Hydrocarbon generation, migration, and venting in a portion of the offshore Louisiana Gulf of Mexico basin

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The offshore Louisiana Gulf of Mexico is one of the earth's most active margins. The erosional debris of an entire continent is depositing there, in places at over 2 km/Ma. Sediments have accumulated to over 16 km thickness. Temperatures at the base of this section are hotter than those in a pizza oven (~300° C). Hydrocarbons are maturing, brines expelling, reservoirs filling, hydrates accumulating, and gas and oil migrating into the ocean, and all this is happening today.

We have known for some time how to model hydrocarbon maturation and to some extent migration. We don't know precisely the richness or thickness of the source beds, but we can geochemically constrain their age and place reasonable bounds on their volume. Perhaps our largest uncertainty for a long time has been the retention of gas and oil between the source strata and the surface.

Fortuitously, we have been able to address this question in the offshore Louisiana basin because two very different hydrocarbon sources (which we characterize here as Eocene and Jurassic, although the reality may be more complex) exist there in the right positions. The requirement from chemical data that Eocene displace Jurassic oil, and in turn be washed by Jurassic gas means that the out-of-source retention of hydrocarbons must be very small (<0.025% of the pore space).

This means that the active portions of the Northern Gulf of Mexico basin are acting like a giant flow-through system. As soon as oil or gas is generated, most is expelled into the Gulf waters. Only crumbs are retained in the basin (outside of the source). These crumbs are still of great economic value. What's happening today (or in geologically very recent times) is what is important. As stated eloquently by Gatenby (2002), "in the Gulf of Mexico, the present is the key to the present."

This article presents the outlines of the geologic/geophysical/geochemical argument for these statements, as well as some interesting side details. The flow-through system perspective may surprise few in our profession, but it is a view that astounds many just outside of it. It has many implications for exploration and environmental matters, upon which I comment briefly in closing.

The study area. The work reported here was funded over many years by the Gas Research Institute with grants to Cornell and subcontracts to Woods Hole. To test a capillary seal hypothesis we collected geologic, geophysical, and geochemical data in an area we felt would be large enough to capture the processes active in the basin. The 120 km E-W × 200 km N-S study area we selected is shown in Figure 1. This broad net caught unexpected things.

Gas washing. The first process that caught our attention was one we call gas washing. Kissen showed that unaltered oils have n-alkane abundances that decrease exponentially from methane to higher carbon number molecules (ethane, propane, decane, etc.). Keith Thompson and others have used this unaltered reference to identify the effects of phase fractionation and other kinds of oil alteration. In his Cornell PhD research, Peter Meulbroek found a such a significant departure in some of the oils at South Eugene Island Block 330 (see Figure 1), and realized that about 15 wt% of the n-alkanes had been removed. Through equation of state modeling he showed that such major alteration could not be accomplished by phase fractionation, but was probably the result of gas washing—a process in which many aliquots of dry gas interact with the oil and preferentially carry off the lighter n-alkanes. He showed that the extent of extraction from the n-alkane chromatogram (e.g., the heaviest n-alkanes removed) depends on the depth of washing (pressure) while the total amount removed depends on the amount of gas that has interacted with the oil. The oil alteration that results from gas washing is depicted in Figure 2.

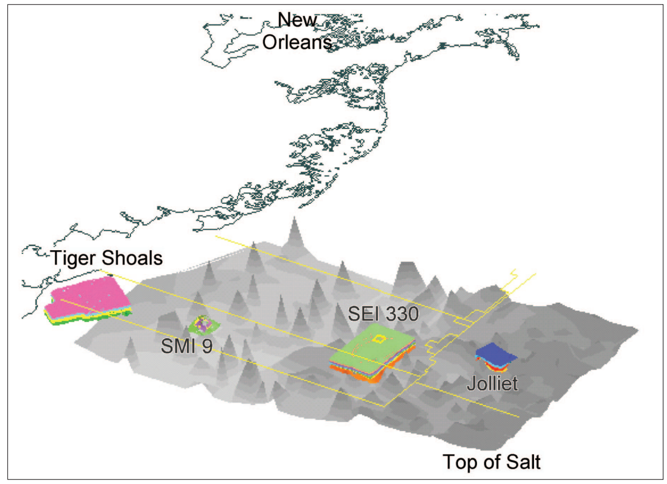
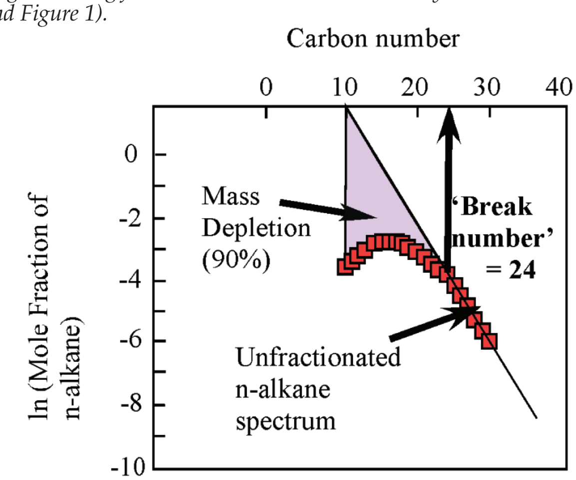


Figure 1. Location of the 125 km E-W by 200 km N-S area of the offshore Lousiana Gulf of Mexico basin that is the subject of the GRI-funded study reported here. Gray shading indicated the top of salt compiled from 2D seismic data. Strata interpreted from 3D seismic data at four localities are also shown. SMI 9 is ChevronTexaco's South Marsh Island 9 salt-piercement-related field, SEI 330 in Pennzoil's (Devon Oil) South Eugene Island Block 330 field, and the southern-most stratigraphic package contains ConocoPhillips Jolliet Field.

