EXECUTIVE SUMMARY

# A Brief Introduction to Implementing Condition-Based Maintenance

## Practical Guidance and Industry Context for Electric Utility Asset Management

Prepared by Planmetrix LLC

## 1. Purpose & Context

This report summarizes a structured, eleven-stage roadmap (Stage 0 through Stage 10) designed to help an electric utility plan, implement, and refine a Condition Based Maintenance (CBM) program for transmission and distribution assets. Rather than prescribing a single methodology, the roadmap functions as a self-assessment and interview guide, prompting a utility to document the drivers, decisions, data sources, staffing, thresholds, technology, and lessons learned at each stage of CBM maturity.

The asset classes named throughout the roadmap are power transformers, bushings, cooling systems, load tap changers, surge arrestors, circuit breakers above 69kV, and gas insulated switchgear (GIS). This report supplements the roadmap's structure with current industry context on how electric utilities are implementing CBM in practice as of 2025–2026, including diagnostic standards, sensor and software trends, common implementation barriers, and the broader trajectory toward predictive/prescriptive-based maintenance (PBM).

### Primary Drivers

| Asset Risk & Reliability | Program Economics | Data & Technology |
|---|---|---|
| Aging transformer and switchgear fleets, rising failure cost, and regulatory pressure for grid reliability are accelerating CBM adoption across the sector. | Transformer supply constraints raise the cost and lead time of unplanned failures, strengthening the case for condition-based approaches that extend safe asset life. | Online DGA monitoring, digital twins, and sensor-equipped equipment are shifting maintenance engineering from reactive to condition-based and predictive. |

## 2. Structure of the Source Roadmap

The roadmap poses open-ended questions across eleven stages, intended to be answered by a utility describing its own CBM journey.

| Stage | Focus |
|---|---|
| 0 | Baseline — continuing current (non-CBM) maintenance practice as the comparison point |
| 1 | Program scope: drivers for adopting CBM and selection of candidate assets |
| 2 | Assessing current asset condition and maintenance needs using historical and inspection data |
| 3 | Developing the monitoring plan: variables, sensors, manual vs. automated data collection |
| 4 | Staffing, training, and organizational change management |
| 5 | Establishing alarm thresholds and monitoring parameters |
| 6 | Assessing backend software, communications, and systems integration needs |
| 7 | Implementation: issues encountered, what worked, use of external expertise |
| 8 | Work management: alarm notification, work order generation, inventory linkage |

| Stage | Focus |
|---|---|
| 9 | Monitoring and refining the program using metrics |
| 10 | Forward planning: program expansion, transition toward PBM, and lessons learned |

*Table 1. Stage-by-stage structure of the CBM roadmap questionnaire.*

## 3. Stage-by-Stage Summary

### Stage 0 – Continue as Normal

Establishes the baseline: the utility's existing maintenance approach prior to any CBM initiative, typically time-based or reactive maintenance, serving as the reference point against which the value of moving to CBM can later be measured.

### Stage 1 – Program Scope and Selecting Assets

Captures why the utility pursued CBM — cost reduction, reliability, competitiveness, employee safety, or regulatory request — and how candidate assets were selected, including what data, cost-benefit analysis, risk assessment, and feasibility or pilot studies informed the selection.

### Stage 2 – Current State of the Assets and Maintenance Need

Characterizes existing asset condition and maintenance needs using historical data analysis, inspections, sensor readings, asset age, replacement cost, failure history and post-mortems, prior failures of similar equipment, and subject matter expert judgment.

### Stage 3 – Develop a Monitoring Plan for Assets

The most detailed stage, covering selection of monitored variables, sensor technology decisions, and the balance between manual (offline) procedures — oil dissolved gas analysis (DGA) and furan sampling, handheld temperature and partial discharge monitors, visual inspection — and continuous online monitoring. Also addresses testing frequency, sensor piloting, reasons for accepting or rejecting monitoring approaches, and whether procurement specifications now require factory-installed sensors.

### Stage 4 – Staffing and Personnel

Addresses organizational readiness: whether a dedicated working group was formed, how maintenance department changes were assessed, how training needs were determined, and how changes to working practices were communicated to staff.

