DER INTEGRATION & COMPENSATION INITIATIVE

WEBINAR #2:
VALUATION OF AGGREGATED DER GRID SERVICES

December 18, 2023
Current and anticipated growth of distributed energy resources (DERs) and introduction of aggregated DERs into wholesale markets as a result of Order 2222 is fundamentally changing the way the grid is planned and operated.

Policy makers and regulators will increasingly need to evaluate, consider, and establish the rules and requirements as well as enabling policies and programs to bring these resources online safely and fairly to provide retail and wholesale services.

New myriad technical and economic issues will require new information and tools to make informed decisions related to the connection, technical operation, and compensation of aggregated distributed energy resources---in the distribution, bulk power system, and wholesale energy markets.
DER-I&C Initiative Description

Convene and support state members to understand the impact of their decision making related to the connection, operation, and compensation of aggregated DERs.

NARUC and NASEO will provide information, tools, access to experts, and peer sharing opportunities that assist members with FERC Order 2222 implementation in RTO/ISO regions and State oversight of transmission-distribution-customer (TDC) coordination outside of RTO/ISO regions.

Objectives:
- Inform key state decision makers
- Raise and evaluate risks and opportunities of different decision options
- Bring different perspectives to the table

Advisory Group:
An advisory group of 10 NARUC and NASEO members representing diverse regional perspectives help guide the project.
The DER I&C Initiative 2023-24 curriculum is designed around three sequential modules:

- **Module 1 – The modern landscape**
  Learn best practices & lessons from what’s being done today

- **Module 2 – Hot topics**
  Collectively explore cutting-edge applications

- **Module 3 – Deep dive**
  Advance a pressing topic through intentional collaboration
Module 1: The Modern Landscape

Learn best practices & lessons from what’s being done today

Module 1 begins with three webinars in December 2023 and January 2024:

• **Webinar 1: Aggregated DER Grid Services**, December 4, 2023
  • Moderator: Commissioner Andrew McAllister, CEC
  • Expert: Samir Succar, ICF
  • Panelist: Natalie Mims Frick, LBNL
  • Panelist: Sandra Sweet, NY DPS

• **Webinar 2: Aggregated DER Valuation**, December 18, 2023, 3:00-4:30pm ET
  • Moderator: Commissioner Andrew McAllister, CEC
  • Expert: Samir Succar, ICF
  • Panelist: Natalie Mims Frick, LBNL
  • Panelist: Sandra Sweet, NY DPS

• **Webinar 3: Compensation Options for Aggregated DER Grid Services**, January 8, 2024, 3:00-4:30pm ET
  • Moderator: Commissioner Riley Allen, VT PUC
  • Expert: Travis Kavulla, NRG
  • Panelist: Pete Polonsky, Hawaii PUC
  • Final panelist TBC.
Today’s Agenda

**Objective:** Explore different approaches to turning benefits and costs into dollar values for customers and utilities. Highlight price discovery and the comparative costs of traditional vs. ADER grid services with a focus on “How can we find out what the right prices are for ADER grid services?”

<table>
<thead>
<tr>
<th>Time (ET)</th>
<th>Agenda</th>
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<tbody>
<tr>
<td>3:00-3:10pm</td>
<td>Welcome and DER I&amp;C initiative</td>
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<tr>
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<td>Opening remarks: Moderator, Commissioner McAllister (CA)</td>
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<tr>
<td>3:10-3:35pm</td>
<td>Presentation on Valuation of ADER Grid Services:</td>
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<tr>
<td></td>
<td>Samir Succar, ICF</td>
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<td>Q&amp;A</td>
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<td>3:35-3:55pm</td>
<td>Panelists:</td>
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<td></td>
<td>Natalie Mims Frick, LBNL</td>
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<td></td>
<td>Sandra Sweet, NY Department of Public Service</td>
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<td>3:55-4:25pm</td>
<td>Moderated and audience Q&amp;A</td>
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<td>4:25-4:30pm</td>
<td>Closing</td>
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CONTACT US

