UM 2005 Distribution Work Group
May 19, 2022, Notes

June 1, 2022

Below are notes from the May 19, 2022, DSP Work Group meeting.

Attendees included (but were not limited to)

- PUC
  - Nick Sayen, Staff
  - Heide Caswell, Staff
- PacifiCorp
  - Erik Anderson
  - Tyler Jones
  - Daniel Talbot
  - Teri Ikeda
  - John Rush
  - Kimberly Alejandro
  - Jonathan Connelly
  - Kari Greer
  - Lee Elder
  - Kathreen Woyak
- Oregon CUB: Sudeshna Pal
- Energy Trust
  - Gina Saraswati
  - Spencer Moersfelder
- IREC: Yochi Zakai
- OSSIA: Jack Watson
- Renewable NW: Micha Ramsey
- NW Energy Coalition
  - Fred Heutte
  - Jeff Bissonnette
- Community Energy Project: Sherrie Villmark
- PGE
  - Andy Eiden
  - Jennifer Galaway
  - Sam Newman
  - Misty Gao
  - Joe Boyles
  - Shadia Duery
  - Emilie Dierickx
  - Walle Brown
- Idaho Power: Marc Patterson

Questions/clarifications/etc. on follow up materials from April 21, 2022, meeting

There were no questions or clarifications on the follow up materials from the April 21, 2022, meeting.

Update on Hosting Capacity Analysis

Staff provided an update on hosting capacity analysis (HCA).

- PGE and Idaho Power initially proposed to move ahead with HCA in Part 1 filings. (PAC met the DSP guideline requirements regarding HCA without proposing implementation.)
- Stakeholders provided feedback to wait on implementation to allow time for a discussion, and possibly Commission action, about key HCA decisions that affect the value of the results of the HCA. Staff concurred, and PGE is holding.
- Staff's March memo recommending acceptance of the Part 1 filings acknowledged this stakeholder feedback on HCA, and that PGE was holding implementation for such a discussion. Staff noted that the Interconnection Modernization Investigation – Docket No. UM 2111 – was in the midst of determining its scope, and this would possibly play a large role in HCA

discussions. Staff recommended that further discussion of HCA in DSP pause until the scope for the UM 2111 was set; DSP stakeholders could then consider continuing discussions of HCA.

- UM 2111 Staff heard stakeholder feedback that the Interconnection investigation should not disturb the momentum of the transparency and HCA discussions underway in DSP.
- As a result, DSP stakeholders can continue to discuss the majority of the HCA key decisions without impacting the UM 2111 investigation, with the condition that some key decisions are likely to change following resolution of UM 2111 Group 1.
- If DSP stakeholders want to begin discussing HCA, some options include:
    - A discussion on continuing to expand helpful data sets (such as the distributed generation evaluation maps)
    - A comprehensive discussion on key HCA decisions that affect the value of the results of the HCA. The likely goal of this would be setting standards for HCA implementation (with the condition that some key decisions may be revised by progress in UM 2111 Group 1).

Staff plans to email stakeholders to gauge interest in continuing a discussion of HCA in DSP. The level of stakeholder interest will be a factor in the Commission setting priorities and timelines.

Staff working on DSP and Staff working on UM 2111 will keep informed of progress and status, and work to integrate activity appropriately.

PGE-led discussion: Continuation of presentation on Risk Assessment Model

Emilie Dierickx presented PGE's approach to utilizing risk assessment modeling in asset management. (The first few slides were presented at the April meeting.) The presentation used the slides attached.

PGE-led discussion: Early learnings of the NWS process

Joe Boyles presented lessons learned to-date from the Non-Wires Solutions process. The presentation used the slides attached.

Adjourn

The meeting adjourned around 3:10 p.m. Pacific.

Please note for your reference future DSP Work Group meetings dates

Date and Time
June 16, 2022, 1:00 – 4:00 p.m. Pacific

Parking-lot for outstanding issues and questions

1. Where and how data will be stored is an important question to discuss early so there is a way to manage, keep safe, and access data as it comes in (from 5/7/21 Data Transparency Workshop).
2. Volunteers to work on establishing common definitions for distribution system planning discussions (from 5/7/21 Data Transparency Workshop).
3. Volunteers to work on further completing Figure 2 for priority data types (from 5/7/21 Data Transparency Workshop).

