Calculation of Worst-Case Discharge (WCD)

TECHNICAL REPORT

Society of Petroleum Engineers

SPE Technical Report

Calculation of Worst-Case Discharge (WCD)

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1. Introduction

1.1 Background

The US Bureau of Ocean Energy Management (BOEM) defines worst-case discharge (WCD) as the single highest daily flow rate of liquid hydrocarbon during an uncontrolled wellbore flow event. That is, the average daily flow rate on the day that the highest rate occurs, under worst case conditions (a blowout). It is neither the total volume spilled over the duration of the event, nor the maximum possible flow rate that would result from high-side reservoir parameters, nor a distribution of outcomes. It is a single value for the expected flow rate calculated under worst case wellbore conditions using known (expected) reservoir properties.

In 30 CFR §550.213(g) and §550.243(h), "a scenario for the potential blowout of the proposed well in your [plan] that you expect will have the highest volume of liquid hydrocarbons," is required. NTL 2010-N06 (US Department of the Interior 2010a) further defined WCD and expanded its application to all federal waters, but many issues needed additional clarity. On June 18, 2010, BOEM issued Frequently Asked Questions (FAQ's) (US Department of the Interior 2010b) with answers to address specific issues and questions regarding NTL No. 2010-N06. This BOEM FAQ's was subsequently updated July 15, 2010, July 21, 2010, and August 10, 2010. An SPE Guideline (Magner et al. 2010) was written to address NTL No. 2010-N06 and FAQ's (US Department of the Interior 2010a and 2010b) regarding WCD in the US Gulf of Mexico in response to the Macondo blowout and spill. For nearly four years since that time, operators have made submissions under these rules.

Regulations in other countries, most notably Norway (*Z-013, Risk and Emergency Preparedness Assessment* 2010) and the UK (UK Department of Energy and Climate Change 2012), apply to drilling, workover, rigless intervention, and production operations from wells and, as a result, are more general in nature. These countries' regulations require the operator to define the wellbore configuration at the time of the discharge event and require modeling of well flow for the duration of the event.

1.2 Process and Scope

All of this practical experience has led to a desire to streamline the process and to develop a consensus guideline so that operators and regulators can have confidence that the methods employed are both reasonable and consistent. In response, the Society of Petroleum Engineers approved a WCD Summit in 2014 including operators, academia, and regulators to examine the assumptions required in calculating worst-case hydrocarbon discharge values for wells in the process of being drilled.

A steering committee of subject matter experts (SMEs) developed the summit agenda. Participants in the summit were nominated by the steering committee as SMEs with experience and knowledge needed to achieve the summit objectives or applied to attend and were accepted by the steering committee. The summit provided a sound technical venue to explore various issues and investigate opportunities to improve the methods of calculating and reporting WCD scenarios.

Upon completion of the summit, input gathered from the technical discussion sessions was reviewed by the steering committee and incorporated into a draft technical report. This draft technical report was posted on the SPE website (www.SPE.org) for 30 days to garner more input from the SPE membership at-large. Once the 30-day web posting expired, the steering committee reviewed and incorporated comments into the draft technical report. The final version of the technical report is presented here. This final version has been approved by the appointed SPE Technical Director and the SPE Board of Directors. It permanently resides electronically in OnePetro (www.onepetro.org) and on SPE.org in a manner that allows continuing comment / discussion. OnePetro is a unique library of technical documents and journal articles serving the oil and gas exploration and production industry.

SPE's mission is "to collect, disseminate, and exchange technical knowledge, and to provide opportunities for professionals to enhance their technical and professional competence." It is not a standard setting body and it does not develop or publish best practices or operational recommendations. Therefore, this technical report sets forth proposed approaches developed by the subject matter experts who participated in the WCD summit and subsequent deliberations.

1.3 Objectives

This technical report documents the findings of the 2014 WCD Summit (17-18 March 2014, New Orleans, Louisiana) and presents a SME consensus for calculating the WCD of liquid hydrocarbons to the environment resulting from a loss of control from a well during openhole drilling. The main purpose of a WCD calculation is to support oil spill response planning. It is not intended for well design, kill design, or casing design, but these processes are all integrally related. It may be the starting point for well containment planning, which may require additional alternate scenarios that may modify the total flow.

The summit focused on defining methods for determining reasonable reservoir properties and fluid analog data to be used as modeling inputs for both shallow water and deep water wells. Discussions included the interaction of water sands and gas sands interspersed with oil sands; multiple sands in the same wellbore in various states of depletion; as well as the effects of secondary gas caps and water encroachment on calculated WCD values. The flowing scenario should be modeled over the duration of the spill to determine when the highest, single-day flow rate from the well occurs, which may or may not be the first day. In multi-well situations, it is important to remember that the WCD well may or may not be the first well drilled on the block or in the field. Each potential well location must be assessed and the WCD determined by the planned well that has the highest WCD flow rate.

This document was created to address the calculation of WCD for exploratory or development wells being drilled in the federal waters of the US, as prescribed by the BOEM. However, the approaches presented in this report may be considered for wells drilled in other regions of the US or elsewhere in the world. This report is based on US Department of Interior regulations and interpretation as of March 2014. This document may be modified in the future.

2. Uncontrolled Flow Rate Calculation

2.1 Overview

The estimate of flow rate from any wellbore normally begins with an inflow/outflow assessment. The inflow performance relationship (IPR) is determined by one of several possible methods, such as Darcy's Law for steady-state radial flow, the use of a numerical reservoir simulator, etc. This requires knowledge of the zones capable of flow, the rock and fluid properties of those zones, and the wellbore configuration. The result is an equation that describes the liquid flow vs. the flowing bottomhole pressure (BHP) in the well. An outflow correlation is used to calculate the pressure drop in the well from reservoir to surface at various flow rates, which is then used to calculate the flowing BHPs. The operating point, or flow rate and associated flowing BHP, is determined from the intersection of these two equations.

The method chosen, between analytical techniques and numerical simulation, should depend on the amount of data available and the understanding of the reservoir. This can be quite different when drilling exploration/appraisal wells vs. development/production wells, and so, different methods may be employed. The tool selection should depend on the data available, the level of understanding, and also on the complexities of the reservoir. In most cases, the various tools and methods will yield similar results for the same set of reservoir and wellbore properties and the engineer should, therefore, focus efforts on the data and assumptions for rock properties, fluid properties, and wellbore conditions. Detailed modeling focusing on precision is not as important as making informed predictions.

A typical process flow diagram for WCD is shown in **Figure 2.1** below.

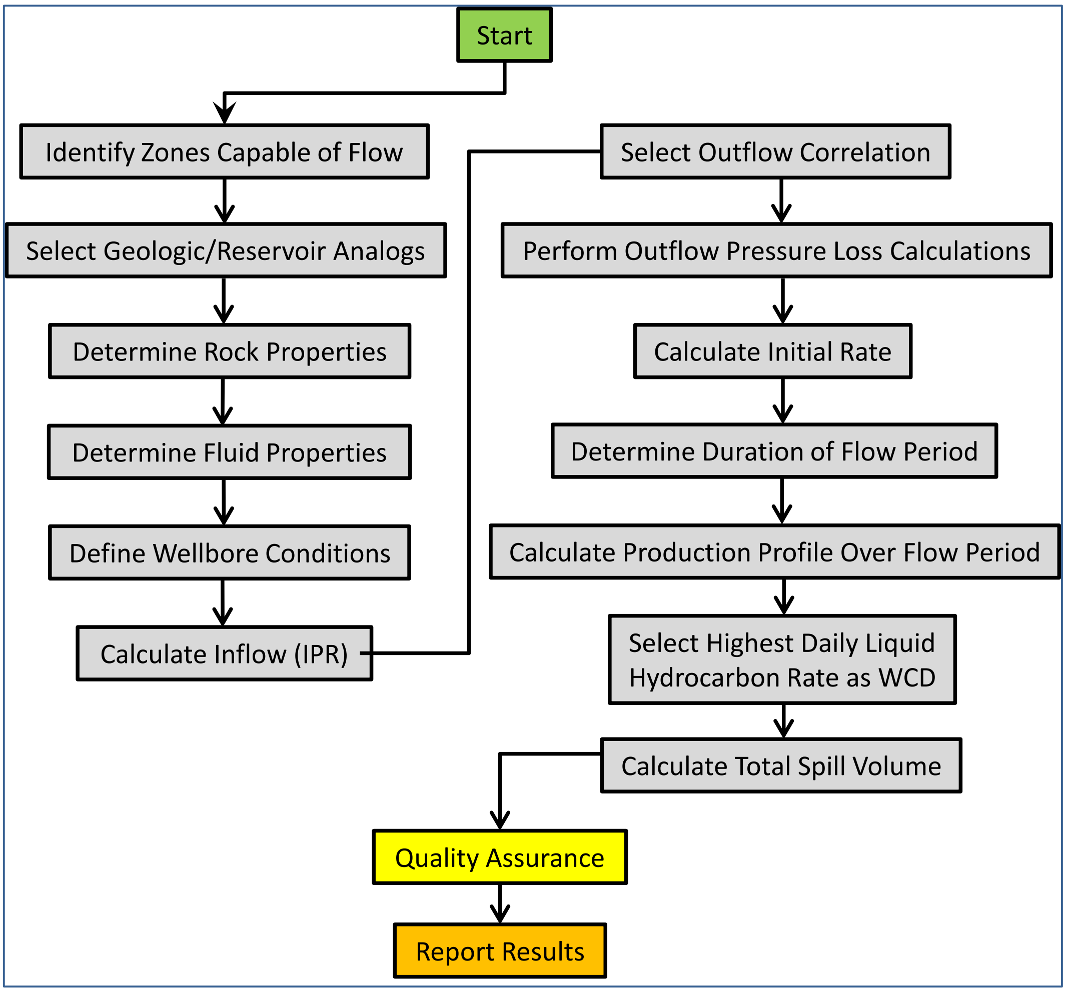

Figure 2.1 Typical workflow for WCD assessment

To define WCD for this technical report, "worst case" pertains to the loss of well control which results in a blowout and the wellbore configuration at that time. Reservoir properties should be selected as best technical estimates (or "success case") for calculation of WCD. Best technical estimates should represent values of properties as measured in nearby analogous well penetrations. In general, these values should not represent the extremes of the uncertainty ranges for the WCD well; although, in some cases, the highest or lowest analog value may be the best technical estimate. The data and values used in the WCD calculation should be no different than those used in the decision to drill the well and to design the casing, tubing, completion, facilities, etc.

