AEP Transmission
Local Plan Development

PJM Sub-regional RTEP
Western Meeting

January 5, 2017

Introduction to AEP

AEP is among the largest electric utilities in the United States

- More than 5 million customers
- 200,000 + sq. mi service territory
- 32 GW of generating capacity
- Over 40,000 miles of electric transmission lines
- More than 3500 substations
- 215,000 miles of electric distribution lines

Largest owner of electric transmission in the United States

- Own, operate and maintain transmission facilities in 3 RTO s and 11 states
- Interconnection with 60 major utilities across the U.S.
- Supplying ~10% of demand in Eastern Interconnection and ~11% of demand in ERCOT

AEP Zone in PJM

- Total AEP Transmission facilities in PJM region: ~23,000 miles

765 kV	~2,200 miles
500 kV	~100 miles
345 kV	~4,000 miles
230 kV	~100 miles
161 kV	~50 miles
138 kV	~9,000 miles
Sub-T	~8,000 miles

- Connected demand modeled in AEP Transmission zone in PJM

	2022 Summer	2022/23 Winter
Appalachian	6,447 MW	7,228 MW
Indiana Michigan	4,863 MW	4,321 MW
Kentucky	1,170 MW	1,401 MW
Ohio	11,425 MW	10,127 MW
Total	**23,905 MW**	**23,077 MW**

- AEP load in the RTEP case is scaled to PJM forecast.

PJM Power Flow Models

- AEP supports development of and updates to RTEP cases.

- AEP participates in development of annual series of ERAG MMWG base cases.
  - Cases include seasonal, near-term, and long-term models used in ERAG and RFC assessments of the Transmission system.

- AEP planning studies utilize available PJM RTEP cases.
  - AEP has both summer and winter peaking zones.
  - Internal cases are developed, on case by case basis, to represent and address local historic constraints observed in real-time.

AEP Planning Criteria – FERC 715

- AEP transmission system is planned in adherence with NERC TPL-001-4 and PJM Planning Criteria outlined in Manual 14B.

- AEP Planning Criteria (FERC 715) aligns with NERC and RTO planning criteria.
  - Also includes criteria to plan non-BES system below 100 kV.

- All planning studies utilize the latest available PJM RTEP cases.

- PJM evaluates compliance and adherence to above standards and criteria from regional perspective (top down), and AEP does the same from a local perspective (bottom up).

Link to AEP FERC 715:
https://www.aep.com/about/codeofconduct/OASIS/TransmissionStudies/GuideLines/AEP_East_FERC_715_2016_Final_Part_4.pdf

Customer Interconnections

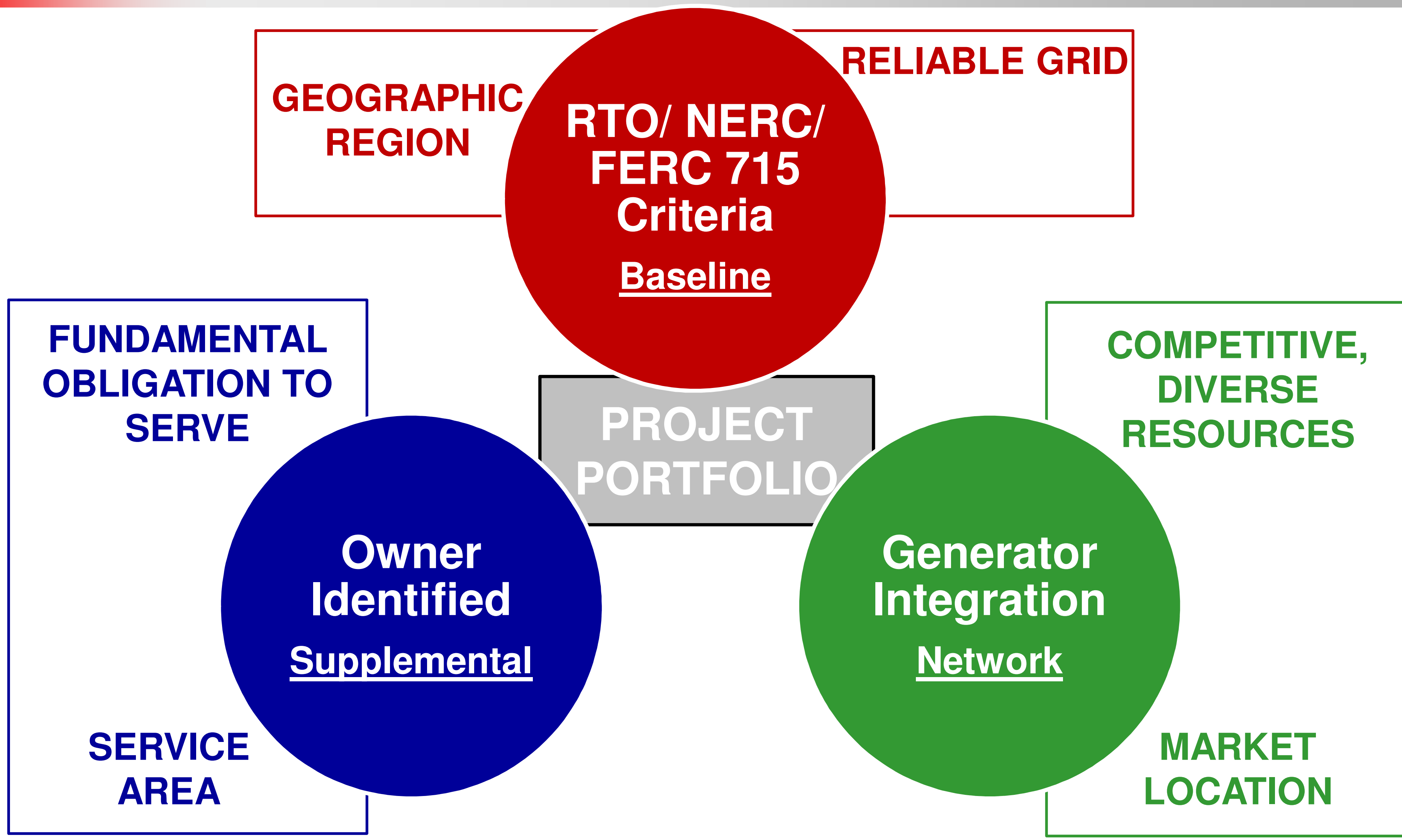
- In accordance with NERC Standard FAC-001-2, AEP has posted requirements for interconnections of end-use customers, generators, and transmission facilities.

