GRIDWORKS

Rule 21 Working Group 3

IN PERSON WORKSHOP

DECEMBER 12, 2018

HTTPS://ENERGYFOUNDATION.ZOOM.US/J/884792096

Agenda

10:00-10:20 Schedule, proponents, and introductions

10:20-10:30 Regulatory updates

10:30-12:00 Issue 12

- Gridworks issue brief/framing
- CALSSA presentation
- IREC presentation
- Facilitated discussion

12:00-1:00 Lunch

Agenda

1:00-1:45 Issue 12 (continued)

- Facilitated discussion (continued)
- Next steps

1:45-2:45 Issue 15

- Gridworks issue brief/framing
- CALSSA presentation
- Facilitated discussion
- Next steps

2:45-2:50 Online collaboration tools update

2:50-3:00 Wrap up, next issues, next call and meeting

Schedule

Date	Meeting	Issue Discuss	Issue Finalize	Location
Jan 3	Call			
Jan 10	In person	16 & 23	15	Trans Pacific Centre (1000 Broadway, Oakland)
Jan 16	Call			
Jan 23	In person	A & B	16	Trans Pacific Centre (1000 Broadway, Oakland)
Feb 6	Call			
Feb 13	In person	20 & 22	12 & 23	CPUC – Golden Gate Room
Feb 27	Call			
Mar 6	In person	24	A & B	CPUC – Golden Gate Room
Mar 20	Call			
Mar 27	In person		20 & 22	CPUC – Courtyard Room
Apr 10	Call			
Apr 17	In person		24 & 27 & 28	CPUC – Courtyard Room
May 1	Call			
May 8	In person	Final report		CPUC – Golden Gate Room
May 22	Call			
May 29	In person		Final report	CPUC – Courtyard Room
Jun 12	Call			

Schedule – SIWG Calls

For Issues 27 and 28, there will be a separate set of phone discussions leading to in-person meeting April 17:

Dec 19, Jan 11, Jan 31, Feb 21, Mar 14, Apr 4

All calls are 1-2:30pm except Dec 19, 2:30-4pm, and Jan 11, 2-4pm.

Schedule Notes

- WG3 phone calls are 2-4pm; in-person meetings are 10-3pm.
- Issues 12, 22, 23, and B require more time, discussion period has been extended to take place over three in-person meetings.
- Consultations or sub-groups should start 2-4 weeks before in-person meeting,
- Sub-groups are desirable at least for Issues 22 and 23.
  - GPI has offered to lead a sub-group for Issue 22.

Issue Proponents

Issue #	Issue	Issue Proponents
12	How can the Commission improve certainty around timelines for distribution upgrade planning, cost estimation, and construction? Should the Commission consider adopting enforcement measures with respect to these timelines? If so, what should those measures be? Addition: When should the Commission consider results of an initial review or detailed study to be binding? Under what circumstances should the Commission allow the results to be changed?	CALSSA with IREC supporting
15	Should the Commission require itemized billing for distribution upgrades to enable customer comparison between estimated and billed costs and verification of the accuracy of billed costs?	CALSSA
16	Should the Commission encourage third party construction of upgrades to support more timely and cost-effective interconnection, and if so, how?	GPI with Clean Coalition supporting
20	How should the Commission coordinate Commission-jurisdictional and Federal Energy Regulatory Commission-jurisdictional interconnection rules for behind-the-meter distributed energy resources, including modification of queuing rules for Rule 21 and Wholesale Distribution Access Tariff (WDAT) projects seeking to interconnect at the same location, clarification of the rules for projects wanting to transfer between the Rule 21 and WDAT queues, and streamlining of the transfer process?	CESA and GPI

Issue Proponents

Issue #	Issue	Issue Proponents?
22	Should the Commission require the Utilities to make improvements to their interconnection application portals? If yes, what should those improvements be?	GPI
23	Should the Commission consider issues related to the interconnection of electric vehicles and related charging infrastructure and devices and, if so, how?	CESA, Honda, Nuvve, and CEC
24	Should the Commission modify the formula for calculating the Cost-of-Ownership charge and, if so, how?	Clean Coalition with support from CALSSA
27	What should be the operational requirements of smart inverters? What rules and procedures should the Commission adopt for adjusting smart inverter functions via communication controls?	SIWG
28	How should the Commission coordinate with the Integrated Distributed Energy Resource proceeding to ensure operational requirements are aligned with any relevant valuation mechanisms?	SIWG
Issue A	What changes are needed to clarify the parameters for approval of system design to achieve non-export and limited export?	CALSSA with support from IREC
Issue B	How should utilities treat generating capacity for behind the meter paired solar and storage systems that are not certified non-export?	CALSSA with support from IREC

