Basin and Petroleum System Modeling
5th Annual Industrial Affiliates Meeting
and
The Petroleum System of the Santa Cruz County Coast, California

November 28-29, 2012
Tresidder Memorial Union
Stanford University

Compiled by Allegra Hosford Scheirer,
Les Magoon, and Steve Graham
http://bpsm.stanford.edu

2012 BPSM Industrial Affiliates Meeting Agenda

9:00 a.m.	**Steve Graham**, Introduction
9:20 a.m.	**Tess Menotti**, Role of silica diagenesis and structural deformation in basin and petroleum system models of the Salinas Basin, Central California
10:10 a.m.	**Inessa Yurchenko**, Evaluation of possible source rocks in Northern Nye County, Nevada: Implications for hydrocarbon exploration; Introduction of Ph.D. research on Alaska North Slope
10:35-10:50 a.m.	Coffee break
10:50 a.m.	**Blair Burgreen**, Petroleum system development in a forearc basin: Importance of structural history integration on 1-D and 2-D basin and petroleum system models in Hawke Bay, North Island, New Zealand
11:30 a.m.	**Yao Tong**, Basin and petroleum system modeling for Piceance Basin, Colorado, and uncertainty quantification
Noon-1:30 p.m.	Lunch (please complete field trip forms if haven't already done so)
1:30 p.m.	**Danica Dralus**, Effects of opal-CT phase transition rates on transition depth in San Joaquin Basin models
1:55 p.m.	**Amrita Sen**, Benchmark basin and petroleum system model
2:15 p.m.	**Wisam H. AlKawai**, Integration of basin and petroleum system modeling with seismic technology to predict pore pressure
2:30-2:45 p.m.	Coffee break
2:45 p.m.	**Tapan Mukerji**, Building Bayesian networks from basin modeling scenarios for improved geological decision making
3:15 p.m.	**Ken Peters**, Theoretical aspects of petroleum system modeling for unconventional resources
4:00 p.m.	**Allegra Hosford Scheirer**, BPSM review and field trip introduction
4:30 p.m.	Group discussion if desired: What would you like to see us working on? What are the problems of utmost priority?

2012 BPSM Industrial Affiliates

Aera
BP
Chevron
ConocoPhillips
Great Bear Petroleum LLC
Hess
Nexen Inc.
Oxy
Petrobras
Saudi Aramco
Schlumberger
Venoco, Inc.

2012 Meeting Attendees

Industry Scientists

Jennifer Adams, ConocoPhillips
Bob Blackmur, Venoco
Eric Bridgford, Venoco
Steven Crews, Hess
Ed Duncan, Great Bear Petroleum
Karen Duncan, Great Bear Petroleum
Plamen Ganev, Aera
Gretchen Gillis, Aramco Services Company
Dave Greeley, BP
Jack Grippi, Aera
Margaret Keller, U.S. Geological Survey
Joseph Lalicata, Aera
Becca Lanners, Oxy
Paul Lillis, U.S. Geological Survey
Fausto Mosca, Nexen
Ken Peters, Schlumberger (also at: Stanford University)
Gregg Pyke, Oxy
Andre Spigolon, Petrobras
Robin Swank, Venoco
Wayne Tolmachoff, Venoco
Robert Tscherny, Chevron
Noel Velasco, Aera

Stanford University Scientists and Graduate Students

Wisam AlKawai, graduate student
Blair Burgreen, graduate student
Danica Dralus, graduate student
Steve Graham, Professor
Allegra Hosford Scheirer, Consulting Professor
Les Magoon, Consulting Professor
Kristian Meisling, Consulting Professor
Tess Menotti, graduate student
Mike Moldowan (Emeritus Professor, now at: Biomarker Technologies Inc.)
Tapan Mukerji, Associate Professor
Amrita Sen, graduate student
Yao Tong, graduate student
Inessa Yurchenko, graduate student

2012 Meeting Announcement

MEETING SUMMARY

The fifth annual Stanford University Basin and Petroleum System Modeling Industrial Affiliates Conference is scheduled for **Wednesday and Thursday, November 28 and 29, 2012.** The meeting will be held in a conference facility on the beautiful Stanford University campus. On Wednesday, Stanford graduate students will present talks and be available for questions on their basin and petroleum system modeling research. Many of the principal advisors in the program will be available for discussions. More details on talks will be available soon.
The following day (Thursday) will feature a field trip to investigate petroleum systems of the San Mateo coast. We will travel south along scenic Highway 1 to examine sandstone filled with degraded oil (injectite complex), an injectite cutting through Santa Cruz Mudstone illustrating diagenetic evidence of a fluid front, an old asphalt quarry, and cold carbonate seeps. Throughout the day we will discuss the impact of the San Gregorio-Hosgri Fault on migration, uplift and breaching of traps, and the juxtaposition of depocenters and structural highs. Before the end of the day we will stop at a winery for refreshment. Please join us!

REGISTRATION

Registration opens September 1. Check back here for the link to the registration site. Members from affiliate companies attend the meeting and field trip at no charge; specially invited guests pay a $500 fee for the meeting and field trip. Please pick the appropriate category when registering: affiliate, affiliate+field trip, nonaffiliate, nonaffiliate+field trip.

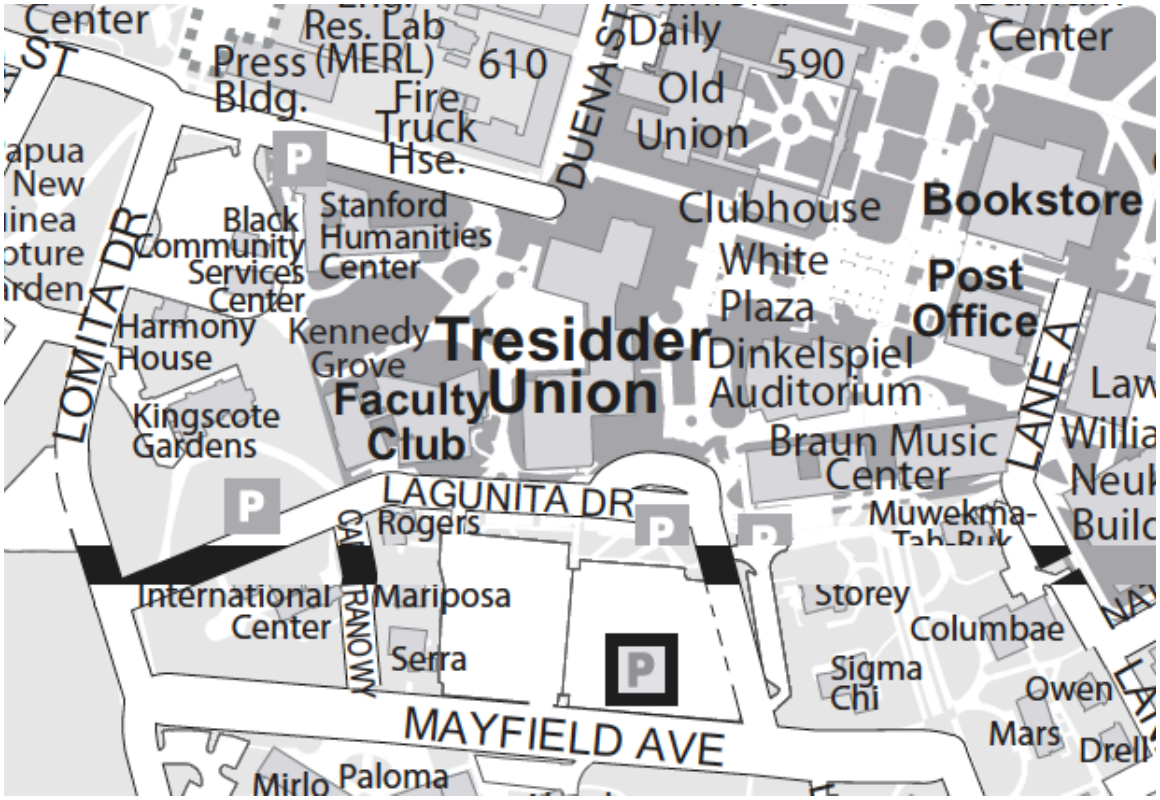
LODGING AND TRANSPORTATION

You may want to arrive on the evening of Tuesday, November 27 and depart following the field trip on Thursday evening, November 29, or Friday morning, November 30. In the past, meeting attendees have stayed at Stanford Terrace Inn, Sheraton, Westin, and The Cardinal Hotel. Early booking is encouraged.

