POTENTIAL TO FLOW (DETAILED) SECTION

This section details

I. The Nodal Analysis model used in FRACE (well integrity, only completed interval allowed to flow), and how by tweaking sensitivities of some inputs, and/or applying more realistic views of some over-simplified assumptions, a No Flow Conclusion can change to a Flow result.
II. The Loss of Integrity Case, well integrity and zonal isolation loss case

Key results for Potential to Flow are summarized in Table 1 Modeling Table in section 3.2 of the main body of the Report and in the Attached full version of the same Table.

Link to Modeling Table

Potential to flow for task 8 and 9 occurs if any realistic scenario and combination of parameters within uncertainties can flow in detectable amounts, then the well is considered as having potential to flow.

Results Sensitivity illustrated with two reservoirs:

It is stated in FRACE that the post-incident Nodal Analysis as conducted represents an optimistic case for flow, because it does not consider restrictions in tubing geometry and flow caused by the incident. However, even given the assumptions of well and zonal isolation integrity, which is contradicted in task 8 and 9 report section 3.3, this is only partially true.

The post-incident calculations in FRACE also assume that the flow capacity of a well post-incident can be estimated considering that the entire perforated interval either flows or not (an “on / off” case). In reality, the post-incident estimates, especially at low rates, should not be excluded. It is likely that flow comes from only part of the perforated interval, in which case the estimates in FRACE would be severely pessimistic to flow. This concept will be discussed at the end of this section.

To better understand the analysis and conclusions in FRACE, the Cobb et. al MBAL results as reported in FRACE were used as inputs, and Nodal Analysis calculations were independently conducted in Prosper. Sensitivities to key inputs were applied to understand how minor tweaks in these could affect a “Flow” or “No Flow” outcome.

Two multi-well reservoir sands are presented as examples to illustrate how the Nodal Analysis no-flow potential post-incident results can change by considering slightly more realistic ranges in inputs (sensitivities) and / or a simplistic assumption.

- Sand L3 RA-2 with Wells A-02, A-10 and A-18; and
- Sand N R20-1 with wells A-06 and A-12

This choice of reservoir/wells was driven by, several factors:

- More complete data sets with at least one (1) Oil Laboratory PVT for each reservoir
- Multiple wells with Reservoir Pressure data in each reservoir (Main Reservoirs)
- Flowing tests data existed that were not used in FRACE that could be used as additional calibration points.

- All wells completed in these sands have Potential to Flow considering Hydrostatic head column vs Recharge Pressure.
- In each of these sands there was at least one well reported as having NO Potential to Flow in the FRACE report based on Nodal analysis.

I-a. Pressure Recharge Sensitivity:

Prior to showing some examples of Recharge Pressure sensitivities on MC-20 wells as calculated in FRACE and how these affect a "Flow" / "No Flow" outcome, it would be useful to understand some simplistic assumption used for Material Balance in FRACE and how these can affect the ranges of calculated Recharge Pressures.

MBAL context: The MBAL software used to match the historical behavior per Reservoir and forecast the Recharge in Pressure is quite robust and the Material Balance methodology is grounded in solid principles of mass conservation.

However, in the MC-20 case there was very limited geological, petrophysical and historical pressure data available to fit the approximate/average nature of a Material Balance analysis and the MBAL tool. FRACE assumes reservoir homogeneity and uses relatively few pieces of data, however, this simplistic approach has limitations, and will give overall /averaged (homogenized) answers when applied to a whole reservoir.

- Material Balance as applied in FRACE assumes the entire oil/gas Reservoir behaves as a single perfectly homogeneous Tank, with instantaneous pressure and fluids equilibrium within the whole reservoir. No heterogeneities, zero dimensions: no depth, no dips, neither areal nor vertical property distributions, etc. as exists in all reservoirs.

  Ideally the Reservoir Pressures used as inputs for MBAL at each and every well in the Tank should track one another perfectly (corrected to a common datum), however in reality there is always noise in the data and thus a quality fit to a single trend gives a level of confidence in the data and corresponding results. In FRACE these was noise in the inputs, see Fig 1 below, however the corresponding output was a deterministic result; i.e. the sensitivity of the result to the variability of the input was never tested.

- The strong aquifer support in most of the M-20 reservoirs was accounted for with a separate aquifer model, coupled to the reservoir tank. The aquifer model selected and used is in FRACE is a simple, but standard model. It assumes the water encroachment from the aquifer takes place in the form of radial inflow within a constant depth cylindrical wedge of homogeneous rock, with the reservoir in the inside and the aquifer in the outside. The user selected input properties for the aquifer like: permeability, size, and effective area of interaction between aquifer and reservoir. These are commonly expressed as a wedge angle, an inner and an outer radius, a thickness, and constant porosities for reservoir and aquifer.

  However, in reality, reservoir and aquifer rocks are quite heterogeneous, even in high quality reservoirs. Usually there is data on the permeability and porosity distributions in the oil leg, but seldom does this type of data exist for the aquifer. Furthermore, the reservoir sands in M-20 are interpreted to consist of multiple meandering, elongated and at places overlapping channel-like sand bodies.

In general, a MBAL History Match is an exercise of simulating forward in time in a sequence of discrete (small) time steps. At each step, the Historical Voidage is extracted from the reservoir Tank (Historical production of Oil, Water and Gas) and the change in Tank pressure is calculated. This process is repeated until the end of the historical data. A trial and error match between the calculated pressures over time and the Historical Reservoir pressures trend is used to tune the input parameters. Typical parameters used in tuning are the Pore Volume of the Tank (connected reservoir pore volume to all wells), the properties of the aquifer and the strength of the aquifer–reservoir connection. Once a match is available, Reservoir Pressures can be forecasted by specifying productions rates for future times and simulating forward. **This type of history match does not have a unique solution.** In general, multiple sets of reservoir parameters can deliver equivalent matches, all consistent with the known pieces of information. **In FRACE one match was used to give one unique forecast.**

We deal with Reservoir Pressures ranges next. Uncertainties in rates will be discussed as context for a separate example (A-06 well). Sensitivities to other input uncertainties will not be considered: fluid properties, rock pore volume compressibility, aquifer and reservoir permeabilities, etc.

A key input when modeling predicted reservoir pressures and reservoir recharge are historical well pressures and well-defined trends which then can be used to more accurately predict future pressure trends or in this case a recharge pressure.

Well Reservoir Pressures:

Except for dedicated observation wells and RFT type measurements, reservoir pressures are not direct measurements, they are inferred from measured bottom hole pressure variations (build-ups) during well shut-ins. Any reservoir pressure reported from such a measurement depends on:

- the length of the shut-in period, how depleted is the well to begin with, the amount and quality of the pressure measurements gathered during the build-up, etc.
- how other wells communicate or not with the shut-in well and what is happening to them.
- whether or not any leakage/inflow or flow barrier are being reflected in the well pressures during the shut-in: from a nearby aquifer, through a baffled connection to another compartment, a sealing fault, etc.

This connectivity amongst wells and with aquifers etc. coupled with the shut-in time impact whether the value is representative of the overall reservoir (the Reservoir Pressure) or just of the pressure in the near vicinity of the well.

The Historical reservoir pressure data available for M-20 is quite sparse, especially for 30 years of production, and it is comprised almost exclusively of static pressure runs of mostly 24hr shut-in tests. In a static test, a sensor is run in and out of the shut-in well recording pressures and temperatures at several depth including the bottom. Static tests do not provide bottom hole pressure trends in time during the shut-in. This limits the application of standard techniques to extrapolate the bottom hole pressure to long shut-in times. In FRACE all well pressures reported were taken as representative and averaged within MBAL to obtain the input historical reservoir tank pressures for the single tank match. Again, this creates uncertainty in any potential output for Recharge Pressure.

Figure 1 contains the Historical Reservoir Pressure data reported in FRACE for the NR20-1 and the L3 RA-2 sands. Visual inspection of this data indicates a scatter of about 200 – 250 psi (5 – 8 %) in the pressure depletion trends for a given well or for the overall Tank. Furthermore, there appear to be two Pressure trends for L3 RA-2: a lower one for A-02 and a higher one for A-10 (with very few points for A-18). This would indicate that the reservoir may be better represented by two tanks with a leaky connection between them, a case that can also be modeled in MBAL but was not shown in FRACE.

