Entergy

Entergy Services, Inc.
639 Loyola Avenue (70113)
P.O. Box 61000
New Orleans, LA 70161-1000
Tel 504 576 4122
Fax 504 576 5579

Michael J. Plaisance
Senior Counsel
Legal Services - Regulatory

May 3, 2018

Via Hand Delivery
Ms. Terri Lemoine Bordelon
Louisiana Public Service Commission
Records and Recording Division
Galvez Building, 12th Floor
602 North 5th Street
Baton Rouge, LA 70802

RE: **2017 Integrated Resource Planning ("IRP") Process for Entergy Louisiana, LLC Pursuant to the General Order No. R-30021, Dated April 20, 2012**
LPSC Docket No. I-34694

Dear Ms. Bordelon:

I have enclosed an original and three copies of Entergy Louisiana, LLC's Responses to IRP Stakeholder Questions raised during the April 19, 2018 Stakeholder Meeting and Updated DSM Potential Study presented by ICF in connection with the referenced matter. Please file an original and two copies into the record, and return a date-stamped copy to our by hand courier.

Should you have any questions regarding the enclosed document, please do not hesitate to contact me.

Sincerely,

Michael J. Plaisance

MJP/
Enclosure

cc: Official Service List (via electronic mail)

LPSC DOCKET NO. I-34694
ELL 2019 INTEGRATED RESOURCE PLAN

ELL'S RESPONSES TO APRIL 19, 2018
INFORMAL STAKEHOLDER QUESTIONS

During the April 19, 2018 Integrated Resource Plan ("IRP") stakeholder meeting ("Stakeholder Meeting"), a number of stakeholders posed questions to Entergy Louisiana, LLC ("ELL") and its consultant, ICF. ELL hereby provides responses to those questions that were not fully answered at the Stakeholder Meeting or otherwise merit further response:[1]

1. ELL was asked which, if any, planned Midcontinent Independent System Operator, Inc. ("MISO") Transmission Expansion Plan ("MTEP") projects were included in ELL's IRP modeling. ELL's IRP modeling in the AURORA model uses a simplified zonal construct in which separate zones are modeled for the South (which includes Louisiana, Texas, Mississippi, and Arkansas), Central, and North regions of MISO. Transmission limitations are represented by the transfer capability between these zones, and no transmission limitations are modeled within each zone. The transfer limit between MISO South and MISO North/Central is based on a contractual agreement and is held constant throughout the IRP study period.

2. Stakeholders requested an explanation for the shape of the historical load curve on slide 8 of ELL's presentation. As part of ELL's load forecasting process, historical load data is "weather normalized." In other words, ELL's historical load data is adjusted to a "normal" level based on whether the actual temperatures were higher or lower than normal. All of the loads shown on slide 8 (historical and forecasted peaks) are weather-normalized. August 2014 was a milder month than normal, and August 2015 was a significantly warmer month than normal. In the process of weather-normalizing those periods, the 2014 peak was adjusted upward, and the 2015 peak was adjusted downward, causing the dip shown in the chart on Slide 8. For reference, the actual peaks for 2014 and 2015 were 9.3 GW and 10.1 GW, respectively.

3. ELL was asked what factors contribute to ELL's projected load growth. ELL's peak and total load is forecasted to increase over time primarily due to increases in consumption from large industrial customers. Increasing load is also supported by expected increases in the numbers of residential and commercial customers but offset by expected decreases in average kWh usage for these residential and commercial customers.

4. A stakeholder asked if ELL's peak load data on slide 8 of ELL's presentation is the sum of the expected individual maximum load values of the various customer classes (*e.g.*, commercial, residential, industrial) or the maximum load value of all customer classes

[1] Because the Stakeholder Meeting was not transcribed, it is possible that the ELL did not capture all of the unanswered questions raised during the meeting.

combined. ELL responds that the peak load data (both forecasted and actual) is the maximum value of the total load for all of the customer classes taken as a whole.

5. A stakeholder asked if ELL's resource planning was done separately for the individual customer classes. ELL's resource planning decisions are generally based on ELL's total load from all customer classes. There are no explicit capacity requirements by class. Overall long-term capacity requirements are determined by adding a 12% installed capacity reserve margin to ELL's forecasted non-coincident peak load (for all customer classes in total). However, ELL has certain planning targets for types of capacity (*e.g.*, baseload, peaking, etc.) based on its customers' collective hourly load shape. If ELL had a different mix of industrial, commercial, and residential customers, then the resulting hourly load shape could result in different resource targets for ELL.

6. The Company notes that electric vehicle penetration was factored into the load forecast, the assumptions for the volumes of which in the near-term are very conservative.

7. The Company was asked to provide its deactivation assumptions by resource. Unit-specific deactivation assumptions are market sensitive information, and disclosure of such information to the market could negatively impact ELL and its customers. Aggregated annual deactivation assumptions are the greatest level of detail required to produce the supply deficit curves for the long-term supply need graphic on slide 9 of ELL's Data Assumptions presentation covered at the Stakeholder Meeting. Instead, ELL provides the aggregated annual deactivations in the table below.

Table 1 - 2019 ELL IRP Supply Resource Deactivation Assumptions (Total MW by Year)

2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
0	11	0	46	0	0	0	401	13	12

2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
508	149	928	1,154	1,754	0	798	0	0	0

Notes:
1- MW values represent ELL's ownership share of the installed capacity ("ICAP") of resources owned by ELL, based on the GVTC ratings effective for the 2018-2019 MISO Planning Year.
2- Deactivation assumptions are planning inputs based on age, criticality, reliability, and unit condition (both current and projected). These deactivation planning assumptions do not represent a deactivation schedule and are subject to change based on changes in unit condition, market condition, or economics.

8. During ICF's DSM Potential Study presentation, ICF was asked to provide assumptions behind time of use ("TOU") rate designs and direct load control ("DLC") measure and cost-effectiveness results for its Energy Efficiency and Demand Response program tests. ICF has provided an updated presentation that includes this information. The Company has attached this updated presentation, which has also been added to the Company's IRP website.

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2019 ELL IRP – DSM Potential Study

Approach and forecast

Entergy®

April 19, 2018

Presentation Team

Ali Bozorgi

Project Manager Deputy

Peter Lemoine

Project Manager

David Pudleiner

Engineering and Modeling Lead

Energy Efficiency

- Approach
- Forecast

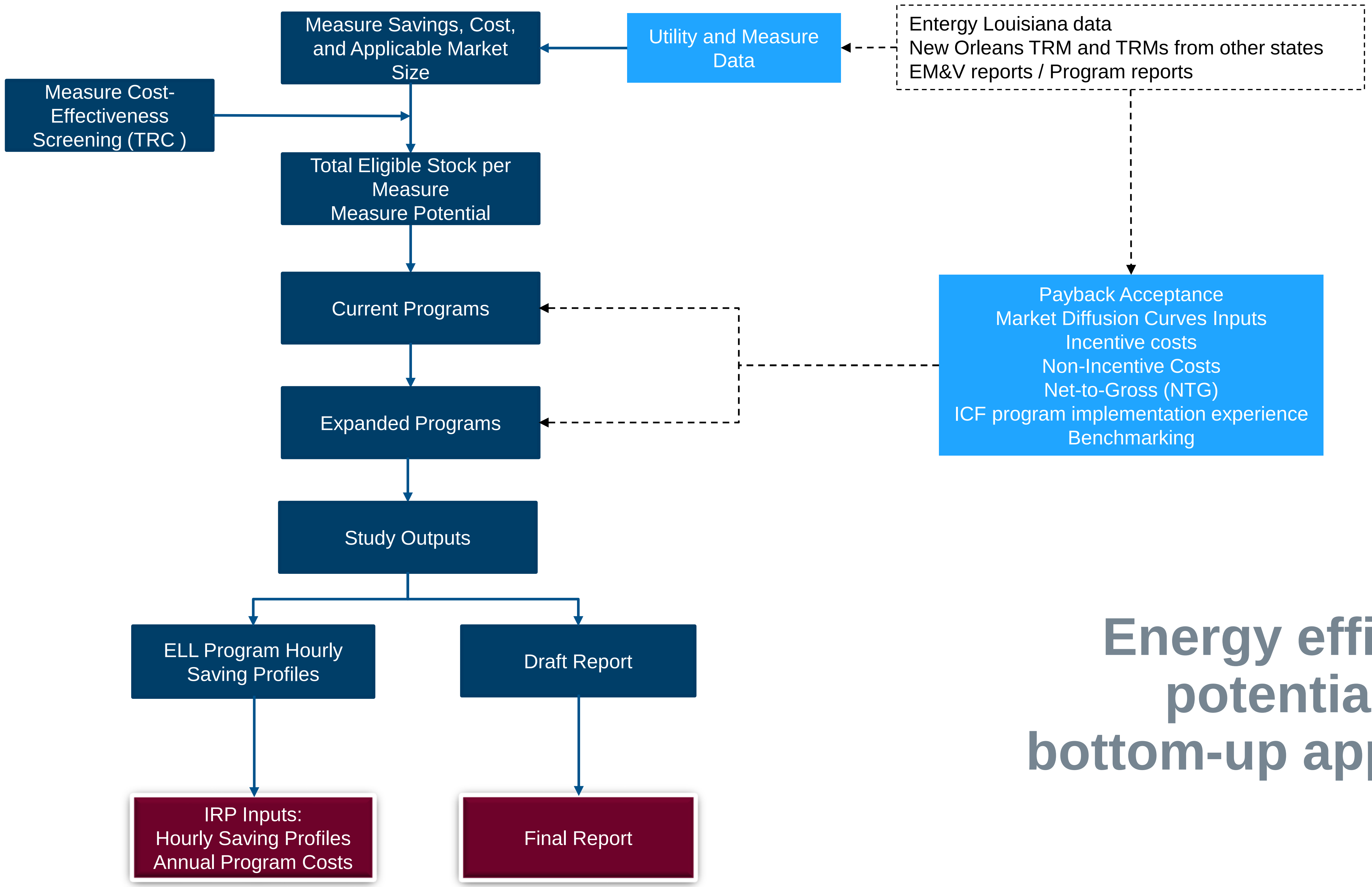
Demand Response

- Approach
- Forecast

Agenda

Energy Efficiency

Energy efficiency potential study bottom-up approach



Energy efficiency scenarios modelled

- **Current programs –** Current ELL programs were modelled largely based on current program designs, but with expanded budgets.

