Well Integrity, Risk Assessment and Cost Analysis for Petroleum Fields and Production Wells with CO2

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Abstract - The performed well integrity problems appears in the production wells, injection wells (including CO2 injection), multilateral wells, production wells with gas lift and temporary abandoned wells. In this paper, well integrity risk-cost analysis (WIRCA) model for some of the Egyptian petroleum fieldsaccompany with the production of CO2has been developed. WIRCAstudies has contributed to a focus on well integrity in a life cycle perspective. It was performed to investigate the possible mechanisms of well integrity challenges, now and in the future, in the different types of wells and reservoirs, why they occur and how to reduce and prevent them from happening. 11 Egyptian petroleum fields were investigated by WIRCA model and resulted in high severity of CO2 for currently producing fields A through I and low severity for currently producing fields J through K but, after three years,only two fields will suffer from the highest severity C and F.

Predictive cost analysis was done for one of the risky well W#13. Three different treatments were tested for dealing with the severity of CO2 in order to prevent failure of well integrity: using Cr13 tubing, Chemical Batches, and corrosion inhibitor downhole continuous injection, then comparing costs of these method with the actual cost of using tubing L80. For 4-5 years production, corrosion inhibitor down hole continuous injection method resulted in the least costs for well and will cost 89-96.4K $ while Using Cr13 tubing, the most expensive method, to keep well integrity for 4-5 years production will cost 1140K $.

Keywords – Well Integrity, Risk Assessment, Cost Analysis, Petroleum fields and production wells, CO2 risks and solutions

I. INTRODUCTION

Well integrity (WI) is one of the most important part in well planning. It has several definitions such as NORSOK D-010[1]definedWI as an application of technical, operational and organizational solution to reduce risk of uncontrolled release of formation fluids throughout the life cycle of the well. BG Group[2] also describes well integrity, thus, as to operate the wells under known, specified conditions, in such a way that the risk of equipment failure, endangering the safety of personnel, the environment and asset value is as low as reasonably practical. In addition, WI was defined by another authors such as Stuart [3], Tobi [4] and Oilfield Services company(Schlumberger) [5]. There is not a common global definition of well integrity, but the NORSOK D-010 definition is widely used[6].

This means, in order to fully have the barriers in place, Engineer should understand and respect them, test and verify them, monitor and maintain them and have contingencies in place when or if the barriers fail during the life cycle of the well. Due to the importance of well integrity during the life cycle of the well, well integrity is considered to be the heart in the well integrity management system[3]. The well integrity management system should identify the potential hazards that can occur during the different phases of the well. Properties such as pressure, temperature, fluids, particles, formation porosity, permeability, faults and unconformities are factors that can influence well integrity. One of the most influent factor is pressure, especial when accompanying with Carbon Dioxide (CO2) production with Hydrocarbons.

CO2 represents the greatest risk to the integrity of all piping systems in petroleum environment. CO2 related damages are far more common compared with piping and tubing failures problems such as fatigue, erosion, stress corrosion cracking or overpressurisation, Unfortunately, engineers should look for solutionswhich require high capital investments in corrosion resistant materials in order to eradicating the CO2 corrosion risk.As figure 1 shows, representing a corrosion allowance of 8 mm to carbon steel flow lines costs a significant sum at circa US$1 million per 5 km but even this is insignificant in terms of costs of the various corrosion resistant options [7].

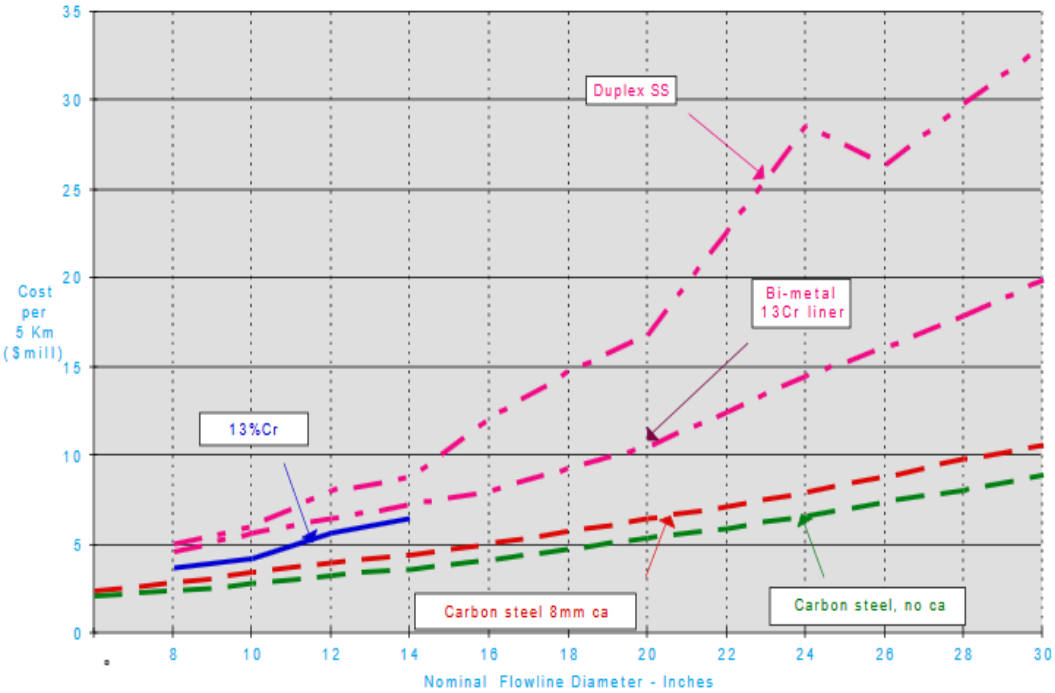

Figure 1. Fully Installed Costs for Various Flowline Materials Options in Colombia [7].

