Louisiana State Water Gulf of Mexico Old Field Resurrection in the Aftermath of the Macondo Disaster

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ABSTRACT

This is a case study of an old field successfully resurrected back to commercial production by means of proper and efficient study, design, and implementation before and after the Macondo disaster. It considers the effects of working in an offshore environment in the aftermath of the Macondo incident compared to just before the incident. It also compares the aftermath effects of other disasters such as Hurricane Katrina.

West Delta 84 Field is located off the coast of Plaquemines Parish, Louisiana near the mouth of the Mississippi River in about 20 ft (6 m) of water. A consortium of major integrated oil and gas companies (Chevron, Conoco, and Texaco) discovered it in 1955 by drilling to a total depth of 14,500 ft (4420 m). It has produced over ten million barrels of oil and 21 billion cubic ft of gas. The field reached marginal profitability for the major companies that discovered it and produced it for over thirty years resulting in their divesture to a small operator in the September 1988. After a short period of continued production, it was shut-in for a period of almost ten years while languishing in and out of bankruptcy court twice from 1990 to 2000 and was actually orphaned by the State of Louisiana at one point during this time. All the while, the structures and wells deteriorated without proper capital input and the continual destruction from multiple hurricanes.

This paper focuses on the time period just before and after the Macondo disaster discussing the difficulties involved with bringing an old field in the Gulf of Mexico back on line after years of many and various technical difficulties, uncooperative weather, and strict (and sometimes illogical) regulatory environments. It outlines what is believed to be a proper and necessary approach for a successful resurrection of an old field in this environment, or at least what has worked in this case.

INTRODUCTION AND HISTORY OF THE FIELD

West Delta Block 84 Field is located off the coast of Plaquemines Parish, Louisiana near the mouth of the Mississippi River in about 20 ft (6 m) of water. A consortium of major oil and gas companies (Conoco, Chevron, and Texaco) discovered it in 1955 through seismic exploratory work and confirmation by drilling to a total depth of 14,500 ft (4420 m). It has produced over ten million barrels of oil (MMbo) and 21 billion cubic ft of gas (Bcfg). The field reached marginal profitability for the major companies that discovered it and produced it for over 30 years resulting in their divesture to a small operator in September 1988. After a short period of continued production, it was shut-in for a period of almost ten years while languishing in and out of bankruptcy court twice from 1990 to 2000 and was orphaned by the State of Louisiana at one point during this time. All the while, the structures and wells deteriorated without proper capital input and the continual destruction from multiple hurricanes.

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There was no real refurbishment of the wells and facilities after the major consortium divestment until the year 2000 when the current operator, IG Petroleum, LLC, was able to consolidate all of the legal issues and ownership into one entity. Even then, the progress was slow and expensive due to hurricanes (and bad weather in general), associated third party failures, lack of service providers (especially after Hurricane Katrina), lack of complete data and well files, and other logistical nightmares. Next the Macondo disaster occurred.

This paper focuses on the time during which IG Petroleum began its operatorship up until today, and on into the future's pending activities, in an attempt to illustrate the difficulties (with just enough success to continue forward) in dealing not with new ultra-deep cutting edge technology, but rather aging wells and facilities in a shallow offshore environment.

Hurricanes and weather have been tenacious pests since the field was discovered in 1955. The major consortium was, of course, far-sighted enough to divest themselves of the field once the wells began shutting-in in need of repair. Flossy hit a year after the discovery well was made. Flossy, Camille, and Betsy were the three hurricanes that forced the industry to redesign their offshore operations. After IG Petroleum took over the field and prior to the Macondo disaster, hurricanes Ivan, Katrina, Rita, and Gustav had pummeled the wells and facilities. IG Petroleum had been severely hampered by these storms and had been unable to accomplish much of anything in the field other than keeping the field alive.

The field is also just far enough offshore to make it difficult to get to. It is not far enough offshore to justify helicopters, but far enough to make for a long boat ride and the need for special personnel willing to do this day in and day out. Quarters once available were continually swept away by storms. New quarters are slated to be built in a protected area sometime this year. This will reduce the daily travel from four hours to one hour.