The uncontrolled flow rate for a given openhole section will be determined using standard petroleum engineering well-flow analysis, also known as nodal-analysis techniques. Whether using numerical simulation or analytical techniques, inflow and outflow equations are cross-plotted, and the intersection of the two curves defines the rate and pressure solution, as shown in **Figure 2.2**.

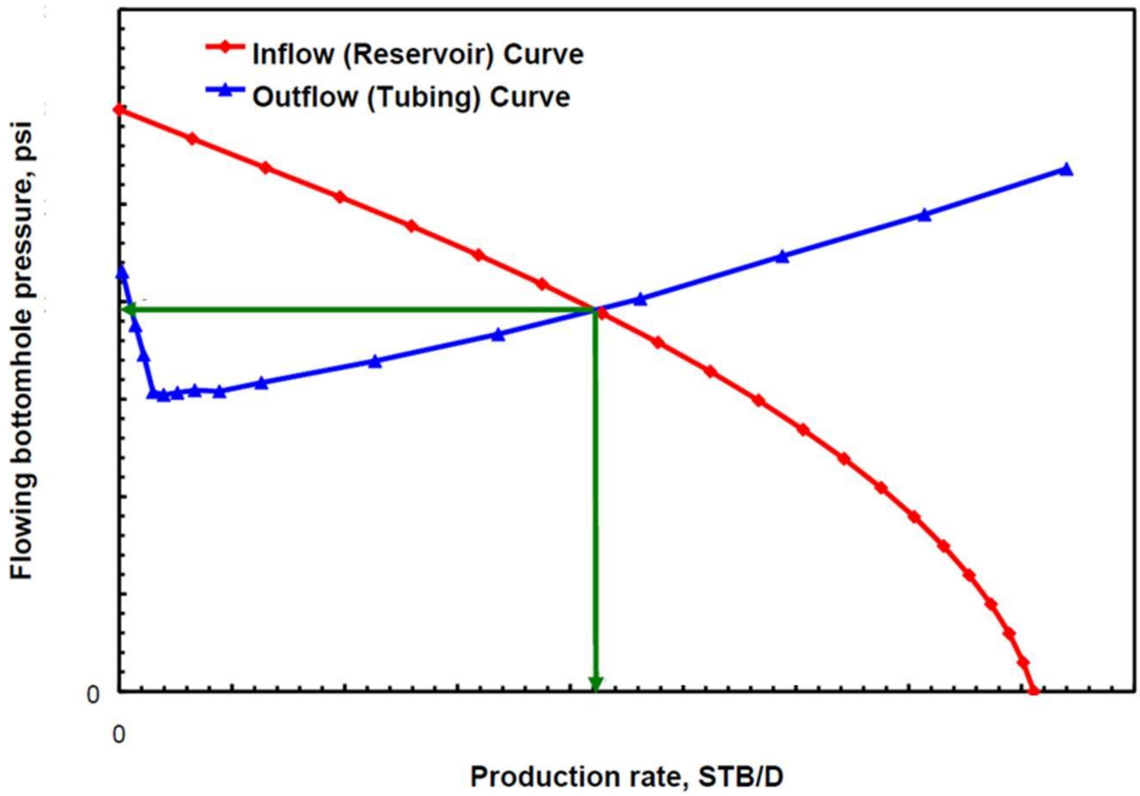

Figure 2.2 Inflow / outflow cross-plot

2.2 Wellbore Configuration

The wellbore configuration provides the starting point for well-flow calculations, providing the wellbore dimensions and lengths of the exposed reservoir sections as well as the size and length of the flow conduit back to surface. For WCD calculations, it is generally assumed that the wellbore configuration is intact as designed and without post-drill restrictions. A typical wellbore configuration contains all of the following elements from total depth (TD) to the discharge point:

- Rig relative to kelly bushing (RKB) elevation above mean sea level and above mud line (ML)
- Wellhead location and location of discharge point
- Casing and liner depths with weights, grades, and inner diameters (IDs) from surface to TD
- All pipe top and bottom depths in measured depth (MD) and true vertical depth (TVD)
- Directional plan showing wellbore inclination and azimuth for deviated wells
- Zones capable of flow expected to be encountered, with clearly defined depth of each
- Openhole size for all hole sections, including under-reaming size, if applicable

A wellbore configuration diagram is far more informative than a table of values. All zones potentially capable of flow that are exposed to any openhole segment of the wellbore during drilling should be identified on the diagram (see **Figure 2.3**). Care should be taken to ensure that depths reported on the wellbore diagram are consistent with depths reported in tables [e.g., US Bureau of Ocean Energy Management (BOEM) Form 137, see the Appendix].

This report discusses wellbore conditions prescribed by BOEM for US waters but regulations vary by country. In some countries, the regulations state that the operator is to describe a "reasonable" or "credible" scenario. This requires the flow engineer to work with the drilling team to describe and model the expected wellbore condition at the time of a WCD, which may or may not include drill pipe in the hole or any restrictions at the wellhead.

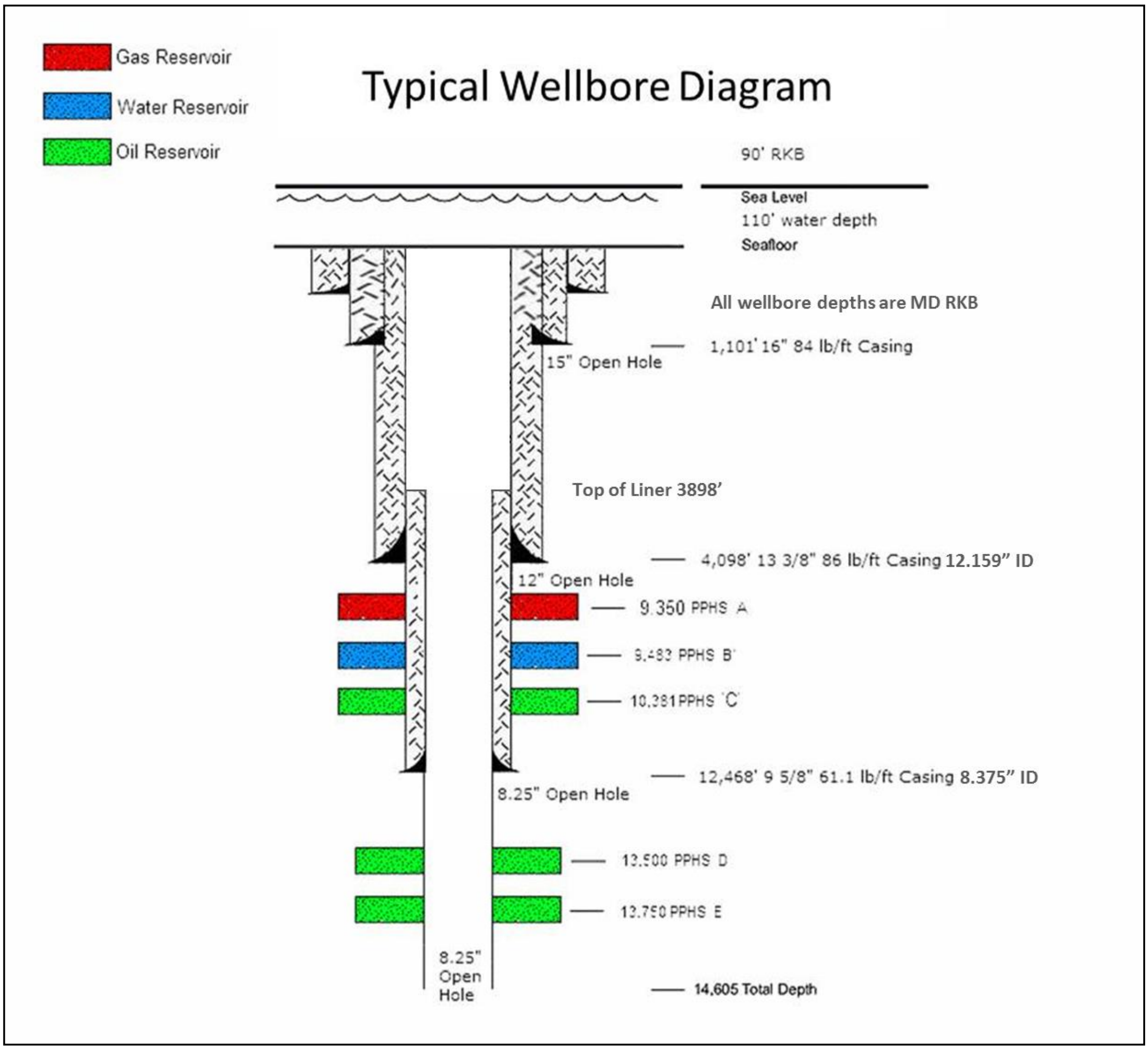

Figure 2.3 Example wellbore configuration showing 2 potential WCD sections (8 ¼ in. and 12 in. openhole sections)(US Department of the Interior 2010b). The WCD report must identify for which section is the WCD scenario.

2.3 Subsurface Characterization

2.3.1 Identification of Zones Capable of Flow

For each section of the wellbore, zones capable of flowing fluids into the wellbore are identified by the subsurface team. This work should include any and all zones capable of flowing oil, gas, or water into the wellbore at measurable quantities. One criterion for zone consideration might be the same as the BOEM's definition of commercial producibility, unless there are analog reservoirs in the same geologic horizon that produce from sands less than 15 ft. true vertical thickness (TVT). For example, BOEM guidance in frequently asked questions (US Department of the Interior 2010b) states:

> "…there are several reservoirs that currently produce from sands less than 15 ft. (TVT except for horizontal wells). Thus, you must consider any analog reservoir that is capable of flowing liquid hydrocarbons and is exposed to the open hole."

The flow calculation is performed for each openhole drilling interval that contains one or more zones capable of flowing up the open hole and shallower casing strings to the wellhead. Under BOEM guidance (US Department of the Interior 2010b), there are no restrictions in the wellbore, such as drill pipe.

