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Phase II Field Demonstration at Plant Smith Generating Station: Assessment of Opportunities for Optimal Reservoir Pressure Control, Plume Management and Produced Water Strategies

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Acknowledgment and Disclaimer

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Presentation Outline

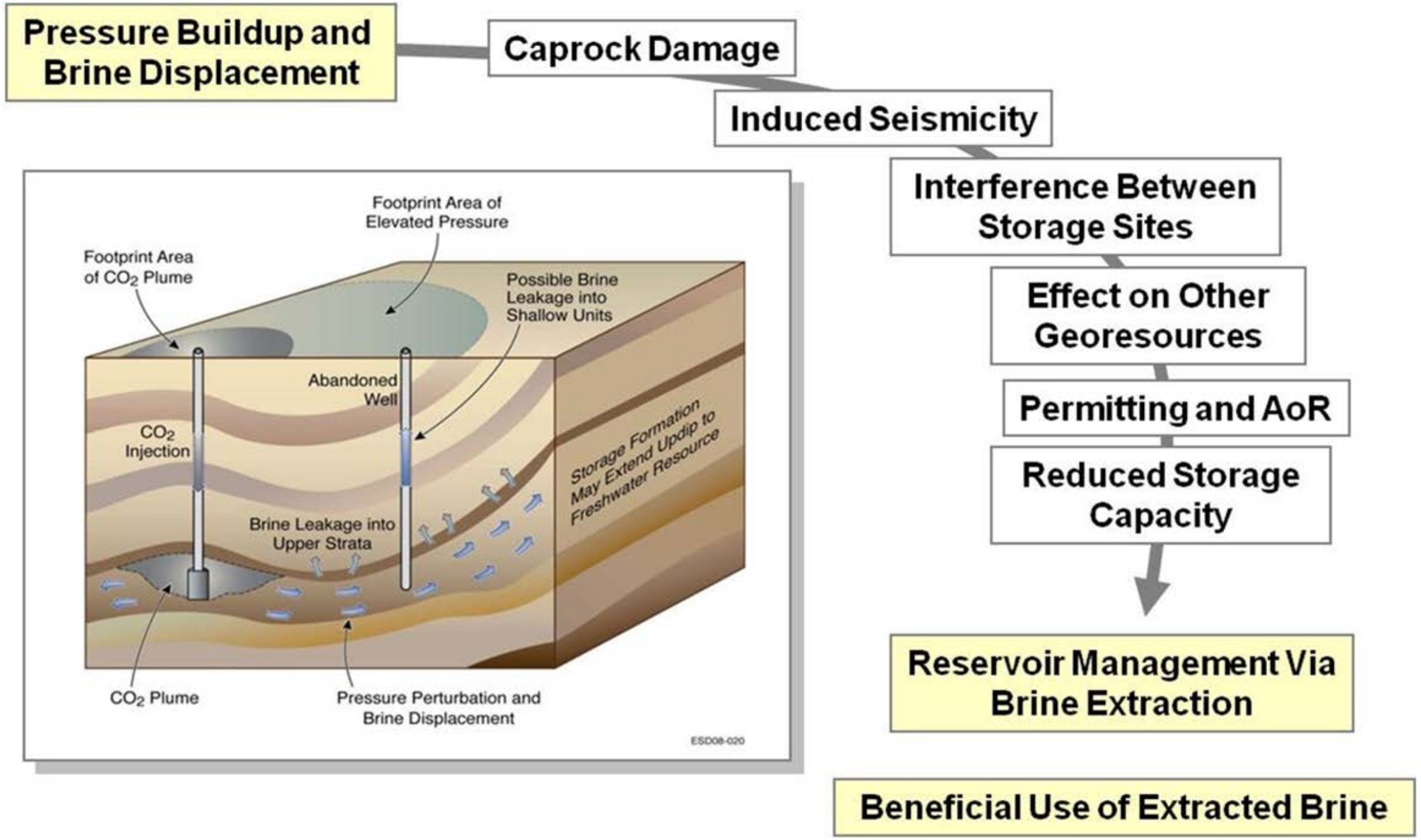
- Project Goals and Objectives
- Project Location
- Technical Objectives
- Scope
  - Experimental Design
  - Infrastructure Design
  - Permitting
  - Water Treatment User Facility
- Accomplishments to Date
- Project Summary

Photographs of existing Gulf Power wellfield. Photos clockwise from upper left: Eocene Injection well EIW-4; graveled access road; pump station under construction; cleared and permitted drilling pad location for future well

Project Overview—Goals and Objectives

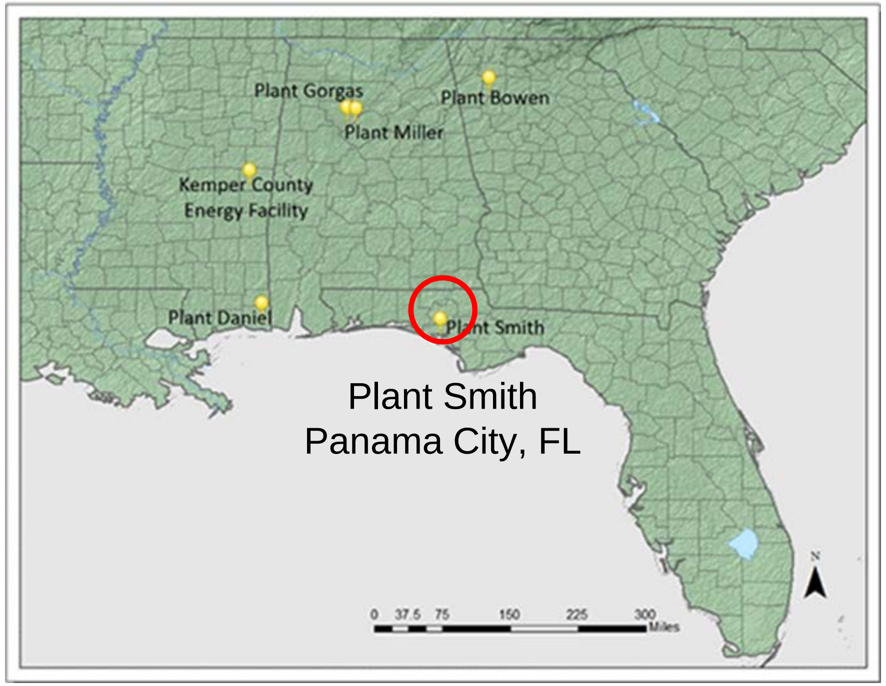
- Objective : Develop cost effective pressure control, plume management and produced water strategies for: 1) Managing subsurface pressure; 2) Validating treatment technologies for high salinity brines