FIELD TRIP

The field trip is optional but we encourage you to attend. There will be no strenuous hiking. Please bring hiking boots (steel toes are not required). Additional items to bring include sunscreen, daypack, camera, and rainy weather gear in case of inclement weather. A field trip guide will be provided to each participant. We will also provide snacks, drinks, and lunch.
Stanford University requires each field trip participant to sign a release form and a medical information form; the latter will be distributed the day of the meeting and

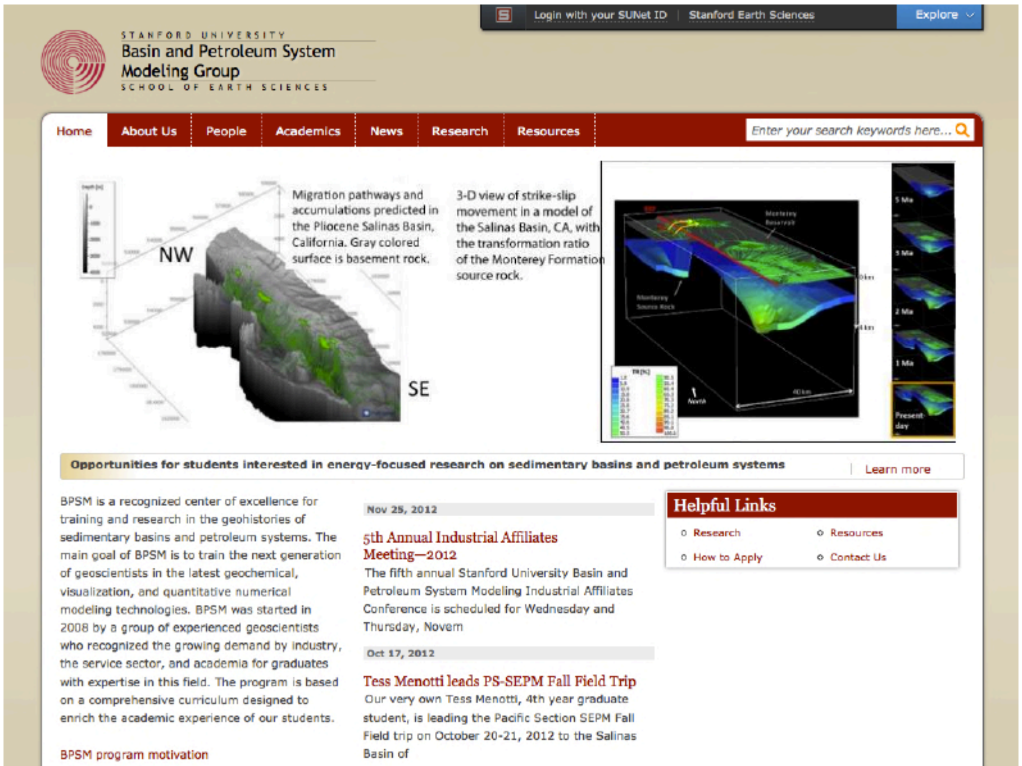
should be returned to us in the provided envelope. This will only be opened in the event of an emergency and will be shredded following the field trip.

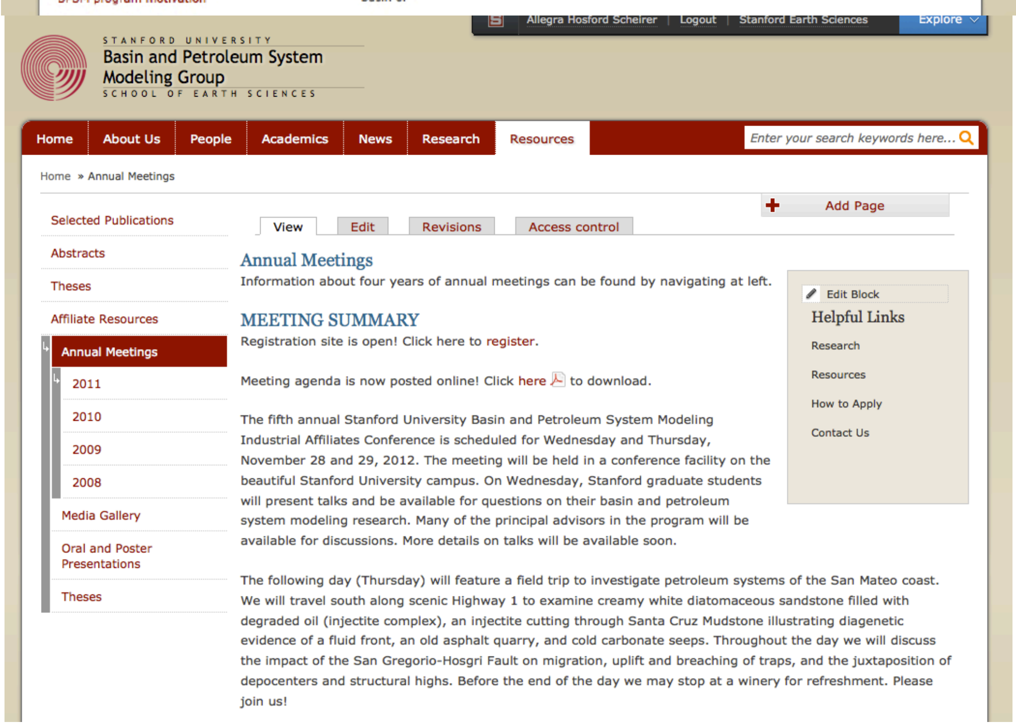


The oral session for the meeting will be held in Cypress North and South conference room on the second floor of Tresidder Union.

2012 Meeting Abstracts

(Have you visited our website lately?)





ROLE OF SILICA DIAGENESIS AND STRUCTURAL DEFORMATION IN BASIN AND PETROLEUM SYSTEM MODELS OF THE SALINAS BASIN, CENTRAL CALIFORNIA

Tess Menotti and Stephan Graham
Department of Geological and Environmental Sciences, Stanford University

