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Commissioner Christi Craddick
Railroad Commission of Texas
P.O. Box 12967
Austin, Texas 78711-2967

Dear Commissioner Craddick,

Thank you for speaking at our recent International Association of Drilling Contractors (IADC) Drilling Onshore Conference in Houston. Your presentation was very well received by the attendees of the conference.

This letter is a follow-up of our conversation regarding issues facing drilling contractors specific to changes in Rule 13. As was suggested, IADC is requesting a meeting with you and the Railroad Commission staff so that we might resolve these issues in a manner that is satisfactory to the Commission and our members.

By way of background, IADC is a trade association representing the interests of operators, service companies and drilling contractors, onshore and offshore, operating worldwide. Our membership includes drilling contractors operating approximately ninety three percent of the active drilling rigs currently in the United States. IADC strongly supports efforts to make the drilling and well servicing operations safe for the environment, general public as well as our member's employees. IADC supports reasonable regulations that are based on credible well engineering and risk assessment.

Our specific concern and the area we hope to discuss with you and staff, revolve around Chapter 3 Oil and Gas Division Rule §3.13 Casing, Cementing, Drilling, Well Control, and Completion requirements, which are directed to the well operators. It falls upon the drilling contractor to provide the drilling equipment compliant with the rule. A key issue among our members is the blanket use of Standard 53 and the requirement of blowout preventer equipment to be certified to the standard.

API Standard 53 was revised and modified in response to the Macondo incident in the Gulf of Mexico. That incident occurred on 20-April-2010. API Standard 53 was published by API in November 2012. To date, offshore drilling contractors and operators in the Gulf of Mexico that are outside of the Texas Railroad Commission area of jurisdiction are not subject to the API Standard 53 by regulation. In addition to certification, there are a number of other items in Standard 53 that are not common practice and create uncertainty and confusion for IADC member companies in complying with Rule 13.

Attached additional points raised by IADC drilling contractors to serve as discussion points for our meeting. If there are any questions, please feel free to contact me.

IADC would be pleased to work with your staff to ascertain a meeting date and time that is convenient for all parties. In the meantime, thank you in advance for your consideration and for your leadership in serving the state of Texas.

Sincerely,

A handwritten signature in cursive script, appearing to read "Joseph Hurt", with a long horizontal flourish extending to the right.

Joseph Hurt
Vice President Onshore Division

Railroad Commission of Texas

Concerns with Rule 13 and API Standard 53

A) "Rule 13":

Texas Administrative Code
TITLE 16 ECONOMIC REGULATION
PART 1 RAILROAD COMMISSION OF TEXAS
CHAPTER 3 OIL AND GAS DIVISION
RULE §3.13 Casing, Cementing, Drilling, Well Control, and Completion Requirements

And

B) "API Std 53":

API STANDARD 53, Blowout Prevention Equipment Systems for Drilling Wells,
FOURTH EDITION, NOVEMBER 2012,

1) API Std 53:

"(vii) All control equipment shall be consistent with API Standard 53: Recommended Practices for Blowout Prevention Equipment Systems for Drilling Wells. Control equipment shall be certified in accordance with API Standard 53 as operable under the product manufacturer's minimum operational specifications. Certification shall include the proper operation of the closing unit valving, the pressure gauges, and the manufacturer's recommended accumulator fluids. Certification shall be obtained through an independent company that tests blowout preventers, stacks and casings. Certification shall be performed every five (5) years and the proof of certification shall be made available upon request of the Commission."

Unclear what "certified in accordance with API Standard 53" entails. API Std 53 does not use the term "certified" (or other derivative of "certify") in such a manner anywhere in the document toward well control equipment.

Getting all equipment operating in Texas certified to some unknown scope would take an unknown amount of time and would be unduly burdensome and costly to the many independent Operators and Drilling Contractors in Texas. It could also cause a number of wells not to be drilled at all and cause the loss of jobs.

Opening sentence in (vii) stateswith API Standard 53: Recommended Practices for.....The correct title for Standard 53 is: "Blowout Prevention Equipment Systems for Drilling Wells"

2) Rule 13:

“Certification shall be obtained through an independent company that tests blowout preventers, stacks and casings. Certification shall be performed every five (5) years and the proof of certification shall be made available upon request of the Commission.”