Addition costs which incurred when specifying corrosion resistant materials downhole or in facilities are seldomexplained. Petroleum producing wells contain a lot of well barriers such as production tubing, surface control subsurface safety valve(SCSSV), tubing hanger, production packers, type completion equipment, gas lift valves, and choke. All these well barriers prevent fluids or gases flowing unintentionally from the formation, into another formation or to surface and shall be designed to ensure well integrity during the well's lifetime[1]. So, CO2hazards represent a great threat to all these barriers.That`s why, CO2 corrosion of carbon steel will always be a problem to deal with. However, controlling CO2damagesbecomes a priority and it may become expensive, so, the quantification and qualification of corrosion risk is surely required at several stages during an assets life. The background of CO2behavior, properties, effects, reactions and previous published papers is considered in this model of re-evaluation of downhole materials of the Egyptian produced wells as well as failure history, probability of failure, work over cost, production, reservoir data, etc.,

Consequently, the demand for a model to study well integrity, risk assessment and cost analysis for petroleum fields and production wells with CO2 became extensively desirable. Therefore, the aim, here, is to develop well integrity risk cost analysis (WIRCA) model for 11 of the Egyptian petroleum fields. The following described model procedures has been used satisfactorily to define reservoirs, analyze pressure performance and predict pressure future performance for the next three years. Then, CO2 partial pressure calculation would be implemented. Risk assessment would be done to define the most risky wells and fields now and after three years. CO2mitigation methods for producing wells would be selected. After that, cost analysis calculations would also done in order to fully determine the best solution or treatment for the risky wells whose integrity would be exposed to failure in the next three.

II. METHODOLOGY AND PROCEDURES

2.1 Fields Pressure profile

To satisfy, firstly, the objective of being able to run the WIRCA model to study history production performance, or to run it in forward model to predict the reservoir pressure performance for 11 different fields, it was necessary to describe field dataand pressure production data. Based on these data, pressure-time profile should be constructed. If the profile shows constantly decline changes with time, it will be used to predict the future performance. If not, predictable methods such as the decline curve analysis (DCA) method [8], Terner [9], Muskat [10] and Tracy [11]prediction methods presented by Craft [12], Wooddy [13] performance calculations method, Saleh [14] performance calculations model, Exxon [15] future performance method,or Kirby [16] depletion history and future performance of a gas-cap-drive reservoir would be used with the help of Material Balance Equation (MBE) and

water influx models.Moreover, Inflow performance relationship (IPR) presented by Vogel [17] Wiggins [18], Standing [19], Fetkovich[20], and Klins-Clark [21] would also be used. For gas reservoirs, volumetric and material balance predictive methods presented by Beggs[22] could also be used.

MBE is shown as follows[12]:

$$N\left[(\beta_g - \beta_{ti}) + m\beta_{ti}\left(\frac{\beta_g}{\beta_{gi}} - 1\right) + \beta_{ti}(1+m)\left(\frac{S_{wi}C_w + C_f}{1 - S_{wi}}\right)\Delta P\right] + W_e = N_p\left[\beta_t + (R_p - R_{si})\beta_g\right] + W_p\beta_{wp} \quad (1)$$

The commonly water influx models are [12]:

Steady State Model

$$W_e = C \ \sum \Delta P \ \Delta t \quad (2)$$

Un-Steady State Model

$$W_e = C \ \sum \Delta P \ Q_{tD} \quad (3)$$

IPR as straight line formula which can be adapted to include the effects for Vogel [17] is:

Q= PI (Pres _ Pwf) (4)

CO2 partial pressure calculations

The critical factors that have a direct effect of CO2 Corrosion the partial pressure of CO2, pH and temperature. Increasing partial pressures of CO2 results in lower pH and higher rates of corrosion. Corrosion occurs in the liquid phase, often at locations where CO2 condenses from the vapor phase. Increasing temperatures increase corrosion rate up to the point where CO2 is vaporized. Increasing the level of chromium in steels offers no major improvement in resistance until a minimum of 13% is reached. Therefore, once the pressure profile is determined, CO2 partial pressure calculations should be done.

Pi = ni. Pres (5)

Where,

Pi= the partial pressure of CO2, is the mole fraction of specific gas times the total pressure,Psi

ni= the composition of CO2in produced fluids, mole percent (%)

Pres= the reservoir pressure, Psi

2.2 Risk assessment for produced wells

However, the improvement in well integrity is an inevitable continuous process. Anything fulfilling a function by time become worn out. This means the more wastes, the higher unsafety becomes. Follow up of anything sustains integrity, and sustain safety results in profit. Therefore, the risk assessment or risk analysis (RA) is not about creating huge amounts of paperwork, but rather about identifying sensible measures to control the risks in your workplace [23]. Risk Analysis is any method — qualitative and/orquantitative — for assessing the impacts of risk on decision situations.The goal of any of these methods is to help thedecision-maker choose a course of action, to enable a better understandingof the possible outcomes that could occur. That`s why, the main goal in this section is to express mathematically, or define total risk (Rtotal) as the sum over individual risks (Ri), which can be computed as the product of potential losses or severity (Si), and their probabilities (Pi)as follows [23]:

Ri= Si .Pi(Si) (6)

Rtotal= ∑iRi=∑iSi .Pi(Si) (7)

Therefore, the risk matrix for the potential hazards of well integrity due to CO2 effect. The corrosion rate of CO2depends on partial pressure, temperature, chloride presence of water and type of material. Consequently, the severity degrees of CO2asa function of the partial pressure were taken as follows [24]:

0-3 psi (Very Low)

3-7 psi (marginal)

7-10 psi (medium to serious problem)

10 psi ≤ (severe problem)

If CO2 mole concentration is 1.5% and the pressure is 300 psi, the partial pressure is 0.015 X 300 = 4 psi.So, Effect of CO2partial pressure on corrosion rate is certainly great and is effected by the type of alloy steel.Therefore, determining the severity of the CO2 damage or corrosion and the type of mitigation method are considered one of the highest priorities for producing wells in order to keep the wells integrity now and in the future during the entire well producing life.