### Stage 5 – Establish Thresholds and Monitoring Parameters

Covers how alarm thresholds were set, drawing on IEEE and CIGRE standards, manufacturer guidelines, predictive modeling, and industry failure databases, along with the supporting software and historical operating data used.

### Stage 6 – Assess Backend Needs

Addresses the technology backbone: additional software requirements, vendor collaboration, communications infrastructure upgrades, integration difficulties, and data capture methods where manual or offline processes remain in use.

### Stage 7 – Implement CBM

A retrospective on implementation itself — issues encountered across hardware, software, sensors, data analysis, and knowledge gaps; what went well; use of external expertise; and how the implementation was tested.

### Stage 8 – Work Management

Examines how the CBM program connects to day-to-day operations: alarm notification, work order generation from monitoring data, maintenance team response, and linkage to inventory management.

### Stage 9 – Monitor and Refine

Addresses how the utility tracks ongoing program performance, what metrics are used, and how the program is refined over time based on that performance data.

### Stage 10 – Plan for the Future

Looks ahead to additional asset classes (cables, pumps, other transformer components), whether the utility intends to move toward Predictive/Prescriptive-Based Maintenance (PBM), and lessons learned to carry forward.

## 4. Industry Context: Electric Utility CBM in Practice

The roadmap's questions map closely onto how CBM is implemented across the electric utility sector. The sections below summarize current practice and supporting standards for the asset classes and decision points the roadmap addresses.

### 4.1 Diagnostic Standards and Core Monitoring Techniques

For power transformers — the centerpiece asset class in most utility CBM programs — dissolved gas analysis (DGA) remains the primary diagnostic technique, evaluating gases dissolved in transformer insulating oil to detect incipient faults such as overheating, arcing, and partial discharge.

- **IEEE C57.104 (2019):** the principal U.S. guide for interpreting dissolved gas analysis results, covering gas generation theory, interpretation methods, operating procedures, and evaluation criteria.
- **IEC 60599:** the complementary international standard used alongside IEEE C57.104, particularly for ratio-based fault classification.
- **Complementary oil tests:** moisture content, acidity, and dielectric strength, which indicate insulation degradation independent of gas evolution.
- **Electrical diagnostics:** power factor (dissipation factor) and winding resistance testing for dielectric integrity, and Frequency Response Analysis (FRA) for mechanical/winding deformation.
- **Infrared thermography:** used to detect abnormal heating from poor connections or cooling system inefficiency, applicable across transformers, breakers, and bushings.

Modern practice favors integrating these methods rather than relying on any single indicator: validating data quality, evaluating gas generation trends over time, applying pattern-based methods such as Duval's triangle/pentagon, cross-checking against IEEE/IEC thresholds, and applying engineering judgment informed by loading history and maintenance records.[1][2]

### 4.2 Asset Classes and Failure Modes

A CBM program is most effective when it is organized around credible failure modes rather than around available sensors. For each asset class named in the roadmap, the table below summarizes typical failure modes, the condition indicators and diagnostic methods used to detect them, and practical guidance for applying CBM to that asset.

| Asset | Failure Modes | Condition Indicators / Diagnostics | CBM Guidance |
|---|---|---|---|
| Power transformers | Thermal or electrical faults, insulation aging, moisture ingress, winding deformation, cooling deficiency, oil degradation. | DGA and gas generation trend, oil quality, furan analysis, moisture, power factor, winding resistance, FRA, infrared, load and temperature history. | DGA remains the cornerstone, but interpretation should validate sample quality, trend rate, and loading context before dispatching field work. |

---

[1] IEEE Standards Association. https://standards.ieee.org/ieee/C57.104/7476/

[2] Power Prognosis. https://powerprognosis.com/integrated-dga-interpretation-for-power-transformers-ieee-c57-104/

