Storage As a Transmission Asset (SATA) Education

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Storage as a Transmission Asset: Regulatory Background

- **Section 1223 of EPAct 2005 – "advanced transmission technologies"**
  - *AUTHORITY.—In carrying out the Federal Power Act (16 U.S.C. 791a et seq.) and the Public Utility Regulatory Policies Act of 1978 (16 U.S.C. 2601 et seq.), the Commission shall encourage, as appropriate, the deployment of advanced transmission technologies.*
  - 18 technology classes listed, including *"(19) any other technologies the Commission considers appropriate"*
    - *"(11) energy storage devices*

    (including pumped hydro, compressed air, superconducting magnetic energy storage, flywheels, and batteries);"

https://georgewbush-whitehouse.archives.gov/infocus/energy/

- ***Nevada Hydro (ER06-278, Mar 2008)***
  - In 2005, Nevada Hydro proposed that the Lake Elsinore Advanced Pump Storage ("LEAPS") project should be treated as a transmission facility under the CAISO's operational control.
  - Nevada Hydro proposed that the ISO serve its ancillary services needs from LEAPS, but the company would bid the stored energy into the market at a price of $0 so as to avoid market distortions.
  - In 2008, FERC determined that *"…it would not be appropriate to allow the costs of the LEAPS facility to be rolled-in through CAISO's transmission rates. The purpose of the TAC is to recover the costs of transmission facilities under the control of the CAISO; the purpose is not to recover bundled services.*"

- ***Western Grid (EL10-19-000, Jan 2010)***
  - Order on Petition for Declaratory Order
  - Establishes precedent for FERC-approved cost-of-service rate recovery for battery storage as a transmission asset, conditional on approval in the (CAISO) transmission planning process.
  - Sodium sulfur (NaS) batteries proposed to operate similar to capacity banks and used to support voltage (10 – 50 MW).
  - No market participation. Incidental positive energy revenue from charging / discharging would be passed through to customers.
  - Makes clear that the Commission rules on energy storage devices as transmission on a case-by-case basis.

- **Tech conference (AD16-25-000, 2016)**

"Utilization in the Organized Markets of Electric Storage Resources as Transmission Assets Compensated Through Transmission Rates, for Grid Support Services Compensated in Other Ways, and for Multiple Services"

  - Utilization of ESR for Transmission Services
  - Utilization of ESR for Grid Support Services
  - Utilization of ESR for Multiple Services

- **Policy Statement (PL17-2-000, 2017)**
  - Provides guidance only with respect to issues that must be addressed if an electric storage resource seeks to receive cost-based rate recovery for certain services, while also receiving market-based revenues for providing separate market-based services.

Addresses the following issues:

1. Avoiding double recovery of costs
2. Minimizing adverse impacts on wholesale electric markets
3. RTO/ISO independence

Storage as a Transmission Asset: Transmission Planning

Reliability Analysis – Steady State Assumptions

- The grid is made up of "N" interconnected components characterized by:
  - Generators
    - MW_{out}, $MW_{max,}$ MW_{min}, $MVAR_{max}$, $MVAR_{min}$, bus regulating (voltage, power factor)
  - Transformers
    - Ratings (Normal/Emergency), Impedance, Turns ratio, Tap Changer setting/range, bus voltage regulating
  - Transmission Lines
    - Ratings (Normal/Emergency), Impedance
  - Shunt Devices
    - VAR capability, Fixed / Switched / Continuous, bus voltage regulating
  - Buses
    - Ratings (Normal/Emergency), Vmax, Vmin
  - Breakers
    - Ratings (Normal/Emergency), fault interrupting capability
  - Loads
    - MW / MVAR

Reliability Analysis – Steady State Assumptions

- Transmission Planning studies account for all N components
  - In-service components maintain their characteristics irrespective of duration
    - i.e. Generators – MW_{out}, MW_{max}, MW_{min}, $MVAR_{max}$, $MVAR_{min}$
  - Out-of-service components, if changed to In-service, would maintain their characteristics irrespective of duration
  - Simulation of unscheduled outages (i.e. N-1, N-1-1, LineFB, Bus, Tower) trips off certain components within the zone of protection based on relay protection schemes.
    - Faulted components remain isolated and out-of-service for an indefinite period
    - Planning studies do not estimate time of restoration of faulted components
- Contingency Definitions – Deterministic approach for identifying system violations based on PJM / NERC TPL criteria
  - Reinforcements are assumed to be available at all times

Transmission Planning - Objectives

- PJM's Planning analyses are designed to ensure all applicable PJM, NERC, regional and Transmission Owner criteria are enforced.