At the time we thought this seemingly major alteration (15 wt% removed) reflected the fact that the South Eugene Island Block 330 reservoirs, the largest on the shelf, were situated near a major hydrocarbon leak point that continued to bleed hydrocarbons as the source strata matured. If this was the case, some oils trapped there might easily be washed by late-generated gas. But when we compared SEI330 to neighbor sites we found that this site was not special in terms of its intensity of gas washing. We found instead the remarkable washing pattern depicted in Figure 2. The most intense washing is near the Louisiana coast in the Tiger Shoals field. About 90 wt% of the n-alkanes have been removed there, and the removal is extremely uniform over fields covering a 30 × 40 km^2 area. The intensity of washing decreases to the south from ~90 wt% at Tiger Shoals, to 50% n-alkane removal at South Marsh Island 9, to 15% at SEI 330 to 0% at Jolliet. The pattern is both dramatic in magnitude and amazingly regular, with just enough irregularity to be interesting.

Modeling the processes. Could the pattern be feasibly pro-

Figure 2. 138 oils analyzed for gas washing are located in the middle figure. The percent mass depletion of n-alkane components ≥C_{10} is defined as the gap (shaded area) between an unaltered oil with exponentially decreasing n-alkane mole fractions and the sample oil (figure to left). The graph on the right shows the regular decrease in the percent of n-alkane mass removed by gas washing from north to south across the study area (middle figure and Figure 1).



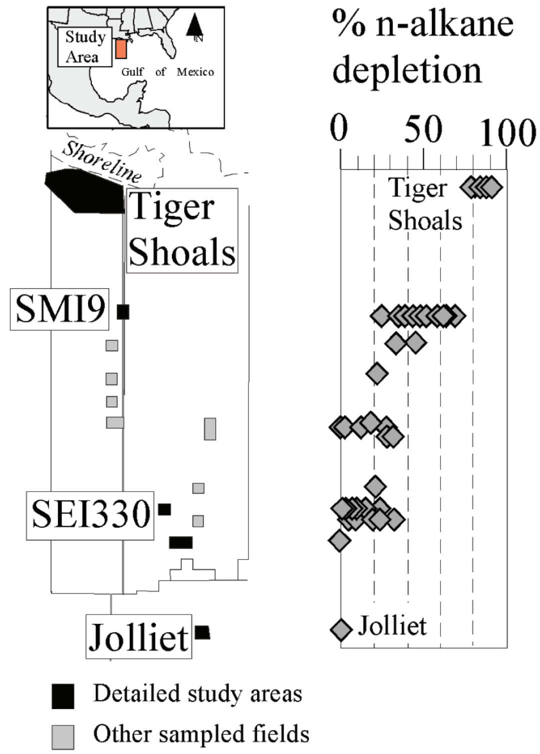
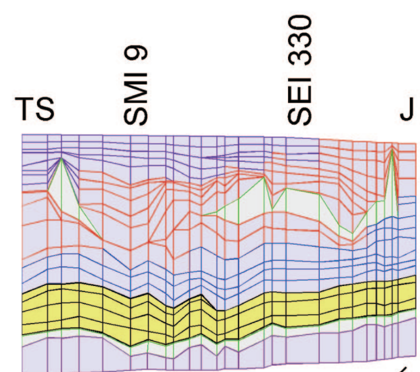
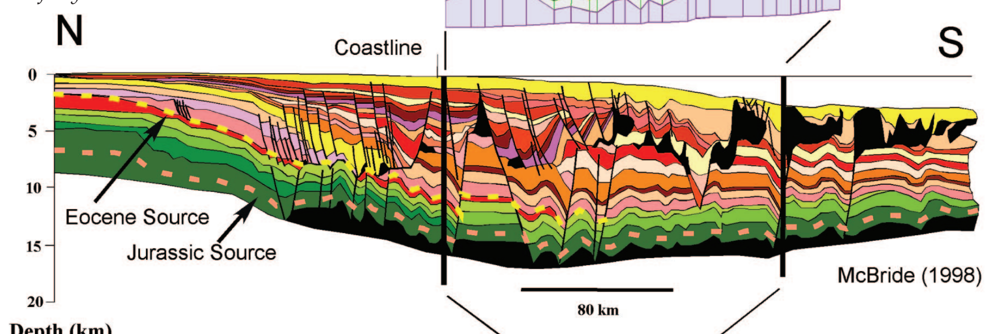
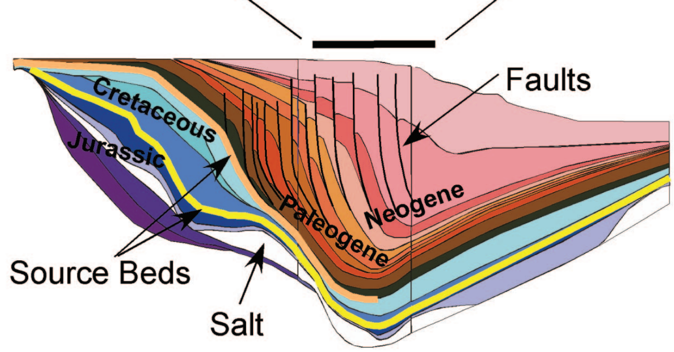