Pressure management practices are needed to avoid these risks. Brine extraction is a possible remedy for reducing or mitigating risk



Phase I Site Screening and Down Selection Resulted in Selection of Plant Smith

- Evaluated existing geologic, geophysical and hydrologic data in the vicinity of each site, including
  - Well records, logs, core data, regional structural and stratigraphic studies and subsurface production/injection data
- Examined existing surface infrastructure at each plant
- Gaged plant commitment to hosting the BEST project
- Selected Plant Smith

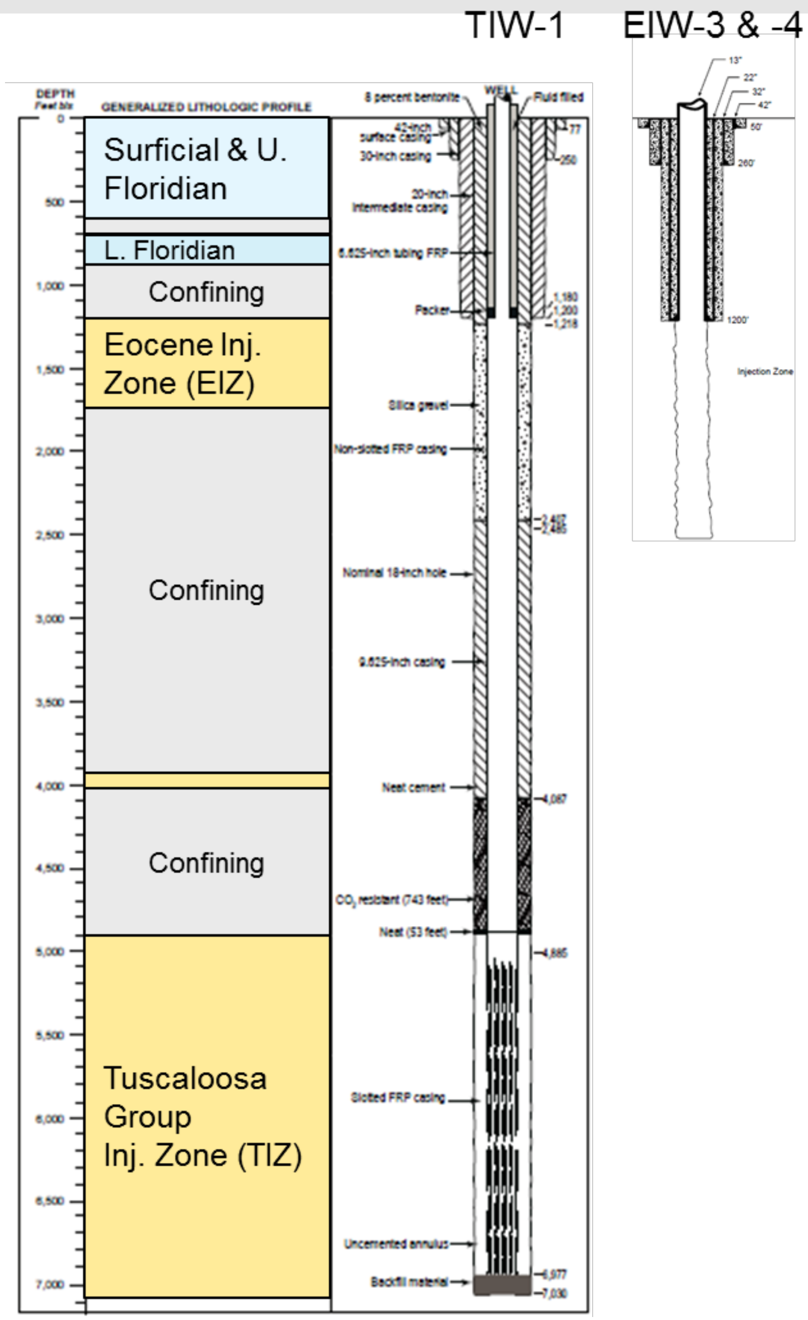


Plant Bowen, Euharlee GA
Plant Daniel, Escatawpa MS
Plant Gorgas, near Parrish AL
Plant Miller, near West Jefferson AL
Kemper Co Energy Facility, MS

Plant Smith Overview

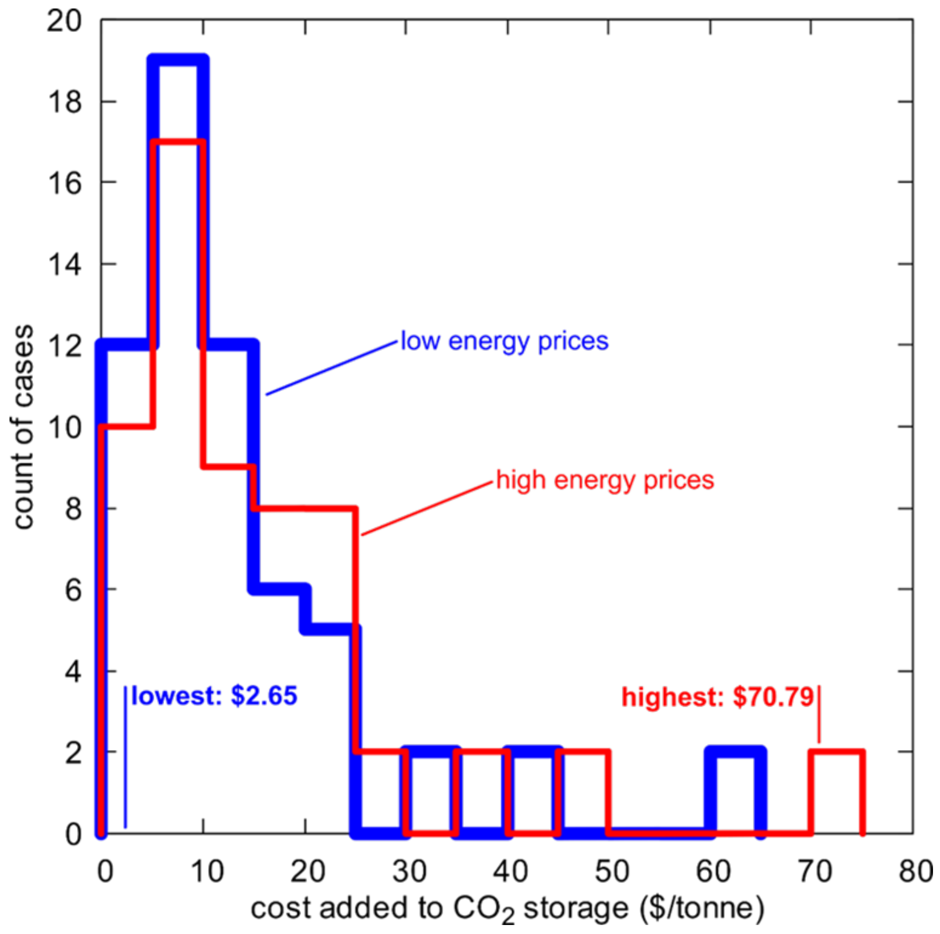
- Multiple confining units
- Thick, permeable saline aquifers
  - Eocene Series (870-2,360)
  - Tuscaloosa Group (4,920-7,050 ft)
  - Represent significant CO_2 storage targets in the southeast US
- Large Gulf Power Co. waste water injection project under construction (infrastructure)
- Water injection pressures will be managed as a proxy for CO_2 injection (~500k-1M gal/day)