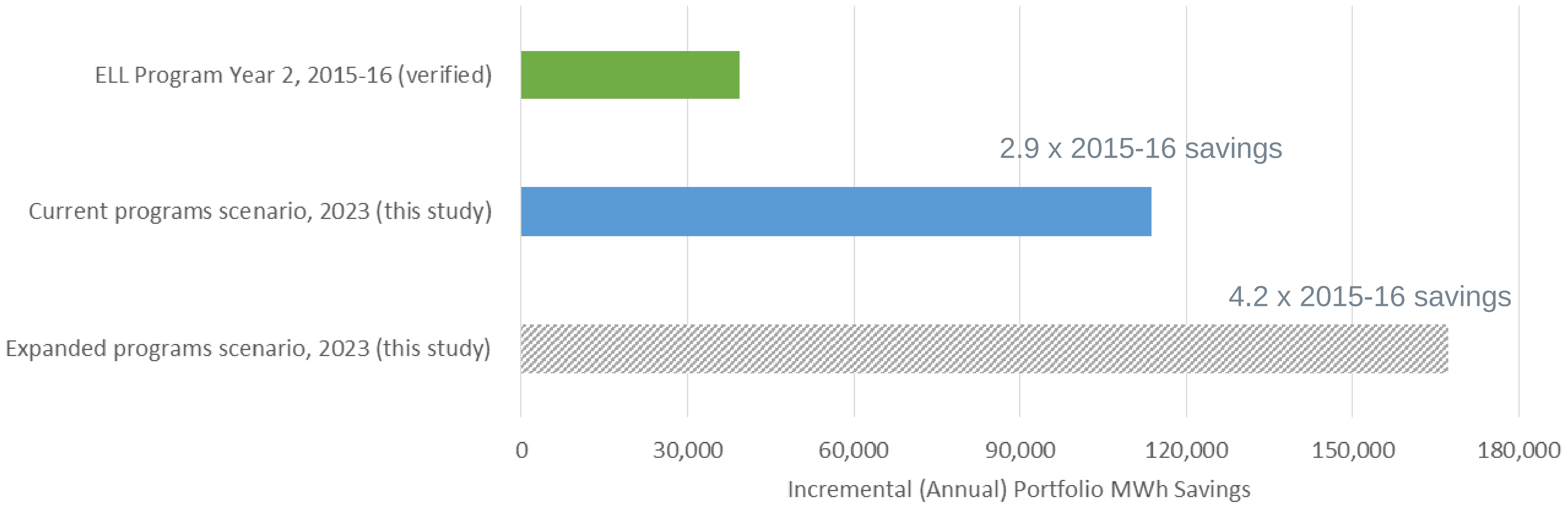
- **Expanded programs –** Includes current programs plus new best practice programs.

Programs modelled

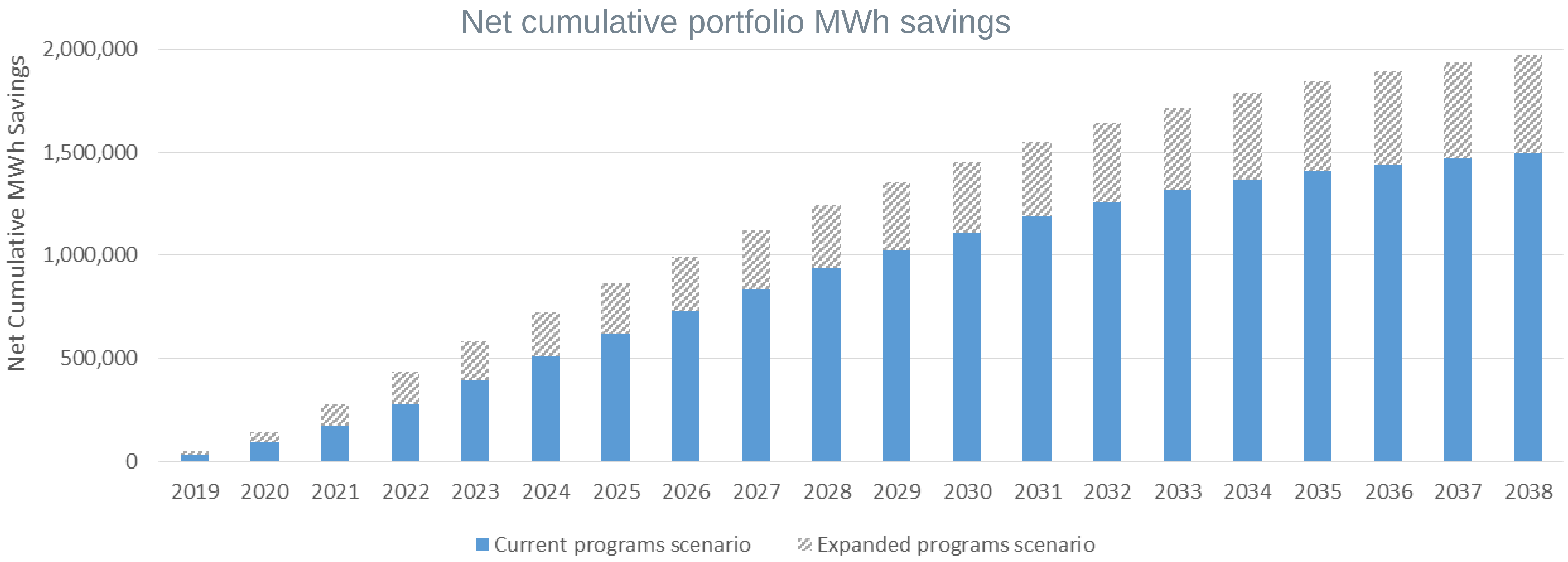
Current Programs	Expanded (New) Programs
• Lighting, Appliances and Electronics • Residential HVAC and Tune-up • Home Audit and Retrofit • Low Income Weatherization • Commercial Prescriptive and Custom • Small Business Solutions • Industrial Prescriptive and Custom	• ENERGY STAR New Homes • Appliances Recycling • Home Energy Use Benchmarking • Midstream Commercial Lighting • Commercial RetroCommissioning • Commercial New Construction • Industrial Strategic Energy Management

Annual savings could quadruple by 2023

Incremental (annual) MWh savings in ELL Program Year 2 (2015-16) (verified) and as forecasted for this study for 2023

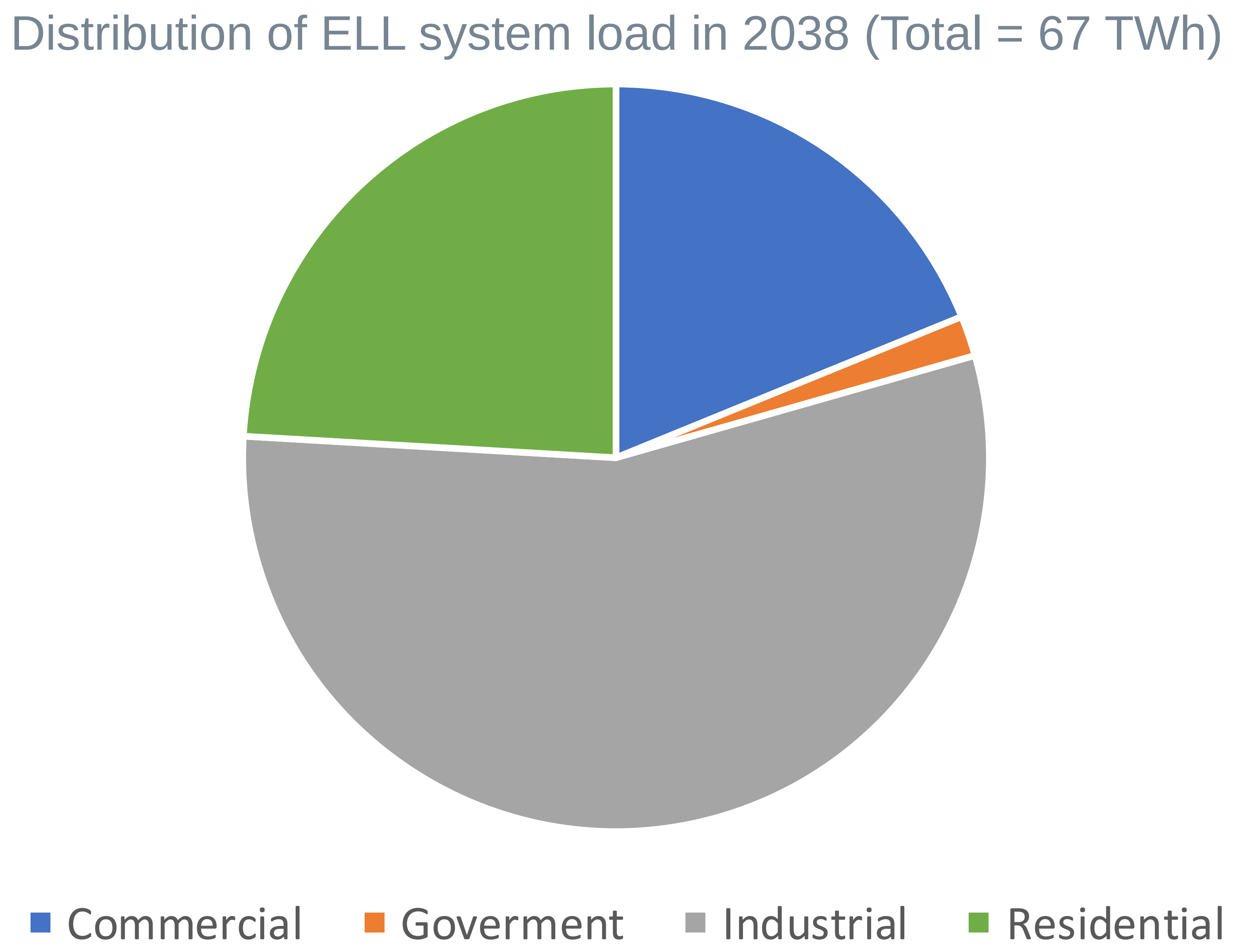


Total (cumulative) savings could grow from ~50 GWh in 2019 to nearly 2,000 GWh by 2038