Figure 3. The Louisiana Section (the bottom figure) is a 1050-km section stretching from the Arkansas-Louisiana border to the Sigesbee knolls (salt outcrop) in the south. This generalized section runs along the west side of the study area (Figure 1) and was compiled from seismic and well log data and contributed to us by Exxon. Colors depict stratigraphic age. The middle, much more detailed section, was published by McBride (1998). It lies ~50 km east of our study area. Salt is indicated by black and other lithologies by color. Our model Jurassic and Eocene source beds lie at the bottom and top of the carbonate (green) layer as indicated. We stretched this section to span the equivalent geology in a N-S section through the middle of out study area (Figure1), and digitized it to produce the section shown at the top. Salt is indicated by green, carbonate sediments by yellow, shales by blue, and sandy shales by red. Note that the Eocene source beds (middle section) extend only half way across the model (top) section; the Jurassic source beds stretch fully across.







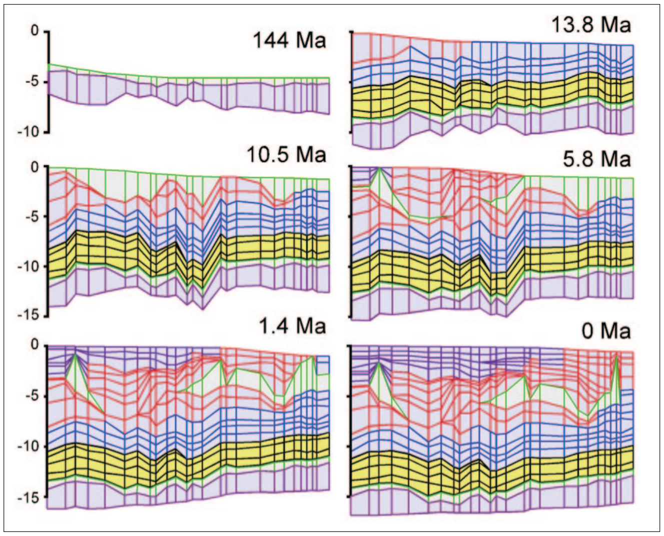


Figure 4. *The geologic evolution of the stretched McBride section shown in Figure 3 was determined by backstripping, decompacting, and moving salt from areas of higher- to less-than-average top of salt depression. In the inferred evolution, the Louann salt migrates to form a salt sill at 10.5 Ma. Sedimentation then produces a salt-withdrawal minibasin in the north (5.8 Ma) and then in the south (1.4 and 0 Ma). Hydrocarbon maturation in the Jurassic and Eocene source strata is significant in the last ~15 Ma (Figure 8).*

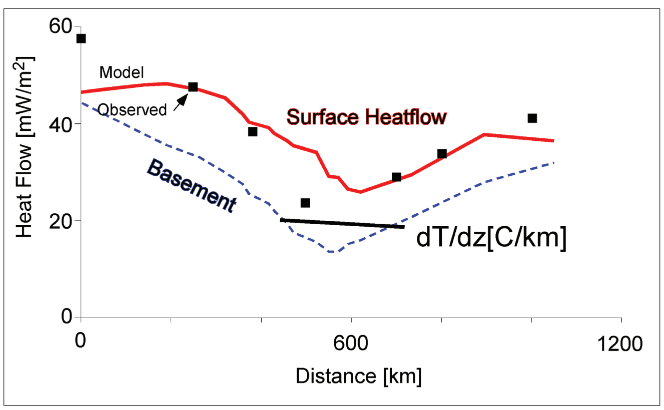


Figure 5. *Model and measured heat flow along the 1050 km long N-S Louisiana section shown in Figure 3. The model heat flow into the base of the sedimentary section is approximately one fourth to one half that leaving the seafloor. The seafloor heat flux agrees well with heat flow measurements (squares). The low model heat flow in the middle of the section is caused by the high sedimentation rates there. The difference between the heat flow into the base of the section and leaving the seafloor is due to radiogenic heat production of 0.73 nW/kg (measured in Frio mudrock by McKenna, 1998). Despite the low heat flow, temperature gradients in the middle of the section are ~20° C/km (data from the Minerals Management Service). This is because the vertical thermal conductivity of the shale is low (~1.5 W/mK).*

duced by oil and gas generation in the study area? Is such a regular trend logical in terms of the geology? To answer these questions we constructed maturation/migration models realistic enough to adequately handle the geologic complexities of this area. The modeling involved the normal backstripping and decompacting, but we also developed automatic salt redistribution algorithms and methods to capture relatively complex faults. The programs are about to be released to the public domain with full documentation (see suggested reading), and I will not go into unnecessary details here. Suffice it so say that we inferred the geologic evolution of a N-S 2D section through the study area in Figure 1 from the present geology. The extraction of a 2D section from the study area is shown in Figure 3 and the geologic history we infer for that section is shown in Figure 4.