2.3 Mitigation methods for CO2 damages in production wells

There are several methods for mitigating CO2 damages in production wells such as using chromium during manufacturing tubes or using corrosion inhibitors. Chromium improves the corrosion resistance by forming a chromium oxide film on the steel. This very thin layer, when placed under the right conditions, can also be self-repairing. The percentage of chromium must be not less than 13 % as after this percentage, there will be no effect for chromium [7]. On the other hand, most corrosion inhibitors used in oilfields are organic compounds, containing nitrogen or sulfur functionalities.

The effect of organic corrosion inhibitors inhibiting CO2 corrosion of carbon steel is concluded in three parts[7]:

Adsorption onto the steel surface (diffusion or protective layer),

Changing the wettability of the steel surface (so it is not wetted with water),

Accumulation at the oil-water interfaces (changing the oil-water interfacial tension and making it easier for the oil to entrain the water).

In general, inhibitors require free and regular access to the steel surface to be effective. Anything that interferes with this will reduce their effectiveness to low or negligible levels. However, batch treatment of oil and gas wells against CO2which is traditional oil soluble corrosion inhibitorsare commonly used in field industry. Oil soluble corrosion inhibitors have improved film forming and film persistency properties than water soluble corrosion inhibitors [7]. However, the mature oil and gas wells which produce more water than oil or condensate need large amounts of oil soluble corrosion inhibitor in order to provide adequate corrosion protection for these high water cut wells. Tubing displacement and standard batch treatments, which are used to place the corrosion inhibitor are the commonly batch-treating techniques in oil and gas field industry [5]. Consequently, choosing between these kinds of mitigation methods is one of the main targets of our model. This selection is based on choosing the optimal method. The optimal method is therefore the method which gives the highest performance with the lowest costs.

2.4 Cost Analysis

Total drilling and completion cost is considered as a value concept for Authority for expenditures (AFE). Drilling and completions costs may represent more 40% of the entire exploration and development costs [25]. These costs represent 25% of the total oilfield exploitation costs mostly in the exploration and development of well drilling [26]. Over the past several decades, various methods have been proposed to evaluate drilling and completions cost and complexity. However, because of the large number of factors and events that impact drilling and completion performance, predictive models are difficult to construct. Quantifying well costs and complexity is challenging, due either to restrictions on data collection and availability, constraints associated with modeling, or combinations of these factors. CO2 is one of these restriction that threats the different barriers in production wells. Consequently, in order to full assure the well integrity now and for the future, and save a lot of money that could be required to do maintenance or to repair failures,predictive cost analysis model for choosing the best method to remedy the prospected failure in well barriers is needed.

2.5. Operating Costs Associated With Corrosion Inhibition

The costs associated with corrosion inhibition are based on the used chemical volume and the chemical cost [7]. Inhibitors are generally moreimportantduring protecting long lengths of completion string or long period of downhole batch treatment while they are rarely cost effective when protecting short runs of process tubing or short period of downhole batch treatment. The quantity of corrosion inhibitor required is dependent on factors such as liquid throughput, CO2 partial pressure, PH and flow regime. Corrosion resistant materials are likely to offer lower life cycle costs for pipes while carbon steel plus inhibition tends to be the cheapest method of construction and operation [7].

2.6 Economic Tools to Use during Materials Selection

CO2 corrosion prediction modelling will give a good indication of the probability of CO2 hazards of producing wells due to internal conditions but will not assist in evaluating the economic consequences of such a failure or the operating costs involved with avoiding or controlling such a CO2failure. Even if CO2corrosion predicts short times to failure, it may be economic to plan for maintenance or repair of carbon steel completion string late in field life rather than to invest in a more robust alternative. Alternatively, inhibitors may be a technically feasible solution but economically and logistically, protecting deep wells may be impractical and corrosion resistant materials may be a better choice.

The technique of life cycle costing (LCC, also known as whole life costing) assists in this risk assessment methods by converting future costs into current monetary value and thereby allowing direct comparisons with capital costs. To carry out accurate, meaningful and useful LCC's the following should be considered [1,7]:

An understanding of the economic factors driving the decision, such as tools daily rates, rates of return on investment and net present values.
The design life and production profile of the development.
An assessment of future costs based on similar developments over several years.
An understanding of the important economic drivers for the task, such as the balance between capital and operating costs.
In some cases, the costs of materials are relatively low and the installationcosts far outweigh them. Expensive deep / offshore producing wells are an obvious example of where workovers are to be avoided due to a materials failure. In that cases, it is common to select robust materials in order to guarantee well integrity against a repeat of the high installation costs but there are many examples where the answer is less clear cut. The key question is, "when is investment in CO2corrosion resistant materials justified?" CO2Corrosion prediction clearly has a key to this but cannot lead the whole answer. Corrosion prediction are normally used as a materials selection tool and taking an extreme example, if there were no consequences of a CO2failure, there would be no justification in investing in corrosion resistant materials. An investment in CO2corrosion resistant alloys (CRAs) aims to protect against the consequences of a failure and therefore materials selection must consider the consequences in the decision making process. Consequences are safety, economic, health, or environmental impacts or all four but in most cases all consequences can be related to a financial impact.

2.7 Cost of using L-80 & Cr 13 material against Corrosion Inhibitors Batch Treatment

The final selection of tubing material is based on the optimal balance between cost and acceptable corrosion allowance considerations for safe operation over estimated lifetime. The cost of CO2corrosion-resistant alloys will reduce with decrease the amount and type of alloying additions. The more corrosion resistant the steel, the higher is prices. Equally important for selection of material is its strength. The use of corrosion inhibitor batch treatment instead of using corrosion-resistance alloys has caught increase interest lately, particularly for completions with no chemical injection valves (as continuous injection). Chemical batch treatment can be applied with normal carbon steel material (L-80) for lower cost to increase lifetime by increase corrosion rate. The low cost of chemical treatment (wither through continuous injection or batch treatment) could give sufficient corrosion protection and accordingly increase lifetime of L-80 that would be considered comparable to use corrosion-resistant alloy.
Rough cost factors of Corrosion-resistant steel relative to carbon steel that were taken as general guide for the Egyptian market are appeared in the table -1.

