An Evaluation of the Risks and Benefits of Penetrations in Subsea Wellheads below the BOP Stack

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Upstream Segment

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Executive Summary

(revised from original Report)

The purpose of this study was to provide an evaluation of the risks and benefits of allowing penetrations in subsea wellheads below the blowout preventer (BOP) stack. Current Minerals Management Service Regulations require that all annuli be monitored for casing pressure. However, industry standards (ISO 13628-4 & API 17D) for the design of subsea wellheads prohibit penetrations in the wellhead, thus allowing the monitoring of only the "A" (production tubing by production casing) annulus.

The scope of this study is limited to completed subsea wells in the Gulf of Mexico (GOM). Special attention was paid to the risks and benefits introduced by allowing penetrations to monitor annuli other than "A". The benefits of allowing penetrations were developed by a panel of experts – the API Spec 17D/ISO 13628-4 Task Group. The risks were evaluated using fault tree analysis for three systems: 1) wellhead system without penetrations, 2) wellhead system with one penetration and 3) wellhead system with two penetrations. The task group developed a risk index for each failure mode. The probability of failure for each of the fault trees was then normalized to one for the no penetration case to indicate relative risk value. In addition, sensitivity analyses were also run to compare the difference in failure between 2-inch wellhead penetrations (preferred by the Task Group) and ½-inch wellhead penetrations.

The benefits of adding penetrations to the subsea wellhead system were identified as follows:

- Allows the monitoring of pressure in annuli other than "A"
- Provides data for determining the collapse margin on the production casing as "A" annulus pressure is bled off
- Allows the monitoring of the pressure in adjacent annuli as the pressure in a particular annulus is increased or decreased
- Potentially allows pressure to be bled off

However, it must be noted that there is a strong likelihood that any wellhead penetration will become plugged at some point during well life; especially in the drilling and cementing phases. If the penetration is plugged, an invalid pressure reading will occur and possibly lead to an erroneous conclusion regarding annular pressure characteristics. If the penetration becomes plugged, the benefits listed above are compromised and the penetration will just provide another leak path in the system.

For the comparative risk analysis, fault trees were built with the top event of the fault tree being "The Inability of the Wellhead System to Maintain a Pressure Barrier over the Life of the Well."' In the fault tree analysis, various potential leak sources and failure modes were identified and individual risk values assigned.

The comparative risk from the fault tree analysis gives the following results:

Relative Risk Analysis Summary				
Event	Configuration	No Penetrations	B-annulus Penetration	B & C-annulus Penetrations
Failure of system to maintain a pressure barrier	2-inch penetrations	1.00	2.50	2.69
Failure of system to maintain a pressure barrier	½-inch penetrations	1.00	3.59	3.75

Finally, the benefits of adding penetrations to the wellhead housing in the subsea wells were weighed against the risks. The study concludes that the risks outweigh the benefits since the risk of maintaining the pressure barrier using a wellhead with penetrations is approximately two-and-a-half times that of a system without penetrations. This is underscored by the task group's assessment that any potential benefit is lost since the additional penetrations will likely become plugged during a well's life and that the plugging is most likely to occur during the early portion of that period. Furthermore, it should be noted that over 50% of sustained casing pressure occurs in the "A" annulus and monitoring of this annulus is readily accomplished using current technology that conforms with global industry specifications.

In conclusion, it is recommended that API/ISO standards continue to prohibit penetrations in subsea wellheads. Emphasis should be placed on well construction and operational practices to minimize the likelihood of casing pressure becoming an unmanageable event.

Subsequent to completion of the report, the contractor submitted the following Addendum after further examination of the MMS data was performed to assess the homogeneity of the well population from a casing-string perspective.

"Initial results of indicate that the most prevalent well type by far has no intermediate casing. Therefore, the statement in section 3.2:

> *For pressures that are greater than 20% MIYP, 2.2% of wells exhibit pressure in the surface casing annulus, while only 1.7% of wells exhibit pressure in the intermediate casing annulus, but 5.8% of the wells exhibit pressure in the production casing annulus. This indicates that the surface casing annulus pressure frequently works its way inward from the formation instead of working outward from the "A" annulus pressure.*

must be read in that context. That is to say, if a well with no intermediate casing exhibits pressure in the surface casing then the source may be from a formation rather than working outward from the "A" annulus."

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1 Purpose

The purpose of this study is to provide an evaluation of the risks and benefits of allowing penetrations in subsea wellheads below the blowout preventer (BOP) stack so annuli other than the production tubing (commonly referred to as the “A” annulus) could be monitored.

Current industry standards (API Spec 17D and ISO 13628-4) for the design of subsea wellheads prohibit penetrations below the (BOP) stack. In contrast, Minerals Management Service (MMS) regulations (30 CFR 250.517) require that all annuli be monitored for sustained casing pressure and that every occurrence of sustained casing pressure be reported immediately to the District Supervisor.

2 Scope

The American Petroleum Institute (API) contracted with Stress Engineering Services (SES) to analyze the risks and benefits inherent in continuing to prohibit penetrations in subsea wellheads and compare them to those introduced by allowing the practice. Special attention was paid to the risk and benefits introduced by monitoring annuli other than the “A” annulus (the annulus between the production tubing and the production casing strings). The “risk-based” portion of this specific study did not need to be fully quantitative, but the analysis was done in a way that will easily lead to a fully quantitative analysis as more complete data become available. The scope of this study is limited to completed conventional subsea wells in the Gulf of Mexico (GOM).

This report documents the results of this study of the risks and benefits of additional penetrations in subsea wellheads below the BOP stack for the purpose of monitoring additional casing annuli for sustained casing pressure (SCP).

3 Background

3.1 Regulatory Requirements

The current industry-standard design philosophy of subsea wellheads prohibits penetrations below the BOP stack. This is codified in the current standards (API Spec 17D and ISO 13628-4). The “no penetrations” language was instituted by the authors of the first edition of API Spec 17D based on intuition and industry practice. No formal reliability analysis (qualitative or quantitative) was performed to ascertain the risks and benefits of allowing penetrations in the wellhead housing below the BOP stack. At a high level, the authors of the standard were concerned with protecting the integrity of the well during drilling operations by preventing the likelihood of a leak below the BOP through a penetration. The apparent concern was that introducing a penetration below the BOP could lead either to a well-control incident caused by loss of the hydrostatic head of drilling fluid in the riser above the BOP or the exacerbation of an existing well-control incident by loss of integrity below the stack. Standard subsea wellhead designs have always provided for monitoring of the “A” annulus for pressure by means of an annulus monitor line in the tree’s production control umbilical and/or an electronic pressure sensor in the tree’s annular flowpath.

However, historically, subsea wellheads have not provided any annular access to outer casing string cavities once a wellhead packoff has been installed after cementing operations.

In 1989, the MMS established regulations, described in 30 CFR 250.517, for sustained casing pressure. These regulations required that all annuli be monitored for sustained casing pressure and that every occurrence of sustained casing pressure be reported immediately to the District Supervisor. In 1991, in an effort to streamline government and reduce burdensome paperwork, the MMS issued a letter that dictated changes in the sustained casing pressure policy. The revised policy allowed for continued operation if:

- The sustained casing pressure is less than 20% of the minimum internal yield pressure (MIYP), and
- The casing pressure bleeds to zero in 24 hours or less when bled through a ½-inch needle valve.

If both of these requirements were met, the lessee was not required to submit the diagnostic test results to the MMS for review and approval for continued operation. Wells meeting both of these criteria were placed into a separate category and referred to as *Self-Approved*.

Records of each diagnostic test must be maintained for each casing annulus with SCP. The records must contain:

- Identification of the casing annulus,
- SCP value at beginning of test,
- Pressure chart or time required to bleed pressure down to zero shown on the gauge,
- Type of fluids bled,
- Volume(s) of liquid(s) recovered,
- Pressure build-up chart or pressure recorded at least once per hour,
- Shut-in and flowing tubing pressure,
- Producing rates of gas, oil, and water, and
- Well status.

In 2002, the MMS requested that the industry perform an evaluation of the risks and benefits of allowing penetrations in subsea wells below the BOP stack. The intent of the request was to reconcile the difference between the MMS regulations for annular monitoring and the current industry standards (API Spec 17D and ISO 13628-4) for subsea wellhead design. To accomplish this, the API contracted Stress Engineering Services to analyze the risks and benefits inherent in continuing to prohibit penetrations below the wellhead and compare them with those introduced by allowing the practice.

3.2 MMS Casing Pressure Data

The MMS maintains a database on casing pressure events in outer continental shelf (OCS) platform wells in the GOM. Table 1 is a summary of the MMS database of 15,516 OCS wells and is shown graphically in Figure 1. Of these wells, 1446 (9.3%) of them are reported to have casing pressure greater than 20% of the minimum internal yield pressure (MIYP) of the casing. Within these 1446 wells, 906 of them have casing pressure in the production casing annulus ("A" annulus – accessible via current subsea designs), 261 of them have casing pressure in the intermediate casing annulus ("B" annulus), 347 of them have casing pressure in the surface casing annulus ("C" annulus), and 95 of them have casing pressure in the conductor casing annulus ("D" annulus).

The data shows that only about 4.5% of the wells are affected by casing pressure in the outer annuli (B, C, or D) at a level greater than 20% of the MIYP pressure of the casing. This drops to 1.8% when the pressure is greater than 30% of the MIYP, and further drops to 0.3% when the pressure is greater than 50% of the MIYP. This indicates that the frequency of occurrence of casing pressure is very low and still has a design margin of two. This data of casing pressure in the outer annuli is shown in Figure 2.

The occurrence index scale defined in Table 2 is based upon this information. One of the observations made from this data (Table 1) is that the frequency of occurrence of casing pressure is greater in the surface casing annulus than the intermediate casing annulus for all levels of pressure. For pressures that are greater than 20% MIYP, 2.2% of wells exhibit pressure in the surface casing annulus, while only 1.7% of wells exhibit pressure in the intermediate casing annulus, but 5.8% of the wells exhibit pressure in the production casing annulus. This indicates that the surface casing annulus pressure frequently works its way inward from the formation instead of working outward from the "A" annulus pressure.

Information from the OCS database is referenced in this analysis. This data covers all wells on the GOM OCS, both dry and subsea trees. It should be noted that the population of dry trees is much greater than that of subsea trees. However, since the well designs are similar, it is a reasonable assumption that the data is valid for the purposes of this study.

The MMS presented data at the American Association of Drilling Engineers (AADE) conference in Houston in January 2003 showing OCS wells in the GOM affected by casing pressure as a function of the age of the well. The data have since been updated as of 9 October 2003 to include all OCS wells affected by casing pressure regardless of the casing annulus and regardless of the pressure level (see Figures 3 and 4).

4 Risk Analysis Method

4.1 General

Risk assessment is a technical and scientific process in which outcomes for various system scenarios are modeled and quantified. Risk assessment provides qualitative and quantitative data to decision-makers for use in risk management. Qualitative risk analysis uses expert opinion to evaluate relative probabilities and consequences for an undesirable event. Quantitative risk analysis relies on probabilistic statistical methods and databases to concretely identify probabilities and consequences for all credible failure scenarios of a system. Failure Modes and Effects Analysis (FMEA) and Fault Tree Analysis (FTA) are generally considered to be qualitative risk analysis techniques.

Although quantitative analysis is the preferred method, it is statistically impractical to perform a quantitative analysis unless all of the wellhead designs and construction methods are mechanically identical. Since subsea wellhead systems vary greatly (different subsea wellhead designs, number of casing strings, where they are “hung off”, how they are sealed with both metal and elastomer sealing packoffs, etc.), a qualitative analysis is the only practical way to evaluate the merits of adding penetrations to the subsea wellhead. For this study, the reliability “numbers” generated through qualitative analysis have been normalized relative to the current subsea system design of no wellhead penetrations. This enables a quantitative reliability comparison of equipment performance of proposed subsea wellhead designs with penetrations to the current designs that provide “A” annulus access only.

4.2 Fault Tree Analysis

Fault tree analysis (FTA) can be described as an analytical technique, whereby an undesired state of the system or safety event is specified and the system is analyzed in the context of its environment and operation to find all credible ways in which the undesired event can occur. The fault tree itself is a graphic model of the various parallel and sequential combinations of faults that lead to the undesired event – which is the top event of the fault tree. Based upon a set of rules and logic symbols from probability theory and Boolean algebra, the fault tree uses a top-down approach to generate a logic model that provides for both qualitative and quantitative evaluation of system reliability.

It is important to understand that a fault tree is not a model of all possible system failures or all possible causes for system failure. A fault tree is tailored to its top event, a particular system failure model, and thus includes only those faults that contribute to this top event. Moreover, these faults are not exhaustive; they cover only the most credible faults as assessed by the analyst.

It is also important to note that a fault tree is not in itself a quantitative model. It is a qualitative model that can be evaluated quantitatively and often is. The fact that a fault tree is a particularly convenient model to quantify does not change the qualitative nature of the model itself. Finally, a fault tree analysis addresses the likelihood of the failure to occur, but does not address the severity of the occurrence.

4.3 Failure Modes and Effects Analysis (FMEA)

A Failure Modes and Effects Analysis (FMEA) is defined as a procedure by which each potential failure mode in a system is analyzed to determine the results or effects thereof on the system and to classify each potential failure mode according to its severity.

Failure mode(s) is defined as the manner by which a failure is observed. It generally describes the way the failure occurs and its impact on equipment operation. It is sometimes defined as the problem, the concern, the opportunity to improve, or the failure. It is the physical description of the manner in which a failure occurs. Examples of failure modes are cracked, leaked, broken, warped, corroded, and binding.

The effect(s) of failure is defined as the outcome of the failure on the system, design, process, or service. In essence, the effect(s) of failure attempts to answer the questions: What happens when a failure occurs? What is (are) the consequence(s) of that failure? The effects of a failure must be addressed from both a local and a global viewpoint. The local viewpoint is that in which the failure is isolated and does not affect anything else in the system. The global viewpoint is that in which the failure can and does affect other functions and/or components. Therefore, a failure with a global effect is more serious than one with a localized effect.

The cause(s) of failure is defined as the physical or chemical processes, design defect(s), quality defect(s), part misapplication, or other processes that are the basic reasons for failure or those that initiate the physical process by which deterioration proceeds to failure. It is the root cause of the noted failure mode. When looking for the cause of the failure, one must look for the root cause, not the symptom of the failure. The cause of a failure may also be due to human error. There may be several causes for one failure mode and all causes should be listed on the FMEA report.

The detection method is the means or method by which a failure can be discovered during normal system operation or by some diagnostic action.

The purpose of the FMEA is to identify and prevent known and potential problems from reaching the customer. The FMEA process helps to define and rank the problems so that they can be addressed with respect to their overall importance. A risk priority number (RPN) is used to articulate the priority of a problem.

The risk priority number (RPN) is defined as the product of the severity of the failure, the frequency of occurrence, and the reliability of the detection method. The highest RPN value is assigned to the problem that should be addressed first to prevent future failures. If the FMEA is to follow the guidelines of a qualitative analysis, the RPN should follow theoretical (expected) behavior of the component. If the guideline is quantitative, it must be specific. It must follow actual data, statistical process control data, historical data, and/or similar or surrogate data for the evaluation.

The severity of failure is a rating that indicates the seriousness of the effect of the potential system failure mode. The rating is based upon a scale of 1 to 10 with 10 being the most severe.

Occurrence is the rating value corresponding to the estimated number of failures that could occur for a given cause over the design life of the system. The rating is based upon a scale of 1 to 10 with 10 being the most frequent.

The detection is a rating corresponding to the likelihood that the proposed system controls will detect a specific root cause of a failure mode. The rating is based upon a scale of 1 to 10 with 10 being the highest likelihood of detecting the cause of failure.

Examples of the FMEA work is shown in Appendix H.

4.4 Methodology Used

Following is the process used in performing the analysis for this study:

1. An FMEA analysis listing each potential failure mode, causes of failure, effects of the failure, and current design controls to detect the failure was developed. An index value (from 1 to 10) was assigned for each of the following: <u>frequency of occurrence</u>, <u>severity of effects</u>, and <u>likelihood of detection</u>. These indices were multiplied together resulting in a risk priority number (RPN) used to rank the design characteristics that were most important to address first. See Reference 6 for method.

2. Once the preliminary results from the FMEA analysis were obtained, it was determined that a better method for meeting the objectives of this study would be to switch to the (FTA) method. The FTA method is more appropriate for developing a comparative risk analysis between two designs (wellhead without penetrations and a wellhead with penetrations). See Reference 8 for method.

3. The FMEA data along with a literature search and brainstorming sessions with well systems experts was used to define the failure modes (causes) for each of the major system components – wellhead penetrations, casing/pipe connections, casing hanger packoff, and casing cement. These failure modes are defined in Tables 3 through 7.

4. An Expert's Forum comprised of members from the API Spec 17D/ISO 13628-4 Task Group was convened to refine (add to or delete from) the list of failure modes and to rank the likelihood of occurrence of each failure mode on a scale of 1 to 10 (10 being almost likely occurrence).

5. The fault tree logic diagram was constructed for three cases – no penetrations; "B" annulus penetration only (one penetration); and "B" annulus plus "C" annulus penetrations (two penetrations).

6. A Weibull analysis (see Figure 5) was performed on the MMS data for OCS wells with casing pressure as a function of well age (see Reference 9). From this Weibull analysis,

the cumulative distribution function (CDF) curve shown in Figure 6 was created. This curve was used to determine the probability that the event will have occurred as a function of time.

7. The probability values from the CDF curve were used for each of the index values in the failure occurrence index table found in Table 2.

8. Based upon each of the frequency index values defined in the Expert's Forum, the failure occurrence values from Table 2 were assigned to each of the lower level failure modes on the fault tree diagram using Boolean logic (see Reference 8). By definition, the "Or-Gate" probability of occurrence is: $P_O = P_1 + P_2 - (P_1 \times P_2)$. For an "And-Gate" the probability of occurrence is: $P_A = P_1 \times P_2$.

9. The probability of failure for each of the fault tree cases (no penetrations, one penetration, and two penetrations) was then normalized relative to the No Penetrations case to give a relative risk value, i.e., the likelihood of failure for a wellhead with one penetration is 2.5 times that of a wellhead with no penetrations.

10. The benefits of allowing penetrations in the subsea wellhead were developed from brainstorming sessions with the project steering committee and the Expert's Forum. They did not come from using specific risk analysis methodologies.

5 Casing Pressure Risk Analysis

5.1 Development Background

The initial objective of this project was to develop a qualitative risk assessment to compare a subsea wellhead design with penetrations (thus allowing for monitoring of pressure in the "B" and "C" annuli) to the existing subsea wellhead design without penetrations. The planned method to accomplish this was to use the FMEA or the Failure Modes, Effects and Criticality Analysis (FMECA). An FMEA is usually recommended as the first step of any risk analysis effort. After meeting with the project Steering Committee in February 2003, this effort was started.

The initial effort involved a literature search on sustained casing pressure. This search yielded some very valuable information on the subject that was used in the analysis and is referenced below. The literature provided useful information regarding the root causes of casing pressure in existing offshore systems. However, the literature did not address the issue of adding penetrations in the subsea wellhead housing for the purpose of monitoring additional annuli for casing pressure.

Based upon the literature research, an FMEA was initiated to identify the causes of failure, frequency of occurrence, and the severity of each mode of failure. This was initially developed for the existing subsea wellhead system design without penetrations. Following this, several brainstorming sessions were held to begin development of the risks associated with adding penetrations in the wellhead housing.

Following this preliminary FMEA effort, a second session with the project steering committee was held in June 2003 evaluate the results. After lengthy discussions, it was decided that the best step forward would be to convert the FMEA data into a fault tree analysis for this study.

Then the main question, in order to properly develop the fault tree, became: What should be the top event of the fault tree? It was decided that the top event should be "The Inability of the Wellhead System to Maintain a Pressure Barrier over the Life of the Well." From this, preliminary fault trees were developed for the two systems – 1) Wellhead System without Penetrations, and 2) Wellhead System with Penetrations.

A typical subsea wellhead system was used for the FTA model. This model is shown in Figure 7 and consists of a production casing string, one intermediate casing string, a surface casing string, and the conductor pipe.

Two meetings were held in August 2003 with reliability engineering experts to review and discuss the preliminary fault trees. It was the consensus of the group at these meetings that: 1) the fault tree was the appropriate method to analyze the risk of wellhead penetrations, 2) the top event of the fault trees was properly defined, and 3) the methodology used for the fault tree construction was correct.

In August 2003, a workshop was held with the API Spec 17D/ISO 13628-4 task group for the following purposes:

- Review the root cause failures for each of the failure modes for relevancy,
- Add to the list of root cause failures as needed, and
- Rank each of the failures by frequency of occurrence based on their consensus opinions.

5.2 Risk Analysis Details

The top event of the fault tree is "The Inability of the Wellhead System to Maintain a Pressure Barrier over the Life of the Well." This means that the wellhead system should be able maintain a pressure barrier between each formation zone and the environment. This is in keeping with the objective of the MMS regulations. In developing the overall fault tree, the FTA looks at each of the potential pressure leak paths. In some cases the leak path is pressure from the "A" annulus leaking to an outer casing annulus and/or to the environment. In other cases it is pressure leaking from the formation to either an inner annulus or to the environment via an annulus. These potential leak paths are shown in each of the illustrations in Appendix A.

There are four groups of potential leak paths. These groups were developed further to determine the root causes of the failure and the frequency of occurrence of failures. The four groups are:

- Leakage through the wellhead housing penetrations,
- Leakage through the casing and/or the casing connections,
- Leakage through the casing's hanger packoff, and
- Leakage through the casing's cement.

In evaluating the risk of subsea-wellhead-housing penetrations, five potential failure modes were identified. Each of these failure modes could have multiple causes for the failure. The following list details these failure modes and the potential causes. They are listed in decreasing order of frequency of occurrence as judged by the task group.

- **False pressure reading from the monitoring port sensor,**
    - The pressure sensor being inoperable,
    - The pressure sensor operating, but giving a wrong signal due to being out of calibration, etc.,
    - The pressure port to the sensor being plugged, or
    - Losing the signal from the pressure sensor,
- **Damage to the valves attached to the wellhead housing penetration from external influences,**
    - Damage to the valves and/or the wellhead housing during the running/installation process,
    - Damage to the valves resulting from contact with the ROV,
    - Damage occurring while landing the tree, or
    - Damage from dropped equipment,
- **Leakage from valve connections or from the valves themselves,**
    - Leakage due to vibration, or
    - Leakage due to corrosion,

- **Failure of the valve to function,**
    - Valve fails to function when in the closed position, or
    - Valve fails to function when in the open position,
- **Wellhead housing integrity,**
    - Structural integrity of the wellhead housing resulting from higher bending moments due to design requiring a taller housing, or
    - Structural integrity of the wellhead housing resulting from stress concentration factors due to penetrations.

The above ranking of the risks associated with the wellhead housing penetrations is based upon the premise of using current industry standard 2-inch valves with a 2-inch penetration in the wellhead. If the size of the penetration is reduced from 2-inch to approximately ½-inch, then the task group felt that the risks would increase in at least two areas: 1) the likelihood of the penetration being plugged would significantly increase, and 2) the occurrence of leakage due to vibration would also increase.

Leakage via the casing and/or the casing connections mode of failure resulted in the identification of seven principal causes of failure. These causes of failure are listed in decreasing order of frequency of occurrence as judged by the task group.

- Corrosion of the pipe and/or corrosion of the connection sealing surfaces
- Thermal cycling loads on the casing string
- Damaged threads
- Wear on the casing string from drilling operations
- Damaged connection sealing surfaces
- Bad or wrong thread compound being used
- Improper make-up of the connections (either over-torqued or under-torqued)

When the task group examined loss of pressure integrity through the casing-hanger-packoff mode of failure, nine principal causes of failure were generated. These causes of failure are listed in decreasing order of frequency of occurrence as judged by the task group.

- Damaged sealing surface
- Thermal cycling loads resulting in additional axial loads on the hanger
- Installation anomalies or improper setting of the hanger packoff
- Corrosion of the sealing surfaces
- Packoff seal damage resulting from high temperatures
- Loss of seal contact pressure during thermal cycling
- Incompatibility between the seal and the fluids
- Solids contamination on the sealing surface
- Vibration

Consideration of leak paths through the casing-cement mode of failure yielded five principal causes. The task group deferred ranking these because of their collective judgments that this was outside their area of expertise. Therefore, additional information was obtained from the API Subcommittee on Well Cements (SC10). Based on that input, the following causes of failure are listed in decreasing order of frequency of occurrence.

- Frac-Pac operations
- Expansion and contraction due to thermal cycling
- Micro-annulus cracks
- Poor formation/cement bonding
- Gas in the cement

Based on the MMS data discussed in section 3.2, a standard Weibull analysis was run to determine the shape of the distribution curve. This defined the statistical probability of the well being affected by casing pressure as a function of the age of the well. The result of the Weibull analysis is shown in Figure 5 and the cumulative distribution function curve is shown in Figure 6. The Weibull analysis yielded a characteristic life of 34.42 years and a shape parameter (beta) of 1.707. Based on the Weibull analysis, casing pressure is expected to affect 32.7% of the wells within the first 20 years of life. However, this does not differentiate on the magnitude of casing pressure or the specific annulus experiencing the pressure. The shape parameter of 1.707 indicates that the wells with casing pressure exhibit more of a "wear out" phenomenon than a purely random failure (beta = 1) or an infantile failure (defective equipment failure beta < 1). It also indicates that the failures resulting in casing pressure come from mixed modes, i.e., sweet vs. sour wells; production rates; pressure; temperature; design configurations; etc. Since subsea wells have design characteristics similar to those in the population analyzed, the shape parameter of the failure distribution curve is expected to be similar; however, the characteristic life may be different.

6 Results

6.1 Risk Analysis

The relative frequency of occurrence values for each of the failure causes was advanced to successively higher levels in the fault trees using Boolean logic for the "And" gates and "Or" gates to obtain a top level value. This value was then normalized to the value obtained for the current subsea wellhead design with no penetrations (rather than using the absolute frequency of occurrence value) and used to compare one fault tree to another. Relative frequency values were used in the analysis since actual field performance data does not exist. Based upon this analysis, the risk of not being able to maintain a pressure barrier with one wellhead housing penetration is about 2.5 times that of having no penetrations. The risk in having two penetrations is about 2.7 times that of having no penetrations. These results are summarized in the table below. This analysis is based upon a 2-inch penetration and 2-inch valves attached to the wellhead. Details of these calculations are included in Appendices B, C, and D.

Event	No Penetration	2-inch B-annulus Penetration	2-inch B & C-annulus Penetrations
Failure of system to maintain a pressure barrier	10.1 % (1.00)	25.3 % (2.50)	27.3 % (2.69)

Another analysis was run to compare ½-inch penetrations with the 2-inch penetrations. Evaluation by the task group suggested that some root cause failures were higher with the ½-inch penetrations. Therefore, an analysis was done to evaluate the overall system reliability. Details of the analysis are contained in Appendix E and summarized in the following table. In this case, the risk associated with a single ½-inch penetration is approximately 3.6 times that of no penetrations and increases to over 3.7 times with two penetrations.

Event	No Penetration	1/2-inch B-annulus Penetration	1/2-inch B & C-annulus Penetration
Failure of system to maintain a pressure barrier	10.1 % (1.00)	36.3 % (3.59)	37.9 % (3.75)

6.2 Sensitivity Study

An analysis was run to evaluate the sensitivity of the 1-to-10 occurrence index values used for each of the root cause failures for the casing pipe / connections (Table 5), casing hanger packoff (Table 6), and the casing cement (Table 7). For the upper limit analysis, each of the risk index values in these tables was reduced by a value of one. In some cases this reduced the frequency of occurrence for that root cause to zero indicating no chance of occurrence. The risk indices for the 2-inch penetrations remained unchanged from the original analysis. The result of this analysis is shown in the following summary table with the details included in Appendix F.

Event	No Penetration	2-inch B-annulus Penetration	2-inch B & C-annulus Penetration
Failure of system to maintain a pressure barrier	3.5 % (1.00)	18.9 % (5.45)	19.7 % (5.66)

A second sensitivity analysis was run to evaluate a lower limit state where the risk index values were increased by two for the casing pipe / connections (Table 5), casing hanger packoff (Table 6), and the casing cement (Table 7). Again, the indices for the 2-inch penetrations remained unchanged from the original analysis. The result of this analysis is shown in the following summary table with the details included in Appendix G.

Event	No Penetration	2-inch B-annulus Penetration	2-inch B & C-annulus Penetration
Failure of system to maintain a pressure barrier	37.4 % (1.00)	48.7 % (1.30)	53.9 % (1.44)

As seen from this sensitivity analysis, the overall system risk certainly changes as the risk for each of the root causes changes. This is as one would expect. However, the risk associated with adding two penetrations to the wellhead housing ranged from a low of 1.44 to a high of 5.66 based on the sensitivity analysis and a mean value of 2.69 times the risk associated with no penetrations.

6.3 Benefits Analysis

The benefits associated with having penetrations in the wellhead are not clear and quantifiable. The consensus of the task group during the workshop was that a penetration in the wellhead housing would permit the monitoring of pressure in the outer annuli casing strings, but would not be a viable remediation avenue. Wellhead penetrations were viewed as an additional diagnostic tool to be used in conjunction with the “A” annulus monitoring, already in use, to determine the source and severity of casing pressure events.

Remediation techniques were also discussed during the workshop. The only two likely remediation techniques, based upon today’s technology, are 1) plug and abandon the well, or 2) re-enter the casing and repair the well.

One of the main concerns associated with having the ability to monitor the outer annuli pressure is the validity of the pressure reading. The consensus of the task group was that at some point during the life of the well a penetration will get plugged and therefore give a false pressure reading – most likely during drilling and cementing phases of the well.

Two benefits of being able to monitor the pressure in the outer annuli casing strings have been identified:

- **Use of outer annuli penetrations for a more complete diagnostic tool.**

  One would know (if plugging does not occur) the magnitude of pressure and pressure changes in each of the outer annuli. This adds to the knowledge of the collapse margin on the production casing as the “A” annulus pressure is being bled off. However, because of the plugging concern, the validity of the reading would always be questioned. With penetrations, more detailed evaluations could be performed, such as:

  - Determining if the pressure is the result of thermal changes or involves communication with a pressure source and

  - Monitoring the pressure in adjacent annuli as the pressure in a particular annulus is being increased or decreased.

- **Having the ability to bleed off pressure from a particular annulus.**
  This is a benefit only if the port does not become plugged.

These benefits, when taken with remediation techniques to bleed off the annulus pressure and the ability to perform preventive maintenance, could reduce the risks associated with pressure penetrating the secondary barrier. This would act to reduce the overall system risk from the current risk associated with having penetrations. This new risk could then be compared to the risk associated with no penetrations.

6.4 Global Risk/Benefits Assessment

So far, the discussion of risks and benefits has focused on a single subsea well. But, there are global risk/benefit tradeoffs if penetrations in the outer annuli are required.

Assume for this discussion that 1000 subsea wells were installed with side penetrations. Further assume (using the same data on which this report is based) that 4.5% of the wells exhibit casing pressure in the outer annuli ("B", "C", and "D") above 20% of MIYP. In this case, the benefits of doing better diagnostic testing is available for the 45 wells, but the risks of having side penetrations will affect the other 955 wells without having the corresponding benefits as a tradeoff.

Further, the benefits of being able to perform more comprehensive diagnostics on the 45 wells and thus reducing the risk of maintaining a pressure barrier must be contrasted with the increased risk in 955 wells of immediate pressure loss in the event (with penetrations) of leakage in the penetrations. In the latter case on penetrations, there is no secondary barrier to prevent catastrophic failure from penetration leakage.

7 Conclusions

An evaluation of the risks and benefits of penetrations in subsea wellheads below the BOP stack was completed. A fault tree analysis methodology was used to evaluate the ability of a wellhead system to maintain a pressure barrier, and the existing wellhead system without penetrations was compared to a system with penetrations. A qualitative risk analysis was performed based on a risk index for each failure mode as assigned by a committee of experts from the API Spec 17D/ISO 13628-4 task group. Based on this analysis, the risk of not being able to maintain a pressure barrier with one wellhead housing penetration is about 2.5 times that of the existing industry–standard design with no penetrations. The risk with having two penetrations is about 2.7 times that of having no penetrations. These results are summarized in the table below. This analysis is based upon a 2-inch penetration and 2-inch valves attached to the wellhead. The experts agreed that the ideal penetration size was 2-inch. However, for some applications designing this size access into subsea wellheads would be prohibitive over a smaller access size. However, the risk associated with having a single ½-inch penetration is about 3.6 times that of having no penetrations and increases to over 3.7 times when you have two penetrations.

On the other hand, the benefits of having penetrations are seen as an additional diagnostic tool to compliment the currently available "A" annulus monitoring. The ability to use a side penetration as a remediation port is questionable. The concern being that at some point the penetration will likely become plugged and present a false reading.

Based upon this analysis, weighing both risks and benefits of adding penetrations to the wellhead housing in subsea wells, it is believed that the additional risks associated with adding penetrations far outweigh the apparent diagnostic benefits achieved from those penetrations. It would be more beneficial to place emphasis on design and operational issues to minimize the likelihood of casing pressure occurring than to address remediation after casing pressure has occurred. Hence, emphasis should be placed on well construction and operational practices that help prevent casing pressure instead of mechanical remediation.

Relative Risk Analysis Summary				
Event	Configuration	No Penetrations	B-annulus Penetration	B & C-annulus Penetrations
Failure of system to maintain a pressure barrier	2-inch penetrations	1.00	2.50	2.69
Failure of system to maintain a pressure barrier	½-inch penetrations	1.00	3.59	3.75

8 Recommendations

Based upon this risk analysis, the risks associated with adding penetrations to the wellhead housing far exceed the benefits from the knowledge obtained with the penetrations. Therefore, it is recommended that API/ISO standards continue to prohibit penetrations in subsea wellheads.

If future technology results in more and improved remediation techniques, then the risk analysis should be reviewed at that time.

