Workover Program for Tuk M-18

Well Name: IESP TUK M-18 69-20-133-00 WID 1933

Objective:

Drill out suspension plugs and run completions assembly to produce gas from the existing Kamik perforations for a Compressed Natural Gas (CNG) and Gas-to-Liquids (GTL) Energy Center for the Inuvialuit Energy Security Project.
Due to the presence of +/- 365m of permafrost, vacuum insulated tubing (VIT) will be run in the top 400m of the well.
A subsurface safety valve (SSSV), chemical injection capillary lines, and a fibre optic distributed temperature monitoring line will be incorporated in the design.

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History:

The well was drilled by Devon Energy along with their partner Suncor Energy in 2002. It was completed in the Kamik sands and extensively tested, after which it was suspended with two permanent bridge plugs.

Operatorship was transferred to CNRL as part of a corporate acquisition in 2020.

The Inuvialuit Petroleum Corporation (IPC) acquired the well in July 2022, and IPC through its wholly owned subsidiary, Inuvialuit Energy Security Project LTD. (IESPL), will develop the well and the Inuvialuit Energy Security Project.

Well Data:

Location: **69˚ 17' 50.6" N 133˚ 04" 34.6" W** **NAD 27**

Total Depth: 2962mKB (2933mTVD) Plugback Depth: 2901mKB

Perforations: 2662-2668mKB (Upper Kamik)
2701-2722mKB (Lower Kamik)

BHP 28,500kPa @ top perf 2662mKB (2644mTVD)
Gradient 10.78kPa/m EMW 1100 kg/m3

Casing and Cement

Conductor Casing
508mm 0-27m
Cemented to surface with Arctic-set

Surface Casing
339mm 107.7kg/m DST 80 LTC 0-207mKB
Cemented to surface (Primary job to 75m (140 tonnes) & 25mm top job (37 tonnes) all Arctic-set

Intermediate Casing
244mm 79.6kg/m DST 80 LTC 0-786mKB
Cemented 36 tonnes Arctic-set and 18 tonnes Class G – 4m3 returns
Minimum internal yield 54.7MPa

Production Casing
178mm 47.6kg/m DST 80 LTC 0-2947
Cemented with stage tool 2947-1414mKB (Glass G)
1414mKB to 115mKB – Mudpush spacer frozen above 115mKB
Suspect frozen partially set Class G cement +/- 365m to 115mKB

Perforations

Upper Kamik

2662-2668mKB	28.378MPa	10.7kPa/m	1090kg/m3	minimum kill weight

Lower Kamik

2701-2722mKB	28.495MPa	10.6kPa/m	1075kg/m3

Tubular Properties

Production Casing - 178mm 47.6kg/m DST 80 LTC
80% of Burst 46.6MPa (Reported burst 58.3MPa)
Drift 151.61 mm (5.968 inches)
Capacity .0188 m3/m2

Tubing – 73mmn 9.52kg/m L-80 Cr13 VAM TOP (Range 2)
80% of Burst 58.3MPa (Reported burst 72.9MPa)
80% of collapse 61.5MPa (Reported collapse 76.9MPa)

80% of tensile yield 51,900daN	(Reported tensile yield 64,500DaN) body/joint
Drift 59.6mm	
Capacity 0.0030m3/m	
Vacuum Insulated Tubing (VIT)	4 ½” 11.6lb/ft L80 X 2 7/8” 8.6lb/ft L80-13Cr 114mm 17.2kg/m X 73mm 12.8kg/m L80-13Cr 73mm VAM TOP thread
80% of Burst 82.5MPa	(Reported burst 103MPa)
80% of Collapse 35.2MPa	(Reported collapse 44MPa) – 114mm OD String
80% of tensile yield 70,000daN	(Reported tensile yield 88,400daN) - body & joint 73mm
Drift 54.88mm	
Capacity 0.0026m3/m	

Note: Drift restriction of 47.67mm at BX profile in SSSV

Well Control Philosophy

The program has been designed to provide the best possible well control during operations, considering the deliverability of the well and the remote location, and the sensitive environment.
The well is currently secured with two bridge plugs (capped with cement) located at 360mKb and 2650mKb respectively.

Phase 1: Drillout of the top plug and casing logging.

> The diesel fuel above the top packer will be replace with 1130 kg/m3 brine prior to drilling out the top plug.
> While the upper plug is drilled out, the well will be secured by the bridge plug located at 2650mKB.
> Due to the diesel fuel below the upper packer, the combined hydrostatic pressure is less than the BHP at the uppermost perforation and thus the lower bridge plug is relied upon to contain that pressure. As a contingency, the BOP used in this segment will be tested to a working pressure of 35MPa.