- Planning Violations and Risks
  - **Voltage magnitude above Vmax** – Arcing, flashover, insulation breakdown, inability to deliver power within Tariff voltage limits
  - **Voltage magnitude below Vmin** – Relays dropping out, motor stall, inability to deliver power within Tariff voltage limits
  - **Voltage change (drop or rise) beyond limits** – cascading voltage collapse
  - **Thermal flow at Normal rating** – continuous operating with Moderate Loss Of Life (MLOL)
  - **Thermal flow at Emergency rating** – limited (2 – 6 hours) operating with MLOL
  - **Thermal flow above Emergency rating** – accelerated Loss Of Life
  - **Thermal flow above Load Dump rating** – imminent facility failure

Transmission Planning criteria supports Operating Policy

- PJM Actual Overload Thermal Operating Policy (M03, Section 2, Exhibit 1)

Thermal Limit Exceeded	Corrective Actions	Time to Correct
Normal Rating (Actual flow greater than Normal Rating but less than Emergency Rating)	Non-cost actions, off-cost actions, emergency procedures except Load Shed Directive (See Manual M-13, Emergency Procedures).	Within 15 minutes of exceedance, load shed is not used.
Emergency Rating (Actual flow greater than Emergency Rating but less than Load Dump Rating)	All of the above including Load Shed Directive to control flow below Emergency Rating.	Within 15 minutes of exceedance (Note 2)

- PJM's Voltage Operating Policy for an actual violation M03, Section 3.2)

Voltage Limit Exceeded	If Actual voltage limits are violated	Time to Correct
Normal High	Use all effective non-cost and off-cost actions.	Within 15 minutes
Normal Low	Use all effective non-cost actions, off-cost actions, and emergency procedures except Load Shed Directive.	Within 15 minutes, load shed is not used.
Emergency Low	All of the above including Load Shed Directive if voltages are decaying.	Within 5 minutes

Transmission Planning – Baseline Reliability Analysis

- M14B, Section 2.3.6-7
  - *“Baseline thermal analysis is a thorough analysis of the reference power flow to ensure thermal adequacy based* ***on normal (applicable to system normal conditions prior to contingencies)*** *and* ***emergency (applicable after the occurrence of a contingency) thermal ratings*** *specific to the Transmission Owner facilities being examined. It encompasses an exhaustive analysis of* ***all NERC P0-P7 events*** *and the most critical common mode outages.”*

  - *“****Baseline voltage analysis parallels the thermal analysis****. It uses the same power flow and examines voltage criteria for* ***all the same NERC P0, P1, P2, P3, P4, P5, P6 and P7 events****.”*

NERC Criteria

- Normal N-0
  - NERC P0
    - Requires all components to be within their seasonal Normal ratings and voltage level
- Single N-1
  - NERC P1
    - Generator, Transmission Circuit, Transformer, Shunt, DC Line
  - NERC P2.1
    - Outage of a networked Transmission Circuit without a fault
  - PJM
    - Bus tie breaker openings without a fault
- Common Mode
  - Line Fault
    - NERC P4 – loss of multiple elements caused be a stuck breaker
    - NERC P5 – loss of multiple elements caused by delayed fault clearing
  - Bus
    - NERC P2.2 - Bus section fault
    - NERC P2.3 - Breaker fault (non-Bus-tie-breaker)
    - NERC P2.4 - Breaker fault (Bus tie-breaker)
  - Tower
    - NERC P7 – loss of two adjacent circuits on a common structure
- N-1-1
  - NERC P3 – loss of a Generator, followed by system adjustments
    - followed by loss of Generator, Transmission Circuit, Transformer, Shunt, DC Line
  - NERC P6 - loss of Transmission Circuit, Transformer, Shunt
    - followed by loss of Transmission Circuit, Transformer, Shunt

Transmission Planning – Core Reliability

- Core Reliability tests
  1. Baseline
     A. Thermal – Single and common mode
     B. Voltage – Single and common mode
  2. Gen Deliverability
     A. Summer
     B. Light Load
     C. Winter
  3. N-1-1
  4. Load Deliverability (singles)
     A. Thermal
     B. Voltage
  5. Baseline Stability
  6. Short Circuit