Each openhole interval containing a producible zone should be evaluated in a top-down fashion (i.e. each permeable zone section added to the openhole section in the depth sequence they are expected to be encountered). This includes a permeable zone of any fluid—water, oil, or gas. As each permeable zone is encountered, the combination of permeable zones penetrated is examined to identify the highest, uncontrolled discharge rate. Once casing is set and tested over each hole section, the zones behind the casing should not be included in further uncontrolled discharge-rate calculations. This analysis is performed throughout the entire drilling program until the well reaches TD. After all the openhole intervals are analyzed, select the WCD interval with the highest potential liquid hydrocarbon discharge rate.

For example, if an openhole section would encounter a water-bearing sand and then an oil-bearing sand before the next casing point, then the uncontrolled discharge would include water and oil flowing. Water sand(s) below the hydrocarbon zone(s) should generally not be modeled as contributing to the inflow calculation. In particular, if a well is expected to penetrate a zone with an oil-water contact (OWC), then the WCD should be evaluated as if the drilling operation stopped at the OWC (i.e. no initial water, although water encroachment would be expected as the well continues to flow). However, if drilling continues in this openhole section to a deeper hydrocarbon zone, then the water interval below the OWC should be included in the inflow calculation. Numerical simulation may be required to correctly model the inflow behavior of these multiple fluid types. Examples showing the proper selection of zones capable of flow are provided in **Figure 2.4**

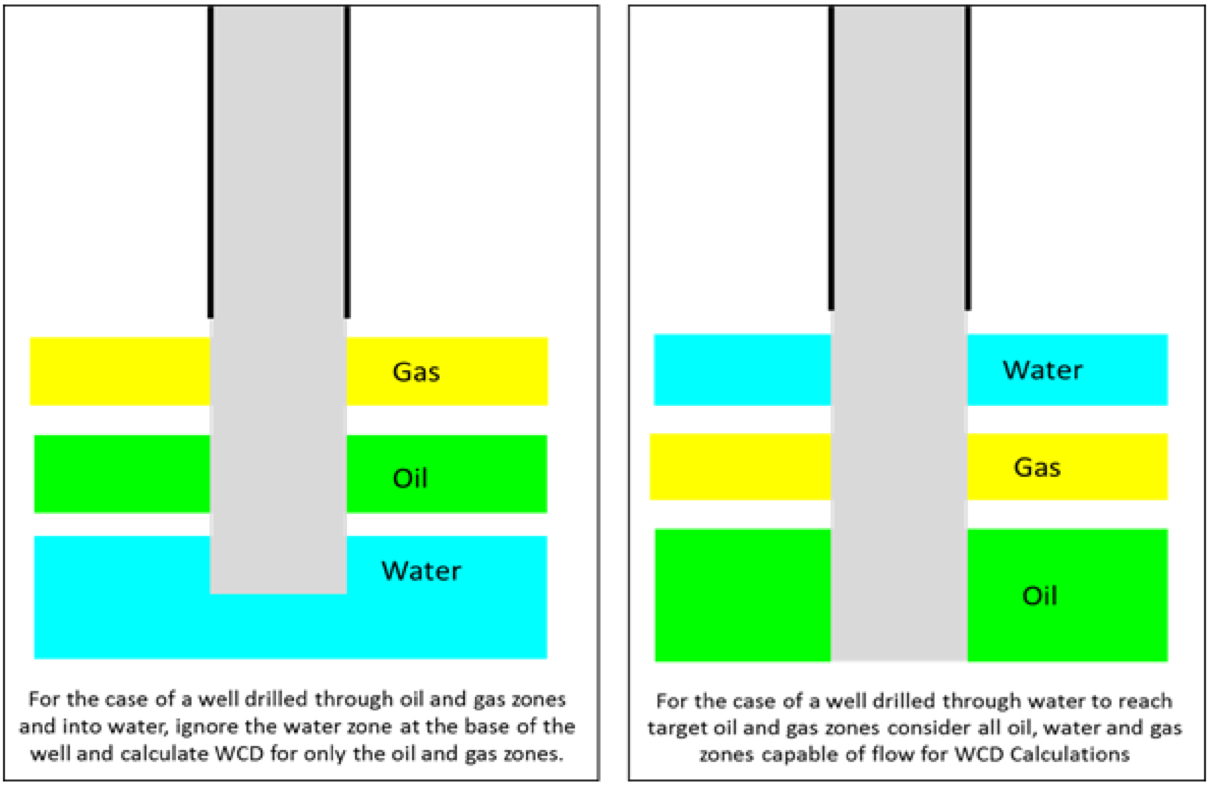

Figure 2.4 Example of proper selection of zones capable of flow

Water-bearing zones require special treatment because of the density difference between water and hydrocarbons. In general, the following rules should be followed regarding water: (1) convincing evidence must exist that the water zone will contribute to flow, and (2) no water zones below the deepest hydrocarbon-bearing zone. The water zone flow justification should include: (1) the presence of the zone, (2) confirmation that it is water bearing, (3) confirmation that it is capable of flow (permeability, pressure, etc.), and (4) confirmation that it is a thick, continuous zone.

For each zone that is to be considered in the WCD calculation, provide a structure map and a description of the interval, including gross and net thicknesses, rock properties, and fluid properties. Inflow performance is calculated based on the best technical estimate of the properties of each layer.

2.3.2 Selection of Analog Data

This section will identify analog well data used for modeling the WCD calculations and the justification for choosing a particular well as an analog for the well seeking permission to be drilled. BOEM Form 137 (see Appendix) must be submitted with an Exploration Plan or Development Operations Coordination Document in US federal waters. If the operator chooses to provide an additional table to justify multiple analogs for varying parameters, then the table should support the information provided on the BOEM Form 137.

A table with the name of each analog well for petrophysical properties, pressure, fluid data, and reservoir rock properties should be provided in this section. An example is shown in **Table 2.1.** The location of each analog well used should also be given (latitude/longitude or lease block, etc.).

Reservoir	Petrophysical Analog	Pressure Analog	Fluid Analog
AAA	Well 1	Well 1	Well 2

Table 2.1 Summary of analogs for proposed well

Table 2.1 provides a summary of the analog information used to establish input parameters for the proposed well-flow analysis. Detailed discussion should be provided in a narrative to show how petrophysical properties, pressure, and fluid information from the analog wells were used to establish the WCD rate for the proposed well. Justifications of the analog well can include, but are not limited to, the following:

- The proposed well's zones capable of flow are anticipated to be of the same geologic age and depositional environment as the corresponding analog well's producing interval.
- The discovered or producing reservoir at the analog well location is expected to be of similar quality to the corresponding reservoir at the proposed well given the expected similarity in age, depositional environment, and reservoir temperature.
- Hydrocarbons to be encountered at the proposed well should have a source type and maturity level similar to hydrocarbons seen at the analog well.
- Fluid pressures predicted for the proposed well are similar to the pressures seen in the analog well.
- The analog well contains the closest comparable reservoir penetration to the proposed prospect.

If more than one well can be considered an analog for the proposed well's input properties, then a justification for choosing the specific analog well should be provided (e.g. proximity of the proposed well, depositional environment, source rock maturity, source rock type, etc.). Different properties may require different/multiple analog well(s). The value of each reservoir property should be assessed as the best technical estimate by the subsurface team using all available data, including seismic, well logs, cores, fluid samples, well tests, pressure and temperature measurements, gradients, etc. Available public databases or regional studies can be used, but care must be taken in applying this data to WCD calculations.

2.3.3 Rock Properties

Care should be taken to consider any known reservoir characteristics. If reservoir characteristics are unknown, then the characteristics of any analog reservoir from the area should be considered for the best technical estimate and an explanation given for the selection of the well(s) and reservoir(s) used. In simple terms, the best technical estimate should be based on the success case the operator can expect to encounter at the well site (i.e. the same basis used to justify the drilling of the well and all associated equipment design). A summary table of all rock properties for each zone should be provided.

Probabilistic methods may be applied to the assessment of values for the individual parameters used in WCD modeling, see Sections 2.1, 4.2, and 4.3.

Depth: For each zone, the depth (MD and TVD) to the top and base of the zone should be determined. The reference depth of the inflow point should be assessed and used in both the inflow and outflow calculations. This should also be the datum depth for fluid properties.

Permeability: Permeability values for each zone can be derived from different sources and are listed in order of preference as:

- Pressure-transient analysis (production data)
- Conventional cores (porosity-permeability relationships)
- Rotary sidewall cores

Wireline formation testers, magnetic resonance logs, and percussion sidewall cores (because of possible core damage) can be used with caution in the absence of better data. Justify or explain the source(s) of the data where analogs are selected based on data quality and on the same lithology, depositional setting, and burial history.

For hydrocarbon zones, use effective permeability to hydrocarbon at S_{wc},

$$K_{eff} = K_{rel} \cdot K_{abs}$$

for reservoir inflow modeling. K_{abs} is measured at 100% saturation under in-situ stress conditions. For gas reservoirs, K_{abs} equals K_{air}. If only K_{air} and Klinkenberg corrected "equivalent" liquid permeability are available, use Klinkenberg. If there are no analog data available for Keff, it is proposed to use a simple Corey model (Corey 1954). Be aware of the different usage of K_{abs} and K_{eff} and the required input to your modeling software. Clearly document your permeability type (K_{abs}, K_{eff}, or otherwise).

Vertical permeability, in addition to horizontal permeability, may also be required in some cases (i.e., horizontal well modeling). Consider the vertical scale of the inflow modeling layers in relationship to core plug vertical permeability scale when accounting for bedding laminations.

Inertial Resistance Coefficient/Turbulence Coefficient: For reservoir cases where high gas flow rates and associated non-Darcy flow are expected, values for the inertial resistance coefficient, also referred to as turbulence coefficient or beta coefficient, may be required. Beta values can be measured from core test data or calculated from standard petroleum engineering correlations (Tek et al. 1962; Firoozabadi and Katz 1979). BOEM does not currently consider turbulence for liquid-flow cases. Turbulence is allowed for gas-flow cases.

Reservoir Thickness: Gross and net thicknesses must be specified for each zone. The choice of true stratigraphic thickness (TST) or true vertical thickness (TVT) must be consistent with the modeling method chosen (**Figure 2.5**) and clearly documented. In general, for nodal analysis or analytical flow rate calculations, TST should be used. When building a numerical simulation model, the TVT should be used. Clearly identify the wellbore inclination angle, azimuth, and bed dip, so as to define TST and TVT. Include net/gross ratios and cutoff values used for evaluation of net-pay thickness values and the reference data used for this analysis. Use net-pay thickness values for modeling reservoir inflow. In any case, the MD thickness must also be considered in the inflow calculation, which may impact geometric skin (Section 2.3.6).