Why every five (5) Years? API Std 53 allows for a different schedule.

Certification should not require an independent company. A competent person (defined in API Std 53) or Professional Engineer should be capable of such certification.

Concerns are new equipment lead times are exceptionally long. These facilities do not have the capacity to take on additional repairs. A Drilling Contractor or third party non-OEM should be able to perform testing, inspections, examinations, repairs and remanufacture of well control equipment in-house with the correct systems, equipment and personnel in place.

3) API Std 53:

“6.2.1.1 Choke and kill systems shall be designed, manufactured, and installed in accordance with API 16C.”

API 16C, FIRST EDITION, JANUARY 29, 1993, is “Specification for Choke and Kill Systems”.

API 16C page 8 in section 1.4, 2 requires valves and other equipment to have an API 6A minimum product specification level of “PSL 3” and minimum material class “EE”.

This means any choke manifolds in Texas using API 6A valves built to PSL 1 or PSL 2 are no longer accepted by the Texas RRC.

API 6A material class DD valves, which are easier to apply hard metal overlay, are no longer accepted by the Texas RRC. It is expected in the next revision to API 16C (currently in draft form and planned to be re-balloted shortly) will allow DD material class valves.

Any drilling Rigs in areas covered by the Texas RRC with choke manifold valves not meeting this requirement for minimum PSL 3 and EE trim will have to be replaced with new (different) equipment. This includes choke manifold valves, kill line valves, chokes, choke line valves and other equipment. Such a change would take an unknown amount of time and would be unduly burdensome and costly to the many independent Operators and Drilling Contractors in Texas.

What is the justification for such a requirement? API 6A PSL Level I valves are safe and reliable. If such a valve fails to seal, there is commonly other valves (redundancy) in the system to maintain well control.

4) API Std 53:

“6.2.1.1 Choke and kill systems shall be designed, manufactured, and installed in accordance with API 16C.”, and

“6.2.3.1.4 See API 16C for equipment-specific requirements for flexible line assemblies.”, and

“6.2.4.2.4 See API 16C for equipment-specific requirements for flexible kill lines and articulated line assemblies.”, and

“7.2.1.1 Choke manifolds and choke and kill lines shall be designed, manufactured and installed in accordance with API 16C.”, and

“7.2.3.1.4 See API 16C for equipment-specific requirements for flexible line assemblies.”

API 16C covers flexible choke and kill lines. API 16C current licensed facilities for Flexible Choke and Kill Lines are currently limited to six (6) facilities. One (1) in USA, One(1) in China, One (1) in Malaysia, One (1) in Hungary, One (1) in Saudi Arabia and One (1) in France. This is five (5) outside of U.S.A. and one (1) in U.S.A. One practical facility in U.S.A. to get API 16C hose products raises restraint of trade issues.

There are many hose companies producing choke hoses and kill hoses that are not API 16C product. It is understood that the original API 16C includes some stringent fire testing requirements developed for offshore applications. The majority of rigs covered by the Texas RRC operate onshore.

With limited manufacture options for API 16C hoses, deliveries take a long time and pricing is very high. Such a change would take an unknown amount of some time and would be unduly burdensome and costly to the many independent Operators and Drilling Contractors in Texas.

5) API Std 53:

“4.12.1 Marking and storage of sealing components of BOP systems shall be in accordance with API 6A, API 16A, or API 17D, as applicable, including identification marking of ring gaskets, bolts, nuts, clamps, and elastomeric seals.”

This implies only equipment covered in the scope of API 6A, API 16A and API 17D from API licensed facilities can be used in areas covered by the Texas RRC.

6) API Std 53:

“6.1.2.11 A minimum Class 4 BOP stack arrangement shall be installed for 10K pressure rated systems, with a minimum of one blind ram or a BSR capable of shearing and sealing the drill pipe in use.”

This means a 2-ram stack with one (1) annular is no longer sufficient for a 10K rated BOP system. Whether the well could be drilled safely with a 5K BOP stack does not matter. Such a decision on number of BOPs should be a risk based decision for the well to be safely drilled. It should not be a function rated working pressure equipment that a Rig might happen to have on hand.

