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Software for Analysis of Drilling Fluid Contamination

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Abstract

The very application of drilling fluid makes it a natural target for contaminants, be they from surface or downhole sources. Procedures to neutralize contaminants or mitigate their effects must necessarily begin with identification and quantification. Precise identification of a contaminant in a water-based drilling fluid requires a thorough analysis of the physical, rheological and chemical properties of the fluid and an understanding of trends and changes in those properties. Variance in the testing results between individuals or from one test to the next is common and can produce misinterpretation of the results. This new software program provides a thorough yet efficient workflow in an effort to manage this variability.

The software not only accounts for the variances in the measurements of fluid properties, but can further help define a specific contaminant. In addition to determining the source of contamination, the software identifies the remedial chemicals needed to correct the problem and precisely calculates how much of each to use for any volume. This program is an invaluable training tool for drilling fluid school students. In addition, it can be a valuable reference aid for lab technicians and field techs and engineers.

Introduction

In an ideal drilling fluid system, assuming that the condition of the hole is stable, the drilling fluid properties such as density, viscosity, filtration, etc. should not change during the drilling operation. However, in practice, this never occurs. In the field, some drilling fluid properties will eventually change even if the condition of the hole is stable. Contamination of the drilling fluid system can come from any one of the following sources: materials coming from the formation, thermal degradation of organics in mud, aeration or overtreatment at the surface.

These different contaminants have different effects and consequences which lead to necessary treatment to minimize and avoid drilling problems. Therefore, it is important to know the contaminants before applying the treatment. Below is a list of typical contaminants:

1. Drilling Solids
2. Anhydrite/Gypsum
3. Cement
4. Salt Formations/Salt Water Flow
5. Carbonates and Bicarbonates
6. Hydrogen Sulfide

The contaminants in the drilling fluid can be determined by testing the drilling fluid properties before and after contamination and evaluating the change in each of those properties. This means that the drilling fluid properties should be determined as accurately as possible using a repeatable and properly selected test procedure. The following is the list of the water-based fluid properties:

1. Density (Mud Weight)
2. Plastic Viscosity
3. Yield Point
4. Gel Strength
5. API Filtrate Loss
6. Cake Thickness
7. pH
8. Pm/Pf/Mf
9. Calcium/Magnesium
10. Chlorides
11. Solids
12. Methylene Blue Test (MBT)
13. Oil Content
14. Water Content

Generally, water-based fluid systems, when compared to non-aqueous fluid systems, are the most susceptible to contamination. Contamination identification techniques apply only to water-based drilling fluid. Therefore the focus of this paper is contamination of water-based fluid systems.

In practice, each Drilling Fluid Service Tech can have varying drilling fluid test results even if the test procedure is consistent. Even repeating the same test, by the same person, may result in some degree of variation. Therefore, the pattern of change in properties may not be definitive for just one contaminant. To compensate for these variations, *a software system was developed to predict the probability of the presence of certain contaminants in a given fluid sample.*

Brief Discussion of Contaminants

The following is a brief discussion of possible contaminants in water-based drilling fluids.

1. Solids:

   Solids are the most common contaminants in drilling fluids. Based on their density or specific gravity (SG), solids are classified into two basic categories:

a) High gravity solids (HGS) are usually the weighting agents i.e., barite, hematite, hausmanite (Mn_3O_4), with SG > 4.0.
b) Low Gravity Solids (LGS), with SG 1.6~2.9 (average SG of 2.5~2.6), are further be classified into three categories:
   1. Commercial bentonites, with an assumed average SG of 2.6.
   2. Drilled formation solids, with an average SG of 2.5 or 2.6.
   3. Calcium carbonate, another weighting agent, with an average SG of 2.7.

HGS are added to increase the density of the drilling fluids and are normally non-reactive solids. Bentonites are reactive solids and purposely added to increase the viscosity of the drilling fluids and reduce the fluid loss to the formation. Drilled formation solids are partially reactive relative to bentonites. The degree of reactivity depends on the formation being drilled. Drilled solids build-up, because solids control equipment removal efficiency is less than 100%. As drilling progresses, the solids are re-circulated. Through the circulation process, mechanical degradation reduces the particle size of the drill solids. The increase in solids concentration and continuous reduction in particle size increases the surface area. The increased surface area results in increased fluid rheology, particularly the plastic viscosity.

Fine solids, generally less than five microns, cannot be removed by the solids control equipment. Dictated by economic analysis, either partial drilling fluid system dilution or total system replacement needs to take place. The efficient use of solids control equipment minimizes the build-up of the undesirable drilled formation solids.

Symptoms of solids contamination in water-based fluid properties are shown in Table 1-A in the Appendix.

2. Anhydrite/Gypsum:

Anhydrite and gypsum are almost identical in chemical composition. Anhydrite is the water-free form of gypsum. Gypsum ($CaSO_4 \cdot 2H_2O$) with its water attached is more soluble than anhydrite ($CaSO_4$). The degree of contamination depends both on the solubility and the amount of the formation drilled.

As $CaSO_4$ solubilizes, the calcium ion goes into solution. Calcium ions flocculate clays in the fluid system and affect the properties of the drilling fluid. This is similar to cement contamination except the pH is lower.

If the source is small anhydrite stringers, calcium may be treated out with soda ash or sodium bicarbonate. It is important to avoid overtreatment as it may cause carbonate/bicarbonate contamination. If drilling massive anhydrite is expected, the original fluid system may be converted to gyp mud system, which will fully tolerate the calcium contamination. If the system is treated rather than converted, soda ash is preferred over bicarb as dictated by the lower pH of a gyp contamination.

A small amount of calcium ions is beneficial to most systems, acting as buffer against undesirable carbonate alkalinity.

Symptoms of anhydrite/gyp contamination in water-based fluid properties are shown in Table 1-A in the Appendix.

3. Cement:

Drilling wells requires drilling cement after each casing or liner is set. Cement chemistry is complex. In water-based drilling fluids, hydrated lime ($Ca(OH)_2$) solubilizes in the water phase producing hydroxyl (OH^-) and calcium (Ca^{2+}) ions. The major contaminant is calcium, similar to gypsum contamination, except the hydroxyl ions raise the pH (pH > 11.5). The degree of contamination depends the amount of cement drilled, the extent to which the cement cured, pre-treatment of chemical, and solids type/concentration. When the pH exceeds 11.7, lime (cement) becomes insoluble. If a large amount of green or soft cement is expected, the original fluid system may be converted to lime mud system, which is tolerant to cement contamination. The hydroxide ion may compound the problem if the temperature >250°F, which may solidify the lime mud system. If the amount of cement contamination is relatively small, the contaminated drilling fluid can be treated with chemicals. The three common basic products used to treat out cement are bicarb, soda ash, and SAPP. SAPP performs better than the other two, but has a temperature limitation of 180°F. Bicarb is preferred over soda ash.

Symptoms of cement contamination in water-based fluid properties are shown in Table 1-A in the Appendix.

4. Salt Formations/Salt Water Flow:

Common salt formations include salt domes, salt stringers, massive complex evaporites, and brine flows.

Sodium chloride is the most common salt encountered. Potassium chloride, calcium chloride, and magnesium chloride are sometimes drilled in complex evaporites. These salts will flocculate the system, lower the pH, and likewise affect the properties of the drilling fluid.