Phase 2: Replace remaining diesel fuel with 1130 kg/m3 brine and evaluate casing to 2645mKB.

> The diesel fuel from 2094mKB will be replaced with 1130 kg/m3 brine and the well will then be circulated to blend the 1130 kg/m3 brine with the 1175 kg/m3 brine between 2650m and 2094m.

> The blended brine will be slightly heavier than 1130 kg/m3, but assuming that value as a minimum, the BHP @ 2650m (lower bridge plug – 2632 mTVD) will be 29,176 kPa (versus BHP at top perforation of 28,500 kPa – approximately a 700kPa over balance).

> The casing will be pressure tested and evaluated using electro-magnetic methods to confirm its integrity, prior to drilling out the lower plug.

Phase 3: Drillout of Lower Plug and Setting Permanent Packer and Tailpipe

> Once the lower plug is drilled out, the wellbore will be exposed to reservoir pressure, but as noted above, the well will be hydrostatically overbalanced by the brine column. As a contingency, the BOP will have been tested to 35MPa with the 88 mm workstring. A trip sheet will be maintained while tripping out, to ensure that the well is neither flowing, or losing excess fluid to the formation, reducing the hydrostatic head.

> The permanent packer will be run on wireline using a lubricator, to provide secondary well control while running. Again, the hole will be maintained full, to account for possible surge effects while running the packer. Once the packer is set and pressure tested, the ceramic disk in the tailpipe will again ensure positive well control.

Phase 4: Running the Tubing

> The tubing is of dual diameter (73mm conventional tubing and 144mm OD Vacuum Insulated Tubing (VIT)). Four strings of capillary tubing will be rum on the outside of the tubing, meaning that the annular preventer will be the BOP used (pipe rams will damage the capillary). The

actuating pressure of the annular pressure will be reduced to minimize the risk of damage to capillary should it be closed. Use of the annular is not anticipated as noted above, the formation is isolated from the wellbore by the tested packer and ceramic disk.

Phase 5: Installing the Wellhead and Establishing Communication with the Formation

Once the tubing is stabbed into the packer and the tubing hanger landed, the wellhead will be installed, and pressure tested. Only after a successful pressure test will the ceramic disk be sheared out with pressure, establishing connection to the existing perforations and the formation. The well will then be ready for cleanup and testing.

Phase 6: Cleanup and Testing of the Well and Tubing

When all the well components are installed, the well will be flowed back to clean up any completion brine and debris that may have entered the formation and confirm the anticipated production rates.

Phase 7: Securing the Well

At the completion of testing, the well will be shut-in, the master valves closed and locked, and the control pressure to the SSSV bled off allowing it to close. Depending on the anticipated shut-in period until the start of production, a back-pressure valve may be run in the wellhead.

Operations:

1. Conduct walkaround on lease to check for hazards, in particular areas of settlement or soft ground. Have construction fill any questionable areas with gravel and compact same.
2. Confirm that well pad area has been filled to final grade and cellar extensions to surface have been installed.
3. Confirm that the cellar has been emptied of fill down to cement pad at base (approximately 2.25 meters below current bottom of tubing spool) and casing valves are exposed.
   Fill is reported to be expanding foam.
   Install curbs and/or fencing around open cellar if not in place.
   If entry into cellar is needed to perform additional cleanout (fill, ice, etc.), follow confined space entry procedures.
4. Mark out lease locations for service rig, test equipment, flare stack, storage tanks, office/crew shacks. All spacing to comply with AER Directive 37.
5. Move in and rig up office shack, crew/survival shack, Mobile Treatment Center (MTC).
   Ensure power, water, etc. are functional.
6. Perform bubble test on surface and intermediate casing, and on wellhead (bleed off any gas from expansion on tubing side prior to test is permitted).
7. Perform wellhead modifications. A wellhead technician will be on site to assist with installation.
   a. Remove both 50mm surface casing valves and intermediate spool valves.
   b. Remove current the 11” 5,000# (278mm 35MPa) tubing spool and wellhead.
   c. Install new 11” 5,000# (278mm 35MPa) extension spools to bring topmost flange to surface.
   d. Install new 11” 5,000# (278mm 35MPa) X 7’ 5000# (178mm 35MPa) tubing spool and wellhead. Torque all 1 7/8” bolts to required level (3220 ft-lbs. – 4366 newton-meters). These connections will be pressure tested to 1400 kPa and 35 MPa once service rig is available.
   e. Install blind flanges on one side of the spools.
   f. Install new 50mm X 35MPa gate valves on the opposite side of both spools with companion flanges on the outboard side.
   g. Install 50mm Schedule 160 (XX) vent piping to surface, with 50mm 35MPa ball valve on each.
      Terminate pipe a minimum of 600mm above grade and facing downward to prevent the entry of precipitation.
      Selection of which casing spool valves to use and how to route piping to be made in conjunction with IESPL representative.
      Final piping must extend beyond the wellhead enclosure (when installed). This piping may be done now or prior to installing the wellhead enclosure.

