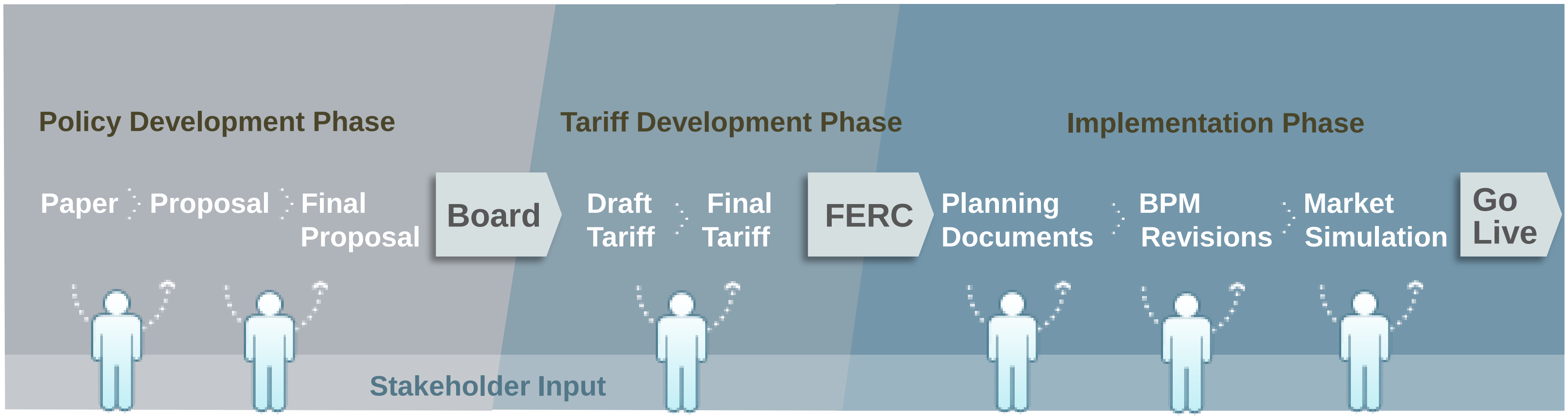
Review Transmission Access Charge Wholesale Billing Determinant

Issue Paper

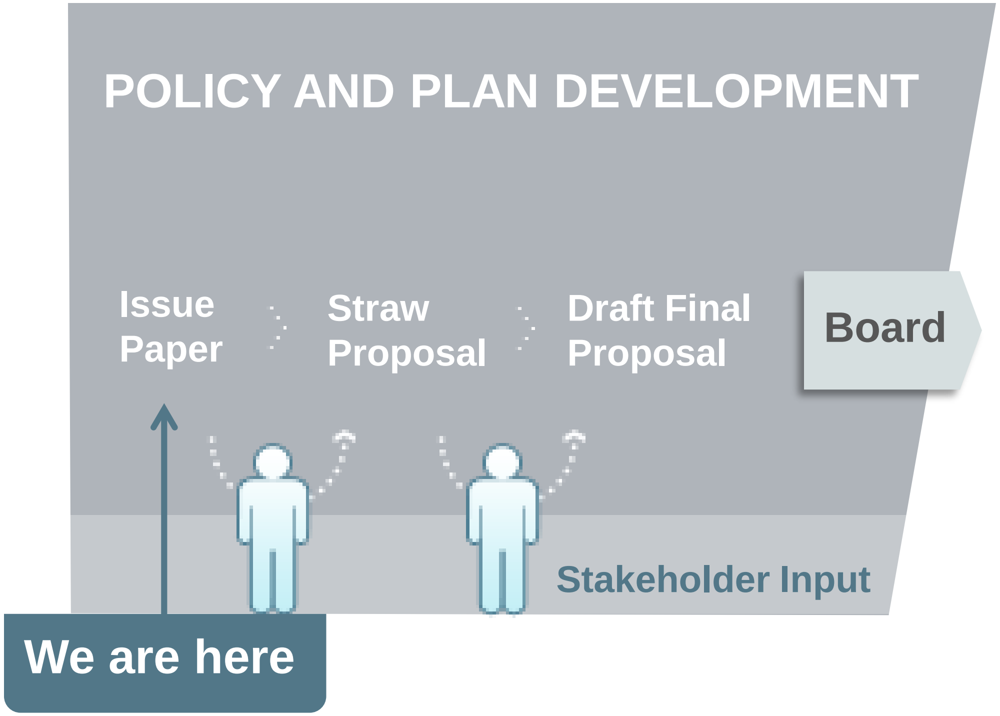
Stakeholder Conference Call – June 14, 2016

ISO Stakeholder Engagement Process

This diagram represents the typical process, often phases will run in parallel.