There are physical and mechanical differences in salt structures. Salt is impermeable and plastic. Salt formations often contain other evaporate minerals, i.e., anhydrite, gypsum, kieserite, limestone or dolomite.

During salt or brine flows, the initial task is adjusting the density of the drilling fluid to prevent further influx. The next task is to condition the mud. Possible treatments include:

a) Increasing salt concentration to saturation to prevent hole enlargement.
b) Increasing salt concentration to slightly below saturation to encourage hole enlargement, minimizing the risk of stuck pipe.
c) Converting the system to a salt-tolerant drilling fluid.
d) Displacing to a salt-tolerant fluid system, such as non-aqueous system.

Symptoms of salt formations/salt water flow contamination in water-based fluid properties are shown in Table 1-A in the Appendix.

5. Carbonates and Bicarbonates:

Carbonates/bicarbonates are two of the most complicated types of contamination. These contaminants flocculate the reactive solids. Therefore, the degree of contamination increases as the reactive solids increase. It is sometimes diagnosed as an increase in solids only. The use of deflocculants has little or no effect. The proportion of carbonates to bicarbonates is a function of pH (see Figure 1). This may be recognized by Mf increasing faster than Pf, YP increasing, and progressive gel strength.

The sources of carbonates and bicarbonates include:

a) CO_2 gas from the formation or from formation water.
b) Overtreatment with bicarb and soda ash when treating out contamination from gyp or cement.
c) Thermal degradation of organic additives (lignosulfonates, lignite, starch, etc.).
d) CO_2 from air injected through mixing equipment and solids removal equipment.
e) Contaminated barite and bentonite.

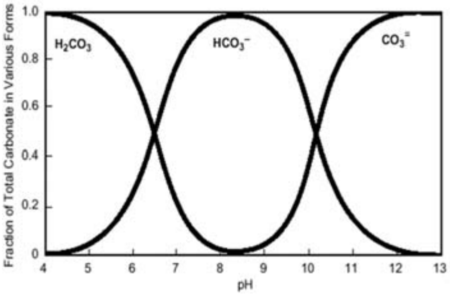


Figure 1 (Carbonate System).

A small amount (millimoles/liter) of carbonates may be tolerated to provide a buffering effect for drilling fluid stability. The two common products used to treat out carbonates/bicarbonates are lime and gyp.

Symptoms of carbonates/bicarbonates contamination in water-based fluid properties are shown in Table 1-A in the Appendix.

6. Hydrogen Sulfide:

In fields with sour gas-bearing formations, the occurrence of hydrogen sulphide (H_2S) is a real hazard. Even in very small quantities, H_2S is lethal when inhaled. The sulfides can also originate from bacteriological decay of organic materials in the fluid system.

High pH converts H_2S to sulphides (SH^-, S^{2-}) which remain in solution so long as the pH remains high. This is considered a potentially dangerous practice, as a small drop in alkalinity will allow the H_2S to reform and be released into the atmosphere. The two common products used to treat out H_2S are zinc oxide and zinc carbonate.

Symptoms of H_2S contamination in water-based fluid properties are shown in Table 1-A in the Appendix.

Varying Test Results of Drilling Fluid Properties

Drilling Fluid Techs can have varying drilling fluid test results despite using the same standard procedure. Some of the reasons are:

1. Visual titration end point of certain properties, such as Pm, Pf, and Mf may not be clear if a filtrate is dark. The use of pH meter, if available, helps determine the end points consistently.
2. Some fluid systems cause elevated values of Pm, Pf, and Mf which may be mistakenly interpreted as coming from the formation.
3. Hardness titration end point may not be easy to see in dark filtrate if using the regular procedure. Additional procedures are recommended by the API.
4. Determination of hardness and calcium may be misleading because some hardness and calcium contaminants could be attached to the solids. In this case, the amount of hardness and calcium is lower in the filtrate than in the drilling fluid, thereby underestimating the contamination determination.

In general, accurately measuring the properties can lead to more accurate troubleshooting of the contaminants, thus avoiding under- or overtreatment.

Experiments on Hardness and Calcium

Lab experiments of hardness and calcium were made with varying concentrations of two contaminants (lime and gypsum) added to a basic lignosulfonate water-based fluid (10.5 pH). In the experiments, the hardness and calcium of the drilling fluid and the filtrate were compared. This is in Table 1 below.

Table 1 (Comparison of Hardness and Calcium from drilling fluid and filtrate).

LAB TEST	BENT PPB	CLS PPB	LIME Added PPB	Hardness Mud mg/l	Hardness Filtrate mg/l	Hard Diff	Ca Mud mg/l	Ca Filtrate Mg/l	Ca Diff
#1	20	2.0	0	520	140	380	340	80	260
#2	20	2.0	1	2000	240	1760	1620	240	1380
#3	20	2.0	2	3200	360	2840	2820	360	2460
#4	20	2.0	3	4600	600	4000	3600	480	3120

LAB TEST	BENT PPB	CLS PPB	GYP Added PPB	Hardness Mud mg/l	Hardness Filtrate mg/l	Hard Diff	Ca Mud	Ca Filtrate	Ca Diff
#1	20	2.0	0	520	140	380	340	80	260
#2	20	2.0	1	1120	440	680	1000	320	680
#3	20	2.0	2	1580	680	900	1460	560	900
#4	20	2.0	3	2100	660	1440	2060	560	1500

In the table above (Table 1), the upper table is for lime contamination and lower table is for gyp contamination. Tests #1 of both the upper and lower tables do not have contamination. Tests #2 to Test #4 have contaminations of increasing concentrations.

The hardness (mg/l) and the calcium (mg/l) should increase if there is either a contamination of lime (cement) or gypsum (anhydrite). From Table 1, the data shows that the hardness (mg/l) and calcium (mg/l) taken (titrated) from the drilling fluid is much higher than taken (titrated) from the filtrate. As the contamination increases, the increase of calcium and hardness taken from the drilling fluid is more obvious than that of calcium taken from the filtrate. Therefore, it is worth taking both the calcium (mg/l) from the drilling fluid and the filtrate (mg/l) to confirm the severity of calcium contamination.

The combined severity will dictate the initial calcium (mg/l) treatment without risking overtreatment. If the treatment is based only on the amount of calcium from the filtrate, the calcium may be undertreated, depending on the amount of calcium and the type of system. See Lab Test #2 in the upper and lower table in Table 1 (Ca mg/l Filtrate). As drilling progresses, some of the calcium attached to solids in the drilling fluid will eventually be released into solution, continuing the process of contamination.

If all the calcium from the drilling fluid is treated (Ca mg/l mud), the drilling fluid may be overtreated. Leaving some calcium (mg/l) buffers the fluid system. This technique can be considered on a case-by-case basis, depending on the system. The initial amount of calcium to treat out is discussed on page 8, in paragraph “Experiments to Treat out the Calcium”.