4. What are preferred sources of public data that include demographics and other details that adequately characterize our communities? (from 6/30/21 Technical Work Group meeting)
5. Working subgroup to focus on demographic and socioeconomic data, useful energy planning metrics, and quantifying measures and data sources for equity (from 6/30/21 Technical Work Group meeting).
6. Working subgroup to focus on practices for handling public accessibility of data (from 6/30/21 Technical Work Group meeting).
7. Venue for solutions providers (companies and vendors) that could provide technology and services to implement DSP.
8. Identify areas of overlap and potential collaboration in utilities' current practices, with the goal of minimizing discrepancies, regarding:
    - Cost effectiveness methodologies
    - Forecasting approaches, including consideration of how EE and DER forecasting feeds into the IRP process
    - Current practices/developments in hosting capacity analysis.
9. Additional steps to disseminate distribution system data, including assessing maps already developed to identify best practices, inclusion of equity data in maps already developed, and organizing/validating/publishing distribution system data not already made public.
10. Locational value.
11. Use of hosting capacity analysis to guide proactive utility investments.

Questions or Feedback

Questions and comments can be directed to Nick Sayen via email at nick.sayen@puc.oregon.gov or by telephone at 503-510-4355.

Strategic Asset Management – Economic Risk Models

Emilie Dierickx, Manager – Asset Management Planning

May 19, 2022

Goals of Today

Asset Management Journey

Models & Benefits

Methodology & Applications

Risk Concentrations

Portfolio Decisions

PGE's Asset Management Journey

2013 – 2015	2016 – 2017	2018 – 2019	2020 – 2022+
• **T&D PAS 55 Assessment** • Strategic Asset Management (SAM) department formed • Initial AM Policy developed • Risk model workshops, POC's, and initial development	• Created T&D Risk Register • Developed geographic risk models • Developed model integrated project evaluation tool (IPT)	• Applied risk methodology to seismic and wildfire analysis • T&D maintenance optimization • **Generation ISO 55000 Self-Assessment** • Generation asset risk model POC	• Developed Asset Management Commitment • Develop Asset Management Strategy • Develop Generation asset models • Enhance geographic risk modeling • Establish "Sustain the Business" Investment Portfolio

What Do the Risk Models Do?

- Allow us to assess the amount of quantitative risk (in dollars) present in our fleet
- Quantitative risk is used to prioritize long-term capital investments and optimize maintenance decisions.
- Risk modeling allows us to obtain a better understand of lifecycle costs and build better business cases for investments, upgrades, and replacements

What are the hard benefits?

- ↓ asset failures and ↑ system reliability
- ↑ asset life leads to ↓ future capital expenditures
- ↓ maintenance costs leads to ↓ customer price pressure

What are the soft benefits?

- A unified way to identify, evaluate & prioritize projects
- Cross-functional collaboration across business lines
- A common language from sponsor to portfolio management
- Works for other business cases: wildfire, seismic & remote sensing
- OPUC acceptance of risk methodology

RISK MODELS – CURRENT AND FUTURE DEVELOPMENT

Existing & Available

Economic Life Cycle Models

Substation Assets
- ✓ Transformer
- ✓ Circuit Breaker
- ✓ Relay System
- ✓ SCADA System
- ✓ Switch

Distribution Assets
- ✓ UG Cable
- ✓ Line Transformer
- ✓ Recloser
- ✓ Regulator
- ✓ Switch

Generation Assets (1)
- ✓ Steam Turbines
- ✓ Gas Turbines
- ✓ Transformers
- ✓ 4160V Breakers
- ✓ Condenser
- ✓ Circ Water Pumps/Motors

Geographic Risk
- ✓ Vegetation/Weather Risk
- ✓ Wildfire Risk
- ✓ Animal Risk
- ✓ Public Risk

Business Case Tools
- ✓ Risk Register
- ✓ Integrated Planning Tool

Maint. Optimization
- ✓ Sub: SCADA & Relays
- ✓ Sub: Breakers & Transformers
- ✓ Distribution: Switches, reclosers & regulator

Planned for 2022+

Economic Life Cycle Models

T&D Assets
- ✓ Poles & Structures
- ✓ **Tx Consequences***

Generation Assets
- ✓ Thermal (Tier II) (2)
- ✓ Hydros (3)
- ✓ **Wind***

Geographic Risk
- ✓ Enhancements to Vegetation/Weather Risk
- ✓ Enhancements to Wildfire
- ✓ **Seismic Risk***

*** 2023+**

1) Completing model data validation in 2022
2) Focus is primarily Tier II assets, but also adding incremental Tier I assets didn't model in 2020/2021
3) Work will likely continue into 2023

Detailed Example

Risk Management

Risk Management is foundational to Asset Management and our decision-making process

How is risk defined?