Transmission Planning – Reliability Analysis N-1-1

- N-1-1 Analysis P3 and P6 (M14B, Section 2.3.8)
  - *“The **<u>first step</u>** of the test is to ensure that post-contingency loadings of **all facilities shall be within their emergency thermal ratings** immediately following the first N-1 contingency”*
  - *“The **<u>second step</u>** of the test is to ensure that post contingency loadings **of all facilities shall be within their normal thermal ratings** after the first N-1 contingency and subsequent re-dispatch and system adjustments.”*
  - *“**<u>After the second N-1-1 contingency</u>**, the thermal loading of any monitored facility that **<u>is above the applicable emergency thermal rating</u>** (long-term or short-term) is considered a reliability criteria violation and a mitigation plan will be needed.”*

Load Deliverability - M14B Attachment C.2

- Purpose – test confirms that within accepted probabilities the Transmission System can support the delivery of energy from the aggregate of available PJM Capacity Resources to PJM electrical areas experiencing a capacity deficiency.

- Base cases – (Summer Peak and Winter Peak)
  - Load Deliverability Area (LDA) under test is modeled with 90/10 load forecast level with greater than expected generation unavailability
    - All other areas beyond the LDA are modeled with 50/50 forecast load level with generation available up to emergency reserves.
  - Contingencies – Singles
    - Thermal and Voltage analysis

Generator Deliverability - M14B Attachment C.3

- Purpose – test examines the ability of an electrical area to export Capacity Resources to the remainder of PJM.

- Base case
  - Reference 5 years in the future
  - PJM load is modeled as non-diversified forecasted 50/50 summer peak
  - Contingencies – Singles and Common Mode

Light Load Reliability Analysis – M14B Attachment D-2

- Purpose – tests the ability of an electrical area to export generation resources to the remainder of PJM during light load conditions

- Base case –
  - Reference 5 years in the future
  - PJM load is modeled as 50% of 50/50 summer peak
  - Queue Resources
    - Non-ISA generators – model as offline
    - ISA generators – model as online
  - Contingencies – NERC P0, P1, P2, P4, P5, P7
    - Not included P3, P6 (there is no N-1-1 testing)

Winter Peak Reliability Analysis – M14B Attachment D-3

- Purpose – tests the ability of an electrical area to export generation resources to the remainder of PJM during winter peak conditions

- Base case –
  - Reference 5 years in the future
  - PJM load is modeled as non-diversified forecasted 50/50 winter peak
  - Transmission Facility Rating uses Winter ratings (50^{o}F, 41^{o}F, or 32^{o}F)
  - Queue Resources
    - Non-ISA generators – model as offline
    - ISA generators – model as online
  - Contingencies – NERC P0, P1, P2, P3, P4, P5, P6, P7
    - P3, P6 (N-1-1 testing is included)

Long-Term Deliverability Analysis - M14B Attachment C.4

- Purpose - to identify any reliability violations on the PJM system that may require an upgrade that requires more than a 5 year lead time to implement.

- Analysis for years 6 through 15
  - generator deliverability
  - load deliverability
  - common mode outage analysis.

- Base Case
  - Reference 5 years and 8 years in the future

- Contingencies – same as near term analysis
  - Ignore overloads on transmission lines below 230 kV
  - Ignore overloads on transformers
  - Ignore overloads that are below the conductor rating (terminal limited)

Cost Analysis – Competing Project Proposals

- PJM performs cost analysis on project proposals submitted through the FERC 1000 competitive window.
- Some of the parameters for cost consideration are:
  - Land and Right-of-Way (ROW) cost - initial
  - Equipment purchase cost – initial
  - Expected years of service – amortization
  - Cost containment provisions
  - Cost escalation risks
- Intangibles
  - Difficulty in Land/ROW acquisition
  - Customized equipment or new technology application
  - Difficult to construct

Storage as a Transmission Asset: Market Efficiency

Market Efficiency - Rules and Considerations

- Simulate electric market operations over a study period
  - Models incorporate future demand, generating unit operating characteristics, fuel forecast, and transmission topology and constraints
  - Calculate hourly production costs, location-specific market clearing prices, line and interface congestion values, and zonal load payments
  - Capture detailed costs of operating the fleet of generators
  - Fuel and emissions costs, O&M costs, start-up costs, etc.
- Engine using an hourly chronological security constrained unit commitment and economic dispatch simulation (8760 hrs)
  - Minimize production costs while simultaneously adhering to a wide variety of transmission and operating constraints
- Network model uses DC powerflow
  - A linearization of the AC powerflow which models line thermal limits but is less detailed than load flow models