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www.naruc.org/cpi-1/energy-distribution/der-integration-compensation/
Aggregated DER Valuation

NARUC-NASEO DER Integration Compensation Initiative

Samir Succar

December 2023
Key Takeaways

Objectives can guide selection of value components

Value can be localized, variable, uncertain, expanding, and evolving

Alignment between resource performance and grid needs enables value

Tradeoffs will inform the impacts of DER valuation
The Utility Industry is moving to an “orchestrated decentralization” model

From one to many

From many to many
Distributed Energy Resources (DER) deliver customer value and system value

- Local jobs
- Local resilience
- Local air quality
- Community empowerment
- Customer choice
- Reduced reliance on utility-scale resources
- Etc.
There are a lot of value components to consider

- DER Valuation methodologies account for both the locational and temporal aspects of DER value

- Value components such as emissions and societal values can vary by jurisdiction

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<th>VALUE CATEGORY</th>
<th>BENEFIT / AVOIDED COST</th>
<th>CA 2016</th>
<th>NY 2017</th>
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<td>RPS COMPLIANCE</td>
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<td>CRITERIA AIR POLLUTANTS</td>
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<td>WATER / LAND IMPACTS</td>
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<td>NON-ENERGY BENEFITS</td>
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Standardized approaches are emerging

• The National Standard Practice Manual for DER provides a comprehensive framework for cost-effectiveness assessment of DERs

• Set of policy-neutral, non-biased, and economically-sound principles, concepts, and methodologies to support single- and multi-DER benefit-cost analysis (BCA) for:
  - Energy Efficiency, Demand Response, Distributed Generation, Distributed Storage, Building Electrification and Electric Vehicles

• Advocates for the formulation of a Jurisdiction Specific Test (JST) which can include utility, host customer and societal impacts

National Standard Practice Manual - NESP
Quantifying DER Impacts - NESP
The National Standard Practice Manual provides guidance on DER value components.

### Host Customer
1. Customer Bill Savings
2. Incremental Costs
3. Interconnection Fees
4. Reliability
5. Tax Incentives
6. Non-energy impacts

### Utility System
1. Energy Generation Impacts
2. Generation, Transmission, and Distribution Capacity
3. Environmental Compliance
4. RPS/CEP Compliance
5. Ancillary Services
6. Utility Performance Incentives
7. Credit & Collection
8. Risk
9. Reliability
10. Resilience

### Societal
1. Resilience
2. Reduced Greenhouse Gas Emissions
3. Economic Development and Jobs
4. Public Health
5. Energy Security

#### Illustrative Example of NWS Cost-Effectiveness
Case Study: Commercial Grid-Interactive Efficient Building (GEB)

![Graph showing benefits and costs](image-url)
Wholesale energy and ancillary services often don’t drive the value

- Transmission tariff and capacity cost avoidance drive 90%+ of value
- Battery and EV chargers, along with existing thermal storage, are by far the most valuable resources on a $/MW basis mainly because they are not dispatch-limited and therefore can have success mitigating transmission tariffs
- Energy value is limited, and AS value is almost negligible under current assumptions
- Costly control technologies required to enable advanced AS not worth the money

→ Drivers of Value: By Service

Source: ICF value stack analysis for Midwest utility
Wholesale energy and ancillary services often don’t drive the value
Wholesale Electricity Market Revenue Forecast for Aggregated Smart Thermostats

*Data is representative of average revenue potential across various zones and/or utilities*
### Pilot Potential Value

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<th>Results</th>
<th>Traditional DR</th>
<th>FLM</th>
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<tr>
<td>Avg. kW Load Shed / Device</td>
<td>0.92</td>
<td>1.02</td>
</tr>
<tr>
<td>Avg. Dispatch Hours / Cohort</td>
<td>2.50</td>
<td>0.68</td>
</tr>
<tr>
<td>Avg. % Opt-Out / Event</td>
<td>14.0%</td>
<td>1.8%</td>
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</tbody>
</table>

**Traditional DR**
- 10 Year NPV Benefits Per Device: $631/Device

**FLM**
- 10 Year NPV Benefits Per Device: $917/Device

*45% increase in value per device over 10-year horizon*
Which value components are relevant?