Role of Issue Proponents

- Preparing an issue brief and/or presentation for circulation at least one week prior to in-person meeting.
  - framing,
  - key questions,
  - considerations,
  - background knowledge,
  - initial proposals, and
  - identification of points for resolution.
- leading an “offline” approach, and/or ad-hoc phone discussions during the interval between initial discussion and issue finalization

Introductions

Regulatory Updates

GRIDWORKS

Issue 12

How can the Commission improve certainty around timelines for distribution upgrade planning, cost estimation, and construction? Should the Commission consider adopting enforcement measures with respect to these timelines? If so, what should those measures be?

Addition (Issue D): When should the Commission consider results of an initial review or detailed study to be binding? Under what circumstances should the Commission allow the results to be changed?

Issue 12 Questions/Framing

Q1. What is the problem/challenge this issue is addressing? How does this issue go beyond the discussion and consensus/non-consensus reached in Issue 10?

Issue 12 Questions/Framing

Q2. Which utilities communicate expected timelines in interconnection agreements? Which utilities don't? How well and in what manner do utilities communicate about timeline adjustments?

Issue 12 Questions/Framing

Q3. Which timelines are most significant or priorities for this issue? Where exactly do we need more certainty? Could be timelines for detailed review, planning, design, cost estimation, and/or construction. Or could be for specific types of projects.

Issue 12 Questions/Framing

Q4. In the absence of communicated timelines for specific projects, are there or could there be well-understood benchmarks or standard practices?

Issue 12 Questions/Framing

Q5. How serious or prevalent are deviations in timelines from expected timelines, communicated timelines, or benchmark timelines? What percentage of projects? What length of delays? What data are available to show the extent of the problem?

Issue 12 Questions/Framing

Q6. What causes variability, and thus up-front uncertainties in timelines? What are lessons learned about delays or lack of responsiveness?

Issue 12 Questions/Framing

Q7. How much of a present-time phenomenon are project delays or uncertainties, given that utilities may have altered their practices recently?

Issue 12 Questions/Framing

Q8. What are some potential enforcement or mitigation measures, or new utility practices?

Issue D Questions/Framing

Q. What is an appropriate cut-off time for getting billed actual costs?

Rule 21 Working Group 3
Issue 12 - Timelines

December 12, 2018

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Timeline Issues to Resolve

A. New timelines needed
B. Enforcement mechanisms
C. Transparency

A. NEW TIMELINES NEEDED

- The Rule 21 Working Group Two report included a recommendation for timelines for design and construction of grid upgrades
- Timelines are needed for installation of net generation output meters (NGOMs)
- Others?

NGOM Timeline

- NGOM is required for NEM paired storage systems larger than 10 kW output capacity.
- Typical timeline for NGOM installation is 6-12 months. This creates major customer expenses if they have to build a system long before they can use it.
- Design and administration can be done before PTO.
- CALSSA recommends a standard of:
  - 20 business days for administration after the utility receives a signed interconnection agreement
  - 20 business days for installation after invoice is paid and documentation is provided