No CO_2 injection will take place



During Phase I EPRI Conducted a Life-Cycle Analysis of Extracting and Treating Brine, Transmitting Treated Water

- Used Plant Smith waters as the basis for the analysis
- Performed techno-economic assessment of a hypothetical CCS water extraction project
  - Extraction
  - Transportation
  - Pre- and primary-treatment assuming zero liquid discharge
  - Residual waste disposal
- Computed power required over 30 years of operation
- Calculated CapEx/OpEx costs for entire system

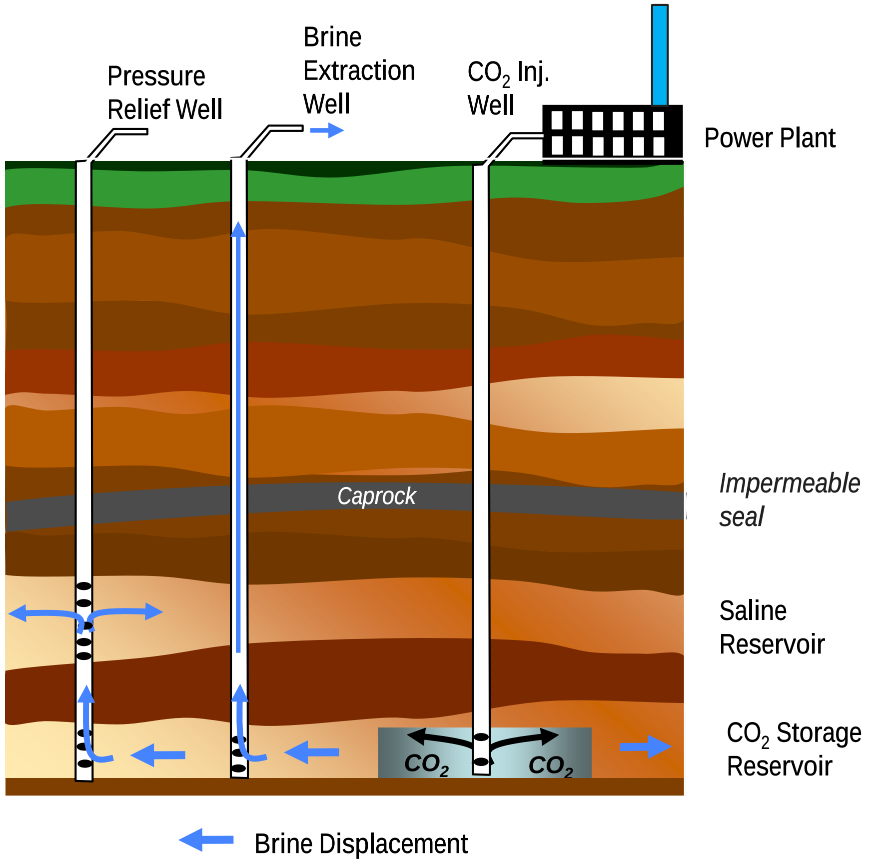


Added cost of water treatment can be significant

Phase II Field Demonstration Experimental Design—Passive and Active Pressure Management

- Passive pressure relief in conjunction with active pumping can reduce pressure buildup, pumping costs and extraction volume
- Existing "pressure relief well" and "new" extraction well will be used to validate passive and active pressure management strategies

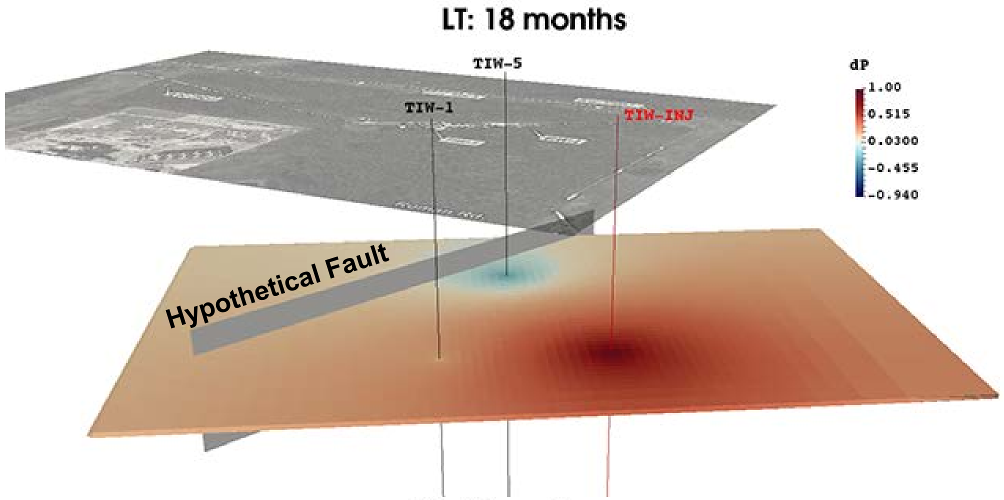
Pressure relief well has the potential to reduce extraction volume by 40%

