Safety & Enforcement Division
Pipeline Safety Program

Commissioners Technical Committee Meeting

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Gas Safety and Reliability Branch

What this Presentation Covers

- The Transmission Integrity Management Process
- High Consequence Areas (HCAs)
- Threats to Gas Transmission Pipeline Integrity
- How Risk is Calculated
- Tools currently used for “Integrity Assessments”
- Limitations of these “Integrity Assessment” tools
- Using Preventative/Mitigative measures to lower risk and remediating the pipeline(repairing the pipeline)

Integrity Management Process Flow Chart

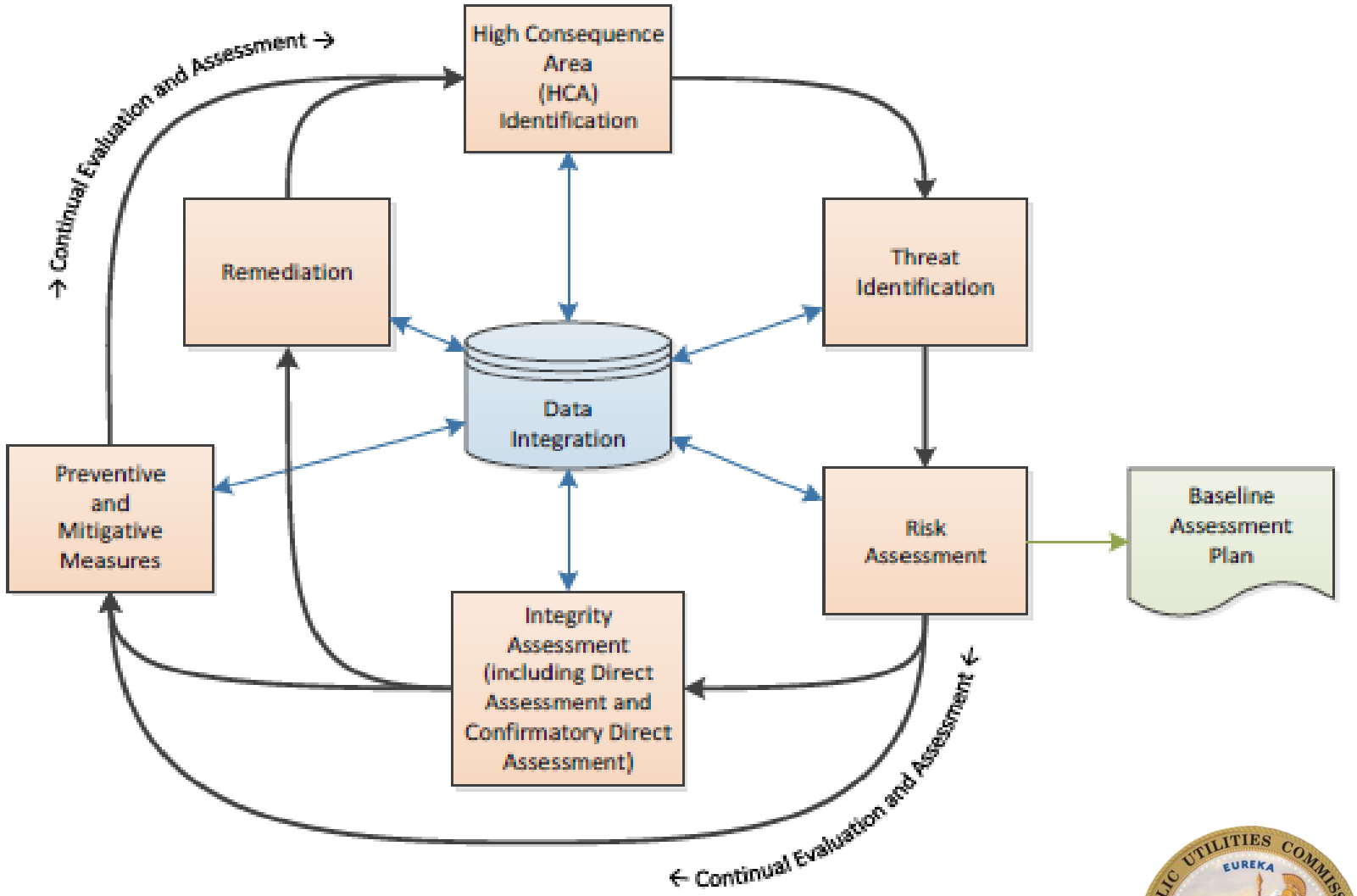


Figure 3. Gas transmission IM program flowchart

Utility Information Systems

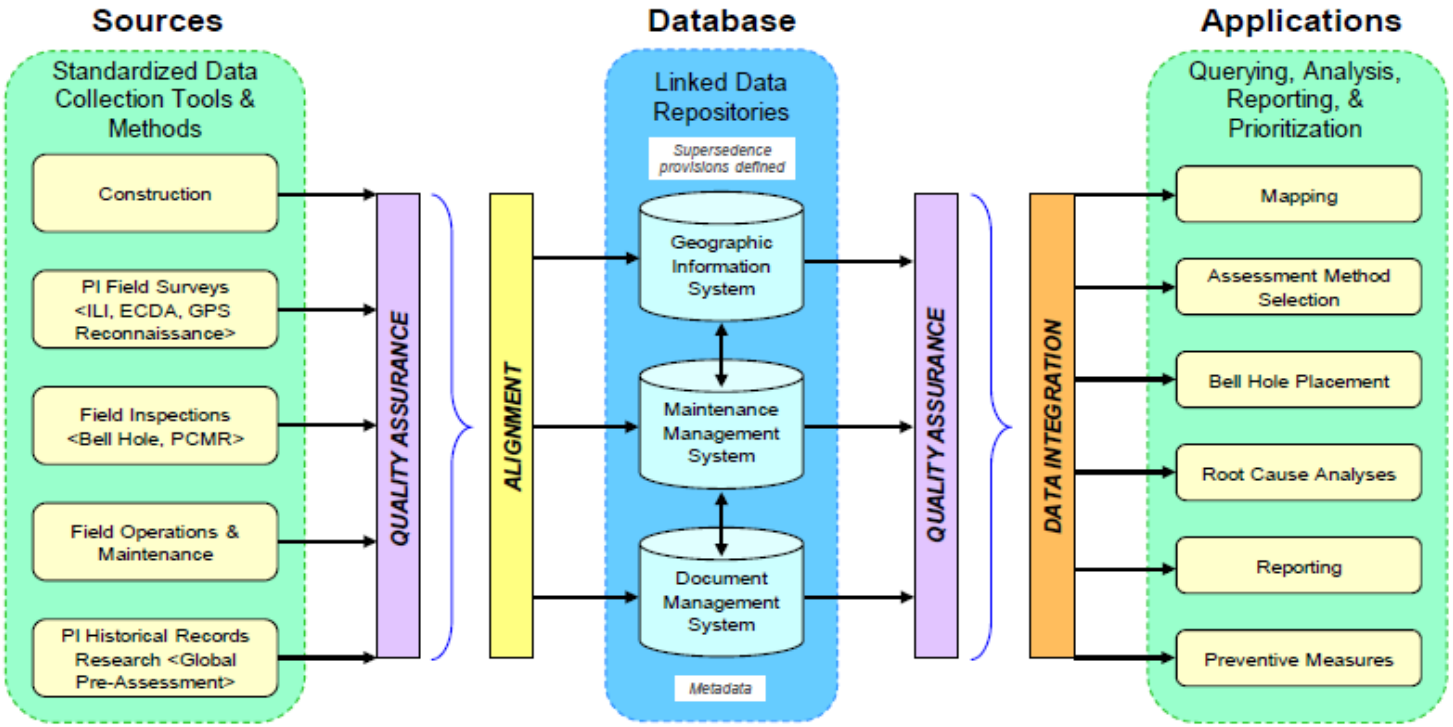
	O&M	GIS	IM Risk Assessment	CRM	SCADA
PG&E	SAP	GD GIS	Synergi Pipeline	Sharepoint	Aveva OASyS
Sempra	SAP	ESRI	ICAM/D	J5 Operations Managment	Aveva OaSySDNA ezXOS
SWG	FOMS	ESRI	Synergi Pipeline	Hourglass	Aveva OASyS 2018
WGS	File Directory	ESRI	N/A	MS Office	WonderWare
LGS	File Directory	ESRI	N/A	MS Office	iFix