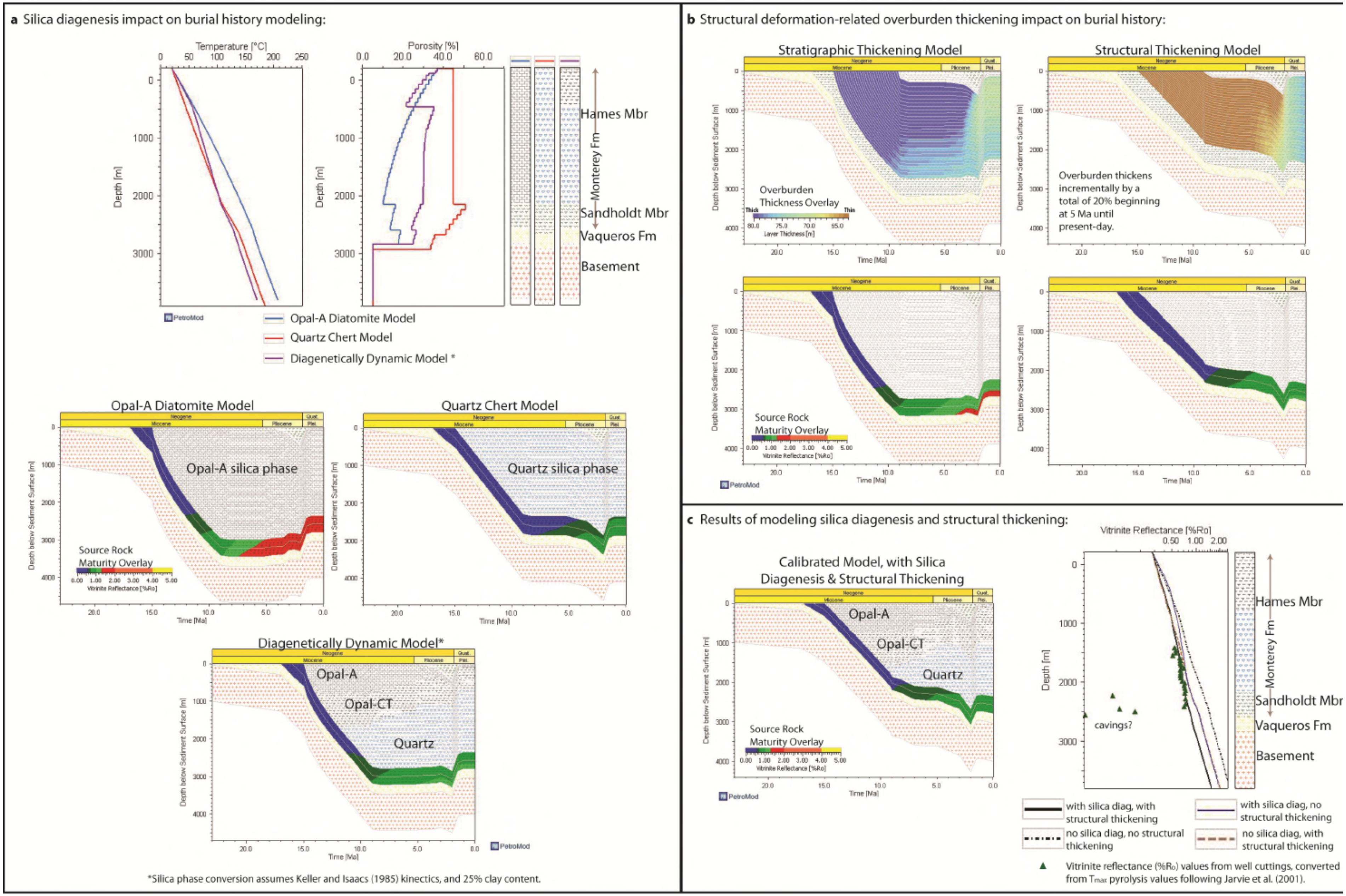
We present one-dimensional (1-D) and three-dimensional (3-D) basin and petroleum system models that demonstrate the role of basin deformation and diagenesis in assessing burial history, source rock maturation and hydrocarbon migration. Analysis of the Salinas Basin petroleum system requires the incorporation of three complexities that, while often excluded from basin models, are key aspects of the basin's history: silica diagenesis of overburden, overburden thickening as a result of deformation, and strike-slip faulting. The Salinas Basin is a strike-slip basin in the Coast Ranges of Central California. Its sedimentary basin fill comprises primarily marine deposits that accumulated in an elongate, northwest-southeast oriented basin of bathyal water depths that abruptly sloped upward to a shelfal setting on the eastern basin margin. Transform-related tectonism controlled the rapid subsidence that created accommodation for deposition of the Monterey Formation during the middle and late Miocene. Tectonic uplift of the basin during the Pliocene into the Quaternary led to the progressive transition from deep marine to shallow marine, then non-marine depositional settings, however these younger deposits are dwarfed in thickness by the Miocene Monterey Formation. The Monterey Formation is composed of two main members: the Sandholdt Member is a calcareous, organic-rich shale, and constitutes the source rock; the Hames Member comprises primarily siliceous deposits that originated as diatomite, and have been diagenetically altered to either porcelanite or chert. The Monterey Formation blankets nearly the entire Salinas Basin, including the bathyal and shelfal zones. While the calcareous and siliceous deposits of the Monterey Formation are nominally devoid of coarse-clastic deposits in the basinal settings, stacked shoreface sandstones with interbedded fine-grained units are present within the basal Monterey Formation along the eastern edge of the basin. Oil accumulations occur in the shelf sandstones, and have been produced as seven oil fields, the largest being the ~half-billion barrel San Ardo oil field. Thus, the Monterey Formation serves as not only source rock, but also as reservoir rock, seal, and overburden for the petroleum system.

Two factors support our motivation for including silica diagenesis in burial history modeling of the Salinas Basin: 1) the Monterey Formation is dominated by diatomaceous sediments, and 2) the siliceous Hames Member is over 3 km thick in some places, and comprises between 20 and 100% of the overburden rock. Silica diagenesis refers to the series of dissolution-reprecipitation reactions of the least stable (opal-A) phase of silica in diatoms to opal-CT (cristobalite-tridymite), and finally to microcrystalline quartz. These reactions occur with time and burial, and are mainly a function of temperature, but are also controlled by clay mineral content, kinetics, silica solubility, porewater chemistry and permeability. With such thick sections of siliceous deposits, these transformations become important to burial history modeling because each silica phase has different thermal and mechanical properties than the others. Thus, with burial, the Monterey Formation has the potential to change porosity and thermal profiles as silica diagenesis ensues (**Figure 1a**). PetroMod® 1-D models demonstrate the impact that variable silica phases of the Monterey Formation have on geothermal gradients, porosity trends, burial history, and source rock maturation timing and magnitude. These models indicate source rock maturation occurs sooner in an opal-A phase model than a quartz phase model. A diagenetically dynamic model (i.e., incorporates silica diagenesis following Keller and Isaacs (1985) kinetics, and assumes 25% clay content) simulates an intermediate source rock maturation history that falls between the two end-member models. Additionally, present-day opal-A/opal-CT and opal-CT/quartz boundaries provide constraints on burial depth, acknowledging assumptions in all other factors controlling silica diagenesis in addition to temperature.