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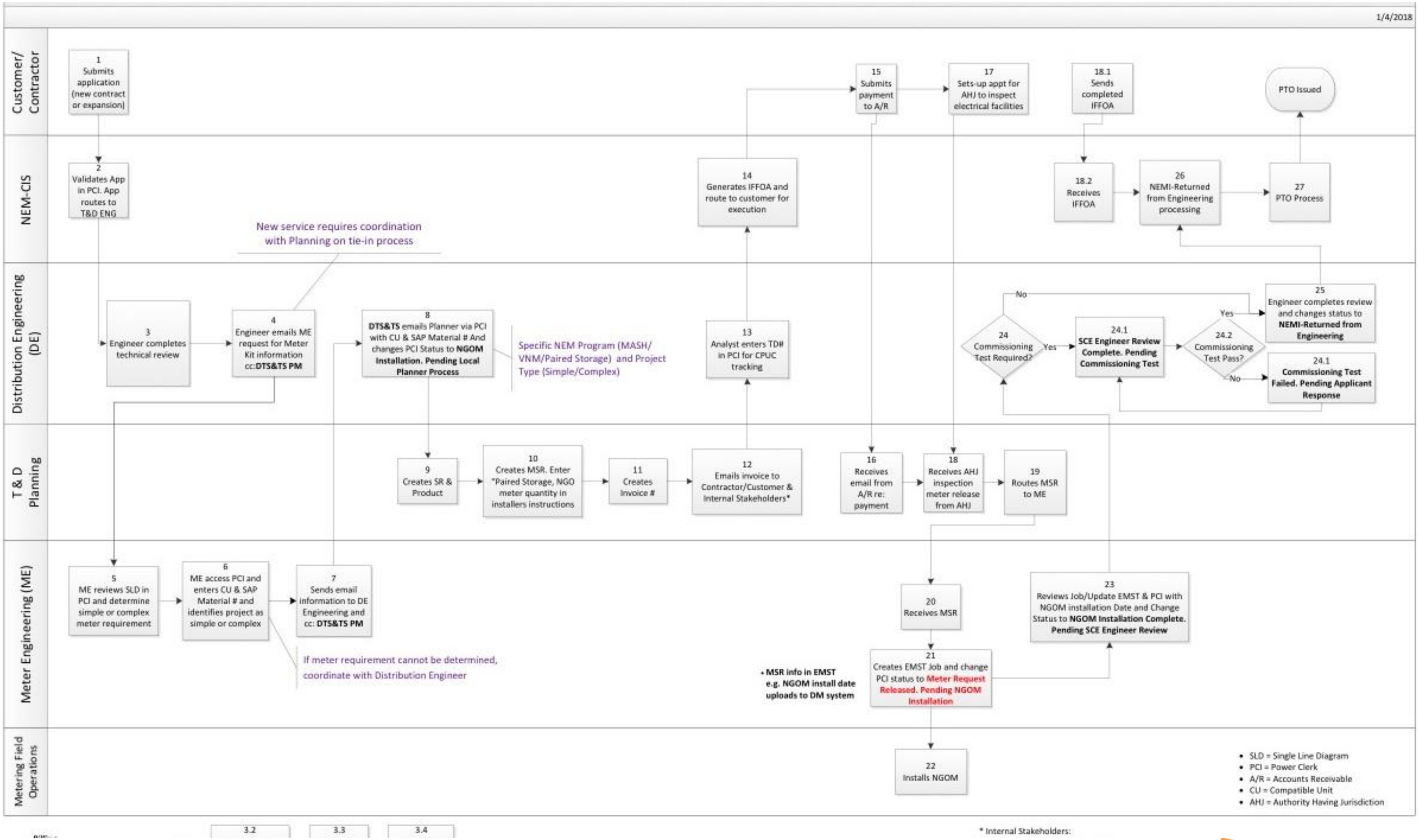
Current NGOM Installation Process



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B. ENFORCEMENT MECHANISMS

- Dirty looks
- Fines/penalties
- Complaint response options
- Performance-based compensation
- GRC cost recovery minimum bar

Complaint Response Options

- Direct appeal
  - Can include Section K meet and confer but is normally done informally
- Complaint
  - Hire a lawyer and an issue expert; fight for a year
- Alternative Dispute Resolution
  - By mutual consent only; utilities have no motivation to engage
- Expedited Dispute Resolution
  - Not established yet; uncertain whether timelines are the right sort of issue
- Interconnection Discussion Forum

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Performance-Based Compensation

- Two examples in other states:
  - Massachusetts
  - New York Earnings Adjustment Mechanism
- Hard to construct in a way that doesn't reward utilities for status quo

GRC Adequacy Test

- Presumption is full cost recovery for interconnection-related expenses
- Utilities need to demonstrate their interconnection performance was adequate to achieve full cost recovery.
- CPUC has discretion to consider some interconnection-related expenses not to be prudent if basic customer service level is not met.

C. TRANSPARENCY

- Better data reporting will help set expectations
  - Independent consultant will make recommendations in the coming months
- Notices should be consistent and clear
  - If utility must miss a Rule 21 deadline or a timeline that had been mutually agreed upon, they should send notices to the customer and the project developer
  - Notices must be timely and include site-specific reasons for delay

Summary of Recommendations

1. NGOM timeline
2. Performance data considered in GRC
3. Data reporting
4. Stronger requirements for notices

Thank You!