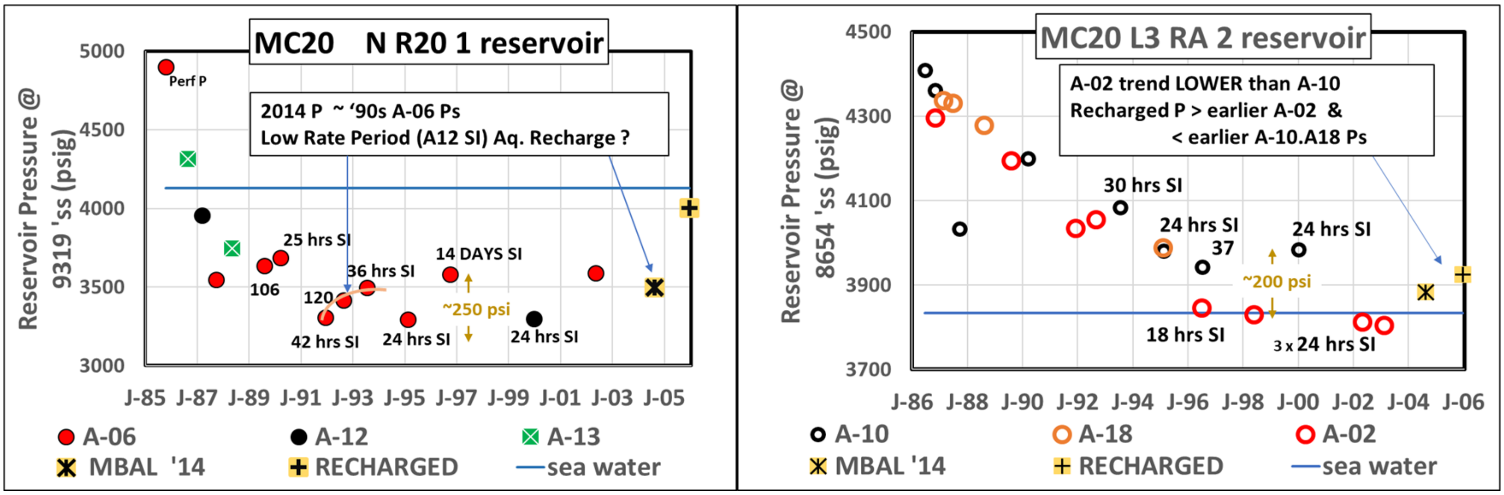

*Figure 1 Datum corrected Historical Reservoir Pressures in time for wells in the N R20-1 and L3 RA-2 Reservoirs. MBAL '14 & RECHARGE, represent the COBB MBAL estimated Sep'04 and Full Recharge deterministic Pressures respectively (**full recharge posted at an artificial date for legibility**). For the late pressures shut-in hours have been posted in the plots, when available. The charts Illustrates the data scatter for a given well and among individual wells in a given reservoir, especially after significant depletion (about 200 – 250 psi or ~ 5 – 8 % scatter). Note that A-02 clearly appears to have a consistent lower Pressure trend vs. A-10 in the L3 RA-2 reservoir.*

In FRACE the L3 RA-2 reservoir, as all other M-20 reservoirs, only a single tank, with a single pressure trend, was used in the FRACE Material Balance work. This combined by a single matched set of parameters, led to a single deterministic result for a long time Reservoir Recharge Pressure.

Based on the scatter of the Reservoir Pressure data in M-20 **(Figure 1)** and on experience with similar unconsolidated high-quality reservoir sands in Gulf of Mexico, for **Task 8 and Task 9 a +/- 10% range was used, as a conservative uncertainty around the Cobb et. al. single deterministic Recharge Pressure estimates.** In fact, variability in results of +/- 20 % or even +/- 30% could be expected from a full sensitivity analysis, given the sparse data set available and the possible ranges and uncertainties for all parameters and inputs. This would be especially the case as in L3 RA-1 where the data indicated two interconnected tanks as a possible alternate representation vs. the single tank used.

<u>L3 RA-2 sand; Wells A-02, A-10 and A-18 results</u>:

The original Cobb et.al. Nodal Analysis used in FRACE that employed a deterministic exercise with no consideration of sensitivities was reviewed by Kelkar et.al; whom pointed out these concerns. The Nodal Analysis work was then revised by Platt Sparks et.al., who evaluated and discussed the impact of

Recharge Pressure changes in the Nodal Analysis results. However, this analysis was only incorporated into the assignment of Flow Potential for one of the 25 wells, the A-10 well in the L3 RA-2 reservoir:

The Deterministic Recharge Pressure estimate for L3 RA-2 Reservoir in FRACE was 3925 psi.

- **A-10 well**:

  The Platt Sparks analysis indicated that a minimal +15-psi increase (under 1% variation), everything else kept unchanged would change the A-10 well result from No-Flow to having Potential to Flow. This 15 psi is so small that A-10 was added to the FRACE list of wells to intervene (Potential to Flow). The original Cobb report classified A-10 having no Potential to Flow well.

- **A-02 and A-18 wells**:

  Although, the same +15 psi increase (same ~1% variation in Recharge pressure, everything else fixed) would also change the A-02 and A-18 wells from NO Flow to Flow in Platt-Sparks' the Nodal Analysis, these wells were not adjusted and remained deemed to have NO Potential to Flow in FRACE, reasoning being;

  - For **A-02** the forecasted oil rate was considered too small (~1 barrel of oil per day, increasing to "only" ~ 2 barrels of oil per day a 75 psi add - a 2% increase), and the well was kept in the FRACE list as NO potential to Flow. It is unclear from reading FRACE why these rates were or would be neglected.

  - For **A-18** it is stated in FRACE that the well would flow "100% water", based on a "Volumetric Analysis"; and did not have to be abandoned. As will be discussed later in this report under water encroachment, the expectation of an oil producer reaching 100% water is extremely simplistic and does not apply quantitatively in any real field situation. The same applies to the MBAL Contact Tracking functionality believed to be behind the "Volumetric Analysis" as quoted.

Other wells, similar to A-10, for which Platt-Sparks et. al. reported sensitivities to Recharge Pressure indicate the FRACE conclusion of no Flow Potential appears difficult to justify, are summarized below.

Well	MBAL 09/04 Reservoir P (psig)	MBAL Reservoir Recharge P (psig)	FRACE Potnl. to Flow	Recharge P threshold to flow P-S (*)	Variation in P (psia) to Flow	Comments WOC = water – oil – contact GWC = gas – water -contact
A-22	**2714**	**2730**	**No**	**2750**	**+20 (<1%)**	**Recharge P range ? on initial gas cap size ⇔ aquifer size**
A-03		**4114**	**No (**)**	**3450(**)**	**flowing**	**Per FRACE calculation this well flows, however in FRACE it was concluded that due to perceived low flow rates it was deemed a "NO FLOW Case" 4 bod @ 97% Wcut neglected as Low Rate (?)**
A-08		**4114**	**No(**)**	**3500(**)**	**flowing**	**Per FRACE calculation this well flows, however in FRACE it was concluded that due to perceived low flow rates it was deemed a "NO FLOW Case" 1 bod @ 92% Wcut, neglected as above (?). DX plug**
A-9ST	**2192**	**2444**	**No**	**2600**	**+154 (6%)**	