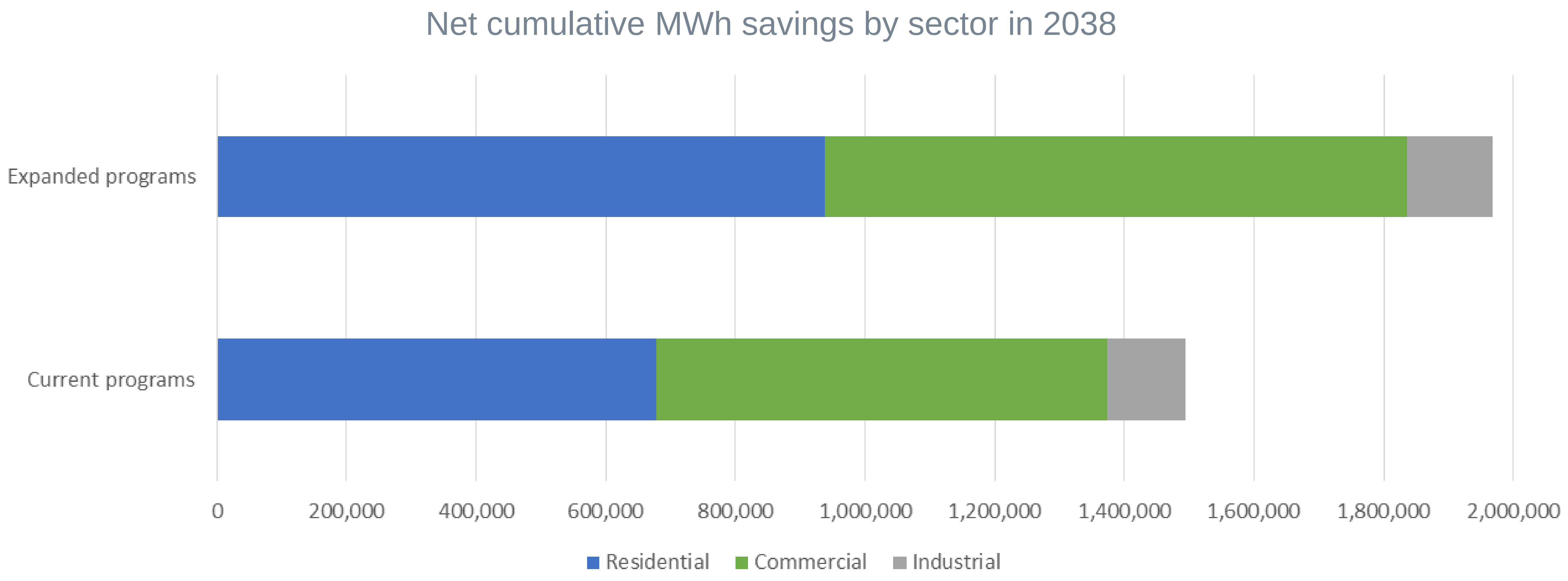


Industry is forecasted to account for 55% of load by 2038

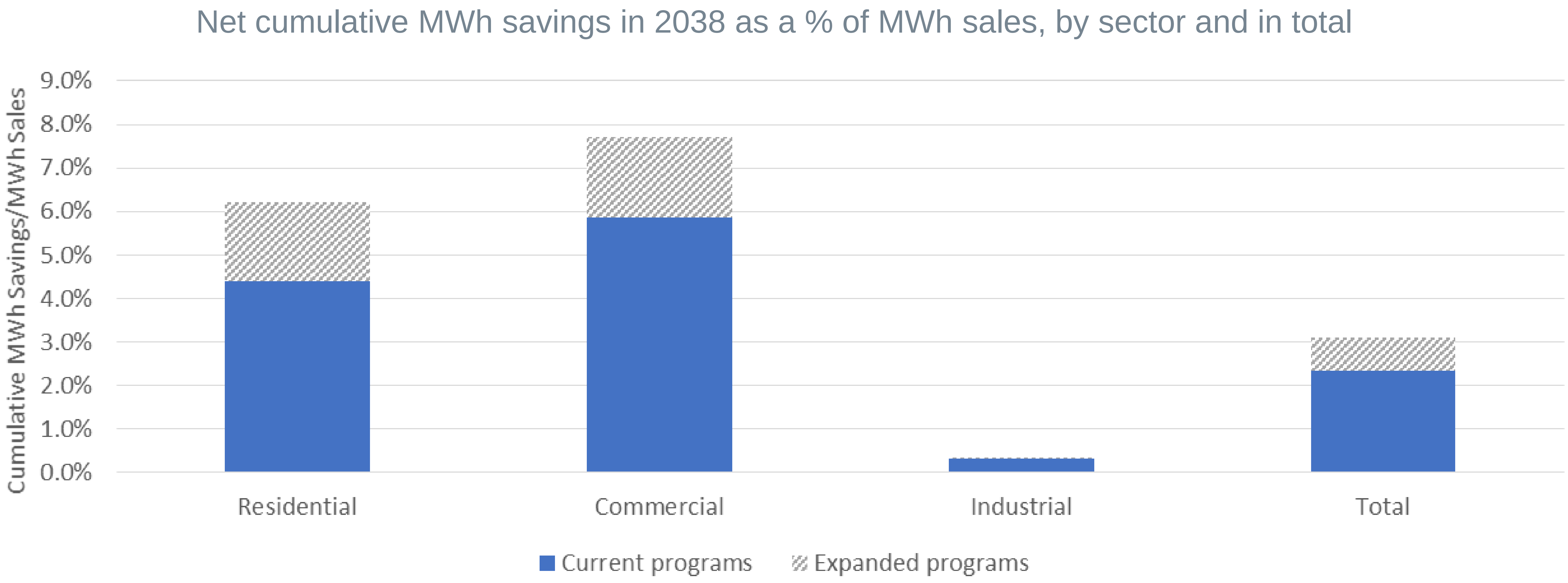
A small fraction of industrial load is for end uses that are facility-related and not used for processes



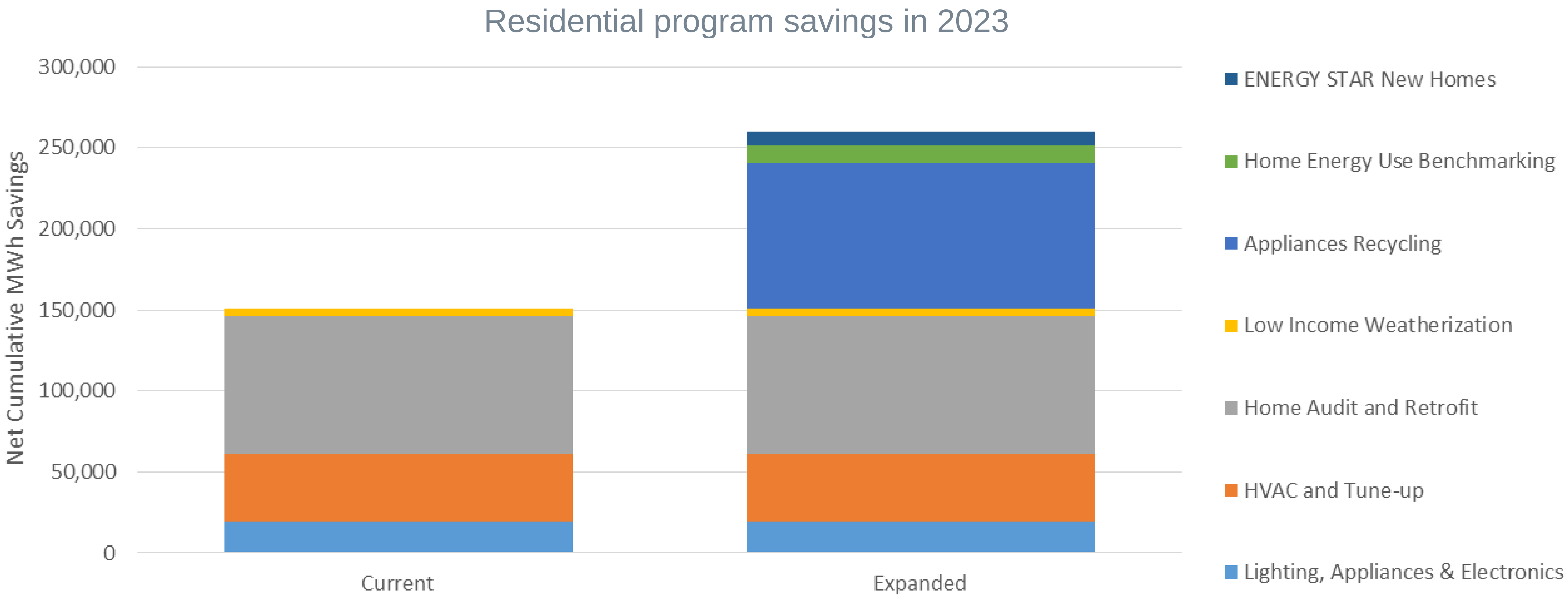
In the Expanded scenario residential and commercial sector level savings are about equal and together comprise 90% of total savings



Residential and commerical savings levels could reach up to 6.2% and 7.7% of sector sales, respectively, by 2038



Whole home efficiency retrofits will replace lighting as the biggest residential savings opportunity – new programs could increase sector savings by two-thirds



Note: Duct sealing is included in the HVAC and Tune-up program and in New Homes. Air sealing is included in Home Audit and Retrofit and in New Homes. Insulation is in the Home Audit and Retrofit program and in New Homes.

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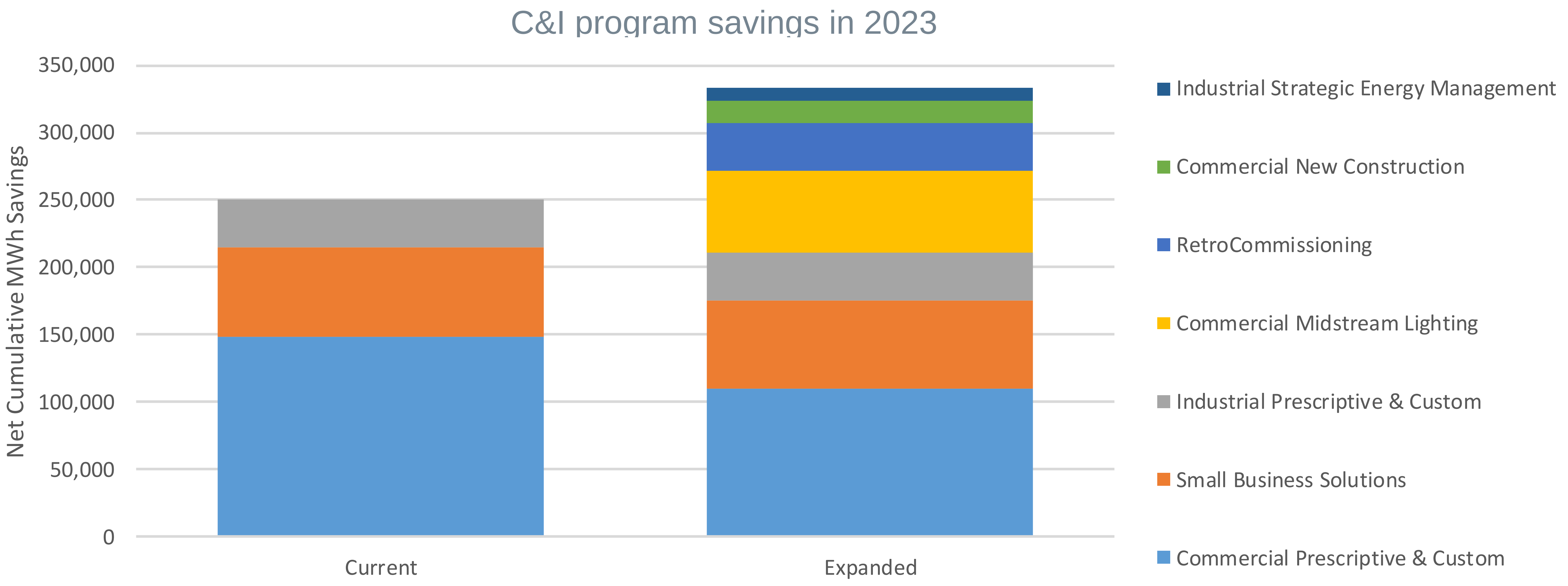
Expanded programs could increase C&I savings by a third



Note: Commercial Prescriptive & Custom savings are lower in the Expanded scenario because non-fixture lighting measures from that program were moved to the Midstream Lighting program for this scenario.

