Transmission Access Charge Options

Stakeholder Working Group Meeting

August 11, 2016

August 11, 2016 working group agenda

Time (PST)	Topic	Presenter
10:00-10:10	Introduction and Stakeholder Process Overview	Kristina Osborne
10:10-12:30	Default Cost Allocation for Regional Transmission Projects	Lorenzo Kristov / Neil Millar
12:30-1:15	Lunch break	
1:15-3:45	Region-wide Rate for Exports	Lorenzo Kristov
3:45-4:00	Next Steps	Kristina Osborne

Default Cost Allocation for New Regional Transmission Projects

FERC Order 1000 requires that the ISO tariff contain "default" cost allocation provisions for new facilities.

- New facilities are defined as transmission facilities (additions or upgrades) planned & approved through an expanded transmission planning process (TPP) conducted by the ISO for the expanded BAA.
- A new facility will be considered for regional cost allocation if it is rated >= 200 kV
- Assumptions for today's discussion:
  - New facilities rated < 200 kV will be recovered entirely from the territory of the PTO whose system the facility connects to
  - Transmission revenue requirements (TRR) are recovered via volumetric rate charged to internal load and exports
  - The ISO's current TPP is a reasonable model for the structure of the future expanded TPP

With the addition of a new PTO, the ISO would conduct an expanded TPP to determine needs and approve transmission upgrades and additions.

- Under the expanded TPP, the ISO would conduct a process of engineering studies and policy-based needs assessments, with opportunities for in-depth stakeholder engagement, and develop an annual comprehensive transmission plan for the expanded BAA region.
- In accordance with the “default” provisions, the plan would specify allocation of costs for the proposed transmission additions and upgrades.
- The comprehensive transmission plan would be subject to approval by the governing board for the expanded BAA.

Today’s ISO Transmission Planning Process

Transmission planning process spans 15 months for phases 1-2, up to 23 months across all three phases.

April Year X — March Year X+1 — October Year X+1

Coordination of Conceptual Statewide Plan

ISO board approval of transmission plan

Phase 1

Development of ISO unified planning assumptions and study plan

- Incorporates State and Federal policy requirements and directives
- Demand forecasts, energy efficiency, demand response
- Renewable and conventional generation additions and retirements
- Input from stakeholders
- Ongoing stakeholder meetings

Phase 2

Technical Studies and Board Approval

- Reliability analysis
- Renewable delivery analysis
- Economic analysis
- Publish comprehensive transmission plan
- ISO Board approval

