RESEARCH ARTICLE

Advanced Pipeline Inspection and Predictive Maintenance for Saudi Hydrocarbon Distribution Networks: Integrating Engineering Risk Assessment, Digital Monitoring, and Asset Integrity Management

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Abstract

Hydrocarbon distribution pipelines require inspection strategies capable of detecting damage before it compromises containment, while avoiding maintenance activity that delivers little reduction in risk. This review examines how advanced in-line inspection, distributed monitoring, predictive modelling and asset integrity governance can be combined for Saudi Arabian distribution networks. A structured, critical synthesis of peer-reviewed studies published during 2020–2025 distinguishes validated engineering methods from promising but incompletely demonstrated digital applications. Evidence indicates that magnetic flux leakage and ultrasonic inspection remain essential for characterising material loss, whereas acoustic, hydraulic and fibre-optic systems provide complementary surveillance between inspection campaigns. Bayesian degradation models and machine-learning predictions can improve maintenance prioritisation when measurement uncertainty, operating changes and failure consequences are represented explicitly. However, high classification accuracy in controlled studies cannot establish field reliability, and algorithmic outputs cannot substitute for fitness-for-service assessment. The proposed framework connects threat registers, inspection coverage, data quality, uncertainty-aware prognosis and documented intervention decisions through an auditable feedback process. Particular attention is given to the implications of sour service, variable operating regimes, remote corridors and increasing infrastructure interdependence in Saudi Arabia. The contribution is a practical decision architecture that treats digital monitoring as additional evidence for engineering judgement, rather than an autonomous guarantee of safety. The review identifies requirements for field validation, accountable model governance and risk-sensitive deployment that can support reliable energy infrastructure under Vision 2030.

Keywords: Hydrocarbon pipelines; in-line inspection; predictive maintenance; asset integrity; Bayesian risk assessment; digital twins; Saudi Arabia

1 Introduction

Hydrocarbon distribution networks connect production, processing, storage and industrial consumers through assets whose failure can have consequences far beyond the damaged pipe section. A leak may interrupt fuel supply, expose personnel, contaminate land or create ignition hazards. Yet the network is not homogeneous: its pipes differ in age, diameter, material, operating envelope, burial conditions, accessibility and consequence exposure. Applying identical inspection intervals across these assets ignores differences in deterioration and social impact. Risk-based integrity management instead links engineering evidence to the likelihood and consequences of failure [1, 2].

Recent research has expanded the information available to pipeline engineers. Instrumented inspection tools identify metal loss and geometry anomalies; permanently deployed sensors record operational departures; predictive algorithms use historical observations to estimate deterioration; and network models explore the wider effects of equipment outages. These capabilities are often presented separately. The difficult practical question is how inconsistent observations should change a maintenance decision when they differ in resolution, confidence and temporal coverage. A precise defect depth from an instrumented inspection run is not interchangeable with a vibration anomaly from an external sensor. One addresses physical condition at a particular date; the other may indicate an event whose cause remains uncertain [3–5].

For Saudi Arabia, integration is especially relevant because pipeline management must address differing product streams, land uses and operational contexts across extensive energy infrastructure. Some systems serve major processing hubs, whereas others cross comparatively remote areas before reaching distribution interfaces. Local corrosion evidence demonstrates that fluid chemistry and operating conditions can materially alter degradation risk [6]. Such observations argue against importing failure rates or predictive thresholds from unrelated networks without calibration. The national development agenda adds an incentive to improve reliability, industrial digital capability and prudent stewardship of existing assets, but these objectives do not themselves prove any particular technology effective.

The research gap is therefore organizational as well as technical. Excellent defect detection does not guarantee that inspection data are aligned to the correct pipe segment, that uncertainty is represented in deterioration forecasts, or that a responsible engineer can explain why repair was recommended. Studies of risk-oriented inspection and reliability optimisation suggest that the decision rule matters as much as the forecasting algorithm [7–9]. This review builds a connected interpretation of sensing, diagnosis, prognosis and intervention, with explicit restrictions on conclusions drawn from controlled laboratory studies.

