Technical Feasibility of an EGS Development at Desert Peak, Nevada

Supported by U.S Department of Energy

Sponsoring Organization: Ormat Nevada, Inc.

Technical Management: GeothermEx, Inc.

Collaborators: University of Nevada Reno, Lawrence Livermore National Laboratory, Lawrence Berkeley National Laboratory, Sandia National Laboratory, United States Geological Survey, GeoMechanics International

Goal: Determine feasibility of developing an artificial underground heat exchanger for generation of 2-5 MWe at Desert Peak

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USDOE's Mission

U.S. Department of Energy
Energy Efficiency and Renewable Energy

- ". . . improve energy security by developing technologies that foster a diverse supply of reliable, affordable, and environmentally sound energy . . . "
- ". . . a long-term vision of a zero-emission future in which the nation does not rely on imported energy . . . "
- ". . . work with the private sector to develop domestic renewable resources . . . "

USDOE's EGS Goal

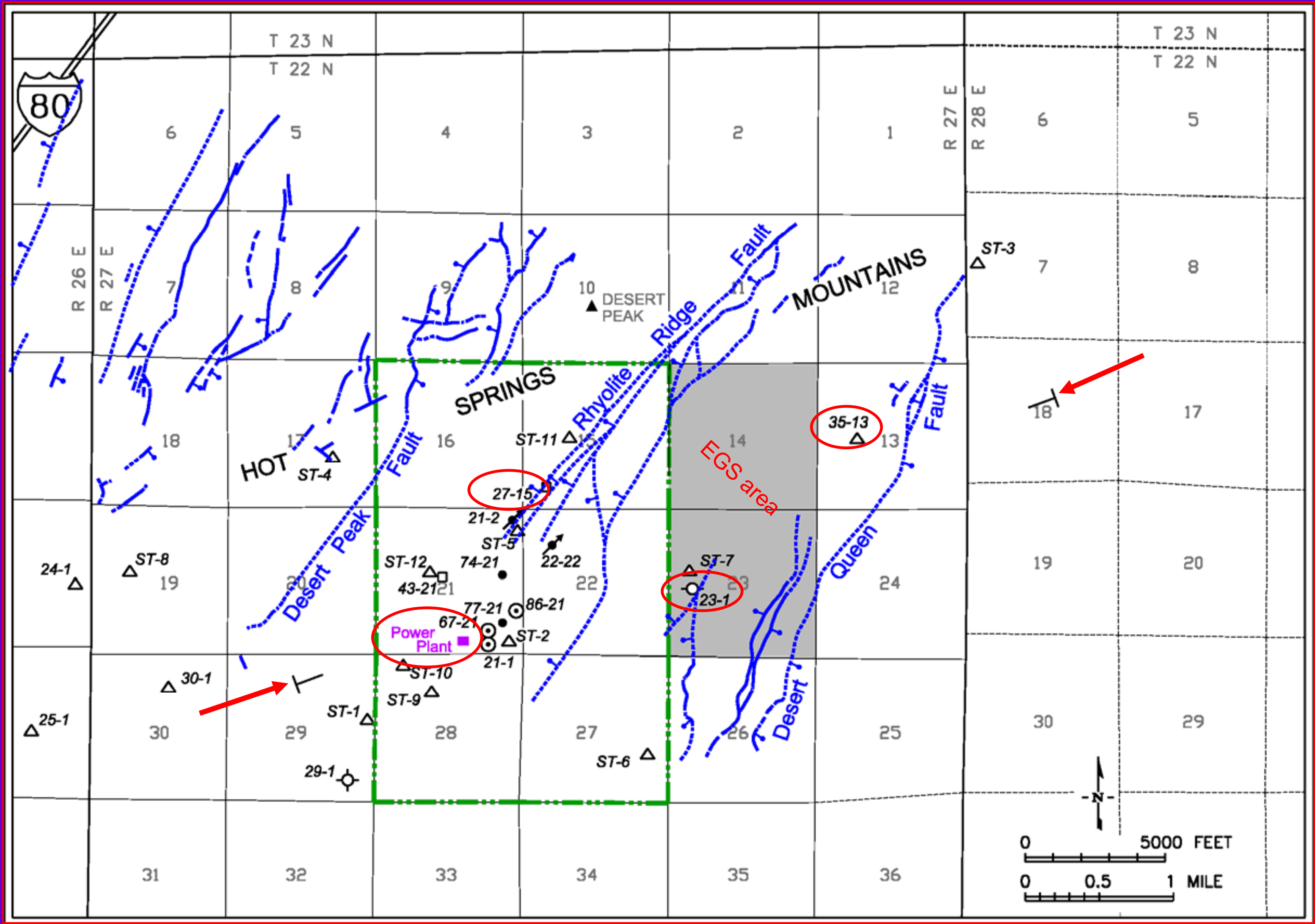
- "Decrease the levelized cost of electricity from Enhanced Geothermal Systems to less than 5 cents per kWh by 2040"

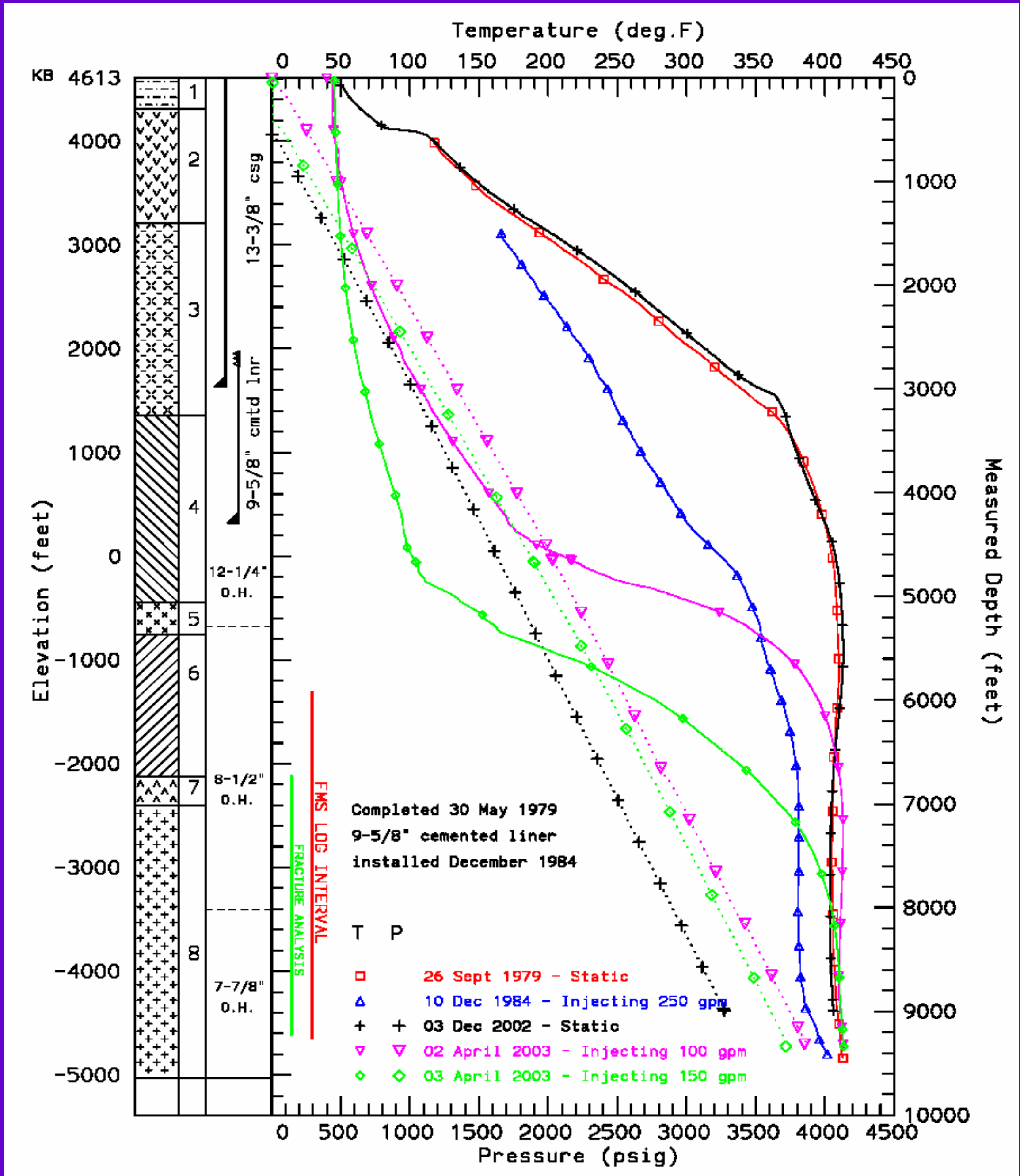
- Achieved through government support for
  - EGS FIELD EXPERIMENTS
  - EGS RESEARCH

Rationale – why this project?

- Focus on existing wells lowers EGS risk and moves USDOE's EGS agenda ahead with significant savings ($$ and time)
- Suggests streamlined methodology for EGS evaluation and implementation – a blueprint?
- Solves generic issues of developing, monitoring and using EGS reservoirs where infrastructure is well developed - resulting power can be used immediately and profitably
- Success at Desert Peak will convince industry