A-20	**2791**	**2844**	**No**	**2950**	**+206 (7%)**	
A-12D	**3185**	**3549**	**No**	**3750**	**+ 201 (5%)**	**100% Wcut on "notional" flat WOC above perfs, DX Plug**
A-14ST	**3005**	**3027**	**No**	**3525**	**+498 (17%)**	**Skin of 1460**
A-02	**3884**	**3925**	**No**	**3925**	**0 (0%) Borderline**	**SKIN of 114; 4 bod w/ +25 psi Recharge P (2%) FRACE calculations are even as to flow / no flow, however chose "No Flow Case"**
A-18	**3884**	**3925**	**No**	**3925**	**0 (0%)**	**100% Wcut on "notional" flat WOC above perfs, DX Plug FRACE calculations are even as to flow / no flow, however chose "No Flow Case"**
A-28	**2495**	**2612**	**No**	**2775**	**+163(6%)**	**100% Water on "notional" flat GWC above perfs**
A-23	**1920**	**1920**	**No**	**< 1500 / >2250**	**flowing +330 (17%)**	**○ Well flowing gas (no lift) 3Q 2004 ○ Recharge neglected & GL valves water influx added See details in section I-f below**
A-06	**3495**	**4002**	**No**	**4150**	**+148 (2%)**	
A-12	**3495**	**4002**	**No**	**4050**	**+48 (1%)**	**DX plug**

(*) P-S indicates Platt-Sparks et.al (**) Low rate flow from Nodal Analysis discarded

<u>I-b. Water encroachment / homogeneous reservoir:</u>

A graphic with 3 images (top, middle and bottom) depicting how water encroachment from an aquifer would look like in a perfectly homogenous (ideal) high quality 2D reservoir, allowing excellent segregation of fluids, is presented in **Figure 2**. This is the standard Dietz model originally developed for application in the high-quality North Sea sands, decades ago. Note that even in this ideal fully homogeneous case, for any commercial level extraction rates, **flow is almost always unstable** and water tends to underrun as in the bottom image.

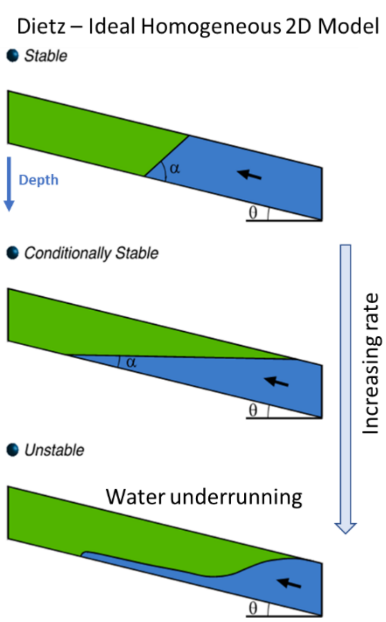

Figure 2 Ideal Homogeneous 2D segregated flowcross section. In almost all cases, at commercial level extraction rates, water front is unstable

A more realistic looking cross section of water encroachment with heterogeneities, is presented in **Figure 3.** This illustration of complex water encroachment is the type of behavior that takes place in high quality but not ideally homogeneous reservoirs such as MC-20. Segregated flow would exist within pockets of contiguous high-quality rock. There would also be barriers and poorer quality rock pockets isolating or delaying water entry, as well as high quality streaks acting as thieve zones for water to preferentially run through. As illustrated in **Figure 3**, after some depletion a well may see oil above water above oil in its perforated interval. Without specialized in-well surveillance, any estimation of water inflow distribution over the perforated interval at a given time is at best an educated guess. Additionally, actual flow takes place in 3D, so the complexities of the distribution of heterogeneities when moving in and out of the 2D view, will also increase complexity and impact results.

Furthermore, water rich areas as in **Figure 3** and as in MC-20 are seldom 100% water with no remaining local movable oil. Displacement down to irreducible oil saturation requires a huge number of pore volumes of water throughput, as governed by the two-phase displacement characteristics within the rock pores.

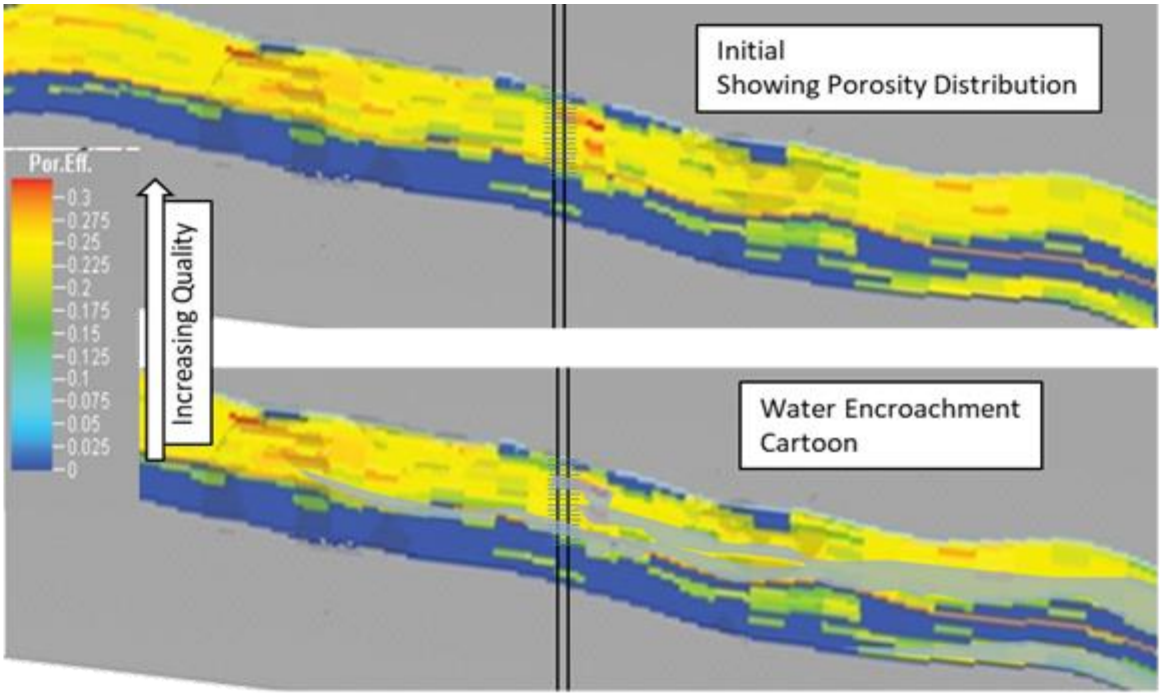

Figure 1 2D cross section cartoon of a "realistic" high quality sand reservoir somewhat analogous to the sands in M20. At the top the colors represent Porosity, with RED = highest porosity (and quality) and BLUE being low porosity (and basically no permeability.

Neither Material Balance nor the standard Nodal Analysis in Prosper as performed in FRACE, take the above uncertainties or complexities into account. The reservoir is considered homogenous with the same average properties throughout; and in the Material Balance as used in FRACE there are no reservoir dips and all wells interact with the very same Tank properties (same pressure, same fluid saturations, etc.). However, MBAL can generate fluid contact outputs which can only use simplified geometrical user inputs and are extremely unrealistic (Contact Tracking).

Accounting for uncertainties and better understanding of the complexities would allow for higher quality results and better definition on output ranges and outcomes.

This tracked planar contact is oversimplified to the highest degree, and assuming there is only movable water remaining behind it is absolutely not realistic.

- Water encroachment in actual reservoirs does not generate a planar surface water-oil contact sweeping 100% of the movable oil as it moves up-dip (Figures 2 and 3)
- For very high-water rates, the ratio used to track water vs. oil in a producing well or field is NOT water cut but Water Oil Ratio (WOR = rate of water divided by rate of oil), which approaches infinity (100 % water) only as the oil rate approaches 0. In actuality, even at extremely high WORs a producer will deliver some oil with the produced water, **this is a basic concept that any professional in the field with even limited experience in handling produced water would know.**

- In actuality oil producers take a very long time (many water pore volumes of throughput through the reservoir surrounding the well) to reach a very high WOR and the approach to 100.0 % water is asymptotic. Commercial wells are shut-in at high WOR for cost/benefit reasons, not because oil production is 0.00. The approximate half a million stripper wells in the US, producing about 0.9 million barrels of oil per day at very high WORs are a testimony to this~~.~~

L3 RA-2 reservoir A-18 well:

This MBAL contact tracking is what appears to be behind the Volumetric Analysis Platt Sparks et. al. used in FRACE to conclude A-18 would flow 100.0 % water. It seems that based upon some estimated PV vs. depth table for L RA-2 input to MBAL, the segregated-planar-surface water-oil contact for the L3 RA-3 MBAL deterministic single Tank model of Cobb, was calculated above the top perforation depth of A-18 at the time of the event. In FRACE, as added support it is mentioned that the flow tests for A-18 in the field had jumped to 100% water some time before the event, and the well had been shut-in.