Table -1. Taken rough cost factors of Corrosion-resistant steel relative to carbon steel.

Material	Cost factors on Weight basis	Cost factors on strength basis
Carbon steel	1	1
13%Cr (AISI 420)	2.5	2
Mo-free Duplex	4	4
Stainless (316L)	4-6	9-14
22%Cr – Duplex	6-8	6-8
25% Cr – super Duplex	9-11	7-9
Stainless (254SMo)	10-12	15-18

Systemic approach will help integrate all knowledge for achieving the objective. Figure -2 Flow Chat below shows the integrated WIRCAmodel of producing wellsprocedures that include three sections:
Field pressure profile data now and performance prediction for three years
Risk assessment for the effect of CO2 on producing wells
Cost analysis for producing well and selecting the best treatment to assure the barrier of wells

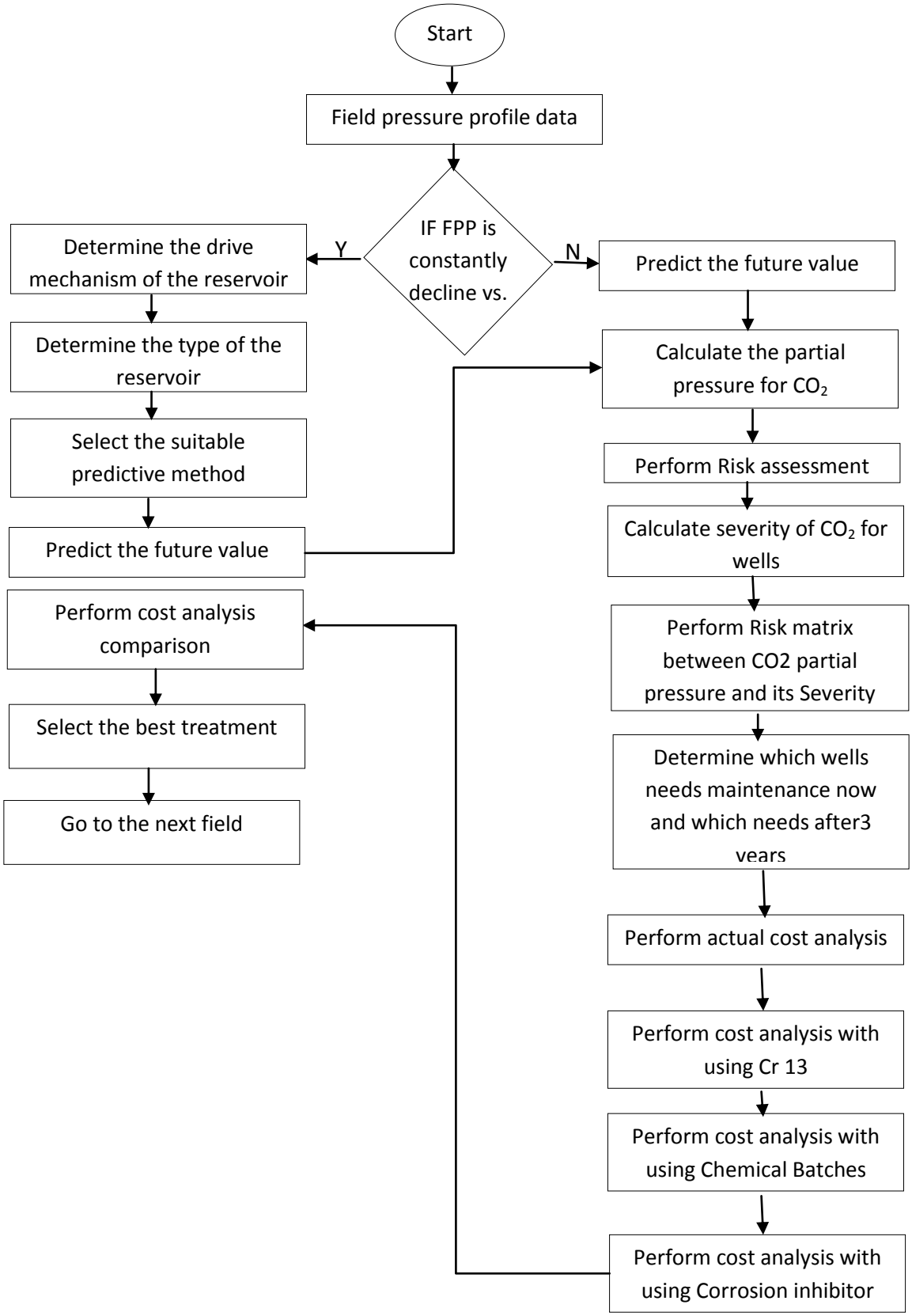

Figure -2. The integrated WIRCA model of producing wells procedures

III. EGYPTIAN FIELDS CASE STUDY

Pressure profile data for various 11 Egyptian fields are appeared from figure (3) through figure (13). These figures also contains reservoir pressure vs. time for now. The actual cost data for risky well W#13 are shown in table (1). WIRCA model will be done for all the 11 fields and for the two risky wells for now and after 3 years.

IV. RESULTS AND DISCUSSION

The pressure performance for future interval for the 3 years decreases gradually with time and the predicted values show a liner decline for all the 11 fields as appeared in figure 3 through figure 13 for fields A through K except 3 three fields E, H and I.Applying the predictable reservoirs methods and choosing the most suitable method for fields E, H and I resulted in a good history match and more accurate values for the next 3 years as illustrated in figures -7, 10, and 11. The current and the predicted values which used in risk assessment for the 11 petroleum fields are presented in table-3. Making CO2 partial pressure calculations and performing the risk matrix for 11 fields led to discovering the highest risky producing fields and producing wells which are suffering from the effect of CO2 hazards as shown in table -3. Currently producing wells and fields A through H are suffering from the highest severity of CO2corrosion and damages while producing wells and fields I through K are more safe than others and the effect of CO2damage is marginal for I, and very low for J and K as appeared in figure -14. After 3 years, in the future, the effect of CO2corrosion and damages will become very low for fields B, D, and G through K, medium for A field, marginal for F field, and high severity for fields C and E. Therefore, engineers should modify well design and choose the optimal method to mitigate CO2 effects. Here, we have chosen one of most risky wells in order to apply the most common treatments and choose the optimal one.