9 References

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10 Tables

Table 1: GOM Shelf Wells with Casing Pressure

% MIYP	Wells with Casing Pressure	Casing String Affected				
		Prod Casing	Intmd Casing	Surface Casing	Conductor Casing	Total Strings Affected
> 0%	6,692	4,783	1,655	2,660	1055	10,153
> 20%	1,446	906	261	347	95	1,609
> 30%	482	229	91	130	55	505
> 40%	174	78	30	51	22	181
> 50%	80	37	12	22	9	80
> 60%	35	14	7	10	4	35
> 0%	43.1%	30.8%	10.7%	17.1%	6.8%	65.4%
> 20%	9.3%	5.8%	1.7%	2.2%	0.6%	10.4%
> 30%	3.1%	1.5%	0.6%	0.8%	0.4%	3.3%
> 40%	1.1%	0.5%	0.2%	0.3%	0.1%	1.2%
> 50%	0.5%	0.2%	0.1%	0.1%	0.1%	0.5%
> 60%	0.2%	0.1%	0.0%	0.1%	0.0%	0.2%
	15,516	**Total Number of Wells**				

Table 2: Relative Failure Occurrence Index

Relative Failure Occurrence Index		
Index	Description	Relative Frequency of Occurrence (CDF)
10	Almost certain	11.34%
9	Very high	9.56%
8	High	7.89%
7	Moderately high	6.34%
6	Medium	4.91%
5	Occasional	3.62%
4	Slight	2.49%
3	Very slight	1.53%
2	Rare	0.77%
1	Unlikely	0.24%

Table 3: Relative Failure Occurrence Index of 2" Penetrations

Risk Index	Relative Failure Occurrence	Failure Mode
	15.62%	**Failure of B or C Annulus Penetration, 2"**
	0.0869	**False Pressure Reading**
6	0.0491	Pressure sensor inoperable
4	0.0249	Pressure sensor lost calibration
2	0.0077	Lost umbilical signal
2	0.0077	Pressure port plugged
	0.0047	**Leakage from connections**
1	0.0024	Leakage due to vibration
1	0.0024	Leakage due to corrosion
	0.0100	**Failure of manual valve to function**
2	0.0077	Valve malfunctions closed
1	0.0024	Valve malfunctions open
	0.0000	**Wellhead housing integrity**
1	0.0024	Higher bending moments due to taller housing
1	0.0024	Stress concentrations due to penetrations
	0.0545	**Damage to valves from external forces**
4	0.0249	Running / Installation damage
3	0.0153	Damage from ROV contact
2	0.0077	Damage when landing tree
2	0.0077	Dropped equipment

Table 4: Relative Failure Occurrence Index of ½" Penetrations

Risk Index	Relative Failure Occurrence	Failure Mode
	27.08%	**Failure of B or C Annulus Penetration, 1/2"**
	0.1679	**False Pressure Reading**
6	0.0491	Pressure sensor inoperable
4	0.0249	Pressure sensor lost calibration
2	0.0077	Lost umbilical signal
9	0.0956	Pressure port plugged
	0.0385	**Leakage from connections**
5	0.0362	Leakage due to vibration
1	0.0024	Leakage due to corrosion
	0.0100	**Failure of manual valve to function**
2	0.0077	Valve malfunctions closed
1	0.0024	Valve malfunctions open
	0.0000	**Wellhead housing integrity**
1	0.0024	Higher bending moments due to taller housing
1	0.0024	Stress concentrations due to penetrations
	0.0545	**Damage to valves from external forces**
4	0.0249	Running / Installation damage
3	0.0153	Damage from ROV contact
2	0.0077	Damage when landing tree
2	0.0077	Dropped equipment

Table 5: Relative Failure Occurrence Index of Casing Pipe / Connections

Risk Index	Relative Failure Occurrence	Failure Mode
	2.69%	**Failure of Production Casing Pipe / Connections to Maintain a Pressure Barrier**
2	0.0077	Corrosion
1	0.0024	Thermal cycling
1	0.0024	Damaged threads
2	0.0077	Damaged sealing surface
1	0.0024	Wear
1	0.0024	Bad / wrong thread compound
1	0.0024	Improper makeup of connection
	3.95%	**Failure of Intermediate Casing Pipe / Connections to Maintain a Pressure Barrier**
2	0.0077	Corrosion
1	0.0024	Thermal cycling
1	0.0024	Damaged threads
2	0.0077	Damaged sealing surface
3	0.0153	Wear
1	0.0024	Bad / wrong thread compound
1	0.0024	Improper makeup of connection
	5.99%	**Failure of Surface Casing Pipe / Connections to Maintain a Pressure Barrier**
2	0.0077	Corrosion
1	0.0024	Thermal cycling
1	0.0024	Damaged threads
2	0.0077	Damaged sealing surface
5	0.0362	Wear
1	0.0024	Bad / wrong thread compound
1	0.0024	Improper makeup of connection

Table 6: Relative Failure Occurrence Index of Casing Hanger Packoff

Risk Index	Relative Failure Occurrence	Failure Mode
	4.91%	**Failure of Casing Hanger Packoff to Maintain a Pressure Barrier**
3	0.0153	Damaged sealing surface
2	0.0077	Thermal cycling / axial movement
2	0.0077	Installation anomalies
2	0.0077	Corrosion
1	0.0024	Seal damage from high temperature
1	0.0024	Loss of seal contact pressure
1	0.0024	Seal / fluid incompatibility
1	0.0024	Solids contamination
1	0.0024	Vibration

Table 7: Relative Failure Occurrence Index of Casing Cement

Risk Index	Relative Failure Occurrence	Failure Mode
	5.98%	**Failure of Production Casing Cement to Maintain a Pressure Barrier**
3	0.0153	Micro-annulus cracks
3	0.0153	Frac-Pac operations
3	0.0153	Expansion and contraction
2	0.0077	Poor formation / cement bond
2	0.0077	Gas in cement
	6.70%	**Failure of Intermediate Casing Cement to Maintain a Pressure Barrier**
3	0.0153	Micro-annulus cracks
3	0.0153	Frac-Pac operations
3	0.0153	Expansion and contraction
3	0.0153	Poor formation / cement bond
2	0.0077	Gas in cement
	1.17%	**Failure of Surface / Conductor Casing Cement to Maintain a Pressure Barrier**
1	0.0024	Micro-annulus cracks
1	0.0024	Frac-Pac operations
1	0.0024	Expansion and contraction
1	0.0024	Poor formation / cement bond
1	0.0024	Gas in cement

11 Figures

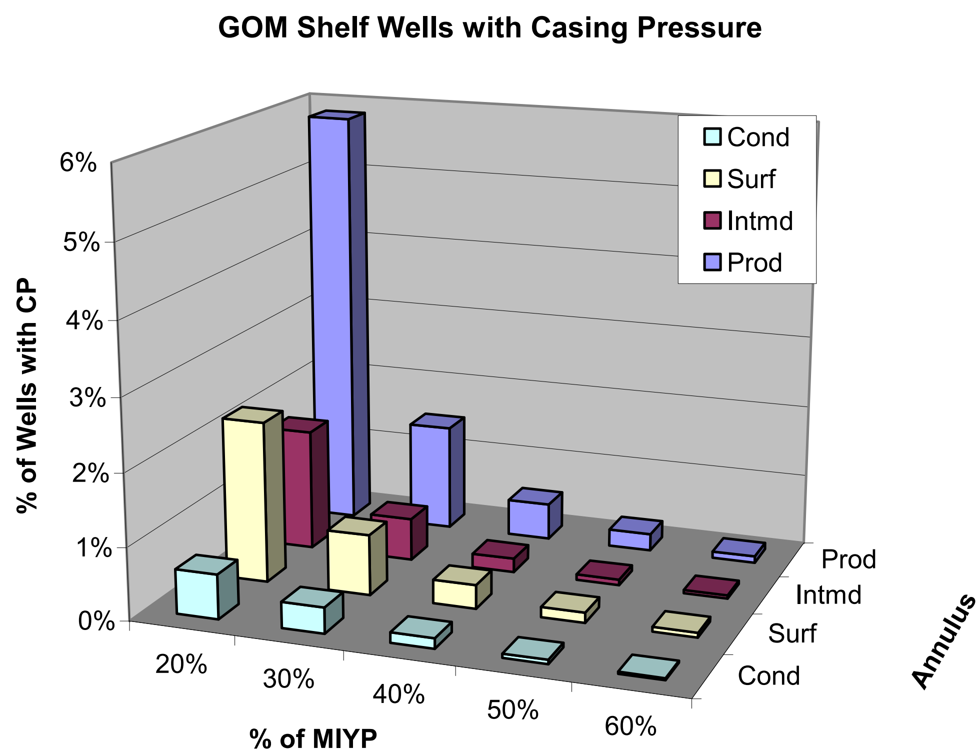


Figure 1: Wells with Casing Pressure by Pipe Strength

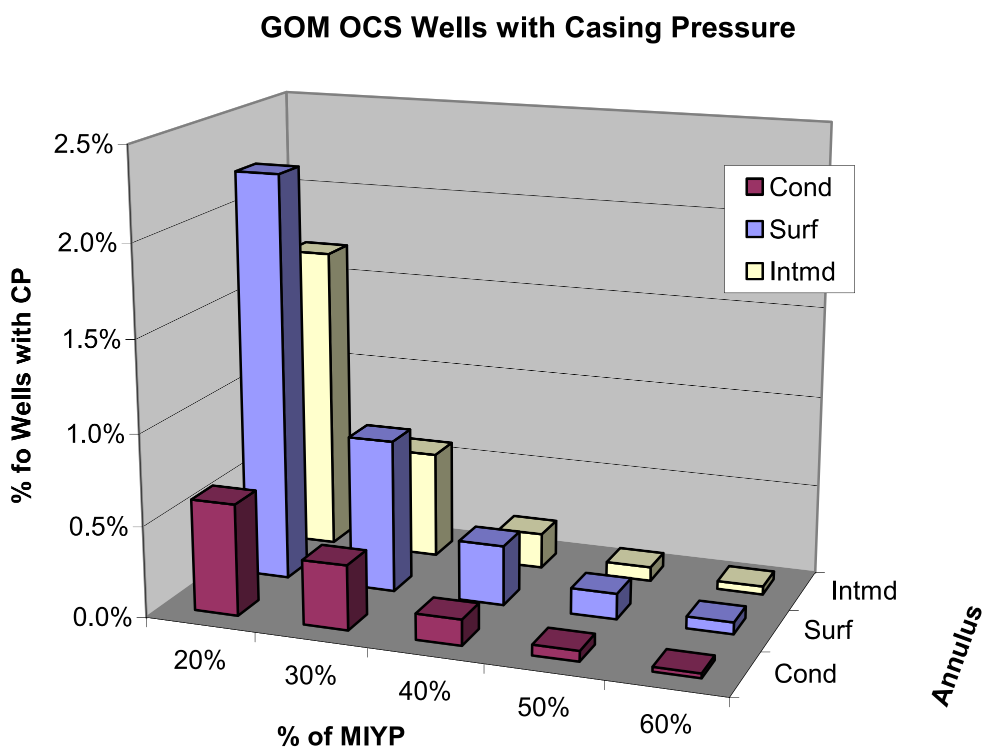


Figure 2: Wells with Casing Pressure by Pipe Strength

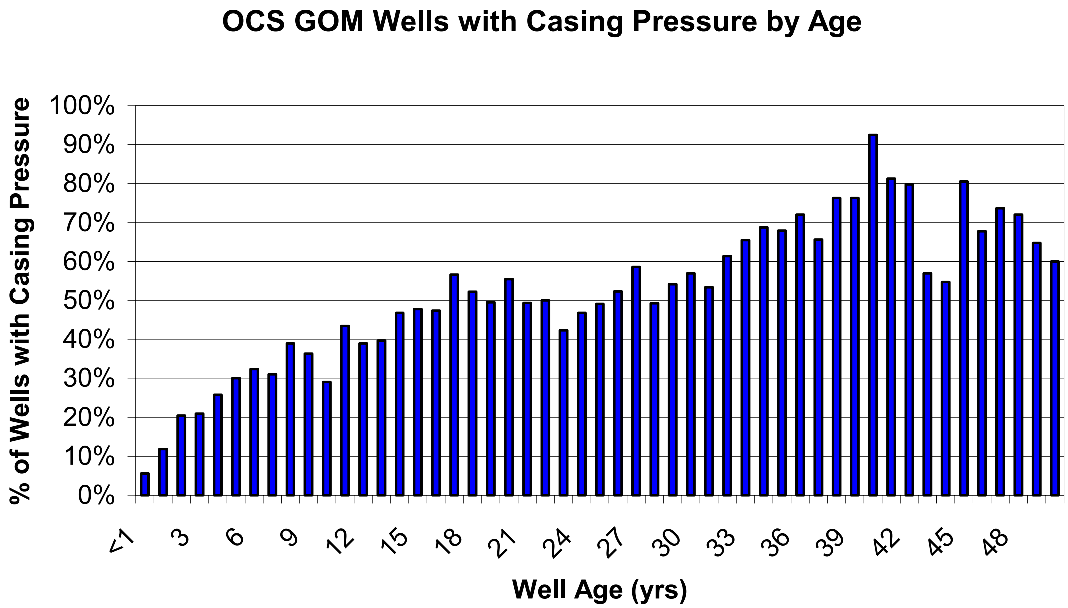


Figure 3: Wells with Casing Pressure by Age

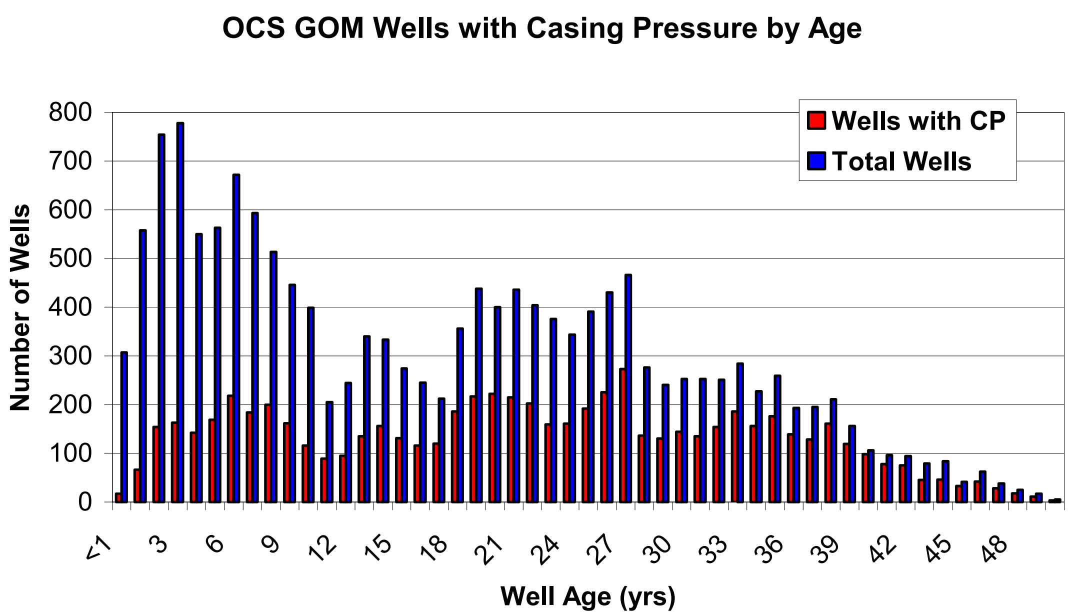


Figure 4: Wells with Casing Pressure by Age

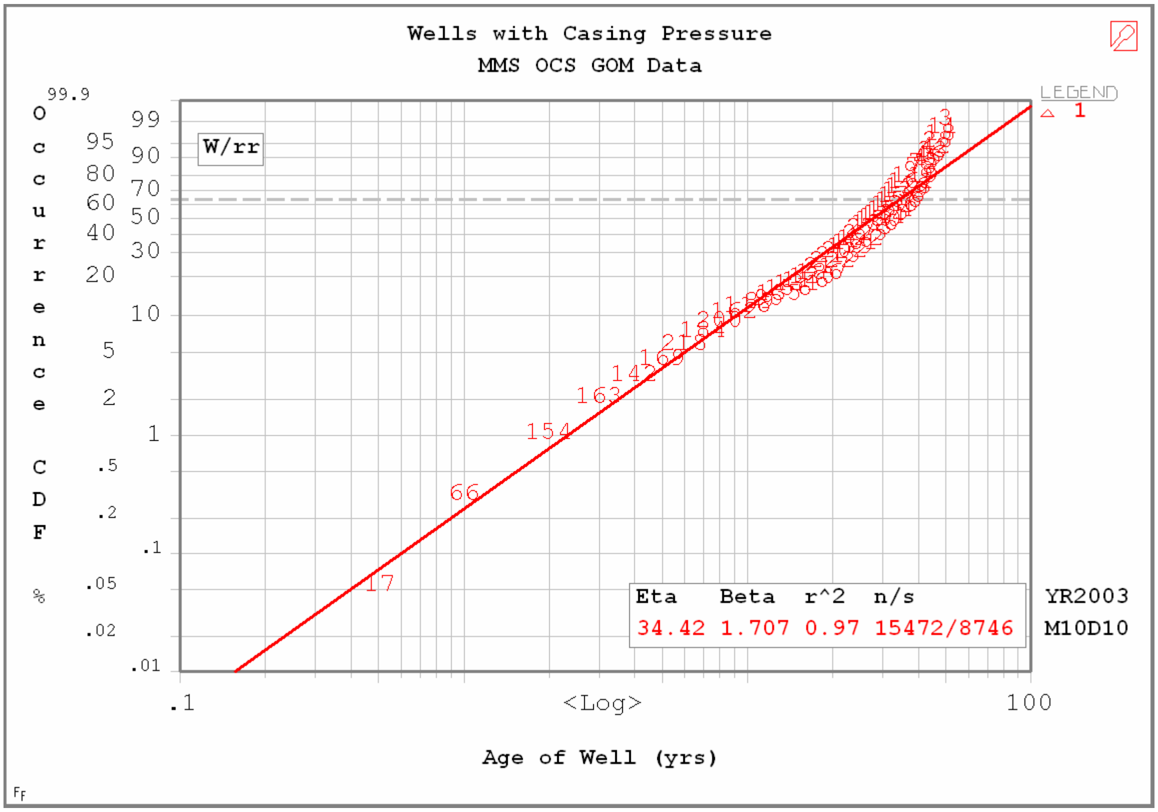


Figure 5: Weibull Analysis of Wells with Casing Pressure by Age

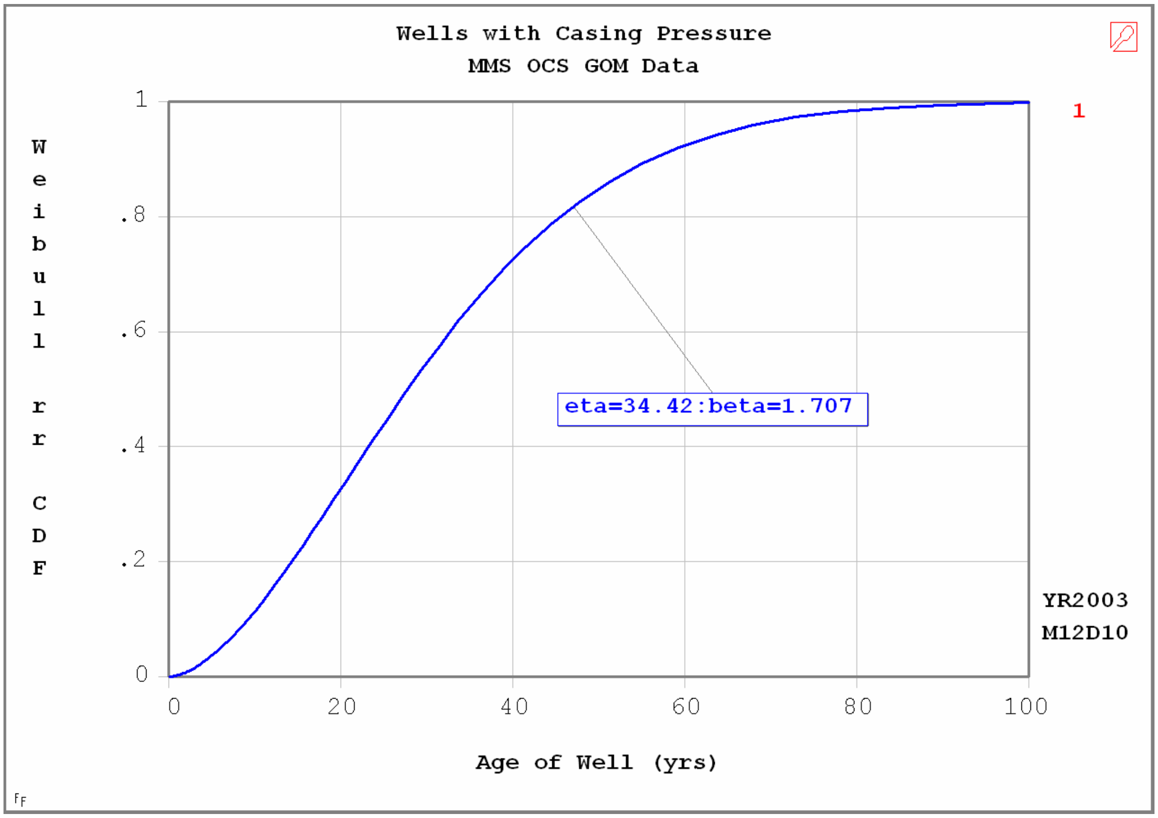


Figure 6: CDF of Wells with Casing Pressure

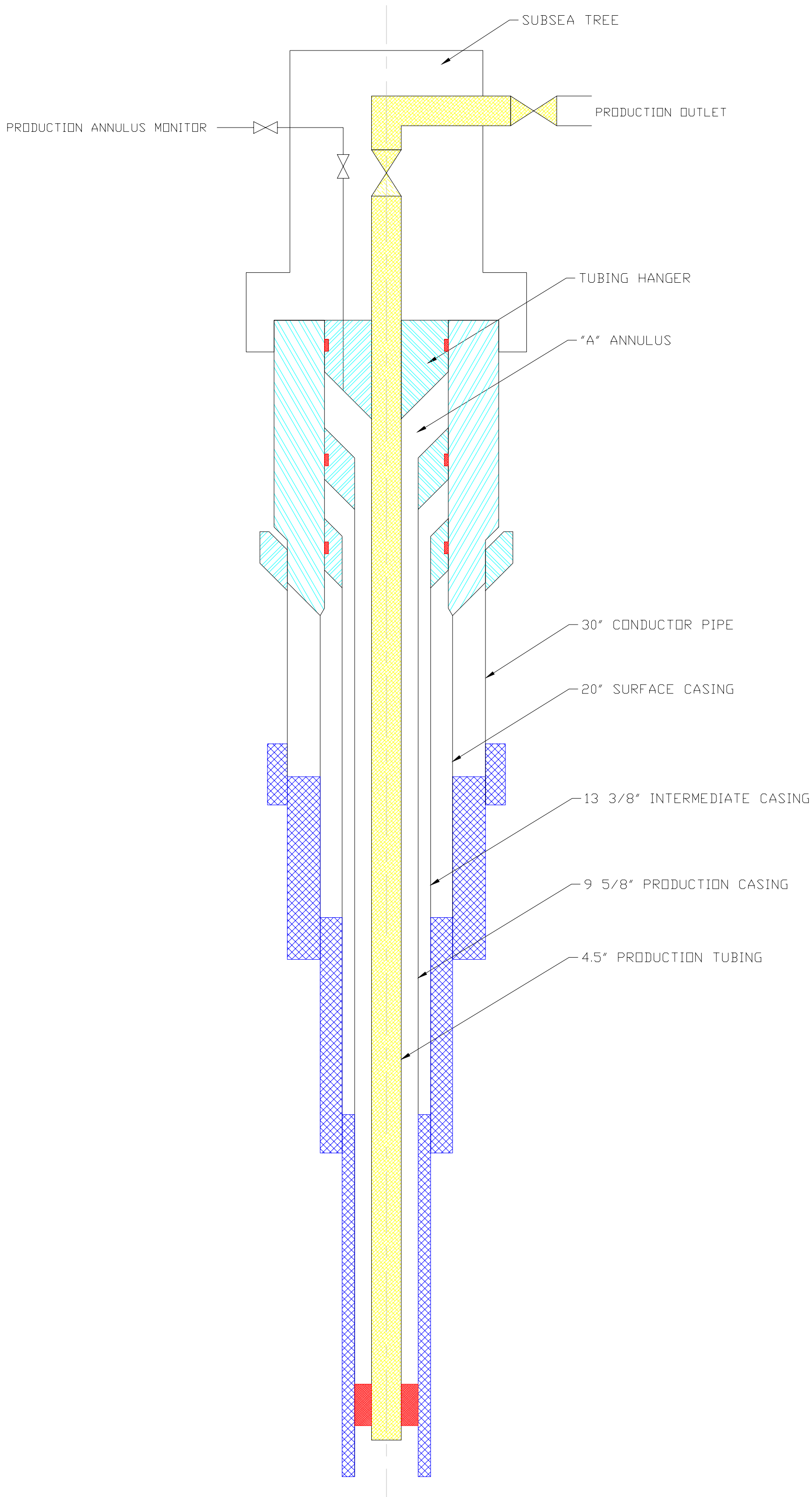
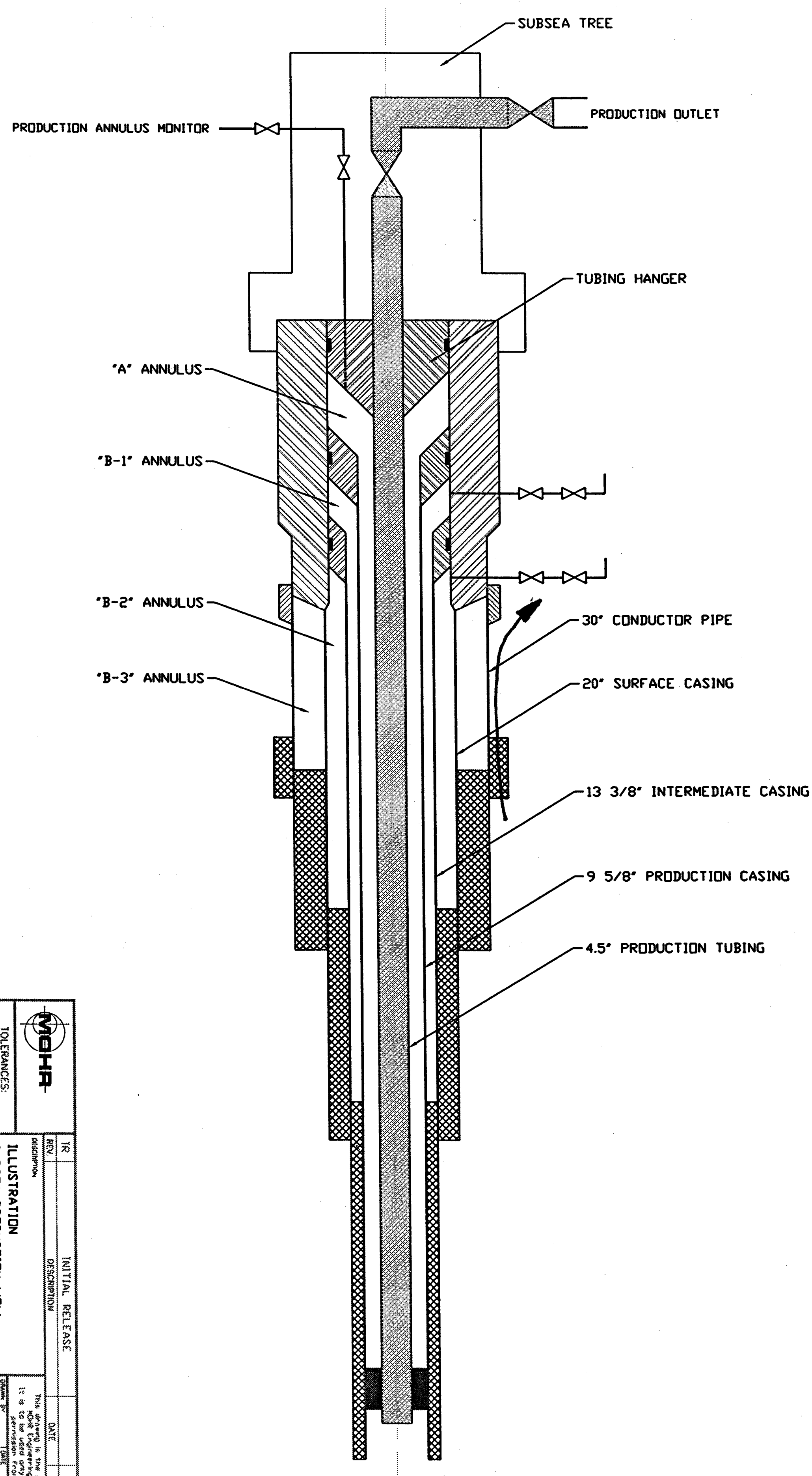


Figure 7: Typical Subsea Wellhead System

12 Appendicies

12.1 Appendix A – Potential Leak Paths



PRESSURE MIGRATES FROM COND PIPE CEMENT

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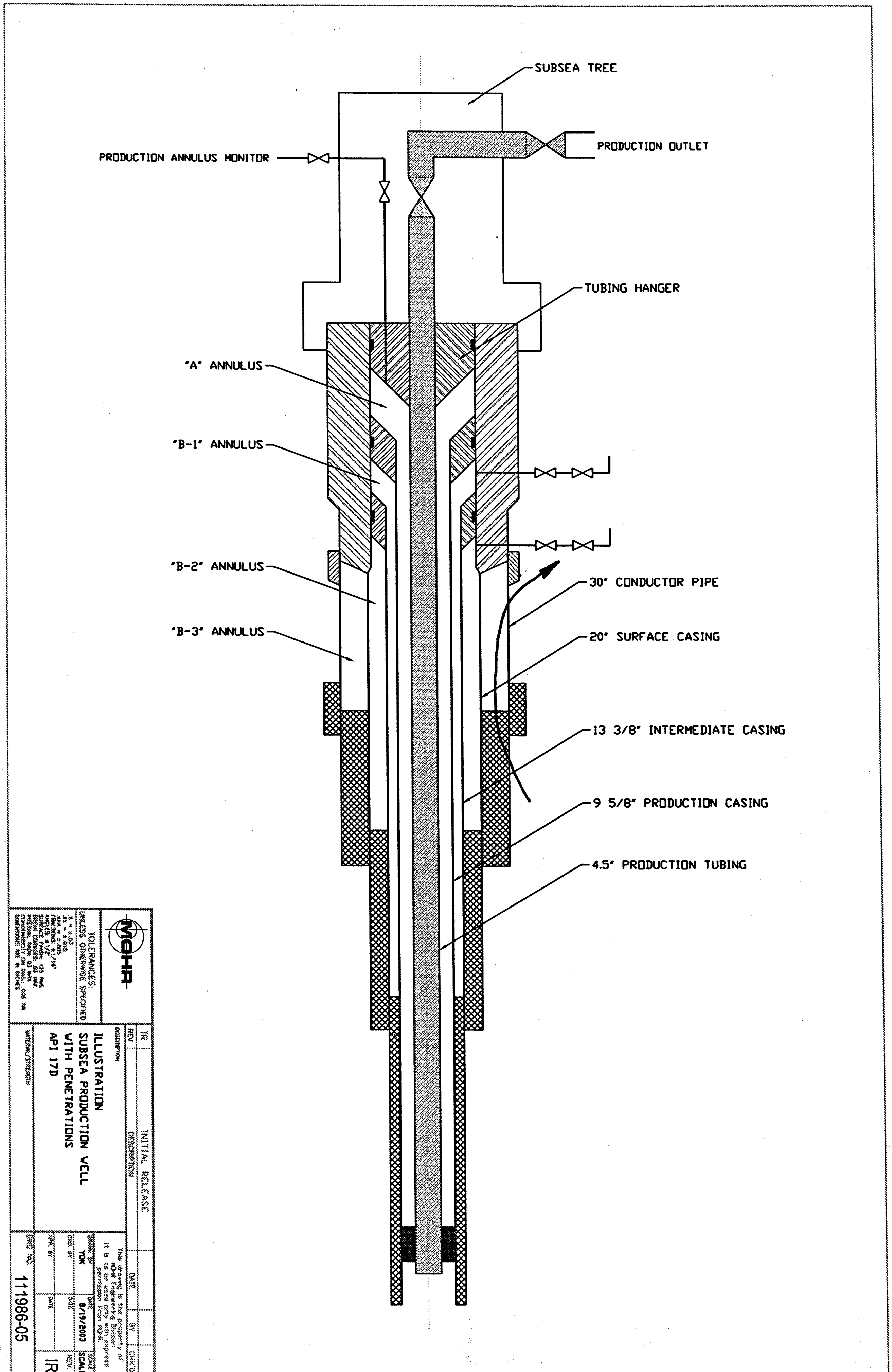

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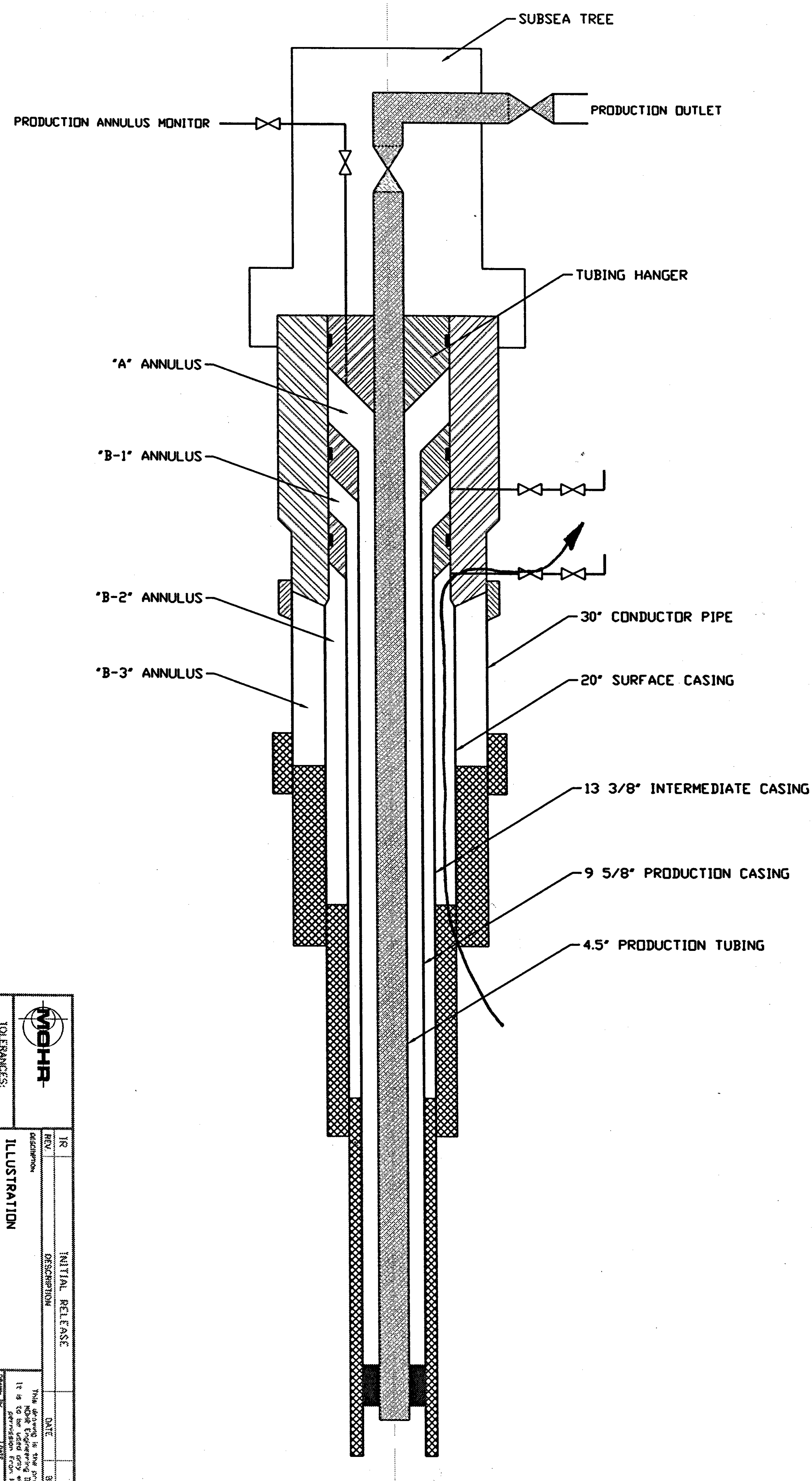