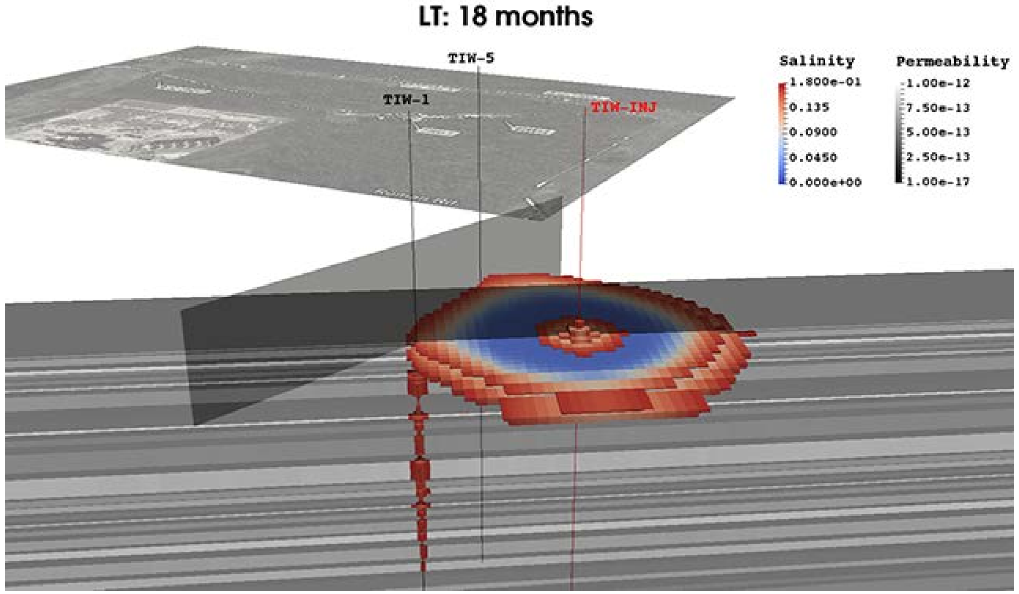


Hypothetical CO_2 storage project showing "active" extraction and "passive" pressure relief well

Goals of Subsurface Pressure Management Via Passive + Active Brine Extraction at Plant Smith

- Scenario—Minimize risks for injection-induced seismic events and leakage along hypothetical faults by controlling
  - Pressure buildup
  - Plume migration
- Limit the size of the Area of Review
- Limit the volume extracted
- Develop and test effectiveness of adaptive optimization methods and tools to manage overall reservoir system response





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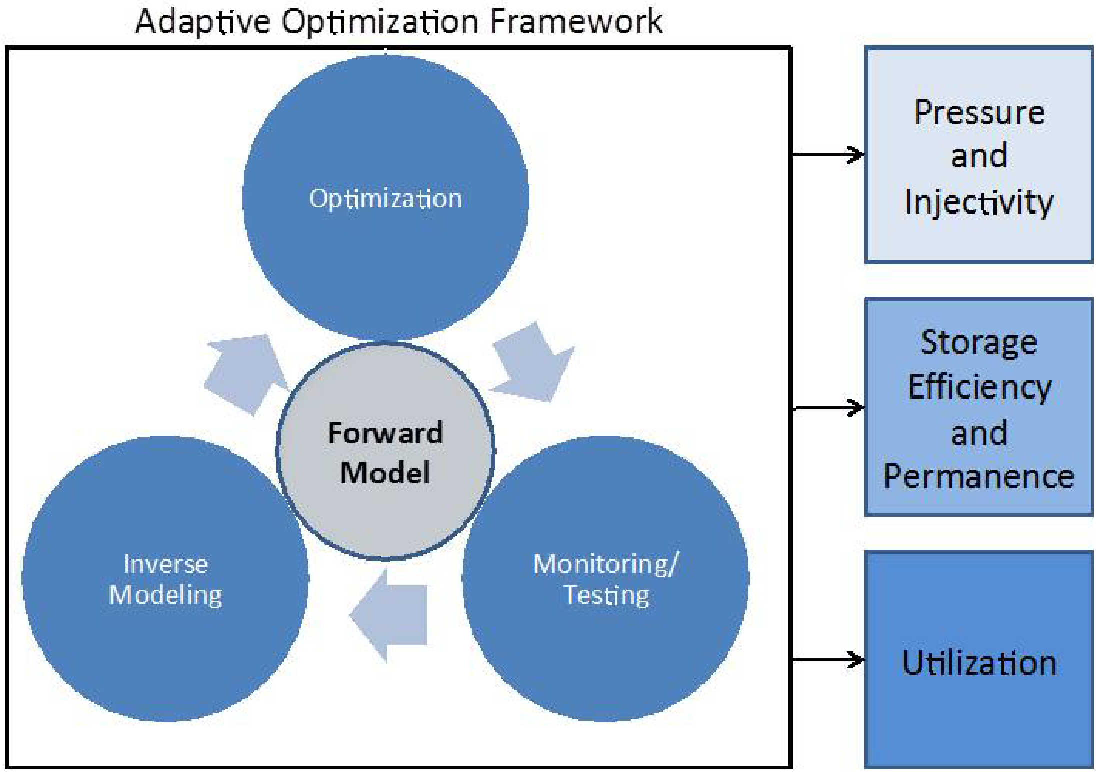
Adaptive Pressure Management will Ensure Proper Control of Pressure and Plume Migration

- The adaptive management workflow integrates modeling + optimization + monitoring + inversion
- The adaptive workflow for optimized management of CO_2 storage projects utilizes the advanced automated optimization algorithms and suitable process models

Why is adaptive management needed?