2 Aim, objectives and contribution

The aim is to formulate an evidence-led engineering framework that converts pipeline inspection and monitoring findings into defensible predictive maintenance decisions for Saudi hydrocarbon distribution assets. Five objectives govern the review: to distinguish inspection technologies by the defects they can establish; to examine how continuous measurements complement periodic examinations; to evaluate corrosion and failure forecasting under imperfect data; to integrate the probability and consequences of failure into maintenance scheduling; and to define accountable implementation requirements for network operators.

Its contribution is not a newly trained prediction model or a claim of measured improvement on Saudi pipelines. Rather, it is a synthesis of interfaces that must function together. The framework specifies which evidence supports each decision, where expert verification is essential and how outcomes should be returned to the integrity register. This distinction prevents conceptual recommendations from being mistaken for field-tested performance.

3 Review design and evidence appraisal

A structured narrative review was selected because relevant publications use incompatible outcomes, including defect sizing error, leak recognition accuracy, probability of failure, remaining life and

expected maintenance cost. Pooling such results into a single quantitative estimate would conceal important methodological differences. The review considered publications from 2020 through 2025 dealing directly with hydrocarbon pipelines, corrosion assessment, inspection, sensing, reliability modelling or maintenance optimisation. Sources were identified through targeted scholarly and publisher searches; candidate records were checked against article titles, publication years and DOI metadata. Related studies of industrial fluid systems were retained only where their sensing or statistical principle was transferable, and that transferability is stated rather than presumed.

Critical appraisal used four linked criteria. First, the physical relevance of the test environment was considered: a simulated corrosion field, instrumented laboratory loop and operating transmission line provide different levels of evidence. Second, the availability and provenance of measurements were assessed, including whether defects had been independently verified. Third, predictive studies were examined for uncertainty treatment, temporal separation between training and testing, and plausible response to distribution change. Fourth, maintenance research was evaluated according to whether an optimisation objective included consequences, inspection imperfections and practical constraints [7, 9–11].

These distinctions are particularly essential when evidence travels between contractors, operators, technical teams and responsible regulators. This is an interpretive review, not a claim of exhaustive coverage. The search did not produce a reproducible census of every relevant publication, and no pooled field-performance effect is reported. The 30 cited studies were selected because together they support an integrated appraisal across technology, degradation and decision management. Findings are therefore formulated as engineering propositions, with clear distinctions among experimental demonstration, model-based evaluation and established operating practice. Saudi-specific sources receive particular attention, without assuming that their results generalise across all products and routes [6, 10].

4 Integrity threats and the evidence required

Corrosion is a principal integrity threat because metal loss reduces the effective pressure-bearing section and may develop unevenly along the line. Internal corrosion depends on factors including free-water availability, fluid composition, temperature, flow regime and deposits. External corrosion depends on protective coating performance, cathodic protection and the surrounding environment. A single corrosion-rate estimate is therefore a poor substitute for segment-specific condition evidence. Experimental and probabilistic work has shown why variation in corrosion behaviour must be reflected in predicted failure probability rather than hidden inside an average deterioration rate [3, 10, 11].

Sour service warrants special caution. Hydrogen sulphide and water chemistry can change corrosion mechanisms and undermine extrapolation from nominally similar sweet-service pipelines. Research involving Saudi operating expertise has examined how water chemistry affects sour-gas internal corrosion risk, supporting the need for chemically informed inspection priorities [6]. The relevant engineering question is not whether a sensor detects corrosion in general, but whether the inspection technique measures the morphology, location and progression of the damage mechanism actually expected in service.

Mechanical damage is another important class of threat. Dents, gouges, bending strains, weld anomalies and excavation-related damage can interact with corrosion. Huang and colleagues [8] showed that inspection planning may change when corrosion and dents are considered together

instead of as isolated defects. Third-party interference also creates time-sensitive threats that a historical corrosion model cannot predict from wall-loss rates alone. Hence a threat register needs multiple causal categories and an explicit distinction between gradual deterioration and sudden external events.