SoCal Gas Data Architecture

Pipeline Integrity Data Management Architecture

Processes and Systems that gather, store, and assess pipeline integrity related data

BENEFITS:
* Measurability
* Repeatability
* Verifiability
* Reliability
* Defensibility



FIELD TOOLS: Geophysical Devices, Measurement & Testing Devices, GPS, PCM, Digital Pen, Barcoding, VisualCE, Excel

OFFICE TOOLS: GeoFields, ArcGIS, Oracle, Maximo, Pathfinder Office, Eccentex, Excel, Access

Transmission Integrity Management Program Requirements

There are two methods defined in Part 192, Subpart “O” for determining HCAs:

- Method 1 (Class 3 and Class 4 locations)
- Method 2 (Potential Impact Radius)

Both methods identify areas of high population density.

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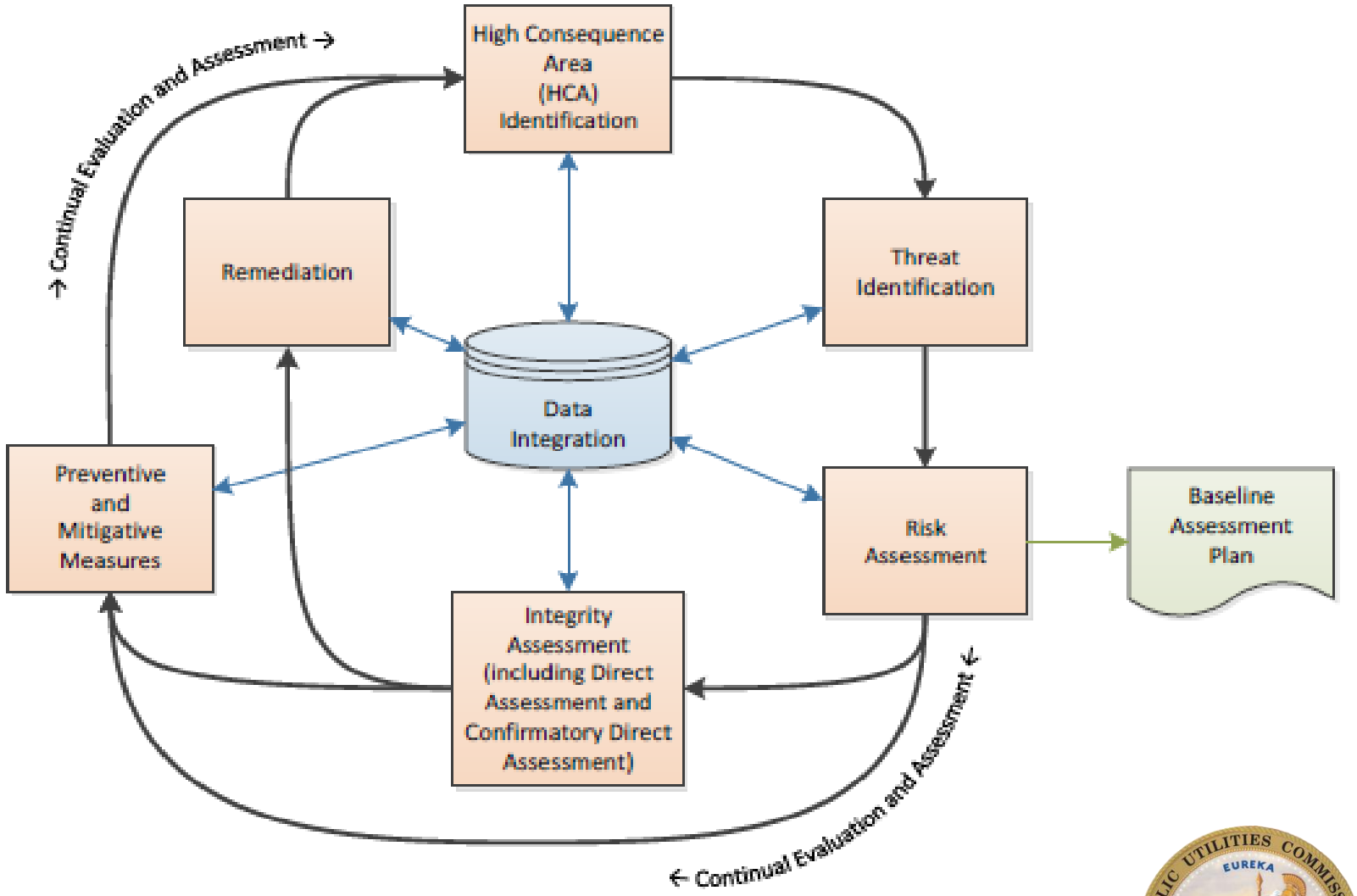

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Part 192.917 Additional Threats

Part 192 is the PHMSA code that the GSRB enforces.

Part 192.917 of that code states:
(a) *Threat identification. An operator must identify and evaluate all potential threats to each covered pipeline segment.* Potential threats that an operator must consider include, but are not limited to, the threats listed in ASME/ANSI B31.8S (incorporated by reference, *see §192.7), section 2…*

Threats Defined by B31.8S-2004

Time Dependent

- External Corrosion
- Internal Corrosion
- Stress Corrosion Cracking

Threats Defined by B31.8S-2004

Stable

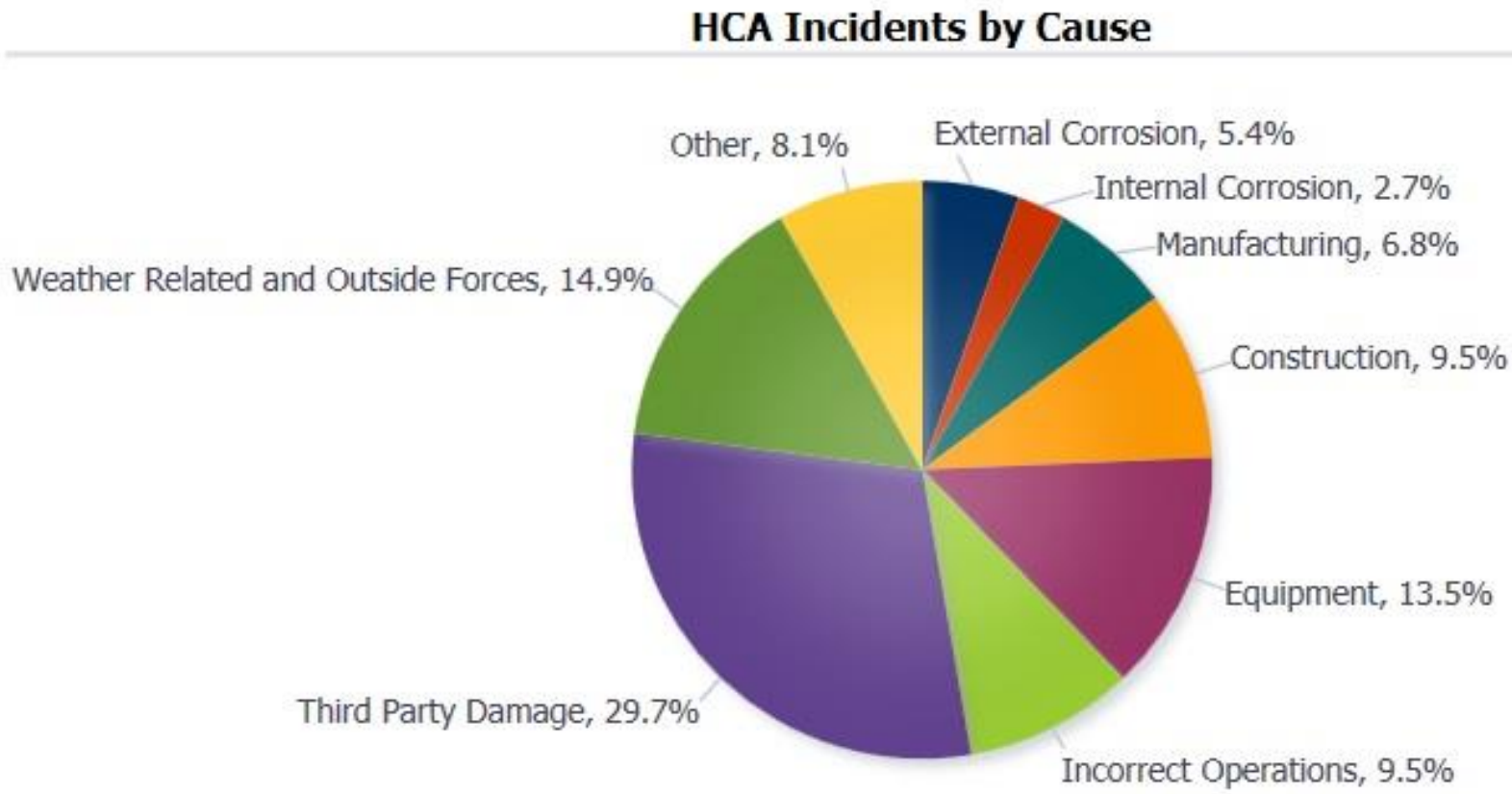
- Manufacturing Defects
- Construction Defects
- Equipment (i.e., Pressure Regulation)