ISO Stakeholder Process



Initiative Schedule

Milestone	Date
Issue Paper posted	June 2, 2016
Stakeholder Conference Call	June 14
Market Surveillance Committee meeting	June 17
Submit written comments by	June 30
ISO Straw Proposal et seq	Dates TBD

Issue Paper

This topic originated with a proposal Clean Coalition submitted to ISO's "Transmission Access Charge Options" initiative in fall of 2016.

- ISO initially included the topic in the "Energy Storage and Distributed Energy Resources Phase 2" (ESDER 2) initiative
- In response to stakeholder comments ISO decided to move the topic to a separate initiative
  - Greater visibility to ensure all interested and affected stakeholders have opportunity to participate
  - Enable the initiative to proceed on its own timeline as needed

Initiative will consider whether to modify wholesale billing determinant applied to collection of Transmission Access Charge (TAC).

- TAC is the settlement vehicle used to recover PTOs' costs of owning, operating & maintaining transmission assets turned over to ISO operational control
  - FERC-approved "transmission revenue requirements" (TRR)

TAC has two components applied to hourly settlements:

- Postage stamp "regional" rate to recover TRR for all facilities rated > 200 kV under ISO operational control
  - $/MWh charge to all ISO internal load and exports
- PTO-specific "local" rates to recover TRR for all facilities < 200 kV under ISO operational control
  - $/MWh charge to internal load in each PTO's territory

The central question is how "internal load" should be calculated for TAC purposes.

- TAC rate is the quotient of PTOs' total FERC-approved TRR divided by forecast of internal load & exports
  - TAC rate may be adjusted mid-year for changes in TRR amount or differences between forecast v. actual load & exports
- ***Internal load is currently defined as the total of end-use customer metered load (EUML)***
- Clean Coalition's proposal to define internal load subject to TAC as ***"transmission energy downflow" (TED)*** measured as the energy flow from transmission to distribution at each T-D interface substation

In general TED will be less than EUML due to the energy generated by “Local DG” in each hour.

- T-D interface substation is where operational control transfers from ISO to utility distribution company (UDC)
- “Local DG” (as defined by Clean Coalition) equals energy generated by distributed generation (DG) on the UDC side of the customer meter, plus energy produced by behind-the-meter DG in excess of customer load in the same hour
  - Load offset by BTM DG in the same hour is already exempt from TAC because it does not show up in EUML
- In general, for each T-D interface, each settlement hour:

TED = EUML – Local DG + (adjustment for losses)

- For now we set aside effects of losses, to simplify the issue and focus on the central question of TED v. EUML.

TRR recovery depends on both the ISO's wholesale TAC settlement method and the CPUC's or LRA's approved rates for retail transmission charges.

- This issue paper assumes there is no change to the CPUC/LRA retail transmission rate structure or method
- Retail transmission rates are currently applied to EUML
- Therefore – for the same TRR to be collected and same end-use consumption – if ISO changes to TED instead of EUML, end-use customers will not see any corresponding change to their retail transmission charges
- Rather, the load-serving entity (LSE) may see a financial surplus or shortfall due to any discrepancy between ISO wholesale TAC charges and retail transmission charges

Non-IOU LSEs operating in IOU territories have two options for billing services.

- Non-IOU LSEs include retail direct access energy service providers (ESPs) & community choice aggregators (CCAs)
- Option A: LSE performs its own retail billing
  1. LSE's SC submits hourly settlement quality meter data (SQMD) to ISO for settlement
  2. ISO charges and LSE pays TAC based on LSE's hourly load values
  3. LSE bills retail customers for CPUC-approved transmission charges based on EUML
- Option B: UDC performs retail billing for the LSE
  1. LSE's SC submits hourly SQMD to ISO for settlement
  2. ISO charges and UDC pays TAC based on total of hourly load values for all LSEs operating in UDC's territory
  3. UDC bills retail customers for CPUC-approved transmission charges based on EUML

Any difference between $ amounts of steps (2) & (3) will have financial impact on the LSE or UDC.

Examples in issue paper illustrate the following points:

1. For fixed TRR, adopting TED increases the TAC rate
2. Absent CPUC changing retail transmission rates, using TED for ISO TAC charges will cause financial shortfall or surplus for the LSE or UDC
3. If UDC has methods and authority to allocate its financial shortfall or surplus to LSEs appropriately, then UDC sees no impact, and billing options A and B lead to the same outcome for the LSEs
4. Assuming point 3 holds, LSEs serving more of their load with Local DG will have financial surplus, while LSEs with little or no Local DG will have financial shortfall
5. If all LSEs within a given IOU territory serve the same share of load with Local DG, switch to TED has no impact

The issue paper identifies a number of questions and issues for stakeholder input and discussion.