Project area, well and fault locations





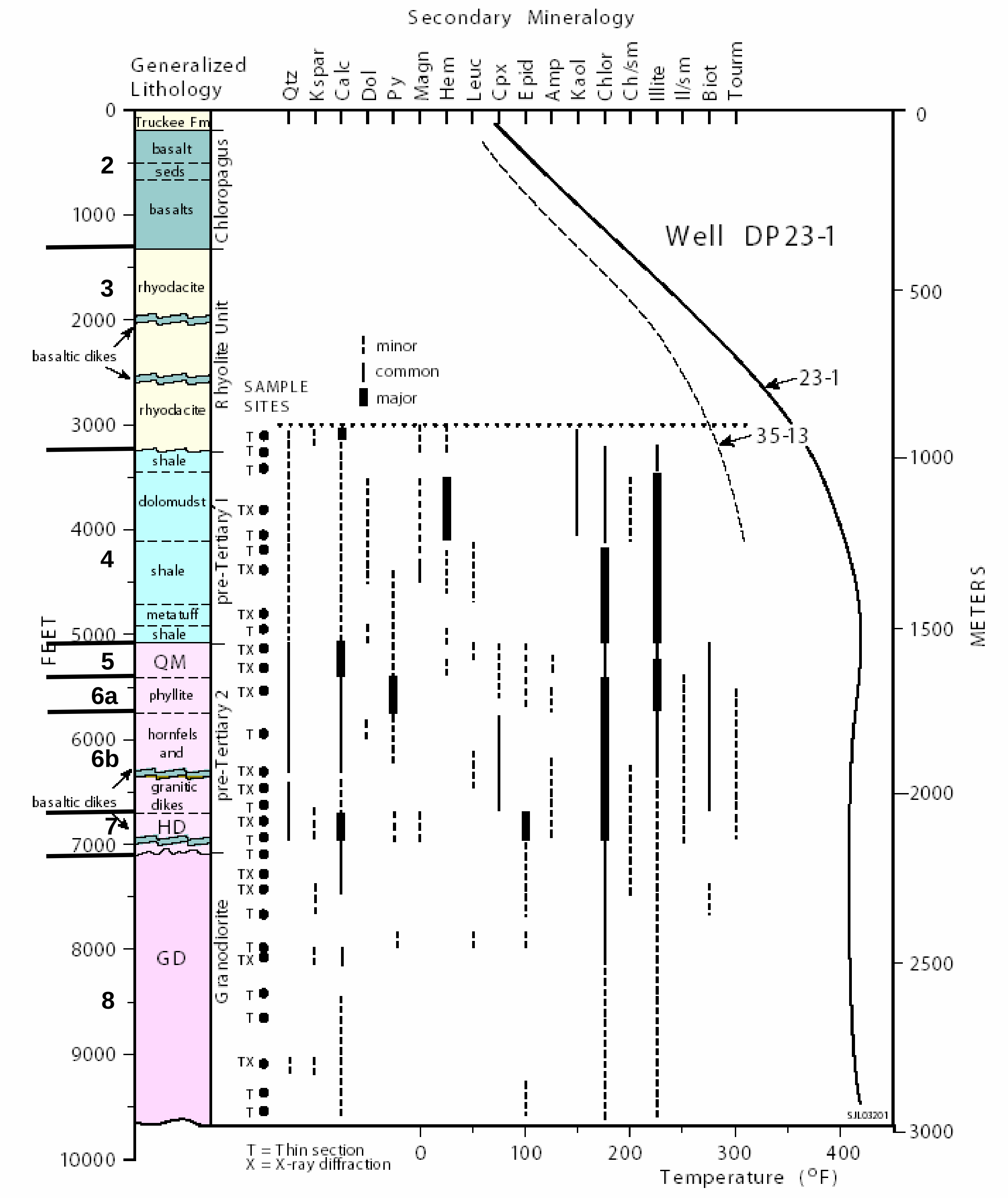
DP 23-1

Hydrologically isolated
Attractive formations

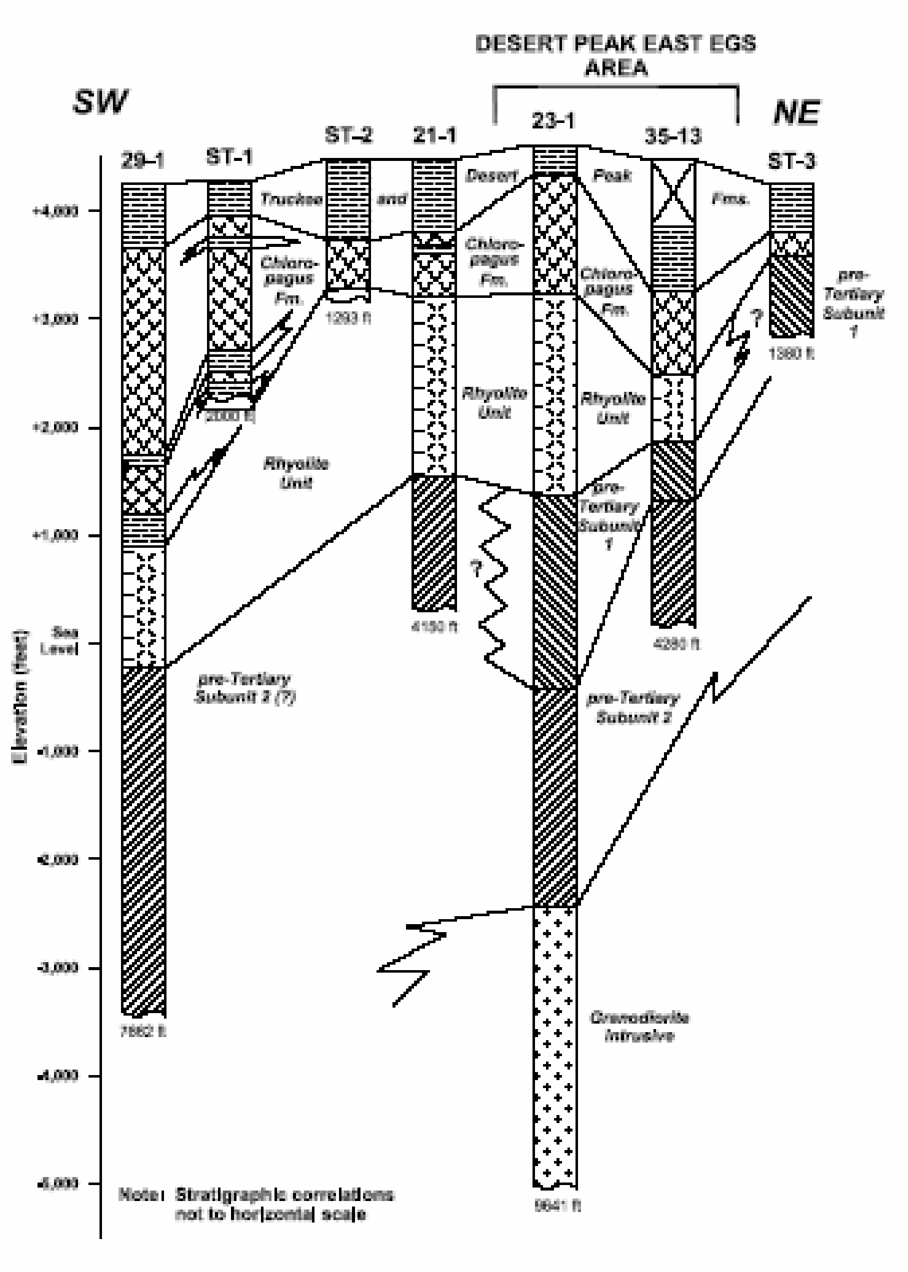
Focus of Phase I:

- Petrology
- Injection testing
- Image logging
- Stress field analysis
- Target selection
- Numerical modeling of heat recovery

23-1 petrology



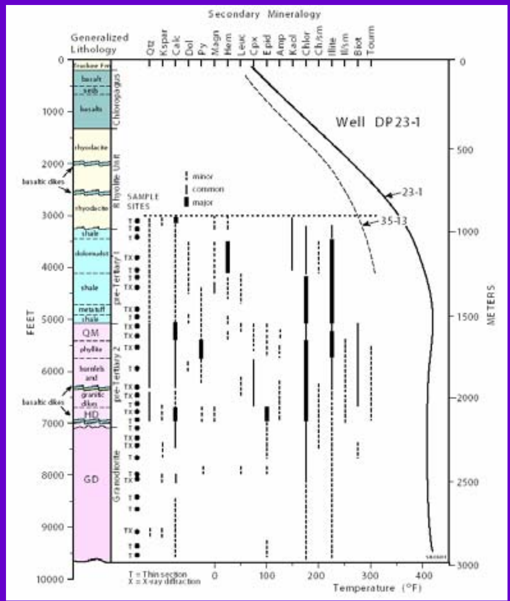
- Re-defined base of Tertiary cover (3-4 boundary)
- Defined 2 Mesozoic packets: pT1 (4) and pT2 (5, 6, 7)
- Defined younger (Cretaceous?) more massive intrusion (8)
- Evaluated secondary mineralogy
- Correlated with nearby core hole (35-13)

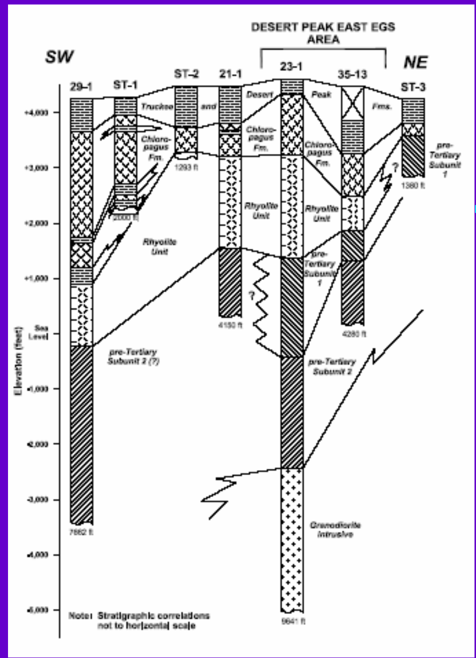


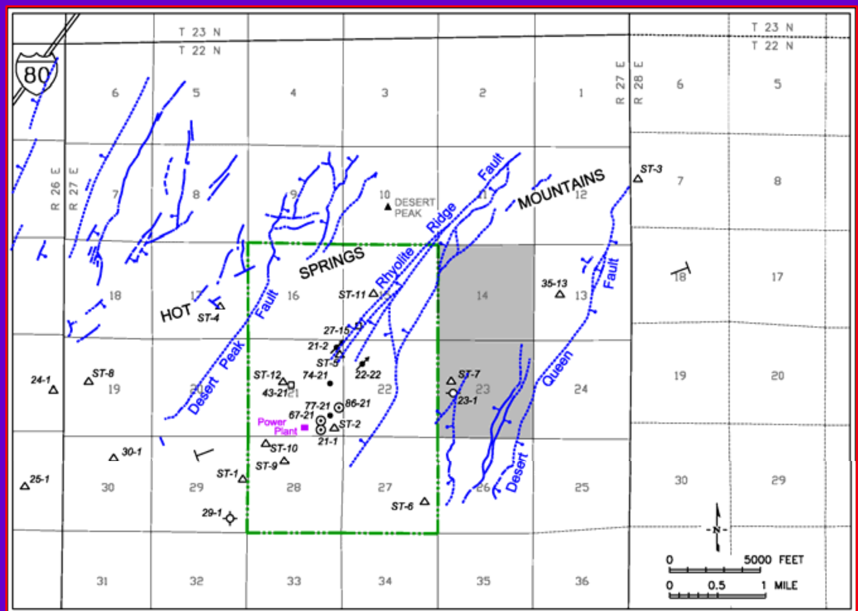
Stratigraphic Correlation

- A more complete sequence in DP 23-1
- Thick pT1 section
- Massive granodiorite
- NE-ward thinning of rhyolite unit

Lessons Learned (1)







- Basic geologic analysis is invaluable
- Low-cost / high-benefit
- Detailed petrographic analysis
- Good structural picture
- Enables overall analysis of project area and insight into mechanical and hydraulic properties of rocks

TARGET SELECTION

Petrophysical Analysis

Sample depth (feet) and lithology	Sample ID	Porosity (%)	Confining pressure (psi)	Young's Modulus (million psi)	Poisson's Ratio
3,484 quartz monzodiorite	A	1.6	300	9.600	0.220
	B	1.5	725	8.262	0.172
	C	2.0	1,450	9.134	0.242
	D	1.9	2,900	9.518	0.214
3,833 granodiorite	A	1.5	300	7.545	0.180
	B	2.1	725	7.265	0.183
	C	1.3	1,450	7.708	0.152
	D	1.5	2,900	6.237	0.285

Sample depth (feet) and lithology	Sample ID	Max. Diff. Stress (psi)	Max. Axial Stress (psi)	Cohesion (S_0) (psi)	Friction Angle (Φ) (deg.)	Failure Angle (β) (deg.)	Unconfined Compressive Strength (psi)
3,484 quartz monzodiorite	A	35,560	35,860	9,129.5	34.8	62.4	34,852
	B	36,940	37,670				
	C	38,960	40,410				
	D	42,540	45,440				
3,833 granodiorite	A	39,130	39,430	9,327.7	37.6	63.8	37,913
	B	35,270	35,990				
	C	23,650	25,100				
	D	49,920	52,820				

Event	Confining Pressure (psi)	V_p (ft/sec)	V_{s1} (ft/sec)	V_{s2} (ft/sec)	Young's Modulus (million psi)	Poisson's Ratio
0	148	16,650	10,312	10,436	8.96	0.183
1	292	16,736	10,328	10,486	9.03	0.185
2	732	16,847	10,390	10,502	9.12	0.188
3	1,464	17,077	10,456	10,518	9.27	0.197
4	2,899	17,464	10,623	10,689	9.62	0.203
5	4,365	17,838	10,761	10,843	9.94	0.210
6	1,453	17,224	10,591	10,604	9.45	0.195
7	726	16,962	10,472	10,518	9.23	0.190
8	141	16,762	10,456	10,502	9.11	0.179

Event	Confining Pressure (psi)	V_p (ft/sec)	V_{s1} (ft/sec)	V_{s2} (ft/sec)	Young's Modulus (million psi)	Poisson's Ratio
0	151	16,191	9,987	9,777	8.21	0.203
1	285	16,230	10,046	9,806	8.27	0.201
2	729	16,512	10,171	9,925	8.51	0.206
3	1,449	16,847	10,410	10,151	8.89	0.203
4	2,899	17,746	10,712	10,505	9.61	0.222
5	4,359	18,333	10,978	10,830	10.19	0.226
6	1,447	17,329	10,541	10,358	9.27	0.214
7	728	16,762	10,328	10,138	8.81	0.203
8	141	16,352	10,138	9,895	8.41	0.200

Lessons Learned (2)

"The world is not made of Westerly Granite . . . . "

Mechanical testing of more EGS candidate rock types would provide a better foundation for understanding EGS development