IG Petroleum was basically the first operator that began approaching the refurbishment of the field in a proactive and long-term outlook since the major oil company consortium divested itself of it in 1988. Work on the field has been nearly continuous since then, but until recently, it has mostly been the result of repairing destruction incurred by hurricanes.

Soon after the Macondo disaster, Hurricane Isaac hit West Delta 84 Field. However, a spurt of facility work had been started and finished prior to this last hurricane with much of the derelict equipment having been removed by this time and damage was minimal. A substantial amount of this work and the resulting minimal amount of destruction was due to a more keen interest and awareness in the robustness of the structures and safety issues at the facilities.

REGIONAL GEOLOGY AND DEPOSITIONAL ENVIRONMENT

The primary depositional environment for the productive Lower Pliocene and Upper Miocene sands at West Delta 84 Field can be described as fining upward point bar sand deposits, formed by meandering channels. As the channels moved back and forth throughout the flood plain the point bar deposits were then overlain by finer grained overbank deposits. These deposits were formed during a primarily regressive subareal coastal environment. However, minor sea-level reversals and changing environments across this region developed "assemblages of deltaic, lagoonal, lacustrine, palustrine and eolian facies" (Hosnan, 1996). These assemblages of deposits are interspersed between the productive West Delta 84 zones. Growth faults also occur in this area brought on by ever increasing overburden of Mississippi river sediment deposits.

Depths to productive reservoirs in this area range from 16,500 ft (5030 m) within the Miocene near West Delta 84 Field to 1500 ft (460 m) within the Pliocene near West Delta 27 Field to the northwest (Goddard, 2001). Equivalent productive reservoirs within the Lower Pliocene Upper Miocene can be found just to the northeast of West Delta 84 Field in Burrwood Field. To the northwest, in West Delta 27 Field, are shallower Plio-Pliestocene gas sands of similar characteristics as those found in West Delta 84 and Burrwood fields.

The local structure is defined by gentle synclines, anticlines, and faults striking east-west. The structure dips to the west at approximately 10 degrees and is trapped to the north and south by down-to-the-south normal faults with approximate vertical displacements of 100 ft (30 m) each. Reservoir limits are defined either by structure (oil-water and gas-oil contacts), faulting or stratigraphy (Kimbrell and Wojtanowicz, 2006).

FACILITIES

West Delta 84 Field presently consists of two platforms, A and B tank battery, several satellite wells and several A wells (which originate and are directionally drilled from the A platform). There were also three B dry-hole wells drilled from the B drill platform (which was actually moved to West Delta 27 Field). All of the wells are designed to produce, through various flowlines, to tanks on the B tank battery platform.

The B tank battery platform supports two internal double hulled 1500 barrel oil storage tanks (two other ones are out of service), three external salt water disposal tanks that are used for gravity separation of the produced water prior to disposal, numerous separators, heater treaters, generators, a gas compressor, a helipad and a Lease Automated Custody Transfer (LACT) unit used for transporting the oil to another heater-treater at the final storage area used for eventual sales. In the past gas was also transported via pipeline to sales. Currently excess gas is stored in a 10 in by 3.5 mi (5.6 km) blocked line.

The A platform presently consists of three levels and has no in-use tanks other than a sump tank. It basically serves as a support facility for the A wells only at this time. At one time the A platform also housed a large compressor and water-flood facility. However, all of this equipment was been removed by IG Petroleum. This included the old out of service tanks and pumps used by the water-flood in service during the seventies and eighties, the compressor house, a dog house and many other extraneous out-of-service junked equipment.

Other than the wellheads for the A wells, there is only a recently-refurbished large crane on the A platform. The crane was recently inspected and was capable of lifting the coiled tubing unit weighing in at 45,000 lbs (20,400 kg) used to work on both the A–7 and A–10 wells in the spring of 2012. So, in essence, the A platform serves as a large cribbing for all of the A wells. It provides an area where equipment necessary for downhole work may reside during these types of operations and it allows easy access to the wellheads. It serves no other purpose at this time. Many of the areas originally used by previous operators are no longer needed or used; some areas have been simply railed off without access because they have no practical use. For example, one set of stairs that are in disrepair and not needed have been railed off.