Predictive cost analysis was done for one of the risky well W#13. Three different treatments were investigated for dealing with the severity of CO2 in order to prevent failure of well integrity during the producing life: using Cr13 tubing, Chemical Batches, and corrosion inhibitor downhole continuous injection. After 4-5 years production, corrosion inhibitor down hole continuous injection method resulted in the least costs for well and will cost 89-96.4K $ while Using Cr13 tubingto keep well integrity more long time for 4-5 years production will cost 1140K $ but it is the most expensive method as shown in tables -4 through 7 . Using normal tubing grade (L80) resulted high costs and loss well integrity in time less than the three treatment methods as appeared in Table -7.

V. CONCLUSIONS AND RECOMMENDATIONS

Based on the results and analysis, the following conclusions are extracted:

Carbon dioxide corrosion can be controlled by using of corrosion inhibitor as a first recommended option to provide well integrity through:

Batch treatment for wells with no downhole injection facilities.

Continuous injection through control line.

Continuous injection with gas lift stream.

Corrosion resistant alloys (CRAs) can also be selected to help prevent carbon dioxide corrosion, so, the use of (Cr 13) would increase the lifetime of used tubing in wells of field C&E, which have current high severity of CO2 and also after 3 years, with respect to CO2 Corrosion. However other problems that could be encountered with Cr-13 should be put into consideration especially scratching due to sand production or handling.

Normal carbon steel tubing (N-80 & L-80) can be used in fields other than C and E as CO2 partial pressure will be dropped within lifetime of the tubing.

More advanced corrosion monitoring techniques (Multi-finger Caliper log) should be used to monitor dominant corrosion phenomena to model well integrity in consecutive periods.

Careful inspection of tubing after retrieving is important to identify corrosion phenomena and its location along well completion string.

VI. NOMENCLATURES

N= Original oil in place, STB

m= Ratio of initial gas-cap-gas reservoir volumeto initial reservoir oil volume,bbl/bbl

We= water influx volume, bbl

Wp= produced water, bbl

C = the aquifer constant, bbl/(day. Psi)

PI = productivity index of well, bbl/day/Psi

Δt= changing in time, days

QtD= Dimensionless water influx,-

Q= oil flow rate, STB/day

Pres= average reservoir pressure, Psi
Pwf= bottom-hole flowing pressure, Psi
βg = gas formation volume factor, bbl/scf
Bwp = produced water formation volume factor, bbl/SCF
βgi = Initial gas formation volume factor, bbl/scf
βt = total oil formation volume factor, bbl/STB
βti = Initial total oil formation volume factor, bbl/STB
Δp = Change in reservoir pressure = pi − p, psi
Swi= intial water saturation, %
Cw= Water compressibility, Psi-1
Cf= formation compressibility, Psi-1

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Table -2. Actual Cost of using L-80 tubing in well W# 13.

Proposed Life time: 3-4 years	
Description	Cost ($)
WIP, DEV – WELLHEAD	60,831.35
WIP, DEV - TUBING & COMPL EQUIP	168,431.42

WIP, DEV - DAMAGES & COMPENSATION	353.42
WELL HEAD MAINTENANCE	15,800.54
SITE PREPARATION	20,033.78
DIRECT - MATERIALS & SUPPLIES	232.22
DIRECT - SURVEYS/ANALYSIS/SAMPLING	88,683.75
DIRECT – OTHER	55,353.41
EQUIPMENT RENTAL CHARGES	19,899.87
RIG DAY RATE	247,426.81
FUEL , LUBRICANTS & DIESEL	89,766.82
MUD CHEMICALS	90,337.76
CEMENT & ADDITIVES	22,640.31
MUD ENGIEERING SERVICES	2,352.24
G & A REALOCATION	6,971.92
PRODUCTION DEFER	Not Considered
GRAND TOTAL	889,115.62

Table -3. CO2 Partial Pressure Calculations and Risk assessment Fields

Field Name	nCO2	Reservoir Temp. (oF)	Current Calculation based on Current Reservoir Pressure			Current Calculation based on predicted Reservoir Pressure after 3 years		
			Reservoir Pressure (Psia)	Partial Pressure (Psia)	Severity Degree	Reservoir Pressure (Psia)	Partial Pressure (Psia)	Severity Degree
A	1.02	220	2908	29.66	Severe	700	7.14	Medium
B	0.45	230	4150	18.75	Severe	500	2.26	Very low
C	0.43	200	3745	16.1	Severe	3550	15.26	Severe
D	0.85	230	1820	15.48	Severe	200	1.7	Very low
E	0.41	205	3600	14.9	Severe	3575	14.8	Severe
F	0.70	225	2065	14.37	Severe	900	6.26	Marginal
G	0.56	217	2550	14.2	Severe	500	2.79	Very low
H	0.41	193	3419	13.92	Severe	400	1.63	Very low
I	0.3	170	2250	6.75	Marginal	920	2.76	Very low
J	0.08	150	2450	1.96	Very low	870	0.69	Very low
K	0.03	135	1700	0.493	Very low	1250	0.363	Very low

Table -4. Estimated Cost of using Cr 13 tubing in well W # 13

Proposed Life time: 4-5 years	
Description	Cost ($)
WIP, DEV – WELLHEAD	60,831.35
WIP, DEV - TUBING & COMPL EQUIP	421,078.55
WIP, DEV - DAMAGES & COMPENSATION	353.42
WELL HEAD MAINTENANCE	15,800.54
SITE PREPARATION	20,033.78
DIRECT - MATERIALS & SUPPLIES	232.22
DIRECT - SURVEYS/ANALYSIS/SAMPLING	88,683.75
DIRECT – OTHER	55,353.41
EQUIPMENT RENTAL CHARGES	19,899.87
RIG DAY RATE	247,426.81
FUEL , LUBRICANTS & DIESEL	89,766.82
MUD CHEMICALS	90,337.76
CEMENT & ADDITIVES	22,640.31
MUD ENGIEERING SERVICES	2,352.24
G & A REALOCATION	6,971.92

PRODUCTION DEFER	Not Considered
GRAND TOTAL	1,141,762.75

Table -5.Actual Cost of well W # 13 batch treatment

Min. time interval for batch job	3 Months
Proposed life time	4-5 years
Description	Cost ($)
Chemicals (Corrosion Inhibitor) cost per job	2500
Pumping unit and operation package (Triplex pump, diaphragm pump, air compressor, storage tank, hoses and other connections, transportation, operator and 2 assistants	3900
Total per job	6400
Total per year (Max.)	25600
Grand Total	102400-128000 (max.)