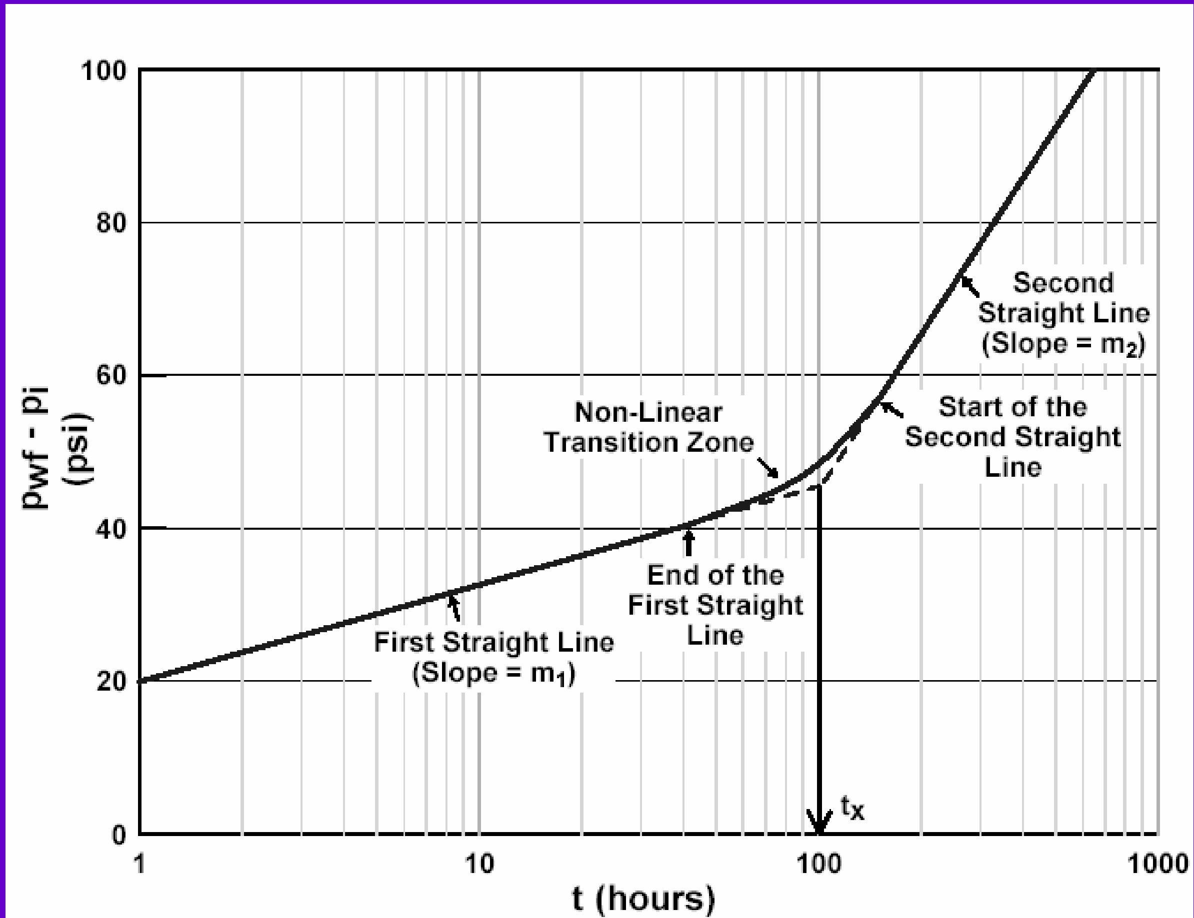
Take the time and expense to take cores (good for lots of things)

DP 23-1 well site during injection testing and logging operations

23-1 injection testing results (besides a cooler well for improved image log quality)

- Very low kh (4,000 md-ft) – far lower than hydrothermal reservoir – and modest storage capacity (0.001 ft/psi)
- No major fracture intersection
- Very low injectivity (0.69 gpm/psi)
- Decrease in “skin factor” - increase in injectivity with time
- Very low porosity (~2%) over a 1,440 foot investigation radius
- Baseline for enhancement (stimulation)
- Derived simple, cheap method to assess improvement by stimulation in terms of:
  – increase in injectivity and flow capacity
  – stimulated volume (vs. un-stimulated surroundings)

A new, simple injection testing methodology to assess stimulated volume and kh



Short-term step-rate/fall-off test to estimate post-stimulation injectivity index, kh and skin factor

Longer-term (weeks) test to "see" beyond the stimulated zone

First straight line: stimulated zone

Second straight line: un-stimulated zone

Slopes and intersection yield kh and radius of stimulated zone

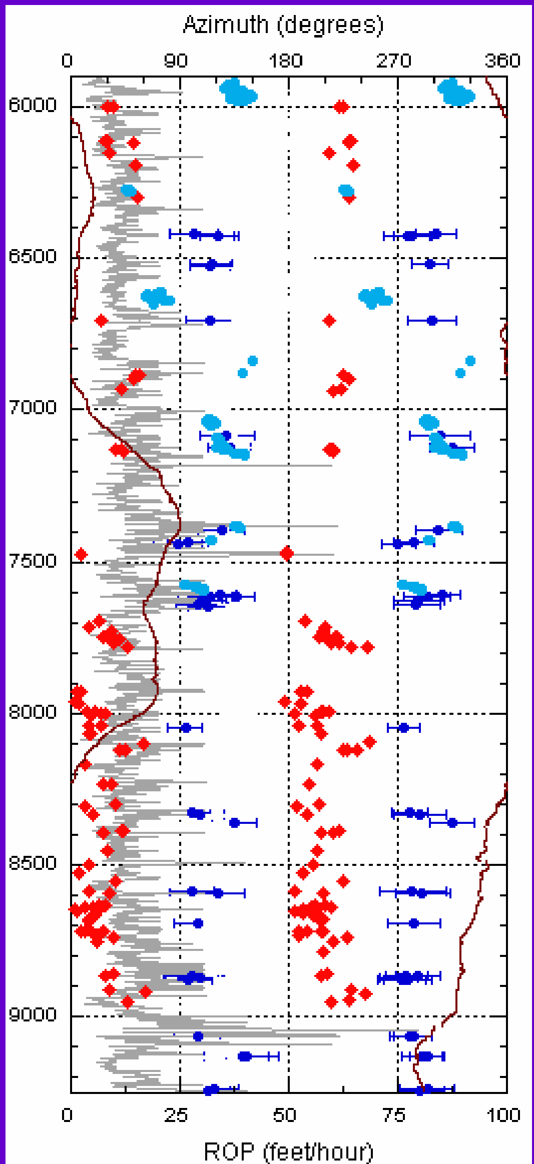
Geophysics shows only extent and geometry – this allows initial estimation of hydraulically active reservoir volume

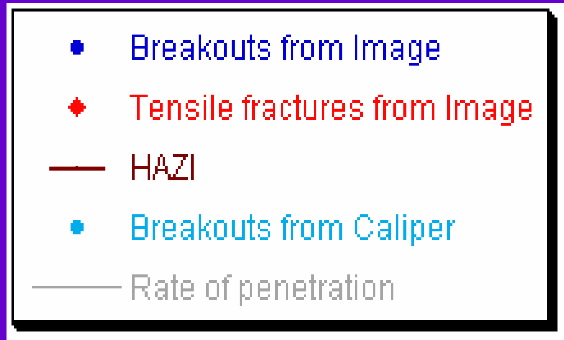
Lessons Learned (3)

- Reservoir engineering analysis needed in early stages of project
- Pre-stimulation injection testing
- Detailed TPS logging
- Single-well tests provide valuable info
- Extract info at every opportunity

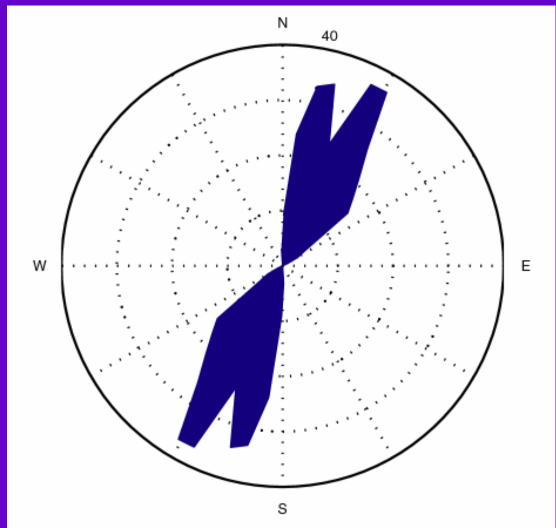
DP 23-1 logging operations

FMS Log Analysis – summary of failure results





SHmax azimuth from image data = N 27°E



Tensile cracks and breakouts reveal the same stress orientation

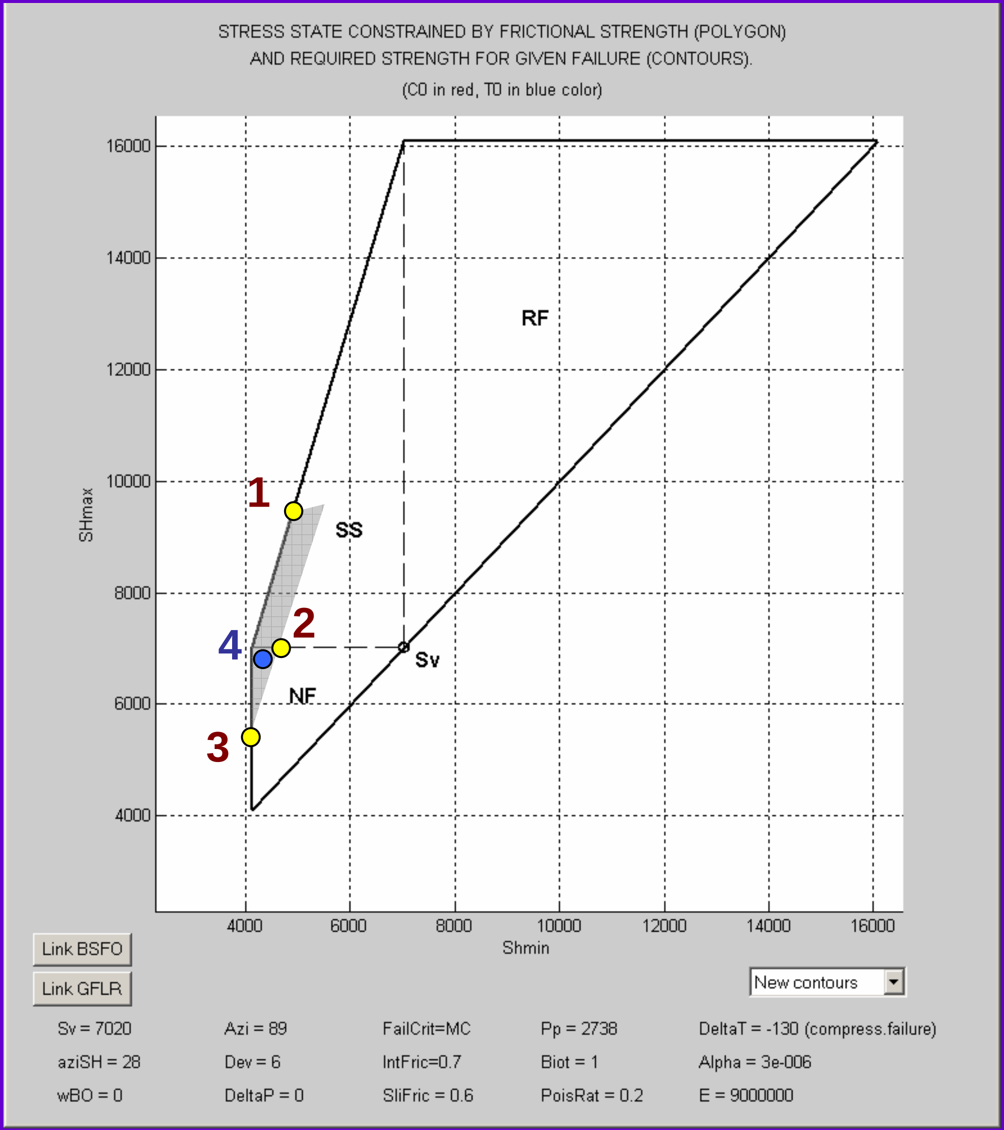
Breakouts from image data correlate with higher ROP, indicating the presence of weak zones where compressive stress overcomes rock strength.