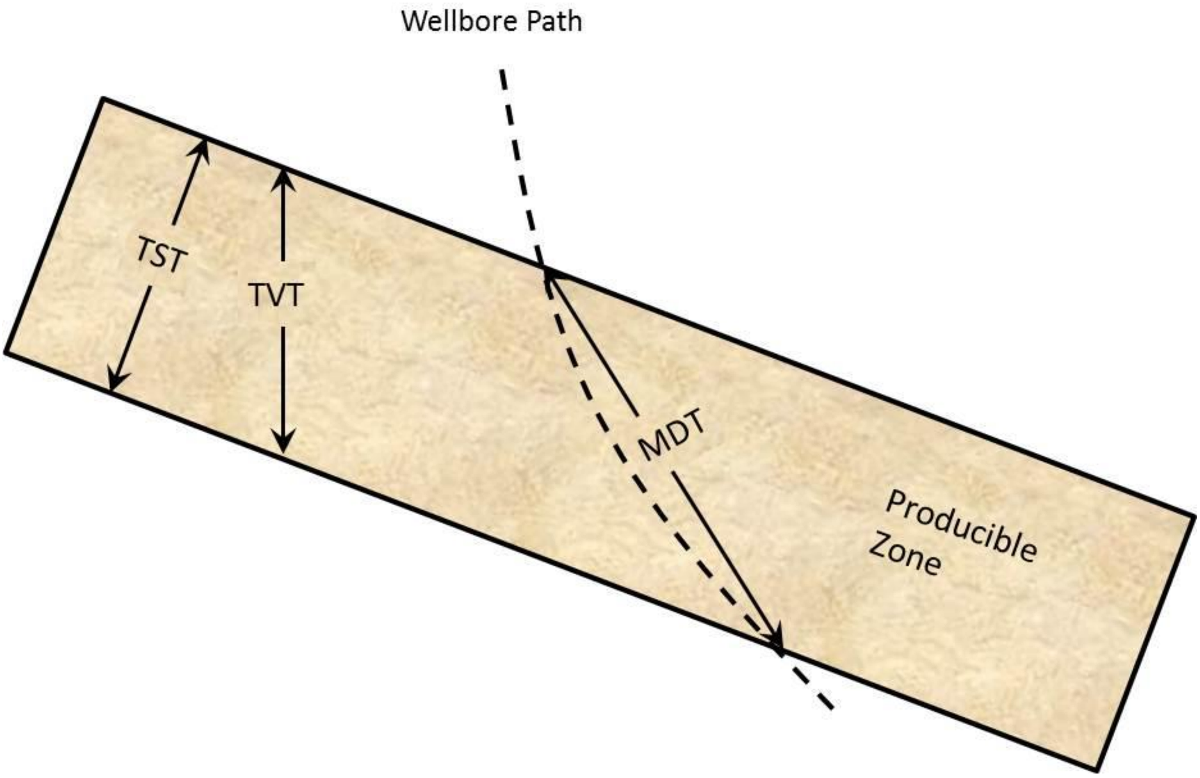

Figure 2.5 Depth references
(MDT = measure depth thickness)

Porosity: Determine the effective porosity of each horizon from available analog data for geologic prognosis. If no analog core or log data is available, porosity can be estimated from seismic correlations, environment of deposition facies, compaction trends, or other exploration trend analyses.

Formation Compressibility: Pore compressibility should be determined from uniaxial tests on vertical core plugs. In the absence of such data, nearby analog data may be used or a predictive technique can be applied (Crawford et al. 2011; Yale et al. 1993) to estimate the formation compressibility (pore compressibility) at current conditions. While formation compressibility will not impact the day one discharge rate, it potentially would have an impact over the flow duration (increased reservoir energy, permeability loss caused by pore compression).

2.3.4 Fluid Properties

A number of parameters must be determined to properly define the reservoir fluid properties of the well to be drilled. When there are available analog data from a well or wells within the same field or nearby developments thought to have been filled by the same source rock, this data should be used. In cases without close analog data, regional studies from reservoirs of similar geologic age, deposition, etc., can be a useful source for fluid data. In general, use analog pressure/volume/temperature (PVT) measurements and tune your fluid model [correlations or equations of state (EOS)] to expected pressures and temperatures at the well.

Include a summary table with properties at reservoir conditions for each zone of interest. Define fluid properties over the expected range of flowing pressures and temperatures from the reservoir to the discharge point. Care should be taken to account for contamination by oil-based mud in any analog PVT samples used. When using correlations or an EOS to estimate fluid properties, document the correlations used and why it was chosen. Several correlations are available for each property and were developed using different data sets from different regions and have been compared against known fluid properties (De Ghetto et al. 1994).

Fluid Type: Determine the fluid type to be penetrated as black oil, volatile oil, gas condensate, wet gas, dry gas, or water. Identify combined cases such as oil with gas cap or gas with oil leg. Justify the selection based on analogs for each productive horizon.

Separator Conditions for PVT Modeling: Fluid properties at the surface and along the wellbore flow path are dependent upon the separator conditions modeled between the reservoir and stock tank conditions. Determine which laboratory experiment (single stage flash, differential liberation, constant volume depletion, separator test, etc.) best approximates the expected flow path and use the fluid properties from that test.
The WCD flow path is complex and nontraditional with no separator conditions Therefore, the single-stage flash data experiment normally best represents a WCD scenario.

Saturations: Define initial and residual saturations of both hydrocarbons and water. Initial and residual saturations can be derived from analog well data.

Reservoir Pressure: Assess the current reservoir pressure based on analog data, historical performance, and offset data. Exploration wells may be assessed using analog and/or regional pressure gradients. New reservoirs should be assessed at initial reservoir pressure. For fields with historical production, estimates of depletion and re-pressurization should be addressed and documented.

Reservoir Temperature: Apply a temperature gradient based on the analog offset wells, from the discharge point to the defined datum. Take into account the sea bed temperature. In subsalt fields, modify temperature calculations to account for salt effect. Similarly, in arctic areas, modify temperature calculations to account for permafrost.

Fluid Viscosity: If available, use measured viscosity from analog PVT studies, adjusted to local conditions. Otherwise, use an industry standard viscosity correlation (Petrosky, Beal, Sutton, Bergman, etc.) that is applicable to the basin and fluid type.

GOR and CGR: Define the gas / oil ratio (GOR) or condensate/gas ratio (CGR) according to supported analogs. Justify and explain the yield curve of condensate gas (condensate yield vs. reservoir pressure).

Saturation Pressures: If available, use measured data from analog PVT studies, adjusted to local conditions. Otherwise, use an empirical correlation (Glasø 1980, Standing 1981, Lasater 1958, Vazquez-Beggs 1980, etc.) that is applicable to the basin and fluid type.

Formation Volume Factors and Fluid Compressibilities: If available, use measured data from analog PVT studies, adjusted to local conditions. Otherwise, use an empirical correlation (Glasø 1980, Standing 1981, Lasater 1958, Vazquez-Beggs 1980, etc.) that is applicable to the basin and fluid type.

Fluid Density (API and Specific Gravity): Define fluid density based on analogs at a similar depth, temperature, and with a common source rock.

Gas Composition: Provide the gas gravity or the molecular weight, and specify the expected non-hydrocarbon impurities, such as hydrogen sulfide, carbon dioxide, and nitrogen.

2.3.5 Drainage Area and Drive Mechanism

Generally, the initial transient flow rate is not dependent on the drainage area or drive mechanism. The drainage area will, however, influence the longer term rate profile during the duration of a WCD event as discussed in later sections. However, the drainage shape, (i.e. the placement of a well relative to flow boundaries), may influence the initial rate and should be properly accounted for using a Dietz shape factor (Dietz 1965), a Fetkovich shape "skin" (Fetkovich and Vienot 1985), or simulation. If the actual shape of the drainage area is unknown, then it is proposed to perform WCD calculations using a circular shape with the well in the center.

The drainage area and associated shape factors should be based on structural maps and defined structural or stratigraphic flow boundaries. In most cases, this should represent the full extent of the reservoir regardless of any offset wells that may or may not be producing.

All expected reservoir drive mechanisms should be accounted for in the analysis and should be described and justified sufficiently, citing any assumed analogs. This includes both depletion drive mechanisms (solution gas drive, gas cap expansion, natural water drive, and compaction drive) as well as injection drive mechanisms (gas or water) that are expected to be in operation during the drilling of the well. Consider likely changes in field operations as a result of a spill (production and injection shut-in) and the impact on the expected reservoir drive mechanisms. Frequently, reservoirs exhibit a dominant drive mechanism, but all mechanisms that are expected to materially contribute to production should be considered.

2.3.6 Wellbore Conditions Affecting Inflow Performance

Several wellbore parameters can affect well inflow performance.

Wellbore Radius: Use the drill bit radius or the size of any under-reamer run through the openhole interval.

Wellbore Inclination: In conventional, non-horizontal wells, the inclination of the wellbore relative to the bedding planes can affect well inflow performance (Cinco et al. 1975; Fair 2008). Wellbore inclination increases the flow area of the wellbore, thereby increasing the rate for a given drawdown. This inclination effect is generally accounted for by using an inclination skin in the flow calculation. Inclination skin effects are not applicable to horizontal wells.

Partial Penetration: In conventional, non-horizontal wells, partial penetration of a thick zone by the wellbore can also affect well inflow performance. For WCD calculations, this would only apply to the special case where a planned TD is only partially through a thick reservoir (e.g. when planning an openhole gravel pack above a known water contact). Opening only a portion of a thick flow interval to the well complicates the flow pattern and reduces well inflow performance (Brons and Marting 1961). This effect is generally accounted for by using a partial penetration skin factor in the flow calculation. Partial penetration skin effects are not applicable to openhole horizontal wells.

Combination of Wellbore Inclination and Partial Penetration: In cases where inclined wells partially penetrate a thick flow interval, special techniques are required to calculate the appropriate skin factor (Cinco-Ley et al. 1975).

Near-Well Drilling Damage: Per BOEM guidance, a mechanical skin of zero should be used. Mud damage and mud filtrate invasion can reduce the near-well permeability. However, because of uncertainties in the magnitude of the permeability reduction, the radial extent of the damage, and the longevity of the damage during high rate flow, these effects should be ignored for WCD calculations.