Table -6.Cost of corrosion inhibitor down hole continuous injection

Proposed life time	4-5 years
Description	Cost ($)
Daily chemical cost	20.2
Chemical cost	29000-36360
Surface Injection Equipment (Chemical skid, Injection access fitting and Injection tube)	35000
Downhole Injection Equipment (Injection Valve, control line and fittings)	25000
Grand Total	89000-96360

Table -7. Methods Costs Summary

Description	Life Time (years)	Yearly cost($)	Total cost($)
Using L80 tubing	3-4	300-400K	900K
Using Cr 13 tubing	4-5	460-575K	1140K
Chemical Batches	4-5	25.6K	102.5-128K
Continuous Chemical Injection	4-5	19-22K	89-96.4K

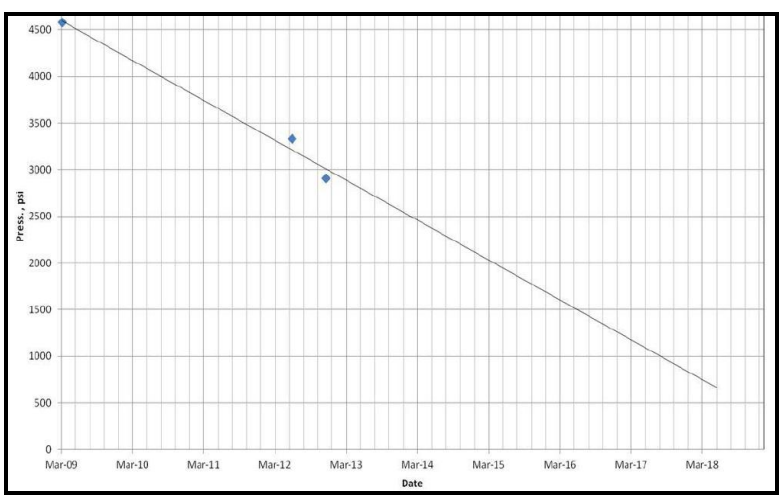

Figure -3. Predicted pressure profile data for field A

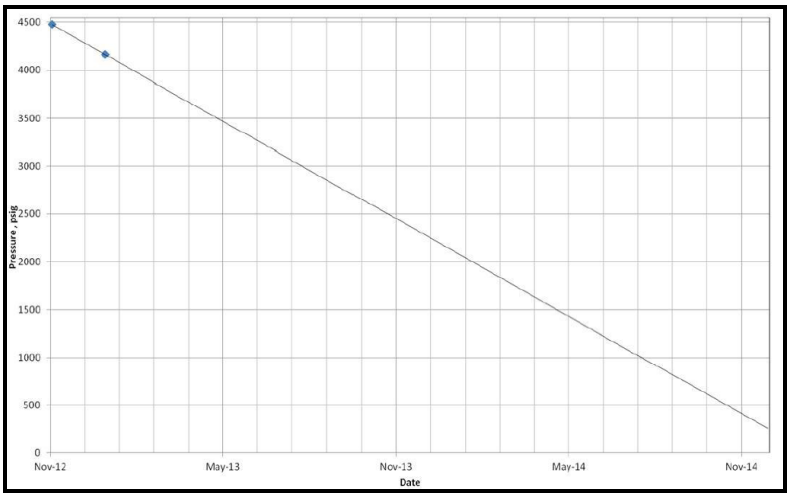

Figure -4. Predicted pressure profile data for field B

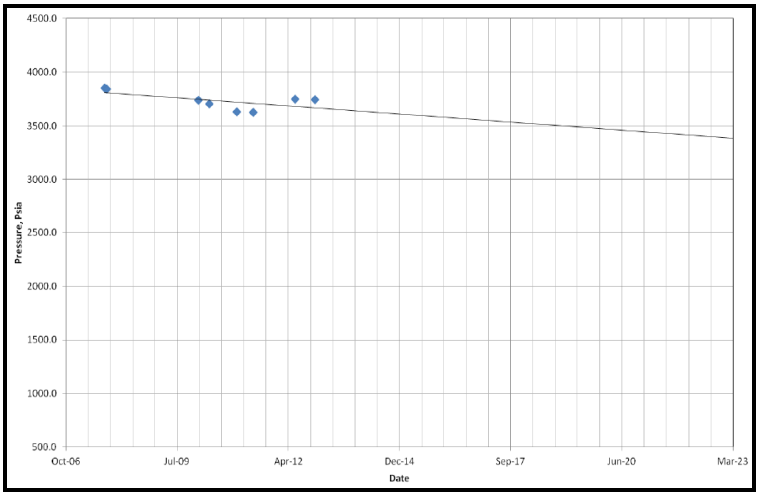

Figure -5. Predicted pressure profile data for field C

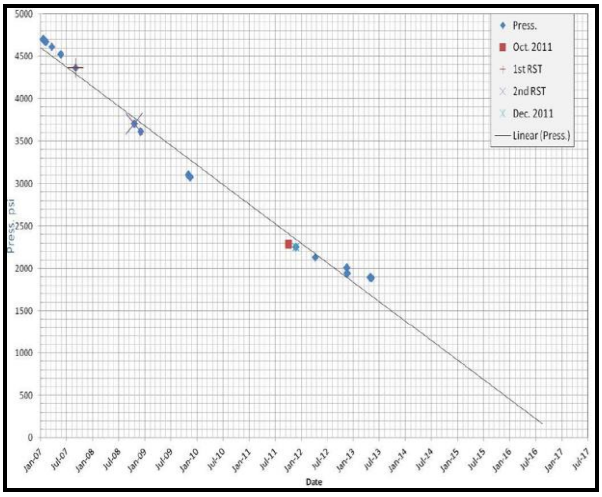

Figure -6. Predicted pressure profile data for field D

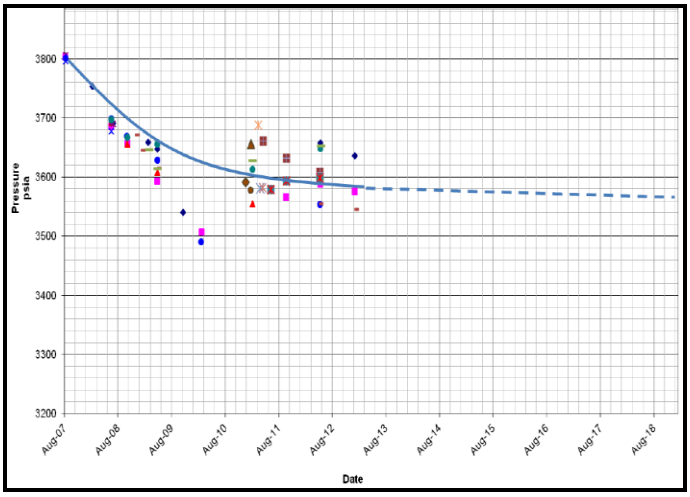

Figure -7. Predicted pressure profile data for field E

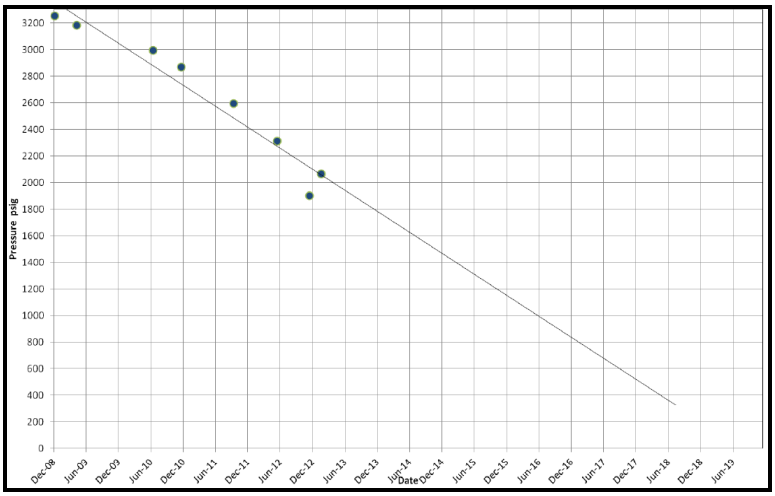

Figure -8. Predicted pressure profile data for field F