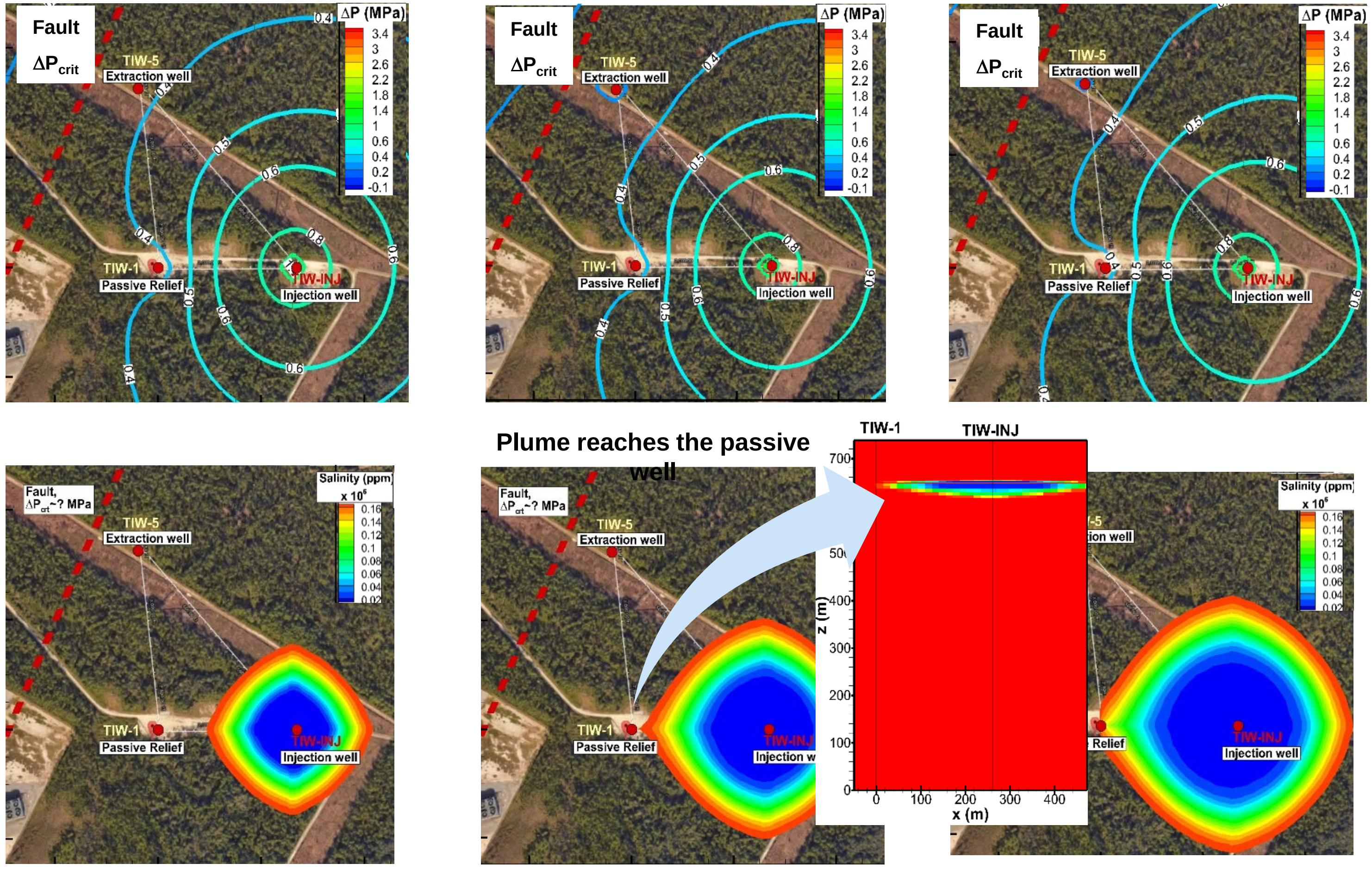
- Incomplete knowledge of subsurface properties exist, especially during the planning stages of CO_2 projects
- During operations, the subsurface system behavior needs to be monitored continuously, and the models need to be frequently updated



Pressure and Salinity Changes for the Base Case Pressure Management Scenario

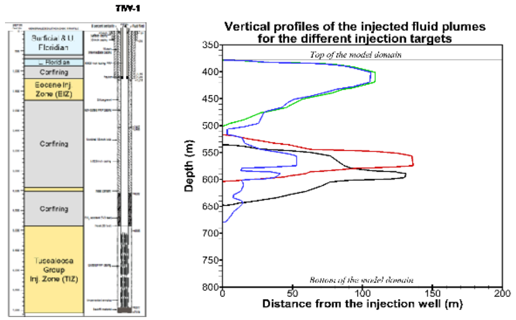
- Developed a preliminary reservoir model based on the existing data and simulated density and viscosity-dependent brine flow
  - Injection =200 gal/min
  - Max. Extraction Rate ~20 gal/min
  - Starting at time = 6 months
- Passive extraction may reduce the total volume extracted up to 40%, according to the base case scenario

6 months 12 months 18 months

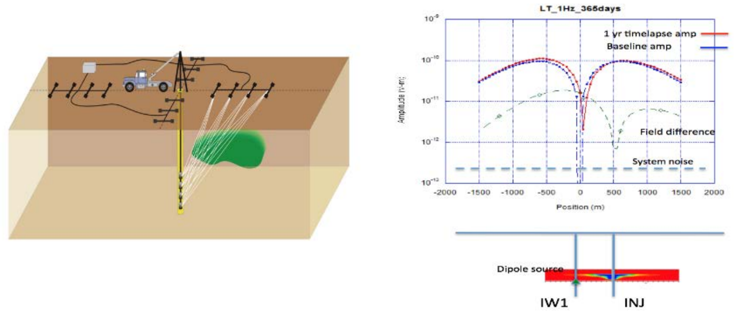


Monitoring – Inversion for Pressure & Salinity

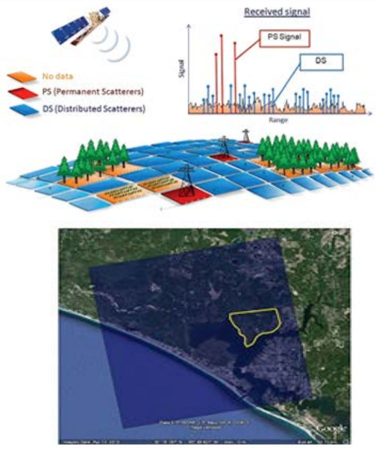
- **Borehole -** Continuous and time-lapse (discrete) borehole measurements of fluid pressure, flow rate, temperature, and electrical conductivity will be used to provide high-resolution, ground-truth, direct measurements at discrete locations (1D).



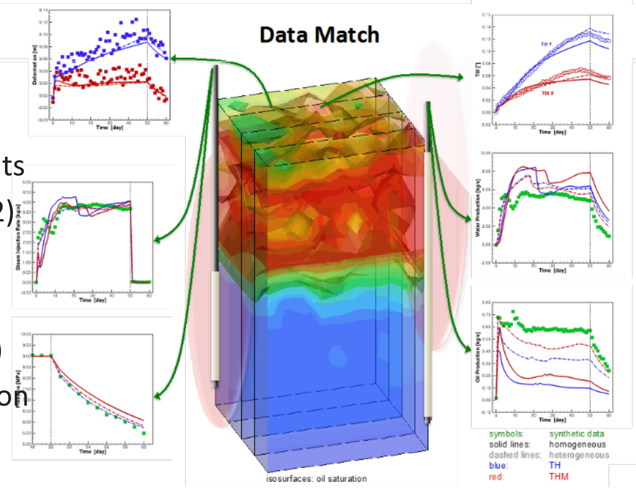
- **EM** - Time-lapse crosswell and borehole-to-surface EM will provide indirect measurements of the higher resistivity injected ash pond water with spatial resolutions in 2D and 3D approaching several meters to tens of meters, respectively.