Wellbore Collapse and Wellbore Fill: Blockage of the open hole by formation collapse, solids inflow, or other wellbore fill should not be considered when performing WCD calculations for wells regulated by the US BOEM. The open hole should be considered to be in the same condition and have the same dimensions as originally drilled (or under-reamed) before the WCD event. For areas outside of the US, other regulations may apply, but wellbore collapse and wellbore fill should not be assumed for WCD unless strongly supported by geo-mechanical testing or analog evidence.

Rate Dependent/Non-Darcy Flow Skin: In cases with high rate gas flow, non-Darcy flow effects can result in a rate dependent, near wellbore pressure loss. The result of this rate dependent or Non-Darcy pressure loss on a well's IPR can be modeled as a rate dependent skin:

$$S_{total} = S' + D \cdot Q$$

where S_{total} is the total skin, S' is the Darcy skin and $D \cdot Q$ represents the non-Darcy, rate dependent skin effect. The effect of a rate dependent skin term will be to reduce flowing BHP at high rates over Darcy calculated values. Non-Darcy D-terms for openhole completions can be derived for oil and gas flow cases using several methods (e.g. Brown 1984). BOEM only considers turbulence in gas wells. Liquid flow is always assumed to follow Darcy's Law.

2.4 Inflow Modelling

Well inflow analysis and material balance are the basic tools to estimate inflow to the wellbore from reservoir zone(s) encountered while drilling the openhole section. Selection of the tool type to use for inflow modeling requires consideration of the reservoir rock and fluid properties, the change in these properties over distance and time, and the reservoir geometry. Nodal/analytical tools are sufficient for simple reservoirs, where the flow duration is short, or where reservoir rock and fluid properties are not expected to change significantly over the duration of flow. For more complex reservoir situations, numerical simulation may be required. In other words, a simple tool is adequate if it can satisfactorily describe and predict the expected well/reservoir system. Use of probabilistic tools to calculate the flow rate is not currently viewed as standard practice and is, therefore, not proposed.

Nodal/analytical models can typically calculate transient, steady-state, or pseudo steady-state flow. The engineer must determine which flow regime is most appropriate for the case to be modeled.

- Steady-state equations are sufficient in cases of high transmissibility ($K{\cdot}H/u$) systems where the transient is expected to reach all boundaries within a short period of time, such as when the stabilization time is less than one day.
- Pseudo steady-state equations should not generally be applied until all of the reservoir system drainage boundaries are reached and the reservoir drainage area is beginning to deplete. This can be used in cases where the stabilization time is an hour or less.
- Transient flow equations should be used when low permeability or high viscosity results in transmissibility values low enough to cause a long period of transient flow, such as when stabilization time is more than one day.

Transient flow can be estimated analytically as a series of steady-state flows. In these calculations, a time-dependent drainage radius is calculated as shown in **Figure 2.6.**

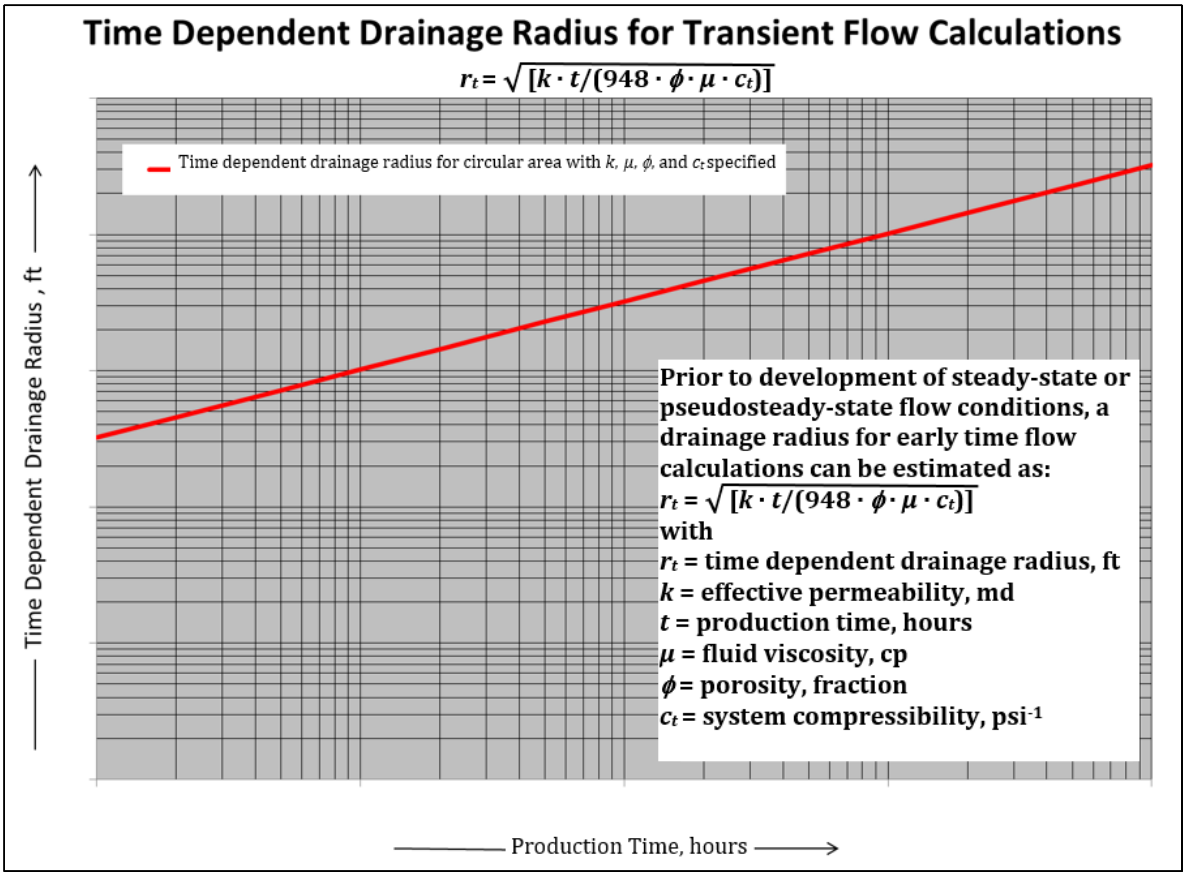

Figure 2.6 Time for pressure transient to reach drainage radius

Drainage area assumptions can have a potentially significant impact on WCD rate estimates when using steady-state or pseudo steady-state equations. A typical nodal analysis approach yields the inverse relationship of rates to drainage areas shown in **Figure 2.7** for a simple under saturated, black-oil case. This behavior is a result of the implicit pseudo steady-state assumption commonly used for nodal IPR calculations.

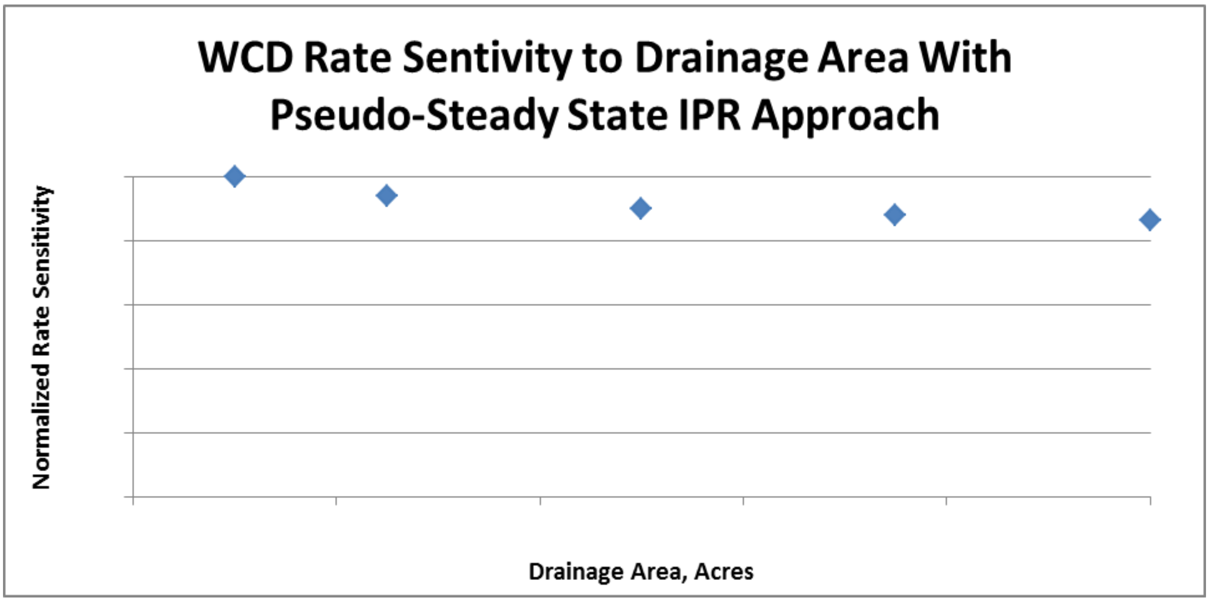

Figure 2.7 Impact of drainage area on rates

By contrast, a transient methodology (e.g. finite difference simulation) results in a negligible effect. Therefore, care should be taken to estimate the drainage area and shape if steady-state or pseudo steady-state equations are used because overestimating the drainage area will result in a lower calculated discharge rate.

Numerical simulation may be desired to adequately predict the rates over the duration of the flow period when complex geology (structure or stratigraphy), complex fluid behavior, or drive mechanisms are expected. Where production history exists, reservoir simulation may be necessary to describe and model the current pressures and saturations.

Liquid zones should be modeled using Darcy flow. Gas and gas condensate inflow should be calculated using a pseudo pressure model with appropriate turbulent effects.

2.4.1 Effect of High Drawdown on Fluid Properties

Be aware that nodal analysis software tools will often assess the fluid properties at the average pressure between the reservoir limit and the wellbore. For example, in cases of high viscosity and large pressure drawdown, the average viscosity may not result in an accurate inflow prediction because neither the pressure vs. radius nor the viscosity vs. pressure may be linear relationships. Numerical simulation with local grid refinement near the wellbore may be required to accurately predict viscosity variations and flow rate.