The Symptoms of the Different Contaminants

A. Chart Method:

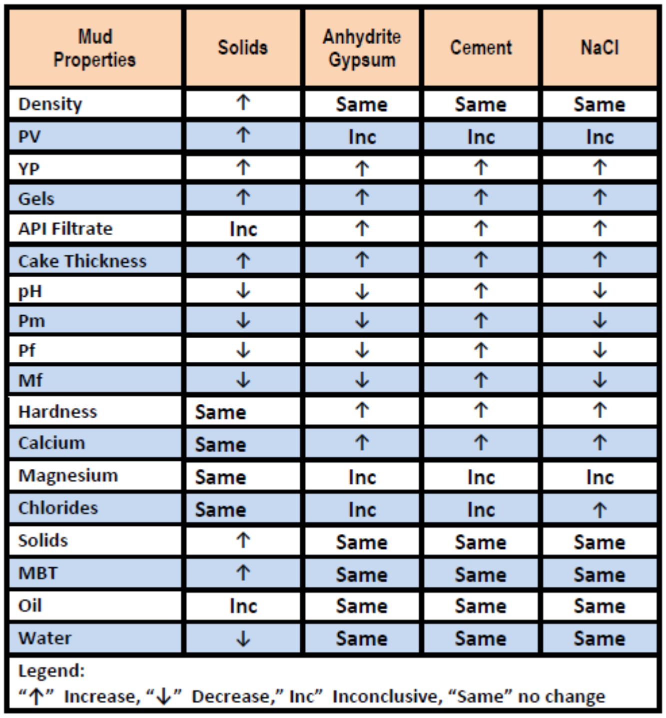
Charting the eight (8) contamination types vs. the 18 fluid properties allows identification of unique sets of relative changes of those properties, thereby allowing determination of the contamination. See Table 2 below (Part 1 of 2 and Part 2 of 2). Table 2 is also shown in the Appendix as Table 1-A, a combined table of both Contamination Chart, Part 1 of 2 and Part 2 of 2.

Table 2 is based on a relative change of the properties, i.e., the comparison change of the each property before and after the contaminations. Four conditions of every change of property are possible:

1. “↑” Increase
2. “↓” Decrease
3. “Inc” Inconclusive (may do either)
4. “Same” No change

Newpark and Chevron fluid techs and engineers use these charts in the field and in respective Drilling Fluid Schools.

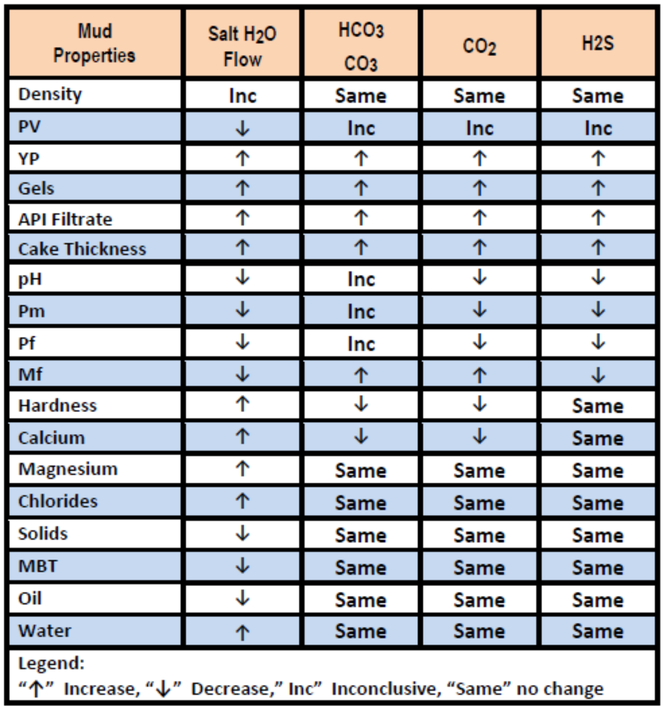
Table 2 (Contamination Chart, Part 1 of 2)



Mud Properties	Solids	Anhydrite Gypsum	Cement	NaCl
Density	↑	Same	Same	Same
PV	↑	Inc	Inc	Inc
YP	↑	↑	↑	↑
Gels	↑	↑	↑	↑
API Filtrate	Inc	↑	↑	↑
Cake Thickness	↑	↑	↑	↑
pH	↓	↓	↑	↓
Pm	↓	↓	↑	↓
Pf	↓	↓	↑	↓
Mf	↓	↓	↑	↓
Hardness	Same	↑	↑	↑
Calcium	Same	↑	↑	↑
Magnesium	Same	Inc	Inc	Inc
Chlorides	Same	Inc	Inc	↑
Solids	↑	Same	Same	Same
MBT	↑	Same	Same	Same
Oil	Inc	Same	Same	Same
Water	↓	Same	Same	Same

Legend:
“↑” Increase, “↓” Decrease,” Inc” Inconclusive, “Same” no change

Table 2 (Contamination Chart, Part 2 of 2)



Mud Properties	Salt H_2O Flow	HCO_3 CO_3	CO_2	H2S
Density	Inc	Same	Same	Same
PV	↓	Inc	Inc	Inc
YP	↑	↑	↑	↑
Gels	↑	↑	↑	↑
API Filtrate	↑	↑	↑	↑
Cake Thickness	↑	↑	↑	↑
pH	↓	Inc	↓	↓
Pm	↓	Inc	↓	↓
Pf	↓	Inc	↓	↓
Mf	↓	↑	↑	↓
Hardness	↑	↓	↓	Same
Calcium	↑	↓	↓	Same
Magnesium	↑	Same	Same	Same
Chlorides	↑	Same	Same	Same
Solids	↓	Same	Same	Same
MBT	↓	Same	Same	Same
Oil	↓	Same	Same	Same
Water	↑	Same	Same	Same

Legend:
“↑” Increase, “↓” Decrease,” Inc” Inconclusive, “Same” no change

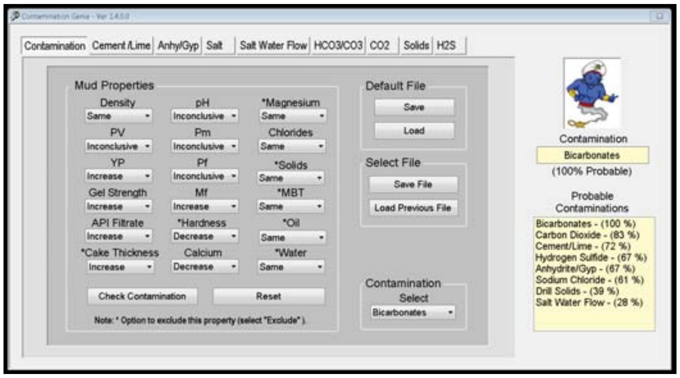
B. Software Method

If fluid property measurements are inaccurate, the pattern of change in properties compared to Table 2 (Contamination Charts) may not be definitive for just one contaminant. To compensate for inaccurate measurements, a software program was developed to determine the *probability of contaminations.* The input into the Contamination Software mirrors the Contamination Chart (Table 2). The magnified image of this software is also in the Appendix, as Figure 2-A. This software aids both contamination troubleshooting (even with inaccuracies of some fluid properties) and treatment recommendation. Students from separate drilling fluid schools of Chevron and Newpark have used this software to confirm the contamination identified in the contamination chart. The software calculated the amount of treatment for each contamination with ease.

As shown in Table 2, four conditions for every property change are possible:

1. "Increase"
2. "Decrease"
3. "Inconclusive" (may do either)
4. "Same" (no change)

Enclosed in the red rectangle of Figure 3 are the 18 fluid properties equivalent to that of the Contamination Chart in Table 2. The magnified image of the red rectangle is shown in Figure 4.