RISK = Probability of Failure X Consequence of Failure

Building Blocks of Annual Failure Probability – What It Is & How It Works

Problem Statement: What is the annual failure probability of a 46-year-old Sub Transformer?

Let's orient ourselves first.

"**Health Index (HI) Score**" = 100 - Deterioration

"**Effective Age**" = Calendar Age + Deterioration*

* An asset's effective age will never be considered younger than it actually is.

"**Failure Multiplier**" = A number > 1 that represents known bad vintages or manufacturers that make a particular asset failure more likely.

Q: What is the annual failure probability based on age?

Develop Weibull failure curves using
- PGE failure data
- Industry information
- SME expertise

Determine what is the annual failure probability of an asset based on its age

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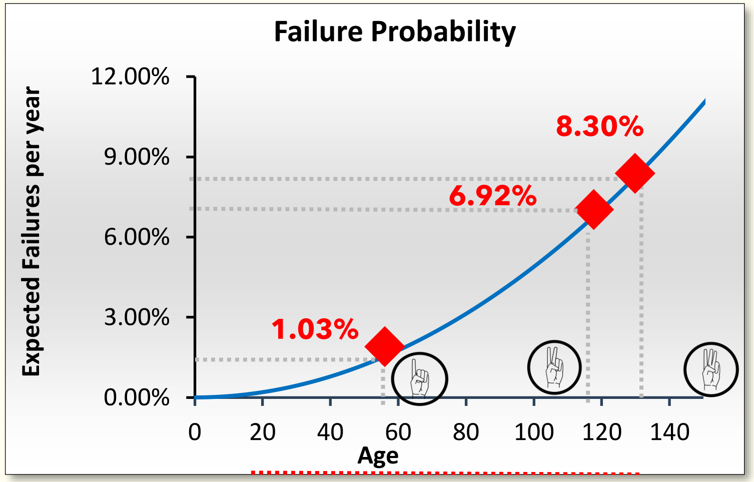
Example: 46 year-old transformer

We can determine the base annual probability failure for a 46-year-old transformer is: **1.03%**



Q: Has any degradation occurred?

Develop HI via SME workshops to:

- Identify major mechanisms could lead an asset to degrade or end of life
- Identify tests/inspections that tell us how far a degradation process has progressed?
- Identify degradation score for each test/inspection

A B C D E

Is it acting better, as anticipated or worse than what we would anticipate for its calendar age?

If worse, adjust its effective age.

Example: Solid Insulation

Poor Furan Oil Analysis (Grade, D confidence 90%) can drive it to end of life.

HI drops to **55** which raises "Effective Age" to 119.
Annual failure probability jumps to **6.92%.**

Q: Are there any known bad vintages, manufacturers or environmental conditions that would make this asset more prone to failure than others in this asset class?

Or in other words, are there failure multipliers?

Identify any failure multipliers via SME workshops via:

- PGE failure data
- SME expertise

Example: Arcing Tapchanger

This would add an additional 20% chance of failing.

We would multiply the current annual failure probability by **1.20** to account for the impact of tapchanger

Annual failure probability would jump to **8.30%**
Effective Age would reach ~**130 years.**

Annual Failure Probability Summary

1: Based on age – **1.03%**
2: Including degradation – **6.92%**
3: Including failure multiplier – **8.30%**

Probability of Failure (%) x **Consequence Of Failure ($)** = Risk ($)

Grid

Economic impact of reliability issues for customers (Value of Service $):

+ Customer Type (R, C, I)
+ Load impacted
+ Duration of impact (U, R, R)
+ Environmental & Safety Impacts
+ Cost of Repair

Consequence of Failure ($)
$0.9M

Transformer Consequence Scenarios

75%	Transformer Trips Under Load (Repairable) $0.6M
15%	Maintenance Finds Failure $0.0M
9%	Transformer Trips Under Load (Failed) $3.1M
1%	Catastrophic Failure $19.0M

Weighted Average Consequence of Failure
$0.9M

Risk Methodology

Annul Probability of Failure (%)	x	Consequence Of Failure ($)	=	Risk ($)

Asset Failure:
- Type of asset
- Age of asset
- Condition of asset

Geographic Risk:
- Vegetation
- Weather
- Animals
- Public

GRID & GENERATION

Direct impact of event on PGE.

Environmental and safety impacts.