Market Efficiency – Market Inputs Assumptions

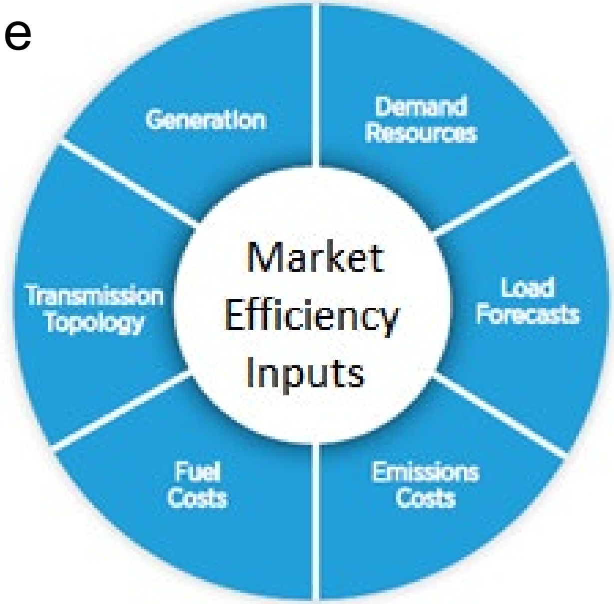
- Forecasted Generation Expansion plan
  - includes in-service generation, active queue ISA generation, announced retirements
  - Modeled inputs:
    - Operational: summer/winter capacity, heat rate, min run/downtime, emission rates
    - Cost: startup cost, variable O&M, curtailment price
- PJM Load Forecast Report
  - Peak Load and Annual Energy adjusted by Energy Efficiency
- Demand Response (DR) modeled as discrete units
  - MW cleared in the RPM BRA auction by delivery year, zone
- Fuel/Emissions Price Forecast developed by the ABB fuels group
  - Gas/Oil/Coal Prices: NYMEX (short term), the EIA Annual Energy Forecast (long term)
  - Three major effluents modeled: SO_2, NO_x, and CO_2

Market Efficiency – Transmission Assumptions

- Transmission topology
  - Includes all approved RTEP baseline, supplemental and network upgrades
  - External world topology
    - Derived from Multi-Regional Modeling Working Group (MMWG) Series
- Thermal Flowgates
  - Historical market constraints; NERC Book of Flowgates;
  - Temperature-based ratings
    - SN/SE 95 degree day-time
    - WN/WE 32 degree day-time (may vary by TO)
- Reactive Limits
  - PV Analysis to determine summer and winter MW transfer limits for commercially significant interfaces in PJM

Market Efficiency - Objectives

- Congestion Forecast
  - Asses future energy and capacity market congestion across the PJM states
- Evaluate impact of new technologies
- RTEP Economic Upgrades
  - Identify new transmission enhancements that may result in economic benefits by relieving congestion



- Multi-Driver
  - Identify "multi-driver" transmission enhancements that provide economic benefits in addition to resolving reliability issues.
- Acceleration
  - Determine which previously approved reliability upgrades, already included in RTEP, have an economic benefit if accelerated or modified.

Congestion Relief

Operating Agreement : 1.5.7 Development of Economic-based Enhancements or Expansions

(b) Following PJM Board consideration of the assumptions, the Office of the Interconnection shall perform a market efficiency analysis to compare the costs and benefits of: (i) accelerating reliability-based enhancements or expansions already included in the Regional Transmission Plan that if accelerated also could relieve one or more economic constraints; (ii) modifying reliability–based enhancements or expansions already included in the Regional Transmission Plan that as modified would relieve one or more economic constraints; and (iii) adding new enhancements or expansions that could relieve one or more economic constraints, but for which no reliability-based need has been identified. Economic constraints include, but are not limited to, constraints that cause: (1) significant historical gross congestion; (2) pro-ration of Stage 1B ARR requests as described in section 7.4.2(c) of Schedule 1 of this Agreement; or (3) significant simulated congestion as forecasted in the market efficiency analysis. The timeline for the market efficiency analysis and comparison of the costs and benefits for items 1.5.7(b)(i-iii) is described in the PJM Manuals.

(c) The process for conducting the market efficiency analysis described in subsection (b) above shall include the following:

(i)The Office of the Interconnection shall identify and provide to the Transmission Expansion Advisory Committee a list of economic constraints to be evaluated in the market efficiency analysis.