Contamination
Select
Bicarbonates

Contamination
Bicarbonates
(100% Probable)

Probable Contaminations
Bicarbonates - (100 %)
Carbon Dioxide - (83 %)
Cement/Lime - (72 %)
Hydrogen Sulfide - (67 %)
Anhydrite/Gyp - (67 %)
Sodium Chloride - (61 %)
Drill Solids - (39 %)
Salt Water Flow - (28 %)

Figure 2 (Contamination Software)

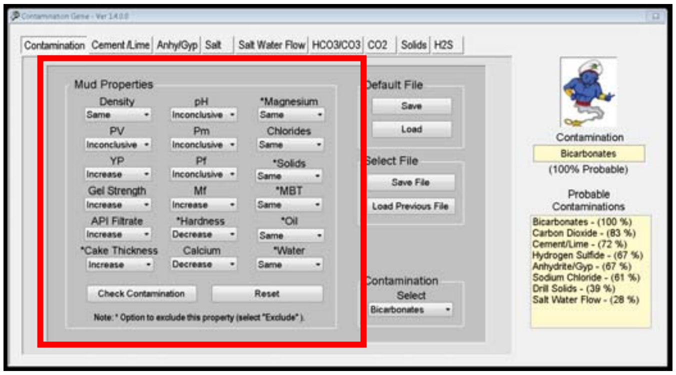
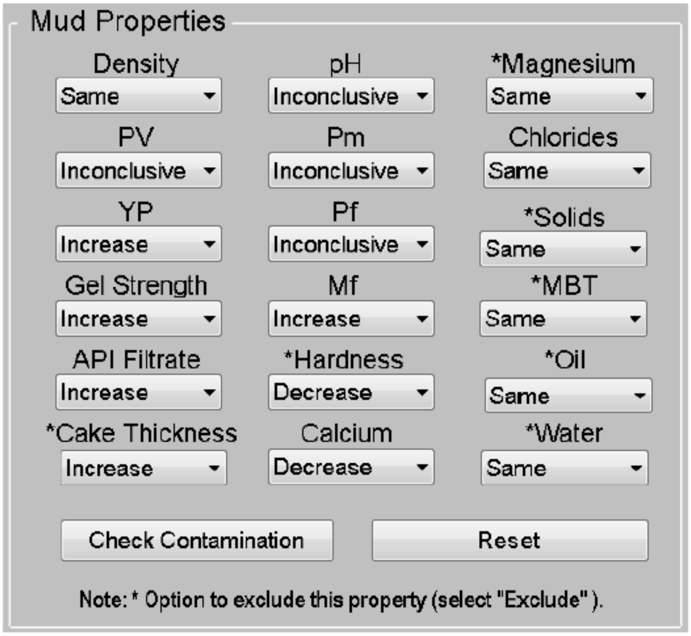


Figure 3 (Fluid Properties of Contamination Software)



Property	Setting	Property	Setting	Property	Setting
Density	Same	pH	Inconclusive	*Magnesium	Same
PV	Inconclusive	Pm	Inconclusive	Chlorides	Same
YP	Increase	Pf	Inconclusive	*Solids	Same
Gel Strength	Increase	Mf	Increase	*MBT	Same
API Filtrate	Increase	*Hardness	Decrease	*Oil	Same
*Cake Thickness	Increase	Calcium	Decrease	*Water	Same

Note: * Option to exclude this property (select "Exclude").

Figure 4 (Magnified Image of Figure 3)

The user selects the condition of the change of fluid property by clicking the button (combo box) of any property and selecting "Increase", "Decrease", "Inconclusive" (may do either), or "Same" (no change). See Figure 5

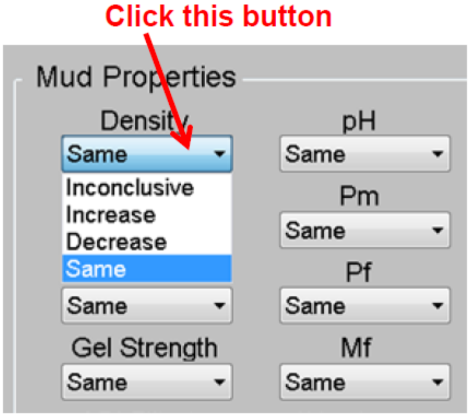


Figure 5 (Four Conditions of Every Change of Fluid Property)

The following fluid properties, denoted with an asterisk (see Figure 4), have an additional option:

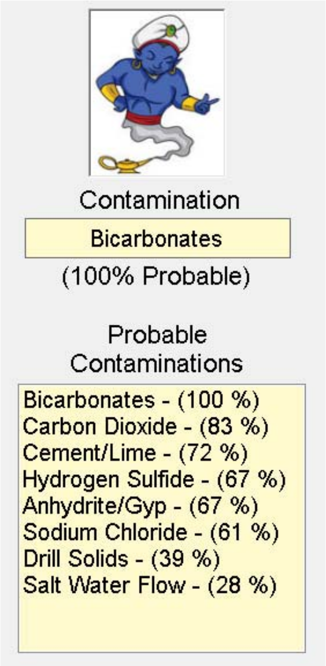
1. *Cake Thickness
2. *Hardness
3. *Magnesium
4. *Solids
5. *MBT
6. *Oil
7. *Water

When a property with an asterisk is clicked an “Exclude” option is included. If “Exclude” is selected, such as shown in Figure 6, this fluid property will not be included in the calculation of the Probable Contamination percentage.

*Cake Thickness
Exclude

Figure 6 (Exclude the Cake Thickness Fluid Property)

To fully explain the software’s functionality, several examples are provided. For the first example, all the changes of the fluid properties are set like Figure 4, which is the same as that of Contamination Chart (Table 2, Contamination Chart, Part 2 of 2, under the column HCO3/CO3). When the button “Check Contamination” is clicked, the Probable Contamination percentages are calculated. Notice that in this particular case Bicarbonates have a Probable Contamination of 100% (see Figure 7). When a contamination has a 100% probability, the treatment window for that containment automatically opens. If no contaminant is 100% probable, the software remains in the “Contamination” tab.