State policies and community and customer needs drive planning objectives and criteria.

Source: Modern Distribution Grid Guidebook, Volume 4, June 2020
Objectives inform DER value components selection

Reliability, safety, security, affordability, resource adequacy, etc.

Resilience, decarbonization, energy storage, etc.

Equity, energy justice, customer choice and engagement, electrification

Traditional Planning Requirements

New Planning Requirements

Emerging Planning Requirements

Sources:
Opportunities to Improve Analytical Capabilities towards Comprehensive Electricity System Planning, NARUC-NASEO Working Paper
Survey of state planning objectives, Schwartz, Berkeley Lab
Changing system composition imply changes in planning

Traditional Resource Characteristics

New Resources Characteristics

Emerging Resource Characteristics

Nameplate capacity, levelized cost, outage rates, O&M costs, etc.

Hourly output, energy duration capability, flexibility

Resilience value, equity impacts, distribution system deliverability, heterogeneous aggregation RA value

Source: Opportunities to Improve Analytical Capabilities towards Comprehensive Electricity System Planning, NARUC-NASEO Working Paper
This also means that the way we define value is evolving

- New objectives -> new value definitions and metrics, and...
- Changing system composition also driving reexamination of traditional objectives
- Quantities related to system dynamics, transient stability and short circuit ratio might become more relevant in the planning context

ESIG “Redefining Resource Adequacy for Modern Power Systems”
Objectives are expanding, the system is changing, DER valuation is evolving.
Connecting DER Performance to DER Value

Example: DER Demand Reduction (Load Relief)

- Evaluated 264 measures, 16 targeted
- Residential TOU, load switch, refrigerator
- Commercial EMS, lighting, sensors
- EE was a key element of the value stack
- Targeting based on segmentation, propensity

- Value depends on performance
- Can system operators and planners depend on DER?
- Temporal and locational specificity

Source: Navigating the complexity and challenges of non-wires solutions (ICF)
Does Value Maximization Provide the Best Outcome?

Testing the Hypothesis: Aligning compensation with system value delivers the best outcomes and helps us maximize DER value to the grid and to customers.
Challenges

- Locational specificity
- Temporal variability
- Uncertainty, volatility
- Performance requirements
- Opportunity cost
- Expanding objectives
- Changing system needs
- Evolving definitions
- Variation across jurisdictions
Does it matter whether DER aggregations span multiple nodes?

Locational Marginal Pricing Nodes for MISO and PJM
Aggregations: the bigger the net, the bigger the catch
Alignment of DER Performance wrt Objectives

- Revenue Certainty for DER Developers and VPP Providers

- Low Revenue Certainty
- High Revenue Certainty

- Low Alignment
- High Alignment

- System Needs
- DER Performance
Low revenue certainty could reflect some combination of price volatility, performance risk penalties, availability requirements that preclude dual participation, deliverability risk, curtailment risk, or other source of uncertainty.

High revenue certainty means project revenues streams and cash flow over asset lifetimes are relatively predictable, uncertainties are well-understood, and risks are quantifiable.

High system value alignment indicates that DER performance requirements are well-aligned to ensure DER address grid needs, meet system planning criteria, advance objectives.

Low system value alignment indicates that DER performance requirements lack direct alignment with the needs on the grid in the relevant timeframe and/or location.
Lack of revenue certainty due to price volatility, etc. could be a barrier to project development, stifle investment, slow DER adoption.

A low degree of value alignment could result in economic inefficiencies, cost shifts, cross-subsidization.

Both are barriers to scalability at high rates of DER adoption.
How does this look in practice?