h. Pressure test both vents to 700 kPa with air.
Use soap and water to check for leaks.
Air may leak off via annulus, so soap test is the most viable test method.

i. Install 12mm, 37mm and 50mm (3/4”, 1 ½” and 2”) NPT extensions (temperature probe, glycol inlet, and glycol return respectively) from the top of the refrigerated/insulated conductor barrel to just above grade.
Note: The nature, size, and condition of the connections will be confirmed when the expanded foam currently surrounding them is removed.
There are no current plans to implement refrigeration of this zone, but piping is being extended to facilitate this contingency if it is determined that it is needed in future.
Fill piping with propylene glycol (RV antifreeze) and pressure test to 700kPa for 10 minutes (Baker pump or equivalent should be sufficient).
The conductor barrel annulus is believed to be full of glycol water and only the volume of the piping should be needed. The maximum volume of glycol/water needed (if the conductor barrel annulus was evacuated which is not expected) is estimated at 1.0m3)
Cap ends of extensions.

Note: Confined space procedures are required for entry into cellar, including air quality testing, positive ventilation, and rescue contingency.
Both gate valves and both ball valves to be fully open.

8. Move in and rig up tank farm of four 200bbl (31.7m3 each) tanks and mixing system to facilitate NaCl addition.
Two 200bbl tanks will be empty for diesel storage when circulated out of well.
Two 200bbl tanks will be used for storing NaCl brine prior to displacement into the well.
    a. Storage tanks are to be double walled and equipped with heating coils (steam or electric).
    b. Install tanks in a bermed enclosure (e.g., plastic or metal wall with impermeable liner). Capacity of the bermed area is to be a minimum of 56m3.
    c. All equipment to be placed on rig mats or equivalent to spread loads and minimize settlement.
9. Haul in 50m3 of 1130 kg/m3 NaCl brine and approximately 2000 kg of NaCl as contingency.
Note: NaCl to be sacked, palletized and double shrink wrapped to facilitate return if not needed.
10. Move in & rig up service rig (excluding BOPs), test/flowback equipment etc.
Note: All equipment to be placed on rig mats or equivalent to spread loads and minimize settlement.
11. Stump test the BOP with water/glycol as follows:
Note: Pass – is a **stabilized** pressure of at least 90 per cent of the test pressure over a 10-minute interval for all pressure tests.
    a. Install a 114mm joint of Vacuum Insulated Tubing (VIT) in the test stump.
    Pressure test the annular preventer to 1400kPa and 7000kPa for 10 minutes each.

Then decrease the actuation pressure on the annular until it leaks slightly.
Note this pressure – the accumulator will be reset to this pressure while running the 114mm VIT with external capillary strings.

Note: Annular pressure is decreased, allowing a small leak to determine the minimum closing pressure in order to prevent the annular element crushing the capillary tubing. The annular should not be needed during the running of the 73mm tubing and VIT because the packer has been set with a burst disk to provide pressure isolation (70MPa from below – pressure tested to 21 MPa from above).
If needed, pressure can be increased from the remote control station at the accumulator as/if needed.

b. Install a 73mm pup joint in the test stump.
Pressure test the annular preventer to 1400kPa and 7000kPa.
Decrease the actuation pressure on the annular until it leaks slightly.
Note this pressure – the accumulator will be set to this pressure while running the 73mm production tubing with external capillary strings.

c. Reset the actuating pressure on the annular to the original pressure (typically 10,500kPa) or as required by manufacturer.
Install an 88mm pup joint in the test stump.
Pressure test the pipe rams to 1400kPa and 35MPa with water.
(This will be the work string used to drill out the plugs and theoretically could face the highest pressure at the wellbore.

d. Remove the pup joint and pressure test the blind rams on test stump to 1400kPa and 35MPa.

12. Conduct an accumulator function test.

    a. Recharge the accumulator, shut off the pump and record the accumulator pressure.

    b. Close each ram and record the start and end pressures and the time to close each ram (Must close in 30 seconds or less).
    Remaining pressure on the accumulator must be 8400 kPa or greater after closing all elements.

    c. Recharge the accumulator and record the time for the accumulator to recharge to the original pressure. (Must recharge in 5 minutes or less.)

    d. Ensure that hand wheels are available and are the correct type and size for all the BOP rams. Record the number of turns to close each ram manually.