Cost and cost-effectiveness metrics

Program	Annual Program Costs (2018 $ mil)				Levelized $ / kWh	TRC Test
	2023	2028	2033	2038		
Lighting, Appliances and Electronics	$ 1.0	$ 0.9	$ 0.9	$ 1.0	$ 0.04	1.7
HVAC and Tune-up	$ 1.8	$ 1.8	$ 1.8	$ 1.8	$ 0.01	4.0
Home Audit and Retrofit	$ 8.0	$ 8.1	$ 7.9	$ 7.7	$ 0.03	2.9
Low Income Weatherization	$ 0.6	$ 0.7	$ 0.7	$ 0.7	$ 0.07	1.9
Total Residential Programs – Current	**$ 11.4**	**$ 11.5**	**$ 11.3**	**$ 11.2**	**$ 0.03**	**3.0**
ENERGY STAR New Homes	$ 0.4	$ 1.6	$ 1.7	$ 1.7	$ 0.01	4.2
Appliances Recycling	$ 2.3	$ 1.7	$ 1.9	$ 2.0	$ 0.03	1.9
Home Energy Use Benchmarking	$ 0.4	$ 0.1	$ 0.2	$ 0.3	$ 0.02	5.1
Grand Total Residential Programs – Expanded + Current	**$ 14.5**	**$ 15.0**	**$ 15.0**	**$ 15.2**	**$ 0.02**	**3.0**

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Cost and cost-effectiveness metrics

Program	Annual Program Costs (2018 $ mil)				Levelized $ / kWh	TRC Test
	2023	2028	2033	2038		
Small Business Solutions	$ 3.2	$ 2.7	$ 2.3	$ 2.4	$ 0.02	2.2
Current Commercial Prescriptive & Custom	$ 13.5	$ 13.0	$ 12.9	$ 12.9	$ 0.04	1.8
Total Commercial Programs - Current	**$ 16.6**	**$ 15.7**	**$ 15.2**	**$ 15.3**	**$ 0.03**	**1.9**
RetroCommissioning	$ 0.3	$ 0.3	$ 0.3	$ 0.3	$ 0.01	3.6
Commercial New Construction	$ 0.7	$ 0.8	$ 0.8	$ 0.8	$ 0.01	2.3
Commercial Prescriptive & Custom	$ 8.4	$ 8.7	$ 8.4	$ 8.4	$ 0.03	2.3
Midstream Commercial Lighting	$ 7.0	$ 6.2	$ 6.2	$ 6.3	$ 0.06	1.1
Grand Total Commercial Programs – Expanded + Current	**$ 19.6**	**$ 18.7**	**$ 18.1**	**$ 18.3**	**$ 0.03**	**1.9**
Industrial Prescriptive & Custom	$ 2.0	$ 2.0	$ 1.9	$ 1.8	$ 0.03	3.2
Industrial Programs - Current	**$ 2.0**	**$ 2.0**	**$ 1.9**	**$ 1.8**	**$ 0.03**	**3.2**
Industrial Strategic Energy Management	$ 0.6	$ 0.5	$ 0.5	$ 0.4	$ 0.03	3.3
Grand Total Industrial Programs – Expanded + Current	**$ 2.6**	**$ 2.5**	**$ 2.3**	**$ 2.3**	**$ 0.03**	**3.2**
Portfolio Total - Current	**$ 30.0**	**$ 29.2**	**$ 28.3**	**$ 28.3**	**$ 0.03**	**2.3**
Portfolio Total - Expanded	**$ 36.7**	**$ 36.2**	**$ 35.5**	**$ 35.7**	**$ 0.03**	**2.4**

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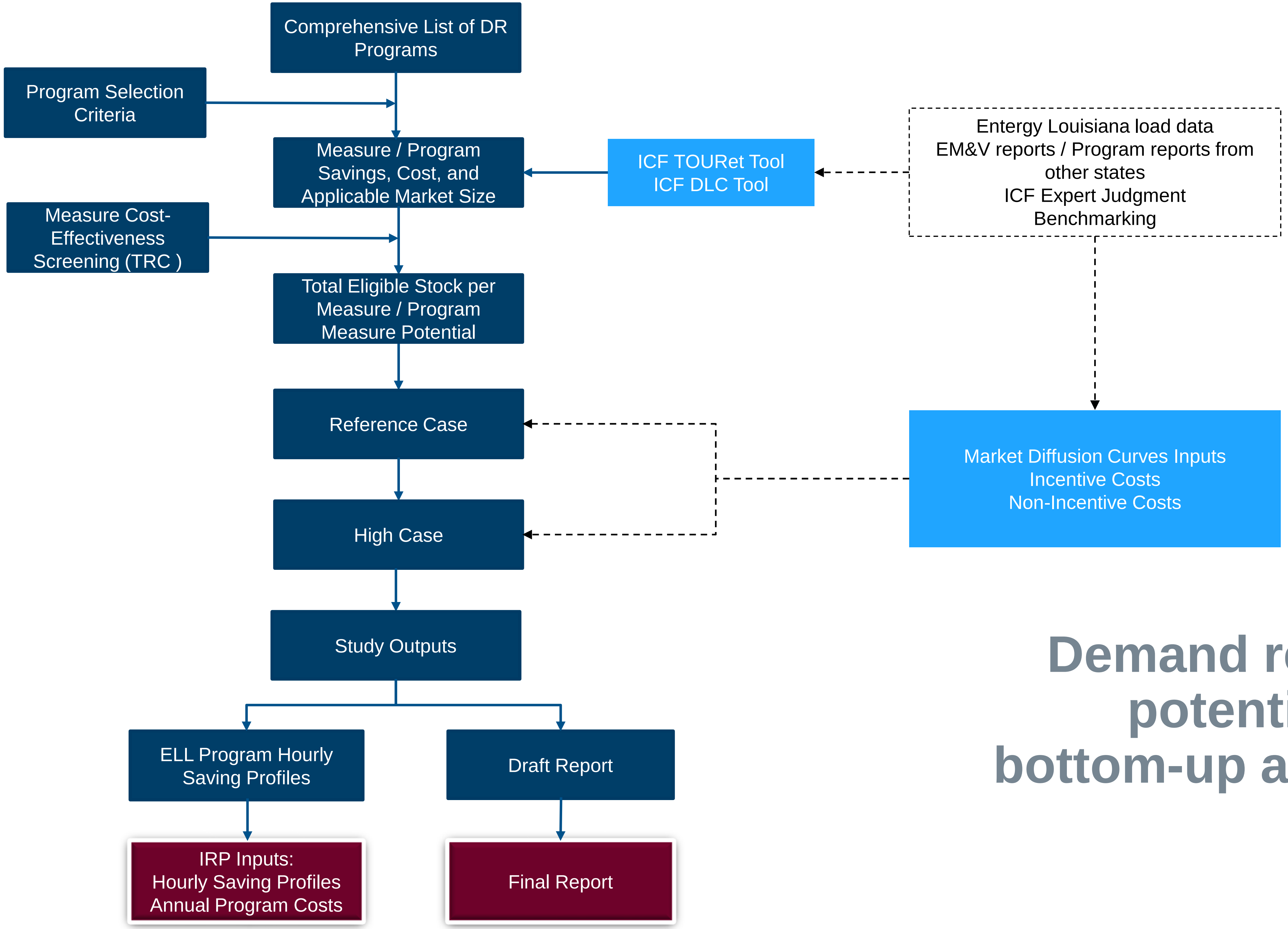
Demand Response (DR)

Demand response potential study bottom-up approach



Different DR program types were initially assessed

Dispatchable / Load Response	Rate-based / Price Response
Direct Load Control	Time-of-use pricing
Interruptible Load	Critical peak pricing
Curtailable Load	Real-time pricing
Automated DR	

Dispatchable - utility offers customers payments for reduction of demand during specified periods

Rate-based - customers voluntarily reduce their demand in response to forward energy price signals

Program selection for ELL based on

- ELL hourly load profile – historic and forecasted (e.g. excluded CPP)
- Availability of data from programs across US, and
- Availability of required technologies for program implementation (e.g. excluded ADR and RTP)

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5 DR programs (and 9 DLC measures) were selected to be modeled for this study

Selected Programs to Model	Class
Time-of-Use	Residential
	Commercial
	Industrial
Direct Load Control	Residential
	Commercial

Class	Measure
Residential	Room AC Switch
	Central AC Switch
	Smart Thermostat
	Water Heater Switch
	Smart Appliances
	Battery Storage
Commercial	Central AC Switch
	Water Heater Switch
	Smart Thermostat

Time-of-Use Rate Evaluation Tool (ToURET) – uses elasticity values and pricing assumptions to model consumer behavior in the form of energy shifts from peak to off-peak and consumption reductions within the same period

Direct Load Control Tool – uses historic and program information to quantify the impact of measures during the DR event period, and account for rebound or snap-back for the periods immediately following the DR event

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7 DLC measures out of 9 DLC measures were included in achievable potential

Class	Measure
Residential	Room AC Switch
	Central AC Switch
	Smart Thermostat
	Water Heater Switch
	Smart Appliances
	Battery Storage
Commercial	Central AC Switch
	Water Heater Switch
	Smart Thermostat

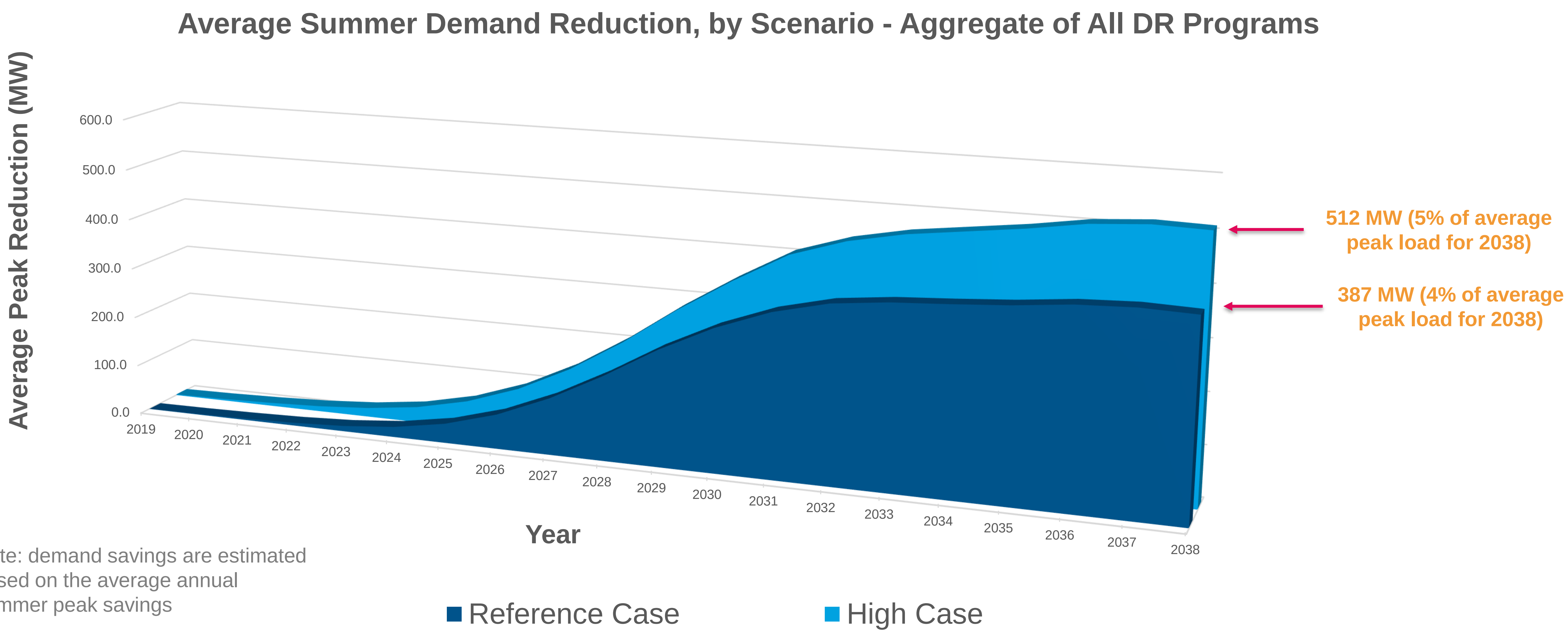
Cost-effectiveness screening (TRC)