- Value maximization comes at a price
- Alignment with grid needs drives complexity and uncertainty
- The choice of tradeoffs varies across products and jurisdictions

Each bubble represents a pricing, procurement or program for DER

Note: This figure is meant to be illustrative, there is no quantitative analysis behind the location of the individual elements, but I welcome your feedback!
Key Takeaways

Objectives can guide selection of value components

Value can be localized, variable, uncertain, expanding, and evolving

Alignment between resource performance and grid needs enables value

Tradeoffs will inform the impacts of DER valuation
Additional Slides
What’s available today?

The California Emergency Load Reduction Program (ELRP) pays customers who voluntarily reduce electricity demand during a grid emergency declared by CAISO, but the frequency and duration of qualifying events is uncertain.

Real-time energy, day-ahead energy, and ancillary services markets (ASM) will have significant price volatility, particularly in the case of ASM, where market saturation introduces significant revenue risk.

The introduction of the avoided cost calculator (ACC) with NEM 3.0 added temporal and geospatial value elements that aligned closer with system impacts of solar but also reduced revenue certainty for solar projects and created further incentives to collocate solar and storage.

Pay for performance programs can better align compensation with achieved efficiency, but this also introduces revenue uncertainty and doesn’t further align reductions in load with times and locations of system constraint.

The VDER demand reduction value (DRV) is intended to provide load relief, but because it isn’t locationally-specific and not tied to a specific need, it is unlikely to directly result in deferred utility investment.

Traditional energy efficiency customer programs typically provide compensation to all resources according to deemed savings with no locational or temporal differentiation.

Feed-in tariffs (FIT) and net energy metering (NEM) as originally implemented in CA provide a great deal of certainty around project cash flow, but don’t align well with system value.

Non-Wires Solutions are designed explicitly to defer distribution investments by delivering system value, but impose performance and availability requirements that increase revenue risk and non-performance penalty risk.

Capacity market participation, e.g. in ISO-NE FCA, provides greater revenue certainty compared to energy markets and ancillary services, but typically only over a limited number of years while also imposing significant performance requirements (duration, availability), must-offer requirements with opportunity cost implications and non-performance penalty risk.

The VDER Locational System Relief Value (LSRV) varies by substation location and has limited available capacity at each location but is locked in for 10 years.

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Electricity Market Revenue Stack for Demand Response Resources

- Energy (ISO/RTO)
- Ancillary Services (ISO/RTO)
- Capacity (ISO/RTO)
- Utility Demand Response Programs
- State Incentives and Programs
Opportunity cost: Eyeing the “value stack”

Source: How to 'Stack' Your Way to a Successful NWA (ICF)
NSPM’s Widespread Regulatory Deployment

NSPM is at the bleeding edge of BCA development. Regulators are increasingly asking utilities to use NSPM for:

• Primary Cost Effectiveness Metric for DSM Portfolio
• Pilots and other Innovative Programs
• Non-Wire Solutions
• Non-Traditional DSM Investments
• Distribution-level Generation Facilities
Energy, environment, and infrastructure

Health and social programs

Consumer and financial

Safety and security

8,000 Employees
75 Global Locations
Reston, VA HQ

1,100+ Energy Professionals

$1.59B 2021 Revenue

Carbon Neutral
Since 2006

50+ Years of Energy Work

53% Female Leaders

“A” ESG Rating from the Carbon Disclosure Project

13.7 Years Average Tenure of ICF Leaders

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ICF’s broad-based energy business

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**Program Planning & Delivery**
- Energy efficiency
- Electrification
- Flexible Load Management
- Marketing & IT
- Innovative rates
- Green bank design, launch and operations
- Unregulated services

**Advisory**
- Decarbonization pathways
- Policy and program design
- Integrated resource planning
- Grid planning & modernization
- Transmission planning
- Market & technology planning
- Resiliency & vulnerability planning
- Asset valuation & management
- Project development, siting, engineering & financing
About me