Asset configuration shapes both detectability and consequence. Short branch lines, complex fittings, valves and reduced-bore components may prevent a standard inspection tool from traversing the route. Buried crossings and inaccessible sections can constrain external inspection. An apparently clean instrumented inspection record means little for an uninspected section or for a threat outside the tool's performance envelope. Inspection coverage must therefore be mapped against the complete asset inventory, with unassessed segments retained as uncertainties rather than silently classified as sound.

Finally, pipeline integrity must include operational transients, pressure cycling and interfaces with pumps, compressors, manifolds and isolation valves. A structurally adequate pipe can still suffer unacceptable loss if an undetected release continues because isolation or alarm escalation fails. The risk assessment must therefore account for barrier performance and operational response, not just wall thickness. Network reliability research reinforces the significance of dependencies between individual components and supply continuity [4, 9].

5 Advanced inspection: Capability, calibration and limitations

In-line inspection is a central evidence source for long-distance assets, but its methods are not interchangeable. Magnetic flux leakage detects changes in magnetic field associated with ferromagnetic material loss. Ultrasonic technologies estimate wall thickness using acoustic propagation; specialised systems may identify particular crack orientations or geometries. Geometry tools map deformation, while inertial measurements can help describe alignment and strain-related concerns. Tool choice should follow the credible threat mechanism, pipe geometry, product properties and demonstrated detection threshold rather than a generic preference for the newest instrument [2, 12, 13].

Magnetic flux leakage output requires interpretation because measured signals depend on defect shape, magnetisation conditions, lift-off, wall thickness and tool response. Machine-learning approaches have been proposed to infer defect dimensions directly from signals; Shen and Zhou [13] used numerical signal generation to train a convolutional model, while Chen and colleagues [12] explored reliability estimation through residual neural networks. These approaches are useful research directions, but simulated training examples cannot establish equivalent accuracy in every real-world steel grade or inspection campaign. Field qualification must examine tool calibration, false-negative behaviour and uncertainty in depth and length estimates.

Inspection planning is fundamentally longitudinal. Repeat surveys can reveal whether the same anomaly is growing, but matching defects across runs requires reliable spatial registration. Odometer drift, different sensor resolutions, repair history and changed feature identifiers may produce artificial growth. An operator should preserve raw data, confidence grades and lineage between reported anomalies, not simply subtract two summary depths. Data-led forecasts of remaining life depend on the quality of these comparisons and on a justified model of growth between inspection dates [14].

External inspection remains indispensable. Targeted excavation, ultrasonic verification, coating surveys and cathodic protection measurements can test the interpretation of in-line findings. Where pigging is impracticable, combinations of local non-destructive examination, direct assessment and permanently mounted monitoring may provide partial coverage; such alternatives should never be described as equivalent without a documented gap analysis. Newer continuously instrumented liner concepts can provide additional observations, although their qualification differs from standard inspection [15]. Table 1 matches representative technologies to their decision value and dominant limitations. It is a qualitative synthesis, not a ranking derived from comparative field trials.

Table 1. Comparative inspection and monitoring roles within a threat-led programme (author synthesis).

Method	Primary evidence	Integrity decision supported	Important limitation
Magnetic flux leakage	Ferromagnetic metal loss	Map corrosion features; identify verification priorities	Sizing uncertainty depends on geometry, magnetisation and tool qualification
Ultrasonic inspection	Wall thickness; selected crack mechanisms	Quantify remaining wall; examine threat-specific anomalies	Requires suitable coupling and access; not universally applicable
Geometry and inertial tools	Dents, ovality, bends and alignment	Screen deformation and route movement	Does not alone establish wall loss or crack severity
Targeted external examination	Accessible corrosion, coatings and local defects	Verify ambiguous inspection findings	Point coverage, excavation exposure and access constraints
Hydraulic or acoustic systems	Leak-related operating transients	Detect and investigate events between inspection runs	False alarms and detection limits depend on operating conditions
Distributed fibre sensing	Location-dependent vibration and strain events	Support corridor surveillance and disturbance investigation	Coupling, background noise and limited defect quantification

The most effective inspection strategy is accordingly staged. Threat screening determines what must be detected; a tool qualification review tests whether the method can detect it; the resulting data establish condition with uncertainty; and selected physical verifications resolve ambiguous anomalies. Inspection then becomes a controlled source of evidence for a documented integrity decision rather than a standalone demonstration of technological sophistication.