Threats Defined by B31.8S-2004

Time Independent

- Third Party Damage
- Incorrect Operations
- Weather Related and Outside Force

National Gas Transmission HCA Significant Incidents by Cause (2004-2018)



Each Threat is defined in B31.8S-2004

Example:

The construction threat is defined in B31.8S-2004, Appendix A.5.1 as:

pipe girth weld, fabrication weld, wrinkle bend or buckle, stripped threads, broken pipe, or coupling…

Data Gathering and Integration is also Defined in B31.8S-2004

Example:

For the construction threat, the following data must be gathered:

(a) pipe material
(b) wrinkle bend identification
(c) coupling identification
(d) post-construction coupling reinforcement
(e) welding procedures
(f) post-construction girth weld reinforcement
(g) NDT information on welds

Data Gathering and Integration is also Defined in B31.8S-2004

Example:

For the construction threat, the following data must be gathered:

(h) hydrostatic test information

(i) pipe inspection reports (bell hole)

(j) potential for outside forces (see para. A9)

(k) soil properties and depth of cover for wrinkle bends

(l) maximum temperature ranges for wrinkle bends

(m) bend radii and degrees of angle change for wrinkle bends

(n) operating pressure history and expected operation, including significant pressure cycling and fatigue mechanism

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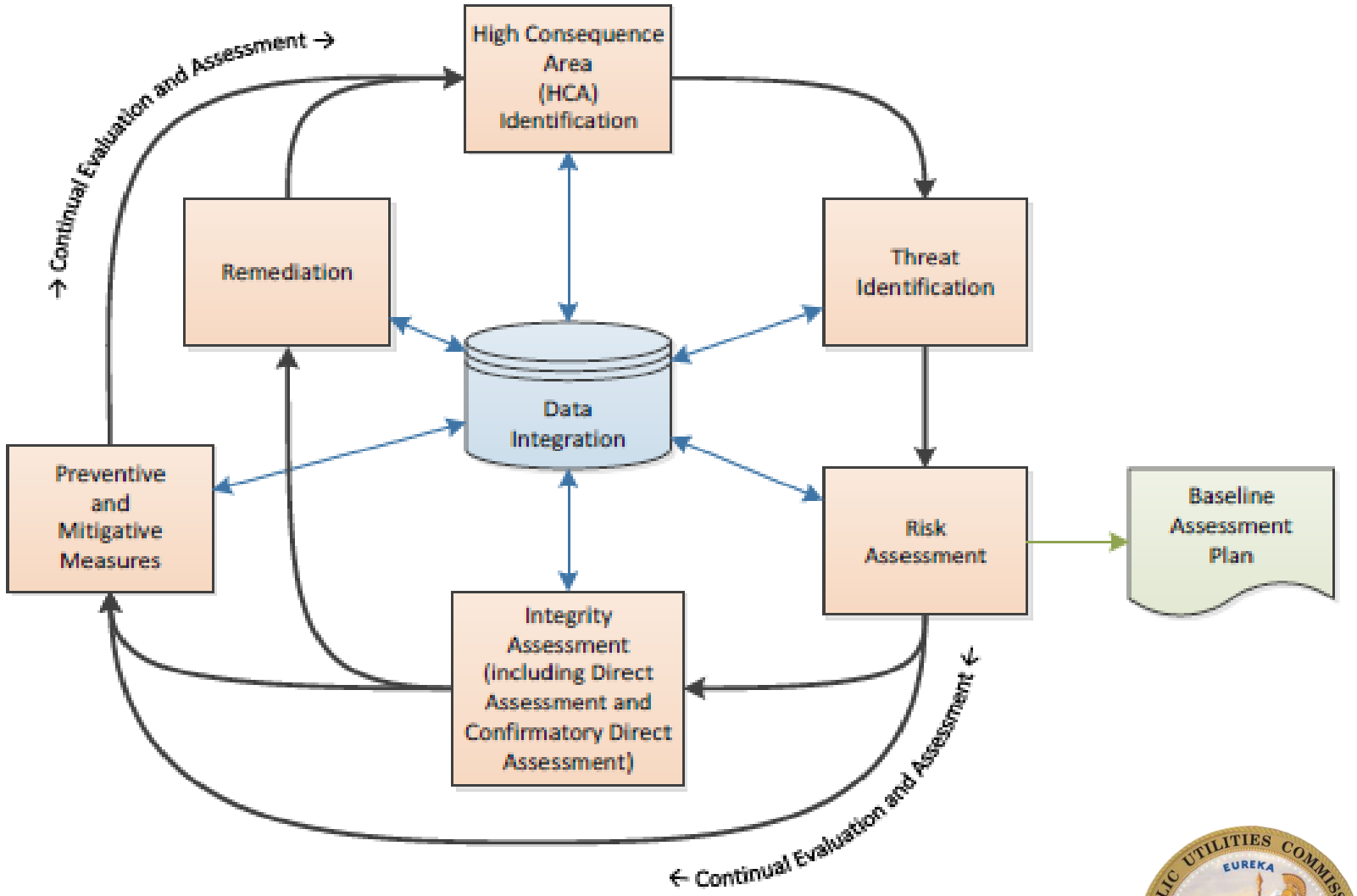

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Definition of Risk from B31.8S-2004, Section 5.2

$$\text{Risk}_i = P_i \times C_i \text{ for a single threat}$$

$$\text{Risk} = \sum_{i=1}^{9} (P_i \times C_i) \text{ for threat categories 1 to 9}$$

Total segment risk

$$= P_1 \times C_1 + P_2 \times C_2 + \ldots + P_9 \times C_9$$

where

C = failure consequence

P = failure likelihood

1 to 9 = failure threat category (see para. 2.2)

Risk Assessment Methods Defined by B31.8S-2004, Section 5.5

- Subject Matter Expert (SME) Approach
- Relative Risk Model
- Scenario Based Model
- Probabilistic Risk Model

The Output of the risk assessment process

- The pipeline system is segmented
- The risk is determined based on the threats each HCA segment is subject to
- The output is typically in the form of a spreadsheet showing a prioritized list of Segments needing integrity assessment
- The “Assessment Techniques” are selected to address the threats for each segment

