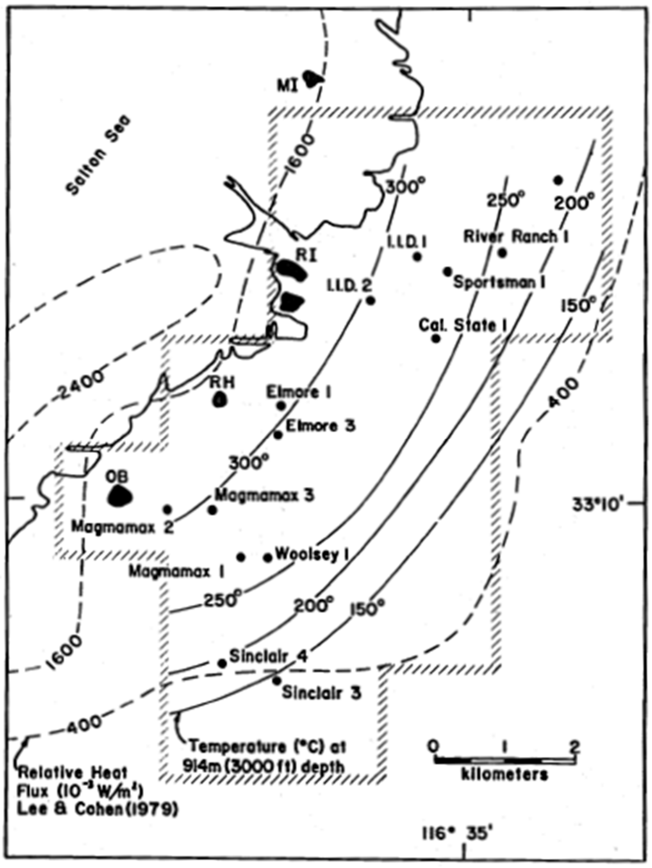

FIGURE 22: Salton Sea geothermal field, showing selected well locations (small black circles), rhyolite domes (larger black blobs), shoreline of Salton Sea, isotherms at about 1 km depth (solid lines - 150, 200, 250 and 300°C), and central area of very high heat flow (dashed lines). Irregular striped figure corresponds to known outline of the high-temperature geothermal field

boiling water, steam and mud. The project was abandoned, but restarted in 1933 as a source for the manufacture of solid carbon dioxide ("dry ice"). This was used as a refrigerant for railroad cars of the nearby Southern Pacific line carrying fresh agricultural produce from Imperial Valley. Over 18.4 million m^3 of CO_2 were produced from 54 wells of 150-210 m depth, until 1954, when refrigerated railroad cars were introduced. A rising lake level buried many of the wells; they now are being revealed as the lake retreats.

FIGURE 23: Small volcanic islands in Salton Sea and on-shore near 4 geothermal power plants. Volcanic domes are Holocene and Latest Pleistocene rhyolite; note intensive irrigated agriculture (photo taken in 2002)

In 1957, the well Sinclair 1 was drilled as an oil and gas test. It was at a location about 8 km from the original carbon dioxide field, at the southern margin of the rhyolite domes. Although it encountered abundant CO_2 and very high temperature, it found no hydrocarbon resource. Since that time, a total of about 200 geothermal wells have been drilled in an area of approximately 30 km^2, to depths that range from 500 m to over 3.4 km, and that cluster around 2.3-2.5 km in depth.

Drilling, logging and testing has revealed a very high salinity, high temperature system, whose temperature and salinity decrease with distance from the domes. The isotherms are open to the northwest, beneath the lake. On-shore the isotherms follow the shape of the Bouguer anomaly and a positive aeromagnetic anomaly of nearly identical outline. This strongly supports the concept that shallow magmatic activity is the source of the heat.

At a distance of about one km south and east of the domes, the temperature reaches 300°C at just under one km in depth. At that same depth but at 3.5 km distant from the domes, the temperature averages

FIGURE 24: Steaming mud pots and mud volcanoes in area exposed by shrinking lake level at southern end of Salton Sea

about 150ºC. At 2 km depth, within 2 km of the domes, the average temperature is about 330ºC. The maximum recorded temperature, in well Elmore 1, less than one km from Red Hill, was 365ºC at 3.1 km. It is unknown if such high temperatures are present immediately north of the domes, beneath the lake. There is considerable speculation that they are.