Note that well data gathered in Task 8 and 9 from BSEE shows that when Well A-18 was shut-in in 1997, it had been flowing 16 Barrels of Oil Per Day along with 1350 Barrels of Produced Water Per Day.

- As discussed previously, the MBAL tracked contact movements are highly oversimplified and not even close to being realistic.
- The A-18 tests did jump from a high water cut to a reported 100% water in testing. However, this must be interpreted as:

(1) a very low oil rate, the field personnel did not attempt to measure, or could not measure with usual procedures (too low, foam, emulsion, etc.) and/or
(2) some mechanical / completion / perforations issue downhole that altered the trend of increasing WOR for the well. Reservoir inflow into a well, on its own, does not jump to 100.00 % water cut in a real reservoir in a few months.

Furthermore, low oil rates considered not significant for oil allocation purposes in the field are not necessarily insignificant in terms of pollution in the water.

Examples for other wells considered with no potential to flow based on 100% water production Field Tests and the idealized MBAL's segregated/flat "tracked contacts", would be:

- **Well A-07ST**
- **Well A-12ST**

I-c. Flow test matching parameters: Flow Pattern Correlation, Skin and Flowing Interval:

In this section the L3 RA-2 sand and the A-02 well are used as to illustrate the impact of input sensitivities and assumptions relating to completion skin, flowing interval and flow pattern correlation on the FRACE Nodal Analysis Flow / No-Flow results.

Background on the Single well Nodal Analysis using well A-02 as example:

The procedure to evaluate Potential to Flow by Nodal Analysis in FRACE using the A-02 well:

- Identify tests to use as calibration points. Note - In order to conduct a robust Nodal Analysis actual field tests with measurements of both flowing bottom hole and tubing head pressures as calibration points are a necessity. Tests with these bottom hole pressures are very scarce in MC-20. For A-02 only 4 could be found (Jul-1996, Jun-1998, May-2002 and Feb-2003). Typically, robust data sets exist only for wells with permanent down hole pressures gauges which are monitored and recorded.
- Build a pre-incident single well model with inflow in Prosper. This requires well inputs (geometry, diameter of tubing, assumed tubing roughness, flow pattern correlation, etc.), reservoir inputs for inflow (average permeability, length of completed interval, etc.) and a PVT model for the hydrocarbon fluids. While a rather complete list of other parameters like Reservoir and Aquifer permeabilities, well perforated interval etc. was provided, there were no details on what PVT properties and/or correlations were used in Platt Sparks (FRACE)
- Calibrate this Nodal Analysis model (reservoir inflow/tubing flow) using the simulated MBAL single tank reservoir pressure trend. In FRACE only a single selected test was used for calibration purposes, the **Early Test** (Feb-2003 for A-02). Note – the matching of multiple tests with the same set of parameters would be considered stronger approach.
- To get the **Early test** to match for A-02 a very large skin factor of ~70 was required. This large skin represents approximately a 10-fold reduction in reservoir inflow to the well vs. no skin.
- Reconstruct a **Late Test** immediately before the incident (~Sept 2004), using the available rate data from test prior to the incident. Estimates of the flowing <u>bottom hole</u> Pressure were calculated with Prosper itself. There was no actual field test data with flowing bottom hole pressure available right before the incident.
- Match this reconstructed **Late test** individually, in the same fashion as for the **Early test**, using the Sept-2004 MBAL estimated reservoir pressure in the inflow inputs. **In the case of A-02, an even larger skin of 114 was needed to get a match, representing almost a 15-fold reduction in fluid inflow (as an additional reference, the current Prosper version used in the task 8 and 9 work rejects a Skin input over 100 by default)**.
- Run a Nodal Analysis prediction of liquid flow rate after the incident as follows:
    - Modify the well geometry: use a shorter tubing ending at the original sea floor and set the Tubing Head pressure to the sea water hydrostatic head at this depth (479 ft). This can be described as a perfectly shared well at the seabed, as sketched in **Figure 9** below.
    - Keep the same flowing water cut and gas oil ratio as in the **Late Test**; excluding Gas Lift
    - Use the Cobb et.al. MBAL estimated Reservoir Recharge Pressure in the inflow inputs
    - Keep all other inputs as in the **Late test**: completion Skin, flowing interval length, reservoir permeability, etc.

If this calculation finds a stable crossover point between the Inflow and the Tubing Performance curves, then this point defines the liquid rate and the flowing bottom hole pressure for the well post-incident (oil and gas rates are easily calculated from the fixed water cut and GOR).

If there is no stable crossover, the well is considered as having no Potential to flow. As discussed at length in FRACE (Cobb et.al and Platt Sparks et.al), a stable crossover is one in which the tubing performance bottom hole pressure (BHP) is increasing with flow rate and the inflow performance BHP is decreasing with flowrate.

It is quite common to interpret non-stable crossovers in this type analysis as an indication of flow in non-steady state conditions (commonly referred as slugging), which can go on for long periods of time. However, in FRACE only stable crossovers were considered, and this appears to be why the term Potential to <u>sustain</u> flow, is used sometimes, instead of just Potential to flow.

In the non-stable cross-overs subject in FRACE, Cobb et.al. claim that such a cross-over implies the well will "kill itself" and argue wells should be considered as having no potential to flow when at the forecasted cross-over both curves have negative slopes. Platt- Sparks et.al. seem not to consider the non-stable cross overs, but in most cases end up using them as "flow points", exceptions appear to be **A-08 and A-03**.

This may have been driven (as pointed out by Kelkar et.al) by the fact that many Nodal Analysis <u>match points</u> for the Field Flowing Tests (<u>the calibration points</u>) show non-stable characteristic (negative slope for both curves: tubing performance and inflow performance). For example

- Early Test Matches A-03, A-04 (borderline), A-09ST, A-14ST, A-17, A-20; and
- Late Test Matches: A-03, A-08, A09ST, A-12, A-14ST, A-20, A-22, A-24

(Figures for the Test Nodal Analysis Matches may be found in the Appendix to Platt-Sparks report in FRACE)

<u>A-02 Nodal Analysis sensitivities:</u>

For the Task 8 and 9, A-02 Nodal analysis work, a set of Prosper models were built using the only PVT Lab Report available for the L3 RA-2 reservoir (A-10 well). This PVT data was matched in Prosper with standard correlations as customary, to allow extrapolation of the single temperature Lab data to other temperatures as needed and to pressures outside the range of the Lab measurements.

The task 8 and task 9 A-02 Nodal Analysis essentially repeated the procedure as done in FRACE, but tweaked the following to provide a more representative model:

- Four tests pre-incident were matched simultaneously. These included Platts-Sparks Early and Late tests, plus two (2) additional earlier tests, from 1996 and 1998 (the 2002 test reports too high a fluid gradient at the bottom of the well and was discarded). There are enough parameters in these models to match any reasonable single well test. Matching multiple test provides a sense of the accuracy of the matches (both from the point of view of the calculations and the measurements being matched)
- A reasonable set of relative permeability curves was inputted as part of the Inflow Performance Model (IPR), to help accommodate the large variations in water cut in the set of tests being matched simultaneously. The FRACE work used no relative permeabilities at all, and matched individual test separately.
- Used the Hagedorn-Brown flow pattern correlation (relying on GoM experience with Prosper). The Petroleum Experts (PetEx) flow correlation as used in the FRACE work, was tested as a sensitivity.