Class	Measure
Residential	Room AC Switch
	Central AC Switch
	Smart Thermostat
	Water Heater Switch
Commercial	Central AC Switch
	Water Heater Switch
	Smart Thermostat

2 scenarios were developed for each program, Reference and High

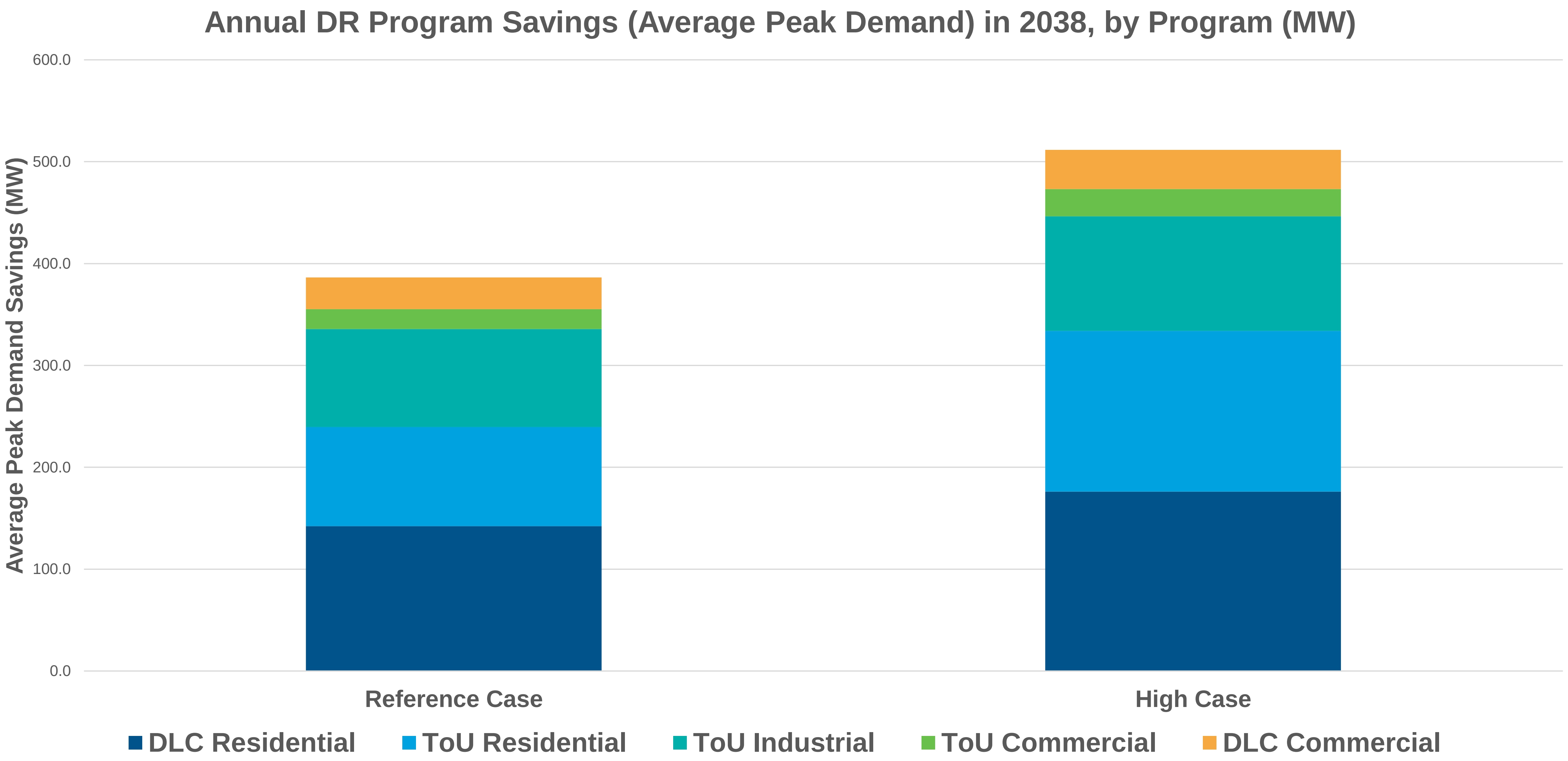
- For Time-of-Use
  - High and Reference cases were created to reflect different levels of pricing signals, specifically peak-to-off-peak price ratios and corresponding price elasticity assumptions
- For DLC
  - Adoption rates and maximum achievable participation varied for the high and reference cases

DR Programs can reduce the peak load in 2038 by 4% to 5%



Note: demand savings are estimated based on the average annual summer peak savings

Residential TOU, Residential DLC and Industrial TOU account for 85%+ of total DR potential in both cases



Note: demand savings are estimated based on the average annual summer peak savings

Residential costs dominate the total annual costs of implementing the DR programs

Reference Case	Cost of Implementation in $ mil			
Sector	**2023**	**2028**	**2033**	**2038**
Residential	$ 0.8	$ 7.8	$ 7.8	$ 7.3
Commercial	$ 0.3	$ 1.8	$ 1.6	$ 1.5
Industrial	$ 0.1	$ 0.3	$ 0.6	$ 0.6
Total	$ 1.2	$ 9.9	$ 9.9	$ 9.3

High Case	Cost of Implementation in $ mil			
Sector	**2023**	**2028**	**2033**	**2038**
Residential	$ 1.2	$ 7.5	$ 10.3	$ 9.4
Commercial	$ 0.4	$ 1.7	$ 2.1	$ 1.8
Industrial	$ 0.1	$ 0.3	$ 0.6	$ 0.7
Total	$ 1.7	$ 9.5	$ 13.0	$ 11.9

Cost and cost-effectiveness metrics

Program Type	Sector	Levelized Costs ($/kW)		TRC Test (Cost-Benefit Ratio)	
		Reference Case	High Case	Reference Case	High Case
Residential DLC	Residential	$76	$77	2.5	2.4
Residential ToU	Residential	$7	$7	13.1	15.1
	Residential Subtotal	$48	$42	3.7	4.1
Commercial DLC	Commercial	$97	$93	1.4	1.5
Commercial ToU	Commercial	$18	$14	5.6	7.1
	Commercial Subtotal	$67	$59	2.0	2.2
Industrial ToU	Industrial	$8	$7	13.1	13.8
	Industrial Subtotal	$8	$7	13.1	13.8
	All DLC	$80	$80	2.2	2.2
	All ToU	$8	$7	11.7	13.2
	Total DR Portfolio	$40	$37	3.9	4.3


Thank you!
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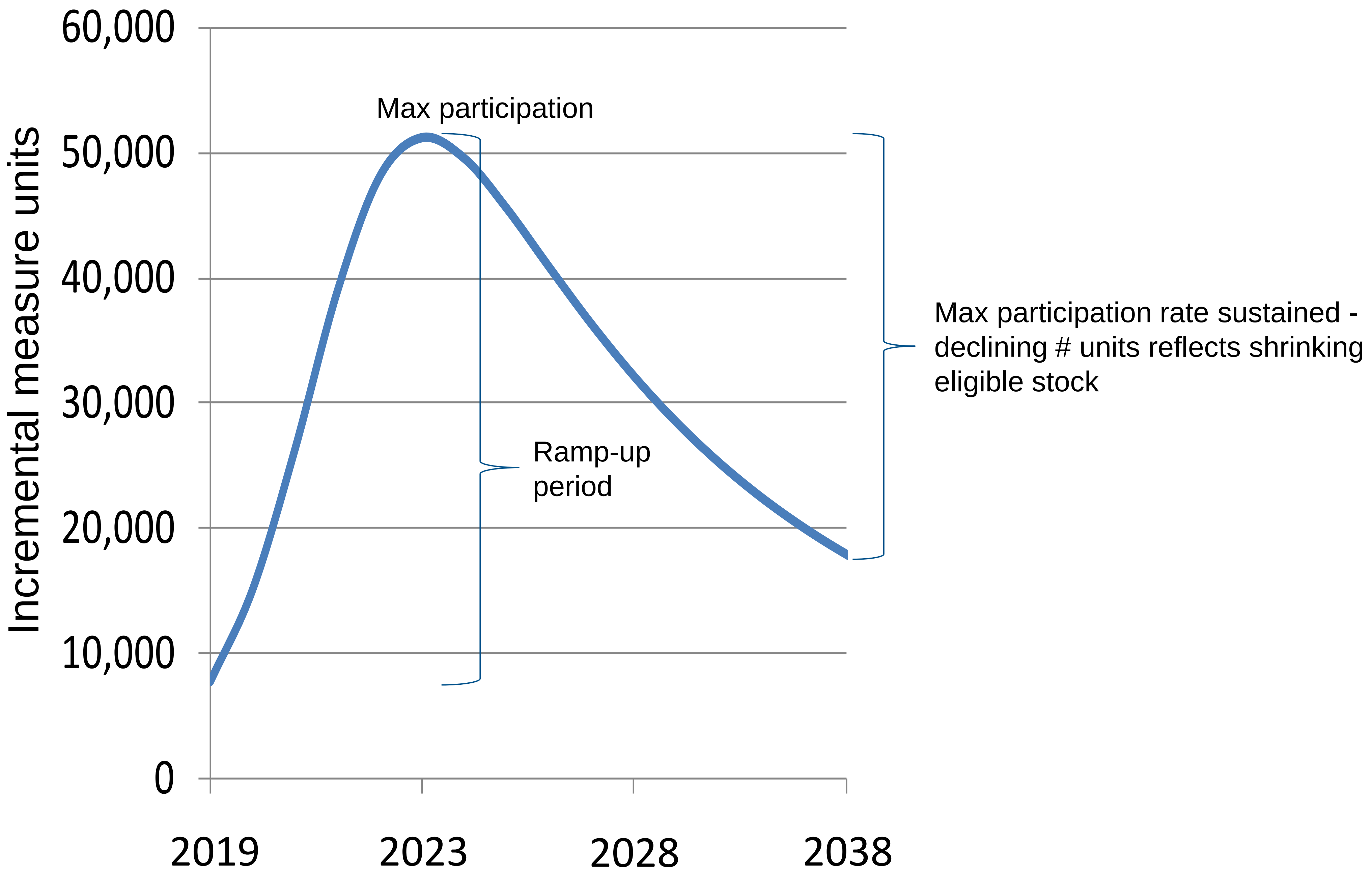
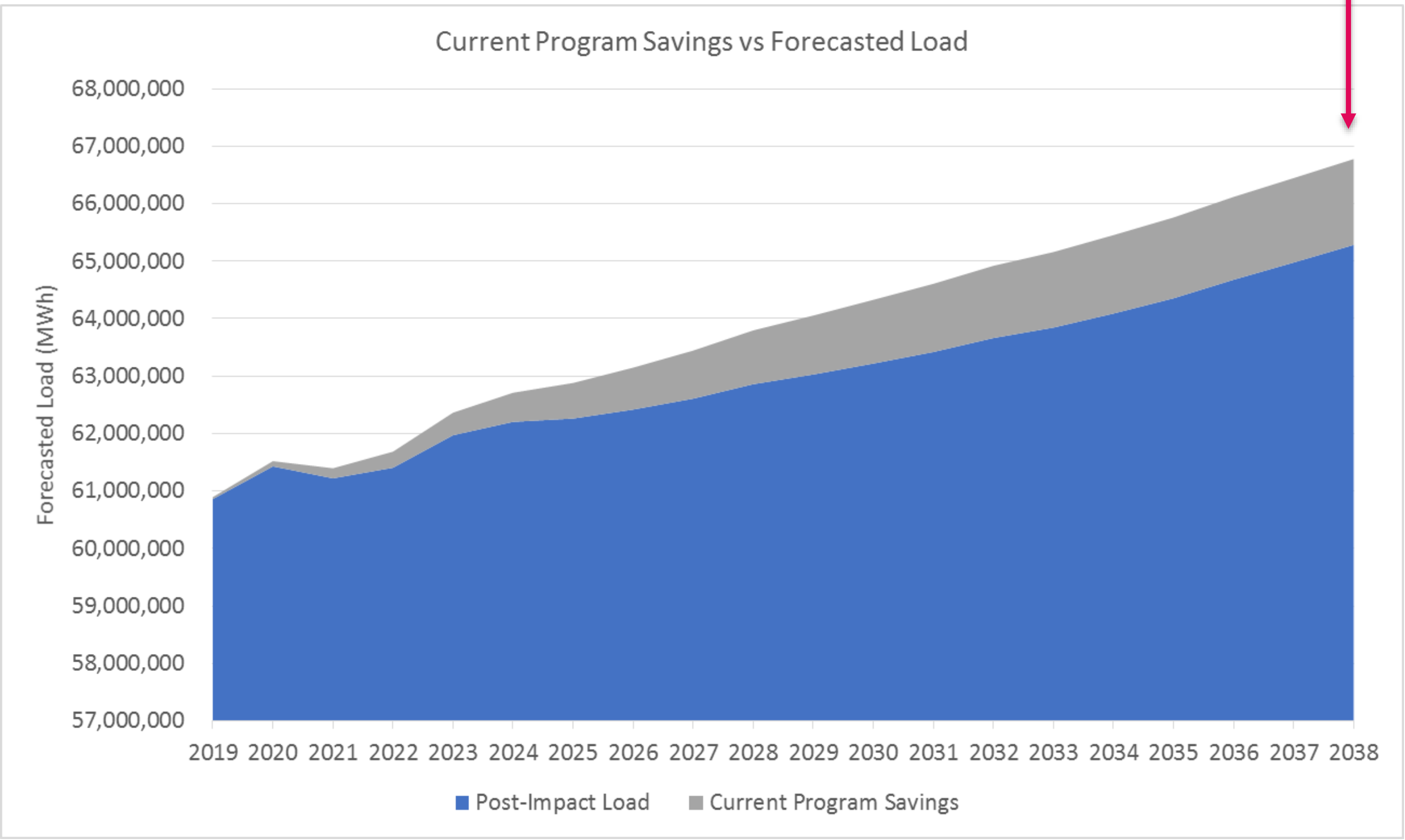
Appendix