Tensile cracks occur where ROP is lower (in stronger rock) and probably result from cooling in an environment where there is a reasonably large difference between SHmin and SHmax.

More tensile cracks are observed below 7,600 feet than above, possibly due to:

- More cooling
- More quartz
- Stiffer rock

Stress state end members for active fracture analysis



- Gray region represents possible stress states consistent with breakouts in the weaker (higher ROP) lithologies and with tensile fractures enhanced by thermal stresses in stronger (lower ROP) zones.
- Yellow dots represent 3 SHmax and SHmin stress pairs that "bracket" the possible stress magnitudes. Stress state 4 (blue dot) is considered to be the most consistent with experiences and observations in the well.
- **1** = Strike-Slip Stress Model

  SHmax > SV > SHmin
- **2** = Transitional (Normal to Strike-Slip)

  SV = SHmax > SHmin
- **3** = Normal Stress Model

  SV > SHmax > SHmin
- **4** = Normal Stress Model

  SV > SHmax > Shmin

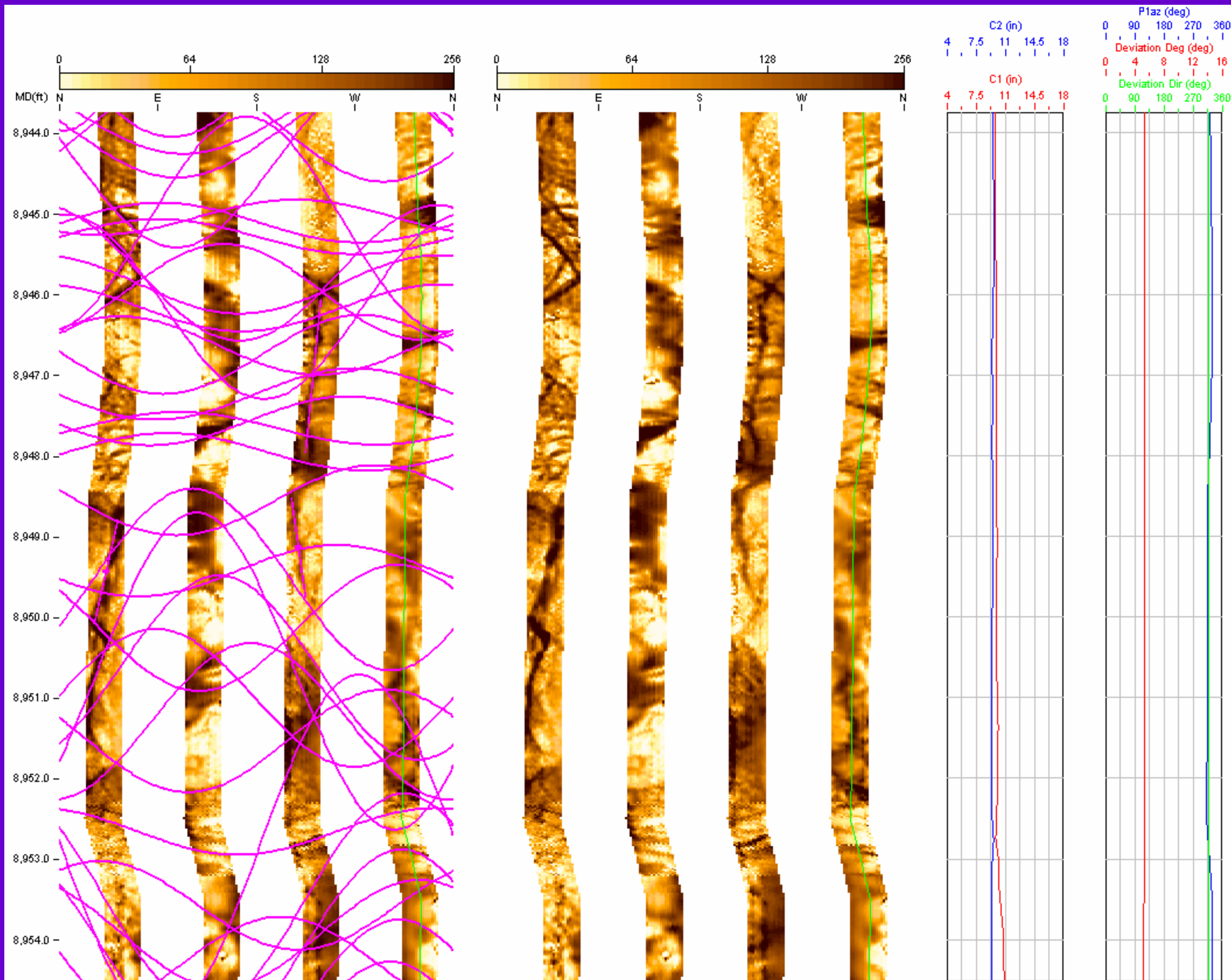
  (SHmax just barely less than SV)

Lessons Learned (4)

- Image log analysis is essential for EGS projects – temperature is a problem – run logs during drilling or after injection
- An approximate stress field model can be developed, even with limited data
- Good well history data needed (drilling rate, mud weights, pressures during injection tests, etc.) + density log
- Regional stress setting info essential

FMS Log Analysis – natural fractures

Interpreted Image Log Uninterpreted Image Log C1 C2 P1AZ DEVI HAZI

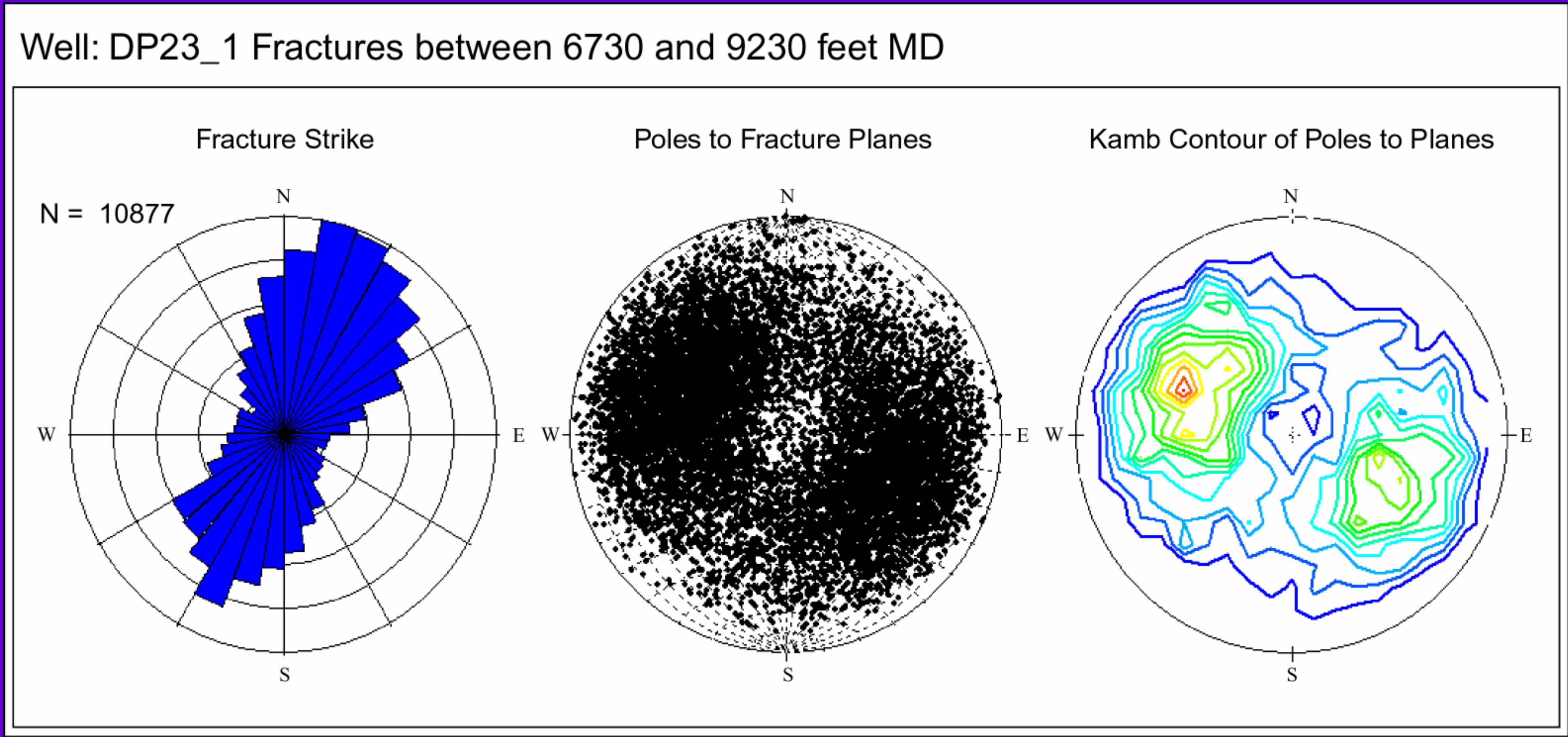


Fractures intersecting the borehole appear as sinusoids on the image data.

Electrical image logs of natural fractures are often discontinuous and show complex patterns at points where several fractures intersect or where fractures are not perfectly planar.

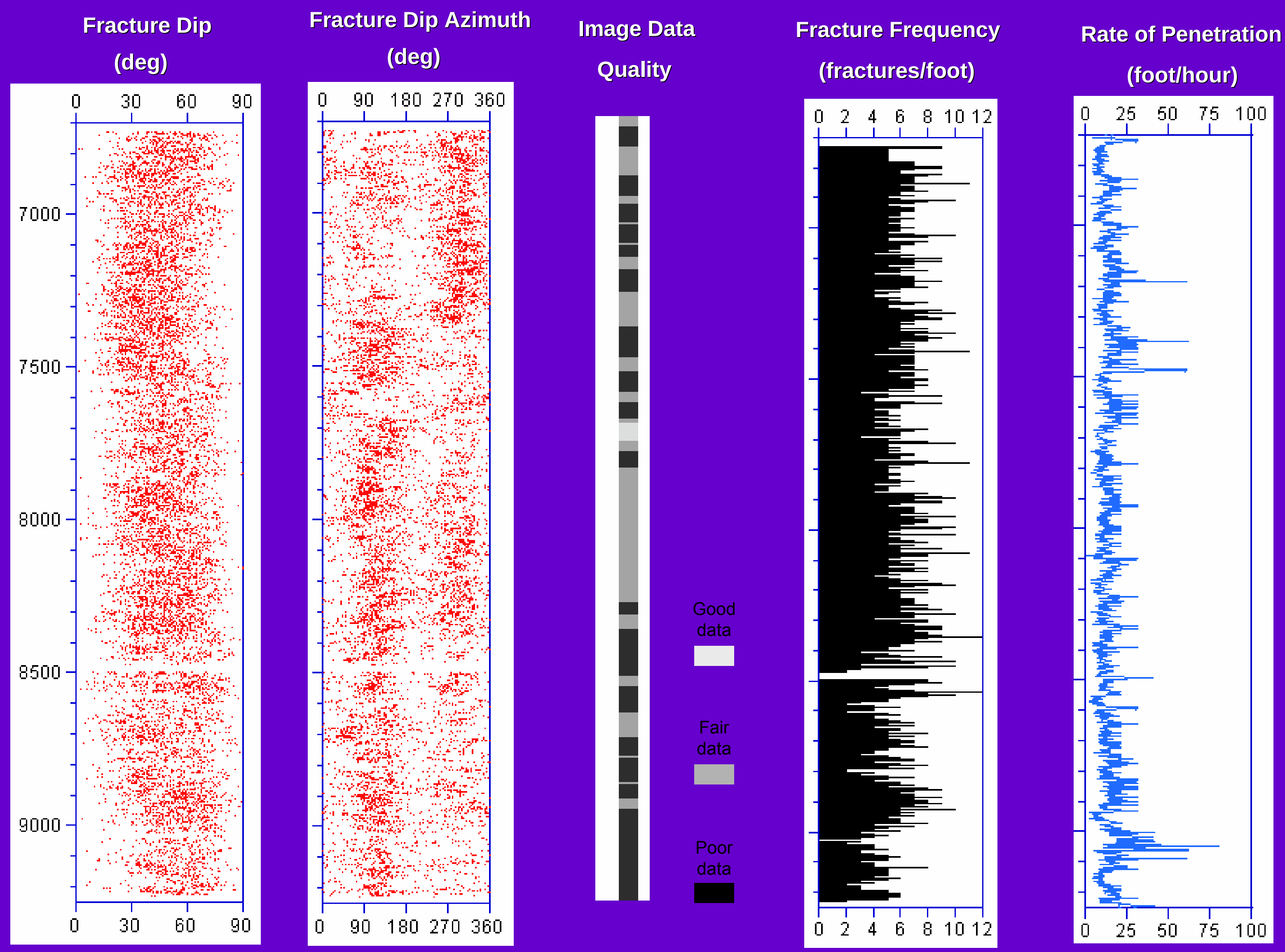
Depth and true/apparent dip and dip direction of the feature for each analyzed fracture.