A reasonable single match for all tests was feasible and required a very significant Skin factor of ~78 (in line with the ~70 for the Early Test match from Platt-Sparks). **Figure 4**

As can be noted in **Figure 4**, the simultaneous matches are not perfect (they seldom are) but 3 out of 4 match quite well, giving some support to the parameters used. All mismatches in bottom hole flowing pressures were small (< 2% other than the **Late test** at 8%) and only the **Late test** had a large mismatch in rate (< 10% except for Late test with >50%: 362 vs. 232 bliq/day as reconstructed in FRACE Platt Sparks). Note that there was no attempt to change parameters independently from test to test, as would be the case when matching individual tests independently.

Figure 3 Zoomed in plot of simultaneous Match for all test A-02 well. Vertical axis is Pressure and Horizontal axis is liquid rate. Green Lines are the inflow performance curves and the magenta lines are the tubing performance curves. The Match point for Test 4 (Late Test – 2004) is out of the plot to the left

The simultaneous match was repeated with the PetEx flow correlation (as used in the FRACE work); with only small changes in the results. These results gave a higher level of confidence in Task 8 and 9 analysis and ability to understand, match and control tweak inputs and assumptions.

Finally, as in FRACE, a no lift low rate forecast post-event was calculated for the sheared top well geometry (post incident model **Figure 9**). Top node sea water head pressure was 212 psig (479 ft * 0.443 psi/ft vs. 217 psig from FRACE from choosing a 0.453 psi/ft sea water gradient). The flow rate ratios (wcut and GOR) were set as in the Late test and the matched skin (~78 in our case) were used. Gas lift was switched off.

Results are shown in **Figure 5** and are summarized and compared with FRACE in the table that follows:

Wel A-02	Flow Pattern Correlation	Skin	Calibration	Recharge Pressure (psi)	Result
Case 1) Per model and calculations in FRACE	PetEx	114	Late Test only	3925	No Flow

Case 2) FRACE with +2% P-Recharge sensitivity, however not accepted in FRACE conclusion	PetEx	114	Late Test Only	+ 75 psi (+2%)	Flow
Case 3) Task 8 & 9, with Flow Correlation Model and Matched Skin (with 4 tests)	Hagedorn-Brown	78	4 Tests	3925	Flow
Case 4) = Case 3 with FRACE Flow Correlation	PetEx	78	4 Tests	3925	Flow
Case 5) = Case 3 with +10% P-Recharge sensitivity	Hagedorn-Brown	78	4 Tests	+ 10%	Flow
Case 6) = Case 4 with +10% P-Recharge sensitivity	PetEx	78	4 Test	+ 10%	Flow

In conclusion, when considering input variabilities, it becomes quite difficult to conclude that Nodal Analysis conclusively indicates the A-02 well has no potential to flow.

As stated previously only small differences were found when matching the 4 tests simultaneously selected for A-02 with either of the flow pattern correlation tested (Hagedorn-Brown and Petex). However, all the calibration tests are for relatively high liquid rates (commercial producing wells with lift). For the smaller rates of **Figure 5** (no lift), the choice of flow correlation makes a difference.

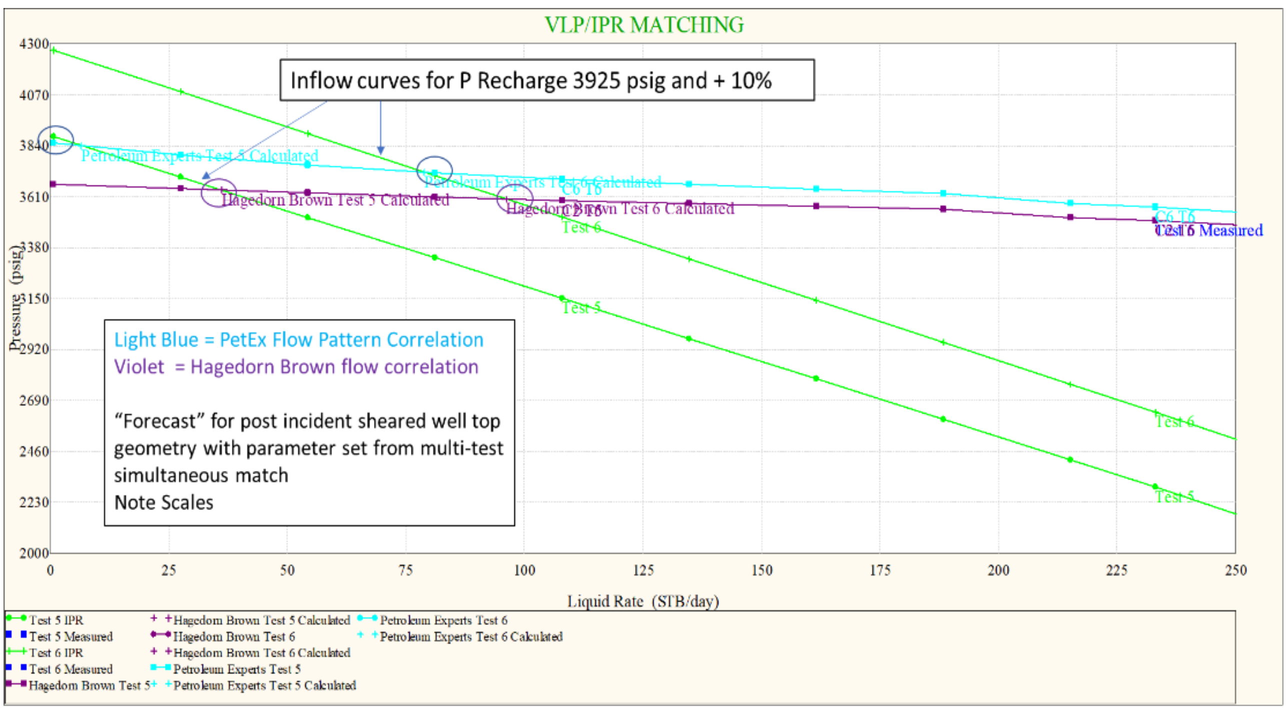

Figure 4 A-02 post incident "forecast" results with Hagedorn-Brown and PetEx Flow pattern correlations. The Light Blue and Violet lines correspond to the tubing calculations using the PetEx flow correlation and the Hagedorn Brown flow correlation, respectively. The Green lines correspond to the Inflow curves for the deterministic Cobb Recharge Pressure, and for the same Pressure + 10%. Note how thedifference in tubing performance pressure from the change of flow correlations grows as the rates become small

Flow pattern correlations are built from series of multiphase laboratory flow experiments (usually air and water), and it is very hard to state which correlation should be better suited for these late rate flow conditions. The choice is usually done by what fits the data better. It would appear therefore, the uncertainties in the data and the limitations and approximations built into the Nodal Analysis calculations themselves, appear to dominate the low rate outcomes.

I-d. Sensitivity to Allocated rates and ratios (Gas, Oil & Water)

The impact of uncertainties in reported rates and fluid flow ratios (water cut, gas oil ratio, etc.) are analyzed next using the A-06 well in the N R20-1 Reservoir as example. There were two historical wells completed in the reservoir: A-06 and A-12. The A-12 completion was reported Shut-in in May-2001 with a DX plug in the tubing and there is very little data applicable to post-incident flow for A-12.

Allocated Well rates:

With very few exceptions the only fluid production rates that are known with good accuracy in an oil field, are the oil and gas export sale rates going through the fiscal meters (Sales and Royalties)

Monthly reported through-well-bore historical well by well hydrocarbon and water rates are not direct measurement. They are calculated through an allocation procedure from the overall export/sales volumes metered (fiscal metering), the overall estimated gas losses (flare, fuel, vent, etc.) and the overall water production estimates for the field. These allocation calculations are based on individual well flow test conducted from time to time for each well.

Allocated Oil production rates by well are almost always the most accurate, followed by Gas and then water. Overall Gas production figures are less accurate because some gas is flared, some is used as fuel to run the field, some is vented; and some is recycled as Gas Lift injection gas that is produced back. Water production is almost always the most inaccurate of all the volumes. Even overall water production is seldom measured accurately. Water is not a product for sale and there are few incentives to measure it accurately even at the overall field level. Its disposal is regulated and can be difficult and costly.