The modeling we carried out was two-dimensional finite element on a grid tied to deposited strata. Most of the physical modeling results educated us on matters already well known but some issues were surprising and required enough digging in the corners of the literature to warrant brief mention. Figure 5 shows heat flow along the 1050 km section shown in Figure 3. Heat flow in the middle of this section is about half normal (~20 mW/m^2) and about one half of this already very low heat flow is generated by radioactive minerals in the basin sediments. The low heat flow is due to the very rapid sedimentation rates. Despite the low heat flow the temperature gradients are near normal throughout the section (~20° C/km). This is because the layering of the platy grains in shales causes them to have about half the thermal conductivity one would expect from the conductivities of their constituent minerals. These matters are reviewed in the extensive GRI report (see suggested reading).

Calculated hydrocarbon fluxes. The point of the modeling was to calculate the history of hydrocarbon generation. Confidence in the computed temperature history of the basin is provided by the fact that model heat flow, temperature, and vitrinite reflectance agree with measured data along the section, and because the model that fits these data was constructed from the observed geology, tested material property algorithms, and measurements on Gulf sediments with no later tuning to achieve a better fit. The basal heat flow was predicted from rifting and sedimentation, and was not adjusted to match temperature profiles.

Hydrocarbons were introduced in two model source strata as shown in Figure 3 and detailed in Table 1. The Jurassic source was taken to be 100-m thick with 5 wt% total organic carbons. It was matured as a Type II kerogen with a modified Burnham and Sweeney maturation kinetics. The Eocene source was taken to be 30-m thick and have 4 wt% TOC. It was matured using Type III Wilcox Coal kinetics. The liquid and gaseous hydrocarbons were moved vertically out of the source strata when their volume equaled 20% of the source strata porosity, and moved vertically from one overlying computational finite element to the next when a specified migration pore fraction was exceeded.

There is a good deal of uncertainty in the chemical modeling. We don't know the richness of the source strata, the distribution of the sources is undoubtedly more complex than just two strata, the maturation models do not necessarily apply to the kerogens that are actually present, and the migration pore fraction is unknown. The biggest of these uncertainties is the migration pore fraction—the fraction of the porosity outside of the source strata that must be filled with hydrocarbon for the hydrocarbons to migrate. We treated this as a parametric variable in our modeling.

Constraints on the migration pore fraction (the out-of-source hydrocarbon retention). The vertical migration modeling produced some interesting insights. It showed for example that for any hydrocarbon to reach the surface, the migration pore volume must be less than ~0.5%. For migration pore fractions more than this, the volume of hydrocarbon generated is simply absorbed within the basin. Brines may be expelled but the hydrocarbons never reach the seafloor. We know hydrocarbons have reached the surface, however, because they are pouring though hundreds of natural seafloor seeps in the offshore Louisiana Gulf of Mexico.

If the migration pore fraction were just sufficient to allow

Table 1. *The likely hydrocarbon source characteristics in the area shown in Figure 1 as synthesized from literature sources**

	Jurassic type II source		Eocene type II/III source	
Bed Thickness (9m)	100		30	
Aerial extent in corridor (km^2)	125 x 201.8 = 25 225		125 x 93 = 11 625	
TOC (Wt %)	5		4	
Generation potential	Oil stage	Gas stage	Oil stage	Gas stage
Initial Kerogen mass (Bt)	313	313	34	34
HI index (g HC/gTOC)	0.652	0.538	0.204	0.179
Generation potential (Bt)	204 (195 oil)	168	6.9 (+ 2.4 CO_2)	6 (+ 2.4 CO_2)
Source retention, S_{HC}=20% (Bt)	30	30	4	4
Expulsion potential (Bt)	174	138	3.5	3.4
Corridor discovered resources, R_c	1.37 Bt hydrocarbons (0.46 Bt oil, 0.91 Bt gas) 11.1 x 10^9 boe (2.62 Bbls oil, 45 TCF gas)			

**The Eocene source underlies only the northern ~one half of the area. The generation potential is calculated according to the HI indices shown. The HI for the Jurassic source rock is a standard Burnham, Braun, Sweeney kinetic models for Type II kerogen maturation. The Eocene HI is based on an industry standard Rock-Eval kinetic model for the Wilcox Coal. The last row of the table gives discovered hydrocarbon resources in the Louisiana Corridor (= recovered to date plus proven reserves = Rc) from data is from the Mineral Management Service Northern Gulf of Mexico CD-ROM.*