Orientation of natural fractures

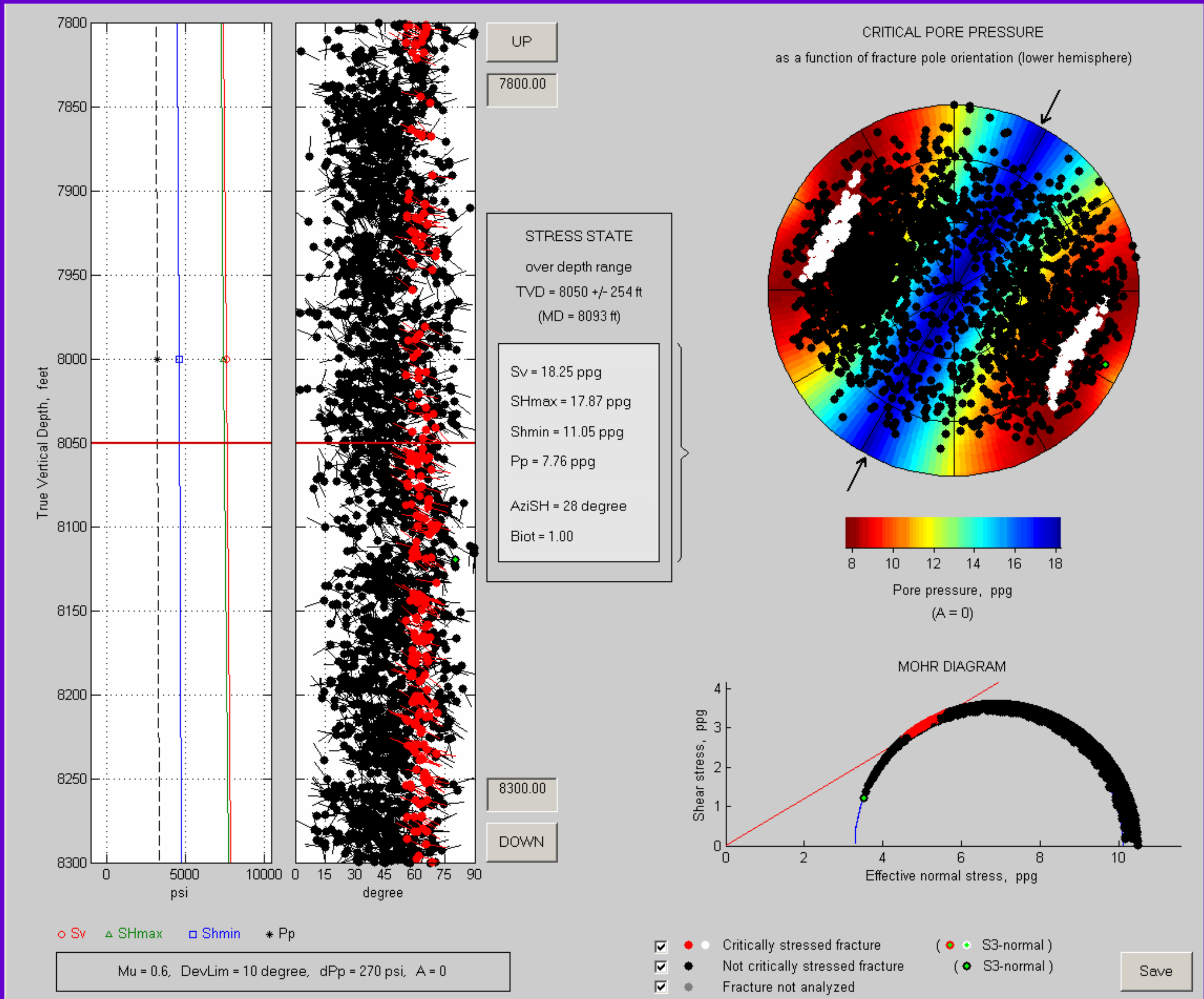


- Fracture orientations have predominantly NNE – SSW strikes. More fractures dip moderately to steeply to the SE; fewer fractures dip moderately to steeply to the NW. The SE-dipping fracture set has a slightly higher average dip.

Distribution of natural fractures



Stress State 4 (normal) – 270 psi pressure increase



- Normal faulting stress model **(SHmax is slightly lower than SV)**

  SV > SHmax > SHmin

- Injecting

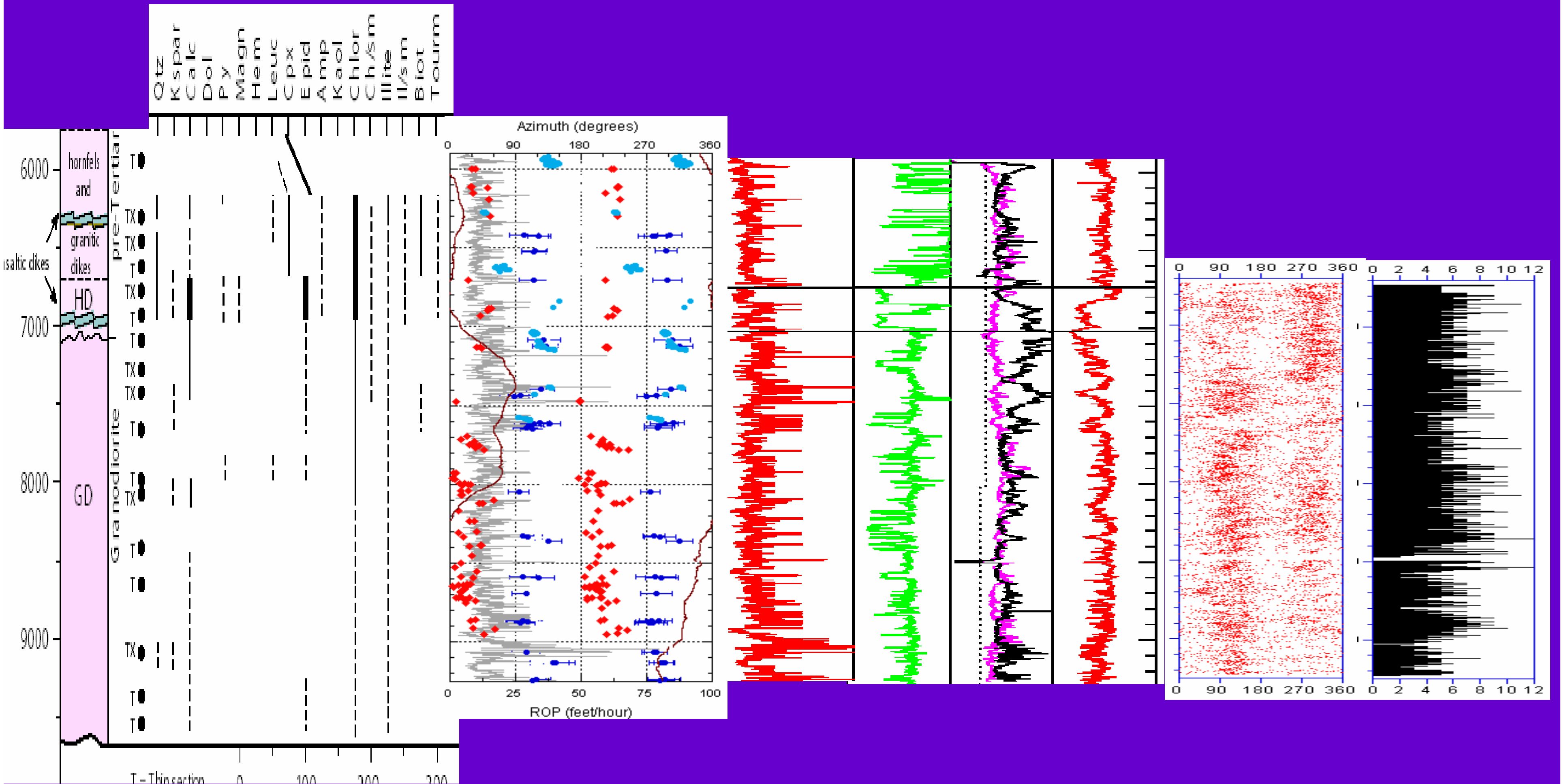
  dPp = 270 psi

- With injection, fractures that strike NE–SW with moderate to steep dips are critically stressed and candidates for stimulation.

GMI
GEOMECHANICS INTERNATIONAL

Lessons Learned (5)

- Resistivity-based image logs may result in over-estimation of number of fractures
- A reasonable subset are pre-existing cracks that can be exploited by stimulation
- The data can be "pushed" by sound analysis to estimate stimulation pressures are needed during stimulation and which fractures will become critically stressed
- An experienced stress analysis team is essential

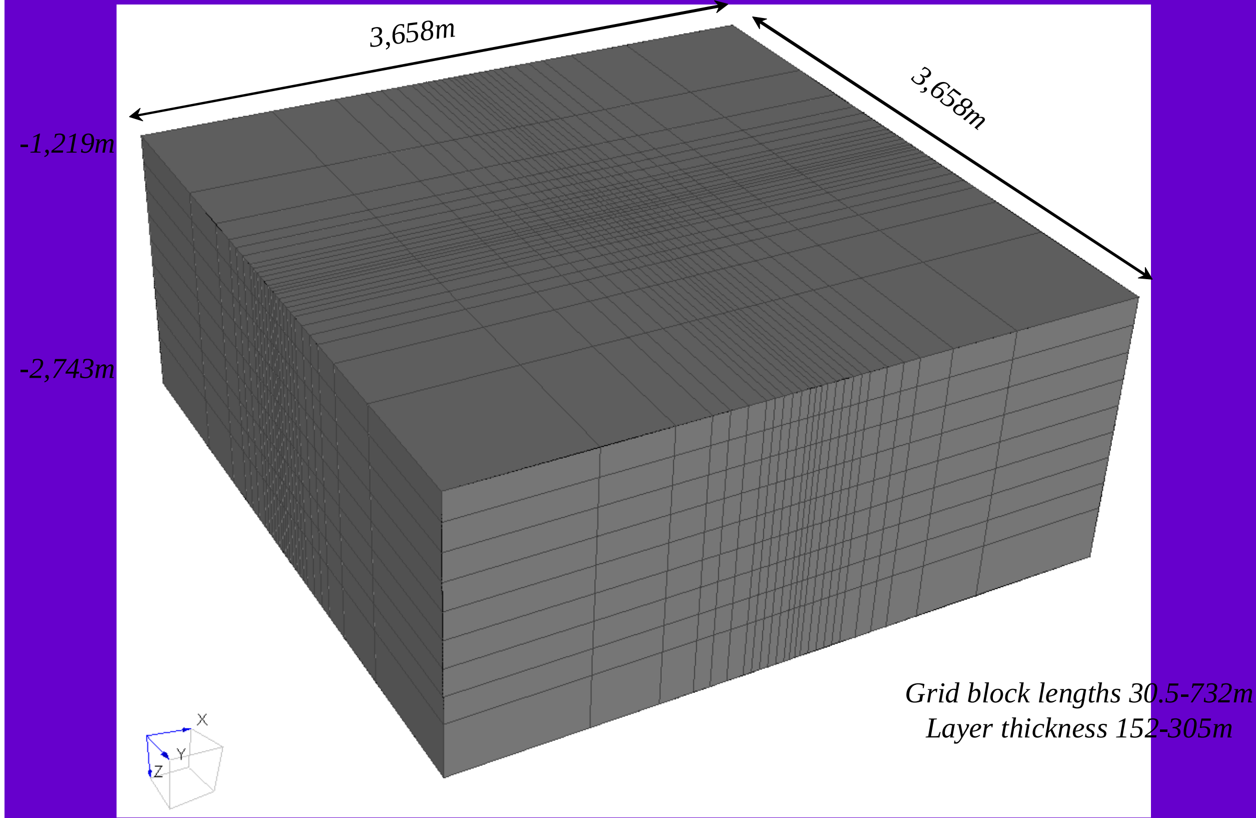


Mineralogy Failures ft/hr GR Cal Den DipAz Fracs/ft

Lessons Learned (6)