Allocated historical through-wellbore-rates per well in mature fields (usually with little or no automatic instrumentation) are as a rule of thumb assigned a 5 – 10% estimated variability. This error comes mainly from: the back-allocation calculations, errors in the test measurements themselves (difficulties with emulsions, foam, etc. during separation, for example), and the correction of these measured volumes to reporting standard conditions.

In tests with gas lift, the produced gas measured through wellbore, needs to be split into gas coming from the injected gas lift (which is NOT reservoir production) and gas coming from the reservoir (which IS). Depending on the field set up, the gas lift gas may be metered at each well head, but usually the lift gas injected per well is allocated based on injection conditions, for the overall gas lift gas compressed.

Moreover, to model the test in Prosper, the depth of gas lift injection needs to be known. This can get complicated if multiple live gas lift valves exist.

A-06 Nodal Analysis sensitivities:

For well A-06, suitable Nodal Analysis test data (including flowing bottom hole pressures) was found for only three (3) flowing tests: Sep-1987, Mar-1990 and May-2002; with the May-2002 test corresponding to the Platt-Sparks **Early Test** calibration point. As in the A-02 case above, an additional A-06 flowing test for Sept-2004 (right before the incident) – the 4th test in the A-06 case - was "reconstructed" by Platt-Sparks and used for their **Late Test** match. For A-06, there appears to have been an allocation test in mid-2004, so the reconstruction of the Late Test in this case appears to have been less of a stretch than for A-02.

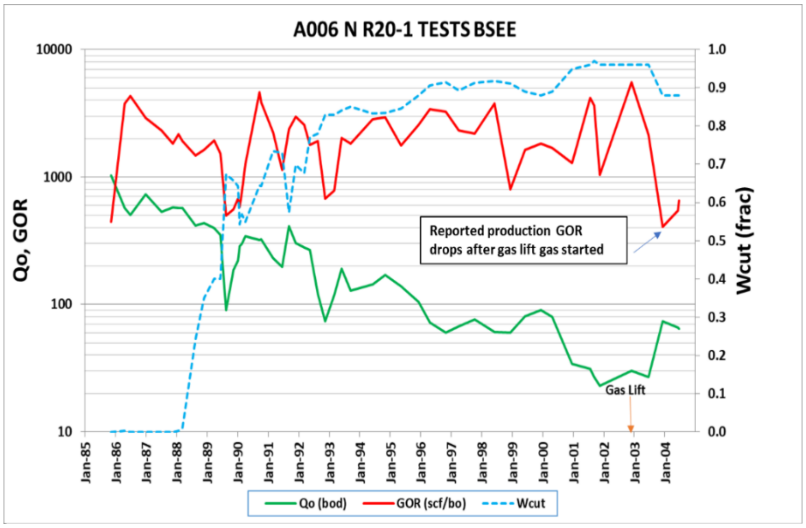

Figure 6 Regulator Reported Test data for well A-06. Note Log scale, ups and down is reported GOR and significant GOR drop after Gas Lift started

As the Sept-1987 test did not trend with the others, it was dropped. There appears to have been a well intervention or workover after this test and before the next test in 1990.

Figure 6 shows all the A-06 flow test as reported to the Regulator for the life of the well:

- A-06 had a relatively high and quite variable Gas Oil Ratio (GOR) reported for most of its life. This GOR behavior appears related to the N sand having an oil leg and a gas cap; this is also an indicator of variability in the reservoir gas measurements during the tests.
- There was a significant reduction in reported GOR after gas lift was started in late 2002.
- The frequency of testing was about once every 6 months; which would affect the allocation calculations if there were significant changes in actual well behavior within the 6 months.
- For the vast majority of these tests, not enough data was measured or reported to use as viable calibration points for any realistic accuracy with Nodal Analysis.

➢ **Again, taking account of minor potential variabilities on the input can have significant impact on the results. This is perceived as a shortcoming in FRACE potential to flow analysis throughout.**

Table 1 summarizes the test data available for A-06 (from Platts-Spark and other sources). It also includes the gas lift gas and water cut sensitivities (in red) that were found to impact the Nodal Analysis outcomes.

Table 1 A-06

Flowing Tests data summary including sensitivity modifications. The Sensitivities to allocated Gas lift gas and water-cut were introduced while keeping overall gas (QG total) unchanged.

Q indicates rate. O=oil, G=gas, W=water, GLG = Gas Lift Gas. THP and BHP refer top tubing head and bottom hole pressures.

Note – Cases 1,2,3 & 5 are from FRACE, Cases 4 & 6 are Task 8 & 9 Sensitivities

Case	Well	Date	Label	Label 2 (*)	THP flwng (psig)	BHP flwng (psig)	BHP SI (psig)	Qo (bod)	Qg (MScf/d)	Qw (bw/d)	QGLG (Mscf/d)	QG total (Mscf/d)	GLG (scf/ stbliq)	Wcut	GOR (Mscf/ stbo)	GLG Depth (MD)
1	A-06	Jul-90	Field		973.6	2709	3615	376	876	450	0	876.1	549	54.5%	2.33	
2	A-06	May-02	Field	EARLY	117.3	2748	3590	29	28	687	393.1	421.1	549	95.9%	0.97	5637
3	A-06	Sep-04	Reconst.	LATE	125	2495	3495	64	29	425	181.9	210.9	372	86.9%	0.45	5637
4		Sensitivity			125	2495	3495	64	49	425	161.9	210.9	331	86.9%	0.77	5637
5	A-06	POST RECH.	Forecast	POST	212		4002			425	0		0	86.9%	0.45	
6		Sensitivity			212		4002				0		0	85.0%	0.77	

The approach in building the Prosper data sets to test sensitivities from Task 8 and 9 work departed some from the procedure in FRACE, this was to strengthen the model and results. Just as in the case of A-02 before:

- the Hagedorn Brown flow correlation was used (instead of the PetEx correlation in Platt-Sparks)
- relative permeabilities were incorporated into the inflow model; and
- all 3 tests (2 field and 1 Reconstructed) were matched simultaneously.

Note also in **Table 1** that for the tests with Gas Lift how much larger is the injected gas lift gas rate vs. the produced gas rate. Therefore, a minor relative variation in the Gas Lift Gas allocation to the well would change very significantly the produced gas component.

Figure 7 shows Nodal Analysis charts for the Simultaneous Match of 4 tests Well A-06; 2 field tests (Tests 2 and 3 shown in chart) and the Late “reconstructed” test twice : once (Test 4 in chart) with the test data gas as in FRACE, and the other (Test 5 in chart) with the sensitivity in the Gas lift/ Reservoir Gas

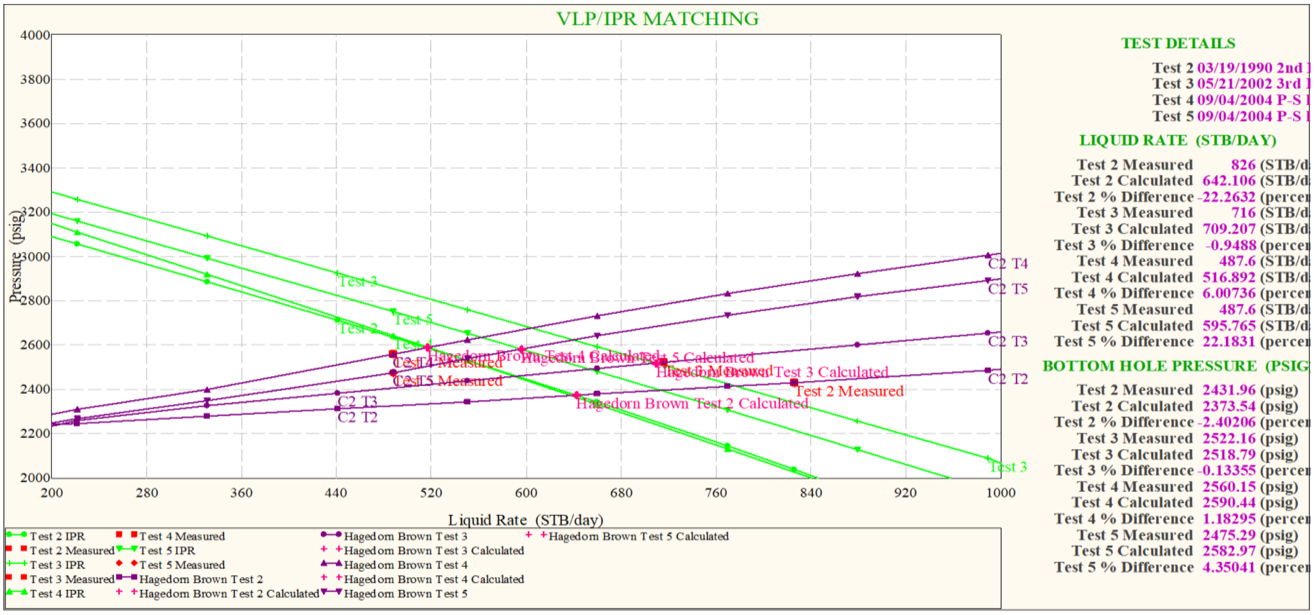

Figure 7 Nodal Analysis charts. Simultaneous matching of the four A-06 Tests (3 + Sept-04 reconstructed), leading to a Skin of 21. The green lines are the inflow performance results and the violet lines represent the tubing performance