| Asset | Failure Modes | Condition Indicators / Diagnostics | CBM Guidance |
|---|---|---|---|
| Bushings | Dielectric deterioration, moisture ingress, partial discharge, power factor/capacitance change. | Power factor/tan delta, capacitance, leakage current, infrared, visual inspection, online bushing monitors. | High-value target because bushing failure can destroy the host transformer; validate online alarms with offline testing. |
| Cooling systems | Fan or pump failure, blocked radiators, controls failure, abnormal top-oil or winding temperature. | Temperature, fan/pump status, current draw, oil flow, infrared, ambient temperature and load correlation. | Often a quick win: failed fans or controls can be repaired before insulation aging accelerates. |
| Load tap changers | Contact wear, coking, drive mechanism problems, timing issues, motor problems. | Operation count, motor current signature, oil tests where applicable, contact wear inspection, timing, acoustic/vibration checks. | Maintenance intervals should reflect operations and duty cycle, not calendar age alone. |
| Circuit breakers >69 kV | Mechanism wear, slow operation, contact deterioration, SF6 or insulating medium issues, control circuit problems. | Trip/close timing, coil current signatures, contact resistance, SF6 density/moisture, operation counters, relay event records. | Breaker CBM must remain aligned with regulatory protection-system maintenance requirements and documentation. |
| Gas insulated switchgear (GIS) | Gas leakage, moisture ingress, partial discharge, corrosion/flange deterioration, mechanism issues. | SF6 density, moisture/dew point, partial discharge (acoustic/UHF) monitoring, infrared, corrosion inspection, operation counters. | Outdoor GIS needs environmental exposure and corrosion management in addition to electrical diagnostics. |

*Table 3. Representative failure modes, condition indicators, and CBM guidance by asset class.*

Breaker and protection-system condition monitoring in particular should be designed alongside, not instead of, mandatory regulatory maintenance. In the United States, NERC Reliability Standard PRC-005-6 requires documented maintenance programs for protection systems, automatic reclosing, and sudden pressure relaying on Bulk Electric System equipment, with maximum allowable maintenance intervals that apply regardless of whether a unit is also covered by condition monitoring.[3]

For transformers specifically, CIGRE's Technical Brochure 962 (2025 edition), which replaces the widely used TB 445, provides an updated international reference for transformer maintenance best practice, including component-level inspection and testing intervals informed by a fresh survey of current utility maintenance practices.[4]

## 4.3 Scholarly Literature on CBM

Academic and IEEE-published research reinforces the practitioner-facing guidance above and extends it across the asset classes named in the roadmap. A 2024 scoping review of power transformer maintenance and condition assessment research found that data analysis methodologies for failure identification and decision support add measurable value to transformer asset management, drawing on literature from twenty-five countries with more than half published in the preceding five years.[5]

---

[3] NERC — PRC-005-6, Protection System, Automatic Reclosing, and Sudden Pressure Relaying Maintenance. https://www.nerc.com/globalassets/standards/reliability-standards/prc/prc-005-6.pdf

[4] CIGRE — TB 962, Guide for Transformer Maintenance (2025 Edition). https://www.e-cigre.org/publications/detail/962-guide-for-transformer-maintenance.html

[5] IEEE Xplore — Emerging Trends in Power Transformer Maintenance and Diagnostics (Scoping Review). https://ieeexplore.ieee.org/document/10632123/

Health-index and machine-learning approaches have become a major research thread for translating raw condition data into actionable maintenance decisions. Recent reviews catalogue dissolved-gas-based criticality models, fuzzy-logic healthiness scoring, and machine-learning lifetime prediction methods as ways of converting DGA, oil, and electrical test results into a single asset health score that can drive prioritization decisions of the kind the roadmap's Stage 5 (thresholds) and Stage 2 (condition assessment) stages call for.[6][7]

Research extends well beyond transformers into the switchgear and circuit breaker asset classes the roadmap explicitly names. A peer-reviewed study on medium-voltage switchgear demonstrates that novel thermal, mechanical, and partial-discharge sensors combined with machine learning can deliver continuous condition monitoring for some of the most safety-critical distribution assets, directly informing the roadmap's Stage 3 sensor-selection questions. Separate research on gas insulated switchgear (GIS) develops health-index and conditional-factor methods for circuit breakers, earthing switches, and disconnecting switches, comparing CBM against scheduled preventive maintenance and finding it can extend service life and lower operating cost when paired with IoT and digital twin diagnostics.[8][9]

At the grid level, a systematic review of predictive maintenance research in smart grid distribution networks catalogues fault types, causes, and prediction methods, and concludes that predictive maintenance scheduling, automated fault and outage management, and self-healing grid capability are converging research priorities as utilities digitize. This mirrors the roadmap's Stage 10 question about moving from CBM toward a more predictive, prescriptive posture.[10]