13. Confirm SICP (Shut-in Casing Pressure) = 0kPa. Bleed off any nominal pressure.
(There is no tubing in the well – SICP = SICP = 0kPa)

14. Fill casing if needed and pressure test casing, new spools, and wellhead to 1400kPa and 7000kPa for 10 minutes each.
Pass – is a **stabilized** pressure of at least 90 per cent of the test pressure over a 10-minute interval.

Due to the volume of the casing, one "bump" to refill and repressure the casing as retest is permitted in the event of an initial test failure.

15. Install suitable temporary cover over cellar cribbing. (E.G., secured 2 X 8 timbers)
16. Install 11" 5000# X 7" 5000# tubing spool.
    Activate internal seals as required.
17. Measure actual distance from top of tubing spool to casing bowl flange.
    All depths in this program are based on the KB elevation of the drilling rig.
    Correct depths in this program to Tubing Hanger Flange (THF) and report as depth THF.
    Depth CF = depth KB – 10.65m
    Depth THF = Depth CF + height from casing bowl flange to top of tubing flange
    (This is done for future work as the casing bowl flange will be inaccessible for future operations).
18. Install the Class III 35MPa BOP.
    Function test BOP by closing and opening each BOP component using both driller's and remote controls. (A joint of 73mm tubing should be hung in the well to function test the annular).
19. Close the blind rams and pressure test the BOP connection, spools, and casing to 1400kPa and 35MPa for 10 minutes each.
    Pass – is a stabilized pressure of at least 90 per cent of the test pressure over the 10-minute interval.
    Due to the volume of the casing, one "bump" to refill and repressure the casing as retest is permitted in the event of an initial test failure.
20. Make up drill collars (101 or 114mm nominal suggested) with 151.6mm single port junk mill.
21. RIH on 88mm drillpipe (3 ½ with 3 ½ IF connection or equivalent) to plug at +/- 355mKB.
    (Allow for change in depths due to raised wellhead).
    Diesel returns are expected due to drillstring displacement.
    Tag plug at approximately 355mKB. Pick up 0.3m.
22. Forward circulate out diesel from 355mKB with 1130kg/m3 NaCl brine.
    Approximately 6.8 m3 diesel is expected.
    Haul out diesel as required to facilitate separation of produced diesel and brine.
    Diesel may be hauled to industrial waste heat boilers in Tuktoyaktuk or Inuvik (if suitable).
    Otherwise it will be hauled to approved disposal location in BC or Alberta.
23. Mill out Halliburton Fas Drill bridge plug and 5m cement cap at 335mKB with reverse circulation.
    Note: Fas Drill is a composite bridge plug and should drill quickly.
    It is designed so that when the top is milled out any pressure beneath it is released before the hold down slips are milled. It is possible, but unlikely that gas may be encountered below the plug.
    Note: There has been an incident where a plug was released and pushed uphole causing injury to a worker. This incident is addressed in OROGO Safety Bulletin SB-01 2021. Because of the design of the plug in this well a snubbing unit is not considered necessary, nor is notification of OROGO required (as this is not within their jurisdiction), but the pre-drillout hazard analysis and precautions listed in the bulletin should be followed.

24. Close the pipe rams and pressure test the BOP connection, spools, and casing to 1400kPa and 35MPa for 10 minutes each.
    Pass – is a stabilized pressure of at least 90 per cent of the test pressure over the 10-minute interval.
    Due to the volume of the casing, one “bump” to refill and repressure the casing as retest is permitted in the event of an initial test failure.

25. RIH and tag plug @ 2645mKB.

26. Forward circulate out diesel with 1130kg/m3 NaCl brine.
    Approximately 32.7m3 diesel is expected.
    Haul out diesel as required to facilitate separation of produced diesel and brine.
    Allow mixing with 1175kg/m3 brine in bottom of the well.
    Circulate until density is consistent (minimum 1130kg/m3 but likely higher due to 1175kg/m3 component).
    Maintain a minimum of 20m3 surface volume (drillstring displacement plus 10m3 surface volume) as 1130kg/m3 (or greater) kill fluid. Add volume as needed during subsequent operations to compensate for losses.

27. Pressure test casing to 1400kPa and 35MPa for 10 minutes each.
    Pass – is a **stabilized** pressure of at least 90 per cent of the test pressure over a 10-minute interval.
    Due to the volume of the casing, one “bump” to refill and repressure the casing as retest is permitted in the event of an initial test failure.

28. Pull out of hole with workstring and mill.
    Maintain hole full.

29. Run casing inspection logs (Electromagnetic & dimensional inspection – brand TBD)
    a. TBD
    b.
    c.

30. RIH with drillstring, collars, and mill to 2645mKB.

31. Mill out Halliburton FAS bridge plug and 5m cement cap with reverse circulation.
    Gas is anticipated below the plug as soon as the top is drilled out.
    The 1130m3/kg brine should maintain well control, but some losses to formation are anticipated.
    Record volume of fluid lost to formation.