in Table 1 (case 4). The matches are all quite close (1 – 20 % mismatch in liquid rates, 2 – 4% mismatch in flowing bottom hole pressure). Note the relatively small changes due to the sensitivity in the Gas Lift Gas / Reservoir Gas allocation. The match led to fixing the Skin factor for the whole of the completed interval as ~ 21 for all tests (which represents approximately a 3 fold reduction in influx vs. no skin). This compares to the skins of 15 for the Early test and 21 for the Late (reconstructed) test, each one matched individually in FRACE -Platt-Sparks.

Rate / flow ratios sensitivities were conducted on well A-06 and it was found that switching just 20 Mscf (~10 %) of the reported gas lift gas to produced gas, keeping the overall gas amount constant, made a significant enough difference in the Nodal Analysis results from a No Flow to a Flow case. These changes are reflected in the Sensitivity lines in Table 1 for the Late (reconstructed) test (Case 4) and the Forecast post-incident (Case 6).

The impact of such small change in gas lift gas is related not only to the differences in depth (produced gas at the bottom, gas lift injection at the active valve depth); but to a peculiarity of the Prosper software: Contrary to how it treats the reservoir gas (instantaneous gas – oil equilibrium everywhere along the tubing), Prosper assumes NO gas – oil equilibration for the Injected Gas Lift gas whatsoever. In the older versions of Prosper (as believed used in the work reported in FRACE) this gas lift gas treatment was a well-known feature. In the newer version use for this work, the same seems to still be the case per the testing conducted.

These parameters were then used in the “sheared top” well model as before and multiple sensitivities once again were tested. Results are shown in **Figure 8** and are summarized in the table that follows

Well A-06 Cases from Table 1	Flow Pattern Correlation	Skin	Calibration	Recharge Pressure	Wcut (%)	GOR sensitivity	Result
Case 5 in FRACE	PetEx	17	Late Test	MBAL (4002 psig)	87%	No	No Flow
Case 5 + 48psi (2%) but not accepted in conclusion*	PetEx	17	Late Test	+ 48 psi (+2%)	87%	No	Flow
Case 6	Haged.-Brown	21	4 Tests	MBAL	87%	No	No Flow
Case 6 with GOR & 5% P recharge sensitivity	Haged.-Brown	21	4 Tests	+5 %	87%	Yes	Flow
Case 6 with +5% pressure & -2% Wcut	Haged.-Brown	21	4 Tests	+ 5%	85%	Yes	Flow

*Note: The Recharge Pressure sensitivity post-incident in FRACE above was taken from Platt-Sparks et.al. in FRACE report

As before, sensitivities in parameters within conservative (small) ranges can switch the Flow – No Flow outcome of the Nodal Analysis calculations. These sensitivities are well within the range of error used in the FRACE model and analysis.

I-e. Skin, contributing Reservoir interval and Applicability of Nodal Analysis to low rates:

Skin is a parameter used in modeling inflow capacity of a well when compared to a no-problems or as-expected situation. A high skin means the completion is underperforming vs. its potential as designed; and used to justify an intervention to attempt increase production. Skin is highly dependent upon the flowing interval (H), which is inputted as parameter into the analysis.

For producing wells, it is customary to set H to all (or almost) of the net perforated interval. In other words, it is assumed that all reservoir exposed to the completion contributes to the flow.

This approach is valuable as a forecast and diagnostic tool for producing wells, however in reality, a nodal analysis gives no information on:

- what may be causing the skin (plugged perforations, sand in the hole, fines migration, high effective viscosity emulsions, scale plugging, asphaltenes, etc.)
- how much of the completed interval (H) is actually flowing
- details about where the oil, gas and water are actually coming from, within the completed interval.

A way to check the impact of the assumed H in the forecasted Flow/no Flow results, is to analyze the components that make up the overall Pressure drop (Reservoir to Tubing Head) in Prosper. The following are the overall pressure drop components:

- Gravity or fluid column weight (Dp Gravity in Prosper output).
- Friction from flowing fluids (Dp Friction in Prosper).
- Completion Skin (Dp Skin in Prosper).

Platts Sparks report the mentioned above components in the Appendix to the FRACE report. For the specific case of the A-02 **Late test**, the sum of the components is ~3600 psi; of pressure drop, of which;

- ~32% is due to fluid weight (gravity) in the tubing,
- only ~ 1% is due to flow friction in the tubing; and
- ~67% is due to Skin (very large skin of 114 impacting only the reservoir-to-well inflow)

In cases like A-02 with standard flow tests that lead to large skins; using those large skins in the forecast will control the Flow Case, i.e. drive a No Flow case. Additionally, for the uncontrolled discharged case at low rates one can not assume the same skin always applies. As flowing conditions change the actual flowing interval can change.

The list of wells with very high skins (> 70) in FRACE post-incident include:

Well	**A-14ST**	**A-02**	**A-13 (Gas)**	**A-20**	**A-12D**	**A-03**
Skin in FRACE post incident Forecast	**1460**	**114**	**111**	**109**	**95**	**73**

These were <u>all listed as having No Potential to flow</u> in FRACE (Platt–Sparks et. al.) As a reference for magnitude of a skin value the current version of prosper does not even allow for skins over 100.

<u>Partial completed interval flow</u>:

The assumption of how much of the perforated interval is contributing to flow goes beyond skins in evaluating Potential to Flow or No Flow. In FRACE it was assumed that the entire perforated interval and associated skin applies to a low rate discharge calculation (Flow / No Flow result).

- Either, the whole perforated interval produces in steady-state (stable cross over), with a Skin, reservoir permeability, watercut and other parameter the full interval flowing test matches
- Or, there can be no flow.

However, actual reservoir source of a low rate discharge can come from:

- just one or more of several sand stringers exposed to the well.
- good quality/permeable streak recharging oil by fluid segregation
- some lower quality rock partially bypassed during production by preferential flow through a high permeability streak.

➢ There are many possibilities, each with its own combination of flowing oil and water and its own local reservoir properties.

Conceptually, if attempting a nodal analysis type model match for one of these small intervals, the local skin would be totally unrelated to the matched Skin for the flowing tests and other inputs, such as H, average permeability, the water cut, GoR etc.

The left side of **Figure 9** illustrates the possibility that only a small part of the completed interval would flow, as well as the partially segregated distribution of oil and water in a heterogeneous reservoir around the well after a period of low or no production. It is compared with a more idealistic representation from the FRACE report on the right, with a homogeneous reservoir and whole perforated interval flowing.