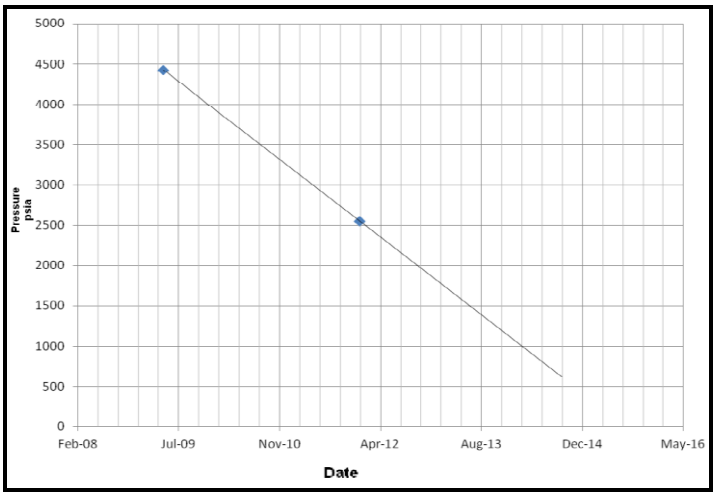

Figure -9. Predicted pressure profile data for field G

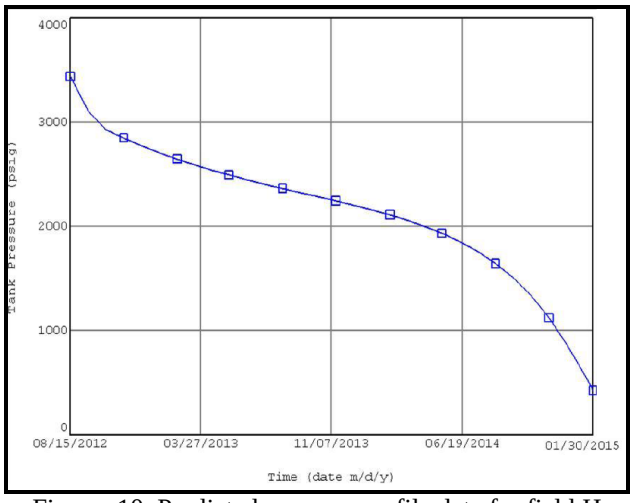

Figure -10. Predicted pressure profile data for field H

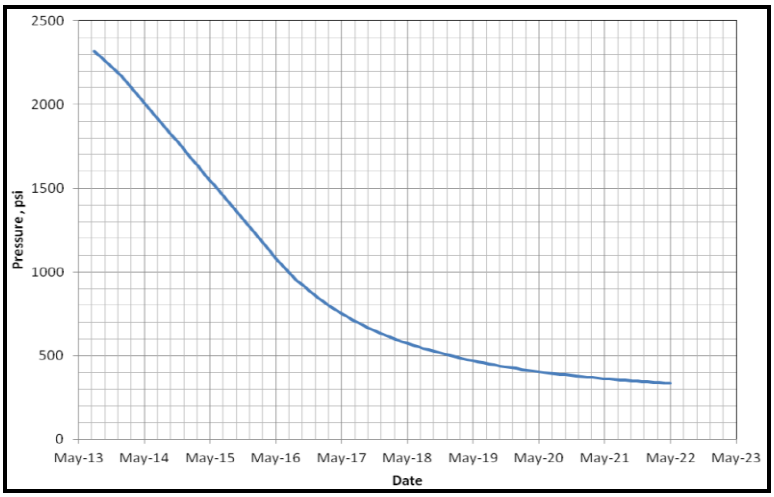

Figure -11. Predicted Pressure profile data for field I

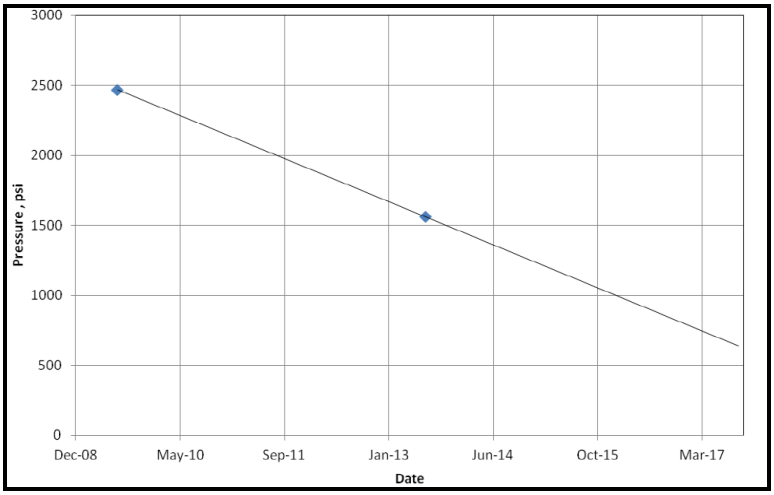

Figure -12. Predicted pressure profile data for field J

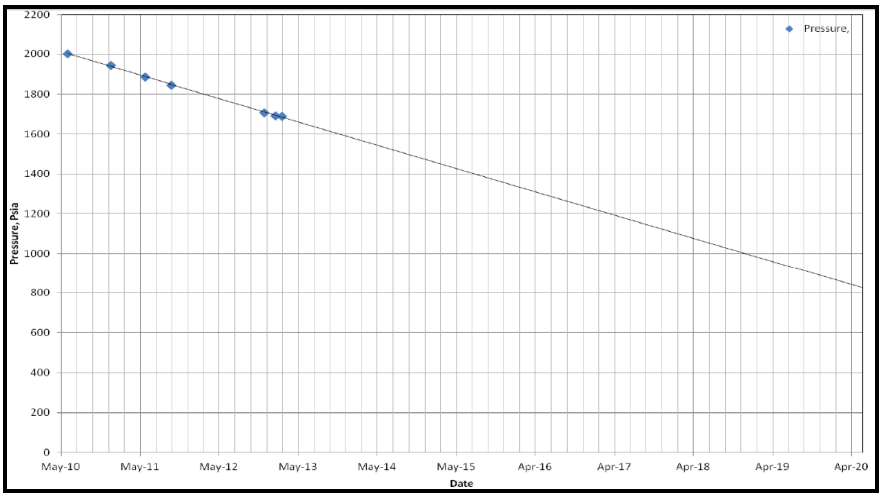

Figure -13. Predicted pressure profile data for field K

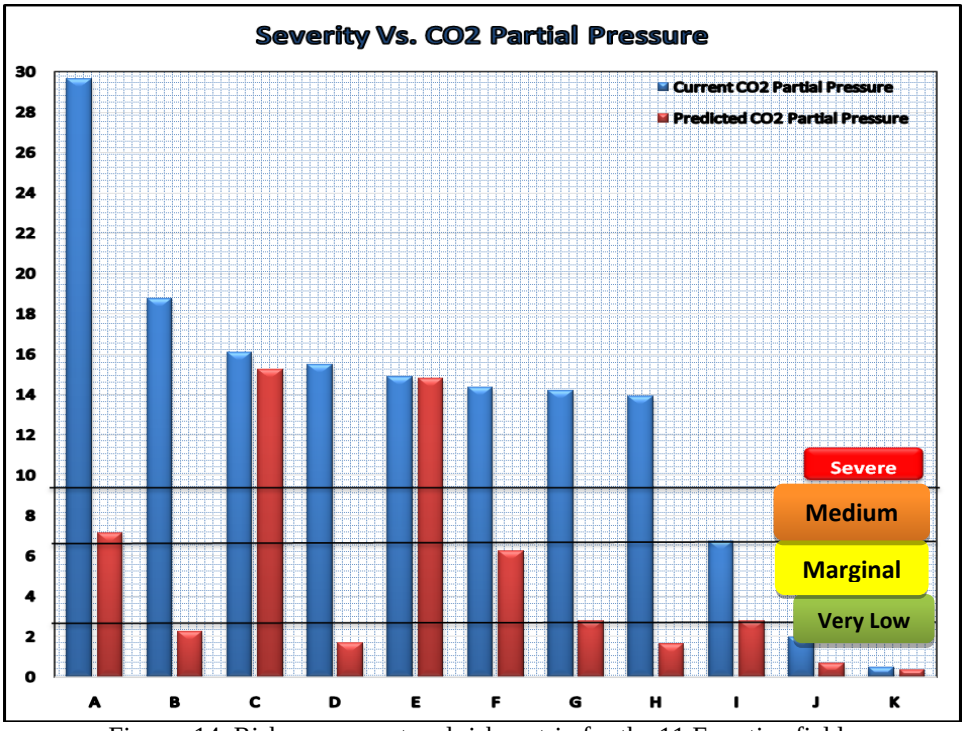

Figure -14. Risk assessment and risk matrix for the 11 Egyptian fields