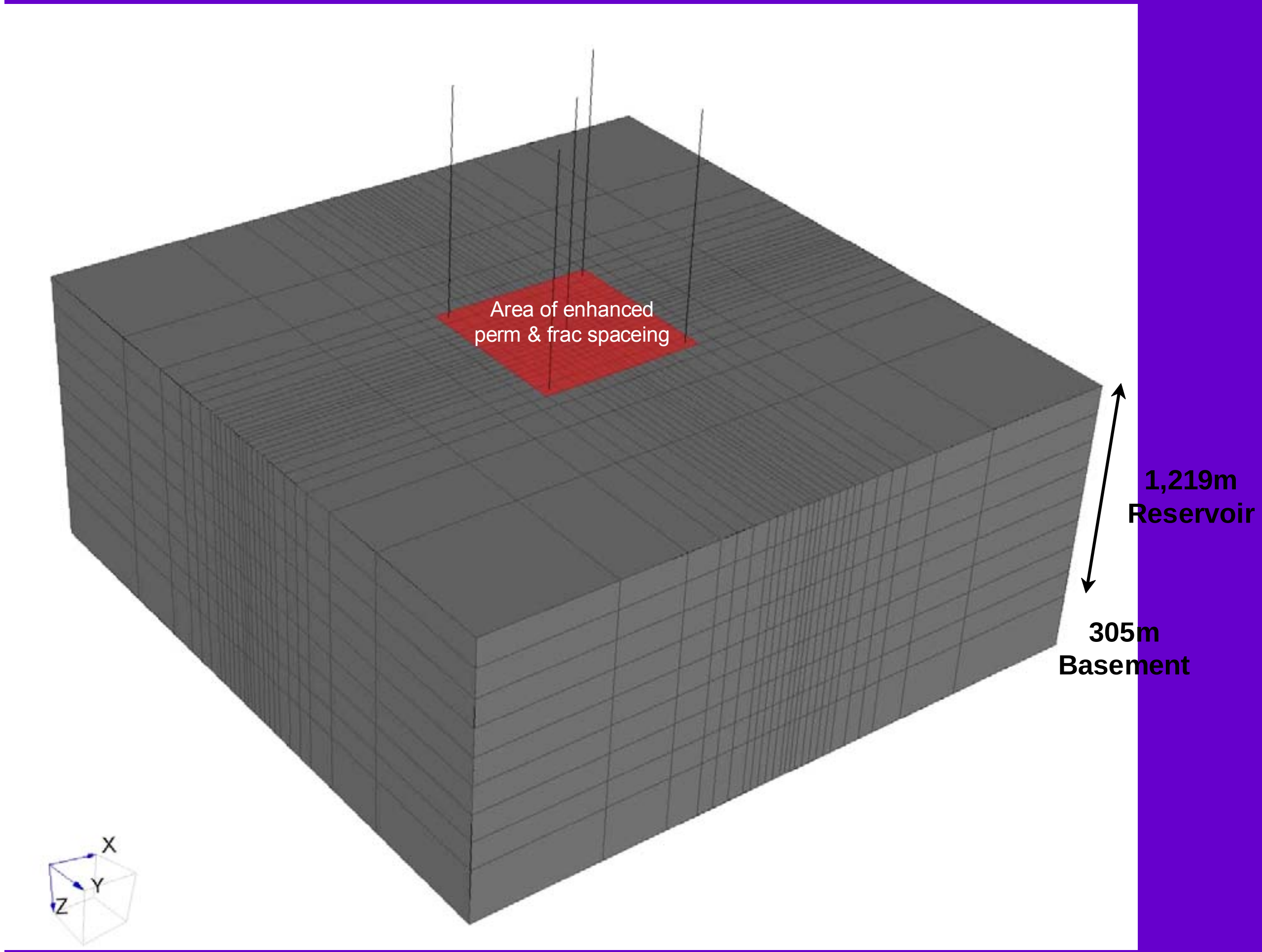
- A multi-disciplinary approach needs to be applied to EGS target selection
- Need to consider (for target unit):
  - Extent and boundaries
  - Lithology and mineralogy
  - What little natural permeability may exist, and where
  - Stress field orientation / rock strength and how these change with depth
  - The nature of pre-existing weaknesses
  - Initial hydraulic characteristics

Model set-up



- 3-D, dual-Φ, finite difference
- Large area to reduce boundary effects
- Low-kh peripheral aquifers on all sides
- Remaining parameters based on conditions at Desert Peak
- Average initial reservoir temperature 210°C
- Fine gridding in center
- Nearly 6,000 blocks

Grid system with 5-spot



K = .01 md; Φ = 2% (matrix)

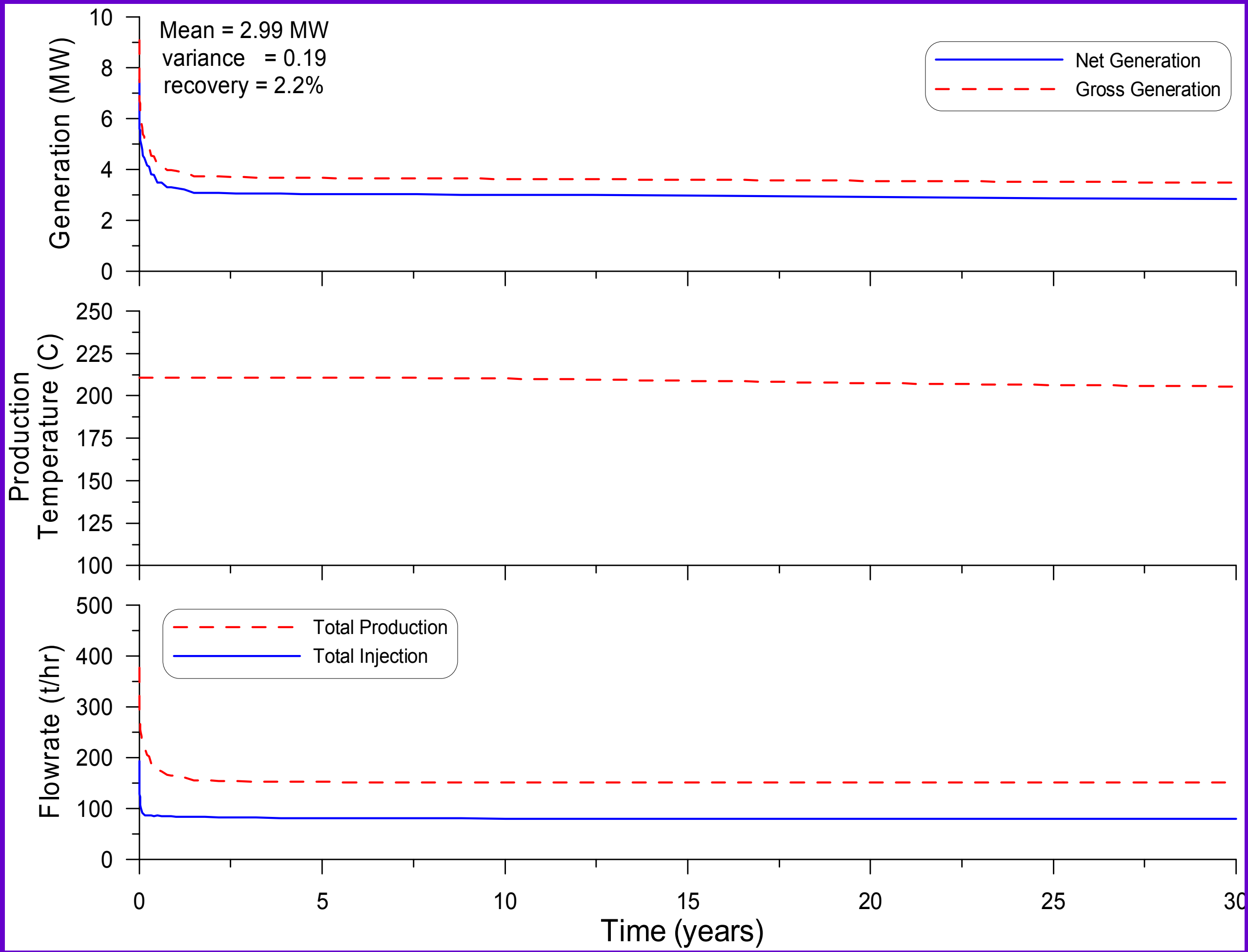
Injection temperature ~80°C

Injection pressures limited to ~7 MPa (downhole) and ~5.5 MPa (surface)

Drawdown limited to ~3.5 MPa

Considered various well geometries (doublet, triplet) and spacings, stimulated thicknesses and degrees of enhancement (fracture spacing and K)

Base Case



Un-stimulated reservoir

Wide fracture spacing (~300 m)

Five-spot configuration (~900 m x ~900 m)

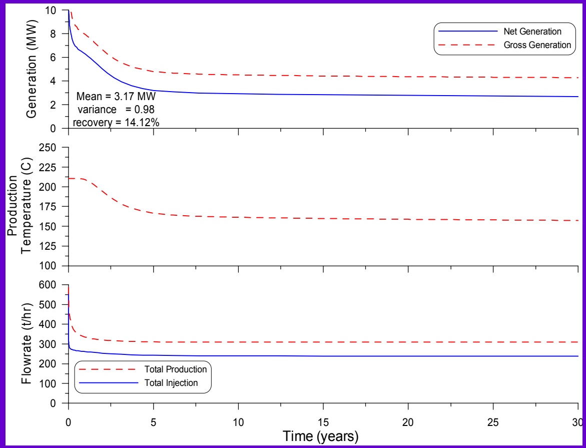
Recovers very little heat from reservoir (~2%)

Production rate varied to achieve stable generation profile

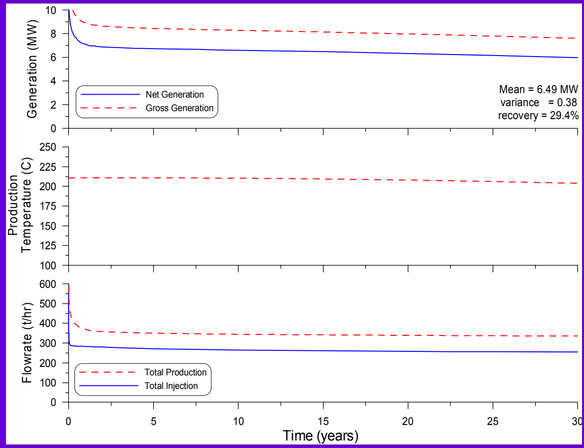
3 MW forever, but . . .