Salinity within the reservoir isn't easy to determine, because of steam separation, pH changes and oxidation of brine *en route* the surface. What is clear is that salinity decreases from a maximum (calculated pre-flash) of about 250,000-260,000 mg/l (250-260 g/l) at Elmore 1, to under 100,000 mg/l in wells about 4 km farther from the domes. Flashing of steam of course results in higher chemical concentration, and some post-flash values are reported to be over 300,000 mg/l, with many in the range of 260,000-290,000. This results in the Salton Sea geothermal system typically being reported as having a 26% salinity, with approximately 0.2% non-condensable gas (essentially all carbon dioxide).

The geothermal fluid is a solution of sodium, potassium and calcium chlorides, with abundant iron and manganese, lesser but notable amounts of barium, boron, lead, lithium, silica, strontium and zinc, and still-lesser amounts of copper and silver. The following table gives the reported range of concentrations of major constituents for the Salton Sea and the Cerro Prieto, Mexico fields. Their temperatures are comparable, and ionic ratios of alkalis and chloride in most cases are not strongly different, suggesting a common source of the water and the various species. However, chemical concentration of almost all species is significantly lower in Cerro Prieto, reflecting a different evolutionary history.

Temperature and TDS of the Woolsey 1 well are significantly lower than for the IID and Hudson Ranch wells. This probably reflects both a shallower depth and a greater distance from the intrusive heat source. As mentioned above, with still greater distance, TDS and temperature drop still more.

Lithologically, the Salton Sea reservoir consists of an upper zone, several hundred meters in thickness, of poorly consolidated silt, clay and evaporite beds of lacustrine and deltaic origin, with intergranular porosity of 15-25%; and an underlying zone of interbedded sandstone and shale, of decreasing porosity (to perhaps 5% or less) and increasing hydrothermal alteration. Beginning at about one km in depth, alteration proceeds through a dolomite-calcite stage, followed progressively by development of zones dominated by chlorite, biotite-quartz, epidote, and garnet. These correspond approximately to temperature controls on the geothermal system, with biotite first appearing at about 310°C, and garnet at approximately 350°C. These represent the greenschist facies of metamorphism.

In the altered zones below about one km, intergranular porosity is replaced by fracture permeability, perhaps on the order of 10 to 100 milliDarcy (mD). Fracture permeability constitutes the principal geothermal reservoir. Because of the decrease in porosity and the partial sealing by secondary minerals as veins and a caprock, there appears to be relatively little vertical communication between the upper and lower lithologic zones. Fluids in the upper zone, therefore, usually are significantly less mineralized than those of the deeper zone.

An unusual suite of minerals is reported as scale in the wells and surface facilities. These are sulphides and oxides of copper and iron, with smaller amounts of silver, antimony and zinc. These minerals also appear in veins that cut the metamorphic assemblage. The geothermal system is recognized as an ore deposit being formed, with the potential to deposit millions of tons of zinc, lead, copper, silver and other sulphide and oxide minerals over the millennia to come.

Salton Sea brines (Table 5) exhibit a relatively low concentration of SiO_2 compared to Cerro Prieto and other high-temperature systems, and are depleted of sulphate ion. Copper also is low relative to the abundance of lead and zinc. Silica and sulphur may have been taken up in secondary minerals

TABLE 5: Brine chemistry – Salton Sea and Cerro Prieto fields
(values in mg/l except as noted)

Species	Wells			
	Hudson Ranch (2014) 3 well average	**IID #2 (1967)**	**Woolsey #1 (1977)**	**Cerro Prieto M-3 (1964), M-5 (1999)**
Na	56,275	53,000	49,727	5,610
K	18,006	16,500	6,510	1,040
Ca	29,778	27,800	12,658	>320
Mg	43	10	n.a.	0.4
Li	228	210	90	12.6
Sr	316	440	n.a.	27
Ba	167	250	n.a.	57
Fe	1,411	2,000	244	<0.3
Mn	1,700	1,370	488	0.7
Pb	108	80	n.a.	<0.3
Zn	487	500	n.a.	0.8
Cu	1	3	n.a.	0.1
B	563	390	n.a	12
SiO_2	437	410	181	>600
Cl	165,442	155,000	83,183	9,694
TDS	278,640	258,800	151,237	>17,000
T, °C	350	332	238	340
pH (%H^+)	4.8	4.6	6.25	n.a.

