

Quantitative Assessment of Failure Probability of Underground Natural Gas Storage Wells Using an Integrated Bow-Tie Bayesian Network Approach

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ABSTRACT

The storage of natural gas in underground reservoirs is an important component of the overall natural gas delivery infrastructure because it permits better management of the supply and demand cycles. Leakage of natural gas to the outside can lead to severe safety and environmental consequences. An integrated Bowtie (BT) and Bayesian Network (BN) model to assess the probability of gas release is presented in this paper. A barrier-based risk management approach, incorporated in the BT model, provides a useful visualization of the operational hazards and their safe management. The BT approach involves the identification of hazards (or threats) leading to a top event, such as release of natural gas to the external environment. Each hazard has several associated barriers that can either prevent the occurrence of the top event or mitigate the consequences. BT models were constructed for well head and sub-surface systems. However, the BT approach does not consider the interactions between different hazards and barriers. Furthermore, the degradation of the barrier effectiveness over time and space is typically not quantified. BN models were constructed to quantify the failure probabilities of the barriers identified by BT. The BN models compute the probabilities of failure of the wellhead and sub-surface systems. Sensitivity and value of information analyses were conducted using the BN model.

Key words: Bayesian network; bowtie; underground gas storage, corrosion; mechanical damage; cement

INTRODUCTION

Underground natural gas storage (UGS) is an important component of the overall natural gas transportation and distribution system. It enables the utilities to supply natural gas during high seasonal demand periods and store gas during periods of lower demand. There are approximately 627 underground gas storage sites worldwide with a working gas capacity of 319.3 Billion m³ (about 11.8 Trillion Cubic feet)¹. The U.S. has a total of 414 natural gas storage fields, out of which 25 are inactive². The active fields stored an average annual volume of 80 Billion m³ (2.96 Trillion Cubic Feet) of working gas underground (the base or cushion gas volume is slightly higher than the working gas volume). Out of these fields, about 10% are salt domes, 12% are in aquifers, and the rest are former oil and gas production fields that are now depleted and used for gas storage.

Evans¹ listed 27 reported leakage events in depleted gas wells world-wide before about 2009, with California accounting for 11 of those events. The main cause of gas leakage events was casing failure. Based on a review of leakage incidents, Papanikolaou *et al.*³ estimated the frequency of major incidents at a UGS facility to be 8.39x10⁻⁴/site/year and 2.02x10⁻⁵ /well/year. Preston and Benson⁴ estimated blowout rates of Southern California oil and gas wells to range from 1x10⁻⁴ per well-year to 6x10⁻⁴ per well-year from 1991 to 2005 considering different operating modes. The blow out frequency decreased substantially from 1991 to 2008. The operating time period of these wells ranged from 45,900 to 516,000 well-years. Watson and Bachu⁵ examined plugged and abandoned oil and gas wells in Alberta, Canada and found that approximately 5% of the 316,500 wells had some leakage of gas long after abandonment. They further examined a sub-set of approximately 500 wells and found that deviated wells, cased and abandoned wells, and low cement or exposed casing were the most important factors in leakage. Of the 142 wells they examined for corrosion, 23% of the casing corrosion arose due to external casing corrosion and 9% from internal corrosion. Poor or lack of cement accounted for 68% of the external corrosion failures.

The natural gas industry developed the American Petroleum Institute (API) Recommended Practice 1171 that addressed risk assessment of depleted hydrocarbon and aquifer storage reservoirs⁶. A Joint Industry Task Force (JITF) was formed by Interstate Natural Gas Association of America (INGAA), the American Gas Association (AGA), and API, which developed a risk scoring approach utilizing API 1171. In this approach, the probability of the totality of casing, wellhead, and cement failures (POF), is given by Eq. 1:

$$POF = G_{ff} \times [Df_{thin} + Df_{mech} + Df_{impact} + Df_{other} + F_{whv} + F_{cmt}] \times credit \quad (1)$$

Where, G_{ff} is the generic failure frequency (an industry-wide failure experience), Df_{thin} is the damage factor for casing mechanical strength due to corrosion, erosion, or other wall thinning; Df_{mech} is the damage due to vibration or other fatigue processes, well intervention damage, and other previous failures; Df_{impact} is the damage due to impact from outside forces both natural and operation/maintenance related; and Df_{other} represents other operator-specific threats. The other factors in Eq. 1 are F_{whv} representing the wellhead valve factor representing the status of the wellhead equipment, F_{cmt} representing the condition of the cement sheath around the casing, and the $credit$ representing a reduction in POF due to the maturity of integrity management practices. Although the risk scoring approach represented by Eq. 1 captures the knowledge of the factors influencing the system integrity, it does not adequately represent the interconnectedness of some of these factors. Furthermore, it is difficult to evaluate the effectiveness of risk mitigation as these scoring indices do not capture the fundamental mechanisms of damage. Most importantly, the scoring factors are subjective and cannot be validated.