7) API Std 53:

“6.1.2.12 A Class 5 BOP arrangement or greater shall be installed for 15K and greater pressure rated systems. The minimum requirements for a Class 5 BOP stack arrangement shall include one annular, one BSR, and two pipe rams. The fifth device may be a ram or annular type preventer, whichever is desired. A risk assessment shall be performed to identify ram placements and configurations, and taking into account annular and large tubular(s) for well control management.”

Thus, blinding shear rams are now required on 15K BOP stacks by the Texas RRC. It does not matter what well is being drilled, just the rated working pressure of the BOP stack. Such a decision for shear rams at the expense of a cavity that might include a more reliable blind ram to close on an open well bore should be a risk based decision.

8) API Std 53:

“6.2.2.9 A minimum of two remotely operated chokes shall be installed on choke manifold systems rated 10K and greater. The choke control panel shall have two independent control valves, one each for the two remotely operated chokes.”

Many 10K choke manifolds have one (1) manual choke, one center run, and one (1) remotely controlled hydraulic choke. These chokes might be a rental item, since Operators have varying preferences on makes/models they prefer. Adding the second hydraulic choke needs plumbing changes and space to accommodate same. This requirement includes no review of the well to be drilled and risk associated with same.

A 10K choke manifold might have been used on a well that only requires a 5K BOP stack. Where a 5K choke manifold may have required only one (1) hydraulic choke, now that choke manifold is required to have two (2).

This would take an unknown amount of some time and would be unduly burdensome and costly to the many independent Operators and Drilling Contractors in Texas.

9) API Std 53:

“6.2.2.18” The choke control station shall include all instruments necessary to furnish an overview of well control operations. This includes the ability to monitor and control such items as stand pipe pressure, casing pressure, and monitor pump strokes.

It unclear how such items would be able to be controlled at the choke control station.

“6.3.10.6” All control system analog pressure gauges shall be calibrated to one percent of full scale at least every three years.”

To test to one percent is excessive.

10) API Std 53:

“6.3.1.1 Control systems for surface BOP stacks shall be designed, manufactured, and installed in accordance with API 16D.”

Many control systems were built before API 16D existed. They certainly were not built to unpublished standards at the time of manufacturer. Pump time requirements and closing time requirements in API Std 53 also fit around current 16D equipment requirements – but perhaps not previously built closing units. It appears the first edition of API 16D was published in 1993. Such a requirement by the Texas RRC obsoletes old equipment that might be perfectly suitable for use in drilling some (or perhaps most) wells. A non-API closing units may also have been built that is not from an API 16D licensed facility. Such a change will take time and money.

“6.3.9.4 The precharge pressure shall be measured prior to BOP stack deployment and adjusted in accordance with the manufacturer-specified API 16D method (A, B, or C),” using the control system manufacturer-supplied surface base pressure, adjusted for operating temperature as required, and shall be documented and retained at the rig site. The calculated precharge pressures along with documentation supporting nonoptimal precharge pressures (if used) shall be filed with the well-specific data package. See Annex C for examples of accumulator precharge calculations.

Full compliance would be undue burden.

11) API Std 53:

“6.3.11.2.5 All rigid or flexible lines between the control system and BOP stack shall meet the fire test requirements of API 16D, including end connections, and shall have RWP equal to the RWP of the BOP control system.”

Many Rigs have rigid piping for closing system, but will not have performed fire testing on this piping. Including the wording “rigid” makes this section difficult to comply with. Why is fire testing required for rigid piping?

In some situations with walking rigs, why would fire testing be required for piping and flexible hoses that are long distance from the well bore?

12) API Std 53:

“6.4.6.1 A trip tank shall be installed and used on all wells.”

This removes the possibility of a Rig filling the hole from main mud tanks on shallow Rigs or spudder type Rigs that just drill the surface interval before a larger Rig is used to drill the more critical parts of the well.

This should be a an engineering based decision and is not necessary on all rigs.

13) API Std 53:

“6.4.7.1 Pit volume measuring systems, complete with audible and visual alarms, shall be installed.”, and

“6.4.7.3 A pit volume totalizer system shall be installed and used on all rigs.”, and

“6.4.8.1 A flow rate sensor mounted in the flow line shall be installed for early detection of formation fluid entering the wellbore or a loss of returns.”