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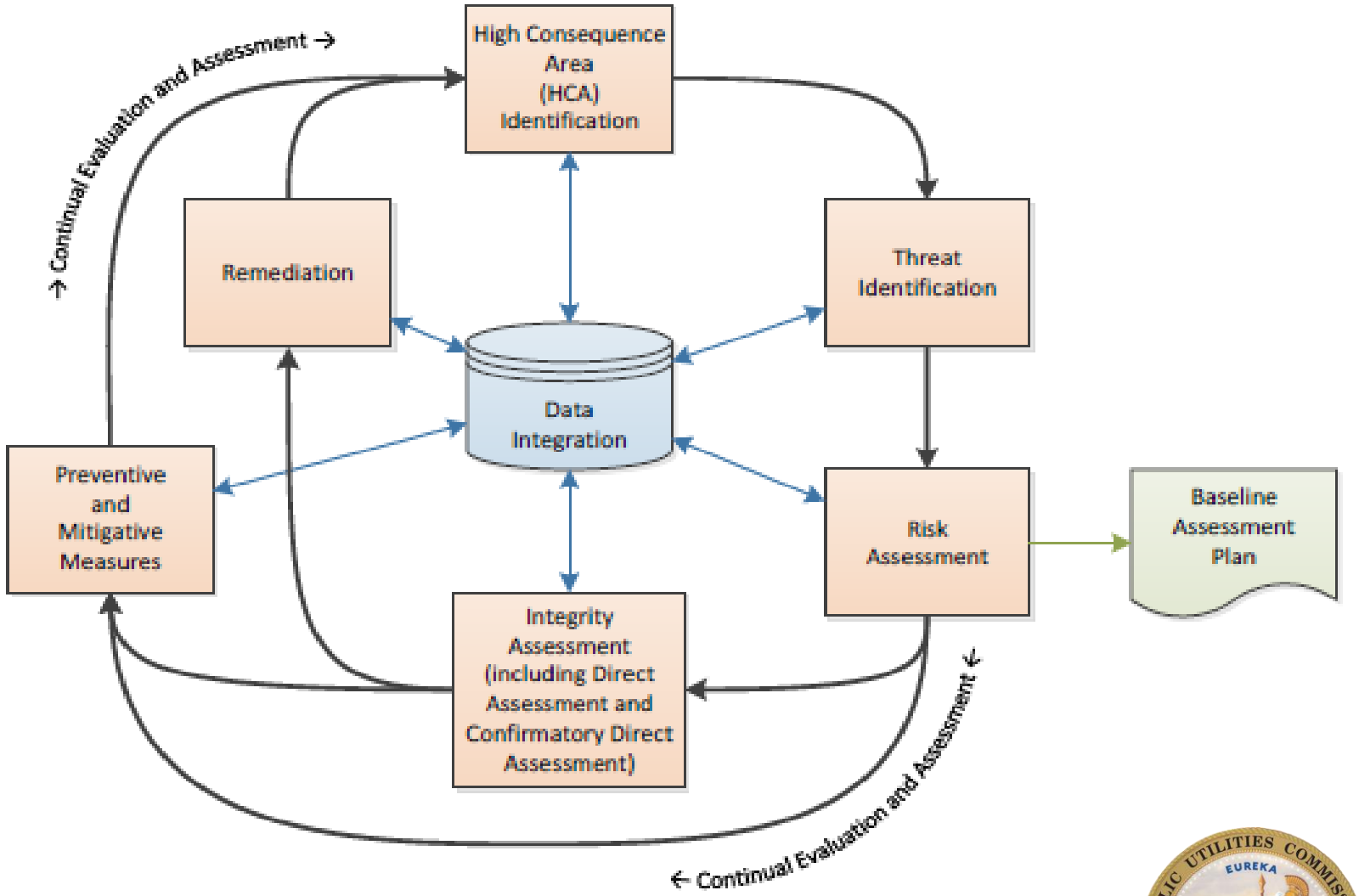

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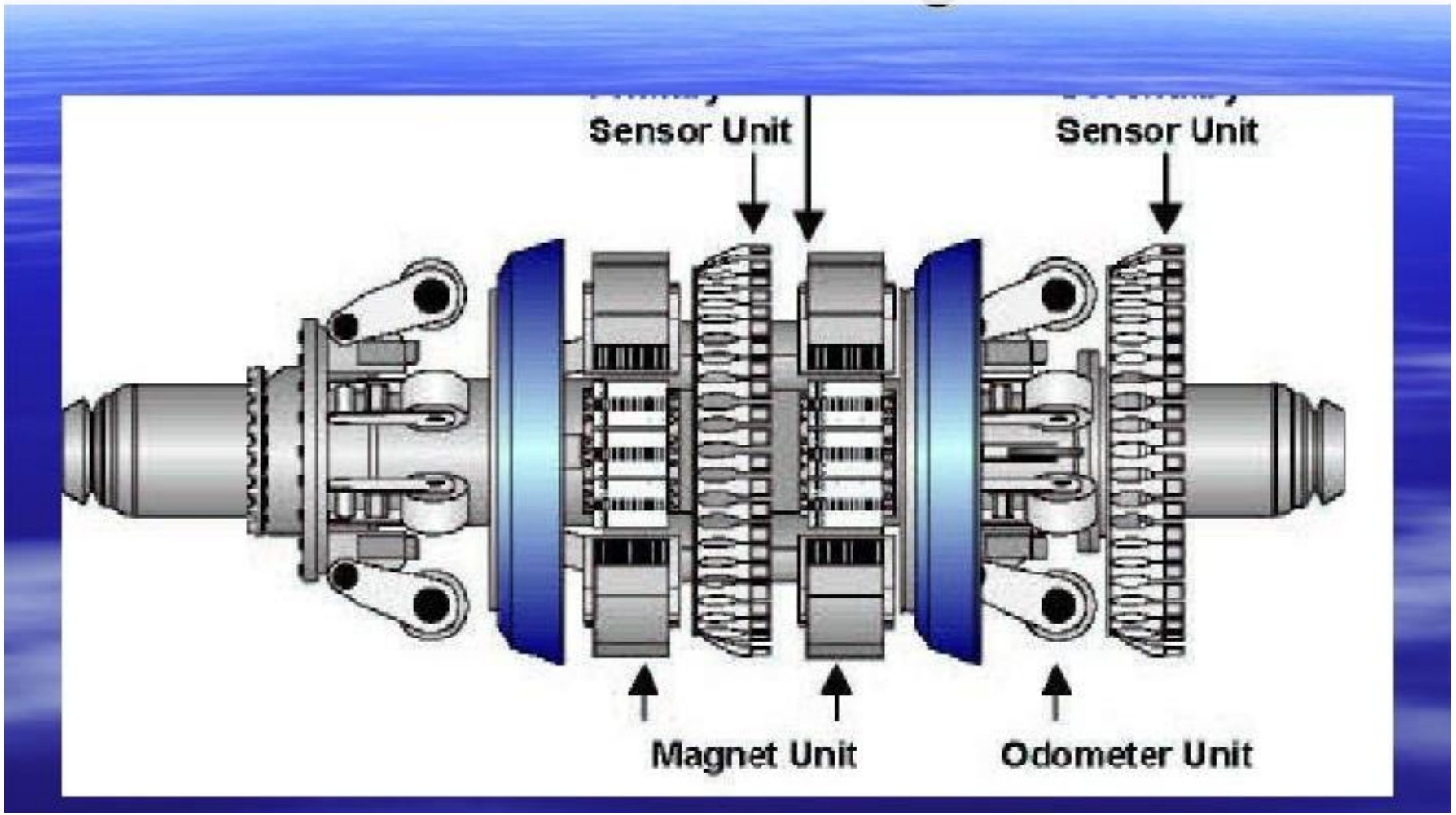
Integrity Assessment Techniques Allowed by Part 192.937(c)

- In-Line-Inspection Tools (a.k.a., Smart PIGs)
- Pressure Testing per Part 192, Subpart J
- Direct Assessment for the threats of External Corrosion, Internal Corrosion and Stress Corrosion Cracking
- Other Technology (i.e., Guided Wave Ultrasonic Technology, etc.)