GRID

Economic impact of reliability issues for customers (Value of Service ($):

+ Customer Type (R, C, I)
+ Load impacted
+ Duration of impact

GENERATION

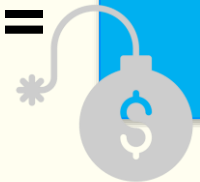
Economic impact of outage, derate or efficiency:

+ MWs impacted
+ Duration of impact
+ Replacement Power Cost

Expressed as a financial value

Probability of Failure (%)	x	Consequence of Failure ($)	=	Risk ($)
8.30%		$0.9M		$0.1M





Practical Application

Substation Transformer Example

Substation Transformer is 47 years old. It has a 1.29% probability of failure but has a $2.7M consequence of failure.

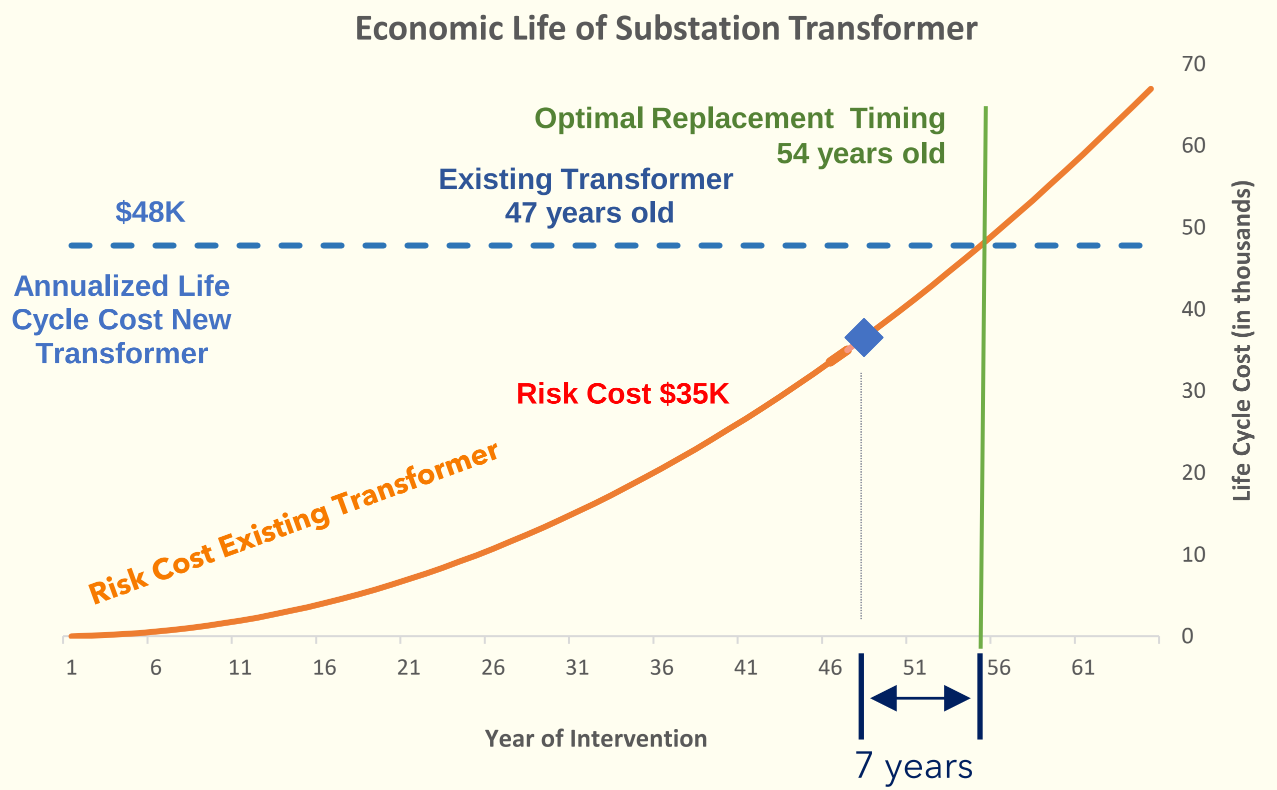
<u>Should it be replaced now or later?</u>

Probability of Failure:

Consequence of Failure:

Risk:

