Codes and Standards Enhancement (CASE) Initiative

2028 California Energy Code

Process Steam

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Acronyms

Table 1 presents a list of acronyms used in this report. Title24stakeholders.com also maintains a glossary of terms, which may not be inclusive of all acronyms used in this report.

Table 1: List of Acronyms

Acronym	Definition
ACM	Alternative Calculation Method
ADA	Americans with Disabilities Act
AHJ	Authority Having Jurisdiction
APCD	Air Pollution Control District
AQMD	Air Quality Management District
ASHRAE	American Society of Heating, Refrigeration, and Air-Conditioning Engineers
ASME	American Society of Mechanical Engineers
ATT	Acceptance Test Technician
BCR	Benefit-to-Cost Ratio
BEA	Bureau of Economic Analysis
BEM	Building Energy Modeling
Btu	British Thermal Units
CAGR	Compound Annual Growth Rate
CALGreen	California Green Building Standards Code
CARB	California Air Resources Board
CASE	Codes and Standards Enhancement
CBSC	California Building Standards Commission
CBECC	California Building Energy Code Compliance Software
CEC	California Energy Commission
CEQA	California Environmental Quality Act
CBO	Community-Based Organization
CO_2e	Carbon Dioxide Equivalent
CPUC	California Public Utilities Commission
CSE	California Simulation Engine
CTF	Conduction Transfer Functions
CZ	Climate Zone
DAC	Disadvantaged Community
DEER	Database of Energy Efficiency Resources
DGS	California Department of General Services

DOAS	Dedicated Outdoor Air System
DOE	Department of Energy
DOSH	Division of Occupational Safety and Health
ECC	Energy Code Compliance
EIR	Environmental Impact Report
EPIC	Electric Program Investment Charge
ESJ	Environmental and Social Justice
EUL	Effective Useful Life
F	Fahrenheit
FGR	Flue Gas Recirculation
FRED	Federal Reserve Economic Data
FSOR	Final Statement of Reasons
GDP	Gross Domestic Product
GHG	Greenhouse Gas
GWh	Gigawatt-Hour
HVAC	Heating, Ventilation, and Air Conditioning
IAC	Industrial Assessment Center
IDF	Input Data File
IECC	International Energy Conservation Code
IOU	Investor-Owned Utility
IPGR	Industrial Production Growth Rate
ISOR	Initial Statement of Reasons
kBtu	Thousand British Thermal Units
kBtu/yr	Thousand British Thermal Units Per Year
Kg/s	Kilograms Per Second
kWh	Kilowatt-Hour
kWh/year	Kilowatt-Hour Per Year
Ib/h	Pounds Per Hour
Ibm	Pound-mass
LF	Linear Foot
LMI	Low- and Moderate-Income
LPD	Lighting Power Density
LSC	Long-term System Cost
MeasureSET	CASE Measure Savings Estimation Template
MG	Million Gallons of Water
MMBtu	Million British Thermal Units
MMBtu/h	Million British Thermal Units Per Hour

NA9	Non-Residential Reference Appendix 9
NAICS	North American Industry Classification System
NIST	National Institute of Standards and Technology
NOx	Nitrogen Oxides
NPDI	Net Private Domestic Investment
NR	Nonresidential
NRCA	Nonresidential Certificate of Acceptance
NRCC	Nonresidential Certificate of Compliance
NRCI	Nonresidential Certificate of Installation
OEM	Original Equipment Manufacturer
OSHA	Occupational Safety and Health Administration
PEP	Public Engagement Plan
ppmv	Parts Per Million by Volume
psig	Pounds Per Square Inch Gauge
PV	Present Value
RO	Reverse Osmosis
SCR	Selective Catalytic Reduction
SDD	Standards Data Dictionary
SOC	Standard Occupational Classification
SPMS	Saturation Pressure Measurement Sensors
SRIA	Standardized Regulatory Impact Assessment
TDS	Total Dissolved Solids
UL	Underwriters Laboratories
W	Watt
μΩ	Micro-ohm

1. Introduction

This is a draft report. The Statewide Codes and Standards Enhancement (CASE) Team encourages readers to provide comments on the proposed code changes and supporting analyses. The CEC will evaluate proposals that the Statewide CASE Team and other stakeholders submit and may revise or reject proposals. More information about the rulemaking schedule and how to participate in the process can be found on CEC's 2028 code cycle website. Suggested revisions will be considered when refining proposals and analyses. The final CASE Report will be submitted to the CEC later in 2026.

For this report, the Statewide CASE Team is requesting input on the following:

1. *Projected changes to process steam load capacity in California*
2. *Market share of new steam loads with condensate return systems*
3. *Average statewide boiler pressure*
4. *Feedback on measure costs and assumptions regarding boiler operation.*

Email comments and suggestions to info@title24stakeholders.com and/or econroy@westmonroe.com. Comments will not be attributed to their authors unless these are publicly docketed or with permission of the contributor.

1.1 Report Context

This proposal describes specific energy efficiency code changes (referred to as measures) aimed at reducing wasteful, uneconomic, inefficient, or unnecessary energy consumption in California. These measures are submitted to the California Energy Commission (CEC) for consideration and potential inclusion in California's Energy Code (Title 24, Part 6), which sets statewide energy efficiency requirements for newly constructed buildings and for additions and alterations to existing buildings. Measures may also be considered for inclusion in California Green Building Standards Code, known as CALGreen (Title 24, Part 11), as voluntary energy efficiency standards, which would take effect only if adopted by a local jurisdiction seeking to exceed the minimum requirements of the Energy Code. Measures submitted to the CEC will be reviewed and may be modified or incorporated into a broader regulatory package proposed and adopted by the CEC.

To be included in the Energy Code, proposed measures must be both cost effective and technically feasible.

1.2 Proposal Sponsors

Three California Investor-Owned Utilities (IOUs) — Pacific Gas & Electric Company, San Diego Gas & Electric, and Southern California Edison sponsored this effort as a group. Where the term, "Statewide CASE Team" is used in this report, it refers the authors of the CASE report and the Codes & Standards programs of the supporting California Investor-Owned Utilities.

1.2.1 Stakeholder Engagement to Inform Proposal

When developing the code change proposal and associated technical information presented in this report, the Statewide CASE Team worked with many industry stakeholders including manufacturers, sales representatives, maintenance and installation providers, an economic research and consulting firm, an industrial energy benchmarking and consulting firm, code compliance professionals, and more. The proposal incorporates feedback received during a public stakeholder workshop that the Statewide CASE Team held on October 29, 2025. Materials from the workshops are available at title24stakeholders.com (Swanson, et al., Process Steam #1: Flash Steam Recovery, 2025; Swanson, et al., Process Steam #2: Condensate Return, 2025; PG&E, SDG&E, SCE, LADWP, and SMUD, 2025)

The Statewide CASE Team engaged with multiple steam boiler manufacturers and representatives to learn more about current industry trends and practices across all the proposed measures. By October 2025, the Statewide CASE Team had formally interviewed five representatives from three steam boiler organizations and received feedback from three additional representatives via email. The interviews covered topics including boiler lifespan, efficiency, and current industry practices related to flash steam recovery and condensate return. These interviews informed this report's estimates for the current commercial landscape of this equipment, including the market share, incremental costs, and barriers to adoption of equipment necessary to comply with the proposed measures. The Statewide CASE Team shared with interviewees specific details of the proposed measures, including planned measure exceptions and requirement thresholds, and received feedback from those stakeholders that was subsequently incorporated into the proposed code language discussed in this report.

Appendix E highlights further details of the Statewide CASE Team's stakeholder engagement.

2. Flash Steam Recovery

2.1 Flash Steam Recovery – Measure Description

2.1.1 Proposed Code Change

A process boiler is a type of boiler with a capacity (rated maximum input) of 300,000 British Thermal Units per hour (Btu/h) or more that serves loads other than space conditioning and service water heating related to human occupancy.

This proposed code change would require all newly installed process boilers with capacities at or above 10 million Btu/hour (MMBtu/h) that are served by a pressurized deaerator to recover and route flash steam from blowdown to the deaerator or another steam load. The requirement would apply to all new process boilers, including replacement boilers and boilers in additions to existing facilities.

There are two proposed exceptions to the requirement:

1. Boiler systems where high-pressure condensate is returned to the deaerator without being flashed (dropped to atmospheric pressure).
2. Boiler systems where the linear length from the boiler to the serving deaerator is greater than or equal to 100 feet, where the linear length is the sum of all horizontal and vertical pipe runs.

All boilers qualifying for one of the exceptions must indicate either the installation of a pressurized condensate return system or the linear length from the boiler to the serving deaerator in the construction documents according to the exception they are pursuing.

Table 2 summarizes the scope of the proposed code change.

Table 2: Scope of Proposed Code Change

A ☑ indicates the proposed code change is relevant.

Building Type(s)	Construction Type(s)	Type of Change
☐ Single Family	☑ New Construction	☑ Mandatory
☐ Multifamily	☑ Additions	☐ Prescriptive
☑Nonresidential (not Group R uses)	☑ Alterations	☐ Performance

Application Climate Zones	Energy Code Sections	Compliance Forms	Sections of ACM Reference Manuals
Climate Zones 1-16	• Part 6, Sections 100.1(b), 120.6(d)	NRCC-PRC-E NRCI-PRC-E	• Mandatory

Third Party Verification	Updates to Compliance Software
☑ No changes to third party verification	☑ No updates
☐ Update existing verification requirements	☐ Update existing feature
☐ Add new verification requirements	☐ Add new feature

2.1.2 Benefits of Proposed Change

When applied in typical steam systems, the proposed flash steam recovery requirement is expected to save approximately one percent of baseline boiler system fuel consumption. The fuel savings result from a decrease in required combustion when flash steam displaces live boiler steam at the deaerator.

Flash steam recovery also reduces water use and the associated chemicals used for water treatment, as the flash steam is no longer vented to the atmosphere and its condensate can be returned to the boiler plant. The reductions in fuel, water, and chemical use result in operating cost savings for steam system owners and operators.

In addition to providing energy and water benefits, these practices would reduce local photochemical smog and improve air quality. The value of improved air quality is amplified by the consideration that many industrial facilities are located near Low- and Moderate-Income (LMI) housing, which typically gets disproportionately exposed to lower air quality. Ancillary benefits may also include improved plant safety and improved public perception through the reduction of steam plumes.

In addition, a requirement for flash steam recovery at large process steam sites will support the market for flash steam recovery equipment.

2.1.3 Background Information

When steam condensate is dropped to a pressure lower than its saturation (boiling-point) pressure, a fraction of it vaporizes, or flashes, into what is known as flash steam. The higher the temperature and pressure of the condensate, the more flash steam is generated when it is lowered in pressure. Most sites vent flash steam to the atmosphere, resulting in significant fuel, water, and chemical losses from the steam system. Many commercially-available steam system design options can reduce the amount of flash steam that is vented.

A blowdown flash steam recovery system consists of a pressurized flash steam recovery vessel, labeled insulated piping, isolation valves, and a check valve. Without a flash steam recovery system, existing sites would already have an atmospheric flash tank in place, which would be replaced by the pressurized flash steam recovery vessel in most cases. Flash steam recovery vessels, also called flash tanks, are used to recover flash steam and reroute it to lower pressure loads such as the deaerator for useful heating, which displaces use of live boiler steam. Recovery of this flash steam reduces the amount of steam vented to the atmosphere and saves fuel, water, and chemicals.

Flash steam recovery has been listed in U.S. Department of Energy (DOE) literature as a best practice since at least the early 2000s, and DOE has published five steam tip sheets for different flash steam recovery methods. This proposed code change originated from discussions with California-based consulting engineers from strategic energy management programs and the DOE Industrial Assessment Center program.

General factors that affect the success of flash steam recovery include the following:

- Stability of supply: Economic viability improves when a load can supply a consistent and reliable mass flow of flash steam. Intermittent loads are less desirable for flash steam recovery.
    - As boilers operate continuously, boiler blowdown provides a stable supply of flash steam.
- Stability of demand: Similar to consideration for supply, the demand for flash steam is best when it is a continuous, lower-pressure load. Satisfying this load must displace live boiler steam or another form of fuel use.
    - Deaerators operate constantly and provide a consistent demand for heat.
- Proximity of supply and demand: It is preferable for the flash steam to be used near its source. Lower-pressure steam, such as flash steam, requires larger pipe diameters to minimize pressure drop and velocity, which increases project cost when the flash steam must be transported long distances.
    - Deaerators are typically located in the same boiler room as the boiler, allowing for short piping lengths. However, if one deaerator serves multiple boilers, the distance from the farthest boiler to the deaerator could be longer.

To ensure cost-effectiveness of this measure, this proposed requirement would only apply to systems that have pressurized deaerators, which provide a continuous heating load, and larger boilers (at and above 10 MMBtu/h), which provide a continuous supply of blowdown flash steam. The proposed requirement also has an exception for boiler systems where the linear length from the boiler to the serving deaerator is greater than or equal to 100 feet. While sites may choose to route recovered flash steam to alternative heating loads in addition to deaerator heating, routing recovered boiler blowdown flash steam to the deaerator provides a constant and cost-effective compliance pathway.

2.1.4 Modifications to Energy Code Documents

This section provides descriptions of how the proposed code change will affect each Energy Code document. See Section 2.6: Flash Steam Recovery – Proposed Code Language of this report for detailed revisions to code language.

2.1.4.1 Energy Code Change Summary

SECTION 100.1(b) – DEFINITIONS AND RULES OF CONSTRUCTION

Subsection 100.1(b): The proposed measure would add new definitions for flash steam and pressurized condensate return.

SECTION 120.6 – MANDATORY REQUIREMENTS FOR COVERED PROCESSES

Subsection 120.6(d)4: The proposed measure would add a requirement for newly installed process boilers with capacities at or above 10 million British Thermal Units per hour (MMBtu/h) that are served by a pressurized deaerator to recover and route flash steam from blowdown to the deaerator or to another heating load. Two exceptions would exempt boiler systems with high-pressure condensate return and boiler systems where the linear length from the boiler to the serving deaerator is greater than or equal to 100 feet.

2.1.4.2 Reference Appendices Change Summary

The proposed measure would not modify the reference appendices.

2.1.4.3 Compliance Manuals Change Summary

The proposed changes would include updates to Section 10.9.2 of the Nonresidential Compliance Manual, which outlines mandatory requirements for process boilers. A newly created subsection would explain the requirement and verification steps for flash steam recovery.

2.1.4.4 Alternative Calculation Method Reference Manual Change Summary

The proposed measure will not modify Alternative Calculation Method (ACM) Reference Manuals because the proposed measure requires no associated software updates.

2.1.4.5 Compliance Forms Change Summary

The existing Process System Certificate of Compliance document (NRCC-PRC-E) and Process System Certificate of Installation document (NRCI-PRC-E) would both need to be updated. In the Certificate of Compliance and Certificate of Installation documents, the Process Boilers section would need new input fields added to ensure qualified boilers meet the flash steam recovery requirement.

2.1.5 Measure Context

2.1.5.1 Comparable Model Codes or Standards

Review finds no relevant model codes or standards.

2.1.5.2 Interactions with Other Regulations

While the American Society of Heating, Refrigeration, and Air-Conditioning Engineers (ASHRAE) does not have a specific standard for flash steam recovery, the ASHRAE Handbook *HVAC Systems and Equipment* and the ASHRAE *Fundamentals of Steam System Design* have application guidance for flash steam recovery (ASHRAE, 2020; ASHRAE, 2006).

The Statewide CASE Team found no known existing federal, state, or local regulatory requirements that address flash steam recovery in process steam systems. Current Title 24, Part 6 requirements cover steam traps in new industrial facilities and steam traps added to support new, non-replacement process equipment in existing industrial facilities where the installed steam trap operating pressure is greater than 15 psig and the total combined connected boiler input rating is greater than 5 MMBtu/hr. The code requires central steam trap fault detection and diagnostics monitoring, steam trap fault detection, and steam trap strainer installation. The proposed requirement for flash steam recovery would have no impact on these existing requirements.