This effect applies to all of the fluid properties. Therefore, in all cases of high drawdown, simulation is proposed. It is proposed to compare nodal analysis with a numerical simulation sector model with sufficient near-wellbore gridding, since the latter accounts for changes in fluid properties in the near-wellbore region when facing severe drawdowns (e.g. in an uncontrolled blowout).

2.4.2 Well Deliverability Impairment Caused by Gas Breakout

In oil-flow cases where the flowing BHP (FBHP) drops below the bubble point, gas will separate from the reservoir oil and form free gas saturation near the wellbore. This free-gas saturation will reduce the relative permeability to oil and impede flow to the well.

In simulation studies, gas-oil relative permeability data can be used to calculate the effect of free-gas saturation in the near-wellbore region. For analytical calculations using nodal analysis techniques alone, the Vogel technique (Vogel 1968) can be used to estimate the effect of free-gas saturation on well-flow performance

2.4.3 Coning and Cusping of Water and Gas

Modeling of gas or water coning or cusping will require the use of reservoir simulation and employing local grid refinement around the wellbore. These phenomena will only affect the WCD rate if they develop during the first day of flow, otherwise, they will not affect the WCD rate, but may be included for the duration of the blowout to estimate total volume. In development drilling, the depths of fluid contacts may be well constrained and coning and cusping effects can be reasonably integrated into the WCD model. Because many WCD models are constructed before drilling the well, the exact depth of penetration of the hydrocarbon zone is unknown and the depth of the fluid contacts may also not be known precisely. Therefore, there will be considerable uncertainty in any coning/cusping behavior and should generally only be included at the operator's discretion for the calculation of the total volume for the duration of the blowout.

2.4.4 Impairment Caused by Condensate Dropout

Inflow impairment can occur from condensate buildup in the near-wellbore region of the reservoir. Several methods (Muskat 1950a, 1950b; Golan and Whitson 1991) are available for predicting this effect. However, there is concern that it may not fully develop during a WCD event; therefore, it is suggested that one should not use it in a WCD submittal unless the phenomenon has been observed and clearly documented with well performance data and PVT laboratory analysis.

2.4.5 Naturally Fractured Reservoirs

Modeling of naturally fractured reservoirs require special consideration to properly account for the dual-permeability nature. Reservoir simulation of these cases is proposed.

2.5 Outflow Modelling

The outflow model should calculate the pressure changes in the well caused by friction, gravity, and acceleration, as well as account for the changing hole size and materials that the fluids flow through. If the well is deviated, a directional survey will be necessary to properly account for pressure drops along the well path.

The location of the deepest blowout preventer (BOP) establishes the general depth of the discharge point and the associated outlet pressure. Jack-up rigs and platform rigs generally position the BOP above the mean sea level, and atmospheric pressure is the outlet pressure. Floating drilling rigs generally position the BOP at the ML, where the hydrostatic head of the sea water at 0.445 psi/ft. sets the well's outlet pressure. Note that BOEM requires that the discharge point be at the top of the wellhead and without the BOP, or if the BOP stack is included that no internal restriction is present.

For wells drilled in US offshore areas regulated by the BOEM, outflow pressure loss predictions should assume that the wellbore flow conduit is composed of fully open BOPs, casing, liner, and open hole without restrictions because of partially closed BOP elements, pipe or open hole collapse, or location of drill pipe in the well. This condition is defined to be the worst-case well condition for uncontrolled discharge of fluids under US BOEM regulations. In other areas of the world, the condition of the wellbore during a WCD event may include drill pipe or BOP restrictions. As a result, it is important to establish an agreed basis for WCD flow conditions in these areas.

2.5.1 Flow Correlations

Several industry-recognized pipe flow correlations (Gomez et al. 1999) have been created and are available in most nodal analysis software packages. Each of these flow correlations has an applicable range for key variables such as GOR, oil gravity, water cut, well inclination, and wellbore size. Careful consideration should, therefore, be given to the selection of an appropriate flow correlation based on these variables.

BOEM uses a set of flow correlations depending on reservoir type and conditions (US Department of the Interior 2010b). Software packages include other correlations that can be used and should be supported in the documentation to BOEM.

It is suggested that the user should calculate the flowing pressure gradient using several of these flow correlations and plot the pressure gradient versus depth from each correlation. In general, Duns and Ross Modified can be used as an upper limit on pressure drop in oil wells (or Beggs and Brill, if the former is not available) and any flow correlation resulting in a lower FBHP can be excluded as not reasonable. Similarly, Fancher-Brown can be used as a lower limit on wellbore pressure drop because it does not consider slippage between the phases. Therefore, any flow correlation with a higher FBHP than calculated by the Fancher-Brown correlation can be excluded as unreasonable. Most flow correlations were developed for small diameter pipe so that their applicability to larger diameter pipe and open hole is uncertain. However, until the industry can test correlations against more real-world flowing conditions, these are the best available. The committee proposes further research and development be conducted of appropriate correlations for high rate flow in large diameter pipe.

The depth of the fluid entry point or points along the wellbore should be set such that friction along the open hole and across the flowing zone is taken into account. Correct placement of the fluid entry point is most important in thick reservoirs and can be insignificant in very thin reservoirs. For a well with a single flowing zone, the depth of the fluid entry point can be set at either the midpoint of the reservoir or the top of reservoir, but the reservoir pressure depth reference must be consistent. The most conservative, lowest backpressure, assumption occurs when all of the reservoir inflow enters the wellbore at the top of the zone. The engineer should be aware that some software packages default to inflow at the base of the zone in some models. Therefore, the depth reference for initial reservoir pressure should be the same depth.

2.5.2 Wellbore Temperature

For effective outflow modeling, the temperature along the outflow path must be estimated. Variations in temperature will affect wellbore fluid properties and resulting fluid density and friction components of the flowing pressure gradient. As a minimum, a linear flowing temperature gradient from the reservoir to the flowing wellhead temperature should be used. For best results, thermal calculations taking into account the fluid properties, the heat transfer coefficient of the well, and the static geothermal temperature gradient should be used to predict the flowing temperature gradient under WCD conditions. For most high rate discharge cases, the flowing wellhead temperature will be significantly higher than the static wellhead temperature and will generally be found to be near the static reservoir temperature. It is suggested that the user test the extreme case where the temperature at the wellhead equals the bottomhole. This will provide an understanding of whether or not the WCD results are sensitive to wellhead temperature. If so, more rigorous thermal models should be used.

Joule-Thompson effects have been observed in some cases of high liquid flow rates across a high pressure-drop choke. This is a complicated effect and has a negligible effect on flow rate. Because there is not a flow restriction in the WCD scenario, this effect is insignificant for the WCD calculations and should be ignored unless the engineer has strong supporting data.

2.5.3 Fluid PVT Correlations

A factor the user should consider in the calculation methodology is how the fluid properties are handled once multiple zones have entered into the wellbore (casing/open hole). Most software applications use mixing rules to estimate the combined fluid properties. Another concern is the estimation of oil viscosity by compositional models. It is proposed to check the results of the compositional model calculation. Very high rates may make the impact of oil viscosity negligible. However, it is worth understanding what your software package calculates. Finally, water salinity is often not carefully considered. However, salinity will change the water viscosity and density, and therefore, the flow characteristics of the system.

2.5.4 Frictional Pressure Losses in Well Outflow Calculations

Frictional pressure losses in well outflow calculations are performed using friction factors related to the fluid velocity in the well, the properties of the flowing fluid, and the size and roughness of the flow conduit. For single-phase liquid or gas flow at high rates, turbulent flow will occur in the well. In these cases, pipe roughness and hole roughness can have a significant effect on outflow friction and associated well flow rates. As a result, most outflow calculation programs will require the user to input one or more roughness values. Appropriate roughness values should be selected on the basis of standard industry correlations or justified on the basis of field specific pressure loss data. The software should use the Colebrook-White method to calculate the impact of friction.

2.5.5 Casing Roughness

Roughness values (Smith et al. 1954; Cullender and Brinkley 1950; Katz 1959; Engineering Division of Crane Co. 1942; Farshad and Rieke 2005) for typical oilfield tubulars are generally approximately 0.0006 in. or 0.00065 in. Roughness of carbon steel pipe has been measured at 0.0018 in., but this value was measured on newly milled line pipe and accounts for the presence of welds and mill scale. Wellbore tubulars are normally screwed together and have been cleaned, resulting in a lower value of roughness. However, the casing and liner stings would have been subjected to drilling and cementing operations, which may increase the roughness. Therefore, until better measurements are made, this committee proposes using a roughness value no higher than 0.0018 in. for carbon steel casing and 0.0006 in. for tubing, unless otherwise justified.

2.5.6 Open hole Roughness

Roughness values for the open hole (Pennington 1998; Johnson 2009; Lyons et al. 2001) may be based on evaluation of flowing pressure loss data measured in the field. In the absence of measured data, some general guidelines are shown in **Table 2.2**.

The roughness value for the openhole sections can be estimated based on an average formation grain size by using an absolute roughness value for rough concrete (i.e. value of 0.02 ft. or 0.24 in.) or by rock type as shown in **Table 2.2**:

Rock Formation Type	Surface Roughness(ft.)	Surface Roughness(in.)
Competent, low fracture • Igneous (e.g., granite, basalt) • Sedimentary (e.g., limestone, sandstone) • Metamorphic (e.g., gneiss)	0.001 to 0.02 ft.	0.012 to 0.24 in.
Competent, medium fracture • Igneous (e.g., granite, basalt) • Sedimentary (e.g., limestone, sandstone) • Metamorphic (e.g., gneiss)	0.02 to 0.03 ft.	0.24 to 0.36 in.
Poor competence, highly fracture • Igneous (e.g., breccia) • Sedimentary (e.g., sandstone, shale) • Metamorphic (e.g., schist)	0.03 to 0.04 ft.	0.36 to 0.48 in.

Table 2.2 Openhole wall absolute surface roughness for various rock types

If values other than those described above are to be used, the engineer should provide documentation demonstrating why other values are more appropriate.

2.5.7 Pressure Loss Between Zones & Within a Zone

When modeling wells with multiple zones of inflow, account for the pressure loss between zones, including friction and gravity. When calculating friction loss between zones, the total flow from all zones below the friction loss interval must be included as shown in **Figure 2.8**.