Brad Heavner
Policy Director
California Solar & Storage Association
brad@calssa.org

Interconnection: Carrots and Sticks

Sky Stanfield & Laura Beaton

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IREC

Massachusetts Timeline Enforcement Mechanism (TEM)

- **Adopted by Commission Order on July 31, 2014**
- **Annual reporting on interconnection timelines is required**
  - Each timeline is tracked and published in a spreadsheet available for review.
- **Tracks total end-to-end process on an aggregate basis**
  - Starts with calculating the <u>total time allowed</u> in the tariff for completing the interconnection process for each “track”
  - Then the <u>actual time that the Utility takes to interconnect projects</u> is tracked and compared to the times identified above.
  - This is then used as the basis to <u>calculate penalties and offsets</u>, subject to a deadband (+/- 5% of target) and caps.

IREC

Penalty and Offset Assessment

- **Each "track" is given different weight depending upon its complexity.**
  - 20 percent for the Simplified Process, 40 percent for the Expedited Process, and 40 percent for the Standard Process
- **Penalties assessed if Utility's Actual Aggregate Time Frames are greater than its Aggregate Allowed Tariff Time Frames**
  - Penalties are paid into the state's general fund
- **Offsets would be earned if a Utility's Actual Aggregate Time Frames are less than its Aggregate Allowed Tariff Time Frames**
  - Offsets are not monetary. They allow for a reduced penalty earned in one Reporting Year by the amount of the offset earned in the prior Reporting Year
  - Cannot be carried forward beyond one year
- **A deadband of +/- 5% is applied for flexibility, and there is a +/- 15% cap for each utility for maximum penalty or offset that can be earned.**

IREC

Calculating Penalties/Offsets

- **Beyond the deadband (+/- 5%), penalties and offsets are determined as follows:**
  - Value of penalty/offset increases each 1/10 of a percent that the actual time frames over or under perform those allowed
- **The monetary value for each 1/10 of a percent for each Utility was established by order (see next slides).**
  - Based on the "total proxy application fee pool" for each Utility
- **Any penalty owed shall be borne by the shareholders and not by the ratepayers**

Value of Penalty/Offset

Distribution Company	Total Proxy Application Fee Pool	Cap[10]	Tenth of a Percent Value[11]
National Grid	$1,960,000	$1,500,000	$19,600
NSTAR	$1,412,000	$1,080,603	$14,120
Unitil	$10,709	$8,196	$107
WMECO	$646,000	$494,383	$6,460

- The cap for National Grid was determined through negotiation. The caps for the rest were calculated by multiplying their respective total proxy application fee pools by a factor of 76.53%.

IREC

Sample of Penalty Calculation- Using NSTAR Values

Performance (> Timelines)		% of penalty	Penalty	Cap
0.05	5%	0	0	$1,080,603
0.06	6%	0.1	$141,200.00	$1,080,603
0.07	7%	0.2	$282,400.00	$1,080,603
0.08	8%	0.3	$423,600.00	$1,080,603
0.09	9%	0.4	$564,800.00	$1,080,603
0.1	10%	0.5	$706,000.00	$1,080,603
0.11	11%	0.6	$847,200.00	$1,080,603
0.12	12%	0.7	$988,400.00	$1,080,603
0.13	13%	0.8	$1,129,600.00	$1,080,603
0.14	14%	0.9	$1,270,800.00	$1,080,603
0.15	15%	1	$1,412,000.00	$1,080,603

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What Has Been the Effect?

- Every year since adopted the utilities have earned their maximum offset. Yay?!
- But…
  - Developers report that this is “laughable” and that timelines for some projects are worse than before.
  - The utilities put projects on “hold” throughout the process and essentially “stop” the clock.
  - Projects where timelines are negotiated by mutual agreement are excluded and the utilities have increased the number of those.
  - Anything that happens "off the tariff" such as reducing system size to avoid upgrades, changing inverters, or the need for additional documents that don’t impact the actual study or review process is not included

IREC Conclusions

- The MA framework for penalties and offsets seems reasonable and fair, being based off the collected fees has an appropriate corresponding relationship with utility interconnection revenue
- Measuring overall timeline vs. step-by-step focuses on big picture and allows some flexibility within the process
- Need to address how “holds” or other “stops” would work to ensure effectiveness
- Process does not cover construction-related timelines and these continue to be controversial in Massachusetts as well
- The most important component to start with is a **baseline method for tracking all the timelines**.
- California’s tariff has many more potential “tracks” and alternate timelines which may make the end-to-end calculations more complex to implement.