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PRESSURE MIGRATES OUTWARD
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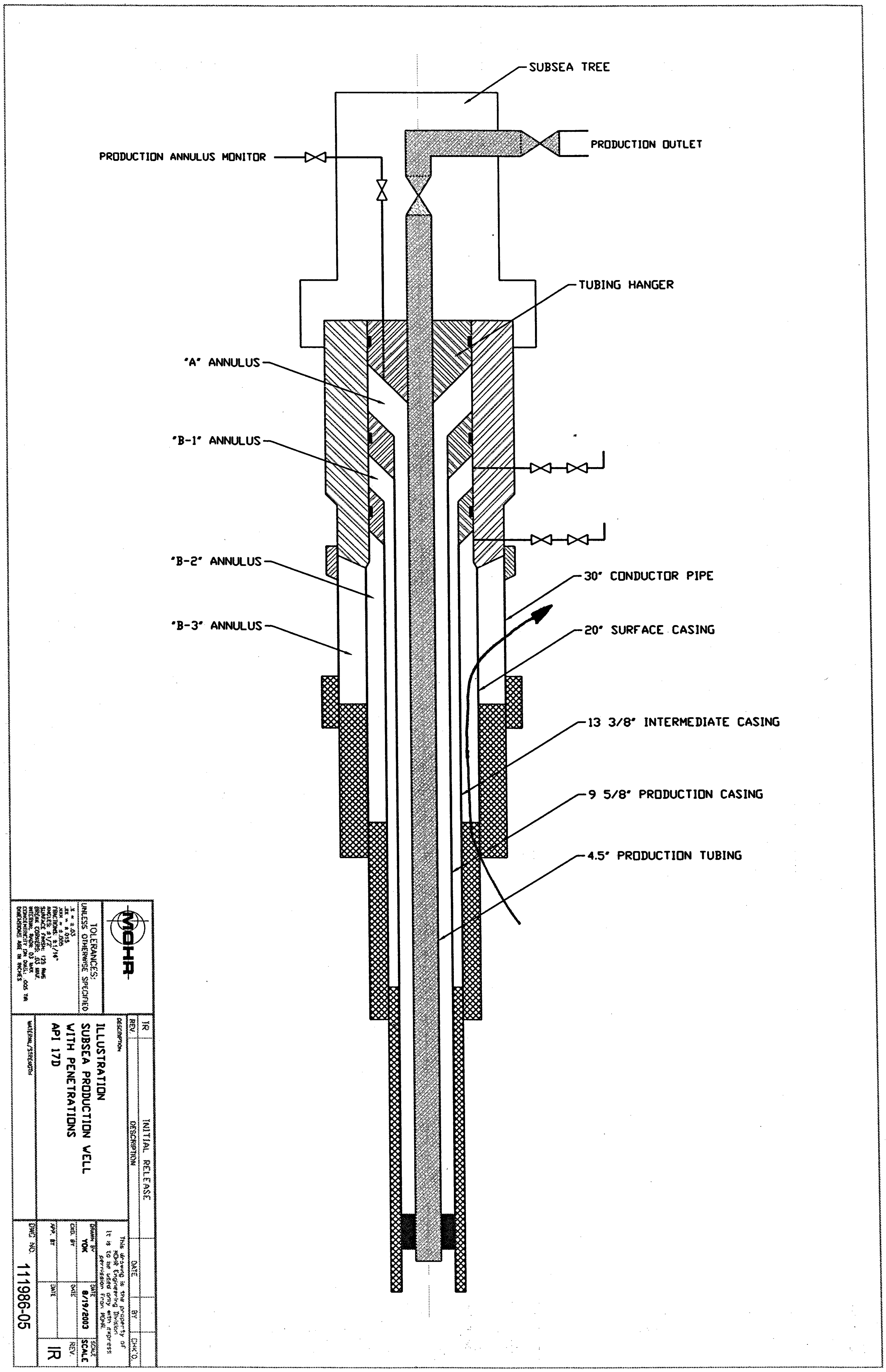
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"B-3" ANNULUS
30" CONDUCTOR PIPE
20" SURFACE CASING
13 3/8" INTERMEDIATE CASING
9 5/8" PRODUCTION CASING
4.5" PRODUCTION TUBING
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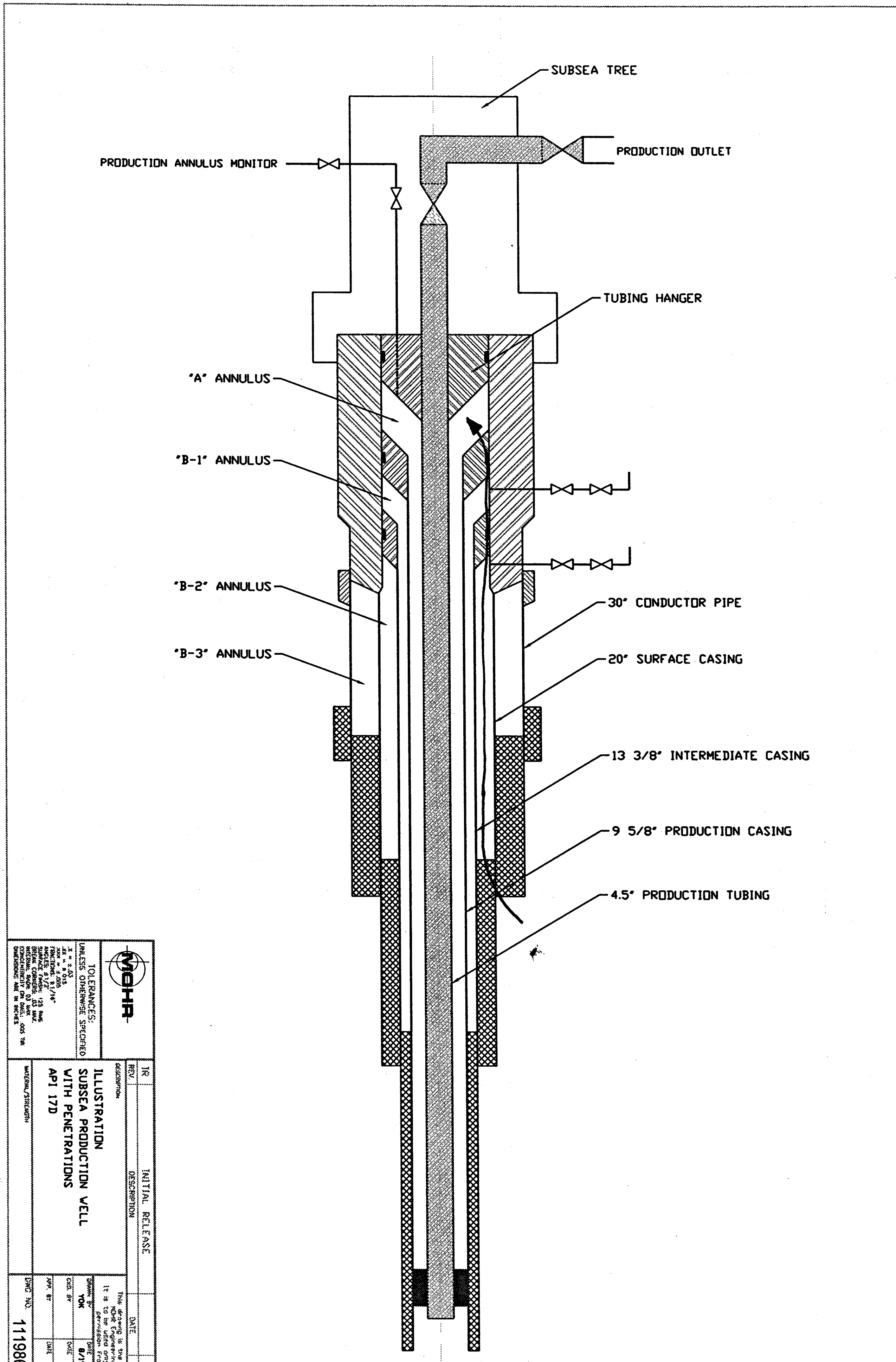

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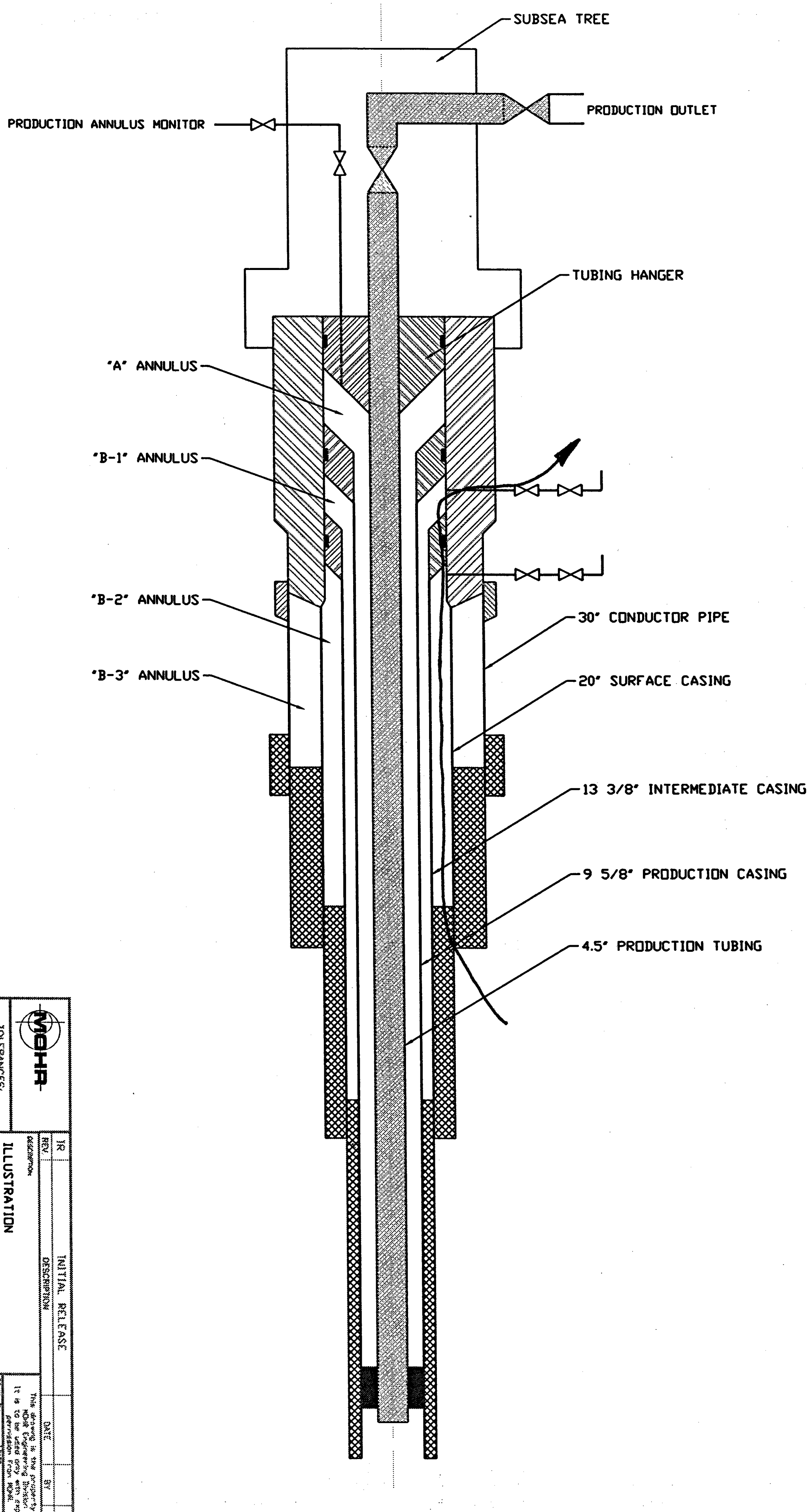

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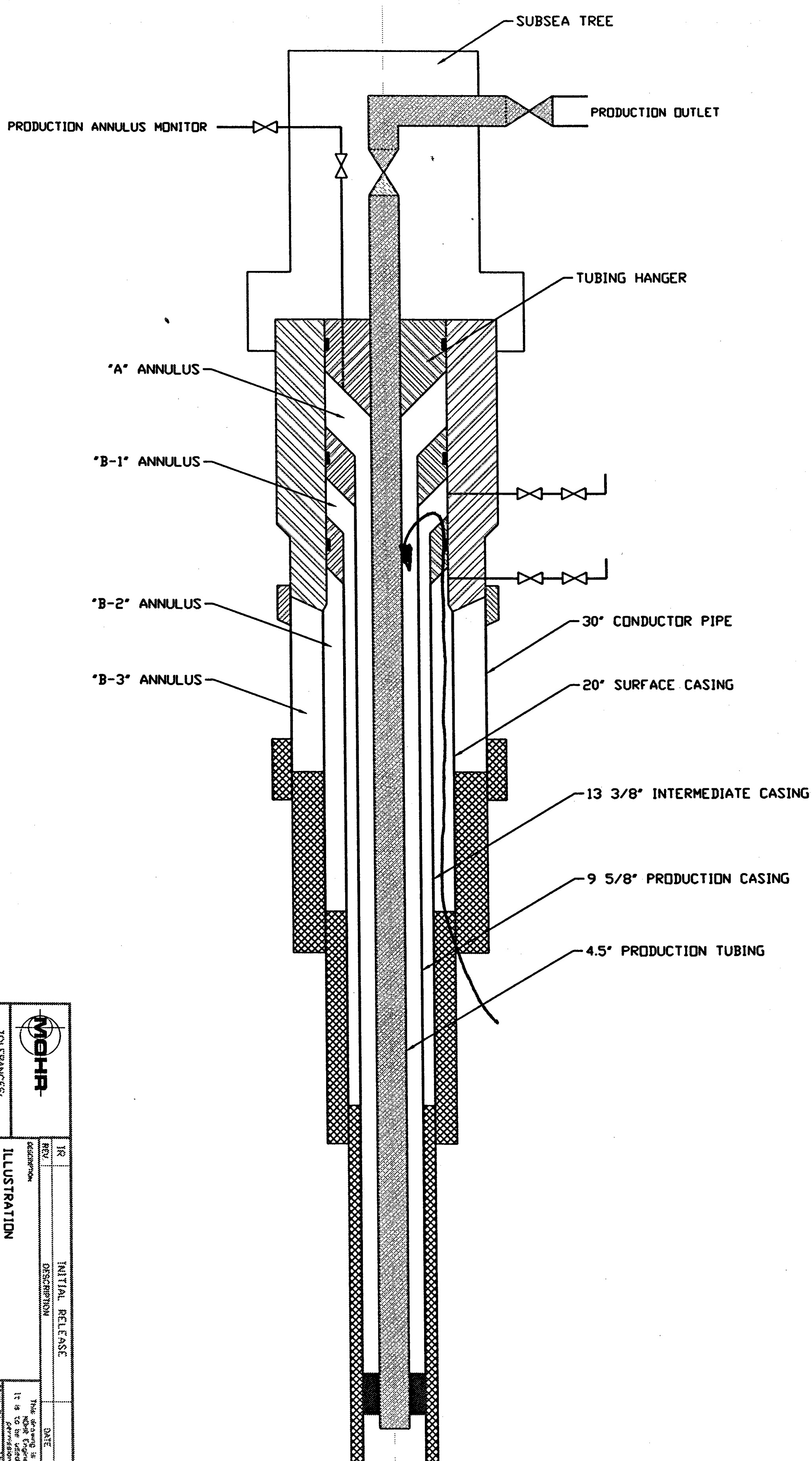

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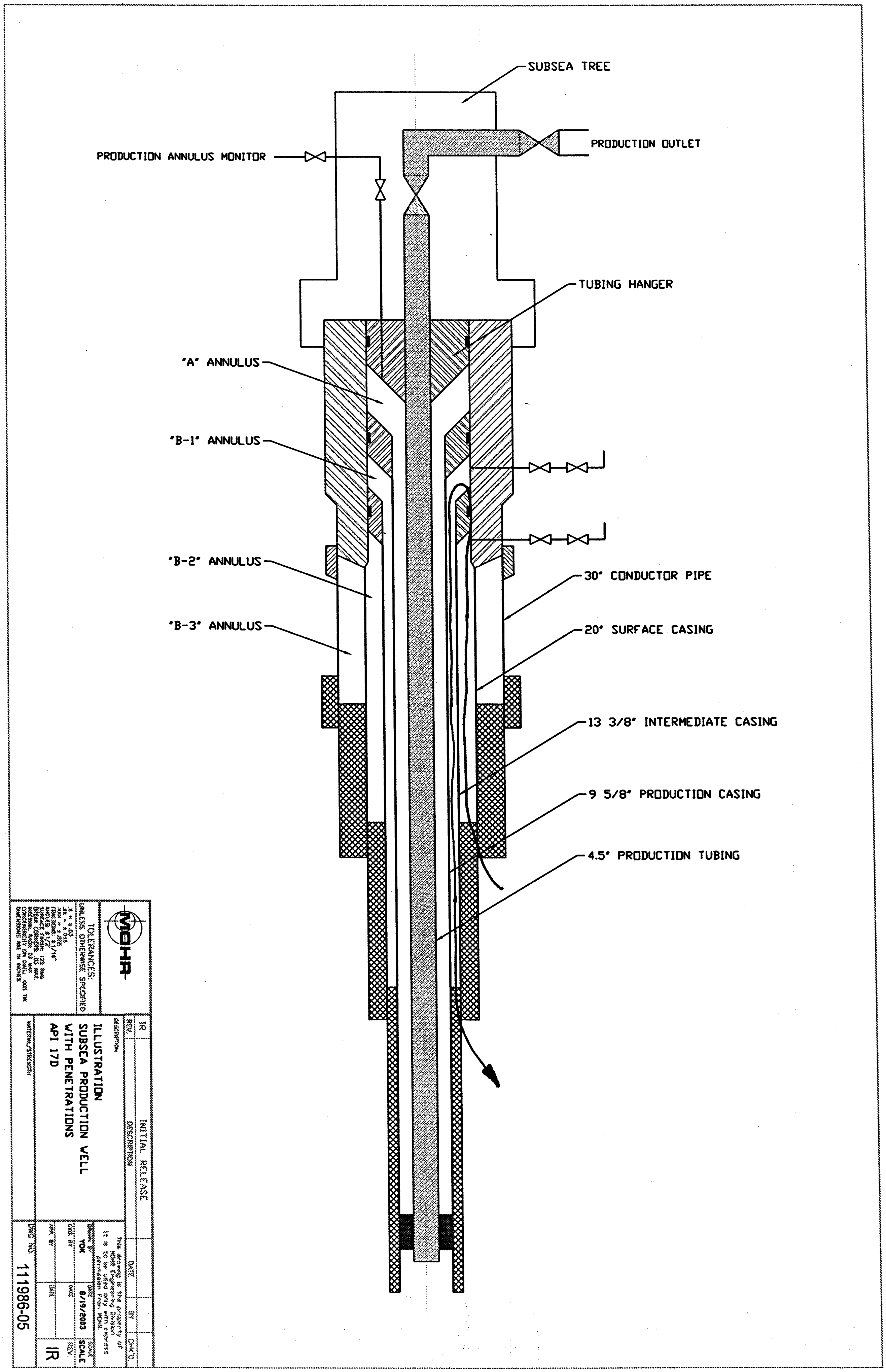
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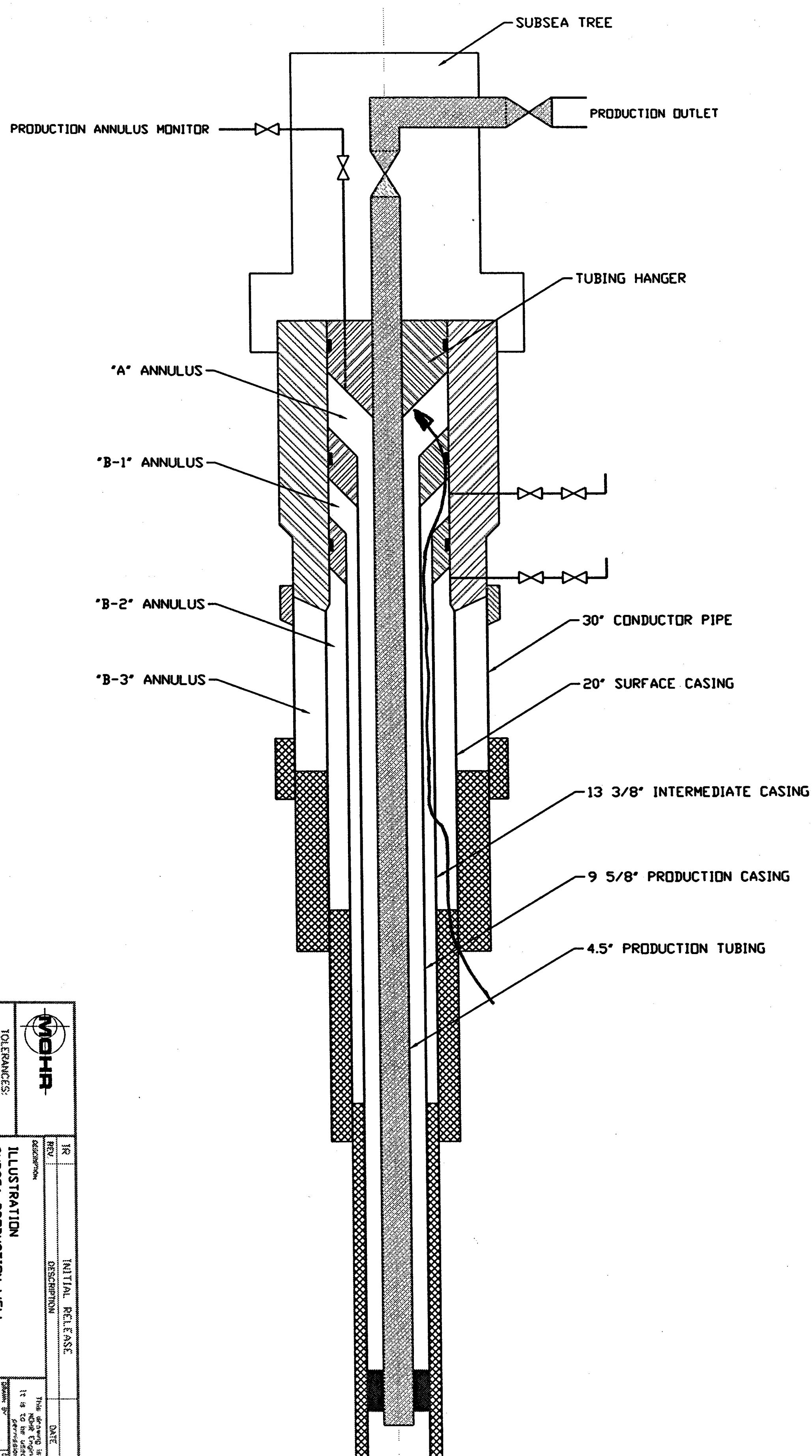

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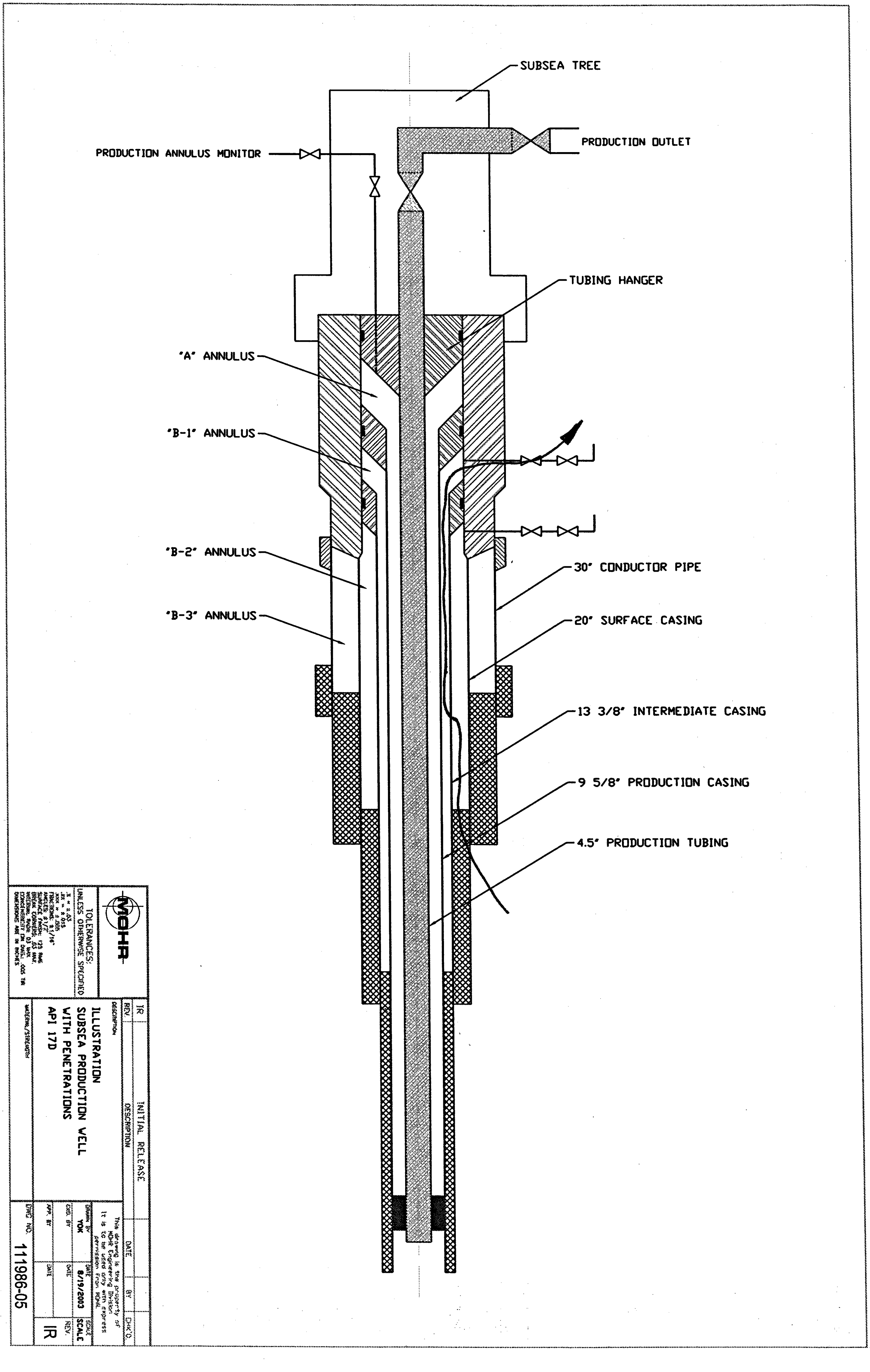
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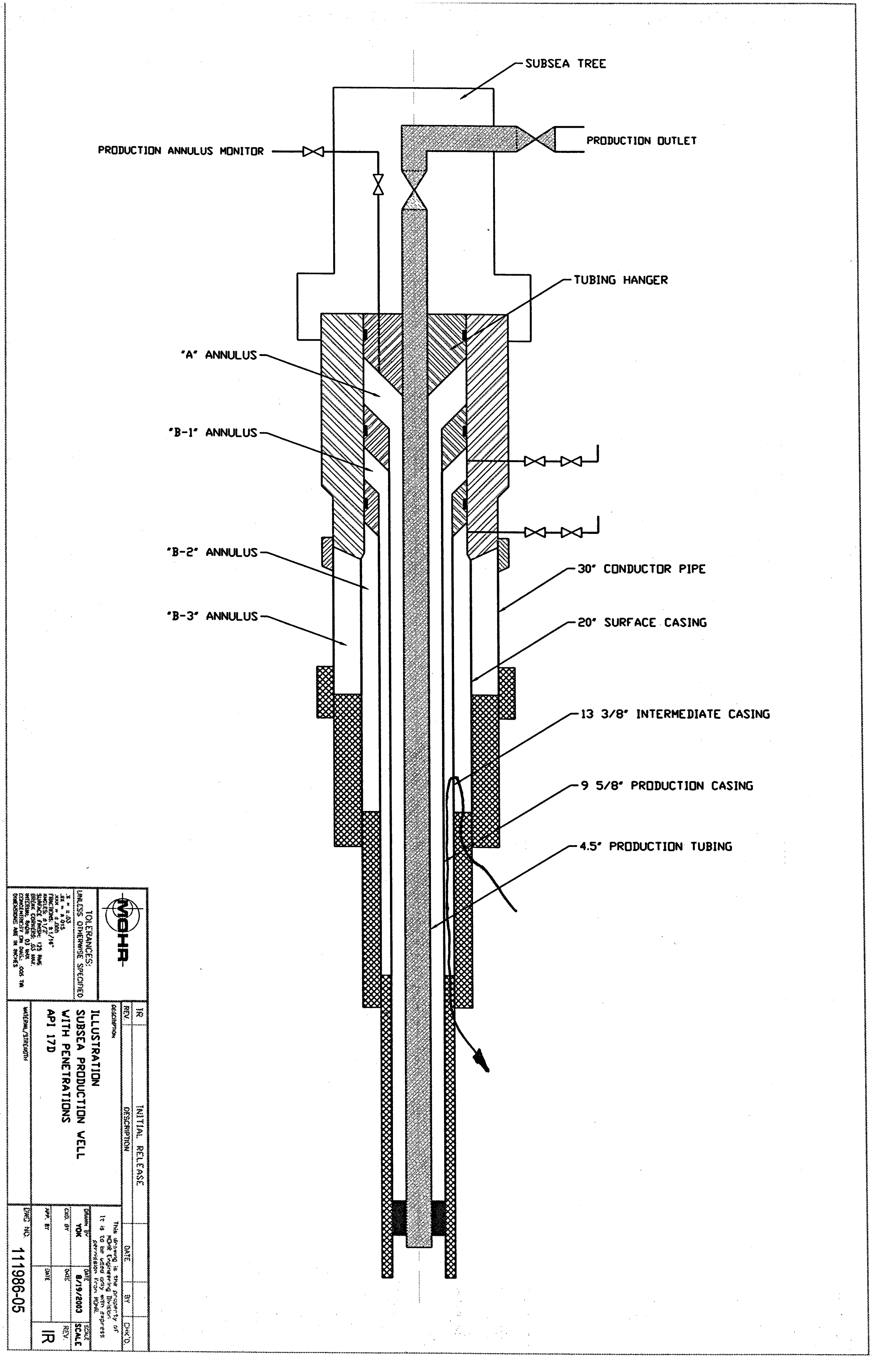
SUBSEA TREE
PRODUCTION ANNULUS MONITOR
PRODUCTION OUTLET
TUBING HANGER
"A" ANNULUS
"B-1" ANNULUS
"B-2" ANNULUS
"B-3" ANNULUS
30" CONDUCTOR PIPE
20" SURFACE CASING
13 3/8" INTERMEDIATE CASING
9 5/8" PRODUCTION CASING
4.5" PRODUCTION TUBING
MOHR
TOLERANCES:
UNLESS OTHERWISE SPECIFIED
IR
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INITIAL RELEASE
DESCRIPTION
DATE
BY
CHK'D
ILLUSTRATION
SUBSEA PRODUCTION WELL
WITH PENETRATIONS
API 17D
MATERIAL/STRENGTH
DRAWN BY
YOK
DATE
8/19/2003
SCALE
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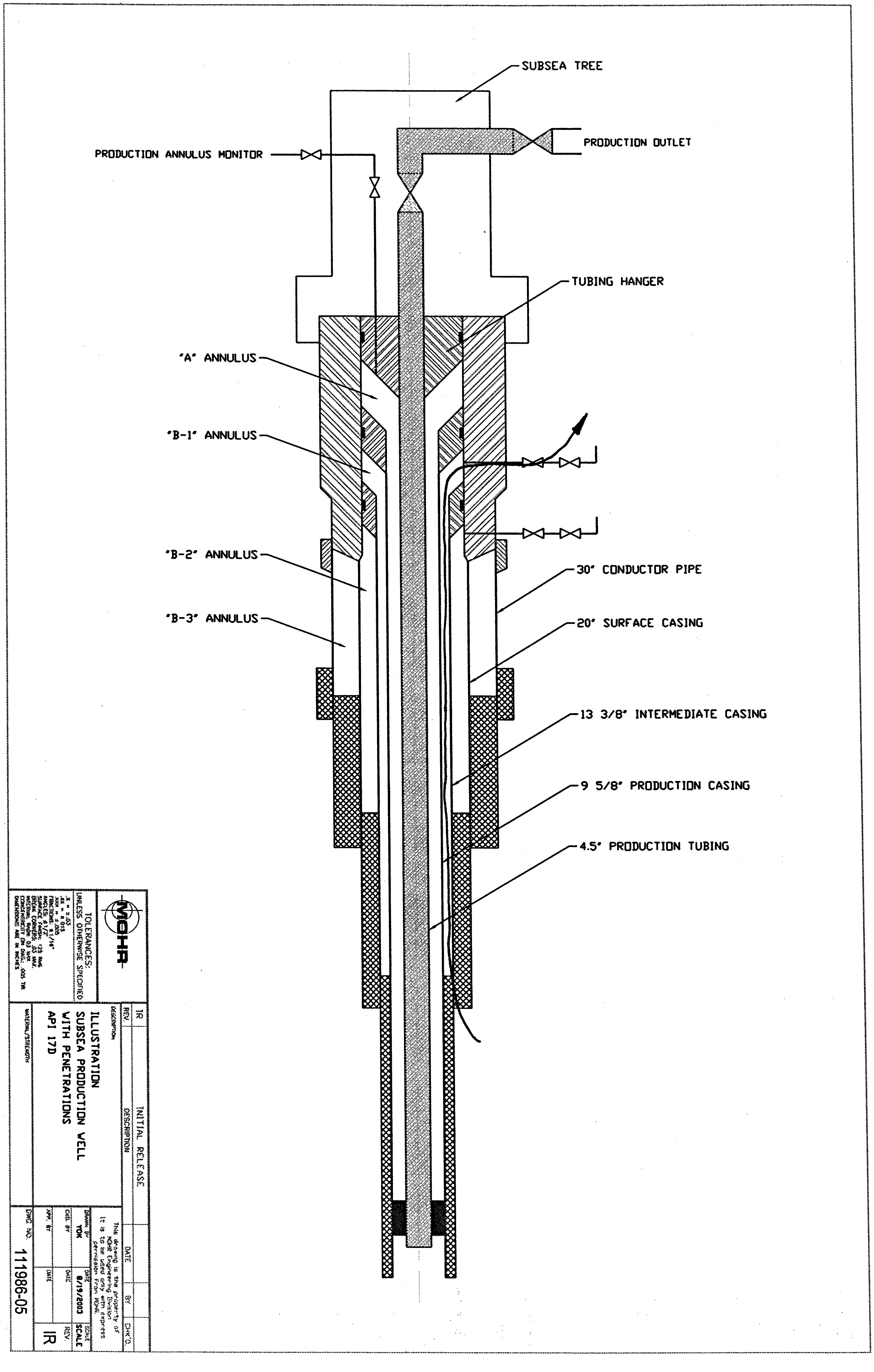
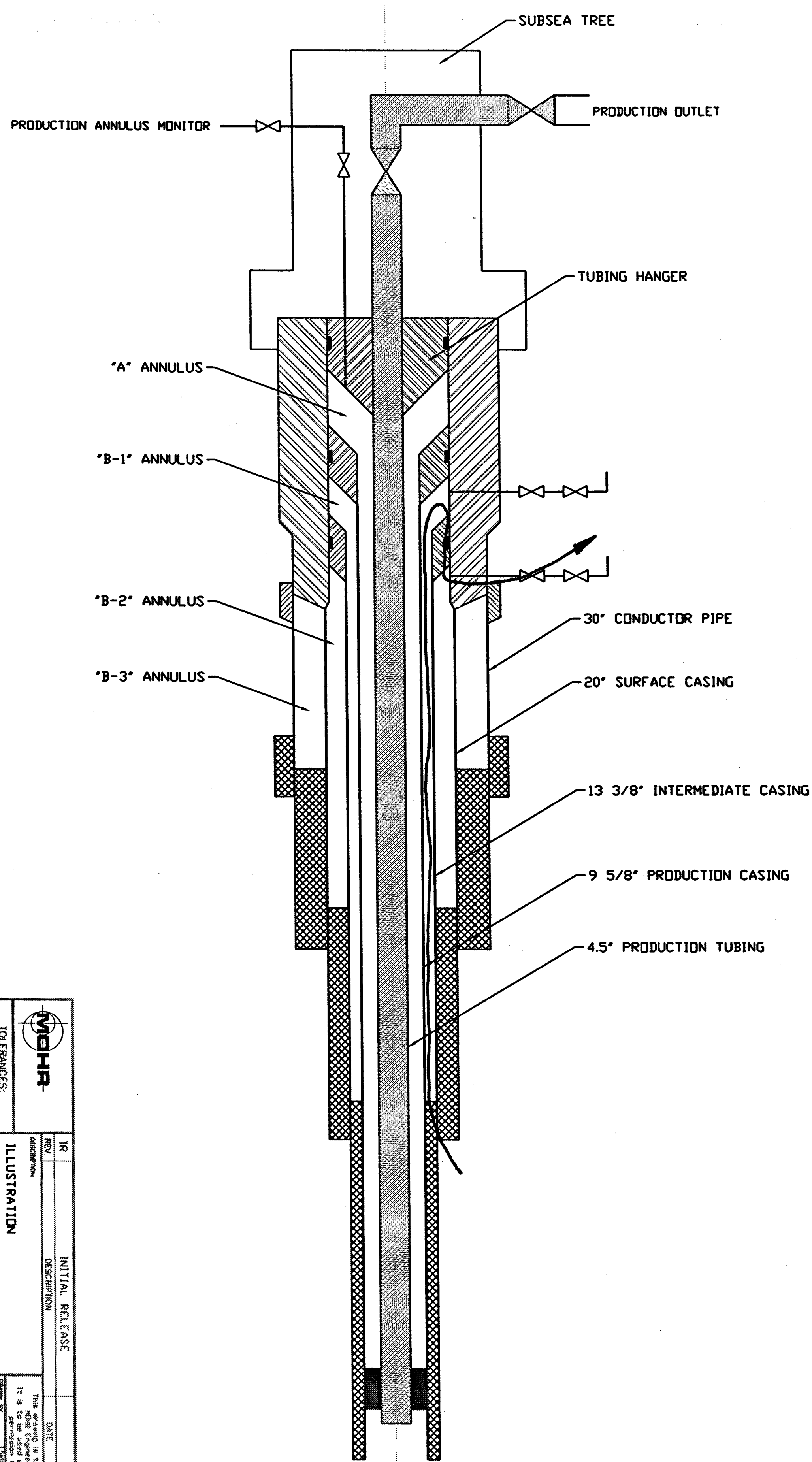
APP. BY
DATE
DWG NO.
111986-05
IR