Contamination
Bicarbonates
(100% Probable)

Probable Contaminations

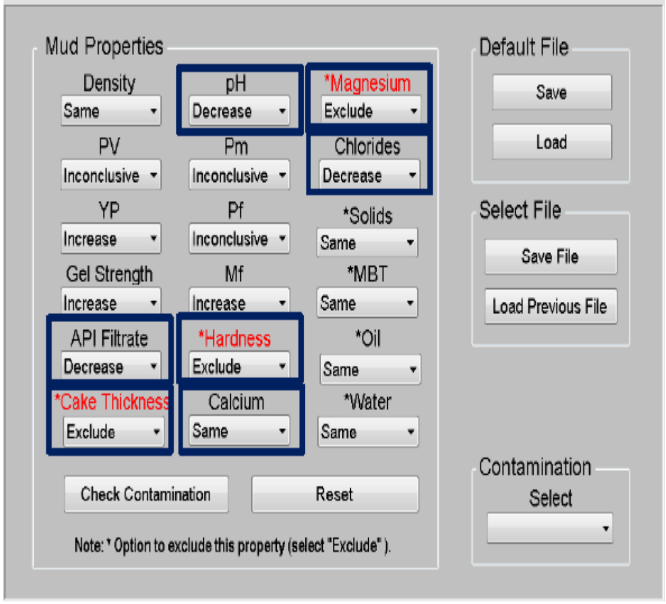
Bicarbonates - (100 %)
Carbon Dioxide - (83 %)
Cement/Lime - (72 %)
Hydrogen Sulfide - (67 %)
Anhydrite/Gyp - (67 %)
Sodium Chloride - (61 %)
Drill Solids - (39 %)
Salt Water Flow - (28 %)

Figure 7 (Magnified Image of Figure 3)

As another example, the settings from the previous (100 % Probable Bicarbonate) case are changed in this way:

1. API Filtrate is “*Decrease*” instead of “*Increase*”
2. Cake Thickness is “*Excluded*” instead of “*Increase*”
3. pH “*Decrease*” instead of “*Inconclusive*”
4. Hardness is “*Exclude*” instead of “*Decrease*”
5. Calcium is “*Same*” instead of “*Decrease*”
6. Magnesium is “*Exclude*” instead of “*Same*”
7. Chlorides is “*Decrease*” instead of “*Same*”

Figure 8 illustrates the example above with changed fluid properties marked with blue boxes. In this example, “Check Contamination” calculates the Probable Contamination percentage as 80% Bicarbonate, which is still the highest. Figure 9 is the result of Probable Contamination percentages. Because the Probable Contamination percentage is not 100%, the HCO3/CO3 tab will have to be opened (clicked) manually for bicarbonates treatment (see Figure 10).

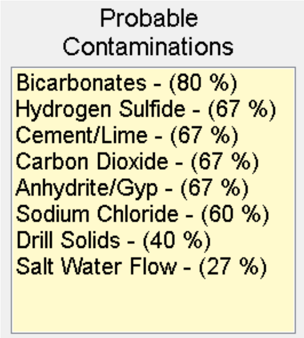


Mud Properties

Density Same
pH Decrease
*Magnesium Exclude
PV Inconclusive
Pm Inconclusive
Chlorides Decrease
YP Increase
Pf Inconclusive
*Solids Same
Gel Strength Increase
Mf Increase
*MBT Same
API Filtrate Decrease
*Hardness Exclude
*Oil Same
*Cake Thickness Exclude
Calcium Same
*Water Same

Note: * Option to exclude this property (select "Exclude").

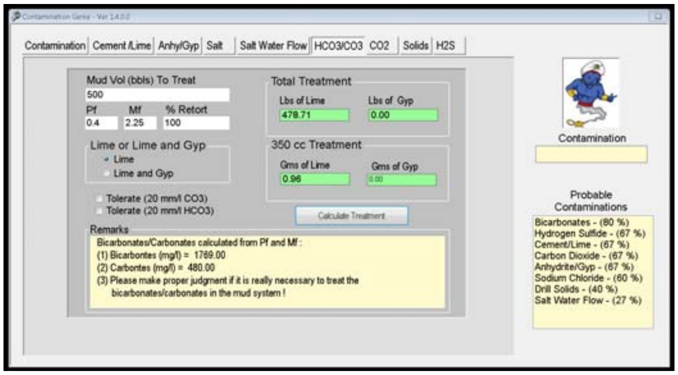
Figure 8 (More Change of Fluid Properties)



Probable Contaminations

Bicarbonates - (80 %)
Hydrogen Sulfide - (67 %)
Cement/Lime - (67 %)
Carbon Dioxide - (67 %)
Anhydrite/Gyp - (67 %)
Sodium Chloride - (60 %)
Drill Solids - (40 %)
Salt Water Flow - (27 %)

Figure 9 (Bicarbonate 80 % Probable)



Mud Vol (bbls) To Treat: 500
Pf: 0.4
Mf: 2.25
% Retort: 100

Lime or Lime and Gyp
● Lime
○ Lime and Gyp

☐ Tolerate (20 mm/l CO3)
☐ Tolerate (20 mm/l HCO3)

Total Treatment
Lbs of Lime: 478.71
Lbs of Gyp: 0.00

350 cc Treatment
Gms of Lime: 0.96
Gms of Gyp: 0.00

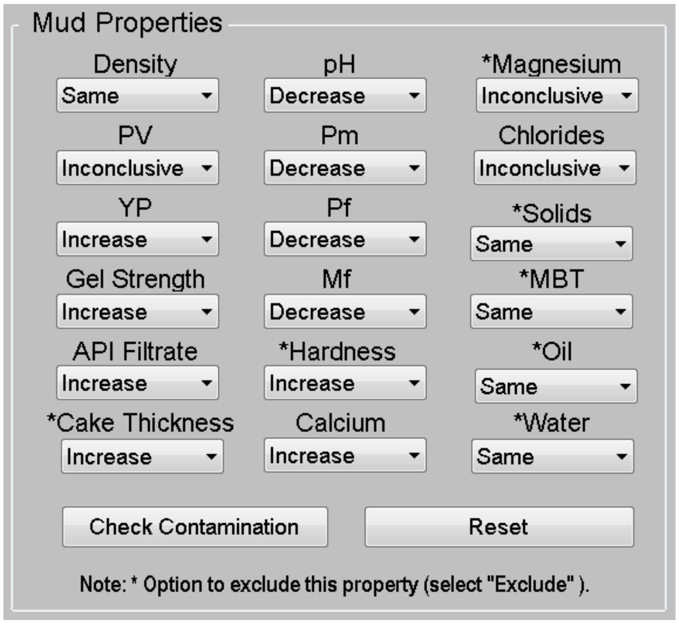
Remarks
Bicarbonates/Carbonates calculated from Pf and Mf :
(1) Bicarbontes (mg/l) = 1769.00
(2) Carbontes (mg/l) = 480.00
(3) Please make proper judgment if it is really necessary to treat the bicarbonates/carbonates in the mud system !

Contamination

Probable Contaminations
Bicarbonates - (80 %)
Hydrogen Sulfide - (67 %)
Cement/Lime - (67 %)
Carbon Dioxide - (67 %)
Anhydrite/Gyp - (67 %)
Sodium Chloride - (60 %)
Drill Solids - (40 %)
Salt Water Flow - (27 %)

Figure 10 (Treatment of $H_2CO_3/HCO_3/CO_3$)

Demonstrating all the combinations of contamination is beyond the scope of this paper. Figure 11 shows a set of changes of fluid properties in which the Probable Contamination percentage is 100% Anhydrite/Gyp (see Figure 12). In this case, because the contaminant is 100% probable, the tab Anhy/Gyp opens automatically. Once the mg/l of calcium is entered and the Calculate button is clicked, the software provides the treatment recommendation. See Figure 13.