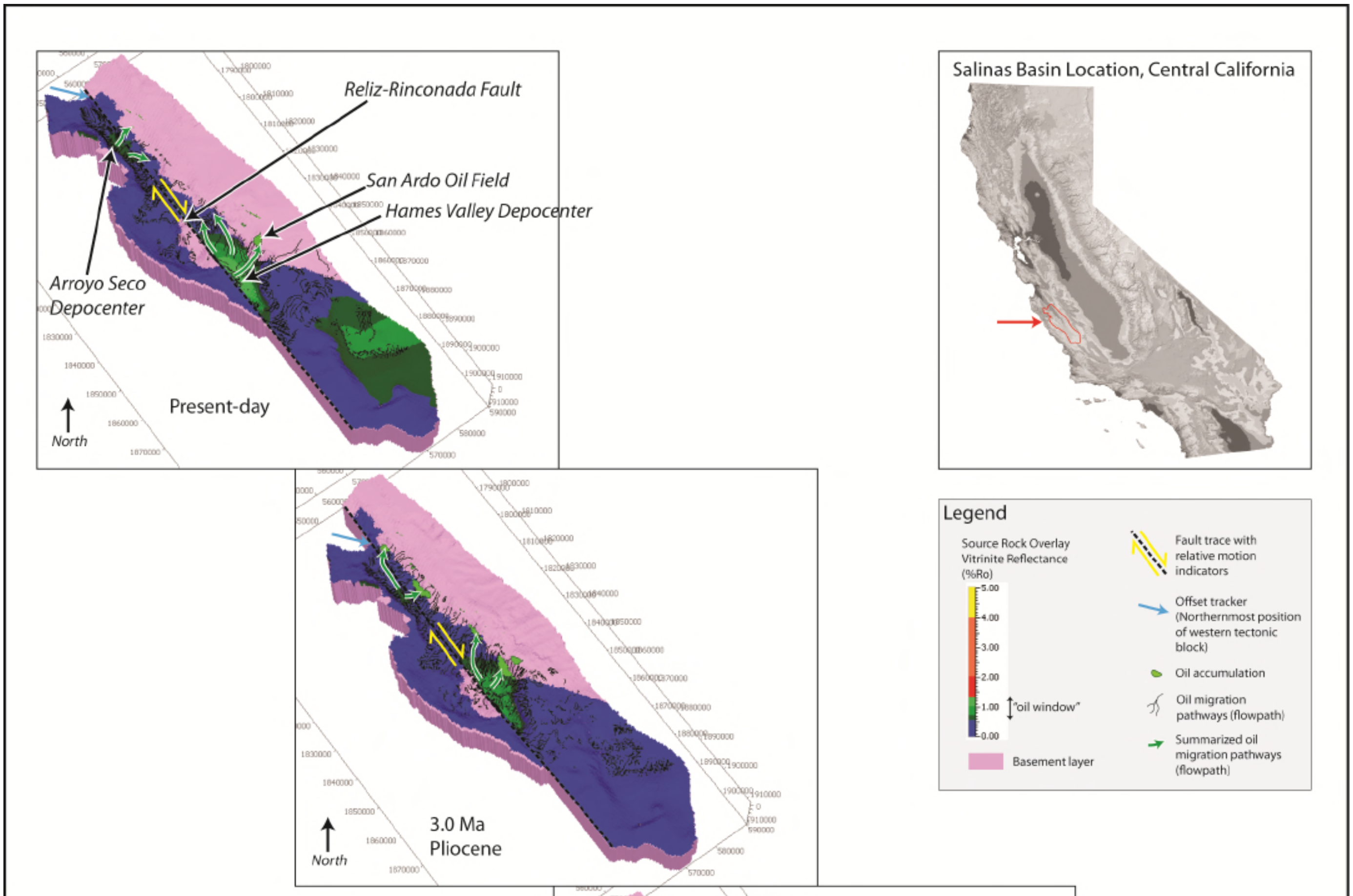
In addition to silica diagenesis, post-depositional deformation of the Monterey Formation in the form of small-scale (10^1 m scale), local folding complicates burial history modeling because folding increases effective overburden thickness. This can occur millions of years after the relatively thin deposited section formed, thereby delaying emplacement of overburden rock. Tight isoclinal folds and steep (>40°) bedding dips in the siliceous Monterey Formation are present in outcrop and in the subsurface of the Salinas Basin, and are the consequence of early Pliocene through Recent transpression. One-dimensional PetroMod® models highlight the impact of assuming that present-day overburden thickness reflects depositional thickness (post-compaction), as opposed to assuming that structural folding of a thinner deposited section produced the present-day vertical thickness (**Figure 1b**). The model that assumes structural thickening (beginning 5 Ma) yields lower source rock maturation levels and later entry into the oil window than the model that assumes stratigraphic thickening only. Combining silica diagenesis and structural thickening yields a present-day vitrinite reflectance (R_o) depth profile that calibrates with T_{max}-derived R_o values (following Jarvie et al. (2001); **Figure 1c**) of well cuttings from a ~3 km deep well in the pod of active source rock. This calibrated model suggests the source rock entered the oil window in the late Miocene, and is presently at ~0.7-0.8% R_o thermal maturation levels.

The transpressional deformation that is responsible for structurally thickening the Monterey Formation overburden is also manifested in the northwest-southeast striking Reliz-Rinconada strike-slip fault. Dextral motion along the fault has offset the pod of active source rock, placing the Arroyo Seco depocenter ~40 km to the northwest of the Hames Valley depocenter (**Figure 2**). The dynamic basin geometry during the Neogene through Quaternary periods necessitates a three-dimensional approach to modeling the petroleum system. The Reliz-Rinconada fault introduces the following complications to be considered in analysis of the Salinas Basin petroleum system: 1) the fault zone can act as a migration pathway, if cataclastic brecciation improved permeability within the zone; 2) the fault zone can be a barrier or baffle to migration if fault gouge reduced permeability; 3) offset of the pod of active source rock potentially juxtaposes source rock beside permeable carrier beds; and 4) offset of the pod of active source rock also changes the entire basin geometry, creating the potential for closer proximity of potential traps to generative source rock. We use PetroMod 3-D TecLink® software to simulate basin shape evolution as the western side of the basin is displaced northwestward with respect to its eastern counterpart. Constraints on fault displacement timing are based on piercing points including offset basement features and stratigraphic contacts. Mapped stratigraphic horizons are primarily based on well log and outcrop data. Three-dimensional TecLink® models demonstrate source rock maturation in and hydrocarbon migration from both pods of active source rock whilst the basement trough containing active source rock is progressively offset beginning in the late Miocene until present day (**Figure 2**).

Figure 1 - *Next page.* **a)** Synthetic 1-D models based on a ~3 km deep well in the basin depocenter test the impact of overburden silica phase on thermal and compaction profiles, burial history, and source rock maturation. **b)** Similar synthetic models also test the role of delayed overburden thickening on source rock maturation. Thickening by ~20% simulates structural folding of the overburden as a result of regional transpression, and occurs between 5 Ma and present-day. **c)** Combining silica diagenesis and structural thickening into burial history modeling of the ~3 km deep well yields simulated maturity results that calibrate better than models that exclude these burial history complications.



a Silica diagenesis impact on burial history modeling:
Temperature [°C]
Porosity [%]
Depth [m]
Hames Mbr
Monterey Fm
Sandholdt Mbr
Vaqueros Fm
Basement
Opal-A Diatomite Model
Quartz Chert Model
Diagenetically Dynamic Model *
Opal-A silica phase
Quartz silica phase
Source Rock
Maturity Overlay
Vitrinite Reflectance [%Ro]
Depth below Sediment Surface [m]
Time [Ma]
Opal-A
Opal-CT
Quartz
*Silica phase conversion assumes Keller and Isaacs (1985) kinetics, and 25% clay content.
b Structural deformation-related overburden thickening impact on burial history:
Stratigraphic Thickening Model
Structural Thickening Model
Overburden
Thickness Overlay
Layer Thickness [m]
Overburden thickens
incrementally by a
total of 20% beginning
at 5 Ma until
present-day.
c Results of modeling silica diagenesis and structural thickening:
Calibrated Model, with Silica
Diagenesis & Structural Thickening
Vitrinite Reflectance [%Ro]
cavings?
with silica diag, with
structural thickening
with silica diag, no
structural thickening
no silica diag, no structural
thickening
no silica diag, with
structural thickening
Vitrinite reflectance (%Ro) values from well cuttings, converted
from Tmax pyrolysis values following Jarvie et al. (2001).
PetroMod