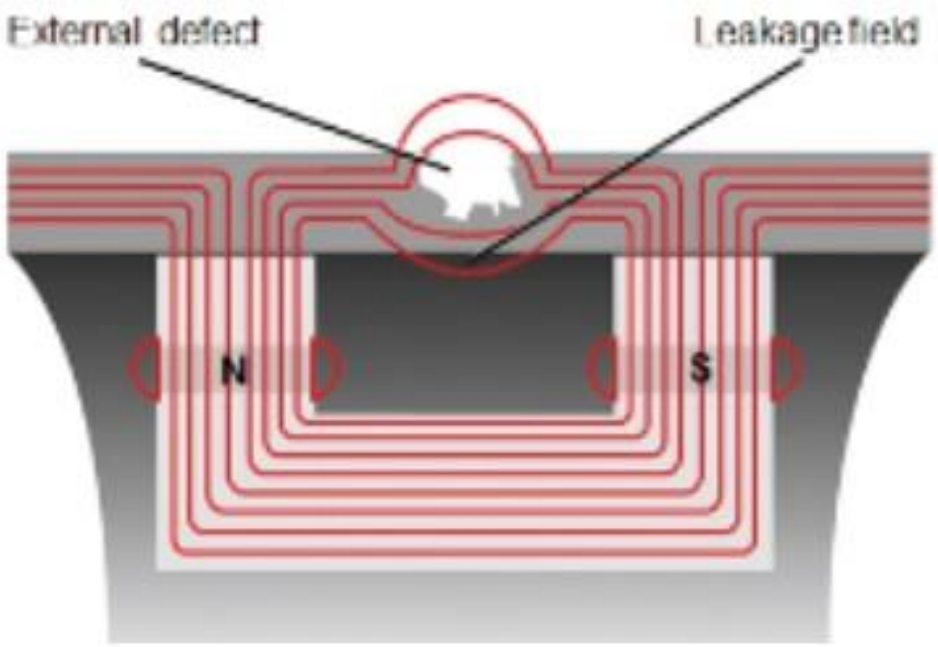
Integrity Assessment Techniques Allowed by Part 192.937(c)

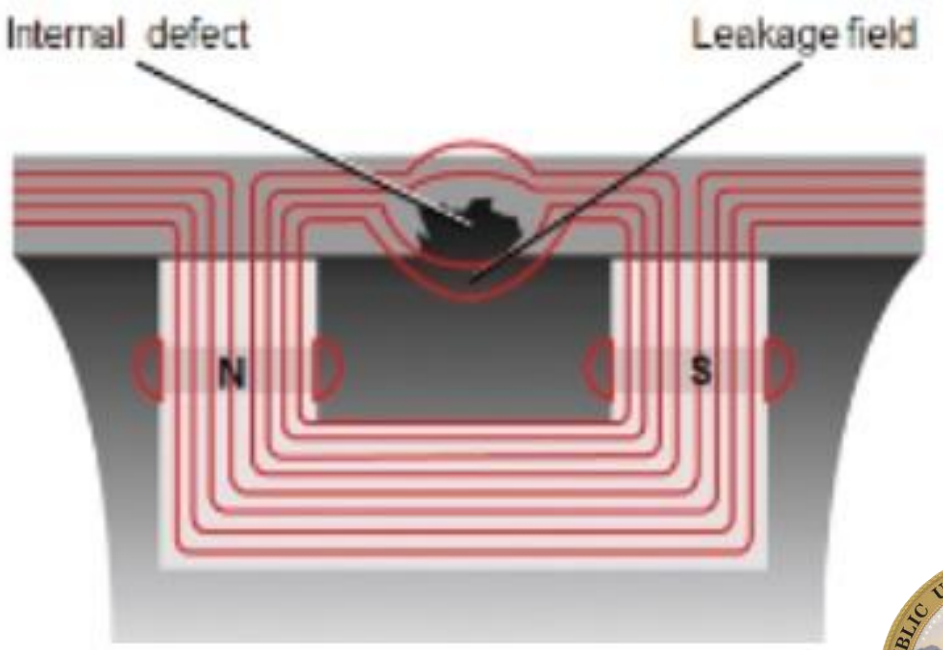
There are advantages and disadvantages to each of the four integrity assessment technique from the previous page.