PRESSURE MIGRATING OUTWARDS FROM PROD CSG CEMENT



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TOLERANCES:
UNLESS OTHERWISE SPECIFIED

REV.	DESCRIPTION	DATE	BY	CHK'D.
IR	INITIAL RELEASE			

DESCRIPTION
ILLUSTRATION
SUBSEA PRODUCTION WELL
WITH PENETRATIONS
API 17D

MATERIAL/STRENGTH

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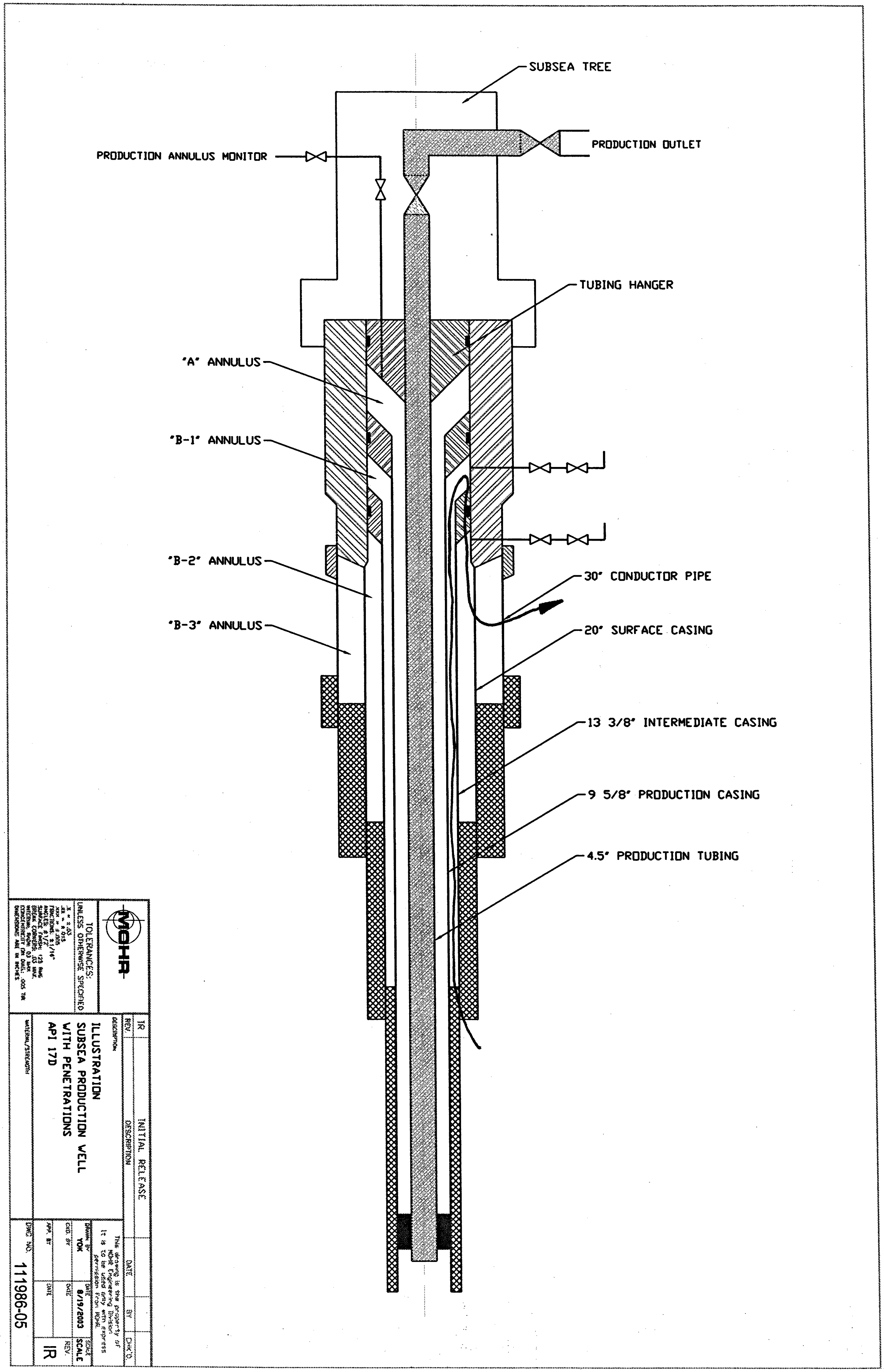
DRAWN BY	DATE	SCALE
YOK	8/19/2003	SCALE
CKD. BY	DATE	REV.
APP. BY	DATE	IR

DWG. NO. 111986-05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PRODUCTION ANNULUS MONITOR
TUBING HANGER
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"B-1" ANNULUS
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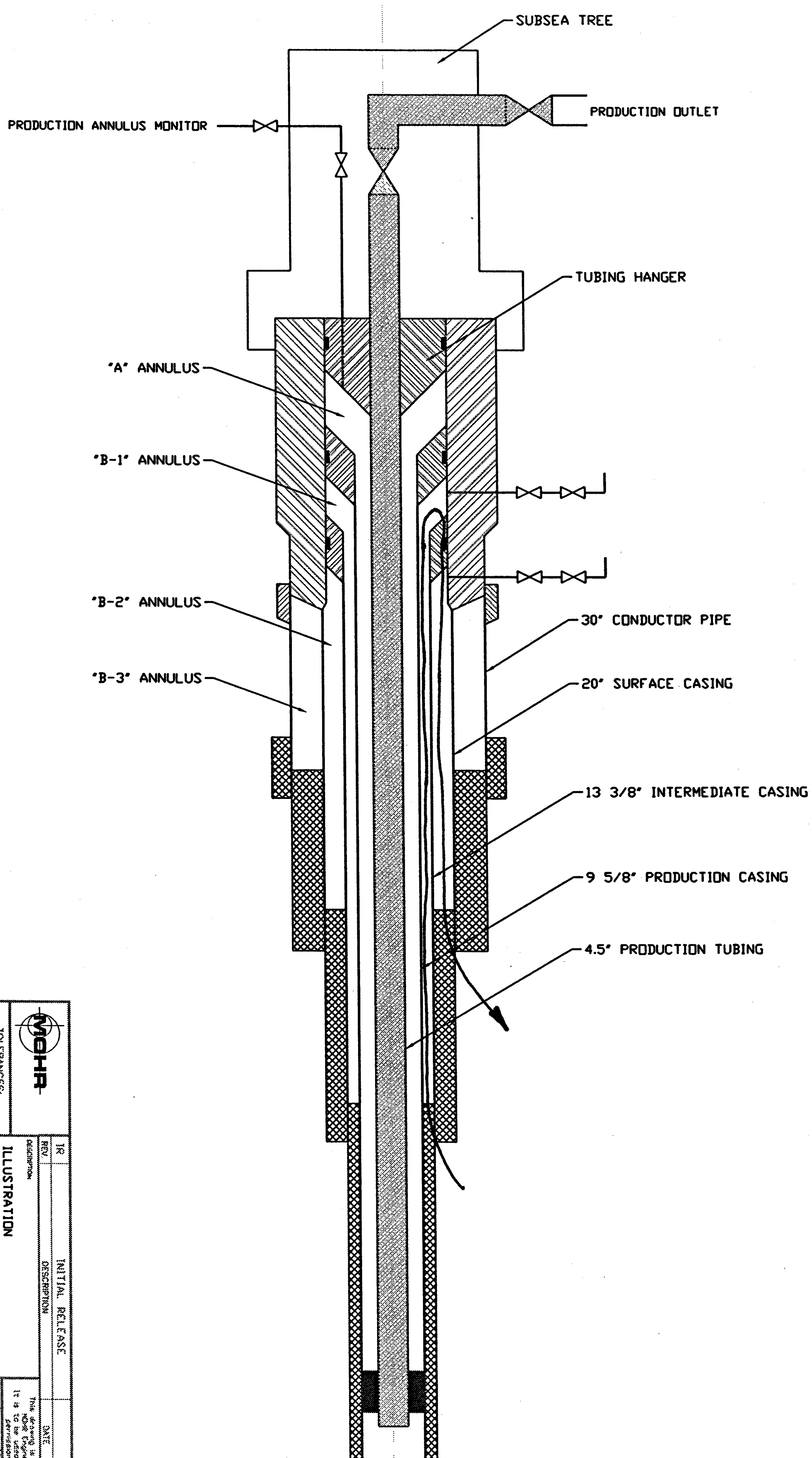
TOLERANCES: UNLESS OTHERWISE SPECIFIED
IR
INITIAL RELEASE
ILLUSTRATION
SUBSEA PRODUCTION WELL
WITH PENETRATIONS
API 17D
DRAWN BY YOK
8/19/2003
DWG NO. 111986-05
IR



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TOLERANCES:
UNLESS OTHERWISE SPECIFIED

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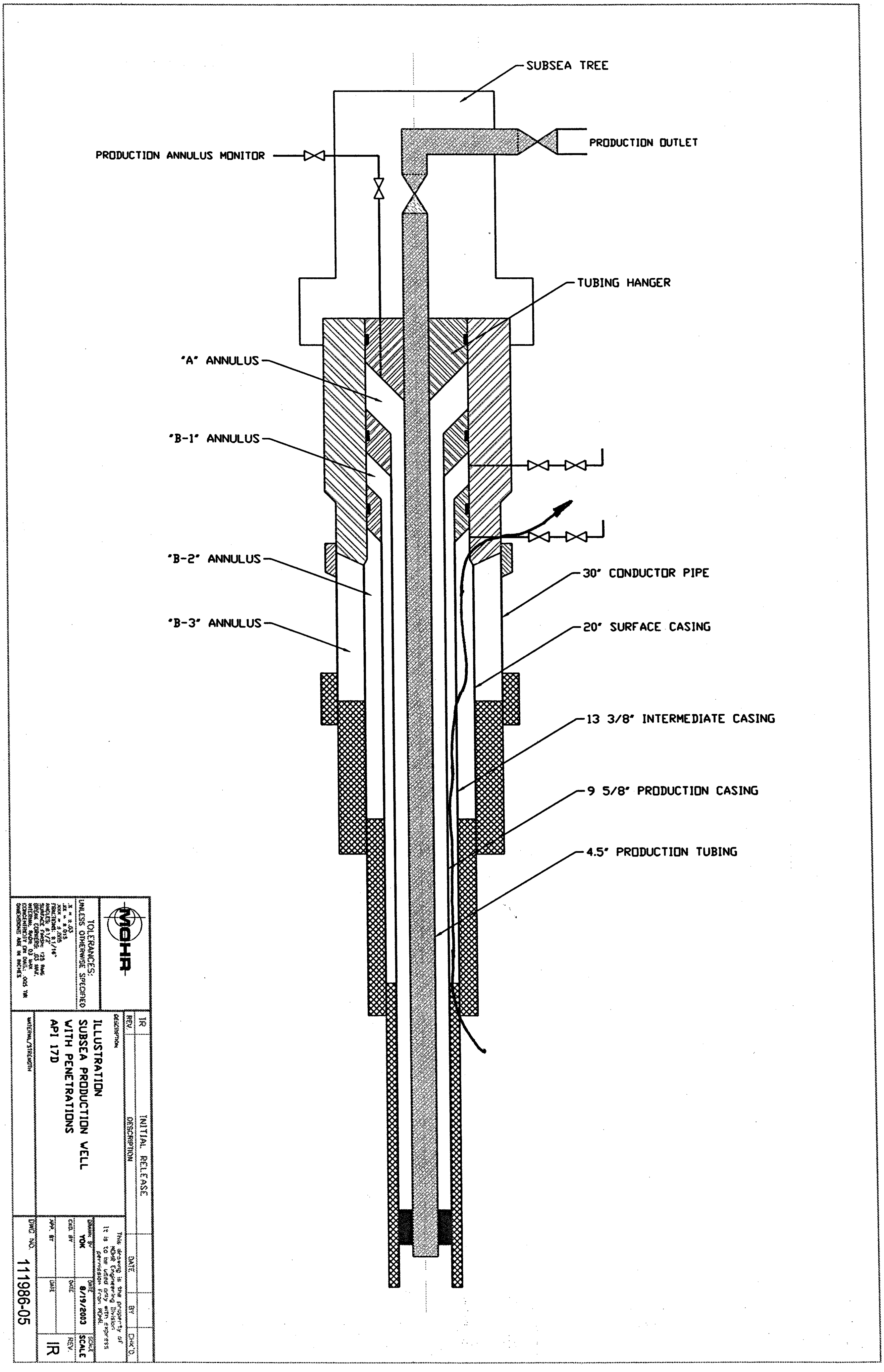
ILLUSTRATION
SUBSEA PRODUCTION WELL
WITH PENETRATIONS
API 17D

DRAWN BY YOK — DATE 8/19/2003

DWG NO. 111986-05 — REV. IR



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TUBING HANGER
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"B-1" ANNULUS
"B-2" ANNULUS
"B-3" ANNULUS
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ILLUSTRATION
SUBSEA PRODUCTION WELL
WITH PENETRATIONS
API 17D
MATERIAL/STRENGTH
DRAWN BY
YOK
DATE
8/19/2003
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REV.
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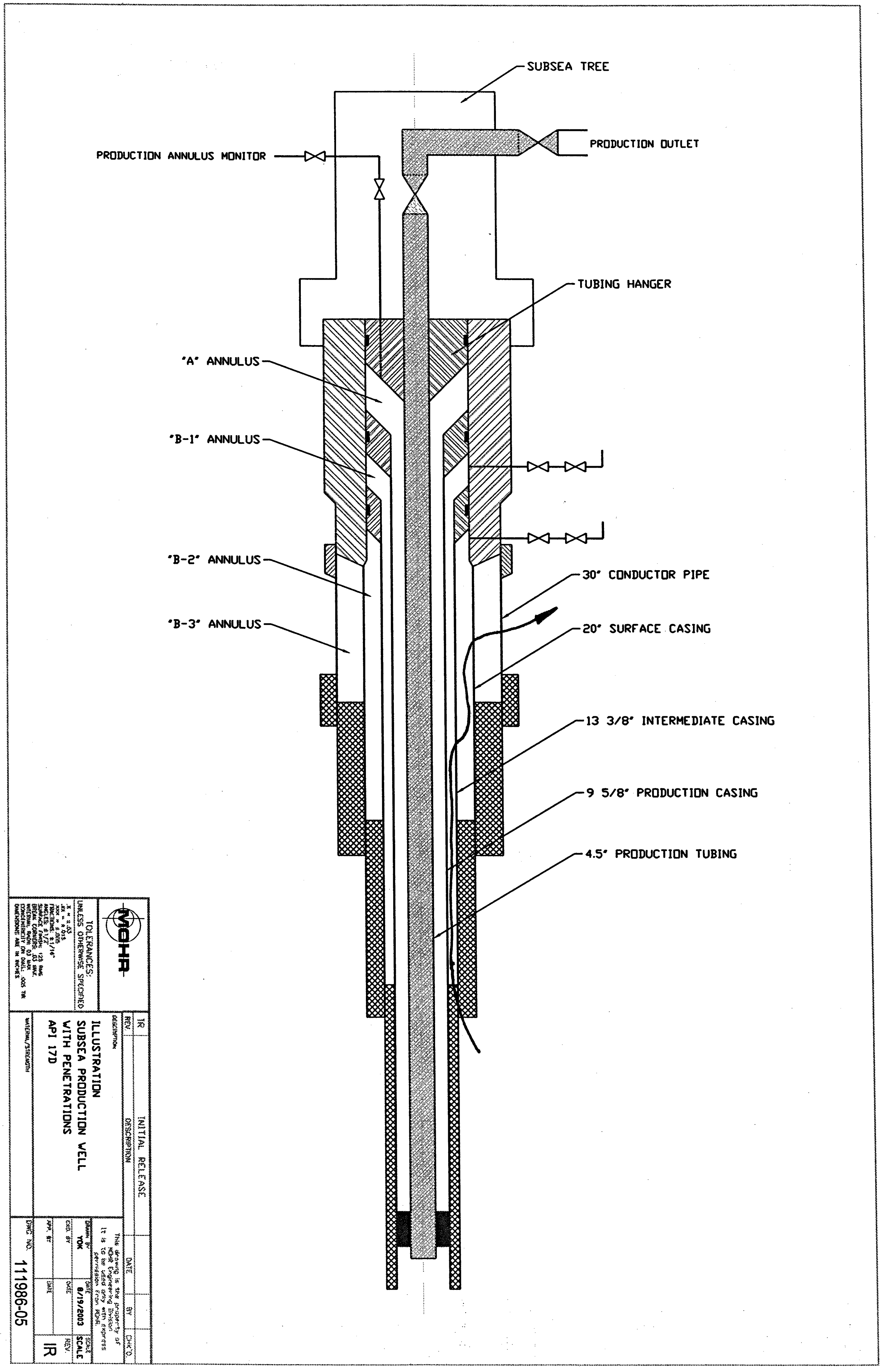
111986-05
IR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PRODUCTION ANNULUS MONITOR
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'B-1' ANNULUS
'B-2' ANNULUS
'B-3' ANNULUS
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INITIAL RELEASE
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DESCRIPTION
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ILLUSTRATION
SUBSEA PRODUCTION WELL
WITH PENETRATIONS
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DATE
8/19/2003
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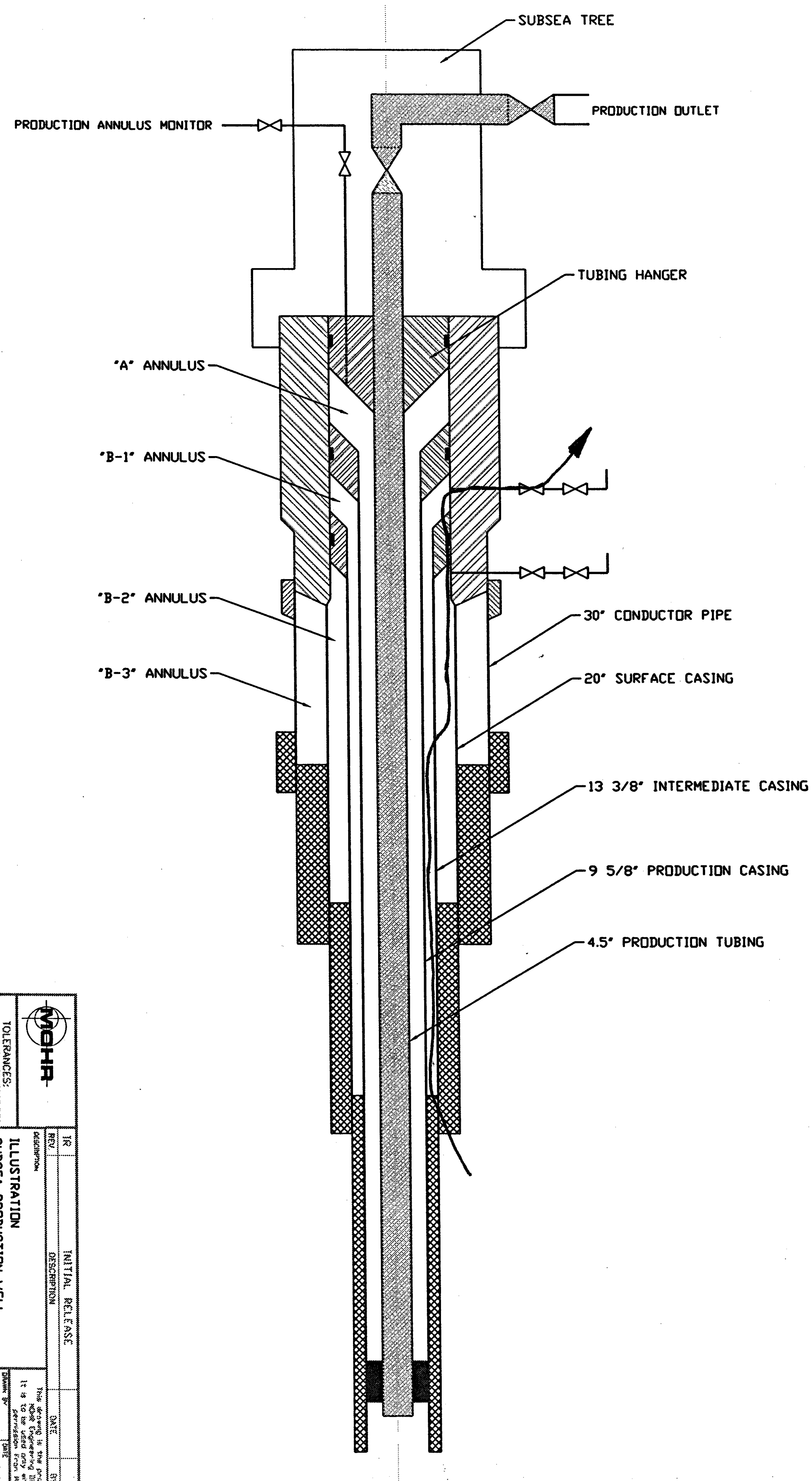
DWG. NO.
111986-05



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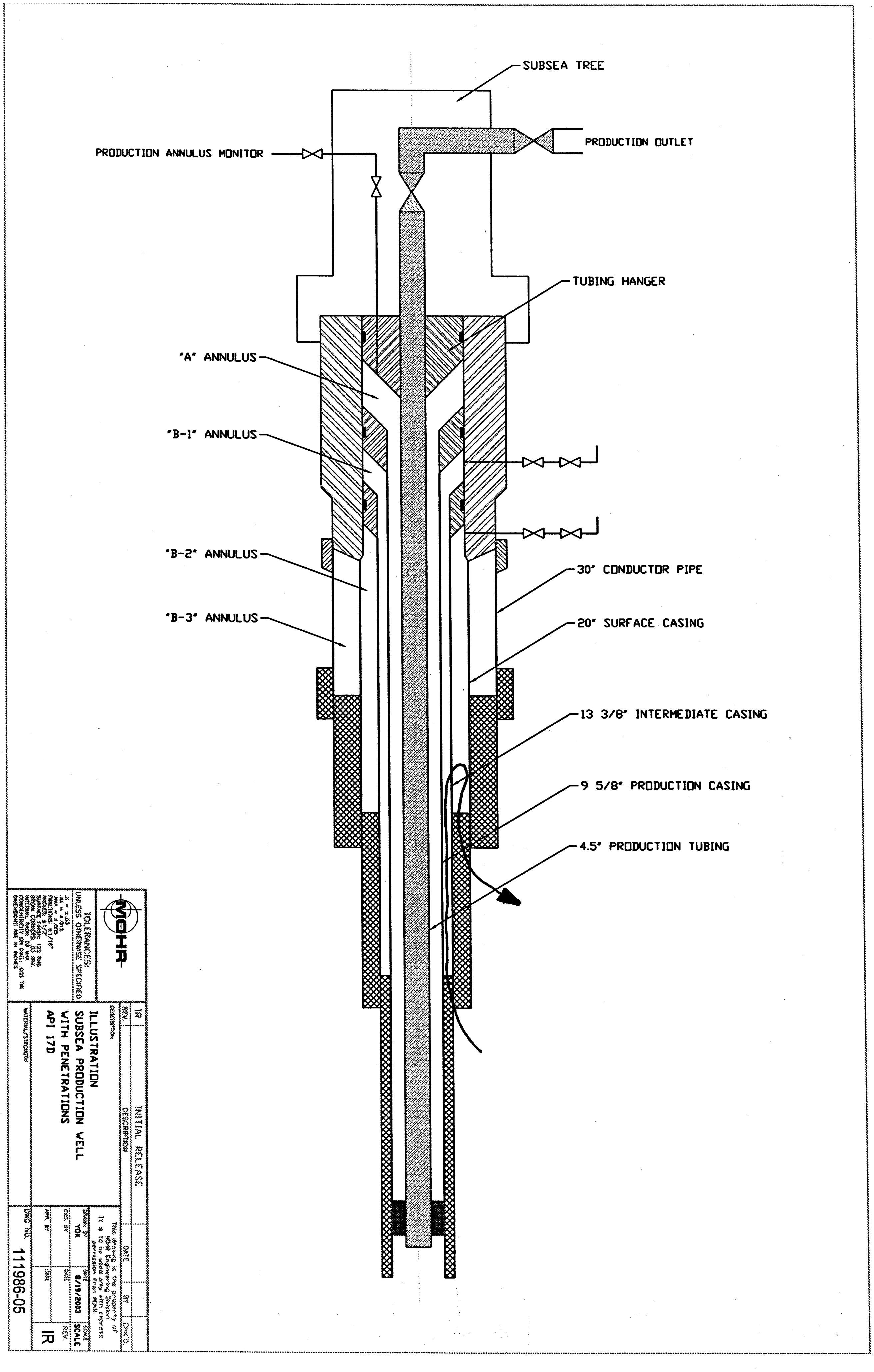
TOLERANCES:
UNLESS OTHERWISE SPECIFIED

REV.	DESCRIPTION	DATE	BY	CHK'D.
IR	INITIAL RELEASE			

DESCRIPTION
ILLUSTRATION
SUBSEA PRODUCTION WELL
WITH PENETRATIONS
API 17D

MATERIAL/STRENGTH

DRAWN BY: YOK
DATE: 8/19/2003
SCALE: SCALE
CKD. BY
APP. BY
DWG NO. 111986-05
REV. IR


SUBSEA TREE
PRODUCTION OUTLET
PRODUCTION ANNULUS MONITOR
TUBING HANGER
"A" ANNULUS
"B-1" ANNULUS
"B-2" ANNULUS
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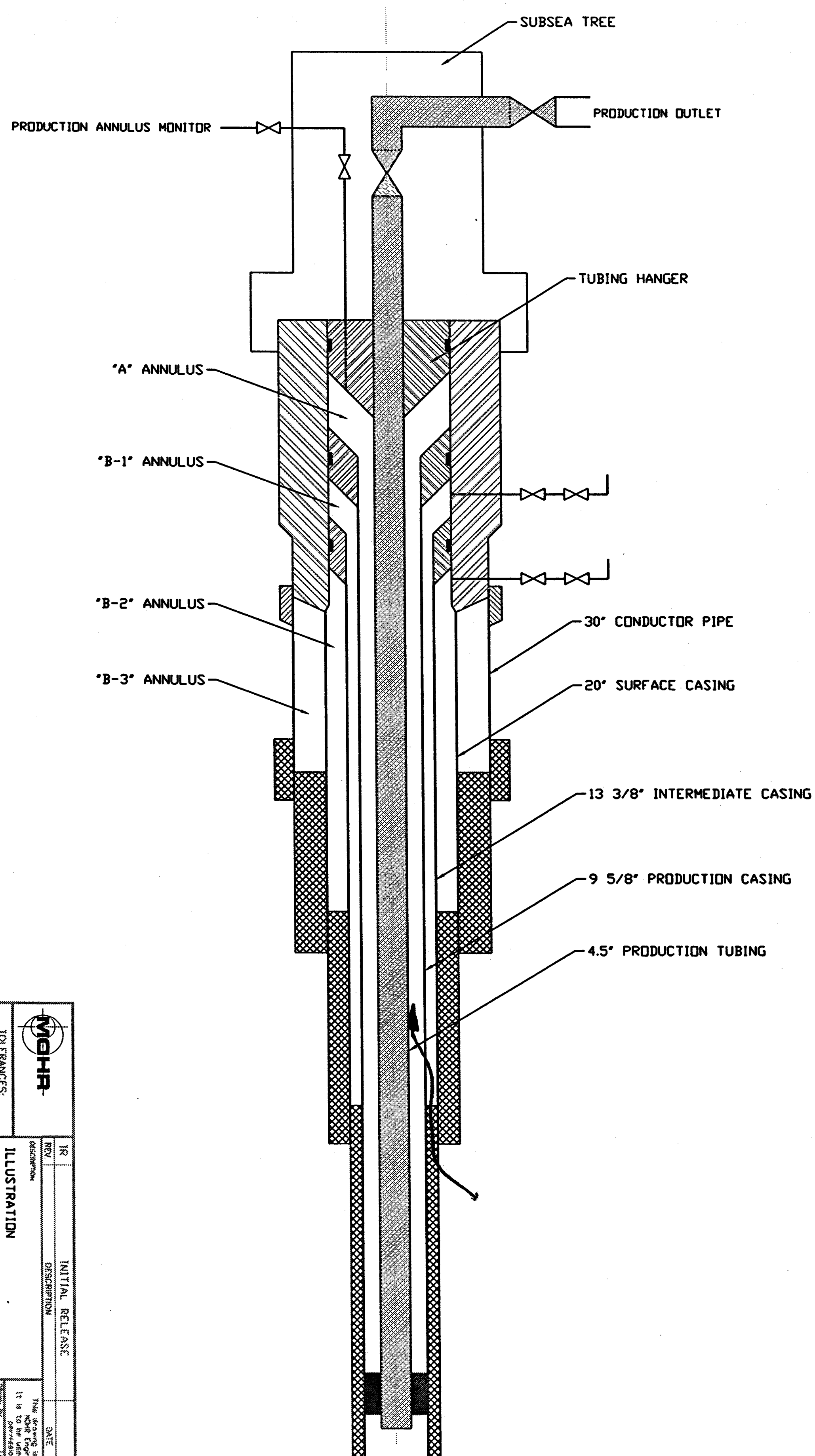
111986-05
REV.
IR