This paper describes a quantitative risk assessment approach using Bayesian Network (BN) models. BN models have been used previously for pipelines⁷⁻¹³ Although, BN models capture the knowledge of

the system as completely as possible, they can be difficult to communicate to all the stakeholders. A bow tie (BT) model is easier to communicate to the different stakeholders and use for operational risk management. This approach is not new since Martins *et al.*¹⁴ proposed a hybrid Fault Tree - BN risk analysis methodology and fault tree are just simplified BNs. In the present paper, we briefly describe a BT-BN model, with emphasis on the BN model. The focus of the paper is on probability of failure of a well and not the consequences.

METHODOLOGY

The overall approach to developing the BT- BN models involved a three-step process: (1) a systematic hazard identification (HAZID) process through a two-day workshop involving various UGS operators, (2) the development of BT models with threats and barriers identification, and (3) the development of BN models quantifying the interactions between the barriers and threats. The HAZID process yielded qualitative descriptions of the various threats to an UGS system (considering the wellhead and the well bore as the boundaries of the system), their consequences, and potential mitigation measures. These threats are listed in Table 1.

Hazard Identification and Bow Tie Models

BT diagrams for various threats and the associated barriers were assembled from the HAZID process. The BT diagrams consist of three major elements: the hazards (threats), Top Event, and consequences. The Top Event, which in the case of UGS is the loss of containment of the gas, is at the center of the BT diagram. The Top Event is the result of losing control of the hazard – and causes of this are examined on the left-hand side of the BT diagram. Once the Top Event has occurred, then undesirable (and potentially dangerous) consequences may result if the accident sequence is not mitigated – which is explored on the right-hand side. Barriers (often also called Controls or Safeguards) control the incident sequence, by either preventing its occurrence or mitigating the Consequences. Preventive barriers appear to the left of the Top Event and are designed to prevent the Cause leading to the Top Event. Mitigative (or reactive) barriers appear to the right of the Top Event. Mitigative barriers do not need to prevent the consequence completely but should be able to at least significantly reduce the severity of occurrence.

An example of a BT for wellhead internal corrosion threat is shown in Figure 2 (the other threats and the consequences from the Top Event have been removed for clarity). The internal corrosion resulting in seal or valve failure leads to the Top Event, the loss of containment of natural gas. The threat (shown in blue at the first level box on the left) is prevented by two barriers: (i) The use of materials resistant to corrosion and erosion from natural gas contaminants in the wellhead components and (ii) the daily inspection and maintenance of these components including the manual shutdown of valves if a leak incident is detected. The first barrier can degrade due to various factors including unwanted contaminants in the gas. The degradation factor (shown in yellow highlight) can be mitigated by appropriate checks on the gas composition and monitoring. The BT diagram identifies actionable items for risk mitigation. It enables the operator to plan, check, act, and revise the risk management process. It can be converted to a fault-tree diagram for quantification of the probability of the Top Event. However, the BT approach has several major limitations, the most important of which is the lack of interactions between the barriers and threats. For example, the internal corrosion threat may affect the threat from mechanical damage by weakening the mechanical strength of the components. The barriers to prevent internal corrosion in terms of materials selection may also affect the barrier related to manual closure of the valves (a corroded valve may be disabled from shutting when a leak occurs). Furthermore, the BT approach lacks the ability to be updated based on observations.

Development of BN Models for Wellhead

The threats and barriers from the BT model were reconfigured into a directed acyclic graphical representation. Interactions between various degradation factors were quantified using conditional

probability tables. An overall view of the wellhead BN model is shown in Figure 3 to illustrate the interconnections between various threats to the Top Event and consequences identified by the BT model. Because the BN model is complex, one of the threats, the internal corrosion threat, is illustrated in Figure 4. The probabilities of internal corrosion rates depend on the gas quality (the concentrations of various contaminants in the gas injected as well as withdrawn), the presence of accidental water intrusion, the formation of protective iron sulfide film, the presence of corrosion inhibitors, and sand production. These factors are interconnected. Uninhibited uniform corrosion of the wellhead is calculated from the chemistry of the water phase (i.e. pH, CO₂, H₂S, Fe²⁺, O₂ and temperature). An open source corrosion model was used to generate the set of conditional probabilities⁽¹⁾. The inhibited uniform corrosion rate is calculated using the uninhibited uniform corrosion rate and the corrosion inhibition node. It should be noted that if water is not present corrosion rate is negligible.

The localized corrosion rate is calculated for two different types of localized corrosion mechanism: the formation of a galvanic cell or simple corrosion under deposit. Galvanic cells are created when an anodic film is destabilized by the presence of chloride. This is unlikely for carbon steel because under acidic conditions there is no protective film, but it may be possible in the presence of H₂S due to the formation of protective iron sulfide scales. Corrosion under deposits happen when the gas velocity is slow enough for sand to deposit, water is then pulled toward to the pipe wall by hygroscopic forces. Another phenomenon to consider is that corrosion inhibitor adsorbs preferentially onto sand deposits, this mechanism may lead to corrosion inhibition concentration gradients and therefore to pitting.