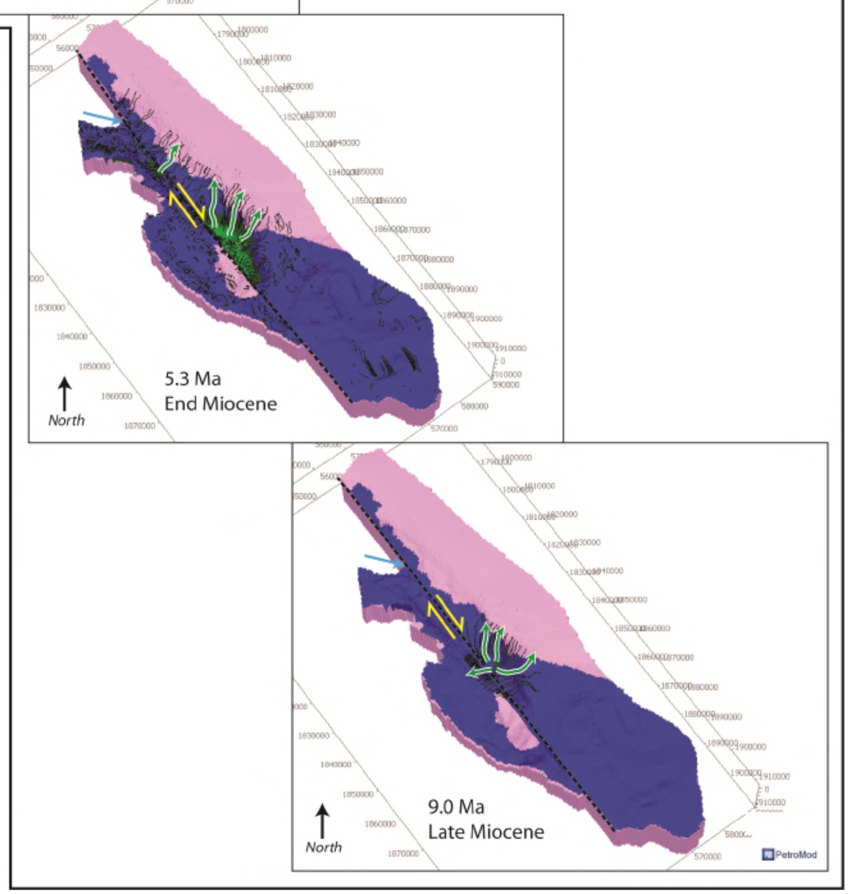


Figure 2 - Three-dimensional basin models integrate strike-slip faulting and resulting right-slip offset of the hydrocarbon charge area from the late Miocene to present-day (blue arrows at each time-step highlight northern-most position of the western tectonic block). Models highlight source rock lateral extent and maturation through time (blue and shades of green, *see* Vitrinite Reflectance (%R_o) legend). Note that both Hames Valley and Arroyo Seco source rock depocenters are within the oil window beginning at the end of the Miocene. Flowpath migration pathways (thin black lines) indicate hydrocarbon migration from both pods of active source rock. Oil accumulations form east of the pods of active source rock, similar to the spatial distribution of known oil fields in the basin, including the San Ardo oil field.

EVALUATION OF POSSIBLE SOURCE ROCKS IN NORTHERN NYE COUNTY, NEVADA: IMPLICATIONS FOR HYDROCARBON EXPLORATION

Inessa Yurchenko[1] and Andrew Hanson[2]
[1]*Department of Geological and Environmental Sciences, Stanford University*
[2]*Department of Geoscience, University of Nevada, Las Vegas*

There are 15 producing oil fields in the valleys of the Basin and Range Province, Nevada, with 90% of production coming from Railroad Valley in northern Nye County. The presence of oil outside of Railroad Valley has sparked the interest of exploration companies in Nevada. To understand the distribution of oil, a complete petroleum system analysis is required. Previous studies confirmed that the Mississippian Chainman Shale and Cretaceous to Paleocene Sheep Pass Formation, Member B are source rocks. However, a number of other source rocks are possible in northern Nye County, but they are not confirmed because of incomplete datasets. The goal of this project is to determine if effective source rocks other than the Chainman Shale and Sheep Pass Formation exist in northern Nye County. I obtained samples from outcrops and used organic geochemistry to test the hypothesis that different strata, including Paleozoic Vinini, Pogonip, Woodruff, Guilmette Formations, Pilot Shale, Ely Limestone, and Cretaceous Newark Canyon Formation have the necessary qualities to be petroleum source rocks.

This evaluation revealed source rock potential for Woodruff Formation, but none of the other analyzed candidate units met the requirements for organic matter quantity, quality, and thermal maturity in order to be called source rocks. The Devonian Woodruff Formation displayed excellent organic matter quantity and oil-prone kerogen type, however samples appeared to be thermally immature. Additional oil – source rock correlation suggested genetic relationship between the Woodruff Formation and Chainman-derived oils from Railroad Valley. This knowledge will help to estimate the petroleum potential of northern Nye County for future exploration and development in Nevada.

Fish Creek Range, northern Nye County, Nevada

PETROLEUM SYSTEM DEVELOPMENT IN A FOREARC BASIN: IMPORTANCE OF STRUCTURAL HISTORY INTEGRATION ON 1-D AND 2-D BASIN AND PETROLEUM SYSTEM MODELS IN HAWKE BAY, NORTH ISLAND, NEW ZEALAND

Blair Burgreen, Stephan Graham, and Kris Meisling
Department of Geological and Environmental Sciences, Stanford University

The East Coast Basin of North Island, New Zealand, is a forearc basin that which in early Miocene time in response to southward propagation of the Tonga-Kermadec-Hikurangi trench. Basin stratigraphy can be subdivided into 1) an inboard highly-overpressured Cretaceous to Oligocene sequence representing passive margin sediments deposited upon an earlier convergent margin, 2) an outboard accretionary sequence derived from the subducting Hikurangi Plateau, and 3) an overlapping, variably overpressured Miocene to Recent sedimentary sequence comprising the forearc and slope basin fill. In Hawke Bay, the basin experienced compressional, extensional, and inversion tectonic regimes in Neogene time as revealed on seismic data by normal fault growth geometry, followed by basin inversion on reactivated listric fault planes, resulting in angular unconformities associated with uplift. This created a variable burial history across the 2-D profile.

Numerous gas and oil shows in the East Coast Basin prove the existence of at least one active petroleum system, but the region remains a frontier basin for petroleum exploration. To assess the prospectivity for hydrocarbon source rock intervals, 2-D basin and petroleum system modeling was conducted across Hawke Bay. Heat flow was based on thermal modeling calculated along the Hikurangi subduction margin and calibrated with vitrinite reflectance data, vitrinite-inertinite reflectance and fluorescence data, bottom hole temperatures, and apatite fission track analyses. Preliminary results indicate prospective source rock layers have likely been buried to depths within the oil window. However, further integration of structural features will better constrain burial histories.

One-dimensional modeling was utilized to test the impact of thrust duplexing during the early Miocene and possible uplift and erosion scenarios. Results reveal duplexing would significantly increase generation of source rock in the footwall block. Future work aims to utilize the 2-D palinspastic reconstructions in basin and petroleum system modeling to test high and low shortening scenarios on generation. These results will also provide a basis as to whether oil and gas seeps onshore can be attributed to the commonly cited source rocks—the Waipawa Black Shale and the Whangai Formation, or must be generated from a deeper undiscovered source rock as suggested by previous workers.

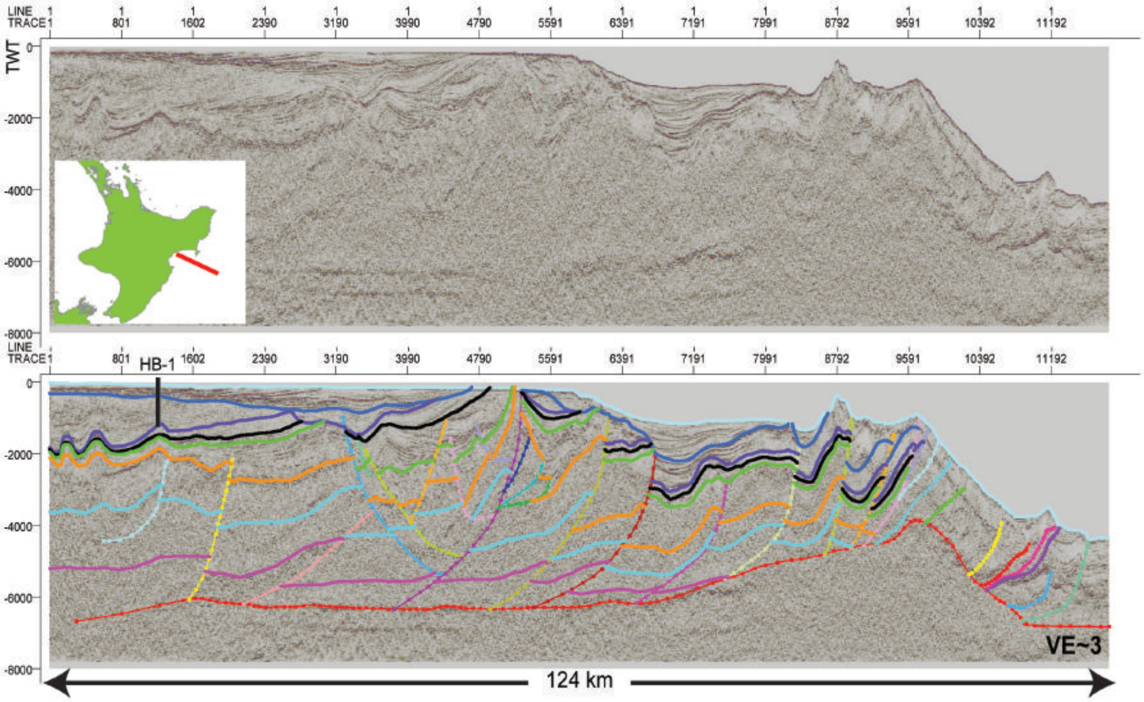


Figure 1. Uninterpreted and interpreted regional seimic line CM05-01 through the Hawke Bay subduction wedge of the East Coast Basin, New Zealand. The red line at the base represents the basal decollemont related to the subduction of the Pacifc plate beneath the Indo-Australian plate. Both reverse and normal faulting are present with numerous faults becoming reactivated and changing slip direction through time. Interpreted structural history is largely based on knowledge of the local tectonic history where other constraints are unavailable. The purpose of this study is to assess the importance of the structural model on petroleum prospectivity, and this interpretation is used as a basis for palinspastical structural reconstruction followed by basin and petroleum system modeling.