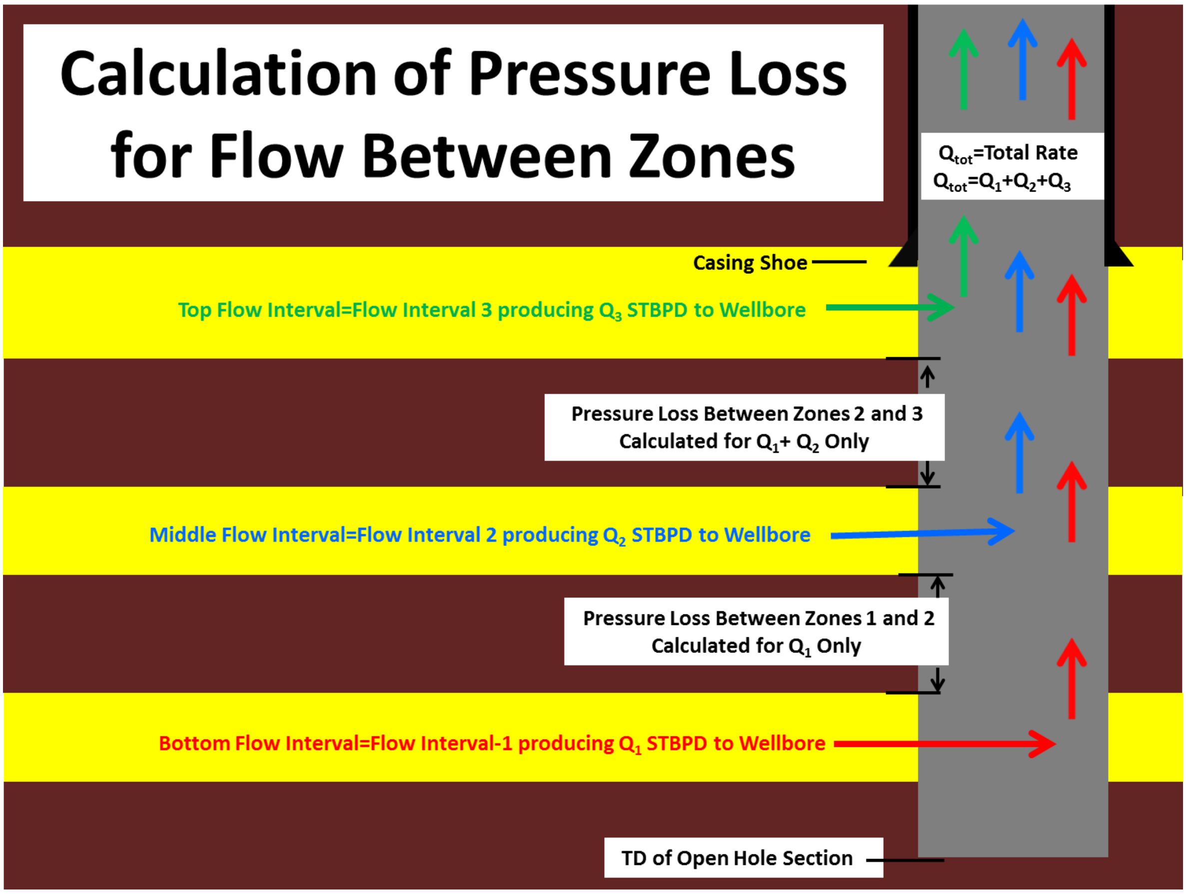

Figure 2.8 Calculation of pressure loss for flow between zones

The pressure loss within a zone could be significant and is not considered in some software packages. One way to incorporate the frictional pressure losses is by modeling flow from the mid-perf depth of each zone. It is important to understand your preferred software's capabilities and limitations.

2.5.8 Crossflow

Crossflow between zones exposed in the openhole section of the well for which WCD is being calculated may be considered. Most nodal analysis and reservoir simulation software includes provisions for calculating and reporting crossflow among multiple zones. This could be important in older fields with pressure-depleted zones. If crossflow is assumed and included in the result, it should be explained and justified. One question to be considered is whether or not the injectivity index is the same as the productivity index.

For new discoveries and new field developments, the magnitude of the drawdown during WCD flow is normally great enough to overcome any differences in the initial static pressures of the individual zones. Therefore, crossflow would not occur.

2.5.9 Sonic Velocity Limitation

At very high gas discharge rates to a low-pressure environment, the well exit velocity may approach sonic velocity and limit the gas flow rate by critical flow choking. This would only apply to wells with a discharge point above sea level allowing flow to the atmosphere. Most Nodal analysis software packages include a sonic velocity check at each calculation node.

Critical flow calculations (Engineering Division of Crane Co. 1942; Sabersky et al. 1999) for high gas flow rate cases at or near sonic velocity can be performed to determine the amount of pressure increase that occurs at the discharge point and the resulting flow limitation that may occur. The increase in pressure is estimated at 100 to 400 psi.

For most cases of practical interest, critical flow limitations are expected to have only a small effect on well discharge rate. As a result, sonic velocity flow limitations should generally be ignored for WCD calculations unless special conditions apply. However, where applicable, it may be invoked by an operator with proper justification. However, until further research is conducted, BOEM will not be applying sonic velocity to the WCD calculation.

2.5.10 Sand Bridging, Hydrates, Washouts

Mechanical earth models or flux calculations can predict the possible occurrence of a collapse or bridging off of an openhole section (Akbarnejad-Nesheli and Schubert 2006; Willson et al. 2013; Willson 2012). However, sand bridging is not proposed for consideration in WCD scenarios. Only in cases where nearby analogs have demonstrated a strong likelihood of the occurrence should sand bridging be considered in WCD calculation. Sand bridging inclusion in the WCD submittal should be properly justified. Similarly, for hydrates and washouts, these phenomena are difficult to predict and the committee proposes ignoring these phenomena for WCD scenarios.

3. Total Discharge Volume

3.1 Duration of Flow Period (Intervention Time)

A blowout may end in several ways, as determined in the well plan. The most likely intervention scenarios are deploying a capping stack or drilling a relief well.

While the likelihood of these scenarios should be discussed in the worst-case discharge (WCD) report (US Department of the Interior 2010a), the maximum duration of the potential blowout shall be used for the subsequent calculation of total spill volume. In practice, this means that the estimated total time required to mobilize a rig, drill a relief well, and perform a kill operation should be estimated and used as the maximum duration of flow period, also known as the intervention time.

In jurisdictions other than those regulated by the US Bureau of Ocean Energy management (BOEM), the duration of the deployment of a capping stack may be appropriate and acceptable to the regulator.

3.2 Profile for Flow Rate Decline

For all cases evaluated, production rates of oil, gas, and water should be calculated for the duration of the expected flow period. From this profile, the maximum daily discharge rate and total intervention discharge volume can be computed in accordance with regulatory guidelines. In addition, the profile will provide an estimate of the expected production decline and any potential changes in the ratio of fluids being produced, which may be a consideration in containment or relief well efforts.
An output table or graph of rate vs. time from the software showing the production profile should be included. Reasons for production decline could include water/gas coning,

cusping, or other breakthrough, nearby boundaries; transient-flow decline; or pressure depletion. If significant decline is expected, it should be explained.

3.3 Total Discharge Volume

The total potential discharge volume for the WCD scenario is defined as the sum of production over the duration of flow period (intervention time). Typically, the discharge rate can be expected to decline over the duration of flow period. Therefore, the total discharge volume can be reported as the total produced volume from the rate profile for production decline, as explained in the previous section.

In addition to the pressure support that may be associated with the expected drive mechanisms, the potential fluids that may break through during the blowout timeframe should also be considered, as these fluids have the potential to change the WCD rate. Likewise, if expected coning of water or gas is incorporated, it should be properly justified. BOEM does not currently model the coning of water or gas.

4. Other Issues / Special Cases

4.1 Quality Assurance

Quality assurance checks should be made by the operator to ensure reasonable input parameters and results from the software used to perform the worst-case discharge (WCD) calculations. This should include, at a minimum, visual checking of the inflow curve, the outflow curve, pressure gradients, hand calculations, or other simpler screening methods. In addition, BOEM conducts an independent assessment of the input parameters and the flow model outputs to verify the operator's results. [Note: This independent assessment may not be conducted by international regulatory agencies.]

4.2 Parametric Sensitivity

A parametric sensitivity analysis should be conducted in order to identify the major variables that impact the result. This is to focus the engineer's efforts on the most important variables.

All parameters used in the WCD calculation have some range of uncertainty around them. The WCD should be based on the best technical estimate for each parameter. For exploration wells, this means that the engineer should assume base case exploration success, the well will reach the target, the formation will contain hydrocarbons, and the reservoir properties will be as expected. The engineer should explain and justify all parameter values, but in all cases should represent the best technical estimate by the geoscience and engineering team, as discussed in Section 1.1. The same values should be used for WCD that were used to justify the drilling of the well and to design the equipment (i.e. one set of values consistently used in all analyses of the well). These are different calculations for different purposes, but the underlying reservoir knowledge is the same. Therefore, the deterministic parameter values should be the same for consistency and transparency.

Some parameters have a much wider range of values than others, while some have a much larger impact on the resulting flow rate. To understand the impacts, each WCD calculation should include an assessment of these ranges of inputs and resulting flow rates. This is especially useful for the engineer in determining which parameters have the largest impact. Then the engineer my focus their efforts on these parameters to ensure the appropriate values have been used in the WCD. In other words, identify what matters and work on it. A graphical representation of the relative impacts of input parameters, such as in a tornado chart shown in

Figure *4.1*, can be very useful in this regard, even when using qualitative assessment of ranges where statistically valid data sets do not exist.