Note: IID data reportedly corrected for steam separation
IID #2 from Helgeson, 1967
Woolsey #1 from Elders and Cohen, 1983
Cerro Prieto M-3 from Alonso and Mooser, 1964; M-5 from unpublished data base, 1999
Hudson Ranch data from unpublished environmental document, 2014

Ionic Ratios, by Weight (from Koenig, 1967)

	IID #2	**M-3**
Ca:Cl	0.18	0.03
Na:Cl	0.35	0.58
K:Cl	0.11	0.11
Li:Cl	0.0013	0.0014
SO_4:Cl	0.0006	0.0014
B:Cl	0.0025	0.0013
K;Na	0.30	0.19
$\sum$alkali:Cl	0.634	0.729

disseminated through the metamorphosed section, and also as copper sulphide ore minerals that fill veins and form scale.

The source of the water and the cause of the extreme salinity of the deeper brines has been a subject of much discussion. It is now generally agreed that the deep-seated water for both the Salton Sea and Cerro Prieto fields had its origin in outflow from the ancestral Colorado River. Whereas subsurface water at Cerro Prieto is able to flow into the Gulf of California, there is no subsurface outflow from the below-sea-level Salton Trough. Continued heating of fluid by igneous intrusions has leached elements from the host rocks, building to extremely high concentration in the confined Salton Sea field. Breakdown of carbonate-rich sediment is believed to be the source of the shallow CO_2 field, with the gas partially trapped by near-surface lacustrine clay and evaporate beds.

4. DEVELOPMENT AND UTILIZATION OF THE SALTON SEA GEOTHERMAL RESOURCE

Estimates of the size of the resource have varied, with 1,000 to 2,000 MW often used, based on calculations of a 115 km^3 volume of suitably fractured metamorphic rock to 3 km depth, having temperatures and mass flow rates sufficient for either flash-steam or ORC (binary) generation. By comparison, the Cerro Prieto resource is estimated as no greater than 1,000 MW.

Installed generating capacity at Salton Sea is about 400 MW from 11 power plants (Figure 25). Individual wells are extremely productive, and there is excess steam at wells across the field. The well VonderAhe 1 produces upwards of 30 MW; and 3 wells are able to supply sufficient steam to operate the 49 MW Featherstone (Hudson Ranch) power plant. Indeed, 28 production wells are sufficient for the 400 MW; or about 13 MW per well on average. Reversing the worldwide average, at Salton Sea there are 1.5 injection wells for each production well.

FIGURE 25: One of the 12 geothermal power plants, located amidst irrigated fields; Salton Sea at upper end of photograph

Given the estimated size of the resource, and the extraordinary well productivity, one must ask why development hasn't risen to that of Cerro Prieto. (At Cerro Prieto, installed capacity peaked at 720 MW, but a shortage of steam and brine-handling difficulties caused the decommissioning of 150 MW. Efforts are being made to increase output at Cerro Prieto above 570 MW, with only moderate success.) Development of the enormous resource at Salton Sea has been hampered by 3 factors:

1. Difficulties in treating the extremely saline brine;
2. Lack of a guaranteed market at a suitable price for electricity;
3. Repeated failures to recover minerals from the brine.

Problems with brine-handling began almost immediately. The original well, Sinclair 1, became plugged with sulphide and some carbonate scale after barely a few weeks. Fluid pH was measured at 4.5 to 5.5, with the possibility that reservoir pH is even lower. Corrosion of casings and surface facilities by the acidic brine were noticed and were worrisome. Post-flash concentration of silica reached and exceeded the saturation limit, increasing fears of silica scaling in wells. And the question remained unanswered how to dispose of the brine. Solving these problems took hard work and creativity. Two of the methods have proven to be extremely important.