BASIN AND PETROLEUM SYSTEM MODELING FOR PICEANCE BASIN, COLORADO, AND UNCERTAINTY QUANTIFICATION

Yao Tong[1], Allegra Hosford Scheirer[2], Tapan Mukerji[1], Paul Weimer[3], and Steve Cumella[4], Ken Peters[5]

[1]*Department of Energy Resources Engineering, Stanford University*

[2]*Department of Geological and Environmental Sciences, Stanford University*

[3]*Department of Geological Sciences, University of Colorado*

[4]*Endeavour International Corporation*

[5]*Schlumberger and Department of Geological and Environmental Sciences, Stanford University*

Gas shale and tight gas represent an enormous potential among unconventional resources. Our study area—Piceance Basin, Colorado—contains tremendous gas reserves in place, especially the Basin-Centered Gas Accumulations (BCGA), which account for more than half of the known gas fields in the basin. However, the generation, migration, and accumulation mechanisms of the BCGA are not well understood. The primary goal of this study is to better understand the BCGA for the Piceance Basin. We will answer these questions through construction and analysis of 1-D and 3-D numerical basin and petroleum system models. Those models will not only enhance our understanding of basin-wide gas generation but also offer a way of reducing exploration risks via advanced uncertainty quantification methods.

Although a recent USGS assessment identified several petroleum systems in the Piceance Basin, for our initial modeling effort we focus on the Cretaceous Cameo Coal, a lower member of the Williams Fork Formation. We constructed a 1-D model at the location of the Mobil Oil T-52-19-G well, located in the structural trough of the Piceance Basin where the Cameo Coal is deeply buried. Stratigraphic depths and erosion episodes derive from the USGS study. Other key model inputs include: the kinetic model of Pepper and Corvi (1995) D/E Type III; Total Organic Carbon of 50%; Hydrogen Index of 150 mgHC/gTOC; and constant heat flow of 60 MW/m^2. With these model inputs, we were able to achieve consistency between calculated vitrinite reflectance and previously published experimental results ('+', Figure 2). Simulation results indicate that the Cameo Coal started to generate gas about 48 Ma and continued until about 10 Ma, when a major episode of uplift began.

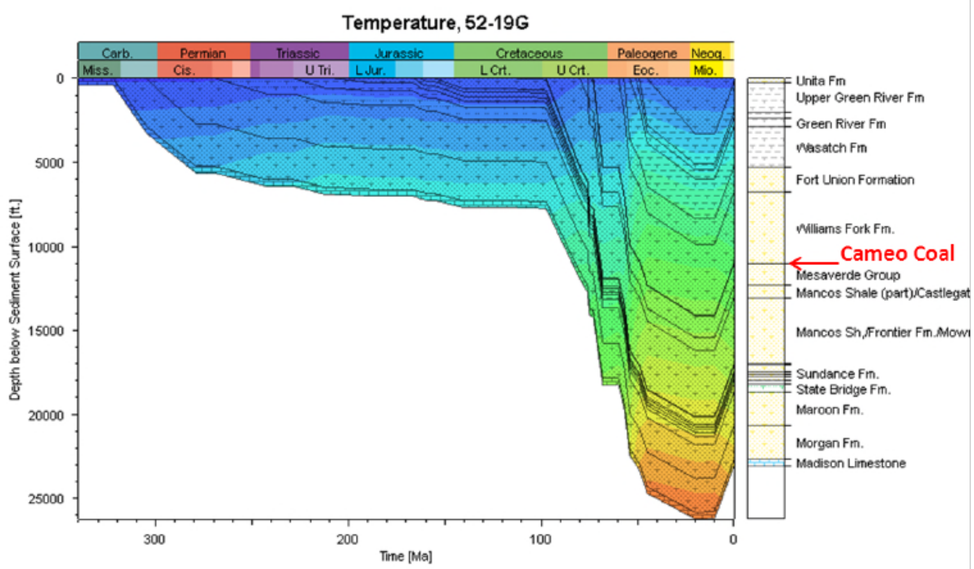


Figure 1: Reconstruction of the burial history and temperature evolution for Mobil Oil 52-19-G, located in the structural trough of the Piceance Basin

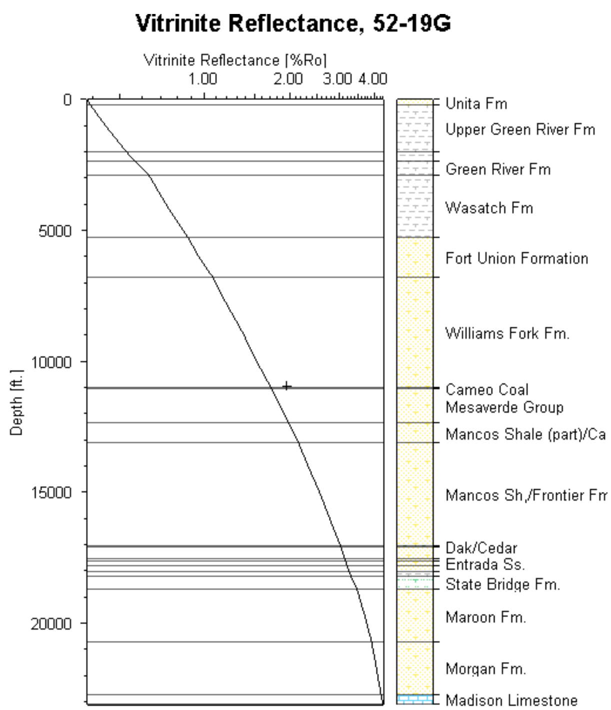


Fig.2 Depth profile shows the Vitrinite Reflectance at Mobil Oil T-52-19-G Well

Starting from this, we plan to build a 3-D basin and petroleum system model to capture basin evolution processes over its full volume. To achieve this, we obtained regional maps in two-way travel time for the tops of six key horizons. These are the basement surface, the Mississippian Leadville Limestone, the Pennsylvanian Maroon Formation, the Cretaceous Dakota Sandstone, the

Cameo Coal, and the Upper Cretaceous Mesaverde Formation. We performed an initial conversion to depth using an average of time-depth relationships in five wells located throughout the basin. We plan to follow up with a more robust time-to-depth conversion, followed by the construction of intervening surfaces from an extensive well-top database.

The following aspects will be better assessed in a 3-D model:

1. Hydrocarbon migration, accumulation, and loss
2. Predicted temperatures will be more accurate, especially because the heat flow is quite variable in the Piceance Basin through time
3. Maturation calculations
4. Pressure calculations - can be performed using 1-D, but information is limited when considering the lateral component of fluid movement in sediments.
5. Hydrocarbon generation timing, location, and type, as well as expulsion can be calculated in 1-D, but the same limitations apply with respect to the thermal and maturation histories.

Another important goal of our study is to address various uncertainty factors. Because basin and petroleum system modeling covers large spatial and temporal intervals, many of the input parameters are highly uncertain: from the micro-scale kinetic model to the macro-scale basin-wide structure map, we tend to use one single deterministic model. However, we would like to expand our insights by exploring the following questions:

a. What are the impacts of uncertainties in the input data on the model?
b. What is the probability of extreme scenarios?
c. How sensitive are the relations between parameter variations and the resulting output variation?
d. What are the impacts of spatial uncertainties in lithologies and rock properties on the model?
e.