Review finds no known interactions with other parts of the California Building Code or local requirements. The proposed requirement would not interfere with compliance with Occupational Safety and Health Administration (OSHA) requirements for pressurized vessels. Only pressurized flash steam recovery vessels operating at 15 psig or would be subject to OSHA requirements for pressurized vessels. Nearly all blowdown flash steam recovery vessels installed to comply with the proposed requirement would operate below 15 psig and therefore not be subject to OSHA requirements for pressurized vessels.

The proposed requirement would not interfere with Air Quality Management District (AQMD) requirements related to boiler emissions because the AQMDs do not regulate water vapor emissions. By reducing overall boiler combustion emissions, the proposed requirement will support AQMD air quality goals in the state of California.

2.2 Flash Steam Recovery – Compliance and Enforcement

2.2.1 Compliance Considerations

When developing this proposal, the Statewide CASE Team considered methods to streamline the compliance and enforcement process and how negative impacts on market actors who are involved in the process could be mitigated or reduced. The Statewide CASE Team believes that compliance and enforcement of the proposed measure is feasible and would not add significant compliance or enforcement burden to those responsible for ensuring compliance with building code when training and education on requirements is provided.

Confirmation steps would need to be taken during permit application to ensure compliance with the proposed flash steam recovery requirement. Plans must indicate the planned installation of a flash steam recovery system.

New fields in the Process Systems Certificate of Compliance document NRCC-PRC-E and the Process System Certificate of Installation document NRCI-PRC-E would need to be created and completed.

Designers: Designers would need to be aware of the new flash steam recovery requirements in section 120.6(d) so they can design compliant process boiler and steam systems. They would need to fill out an updated NRCC-PRC-E form and submit design documents indicating a compliant design.

Authorities Having Jurisdiction (AHJ) plan checkers: During the permit application phase, AHJ plan checkers would review the submitted NRCC-PRC-E form and design documents to confirm that the design includes a blowdown flash steam recovery system.

Installation contractors: Installation contractors would need to correctly install blowdown flash steam recovery systems in accordance with design and manufacturing specifications and OSHA requirements, which is already required as part of normal operating procedures. When the installation contractor fills in the NRCI-PRC-E form, they would need to include the model number of the flash steam recovery vessel.

Field technicians: Field technicians would not be impacted by the proposed measure. With industry standard design and installation, the pressurized flash steam recovery vessel would have comparable maintenance needs to the alterative atmospheric flash tank. The piping, isolation valves, and check valve should require minimal maintenance and not meaningfully impact site maintenance needs.

AHJ building inspectors: The AHJ building inspector would need to verify the installation of the blowdown flash steam recovery system that matches the design documents in addition to any other process boiler items requirements that are part of a new boiler inspection.

Review finds that all definitions added for new proposed code language do not conflict with any existing definitions in other parts of Title 24.

2.2.2 Impact on Market Actors

Table 3 summarizes impacts on market actors and suggests outreach and education that might be helpful to support market actors as they prepare for the effective date of the requirements.

Table 3: Impacts on Market Actors and Suggested Training and Education Opportunities

Market Actor	Impact(s)	Suggested Outreach and Education
Developers[a]	Be aware that blowdown flash steam recovery is required, and plan for additional costs.	Additional training likely unnecessary.
Design Professionals[b]	Be aware of new requirements for flash steam recovery from boiler blowdown when designing process steam systems and include flash steam recovery equipment specifications in design documents. Complete new fields of NRCC-PRC-E Process Boilers section.	Industrial process steam design firms should be provided training on updates to the energy code requirements and compliance documentation.
Construction Team[c]	Install a blowdown flash steam recovery system as specified in the approved design documents, consistent with standard practice. Complete fields in the Process Boilers section of NRCI-PRC-E.	System installer should be provided training on the energy code updates and supporting documentation, compliance requirements, and compliance documentation.
Building Departments[d]	Plan Reviewers will have an additional requirement to check when reviewing NRCC form and design documents.	Provide education and training to local building department plans examiners to familiarize with new code language.
Verification Testers[e]	No verification testing is required.	N/A
Building Owners, Managers, and Occupants	Higher upfront cost and reduced energy and water bills. Need to maintain flash steam recovery equipment.	Outreach to owners and operations personnel could improve understanding of the benefits of flash steam recovery. Additional training could reinforce the importance of piping insulation maintenance.
Manufacturers and Distributors	Additional sales of flash steam recovery equipment.	Additional training likely unnecessary.

a. Developers plan the project, manage finances, and manage risks from start to finish.

b. Design professionals include architects, interior designers, engineers (mechanical, electrical, plumbing, structural), specification writers, cost estimators, commissioning agents, lighting designers, and energy consultants.

c. Construction team includes general contractors, design-build contractors, installation contractors (e.g., HVAC, plumbing, electrical), commissioning agents, and tradespeople.

d. Building departments include plans reviewers, building inspectors, specialty inspectors, permit counter technicians, and sustainability department staff.

e. Verification testers include commissioning agents, Energy Code Compliance Raters, and Acceptance Test Technicians.

f. Manufacturers and distributors include component manufacturers, original equipment manufacturers (OEMs), steam system equipment manufacturers, manufacturer representatives, and distributors.

The 2028 CASE Methodology Report presents a quantitative assessment of how changes to the California building code impact builders, building designers and energy consultants, and facility owners. The analysis in the methodology report is not specific to the code changes presented in this report. The following section provides a qualitative description of how this specific code change affects various market actors and additional quantitative analyses of its potential impacts on building industry subsectors.

Builders: The proposed change would likely affect industrial and commercial builders; however, it would likely not impact firms focused on the construction or retrofitting of residential buildings, utility systems, public infrastructure, or other heavy construction. The proposed change would not affect all firms and workers in the industrial and commercial building industries equally; instead, it would primarily affect specific subsectors within the industries. Table 4 shows the construction subsectors that the Statewide CASE Team expects to be impacted by the changes proposed in this report.

Table 4: Specific Subsectors of the California Commercial and Industrial Building Industries Impacted by Proposed Change to Code by Subsector in 2029 (Estimated)

Construction Subsector	Establishments*	Employment	Annual Payroll (Billions $)
Industrial Building Construction	TBD	TBD	TBD
Nonresidential Structural Steel Contractors	365	11,899	1.1
Nonresidential Plumbing & HVAC Contractors	2,270	55,182	5.8
Other Nonresidential Equipment Contractors	580	9,749	1.1
Nonresidential Site Preparation Contractors	1,147	19,273	1.9
All Other Nonresidential Trade Contractors	948	17084	1.7

a. Source: (State of California, n.d.)

b. *An establishment is single economic unit, typically at one physical location, that engages in one, or predominantly one, type of economic activity for which a single industrial classification may be applied. Many businesses are composed of multiple establishments. US Bureau of Labor Statistics, Handbook of Methods. https://www.bls.gov/opub/hom/cew/concepts.htm

Facility owners: Facility owners would need to pay higher first costs for new boiler installations. Regular equipment maintenance costs would also slightly increase. At the same time, owners would benefit from fuel and water cost savings.

The Statewide CASE Team estimates that, on average, the proposed change to Title 24, Part 6 would increase boiler first costs by about $98 to $1,579 per MMBtu/h of boiler capacity and would increase maintenance costs by $18 to $492 per MMBtu/h of boiler capacity over 30 years, depending on the individual boiler’s capacity. However, the measure would ultimately result in a savings of about $16,750 to $25,750 per MMBtu/h of boiler capacity in energy cost savings over 30 years, with slight variations by climate zone. Overall, the Statewide CASE Team expects the 2028 Title 24, Part 6 updates would save owners about $500 to $850 per year per MMBtu/h of boiler capacity relative to facilities that remain minimally compliant with the 2025 Title 24, Part 6 requirements.

Manufacturers: As discussed in Section 2.3.1.1, multiple manufacturers and installers of flash steam equipment operate in California, and these businesses would sell and install components of flash steam recovery systems. Refer to Section**Error! Reference source not found.** 2.3.4 for more information on the resultant impact to California jobs.

2.2.3 Compliance Software Updates

Review finds no compliance software updates required for this proposal.

2.2.4 Cost of Enforcement

The Statewide CASE Team acknowledges that changes to the code will impact enforcement costs. This report is an evaluation of specific measures, and the collective impact of all proposed changes for the 2028 Title 24, Part 6 may represent an increase in training and/or workload for enforcement personnel.

Costs of enforcement would include costs to deliver training to enforcement officials to enable them to adequately enforce the proposed measure. This training can leverage current education programs to minimize expenses. Plan examiners would need to check for one new requirement, and building inspectors would need to verify installation of one additional requirement. Local governments will need to retrain building department staff; however, this practice aligns with the regular triennial code update cycle and is supported by resources such as Energy Code Ace. The Statewide CASE Team will estimate the cost of enforcement after planned discussions with California building departments and AHJs.

Costs for updating standards, compliance materials, and responding to inquiries are expected to remain within existing code development and enforcement budgets.

2.3 Flash Steam Recovery – Market and Economic Analysis

2.3.1 Market Structure and Availability

2.3.1.1 Current Market Structure and Availability

The market for blowdown flash steam recovery system equipment includes steam system designers, component manufacturers, OEMs, steam system equipment manufacturers, manufacturer representatives, distributors, mechanical contractors, and service technicians. Designers specify blowdown flash steam recovery systems, ensuring proper component sizing and identifying the best low-pressure steam applications to meet steam and boiler system needs. Component manufacturers and OEMs design, manufacture, and supply the system components, traditionally piping and flash recovery vessels, or tanks, which they sell as packaged systems and as individual components. Manufacturer representatives and distributors act as the local sales and distribution channel for the component manufacturers and specialized steam equipment companies. Mechanical contractors handle the physical installation of the system. Equipment manufacturer representatives and mechanical contractors typically perform startup and commissioning.

The market for blowdown flash steam recovery systems is mature, with multiple manufacturers and suppliers providing designers and contractors with many options for traditional flash steam recovery equipment (vessels and piping). Additional equipment may be required based on specific applications chosen by a site. Table 5 lists companies that the Statewide CASE Team has identified as major market actors.

Table 5: Major Flash Steam Recovery Market Actors

Company	Market Actor Type	Product Offering	Headquartered in California
Armstrong	Manufacturer	Flash vessel	No
A Louis Supply	Distributor	Flash vessel	No
Didion Vessel LLC	Manufacturer	Flash vessel	No
Calpacific Equipment Company	Vendor	Flash vessel (Madden Engineered Products)	Yes
PVV Corp	Manufacturer	Flash vessel, piping	Yes
Spirax Sarco	Manufacturer	Flash vessel	No
Watson McDaniel	Manufacturer	Flash vessel	No

The Statewide CASE Team believes that steam and boiler system designers are familiar with flash steam recovery systems but many would likely require training on code updates to ensure boiler and steam system designs meet the proposed code requirements. Major steam equipment vendors tend to be familiar with flash steam recovery, and some have application engineers with expertise in this area. Mechanical contractors tend to be familiar with the basic application that would be required for measure compliance.

The Statewide CASE Team's estimated that 10 percent of newly added qualifying boiler capacity is installed with flash steam recovery systems, based on field experience in California and stakeholder feedback from a public stakeholder workshop that the Statewide CASE Team held on October 29, 2025. The Statewide CASE Team plans to reach out to additional stakeholders to gather more information about adoption of flash steam recovery in the market today and may update this estimate based on additional stakeholder feedback from a public stakeholder workshop that the Statewide CASE Team will hold in March 2026.

The Statewide CASE Team does not foresee that the proposed requirement would have any negative impacts on technology adoption.

2.3.1.2 Market Challenges and Solutions

The Statewide CASE Team surveyed manufacturer websites to confirm the availability of blowdown flash steam recovery systems in the current market from several manufacturers. Multiple vendors and suppliers have decades of experience procuring and installing these systems, confirming a mature and well-established market for flash steam recovery systems. The flash steam market has proven supplier stability and reliability, as flash steam products have been consistently available in manufacturer catalogs for decades (Armstrong International, 2011).

Flash steam recovery is not common practice, but flash steam recovery from boiler blowdown is well understood among equipment vendors and some designers and contractors. Rerouting flash steam from boiler blowdown for deaerator heating is the most common application of flash steam recovery.

Despite the availability of clear fuel, water, and chemical savings, many sites continue to vent all flash steam to the atmosphere. They implement this practice largely due to the upfront cost of flash steam recovery systems and a lack of awareness of the cost-effectiveness of these systems. Typical investments for industrial process equipment have payback periods of 1 to 3 years, while flash steam recovery paybacks can be longer, at about one to seven years. Industrial facilities often operate with a high barrier for capital expenditure on auxiliary equipment, even if the payback period from operational savings is short (Energy Efficiency Movement, 2025). Facility owners often prefer to save the immediate capital expense.

The presence and stability of low-pressure steam loads where flash steam recovery can be used varies between facilities. This proposed requirement would only apply to facilities with a pressurized deaerator to ensure that the site has at least one low-pressure steam application available for application of recovered flash steam. This criterion was added based on input from a boiler systems manufacturer during a stakeholder interview.

Though rare, some steam system designs use pressurized condensate return systems. These systems maintain recovered condensate above atmospheric pressure throughout the recovery process, which reduces the generation of flash steam and allows the associated flash steam to be piped back to the deaerator. For systems with pressurized condensate return, blowdown flash steam recovery would be less cost-effective due to the lower quantity of available flash steam and the possible need for higher-cost flash vessels designed for higher pressures. Therefore, this code change proposal includes an exception for boiler systems with pressurized condensate return, as these systems already recover significant flash steam energy.

See Section 2.2 for a description of workforce trainings that may be needed to ensure effective design, installation, and commissioning.

2.3.2 Design and Construction Practices

2.3.2.1 Current Design and Construction Practices

Industry widely accepts flash steam recovery as a best practice. DOE has developed five steam tip sheets that discuss the benefits of recovering flash steam and several potential recovery methods, including recovering flash steam from boiler blowdown (DOE, 2012). Blowdown flash steam recovery systems include a flash vessel and piping. Flash vessels are American Society of Mechanical Engineers (ASME)-stamped pressure vessels that separate condensate from flash steam (Wessels Company, n.d.). The vessels are offered in vertical and horizontal arrangements, with the vertical orientation allowing for better separation of flash steam and condensate (National Health Institute, 2023). When designing a blowdown flash steam recovery system, designers must calculate the design condition blowdown flow rate, select a flash vessel size for that flow rate, and size the flash steam piping to limit the steam velocity leaving the vessel. Flash vessel manufacturers often assist designers with vessel selection. Proper vessel selection and pipe sizing prevents carryover of liquid droplets into the flash steam piping (wet steam), which can accelerate fouling and erosion and reduce the useful life of the equipment and its lifetime energy savings.

2.3.2.2 Health and Safety Considerations

The proposed code change does not alter any existing federal, state, or local regulations pertaining to safety and health, including rules enforced by the California Division of Occupational Safety and Health (DOSH). All existing health and safety rules would remain in place. The proposed code change would increase the quantity of onsite piping that is carrying steam and lightly pressurized. Facility staff and those involved with the construction, commissioning, and maintenance of the site would not experience any adverse impacts on safety or health associated with the proposed code change. The proposed code change would reduce photochemical smog and improve air quality near the facility by reducing boiler fuel consumption and associated emissions.

2.3.2.3 Design and Construction Challenges and Solutions

The Statewide CASE Team has identified two potential design and construction challenges for flash steam recovery systems: 1) limited applications for recovered flash steam, and 2) long distances between recovery and use that require long pipe runs.

When designing flash steam recovery systems, designers must consider the size and stability of low-pressure loads where the recovered flash steam can be applied. The Statewide CASE Team developed the proposed code language for this measure to include flexibility in the choice of flash steam-recovery application,~~.~~ Additionally, the proposed requirement would only apply to steam systems with pressurized deaerators, ensuring that the system has at least one constant source of low-pressure steam demand through deaerator heating.

The distance of pipe runs between the source and application of recovered flash steam may vary between sites. However, boiler deaerators are typically located in the same room as the boiler they serve, ensuring that flash steam recovery pipe runs will not be unduly long at qualifying sites. A measure exception for boiler systems where the linear length from the boiler to the serving deaerator is greater than or equal to 100 feet accounts for sites with a long distance between the boiler and the serving deaerator.