Samir Succar, Ph.D.
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My work focuses on transmission-distribution coordination, DER integration/utilization, system planning, distribution system operations and DER aggregation, optimization, and coordination. As part of ongoing work with DOE OE, he has participated in the NARUC-NASEO Task Force on Comprehensive Electricity Planning, the TDC coordination initiative, the NARUC Utility Data Sharing Collaborative, Integrated Distribution Planning studies and numerous state technical assistance efforts.
Distributed Demand-Side Resources Aggregation by Utilities: Insights and Challenges from Arizona

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NARUC – NASEO Distributed Energy Resources Integration & Compensation Initiative
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DER Aggregation Example: Arizona (1)

- The Arizona Corporation Commission (ACC) directed Arizona Public Service (APS) to file a tariff for Distributed Demand-Side Resources (DDSR) Aggregation in 2020 (Decision 77855).

- The ACC required that the tariff provide compensation for multiple values provided by DDSR aggregation, including capacity, demand reduction, load shifting, locational value, voltage support, and ancillary and grid services.

- ACC requested and approved technical assistance from Berkeley Lab to support review of the tariff.

- APS issued a request for proposals (RFP) in June 2021 to inform the tariff and select an aggregator to provide grid services in 2023 (DDSR pilot).

- Berkeley Lab reviewed the draft RFP based on criteria established by the ACC and compared it with typical practices by other U.S. utilities. We identified several issues, some of which APS addressed in the final RFP.

### APS’s DER Aggregation Programs

<table>
<thead>
<tr>
<th>Program</th>
<th>Forecasted Capacity</th>
<th>Participation</th>
<th>Availability</th>
<th>Event Parameters</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cool Rewards</td>
<td>116 MW+</td>
<td>~80k t-stats</td>
<td>June 1-Sept 30</td>
<td>≤3 hours/event ≤20 events; ≤3 consecutive days</td>
</tr>
<tr>
<td>Peak Solutions</td>
<td>50MW</td>
<td>75+ C&amp;I customers</td>
<td>June 1-Sept 30</td>
<td>≤5 hours/event ≤18 events; ≤3 consecutive days</td>
</tr>
<tr>
<td>Res. Battery Pilot</td>
<td>1 MW</td>
<td>126+ res. batteries</td>
<td>Year round</td>
<td>≤4 hours/event ≤100 events/year</td>
</tr>
<tr>
<td>Energy Savings Days</td>
<td>7 MW</td>
<td>340k emails sent to res. customers</td>
<td>June 1-Sept 30</td>
<td>≤5 events Voluntary request to reduce peak usage in afternoon/evening</td>
</tr>
</tbody>
</table>
DER Aggregation Example: Arizona (2)

- APS received responses from 6 bidders (see table) and selected one aggregator to provide all three grid services with residential batteries. APS also used RFP responses to inform tariff design and define tariff issues and values.

- A Berkeley Lab expert review of APS’s cost/benefit analysis found undercounted and excluded benefits.

- For example, using a 10-year battery life, instead of APS’s proposed program term (5 years), would make most capacity bids cost-effective. And a more conventional de-rating of energy and capacity benefits would make most locational value bids cost-effective.

- Berkeley Lab’s analysis (Attachment 3) of the proposed aggregation found significant reductions in peak load for the utility system. And considering reliability and resilience benefits, 66% of Product A (capacity) customers and 50% of Product B (locational value) customers would be expected to benefit financially.

- APS discontinued the DDSR pilot program with the RFP selected aggregator (see next slide).

- Separately, the ACC rejected APS’s tariff and required the utility to issue a new RFP and DDSR Aggregation tariff (see next slide).
Some Lessons Learned

RFP
- **Keep the proposal fee modest.** (The RFP fee was $10,000; a separate fee was required for changing terms such as in-service date.) Many utilities do not require any proposal fees for RFPs seeking demand-side resources, as the effort required to submit a responsive bid is barrier enough to eliminate non-serious respondents.
- **Do not include a preference for proposals offering multiple products.** Firms that can site and install DDSR to provide capacity for seasonal peak capacity needs may not have expertise to provide ancillary and grid services. And firms that specialize in providing certain types of services may offer lower prices for them.
- **Appropriately value all benefits** and use best practices for inputs and calculations.
- For locational value, **target feeders where reducing demand has infrastructure deferral value** — e.g., where an upgrade is likely needed within 6 years. (Distribution deferral benefits were not analyzed because the targeted feeder was not constrained.)