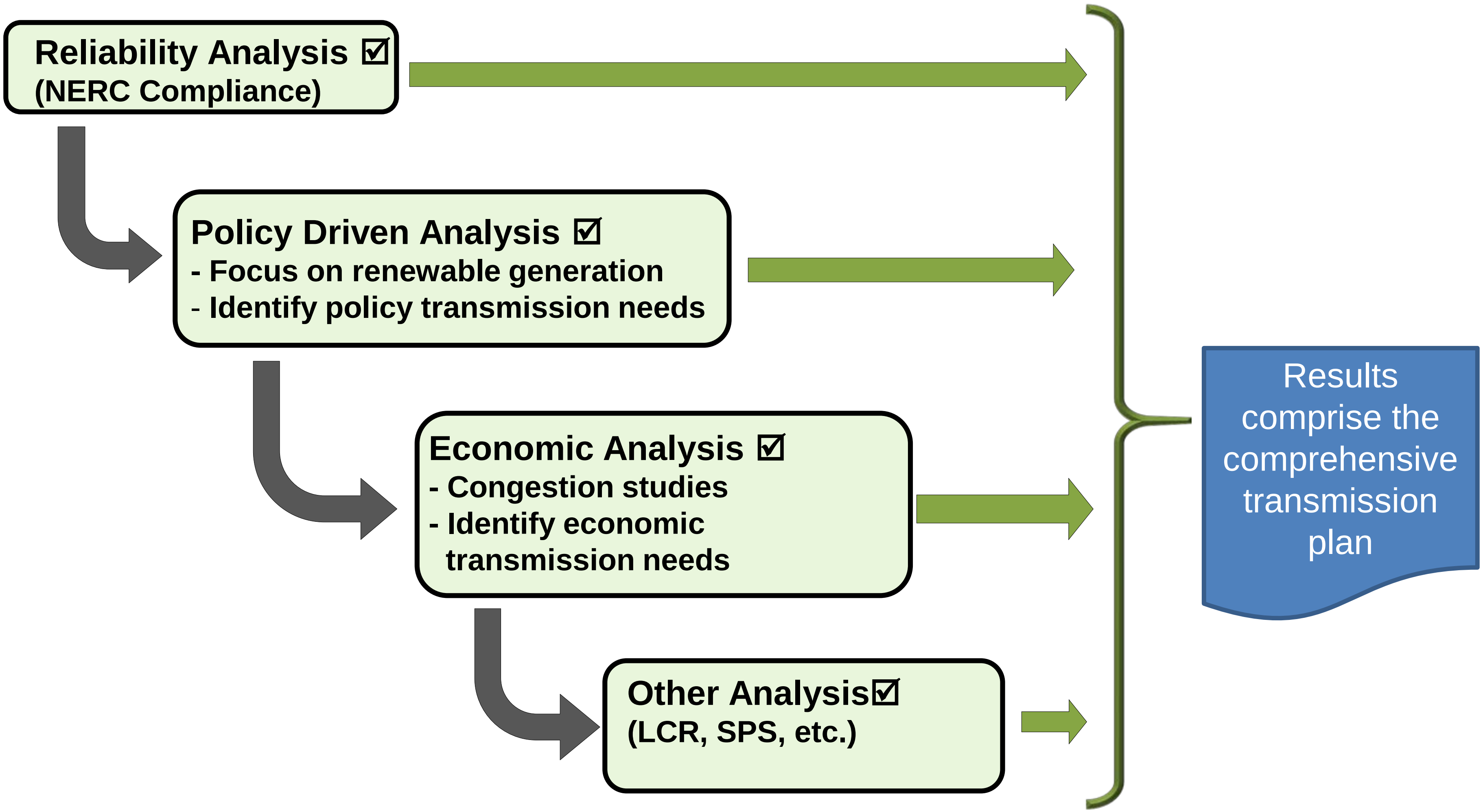
Phase 3

Competitive Solicitation Process

- Receive proposals to build identified reliability, policy and economic transmission projects
- Evaluate proposals to meet qualification for consideration
- Take necessary steps to determine Approved Project Sponsor(s)

Continued regional and sub-regional coordination

In Phase 2, the ISO's technical analysis is conducted in three deliberate stages in identifying needs and solutions.



The analysis and project identification is staged – it is not three separate and parallel study paths.

- "Reliability driven projects" consider the comparative economic benefits and costs of alternatives to meet the reliability need, but do not produce benefit-cost results.
- Policy needs may result in modifying or enhancing a reliability driven project to meet the reliability need AND the policy need. The resulting project is designated a "policy driven project."
- Similarly, economic analysis may result in enhancing a reliability driven and/or policy driven project, and the result is designated an "economically driven project."
- Only economic projects require a benefit-cost analysis and resulting benefit/cost ratio of at least 1.0.

Future areas of emphasis expected in ISO planning:

- Addressing higher levels of renewable generation
  - Initiating interregional coordination to consider interregional projects supporting geographic and resource diversity as part of 50% RPS target
  - Modeling improvements to enhance frequency response analysis
  - Potential for increased economically driven retirement of gas fired generation
- Further consideration of use of slow response resources (e.g., DR) to meet local capacity needs
- Expanding on gas-electric coordination analysis
- Support increased challenges in load forecasting given behind the meter emerging issues.

Economically driven analysis builds on policy-driven and reliability-driven analysis.