New York
Interconnection EAM History

- EAM = Earnings Adjustment Mechanism
- Arose out of NY REV Docket
- While other EAMs were to be “positive only,” interconnection was to be “symmetrical” (+ and -)
- The specific targets and incentives were to be developed on a utility-specific basis as part of rate cases or other company-specific filings

Key Requirements

- No EAMs for projects under 50 kW
- Could consider negative EAM “in the context of individual utility proceedings”
- Three EAMs identified:
  1. Adherence to the timeliness requirements established in the interconnection procedures (threshold)
  2. A survey of applicants to assess overall satisfaction, and
  3. A periodic and selective third-party audit of failed applications to assess accuracy, fairness, and key drivers of failure
- For now, market-based incentives will be developed for only two components of the EAM:
  - A threshold requirement to achieve 100% compliance with three timelines. This carries with it the possibility of unspecified negative market adjustments for failure to achieve compliance.
  - Positive market adjustments based on customer satisfaction scores from the applicant survey. The specific incentives chosen will be decided on a utility-by-utility basis.

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Timelines

- EAM for **three** timelines:
  - 10 BD to determine application completeness;
  - 15 BD requirement to complete the preliminary screening; and
  - 60 or 80 BD to complete the CESIR
- Rejected using *positive* earnings for timelines. Meeting the timelines <u>must be a threshold for positive earnings</u>, and a negative adjustment will be considered for not meeting those.
- Rejected including additional timelines, and also rejected using the holistic MA approach
- There is real concern that utilities will strive to meet the three timelines, and let other important steps slip as a result.

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Survey

- Only currently proposed opportunity for a positive earnings adjustment (timeline is threshold, audit stalled)
- Does not include projects below 50 kW, but encouraged to “survey for informational purposes.”
- Requires survey of applicants after preliminary review, and again at the end of the process (will at least capture some projects that “fail” and be more statistically significant)
- There was discussion of benchmarking customer satisfaction with JD Power reports - Con Ed has yet to achieve the national average score of 70 (out of 100) on any of the surveys it has conducted

ConEd’s Performance to Date

- ConEd submitted its first annual report to the PSC regarding its performance with respect to the timelines and customer satisfaction metrics in 2017. It reported the following:
  - Compliance with respect to SIR deadlines:
    - 10 day business requirement to review and determine application completeness: **94.3%**
    - 15 day business requirement to complete preliminary screening: **97.5%**
    - 60 or 80 day business requirement to complete CESIR: **96.7%**
  - With respect to the customer satisfaction metrics, the report indicated that the company achieved a 2017 year-end **customer satisfaction score of 67.1**.

Failed Application Audit

- A periodic and selective third-party audit of failed applications to assess accuracy, fairness, and key drivers of failure in order to support continual process improvement.
- The audit including examining various factors that could have lead to withdraw or failure of projects and how they were influenced by customer and utility actions
- Details on the exact impact on earnings and consistency across utilities were deferred to individual rate cases
- However, later the PSC indicated that due to recent queue restructuring, establishing a market-based mechanism for tracking performance with respect to failed applications is premature at this point.

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Current Status

- The details were to be negotiated and determined in individual utility rate cases
  - IREC did not participate and many others did not as well due to vast resources required by this approach.
- Settlement was not reached in ConEd’s case, and after two rounds the Commission has failed to issue a ruling.
- In National Grid’s case, there was progress on other EAMs but the interconnection ones were put off, and no decision has been made
- IREC has not researched all utility cases but we believe similar issues exist across the board
- The Staff filed a motion in October to **eliminate** the interconnection EAMs altogether! Decision pending.
  - Staff reported good progress on interconnection
  - However there is strong concern from the DER community

What for California?