DDSR Aggregation Pilot
- **Identify customer needs.** APS customers were interested in whole home backup over the cooling season. Such systems exceed the largest battery the aggregator offered, resulting in low participation.
- **Consider aggregator and installer infrastructure.** The aggregator did not have a significant presence in Arizona, and their largest installer went bankrupt.
- **Mitigate competition with the utility.** APS’s residential battery pilot is similar to the DDSR aggregation offer that APS selected, and the offers were marketed to customers at the same time. APS’s DDSR aggregation could have instead tested a combination of resources — e.g., demand response plus batteries.
## Wholesale Market Resources
- NASEO and NARUC, *Summary of Expert Recommendations for Supporting DER Aggregator Participation in Wholesale Markets and Operations in Line with FERC Order 2222*
- Energy Systems Integration Group, *DER Integration into Wholesale Markets and Operations*
- Advanced Energy United, *FERC Order No. 2222 Implementation: Preparing the Distribution System for DER Participation in Wholesale Markets*
- Electric Power Research Institute, *DER Aggregation Participation in Electricity Markets: EPRI Collaborative Forum Final Report and FERC Order 2222 Roadmap*
- FERC Dockets EL-16-92/ER17-996

## Retail and Mixed Wholesale/Retail Market Resources
- Berkeley Lab, *Regulation of Third-Party Aggregation in the MISO and SPP Footprints*
- Berkeley Lab, *Opportunities and Challenges to Capturing Distributed Battery Value via Retail Utility Rates and Programs*
- Berkeley Lab, *Integrated Distribution System Planning*
- Berkeley Lab, *Locational Value of Distributed Energy Resources*
- Arizona Public Service Distributed Demand-Side Resources Aggregation tariff (*Docket E-01345A-22-0143 and Docket E-01345A-19-0148*)
- *Demand Response Information Workshop*, Missouri PSC. Recording forthcoming.
Background
1997: Legislation enacted residential Net Energy Metering (NEM) for solar systems <10 kW

1997-2011: Legislature expands NEM eligibility through multiple changes in law.

2012: Legislature Authorizes Remote Net Metering (RNM) for Commercial --The “Lightbulb in the Field”

2014: NYS PSC ends “monetary” RNM crediting and implements “Volumetric” RNM

July 2015: PSC Approves Community Distributed Generation “Community Solar” which allows “Satellite” customers who cannot install DER on-site to participate in NEM

Oct. 2015: PSC Begins VDER Case to Transition from NEM to Value-Based Crediting

Mar. 2017: First VDER Order

Sept. 2017: Implemented VDER Phase One NEM and VDER Value Stack

July 2020: Phase One NEM – Customer Benefit Charge

July 2023: VDER Wholesale Value Stack per FERC Order No. 2222
Why is Net-Energy Metering Changing?

- Cost shifts to non-NEM customers became unsustainable in certain utilities & rate classes
- Public Benefit Programs\(^3\) not funded by current NEM customers... 13% - 26% of total cost shift in 2018
- NEM poorly aligned with Principles of Rate Design\(^2\) & doesn’t encourage use of the grid at beneficial times
- VDER Transition Order (2017) directs Staff to replace Phase One NEM by 1/1/2020... later extended to 1/1/2022 to allow industry to recover from COVID

Successor tariff(s) should transition to more equitable compensation frameworks w/gradual, customer-oriented transition

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1 – The Principles of Rate Design were introduced in the REV Track Two order.
2 – The non-supply Public Benefit Programs include Low- & Moderate-Income programs, Energy Efficiency and Clean Energy Programs. RECs and ZECs are excluded.
Crediting/Compensation Types

- **Monetary Crediting**
  - A utility will convert any kWh injections into the electric distribution system to a dollar value
  
  **Example:** In a monthly billing cycle, the kWh delivery rate is $0.04472. A DG customer generates 200 kWh. The customer has consumption of 100 kWh. The monetary credit that is applied to the utility bill is $4.47.
  
  \[
  \frac{0.04472}{kWh} \times 100 \text{ kWh} = 4.47 
  \]

- **Volumetric Crediting**
  - A utility will net the usage and injections and apply the Net Excess kWh’s as a direct credit to a customer’s next monthly bill with any remaining kWh credits rolling over until consumed.
  