There are 13 A platform wells, three of which were dually completed as listed in Table 1. All of these A wells have future utility with the exception of the A–1 and A–1–D (serial numbers 112378 and 117237). This dual well has been temporarily plugged and abandoned in that it has cement plugs downhole according to regulation, but the well head and above surface casing remain awaiting final abandonment of the platform and removal. There are also currently seven satellite wells as listed in Table 2.

SANDS AND RESERVOIRS

In order to properly prioritize the refurbishment of West Delta 84 Field (and attract investors), an understanding of the productive sands and reservoirs along with the wells that produced them was necessary. Because

Table 1. List of thirteen A platform wells. All have future utility with the exception of the A–1 and A–1–D.

OA A0232	A–1	112378
OA A0232	A–1–D	117237
WDB84 KF1 SU; OA A0232	A–3	117925
OA A0232	A–4	118328
WDB84 KF1 SU; OA A0232	A–5	118869
OA A0232	A–6	119247
OA A0232	A–6–D	119756
OA A0232	A–7	119744
OA A0232	A–8	120240
OA A0232	A–8–D	120630
WDB84 KF1 SU; OA A0232	A–9	120669
OA A0232	A–10	121128
WDB84 KF1 SU; OA A0232	A–11	121874
OA A0232	A–12	122359
WDB84 KF1 SU; OA A0232	A–13	122936
OA A0232	18	167657

Table 2. List of the seven satellite wells.

OA A0232	4	62347
OA A0232	6	66598
OA A0232	10	84790
OA A0232	11	85660
OA A0232	11–D	86155
OA A0232	12	86079
OA A0232	15	108695
OA A0232	18	167657

records were not complete, a logic base for a proposed expert system was employed (Kimbrell and Wojtanowicz, 2006). The methodology was designed "to reduce the risk of overlooking unfamiliar possibilities" (Duda, 1978) and yet be able to reach reasonable conclusions in order to prioritize the efforts needed for a return to commerce. This methodology has three basic rules:

1) Speed at the expense of detail initially,
2) No multi-tasking, and
3) Proceed even when there is missing information.

Consideration of the previous operators and controllers of the field was deemed necessary as well. The field had been discovered and managed by a consortium of major integrated oil and gas companies for approximately the first thirty years while producing the "easy" recoverable reserves under their stringent profit criteria. The last twenty-five years operations were by numerous unrelated very small micro independent companies with no expertise on staff when the reserves were harder to get due to previous production from old wells and facilities. Micro independents have a totally different profit criteria and managerial style than a consortium of major integrated oil and gas companies. The field went into disrepair upon the divestment of the consortium. A certain amount of theoretical game strategy was employed for this reason to attempt to uncover potential remaining reserves that would more likely be recovered because of variable incentives from the previous owners and operators (Kimbrell, 2008).

West Delta 84 Field has produced or tested five Lower Pliocene and Upper Miocene sands, KE, KF, GR, 11,800 ft, and JM from nine individual reservoirs, KEKF–1, KE–9, KE–A–10, GR, KP, KE–5, KE–2, KE–3, and JM totaling thirty completions.

KEKF–1 Reservoir

The main reservoir, the KEKF–1, was discovered in the field with the drilling of well 1, which was completed in the lower KF sand. Two reservoirs, the KE–1 and KF–1, originally believed to be separate non-communicating reservoirs have been proven to be actually one communicating reservoir, the KEKF–1. After study, it was also believed that a water-flood into the KF–1 reservoir was not totally effective, that oil reserves were bypassed, and a substantial portion of these bypassed oil reserves could be recovered without drilling new wells (Kimbrell, 2002). It is a gas cap/solution gas driven reservoir with an initial pressure of 5950 psi, average porosity is 30.2% and the average water saturation is 23.5%. The original oil in place (OOIP) has been estimated to be 14.7 MMbo, the original gas cap gas in place is estimated at 9.6 Bcfg and the estimated original solution gas in place is estimated at 18 Bcf.