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TOLERANCES:
UNLESS OTHERWISE SPECIFIED

REV.	DESCRIPTION	DATE	BY	CHK'D
IR	INITIAL RELEASE			

DESCRIPTION
ILLUSTRATION
SUBSEA PRODUCTION WELL
WITH PENETRATIONS
API 17D

MATERIAL/STRENGTH

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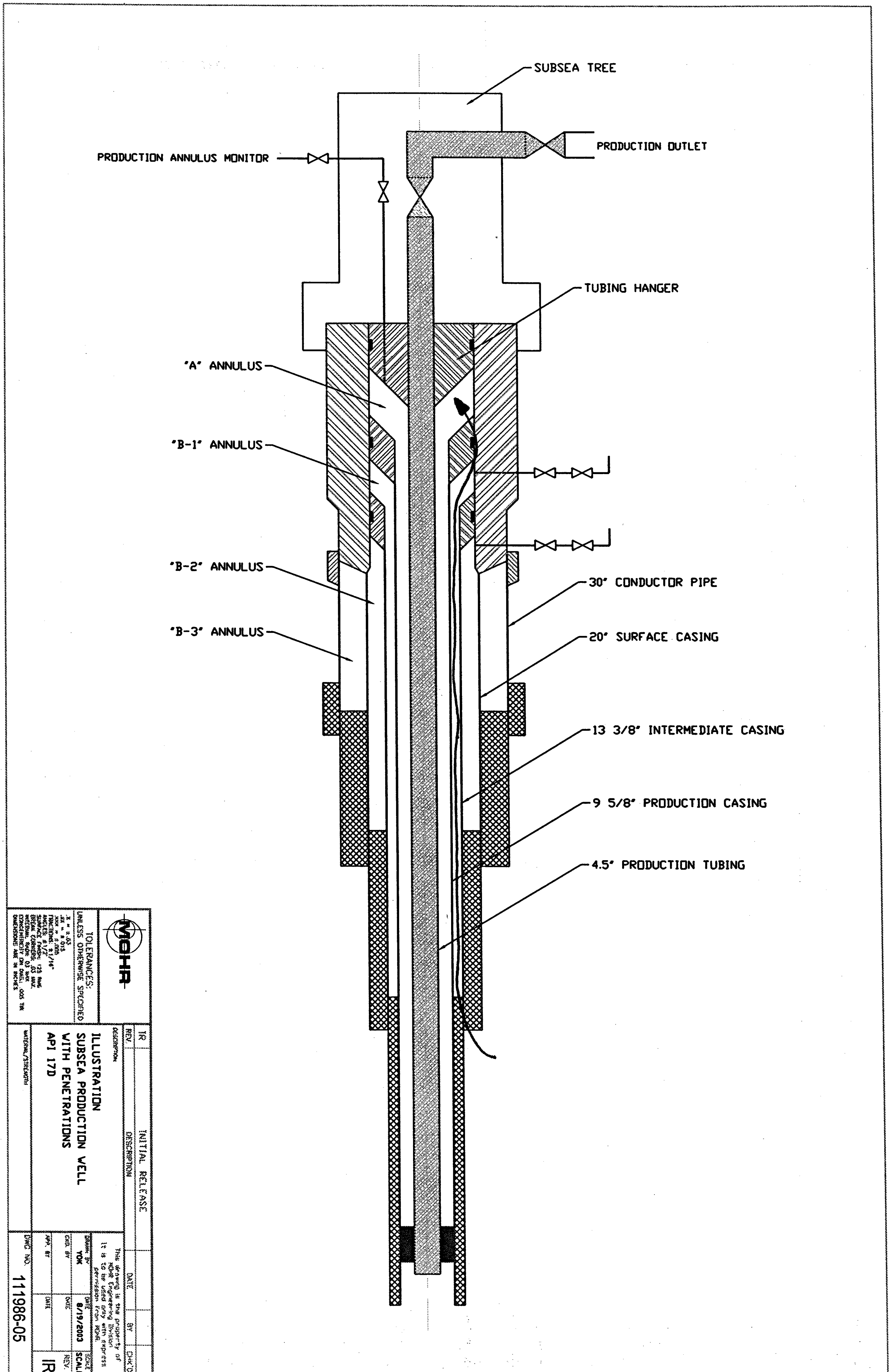
CKD. BY | DATE | REV.
APP. BY | DATE
DWG NO. 111986-05 | IR

PRESSURE MIGRATING
INWARDS FROM PROD CSG CEMENT



SUBSEA TREE
PRODUCTION ANNULUS MONITOR
PRODUCTION OUTLET
TUBING HANGER
"A" ANNULUS
"B-1" ANNULUS
"B-2" ANNULUS
"B-3" ANNULUS
30" CONDUCTOR PIPE
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MOHR
TOLERANCES:
UNLESS OTHERWISE SPECIFIED
IR
INITIAL RELEASE
REV
DESCRIPTION
DATE
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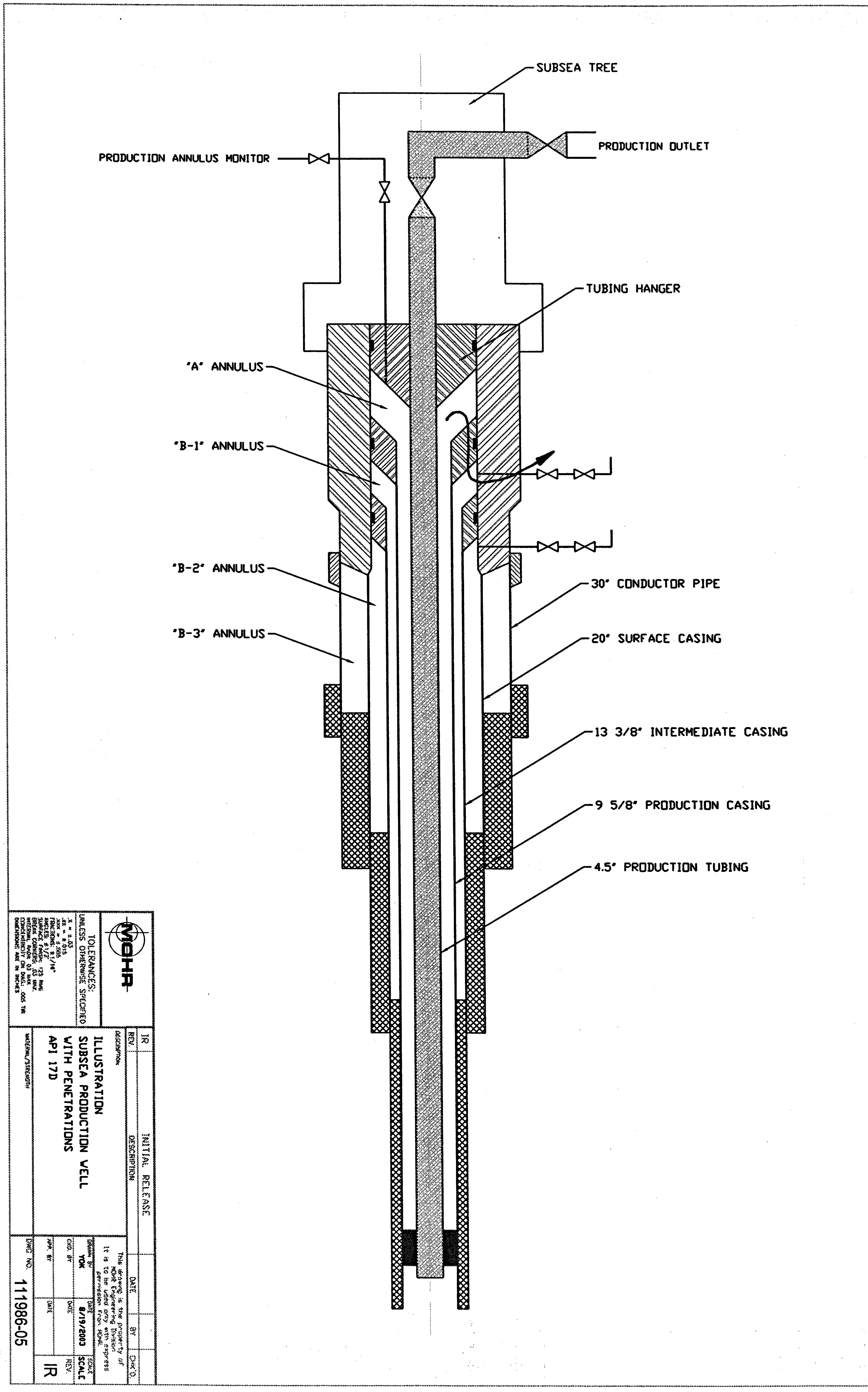
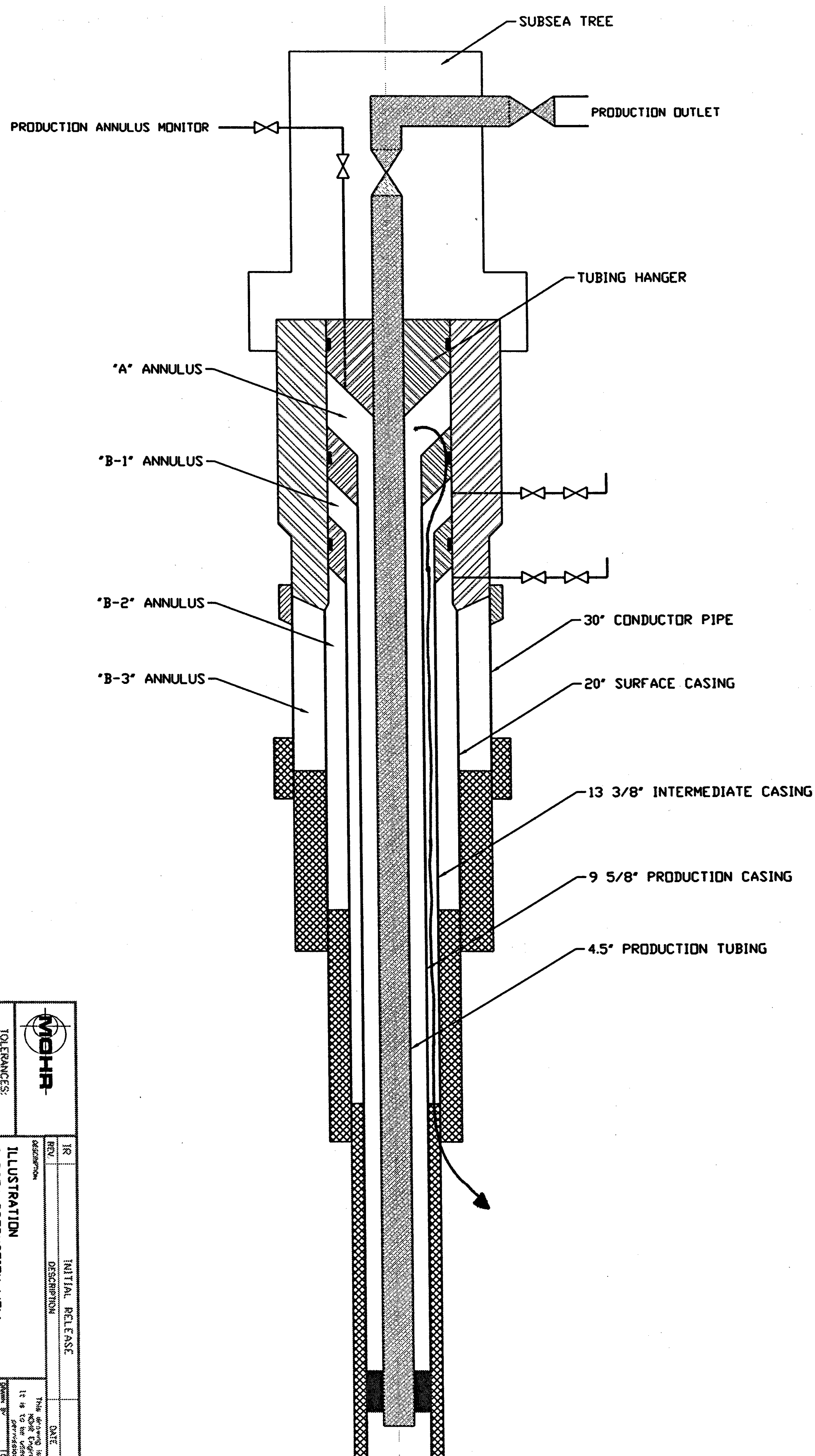
CHK'D
ILLUSTRATION
SUBSEA PRODUCTION WELL
WITH PENETRATIONS
API 17D
MATERIAL/STRENGTH
DRAWN BY
YOK
DATE
8/19/2003
SCALE
CHKD BY
APP. BY
REV.
DWG. NO.
111986-05
IR



PRESSURE MIGRATING OUTWARDS FROM "A" ANNULUS



MOHR

TOLERANCES:
UNLESS OTHERWISE SPECIFIED

REV.	DESCRIPTION	DATE	BY	CHK'D.
IR	INITIAL RELEASE			

DESCRIPTION
ILLUSTRATION
SUBSEA PRODUCTION WELL
WITH PENETRATIONS
API 17D

MATERIAL/STRENGTH

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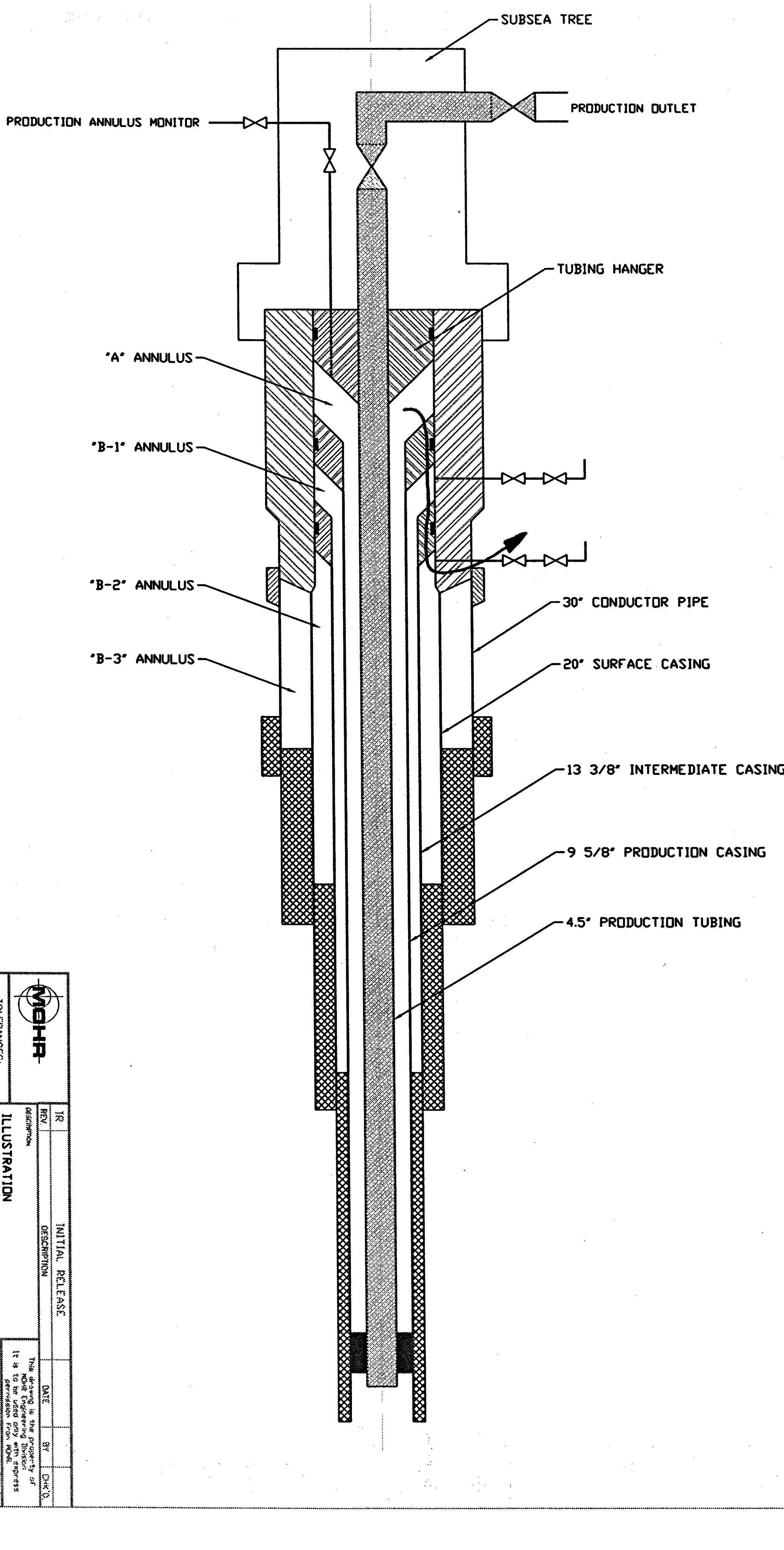
CHKD. BY:	DATE:	REV.: IR
APP. BY:	DATE:	

DWG NO. 111986-05



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TOLERANCES:
UNLESS OTHERWISE SPECIFIED

REV.	DESCRIPTION	DATE	BY	CHK'D
IR	INITIAL RELEASE			

DESCRIPTION: ILLUSTRATION SUBSEA PRODUCTION WELL WITH PENETRATIONS API 17D

MATERIAL/STRENGTH

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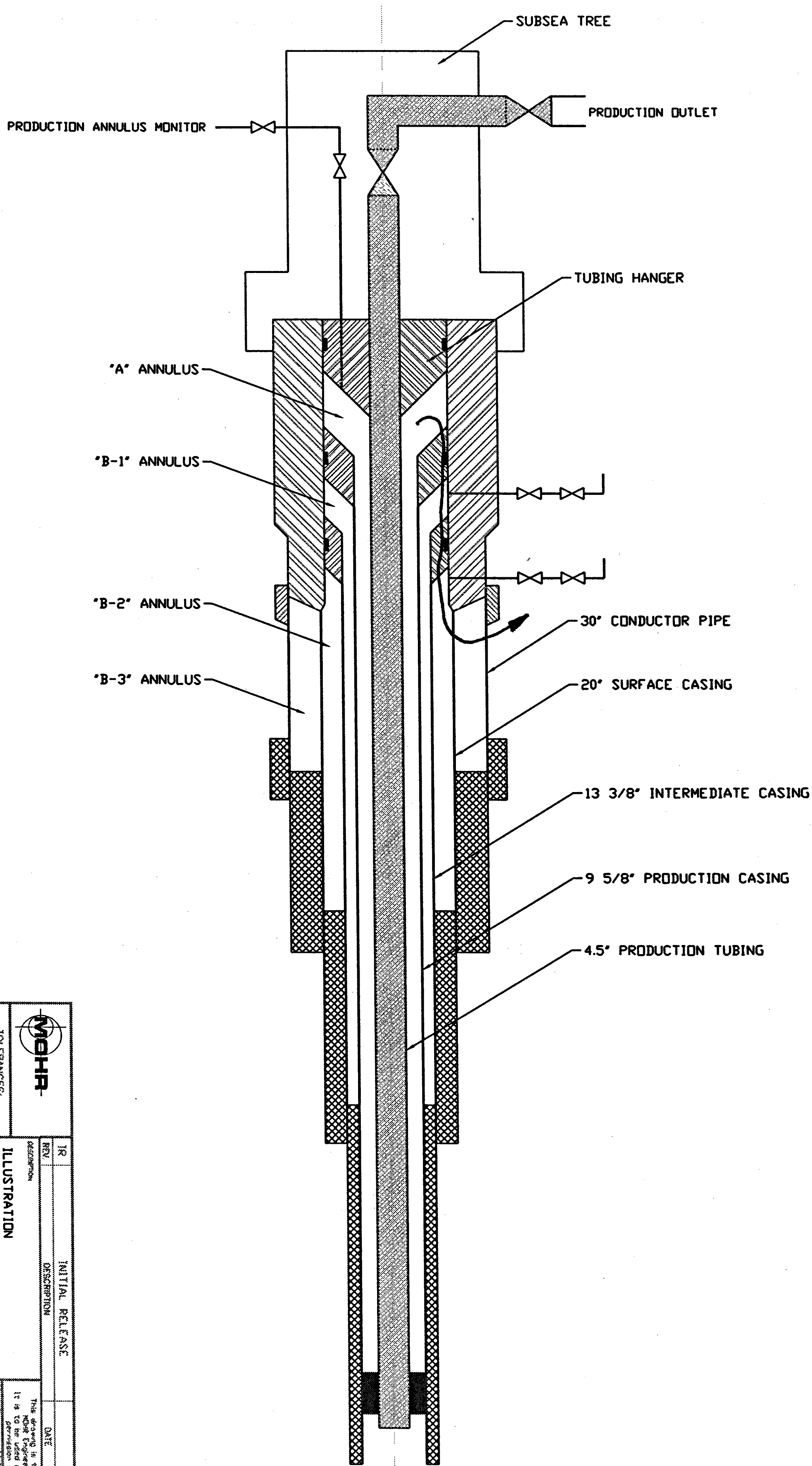
CKD BY	DATE	REV.
APP. BY	DATE	IR
DWG NO. 111986-05		



MOHR

TOLERANCES:
UNLESS OTHERWISE SPECIFIED

REV.	DESCRIPTION	DATE	BY	CHK'D.
IR	INITIAL RELEASE			

DESCRIPTION
ILLUSTRATION
SUBSEA PRODUCTION WELL
WITH PENETRATIONS
API 17D

MATERIAL/STRENGTH

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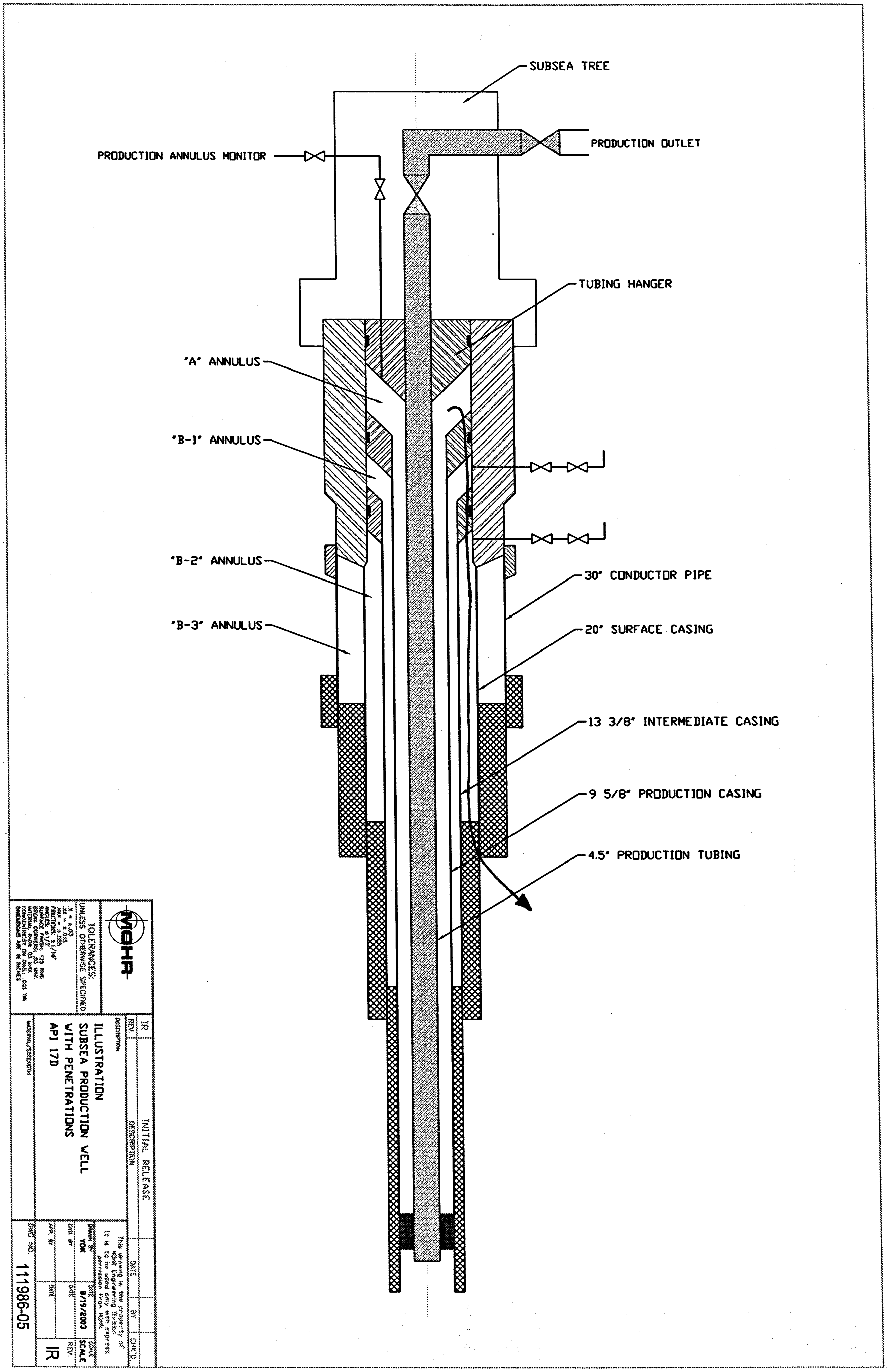
DRAWN BY: YOK | DATE: 8/19/2003 | SCALE: SCALE
CKD. BY | DATE | REV.
APP. BY | DATE | IR
DWG NO. 111986-05


SUBSEA TREE
PRODUCTION OUTLET
PRODUCTION ANNULUS MONITOR
TUBING HANGER
"A" ANNULUS
"B-1" ANNULUS
"B-2" ANNULUS
"B-3" ANNULUS
30" CONDUCTOR PIPE
20" SURFACE CASING
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TOLERANCES:
UNLESS OTHERWISE SPECIFIED
IR
INITIAL RELEASE
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DESCRIPTION
DATE
BY
CHK'D.
ILLUSTRATION
SUBSEA PRODUCTION WELL
WITH PENETRATIONS
API 17D
DRAWN BY
YOK
DATE
8/19/2003
SCALE
CKD. BY
DATE
REV.
APP. BY
DATE
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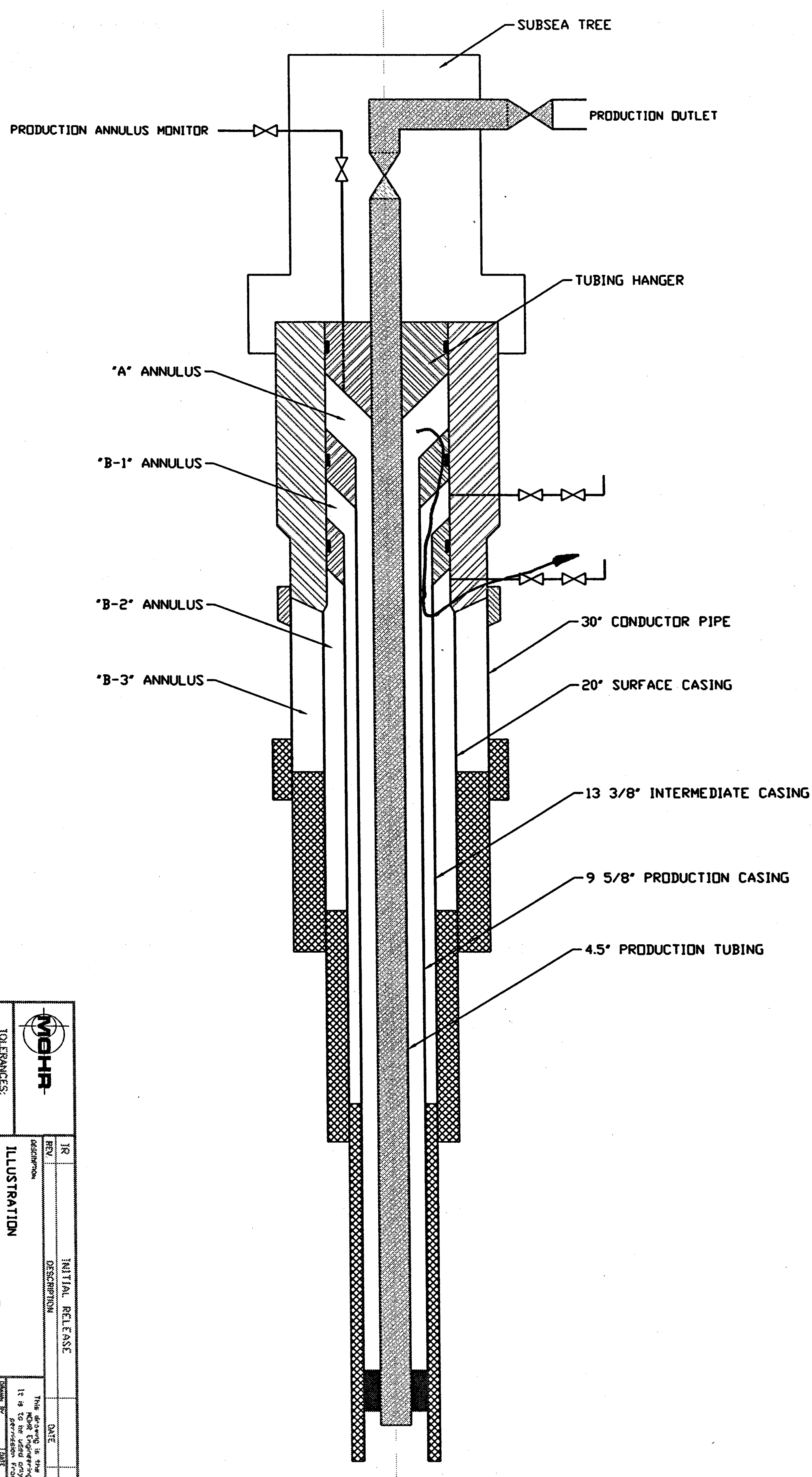
DWG NO.
111986-05



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UNLESS OTHERWISE SPECIFIED

REV.	DESCRIPTION	DATE	BY	CHK'D.
IR	INITIAL RELEASE			

DESCRIPTION

ILLUSTRATION
SUBSEA PRODUCTION WELL
WITH PENETRATIONS
API 17D

MATERIAL/STRENGTH

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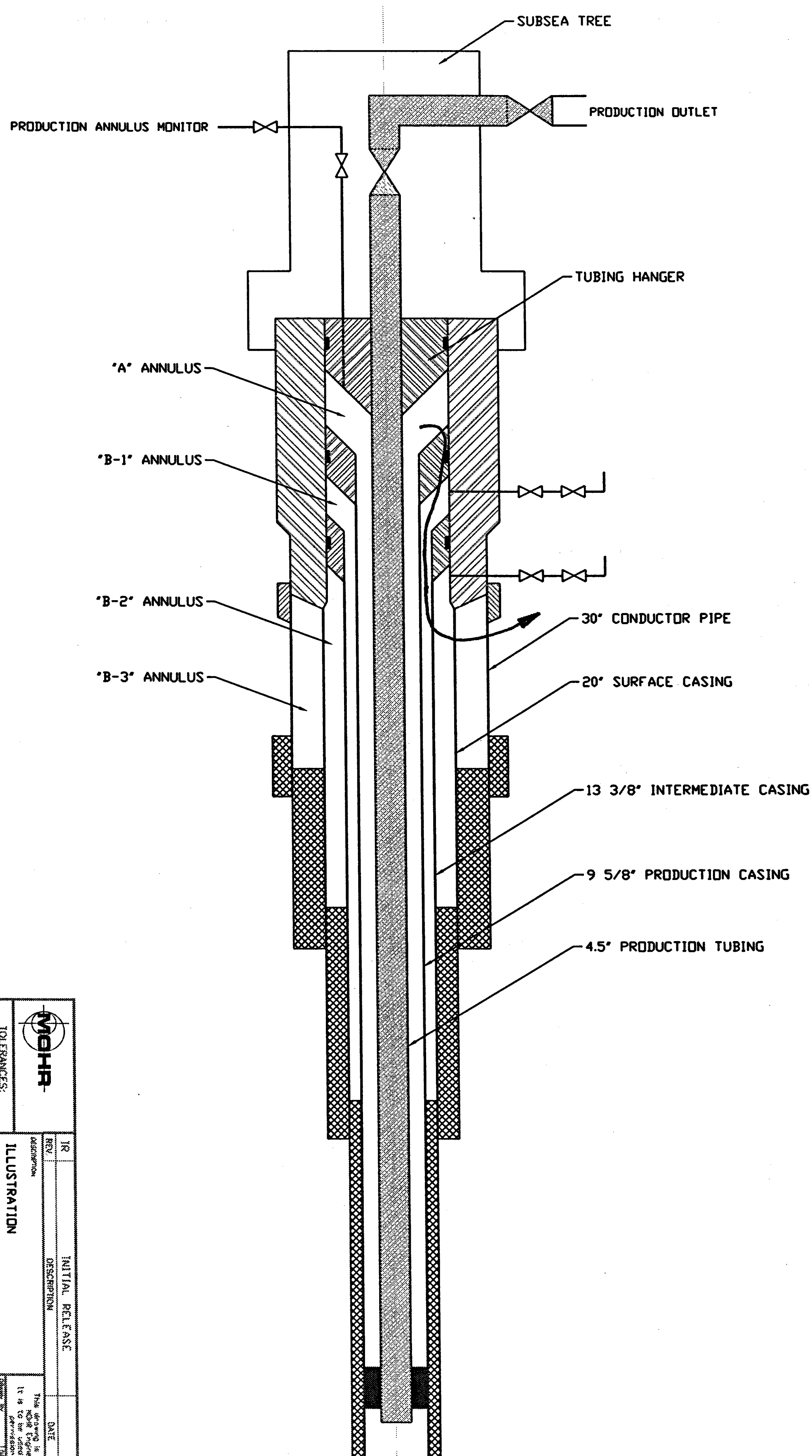
DRAWN BY: YOK | DATE: 8/19/2003 | SCALE: SCALE
CHK'D. BY: | DATE: | REV.
APP. BY: | DATE: | IR

DWG NO. 111986-05



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TOLERANCES: UNLESS OTHERWISE SPECIFIED