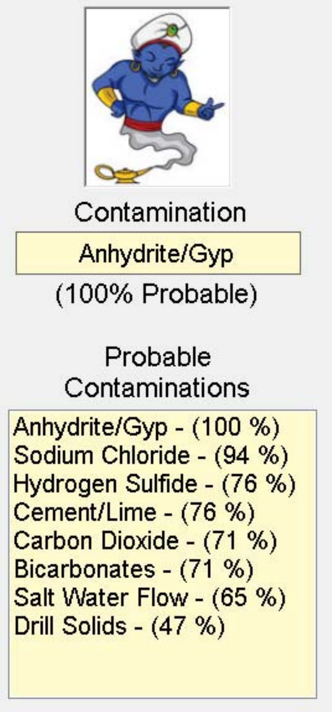


Mud Properties

Density: Same
PV: Inconclusive
YP: Increase
Gel Strength: Increase
API Filtrate: Increase
*Cake Thickness: Increase
pH: Decrease
Pm: Decrease
Pf: Decrease
Mf: Decrease
*Hardness: Increase
Calcium: Increase
*Magnesium: Inconclusive
Chlorides: Inconclusive
*Solids: Same
*MBT: Same
*Oil: Same
*Water: Same

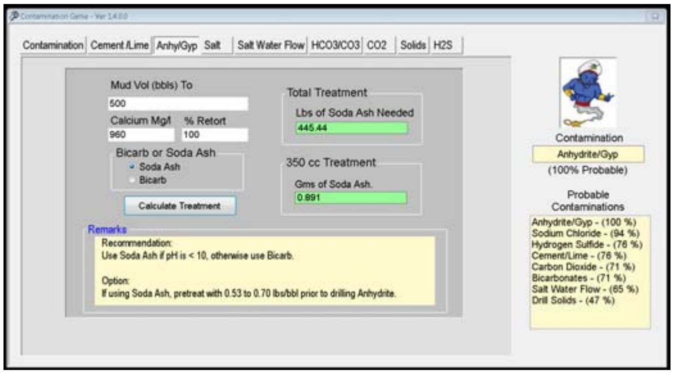
Note: * Option to exclude this property (select "Exclude").

Figure 11 (Last Example)


Contamination
Anhydrite/Gyp
(100% Probable)

Probable Contaminations
Anhydrite/Gyp - (100 %)
Sodium Chloride - (94 %)
Hydrogen Sulfide - (76 %)
Cement/Lime - (76 %)
Carbon Dioxide - (71 %)
Bicarbonates - (71 %)
Salt Water Flow - (65 %)
Drill Solids - (47 %)

Figure 12 (Anhydrite/Gyp 100 % Probable)



Mud Vol (bbls) To: 500
Calcium Mg/l: 960
% Retort: 100

Bicarb or Soda Ash
● Soda Ash
○ Bicarb

Total Treatment
Lbs of Soda Ash Needed: 445.44

350 cc Treatment
Gms of Soda Ash.: 0.891

Remarks
Recommendation:
Use Soda Ash if pH is < 10, otherwise use Bicarb.

Option:
If using Soda Ash, pretreat with 0.53 to 0.70 lbs/bbl prior to drilling Anhydrite.

Contamination
Anhydrite/Gyp
(100% Probable)

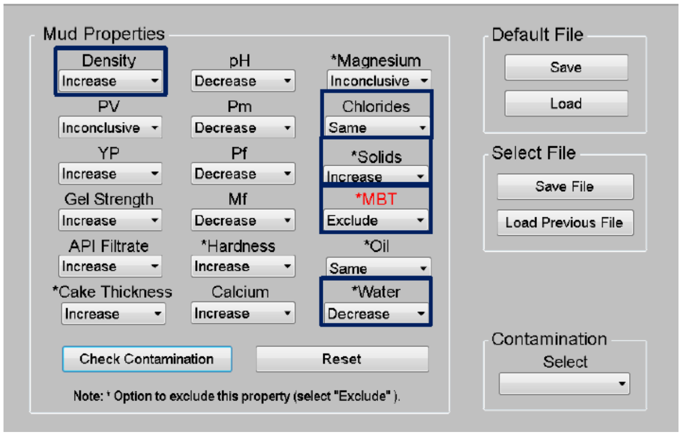
Probable Contaminations
Anhydrite/Gyp - (100 %)
Sodium Chloride - (94 %)
Hydrogen Sulfide - (76 %)
Cement/Lime - (76 %)
Carbon Dioxide - (71 %)
Bicarbonates - (71 %)
Salt Water Flow - (65 %)
Drill Solids - (47 %)

Figure 13 (Anhydrite/Gyp 100 % Probable)

As a final example, the settings from Figure 11 (100% probability Anhydrite/Gyp) are changed in this way:

1. Density is “*Increase*” instead of “*Same*”
2. Solids is “*Increase*” instead of “*Same*”
3. MBT is “*Exclude*” instead of “*Same*”
4. Water is “*Decrease*” instead of “*Same*”
5. Chlorides is “*Same*” instead of “*Inconclusive*”

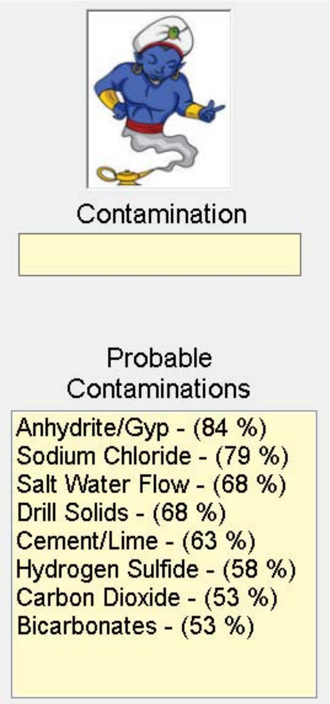
Figure 14 illustrates the example above with changed fluid properties marked with blue boxes


Mud Properties
Density: Increase
pH: Decrease
*Magnesium: Inconclusive
PV: Inconclusive
Pm: Decrease
Chlorides: Same
YP: Increase
Pf: Decrease
*Solids: Increase
Gel Strength: Increase
Mf: Decrease
*MBT: Exclude
API Filtrate: Increase
*Hardness: Increase
*Oil: Same
*Cake Thickness: Increase
Calcium: Increase
*Water: Decrease

Note: * Option to exclude this property (select "Exclude").

Figure 14 (More Changes of Fluid Properties)

The Probable Contamination percentages are shown below (Figure 15).



Probable Contaminations

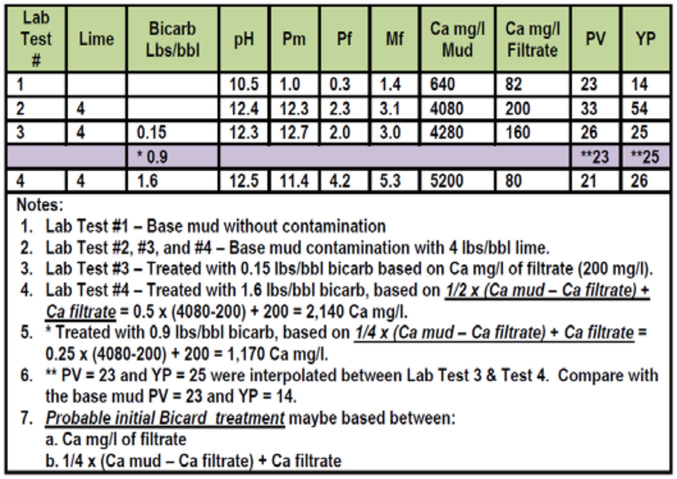
Anhydrite/Gyp - (84 %)
Sodium Chloride - (79 %)
Salt Water Flow - (68 %)
Drill Solids - (68 %)
Cement/Lime - (63 %)
Hydrogen Sulfide - (58 %)
Carbon Dioxide - (53 %)
Bicarbonates - (53 %)

Figure 15 (Anhydrite/Gyp 84 % Probable)

Experiments to Treat Out the Calcium

These laboratory experiments are designed to find the initial amount of bicarb treatment for cement (lime) contamination and the initial amount of soda ash for anhydrite/gyp contamination while avoiding overtreatment. Table 3 is the result of lime (cement) treatment using bicarb and Table 4 is the result of gyp treatment using soda ash.