## 4.4 Sensor and Monitoring Technology Trends

The roadmap's Stage 3 questions on sensor selection, piloting, and rejection reasons mirror current sector-wide trends. Utilities are increasingly extending condition-based monitoring beyond transformers to circuit breakers, voltage regulators, capacitor banks, and cables, since the underlying logic generalizes across equipment types.[11]

- Online (continuous) DGA monitoring is increasingly deployed alongside, rather than instead of, periodic offline oil sampling, since the two methods serve complementary purposes.
- Digital twin models — virtual replicas of substations or grid segments — support predictive maintenance scenario planning, shifting maintenance engineering from reactive to condition-based and predictive.
- Sensor-equipped "smart" transformers, mobile inspection applications, and GIS-enabled field data collection are part of a broader grid modernization and digitization trend extending into 2026.
- Procurement specifications increasingly require monitoring sensors be factory pre-installed on new equipment, directly reflecting the roadmap's question on changed procurement policy.[12]

## 4.5 Market and Asset-Risk Drivers

The cost-benefit pressures referenced in the roadmap's Stage 1 are intensifying. Industry modeling estimates a substantial supply shortfall across power and distribution transformers, with more than half of

---

[6] Power Transformer Health Index and Life Span Assessment: A Comprehensive Review (arXiv). https://arxiv.org/pdf/2504.15310

[7] An Integrated Fuzzy Logic Approach for Valuation of Power Transformer's Degree of Healthiness or Faultiness (PMC). https://www.ncbi.nlm.nih.gov/pmc/articles/PMC11889552/

[8] PMC — Integration of Novel Sensors and Machine Learning for Predictive Maintenance in Medium Voltage Switchgear. https://www.ncbi.nlm.nih.gov/pmc/articles/PMC7181000/

[9] MDPI Energies — Condition Assessment of Gas Insulated Switchgear Using Health Index and Conditional Factor Method. https://www.mdpi.com/1996-1073/15/24/9393

[10] MDPI Energies — The Current State of the Art in Research on Predictive Maintenance in Smart Grid Distribution Networks (Systematic Review). https://www.mdpi.com/1996-1073/14/16/5078

[11] Renewable Energy World. https://www.renewableenergyworld.com/power-grid/grid-modernization/how-utilities-are-making-the-grid-more-reliable-with-condition-based-transformer-monitoring/

[12] Think Power Solutions. https://www.thinkpowersolutions.com/blogs/utility-infrastructure-modernization/

U.S. distribution transformers already operating beyond their expected service life, and demand for higher-voltage units growing sharply since 2019, driven in part by data center load growth.[13]

The U.S. Department of Energy's 2024 Large Power Transformer Resilience Report to Congress reinforces this picture at the high end of the fleet, documenting long acquisition lead times for large power transformers and describing industry-driven sparing and reserve-sharing programs as the primary near-term mitigation, since most large units are well beyond the 38–40 year average age DOE has previously reported for the North American fleet.[14]

These supply constraints raise the cost and lead time of replacing a failed transformer, strengthening the economic case for condition-based approaches that extend safe operating life and avoid unplanned outages. Industry risk models commonly tie transformer condition ratings to expected annual failure probabilities — ranging roughly from under 1% for assets in good condition to 3% or more for those rated poor — which utilities can use to prioritize CBM monitoring investment toward the highest-risk units.[15]

## 4.6 Standards Landscape Beyond Transformers

The roadmap's broader asset scope — bushings, circuit breakers, gas insulated switchgear — is increasingly supported by recently updated IEEE standards. Updates such as IEEE C57.19.100 (power apparatus bushings), IEEE C57.170 (transformer condition assessment), IEEE 1686 (intelligent electronic device cybersecurity), and IEEE 495 (faulted circuit indicators) reflect a substation engineering environment that is becoming more instrumented, automated, and cybersecurity-aware, shaping the backend integration questions the roadmap raises in Stage 6.[16]

**Key Finding**

Sensor technology is rarely the limiting factor. Across condition-based and predictive maintenance programs generally — with direct parallels in utility deployments — incomplete sensor coverage, workforce skills gaps, legacy system integration, and ROI justification are the barriers most frequently cited as slowing or stalling implementation.