Magnetic Flux Leakage (MFL) Smart PIG

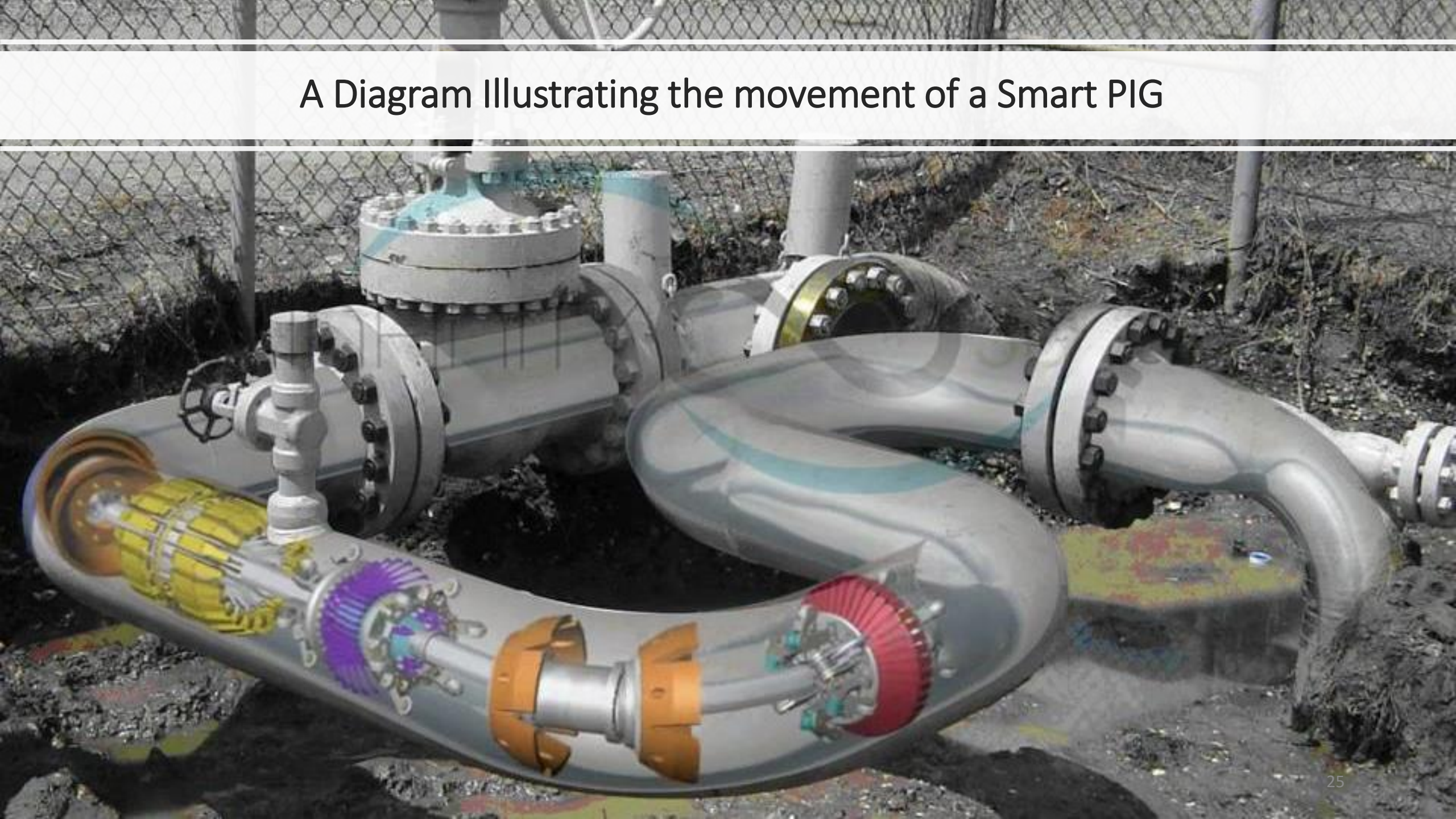


MFL Principle of Operation

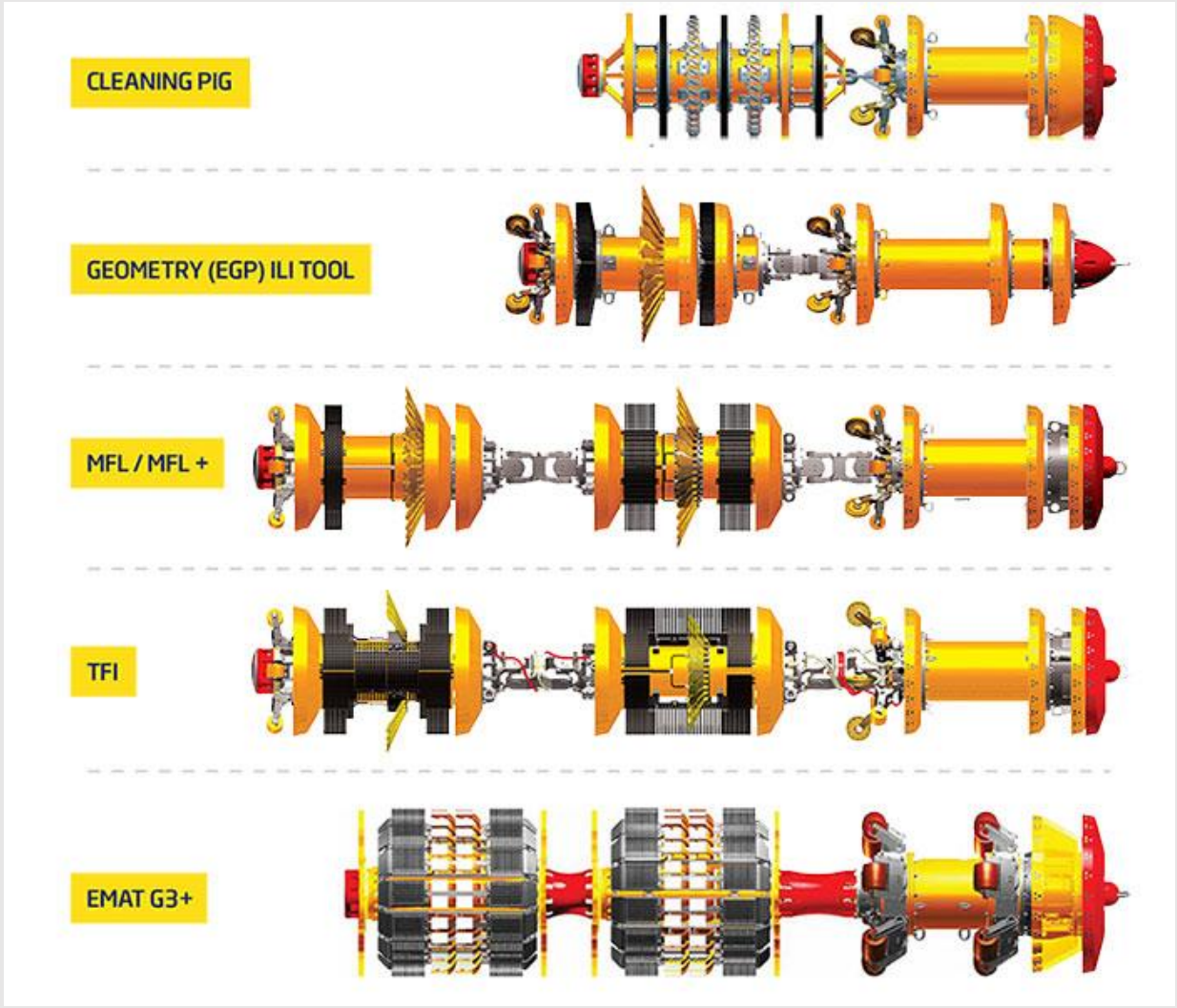




A Diagram Illustrating the movement of a Smart PIG



Different Types of PIGS



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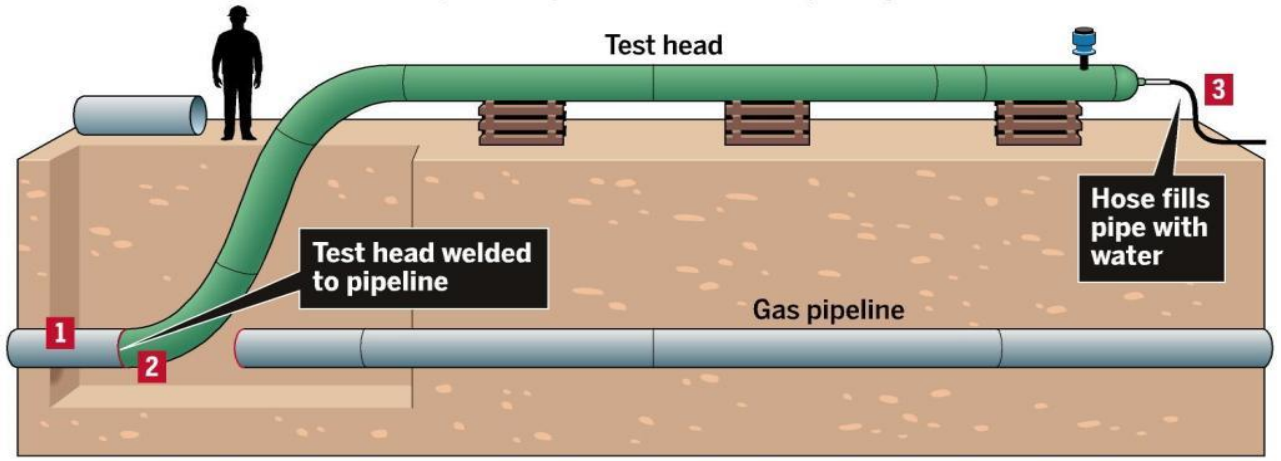
Pressure Testing a Segment of Pipe

How pressure testing works

To conduct a hydrostatic pressure test on its gas pipelines, PG&E first obtains all needed work permits, coordinates with local agencies and provides gas to customers temporarily from an alternative source.



1 The section of pipeline to be tested is excavated, vented of gas and cut open at both ends. The inside is mechanically cleaned before testing.

2 A "test head," a piece of pipe with a hose at one end, is welded to one end of the underground pipe being tested. Another test head is attached to the other end of the tested section.

3 The pipeline is filled with water through the hose.

4 The pipeline is pressurized to a specified pressure, much higher than normal operating pressure — for example, 600 psi if maximum allowable pressure is 400 psi.

5 The test pressure is held and monitored for at least eight hours.

6 Pipe sections that fail the test are replaced with new pipe that has already passed a pressure test.

7 Pipe is emptied of water, dried and returned to service.

Source: PG&E

MERCURY NEWS

Integrity Assessment Techniques Allowed by Part 192.937(c)

- In-Line-Inspection Tools (a.k.a., Smart PIGs)
- Pressure Testing per Part 192, Subpart J
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Direct Assessment for three threats

External Corrosion Direct Assessment (ECDA) is defined as:
ECDA is a four-step process that combines preassessment, indirect inspection, direct examination, and post assessment to evaluate the threat of external corrosion to the integrity of a pipeline.