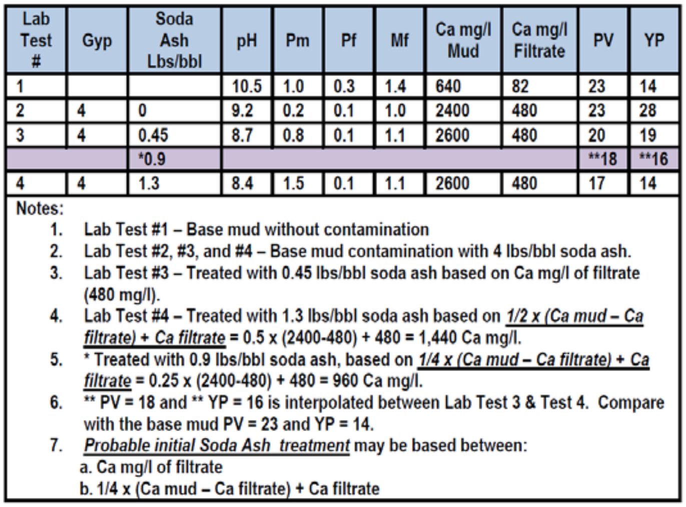
Table 3 (Lime Treatment Using Bicarb)



Lab Test #	Lime	Bicarb Lbs/bbl	pH	Pm	Pf	Mf	Ca mg/l Mud	Ca mg/l Filtrate	PV	YP
1			10.5	1.0	0.3	1.4	640	82	23	14
2	4		12.4	12.3	2.3	3.1	4080	200	33	54
3	4	0.15	12.3	12.7	2.0	3.0	4280	160	26	25
		* 0.9							**23	**25
4	4	1.6	12.5	11.4	4.2	5.3	5200	80	21	26

Notes:
1. Lab Test #1 – Base mud without contamination
2. Lab Test #2, #3, and #4 – Base mud contamination with 4 lbs/bbl lime.
3. Lab Test #3 – Treated with 0.15 lbs/bbl bicarb based on Ca mg/l of filtrate (200 mg/l).
4. Lab Test #4 – Treated with 1.6 lbs/bbl bicarb, based on *1/2 x (Ca mud – Ca filtrate) + Ca filtrate* = 0.5 x (4080-200) + 200 = 2,140 Ca mg/l.
5. * Treated with 0.9 lbs/bbl bicarb, based on *1/4 x (Ca mud – Ca filtrate) + Ca filtrate* = 0.25 x (4080-200) + 200 = 1,170 Ca mg/l.
6. ** PV = 23 and YP = 25 were interpolated between Lab Test 3 & Test 4. Compare with the base mud PV = 23 and YP = 14.
7. *Probable initial Bicard treatment* maybe based between:
   a. Ca mg/l of filtrate
   b. 1/4 x (Ca mud – Ca filtrate) + Ca filtrate

Table 4 (Gyp Treatment Using Soda Ash)



Lab Test #	Gyp	Soda Ash Lbs/bbl	pH	Pm	Pf	Mf	Ca mg/l Mud	Ca mg/l Filtrate	PV	YP
1			10.5	1.0	0.3	1.4	640	82	23	14
2	4	0	9.2	0.2	0.1	1.0	2400	480	23	28
3	4	0.45	8.7	0.8	0.1	1.1	2600	480	20	19
		*0.9							**18	**16
4	4	1.3	8.4	1.5	0.1	1.1	2600	480	17	14

Notes:
1. Lab Test #1 – Base mud without contamination
2. Lab Test #2, #3, and #4 – Base mud contamination with 4 lbs/bbl soda ash.
3. Lab Test #3 – Treated with 0.45 lbs/bbl soda ash based on Ca mg/l of filtrate (480 mg/l).
4. Lab Test #4 – Treated with 1.3 lbs/bbl soda ash based on *1/2 x (Ca mud – Ca filtrate) + Ca filtrate* = 0.5 x (2400-480) + 480 = 1,440 Ca mg/l.
5. * Treated with 0.9 lbs/bbl soda ash, based on *1/4 x (Ca mud – Ca filtrate) + Ca filtrate* = 0.25 x (2400-480) + 480 = 960 Ca mg/l.
6. ** PV = 18 and ** YP = 16 is interpolated between Lab Test 3 & Test 4. Compare with the base mud PV = 23 and YP = 14.
7. *Probable initial Soda Ash treatment* may be based between:
   a. Ca mg/l of filtrate
   b. 1/4 x (Ca mud – Ca filtrate) + Ca filtrate

As shown in Table 4, the probably initial treatment for cement (bicarb) and anhydrate/gyp (soda ash) can be determined by the following:

1. Ca filtrate (minimum)
2. 1/4 x (Ca mud – Ca filtrate) + Ca filtrate (maximum)

Until further test results are published, pilot testing is suggested. Newpark and Chevron will conduct more lab and field tests in the future. Definitely, the initial treatment should not be based only from calcium in the filtrate.

Conclusion

It can be concluded that converting the Contamination Chart to a Software Contamination Program and implementing the percentage probability logic can easily help determine the type of contaminants. It is a very friendly learning tool for both the Drilling Fluid Schools and the field techs and engineers.

Furthermore, regarding the calcium contaminant, it would be beneficial to titrate both the Calcium from filtrate and the drilling fluid for troubleshooting purposes and for the potential of calculating the initial value of Calcium for treatments of both the Cement and Anhydrite/Gyp contaminations. This would help to avoid overtreatments of the contaminates. Therefore, it would be a good practice to include both the calcium from the filtrate and the drilling fluid to be monitored and recorded in the mud reports for water-based fluid systems.