Cumulative production from the reservoir is approximately 4.8 MMbo, 12 Bcfg, and 2526 million barrels of water (MMbw). The wells which produced the KEKF–1 reservoir are wells 1, 4, 12, 15, 18, A–1, A–3, A–4, A–11, A–13, and 3. The 1, A–1, A–11, and 3 wells had been plugged and abandoned, well 4 had been recompleted into the JM sand (unsuccessfully) and the well A–13 had been converted to a water injection well. The 12, 15, 18, A–3, A–4, and A–11 wells are available for production or as work-over candidates.

Well 12

Well 12 is a gas-cap well in the KEKF–1 and is sanded up. Since it is a gas-cap well, the well will not be brought back on line in the KE sand interval until time for the final blow-down of the gas cap. The wellhead was hit by a boat, however, and the economics of bringing it back on are questionable. This well may ultimately just be plugged and abandoned.

Well 15

Well 15 is very close structurally to the 18 well, which is currently awaiting gas for gas lift operations. A workover initiated in September 2001 recovered 120 barrels of oil during these operations, but the well sanded up immediately afterwards.

Well 18

Well 18 is active and currently awaits gas for gas lift operations. The expected production is between 150–250 bopd.

Well A–3

It is believed that well A–3 coned water into its perforations sometime after the water-flood of the KF sand. It produced until July 1981 when it was shut-in with a water-cut above 90%. An unsuccessful workover attempt in the late 1980s left wireline and cement junk in the hole.

Well A–4

Well A–4 has a KBM mandrel laying sideways in the well which needs to be removed and the gas lift should be restarted.

Well A–11

Well A–11 was shut-in with a water cut of 90 percent. Cumulative production for the well was 350 thousand barrels of oil (Mbo), 735 million cubic ft of gas (MMcfg), and 795 thousand barrels of water (Mbw).

GR Reservoir

The GR sand is the shallowest reservoir discovered by well 6 in 1957. Its drive mechanism is a strong water drive as indicated by an initial reservoir pressure of 3453 psi at a datum of 7750 ft (2360 m) below sea level and a current reservoir pressure of approximately 3275 psi. Average porosity is estimated to be 29% and average water saturation is estimated to be 25%. The OOIP is estimated to be 11.1 MMbo with original solution gas in place at 5.8 Bcf.

Cumulative production from the GR reservoir is 2.617 MMbo, 1807 MMcfg, and 1.473 MMbw as of December 1, 1999, from 5 wells. The wells which produced the GR reservoir are the 6–D, 9–AD, 10, 11–D, and 13. Wells 9–AD and 13 are plugged and abandoned, while the 6–D, 10, and 11–D wells remain viable work-over candidates.

Well 6

The 6 was shut in when the production was declining at 28% and the oil rate had tested at 131 bopd in March 1985. At present, the well has parted tubing at 747 ft (228 m).

Well 10

The 10 was shut-in because of paraffin with a water cut reported at 30%. The completion had accumulated 607 Mbo, 417 MMcfg, and 258 Mbw. The BHP in well 10 remained in the 3200 psi range indicating a strong water drive reservoir. A new wellhead was installed during the fall of 2012.

Well 11–D

The 11 produced until March 1990 when it was shut in. The short string in the GR sand cumulated 17 Mbo, 0 MMcfg, and 0.6 Mbw. The well recently was tested and determined to be commercial. Afterwards, Hurricane Isaac damaged the wellhead and a new one has been built and is scheduled to be installed the summer of 2013.

KE–A–10 Reservoir

The KE–A–10 reservoir is an oil reservoir with a gas cap. The A–6 discovered the reservoir in 1967. Its drive mechanism is pressure depletion with a weak gas cap expansion. Initial pressure was 6005 psi at a datum of 11,000 ft (3350 m) below sea level. Average porosity of the reservoir is estimated to be 29.2% and average water saturation is estimated to be 25%. The OOIP is estimated to be 5.6 MMbo, the original gas in place (OGIP) in the gas cap is estimated to be 4420 MMcf and the original solution gas in place is estimated to be 15,300 MMcf.

Cumulative production from 5 wells in the KE–A–10 reservoir is 1669 Mbo, 4610 MMcfg, and 986 Mbw and the current pressure is estimated to be between 1800 and 2200 psi. Those wells which have produced the KE–A–10 reservoir are A–6–D, A–7, A–8–D, A–10, and A–12. A pressure maintenance program was initiated for a short period. An undetermined amount of water was injected into well A–12. Reservoir pressure in the well A–7 indicated a response to the injection. Records also indicate well A–7 never produced after the injection project was initiated.