1.29% X $2.7M = $35K



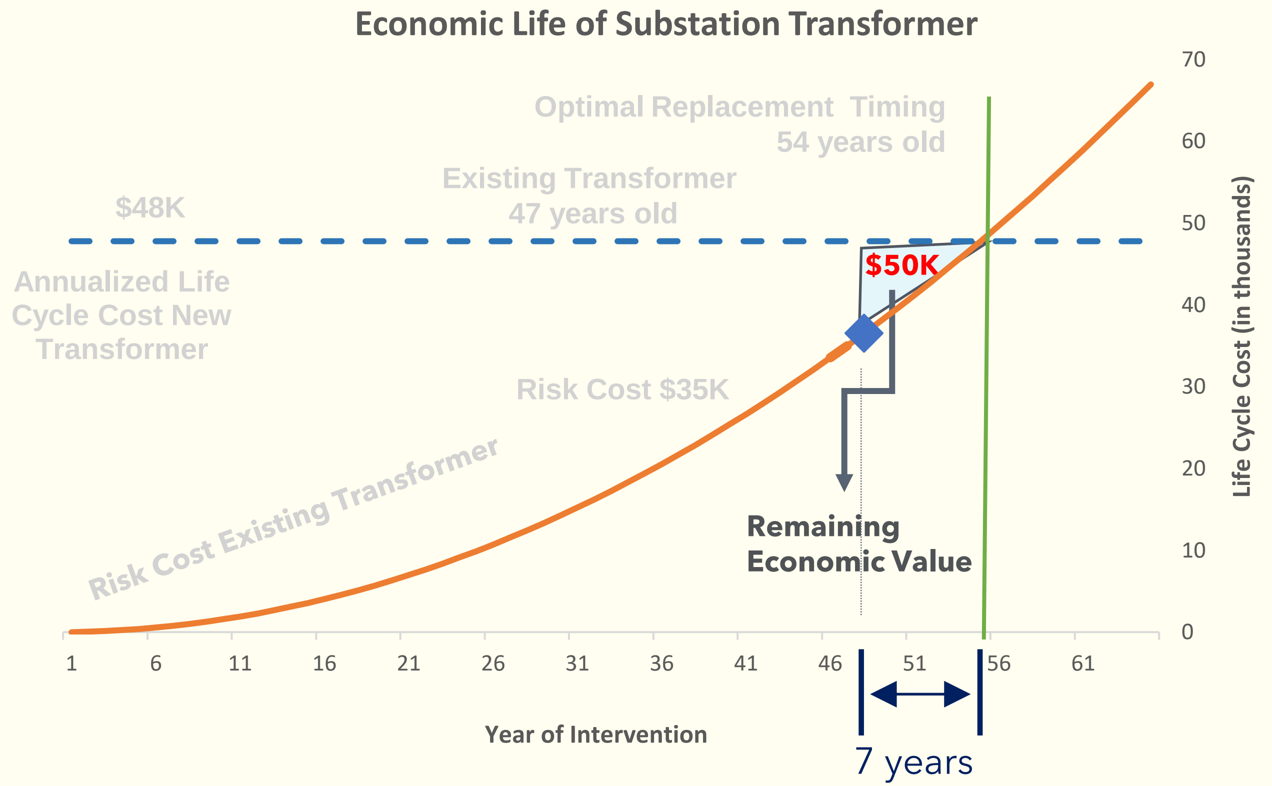
Outputs of Economic Life Cycle Model	
Annualized life cycle cost new transformer	$48K
Risk Cost of existing transformer	$35K
Years to Replacement	7 years

Proactive Replacement Recommended in 7 years

Substation Transformer Example

Substation Transformer is 47 years old. It has a 1.29% probability of failure but has a $2.7M consequence of failure.