2.3.3 Energy Equity and Environmental Justice

The Statewide CASE Team evaluated the potential impact on environmental and social justice (ESJ) communities,[1] including impacts related to race, class, and gender. The Statewide CASE Team determined that the proposed measure would positively impact ESJ communities located near industrial sites. Flash steam recovery reduces the amount of new live boiler steam needed to supply steam to low- pressure loads. The reduction in live boiler steam production lowers boiler fuel consumption, leading to a reduction in greenhouse gas (GHG) emissions and improved local air quality. The value of improved air quality through compliance with the proposed requirement is amplified by the fact that many industrial facilities are located near LMI communities, which are disproportionately exposed to lower air quality.

The Statewide CASE Team identified potential impacts of the proposed code change via research and field experience. While the listed potential impacts should be comprehensive, they may not yet be exhaustive. Recognizing the importance of engaging ESJ communities and gathering their input to inform the code change process and proposed measures, the Statewide CASE Team is working to build relationships with community-based organizations (CBOs) to facilitate meaningful engagement. Any stakeholders with input on how this proposal may impact ESJ communities or who want to offer their perspective should reach out to Emma Conroy (econroy@westmonroe.com).

2.3.4 Impacts on Jobs and Businesses

The Statewide CASE Team will complete this section for the Final CASE Report.

2.3.5 Economic and Fiscal Impacts

The Statewide CASE Team will complete this section for the Final CASE Report.

2.4 Flash Steam Recovery – Cost Effectiveness

2.4.1 Cost Effectiveness Methodology

The Statewide CASE Team collaborated with CEC staff to confirm that the cost-effectiveness methodology aligns with CEC guidelines, including cost inclusion parameters. The 2028 CASE Methodology Report and Appendix A provide reproducibility details.

[1] The CPUC refers to ESJ communities as “low-income or communities of color that have been underrepresented in the policy setting or decision-making process, are subject to a disproportionate impact from one or more environmental hazards, and likely to experience disparate implementation of environmental regulations and socio-economic investments in their communities” (CPUC 2022). ESJ communities also include the CPUC definition for Disadvantaged Communities, which comprises “(1) Census tracts receiving the highest 25 percent of overall scores in CalEnviroScreen 4.0 (1,984 tracts); (2) Census tracts lacking overall scores in CalEnviroScreen 4.0 due to data gaps, but receiving the highest 5 percent of CalEnviroScreen 4.0 cumulative pollution burden scores (19 tracts); (3) Census tracts identified in the 2017 DAC designation as disadvantaged, regardless of their scores in CalEnviroScreen 4.0 (307 tracts); and (4) Lands under the control of federally recognized Tribes (OEHHA, 2022).

Per California Law (Public Resources Code 25000), a measure is considered cost effective if its Benefit-to-Cost Ratio (BCR) is 1.0 or greater, amortized over the economic life of the structure. The Statewide CASE Team calculates BCR by dividing total dollar benefits by total dollar costs over a 30-year analysis period.

Benefits are based on Long-term System Cost (LSC), which assigns an hourly dollar value to energy use. LSC hourly factors weigh the long-term value of each hour differently, where times of peak demand are valued more than off-peak hours. These factors are not utility rates, forecasts, or bill estimates. The CEC develops and publishes LSC hourly conversion factors for each code cycle.

Costs include first costs and ongoing maintenance costs assessed over the 30-year period. Benefits and costs are evaluated incrementally, relative to the most recently adopted Energy Code. The analysis excludes design costs and incremental code compliance verification costs.

2.4.2 Energy and Energy Cost Savings Results

To analyze the energy savings for the proposed flash steam recovery requirement, the Statewide CASE Team calculated the difference in energy consumption between the baseline (no flash steam recovery) and measure case (recovers all flash steam from boiler blowdown and routes it to the deaerator supply line).

The savings calculations used a custom analysis model. At a high level, the calculation steps were as follows:

1. **Baseline**: Model all mass and energy flows for a boiler system, where all blowdown is lowered to atmospheric pressure and flash steam is vented.
2. **Proposed**: Model all mass and energy flows for a boiler system, where flash steam is recovered and routed to the deaerator.
3. **Savings**: The energy savings and water savings are taken as the differences in energy use and water use between the baseline and proposed scenarios.

Natural gas and water savings increase with the associated steam boiler input capacity because the total volume of flash steam recovered is higher at boilers with larger loads. The water savings also scale based on the boiler capacity, and the greater the water savings the greater the energy saved from avoided make-up water heating. To ensure cost-effectiveness, the proposed flash steam recovery requirement only applies to process steam systems that have one or more connected boilers with an input rating (capacity) of 10 MMBtu/h or greater and that have a boiler design condition pressures of 100 psig or greater.

The more the boiler is operated, the greater the resultant savings. As such, boilers that operate infrequently throughout the year due to seasonal loads will experience lower savings. Due to this variance, the Statewide CASE Team calculated annual energy savings and cost-effectiveness for boilers with seasonal loads separately from boilers with more typical annual loads. Calculations for boilers operating annually assumed 6,500 operating hours per year at 40 percent load, while calculations for seasonal boilers assumed 2,400 operating hours per year (primarily July through October) at 80 percent load. The Statewide CASE Team based these assumptions for operating hours and load factor on analysis of data from a survey of 128 California steam-using sites in an Industrial Assessment Center (IAC) database. Since boiler and flash steam recovery systems are frequently sized for higher capacities than they typically operate at, the Statewide CASE Team applied an 80 percent load assumption for all boilers, year-round and seasonal, to calculate steam loads for the cost analysis.

Savings from flash steam recovery should stay constant over the measured lifetime. However, flash steam recovery system components could fail, which would decrease the energy savings from the measure.

Per-unit savings for the first year are expected to be 30,919 thousand British Thermal Units (kBtu) per MMBtu/h of boiler capacity for year-round boiler operation, and 22,800 kBtu per MMBtu/h of boiler capacity for seasonal boiler operation, as shown in Table 6. No electric savings or demand reductions are associated with this measure. The per-unit energy savings of this measure are not impacted by climate zone and are the same whether they occur in new construction, additions, or alterations.

Table 7 presents total per-unit energy cost savings for newly added boilers in terms of LSC savings realized over a 30-year period, in 2029 present value dollars (2029 PV$) for year-round and seasonal boilers in the various size bins by climate zone. While the energy savings do not differ across climate zones, the LSC factors do vary slightly by climate zone.

Table 6: First Year Natural Gas Savings (kBtu) Per MMBtu/h of Boiler Capacity – Flash Steam

Boiler Type	First Year Natural Gas Savings (kBtu)
Year-Round	30,919
Seasonal	22,800

Table 7: Total 30-Year LSC Savings (2029 PV$) Per MMBtu/h of Boiler Capacity – Flash Steam

Prototype	CZ 1	CZ 2	CZ 3	CZ 4	CZ 5	CZ 6	CZ 7	CZ 8	CZ 9	CZ 10	CZ 11	CZ 12	CZ 13	CZ 14	CZ 15	CZ 16
Year-Round	25,609	25,609	25,609	25,609	25,609	25,917	25,841	25,917	25,917	25,917	25,609	25,609	25,609	25,917	25,917	25,917
Seasonal	16,763	16,763	16,763	16,763	16,763	16,787	16,783	16,787	16,787	16,787	16,763	16,763	16,763	16,787	16,787	16,787

2.4.3 Incremental First Cost

The baseline case to estimate the costs of this measure is assumed to be a process boiler system with no flash steam recovery. This baseline ensures cost effectiveness in the rare occasion that sites that would need to replace existing flash steam recovery equipment to comply with this measure in addition to sites with without any flash steam recovery equipment. The incremental first costs are consistent between new boilers at new steam loads (new construction and additions) and newly installed replacement boilers at existing industrial facilities (alterations).

The incremental first cost of a blowdown flash steam recovery system includes the design, equipment, installation, startup, and commissioning costs of flash steam recovery equipment, which includes a pressurized flash steam recovery vessel, piping, isolation valves, and a check valve. Table 8: Flash Steam Recovery System Incremental First Cost By shows the total estimated incremental first costs of installing a flash steam recovery system by prototype. The incremental first costs for seasonal boilers and boilers that operate year-round are equivalent because the systems are typically sized for similar load factors regardless of the actual operating load factors. When sized for larger steam loads, piping and associated components are larger and more expensive.

The Statewide CASE Team assumed a conservative piping distance of 100 feet between the boiler blowdown flash recovery vessel and the deaerator to calculate measure energy savings across both seasonal and year-round boiler operating profiles.

Table 8: Flash Steam Recovery System Incremental First Cost By Boiler Capacity

Prototype	Flash Steam Recovery System First Cost	Flash Steam Recovery System First Cost Per Unit
10-15[2] MMBtu/h	$18,900	$1,579
15-25 MMBtu/h	$18,900	$972
25-50 MMBtu/h	$22,970	$705
50-100 MMBtu/h	$25,716	$364
100-200 MMBtu/h	$30,845	$216
200+ MMBtu/h	$72,381	$98

The majority of the first cost comes from installation labor costs. Piping, pipe insulation, and flash vessels make up the majority of material costs. The cost of additional piping components and design, startup, and commissioning costs make up the remaining small proportion of the total first costs.

[2] All boiler capacity bins use an inclusive lower bound. For example, the 10-15 MMBtu/h bin means 10 ≤ boiler capacity < 15.

Depending on a site's steam distribution system, flash steam recovery equipment installation at an existing site could marginally lengthen the downtime of existing steam loads during the connection of the new boiler to the existing system. In most cases, the Statewide CASE Team expects the site to connect the new flash steam recovery system at the same time as the new steam boiler, and any incremental downtime due to the flash steam recovery system would be insignificant compared to the necessary downtime to install the replacement boiler. Most year-round facilities plan for one to two weeks of downtime annually or semi-annually and would typically connect the new boiler and new flash steam recovery equipment during this planned downtime.

The blowdown vessel and flash steam piping are sized based on the estimated design condition blowdown mass flow. The pipe insulation is sized based on the pipe diameter and flash steam temperature in accordance with Title 24 requirements. The vessel is sized according to the vessel ratings of one major steam equipment vendor, which considers the total blowdown mass flow—liquid and flash steam. The flash steam pipe diameter is sized based on maintaining the flash steam velocity at under 3,000 feet per minute and rounded to the next highest nominal pipe diameter, which is a conservative industry rule of thumb.

Equipment costs were obtained from manufacturer websites and the software platform RSMeans. The Statewide CASE Team estimated the labor hours required to design a flash steam recovery system and the costs of commissioning and compliance verification based on field experience and historical project costs. All incremental first costs are expected to increase with inflation.

An example breakdown of the cost calculations and sources for a boiler with an input capacity of 32.6 MMBtu/h is included in Appendix A.

The Statewide CASE Team will update first costs according to additional stakeholder input costs and cost assumptions gathered during the public meeting in March 2026.

2.4.4 Incremental Maintenance and Replacement Costs

The incremental maintenance cost for a flash steam recovery system includes estimated maintenance and replacement costs of piping insulation. Maintenance for steam piping and the flash vessel were not included in the cost estimates, as stainless steel and carbon steel piping and vessels have a lifespan ranging from 20 to 50 years or more (Pak Industrial Services, n.d.).

The maintenance of insulation on steam piping is crucial to conserve energy and reduce heat loss. DOE estimates that insulating steam piping can reduce energy lost as heat to the atmosphere by up to 90 percent (DOE, 2012). DOE also estimates that heat is lost at a rate of 285 MMBtu per year per 100-ft stretch of 1-inch uninsulated pipe on a 150-psig system (DOE, 2012). At an average price of $0.90/therm, that level of loss equals

$2,565 per year. Damaged insulation is usually the result of installing the wrong type or amount of insulation for the process, improper installation practices, physical damage such as walking or climbing on uninsulated pipes, and corrosion or contamination of insulation exposed to process or steam leaks (Multiservice Industrial, 2022). Maintenance and replacement of damaged piping insulation can be performed by general maintenance staff and is important to ensure the savings associated with this measure persist throughout the 30-year analysis period.

The incremental cost for insulation maintenance was based on the expected degradation of piping insulation at a rate of about 10 percent every 10 years. The cost is estimated to be equivalent to the proportional first cost of the amount of insulation being replaced due to degradation. The maintenance and replacement frequency estimations were based on the 2025 Process Pipe Load CASE Report (Amoni & Alkhatib, 2023). The Statewide CASE Team plans to conduct further stakeholder outreach to obtain additional input on maintenance cost and frequency.

For detailed maintenance cost information, see Appendix A. A description of the incremental maintenance and replacement costs is provided in the 2028 CASE Methodology Report.

2.4.5 Cost Effectiveness

Results of the per-unit cost-effectiveness analyses are presented in Table 9 and Table 10. The results do not vary between new construction, additions, and alterations.

The proposed measure saves money over the 30-year period of analysis relative to the existing conditions. The proposed measure is cost effective in every climate zone and for alterations (newly installed boilers at existing sites) in addition to additions and new construction.

In Table 9 and Table 10, all values are presented in 2029 PV$. Benefits represent 30-year LSC savings and other savings, including incremental first-cost savings if the proposed first cost is less than the current first cost, incremental maintenance cost savings if the proposed maintenance costs are less than the current maintenance costs, and incremental residual value if proposed residual value is greater than current residual value at the end of the 30-year period of analysis. Costs represent the total incremental PV cost, including incremental equipment, replacement, and maintenance costs over the period of analysis. The analysis treats a negative incremental maintenance cost as a positive benefit. If total incremental costs are zero, the BCR is considered infinite. Costs and other savings are discounted at a real (inflation-adjusted) three percent rate. If there are no total incremental PV costs, the BCR is infinite. A BCR of “NA” indicates that there is no boiler capacity in that climate zone that would be impacted by the proposed requirement. As the changes in LSC savings only vary very slightly by climate zone, Table 9 includes the LSC savings for Climate Zone 1.

Table 9: 30-Year Cost-Effectiveness Summary Per MMBtu/h of Boiler Capacity – Flash Steam

Prototype	Benefits LSC Savings + Other PV Savings (2029 PV$)	Costs Total Incremental PV Costs (2029 PV$)	Benefit-to-Cost Ratio
Year-Round Boiler 10-15 MMBtu/h	$25,764.62	$2,070.85	12.44
Year-Round Boiler 15-25 MMBtu/h	$25,762.43	$1,274.38	20.22
Year-Round Boiler 25-50 MMBtu/h	$25,739.03	$911.45	28.24
Year-Round Boiler 50-100 MMBtu/h	$25,626.51	$466.52	54.93
Year-Round Boiler 100-200 MMBtu/h	$25,683.06	$273.10	94.04
Year-Round Boiler 200+ MMBtu/h	$25,823.22	$116.17	222.29
Seasonal Boiler 10-15 MMBtu/h	$16,775.30	$2,070.85	8.10
Seasonal Boiler 15-25 MMBtu/h	$16,775.10	$1,274.38	13.16
Seasonal Boiler 25-50 MMBtu/h	$16,773.34	$911.45	18.40
Seasonal Boiler 50-100 MMBtu/h	$16,764.83	$466.52	35.94
Seasonal Boiler 100-200 MMBtu/h	$16,769.08	$273.10	61.40
Seasonal Boiler 200+ MMBtu/h	$16,779.64	$116.17	144.44

Table 10: Benefit-to-Cost Ratio – Flash Steam

Prototype	CZ 1	CZ 2	CZ 3	CZ 4	CZ 5	CZ 6	CZ 7	CZ 8	CZ 9	CZ 10	CZ 11	CZ 12	CZ 13	CZ 14	CZ 15	CZ 16
Year-Round 10-15 MMBtu/h	12.4	12.4	12.4	12.4	12.4	12.5	12.5	12.5	12.5	12.5	12.4	12.4	12.4	12.5	12.5	12.5
Year-Round 15-25 MMBtu/h	N/A	20.1	20.1	20.1	20.1	20.3	20.3	20.3	20.3	20.3	20.1	20.1	20.1	20.3	20.3	20.3
Year-Round 25-50 MMBtu/h	28.1	28.1	28.1	28.1	28.1	28.4	28.4	28.4	28.4	28.4	28.1	28.1	28.1	28.4	28.4	28.4
Year-Round 50-100 MMBtu/h	N/A	54.9	54.9	54.9	54.9	55.6	55.4	55.6	55.6	55.6	54.9	54.9	54.9	55.6	55.6	55.6
Year-Round 100-200 MMBtu/h	N/A	93.8	93.8	93.8	N/A	94.9	N/A	94.9	94.9	94.9	93.8	93.8	93.8	94.9	94.9	94.9
Year-Round 200+ MMBtu/h	220.4	220.4	220.4	220.4	N/A	223.1	N/A	223.1	223.1	223.1	220.4	220.4	220.4	223.1	223.1	223.1
Seasonal 10-15 MMBtu/h	8.1	8.1	8.1	8.1	8.1	8.1	8.1	8.1	8.1	8.1	8.1	8.1	8.1	8.1	8.1	8.1
Seasonal 15-25 MMBtu/h	N/A	13.2	13.2	13.2	13.2	13.2	13.2	13.2	13.2	13.2	13.2	13.2	13.2	13.2	13.2	13.2
Seasonal 25-50 MMBtu/h	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4
Seasonal 50-100 MMBtu/h	N/A	35.9	35.9	35.9	35.9	36.0	36.0	36.0	36.0	36.0	35.9	35.9	35.9	36.0	36.0	36.0
Seasonal 100-200 MMBtu/h	N/A	61.4	61.4	61.4	N/A	61.5	N/A	61.5	61.5	61.5	61.4	61.4	61.4	61.5	61.5	61.5
Seasonal 200+ MMBtu/h	144.3	144.3	144.3	144.3	N/A	144.5	N/A	144.5	144.5	144.5	144.3	144.3	144.3	144.5	144.5	144.5

2.5 Flash Steam Recovery – Statewide Impacts

2.5.1 Statewide Energy and Energy Cost Savings

The Statewide CASE Team took the following steps to determine statewide savings from the proposed flash steam recovery measure.