Acknowledgments

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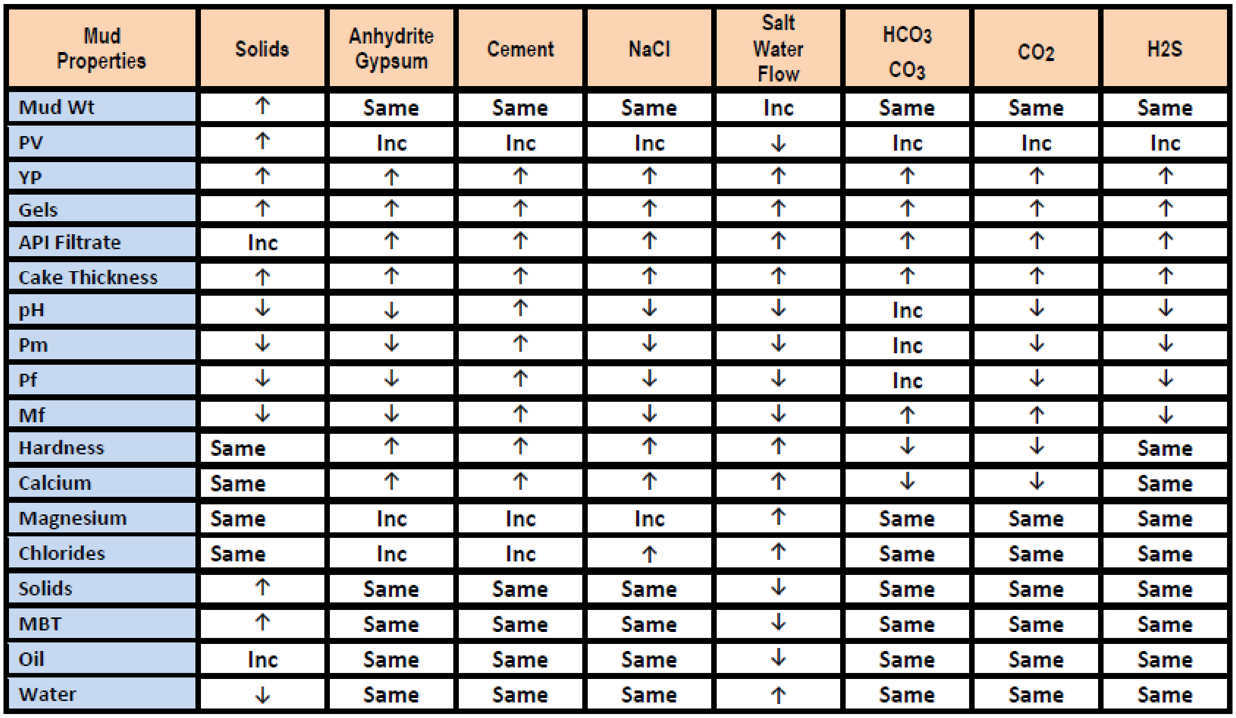
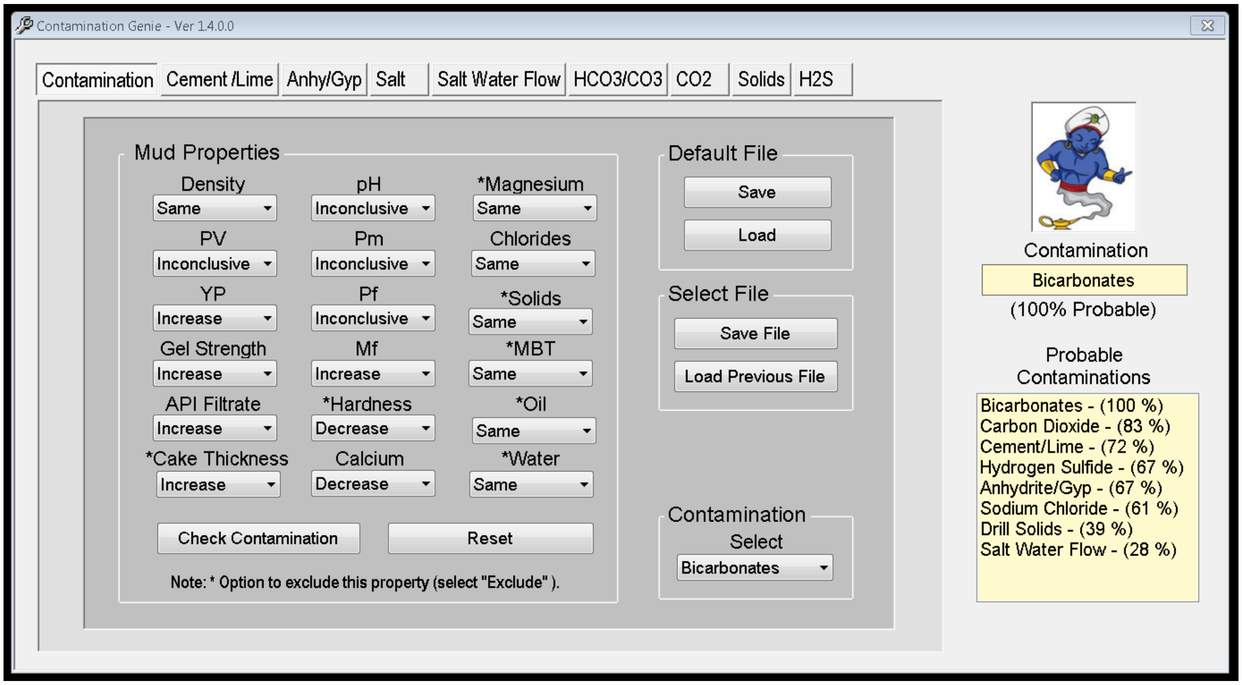
Appendix:

Table 1-A (Contamination Chart)



Mud Properties	Solids	Anhydrite Gypsum	Cement	NaCl	Salt Water Flow	HCO_3 CO_3	CO_2	H_2S
Mud Wt	↑	Same	Same	Same	Inc	Same	Same	Same
PV	↑	Inc	Inc	Inc	↓	Inc	Inc	Inc
YP	↑	↑	↑	↑	↑	↑	↑	↑
Gels	↑	↑	↑	↑	↑	↑	↑	↑
API Filtrate	Inc	↑	↑	↑	↑	↑	↑	↑
Cake Thickness	↑	↑	↑	↑	↑	↑	↑	↑
pH	↓	↓	↑	↓	↓	Inc	↓	↓
Pm	↓	↓	↑	↓	↓	Inc	↓	↓
Pf	↓	↓	↑	↓	↓	Inc	↓	↓
Mf	↓	↓	↑	↓	↓	↑	↑	↓
Hardness	Same	↑	↑	↑	↑	↓	↓	Same
Calcium	Same	↑	↑	↑	↑	↓	↓	Same
Magnesium	Same	Inc	Inc	Inc	↑	Same	Same	Same
Chlorides	Same	Inc	Inc	↑	↑	Same	Same	Same
Solids	↑	Same	Same	Same	↓	Same	Same	Same
MBT	↑	Same	Same	Same	↓	Same	Same	Same
Oil	Inc	Same	Same	Same	↓	Same	Same	Same
Water	↓	Same	Same	Same	↑	Same	Same	Same



Mud Properties

Density: Same
PV: Inconclusive
YP: Increase
Gel Strength: Increase
API Filtrate: Increase
*Cake Thickness: Increase
pH: Inconclusive
Pm: Inconclusive
Pf: Inconclusive
Mf: Increase
*Hardness: Decrease
Calcium: Decrease
*Magnesium: Same
Chlorides: Same
*Solids: Same
*MBT: Same
*Oil: Same
*Water: Same

Note: * Option to exclude this property (select "Exclude").

Contamination Select: Bicarbonates

Contamination: Bicarbonates (100% Probable)

Probable Contaminations

Bicarbonates - (100 %)
Carbon Dioxide - (83 %)
Cement/Lime - (72 %)
Hydrogen Sulfide - (67 %)
Anhydrite/Gyp - (67 %)
Sodium Chloride - (61 %)
Drill Solids - (39 %)
Salt Water Flow - (28 %)

Figure 2-A (Contamination Software)