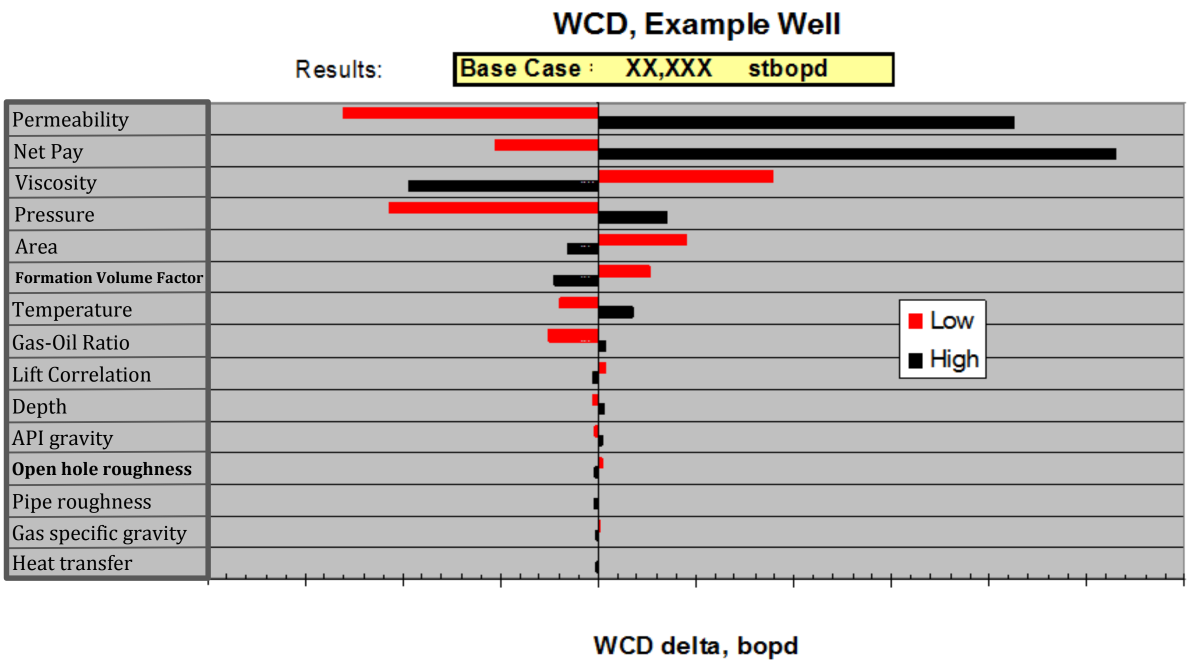

Figure 4.1 WCD uncertainty analysis example tornado chart

Parameters that have negligible impact on the result are then not worth further pursuit. It is also recognized that combining high side values of several parameters is a highly unlikely outcome and is generally not warranted. Uncertainty analysis is internally useful for the engineer, but it is not required by BOEM. In fact, for the WCD prediction, 30 CFR requires "a volume" (i.e. one number that represents the predicted volume under the described scenario), not a range.

4.3 Probabilistic Assessments

As stated previously, the current USA regulations require "a volume" for WCD and the determination "must consider known reservoir characteristics" of the reservoir, or if not known, then the known characteristics of an analogous reservoir -- "not a combination of extreme values". This wording in the regulations makes it very difficult to meet the requirements with any type of probabilistic modeling. However, this SPE Committee would welcome any proposed methods that could improve the current practices while meeting the federal regulations.

The number of data points is often insufficient to support statistical analysis, especially in exploration plays. This prohibits a purely statistical approach and should be replaced with sound geology, geophysics, and engineering judgment which considers the physical trends (e.g. proximal to distal depositional trend for thickness and permeability).

The requirements for WCD appeared for the first time in the Oil Pollution Act of 1990 and have become more robust since the Deepwater Horizon / Macondo incident of 2010. As the industry continues to evolve in this area, a probabilistic method may someday be acceptable. Such a method would need to provide for modeling the decline in pressure and flow rate over time and provide the details necessary to plan capping stack design and procedures.

Probabilistic assessments and statistical analyses can certainly provide useful information on the range of potential outcomes via cumulative probability distributions from which high-side and low-side estimations can be made (e.g. P90, P10). However, the "worst case" description is applied to the wellbore conditions that are prescribed for WCD and are extreme cases (i.e. all reservoirs are completely penetrated, no drill pipe in the hole, no restrictions at the surface, etc.). To impose a high-side reservoir outcome upon an already highly unlikely wellbore scenario would result in an extreme case with very low probability of occurrence, which BOEM has already stated as unacceptable. Therefore, this committee has elected to better define the modeling of realistic reservoir properties that is then used for detailed response planning in a worst case operational scenario.

4.4 Updates during Drilling Operations

During the drilling of a well, it may become apparent that reservoir and/or wellbore conditions are significantly different than what was expected when the WCD was calculated. In these cases, the impact on WCD should be assessed, and if the new flow rate exceeds the demonstrated capability to respond in the oil spill response plan (OSRP), a revision must be submitted (according to US federal regulations, e.g. NTL No. 2010-N06). However, an OSRP update is not strictly volume-dependent. It also depends on the location of the well and other conditions. The US Bureau of Safety and Environmental Enforcement (BSEE) specifies (US Department of the Interior 2013) what is a significant change. In these cases, BSEE must be notified and the changes and impacts discussed.

5. Reporting of Results

5.1 Included Information

A worst-case discharge (WCD) report is required for permitting in US federal offshore waters and should include the following:

- Summary of the results, showing the WCD rate with inflow/outflow graphs and total volume
- Wellbore diagram
- Structure maps of each producible zone
- Log section from analog wells identifying the zones expected to be penetrated
- Interpreted seismic line
- Narrative describing the assumed values for every parameter, including the sources of data and analysis conducted to normalize or adjust the data as necessary
- Table of parameter values (see the Appendix or Form BOEM-0137, pages 3 and 4)
- Description of modeling techniques and the software used
- Laboratory data reports and any corrections:
    - Fluid pressure/volume/temperature reports with corrections for oil-based mud contamination
    - Routine core analysis reports with average porosity/permeability and method of core plug averaging used
    - Pressure-transient-analysis reports with average permeability and non-Darcy turbulence
    - Summary of special core analysis reports with relative permeability tables

Results may be reported by zone, but only if that additional data will help to explain any anomalous behavior in the well performance over time. Otherwise, results for the WCD flow rate and production decline should be reported at the well level.

5.2 Common Reporting Errors

In 2013, BOEM observed the following three most common reporting errors responsible for the majority of review delays (i.e. data either missing altogether or inconsistent within the submittal):

- Proposed casing and/or openhole sizes
- Proposed directional survey
- Form BOEM-0137 information

Errors and/or inconsistency within a WCD submittal exacerbate the time necessary for the regulator to review the material, reach a true understanding of the prospect, and disrupt investigation of more important, critical parameters. Reducing the following, frequently observed errors should allow improved reviews:

- Inconsistent or missing critical information within the plan
    - Engineering section of Form BOEM-0137 is incomplete or inconsistent with narrative and/or modeling reports
    - Analog well(s) not clearly identified (API number is appreciated)

    - Analog well listed on Form BOEM-0137, but regional trend is cited elsewhere
- Critical factors (permeability, thickness, and pressure) are not sufficiently documented
    - Missing directional survey or too little directional information (only a few data points)
    - Missing structure maps on hydrocarbon sands in the open hole (must be clear/legible)
    - Missing wellbore/casing diagram
    - Missing geologic cross section
- Target sand is deeper than shallower intervals that may have higher WCD
- Submittal indicates significant deeper drilling below target (final) sand

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7. Abbreviations and Acronyms

The following abbreviations and acronyms are used in this report.

API	American Petroleum Institute
BHP	bottomhole pressure
BOEM	U.S. Bureau of Ocean Energy Management
BOP	blowout preventer
BSEE	US Bureau of Safety and Environmental Enforcement
CFR	Code of Federal Regulations
CGR	condensate/gas ratio
DOCD	Development Operations Coordination Document
FAQ	frequently asked question
FBHP	flowing bottomhole pressure
GOR	gas/oil ratio
IPR	inflow performance relationship
MD	measured depth
ML	mud line
NTL	Notice to Lessees and Operators
PPHS	potentially producible hydrocarbon sand
PVT	pressure-volume-temperature
RKB	relative to kelly bushing
SG	specific gravity
SPE	Society of Petroleum Engineers
TD	total depth
TST	true stratigraphic thickness
TVD	true vertical depth
TVT	true vertical thickness
VLP	vertical lift profile
WCD	worst case discharge

8. Appendix

Tables for reporting [from the US Bureau of Ocean Energy Management (BOEM)]. http://www.boem.gov/About-BOEM/Procurement-Business-Opportunities/BOEM-OCS-Operation-Forms/BOEM-0137.aspx

Example report tables:

WCD Calculation is in the XX.XX-in. Openhole Section			Top (MD ft)	Base (MD ft)	WD (ft)	KB (ft)
Sand Name	**Top (MD/SSTVD)**	**Base (MD/SSTVD)**	**Gross Height (MD ft)**	**Net Pay (TVT ft)**	**Fluid Type (oil/gas/water)**	**Used in WCD?**

Sand Name	Zone 1 Name	
Characteristic	**Value**	**Analog/Source**
Initial pressure, psig		
Initial temperature, °F		
Permeability, md		
Porosity, %		
Water saturation, %		
Rock compressibility, usips		
Water salinity, ppm		
Drainage area, acres		
Drive mechanism		
Gas Data		
Condensate gravity, API		
Gas SG, air = 1		
Cond yield, stb/mmscf		
Fluid gradient, psi/ft		
Turbulence D, 1/mscfd		
Gas viscosity, cp		

Sand Name	Zone 2 Name	
Characteristic	**Value**	**Analog/Source**
Initial pressure, psig		
Initial temperature, °F		
Permeability, md		
Porosity, %		
Water saturation, %		
Rock compressibility, usips		
Water salinity, ppm		
Drainage area, acres		
Drive mechanism		
Oil Data		
Bubblepoint, psig		
Oil volume factor, rb/stb		
Oil viscosity, cp		
Oil compress, 1/psi		
Oil gravity, °API		
Fluid gradient, psi/ft		
Solution GOR, scf/stb		
Gas SG, air = 1		

Source of Permeability Used						
Pressure transient analysis	Buildup		Drawdown		Falloff	
Conventional cores	Whole core		Plugs		Other	
Sidewall cores	Rotary		Percussion		Other	
Wireline formation tester	Probe		Dual packer		Other	
Magnetic resonance log						

Relative Permeability Functions	Value	Analog/Source
S_{org}, Residual oil to gas (= 1 – S_{lc} – S_{wc})		
S_{orw}, Residual oil to water (= S_{oc})		
S_{gc}, Critical gas saturation		
S_{gt}, Trapped gas saturation		
K_{ro} Endpoint (fraction of K_{abs})		
K_{rg} Endpoint (fraction of K_{abs})		
K_{rw} Endpoint (fraction of K_{abs})		
N_o, Oil corey exponent		
N_g, Gas corey exponent		
N_w, Water corey exponent		