Capital costs are prohibitive (5 wells)

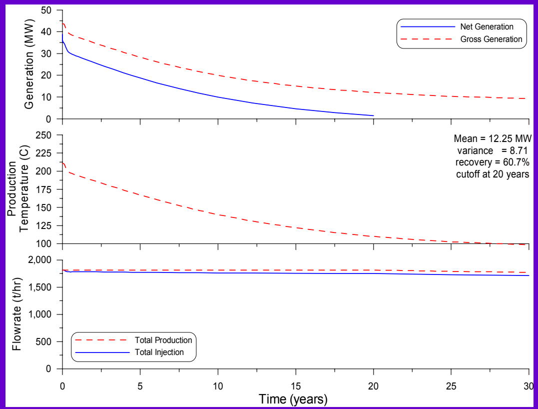
Hundreds of Cases



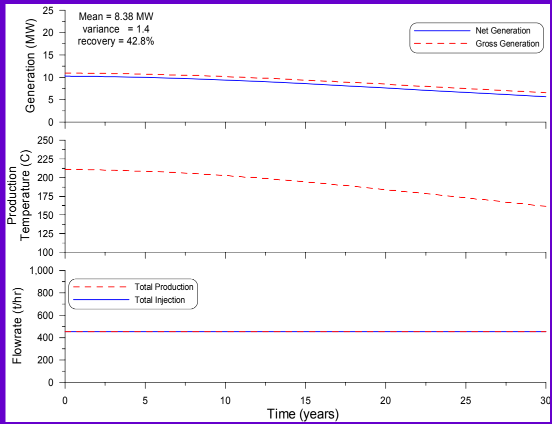
Increased k



Increased k + decreased spacing



>>k + decreased spacing

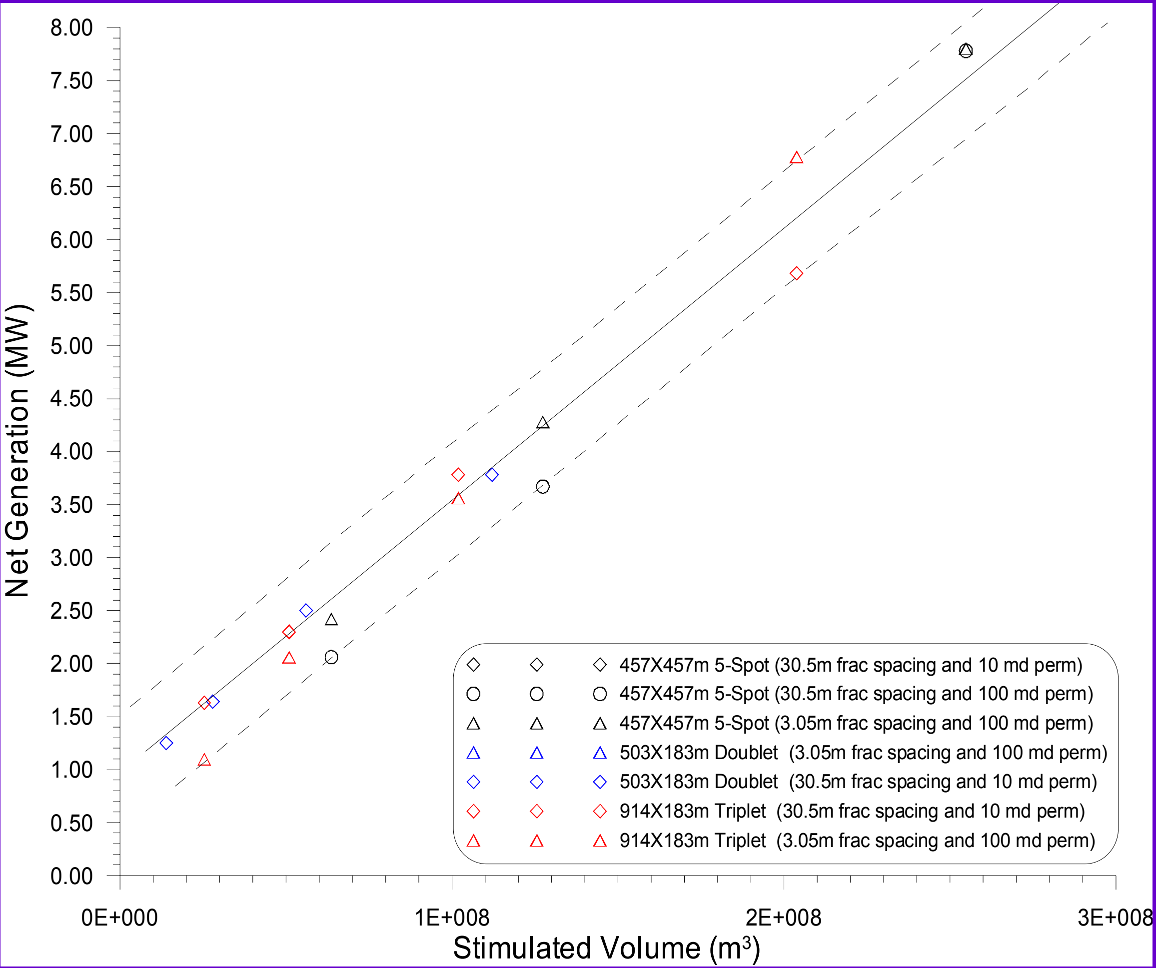


> k+ < spacing + decreased prod rate

More simulation runs . . .

- To develop practical correlations that can be qualitatively applied to any EGS project
- Plotted and grouped net generation results
- Reduced production rates to achieve acceptable generation profiles
- Sought <15% variance in net generation over 30 years
- Results presented for optimized cases

Generation vs. stimulated volume for various systems

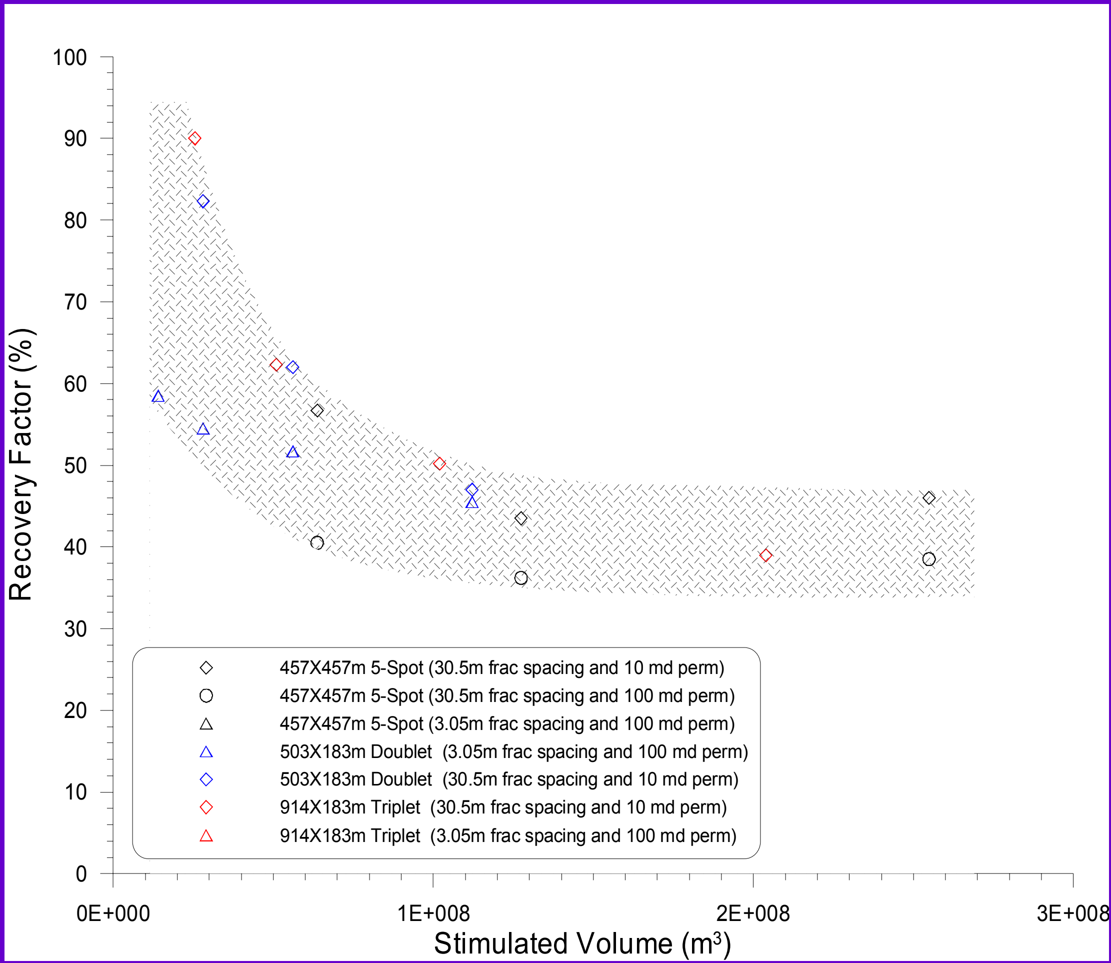


Linear correlation exists for optimized results

Independent of fracture domain permeability, fracture spacing or well geometry

An unanticipated result

Recovery factor vs. stimulated volume



Range of geometries, fracture spacings and permeability

Optimized production rate

For large (>0.1 km^3) stimulated volumes, recovery factor remains constant at 40-50% irrespective of other variables

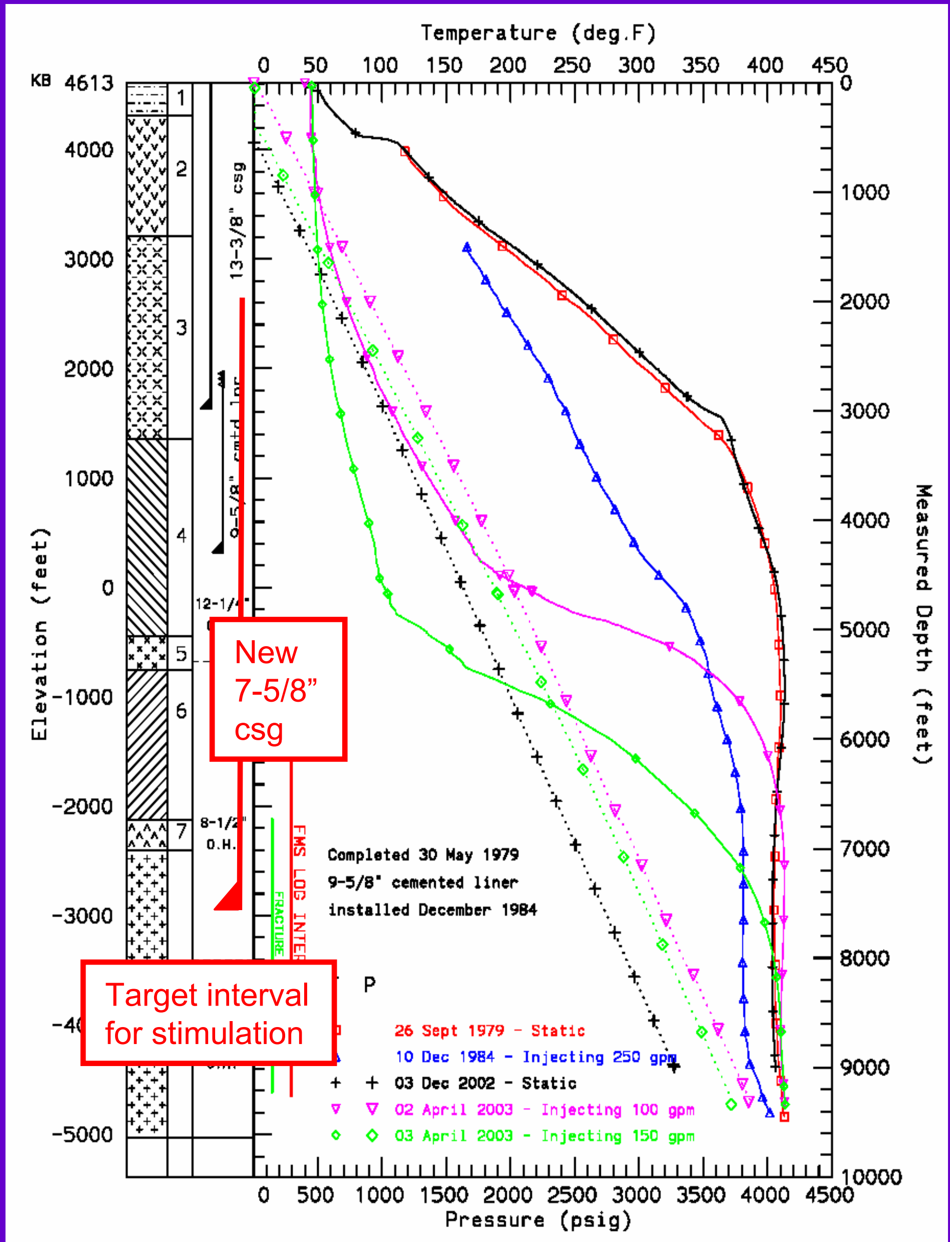
Remember, all of the above results are for OPTIMIZED cases