We plan to use the global sensitivity analysis technique recently developed by SCRF (Stanford Center for Reservoir Forecasting) to address the above questions.

EFFECTS OF OPAL-CT PHASE TRANSITION RATES ON TRANSITION DEPTH IN SAN JOAQUIN BASIN MODELS

Danica Dralus[1], Ken Peters[2], Oliver Schenk[3]
[1]*Department of Geophysics, Stanford University*
[2]*Schlumberger and Department of Geological and Environmental Sciences, Stanford University*
[2]*Schlumberger (Aachen Technology Center)*

One strength of a basin and petroleum system model is that, unlike a reservoir model, it accounts for not only the basin's current structure but also its past structure and its evolution through geologic time. These changes can be mechanical or chemical in origin. For example, mechanical compaction of sediment causes porosity reduction, whereas the chemistry of hydrocarbon generation causes saturation and pore pressure changes.

In basins containing siliceous facies, amorphous opal-A undergoes a phase transformation to microcrystalline opal-CT, which in turn transforms to crystalline quartz. These mineralogical changes are accompanied by structural changes in porosity and permeability, which affect migration and trapping of fluids. Moreover, these changes often lead to the formation of a diagenetic trap where no structural trap exists. The rate and timing of the phase transformations is therefore important to consider when modeling the evolution of a basin with siliceous deposits.

This study compares different phase transformation descriptors by looking at their ability to accurately predict the transition depth from opal-CT to quartz in known oil fields. Full basin models were run in PetroMod along a seismic section in the southern San Joaquin Basin, California, and compared to the transition depth in the nearby Rose and North Shafter oil fields. The phase change was predicted by the chemical kinetics determined experimentally by Ernst and Calvert (1969) and again by Dralus et al. (*in prep*), and then by the basin-specific nomograph based on detrital content developed by Keller and Isaacs (1985).

Results show the known opal-CT to quartz transition depth in the Monterey Formation of the southern San Joaquin Basin is best predicted by the Keller and Isaacs nomograph. The Ernst and Calvert kinetics underestimate the transition depth by approximately 2000 feet. The Dralus et al. kinetics improve on the Ernst and Calvert prediction by roughly 300 feet.

The discrepancy between predicted transition depths from the regional nomograph and from laboratory kinetics data suggests there is a yet unknown factor retarding the opal-CT conversion *in situ*. Keller and Isaacs correlate this with clay content, though whether that correlation is causal or coincidental is unclear. Until the retarding mechanism is identified and properly characterized, the Keller and Isaacs nomograph remains the best predictor of silica transition depths in the San Joaquin Basin. However, it cannot be expected to be an accurate predictor in basins with different mineralogy or burial histories.

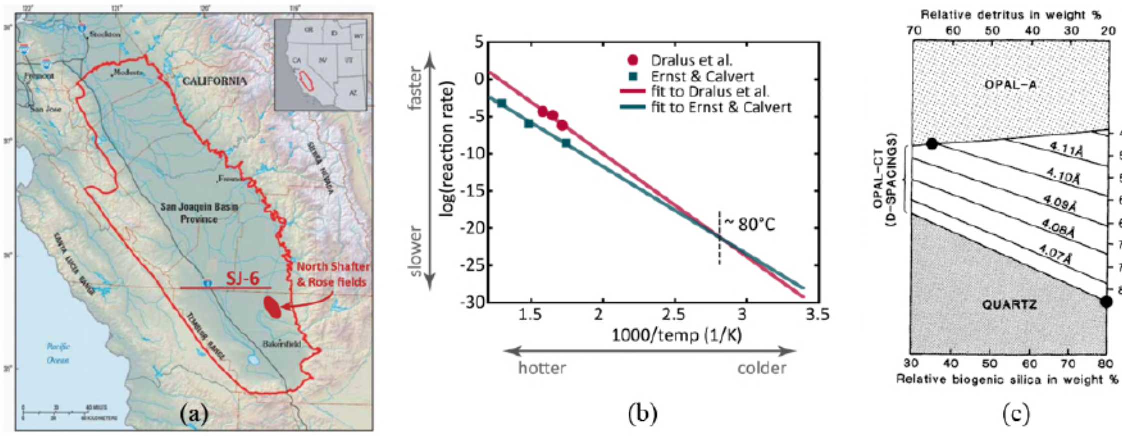


Figure 1: (a) Locations of the SJ-6 seismic line and the North Shafter and Rose oil fields used for comparison to the models. (b) Laboratory results determining the kinetic parameters used to describe the opal-CT to quartz phase transition for the Dralus et al. (2011) and Ernst and Calvert (1969) experiments. (c) Nomograph from Keller and Isaacs (1985) for determining the phase transition temperatures for silica in the San Joaquin Basin.

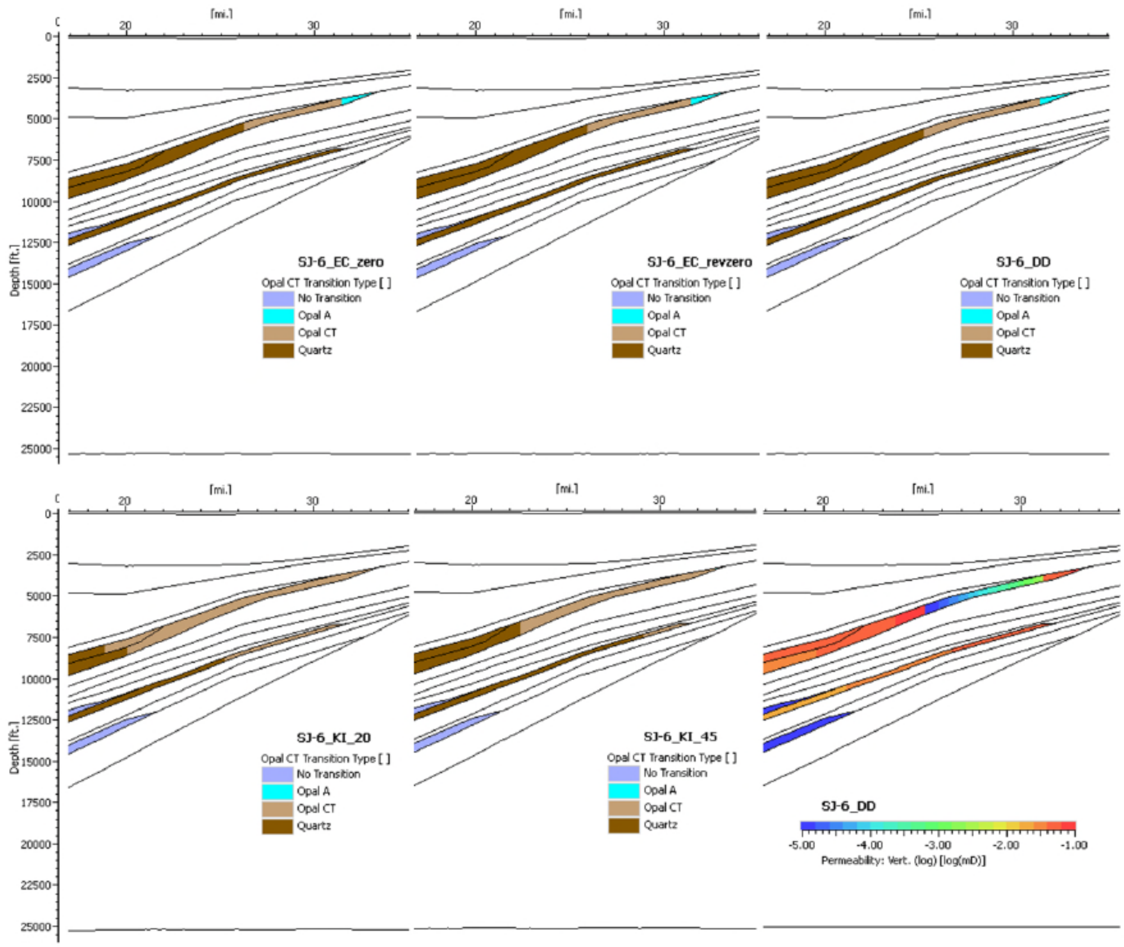


Figure 2: Modeling results depicting the phase transition depths for the five scenarios discussed in the text. Top row, left to right: transition depths for Ernst and Calvert (1969) kinetics, revised Ernst and Calvert kinetics, and Dralus et al. (*in prep*) kinetics. Bottom row, left to right: transition depths for Keller and Isaacs (1985) nomograph with 20% clay, and for Keller and Isaacs nomograph with 45% clay; and a representative permeability trend spanning the phase transitions.