Table 2. *Distribution, according to our model, of mobile and nonmobile hydrocarbons in the study area shown in Figure 1 at the present day. Units are in billions of tons of petroleum.*

<table>
<tr><th></th><th>Oil</th><th>Gas</th><th>Total Mob. HC</th><th>CO_2</th><th>Unreacted Kerogen</th><th>Precip solids</th><th>Total</th></tr>
<tr><td>Vented</td><td>108.2</td><td>23.0</td><td>131.3</td><td>1.75</td><td></td><td></td><td>133.1</td></tr>
<tr><td>In source strata</td><td>12.6</td><td>24.6</td><td>37.2</td><td rowspan="2">0.7</td><td rowspan="2">2.8</td><td rowspan="2">61.9</td><td rowspan="2">117.7</td></tr>
<tr><td>Migrating</td><td>7.6</td><td>7.4</td><td>15.0</td></tr>
<tr><td>Total</td><td>128.5</td><td>55.1</td><td>183.6</td><td>2.4</td><td>2.8</td><td>61.9</td><td>250.8</td></tr>
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hydrocarbons to vent, the hydrocarbons that vent would be those that were generated first—the Jurassic oils. The later-generated Eocene oil and gas and Jurassic gas would presently propel these oils, but would be far back in the migration chain.

Here chemistry enters in a crucial way again (Figure 6). The oils produced in the northern part of our model section are Eocene oils, or at least contain a significant faction of Eocene oil. We are quite certain of this because the oils contain oleanane, and oleanane was not synthesized in nature before evolutionary developments in mid-Cretaceous time. Also the most dramatic north-to-south change in oil chemistry is the increase in sulfur-bearing benzothiophenes. Because iron is less available in carbonate than silicate source strata, sulfur tends not to be tied up in pyrite formation and oils from carbonate strata tend to be sulfur-rich. The fact that Benzothiophene increases to the south therefore suggests that the oils sampled in reservoirs to the south are Jurassic carbonate-sourced oils, whereas those in the north are silicate-sourced Eocene oils.

Modeling shows that for the oils in the north to be substantially Eocene-sourced, the migration pore fraction must be about an order of magnitude less than is required for the oils to vent, or less than ~0.05%. Figure 7 shows that if the migration pore fraction is 0.025%, the oils are 89% Eocene at Tiger Shoals and decrease to the south in a fashion similar to that observed in Figure 6. Figure 7 also shows that the gas-oil ratio of hydrocarbon migration through the model section today is high enough to gas wash the oils as observed at Tiger Shoals. The GOR drops to the south and is reduced by an order of magnitude at Jolliet, helping to explain the lack of gas washing there.

For the low migration pore fraction, almost all of the oil and gas that is generated is discharged into the ocean. The history of hydrocarbon generation and venting is shown for the entire section in Figure 8. The fact that the vented and expelled from source curves are so close together in Figure 8 shows the "flow through" nature of the hydrocarbon system in this portion of the Gulf of Mexico basin.

Resources. With such a large proportion of the generated hydrocarbons venting into the ocean there might be concern that not much would be left in the subsurface to discover. The crumbs left in the basin are quite sufficient to interest us economically, however. Table 1 summarizes the hydrocarbon generation potential, and Table 2 shows how much oil and gas has been generated in the area shown in Figure 1. This small area has generated and expelled into the ocean ~131 billion tons of hydrocarbon, or, at 7.6 billion barrels/ton, ~1000 bbls of hydrocarbon. This is more than humans have produced and consumed over the entire petroleum era. Most of the liquid hydrocarbons still in the basin are locked in the source strata, but ~15 billion tons (~100 bbls) of hydrocarbon is migrating in conduits within the small portion of the Gulf of Mexico basin shown in Figure 1, according to our model. The resources in the Gulf of Mexico are potentially huge by human measures, even though they are a small fraction of what they could have been if the system was less flow-through.

Catching the migrating hydrocarbon streams. An aspect of the flow-through nature of the hydrocarbon system, and the statement that in the Gulf of Mexico "the present is the key to the present," means that producing reservoirs should reflect the present flow pattern and have filled recently, at least in the geologic sense of recent. This raises the question of how recently present reservoirs could have been filled from model rates of hydrocarbon production. The answer (Figure 9) is that the reservoirs could have filled in the very recent times intervals that are geologically required if those hydrocarbons were collected from areas roughly the size of the salt-withdrawal minibasins that control the sedimentation and structure pattern of this part of the Gulf.