First, the Statewide CASE Team used a statewide boiler inventory of local AQMD boiler permits (Swanson & Staller, Steam Trap Fault Detection & Diagnostics in Existing Industrial Applications, 2025) to estimate statewide boiler capacities and total quantity of installations by boiler capacity bins. More information on the data can be found in Appendix C.

The Statewide CASE Team refined the statewide capacity for each capacity bin to account for Title 24, Part 6 purview and to measure qualification, making the following changes:

1. Removed boilers with input capacities under 10 MMBtu/h and any units that were indicated to be hot water boilers or hot water heaters in the permit data.
2. Removed oilfield and utility boilers, which are not subject to Title 24, Part 6 requirements.
3. Removed five percent of remaining boiler capacity to account for boilers that are not served by a pressurized deaerator and boilers that are expected to qualify for the measure exceptions, based on field experience.
4. Assumed the cannery industry used seasonal boilers and thus separated them from year-round boilers.
    a. The cannery capacity includes the capacity from major tomato and canned fruit and vegetable processers in the state. The Statewide CASE Team is not aware of other major facility types in California that would typically operate boilers seasonally.

The statewide capacity after these changes represents the Existing Steam Boiler Stock. Boilers in the healthcare, education, and refinery sectors were included in the statewide capacity totals. The Statewide CASE Team may update inclusion of these boilers and utility boilers according to ongoing conversations regarding Title 24, Part 6 and process load applicability in these sectors.

To estimate the capacity of new process boilers installed annually from new construction and additions, the Statewide CASE Team calculated two Industrial Product Growth Rates (IPGRs) for California process boiler capacity, one for year-round boilers and one for seasonal boilers. See Appendix C for details on how the Statewide CASE Team calculated the IPGRs. The annual new construction and additions forecast is equivalent to the Existing Boiler Stock multiplied by the IPGR.

To estimate the capacity of new process boilers installed annually from alterations or replacements, the Statewide CASE Team calculated the replacement rate for boilers and applied it to Existing Boilers Stock. Boiler lifetimes range widely, with most estimates in the 25- to 40- year range (Van Wortswinkel & Nijs, 2010). The boiler replacement rate is based on a 30-year boiler lifetime, which means that 3.3 percent of the Existing Boiler Stock is replaced each year. The boiler alterations forecast is therefore equivalent to the Existing Boiler Stock multiplied by 3.3 percent.

The Statewide CASE Team then multiplied the per-unit measure savings by the annual new construction and additions forecast and by the alterations forecast to get first-year statewide savings, not accounting for natural market adoption. To estimate the share of new qualifying boilers that would install blowdown flash steam recovery systems without the requirement in place, the Statewide CASE Team leaned on input from boiler manufacturers and vendors during stakeholder interviews and an analysis of IAC Audit Data from 64 boilers at 32 steam-using industrial plants from 2010 to 2022. The Statewide CASE Team applied a market share percentage of ten percent to the statewide savings for each boiler capacity bin to arrive at the final statewide savings estimate.

More details on the methodology and context about estimating the statewide energy and energy cost savings can be found in the 2028 CASE Methodology Report. Appendix C presents the assumptions on the percentage of the total construction forecast that the proposed measure would impact.

The tables below present the first-year statewide energy and LSC savings from newly constructed buildings and additions (Table 11) and alterations (Table 12) by climate zone.

Table 13 presents first-year statewide savings from new construction, additions, and alterations.

Table 11: Statewide Energy and LSC Impacts – New Construction and Additions

Climate Zone	Statewide New Construction and Additions Impacted by Proposed Change in 2029 (MMBtu/h)	First-Year Electricity Savings (GWh)	First-Year Peak Electrical Demand Reduction	First-Year Natural Gas Savings (Million Therms)	First-Year Source Energy Savings (Million kBtu)	30-Year Present Valued LSC Savings (Million 2029 PV$)
1	**4.69**	**-**	**-**	**0.001**	**-**	**$0.12**
2	**12.97**	**-**	**-**	**0.004**	**-**	**$0.33**
3	**87.72**	**-**	**-**	**0.027**	**-**	**$2.22**
4	**35.08**	**-**	**-**	**0.011**	**-**	**$0.88**
5	**7.43**	**-**	**-**	**0.002**	**-**	**$0.19**
6	**56.89**	**-**	**-**	**0.017**	**-**	**$1.45**
7	**16.77**	**-**	**-**	**0.005**	**-**	**$0.43**
8	**85.52**	**-**	**-**	**0.026**	**-**	**$2.17**
9	**105.91**	**-**	**-**	**0.032**	**-**	**$2.70**
10	**71.67**	**-**	**-**	**0.022**	**-**	**$1.83**
11	**35.79**	**-**	**-**	**0.011**	**-**	**$0.89**
12	**268.42**	**-**	**-**	**0.082**	**-**	**$6.80**
13	**302.03**	**-**	**-**	**0.093**	**-**	**$7.66**
14	**37.79**	**-**	**-**	**0.011**	**-**	**$0.96**
15	**18.90**	**-**	**-**	**0.006**	**-**	**$0.48**
16	**10.23**	**-**	**-**	**0.003**	**-**	**$0.26**
Total	1,157.80	-	-	0.354	-	$29.36

Table 12: Statewide Energy and LSC Impacts – Alterations

Climate Zone	Statewide Alterations Impacted by Proposed Change in 2029 (MMBtu/h)	First-Year Electricity Savings (GWh)	First-Year Peak Electrical Demand Reduction	First-Year Natural Gas Savings (Million Therms)	First-Year Source Energy Savings (Million kBtu)	30-Year Present Valued LSC Savings (Million 2029 PV$)
1	**11.55**	**-**	**-**	**0.00**	**-**	**$0.27**
2	**29.37**	**-**	**-**	**0.01**	**-**	**$0.71**
3	**195.09**	**-**	**-**	**0.06**	**-**	**$4.77**
4	**79.15**	**-**	**-**	**0.02**	**-**	**$1.92**
5	**15.17**	**-**	**-**	**0.00**	**-**	**$0.39**
6	**127.71**	**-**	**-**	**0.04**	**-**	**$3.14**
7	**34.21**	**-**	**-**	**0.01**	**-**	**$0.88**
8	**196.46**	**-**	**-**	**0.06**	**-**	**$4.79**
9	**241.77**	**-**	**-**	**0.07**	**-**	**$5.91**
10	**162.71**	**-**	**-**	**0.05**	**-**	**$3.99**
11	**87.87**	**-**	**-**	**0.03**	**-**	**$2.06**
12	**587.32**	**-**	**-**	**0.18**	**-**	**$14.47**
13	**650.69**	**-**	**-**	**0.20**	**-**	**$16.15**
14	**89.66**	**-**	**-**	**0.03**	**-**	**$2.15**
15	**44.13**	**-**	**-**	**0.01**	**-**	**$1.07**
16	**23.79**	**-**	**-**	**0.01**	**-**	**$0.58**
Total	2,576.64	-	-	0.77	-	$63.24

Table 13: Statewide Energy and LSC Impacts – New Construction, Additions, and Alterations

Construction Type	First-Year Electricity Savings (GWh)	First-Year Peak Electrical Demand Reduction (MW)	First -Year Natural Gas Savings (Million Therms)	First-Year Source Energy Savings (Million kBtu)	30-Year Present Valued LSC Savings (Million 2029 PV$)
New Construction and Additions	-	-	0.35	-	$29.36
Alterations	-	-	0.77	-	$63.24
Total	**-**	**-**	**1.12**	**-**	**$92.60**

2.5.2 Statewide Greenhouse Gas Emissions Reductions

Table 14 presents the estimated first-year reduction in GHG emissions resulting from the proposed code change. In this initial year, the Statewide CASE Team expects to avoid 3,775 metric tons of carbon dioxide equivalent (CO_2e) emissions. These reductions, along with their associated monetary value, were calculated using hourly GHG emissions factors published alongside the LSC hourly factors and source energy hourly factors in the research versions of CBECC, as well as data from the CEC's 2028 Metrics Report. See the 2028 CASE Methodology Report for additional information.

Table 14: First-Year Statewide GHG Emissions Impacts

Construction Type	Reduced GHG Emissions from Electricity Savings (Metric Tons CO_2e)	Reduced GHG Emissions from Natural Gas Savings (Metric Tons CO_2e)	Total Reduced GHG Emissions (Metric Ton CO_2e)	Total Monetary Value of Reduced GHG Emissions ($)
New Construction	0	0	1,848.65	227,657.15
Additions & Alterations	0	0	4,015.15	494,455.32
Total	**0**	**0**	**5,863.80**	**722,112.47**

2.5.3 Statewide Water Use Impacts

The water savings are equivalent to the difference in baseline and proposed flash steam mass flows. Appendix A contains further calculation details.

Table 15 presents the impact on water use. See the 2028 CASE Methodology Report for additional information on the embedded electricity savings estimates, which assume embedded energy factors of 5,440 kWh per million gallons of water for indoor use and 3,280 kWh per million gallons of water for outdoor water use (SBW Consulting, Inc. 2022).

Table 15: Impacts on Water Use and Embedded Electricity in Water

Impact	On-Site Indoor Water Savings (Gallons/Year)	On-site Outdoor Water Savings (Gallons/Year)	Embedded Electricity Savings (kWh/Year)
Average Per Unit (MMBtu/h) Impacts	2,970	-	16
First-Year Statewide Impacts for New Construction	3,496,451	-	19,021
First-Year Statewide Impacts for Additions and Alterations	7,594,617	-	41,315
Total First-Year Statewide Impacts	**11,091,068**	**-**	**60,335**

2.5.4 Statewide Material Impacts

The proposed code change requires the installation of flash steam piping and vessels. However, even without a flash steam recovery system, existing sites would already have, or new sites would install, an atmospheric flash tank. The atmospheric tank would be typically replaced by the pressurized flash steam recovery vessel in most cases, and installation of the flash steam recovery vessel would not lead to a net increase in material use. Flash steam piping is typically made of carbon steel and stainless steel (Ryan Waldron, 2023). The proposed requirement would lead to an increase in the demand for steel at industrial sites as shown in Table 16. For more information on the Statewide CASE Team's methodology and assumptions used to calculate embodied GHG emissions, see the 2028 CASE Methodology Report.

Table 16: First-Year Statewide Impacts on Material Use

Material	Impact	Per-Unit Impacts (Pounds per MMBtu/h)	First-Year Statewide Impacts (Pounds)	Embodied GHG emissions saved (Metric Tons CO_2e)
Mercury	No change	-	-	-
Lead	No change	-	-	-
Copper	No change	-	-	-
Steel	Increase	0.43	1,623	-1
Plastic	No change	-	-	-
TOTAL	**NA**	**0.43**	**1,623**	**-1**

2.5.5 Environmental Impacts

Flash steam recovery systems reduce water by using flash steam to serve low-pressure loads instead of down-regulating live boiler steam. The reduction in energy consumption because of increasing flash steam recovery would also indirectly lead to improvements in local air quality. Combustion of natural gas produces nitrogen oxides (NOx), a chemical precursor to ozone. Reducing the consumption of natural gas will therefore indirectly lead to reduced ozone (Chen, Omotesho, & Johnson, 2025).

The Statewide CASE Team considered opportunities to minimize the environmental impact of the proposal, including evaluation of "specific economic, environmental, legal, social, and technological factors" (Cal. Code Regs., tit. 14, § 15021). The Statewide CASE Team did not determine this measure would result in significant direct or indirect adverse environmental impacts and therefore did not develop any mitigation measures.

2.5.6 Other Non-Energy Impacts

Increasing the quantity of flash steam recovered and returned to the boiler system for reuse reduces consumption of water and chemicals used to treat it. In addition to water and chemical savings, the reduction in fuel usage from recovering flash steam lowers boiler NOx emissions. This practice would reduce local photochemical smog and improve air quality.

2.6 Flash Steam Recovery – Proposed Code Language

2.6.1 Guide to Markup Language

The proposed changes to the standards, Reference Appendices, and the ACM Reference Manuals are provided below. Changes to the 2025 documents should be marked with dark blue underlining (new language) and ~~strikethroughs~~ (deletions).

2.6.2 Administrative Code (Title 24, Part 1)

No changes are proposed to Title 24, Part 1.

2.6.3 Energy Code (Title 24, Part 6)

SECTION 100.1 – DEFINITIONS AND RULES OF CONSTRUCTION

Section 100.1(b) – Definitions: Recommends new or revised definitions for the following terms:

FLASH STEAM is water vapor that is generated when condensate is dropped to a pressure lower than its saturation pressure, which then vaporizes a fraction of the liquid in a process called flashing.

PRESSURIZED CONDENSATE RETURN is a steam condensate return system that continuously operates at a pressure above 15 psig during normal operation and is not vented to atmosphere. The system contains liquid condensate and any associated steam vapor that may be present in the piping.

SUBCHAPTER 3 – NONRESIDENTIAL, HIGH-RISE RESIDENTIAL, HOTEL/MOTEL OCCUPANCIES, AND COVERED PROCESSES--MANDATORY REQUIREMENTS

SECTION 120.6 – MANDATORY REQUIRMENTS FOR COVERED PROCESSES

120.6(d)4 Mandatory requirements for process boilers.

4. Any newly installed process steam boilers with capacities at or above 10 MMBtu/h that have or are connected to a system with a pressurized deaerator are required to recover and route flash steam from blowdown to the deaerator or another heating load.

Exception 1 to 120.6(d)4: Newly installed process steam boiler systems where high-pressure condensate is returned to the deaerator without being flashed (dropped to atmospheric pressure).

Exception 2 to 120.6(d)4: Newly installed process steam boiler systems where the linear length from the boiler to the serving deaerator is greater than or equal to 100 feet. The linear length is the sum of all horizontal and vertical pipe runs. Elbows and pipe fittings, including reducers, shall be excluded from the calculation.

2.6.4 Reference Appendices

The Statewide CASE Team proposes no changes to the Reference Appendices.

2.6.5 Compliance Manuals

The Statewide CASE Team will provide the CEC with recommended revisions to compliance manuals after the 45-Day Language is published.

2.6.6 ACM Reference Manual

The Statewide CASE Team proposes no changes to the ACM Reference Manual.