5.1 Inspection uncertainty as a management variable

An inspection report should distinguish a detected feature from a fully characterised defect. Probability of detection concerns whether a relevant anomaly is found at all; sizing accuracy concerns what is measured after detection. Confusing these questions may lead to overconfidence in a fitness-for-service calculation. Operators should request tool performance specifications for the applicable wall thickness, product, speed, anomaly geometry and inspection environment. Where reported dimensions are close to a repair threshold, sensitivity analysis should test credible upper and lower defect sizes. Disagreement between repeat surveys should trigger reconciliation of tool technology and feature matching before being interpreted as accelerated deterioration. A targeted verification excavation is justified when the value of resolving uncertainty exceeds its costs and risks. The

defensible output is a condition estimate accompanied by measurement bounds, qualification records and a clear plan for investigating unresolved findings.

6 Continuous digital monitoring and event diagnosis

Continuous surveillance fills temporal gaps between periodic examinations, but its information should be interpreted according to the phenomenon measured. Hydraulic leak detection examines differences between expected and observed flow or pressure behaviour. Acoustic systems identify sound or vibration signatures, while distributed optical sensing can monitor events along extended corridors. Studies of optical-fibre approaches demonstrate promising localisation and event recognition under defined conditions, although burial depth, coupling, soil characteristics and background activity affect performance [16–19].

Independent acoustic event-tracking research likewise shows that leak detection methods differ in their dependence on labelled failures [20]. Recent work on transfer learning and sensor fusion addresses variation in operating conditions. Liu and colleagues [21] investigated acoustic emission models across differing experimental environments; Miao and Zhao [17] combined heterogeneous sensing information for leakage diagnosis. Such methods are attractive because a single sensor may be noisy or ambiguous. Yet fusion can also give misplaced confidence when correlated measurements are treated as independent confirmation. The engineering case for combining sensors requires a clear failure hypothesis, a traceable physical relationship and evidence that the combined system performs better under plausible disturbances.

Operational data streams create further complications. Supervisory control and data acquisition records may contain missing intervals, sensor drift, asynchronous sampling, instrument replacement and changing operating set points. An anomaly detector trained on one product or throughput range can confuse normal transitions with a leak. Work on semi-supervised multivariate time series is relevant because confirmed leak examples are scarce, but scarce labelled events also make performance estimates uncertain [22]. Algorithms must be challenged with planned shutdowns, pressure surges, maintenance operations and sensor failures, not merely with clean simulated leak signatures.

Digital twins can connect hydraulic assumptions to incoming measurements and produce expected operating states. Al-Ammari and colleagues [23] developed a gas-pipeline diagnostic twin that combines modelling with case-study evaluation. Such a system is most credible when its boundaries, calibration conditions and update logic are explicit. A useful twin is neither a decorative dashboard nor a substitute for field observations; it is a continually tested representation of the asset that makes discrepancies visible and interpretable.

Figure 1 therefore portrays monitoring as one part of a closed evidence cycle. Inspection establishes physical condition; sensors detect potentially rapid departures; engineering models interpret behaviour; risk evaluation sets priority; and verified maintenance outcomes update assumptions. The cycle needs human sign-off at significant decision points because model error and incomplete coverage can otherwise propagate unnoticed across operational systems.