Once the possibility of one or more individual streaks of the whole reservoir at the completion is flowing is accepted, the whole Nodal Analysis approach as used in FRACE to forecast possible low flow

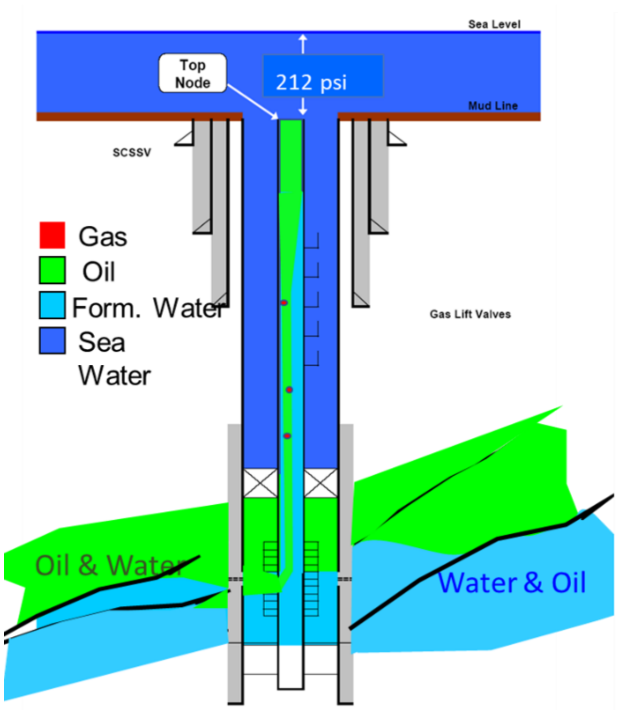

Figure 9 To the left cartoon representation of a more complex near well heterogeneous subsurface and partially segregated fluids with the possibility that only a small part of the completed interval (the likely low damage, highest quality part) is flowing. To the right the cartoon representation (from Platt-Sparks in FRACE) illustrates a calculation which implicitly assumes the only flow can come from the whole interval with the parameters from "commercial rates" flow test matches.

rates in the M20 wells post incident loses most of its value. It becomes a conceptual model that may not apply at all.

I-f. Gas Lift valves, the case of well A-23:

The A-23 well represents a different twist on risking the possibility of an uncontrolled release (potential to flow). A-23 was a gas well and the only producer in the M-1 RA. In a mid '04 most recent production test, it was flowing gas naturally (no lift) with a very healthy tubing head pressure of over 1000 psi, and negligible water. While this well would be a seemingly obvious candidate to be designated as having a potential to flow, FRACE concluded that it belonged in the No Flow case.

The available A-23 completion diagram lists not one, but four live gas lift valves in the completion between ~2200 and ~4900 ft TVD over 4000 ft shallower that the perforated interval ~ 9270 ft TVD. The data also shows that A-23 was never actually gas lifted. It is highly unusual to fit relatively shallow gas lift valves in a gas well, these valves would have little to no impact in overcoming potential liquid loading (water accumulated at the bottom of the well), which is the usual reason to artificially lift a gas well and was not occurring at the time according to the data.

Cobb et.al did not conduct MBAL or Nodal Analysis work on the M-1 RA reservoir for FRACE, since A-23 was flowing without lift right before the incident and any aquifer inflow would only increase the reservoir pressure and the flow. It was concluded A-23 had Potential to Flow post-incident.

However, in the Platt-Sparks et. al. FRACE revision of Cobb's work, A-23 was set to No Potential to Flow on an assumption that a sea water influx through the gas lift valves killed the well.

In the FRACE revision of the earlier Cobb work, Platt-Sparks performed Nodal Analysis calculation for A-23 and concluded that the well would Flow. As the only recorded pressure from this reservoir was from initial conditions, a reservoir pressure was estimated to be 1920 psi at A-23 in Sept-2004 and this was deemed a reasonable. From the derived Reservoir Pressure behavior and the lack of water production, it was concluded there was little or no aquifer support and the same estimated 1920 psi was used as a Recharge Pressure for the reservoir (Assumed 0 recharge).

Separately, Boots and Coots in FRACE (March 2010) stated that sea water would kill the A-23 well for any reservoir pressure lower than 2250 psi. Platt-Sparks then concluded the water influx through the gas lift valves would kill the well and changed the result to a NO Potential to Flow.

Some rather glaring uncertainties not accounted for in this conclusion:

(1) Did the well actually have live gas lift valves in the completion at the incident? and if so, were they really operational to open on annular pressure? Or were they plugged/not operable due (a) years of no use inside a flowing well (b) the impacts of the incident on the well tubulars. As mentioned above it is highly unusual for a gas well to have shallow live gas lift valves in the completion and A-23 was never reported as being gas lifted.
(2) The 1920 psig reservoir pressure in Sept-2004 is a much more uncertain estimate than the equivalent pressures for other reservoirs with multiple historical pressure calibration points for the MBAL model. In addition, keeping the Recharge Pressure equal to the 2004 pressure at 1920 psig is yet another assumption (no aquifer inflow at all). Taking the 2250 psig estimated minimum reservoir pressure to flow post-incident at face value (no variability) all it would take is a +17% variation in the recharge pressure estimate to reach the onset of flow conditions (1920 + 17% ~ 2250). This 17% seems conservative when compared with the conservative 10% used in task 8 and 9 work and the realistic possibility of a 20% to 30% potential variability discussed in the pressure recharge section.

Erring on the side of prudence, as is required in evaluating the possibility of an uncontrolled discharge situation, would indicate that the original Potential to Flow conclusion is recommended.

II. Well Integrity

The Potential to Flow analysis in FRACE uses Nodal Analysis as described above and therefore assumes well integrity and zonal isolation below the mudline. In other words, only the perforated interval can flow, and do so only through the tubing; in confusing manner this concept is referred to in FRACE as "assuming loss of integrity". This approach is justified in FRACE by describing it as optimistic to flow, because it does not consider restrictions and blockages in the tubing due to the incident.

The following is what is actually assumed in the "Loss of Integrity" case in FRACE:

- Considers an additional pressure resulting from of a column of sea water from Mud line up vs. a lighter oil / gas column, an addition of pressure on the well which is detrimental to a Flow case.

- It still assumes that flow is coming through the completion, into the tubing and flowing through tubing up to the mud line. Complete integrity and zonal isolation are assumed below the mud-line all the way to the perforated interval.

    ➢ The approach in FRACE is actually extremely pessimistic to flow. By assuming integrity and zonal isolation, it completely disregards many alternate paths to flow due barrier failures. Failures in cement, tubulars, seals, packers, valves and/or other barriers below the mudline, could allow fluids to not only bypass the tubing but even the inside of the well altogether, and potentially show up at surface.

    This assumption in FRACE completely contradicts actual observations that were stated in the actual FRACE report itself (see p.57 FRACE);

    "At MC-20 the Christmas trees and wellheads were severely damaged and compromised as they were pulled from the deck and stripped through the jacket assembly. This was confirmed during salvage of the production deck. Essentially all the annuli and tubing above the mud-line can be considered "open-ended" in the area where the wellheads were originally installed."

Considering the likelihood of severe loss of integrity and of zonal isolation, resulting from the incident; all penetrated hydrocarbon sands, above hydrostatic pressure, have the Potential to Flow.

This above applies to:

- Shallow (not produced) hydrocarbon bearing sands
- Thin "non- commercial" hydrocarbon sands within the produced reservoir stack
- Pressure recharged sands above hydrostatic behind casing in a particular well (completed or not)

The loss of integrity model is supported by:

- The potential for massive lateral and vertical displacements of the well tubulars as a result of the event.

- The presence of an active discharge while all wells were equipped with subsurface safety valves, which if self-actuating per design, should have closed the tubing to flow in all cases.
- Well Integrity issues, Finding #3 in this report
- All initial (pre-production) hydrocarbon pressures in MC-20, for all sands/reservoirs above hydrostatic.
- The cement bond quality of the wells prior to the incident is reported as good only in limited spots in some wells. In most instances it is unknown and/or reported as poor
- In mature fields with stacked reservoirs, it is not un-common to have zonal isolation issues (communication behind casing) between producing and non-producing reservoirs.

This potential to flow from loss of well integrity was clearly discussed in the Stuart Wright et.al report, within the context of their Well integrity Risk Analysis. It was also mentioned, but not discussed in detail, in the Kelkar and Associates Report, when assessing the Cobb et.al Potential to Flow Report in FRACE.