Two Step approach

- Step One: Settings goals for incremental improvement over 3 years, and careful and detailed reporting on adherence to all timelines.
  - Establish to process to set goals
    - *Example*: End goal of achieving within +/- 5% of end-to-end timelines for aggregate
  - Need to consider what serious tracking of compliance looks like.
  - This is the key to enforcement.
- Step Two: After three years, assessment of progress to goals and identifying next steps
  - Review and vet existing timelines
  - Consider Commission action
  - Consider enforcement mechanisms
  - Possible differences in how to treat construction timelines vs. other process timelines

IREC

www.irecusa.org

info@irecusa.org

@IRECUSA

Facebook & LinkedIn

@Interstate Renewable Energy Council

Text 22828

enter email for news, reports & insights

Issue 12 – Discussion

Lunch

Issue 12 – Discussion

Issue 12 – Next Steps

Issue 15

Should the Commission require itemized billing for distribution upgrades to enable customer comparison between estimated and billed costs and verification of the accuracy of billed costs?

Issue 15 – Questions/Framing

Q1. Why is itemization important?

Issue 15 – Questions/Framing

Q2. What is an appropriate level of detail for itemization?

Issue 15 – Questions/Framing

Q3. How onerous is it for utilities to provide the appropriate level of detail, given their existing information and management systems?

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Issue 15 – Itemized Billing

December 12, 2018

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Standard Business Practice

- Providing a detailed bill is a basic customer courtesy.
- Customers are frustrated by the time and uncertainty of the interconnection process. Getting a lump sum bill compounds their frustration.
- In a competitive market, a company would never issue a lump sum bill. Customers expect basic information.

Real Cost Data Is Needed

- In 2016, the Commission required the IOUs to issue Unit Cost Guides for typical upgrade costs. The Unit Cost Guide is very helpful, but it should be combined with real experience. Costs vary, and project developers want to gain understanding of the variance so they can provide appropriate expectations to customers.

- If third party construction becomes a more viable option, project developers need to have a strong understanding of how much things cost.

- Lump sum bills shield utilities from accountability. It is hard for the Commission to know if costs for particular upgrades are not in line with the Unit Cost Guide or if one utility service office is an outlier.

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PG&E Current Practice

- When the engineering study results are issued for a project that utilized Supplemental Review or Detailed Study, the project cost estimates are itemized.
- PG&E will then issue an engineering advance invoice for approximately 20% of the project's *estimated* upgrade cost prior to project design.
- Once the project design is completed (typically 2-8 months), the customer is provided with the total upgrade costs.
- Although the estimate had been itemized, the final cost is in lump sum format (with the exception of Cost of Ownership and ITCC).

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SCE Current Practice

- After engineering studies, SCE issues the estimated costs for the project. The customer pays the full amount in advance of the design work being completed.
- The cost is in lump sum format.
- Until January 2018, SCE's practice was not to do a reconciliation. SCE is now reconciling all past projects.
- CALSSA strongly objects to revisiting costs for any project more than 18 months after permission to operate. (In Issue 10, CALSSA recommended a standard of six months.)

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Cost Categories

Unit Cost Guides include 37-93 categories, depending on utility, including:

- Transformer
- Overhead to underground extension
- Overhead line extension
- Underground line extension
- Metering
- Telemetry
- Switch
- Capacitor
- Regulator
- Fuses
- Reclose blocking
- Relocate equipment
- Settings modifications
- Direct transfer trip
- Load tap control change
- Hardwire trip
- IPAC relay cabinet

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Initial Recommendation

- No change to the billing process (PG&E requires deposit; SCE charges full cost upfront)
- Estimates and final bills include the same cost categories as the Unit Cost Guides

Thank You!

Brad Heavner
Policy Director
California Solar & Storage Association
brad@calssa.org

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Issue 15 -- Discussion

Issue 15 – Next Steps

GRIDWORKS

Online Collaboration Tools Update

- Online collaboration tools will be finalized and shared with the WG in early January.

Next Issues

- Issue 16 (GPI with Clean Coalition supporting)
  - Issue brief circulated no later than January 3

- Issue 23 (CESA, Honda, Nuvve, and CEC)
  - Issue brief circulated no later than January 3

Wrap Up

Next meeting:

- Dec 19 – Issue 27/28 SIWG call
- Jan 3 – WG call
- Jan 10 – In person meeting (Oakland center)
- Jan 11 - Issue 27/28 SIWG call
- Jan 16 - WG call
- Jan 23 – In person meeting (Oakland center)
- Jan 31 - Issue 27/28 SIWG call