32. RIH and tag PBTD (estimated at 2880mKB (reports are inconclusive)).

33. Forward circulate annular volume (approximately 37 m3) to remove any gas in annulus.
    POOH.

34. Pick up casing scraper for 178mm nominal casing. (151.6mm drift ID).

35. RIH to 2680mKB.
    Work casing section from 2600mKB to 2800mKB to ensure good seat for permanent packer.
    Use reverse circulation.

36. POOH.
    Maintain hole fill record.
    Record and report fluid lost to formation daily during operations.

37. Change 88mm pipe rams to 73mm rams in BOP.
    Pick up tubing hanger with 73mm pup, land hanger and pressure test 73mm rams to 1400kPa and 35MPa for 10 minutes each.
    Pass – is a stabilized pressure of at least 90 per cent of the test pressure over the 10-minute interval.
    Remove tubing hanger.

38. Make up the packer and tailpipe assembly as per attached drawing from Baker Hughes.
    Ensure ceramic disk assembly is installed on tailpipe.
    Set burst value from above at approximately 28MPa (or as directed by tool technician).
    Note burst from below is 70MPa – fixed.

    Assembly will be run on E-line with lubricator for well control.
    Due to the length of the assembly, it may not be practical to have a full length lubricator.
    In that case, make up and place lower sections of tailpipe into well, using the 73mm pipe rams for well control. Make up remaining section(s) of completion assembly, running tools, and lubricator.
    Lock pipe rams with hand wheels. Pressure test lubricator to 7MPa with nitrogen. (Water/glycol may be used as an alternative.)
    Note: Pipe rams may allow fluid to leak past them into wellbore due to pressure above them – this is not a failure of the P-test.

39. RIH and set packer at approximately 2635mKB.
    Packer to be in approximately the middle of the casing joint (use E-log run previously if needed).
    Wireline re-entry guide to be approximately 2652mKB (10m above top perforation).

40. POOH and pressure test packer assembly to 1400kPa and 21MPa with brine.
    Do not exceed 21MPa to ensure Ceramic Disk Assembly is not broken.

41. Install temporary cover over the pipe ram controls (rig floor & remote) to minimize the possibility of accidental closure on the capillary lines.
    Note: Until the pump-out plug in the tailpipe is sheared out, the packer/plug combination provide the primary barrier and the hydrostatic head of the completion fluid provides an additional barrier. The BOP provides the secondary barrier.

42. Reset the annular closing pressure to the value previously determined for the 73mm pipe to minimize the risk of crushing the capillary lines.

43. Rig in Torque-Turn unit and spooling system for capillary lines.

44. Make up and run completion tubing as per the attached drawing from Baker Hughes, including.

    a. Locator seal assembly, On/Off connector, BX seating nipple, dual ported injection sub (c/w dual 9.5mm (3/8”) capillary injection lines.

b. Approximately 2,067 m of 73mm 9.52kg/m3 L-80 13Cr tubing with VAM TOP connections.
   Fibre optic temperature monitoring string will be installed on the outside of the tubing from approximately 900mKB (1000m minimum manufacturer supply – allow 100m for surface connection).

c. Flow couplings and "Select EQ" tubing retrievable Sub Surface Safety Valve (SSSV) (Approx. final depth 550 mKB – MUST NOT BE BELOW 600m)
   6mm (1/4") control line will be run to surface.

d. Approximately 500m of 73mm 9.52kg/m3 L-80 13Cr tubing with VAM TOP connections.

Function test SSSV once installed, prior to continuing to run in hole.
Control line will be run with pressure applied to ensure it is not damaged while running.
Capillary clamps/guards will be supplied for installation.

Follow directions of on-site Baker-Hughes representatives regarding running and assembly of completion string.

Discuss with service rig toolpush and operator how to minimize risk to capillary lines from slips and/or BOP while running tubing.

45. Reset the annular preventer closing pressure to the value previously determined for the 114mm OD VIT.

46. Continue running in hole with approximately 500m Vacuum Insulated Tubing (VIT).
    114mm OD X 73mm VAM TOP inner pipe. Note: Inner pipe provides the structural connection. Insulating sleeves are installed on the connections once they are made up.
    VIT IS FLUSH JOINT - USE PICK UP SUB AND DOG COLLAR WHEN RUNNING
    DO NOT PLACE TONGS ON THE ORANGE BAND ON THE TUBING (PIN END).