Economic Justified Transmission Enhancements

Operating Agreement : 1.5.6 Development of the Recommended Regional Transmission Expansion Plan

(i) The recommended plan shall identify enhancements and expansions that relieve transmission constraints and which, in the judgment of the Office of the Interconnection, are economically justified. Such economic expansions and enhancements shall be developed in accordance with the procedures, criteria and analyses described in Sections 1.5.7 and 1.5.8 of this Schedule 6.

Market Efficiency vs. Transmission Planning models

Production Cost Model	Power Flow Model
Security Constrained Unit Commitment & Economic Dispatch: Cost Based	Hand Dispatch (merit order)
Simulate all hours (8760 for year)	Peak hour
DC Transmission (linearized AC)	AC and DC load flows
Can monitor only selected number of security constraints	Can monitor all lines
Market Analysis/ Transmission analysis/planning	Basis for transmission reliability & operational planning
Outputs LMPs (and components), production cost, load payments, etc	Outputs line flows, overloads, voltage levels

PJM Eligible Congestion Drivers

- In determining eligible congestion drivers PJM considers all binding flowgates internal to the PJM footprint (including tie lines), current active Market-to-Market flowgates listed in the NERC book of flowgates, and potential future Market-to-Market flowgates between PJM and MISO
- Eligible congestion drivers are selected to focus proposals on significant issues
  - Identified coincident with the opening of market efficiency proposal window
- Only proposals which address one or more of these PJM identified congestion drivers will be evaluated
  - If the proposal does not substantially address a PJM identified congestion driver, or is otherwise substantially deficient or is seriously flawed, it will be rejected and the proposer will be notified
- Interregional congestion drivers identification and benefit determination conducted in each regional process consistent with current effective JOA

Target Congestion Drivers Criteria*

- Annual simulated congestion frequency
  - least 25 hours in each RTEP and RTEP+3 study years
- Congestion threshold (each RTEP and RTEP+3 study years):
  - Lower voltage facilities: min $1 million annual simulated congestion
  - Regional facilities: min $10 million annual simulated congestion
  - Interregional facilities: min $0.5 million congestion in each RTEP and RTEP+3 study years (lower threshold as there may be interregional benefits in addition to the regional benefits)
- Congestion for RTEP+6 study year is considered more uncertain and therefore will be monitored in future analysis
- Exceptions for posting Target Congestion Drivers:
  - Congestion is significantly influenced by a FSA generator or a set of FSAs
  - Majority of the congestion was already addressed in previous window(s)
  - Simulated congestion for future study years displays a declining trend

*Criteria used for the 2018/19 Window

Market Efficiency – Analysis

- Production Costing Simulations
  - Run two cases, one with proposed transmission upgrade, one without
  - For each case, calculate benefits for each Transmission Zone
- Bright line tests
  - Proposal must reduce or relieve economic congestion on identified PJM constraints
  - Proposal's Benefit/Cost Ratio > 1.25
- Other factors considered to distinguish between competitive proposals
  - Overall PJM simulated congestion, PJM Total Load Payments, PJM Total Production Cost
  - Sensitivities
    - Gas Sensitivity
    - Load Sensitivity
    - Other sensitivities as needed

Storage as a Transmission Asset: Operations and Markets

Potential SATA Dispatch Strategies

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Thermal

Voltage

Auxiliary

Scheme

Load Security

Operational Types

Thermal	Voltage	Auxiliary	Scheme	Load Security
• Installed for N-1 or N-1-1 thermal issue (Market Efficiency or RTEP) • Dispatched as non-cost action prior to off-cost • Need for input into DA Market • Charging period needs to be considered	• Installed for actual or N-1 voltage issue • Optimal dispatch may be at fraction of Pmax • Operation similar to switched capacitor / reactor banks.	• Normally operated at full charge • Available for quick response for unplanned loss of key facility • E.g. lone EHV feed into isolated region. • No dispatch for other reliability issues, unless no other options.	• Normally operated at full charge • Automatic response to pre-defined system condition • RAS? • Scheme-Failed scenario operated to LD limit • Discharged manually for conditions beyond LD limit	• Normally operated at full charge • Co-located with local load • Serves islanded load following loss of source • Ineligible for alternate use

More Flexible ⟷ Less Flexible

Potential Triggers

- Thermal overload
- Voltage control
- Load threshold
- Seasonal (e.g. 6/15-9/15)
- Owner request
- Specific outage (Auxiliary type)