Illustrative measure market adoption curve

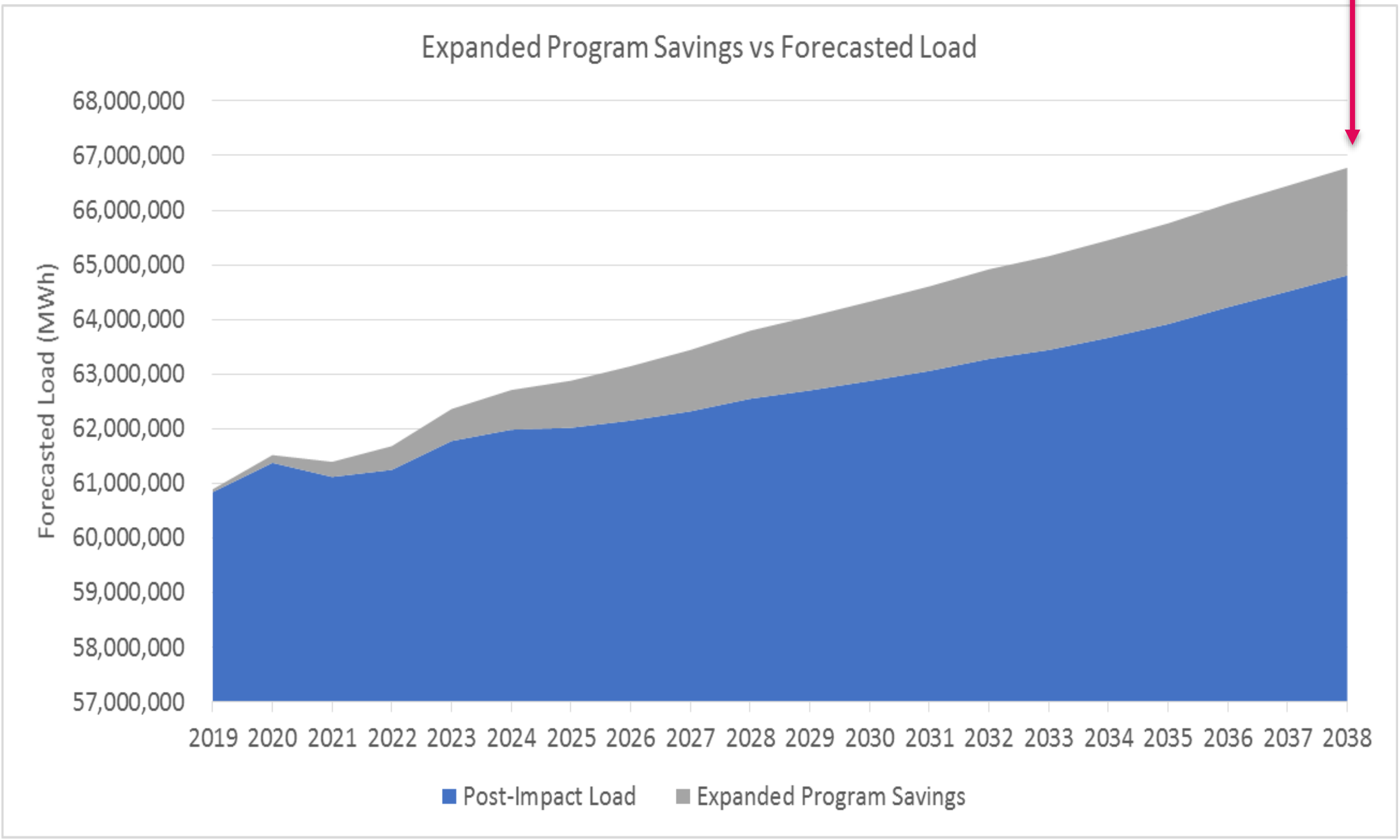


Energy efficiency programs could offset up to a third of load growth

~24% load growth offset by EE programs by 2038



~33% load growth offset by EE programs by 2038

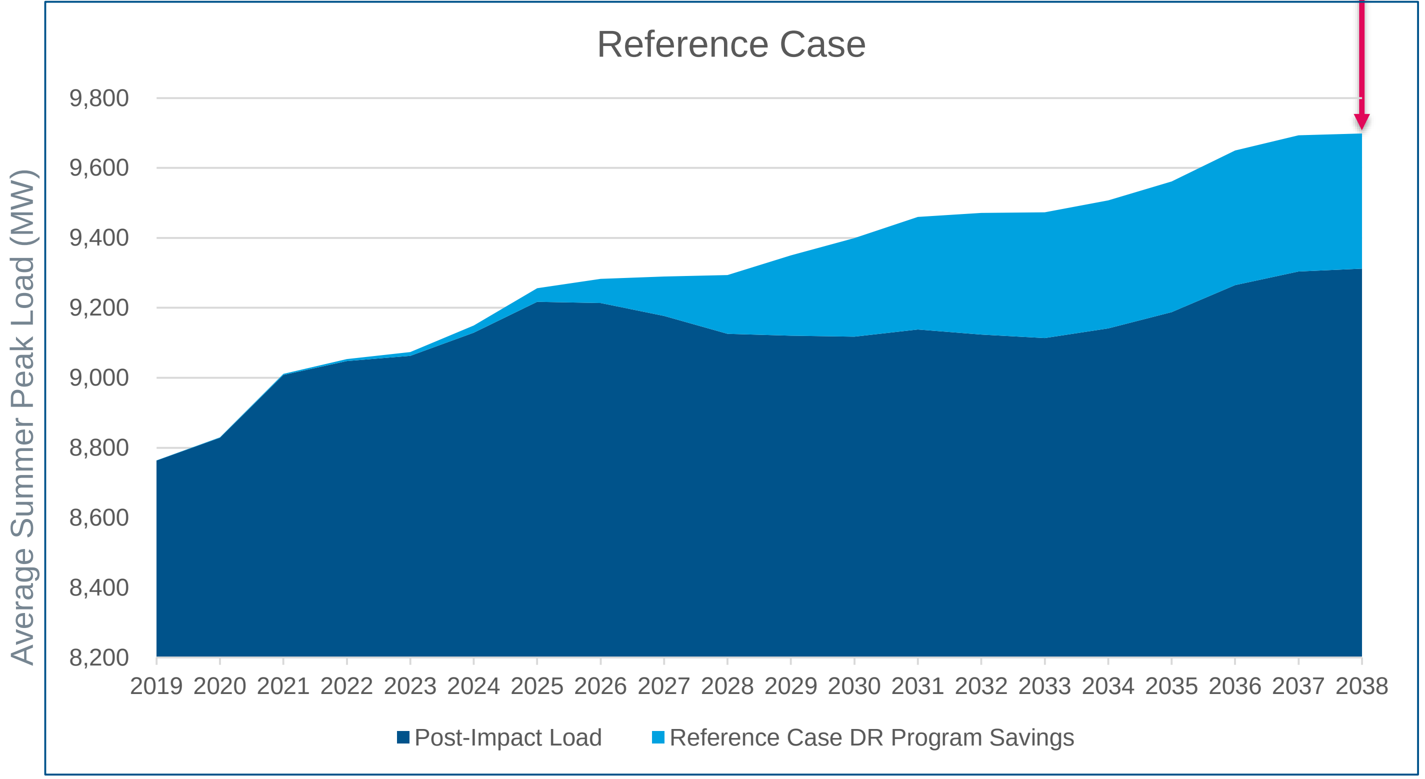


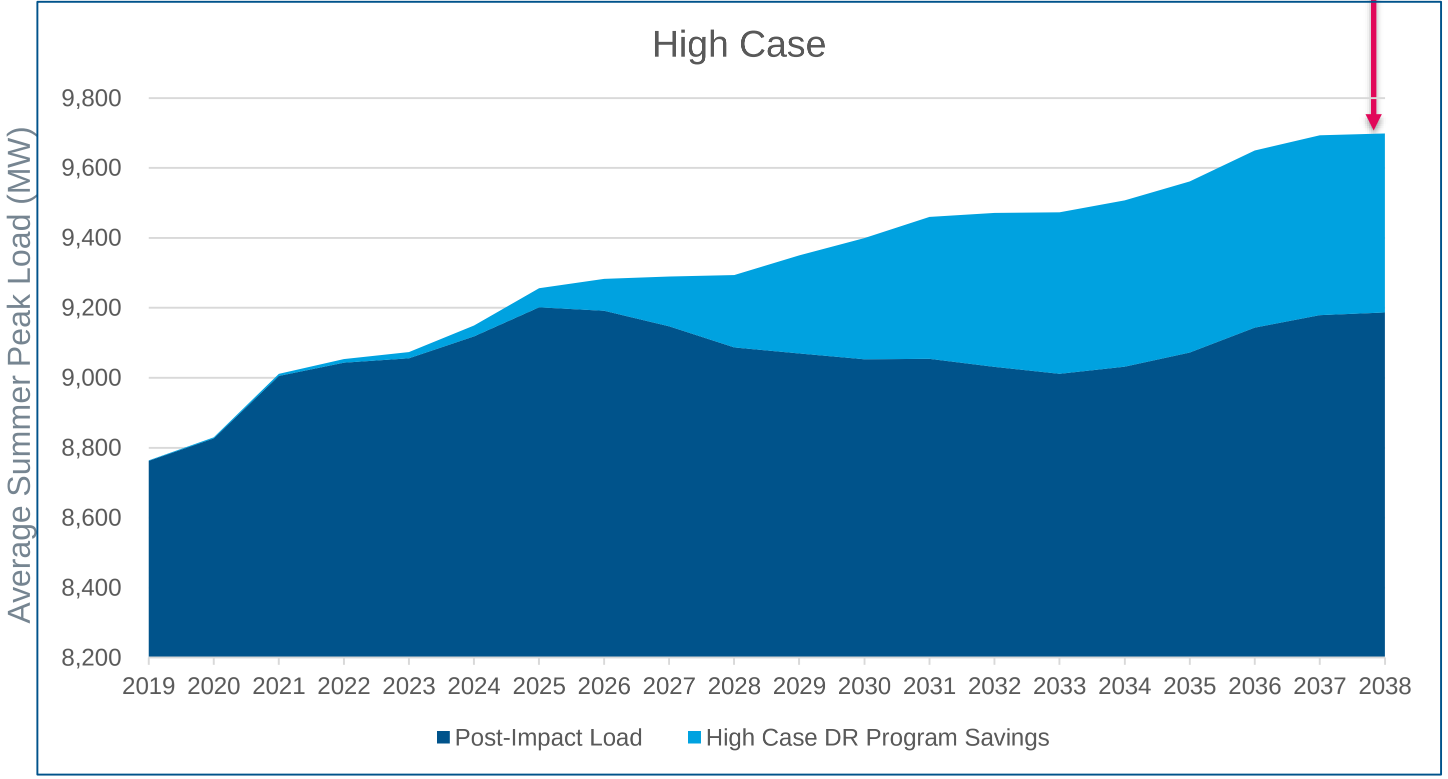
Energy consumption (MWh) grows by 10% from 2019 to 2038.

DR programs could offset a major portion of ELL average summer peak demand growth by 2038 – up to 41% in the reference case and 55% in the high case