<u>How much to spend on repairs?</u>



Probability of Failure: 1.29%

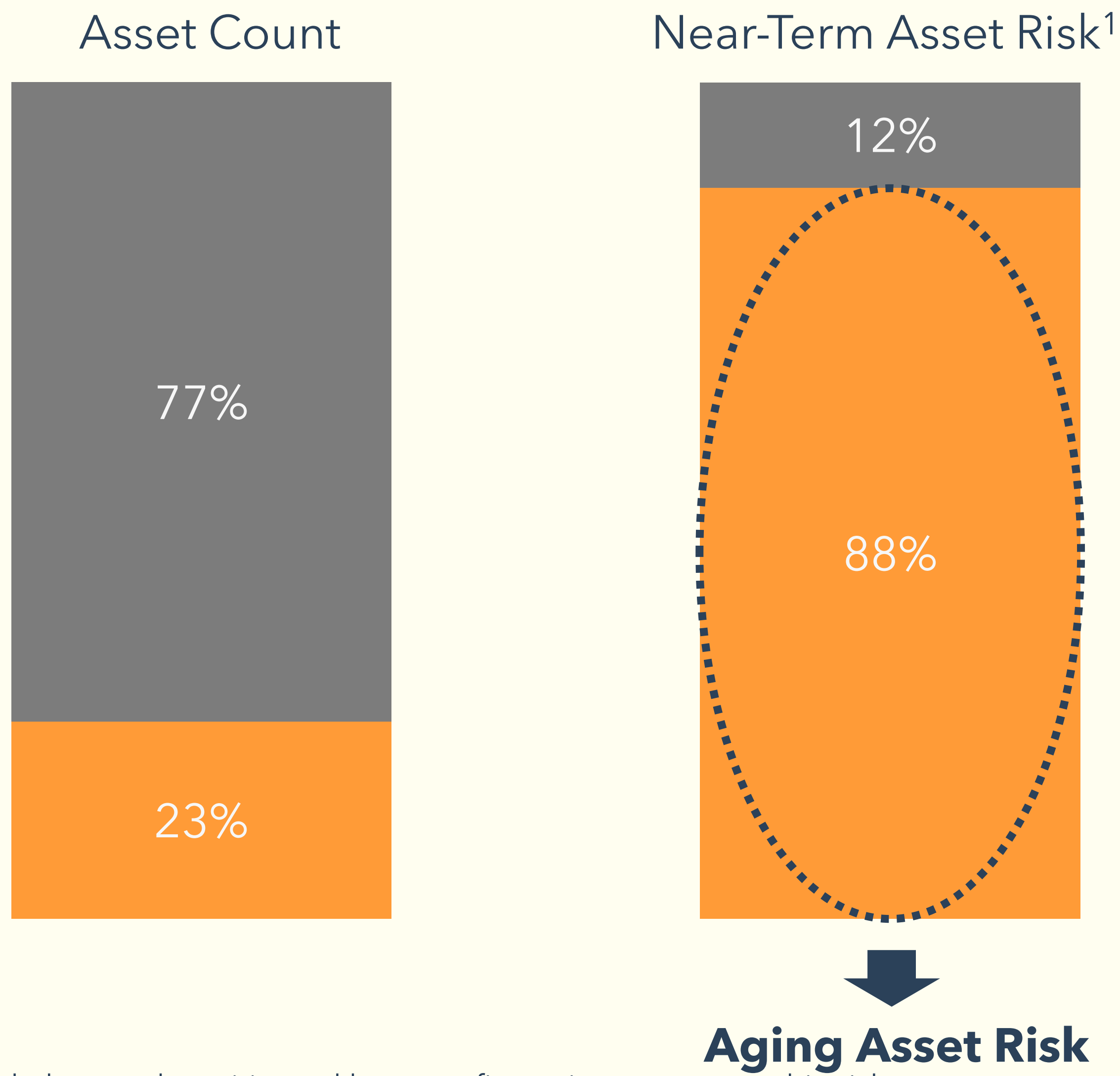
Consequence of Failure: X $2.7M

Risk: = $35K

Outputs of Economic Life Cycle Model	
Annualized life cycle cost new transformer	$48K
Risk Cost of existing transformer	$35K
Years to Replacement	7 years
Cost Of Ownership, replaced now	$1.0
Cost Of Ownership, replaced optimally	$0.9
Remaining Economic Value	$50K

Risk Concentrations

T&D Aging Asset Risk Concentration (2)