Such instrumentation systems and pit volume systems might be rental items only used during the more critical portions of a more critical well. The Texas RRC commission is now requiring these systems on all wells at all times. This would include a Rig that only drills and sets conductor pipe. Such a decision should be based on risks and the drilling engineer’s assessment of the requirements of well that is being drilled.

14) API Std 53:

“6.5.3.1.5 Actuation times shall be recorded in a database for evaluating trends (see sample worksheets in Annex A)”.

What is the benefit of adding this undue burden to put this information in a database?

“6.5.3.4.3 Chamber pressure tests shall be performed and charted as follows:

- a) At least once yearly,*
- b) When equipment is repaired or remanufactured,*
- c) In accordance with equipment owner’s PM program.”*

Requiring the test to be charted is over burdensome.

“TABLE 2 Pressure test

d The MGS requires a onetime hydrostatic test during manufacturing or upon installation. Subsequent welding on the MGS vessel shall require an additional hydrostatic test to be performed.

OEM repair procedures may not require hydrostatic testing. It is unclear if hydrostatic testing requires holding pressure on the vessel. Not all MGS are pressure vessels.”

“6.5.6.2.2 This test shall be performed after the initial nipple-up of BOPs, after any repairs that required isolation/partial isolation of the system, or every 6 months from previous test, using the following example (see Annex A).

g) Record the final accumulator pressure. The final accumulator pressure shall be equal to or greater than 200 psi (1.38 MPa) above precharge pressure.

Note 1 When performing the accumulator drawdown test, wait a minimum of 1 hour from the time you initially charged the accumulator system from precharge pressure to operating pressure. Failure to wait sufficient time may result in a false positive test.

Note 2 Because it takes time for the gas in the accumulator to warm up after performing all of the drawdown test functions, you should wait 15 minutes after recording the pressure, if the pressure was less than 200 psi (1.38 MPa) above the precharge pressure. If there is an increase in pressure, indications are that the gases are warming and there is still sufficient volume in the accumulators. If the 200 psi (1.38 MPa) above precharge pressure has not been reached after 15 minutes you may have to wait an additional 15 minutes due to ambient temperatures negatively affecting the gas properties. After 30 minutes from the time the final pressure was recorded, if the 200 psi (1.38 MPa) above precharge has not been reached, bleed down the system and verify precharge pressures and volume requirements for the system.”

Waiting an hour for the drawdown test is not a common practice in the onshore industry.

15) API Std 53:

“6.5.8.2.1 Fasteners in the load path, both male and female threads, shall be tested using a go, no-go gauge.”

Such a requirement to check all fasteners is new and over-burdensome. We have no evidence establishing this need based on fastener failures or problems.

16) API Std 53:

“6.5.8.6 Poor Boy Degasser/Mud-Gas Separation Systems Inspection and Maintenance

6.5.8.6.1 Equipment owner’s PM program shall include removal of inspection plates and clearing of debris.”

This requirement will require adding (welding) inspection plates to existing poor boy degassers that lack same. How to safely weld on vessels that might include flammable gases and/or liquids is not without risk – if done improperly.

17) API Std 53:

“6.5.8.2.6 After the initial pressure test is completed, all bolts shall then be rechecked for proper torque.”

If the initial torque is applied per specification, and pressure test achieved, it should not be necessary to rechecked for proper torque. (Note: Bolts may be re-torqued on subsequent BOP tests.)

18) API Std 53:

“6.5.10.1.2 The equipment owner shall be responsible for retaining records and documentation within the previous 2 year period at the rig site.”, and

“6.5.10.6.4 Pressure and function test reports shall be retained for a minimum of 2 years at the rig site, and copies of these documents shall be retained at a designated offsite location.”

“7.6.11.1.2 The equipment owner shall be responsible for retaining records and documentation within the previous 2 year period at the rig site.”

This is a new requirement. Equipment may move from rig to rig which makes this complicated and not feasible. Most records are kept at the office.

19) API Std 53:

“6.5.10.5.4 The equipment owner shall maintain a log of BOP and control system failures. The log shall provide a description and history of the item that failed along with the corrective action. The failure log shall be limited to items used for wellbore pressure control and equipment used to function this equipment.”

It is unclear as what is meant by a failure and what needs to be reported to the equipment manufacturer.