41% of average peak demand growth offset by DR programs by 2038

55% of average peak demand growth offset by DR programs by 2038

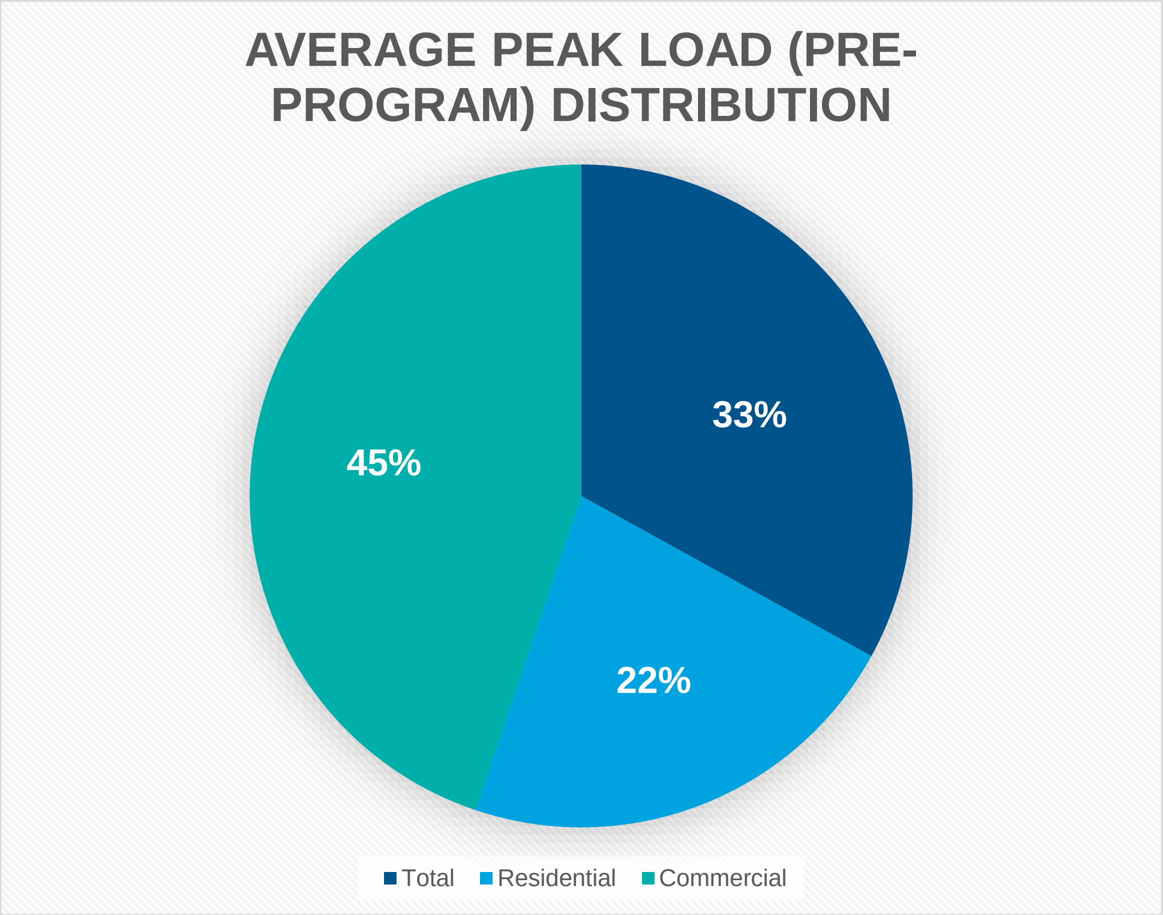


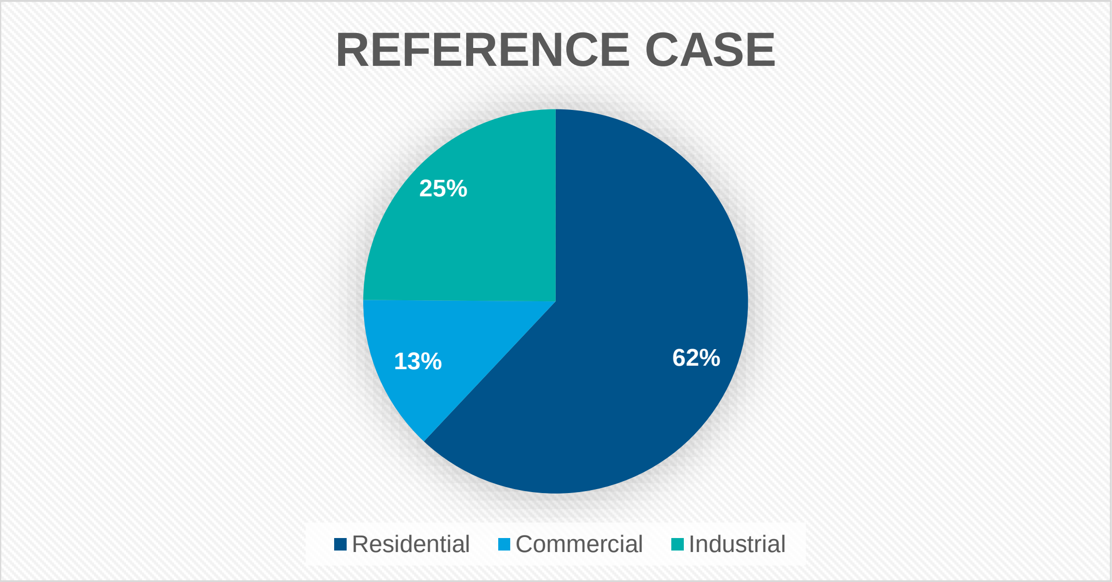


Average Summer Peak Load (MW) grows by 11% from 2019 to 2038.

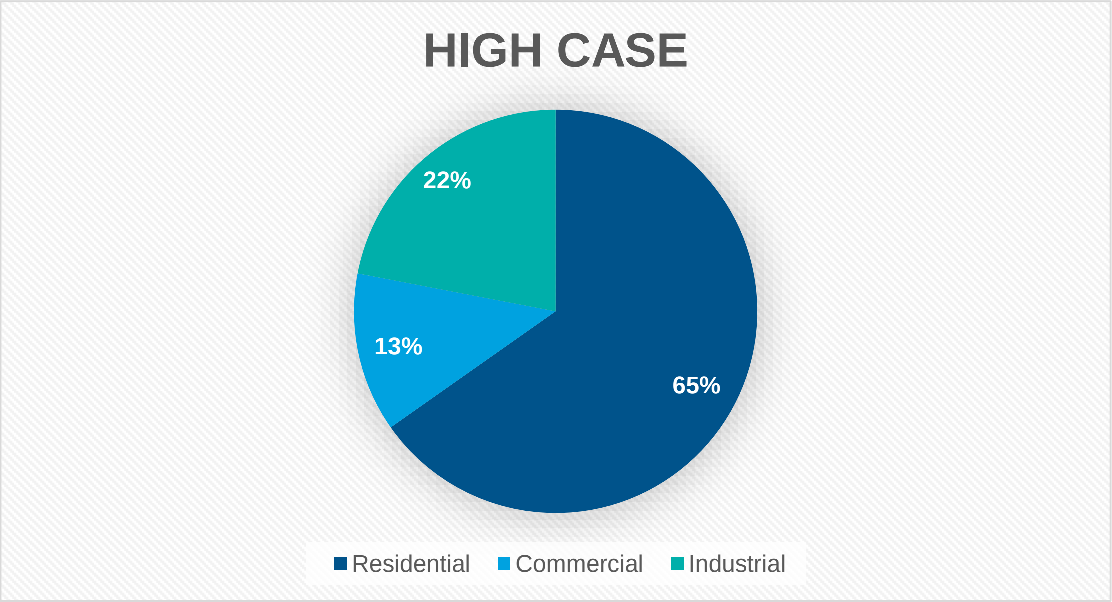
Note: Demand savings are estimated based on the average annual summer peak savings.