Well A–10

In 2012, well A–10 was successfully put back to production, not as a gas cap well, but as a well making 250–300 bopd and associated gas.

Well A–6–D

Well A–6 was shut in with 60% water cut and flowing above 50 bopd. Cumulative production from the KE–A–10 sand was 719 Mbo, 899 MMcfg, and 183 Mbw.

Well A–7

Well A–7 is shut in with a wireline tool stuck at 150 ft (45 m). A 16 ft (5 m) stem, 3 rope sockets, 2-1/2 in (6.35 cm) pulling tool, a wire grab and 300 ft (90 m) of wire remain in the hole.

Well A–8–D

Well A–8–D was shut in June 1970 with a 40% water cut. Cumulative production from the KE–A–10 reservoir was 65 Mbo, 81 MMcfg, and 18 Mbw.

WELL AND PLATFORM REFURBISHMENTS

Between 2000 and 2010, two major work-overs were attempted in the field, on wells 15 and 18. The work-over on well 15 was an initial success, but the well sanded up soon after the test, probably from an overzealous attempt at maximum production. The well remains shut-in today, but is slated for another attempt within the next couple of years if not sooner. The work-over on the 18 well was ultimately a success, but not after downhole work resulted in problems when the gas lift design was changed. This one mistake by a third party service company almost meant the end to IG Petroleum and its progress at West Delta 84 Field. The rest of the time between 2000 and 2010 was spent repairing damage inflicted by numerous hurricanes, including Katrina, while limping along with only well 18 producing.

This is a good example of the difference between the two types of operators, one being a consortium of savvy major integrated oil and gas companies and the other being micro independents. Where a major company could move forward on repairs without insurance money or outside investors, a micro independent is different. It must wait for funds and it must wait for service companies. One of the severe consequences after both Katrina and the Macondo disaster was the initial inability to obtain third party service companies. Prior to Katrina, all of the jack-ups and other essential services had been placed under contract by every major company in the area or were dealing with extreme emergencies. Service companies' availability in the Gulf of Mexico to micro independents did not become readily available until basically a year after Katrina. The affect was not as severe after the Macondo disaster, probably due to its totally unexpected nature and the ultra-deepwater locale.

This status quo continued after Katrina, however, until about 2010. At about that time, insurance monies were finally catching up to the repairs and several studies (including a portion of a 3D seismic shoot) started to provide some missing data and support the earlier conclusions reached with very little information. Plans were being made to begin some other workover projects in the field when the gas supply for start-up ran into a major issue. The B tank battery platform received and sold gas via a 10 in (25 cm) gas line that was owned and operated by Tennessee Gas. In 2010, the gas line was compromised about 3.5 mi (5.6 km) north of West Delta 84 Field, and the field was unable to receive or sell gas. A buy/sell back line or one capable of storing excess gas for future use is a necessity for the field for gas lift start up. Therefore, starting in 2011, the prioritization for the recent refurbishment of the facilities, particularly the A platform, keyed on which wells could provide gas for gas lift operations since the Tennessee Gas Pipeline had not been repaired or scheduled for repair and its status was in a holding pattern.

The natural well for the supply of gas was the A–10 well, the most updip well in the KE–A–10 reservoir and when drilled it was entirely within the gas cap of that reservoir. The last information available on the downhole condition of the A–10 well was that it only sanded up. Therefore, a plan was formulated to use a coiled tubing unit (CTU) to go into the well and wash out the sand. The coiled tubing unit package weighs approximately 45,000 lbs (20400 kg) and the A–10 well was drilled and completed as a directional well from the A platform and so in order to rework the A–10 well, the A platform required work. It required space and it required additional strength. The old waterflood equipment, which still resided on the top deck of the A platform, was removed along with the compressor house and other miscellaneous abandoned equipment to provide the space. Once that was accomplished, the entire deck was strengthened and upgraded by laying down new grating and plate and remarking the support beams on top. The well bays were refurbished as well to allow for safe access to the wellheads and wells. Stairs and railings were repaired. Sections of the platform not used were railed off.