2.6.7 Compliance Forms

As discussed in Section 2.1.4.5, NRCC-PRC-E and NRCI-PRC-E would both need to be updated to reflect the proposed change. The Statewide CASE Team can support the CEC in implementing these updates if the proposed change is adopted. These potential updates would look as follows:

NRCC-PRC-E

Within section I PROCESS BOILER table:

- Create the following columns in the table:
    - Which rated input capacity aligns with this process steam system (Btu/h)?

        - In Virtual Compliance Assistant, add the following dropdown options:
            - Rated input capacity for one or more connected boilers to include: $\geq$ 10MMBtu/h
            - Rated input capacity for one or more connected boilers to include: $<$10MMBtu/h
    - Provide sheet number that supports the required calculation for the amount of flash steam recovered or reduced.
    - Does the process steam boiler recover and route flash steam from boiler blowdown to the deaerator or another heating load?
        - In Virtual Compliance Assistant, add the following dropdown options:
            - Yes
            - This doesn't apply because the process boiler has a rated capacity less than 10MMBtu/h.
            - This doesn't apply because the system does not have a pressurized deaerator.
            - This doesn't apply because the system has a pressurized condensate return system installed.

NRCI-PRC-E

- Add the following to the Process Boilers Table:
    - Column for Blowdown Flash Steam Recovery
    - Column for Blowdown Flash Steam Recovery Flash Tank Overhead Piping
    - Column for Flash Tank Piping Open Valves

3. Condensate Return

3.1 Condensate Return – Measure Description

3.1.1 Proposed Code Change

A process steam system is a steam-producing boiler system that serves loads other than space heating or service water heating for human occupants, such as manufacturing or industrial processes. A condensate return system, consisting of piping, collection tanks, and pumps, returns hot condensate—which is generated after process loads use steam—to the boiler system for reuse.

This proposed measure would require newly constructed process steam systems and newly added process steam loads that a) use indirect-contact heat exchangers and b) generate condensate during normal operation to return steam condensate to the boiler for reuse via a condensate return system. Qualifying process steam systems must also return condensate from associated drip legs.

The proposed measure would only apply to steam systems that meet certain criteria for load size and condensate return piping lengths. Condensate return from direct steam injection (that comes in direct contact with the process) would be exempt from the requirement for condensate return.

To meet the criteria for load size and condensate return piping lengths, the linear length from the load to the condensate return tank or the deaerator, measured across both horizontal and vertical dimensions, must be under a maximum length depending on the system steam flow. The linear lengths for each steam flow range of the individual load are specified in Table 17.

Table 17: Condensate Return Distance Code Trigger Criteria

Steam Flow (lbs/h)	Linear Length[3] (ft) less than
<1,000	Exempt
≥1,000, <2,000	400
≥2,000, <3,000	600
≥3,000, <4,000	800
≥4,000, <6,000	1,100
≥6,000	1,300

All steam loads that are above the maximum linear length for their steam flow shall include the condensate return distance from the load to the condensate return tank or the deaerator in the steam system construction documents to prove that the requirement is not applicable to that steam load.

Table 18 summarizes the scope of the proposed code change.

[3] Linear length shall include the sum of all horizontal and vertical pipe loads. Elbows and pipe fittings, including reducers, shall be excluded from the distance calculation.

Table 18: Scope of Proposed Code Change

A ☑ indicates the proposed code change is relevant.

Building Type(s)	Construction Type(s)	Type of Change
☐ Single Family	☑ New Construction	☑ Mandatory
☐ Multifamily	☑ Additions	☐ Prescriptive
☑ Nonresidential (not Group R uses)	☑ Alterations	☐ Performance

Application Climate Zones	Energy Code Sections	Compliance Forms	Sections of ACM Reference Manuals
Climate Zones 1-16	• Part 6, Sections 100.1 and 120.6(l)	NRCC-PRC-E NRCI-PRC-E	• N/A

Third Party Verification	Updates to Compliance Software
☑ No changes to third party verification	☑ No updates
☐ Update existing verification requirements	☐ Update existing feature
☐ Add new verification requirements	☐ Add new feature

3.1.2 Benefits of Proposed Change

Condensate return is a widely accepted best practice for steam systems and provides significant fuel and water savings by reducing the need for make-up water, pre-heating fuel, and chemicals for water treatment. During the October 29 Utility-Sponsored Stakeholder Meeting covering this proposed flash steam measure, one stakeholder commented, "Given California's historic water shortage issues, how has [condensate return] not been incorporated in Title 24 [requirements] already?"

Some sites may also benefit from a reduction in wastewater costs. Because condensate is effectively distilled water, its recovery also reduces the need for boiler blowdown, which results in additional energy savings. Depending on site conditions, condensate return is expected to yield energy savings of approximately 5 percent to 8 percent of baseline boiler system fuel use.

There are two main sources of energy and water savings when condensate is returned to the boiler for reuse: (1) the warmer returned condensate decreases the fuel required to preheat fresh make-up water for boiler feedwater, and (2) boiler feedwater from condensate return has fewer dissolved solids, reducing the need for blowdown and associated blowdown losses. As less fresh make-up water is needed, overall water use is reduced along with chemicals used for water treatment.

The reductions in fuel consumption, water, sewer use, and chemicals for water treatment associated with condensate return all reduce costs for facilities. Overall, condensate return is highly cost-effective. During a stakeholder interview, one boiler manufacturer told the Statewide CASE Team that condensate return was one of the top three recommendations for site owners purely from an economic standpoint, saying, “Most people know that condensate is extremely lucrative to pump back.”

In addition to the energy and water benefits, these practices would reduce local photochemical smog and improve air quality. The value of improved air quality is amplified by the consideration that many industrial facilities are located near LMI housing, which typically gets disproportionately exposed to lower air quality. Ancillary benefits include improved public perception through reduction of steam plumes.

3.1.3 Background Information

In process steam systems, condensate is formed when steam releases its heat of condensation in a heat exchanger and condenses into liquid. After process loads use steam, hot condensate remains. Drip legs are vertical pipe sections designed to collect this condensate and prevent it from accumulating in the pipes. The condensate can be drained to wastewater or returned to the boiler for reuse. Condensate that is drained to waste must be replaced with fresh, cold make-up water, which requires chemical treatment and heating. Condensate is essentially distilled water, meaning it does not require chemical treatment and is warmer than fresh make-up water, making it ideal for boiler feedwater.

Processes that use steam in direct contact with a product or contaminant per design or during normal operation are exempt from the proposed condensate return requirement because the steam, and therefore the condensate formed from the steam, may be contaminated with particulate matter and is not fit for immediate reuse.

DOE literature has recommended increasing the percentage of returned condensate as a steam system best practice in since at least the early 2000s, while DOE also provides a steam tip sheet specifically on improving condensate return (DOE, 2012). This proposed code change originated from discussions with California-based consulting engineers from strategic energy management programs and the DOE IAC program. International Energy Conservation Code (IECC) does not cover condensate return. ASHRAE does not have a specific standard for condensate return but it has considerations for condensate return in piping design, steam system operation, and energy efficiency.

To the knowledge of the Statewide CASE Team, condensate return requirements have not been proposed in previous code cycles. In 2013, Title 24 Part 6 first adopted requirements for process boilers. In 2022, Title 24 Part 6 adopted requirements for strainers and fault detection and diagnostics in steam trap assemblies.

3.1.4 Modifications to Energy Code Documents

This section provides descriptions of how the proposed code change will affect each Energy Code document. Section 3.6 Condensate Return – Proposed Code Language of this report provides detailed revisions to code language.

3.1.4.1 Energy Code Change Summary

SECTION 100.1(b) – DEFINITIONS AND RULES OF CONSTRUCTION

Subsection 100.1(b): The proposed measure would add new definitions for a process steam system and condensate return system.

SECTION 120.6 – MANDATORY REQUIREMENTS FOR COVERED PROCESSES

Subsection 120.6(l). Mandatory Requirements for Process Steam Systems.

Subsection 120.6(l)1: The proposed regulations would add a requirement for a condensate return system that returns condensate to the boiler plant for reuse at newly constructed process steam systems and for additions and alterations that add a process steam load which generates condensate during normal operation. The requirement would only apply to steam systems that meet certain criteria for load size and condensate return piping lengths and would not include condensate return from direct steam injection.

3.1.4.2 Reference Appendices Change Summary

There are no proposed changes to the reference appendices.

3.1.4.3 Compliance Manuals Change Summary

The proposed changes would create a new section in the Nonresidential Compliance Manual, which would outline mandatory requirements for process steam systems. A newly created sub section would explain the condensate return requirement and verification steps.

3.1.4.4 Alternative Calculation Method Reference Manual Change Summary

The proposed measure will not modify ACM Reference Manuals because the proposed measure requires no associated software updates.

3.1.4.5 Compliance Forms Change Summary

NRCC-PRC-E and NRCI-PRC-E, Plumbing would both need to be updated. In the Certificate of Compliance form, a new section would be added to cover Steam Systems and the condensate return requirement in 120.6(l). The Process System Certificate of Installation document (NRCI-PRC-E) would require new input fields in a Process Steam section to ensure that qualified steam systems meet the condensate return requirement and to verify qualification for the exception if applicable.

3.1.5 Measure Context

3.1.5.1 Comparable Model Codes or Standards

Review finds no relevant model codes or standards for measuring context.

3.1.5.2 Interactions with Other Regulations

While ASHRAE does not have a specific standard for condensate return, it has considerations for condensate return in piping design, steam system operation, and energy efficiency. Review found no known existing federal, state, or local regulatory requirements that address condensate return in process steam systems. Current Title 24, Part 6 requirements cover steam traps in new industrial facilities and steam traps added to support new, non-replacement, process equipment in existing industrial facilities where the installed steam trap operating pressure is greater than 15 psig and the total combined connected boiler input rating is greater than 5 MMBtu/hr. The code requires central steam trap fault detection and diagnostics monitoring, steam trap fault detection, and steam trap strainer installation. The proposed condensate return requirement discussed in this document would have no impact on these existing requirements. There are no known interactions with other parts of the California Building Code or local requirements. The proposed requirement would not interfere with compliance with OSHA requirements for pressurized vessels or AQMD requirements related to boiler emissions.

3.2 Condensate Return – Compliance and Enforcement

3.2.1 Compliance

To ensure compliance with the proposed condensate return requirement, confirmation steps would need to be taken during permit application (plans review). Plans must indicate planned installation of condensate return, including pipe length and pipe size (or else the planned installation of direct steam injection). If the steam load does not qualify for the requirement based on the code trigger table, they must include calculations documenting the linear length from the load to the condensate return tank or the deaerator in the steam system construction documents to prove that the requirement is not applicable to that steam load. New fields in NRCC-PRC-E and NRCI-PRC-E would need to be completed.

Designers: Designers would need to be aware of the new condensate return requirement in section 120.6(l) so they can design compliant process steam systems. They would need to fill out an updated NRCC-PRC-E form and to submit design documents indicating a compliant design. The form would need to include the planned installation of condensate return lines, including pipe length and pipe size.

AHJ plan checkers: During the permit application phase, AHJ plan checkers would review the submitted NRCC-PRC-E form and design documents to confirm that the design includes either direct steam injection lines or condensate return piping for each load.

Installation contractors: Installation contractors would be required to correctly install condensate return lines in accordance with design and manufacturing specifications, which their normal operating procedures already require. When the installation contractor fills in the NRCI-PRC-E, they would need to include a confirmation of labeled condensate return piping.

Field technicians: Field technicians would not be affected by the proposed measure. Field technicians may experience additional site maintenance visits if the condensate return pump fails.

AHJ building inspectors. The AHJ building inspector would need to verify the installation of condensate return system (tanks and piping) from all loads with heat exchangers.

Review finds that all definitions added for new proposed code language do not conflict with any existing definitions in other parts of Title 24.

3.2.2 Impact on Market Actors

Table 19 summarizes impacts on market actors and suggests outreach and education that might be helpful to support market actors as they prepare for the effective date of the requirements.

Table 19: Impacts on Market Actors and Suggested Training and Education Opportunities

Market Actor	Impact(s)	Suggested Outreach and Education
Developers[a]	Be aware that condensate return is required and plan for additional costs.	Developers likely will not require additional training.
Design Professionals[b]	Be aware of new requirements and code triggers when designing process boiler and steam systems. Include condensate return equipment where required and include relevant equipment specifications in design documents. Complete new Process Steam section of NRCC-PRC-E.	Industrial boiler equipment and steam system design firms should be provided training on the energy code including compliance requirements and compliance documentation.
Construction Team[c]	Install condensate return piping as specified in the approved design documents, consistent with standard practice. Complete new section for Process Steam in the NRCI-PRC-E form.	System installer should be provided training on the energy code updates and supporting documentation, compliance requirements, and compliance documentation.
Building Departments[d]	Plan Reviewers will have an additional requirement to check when reviewing NRCC and NRCI forms and design documents.	Local building department plan examiners will need education and training to familiarize them with new code language.
Verification Testers[e]	No verification testing is required.	NA
Building Owners, Managers, and Occupants	Higher upfront cost and reduced energy bills. Need to maintain condensate return system.	Outreach to owners and operations personnel could improve understanding of the benefits of condensate return.
Manufacturers and Distributors[f]	Additional sales of condensate return piping and equipment.	Manufacturers and distributors will likely not require additional training.

a. Developers plan the project, manage finances, and manage risks from start to finish.

b. Design professionals include architects, interior designers, engineers (mechanical, electrical, plumbing, structural), specification writers, cost estimators, commissioning agents, lighting designers, and energy consultants.

c. Construction team includes general contractors, design-build contractors, installation contractors (e.g., HVAC, plumbing, electrical), commissioning agents, and tradespeople.

d. Building departments include plans reviewers, building inspectors, specialty inspectors, permit counter technicians and sustainability department staff.
e. Verification testers include commissioning agents, ECC Raters, and Acceptance Test Technicians.
f. Manufacturers and distributors include steam system designers, component manufacturers, OEMs, steam system equipment manufacturers, manufacturer representatives, and distributors.

The 2028 CASE Methodology Report presents a quantitative assessment of how changes to the California building code impact builders, building designers, energy consultants, and building owners. The analysis in the methodology report is not specific to the code changes presented in this report. The following provides a qualitative description of how this specific code change affects various market actors and additional quantitative analyses of its potential impacts on building industry subsectors.

Builders: The proposed change would likely affect commercial and industrial builders; however, it would likely not impact firms focused on the construction or retrofitting of industrial buildings, utility systems, public infrastructure, or other heavy construction. The proposed change would not affect all firms and workers in the industrial and commercial building industries equally; instead, it would primarily affect specific subsectors within the industries. Table 20 shows the commercial and industrial building subsectors that the Statewide CASE Team expects to be impacted by the changes proposed in this report.

Table 20: Specific Subsectors of the California Commercial and Industrial Building Industry Impacted by Proposed Change to Code/Standard by Subsector in 2029 (Estimated)

Construction Subsector	Establishments*	Employment	Annual Payroll (Billions $)
Industrial Building Construction	TBD	TBD	TBD
Nonresidential Structural Steel Contractors	365	11,899	$1.1
Nonresidential Plumbing & HVAC Contractors	2,270	55,182	$5.8
Other Nonresidential Equipment Contractors	580	9,749	$1.1
Nonresidential Site Preparation Contractors	1,147	19,273	$1.9
All Other Nonresidential Trade Contractors	948	17,084	$1.7

a. Source: (State of California, n.d.)
b. * An establishment is single economic unit, typically at one physical location, that engages in one, or predominantly one, type of economic activity for which a single industrial classification may be applied. Many businesses are composed of multiple establishments. US Bureau of Labor Statistics, Handbook of Methods. https://www.bls.gov/opub/hom/cew/concepts.htm

Facility owners: Facility owners would need to cover the upfront costs of the condensate return equipment and ongoing maintenance costs, but they would also save money from reduced fuel costs due to decreased energy consumption and reduced water costs due to decreased water consumption. Overall, the proposed code changes would result in lower energy and water bills for California facility owners.

The Statewide CASE Team estimates that, on average, the proposed change to Title 24, Part 6 would increase new steam system costs by about $6,672 to $12,139 per MMBtu/h of boiler capacity and would increase maintenance costs by $764 to $3,016 per MMBtu/h of boiler capacity over 30 years. However, the measure would ultimately result in a savings of $101,000 to $155,000 per MMBtu/h of boiler capacity over 30 years with slight variations by climate zone. Overall, the Statewide CASE Team expects the 2028 Title 24, Part 6 updates would save facility owners about $3,120 to $4,660 per year per MMBtu/h of boiler capacity relative to facilities that remain minimally compliant with the 2025 Title 24, Part 6 requirements.