The residential sector has the largest peak load reduction potential for the DR programs





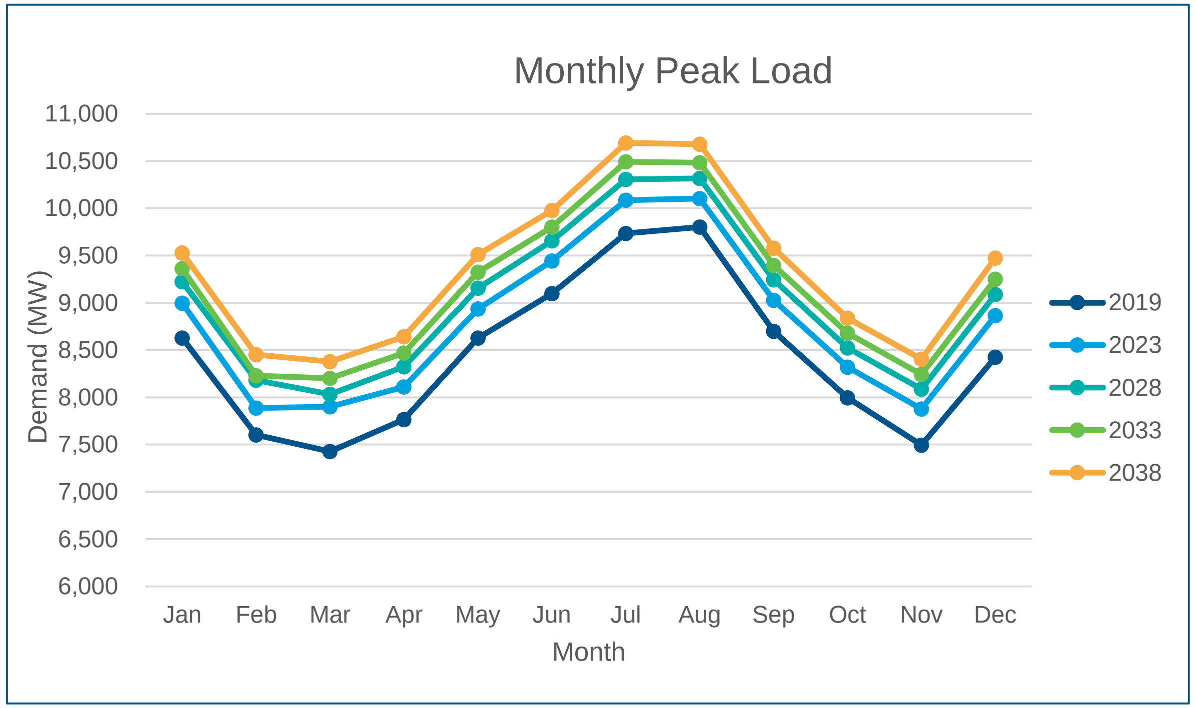
Program Impact by Sector

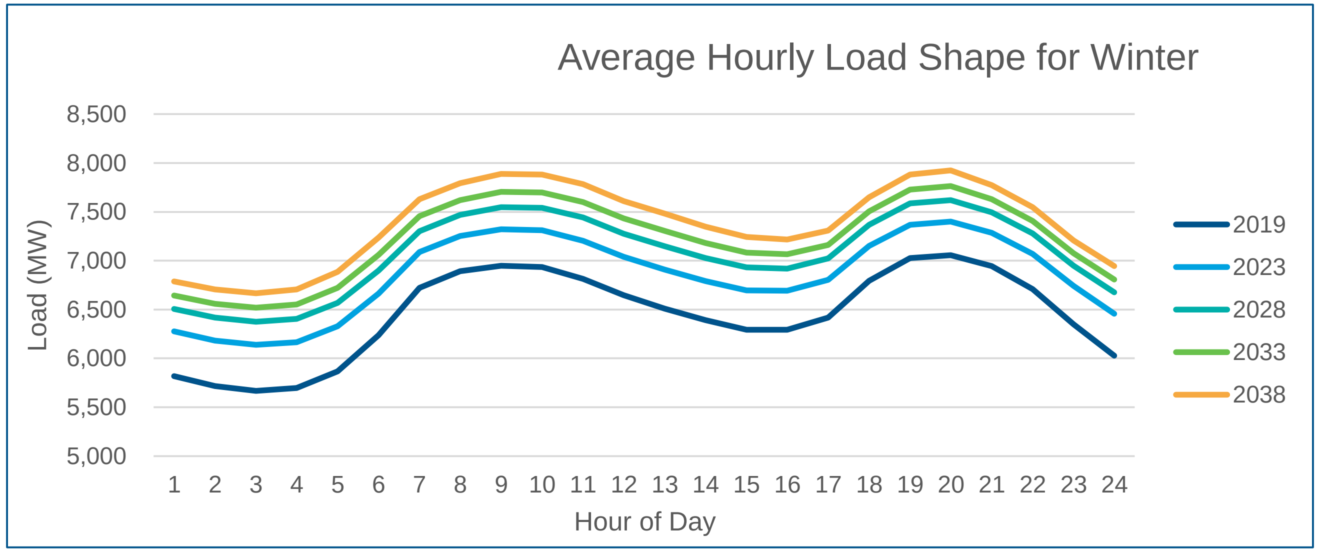


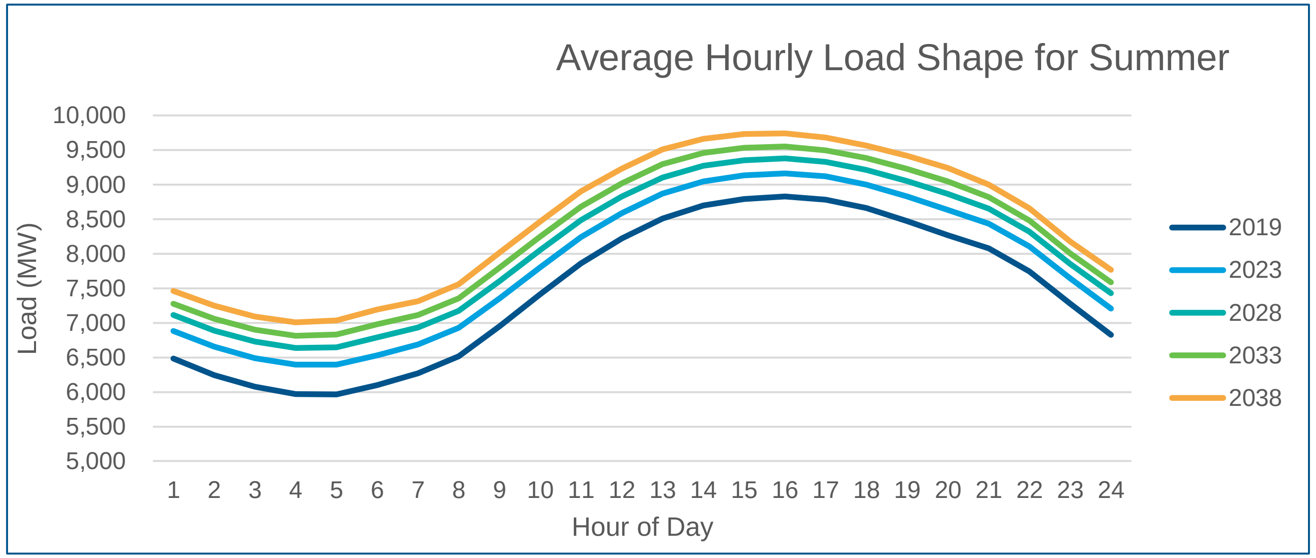
Share of Load and Program Impact by Sector, for 2038

TOU Program Assumptions

ELL Total load Forecasts – Peaks and Daily Average Shapes







Seasons based on monthly peaks for system load:

- Summer –Jun, Jul, Aug
- Winter – Jan, Dec

Peak period definitions based on average daily load shape for each of the seasons:

- Summer peak – Hour Ending (HE) 13-19
- Winter Peak – HE 7-10, HE 19-21

The Time-of-Use Pricing and Elasticity Assumptions

	Summer		Winter	
	High	Reference	High	Reference
Peak-to-OffPeak Ratio	3.5	3	2	1.5
TOU Off-peak discount	0.333	0.250	0.150	0.075

- Flat base prices for each class/sector – based on ELL Tariffs
    - Residential - $0.04779/KWh
    - Commercial - $0.03867/KWh
    - Industrial - $0.00784/KWh

These excluded the demand charges for commercial and industrial sectors

Other Program Assumptions

- All programs were assumed to be opt-in
- Adoption logic
  - Initial adoption is limited by the AMI installations in the ELL service area
- Costs
  - There are no incentive costs associated with the Time-of-Use programs

Additional Cost-effectiveness Results (PAC, RIM, and PCT Tests)

All cost-effective tests are calculated based on “California Standard Practice Manual - Economic Analysis Of Demand-side Programs And Projects ”

A copy of the manual can be found at http://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/Utilities_and_Industries/Energy_-_Electricity_and_Natural_Gas/CPUC_STANDARD_PRACTICE_MANUAL.pdf

The additional cost-effectiveness results include:

- Program Administrator Cost (PAC)
- Rate Impact Measure (RIM)
- Participant Cost Test (PCT)

Additional cost-effectiveness metrics for EE programs

Program	PAC	RIM	PCT
Lighting, Appliances and Electronics	2.0	0.7	4.4
HVAC and Tune-up	7.5	0.8	3.8
Home Audit and Retrofit	3.7	0.8	2.9
Low Income Weatherization	1.9	0.5	2.8
Total Residential Programs – Current	**3.1**	**0.7**	**3.2**
ENERGY STAR New Homes	9.2	0.8	3.7
Appliances Recycling	2.8	0.8	2.3
Home Energy Use Benchmarking	5.1	1.2	4.5
Grand Total Residential Programs – Expanded + Current	**4.2**	**0.8**	**3.1**

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Additional cost-effectiveness metrics for EE programs

Program	PAC	RIM	PCT
Small Business Solutions	3.7	0.6	3.7
Current Commercial Prescriptive & Custom	3.5	0.6	6.7
Total Commercial Programs - Current	**3.6**	**0.6**	**5.3**
RetroCommissioning	6.8	0.6	6.0
Commercial New Construction	5.9	0.7	3.6
Commercial Prescriptive & Custom	2.9	0.6	6.8
Midstream Commercial Lighting	1.3	0.5	4.2
Grand Total Commercial Programs – Expanded + Current	**2.7**	**0.6**	**5.0**
Industrial Prescriptive & Custom	3.1	0.6	14.8
Industrial Programs - Current	**3.1**	**0.6**	**14.8**
Industrial Strategic Energy Management	2.8	0.6	18.9
Grand Total Industrial Programs – Expanded + Current	**3.0**	**0.6**	**15.4**
Portfolio Total - Current	**3.3**	**0.7**	**5.0**
Portfolio Total - Expanded	**3.3**	**0.7**	**4.7**

Additional cost-effectiveness metrics for DR programs

Program Type	Sector	RIM Test		PAC Test	
		Reference Case	High Case	Reference Case	High Case
Residential DLC	Residential	1.3	1.3	1.3	1.3
Residential ToU	Residential	10.3	12.5	13.1	15.1
Residential Subtotal		2.0	2.3	2.0	2.3
Commercial DLC	Commercial	1.0	1.1	1.0	1.1
Commercial ToU	Commercial	4.4	5.6	5.6	7.1
Commercial Subtotal		1.4	1.6	1.5	1.7
Industrial ToU	Industrial	12.6	13.2	13.1	13.8
Industrial Subtotal		12.6	13.2	13.1	13.8
All DLC		1.2	1.2	1.2	1.2
All ToU		9.9	11.5	11.7	13.2
Total DR Portfolio		2.4	2.6	2.4	2.7

Note: The PCT test is not applicable for these DR Programs since there is not cost to customers to participate in DR programs