47. Set down into the packer and space out tubing in neutral tension (i.e., +/1 full string weight). Standard 13Cr 73mm pup joints will be used to space out. (Most/all of the space out pup joints will be inside the cellar/wellhead extension and thus opposite insulation filled cellar culvert. I.E., there is no risk of additional permafrost thawing.

48. Install tubing hanger with terminations for two 10mm injection lines, 6mm control line and fibre optic sensor.
    Install tags labelling each line for service and location in the well and document in daily report (sketch).

49. Land tubing hanger.

50. Rig down Torque-Turn unit and spooling system for capillary lines.

51. Rig down BOP and install top section of wellhead, consisting of:
    a. 179mm 70MPa X 65mm 35Mpa adapter flange
    b. Two master valves - 65mm 35Mpa gate valves
    c. Flow cross
    d. Swab valve 65mm 35Mpa gate valve
    e. Wing valve 65mm 35Mpa gate valve

52. Terminate injection and control lines and feed through fibre optic line.
53. Install solid Back Pressure Valve.
54. Pressure test wellhead to 1400kPa and 35,000kPa for 10 minutes each.
    Pressure test annulus to 1400kPa and 35,000kPa for 10 minutes each.
    Pass – is a stabilized pressure of at least 90 per cent of the test pressure over a 10-minute interval.
55. Remove Back Pressure valve.
56. Apply opening pressure to SSSV control line.
57. Run tubing inspection logs for initial (baseline tubing) condition.
58. Pressure up on tubing to shear Ceramic Disk in tailpipe and open well to flow.
    A surface pressure of 21MP is anticipated.
    Pressure should drop significantly when Ceramic Disk is opened.
59. Rig up swabbing equipment and flowback equipment (inc. flare stack) to well.
60. Install pressure gauge and 1400kPa pop valve on 178mm casing annulus.
    Route returns (brine with possible diesel) to pop tank.
    Leave valves open to 339mm X 244mm surface casing annulus and 244mm X 178mm intermediate casing annulus. Monitor during flow testing.
61. Rig up flow testing equipment inc. single stage 3 phase separator and 18m (60 foot) flare stack.
62. Swab well until it begins to flow on its own.
    Kill fluid provides minimal overbalance so limited swabbing should be needed.
    Flow well gradually to warm up tubing and surface equipment and recover kill fluid in tubing and lost to formation.
    Increase to steady flow of approximately 285 E3m3/d (10mmscfd).
    Maintain flow until kill fluid returns (brine/diesel) are negligible (anticipated max 12 hours).
    Record flowrates (gas, water, condensate), pressures and wellhead temperatures.
    Read & report salinity of recovered fluid (Anticipated to be negligible once lost kill fluid is recovered).
63. Flow well for 24 hours and collect 2 sets of 2 pressurized gas samples and condensate samples at approximately 12 and 24 hours into the flow period.
    Condensate samples should be taken from separator and shipped in pressurized containers.
    Record separator pressure when samples are taken.
    Note: Samples cannot be shipped by air.

    Heat from the flare stack may melt snow cover on the well and sump pad. This is not a concern, but if the snow begins to melt beyond the pad contact well engineer for direction.
64. Shut-in well.
    Record & report shut-in pressure and temperature (for calculation of SSSV acceptance).
65. Test SSSV for sealing.

a. Close SSSV by releasing control pressure.

b. Bleed off gas above SSSV to test equipment.
Shut in wing valve.

c. Check for flow/pressure buildup for 30 minutes.
Both should be zero to negligible.
Report pressure after 30 minutes to well engineer for SSSV acceptance calculation.
(Acceptable leak rate is 0.43m3/min @ STP per API 16B Annex A.2.8.)

66. Shut-in well.
Close wing and master valves.
Bleed off opening pressure to SSSV and allow it to close.
Bleed off pressure above SSSV and verify that is has closed and is sealing.
Confirm with IESPL representatives if a Back Pressure Valve (BPV) will be run (dependent on anticipated duration until production).

67. Rig down all equipment if SSSV is holding.

68. Secure well with tapped bull plugs and 12mm needle valves.
Re install well sign.
Chain and lock valves.

69. Physically confirm the gate valves on surface casing and intermediate casing vent are fully open (12 turns). Ensure gate valves and ball valves on intermediate spool vent and surface casing vent are open.
Pressure test the surface casing and intermediate spool vent to 700kPa with air and soap test for leaks.
Note: Due to potential leak of at casing shoe, pressure may bleed off. Use soap test to confirm no leaks have developed in the piping before it is encapsulated in expandable foam insulation.