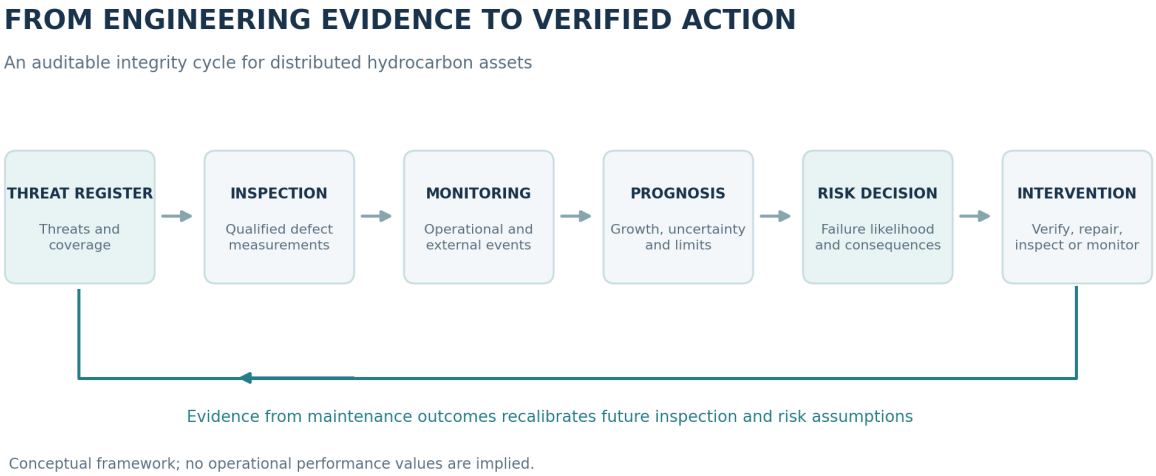


Figure 1. Proposed evidence-to-action cycle for risk-based pipeline integrity (original conceptual illustration).

7 Predictive maintenance: From anomalies to prognosis

Predictive maintenance should estimate when an intervention is justified, not simply label an asset as healthy or unhealthy. For corrosion, forecasts can estimate future depth, remaining pressure capacity or the probability of crossing a defined engineering limit. Machine-learning studies have applied simulated process information, inspection records and physically informed features to these tasks [14, 24, 25]. Their practical value depends on whether the predicted variable corresponds to an intervention threshold and whether the uncertainty surrounding it can be explained.

Prediction of defect growth is difficult because corrosion can accelerate, stagnate or localise when fluids and operating regimes change. Fang and colleagues [24] trained algorithms using corrosion scenarios derived from mechanistic simulation. Du and colleagues [25] embedded physical considerations into automated learning of pitting depth. Such hybrid strategies may reduce implausible predictions, but a simulator's assumptions become part of the model's uncertainty. Validation should therefore compare forecasts with later inspections, record failure modes of the model and investigate biases by pipeline class.

Inspection-derived remaining-life calculations are especially sensitive to the distribution of measurement error. A model can report a plausible mean depth growth rate while underestimating a small subset of severe features. Risk-based decision making must focus on the tail of the degradation distribution when that tail controls rupture probability. Studies of probabilistic corrosion assessment demonstrate the importance of representing uncertainty in both existing defect dimensions and future rates [7, 11]. Stochastic process models further illustrate how changing corrosion drivers affect forecasts [26, 27]. The output should include an uncertainty interval, data-quality statement and known failure conditions, not a solitary remaining-life date.

Predictive claims also require careful performance terminology. Classification accuracy does not tell an operator how many true leaks are missed when leaks are rare. Precision, recall, detection latency, false alarms per operating period and performance under previously unseen conditions must be assessed separately. A favourable laboratory score may not survive changes in topology, product type or ambient noise. Similarly, a model that predicts wall loss accurately may still recommend incorrect maintenance if failure consequences or repair lead times are omitted. The distinction between statistical skill and decision usefulness is essential.

Data governance should precede model deployment. Each segment needs a stable identifier connecting materials records, weld maps, past incidents, inspection features, repairs and live operating data. Training data should be separated in time and preferably by asset, to prevent repeated observations from the same pipe appearing in both development and validation sets. Predictions should carry model version, training population, calibration status and the engineer who approved the forecast. When operating conditions move outside the validated domain, the system should abstain or escalate rather than return unjustified certainty.