REV	DESCRIPTION	DATE	BY	CHK'D
IR	INITIAL RELEASE			

DESCRIPTION: ILLUSTRATION SUBSEA PRODUCTION WELL WITH PENETRATIONS API 17D

MATERIAL/STRENGTH

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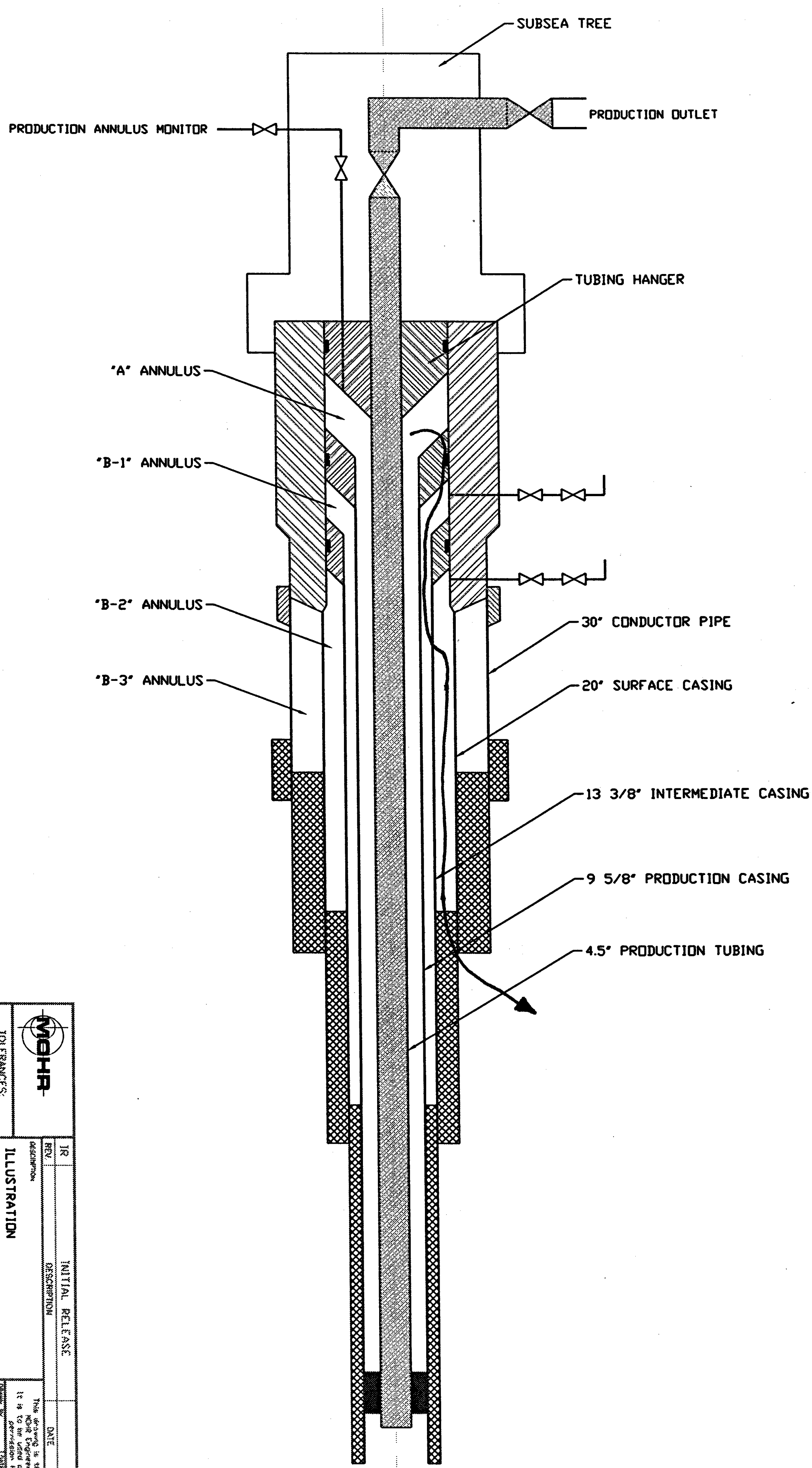
DRAWN BY: YOK DATE: 8/19/2003 SCALE

CKD. BY

APP. BY DATE REV. IR

DWG NO. 111986-05



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TOLERANCES:
UNLESS OTHERWISE SPECIFIED

REV.	DESCRIPTION	DATE	BY	CHK'D.
IR	INITIAL RELEASE			

DESCRIPTION

ILLUSTRATION
SUBSEA PRODUCTION WELL
WITH PENETRATIONS
API 17D

MATERIAL/STRENGTH

DRAWN BY: YOK
DATE: 8/19/2003
SCALE: SCALE
CKD. BY
APP. BY
REV. IR
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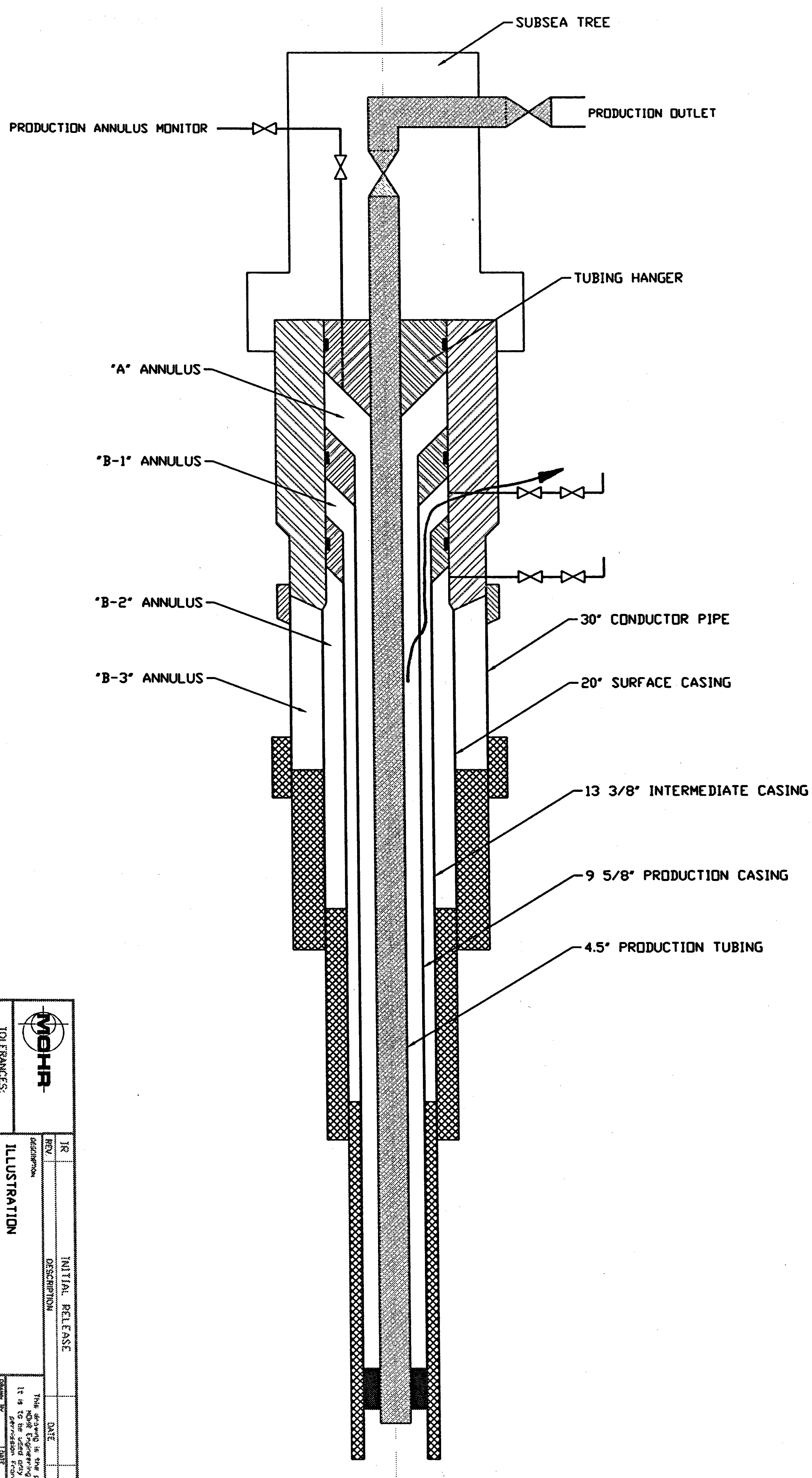

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REV	DESCRIPTION	DATE	BY	CHK'D
IR	INITIAL RELEASE			

DESCRIPTION
ILLUSTRATION
SUBSEA PRODUCTION WELL
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API 17D

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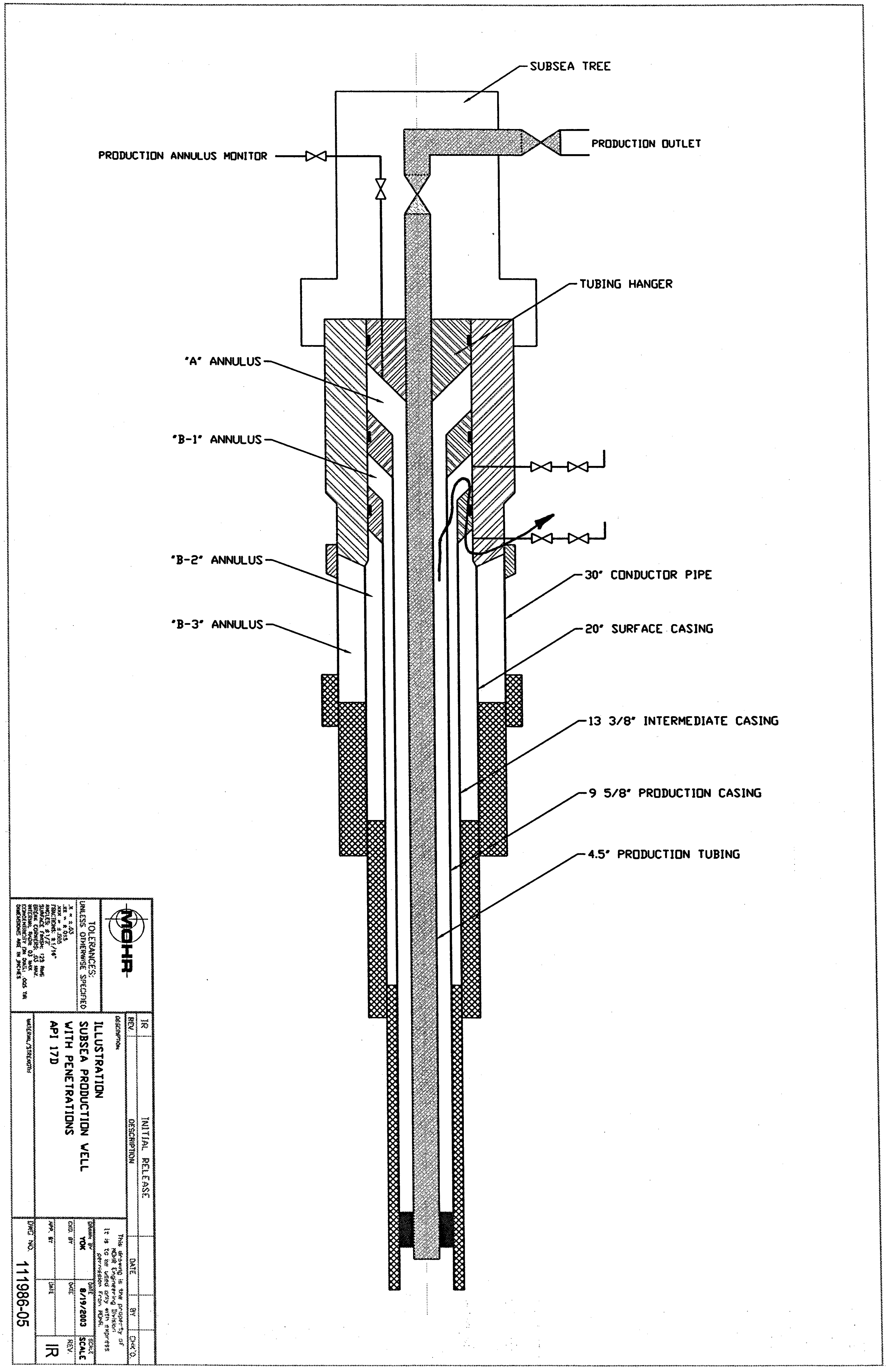
DATE
REV. IR
DWG NO. 111986-05



SUBSEA TREE
PRODUCTION OUTLET
PRODUCTION ANNULUS MONITOR
TUBING HANGER
"A" ANNULUS
"B-1" ANNULUS
"B-2" ANNULUS
"B-3" ANNULUS
30" CONDUCTOR PIPE
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MOHR
TOLERANCES:
UNLESS OTHERWISE SPECIFIED
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INITIAL RELEASE
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DESCRIPTION
DATE
BY
CHK'D
ILLUSTRATION
SUBSEA PRODUCTION WELL
WITH PENETRATIONS
API 17D
MATERIAL/STRENGTH
DRAWN BY
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DATE
8/19/2003
SCALE
CKD. BY
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APP. BY
DATE
REV.
DWG NO.
111986-05
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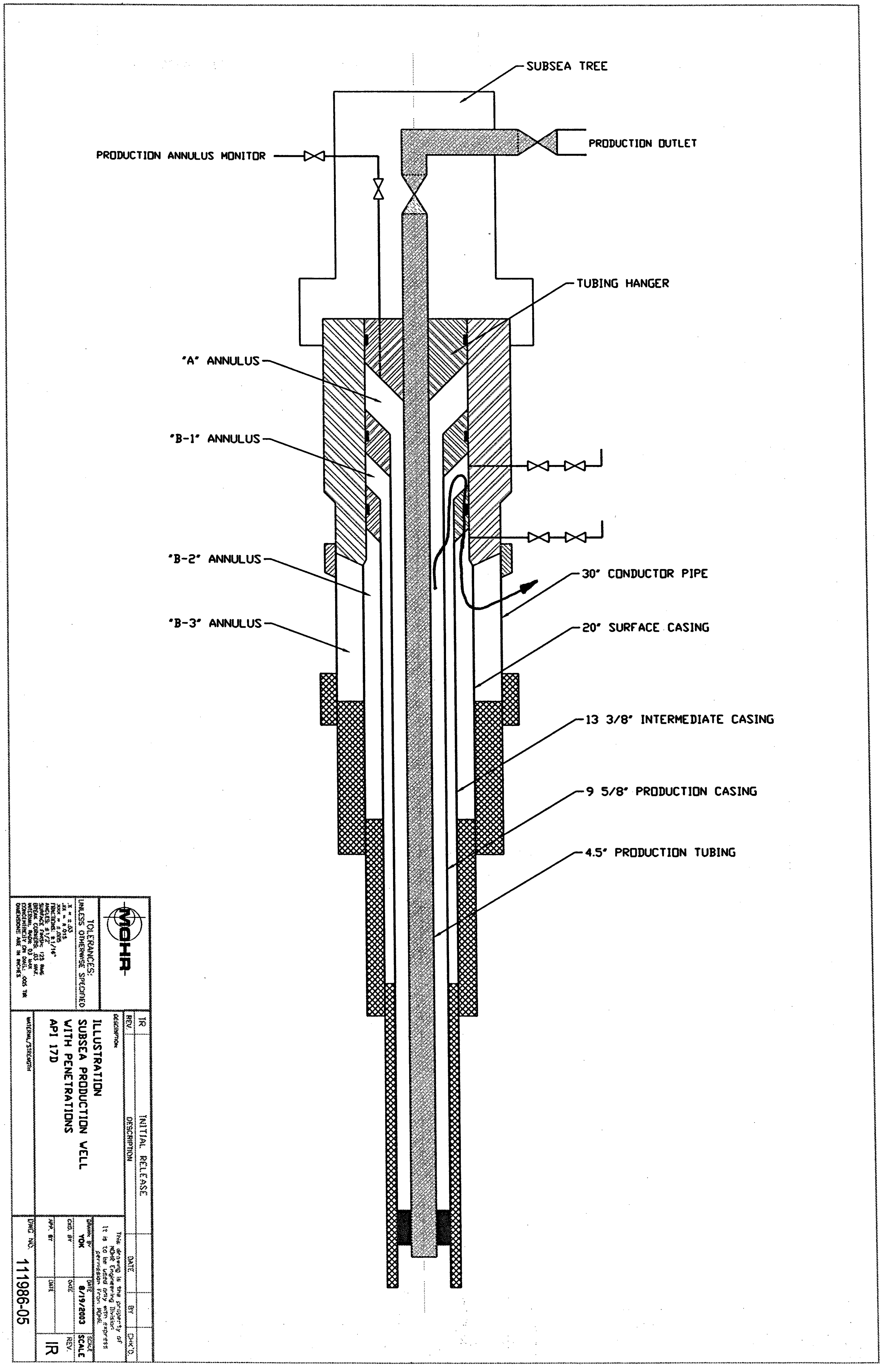

SUBSEA TREE
PRODUCTION OUTLET
PRODUCTION ANNULUS MONITOR
TUBING HANGER
"A" ANNULUS
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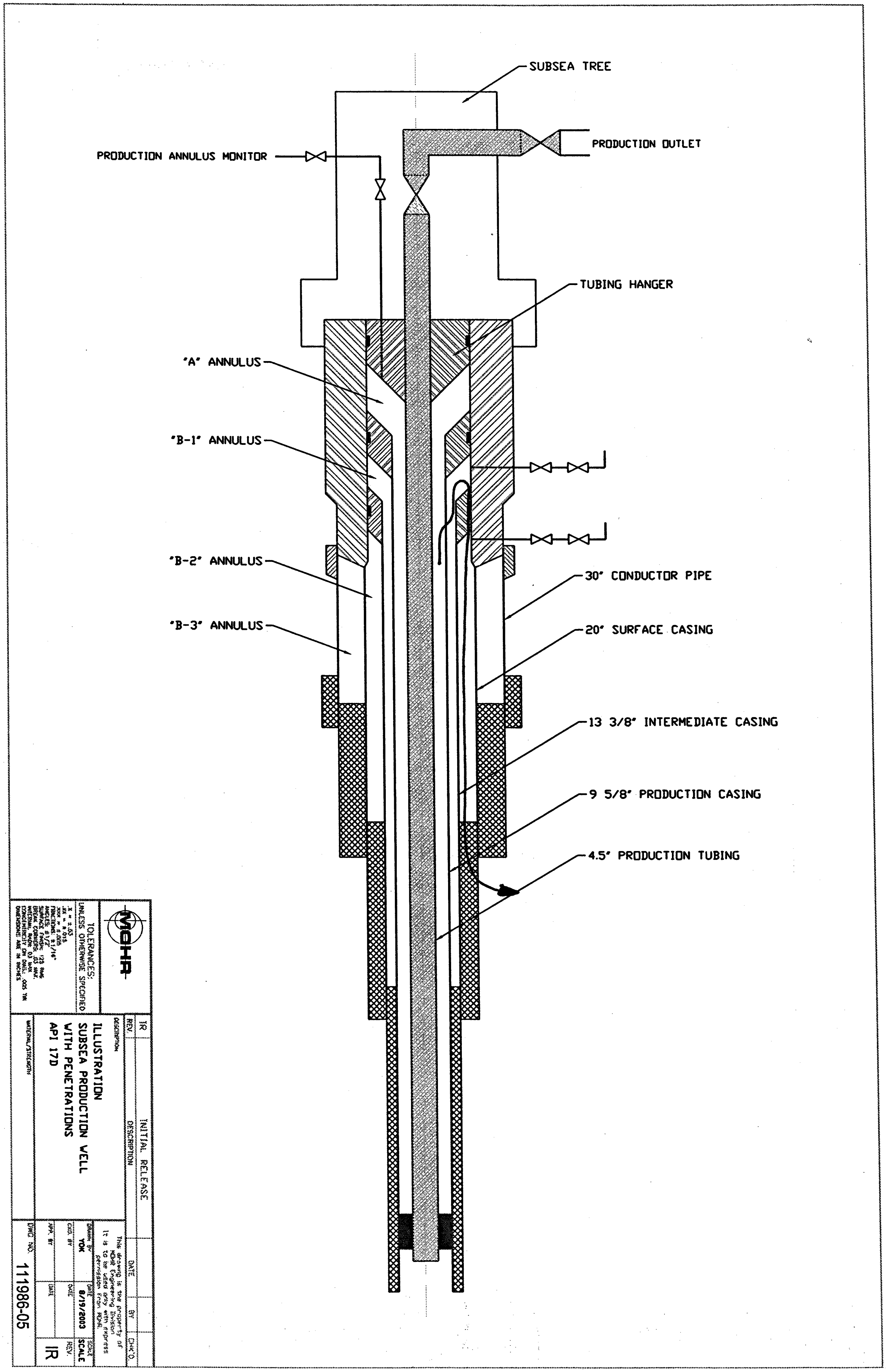
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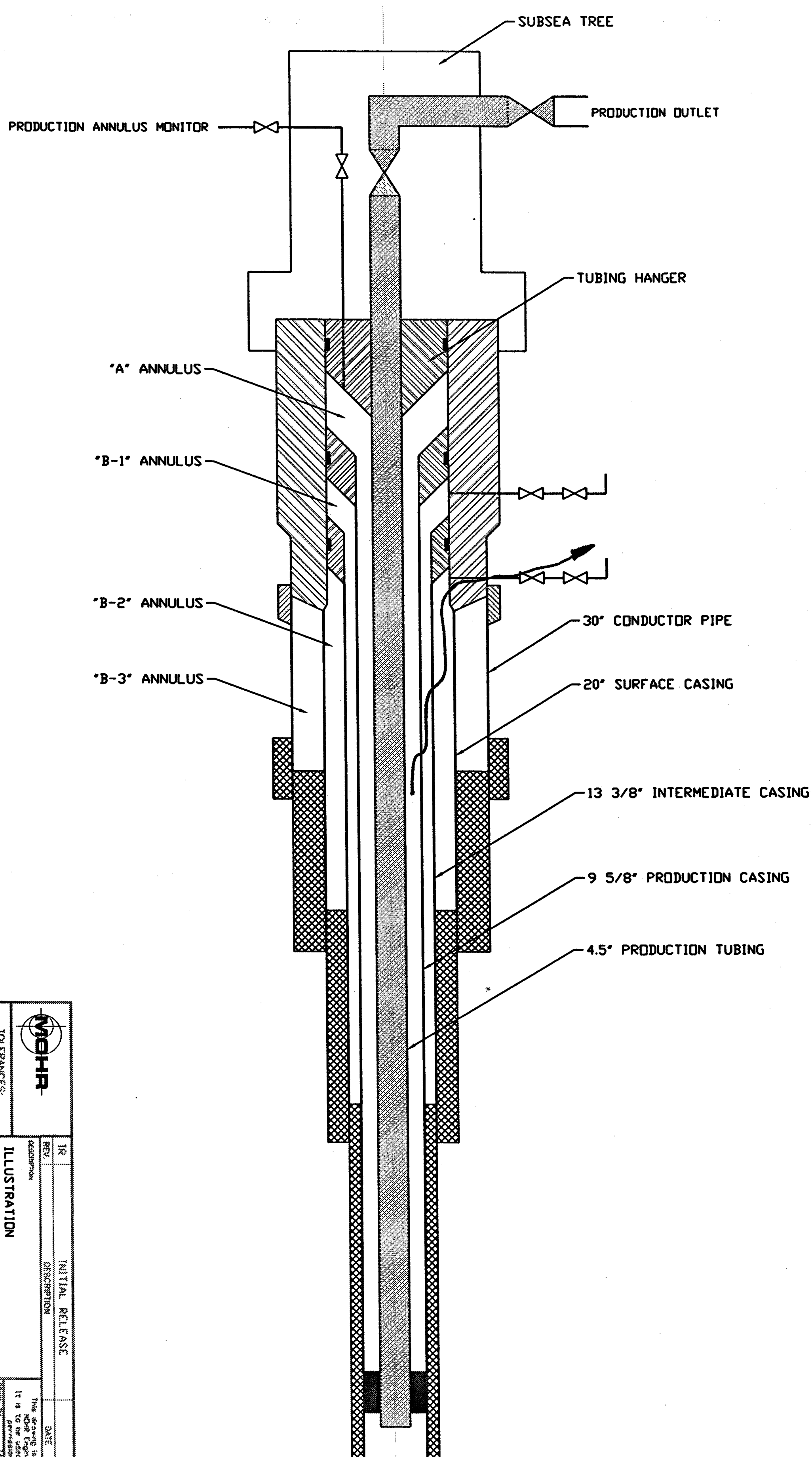

MOHR

TOLERANCES: UNLESS OTHERWISE SPECIFIED

REV	DESCRIPTION	DATE	BY	CHK'D
IR	INITIAL RELEASE			

DESCRIPTION
ILLUSTRATION
SUBSEA PRODUCTION WELL
WITH PENETRATIONS
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MATERIAL/STRENGTH

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DATE: 8/19/2003
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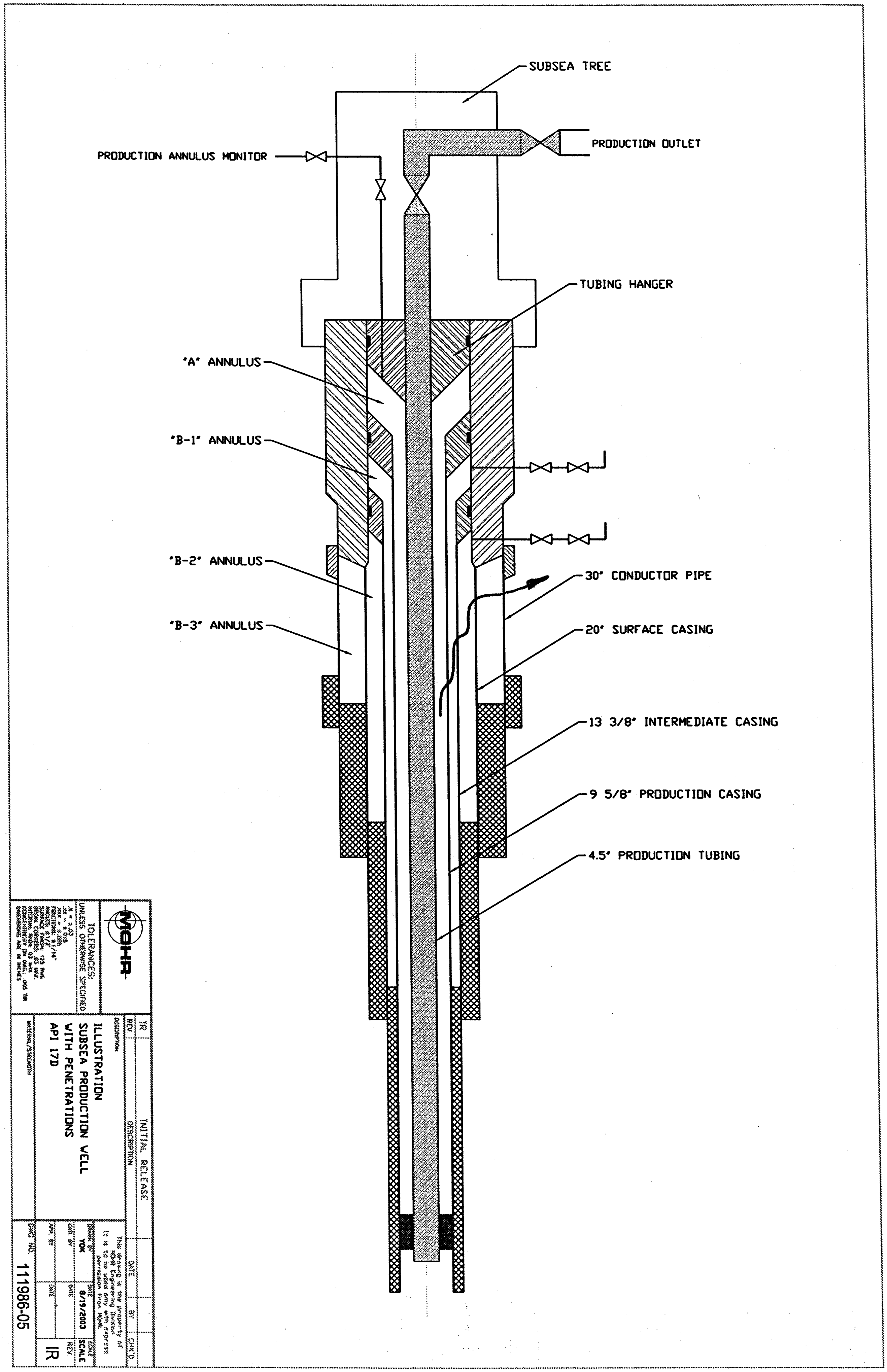
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API 17D
MATERIAL/STRENGTH
DRAWN BY
YDK
DATE
8/19/2003
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CKD. BY
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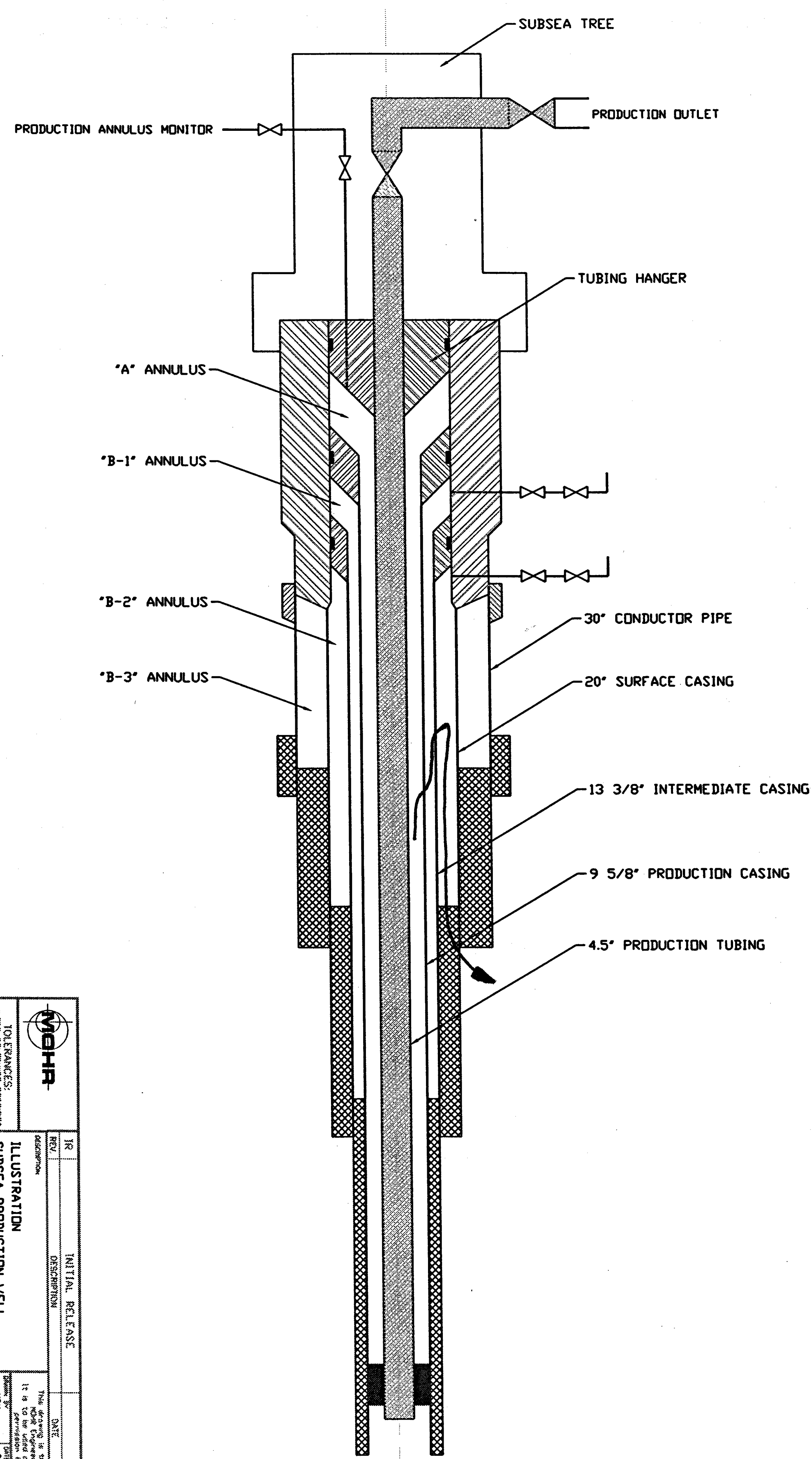

MOHR

TOLERANCES:
UNLESS OTHERWISE SPECIFIED

REV.	DESCRIPTION	DATE	BY	CHK'D
IR	INITIAL RELEASE			

DESCRIPTION
ILLUSTRATION
SUBSEA PRODUCTION WELL
WITH PENETRATIONS
API 17D

MATERIAL/STRENGTH

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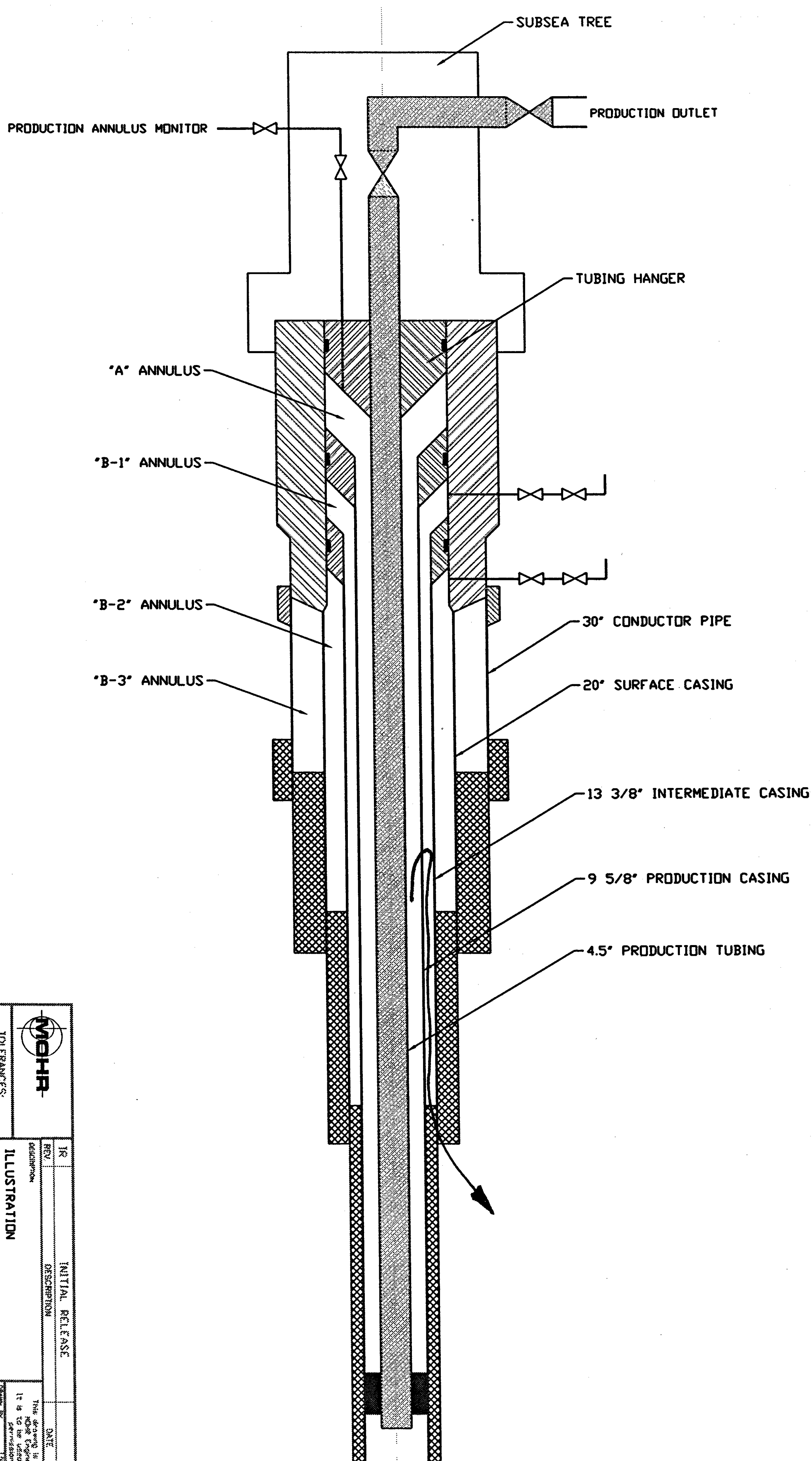
DRAWN BY: YOK | DATE: 8/19/2003 | SCALE: SCALE
CKD. BY | DATE | REV.
APP. BY | DATE | IR