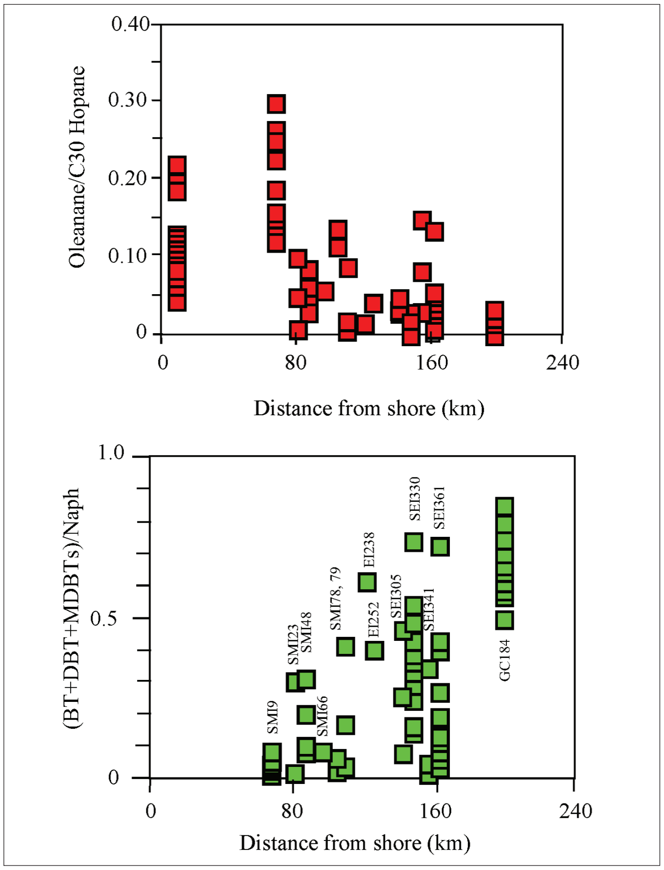

Figure 6. *The decrease in oleanane to C30 hopane ratio to the south suggests a decreased contribution of oleanane-bearing Eocene-sourced hydrocarbons. An increase in sulfur-bearing benzothiophenes (BT+DBT+MDBT) to the south suggests an increase to the south of marine Jurassic-sourced hydrocarbons. Data is from 2002 GRI report. Analysis is mostly by J. Whelan, Woods Hole Oceanographic Institution.*

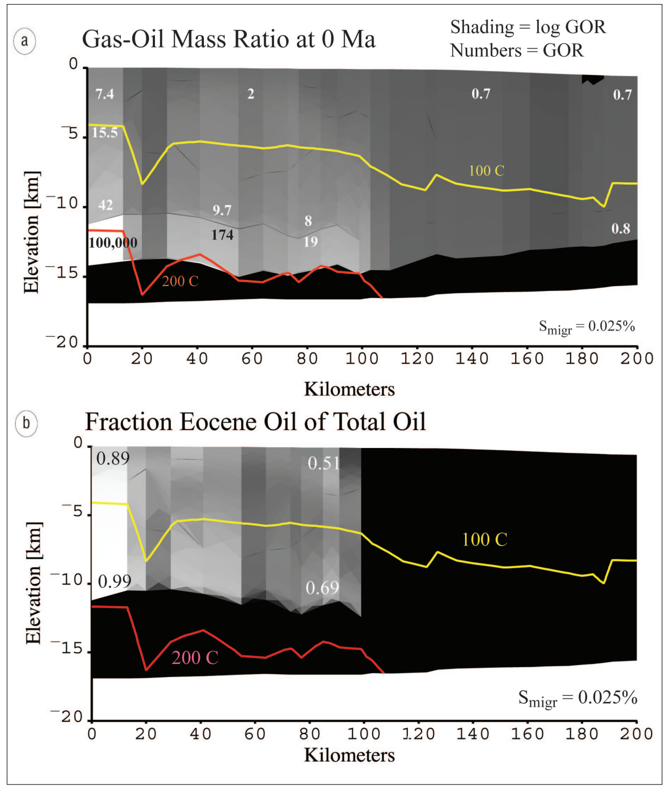

Figure 7. *(a) Model gas-oil ratio of hydrocarbons migrating today. (b) The fraction of the presently migrating model oil that is Eocene. Both figures assume a migration pore fraction of 0.025%.*

Confirmation from accumulating hydrates. Independent support for the maturation model hydrocarbon fluxes is provided by the rate of hydrate accumulation at the Bush Hill gas vent and hydrate mound. The 800-m diameter mound is located at the outcrop of a fault spur to the faults that host the Jolliet oil and gas reservoirs. The isotopic composition of the venting gas is identical to that in the Jolliet reservoirs, and the compositional shift is just that expected if, on average, ~9% of this gas crystallizes as hydrate between ~600 m depth and the seafloor. The profile of subsurface hydrate crystallization predicted by a kinetic model of hydrate crystallization indicates that the mound contains ~ 0.8 million metric tons of methane hydrate gas. If the hydrate accumulated over the last 10 000 years and represents 10% of the gas the venting gas, methane has vented into the Gulf from this one site at an average rate of 800 t/yr for the last 10 000 yrs. This is larger, but very much in the same ballpark as the 310 t/yr venting estimate from the maturation calculation. Given the uncertainties of kerogen grade and volume, timing of maturation, and the possibility of nonsteady venting, this agreement is remarkably good.