Internal Corrosion Direct Assessment (ICDA) is defined as:
A process an operator uses to identify areas along the pipeline where fluid or other electrolyte introduced during normal operation or by an upset condition may reside, and then focuses direct examination on the locations in covered segments where internal corrosion is most likely to exist…

Stress Corrosion Cracking Direct Assessment (SCCDA) is defined as:
A process to assess a covered pipe segment for the presence of SCC primarily by systematically gathering and analyzing excavation data for pipe having similar operational characteristics and residing in a similar physical environment.

Integrity Assessment Techniques Allowed by Part 192.937(c)

- In-Line-Inspection Tools (a.k.a., Smart PIGs)
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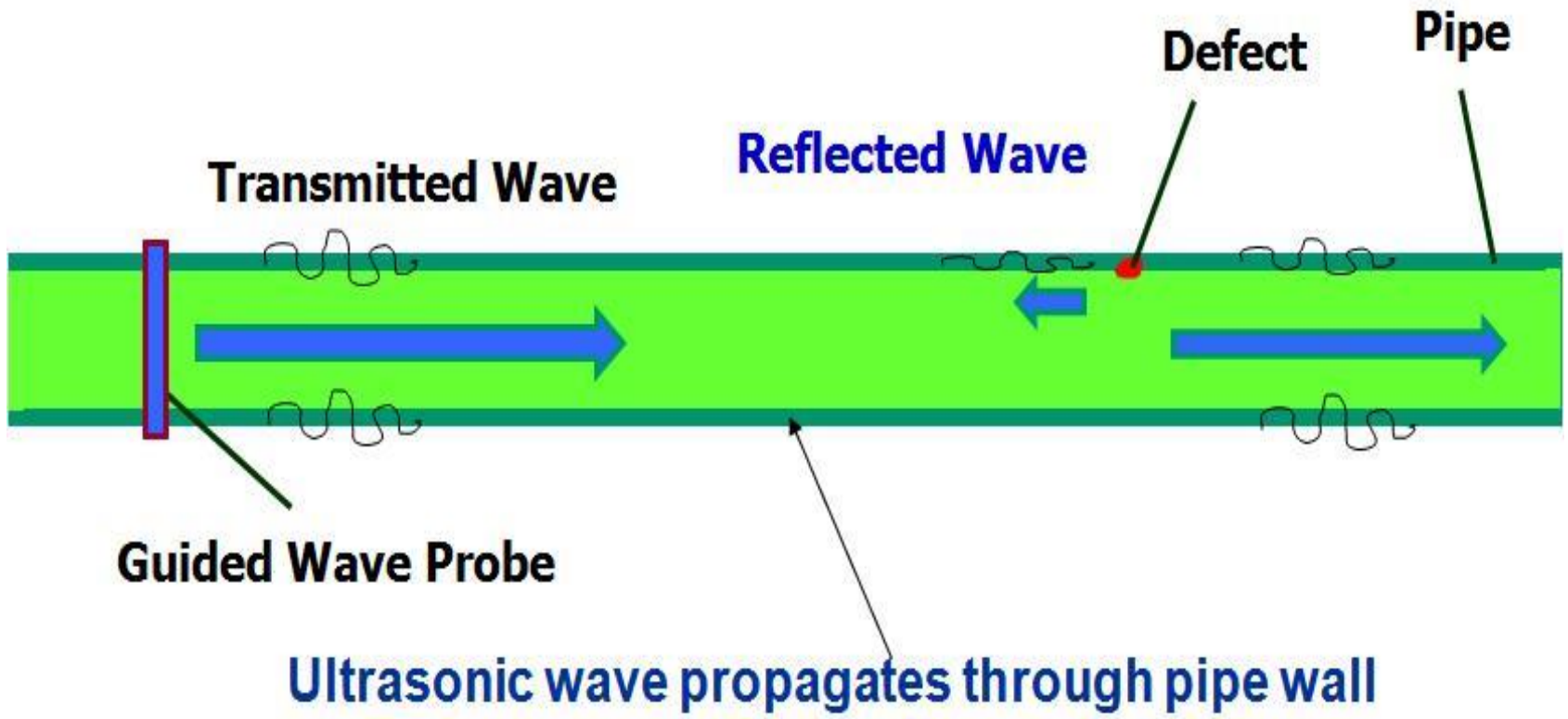
Guided Wave Ultrasonic Technology (GWUT)



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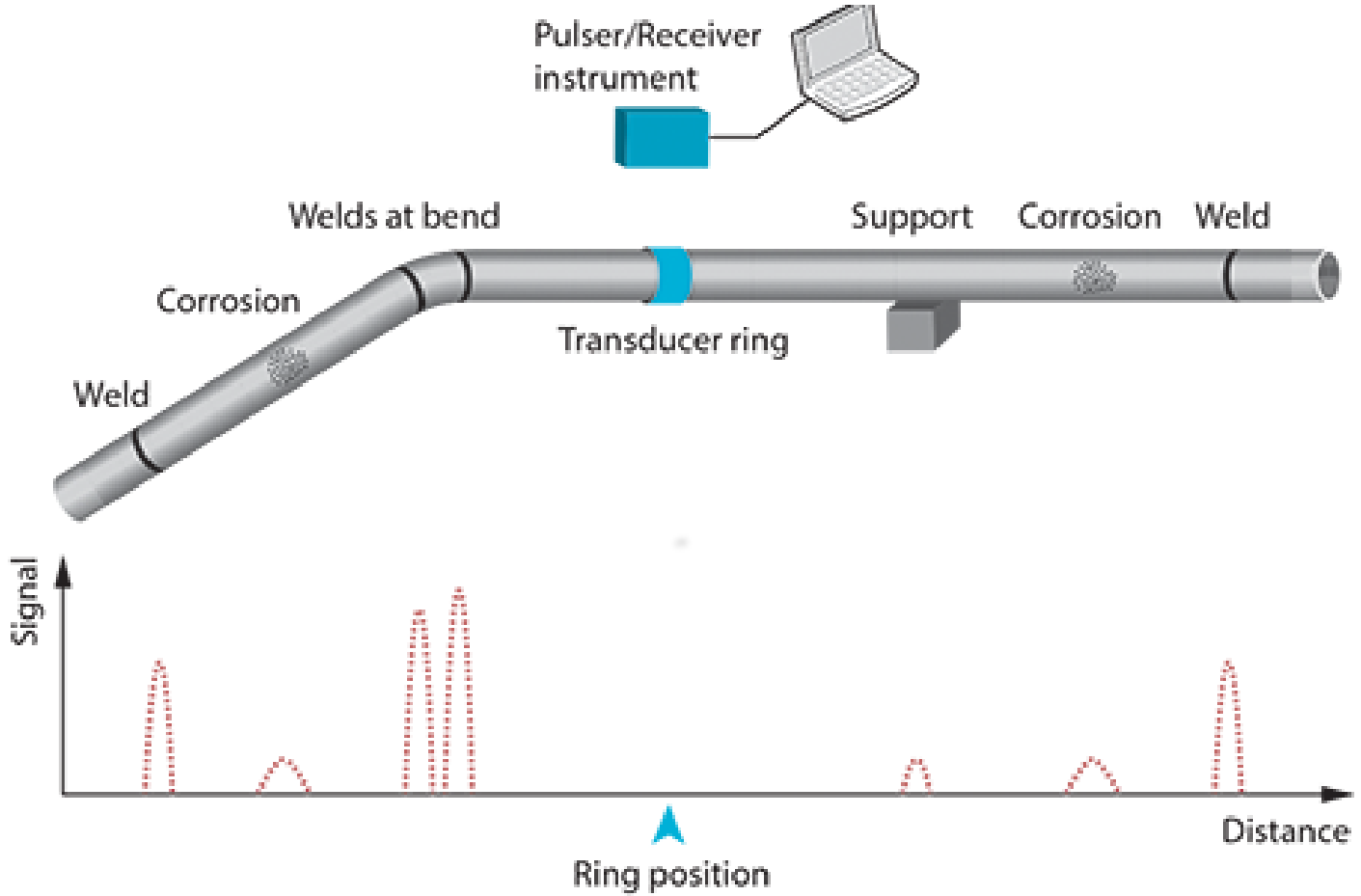