- **InSAR** - InSAR will be used to map surface deformations resulting from subsurface pressure increases over 16 day intervals

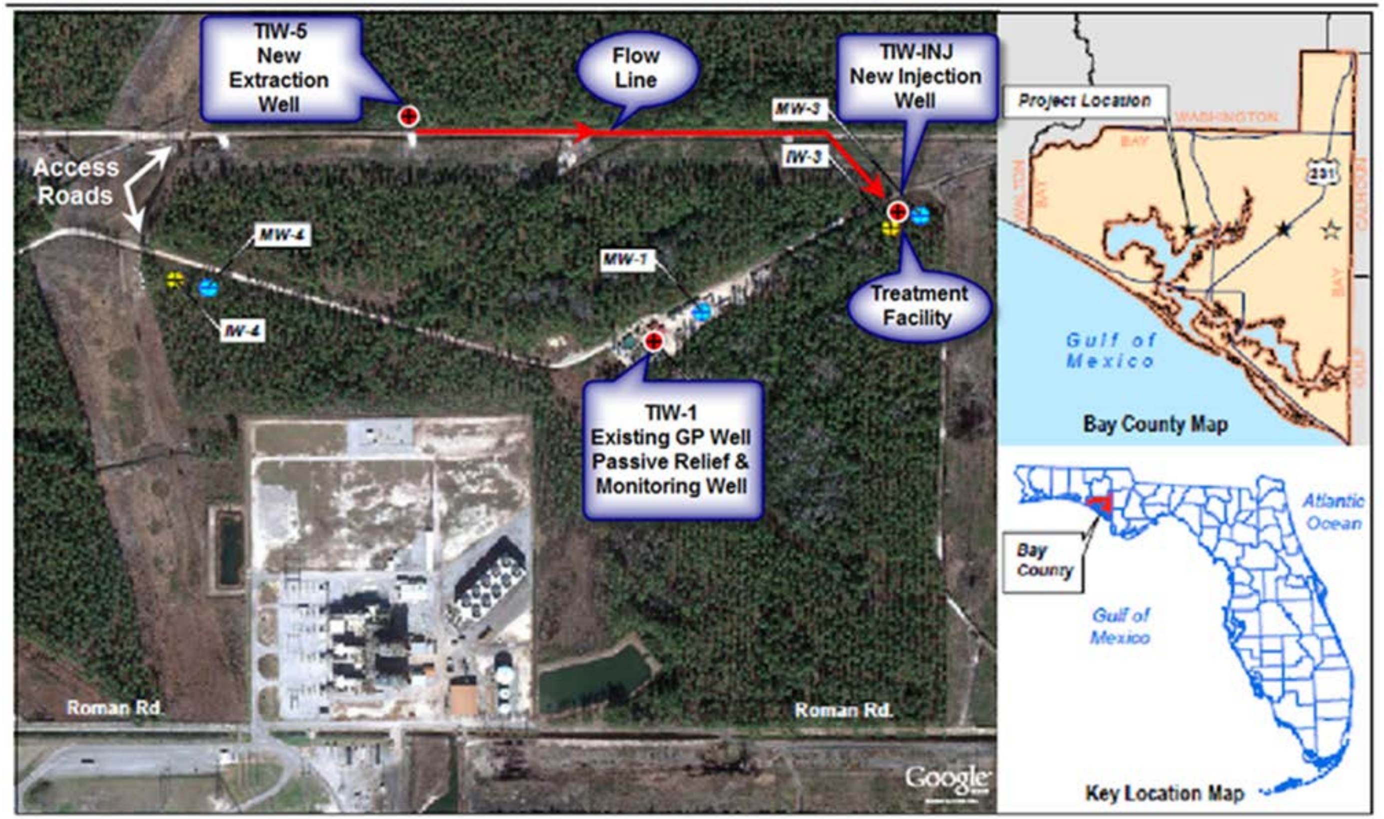


Joint Inversion - We will use LBNL's powerful inverse modeling and parameter estimation tool iTOUGH (in its parallel version MPiTOUGH2) for the automated joint inversion of hydrological, large-scale geophysical (EM) data, and surface deformation data.



Well Field Infrastructure Design

- Developed detailed technical specifications for:
  - Well pads
  - Extraction well
  - Injection well including four casing/tubing options
  - Flowline
  - Submersible pump
  - Power requirements



BEST project infrastructure layout showing the proposed location of the extraction well (TEMW-A), injection well (TIW-2) and flowline, and the existing passive-relief well (TIW-1)

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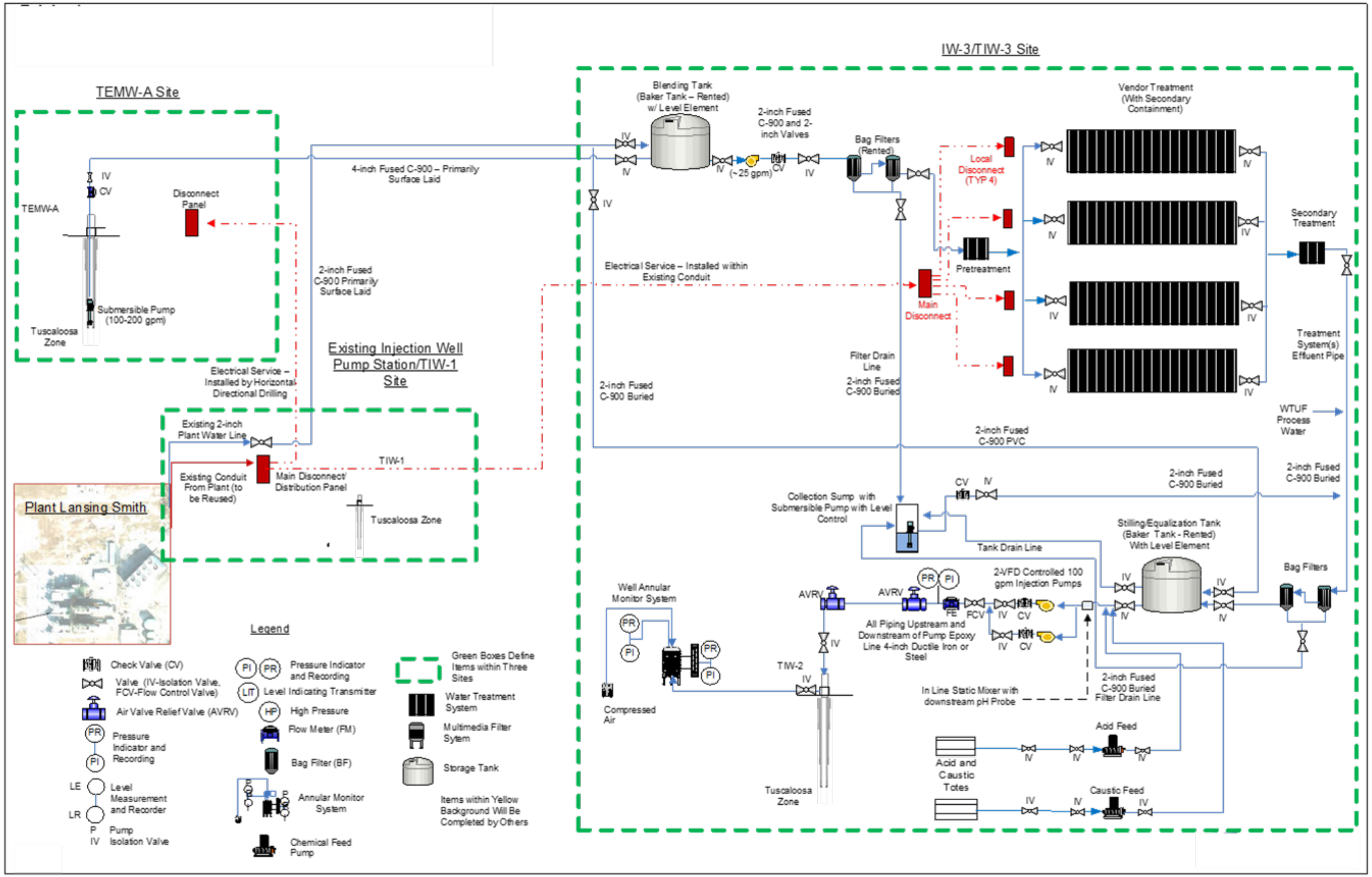
Water Treatment User Facility Design 60% Complete