- The solutions identified after the reliability and policy stages are assumed in the initial economic analysis
- The economic analysis could result in new projects or enhancements or replacements of solutions identified in stages 1 and 2.
- Potential study areas are found through ISO analysis <u>or</u> through stakeholder requests:
  - Economic Planning Study <u>Requests</u> are submitted to the ISO during the comment period of the draft Study Plan
  - The ISO considers the Economic Planning Study Requests as identified in section 24.3.4.1 of the ISO Tariff as well as high priority areas the ISO identifies

Economic planning study steps

- Database development for production cost simulation
- Congestion analysis based on production cost simulations for 5-year and 10-year future horizons
- Evaluation of economic study requests
- Selection of high priority studies
  - Rank congestions by severity
  - Consider economic study requests
  - Determine high priority studies
- Assessment for high priority studies using documented methodology (Transmission Economic Assessment Methodology - TEAM)

Transmission Economic Assessment Methodology (TEAM)

- Considers a wide range of economic benefits:
  - Market efficiency – economic dispatch
    - Does not currently include EIM benefits due to minimal exit provisions committed to by participants
  - Transmission line losses
  - Resource adequacy capacity benefits.
- Various alternatives for calculating benefits and the present value of benefits are provided
  - Does a single base scenario need to be developed?
- The ISO is updating the existing documentation to reflect current practices

Default Cost Allocation Concepts for Discussion

Projects with no specific reliability or policy driver must have economic benefits exceeding the project cost.

- An economic project's estimated benefits must exceed its cost (i.e., its benefit-to-cost ratio (BCR) must be 1.0 or greater).

- The economic benefits of a project driven by a reliability need or policy directive do not need to exceed the project costs.

Concepts for default cost allocation

- If benefit to cost ratio is 1.0 or greater, costs would be allocated to sub-regions in proportion to each sub-region's benefits.

- If benefit to cost ratio is less than 1.0, each sub-region is allocated a cost share equal to the amount of its benefits, and the remaining costs are allocated as follows:
  – To the sub-region whose reliability need or policy mandate was a driver of the project, if the driving need came from a single sub-region

Concepts for default cost allocation (Contd.)

– If reliability needs or policy mandates come from more than one sub-region, each relevant sub-region would be allocated a share of the remaining costs

1. In proportion to its projected total internal load for the year in which the project will be placed in service; or
2. In proportion to each sub-region's avoided cost if the sub-region had to develop its own project to meet the need; or
3. Other possibilities?

Possible variant on the determination of benefits of a project – considering “avoided costs”

- Add a sub-region’s avoided cost for reliability or policy driven alternatives to the total benefits, then calculate sub-regional benefit shares. Example:
  - Cost of preferred project = $100 million
  - Sub-region A benefits
    - $30 million production cost savings (from TEAM)
    - Meets sub-region A reliability need, where sub-regional alternative would cost $60 million but with no economic benefit
  - Sub-region B benefits
    - $40 million production cost savings (from TEAM)
  - Cost responsibility:
    - Sub-region A = $100M ($30M+$60M)/($30+$40M+$60M) = $69M
    - Sub-region B = $100M ($40M)/($30+$40M+$60M) = $31M
- Is the avoided cost of a hypothetical sub-regional alternative an appropriate basis for cost allocation?

Applying TEAM
to Regional Cost Allocation

Implications for the Expanded TPP

- Reliability projects may also be providing economic benefits
  - Apply TEAM to calculate total economic benefits and sub-regional shares of benefits
- Policy projects may also be providing reliability or economic benefits
  - Apply TEAM to calculate total economic benefits and sub-regional shares of benefits
- Economic projects may also be meeting reliability or policy needs
  - Economic project require BCR > 1 so reliability & policy benefits are ignored in cost allocation

Using TEAM results to determine sub-regional shares of economic benefits

- Production cost savings (from end-use ratepayer perspective) will be extracted from production simulation results
- Capacity benefits can be manually derived based on capacity requirements a sub-region basis
- Transmission line losses will be extracted from snapshot powerflow cases used for reliability analysis and extrapolated to calculate annual benefits
- The present value of annual benefits results will be calculated using social discount rate ranges
- Can flexibility be maintained to consider other potential benefits in TEAM?
- Does cost allocation require that all valuation assumptions be pre-specified?

Single Region-wide Export Access Charge

The ISO proposed to create a single region-wide export rate for all exports from the expanded BAA.