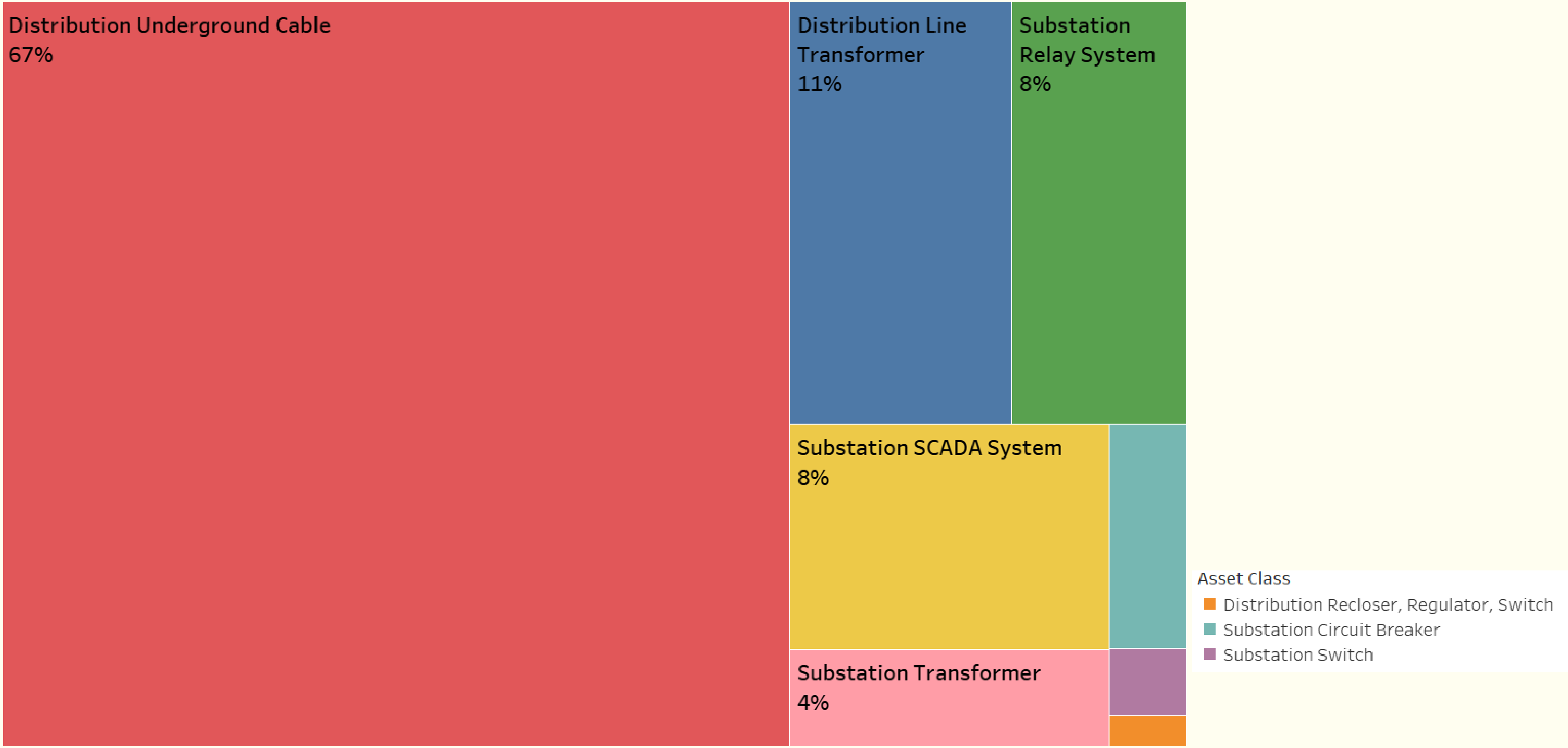
Years to Intervention

- >10 years
- 0-10 years (aging assets)

Aging assets due for replacement over the next 10 years contribute a disproportionate amount of risk.