- To provide service to end-use customers, AEP performs initial studies to determine the system impacts and develop a plan of service for contracted load levels.
  - Required transmission upgrades are validated by PJM under baseline reliability criteria.

- AEP may, at its discretion, develop plans to serve projected (non-contracted) load levels provided by customers in consultation with local and state economic development organizations.
  - Any required upgrades to meet projected loads are considered supplemental.

Link to AEP Interconnection Requirements:
http://www.aep.com/about/codeofconduct/OASIS/TransmissionStudies/Requirements/AEP_Interconnection_Requirements_Rev1.pdf

Types of Projects in PJM Region



Supplemental Project Drivers

TO Identified Projects

External Drivers	*Internal Drivers*
Customer	*Safety*
↓	↓
Compliance	*Equipment*
↓	↓
Regulatory	*Performance*
↓	↓
Standards	*Risk*
↓	↓
Contractual	*Resilience*

Projects, Programs & Multi-Value Solutions

Transmission Needs Identification

Source	Types of Input	Sample Examples
Internal	Field reports on asset conditions Asset Health Monitoring	Station and line equipment age; Equipment deterioration identified during routine inspections; Transmission line structure deterioration (rot, woodpecker damage)
	Capabilities and abnormal conditions	Relay misoperation; Voltage unbalance
	Obsolete system configurations	Ground switch protection schemes for transformers; Transmission line taps without switches; Equipment with no parts or no longer supported by vendors
	Outage duration and frequency	Outages resulting from equipment failures, misoperation, or inadequate lightning protection
	Operations and maintenance costs	Costs to operate and maintain equipment
External	Regional Transmission Operator (RTO) or Independent System Operator (ISO) issued notices	Post Contingency Local Load Relief Warnings (PCLLRWs) issued by the RTO that can lead to customer load impacts
	Stakeholder input	Input received through stakeholder meetings, such as PJM's Sub Regional RTEP Committee (SRRTEP) meetings
	Customer feedback	Voltage sag issues to customer delivery points due to poor sectionalizing, frequent outages to facilities directly affecting customers
	State & Federal policies, standards, or guidelines	New NERC standards for dynamic disturbance recording
Both	Environmental & community impacts	Equipment oil spills & gas leaks, facilities currently installed at or near national parks, national forests, or metropolitan areas
	Safety risks and concerns	Station and Line equipment that does not meet ground clearances; Facilities identified as being in flood zones; New Occupational Safety and Hazards Administration (OSHA) regulations

Transmission Needs Prioritization

Customers Input

- Collect Customer & Stakeholder Feedback
  - Historic & Projected Impacts
  - Customers' plans for the future

Historical Performance

- Review Reliability & Availability Metrics
  - System : TSAIFI,TSAIFI-S, TMAIFI, TSAIDI
  - Customer: SAIFI, SAIDI, CAIDI, CMI
  - Evaluate asset contributions to metrics
- Review Trends & Analyze Root Causes
  - Initiating causes; sustained v. momentary causes
  - Maintenance & remediation requirements & trends

Asset Condition

- Assess Asset Condition (Per Internal Standards)
  - # conditions requiring immediate attention
  - # conditions requiring mitigation within 18 months
  - # conditions requiring mitigation in 2-3 years

Future Risk

- Evaluate risk
  - Review anticipated customer/system/public impact

Prioritize Needs & Develop Mitigations

Mitigating Solutions

Integrate

- Develop cost effective, holistic solutions; combine needs in a given area to reduce outages, number of crews, mobilization, etc.
- Address all conditions identified, where possible, for a given asset being revitalized
- Determine and reduce environmental / outage / public impact

Scope

- Define & vet specific project scopes, schedules and estimates
- Conceptual and Functional level scopes and estimates developed to assess the viability of a given solution

Execute

- Review portfolio of needs and solutions with stakeholders
- Submit model changes to RTO for topology changes
- Detailed level scopes, estimates and schedules developed

Note: Not all TO-identified projects alter system topology: e.g., SCADA, RTU, PMU, Telecom, physical/cyber security, protection & control, monitoring, like kind asset replacement, etc.