The initial intention of using a CTU to clean the A–10 perforations was simply to draw the required start up gas for the well 18 gas lift, start up the 18 well, and shut-in the A–10 well to save the gas. Zero to minimal oil was expected to be produced, but because the KE–A–10 reservoir had undergone water-flooding the oil gas contact had moved up. The A–10 well was successfully washed down to the perforations and the well was restored to production, flowing a substantial amount of oil along with the gas. It currently produces approximately 150 bopd on a 9/64 in choke. However, the rate of gas the A–10 well is capable of producing is not enough to support the temporary high rate that is demanded during a gas lift start up previously provided by the 10 in (25 cm) Tennessee Gas line (now owned by IG Petroleum). This problem has been resolved by storing the excess gas produced by the A–10 well and drawing on the stored gas during a gas lift start up. The 10 in (25 cm) line was blocked and used as a 10 in (25 cm) by 3.5 mi (5.6 km) gas storage container. Now the field stores excess gas in the 10 in (25 cm) line and draws from it during a field or gas lift start up.

While the CTU was on the platform, it was decided to move it to the A–7 well. The A–7 has junk in the tubing. According to past operator notes, a slickline unit got stuck while coming out of the hole with a storm plug, and the slickline parted. There were several failed attempts to retrieve the junk with slickline, but these attempts resulted with more junk in the hole. IG Petroleum attempted to mill out the junk with the CTU. The junk is shallow at about 150 ft (45 m) and the CTU was not able to put the weight on the bit necessary to mill effectively. Future attempts to mill the junk will likely require a snub unit and power swivel.

In addition to the above, navigation-aid lights and fog horns were installed on all wellheads that required them, as were new identifying signs. Wellheads on several wells were repaired or replaced for planned future production. After Hurricane Isaac passed through the area in October 2012, work turned to the B platform where grating, stairs, and railings were repaired or replaced.

REGULATORY ISSUES

The facility is also undergoing an update of its Spill Prevention, Control, and Countermeasures (SPCC) Plan and other required emergency and safety plans. In addition to meeting the rules and regulations of the Louisiana Office of Conservation, Division of Natural Resources (LDNR), which is the primary regulatory agency overseeing WD84, federal guidelines and regulations must also be met separately.

The specific rules and regulations under LDNR are known as Statewide Order 29–B or specifically LAC Title 43 Part XIX. The Environmental Protection Agency (EPA) Oil Pollution Prevention Act, published under the Federal Water Pollution Control Act (Clean Water Act), also requires certain facilities to prepare and implement a plan that will prevent any discharge of oil into or upon navigable waterways of the United States or its adjoining shorelines. This plan is referred to as a SPCC Plan and is the basis of the EPA's oil spill prevention program. The main goal behind the plan is to ensure that proper protocols, prepared in accordance with good engineering practices, are in place to prevent the discharge of oil, which in turn will prevent the costly response and cleanup operations that negatively impact the industry and the environment. Those facilities that are subject to the SPCC Rule must be:

1) Non-transportation related,
2) Have an aggregate above ground storage capacity greater than 1320 gallons or a completely buried storage capacity greater than 42,000 gallons, and
3) There must be a reasonable expectation of a discharge into or upon navigable waterways of the United States or adjoining shorelines.

The facility owner or operator is required to prepare the SPCC plan and implement its stipulations. To comply with federal mandates of 40 CFR 112, certain parts are required in the plan including that all operations procedures of the facility that are in place to prevent the discharge of oil, control measures have been installed and implemented in a manner in which prevents oil from entering navigable waterways, and countermeasures that enable containment and cleanup in the event of an oil spill must all be documented. Some other requirements include facility inspections, facility diagrams, oil spill predictions, facility drainage, management approval and proof that it has been certified by a Professional Engineer.

The Facility Response Plan (FRP) rule of the EPA's Oil Prevention Program is engineered to ensure that certain facilities have sufficient oil spill response measures in place and are capable of carrying out these measures. Those facilities that are SPCC-regulated and could cause "substantial harm" to the environment must prepare an FRP and submit it to the regional EPA office. After submitting an FRP, the EPA will determine whether or not the facility meets the criteria of being capable of causing "substantial harm" as deemed by 40 CFR 112.20(f)(1).