Manufacturers: As discussed in Section 3.3.1.1, multiple manufacturers and installers of condensate return-related equipment are based in California, and these businesses would sell and install additional equipment including pumps, piping, insulation, and tanks. Refer to Section 3.3.4 for more information on the resultant impact on California jobs.

3.2.3 Compliance Software Updates

Review finds no compliance software updates required for this measure proposal.

3.2.4 Cost of Enforcement

The Statewide CASE Team acknowledges that changes to the code will impact enforcement costs. This report is an evaluation of specific measures, and the collective impact of all proposed changes for the 2028 Title 24, Part 6 may represent an increase in training and/or workload for enforcement personnel.

Costs of enforcement would include costs to deliver training to enforcement officials to enable them to adequately enforce the proposed measure.

This training can leverage current education programs to minimize expenses. Plan examiners would need to check for one new requirement, and building inspectors would need to verify installation of one additional requirement. Local governments will need to retrain building department staff; however, this practice aligns with the regular triennial code update cycle and is supported by resources such as Energy Code Ace.

Costs for updating standards, compliance materials, and responding to inquiries are expected to remain within existing code development and enforcement budgets.

3.3 Condensate Return – Market and Economic Analysis

3.3.1 Market Structure and Availability

3.3.1.1 Current Market Structure and Availability

Players in the condensate return system market include steam system designers, component manufacturers, OEMs, steam system equipment manufacturers, manufacturer representatives, distributors, mechanical contractors, boiler technicians, and water treatment companies. Designers specify condensate recovery systems that meet steam and boiler system needs. Component manufacturers and OEMs design, manufacture, and supply the system components, including piping, pumps, and condensate return tanks, which are sold as packaged systems and as individual components. Manufacturer representatives and distributors act as the local sales and distribution channel for the component manufacturers and specialized steam equipment companies. Mechanical contractors handle the physical installation of the system, including any electrical needs for condensate pumps or tank level controls. Equipment manufacturer representatives and mechanical contractors typically perform commissioning and startup.

The market for condensate return systems and system components is mature, with multiple manufacturers and suppliers providing designers and contractors with many options for purchase. Table 21 lists companies that the Statewide CASE Team has identified as major market actors.

Table 21: Major Condensate Return System Component Manufacturers, Installers, and Vendors

Company	Market Actor Type	Product Offering	Headquartered in California
Armstrong	Manufacturer	Pumps	No
Boiler Supplies	Distributor	Pumps, tanks	No
Calpacific Equipment Company	Vendor	Pumps, tanks	Yes
National Pump Supply	Distributor	Pumps	No
Parker Boiler	Manufacturer	Pumps, tanks	Yes
Solenis	Water Treatment	Boiler water chemical treatment, monitoring and controls, field and lab expertise	No
Spirax Sarco	Manufacturer	Pumps	No
Rema	Manufacturer	Pumps, tanks	No

Condensate recovery systems are commonly included in standard steam system designs. Steam and boiler system designers are familiar with these systems, but many may require brief training on code updates to ensure steam system designs meet proposed code requirements. Manufacturers and vendors are typically familiar with condensate return equipment.

The Statewide CASE Team estimates that 30 percent of total steam flow is returned across new qualifying statewide steam capacity in California today. Stakeholder interviewees stated that condensate return rates varied widely between industries and often depended on the application and perceived quality of the steam. Chemical plants and pharmaceutical companies generate clean condensate and have higher condensate recovery rates. Food processing facilities often use steam for direct injection, generating contaminated condensate that cannot be returned to the boiler system and would not be required to comply with this code proposal.

To account for contaminated condensate in energy savings estimates, the Statewide CASE Team assumed that 75 percent of total steam flow is returned as condensate in the measure case. The remaining 25 percent of condensate accounts for contaminated condensate and return losses as well as deaerator steam supply.

The Statewide CASE Team plans to reach out to additional stakeholders to gather more information about market adoption and will update the market share estimate based on additional stakeholder feedback from the second public stakeholder workshop to be held on March 17, 2026.

The Statewide CASE Team does not foresee this regulation having negative impacts on technology adoption.

3.3.1.2 Market Challenges and Solutions

The market for condensate return systems is well-established, with multiple vendors and suppliers with decades of experience designing and installing condensate return systems. The Statewide CASE Team does not anticipate any challenges related to product availability with the current market.

Despite the clear fuel, chemical, water, and wastewater savings provided by condensate return systems, many industrial process facilities do not install condensate return systems or increase the size of a condensate return system when new steam loads are added. These facilities often focus on the upfront cost of installing or upgrading condensate return systems. Typical investments for industrial process equipment have payback periods of one to three years, while condensate return system payback periods are often longer, ranging up to about ten years. Industrial facilities often operate with a high barrier for capital expenditure on auxiliary equipment, even if the payback period from operational savings is short (Energy Efficiency Movement, 2025). To address these concerns, the Statewide CASE Team included the cost of all new equipment in the cost-effectiveness analysis and added measure qualifications based on steam load sizes and piping lengths to ensure that only cost-effective combinations of steam loads and return system piping distances need to comply with the proposed requirement. Seasonal facilities may experience longer payback periods than facilities that operate year-round as they operate for fewer hours and have less time to recoup the initial installation costs through avoided energy usage. The Statewide CASE Team calculated cost-effectiveness separately for seasonal steam systems in addition to year-round steam systems and confirmed that the proposed requirement is cost-effective for seasonal steam systems.

Facilities may also be concerned with the potential for condensate to become contaminated after unplanned contact with a process, making it unfit to return to the boiler for reuse. To address this concern, condensate return from direct steam injection is not required to be returned to the system for reuse. Any other sources of contaminated condensate, such as mechanical defects or heat exchanger tube leaks, would need to be monitored and repaired for viable condensate return. Newly installed heat exchangers do not typically experience leaks, as leaks are usually the result of poor water quality or maintenance practices over time. Proper water quality practices, including conductivity monitoring, can ensure newly installed exchangers remain in robust condition and prolong the life of existing heat exchangers by minimizing exposure to poor quality water.

During a stakeholder interview, a steam equipment vendor informed the Statewide CASE Team about the prevalence of heat exchanger stall in lower-temperature applications which leads to operators bypassing steam traps and dumping condensate and steam[4]. The proposed condensate return measure does not diminish these condensate losses. The vendor recommended the use of steam-motive pump traps to prevent heat exchanger stall. The Statewide CASE Team recommends further consideration of heat exchanger stall and steam-motive pump traps in future code cycles.

Section 2.2 describes workforce trainings that may be needed to ensure effective design, installation, and commissioning.

3.3.2 Design and Construction Practices

3.3.2.1 Current Design and Construction Practices

Condensate return is a widely accepted best practice for steam systems, and DOE has included condensate return in the steam tip sheets for over a decade (DOE, 2012). Condensate return systems typically consist of condensate return piping, collection tanks, and pumps. These systems require adequate physical space for installation but can typically be accommodated at existing facilities installing equipment for newly added steam loads. Because condensate piping is smaller than steam piping, and the tank and pump are sized for minimum transient time, heat loss from the condensate is reduced and pump and tank sizing are kept to a minimum. Condensate return piping is generally made of stainless steel to prevent carbonic acid corrosion and should always be insulated to minimize heat loss and maximize energy recovery in a steam system (Paffel, Best Practices for Condensate Piping , 2011). Piping should also be designed for two-phase flow to account for the creation of flash steam in condensate headers. Connections to the condensate header should only be made on a horizontal header and directly on top of the header to prevent water hammering as a result of flash steam entering directly into the condensate space of a header from a piping connecting on to the side or bottom of the header (Paffel, Best Practices for Condensate Piping , 2011). To further avoid the potential of water hammer, low pressure system condensate return lines should be sloped to allow for drainage by gravity and avoid collection of

[4] According to this stakeholder, temperature-controlled heat exchangers serving lower-temperature processes, such as 180°F to 190° hot water routinely enter into vacuum on the steam side. The steam trap then cannot discharge condensate and water accumulates in the heat exchanger in a condition known as stall. The control valve then begins hunting and water hammer results from thermal shock. Operators then bypass the steam trap to protect the process, which wastes significant condensate, flash steam, and live steam. One solution for these applications is the use of steam-motive pump traps, which are sold by multiple major manufacturers. When a steam-motive pump trap cannot discharge condensate normally and liquid accumulates inside of it, a high-limit switch is tripped which introduces live steam to force the condensate out of the trap.

condensate in the pipe that can be picked up by high velocity flash steam (Paffel, Best Practices for Condensate Piping , 2011). For longer distances or higher-pressure situations, condensate return flows by gravity into a receiver tank and is pumped back to the condensate header, ensuring minimum time in the receiver to avoid additional heat loss from the condensate. Condensate receivers are offered in various configurations, such as cylindrical and rectangular, and can be installed at various elevations to meet pump needs (Sengheiser, 2021). Receivers are often sold in packages with pumps, although pumps can be purchased separately. Condensate return pumps come in two main forms: electrical and pressure operated (Paffel, Best Practices for Condensate Piping , 2011). Electrical pumps consist of a condensate receiver and a float switch that is tripped by condensate level, activating the pump to empty the receiver (Paffel, Best Practices for Condensate Piping , 2011). Pressure operated pumps use steam or air as the pumping motive, which is activated by a mechanical or electrical valve based on condensate level. Both types of pumps can be sold as individual pumps (simplex) or a set of pumps (duplex), allowing for pump redundancy (Paffel, Best Practices for Condensate Piping , 2011). Condensate return systems are common in boiler and steam system design today and the proposed changes would come with no anticipated impacts to current design and construction best-practices.

3.3.2.2 Health and Safety Considerations

The proposed code change does not alter any existing federal, state, or local regulations pertaining to safety and health, including rules enforced by the California DOSH. All existing health and safety rules would remain in place. Complying with the proposed code change is not anticipated to have adverse impacts on the safety or health of occupants or those involved with the construction, commissioning, and maintenance of the site. The proposed code change would reduce photochemical smog and improve air quality near the facility by reducing boiler fuel consumption and associated emissions.

3.3.2.3 Design and Construction Challenges and Solutions

The Statewide CASE Team identified pump reliability as the main design and construction challenge for the condensate return measure. During an interview with the Statewide CASE Team, a boiler and steam systems representative stated that the main reason condensate is not always returned at a facility with a condensate return system is due to issues with the condensate pump. The condensate pump may not be sized correctly or may not operate as designed. The pump could fail to adequately drain a condensate receiver, leading to condensate tank overflow, or it could run continuously and eventually break. Operators often do not consider condensate pumps to be critical equipment and therefore may not always prioritize repair of these pumps. To address the impact of pump repairs, the Statewide CASE Team included the costs of pump maintenance and full replacement in the cost-effectiveness calculations to ensure maintenance costs are not a barrier to measure viability.

Table in Section 2.2.2 describes workforce trainings that could support effective design, installation, and commissioning.

3.3.3 Energy Equity and Environmental Justice

The Statewide CASE Team evaluated the potential impact on ESJ communities, including impacts related to race, class, and gender. The Statewide CASE Team determined that the proposed measure would positively impact ESJ communities located near industrial sites. Increasing condensate return lowers the need for fresh make-up water, decreasing the fuel usage onsite. The reduction in boiler fuel consumption because of lower water heating requirements also results in a reduction of GHG emissions and an improvement in local air quality. The value of improved air quality by complying with this code change is amplified by the fact that many industrial facilities are located near LMI communities, which are disproportionately exposed to lower air quality.

The Statewide CASE Team identified potential impacts of the proposed code change via research and field experience. While the listed potential impacts should be comprehensive, they may not yet be exhaustive. Recognizing the importance of engaging ESJ communities and gathering their input to inform the code change process and proposed measures, the Statewide CASE Team is working to build relationships with CBOs to facilitate meaningful engagement. Any stakeholders with input on how this proposal may impact ESJ communities or other perspectives should reach out to Emma Conroy (econroy@westmonroe.com).

3.3.4 Impacts on Jobs and Businesses

This section will be completed for the Final CASE Report.

3.3.5 Economic and Fiscal Impacts

This section will be completed for the Final CASE Report.

3.4 Condensate Return – Cost Effectiveness

3.4.1 Cost Effectiveness Methodology

The Statewide CASE Team collaborated with CEC staff to confirm that the cost-effectiveness methodology aligns with CEC guidelines, including cost inclusion parameters. The 2028 CASE Methodology Report and Appendix A provide reproducibility details.

Per California Law (Public Resources Code 25000), a measure is considered cost effective if its BCR is 1.0 or greater, amortized over the economic life of the structure. The Statewide CASE Team calculates BCR by dividing total dollar benefits by total dollar costs over a 30-year analysis period.

Benefits are based on LSC, which assigns an hourly dollar value to energy use. LSC hourly factors weigh the long-term value of each hour differently, where times of peak demand are valued more than off-peak hours. These factors are not utility rates, forecasts, or bill estimates. The CEC develops and publishes LSC hourly conversion factors for each code cycle.

Total measure costs include first costs and ongoing maintenance costs assessed over the 30-year period. Benefits and costs are evaluated incrementally, relative to the most recently adopted Energy Code. The analysis excludes design costs and incremental code compliance verification costs.

3.4.2 Energy and Energy Cost Savings Results

To analyze the energy savings for the proposed condensate return requirement, the Statewide CASE Team calculated the difference in energy consumption between the baseline (a steam system returning 30 percent of its condensate) and measure case (a steam system returning 75 percent of its condensate). Savings calculations were completed for two separate components driving savings:

- Deaerator preheating savings: Replacing cold make-up water with warm or hot returned condensate reduces the energy required to heat the deaerator. Returned condensate is typically at 200 degrees Fahrenheit (F), while cold make-up water is around 65°F. The energy savings calculations are based on the amount of energy required to heat the water in the baseline case compared with the measure case and account for temperature losses due to condensate pipe length.
- Blowdown reduction: Replacing make-up water (which contains dissolved solids) with condensate (which is effectively distilled water) reduces the quantity of water that needs to be blown down from the boiler and replaced. Blowdown for a 100 psig boiler reaches 338°F prior to discharge, and reducing water lost to blowdown reduces energy losses by avoiding the need to heat more make-up water. The Statewide CASE Team first calculated the difference in water lost to blowdown between the baseline case and the measure case and then calculated the energy that would have been required to heat that water.

Natural gas and water savings increase as the associated steam boiler capacity increases because the total volume of returned condensate increases. The water savings also scale based on the boiler capacity, and the greater the water savings the greater the energy saved from avoided make-up water heating.

The more the boiler is operated, the greater the resultant savings. As such, boilers that operate infrequently throughout the year due to seasonal loads will experience lower savings. Due to this variance, the Statewide CASE Team calculated annual energy savings for boilers with seasonal loads separately from boilers with more typical annual loads. Calculations for boilers operating annually assumed 6,500 operating hours per year at 40 percent load, while calculations for seasonal boilers assumed 2,400 operating hours per year (primarily July through October) at 80 percent load. The Statewide Case TEAM based these assumptions for operating hours and load factor on analysis of data from a survey of 128 California steam-using sites in IAC database (Swanson & Staller, Steam Trap Fault Detection & Diagnostics in Existing Industrial Applications, 2025). Since boiler and flash steam recovery systems are frequently sized for higher capacities than they typically operate at, the Statewide CASE Team applied an 80 percent load assumption for all boilers, year-round and seasonal, to calculate steam loads for the cost analysis.

Savings from condensate return should stay constant over the measured lifetime. However, condensate return system components could fail, which would decrease the energy savings from the measure.

Per-unit savings for the first year are expected to be 186,415 kBtu per MMBtu/h of boiler capacity for year-round boiler operation and 137,900 kBtu per MMBtu/h of boiler capacity for seasonal boiler operation, as shown in Table 22. The per-unit energy savings of this measure are not impacted by climate zone and are the same for new construction, additions, and alterations.