A practical maintenance trigger combines engineering limit-state evaluation with probability, consequence, available response time and verification cost. For a high-consequence line, uncertain but credible evidence may justify early targeted inspection even before a model predicts near-term failure. Conversely, an isolated low-consequence segment with strong protection evidence may not warrant immediate intrusive repair for a low-confidence signal. Predictive maintenance is thus a rule for allocating attention under uncertainty, rather than a promise that failure dates can be predicted exactly.

7.1 Testing whether predictions improve decisions

A validation exercise should begin with a baseline decision process, such as the existing corrosion growth estimate and an agreed inspection rule. The proposed model is then evaluated on later observations that played no role in its development. For a depth forecast, useful measures include bias, error distribution and calibration of prediction intervals. For leak detection, operators should record false alarms per route length and operating month, alongside sensitivity at realistic leak sizes. For maintenance scheduling, the relevant evaluation is whether recommended actions would have reduced expected failure loss or unnecessary intervention compared with the baseline. Prospective trials should also document delayed labels, independent defect verification and the effect of human review. Only after these checks can a predictive model support a change to established inspection intervals or maintenance trigger criteria. This is a considerably stronger test than reporting a favourable accuracy score from randomly divided observations.

8 Dynamic risk assessment and intervention selection

Risk evaluation links the probability of loss of containment to the severity of its consequences. These components must remain distinct: a low probability does not make a densely exposed location harmless, and high predicted deterioration does not automatically imply identical urgency across routes. Consequence models should include credible release scenarios, inventory, isolation time, receptors, ignition potential, environmental sensitivity and supply dependencies. Their assumptions should be transparent and revised when land use or network configuration changes [1, 4].

Dynamic Bayesian networks provide one approach for updating failure likelihood as inspections and maintenance records arrive. Abubakirov and colleagues [1] analysed optimal inspection intervals for buried pipelines; Huang and colleagues [8] considered interactions between dents and corrosion; and Zhong and colleagues [28] modelled imperfect maintenance effects. Pitting-aware decisions offer a further example of targeted maintenance selection [29]. These studies illustrate why risk is time dependent and why an intervention does not necessarily restore an asset to an as-new condition. The correct model is conditional on the evidence and maintenance action, not just elapsed calendar time.

Reliability-based optimisation extends the assessment from one pipe to the network. Zerouali and colleagues [9] showed the relevance of spatial and stochastic dependencies in long-distance pipeline

networks. An outage at a critical junction may affect several downstream consumers, so priorities should incorporate system redundancy and recoverability. Maintenance cost is only one criterion; statutory constraints, safety thresholds, access restrictions and operational windows can dominate an otherwise inexpensive repair schedule.

Decision governance should separate three questions: Is the observed anomaly credible? Does its forecast condition exceed an engineering acceptance threshold? What action gives a proportionate reduction in expected harm? This sequence helps prevent an automated risk score from replacing an integrity engineer's fitness-for-service judgement. Figure 2 presents the proposed escalation logic. It is deliberately qualitative, because universal numerical risk tolerances would be inappropriate without operator-specific criteria and regulatory review.