DWG. NO. 111986-05



MOHR

TOLERANCES:
UNLESS OTHERWISE SPECIFIED

REV.	DESCRIPTION	DATE	BY	CHK'D.
IR	INITIAL RELEASE			

DESCRIPTION: ILLUSTRATION
SUBSEA PRODUCTION WELL
WITH PENETRATIONS
API 17D

MATERIAL/STRENGTH

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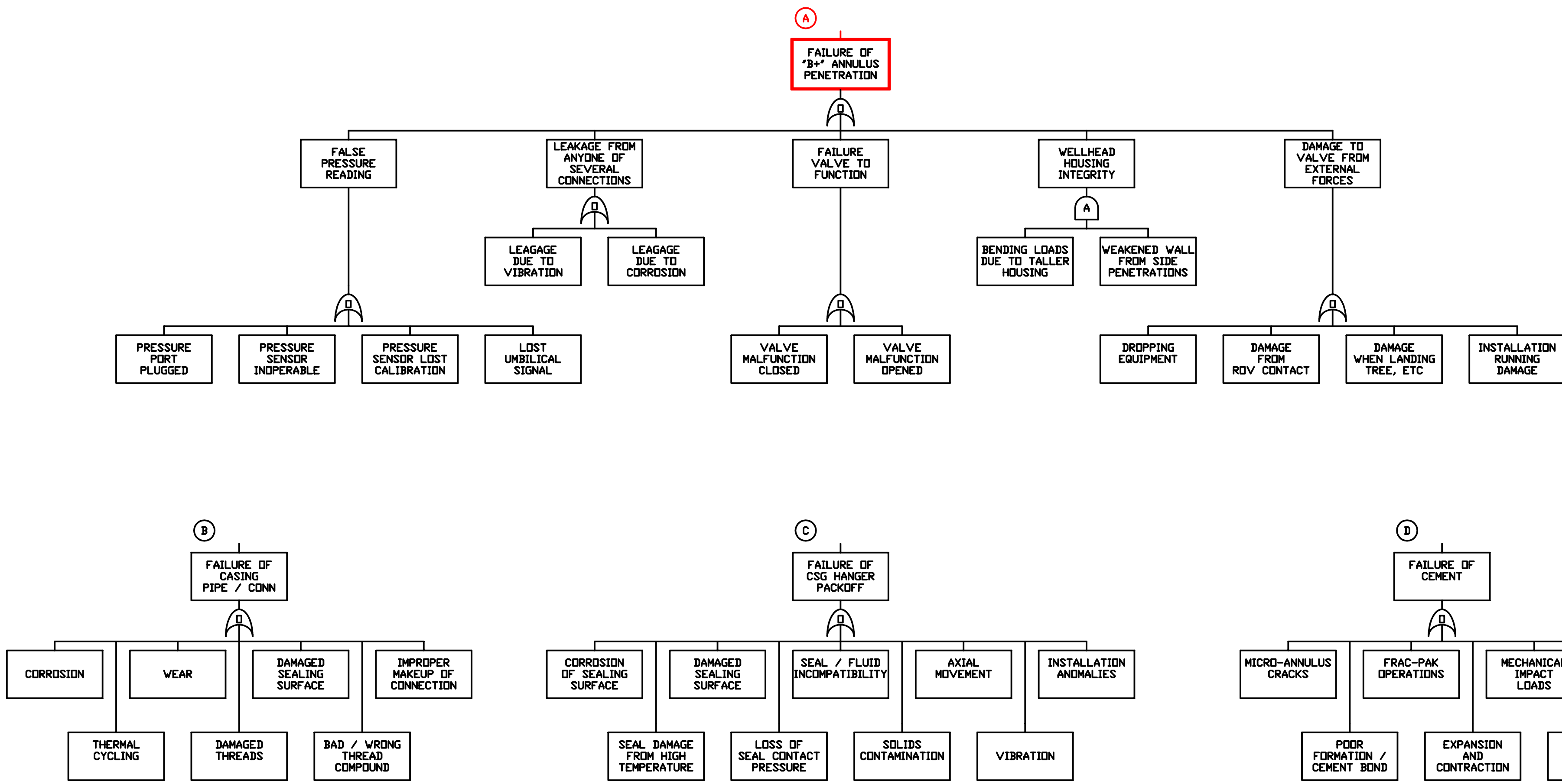
CKD. BY — DATE — REV.: IR
APP. BY — DATE

DWG NO. 111986-05

12.2 Appendix B – Fault Tree Details for No Penetrations



REV.	DESCRIPTION	DATE	BY	CHK'D.
A	UPDATE FROM COMMITTEE MEETING	8/28/2003	YOK	
IR	INITIAL RELEASE			

MOHR

TOLERANCES:
UNLESS OTHERWISE SPECIFIED
.X = ±.03
.XX = ±.015
.XXX = ±.005
FRACTIONS: ±1/16"
ANGLES: ±1/2°
SURFACE FINISH: 125 RMS
BREAK CORNERS: .03 MAX.
INTERNAL RADII: .03 MAX.
CONCENTRICITY ON DIAS.: .005 TIR
DIMENSIONS ARE IN INCHES

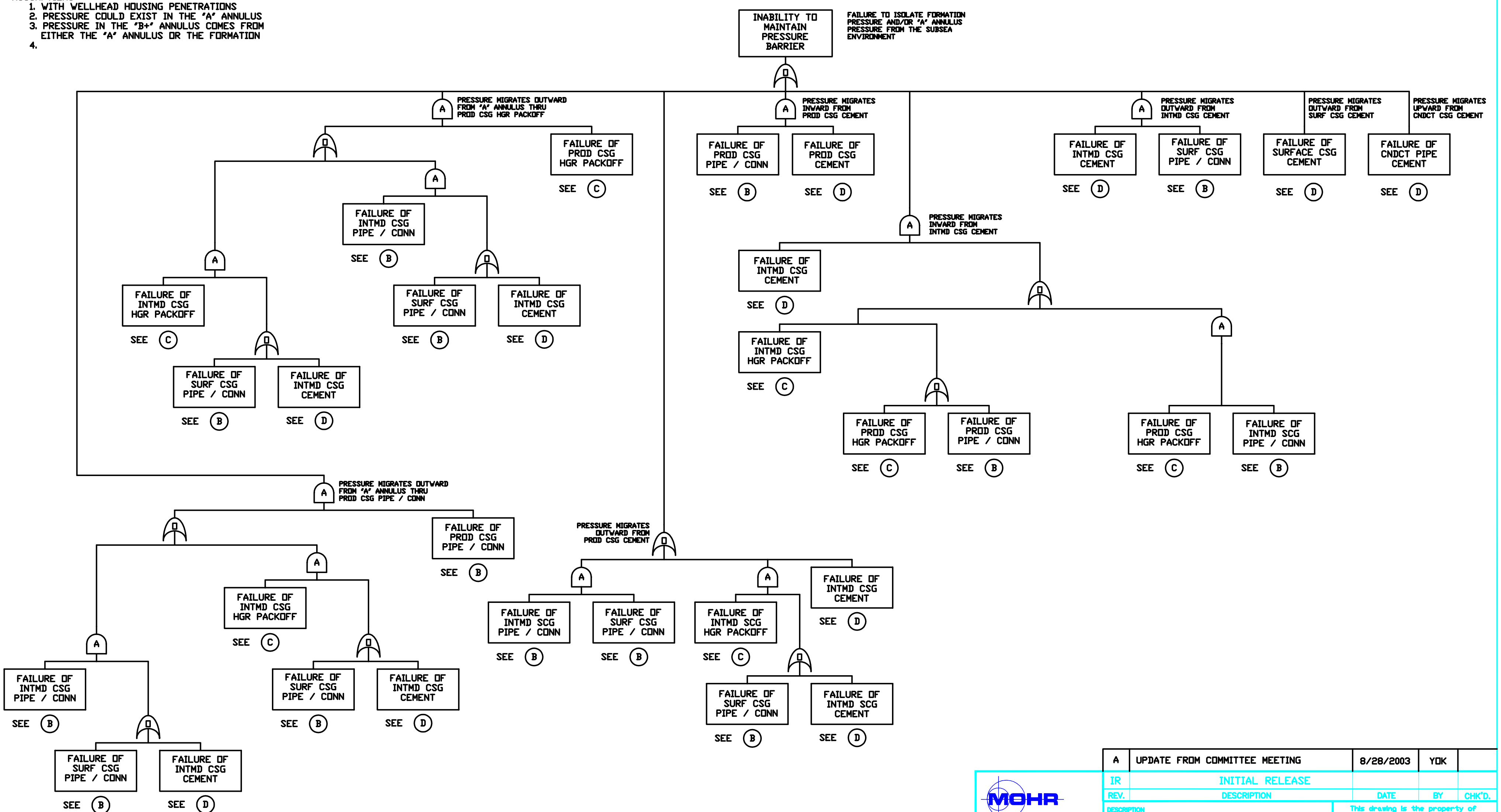
DESCRIPTION
FAULT TREE ANALYSIS
SUSTAINED CASING PRESSURE
SUBSET ANALYSIS
API 17D

MATERIAL/STRENGTH

DRAWN BY: YOK	DATE: 8/25/03	SCALE: SCALE
CKD. BY	DATE	REV.
APP. BY: K. YOUNG	DATE: 8/26/2003	IR

DWG NO. 111986-11

ASSUMPTIONS:
1. WITH WELLHEAD HOUSING PENETRATIONS
2. PRESSURE COULD EXIST IN THE "A" ANNULUS
3. PRESSURE IN THE "B+" ANNULUS COMES FROM EITHER THE "A" ANNULUS OR THE FORMATION
4.



A	UPDATE FROM COMMITTEE MEETING	8/28/2003	YOK	
IR	INITIAL RELEASE			
REV.	DESCRIPTION	DATE	BY	CHK'D.

MOHR

TOLERANCES:
UNLESS OTHERWISE SPECIFIED
.X = ±.03
.XX = ±.015
.XXX = ±.005
FRACTIONS: ±1/16"
ANGLES: ±1/2°
SURFACE FINISH: 125 RMS
BREAK CORNERS: .03 MAX.
INTERNAL RADII: .03 MAX.
CONCENTRICITY ON DIAS.: .005 TIR
DIMENSIONS ARE IN INCHES

DESCRIPTION
FAULT TREE ANALYSIS
SUSTAINED CASING PRESSURE
WITHOUT PENETRATIONS
API 17D

MATERIAL/STRENGTH

DRAWN BY	DATE	SCALE
YOK	8/25/03	SCALE
CKD. BY	DATE	REV.
APP. BY K. YOUNG	DATE 8/27/2003	IR

DWG NO. 111986-10

Fault Tree without Penetrations	
Failure Occurrence	**Failure Mode**
10.12%	**Inability to Maintain a Pressure Barrier**
0.0003	Pressure migrates outward from "A" annulus through the production casing pipe / connections
0.0269	Failure of production casing pipe / connection
0.0109	Failure of secondary barrier
0.0049	Failure of intmd casing flow path
0.0395	Failure of intermediate casing pipe / connections
0.1229	Failure of secondary barrier
0.0599	Failure of surface casing pipe / connections
0.0670	Failure of intermediate casing cement
0.0060	Failure of intmd csg hgr packoff flow path
0.0491	Failure of intermediate casing hanger packoff
0.1229	Failure of secondary barrier
0.0599	Failure of surface casing pipe / connections
0.0670	Failure of intermediate casing cement
0.0005	Pressure migrates outward from "A" annulus thru production casing hanger packoff
0.0491	Failure of production casing hanger packoff
0.0109	Failure of secondary barrier
0.0060	Failure of intmd csg hgr packoff flow path
0.0491	Failure of intermediate casing hanger packoff
0.1229	Failure of secondary barrier
0.0599	Failure of surface casing pipe / connections
0.0670	Failure of intermediate casing cement
0.0049	Failure of intmd casing flow path
0.0395	Failure of intermediate casing pipe / connection
0.1229	Failure of secondary barrier
0.0599	Failure of surface casing pipe / connections
0.0670	Failure of intermediate casing cement

Fault Tree without Penetrations	
Failure Occurrence	**Failure Mode**
0.0734	Pressure migrates outward from production casing cement
0.0670	Failure of intermediate casing cement
0.0045	Failure of intmd csg hgr packoff flow path
0.0491	Failure of intermediate casing hanger packoff
0.0921	Failure of secondary barrier
0.0269	Failure of surface casing pipe / connections
0.0670	Failure of intermediate casing cement
0.0024	Failure of third flow path
0.0395	Failure of intermediate casing pipe / connections
0.0599	Failure of surface casing pipe / connections
0.0016	Pressure migrates inward from production casing cement
0.0598	Failure of production casing cement
0.0269	Failure of production casing pipe / connections
0.0117	Failure of surface casing cement
0.0117	Failure of conductor pipe cement
0.0004	Pressure migrates inward from intermediate casing cement
0.0670	Failure of intermediate casing cement
0.0037	Failure of second flow path
0.0491	Failure of intermediate casing hanger packoff
0.0747	Failure of secondary flow path
0.0491	Failure of production casing hanger packoff
0.0269	Failure of production casing pipe / connections
0.0019	Failure of third flow path
0.0395	Failure of intermediate casing pipe / connections
0.0491	Failure of production casing hanger packoff
0.0040	Pressure migrates outward from intermediate casing cement
0.0670	Failure of intermediate casing cement
0.0599	Failure of surface casing pipe / connections

12.3 Appendix C – Fault Tree Details with One Penetration

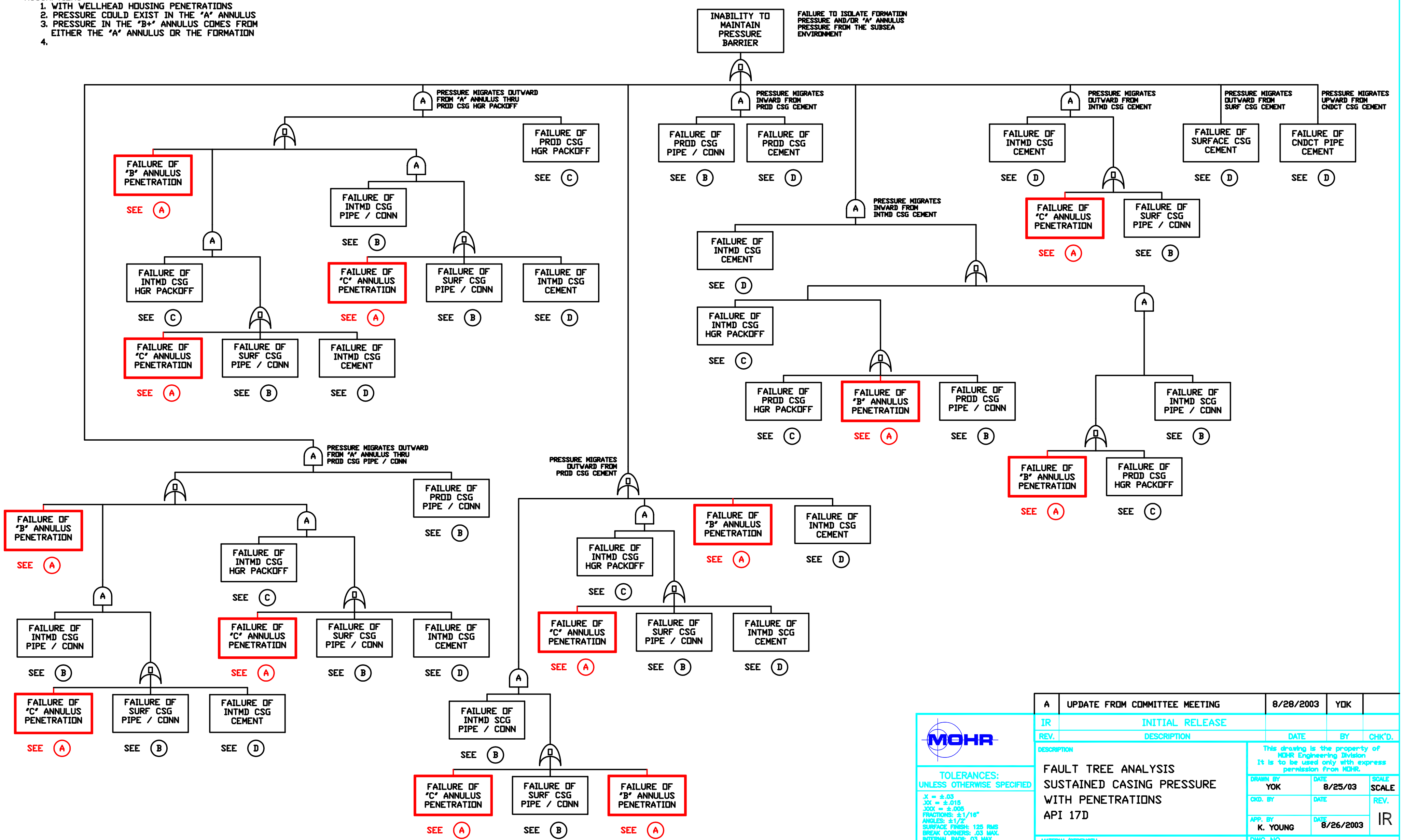
Fault Tree with One Penetration	
with 2" penetration / valves	
Failure Occurrence	**Failure Mode**
25.30%	**Inability to maintain Pressure Barrier**
0.0044	Pressure migrates outward from "A" annulus thru production casing pipe / connections
0.0269	Failure of production casing pipe / connection
0.1653	Failure of secondary barrier
0.1562	Failure of "B" annulus penetration
0.0049	Failure of second flow path
0.0395	Failure of intermediate casing pipe / connections
0.1229	Failure of secondary barrier
0.0599	Failure of surface casing pipe / connections
0.0670	Failure of intermediate casing cement
0.0060	Failure of third flow path
0.0491	Failure of intermediate casing hanger packoff
0.1229	Failure of secondary barrier
0.0599	Failure of surface casing pipe / connections
0.0670	Failure of intermediate casing cement
0.0081	Pressure migrates outward from "A" annulus thru production casing hanger packoff
0.0491	Failure of production casing hanger packoff
0.1653	Failure of secondary barrier
0.1562	Failure of "B" annulus penetration
0.0060	Failure of second flow path
0.0491	Failure of intermediate casing hanger packoff
0.1229	Failure of secondary barrier
0.0599	Failure of surface casing pipe / connections
0.0670	Failure of intermediate casing cement
0.0049	Failure of third flow path
0.0395	Failure of intermediate casing pipe / connection
0.1229	Failure of secondary barrier
0.0599	Failure of surface casing pipe / connections
0.0670	Failure of intermediate casing cement

Fault Tree with One Penetration	
with 2" penetration / valves	
Failure Occurrence	**Failure Mode**
0.2201	Pressure migrates outward from production casing cement
0.0670	Failure of intermediate casing cement
0.1562	Failure of "B" annulus penetration
0.0033	Failure of second flow path
0.0491	Failure of intermediate casing hanger packoff
0.0670	Failure of secondary barrier
0.0599	Failure of surface casing pipe / connections
0.0670	Failure of intermediate casing cement
0.0062	Failure of third flow path
0.0395	Failure of intermediate casing pipe / connections
0.1562	Failure of secondary barrier
0.0599	Failure of surface casing pipe / connections
0.1562	Failure of "B" annulus penetration
0.0016	Pressure migrates inward from production casing cement
0.0598	Failure of production casing cement
0.0269	Failure of production casing pipe / connections
0.0117	Failure of surface casing cement
0.0117	Failure of conductor pipe cement

Fault Tree with One Penetration	
with 2" penetration / valves	
Failure Occurrence	**Failure Mode**
0.0012	Pressure migrates inward from intermediate casing cement
0.0670	Failure of intermediate casing cement
0.0108	Failure of second flow path
0.0491	Failure of intermediate casing hanger packoff
0.2192	Failure of secondary barrier
0.1562	Failure of "B" annulus penetration
0.0491	Failure of production casing hanger packoff
0.0269	Failure of production casing pipe / connections
0.0078	Failure of third flow path
0.0395	Failure of intermediate casing pipe / connections
0.1976	Failure of secondary barrier
0.1562	Failure of "B" annulus penetration
0.0491	Failure of production casing hanger packoff
0.0040	Pressure migrates outward from intermediate casing cement
0.0670	Failure of intermediate casing cement
0.0599	Failure of surface casing pipe / connections

12.4 Appendix D – Fault Tree Details with Two Penetrations

ASSUMPTIONS:
1. WITH WELLHEAD HOUSING PENETRATIONS
2. PRESSURE COULD EXIST IN THE 'A' ANNULUS
3. PRESSURE IN THE 'B+' ANNULUS COMES FROM EITHER THE 'A' ANNULUS OR THE FORMATION
4.



A	UPDATE FROM COMMITTEE MEETING	8/28/2003	YOK	
IR	INITIAL RELEASE			
REV.	DESCRIPTION	DATE	BY	CHK'D.

MOHR

TOLERANCES: UNLESS OTHERWISE SPECIFIED
.X = ±.03
.XX = ±.015
.XXX = ±.005
FRACTIONS: ±1/16"
ANGLES: ±1/2°
SURFACE FINISH: 125 RMS
BREAK CORNERS: .03 MAX.
INTERNAL RADII: .03 MAX.
CONCENTRICITY ON DIAS.: .005 TIR
DIMENSIONS ARE IN INCHES

DESCRIPTION
FAULT TREE ANALYSIS
SUSTAINED CASING PRESSURE
WITH PENETRATIONS
API 17D

MATERIAL/STRENGTH

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DRAWN BY: YOK
DATE: 8/25/03
SCALE
CKD. BY
DATE
REV.: IR
APP. BY: K. YOUNG
DATE: 8/26/2003
DWG NO. 111986-09

Fault Tree with Two Penetrations	
with 2" penetration / valves	
Failure Occurrence	**Failure Mode**
27.26%	**Inability to maintain Pressure Barrier**
0.0047	Pressure migrates outward from "A" annulus thru production casing pipe / connections
0.0269	Failure of production casing pipe / connection
0.1751	Failure of second barrier
0.1562	Failure of "B" annulus penetration
0.0101	Failure of second flow path
0.0395	Failure of intermediate casing pipe / connections
0.2554	Failure of second barrier
0.1511	Failure of "C" annulus penetration
0.0599	Failure of surface casing pipe / connections
0.0670	Failure of intermediate casing cement
0.0125	Failure of third flow path
0.0491	Failure of intermediate casing hanger packoff
0.2554	Failure of second barrier
0.1511	Failure of "C" annulus penetration
0.0599	Failure of surface casing pipe / connections
0.0670	Failure of intermediate casing cement
0.0086	Pressure migrates outward from "A" annulus thru production casing hanger packoff
0.0491	Failure of production casing hanger packoff
0.1751	Failure of second barrier
0.1562	Failure of "B" annulus penetration
0.0125	Failure of second flow path
0.0491	Failure of intermediate casing hanger packoff
0.2554	Failure of second barrier
0.1511	Failure of "C" annulus penetration
0.0599	Failure of surface casing pipe / connections
0.0670	Failure of intermediate casing cement
0.0101	Failure of third flow path
0.0395	Failure of intermediate casing pipe / connection
0.2554	Failure of second barrier
0.1511	Failure of "C" annulus penetration
0.0599	Failure of surface casing pipe / connections
0.0670	Failure of intermediate casing cement

Fault Tree with Two Penetrations	
with 2" penetration / valves	
Failure Occurrence	**Failure Mode**
0.2326	Pressure migrates outward from production casing cement
0.0670	Failure of intermediate casing cement
0.1562	Failure of "B" annulus penetration
0.0125	Failure of second flow path
0.0491	Failure of intermediate casing hanger packoff
0.2554	Failure of second barrier
0.1511	Failure of "C" annulus penetration
0.0599	Failure of surface casing pipe / connections
0.0670	Failure of intermediate casing cement
0.0129	Failure of third flow path
0.0395	Failure of intermediate casing pipe / connections
0.3265	Failure of second barrier
0.1511	Failure of "C" annulus penetration
0.0599	Failure of surface casing pipe / connections
0.1562	Failure of "B" annulus penetration
0.0016	Pressure migrates inward from production casing cement
0.0598	Failure of production casing cement
0.0269	Failure of production casing pipe / connections
0.0117	Failure of surface casing cement
0.0117	Failure of conductor pipe cement

Fault Tree with Two Penetrations	
with 2" penetration / valves	
Failure Occurrence	**Failure Mode**
0.0012	Pressure migrates inward from intermediate casing cement
0.0670	Failure of intermediate casing cement
0.0185	Failure of secondary flow path
0.0108	Failure of second flow path
0.0491	Failure of intermediate casing hanger packoff
0.2192	Failure of secondary flow path
0.1562	Failure of "B" annulus penetration
0.0491	Failure of production casing hanger packoff
0.0269	Failure of production casing pipe / connections
0.0078	Failure of third flow path
0.0395	Failure of intermediate casing pipe / connections
0.1976	Failure of secondary flow path
0.1562	Failure of "B" annulus penetration
0.0491	Failure of production casing hanger packoff
0.0135	Pressure migrates outward from intermediate casing cement
0.0670	Failure of intermediate casing cement
0.2019	Failure of secondary flow path
0.0599	Failure of surface casing pipe / connections
0.1511	Failure of "C" annulus penetration

12.5 Appendix E – Fault Tree Details with ½-inch Penetrations

Fault Tree Analysis of Casing Pressure Subsets

Risk Index	Relative Failure Occurrence	Failure Mode
	27.08%	**Failure of B or C Annulus Penetration, 1/2"**
	0.1679	**False Pressure Reading**
6	0.0491	Pressure sensor inoperable
4	0.0249	Pressure sensor lost calibration
2	0.0077	Lost umbilical signal
9	0.0956	Pressure port plugged
	0.0385	**Leakage from connections**
5	0.0362	Leakage due to vibration
1	0.0024	Leakage due to corrosion
	0.0100	**Failure of manual valve to function**
2	0.0077	Valve malfunctions closed
1	0.0024	Valve malfunctions open
	0.0000	**Wellhead housing integrity**
1	0.0024	Higher bending moments due to taller housing
1	0.0024	Stress concentrations due to penetrations
	0.0545	**Damage to valves from external forces**
4	0.0249	Running / Installation damage
3	0.0153	Damage from ROV contact
2	0.0077	Damage when landing tree
2	0.0077	Dropped equipment

Risk Index	Relative Failure Occurrence	Failure Mode
	2.69%	**Failure of Production Casing Pipe / Connections to Maintain a Pressure Barrier**
2	0.0077	Corrosion
1	0.0024	Thermal cycling
1	0.0024	Damaged threads
2	0.0077	Damaged sealing surface
1	0.0024	Wear
1	0.0024	Bad / wrong thread compound
1	0.0024	Improper makeup of connection
	3.95%	**Failure of Intermediate Casing Pipe / Connections to Maintain a Pressure Barrier**
2	0.0077	Corrosion
1	0.0024	Thermal cycling
1	0.0024	Damaged threads
2	0.0077	Damaged sealing surface
3	0.0153	Wear
1	0.0024	Bad / wrong thread compound
1	0.0024	Improper makeup of connection
	5.99%	**Failure of Surface Casing Pipe / Connections to Maintain a Pressure Barrier**
2	0.0077	Corrosion
1	0.0024	Thermal cycling
1	0.0024	Damaged threads
2	0.0077	Damaged sealing surface
5	0.0362	Wear
1	0.0024	Bad / wrong thread compound
1	0.0024	Improper makeup of connection

Risk Index	Relative Failure Occurrence	Failure Mode
	4.91%	**Failure of Casing Hanger Packoff to Maintain a Pressure Barrier**
3	0.0153	Damaged sealing surface
2	0.0077	Thermal cycling / axial movement
2	0.0077	Installation anomalies
2	0.0077	Corrosion
1	0.0024	Seal damage from high temperature
1	0.0024	Loss of seal contact pressure
1	0.0024	Seal / fluid incompatibility
1	0.0024	Solids contamination
1	0.0024	Vibration

Risk Index	Relative Failure Occurrence	Failure Mode
	5.98%	**Failure of Production Casing Cement to Maintain a Pressure Barrier**
3	0.0153	Micro-annulus cracks
3	0.0153	Frac-Pac operations
3	0.0153	Expansion and contraction
2	0.0077	Poor formation / cement bond
2	0.0077	Gas in cement
	6.70%	**Failure of Intermediate Casing Cement to Maintain a Pressure Barrier**
3	0.0153	Micro-annulus cracks
3	0.0153	Frac-Pac operations
3	0.0153	Expansion and contraction
3	0.0153	Poor formation / cement bond
2	0.0077	Gas in cement
	1.17%	**Failure of Surface / Conductor Casing Cement to Maintain a Pressure Barrier**
1	0.0024	Micro-annulus cracks
1	0.0024	Frac-Pac operations
1	0.0024	Expansion and contraction
1	0.0024	Poor formation / cement bond
1	0.0024	Gas in cement

Fault Tree with One Penetration	
with 1/2" penetration / valves	
Failure Occurrence	**Failure Mode**
36.35%	**Inability to maintain Pressure Barrier**
0.0075	Pressure migrates outward from "A" annulus thru production casing pipe / connections
0.0269	Failure of production casing pipe / connection
0.2788	Failure of secondary barrier
0.2708	Failure of "B" annulus penetration
0.0049	Failure of second flow path
0.0395	Failure of intermediate casing pipe / connections
0.1229	Failure of secondary barrier
0.0599	Failure of surface casing pipe / connections
0.0670	Failure of intermediate casing cement
0.0060	Failure of third flow path
0.0491	Failure of intermediate casing hanger packoff
0.1229	Failure of secondary barrier
0.0599	Failure of surface casing pipe / connections
0.0670	Failure of intermediate casing cement
0.0137	Pressure migrates outward from "A" annulus thru production casing hanger packoff
0.0491	Failure of production casing hanger packoff
0.2788	Failure of secondary barrier
0.2708	Failure of "B" annulus penetration
0.0060	Failure of second flow path
0.0491	Failure of intermediate casing hanger packoff
0.1229	Failure of secondary barrier
0.0599	Failure of surface casing pipe / connections
0.0670	Failure of intermediate casing cement
0.0049	Failure of third flow path
0.0395	Failure of intermediate casing pipe / connection
0.1229	Failure of secondary barrier
0.0599	Failure of surface casing pipe / connections
0.0670	Failure of intermediate casing cement

Fault Tree with One Penetration	
with 1/2" penetration / valves	
Failure Occurrence	**Failure Mode**
0.3292	Pressure migrates outward from production casing cement
0.0670	Failure of intermediate casing cement
0.2708	Failure of "B" annulus penetration
0.0033	Failure of second flow path
0.0491	Failure of intermediate casing hanger packoff
0.0670	Failure of secondary barrier
0.0599	Failure of surface casing pipe / connections
0.0670	Failure of intermediate casing cement
0.0107	Failure of third flow path
0.0395	Failure of intermediate casing pipe / connections
0.2708	Failure of secondary barrier
0.0599	Failure of surface casing pipe / connections
0.2708	Failure of "B" annulus penetration
0.0016	Pressure migrates inward from production casing cement
0.0598	Failure of production casing cement
0.0269	Failure of production casing pipe / connections
0.0117	Failure of surface casing cement
0.0117	Failure of conductor pipe cement

Fault Tree with One Penetration	
with 1/2" penetration / valves	
Failure Occurrence	**Failure Mode**
0.0019	Pressure migrates inward from intermediate casing cement
0.0670	Failure of intermediate casing cement
0.0160	Failure of second flow path
0.0491	Failure of intermediate casing hanger packoff
0.3253	Failure of secondary barrier
0.2708	Failure of "B" annulus penetration
0.0491	Failure of production casing hanger packoff
0.0269	Failure of production casing pipe / connections
0.0121	Failure of third flow path
0.0395	Failure of intermediate casing pipe / connections
0.3067	Failure of secondary barrier
0.2708	Failure of "B" annulus penetration
0.0491	Failure of production casing hanger packoff
0.0040	Pressure migrates outward from intermediate casing cement
0.0670	Failure of intermediate casing cement
0.0599	Failure of surface casing pipe / connections