While the energy savings do not differ across climate zones, the LSC factors do vary slightly by climate zone. Table 23 presents total per-unit energy cost savings for newly added boilers in terms of LSC savings realized over a 30-year period, in 2029 PV$ for year-round and seasonal boilers in the various size bins by climate zone.

Table 22: First Year Natural Gas Savings (kBtu) Per MMBtu/h of Boiler Capacity – Condensate Return

Prototype	First Year Natural Gas Savings (kBtu)
Year-Round	186,415
Seasonal	137,900

Table 23: Total 30-Year LSC Savings (2029 PV$) Per MMBtu/h of Boiler Capacity – Condensate Return

Prototype	CZ 1	CZ 2	CZ 3	CZ 4	CZ 5	CZ 6	CZ 7	CZ 8	CZ 9	CZ 10	CZ 11	CZ 12	CZ 13	CZ 14	CZ 15	CZ 16
Year-Round	154,397.97	154,397.97	154,397.97	154,397.97	154,397.97	156,256.07	155,798.94	156,256.07	156,256.07	156,256.07	154,397.97	154,397.97	154,397.97	156,256.07	156,256.07	156,256.07
Seasonal	101,389.62	101,389.62	101,389.62	101,389.62	101,389.62	101,530.04	101,504.96	101,530.04	101,530.04	101,530.04	101,389.62	101,389.62	101,389.62	101,530.04	101,530.04	101,530.04

3.4.3 Incremental First Cost

The Statewide CASE Team assumes the baseline case for calculating the incremental costs of this measure to be a steam system with no condensate return. This assumption allowed for the incremental first cost estimate to be conservative and ensure cost-effectiveness at both facilities with no existing condensate systems and facilities that would require full replacements (i.e., upgrades) of their existing systems to comply with this measure. Incremental first costs are consistent between newly added steam loads at new industrial facilities (i.e., new construction) and newly added steam loads at existing industrial facilities (i.e., additions or alterations).

The incremental first cost for a condensate return system includes the cost of purchasing and installing condensate return piping, piping insulation, condensate tank, and condensate pumps. Table 24 shows the total estimated incremental first costs of installing a condensate return system by prototype. The incremental first costs for seasonal boilers and boilers that operate year-round are equivalent because the systems are typically sized for similar load factors regardless of the actual operating load factors.

Table 24: Condensate Return System Incremental First Cost By Boiler Capacity

Boiler Capacity	Condensate Return System First Cost	Condensate Return System First Cost Per Unit
12 MMBtu/h	$145,264	$12,139
19 MMBtu/h	$253,362	$13,034
33 MMBtu/h	$380,043	$11,666
71 MMBtu/h	$896,345	$12,682
143 MMBtu/h	$1,692,933	$11,862
739 MMBtu/h	$4,931,741	$6,672

Condensate return system installation labor costs are the largest contributor to first costs. The costs of piping, piping insulation, and equipment such as tanks, valves, and fittings are also significant and increase with steam system load. When sized for larger steam loads, piping and associated components are larger and more expensive. Additionally, each additional steam load incurs the cost of an additional pump. The Statewide CASE Team assumed an increasing number and size of steam loads at the boiler as boiler capacity increases, from two steam loads up to 12 for the largest boilers.

The pipe length used for the cost analysis was equal to 75 percent of the predetermined cost-effective maximum length from the code trigger table for each steam system size.

Condensate return piping, insulation, tank and pump costs were obtained from the RSMeans database. Installation cost estimates, including the costs of commissioning and compliance verification, were based on field experience and historical project costs.

All incremental first costs are expected to increase with inflation. Additional details on cost assumptions can be found in Appendix A.

Appendix A also includes an example breakdown of the cost calculations and sources for an example boiler. The Statewide CASE Team will update first costs according to additional stakeholder input costs and cost assumptions gathered during the public meeting in March 2026.

3.4.4 Incremental Maintenance and Replacement Costs

The incremental maintenance and replacement cost for a condensate return system includes insulation maintenance and pump and tank and replacement. Maintenance costs for the steam piping itself were not included due to stainless steel and carbon steel piping having a lifespan that ranges from 20 years to over 50 years (Pak Industrial Services, n.d.).

Condensate return lines are insulated to minimize heat loss from the condensate being returned to the boiler for reuse. DOE estimates that insulating steam distribution and condensate lines can reduce energy lost as heat to the atmosphere by up to 90 percent (DOE, 2012). Damaged insulation is usually the result of installing the wrong type or amount of insulation for the process, improper installation practices, physical damage such as walking or climbing on uninsulated pipes, and corrosion or contamination of insulation exposed to process or steam leaks (Multiservice Industrial, 2022). The incremental cost for insulation maintenance was based on an expected piping insulation degradation rate of about 10 percent every 10 years. The cost of replacing the degraded piping was estimated to be equivalent to the proportional first cost of the amount of insulation being replaced due to degradation. Insulation maintenance and replacement frequency estimations were drawn from the 2025 Process Pipe Load CASE Report (Amoni & Alkhatib, 2023), but the Statewide CASE Team plans to conduct further stakeholder outreach to obtain additional input on maintenance frequency and cost.

The replacement frequency for typical pump per DEER data is 15 years (California Electronic Technical Reference Manual, 2013). The Statewide CASE Team's measure costs include condensate pumps' replacement at a conservative frequency of 10 years, or replacement twice during the 30-year analysis period. Condensate tank lifespans last between 15 and 50 years. (Savannah Tank and Equipment Corporation, n.d.). The measure maintenance costs include the cost of condensate tank replacement incurred in year 20 of the analysis period.

The Statewide CASE Team plans to refine the per-unit pump costs with additional stakeholder input and assessment of the relationship between equipment costs and steam system size. For detailed maintenance costs, see Appendix A. Descriptions of the incremental maintenance and replacement costs, as well as estimation of present value of maintenance and replacement costs, are provided in the 2028 CASE Methodology Report.

3.4.5 Cost Effectiveness

Results of the per-unit cost-effectiveness analyses are presented in Table 25 and Table 26. The results do not vary between new construction, additions, and alterations. The proposed measure saves money over the 30-year period of analysis relative to the existing conditions. The proposed code change is cost effective in every climate zone and for additions and alterations in addition to new construction. Because the changes in LSC savings only vary very slightly by climate zone, LSC savings for climate zone 1 are included in Table 25.

In the tables below, all values are presented in 2029 PV$. Benefits represent 30-year LSC savings and other savings, including incremental first-cost savings if the proposed first cost is less than the current first cost, incremental maintenance cost savings if the proposed maintenance costs are less than the current maintenance costs, and incremental residual value if proposed residual value is greater than current residual value at the end of the 30-year period of analysis. Costs represent the total incremental PV cost, including incremental equipment, replacement, and maintenance costs over the period of analysis. The analysis treats a negative incremental maintenance cost as a positive benefit. If total incremental costs are zero, the BCR is considered infinite. Costs and other savings are discounted at a real (inflation-adjusted) three percent rate. If there are no total incremental PV costs, the BCR is infinite. A BCR of “NA” indicates that there is no boiler capacity in that climate zone that would be impacted by the proposed requirement.

Table 25: 30-Year Cost-Effectiveness Summary Per MMBtu/h of Boiler Capacity – Condensate Return

Prototype	Benefits LSC Savings + Other PV Savings (2029 PV$)	Costs Total Incremental PV Costs (2029 PV$)	Benefit-to-Cost Ratio
Year-Round Boiler 10-15 MMBtu/h	$155,338.14	$15,155.12	10.25
Year-Round Boiler 15-25 MMBtu/h	$155,324.89	$15,366.36	10.11
Year-Round Boiler 25-50 MMBtu/h	$155,183.83	$13,725.00	11.31
Year-Round Boiler 50-100 MMBtu/h	$154,505.44	$14,382.62	10.74
Year-Round Boiler 100-200 MMBtu/h	$154,846.36	$13,263.16	11.67
Year-Round Boiler 200+ MMBtu/h	$155,691.47	$7,435.78	20.94
Seasonal Boiler 10-15 MMBtu/h	$101,461.15	$15,155.12	6.69
Seasonal Boiler 15-25 MMBtu/h	$101,459.92	$15,366.36	6.60
Seasonal Boiler 25-50 MMBtu/h	$101,449.28	$13,725.00	7.39
Seasonal Boiler 50-100 MMBtu/h	$101,397.79	$14,382.62	7.05
Seasonal Boiler 100-200 MMBtu/h	$101,423.51	$13,263.16	7.65
Seasonal Boiler 200+ MMBtu/h	$101,487.37	$7,435.78	13.65

Table 26: Benefit-to-Cost Ratio – Condensate Return

Prototype	CZ 1	CZ 2	CZ 3	CZ 4	CZ 5	CZ 6	CZ 7	CZ 8	CZ 9	CZ 10	CZ 11	CZ 12	CZ 13	CZ 14	CZ 15	CZ 16
Year-Round 10-15 MMBtu/h	10.2	10.2	10.2	10.2	10.2	10.3	10.3	10.3	10.3	10.3	10.2	10.2	10.2	10.3	10.3	10.3
Year-Round 15-25 MMBtu/h	N/A	10.0	10.0	10.0	10.0	10.2	10.1	10.2	10.2	10.2	10.0	10.0	10.0	10.2	10.2	10.2
Year-Round 25-50 MMBtu/h	11.2	11.2	11.2	11.2	11.2	11.4	11.4	11.4	11.4	11.4	11.2	11.2	11.2	11.4	11.4	11.4
Year-Round 50-100 MMBtu/h	N/A	10.7	10.7	10.7	10.7	10.9	10.8	10.9	10.9	10.9	10.7	10.7	10.7	10.9	10.9	10.9
Year-Round 100-200 MMBtu/h	N/A	11.6	11.6	11.6	N/A	11.8	N/A	11.8	11.8	11.8	11.6	11.6	11.6	11.8	11.8	11.8
Year-Round 200+ MMBtu/h	20.8	20.8	20.8	20.8	N/A	21.0	N/A	21.0	21.0	21.0	20.8	20.8	20.8	21.0	21.0	21.0
Seasonal 10-15 MMBtu/h	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7
Seasonal 15-25 MMBtu/h	N/A	6.6	6.6	6.6	6.6	6.6	6.6	6.6	6.6	6.6	6.6	6.6	6.6	6.6	6.6	6.6
Seasonal 25-50 MMBtu/h	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4
Seasonal 50-100 MMBtu/h	N/A	7.0	7.0	7.0	7.0	7.1	7.1	7.1	7.1	7.1	7.0	7.0	7.0	7.1	7.1	7.1
Seasonal 100-200 MMBtu/h	N/A	7.6	7.6	7.6	N/A	7.7	N/A	7.7	7.7	7.7	7.6	7.6	7.6	7.7	7.7	7.7
Seasonal 200+ MMBtu/h	13.6	13.6	13.6	13.6	N/A	13.7	N/A	13.7	13.7	13.7	13.6	13.6	13.6	13.7	13.7	13.7

3.5 Condensate Return – Statewide Impacts

3.5.1 Statewide Energy and Energy Cost Savings

To determine statewide savings from the proposed condensate return measure, the Statewide CASE Team first used a statewide boiler inventory of local AQMD boiler permits to estimate statewide boiler capacities and total quantity of installations by boiler capacity bins (Swanson & Staller, Steam Trap Fault Detection & Diagnostics in Existing Industrial Applications, 2025). Appendix C contains more information on these data.

The Statewide CASE Team then refined the statewide capacity for each capacity bin to account for Title 24, Part 6 purview and measure qualification, making the following changes:

5. Removed boilers with input capacities under 10 MMBtu/h and hot water boilers;
6. Removed oilfield and utility boilers, which are not subject to Title 24, Part 6 requirements;
7. Removed 10 percent of remaining boiler capacity to account for steam loads that would not qualify for the requirement via the code trigger table; and
8. Separated seasonal boilers from annual boilers by classifying boilers at major tomato and canned fruit and vegetable processers as seasonal boilers.
    a. The cannery capacity includes the capacity from major tomato and canned fruit and vegetable processers in the state. The Statewide CASE Team is not aware of other major facility types in California that would typically operate boilers seasonally.

The statewide capacity after these changes represents the Existing Boilers Stock. The analysis included boilers in the healthcare, education, and refinery sectors in the statewide capacity totals. The Statewide CASE Team plans to update inclusion of these boilers and utility boilers according to ongoing conversations regarding Title 24, Part 6 and process load applicability in these sectors.

To estimate the capacity of new steam loads installed annually, the Statewide CASE Team calculated four IPGRs for California: 1) year-round new construction, 2) year-round additions and alterations, 3) seasonal new construction, and 4) seasonal additions and alterations. Appendix C includes additional details on how the Statewide CASE Team calculated the IPGR. The annual new construction and additions and alterations forecasts are equivalent to the Existing Steam Boiler Stock multiplied by the IPGRs for each category.

The Statewide CASE Team then multiplied the per-unit measure savings by the new construction growth rate forecast and by the additions and alterations growth rate forecast to get first-year statewide savings, not accounting for natural market adoption.

To estimate the share of new qualifying steam systems that would install condensate return systems without the proposed requirement enacted, the Statewide CASE Team leaned on input from boiler manufacturers and vendors during stakeholder interviews and an analysis of IAC Audit Data from 64 boilers at 32 steam-using industrial plants from 2010 to 2022. The Statewide CASE Team applied this market share of 50 percent to the statewide estimates of impacted boiler capacity to arrive at the final statewide savings estimate. Appendix C presents the assumptions on the percentage of the total construction forecast that the proposed measure would impact.

The 2028 CASE Methodology reports includes further details on how statewide savings are calculated and the methodology and context about estimating the current market share rate, as well as statewide energy and energy cost savings.

Table 27 presents the first-year statewide energy and LSC savings from new steam loads at newly constructed industrial facilities, and Table 28 does the same for new steam loads that are part of additions or alterations to existing facilities by climate zone.

Table 29 presents first-year statewide savings from new construction, additions, and alterations.