- Design provides different water qualities for testing by DOE researchers and commercial water treatment vendors
  - Low (30 mg/L) to high salinity (166,000 mg/L) TDS waters
- Final design pending collection of a representative water sample
  - Injection water compatibility



Update - Site Preparation

Drill pad installation

Monitoring well installation

Update - Drilling Operations

Welding sections of 48-inch dia. conductor casing together

Installation of the 48-inch conductor casing

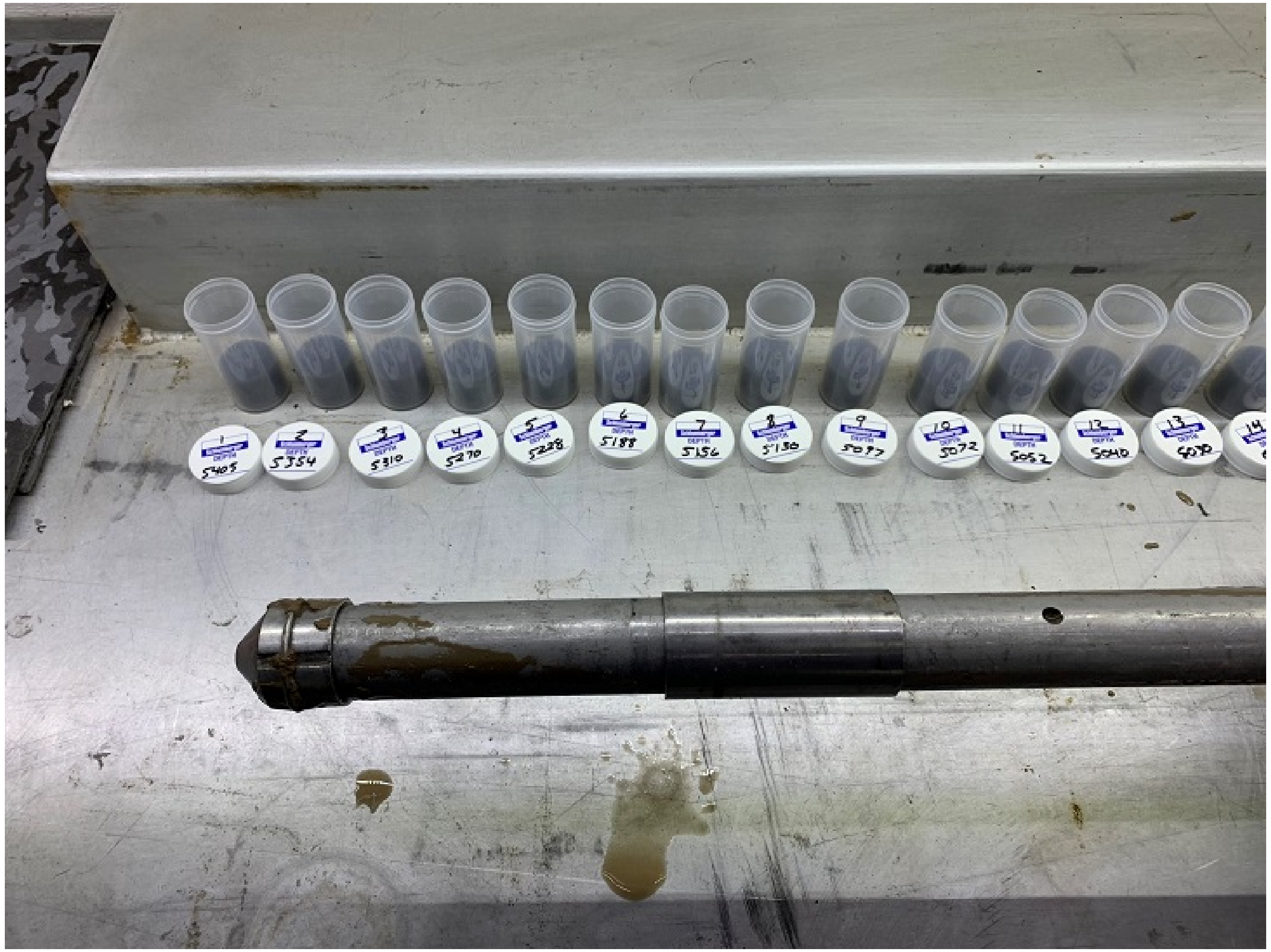
Update - Drilling Operations Nearing Total Depth

Electric rig drilling injection well TIW-2

Diesel rig drilling observation well TEMW-A

Side-Wall Coring to Collect Geologic Samples for Testing

Retrieving the core barrel via wireline



Capped core barrel containing core

Core Samples from ~5,000 ft (~1,524 m)