Fault Tree with Two Penetrations	
with 1/2" penetration / valves	
Failure Occurrence	**Failure Mode**
37.95%	**Inability to maintain Pressure Barrier**
0.0077	Pressure migrates outward from "A" annulus thru production casing pipe / connections
0.0269	Failure of production casing pipe / connection
0.2873	Failure of second barrier
0.2708	Failure of "B" annulus penetration
0.0101	Failure of second flow path
0.0395	Failure of intermediate casing pipe / connections
0.2554	Failure of second barrier
0.1511	Failure of "C" annulus penetration
0.0599	Failure of surface casing pipe / connections
0.0670	Failure of intermediate casing cement
0.0125	Failure of third flow path
0.0491	Failure of intermediate casing hanger packoff
0.2554	Failure of second barrier
0.1511	Failure of "C" annulus penetration
0.0599	Failure of surface casing pipe / connections
0.0670	Failure of intermediate casing cement
0.0141	Pressure migrates outward from "A" annulus thru production casing hanger packoff
0.0491	Failure of production casing hanger packoff
0.2873	Failure of second barrier
0.2708	Failure of "B" annulus penetration
0.0125	Failure of second flow path
0.0491	Failure of intermediate casing hanger packoff
0.2554	Failure of second barrier
0.1511	Failure of "C" annulus penetration
0.0599	Failure of surface casing pipe / connections
0.0670	Failure of intermediate casing cement
0.0101	Failure of third flow path
0.0395	Failure of intermediate casing pipe / connection
0.2554	Failure of second barrier
0.1511	Failure of "C" annulus penetration
0.0599	Failure of surface casing pipe / connections
0.0670	Failure of intermediate casing cement

Fault Tree with Two Penetrations	
with 1/2" penetration / valves	
Failure Occurrence	**Failure Mode**
0.3393	Pressure migrates outward from production casing cement
0.0670	Failure of intermediate casing cement
0.2708	Failure of "B" annulus penetration
0.0125	Failure of second flow path
0.0491	Failure of intermediate casing hanger packoff
0.2554	Failure of second barrier
0.1511	Failure of "C" annulus penetration
0.0599	Failure of surface casing pipe / connections
0.0670	Failure of intermediate casing cement
0.0165	Failure of third flow path
0.0395	Failure of intermediate casing pipe / connections
0.4181	Failure of second barrier
0.1511	Failure of "C" annulus penetration
0.0599	Failure of surface casing pipe / connections
0.2708	Failure of "B" annulus penetration
0.0016	Pressure migrates inward from production casing cement
0.0598	Failure of production casing cement
0.0269	Failure of production casing pipe / connections
0.0117	Failure of surface casing cement
0.0117	Failure of conductor pipe cement

Fault Tree with Two Penetrations	
with 1/2" penetration / valves	
Failure Occurrence	**Failure Mode**
0.0019	Pressure migrates inward from intermediate casing cement
0.0670	Failure of intermediate casing cement
0.0279	Failure of secondary flow path
0.0160	Failure of second flow path
0.0491	Failure of intermediate casing hanger packoff
0.3253	Failure of secondary flow path
0.2708	Failure of "B" annulus penetration
0.0491	Failure of production casing hanger packoff
0.0269	Failure of production casing pipe / connections
0.0121	Failure of third flow path
0.0395	Failure of intermediate casing pipe / connections
0.3067	Failure of secondary flow path
0.2708	Failure of "B" annulus penetration
0.0491	Failure of production casing hanger packoff
0.0135	Pressure migrates outward from intermediate casing cement
0.0670	Failure of intermediate casing cement
0.2019	Failure of secondary flow path
0.0599	Failure of surface casing pipe / connections
0.1511	Failure of "C" annulus penetration

12.6 Appendix F – Sensitivity Analysis Scenario 1

Fault Tree Analysis of Casing Pressure Subsets

Risk Index	Relative Failure Occurrence	Failure Mode
	15.62%	**Failure of B or C Annulus Penetration, 2"**
	0.0869	**False Pressure Reading**
6	0.0491	Pressure sensor inoperable
4	0.0249	Pressure sensor lost calibration
2	0.0077	Lost umbilical signal
2	0.0077	Pressure port plugged
	0.0047	**Leakage from connections**
1	0.0024	Leakage due to vibration
1	0.0024	Leakage due to corrosion
	0.0100	**Failure of manual valve to function**
2	0.0077	Valve malfunctions closed
1	0.0024	Valve malfunctions open
	0.0000	**Wellhead housing integrity**
1	0.0024	Higher bending moments due to taller housing
1	0.0024	Stress concentrations due to penetrations
	0.0545	**Damage to valves from external forces**
4	0.0249	Running / Installation damage
3	0.0153	Damage from ROV contact
2	0.0077	Damage when landing tree
2	0.0077	Dropped equipment

Risk Index	Relative Failure Occurrence	Failure Mode
	0.47%	**Failure of Production Casing Pipe / Connections to Maintain a Pressure Barrier**
1	0.0024	Corrosion
0	0.0000	Thermal cycling
0	0.0000	Damaged threads
1	0.0024	Damaged sealing surface
0	0.0000	Wear
0	0.0000	Bad / wrong thread compound
0	0.0000	Improper makeup of connection
	1.24%	**Failure of Intermediate Casing Pipe / Connections to Maintain a Pressure Barrier**
1	0.0024	Corrosion
0	0.0000	Thermal cycling
0	0.0000	Damaged threads
1	0.0024	Damaged sealing surface
2	0.0077	Wear
0	0.0000	Bad / wrong thread compound
0	0.0000	Improper makeup of connection
	2.95%	**Failure of Surface Casing Pipe / Connections to Maintain a Pressure Barrier**
1	0.0024	Corrosion
0	0.0000	Thermal cycling
0	0.0000	Damaged threads
1	0.0024	Damaged sealing surface
4	0.0249	Wear
0	0.0000	Bad / wrong thread compound
0	0.0000	Improper makeup of connection

Risk Index	Relative Failure Occurrence	Failure Mode
	1.47%	**Failure of Casing Hanger Packoff to Maintain a Pressure Barrier**
2	0.0077	Damaged sealing surface
1	0.0024	Thermal cycling / axial movement
1	0.0024	Installation anomalies
1	0.0024	Corrosion
0	0.0000	Seal damage from high temperature
0	0.0000	Loss of seal contact pressure
0	0.0000	Seal / fluid incompatibility
0	0.0000	Solids contamination
0	0.0000	Vibration

Risk Index	Relative Failure Occurrence	Failure Mode
	2.75%	**Failure of Production Casing Cement to Maintain a Pressure Barrier**
2	0.0077	Micro-annulus cracks
2	0.0077	Frac-Pac operations
2	0.0077	Expansion and contraction
1	0.0024	Poor formation / cement bond
1	0.0024	Gas in cement
	3.27%	**Failure of Intermediate Casing Cement to Maintain a Pressure Barrier**
2	0.0077	Micro-annulus cracks
2	0.0077	Frac-Pac operations
2	0.0077	Expansion and contraction
2	0.0077	Poor formation / cement bond
1	0.0024	Gas in cement
	0.00%	**Failure of Surface / Conductor Casing Cement to Maintain a Pressure Barrier**
0	0.0000	Micro-annulus cracks
0	0.0000	Frac-Pac operations
0	0.0000	Expansion and contraction
0	0.0000	Poor formation / cement bond
0	0.0000	Gas in cement

Fault Tree without Penetrations

Failure Occurrence	Failure Mode
3.47%	**Inability to Maintain a Pressure Barrier**
0.0000	Pressure migrates outward from "A" annulus through the production casing pipe / connections
0.0047	Failure of production casing pipe / connection
0.0017	Failure of secondary barrier
0.0008	Failure of intmd casing flow path
0.0124	Failure of intermediate casing pipe / connections
0.0612	Failure of secondary barrier
0.0295	Failure of surface casing pipe / connections
0.0327	Failure of intermediate casing cement
0.0009	Failure of intmd csg hgr packoff flow path
0.0147	Failure of intermediate casing hanger packoff
0.0612	Failure of secondary barrier
0.0295	Failure of surface casing pipe / connections
0.0327	Failure of intermediate casing cement
0.0000	Pressure migrates outward from "A" annulus thru production casing hanger packoff
0.0147	Failure of production casing hanger packoff
0.0017	Failure of secondary barrier
0.0009	Failure of intmd csg hgr packoff flow path
0.0147	Failure of intermediate casing hanger packoff
0.0612	Failure of secondary barrier
0.0295	Failure of surface casing pipe / connections
0.0327	Failure of intermediate casing cement
0.0008	Failure of intmd casing flow path
0.0124	Failure of intermediate casing pipe / connection
0.0612	Failure of secondary barrier
0.0295	Failure of surface casing pipe / connections
0.0327	Failure of intermediate casing cement

Fault Tree without Penetrations	
Failure Occurrence	**Failure Mode**
0.0336	Pressure migrates outward from production casing cement
0.0327	Failure of intermediate casing cement
0.0005	Failure of intmd csg hgr packoff flow path
0.0147	Failure of intermediate casing hanger packoff
0.0372	Failure of secondary barrier
0.0047	Failure of surface casing pipe / connections
0.0327	Failure of intermediate casing cement
0.0004	Failure of third flow path
0.0124	Failure of intermediate casing pipe / connections
0.0295	Failure of surface casing pipe / connections
0.0001	Pressure migrates inward from production casing cement
0.0275	Failure of production casing cement
0.0047	Failure of production casing pipe / connections
0.0000	Failure of surface casing cement
0.0000	Failure of conductor pipe cement
0.0000	Pressure migrates inward from intermediate casing cement
0.0327	Failure of intermediate casing cement
0.0003	Failure of second flow path
0.0147	Failure of intermediate casing hanger packoff
0.0193	Failure of secondary flow path
0.0147	Failure of production casing hanger packoff
0.0047	Failure of production casing pipe / connections
0.0002	Failure of third flow path
0.0124	Failure of intermediate casing pipe / connections
0.0147	Failure of production casing hanger packoff
0.0010	Pressure migrates outward from intermediate casing cement
0.0327	Failure of intermediate casing cement
0.0295	Failure of surface casing pipe / connections

Fault Tree with One Penetration	
with 2" penetration / valves	
Failure Occurrence	**Failure Mode**
18.92%	**Inability to maintain Pressure Barrier**
0.0007	Pressure migrates outward from "A" annulus thru production casing pipe / connections
0.0047	Failure of production casing pipe / connection
0.1576	Failure of secondary barrier
0.1562	Failure of "B" annulus penetration
0.0008	Failure of second flow path
0.0124	Failure of intermediate casing pipe / connections
0.0612	Failure of secondary barrier
0.0295	Failure of surface casing pipe / connections
0.0327	Failure of intermediate casing cement
0.0009	Failure of third flow path
0.0147	Failure of intermediate casing hanger packoff
0.0612	Failure of secondary barrier
0.0295	Failure of surface casing pipe / connections
0.0327	Failure of intermediate casing cement
0.0023	Pressure migrates outward from "A" annulus thru production casing hanger packoff
0.0147	Failure of production casing hanger packoff
0.1576	Failure of secondary barrier
0.1562	Failure of "B" annulus penetration
0.0009	Failure of second flow path
0.0147	Failure of intermediate casing hanger packoff
0.0612	Failure of secondary barrier
0.0295	Failure of surface casing pipe / connections
0.0327	Failure of intermediate casing cement
0.0008	Failure of third flow path
0.0124	Failure of intermediate casing pipe / connection
0.0612	Failure of secondary barrier
0.0295	Failure of surface casing pipe / connections
0.0327	Failure of intermediate casing cement

Fault Tree with One Penetration	
with 2" penetration / valves	
Failure Occurrence	**Failure Mode**
0.1857	Pressure migrates outward from production casing cement
0.0327	Failure of intermediate casing cement
0.1562	Failure of "B" annulus penetration
0.0005	Failure of second flow path
0.0147	Failure of intermediate casing hanger packoff
0.0327	Failure of secondary barrier
0.0295	Failure of surface casing pipe / connections
0.0327	Failure of intermediate casing cement
0.0019	Failure of third flow path
0.0124	Failure of intermediate casing pipe / connections
0.1562	Failure of secondary barrier
0.0295	Failure of surface casing pipe / connections
0.1562	Failure of "B" annulus penetration
0.0001	Pressure migrates inward from production casing cement
0.0275	Failure of production casing cement
0.0047	Failure of production casing pipe / connections
0.0000	Failure of surface casing cement
0.0000	Failure of conductor pipe cement

Fault Tree with One Penetration	
with 2" penetration / valves	
Failure Occurrence	**Failure Mode**
0.0002	Pressure migrates inward from intermediate casing cement
0.0327	Failure of intermediate casing cement
0.0025	Failure of second flow path
0.0147	Failure of intermediate casing hanger packoff
0.1725	Failure of secondary barrier
0.1562	Failure of "B" annulus penetration
0.0147	Failure of production casing hanger packoff
0.0047	Failure of production casing pipe / connections
0.0021	Failure of third flow path
0.0124	Failure of intermediate casing pipe / connections
0.1686	Failure of secondary barrier
0.1562	Failure of "B" annulus penetration
0.0147	Failure of production casing hanger packoff
0.0010	Pressure migrates outward from intermediate casing cement
0.0327	Failure of intermediate casing cement
0.0295	Failure of surface casing pipe / connections

Fault Tree with Two Penetrations	
with 2" penetration / valves	
Failure Occurrence	**Failure Mode**
19.66%	**Inability to maintain Pressure Barrier**
0.0008	Pressure migrates outward from "A" annulus thru production casing pipe / connections
0.0047	Failure of production casing pipe / connection
0.1608	Failure of second barrier
0.1562	Failure of "B" annulus penetration
0.0025	Failure of second flow path
0.0124	Failure of intermediate casing pipe / connections
0.2030	Failure of second barrier
0.1511	Failure of "C" annulus penetration
0.0295	Failure of surface casing pipe / connections
0.0327	Failure of intermediate casing cement
0.0030	Failure of third flow path
0.0147	Failure of intermediate casing hanger packoff
0.2030	Failure of second barrier
0.1511	Failure of "C" annulus penetration
0.0295	Failure of surface casing pipe / connections
0.0327	Failure of intermediate casing cement
0.0024	Pressure migrates outward from "A" annulus thru production casing hanger packoff
0.0147	Failure of production casing hanger packoff
0.1608	Failure of second barrier
0.1562	Failure of "B" annulus penetration
0.0030	Failure of second flow path
0.0147	Failure of intermediate casing hanger packoff
0.2030	Failure of second barrier
0.1511	Failure of "C" annulus penetration
0.0295	Failure of surface casing pipe / connections
0.0327	Failure of intermediate casing cement
0.0025	Failure of third flow path
0.0124	Failure of intermediate casing pipe / connection
0.2030	Failure of second barrier
0.1511	Failure of "C" annulus penetration
0.0295	Failure of surface casing pipe / connections
0.0327	Failure of intermediate casing cement

Fault Tree wiht Two Penetrations	
with 2" penetration / valves	
Failure Occurrence	**Failure Mode**
0.1892	Pressure migrates outward from production casing cement
0.0327	Failure of intermediate casing cement
0.1562	Failure of "B" annulus penetration
0.0030	Failure of second flow path
0.0147	Failure of intermediate casing hanger packoff
0.2030	Failure of second barrier
0.1511	Failure of "C" annulus penetration
0.0295	Failure of surface casing pipe / connections
0.0327	Failure of intermediate casing cement
0.0038	Failure of third flow path
0.0124	Failure of intermediate casing pipe / connections
0.3048	Failure of second barrier
0.1511	Failure of "C" annulus penetration
0.0295	Failure of surface casing pipe / connections
0.1562	Failure of "B" annulus penetration
0.0001	Pressure migrates inward from production casing cement
0.0275	Failure of production casing cement
0.0047	Failure of production casing pipe / connections
0.0000	Failure of surface casing cement
0.0000	Failure of conductor pipe cement

Fault Tree with Two Penetrations	
with 2" penetration / valves	
Failure Occurrence	**Failure Mode**
0.0002	Pressure migrates inward from intermediate casing cement
0.0327	Failure of intermediate casing cement
0.0046	Failure of secondary flow path
0.0025	Failure of second flow path
0.0147	Failure of intermediate casing hanger packoff
0.1725	Failure of secondary flow path
0.1562	Failure of "B" annulus penetration
0.0147	Failure of production casing hanger packoff
0.0047	Failure of production casing pipe / connections
0.0021	Failure of third flow path
0.0124	Failure of intermediate casing pipe / connections
0.1686	Failure of secondary flow path
0.1562	Failure of "B" annulus penetration
0.0147	Failure of production casing hanger packoff
0.0058	Pressure migrates outward from intermediate casing cement
0.0327	Failure of intermediate casing cement
0.1761	Failure of secondary flow path
0.0295	Failure of surface casing pipe / connections
0.1511	Failure of "C" annulus penetration

12.7 Appendix G – Sensitivity Analysis Scenario 2

Fault Tree Analysis of Casing Pressure Subsets

Risk Index	Relative Failure Occurrence	Failure Mode
	15.62%	**Failure of B or C Annulus Penetration, 2"**
	0.0869	**False Pressure Reading**
6	0.0491	Pressure sensor inoperable
4	0.0249	Pressure sensor lost calibration
2	0.0077	Lost umbilical signal
2	0.0077	Pressure port plugged
	0.0047	**Leakage from connections**
1	0.0024	Leakage due to vibration
1	0.0024	Leakage due to corrosion
	0.0100	**Failure of manual valve to function**
2	0.0077	Valve malfunctions closed
1	0.0024	Valve malfunctions open
	0.0000	**Wellhead housing integrity**
1	0.0024	Higher bending moments due to taller housing
1	0.0024	Stress concentrations due to penetrations
	0.0545	**Damage to valves from external forces**
4	0.0249	Running / Installation damage
3	0.0153	Damage from ROV contact
2	0.0077	Damage when landing tree
2	0.0077	Dropped equipment

Risk Index	Relative Failure Occurrence	Failure Mode
	9.91%	**Failure of Production Casing Pipe / Connections to Maintain a Pressure Barrier**
4	0.0249	Corrosion
3	0.0153	Thermal cycling
3	0.0153	Damaged threads
4	0.0249	Damaged sealing surface
2	0.0077	Wear
2	0.0077	Bad / wrong thread compound
2	0.0077	Improper makeup of connection
	13.83%	**Failure of Intermediate Casing Pipe / Connections to Maintain a Pressure Barrier**
4	0.0249	Corrosion
3	0.0153	Thermal cycling
3	0.0153	Damaged threads
4	0.0249	Damaged sealing surface
5	0.0362	Wear
3	0.0153	Bad / wrong thread compound
3	0.0153	Improper makeup of connection
	16.26%	**Failure of Surface Casing Pipe / Connections to Maintain a Pressure Barrier**
4	0.0249	Corrosion
3	0.0153	Thermal cycling
3	0.0153	Damaged threads
4	0.0249	Damaged sealing surface
7	0.0634	Wear
3	0.0153	Bad / wrong thread compound
3	0.0153	Improper makeup of connection

Risk Index	Relative Failure Occurrence	Failure Mode
	17.26%	**Failure of Casing Hanger Packoff to Maintain a Pressure Barrier**
5	0.0362	Damaged sealing surface
4	0.0249	Thermal cycling / axial movement
4	0.0249	Installation anomalies
4	0.0249	Corrosion
3	0.0153	Seal damage from high temperature
3	0.0153	Loss of seal contact pressure
3	0.0153	Seal / fluid incompatibility
3	0.0153	Solids contamination
3	0.0153	Vibration

Risk Index	Relative Failure Occurrence	Failure Mode
	14.87%	**Failure of Production Casing Cement to Maintain a Pressure Barrier**
5	0.0362	Micro-annulus cracks
5	0.0362	Frac-Pac operations
5	0.0362	Expansion and contraction
4	0.0249	Poor formation / cement bond
4	0.0249	Gas in cement
	15.86%	**Failure of Intermediate Casing Cement to Maintain a Pressure Barrier**
5	0.0362	Micro-annulus cracks
5	0.0362	Frac-Pac operations
5	0.0362	Expansion and contraction
5	0.0362	Poor formation / cement bond
4	0.0249	Gas in cement
	7.42%	**Failure of Surface / Conductor Casing Cement to Maintain a Pressure Barrier**
3	0.0153	Micro-annulus cracks
3	0.0153	Frac-Pac operations
3	0.0153	Expansion and contraction
3	0.0153	Poor formation / cement bond
3	0.0153	Gas in cement

Fault Tree without Penetrations	
Failure Occurrence	**Failure Mode**
37.40%	**Inability to Maintain a Pressure Barrier**
0.0089	Pressure migrates outward from "A" annulus through the production casing pipe / connections
0.0991	Failure of production casing pipe / connection
0.0898	Failure of secondary barrier
0.0409	Failure of intmd casing flow path
0.1383	Failure of intermediate casing pipe / connections
0.2954	Failure of secondary barrier
0.1626	Failure of surface casing pipe / connections
0.1586	Failure of intermediate casing cement
0.0510	Failure of intmd csg hgr packoff flow path
0.1726	Failure of intermediate casing hanger packoff
0.2954	Failure of secondary barrier
0.1626	Failure of surface casing pipe / connections
0.1586	Failure of intermediate casing cement
0.0155	Pressure migrates outward from "A" annulus thru production casing hanger packoff
0.1726	Failure of production casing hanger packoff
0.0898	Failure of secondary barrier
0.0510	Failure of intmd csg hgr packoff flow path
0.1726	Failure of intermediate casing hanger packoff
0.2954	Failure of secondary barrier
0.1626	Failure of surface casing pipe / connections
0.1586	Failure of intermediate casing cement
0.0409	Failure of intmd casing flow path
0.1383	Failure of intermediate casing pipe / connection
0.2954	Failure of secondary barrier
0.1626	Failure of surface casing pipe / connections
0.1586	Failure of intermediate casing cement

Fault Tree without Penetrations

Failure Occurrence	Failure Mode
0.2118	Pressure migrates outward from production casing cement
0.1586	Failure of intermediate casing cement
0.0418	Failure of intmd csg hgr packoff flow path
0.1726	Failure of intermediate casing hanger packoff
0.2419	Failure of secondary barrier
0.0991	Failure of surface casing pipe / connections
0.1586	Failure of intermediate casing cement
0.0225	Failure of third flow path
0.1383	Failure of intermediate casing pipe / connections
0.1626	Failure of surface casing pipe / connections
0.0147	Pressure migrates inward from production casing cement
0.1487	Failure of production casing cement
0.0991	Failure of production casing pipe / connections
0.0742	Failure of surface casing cement
0.0742	Failure of conductor pipe cement
0.0106	Pressure migrates inward from intermediate casing cement
0.1586	Failure of intermediate casing cement
0.0439	Failure of second flow path
0.1726	Failure of intermediate casing hanger packoff
0.2546	Failure of secondary flow path
0.1726	Failure of production casing hanger packoff
0.0991	Failure of production casing pipe / connections
0.0239	Failure of third flow path
0.1383	Failure of intermediate casing pipe / connections
0.1726	Failure of production casing hanger packoff
0.0258	Pressure migrates outward from intermediate casing cement
0.1586	Failure of intermediate casing cement
0.1626	Failure of surface casing pipe / connections

Fault Tree with One Penetration	
with 2" penetration / valves	
Failure Occurrence	**Failure Mode**
48.71%	**Inability to maintain Pressure Barrier**
0.0230	Pressure migrates outward from "A" annulus thru production casing pipe / connections
0.0991	Failure of production casing pipe / connection
0.2319	Failure of secondary barrier
0.1562	Failure of "B" annulus penetration
0.0409	Failure of second flow path
0.1383	Failure of intermediate casing pipe / connections
0.2954	Failure of secondary barrier
0.1626	Failure of surface casing pipe / connections
0.1586	Failure of intermediate casing cement
0.0510	Failure of third flow path
0.1726	Failure of intermediate casing hanger packoff
0.2954	Failure of secondary barrier
0.1626	Failure of surface casing pipe / connections
0.1586	Failure of intermediate casing cement
0.0400	Pressure migrates outward from "A" annulus thru production casing hanger packoff
0.1726	Failure of production casing hanger packoff
0.2319	Failure of secondary barrier
0.1562	Failure of "B" annulus penetration
0.0510	Failure of second flow path
0.1726	Failure of intermediate casing hanger packoff
0.2954	Failure of secondary barrier
0.1626	Failure of surface casing pipe / connections
0.1586	Failure of intermediate casing cement
0.0409	Failure of third flow path
0.1383	Failure of intermediate casing pipe / connection
0.2954	Failure of secondary barrier
0.1626	Failure of surface casing pipe / connections
0.1586	Failure of intermediate casing cement

Fault Tree with One Penetration	
with 2" penetration / valves	
Failure Occurrence	**Failure Mode**
0.3243	Pressure migrates outward from production casing cement
0.1586	Failure of intermediate casing cement
0.1562	Failure of "B" annulus penetration
0.0274	Failure of second flow path
0.1726	Failure of intermediate casing hanger packoff
0.1586	Failure of secondary barrier
0.1626	Failure of surface casing pipe / connections
0.1586	Failure of intermediate casing cement
0.0216	Failure of third flow path
0.1383	Failure of intermediate casing pipe / connections
0.1562	Failure of secondary barrier
0.1626	Failure of surface casing pipe / connections
0.1562	Failure of "B" annulus penetration
0.0147	Pressure migrates inward from production casing cement
0.1487	Failure of production casing cement
0.0991	Failure of production casing pipe / connections
0.0742	Failure of surface casing cement
0.0742	Failure of conductor pipe cement

Fault Tree with One Penetration	
with 2" penetration / valves	
Failure Occurrence	**Failure Mode**
0.0163	Pressure migrates inward from intermediate casing cement
0.1586	Failure of intermediate casing cement
0.0640	Failure of second flow path
0.1726	Failure of intermediate casing hanger packoff
0.3710	Failure of secondary barrier
0.1562	Failure of "B" annulus penetration
0.1726	Failure of production casing hanger packoff
0.0991	Failure of production casing pipe / connections
0.0418	Failure of third flow path
0.1383	Failure of intermediate casing pipe / connections
0.3018	Failure of secondary barrier
0.1562	Failure of "B" annulus penetration
0.1726	Failure of production casing hanger packoff
0.0258	Pressure migrates outward from intermediate casing cement
0.1586	Failure of intermediate casing cement
0.1626	Failure of surface casing pipe / connections

Fault Tree with Two Penetrations	
with 2" penetration / valves	
Failure Occurrence	**Failure Mode**
53.94%	**Inability to maintain Pressure Barrier**
0.0256	Pressure migrates outward from "A" annulus thru production casing pipe / connections
0.0991	Failure of production casing pipe / connection
0.2583	Failure of second barrier
0.1562	Failure of "B" annulus penetration
0.0556	Failure of second flow path
0.1383	Failure of intermediate casing pipe / connections
0.4019	Failure of second barrier
0.1511	Failure of "C" annulus penetration
0.1626	Failure of surface casing pipe / connections
0.1586	Failure of intermediate casing cement
0.0694	Failure of third flow path
0.1726	Failure of intermediate casing hanger packoff
0.4019	Failure of second barrier
0.1511	Failure of "C" annulus penetration
0.1626	Failure of surface casing pipe / connections
0.1586	Failure of intermediate casing cement
0.0446	Pressure migrates outward from "A" annulus thru production casing hanger packoff
0.1726	Failure of production casing hanger packoff
0.2583	Failure of second barrier
0.1562	Failure of "B" annulus penetration
0.0694	Failure of second flow path
0.1726	Failure of intermediate casing hanger packoff
0.4019	Failure of second barrier
0.1511	Failure of "C" annulus penetration
0.1626	Failure of surface casing pipe / connections
0.1586	Failure of intermediate casing cement
0.0556	Failure of third flow path
0.1383	Failure of intermediate casing pipe / connection
0.4019	Failure of second barrier
0.1511	Failure of "C" annulus penetration
0.1626	Failure of surface casing pipe / connections
0.1586	Failure of intermediate casing cement

Fault Tree with Two Penetrations	
with 2" penetration / valves	
Failure Occurrence	**Failure Mode**
0.3758	Pressure migrates outward from production casing cement
0.1586	Failure of intermediate casing cement
0.1562	Failure of "B" annulus penetration
0.0694	Failure of second flow path
0.1726	Failure of intermediate casing hanger packoff
0.4019	Failure of second barrier
0.1511	Failure of "C" annulus penetration
0.1626	Failure of surface casing pipe / connections
0.1586	Failure of intermediate casing cement
0.0554	Failure of third flow path
0.1383	Failure of intermediate casing pipe / connections
0.4001	Failure of second barrier
0.1511	Failure of "C" annulus penetration
0.1626	Failure of surface casing pipe / connections
0.1562	Failure of "B" annulus penetration
0.0147	Pressure migrates inward from production casing cement
0.1487	Failure of production casing cement
0.0991	Failure of production casing pipe / connections
0.0742	Failure of surface casing cement
0.0742	Failure of conductor pipe cement

Fault Tree with Two Penetrations	
with 2" penetration / valves	
Failure Occurrence	**Failure Mode**
0.0163	Pressure migrates inward from intermediate casing cement
0.1586	Failure of intermediate casing cement
0.1031	Failure of secondary flow path
0.0640	Failure of second flow path
0.1726	Failure of intermediate casing hanger packoff
0.3710	Failure of secondary flow path
0.1562	Failure of "B" annulus penetration
0.1726	Failure of production casing hanger packoff
0.0991	Failure of production casing pipe / connections
0.0418	Failure of third flow path
0.1383	Failure of intermediate casing pipe / connections
0.3018	Failure of secondary flow path
0.1562	Failure of "B" annulus penetration
0.1726	Failure of production casing hanger packoff
0.0458	Pressure migrates outward from intermediate casing cement
0.1586	Failure of intermediate casing cement
0.2891	Failure of secondary flow path
0.1626	Failure of surface casing pipe / connections
0.1511	Failure of "C" annulus penetration

12.8 Appendix H – FMEA Data

FMECA Report	**Equipment:**	**Subsea Wells in GOM** **Current Design Configuration without Penetrations**
Date: **11-Dec-2003**	**Phase:**	**Completed Wells**
Rev:	**Activity:**	**Sustained Casing Pressure**

Index	Component Identification	Potential Failure Mode(s)	Potential Cause(s) of Failure	Probability Index	Potential Effect(s) of Failure	Severity Index	Current Design Controls	Detection Index	Risk Priority Index
1	Production casing tubing hanger	Leakage of pressure / fluid past the casing hanger into the "B-1" annulus	Corrosion of seal surfaces		High pressure in the intermediate casing annulus				
2	Production casing tubing hanger	Leakage of pressure / fluid past the casing hanger into the "B-1" annulus	Seals not compatible with the high temperatures		High pressure in the intermediate casing annulus				
3	Production casing tubing hanger	Leakage of pressure / fluid past the casing hanger into the "B-1" annulus	Hangling or wear damage to the sealing surfaces		High pressure in the intermediate casing annulus				
4	Production casing tubing hanger	Leakage of pressure / fluid past the casing hanger into the "B-1" annulus	Lack of seal contact pressure		High pressure in the intermediate casing annulus				
5	Production casing tubing hanger	Leakage of pressure / fluid past the casing hanger into the "B-1" annulus	Incompatibility of the seal with the contained fluids		High pressure in the intermediate casing annulus				
6	Production casing tubing hanger	Leakage of pressure / fluid past the casing hanger into the "B-1" annulus	Solids contamination on the sealing surface		High pressure in the intermediate casing annulus				
7	Production casing tubing hanger	Leakage of pressure / fluid past the casing hanger into the "B-1" annulus	Loss of sealability due to vibration		High pressure in the intermediate casing annulus				

FMECA Report	**Equipment:**	**Subsea Wells in GOM** **Current Design Configuration without Penetrations**
Date: **11-Dec-2003**	**Phase:**	**Completed Wells**
Rev:	**Activity:**	**Sustained Casing Pressure**

Index	Component Identification	Potential Failure Mode(s)	Potential Cause(s) of Failure	Probability Index	Potential Effect(s) of Failure	Severity Index	Current Design Controls	Detection Index	Risk Priority Index
8	Production casing / connections	Leakage of pressure / fluid through the production casing / connections into the "B-1" annulus	Corrosion of the connection sealing surfaces		High pressure in the intermediate casing annulus				
9	Production casing / connections	Leakage of pressure / fluid through the production casing / connections into the "B-1" annulus	Overload of the pipe / connections due to thermal cycling		High pressure in the intermediate casing annulus				
10	Production casing / connections	Leakage of pressure / fluid through the production casing / connections into the "B-1" annulus	Wear of the pipe from drilling operations		High pressure in the intermediate casing annulus				
11	Production casing / connections	Leakage of pressure / fluid through the production casing / connections into the "B-1" annulus	Damaged threads		High pressure in the intermediate casing annulus				
12	Production casing / connections	Leakage of pressure / fluid through the production casing / connections into the "B-1" annulus	Damaged sealing surfaces		High pressure in the intermediate casing annulus				
13	Production casing / connections	Leakage of pressure / fluid through the production casing / connections into the "B-1" annulus	Bad / wrong thread compound		High pressure in the intermediate casing annulus				

FMECA Report	**Equipment:**	**Subsea Wells in GOM** **Current Design Configuration without Penetrations**
Date: **11-Dec-2003**	**Phase:**	**Completed Wells**
Rev:	**Activity:**	**Sustained Casing Pressure**

Index	Component Identification	Potential Failure Mode(s)	Potential Cause(s) of Failure	Probability Index	Potential Effect(s) of Failure	Severity Index	Current Design Controls	Detection Index	Risk Priority Index
14	Production casing / connections	Leakage of pressure / fluid through the production casing / connections into the "B-1" annulus	Improper thread make-up		High pressure in the intermediate casing annulus				
15	Production casing cement	Leakage of pressure / fluid from formation through the cement into the "B-1" annulus	Micro-annulus cracks in the cement		High pressure in the intermediate casing annulus				
16	Production casing cement	Leakage of pressure / fluid from formation through the cement into the "B-1" annulus	Poor formation / cement bond		High pressure in the intermediate casing annulus				
17	Production casing cement	Leakage of pressure / fluid from formation through the cement into the "B-1" annulus	Frac-Pack operations		High pressure in the intermediate casing annulus				
18	Production casing cement	Leakage of pressure / fluid from formation through the cement into the "B-1" annulus	Expansion / contraction from thermal cycling		High pressure in the intermediate casing annulus				
19	Production casing cement	Leakage of pressure / fluid from formation through the cement into the "B-1" annulus	Mechanical impact loads		High pressure in the intermediate casing annulus				

FMECA Report	**Equipment:**	**Subsea Wells in GOM** **Current Design Configuration without Penetrations**
Date: **11-Dec-2003**	**Phase:**	**Completed Wells**
Rev:	**Activity:**	**Sustained Casing Pressure**

Index	Component Identification	Potential Failure Mode(s)	Potential Cause(s) of Failure	Probability Index	Potential Effect(s) of Failure	Severity Index	Current Design Controls	Detection Index	Risk Priority Index
20	Production casing cement	Leakage of pressure / fluid from formation through the cement into the "B-1" annulus	Gas in cement during setting process		High pressure in the intermediate casing annulus				

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