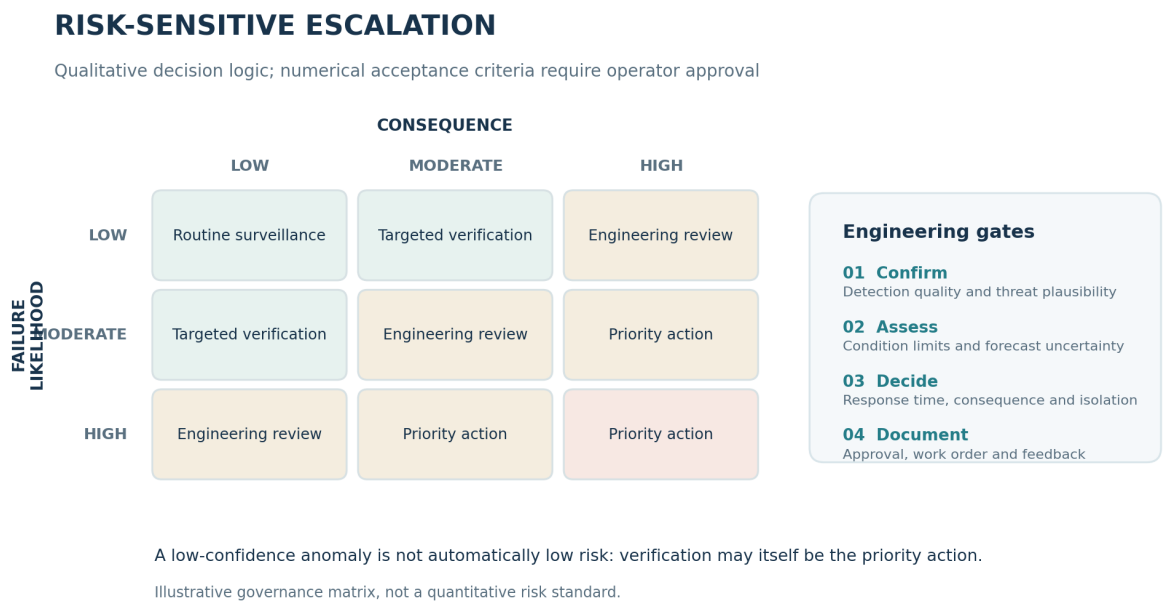


Figure 2. Qualitative risk escalation and engineering approval gates (original conceptual illustration).

9 Saudi Arabian deployment architecture

A staged implementation is preferable to a network-wide deployment of unproven digital models. The first stage should reconcile asset registers and identify high-consequence segments, non-piggable sections, ageing assets and locations where prior incidents or inspection omissions create uncertainty. Material specifications, product composition, maximum operating limits, inspection history, coating data and maintenance records should be linked at segment level. These are basic integrity controls; digitisation adds value only when these records are dependable.

The second stage should develop threat-specific monitoring plans. Sour-gas service may warrant particular attention to water chemistry and corrosion mechanisms, as the Saudi-focused study by Albrahim and colleagues [6] illustrates. Remote corridors may make distributed sensing operationally attractive, while complex manifolds and fittings require local verification. Technology selection should reflect product properties, access, defect morphology and instrument qualification rather than a uniform national template. Local corrosion exposure and soil conditions must be measured rather than inferred from regional climate descriptions.

The third stage should pilot models on selected assets with independent and rigorously validated inspection outcomes. Each pilot requires predefined decision questions, acceptable false-alarm burden, escalation protocol and validation period. A pilot should compare the digital approach with existing engineering practice rather than with an unrealistic no-monitoring baseline. Results should be reported separately for anomaly detection, defect characterisation, forecast calibration and maintenance impact. Unsuccessful or uncertain cases are important evidence for setting operational limits.

The final stage should embed governance across inspection contractors, integrity engineers, operations teams and management. Table 2 outlines the evidence, accountable owner and decision gate for each stage. Such arrangements align with Vision 2030's objectives of dependable infrastructure and strengthened technical capability without implying that a review has measured programme-level national benefits. The immediate engineering outcomes should be demonstrable: better traceability, defensible inspection priorities and faster resolution of credible threats.

Table 2. Staged operational architecture for a Saudi hydrocarbon network (proposed governance model).