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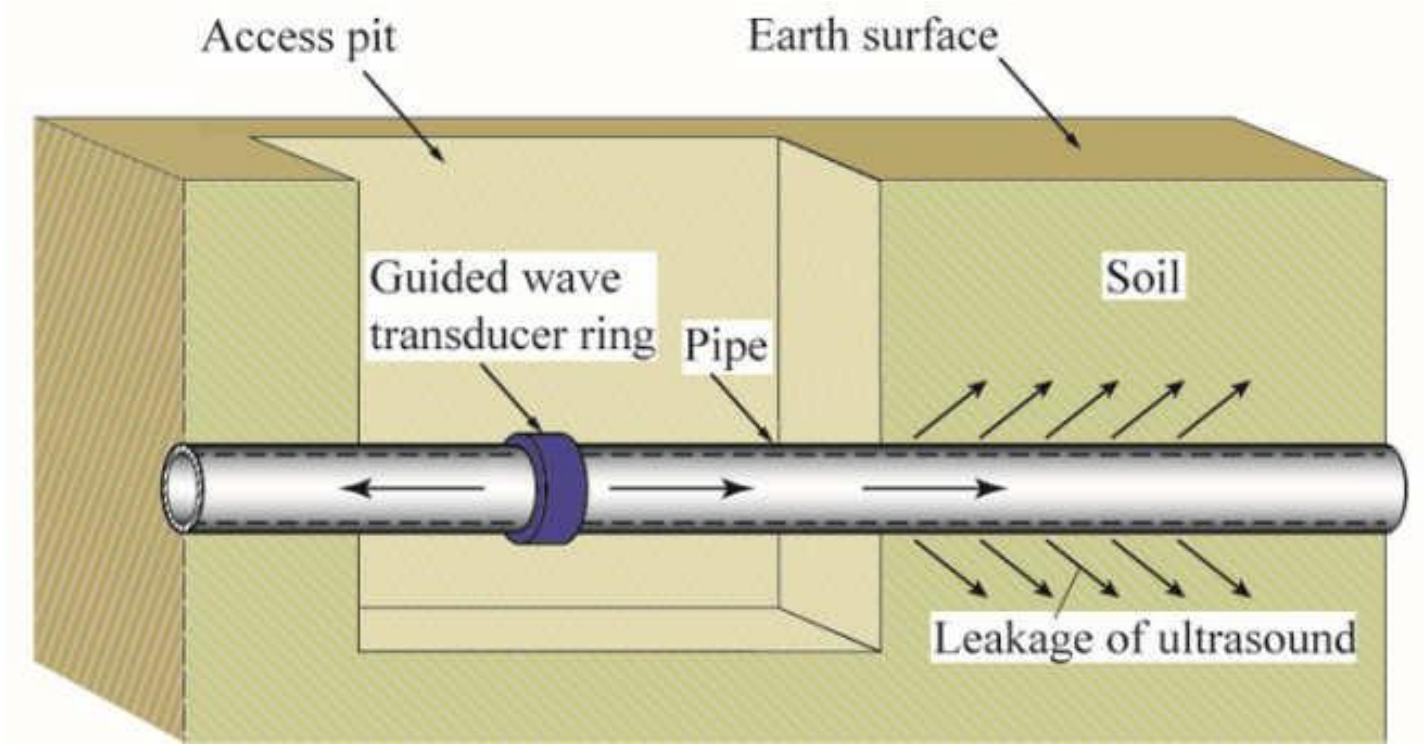

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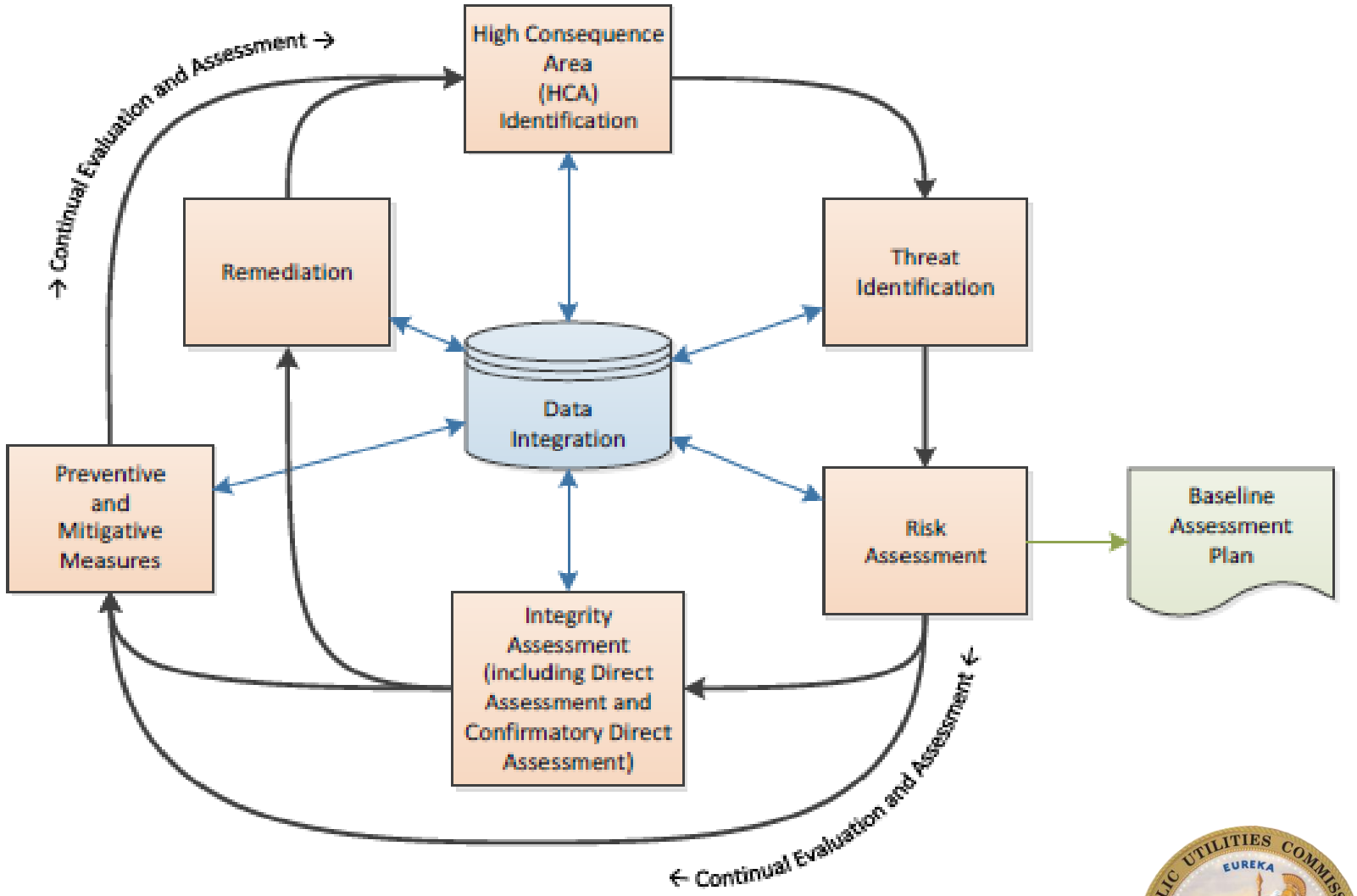

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Remediation (i.e., Repair) and/or Preventative/ Mitigative Measures

- The output of the integrity assessments are locations along the pipeline that need further investigation (i.e., direct examinations) or repair
- Depending on the root cause(s) of the pipeline issues that need repair, addition preventative or mitigative measure may be chosen to reduce risk.

Questions