Both uniform and localized corrosion rates are used to calculate the size of the flaws in the wellhead in percentage of original wall thickness. A simple assumption is used to combine uniform and localized corrosion: if the size of a flaw is larger than 80% of the pipe wall, then both the envelope design and the internal corrosion nodes are considered to fail. The various parameters in the BN nodes are shown in Table 2. The BN model is made of nodes, each with multiple states and associated probabilities. The states can be numbers (e.g. 0, 1, 2), ranges (e.g. [0,1[, [1,2[, [2,3]), or descriptions (e.g. yes, no). States of a node must be mutually exclusive. The sum of the probabilities of a node's states must be equal to one.

Development of BN Models for Sub-Surface

Unlike the wellhead sub-system that has discrete components, the sub-surface sub-system consists of mostly continuous components such as casings and tubing with some discrete components, such as packers and sub-surface safety valves. Multiple threats could act on a single component. Quantitative probabilities of damage (e.g. flaw depth, corrosion) from each threat should be combined for the respective component on which the threat acts. For example, the production casing, at any point along its length can have a damage or flaw causing a reduction in its thickness due to three separate threats, annular corrosion (occurring at the internal surface), external corrosion (occurring at the external, cement facing surface) and intervention activities (tool milling occurring on the internal surface). Each of the 3 components (tubing, production and surface casings) will be affected by threats from defects created by mechanical design and subsurface movement. The effect of these two threats on increasing the failure probability of the components is qualitatively modelled in this work. Each of the following 4 mechanisms can cause release of gas from the sub-surface well to the environment, leading to sub-surface well failure:

- tubing (primary barrier) and production casing (secondary barrier),
- gas migration,
- hydrostatic control failure

As discussed above, the production casing (secondary barrier) and tubing (primary barrier) are modelled in the BN considering all the interactions. Surface casing failure, although modelled in the BN, is not considered in the overall sub-surface integrity, as it does not directly allow for gas leakage. The

⁽¹⁾ FREECORP 1.0, 2019, <http://www.icmt.ohio.edu/freecorp>, retrieved 2/7/2019.

'gas migration' and the 'hydrostatic control' threats are also modelled and their effect on the leakage probability is considered.

An example of the BN model for external corrosion threat is shown in Figure 5. The external corrosion of production and surface casing is influenced by the groundwater composition, cement, microbiological colonies, and cathodic protection. Cement bond logs and similar inspection data provide information about the status of cement coverage and the presence of water, which will be used as inputs in the BN model to calculate whether the casings could undergo external corrosion. Along with water presence, the following factors affect the corrosion rate:

- Salts / chlorides concentration
- Dissolved oxygen concentration
- pH
- Temperature

OLI Systems Corrosion Analyzer⁽²⁾ was used to compute the probabilities of corrosion rates as a function of the parameters listed above for the case where cement is absent or completely debonded and a thick water layer is formed in contact with the metal surface. For the case where the cement debonds slightly to form a thin water layer at the metal interface, the properties of cement affect the corrosion rate, along with the parameters listed above. For this case, literature reports where corrosion rates are experimentally measured on steel in wetted cement were used to estimate the corrosion rates¹⁵⁻¹⁸. Cathodic protection, when optimally applied, provides protection from corrosion in the absence of cement, but might not be able to protect in the case of slightly debonded surface due to the lack of access of the electrical field to the metal surface. These effects of cathodic protection (CP) are also modeled in the BN.

The BN models were implemented using commercially available software HUGIN EXPERT⁽³⁾. The BN models can be ported in the form of ".net" files to other commercially available software, such as GeNie⁽⁴⁾ with different functionalities and user capabilities (Figures 4 and 5).

Data Inputs

UGS systems present considerable challenges to quantitative risk assessment due to the paucity of data and the sensitivity of the operators to publicly release well-specific data. The results presented in this paper relied on a combination of publicly available data sources, such as the California Department of Oil and Gas and Geothermal Resources (DOGGR), and anonymized operator data. Much of these data were descriptive and were converted to probability distributions.

RESULTS AND DISCUSSION

Scenario Analyses of Wellhead Failures

With the inputs received from the industry partners, the probability of wellhead failure was calculated for a hypothetical well. The results are shown in Figure 6. It should be noted that threats are connected and the evolution of one threat has effects on other threats. Therefore, "time independent" threats evolve in time because they are linked to time dependent threats. For example, the earthquake probability is not time dependent, but the earthquake threat evolves in time because the resistance of the well is impacted by the internal and external corrosion threats. Figure 6 shows that the failure probability due to internal corrosion rises from 0% in 2020 (year 15) to 0.42% in 2030 (year 25), assuming that in 2020 the maximum flaw size is 10% of the original wall thickness (*i.e.* no significant

⁽²⁾ OLI 2018, OLI Studio 9.5, Version 9.5.4, OLI Systems, Inc., <https://www.olisystems.com>.

⁽³⁾ www.hugin.com

⁽⁴⁾ www.bayesfusion.com

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