Key elements of an FRP include but are not limited to:

1) Emergency Action Response Plan,
2) Facility name, type, location, owner, and operator information,
3) Emergency notification, equipment, personnel, evidence that equipment and personnel are available,
4) Identification and evaluation of potential discharge hazards,
5) Identification of small, medium, and worst case discharge scenarios and response actions,
6) Diagrams of the facility (topography, drainage flow, evacuation paths),
7) Facility and response training and exercise logs, and
8) Cover sheet (with basic information of the facility).

While the rules and regulations have remained essentially the same since the Macondo disaster, the oversight by regulators has increased. However, due to this increased oversight, many of the field inspectors are inexperienced and lack the ability to recognize inapplicable criteria in the field. Some confusion and frustration has resulted. This will ultimately work itself out, however, as only experience will resolve the issue.

FUTURE CHALLENGES

The future challenges at West Delta 84 Field are producing other wells that have potential, upgrading/ replacing production facilities, repairing the old Tennessee Gas line past the block, and the ability to ship more oil. Through a large initial effort and regular maintenance, the facilities and wellheads are in better condition than they have been in many years. The major problem now is insufficient storage capacity for the oil produced. The A–18 well was brought on successfully for a one day period of time and had to immediately be shut-in due to the combined production of over 500 bopd between the A–10 and A–18 wells. Because the B tank battery platform will hold only 3000 barrels and shipping ability to the final heater-treater at well W–5 is only during daylight hours and at a slower rate than the actual production, the 18 had to be shut-in and the A–10 well was choked back. In addition to flow rate constraints of oil shipments, the line to well W–5 is co-owned with another operator. They also utilize this line for their own shipments of oil and only one can ship at a time. Also Hurricane Isaac equipment repairs caused long delays in the ability for IG Petroleum to ship its oil resulting in the shut-in of the productive wells for an extended period of time.

There are several satellite wells that have oil and gas potential, including the 10 (which has a new wellhead) and the 11 (which has a new wellhead built and ready to be installed). Making these wells producible involves not only these tree repairs but also cribbing, flow line, and riser repair.

This increase in production will also require upgrading/ replacing the production facilities, repairing the gas sales line (if we bring gas wells on line), and shipping oil via another method. Upgrading and repairing the facilities would likely involve setting up new oil and water tanks, separators, heater-treaters, LACT unit, sales pump, and compressor very close to the B tank battery platform. IG Petroleum would phase out of the use of the B tank battery platform facilities and decommission the parts not being used. Repairing the 10-in gas line would involve installing a 60 ft to 100 ft (18 to 30.5 m) section of line located about 3.5 mi (5.6 km) north of the West Delta 84 Field. This will be a challenging task. Divers will have to uncover the line on a sand shore in 3–5 ft (1–1.5 m) of water with 20 ft (6 m) of ground cover. A spool will have to be fabricated and connected with 1500 psi smart flanges.

In addition to shipping oil via the sales line, IG Petroleum plans to increase the shipping potential by transporting via barge. This would involve installing an additional processing facility and oil storage tanks on the west bank of Southwest Pass of the Mississippi River and building a barge dock facility in the river.

CONCLUSIONS

One of the severe consequences after both Katrina (and hurricanes in general) and the Macondo disaster was the initial inability to obtain third party service companies. It took a year after Katrina to have ready access to service company equipment and manpower. The effect was not as severe after the Macondo disaster, probably due to its totally unexpected nature and the ultra-deepwater locale.

While the rules and regulations have remained essentially the same since the Macondo disaster, the oversight by regulators has increased and because of this, many of the field inspectors are inexperienced and lack the ability to recognize inapplicable criteria in the field. Some confusion and frustration has resulted. This will ultimately work itself out. Only experience will resolve the issue.

It is now possible (and essential) for micro independents to operate in the Gulf of Mexico, even after the twin extreme disasters faced in Katrina and Macondo. This is due to the experience the micro independents have gained by working in the Gulf now for decades..

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