  **Example:** In a monthly billing cycle, a DG system generates 100 kWh and consumes 50 kWh. The difference of 50 kWh will be applied to the bill and the excess will roll over to the next billing cycle.

- **VDER**
  - Phase One NEM (Volumetric)
  - VDER Value Stack (Monetary)
  - VDER Wholesale Value Stack (Monetary)
VDER - Value Stack
NEM vs. VDER Value Stack Components

- **Avoided Distribution Value** – Includes demand reduction value (DRV) & locational system relief value (LSRV)
- **E** – environmental benefit
- **Capacity** – ICAP
- **LBMP** – energy commodity

*Note – reflects NEM and Phase One NEM compensation levels*
VDER Value Stack Phases

- **Value Stack Phase One:**
  - Applies to:
    - Customers that, on or prior to July 26, 2018, have paid at least 25 percent of their interconnection costs or executed the interconnection agreement if no such payment is required; and,
    - Customers that have met criteria (1) and had opted into the Value Stack Tariff prior to June 1, 2019.

- **Value Stack Phase Two:**
  - Modifications were made to Capacity Component Alternatives 1 and 2
  - Applies to:
    - Customers that, on or after July 27, 2018, have paid at least 25 percent of their interconnection costs or executed the interconnection agreement if no such payment is required; and,
    - Customers who opt into the Value Stack Tariff on or after June 1, 2019 subject to the next paragraph.
The PSC approved the implementation of the Wholesale Value Stack beginning on July 1, 2023.

Utilities propose to implement a Wholesale Value Stack for DER customers to opt in and sell energy and capacity in the wholesale market directly to the New York State Independent System Operator (NYISO) while preventing duplicate compensation from the retail and wholesale markets.

Customers who elect to export to the NYISO will also take service under each utilities’ Wholesale Distribution Service tariff to be filed with FERC.
Appendix
Resources for New York State DER

- Standard Interconnection Requirements Addendum
  - https://dps.ny.gov/distributed-generation-information

- New York State Utility Electric Tariffs
  - https://dps.ny.gov/electric-tariffs

- New York State Energy Research and Development Authority
  - https://www.nyserda.ny.gov/All-Programs/NY-Sun/Contractors/Value-of-Distributed-Energy-Resources/Solar-Value-Stack-Calculator
• 2002 – added anaerobic digester (farm waste) electric generators up to 400 kW.
• 2004 – added wind generators up to 25 kW for residential and 125 kW for residential/farm customers.
• 2008 – increased residential solar to 25kW, added non-residential solar and wind up to the lesser of 2 MW or customer’s prior 12-month historical peak billing demand, and increased farm waste digesters and residential/farm wind generators to 500 kW.
• 2009 – added residential micro-turbine CHP and fuel cell installations up to 10 kW and 1.5 MW for non-residential.
• 2012 – the size of micro-hydroelectric generating systems was increased up to 25 kW for residential customers.
• 2014 – size of fuel cells increased from 1.5 MW to 2 MW and farm waste increased from 500 kW to 1 MW.
Thank you for joining today!

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Upcoming:

- **Webinar:** Compensation Options for ADER Services, Jan 8, 2024, 3-4:30pm ET
- **In-Person:** Integrated Distribution System Planning & Resilience Training, Jan 24-25, 2024 in Irvine, CA [state agencies only]

www.naruc.org/about-naruc/event-calendar/western-dspr-training/

www.naruc.org/cpi-1/energy-distribution/der-integration-compensation/