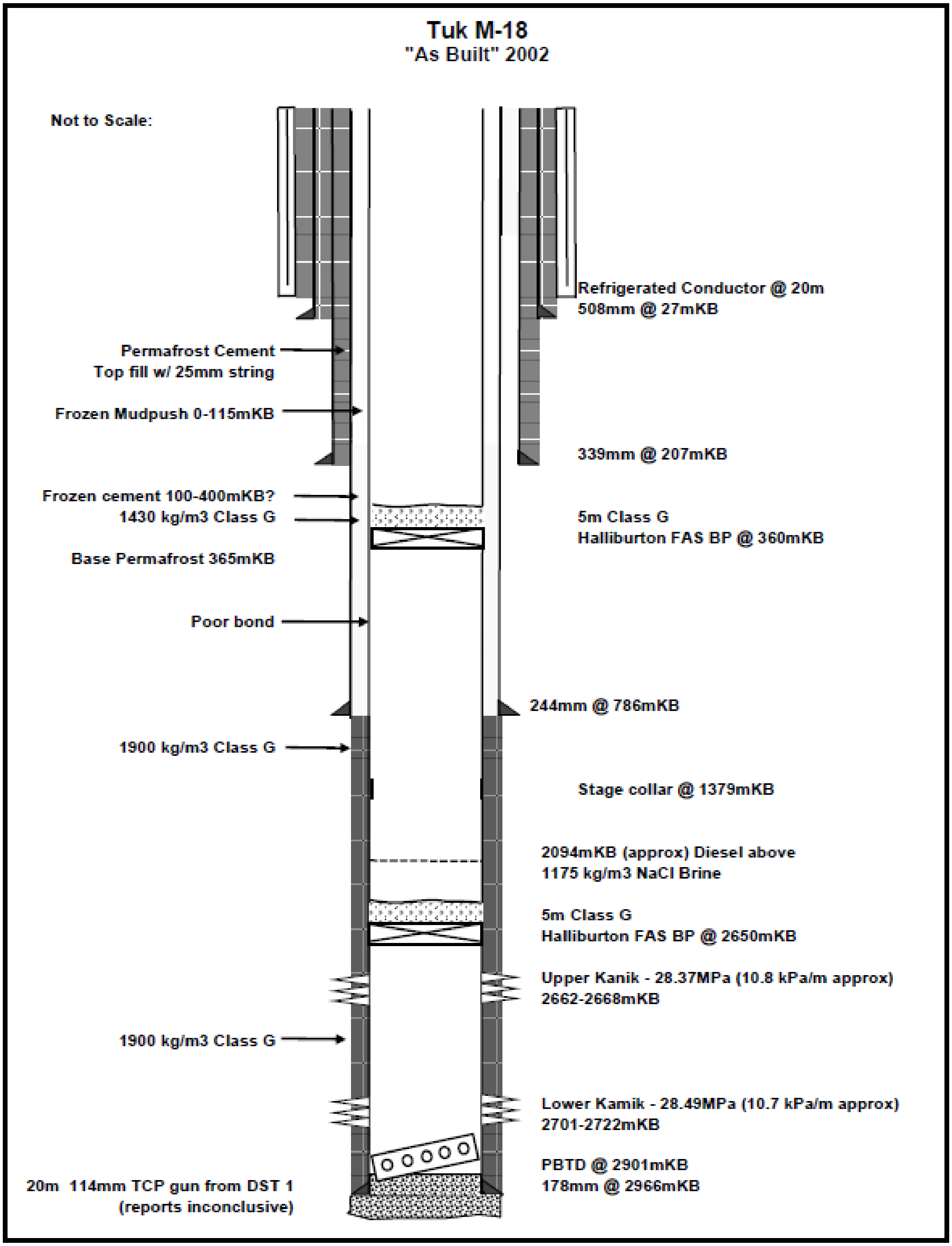
70. Repeat the pressure test of the conductor barrel piping to 700kPa for 10 minutes with propylene glycol (RV antifreeze). Baker pump or equivalent should be sufficient.
Cap ends of extensions.