BENCHMARK BASIN AND PETROLEUM SYSTEM MODEL

Amrita Sen[1], Tapan Mukerji[2], Allegra Hosford Scheirer[3]
[1]*Department of Geophysics, Stanford University*
[2]*Department of Energy Resources Engineering, Stanford University*
[3]*Department of Geological and Environmental Sciences, Stanford University*

The BPSM Industrial Affiliates Program incorporates scientists across the School of Earth Sciences. Accordingly, we approach basin and petroleum system models from a variety of perspectives. To complement both the laboratory-based (experimental) approaches to basin modeling and the observational approach in which sedimentary basins and their contained petroleum are investigated in 1-D, 2-D, or 3-D, we created a benchmark basin and petroleum system model, also sometimes called a "synthetic" model. The basis for the benchmark model is a set of 24 layers corresponding to actual rock formations from a Cenozoic sedimentary basin. Of the 24 model layers, one is a shale source rock, five are reservoir rocks, and the rest act as overburden rocks, underburden rocks, or seal rocks. To generalize the model, we extracted a rectangular model volume approximately 180 by 100 km in size. Currently, the benchmark model has a grid spacing of 500 m in each of the three coordinate directions, but can be upscaled or downscaled as needed.

The benchmark basin model can be used by the BPSM research group in several ways. First, it can be used as a teaching tool. Professors can prepare labs using the benchmark basin model as a "perfect" data set. Second, it can be used to test the effectiveness and ease of using parameters other than vitrinite reflectance and Tmax for model calibration. Third, it can be used for both scenario testing and workflow testing so that schemes can be developed in a perfect situation before application to the real world environment. Fourth, we can introduce the concept of stochastic descriptions of layer properties, rather than the more typical deterministic ones. Finally, we can intersect the field of rock physics with basin and petroleum system modeling in ways that have not yet been accomplished.

To that end, we would like to start by creating a corresponding seismic volume to go with the benchmark basin model and compare this with a version of the model that includes spatial distributions of porosity for the reservoir layers of interest. After simulation, we obtain velocity and density volumes for the model. Based on these, we can obtain a near and far stack seismic volume. The benchmark basin and petroleum system model provides us both with a base case, as well as an experimental environment in which we can explore the influence of key inputs for modeling.

INTEGRATION OF BASIN AND PETROLEUM SYSTEM MODELING WITH SEISMIC TECHNOLOGY TO PREDICT PORE PRESSURE

Wisam H. AlKawai
Department of Geological and Environmental Sciences, Stanford University

Basin and Petroleum System Modeling (BPSM) has grown as an important key technology in hydrocarbon exploration. It has been a common practice of BPSM to build a model that describes the deposition and erosion history and simulates the history of thermal maturity, hydrocarbon generation, migration, and accumulation. BPSM results in numerous outputs, including pore pressure. Integrating BPSM pore pressure output with seismic methods can yield results toward more robust predictions.

One interesting avenue we may pursue is calibrating predicted pore pressure from BPSM simulation results with seismic cubes of pore pressure prediction. It has been a common practice in BPSM to calibrate the outputs with available data at well locations, which is limited to the location of the well. On the other hand, calibrating a BPSM output for pore pressure with seismic data will be valid over the volume of the seismic cube.

Another interesting area that can be is the fidelity of the traditional practice of predicting pore pressure from seismic data using velocity compaction transforms or correlating the velocity to pore pressure directly. It has been argued that the fidelity of this method is mostly limited to cases where the compaction of sediments purely corresponds to the effective stress, not to other overpressuring mechanisms such as diagenetic processes in clay minerals and fluid expansion associated with hydrocarbon maturation. Basin models can be used to examine the impact of these processes on pore pressure and that will help in choosing a more robust transformation to correlate seismic velocities with pore pressure. These two approaches of integrating seismic methods with BPSM in pore pressure prediction can then yield superior results because they enhance the seismic prediction, making it more robust, and they enhance the basin models as well by calibrating them with pore pressure predictions from seismic data.

BUILDING BAYESIAN NETWORKS FROM BASIN MODELING SCENARIOS FOR IMPROVED GEOLOGICAL DECISION MAKING

Gabriele Martinelli[1], Sara Tviberg[1], Jo Eidsvik[1], Richard Sinding-Larsen[1], Tapan Mukerji[2]
[1]*NTNU, Trondheim, Norway*
[2]*Department of Energy Resources Engineering, Stanford University*

Integration of geological and geophysical information within a decisional framework for the purpose of oil and gas exploration is a challenge that will increase in importance with increasing cost and exploration difficulties of new targets. Currently it is common practice among geologists to quantify information about risk through detailed exploration analysis, and then forward these results to the decision analysts. In the transition towards the decision makers the information is processed and quantified for risk assessment and multiple-scenario evaluation. A type of probabilistic model often used in decision analysis is Bayesian Networks (BN). In this work we propose a possible framework for integrating directly basin modeling scenarios and decision strategies using Bayesian Networks. In moving from the Earth model to the decision space, the geological and geophysical know-how is first translated into basin and petroleum system modeling (BPSM). Outputs from multiple runs of basin modeling under different geologic scenarios are then used to establish a Bayesian network that models petroleum system element dependencies. The Bayesian network is then used to test decisions. In the current framework, a sensitivity analysis is carried out, and a database with multiple runs (corresponding to different geologic scenarios) is built. The database is the starting point for the value assessment part that provides the basis for efficient decisions. The main idea is to train the probabilistic structure of the BN from the multiple basin modeling outputs. When this BN model is established, it integrates the geological processes and their response with risk assessment. Assigning expected revenues to segments, the production strategy and other required economic variables can now easily be communicated. The BN model provides explicit probability statements, at single-segments and for prospects. In the paper, we will illustrate useful decision-making applications via the evaluation of what-if scenarios and analysis of value of information from the Bayesian Network trained through multiple BPSM computational runs.

THEORETICAL ASPECTS OF PETROLEUM SYSTEM MODELING FOR UNCONVENTIONAL RESOURCES

Ken Peters[1,2]
[1]*Schlumberger Information Solutions*
[2]*Department of Geological and Environmental Sciences, Stanford University*

Integrated geochemistry, geomechanics, and three-dimensional (3-D) petroleum system modeling is key to successful exploitation of unconventional resources. Three main factors influence the successful exploitation of unconventional plays: 1) Understand the geology, geochemistry, and technology (e.g., vertical heterogeneity, microseismic events defining extent of fractures, stable carbon isotopic "rollover"); 2) understand special functions for shale oil and gas modeling (e.g., Langmuir adsorption, organic porosity modeling, and geomechanics, including stress regime and history); and 3) leverage 3-D models to identify suitable exploitation technologies (e.g., aim for areas showing high stress).

Shales vary both within and between plays. These variations impact reservoir quality and geomechanical properties, which control our ability to effectively stimulate the rock. 'Sweet spots' within the shale must be porous (e.g., >4%) and permeable (e.g., >400 nD). Their distribution can be established using relationships between rock type and log response and by relating log response to seismic data in order to interpolate between wells and characterize porosity, permeability, and gas-in-place. This information can be used to steer horizontal wells, e.g., through brittle carbonate while avoiding ductile clay. Rock stress and reservoir quality impact the productivity of horizontal wells and can be integrated into models to identify sweet spots. Combining maps of good reservoir quality with maps of favorable geomechanical properties improves prediction of sweet spots. Incorporating these interpretations into 3-D models helps to define the distribution of the best reservoir and where the rock properties are most likely to facilitate successful stimulation of horizontal wells.