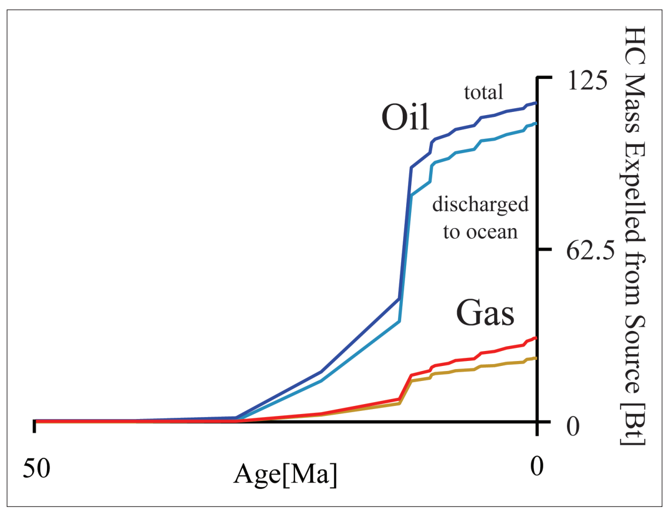

Figure 8. *Total and vented masses of mobile hydrocarbons that have been expelled from their source rock in the model section shown in Figures 3, 4, and 7. The total curves (the upper curve in each pair) represent the total oil and gas expelled from the source beds. These curves sum to 147 Bt at 0 Ma. The vented curves show that 131.5 Bt of hydrocarbon has vented into the ocean. The difference (15.5 Bt) is the mass of hydrocarbon retained within the migration conduits along the section. Migration is vertical. The migration pore saturation, S_{migr}=0.05%. The hydrocarbon numbers cited, although based on a single 2D model section, apply to the 125 × 200 km study area shown in Figure 1.*

Messenger gas and a mouse's banquet. The above analysis is simple; in some sense, that is its strength. As with any geologic analysis there is a lot of uncertainty that is difficult to fully quantify, and some matters need further analysis. We have not explored the sensitivity of our conclusions to reasonable variations in maturation kinetics, for example. It looks like this can make some difference. We would like to know more about the quantitative abundance of oleanane to quantify better how large a fraction of Eocene oil is needed in the north of our section. Because the low out-of-source retention is a conclusion that has many important implications, we need to probe it carefully, and we have not fully done this yet.

Despite uncertainties, two conclusions appear particularly important. First, gas washing of oil is clearly a first-

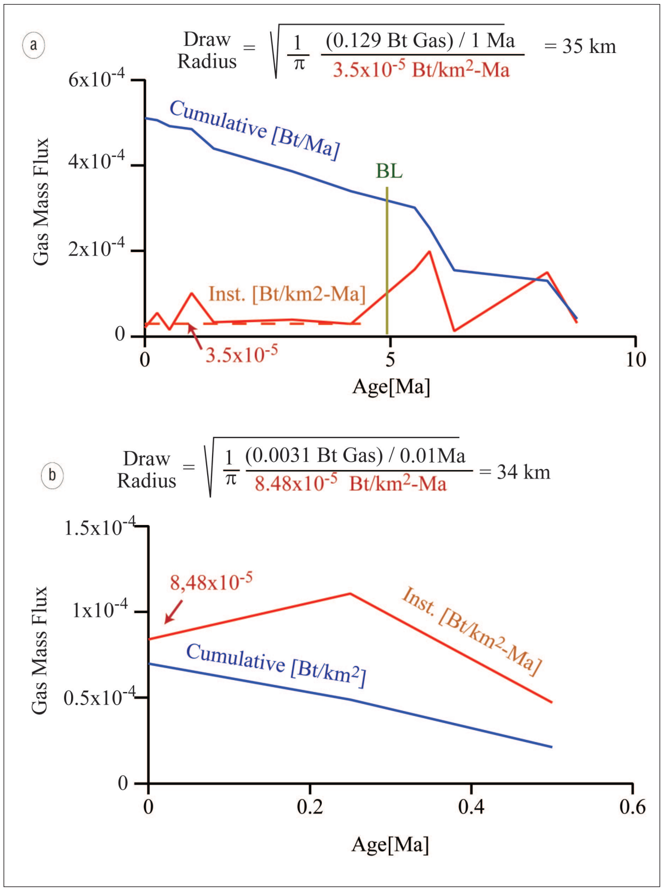

Figure 9. *(a) The cumulative and instantaneous gas mass flux across the 10.1 Ma time-stratigraphic horizon (see Figure 1 or 3 for location). BL is the biodegradation limit (the time at which the upper half of the 10.1-8.8 Ma stratigraphic interval reached 65°C. To fill at a rate of ~130 t/a, a draw radius of 35 km is required. With this draw radius, the reservoirs could have filled in any 1 Myr interval over the last ~5 Ma. (b) The cumulative and instantaneous gas mass flux across the 0.95 Ma time-stratigraphic horizon in the Jolliet area located in Figures 1 and 3. The Jolliet reservoirs filled in the last ~10 000 years. A draw radius of ~32 km will deliver gas to the Jolliet reservoirs at 310 t/a and fill them in this time. Note that with a slight increase in kerogen grade or source bed thickness, the draws could be reduced to the ~20 km radius draw of a typical salt-withdrawal minibasin.*