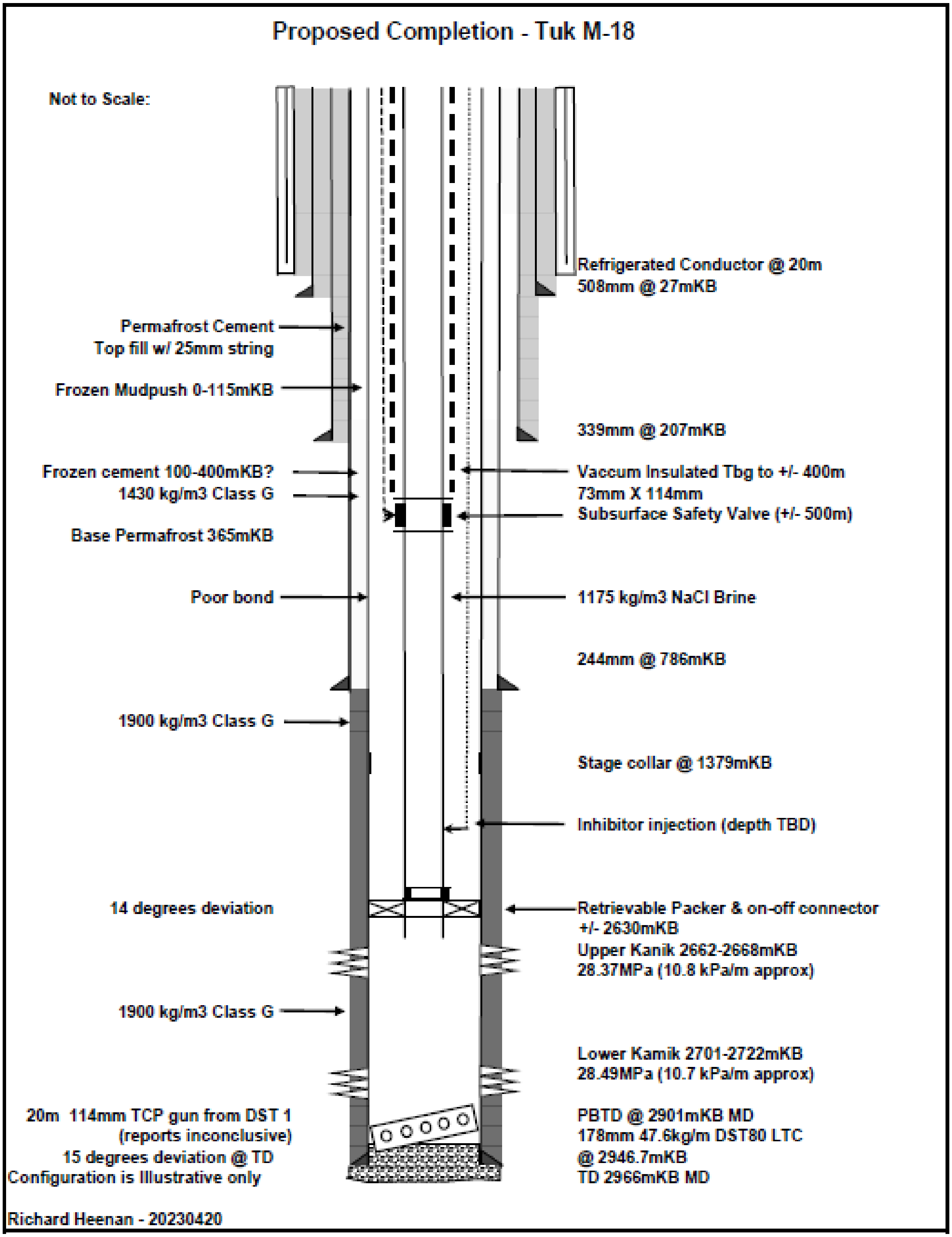
71. Backfill the casing with expanded closed cell foam.
(This may be deferred and performed after the service rig is demobilized).

72. Haul fluid to approved disposal facility
Waste brine/produced water will be trucked to an approved disposal well.
Recovered diesel and condensate from the flowback may be repurposed in local waste oil burners. If not possible, this fluid will also be trucked to a disposal well.

73. Demobilize remaining equipment and clean up lease.
No material is to be left on location except as directed by IESPL representatives.

Replace these 2 drawings with origional PDF when document is assembled




Proposed Completion - Tuk M-18
Not to Scale:
Refrigerated Conductor @ 20m
508mm @ 27mKB
Permafrost Cement
Top fill w/ 25mm string
Frozen Mudpush 0-115mKB
339mm @ 207mKB
Frozen cement 100-400mKB?
1430 kg/m3 Class G
Vaccum Insulated Tbg to +/- 400m
73mm X 114mm
Subsurface Safety Valve (+/- 500m)
Base Permafrost 365mKB
Poor bond
1175 kg/m3 NaCl Brine
244mm @ 786mKB
1900 kg/m3 Class G
Stage collar @ 1379mKB
Inhibitor injection (depth TBD)
14 degrees deviation
Retrievable Packer & on-off connector
+/- 2630mKB
Upper Kanik 2662-2668mKB
28.37MPa (10.8 kPa/m approx)
1900 kg/m3 Class G
Lower Kamik 2701-2722mKB
28.49MPa (10.7 kPa/m approx)
20m 114mm TCP gun from DST 1
(reports inconclusive)
15 degrees deviation @ TD
Configuration is Illustrative only
PBTD @ 2901mKB MD
178mm 47.6kg/m DST80 LTC
@ 2946.7mKB
TD 2966mKB MD
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