Stage	Required evidence	Owner	Decision gate
1. Asset basis	Segment IDs, design limits, incident history, product data	Asset engineering	Approved completeness and threat register
2. Inspection strategy	Threat-specific tool qualification and coverage map	Integrity engineering	Documented detection and uncertainty limits
3. Sensor integration	Calibrated time-series and event classification rules	Operations and instrumentation	Alarm response tested against transients
4. Predictive models	Independent validation, interval calibration and drift checks	Reliability and analytics	Approved model domain and fallback rules
5. Risk decision	Fitness-for-service analysis, consequence exposure, work order	Accountable integrity authority	Risk acceptance and intervention approval
6. Feedback	Verification results, repairs, model errors and post-work tests	Asset integrity governance	Closed actions and updated risk assumptions

9.1 Assurance indicators and operational ownership

Implementation needs measures that are both auditable and linked to the risk process. Useful leading indicators include the percentage of high-consequence segments with current threat assessments, the extent of qualified inspection coverage, the proportion of critical anomalies independently verified and the timeliness of action closure. Data quality should be monitored through unresolved asset identifiers, missing operating records and untraceable feature matching between surveys. Lagging indicators, including releases and unplanned outages, remain necessary but are too infrequent to assess the quality of every model update. An integrity committee should periodically examine cases in which model recommendations conflicted with engineering assessment and document the reason for resolution. Cybersecurity and access control also matter, because inaccurate or manipulated sensor streams can influence operational decisions.

10 Discussion: Integration rather than technological substitution

The literature reveals an important asymmetry. The capability to identify patterns in sensor data has advanced rapidly, but the evidence needed to justify a repair remains rooted in physical measure-

ments and validated failure criteria. Deep-learning recognition of magnetic flux leakage signals [12, 13] and sensor-based leakage classification [21, 30] can shorten analysis time. They do not remove the need to investigate measurement coverage, false negatives or uncertainty in consequences. The weakest step in the decision chain may determine overall integrity assurance, regardless of the sophistication of a single algorithm.

Three practical tensions follow. Greater sensor density improves observability but increases data processing and alarm-management burdens. More complex models can capture nonlinear deterioration but become harder to audit and recalibrate. More frequent inspections reduce some uncertainty but can raise cost and operational exposure. These tensions favour targeted deployment guided by the value of additional information. The best technology is the one that changes a consequential decision reliably, not necessarily the one reporting the highest laboratory classification score.

A credible integrated programme should therefore retain distinct evidence types, preserve uncertainty and document professional override. If a live sensor reports a suspicious transient while a previous inspection indicated adequate wall thickness, neither result invalidates the other. The correct response is a structured investigation of competing explanations, possible rapid damage and instrument malfunction. This evidence-based discipline is the essential bridge between monitoring innovation and accountable asset management.

11 Limitations and research priorities

This synthesis is constrained by the uneven availability of Saudi network-level datasets and by the difference between experimental performance and operational reliability. The reviewed studies do not provide a common dataset from which to calculate a Saudi-wide failure rate or a universal return on digital investment. Research comparisons are also complicated by inconsistent defect classes, alarm thresholds, sensor placement and validation protocols. Accordingly, the framework is a proposal requiring site-specific testing rather than a certified integrity standard.

Priority research should include independent multisite trials in representative Saudi service conditions; uncertainty-aware models trained on temporally separated inspection runs; performance evaluation under sensor faults and operating transitions; and decision studies that measure avoided risk, not merely prediction accuracy. Shared data definitions and secure interfaces would enable better comparison without compromising sensitive infrastructure information. Prospective audits should record whether model recommendations were accepted, overridden or proven wrong after verification.

12 Conclusion

Advanced inspection, continuous monitoring and predictive algorithms provide complementary information for hydrocarbon distribution pipelines, but their benefits depend on disciplined integration. In-line inspection establishes much of the physical condition evidence; distributed sensors can detect events between campaigns; and probabilistic models translate evolving observations into risk-sensitive intervention priorities. No individual method offers complete threat coverage or eliminates uncertainty.

The proposed Saudi-oriented framework connects threat identification, qualified measurement, model validation, consequence assessment, engineering approval and feedback from maintenance outcomes. Its central implication is that predictive maintenance must be judged by whether it

improves transparent, timely and proportionate integrity decisions. Responsible deployment should begin with trustworthy asset records and targeted pilots, expand only after independent validation and preserve explicit professional accountability. These measures offer a technically credible route to improving network resilience and operational stewardship as Saudi energy infrastructure develops.

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