order basin process. Since a lot of gas must interact with the oil to wash it as observed (~20 moles of gas per mole of oil), the washing must reflect major movements of gas in the basin. Data so far suggests that the interaction of oil and gas occurs in the first (deepest) regional sand in an area. The Rob L. sand under Tiger Shoals was and is at the right depth for oils to be washed there, for example. Figure 10 illustrates how gas might wash oil in such deep, aerially extensive sands. The important exploration point is that when oils that, from their chromatograms, we know have been washed are collected, the depth of washing can be determined from the carbon number at which the chromatograms depart from the Kissen trend. If the washing does occur in a sand, the sand will be found at the indicted depth and will be highly prospective for gas exploration because a great deal of gas must have passed through it and therefore traps in this sand have a very high likelihood of being filled with gas. If enough oils are analyzed to show a pattern of variable washing, this pattern may point to the gas source.

The other conclusion that is important is that a large amount of hydrocarbon has been vented into the ocean on a steady basis over the last ~15 million years. The situation in the Gulf may be likened to a mouse's banquet. The mice that emerge to explore for crumbs after a human banquet are delighted with the abundant crumbs they find. What is inconceivable to them is the quantity of food consumed before they arrived. The quantity of hydrocarbons vented into the ocean may, to us, be almost as inconceivably large.

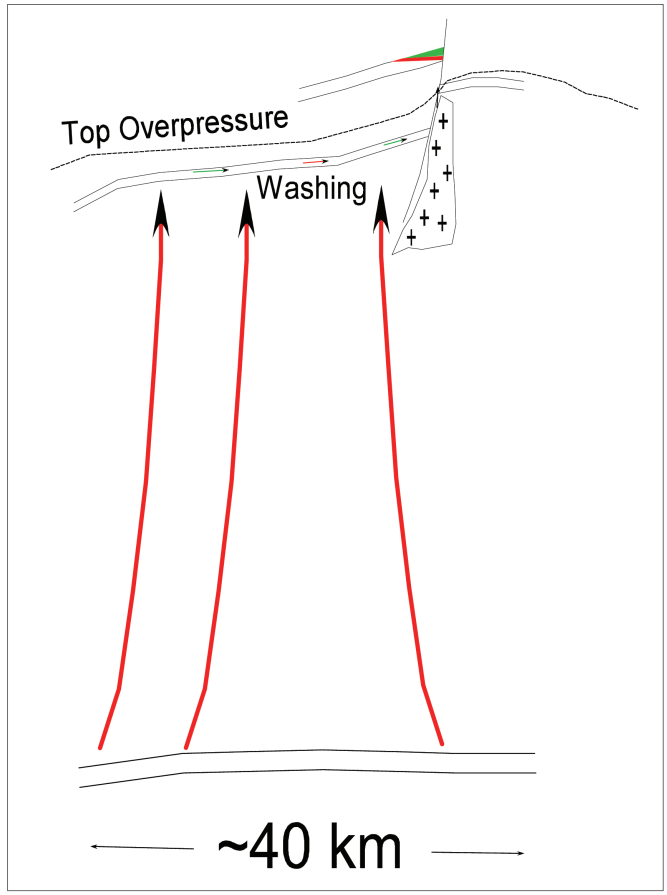

Figure 10. *Cartoon of how gas washing may take place in the deepest regional sand in an area and focus hydrocarbon discharge on a salt-withdrawal minibasin scale. The sands will be particularly effective in focusing flow if they lie below the top overpressure, as shown.*

Suggested reading. This paper is based on a six-volume final report with a GoCAD database and Excel spreadsheet of all data that available from the Gas Research Institute (GRI-03/0065, *www.gri.org*). An Executive Summary (Volume I) summarizes each subsequent volume with approximately three pages of text and key figures. The remaining volumes describe the geology, geophysics, geochemistry, and GoCAD Database, the organic geochemistry, gas washing of oil and its implications, the modeling described in this paper, and a theoretical analysis of the inorganic alteration caused by the flow of brines through seals. Full references are given in the GRI report, but briefly Gatenby's quote can be found in a paper published in 2001 by the GCSSEPM for the 21st Bob F. Perkins Research Conference on Petroleum Systems of Deep Water Basins: Global and Gulf of Mexico Experience. A good description of the organic source distribution in the northern Gulf can be found in this CD in an article by Colling and others. Our salt redistribution algorithm is described in an article by Cornelius and Cathles in a 2003 AAPG CD-ROM edited by Duppenbecker and Marzi. Hydrocarbon and heat flow data can be found in the *2001 MMS Atlas of Gulf of Mexico Gas and Oil Sands* edited by Bascle, Nixon and others. Thermal conductivity is discussed in a 1994 *Journal of Geophysical Research* article by Deming. The model upon

(Continued on p. 770)

(Cathles, from p. 765)

which the conclusions in this paper are based is available, with full description, from *www.geo.cornell.edu/geology/easresearch/geomodeling/basinlab*. TLE

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