Lessons Learned (7)

- Net generation vs. time is more meaningful than cooling rate vs. time for evaluating EGS performance, because it takes into account all parasitic power needs and the impact of cooling on generation
- Reducing throughput improves net generation profile
- Increasing the stimulated volume increases generation
- Well geometry does not significantly affect generation vs. stimulated volume
- Neither well geometry, fracture spacing nor fracture domain permeability have a strong impact on recovery factor (~40 – 50% for stimulated volumes >0.1 km^3)
- To determine the economics of EGS, long-term system performance must be taken into account

Re-completion and mini-frac: OBJECTIVES

- Work over vertical well 23-1 to prepare for massive hydraulic stimulation
- Obtain petrophysical data
- Evaluate stress field



Procedure

- Core @ TD
- Sonic log
- Bridge plug, sand and cement plugs
- 7-5/8-inch liner (2,200-7,700 feet)
- Clean out upper cement and sand
- Mini-frac
- Clean out lower sand and cement
- Ready for stimulation

WORK PLAN

Table 2. Schedule for Re-Completion and Mini-frac Test in DP 23-1

Duration (days)	Activity
4	Condition hole with mud. Cut 60 feet of 6-inch core on bottom.
1	Circulate hole with mud to lower temperature to about 250°F. Run BHC Sonic log from bottom of cored interval (9,701 ft) to 7,700 ft.
2	Set open-hole retrievable packer in 8-1/2-inch hole at apx 7,800 ft. Cap with 2 sequences of sand and cement (e.g., 30 ft sand, 30 ft cmt, 30 ft sand, and 30 ft cmt). Dress off upper cement layer to 7,700 ft.
3	Run and cement 7-5/8-inch liner from 2,200 ft to 7,700 ft. Drill out upper layer of cement at shoe and reverse out 30 ft of sand (to top of lower cement layer at about 7,740).
2	Perform mini-frac on interval from 7,700 to 7,740 feet.
1	Drill out lower cement lower cement layer, reverse out lower layer of sand, and retrieve open-hole packer at 7,800 ft.
1	Circulate hole with geothermal brine from separators at Desert Peak plant. Run USGS Borehole Televiewer log from TD to 7,700 feet.
1	Secure wellhead and release rig.
15	

Cost estimate: ~$1.5 million

RESULTS

Actual History of DP 23-1 Workover

Duration (days)	Activity
1	Rigging up
4	Run in hole to TD (9,641'); circulate and ream
2	Twist off and single out of hole
5	Fishing (top of fish at 7,518')
2	Run free point survey
2	Wait on orders; wait on new 3.5" drill pipe; decision made to side-track
3	Run in hole to 7,350'
1	Attempt to set inflatable bridge plug (won't pass liner top); set cement plug at 7,350'
2	WOC, circulate; tag cement, drill cement to 7,148 feet, wait on directional equipment
10	Directional drill to get off plug using various BHAs. Drilling 98% formation at 7,400'
1	POOH w/ directional tools, pipe stuck at 7,120'
2	Run free point survey, fishing, POOH with fish, RIH with new BHA
1	Drill to 7,422'
6	Lose slips down hole; fishing, retrieve part of fish; run video (slips intact across casing at liner top); continue fishing (liner top damaged - tapered mill will pass through but magnet cannot)
1	Wait on orders; decision made to terminate operations
1	Secure wellhead and release rig.
44	

Actual Costs: ~$1.6 million

Lessons Learned (8)

- Top-notch drillers needed for EGS operations
- High-level supervision through all phases of re-completion operations – good communication between drill site and EGS technical personnel
- Reasonable contingency in budget (25%)
- "Radical" BHAs to kick-off in hard rock – capitalize on Geysers forking experience?
- "Wells of opportunity" approach can work

Desert Peak Phase II

- Repair liner hanger, complete side-track and mini-frac of well DP 23-1
- Drill core holes for seismic monitoring
- Stimulate well 23-1
- Analyze seismic (+ other ?) data
- Locate, drill and stimulate well #2
- Circulation test
- Well #3 ?

Continued Cooperation in Phase II

Mechanical testing and permeability analysis of cores

Mini-frac design, execution and analysis

High-temperature borehole televiewer logging

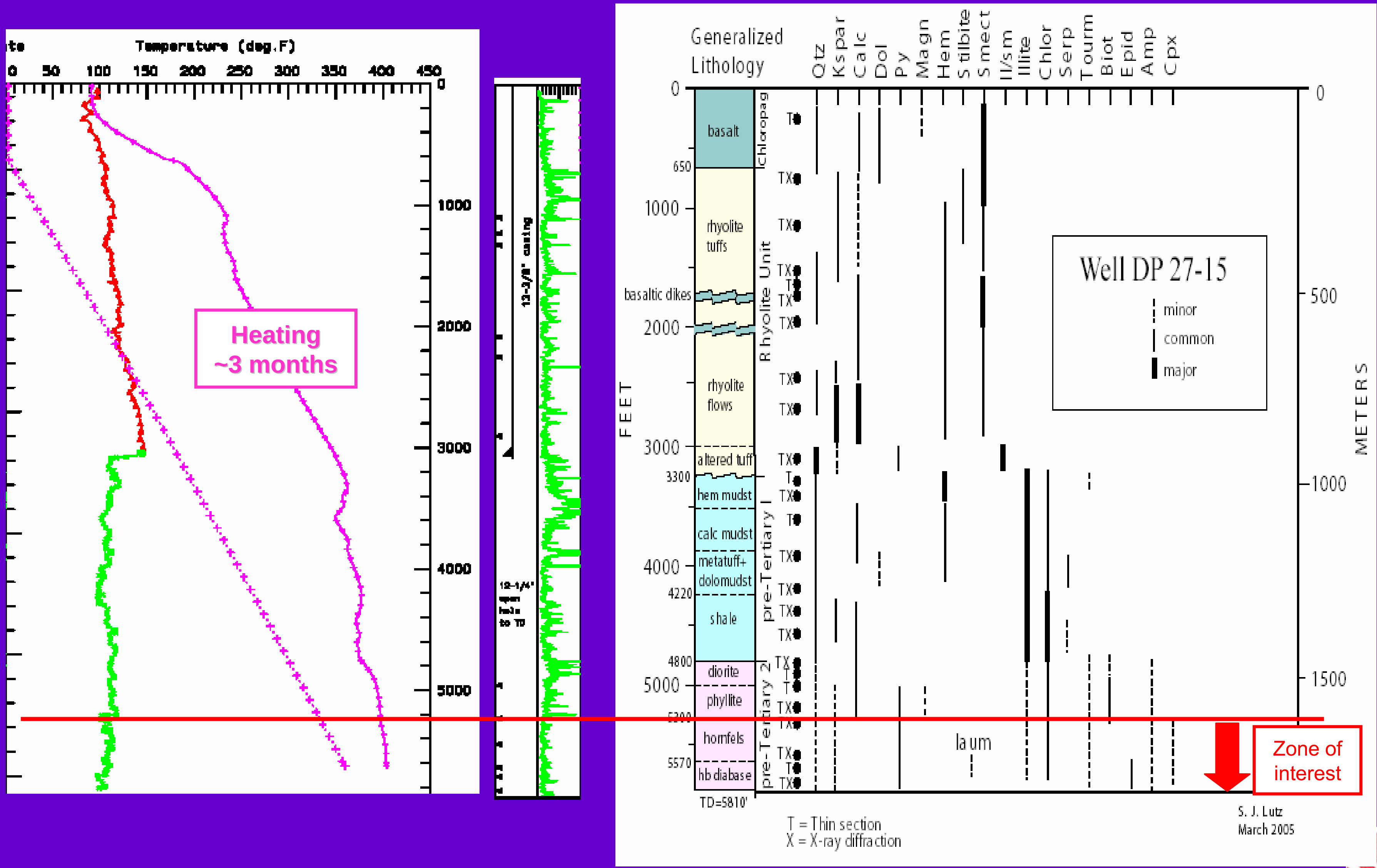
Sonic log analysis and update of stress field model

Seismic monitoring of mini-frac, development of velocity model, stimulation monitoring

Lessons Learned (9)

- Industry vs. “Academic” / “Scientific” approach to field development
- Industry could get there faster and cheaper – there are places where corners can be cut
- **Science must be done - on paper, in the lab and in the field - to enable results to be applied elsewhere**
- Government support required to demonstrate overall feasibility and “portability” of methodologies
- Industry support required to move technology ahead

In-field program - well 27-15



Desert Peak In-Field EGS Program - Preliminary Cost Estimate 060626 AR-T

	Technical Milestone	Compl. Date	$1,100 GX days	$800 Ormat days	Total Labor	Subcontracts / Other Costs Description / assumptions	Subcontracts / Other Costs Cost	Total	*Running Total*
1	Investigatge conditions in wells DP27-15 and DP43-21	15-Jul-06	0	1	$800	Assumes Welaco costs of $8,000	$8,000	**$8,800**	*$8,800*
2	Detailed geologic analysis (petrography, XRD, interpretation)	15-Aug-06	6	4	$9,800	Per Sue Lutz estimate 060314. Work includes detailed work on new wells and review of data from 4 older wells.	$40,000	**$49,800**	*$58,600*
3	Acquisition of standard geophysical logs, wellbore image log and stress field analysis	31-Aug-06	4	2	$6,000	Assumes will use USGS televiewer. Includes $10K for USGS misc. costs, $5K for crane etc, $40K for sonic-density-gamma log (Schlumberger), $30K for subcontract to GMI for analysis, $8K for tool insurance.	$93,000	**$99,000**	*$157,600*
4	Identification of intervals for chemical and/or hydraulic stimulation; development of stimulation plans	30-Sep-06	17	5	$22,700	None	$0	**$22,700**	*$180,300*
	TRAVEL COSTS				$4,000	Attend stimulation workshop		**$4,000**	*$184,300*
5	Stimulation procurement and installation of monitoring networks (includes drilling 3 shallow seismic monitoring holes)	30-Nov-06	20	20	$38,000	Drilling 3 shallow core holes ($60,000 ea), geophone deployment and monitoring system assumed to be provided by Ernie Majer (LBNL)	$180,000	**$218,000**	*$398,300*
6	Baseline injection test; chemical and hydraulic stimulation w/ monitoring; post-stimulation injection test	31-Mar-07	15	10	$24,500	Frac pump rentals (5 days @$100K), water handling equipment ($100K), acid and misc equipment ($60K - no CT unit, bullhead acid job?); PTS logging and downhole P-monitoring ($100K)	$760,000	**$784,500**	*$1,182,800*
7	Stimulation analysis	30-Apr-07	15	3	$18,900	None	$0	**$18,900**	*$1,201,700*
8	Reservoir circulation/interference testing and analysis of results	31-Jul-07	30	10	$41,000	Water handling equipment ($125K), flow metering equipment ($75K), PTS logging and downhole P-monitoring ($150K), chemical analyses ($50K); tracer testing ($50K)	$425,000	**$466,000**	*$1,667,700*
a	Reporting to DOE		30	10	$41,000	None	$0	**$41,000**	*$1,708,700*
b	Travel		included above		$0	Travel costs (6 trips Richmond-DP @ $1000)	$6,000	**$6,000**	*$1,714,700*
c	Contingency					10% of subcontracted work	$150,400	**$150,400**	*$1,865,100*
	Totals before cost-share:	**Total days:**	**137** GX	**64** Ormat	**$205,900** Total labor		**$1,654,400** Total subcontract costs	**$1,860,300**	

Go / No-Go Decision Point After Highlighted Tasks