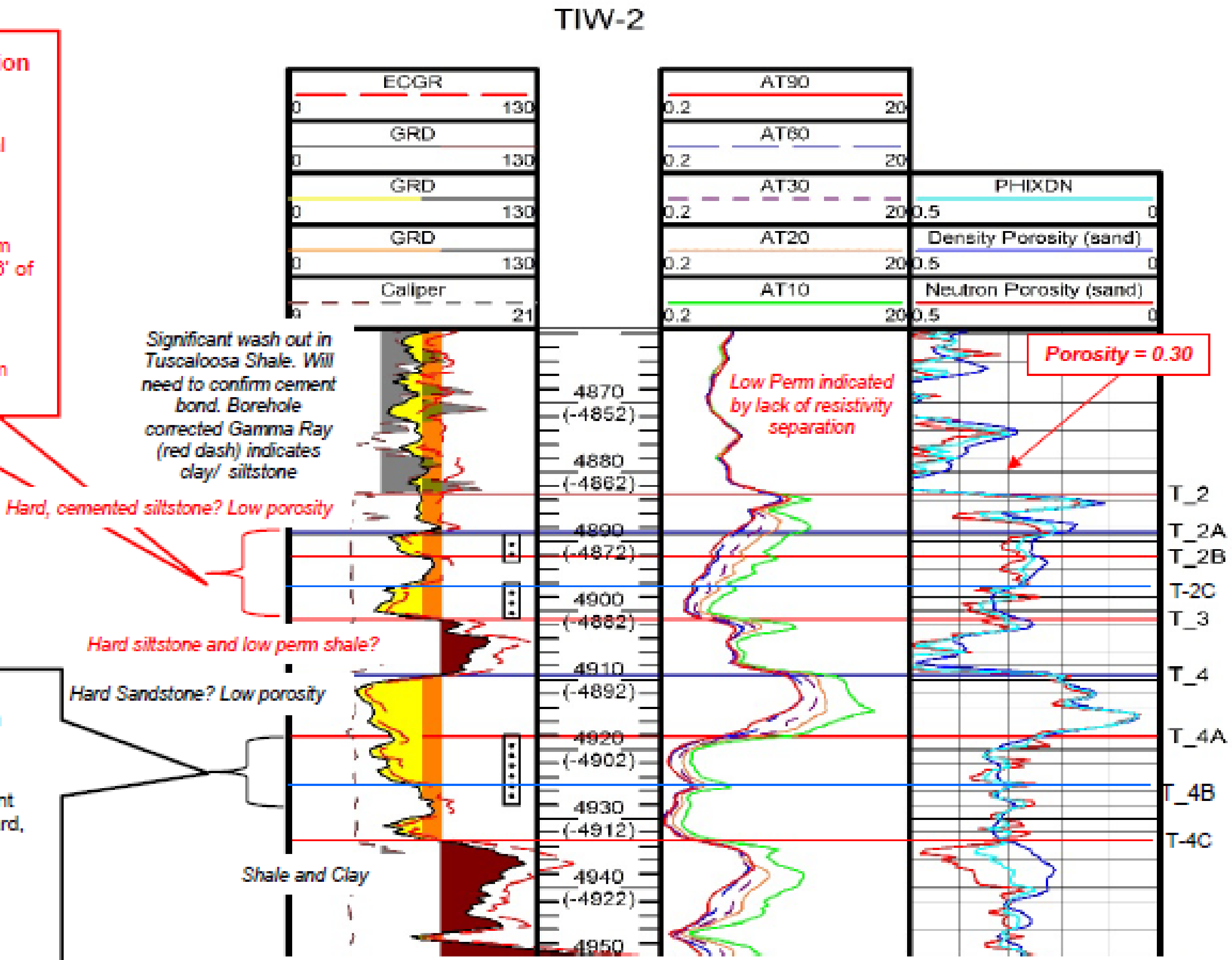
Core barrel containing continuous side-wall cores

Close-up view of side-wall cores
Clay (left) and sandstone (Right)

Open-Hole Well Logs

Proposed Primary Injection Perfs: 4889 – 4901

- Corresponds to hypothetical injection zone in current reservoir simulation
- Bounded on top by low perm Tuscaloosa shale and 4' – 6' of hard cemented siltstone or sandstone
- Bounded below by low perm shale/ claystone



Proposed Back-Up (Secondary) Injection Perfs: 4918 – 4928

- Bounded on top by apparent low porosity sandstone. Hard, cemented?
- Bounded below by low permeability shale and unconsolidated clay

Reservoir Simulation for Test Design

	Thickness (m)	Top depth (m)	Porosity	Perm (mD)
Confining Zone: Tuscaloosa Marine Shale	46.3296	1403.2992	0.24	0.2
Confining	15.5448	1449.6288	0.2	0.1
Lower Tuscaloosa - Sandstone ("Pilot Sand") - Confining	11.8872	1465.1736	0.2	12
Confining	11.2776	1477.0608	0.2	0.5
Potential Injection Zone 1	3.3528 2.1336	1488.3384 1491.6912	0.26 0.31	**190** **800**
Confining	2.4384	1493.8248	0.15	0.5
Potential Injection Zone 2	7.3152	1496.2632	0.32	**1300**
Confining	5.7912	1503.5784	0.27	7
Potential Injection Zone 3	7.9248	1509.3696	0.325	**2625**
Confining	7.0104	1517.2944	0.27	10
Potential Injection Zone 4	4.572 2.1336 5.7912	1524.3048 1528.8768 1531.0104	0.3 0.29 0.32	**600** **550** **1060**
Confining	3.6576	1536.8016	0.12	0.5

- Assessed four individual injection zone options with
  - Base case geological model for 100 gpm and 200 gpm injection rates
  - Reduced confining layer permeability values by a factor of 10 for 100 gpm injection rate
  - Reduced injection layer permeability values by a factor of 10 for 100 gpm injection rate
- Assessed combination of iz1 and iz2 with
- Reduced confining layer permeability values by a factor of 10 for 100 gpm injection rate
- Reduced injection layer permeability values by a factor of 10 for 100 gpm injection rate
- Assessed individually 4 injection zones (100gpm) with less contrast between permeability of confining layers (increased by a factor of 5) and permeability of injection layers (increased by a factor of 2)

Challenges

- Well costs higher than expected in Florida
  - Non-competitive market
  - Special Florida injection well regulations contribute to costs
- Contracting – never goes as quickly as hoped or planned
  - Lump sum drilling contract with stipulated penalties provided cost protection but had unintended technical consequences
- Weather delays – Hurricane Michael
- Mechanical delays
- Technical
  - Injection/formation water compatibility impacts on design
  - Reliable source of water for injection
  - Unconsolidated sediments have a unique set of laboratory challenges

Next Steps

- BP3 (2018-2021) plans include:
  - Casing installation and hydraulic tests
  - Final design and installation of the water treatment user facility
  - Equipment commissioning
  - 6 months of injection followed by 12 months of injection and extraction
- BP4 (2021-) plans include:
  - Site restoration
  - Final reporting

Plant Smith (foreground) and Panama City (background)

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