1. What policy objectives should TAC billing support?
   a. More accurate comparison of RPS procurement options?
   b. Improve distribution resources plans (DRPs)?
   c. Avoid or defer T or D investments?
   d. Reduce line losses?
   e. Enhance local environment, economy, resilience?

2. What guiding principles should apply?
   a. How should “usage pays” principle apply? Is it true that load offset by Local DG gets <u>no benefit</u> from transmission?
   b. Could it be true that load offset by Local DG gets <u>less benefit</u> from transmission? If so, how could this be quantified?
   c. Some parties commented that cost shifts must be prevented. How can the principle of aligning costs with system usage and benefits be balanced against cost-shift concerns?

Policy issues and design questions - continued

3. Should any change to TAC billing determinant distinguish between TRR for facilities in service vs. avoidance of future upgrades? If so, how might this TAC be designed?
   a. How could we measure the benefit of DG in reducing transmission investment?
4. If the benefit of DG in reducing transmission cost is related to peak load reduction rather than total energy, how might TAC allocation reflect peak impacts?
5. What is the linkage between adopting a TED-based TAC and increased investment in DG?
   a. How does TAC figure into LSE procurement decisions?
6. What other questions and issues need to be considered?

Next steps …

Market Surveillance Committee meeting Friday June 17

Please submit written comments by June 30.

Appendix
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Numerical examples in issue paper

Numerical examples incorporate several assumptions.

1. Single IOU PTO distribution/transmission territory
2. Single ISO hourly settlement period
3. TRR = $21,600 for in-service transmission facilities
4. Total EUML = 1440 MWh => TAC rate = $15/MWh
5. Example 1 total Local DG output = 60 MWh which => TAC rate = $15.65/MWh
6. Example 2 all LSEs serve 20% of load with Local DG, total Local DG output = 288 MWh => TAC rate = $18.75/MWh
7. No change to retail transmission charges, which are based on EUML at $15/MWh rate
8. Different non-IOU LSEs at different T-D interfaces
9. Ignore distribution line losses
10. Assume UDC can correctly assign TAC shortfall or surplus to LSEs based on their load served by Local DG

Example 1 – LSEs have different financial impacts depending on how much load is offset by Local DG

Load and DG assumptions

	Interface 1		Interface 2		Interface 3		Rest of System		Total MWh
	IOU	ESP1	IOU	ESP2	IOU	ESP3	IOU	ESPs	
End-use Metered Load (MWh)	100	40	150	10	120	20	1000	0	1440
DG Production (MWh)	20	15	0	10	15	0	0	0	60
Net Load at T-D Interface (TED)	80	25	150	0	105	20	1000	0	1380

Financial results

	Interface 1		Interface 2		Interface 3		Rest of System	
	IOU	ESP1	IOU	ESP2	IOU	ESP3	IOU	ESPs
TRR charge by ISO to LSE per EUML	$1,500.00	$600.00	$2,250.00	$150.00	$1,800.00	$300.00	$15,000.00	$0.00
TRR charge by ISO to LSE per TED	$1,252.17	$391.30	$2,347.83	$0.00	$1,643.48	$313.04	$15,652.17	$0.00
LSE recovers from retail customers	$1,500.00	$600.00	$2,250.00	$150.00	$1,800.00	$300.00	$15,000.00	$0.00
LSE surplus or shortfall	$247.83	$208.70	($97.83)	$150.00	$156.52	($13.04)	($652.17)	$0.00

Example 2 – If all LSEs offset the same percentage of load by Local DG, then TED-based TAC has no impact.

Load and DG assumptions

	Interface 1		Interface 2		Interface 3		Rest of System		Total MWh
	IOU	ESP1	IOU	ESP2	IOU	ESP3	IOU	ESPs	
End-use Metered Load (MWh)	100	40	150	10	120	20	1000	0	1440
DG Production (MWh)	20	8	30	2	24	4	200	0	288
Net Load at T-D Interface (TED)	80	32	120	8	96	16	800	0	1152

Financial results

	Interface 1		Interface 2		Interface 3		Rest of System	
	IOU	ESP1	IOU	ESP2	IOU	ESP3	IOU	ESPs
TRR charge by ISO to LSE per EUML	$1,500.00	$600.00	$2,250.00	$150.00	$1,800.00	$300.00	$15,000.00	$0.00
TRR charge by ISO to LSE per TED	$1,500.00	$600.00	$2,250.00	$150.00	$1,800.00	$300.00	$15,000.00	$0.00
LSE recovers from retail customers	$1,500.00	$600.00	$2,250.00	$150.00	$1,800.00	$300.00	$15,000.00	$0.00
LSE surplus or shortfall	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00

The End