IPA Integrated Resource Planning Workshop #3: Customer Cost Impacts Methodology

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Question 1

How should "commercial" versus "industrial" customer classes be defined for purposes of reporting customer cost impacts?

AIC recommends that E3 define "commercial" and "industrial" customer classes using existing utility tariff and cost-of-service classifications as the primary basis, with a transparent crosswalk into the three IRP reporting categories: residential, commercial, and industrial. From AIC's perspective, each delivery service point has its own designated NAICS code, meaning true commercial or industrial customers could show up anywhere between DS-2 through DS-6. However, the company recognizes that for this study some simplification may be necessary. This would generally mean mapping DS-1 Residential Delivery Service to the residential class; DS-2 Small General Delivery Service and DS-3 General Delivery Service to the commercial class; and DS-4 Large General Delivery Service to the industrial / large-load class. DS-5 Lighting should either be mapped to commercial / public-sector load or separately disclosed if material, while DS-6 Temperature Sensitive Delivery Service should be mapped as Industrial. Any data center large loads should be characterized as industrial. The load forecast provided by AIC includes these delivery service designations. Commercial: Non-residential customers served under small or general delivery service tariffs, including AIC DS-2 and DS-3 customers. These generally include offices, retail, health care, education, public-sector, hospitality, warehousing, and other general business or institutional loads. Although DS-5 is often called out separately, it would be better characterized as commercial in most cases (e.g., town lighting) rather than industrial, if necessary. Industrial: Non-residential customers served under large general delivery, large power, primary, high-voltage, special contract, or industrial tariffs, including AIC DS-4 and DS-6 customers. These generally include manufacturing, processing, data centers, and other large-load or high-load-factor customers whose usage and cost-causation profiles differ materially from general commercial customers. The aforementioned approach is consistent with how customer cost impacts are typically reported in IRP and rate impact analyses, where broad residential / commercial / industrial categories are built from existing rate classes and cost-of-service studies rather than standalone sector labels. It also aligns with E3's stated plan to use recent ComEd and Ameren rate cases and

EIA data as the starting cost-of-service inputs, and to develop allocation factors using metrics such as energy shares, class contribution to system peak, and non-coincident peaks. AIC also recommends that E3 separately disclose or sensitivity-test very large loads, especially data centers, rather than allowing them to distort the broader industrial average. E3 indicated in the workshop Q&A that data centers are currently planned to be included in the industrial class, with separate incremental load shapes across data center scenarios.

Question 2

If "commercial" and "industrial" are defined using load thresholds, what threshold(s) do you recommend and why?

If E3 uses load thresholds, AIC recommends that they be used as a secondary tool to support tariff / COSS mapping, not as the sole basis for defining customer classes. A practical framework would be: Commercial: Non-residential customers below 1,000 kW of maximum monthly demand. This includes DS-2 Small General Delivery Service customers below 150 kW and DS-3 General Delivery Service customers from 150 kW to below 1,000 kW. Industrial: Non-residential customers at or above 1,000 kW of maximum monthly demand. This aligns with DS-4 Large General Delivery Service, which captures customers at or above the 1,000 kW threshold. Large-load sensitivity: Customers above approximately 10 MW, including data centers or very large industrial facilities. The 10 MW threshold should be used for a separate large-load sensitivity because very large customers can materially affect capacity, transmission, distribution, and average rate results. This is particularly important because E3's class average rates are normalized across total class costs and total kWh, which may obscure demand-driven cost impacts for large loads such as data centers.

Question 3

For the stakeholder group(s) that you are representing in the IRP process, what are you hoping to learn from the cost impact analysis specific to the customer group you are interested in?

For the customer segments of interest, the cost impact analysis should help explain how IRP scenarios translate from system-level planning into customer-facing rate, affordability, and cost-allocation impacts. As both an electric and gas utility, AIC's role is to provide load forecasts, plan and operate the delivery system, and help ensure customers understand and can absorb the cost impacts of different IRP pathways. While AIC is not responsible for generation procurement, future resource planning decisions still materially affect AIC customers through supply cost exposure, transmission and distribution investment needs, and the timing and allocation of rate impacts. Since E3 plans to conduct full customer cost analysis only for a subset of scenarios, the analysis should provide enough transparency to understand the major drivers of customer cost impacts, affordability risks, and planning tradeoffs across customer classes. AIC seeks to understand the following focus areas: Class-level rate and affordability impacts: Clarify how each scenario affects residential, commercial, and industrial customers, including which classes experience the greatest average rate pressure and why. This should include not only $/kWh impacts, but also enough

supporting detail to discern whether residential and small commercial customers face disproportionate affordability impacts relative to large commercial or industrial customers. Cost drivers and allocation methodology: Identify which components are driving customer cost impacts, including supply, capacity, REC / policy costs, transmission, distribution, and program fees. The analysis should also clarify how these costs are allocated across classes, including the use of energy shares, system peak contribution, and non-coincident peak contribution, because different allocation assumptions could materially change reported customer impacts. To reiterate comments provided during the workshop, cost drivers such as customer-side requirements (e.g., heat pump equipment) and program fees need to be included in non-flat and nominal terms to fully reflect the cost of scenarios such as those under high electrification conditions. Resource strategy and market reliance: Identify what resources the model is relying on to meet Illinois customer needs, including the balance between in-state build, imports, and market purchases from PJM / MISO. This should clarify which least-cost resources the system is designed around, how much Illinois depends on external capacity or energy, and what that means for reliability, transmission needs, resource adequacy, customer price exposure, and long-term planning flexibility. Large-load and electrification impacts: Assess how data centers, large industrial customers, and electrification-driven load growth affect capacity needs, transmission and distribution investment, and class average rates. Since these loads may have materially different load shapes and cost-causation profiles, the analysis should show whether they are increasing costs for their own class or shifting costs to broader residential, commercial, or industrial customers. Customer-side resources and planning implications: Evaluate how VPPs, DERs, demand response, storage, and other customer-side assets are treated, especially where costs may not be fully reflected in PLEXOS outputs. The analysis should help identify what planning, rate design, or customer program tools may be needed to maintain reliability and affordability under different IRP pathways.