The acidic brine could destroy a casing in a matter of several months through pitting, corrosion and stress fracturing. Experiments with different materials led to the introduction of corrosion-resistant titanium-based alloys as casing on almost all wells. Chromium and nickel were found to have corrosion-resistant properties, whereas the presence of copper, even in trace amounts, weakened steel.

The issue of scale control proved more difficult. Carbonate scale was found at the lower temperature zones closer to the surface. Silica scale was found on casings wherever supersaturation was accompanied by lengthy residence time of brine in a well. Iron and other sulphides appear to form scale deeper in the system.

An innovative brine treatment was developed after much research and testing. The new technology, known as the crystallizer-clarifier process, keeps SiO_2 from being deposited in the well or on surface facilities. Steam is flashed from the brine in the crystallizer, followed by the immediate injection of crystals of silica as a 'seeding' agent. Silica deposits onto these seed crystals, forming silica sludge within the brine. The brine carried the sludge to the clarifier tank, where it is allowed to settle, and then is removed by truck to a sanitary landfill.

A subsequent improvement in the process involves the addition of hydrochloric acid (HCl) to the post-separation brine. In effect, this re-balances the fluid pH sufficiently to keep silica in solution. It thereby avoids the need to truck a deposit of sludge to a secure landfill. The residual brine is blended back with steam condensate from the cooling towers, and then injected. In this way, nearly 80% of the total produced mass is injected back into the reservoir, at once serving to support reservoir pressure, while allowing safe disposal of the highly mineralized brine.

Treating – and disposing of – the corrosive, mineral-rich brine is a delicate and costly process. This has raised the cost of generating geothermal electricity to what may be record high levels. One operator estimates that the full cost for a 50 MW wellfield and power plant is over US$ 4 million/MW; the reported cost for the 49.9 MW Featherstone power plant was an astonishing US$ 8 million/MW, despite needing only 3 production wells. This compares with a world average range of between US$ 2.0 and 4.0 million/MW.

Such high costs require both a guaranteed market and a high tariff for electricity. This has been very difficult to obtain, especially with the competitive costs and shorter lead times for solar and wind power, and the availability of low-cost coal-fired generation. Another limiting factor has been the lack of carrying capacity on existing transmission lines. The major market for electricity is the San Diego-Orange County-Los Angeles metropolis, with over 20 million inhabitants. Plans for new transmission lines have been delayed because of high per-mile land acquisition costs and community resistance. This has limited market access for geothermal electricity. However, a new transmission corridor is in final planning stages; and this may aid the further development of Salton Sea field. As a result, only one new geothermal plant has been built at Salton Sea during the past 20 years; a second plant remains on the drawing boards.

It has been hoped, through the years, that commercial extraction and sale of various mineral products would provide an additional revenue stream. Efforts have been made in past years to recover and sell both potassium chloride and calcium chloride, as well as table salt and silica. The earlier commercial use of CO_2 has not been repeated. A major effort was made over a decade ago to extract zinc from the brine. A facility was constructed and operated on a pilot basis, but was not commercially successful. Most recently, there has been the effort to extract lithium. It remains uncertain whether this will be successful.

On the positive side, the brine-handling issues have been resolved, and CO_2 emissions are at a very low level. There are no major land-use or environmental issues. And the possibility exists that the growing demand to 'save' Salton Sea will result in an increased demand for geothermal electricity for pumping and desalination. The Governor of California in 2015 signed into law a bill requiring that 50% of all electricity come from 'renewable' sources – including geothermal – by 2030. The State Legislature now is considering a bill to require that up to 500 MW of new geothermal electricity be produced from Salton Sea field, with purchase of electricity by the regional electric utilities, as part of a plan to promote economic growth in the economically depressed Salton Trough. The State budget authorizes spending US$ 80 million to begin the process of 'saving' Salton Sea.

The Salton Sea geothermal field was once described as a treasure chest without a key. The key may be found in the efforts to save the Salton Sea from evaporating.

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