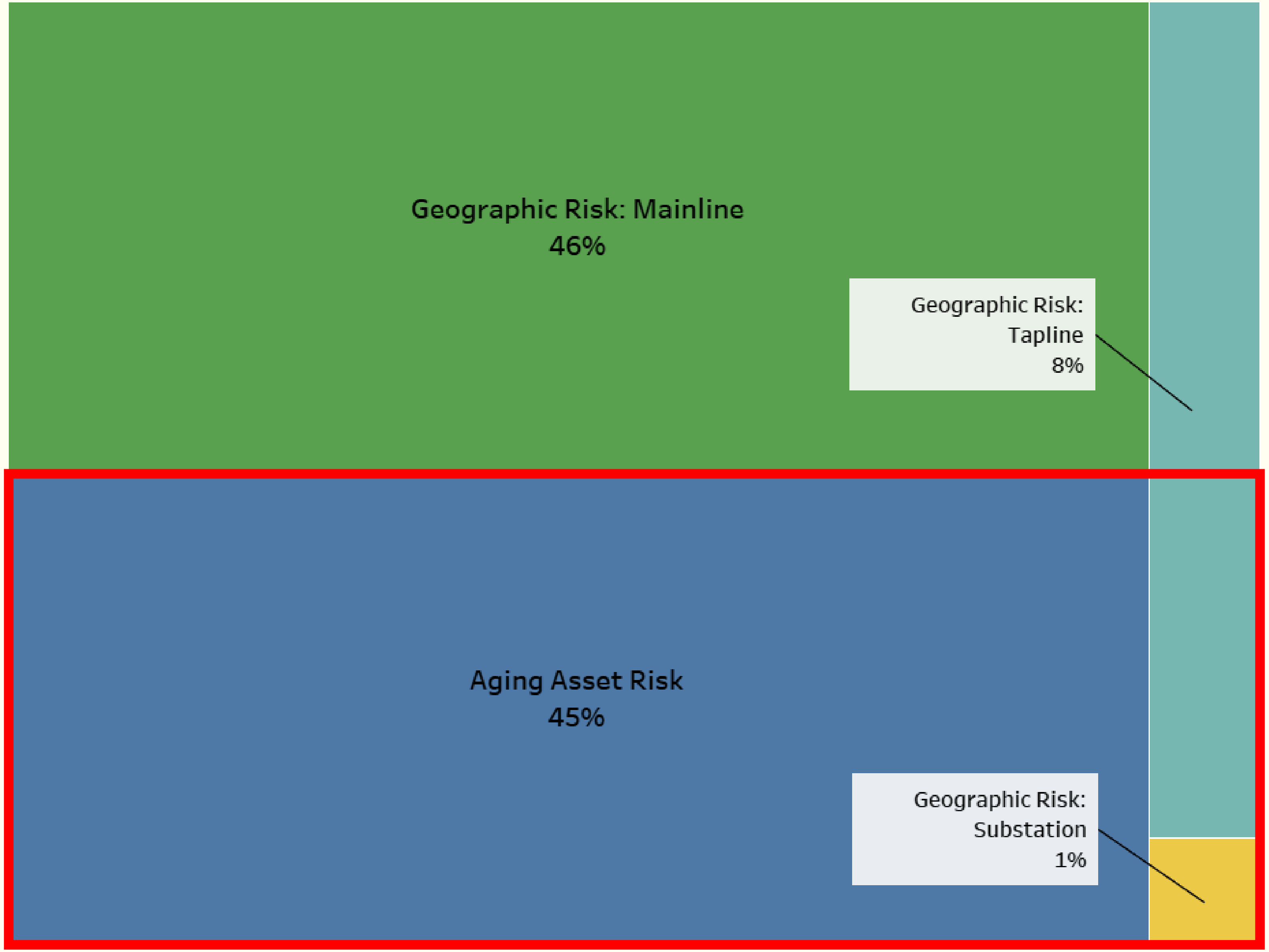
1) Does not include risk that can be mitigated by reconfiguration or geographic risk
2) 2020/2021 values; does not reflect 2022 model updates May 2022

T&D Aging Asset Risk % by Class (1)



1) 2020/2021 values; does not reflect 2022 model updates occurring May 2022

T&D Risk Proportions (1)



Includes 3 types of geographic risk: vegetation + weather, wildlife, other.

1) 2020/2021 values; does not reflect 2022 model updates occurring May 2022

Discretionary Capital Decision Framework

STB Discretionary Framework Equation

Priority Score:	
Extreme	4
Strong	3
Moderate	2
Low	1
None	0

Weighted Sum Model

$$\sum \left(\text{Category Scores} \times \text{Category Weightings} \right) = \text{Final Scores}$$

Tree Wire Program: Example

	Score	Weighting	Weighted Score
Reliability	4	27%	1.08
Risk	4	27%	1.08
Financial	4	27%	1.08
Safety	0	4%	0
Compliance	0	4%	0
Environmental	0	4%	0
Operational	1	4%	0.04
Customer	4	4%	0.16

3.2 SAM Score

+

0. 2 Portfolio score

Total Value **3.40**

Final Prioritization Score;
Optimizes on Value

Total Value = 3.40

Priority Score:

Extreme	**4**
Strong	**3**
Moderate	**2**
Low	**1**
None	**0**

Non-wires Solutions Lessons Learned (so far…)

NWS Lessons Learned

Scale – it's hard to find a grid need that will make it through the screening process. e.g., California narrowed 392 "needs" down to 11 NWS candidates

Granularity – shows up a few ways - forecast, problem isolation, modeling

Level of effort – 2x or more increase in workload

Community engagement – education is a necessary element of participation. Anticipate learning more in next community workshop

Valuation – deferral value depends on how long we need the solution and we don't model that today

Efficacy of DERs – not necessarily novel learnings, but more hands on experience with findings in other jurisdictions

Let’s meet the future together.

PGE