Question 4

E3 proposes to estimate the future delivery revenue requirement by starting with the current delivery revenue requirement and applying a growth rate based on historical authorized revenue requirement increases over the past 10 years, along with modeled additions for new transmission and distribution investments. Do you believe this is a reasonable approach for projections?

Yes, but should be adjusted

Question 5

If "Yes, but should be adjusted" or "No" was selected in the previous question, what adjustment is most appropriate?

Align growth rate with recent multi-year rate plans (e.g., using recent approved increases as a forward-looking proxy)

Question 6

If "Use a different historical window" was selected in the previous question, what lookback period should be used to estimate the growth rate and why?

N/A

Question 7

Energy burden is defined as the percentage of a household's annual income spent on household energy bills. What baseline would be most useful for examining energy burden in the IRP (e.g., historical, business-as-usual, etc.)?

AIC recommends using a business-as-usual baseline as the primary benchmark for energy burden, with historical energy burden used as supporting context. A BAU baseline is most useful because it shows how each IRP scenario changes affordability relative to the trajectory customers would otherwise face, including expected changes in utility costs, usage, income, and load growth. Historical data should be used to identify existing affordability challenges and high-burden communities. Generally speaking, census-tract level income could be used as the baseline to compare the expected utility bills against – Of course there are unique differences in housing stock, etc. but the relative percentage of energy burden will be indicatively correct across regions and relative customer classes. E3 should also clearly identify the new sources of energy burden created by each scenario, including whether customer impacts are driven by electric supply costs, delivery investments, program fees, electrification-related load growth, or other cost categories. At the same time, E3 should distinguish gross bill increases from net customer wallet impacts wherein electrification changes what customers pay for. For example, vehicle electrification may increase electric bills, but it can also reduce or replace household fuel or gasoline spending; if the analysis counts only the incremental electric bill impact without identifying displaced fuel expenditures, it may overstate the net affordability impact on participating households. The anticipated tie-in with transportation electrification is likely the largest and most critical customer-wallet shift to consider in the energy burden analysis. Where feasible, E3 should also examine total household energy burden, including both gas and electric bills, because a customer's affordability experience may not be accurately captured through electric bills alone.

Question 8

Are there data sources available at the community or census-tract level in Illinois that should inform how EJ and equity investment eligible communities are identified and characterized?

Yes. E3 should use the Equity Investment Eligible Community (EIEC) Map as the primary Illinois-specific designation tool for identifying equity investment eligible communities. The EIEC Map relies on Restore, Reinvest, and Renew (R3) Program Area designations and Illinois Solar for All (ILSFA) Environmental Justice Community (EJC) designations. The ILSFA team uses updated U.S. Census data and U.S. EPA EJScreen data to update EJC designations every five years, with the next planned update in 2028. E3 should supplement this designation source with DOE LEAD estimates

to characterize energy burden, income, fuel type, housing type, and renter / owner characteristics within those communities. For IRP purposes, E3 should use these datasets not only to identify whether a community qualifies as EJ or EIEC, but also to characterize the underlying drivers of vulnerability, such as income, pollution exposure, housing type, renter status, and historical underinvestment. This would allow customer cost and energy burden results to be segmented in a more meaningful way than statewide averages alone.

Question 9

What are the most significant barriers to participation in existing programs for EJ and/or equity investment eligible communities, e.g. upfront costs, eligibility restrictions, lack of information, or structural factors like renter status?

The most significant barriers to participation in existing programs for EJ and equity investment eligible communities often reflect a combination of financial, structural, and administrative constraints. Financial barriers remain among the most significant. Even where incentives are available, customers may not be able to pay the remaining project cost, wait for reimbursement, or finance enabling upgrades such as electrical panels, weatherization, or health and safety repairs. As a result, participation in EJ and equity investment eligible communities may require higher incentive levels, upfront incentives, or direct-install / turnkey delivery models. Structural barriers are also significant, particularly renter status, multifamily housing, and split incentives. Many customers in EJ and equity investment eligible communities may not have authority to approve building-level improvements, while landlords may have limited incentive to invest if tenants receive the bill savings. Older housing stock and deferred maintenance can further limit participation unless enabling repairs are funded. Administrative and outreach barriers can also reduce participation. Eligibility rules, documentation requirements, landlord consent requirements, contractor availability, language access, and lack of trusted outreach can all prevent participation even when customers are technically eligible. For purposes of the IRP cost impact analysis, E3 should not assume that customer-side program adoption can be achieved without reflecting the incremental programmatic costs needed to overcome these barriers. If scenarios rely on higher participation from EJ or equity investment eligible communities, the analysis should capture associated increases in subsidies, outreach, administration, enabling upgrades, contractor support, and direct-install program costs. Keeping program fees or surcharges flat in real terms across scenarios will likely understate customer cost impacts where additional program investment is necessary to achieve modeled adoption levels.