- For today's discussion, this new export rate is called the "export access charge" (EAC) to distinguish it from the existing "wheeling access charge" (WAC)
  - Today ISO charges WAC to the internal load of non-PTO entities embedded within the ISO BAA, as well as to exports
  - Under the proposal, non-PTO entities would pay the same sub-regional TAC rate paid by other loads in the same sub-region
  - Only exports and wheel-through schedules from the expanded BAA would pay the EAC
  - Consistent with above, assume for today's discussion that a new PTO that is embedded within an existing sub-region would be part of that sub-region, not a new sub-region
- The EAC rate would be calculated as a load-weighted average of the sub-regional license plate rates

Conceptual structure of the proposed EAC

- Let TRR1 and TRR2 be the high-voltage TRRs for the 2 sub-regions
- L1 and L2 be the internal load MWh for the sub-regions
  – Then TAC1 = TRR1/L1 and TAC2 = TRR2/L2 are the sub-regional HV TAC rates
  – And the EAC rate = (TRR1 + TRR2) / (L1 + L2)
- Let E1 and E2 be the export MWh for the sub-regions
  – Then EAC revenues = (E1 + E2) * (EAC rate)

Concept for allocation of EAC revenues

Each sub-region would receive revenues based on the volume of exports on that sub-region's intertie facilities times the relevant sub-regional TAC rate

- This means
  - Sub-region 1 <u>unadjusted</u> EAC revenues = E1 * TAC1
  - Sub-region 2 <u>unadjusted</u> EAC revenues = E2 * TAC2

It is likely, however, that the unadjusted revenue shares will not exactly add up to actual EAC revenues collected, so the shares would be adjusted as follows:

Sub-region 1 share

= (EAC revenues) * E1*TAC1 / (E1*TAC1 + E2*TAC2)

Sub-region 2 share

= (EAC revenues) * E2*TAC2 / (E1*TAC1 + E2*TAC2)

Example using 2015 data

Objective: Compare EAC revenues for each sub-region after regional expansion to export WAC revenues to CAISO before regional expansion.

  - WAC revenues from non-PTOs in CAISO are not affected because these entities will pay the CAISO sub-regional rate

- CAISO is sub-region 1 (ISO TAC rates, 10/19/15)
  - TRR1 = $2,071,851,575
  - L1 = 211,786,041 MWh
  - TAC1 = $9.78
- PAC is sub-region 2 (Feb. 2016 TAC Options model)
  - TRR2 = $291,318,198
  - L2 = 70,675,826 MWh
  - TAC2 = $4.12

2015 example, page 2

- Weighted average EAC rate = $8.37
- E1 = exports from CAISO to PAC = 1136 MWh
- E2 = exports on other CAISO ties = 1,854,995 MWh
- E3 = exports on other PAC ties = 34,996,078 MWh
- W = non-PTO load inside CAISO = 11,229,506 MWh

CAISO 2015 <u>export WAC</u> revenues (<u>before expansion</u>)

= (E1+E2)*TAC1 = $18,158,079

CAISO 2015 WAC revenues from non-PTO load

= W * TAC1 = $109,855,537

2105 example, page 3

Compare EAC revenues and revenue allocation after expansion of the BAA

- Scenario 1 – No change in export volumes
- Scenario 2 – PAC exports reduced by 25% due to integration into expanded BAA
- Scenario 3 – PAC exports reduced by 50% due to integration into expanded BAA
- Total EAC revenues = (E2+E3) * (EAC rate)

2105 example results

	Scenario 1	Scenario 2	Scenario 3
PAC export MWh	34,996,078	26,247,058	17,498,039
EAC revenues	$308,308,311	$235,111,110	$161,913,908
CAISO share unadjusted	$18,146,968	$18,146,968	$18,146,968
PAC share unadjusted	$144,250,090	$108,187,567	$72,125,045
Leftover revenue	$145,911,254	$108,776,574	$71,641,895
CAISO share adjusted	$34,451,739	$33,771,872	$32,548,809
PAC share adjusted	$273,856,572	$201,339,238	$129,365,099

Next Steps

Next Steps

- Stakeholder comments on today's working group discussions are due August 25, 2016; submit to initiativecomments@caiso.com

- Subsequent activities on this initiative will be announced by market notice in the near future.