## 4.7 Common Implementation Barriers

Across condition-based and predictive maintenance programs generally, the barriers most frequently cited as slowing or stalling implementation are organizational and data-related rather than purely technical:

| Barrier | Practical Impact |
|---|---|
| Incomplete sensor coverage / data integration | Partial instrumentation and siloed data sources produce unreliable readings and reduce confidence in alarms and trend analysis. |
| Workforce skills gaps | Diagnostics, data interpretation, and AI-assisted analysis require skills that differ from traditional time-based maintenance work, and training is often underfunded relative to the technology investment. |
| Legacy system integration | Asset registries, SCADA/historian data, and work-order systems frequently remain disconnected, limiting a comprehensive view of asset condition. |
| Budget / ROI justification | Because avoided failures are inherently counterfactual, building a credible business case for upfront sensor and software costs is harder than justifying routine maintenance spending. |

---

[13] POWER Magazine. https://www.powermag.com/transformers-in-2026-shortage-scramble-or-self-inflicted-crisis/

[14] U.S. Department of Energy — Large Power Transformer Resilience Report to Congress (2024). https://www.energy.gov/sites/default/files/2024-10/EXEC-2022-001242%20-%20Large%20Power%20Transformer%20Resilience%20Report%20signed%20by%20Secretary%20Granholm%20on%207-10-24.pdf

[15] Electric Energy Online. https://electricenergyonline.com/energy/magazine/229/article/Assessing-Health-and-Criticality-of-Substation-Transformers.htm

[16] Keentel Engineering. https://keentelengineering.com/ieee-2025-substation-design

*Table 2. Commonly reported predictive/condition-based maintenance implementation barriers.*

The U.S. Department of Energy's Federal Energy Management Program estimates that a well-run predictive maintenance program typically saves 8–12% over a preventive-maintenance-only program, with savings exceeding 30–40% possible at facilities that rely heavily on reactive maintenance — figures consistent with the pattern that organizational and data-integration barriers, not sensor technology itself, are usually what separate programs that capture this value from those that do not.[17]

### 4.8 From CBM Toward Predictive/Prescriptive-Based Maintenance (PBM)

The roadmap's final question — whether the utility intends to move toward PBM — reflects the recognized next stage of maintenance maturity. Where CBM acts on current measured condition against defined thresholds, predictive/prescriptive approaches use historical and real-time data, statistical or machine-learning models, and asset failure-mode libraries to forecast time-to-failure and recommend specific interventions before a threshold is reached.

Utilities considering this transition typically follow a phased path rather than a single conversion: an assessment and planning phase to establish data quality and a credible baseline, a pilot phase on a limited set of critical assets to validate that predictive models actually change maintenance decisions, and only then a broader rollout once the organization has confidence in both the models and the workflow that turns predictions into action. The scholarly literature reviewed above reflects this same maturity sequence, with smart grid predictive maintenance research increasingly converging on automated fault management and self-healing capability as the end state of this trajectory, built on the data and organizational foundations a CBM program establishes.

## 5. Conclusions

Read together, the roadmap and current industry practice point to a consistent picture: asset prioritization should be risk-driven, DGA remains foundational for transformers but is most effective combined with complementary diagnostic methods, and sensor strategy is a balance between continuous online monitoring and periodic offline confirmation rather than a binary choice.

Organizational and data-integration barriers, not sensor technology itself, are the most frequently cited reasons CBM and predictive maintenance programs underperform — reinforcing the roadmap's dedicated stages on staffing (Stage 4) and backend integration (Stage 6). CBM itself is best understood as a maturity step rather than an end state, with the roadmap's Stage 10 question on moving toward PBM reflecting an industry-wide trajectory from time-based, to condition-based, to predictive/prescriptive maintenance.

**Overall Assessment**

The roadmap provides a sound diagnostic framework for any utility assessing its CBM maturity, and current industry evidence validates its emphasis on asset risk prioritization, integrated diagnostics, organizational readiness, and backend systems integration. The decisive test for any CBM program is not whether sensors can be deployed, but whether the resulting data measurably changes maintenance decisions and reduces unplanned failures.

---

[17] U.S. DOE Federal Energy Management Program / PNNL — Operations & Maintenance Best Practices Guide, Release 3.0. https://www.energy.gov/sites/prod/files/2020/04/f74/omguide_complete_w-eo-disclaimer.pdf