Table 27: Statewide Energy and LSC Impacts – New Construction

Climate Zone	Statewide New Construction Impacted by Proposed Change in 2029 (MMBtu/h)	First-Year Electricity Savings (GWh)	First-Year Peak Electrical Demand Reduction	First-Year Natural Gas Savings (Million Therms)	First-Year Source Energy Savings (Million kBtu)	30-Year Present Valued LSC Savings (Million 2029 PV$)
1	**0.62**	**-**	**-**	**0.00**	**-**	**$0.09**
2	**1.52**	**-**	**-**	**0.00**	**-**	**$0.23**
3	**10.14**	**-**	**-**	**0.02**	**-**	**$1.55**
4	**4.10**	**-**	**-**	**0.01**	**-**	**$0.62**
5	**0.83**	**-**	**-**	**0.00**	**-**	**$0.13**
6	**6.84**	**-**	**-**	**0.01**	**-**	**$1.05**
7	**1.87**	**-**	**-**	**0.00**	**-**	**$0.29**
8	**10.51**	**-**	**-**	**0.02**	**-**	**$1.61**
9	**12.93**	**-**	**-**	**0.02**	**-**	**$1.99**
10	**8.72**	**-**	**-**	**0.02**	**-**	**$1.34**
11	**4.66**	**-**	**-**	**0.01**	**-**	**$0.70**
12	**30.40**	**-**	**-**	**0.06**	**-**	**$4.64**
13	**33.91**	**-**	**-**	**0.06**	**-**	**$5.19**
14	**4.59**	**-**	**-**	**0.01**	**-**	**$0.70**
15	**2.32**	**-**	**-**	**0.00**	**-**	**$0.36**
16	**1.23**	**-**	**-**	**0.00**	**-**	**$0.19**
Total	135.20	-	-	0.25	-	$20.69

Table 28: Statewide Energy and LSC Impacts – Additions and Alterations

Climate Zone	Statewide Additions and Alterations Impacted by Proposed Change in 2029 (MMBtu/h)	First-Year Electricity Savings (GWh)	First-Year Peak Electrical Demand Reduction	First-Year Natural Gas Savings (Million Therms)	First-Year Source Energy Savings (Million kBtu)	30-Year Present Valued LSC Savings (Million 2029 PV$)
1	**5.61**	**-**	**-**	**0.01**	**-**	**$0.84**
2	**13.68**	**-**	**-**	**0.03**	**-**	**$2.08**
3	**91.27**	**-**	**-**	**0.17**	**-**	**$13.91**
4	**36.93**	**-**	**-**	**0.07**	**-**	**$5.62**
5	**7.48**	**-**	**-**	**0.01**	**-**	**$1.15**
6	**61.56**	**-**	**-**	**0.11**	**-**	**$9.48**
7	**16.86**	**-**	**-**	**0.03**	**-**	**$2.62**
8	**94.56**	**-**	**-**	**0.17**	**-**	**$14.52**
9	**116.35**	**-**	**-**	**0.21**	**-**	**$17.88**
10	**78.49**	**-**	**-**	**0.14**	**-**	**$12.07**
11	**41.96**	**-**	**-**	**0.08**	**-**	**$6.32**
12	**273.62**	**-**	**-**	**0.51**	**-**	**$41.78**
13	**305.15**	**-**	**-**	**0.56**	**-**	**$46.69**
14	**41.35**	**-**	**-**	**0.08**	**-**	**$6.32**
15	**20.86**	**-**	**-**	**0.04**	**-**	**$3.20**
16	**11.10**	**-**	**-**	**0.02**	**-**	**$1.70**
Total	1,216.81	-	-	2.25	-	$186.18

Table 29: Statewide Energy and LSC Impacts – New Construction, Additions, and Alterations

Construction Type	First-Year Electricity Savings (GWh)	First-Year Peak Electrical Demand Reduction (MW)	First -Year Natural Gas Savings (Million Therms)	First-Year Source Energy Savings (Million kBtu)	30-Year Present Valued LSC Savings (Million 2029 PV$)
New Construction	-	-	**0.25**	**-**	**$20.69**
Additions & Alterations	-	-	**2.25**	**-**	**$186.18**
Total	**-**	**-**	2.50	-	$206.87

3.5.2 Statewide Greenhouse Gas Emissions Reductions

Table 29 presents the estimated first-year reduction in GHG emissions resulting from the proposed code change. In this initial year, the Statewide CASE Team expects to avoid 0.94 metric tons of CO_2e emissions. These reductions, along with their associated monetary value, were calculated using hourly GHG emissions factors published alongside the LSC hourly factors and source energy hourly factors in the research versions of the California Building Energy Code Compliance Software (CBECC), as well as data from the CEC's 2028 Metrics Report. See the 2028 CASE Methodology Report for additional information.

Table 29: First-Year Statewide GHG Emissions Impacts

Construction Type	Reduced GHG Emissions from Electricity Savings (Metric Tons CO2e)	Reduced GHG Emissions from Natural Gas Savings (Metric Tons CO2e)	Total Reduced GHG Emissions (Metric Ton CO2e)	Total Monetary Value of Reduced GHG Emissions ($)
New Construction	0	1,302	1,302	160,378
Additions & Alterations	0	11,721	11,721	1,443,398
Total	**0**	**13,023**	**13,023**	**1,603,776**

3.5.3 Statewide Water Use Impacts

The Statewide CASE Team calculated water savings by adding the increase in condensate flow and the decrease in blowdown flow between the baseline and proposed cases. Appendix A provides further calculation details.

Table 30 presents the impact on water use from the proposed measure. The 2028 CASE Methodology Report includes additional information on the embedded electricity savings estimates, which assume embedded energy factors of 5,440 kWh per million gallons of water for indoor use and 3,280 kWh per million gallons of water for outdoor water use (SBW Consulting, Inc. 2022).

Table 30: Impacts on Water Use and Embedded Electricity in Water

Impact	On-Site Indoor Water Savings (Gallons/Year)	On-site Outdoor Water Savings (Gallons/Year)	Embedded Electricity Savings (kWh/Year)
Average Per MMBtu/h of Boiler Capacity Impacts	119,370	-	649
First-Year Statewide Impacts for New Construction	15,521,949	-	84,439
First-Year Statewide Impacts for Additions and Alterations	139,697,539	-	759,955
Total First-Year Statewide Impacts	**155,219,488**	**-**	**844,394**

3.5.4 Statewide Material Impacts

Condensate return piping, pumps, and tanks are typically made from carbon steel and stainless steel (Plant Engineering, 2011). The proposed requirement would lead to an increase in the demand for steel at industrial sites. Because piping contributes significantly more steel than pumps and tanks in a condensate return system, only piping was considered for material impacts. To calculate the total steel contributions per boiler capacity size, the 75 percent of the maximum cost-effective pipe length was obtained from the code trigger table. Table 31 shows a summary of the steel impact.

The 2028 CASE Methodology Report provides more information on the Statewide CASE Team's methodology and assumptions used to calculate embodied GHG emissions.

Table 31: First-Year Statewide Impacts on Material Use

Material	Impact	Per-Unit Impacts (Pounds per MMBtu/h)	First-Year Statewide Impacts (Pounds)	Embodied GHG emissions saved (Metric Tons CO2e)
Mercury	No change	-	-	-
Lead	No change	-	-	-
Copper	No change	-	-	-
Steel	Increase	137	185,862	-102
Plastic	No change	-	-	-
TOTAL	**Increase**	**137**	**185,862**	**-102**

3.5.5 Environmental Impacts

Condensate return systems reduce water use by replacing fresh make-up water that would otherwise be needed for boiler feedwater. Fresh make-up water also requires additional heating from the boiler, so replacing fresh make-up water with condensate return also decreases boiler fuel consumption. This reduction in fuel consumption would also indirectly improve local air quality. Combustion of natural gas produces NOx, a chemical precursor to ozone. Reducing the consumption of natural gas will therefore indirectly lead to reduced ozone (Chen, Omotesho, & Johnson, 2025).

The Statewide CASE Team has considered opportunities to minimize the environmental impact of the proposal, including an evaluation of "specific economic, environmental, legal, social, and technological factors" (Cal. Code Regs., tit. 14, § 15021). The Statewide CASE Team did not determine this measure would result in significant direct or indirect adverse environmental impacts and therefore, did not develop any mitigation measures.

3.5.6 Other Non-Energy Impacts

By minimizing the need for fresh make-up water as condensate is returned to the boiler, this proposed measure reduces use of water and chemicals used to treat it. In addition to water and chemical savings, the reduction in fuel usage to heat fresh make-up water results in lower boiler NOx emissions. This practice would reduce local photochemical smog and improve air quality.

3.6 Condensate Return – Proposed Code Language

3.6.1 Guide to Markup Language

The proposed changes to the standards, Reference Appendices, and the ACM Reference Manuals are provided below. Changes to the 2025 documents should be marked with dark blue underlining (new language) and ~~strikethroughs~~ (deletions).

3.6.2 Administrative Code (Title 24, Part 1)

No changes are proposed to Title 24, Part 1.

3.6.3 Energy Code (Title 24, Part 6)

SECTION 100.1 – DEFINITIONS AND RULES OF CONSTRUCTION

Section 100.1(b) – Definitions: Recommends new or revised definitions for the following terms:

CONDENSATE RETURN SYSTEM is a system designed to return steam condensate to a boiler plant for reuse that includes piping and may also include condensate collection tanks and mechanical pumping.

PROCESS STEAM SYSTEM is a type of steam system that serves a process.

SUBCHAPTER 3 – NONRESIDENTIAL, HIGH-RISE RESIDENTIAL, HOTEL/MOTEL OCCUPANCIES, AND COVERED PROCESSES--MANDATORY REQUIREMENTS

SECTION 120.6 – MANDATORY REQUIRMENTS FOR COVERED PROCESSES

120.6(l) Mandatory requirements for process steam systems.

2. The following requirements apply to newly constructed process steam systems and new, non-replacement process steam loads at existing facilities that meet the below conditions:

1. have one or more connected boilers with an input rating (capacity) of 10 MMBtu/h or greater
2. use indirect-contact heat exchangers,
3. generate condensate during normal operation, and
4. meet the criteria for load size and condensate return piping lengths in Table 120.6-X

TABLE 120.6-X CONDENSATE RETURN LENGTH CODE TRIGGER CRITERIA

Steam Flow (lb/h)	**Linear Length[5] (ft) Less Than**
<1,000	Exempt
≥1,000, <2,000	400
≥2,000, <3,000	600
≥3,000, <4,000	800
≥4,000, <6,000	1,100
≥6,000	1,300

Qualifying process steam systems shall install a condensate return system to return all uncontaminated condensate, including condensate from associated drip legs, to the boiler plant for reuse. Condensate from processes that use steam in direct contact with a product or contaminant per design or during normal operation does not need to be returned.

All steam loads that do not qualify for 120.6(l)2 based on the criteria in Table 120.6-X shall include the following in the steam system construction documents:

a. Sum of all horizontal and vertical pipe runs that make up the linear length from the steam trap serving the load to the nearest condensate return tank or the deaerator serving the steam boiler, whichever is closer. Elbows and pipe fittings, including

[5] Footnote to TABLE 120.6-X: Linear length from the steam trap serving the load to the nearest condensate return tank or the deaerator serving the steam boiler, whichever is closer. The linear length shall include the sum of all horizontal and vertical pipe runs. Elbows and pipe fittings, including reducers, shall be excluded from the linear length calculation.

reducers, shall be excluded from the linear length calculation.

3.6.4 Reference Appendices

There are no proposed updates to the Non-Residential Appendices.

3.6.5 Compliance Manuals

The Statewide CASE Team will provide CEC with recommended revisions to compliance manuals after the 45-Day Language is published.

3.6.6 ACM Reference Manual

The Statewide CASE Team proposes no changes to the ACM Reference Manual.

3.6.7 Compliance Forms

NRCC-PRC-E and NRCI-PRC-E would both need to be updated to reflect the proposed change. The Statewide CASE Team can support the CEC in implementing these updates if the proposed change is adopted. These potential updates would look as follows:

NRCC-PRC-E

Create new section S PROCESS Steam table and update proceeding section's lettering:

- Create the following columns in the table:
  - Which rated input capacity aligns with this process steam system (Btu/h)?
    - In Virtual Compliance Assistant, add the following dropdown options:
      - Rated input capacity for one or more connected boilers to include: ≥ 10MMBtu/h
      - Rated input capacity for one or more connected boilers to include: <10MMBtu/
  - Does the process steam system have a condensate return system to return all uncontaminated condensate, including condensate drip legs, to the boiler for reuse?
    - If the system is claiming it does not trigger the requirement because of the pipe lengths in the code trigger table, provide the sheet number that supports the required calculation for the total pipe length required.
    - In Virtual Compliance Assistant, add the following dropdown options:
      - Yes
      - This doesn't apply because the process steam system has a rated capacity less than 10MMBtu/h.

- This doesn’t apply because the process uses steam that comes into direct contact with a product or contaminant per design during normal operation.
- This doesn’t apply because this process does not generate condensate during normal operation.
- This doesn’t apply because the system has a pressure that is less than 100psig.
- This doesn’t apply because the total pipe length required is greater than the maximum length listed in the code trigger table for this steam load.

NRCI-PRC-E

- Add the following to a new table for Process Steam:
    - Column for Condensate Return System
    - Column for Condensate Return Pump (if applicable)
    - Column for Condensate Return Labeled Piping

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Appendix A: Assumptions for Cost-effectiveness Analysis

A.1 Assumptions for Energy Savings Analysis

Flash Steam Recovery

For the flash steam recovery requirement, the baseline case is a steam system that does not recover any flash steam from boiler blowdown, and the proposed case is a steam system that recovers all of its flash steam from boiler blowdown.

Savings calculation assumptions for both the baseline and proposed cases include the following:

a. Boiler operation (year-round boilers): 6,500 hours per year, based on a survey of 128 California steam-using sites sourced from the national IAC database (Swanson & Staller, Steam Trap Fault Detection & Diagnostics in Existing Industrial Applications, 2025).
b. Boiler operation (seasonal boilers): 2,400 hours per year, based on a survey of 128 California steam-using sites sourced from the national IAC database (Swanson & Staller, Steam Trap Fault Detection & Diagnostics in Existing Industrial Applications, 2025).
c. Boiler load: constant 40 percent daily load for year-round boilers and constant 80 percent daily load for seasonal boilers, based on field experience and the assumption that seasonal boilers are operated at higher load factors to meet seasonal demand.
d. Combustion air temperature: 75°F, based on outdoor air temperatures in California.
e. Combustion efficiency: 80.5 percent, based on field data from 10 sites.
f. Shell losses: 1.0 percent, based on industry standard rule of thumb.
g. Boiler efficiency: 79.5 percent, equivalent to the combustion efficiency minus shell losses.
h. Feedwater temperature (deaerator operating temperature): 227°F
i. Condensate temperature: 200°F
j. Make-up water temperature: 65°F
k. Condensate conductivity: 20 micro-mhos (μ℧), based on sample boiler log data.
l. Make-up water conductivity: 440 (μ℧), based on sample boiler log data.
m. Percent of steam loads with returned condensate: 30%
n. Boiler steam pressure: 100 psig
o. Flash steam pressure: 8 psig
p. Deaerator pressure: 5 psig, based on field experience.

q. Enthalpy values calculated from steam tables.

Savings calculation assumptions and outputs for the baseline case include the following:

- Flash steam recovery: 0 percent recovery from blowdown

Savings calculation assumptions and outputs for the proposed measure case include the following:

- Flash steam recovery: 100 percent recovery from blowdown

Condensate Return

For the condensate return requirement, the baseline case is a steam system that reuses 30 percent of its condensate, and the proposed case is a steam system that reuses 75 percent of its total steam flow returned as condensate.

Savings calculation assumptions for both the baseline and proposed cases include the following:

a. Boiler operation (year-round boilers): 6,500 hours per year, based on a survey of from 128 California steam-using sites sourced from the national IAC database (Swanson & Staller, Steam Trap Fault Detection & Diagnostics in Existing Industrial Applications, 2025).

b. Boiler operation (seasonal boilers): 2,400 hours per year, based on a survey of from 128 California steam-using sites sourced from the national IAC database (Swanson & Staller, Steam Trap Fault Detection & Diagnostics in Existing Industrial Applications, 2025).

c. Boiler load: 40 percent load for year-round boilers and 80 percent load for seasonal boilers for energy savings analysis. The Statewide CASE Team used 80 percent load for both seasonal and year round boilers to calculate cost due to common practice of sizing for full load.

d. Combustion air temperature: 75°F, based on outdoor air temperatures in California.

e. Combustion efficiency: 80.5 percent, based on field data from 10 sites.

f. Shell losses: 1.0 percent, based on industry standard rule of thumb.

g. Boiler efficiency: 79.5 percent, equivalent to the combustion efficiency minus shell losses.

h. Feedwater temperature: 226°F, based on a deaerator pressure of 5psig.

i. Condensate temperature: 200°F, based on data from industrial steam sites.

j. Make-up water temperature: 65°F, estimated based on California waters supply temperatures.

k. Condensate conductivity = 20 (μ℧), based on field data from two industrial sites from prior work with Cascade Energy.

l. Make-up water conductivity = 440 (μ℧), based on field data from two industrial sites from prior work with Cascade Energy.
m. Feedwater conductivity = 345 (μ℧), based on based on field data from two industrial sites from prior work with Cascade Energy.
n. Steam pressure: 100 psig, average industry steam header pressure.
o. Enthalpy values calculated from steam tables.

Savings calculation assumptions and outputs for the baseline case include the following:

- Condensate return: 30 percent, a conservative estimate based on field experience.

Savings calculation assumptions and outputs for the proposed measure case include the following:

- Condensate return: 75 percent, an estimate of the total steam flow as viable condensate for return and reuse at the average site based on field experience and stakeholder input. The remaining 25 percent includes contaminated condensate and deaerator steam supply.

The energy impacts of flash steam recovery would not vary due to individual equipment makes or models, but they will vary based on the steam system design and operating characteristics (e.g., operating pressure, relative load size, and load profile).

Energy savings do not vary by climate zone for either proposed measure. The Statewide CASE Team applied the climate-zone-specific LSC hourly factors when calculating energy cost impacts for both measures.

Energy Savings Methodology

Prototype Development – Flash Steam Recovery and Condensate Return

The Statewide CASE Team analyzed energy savings and cost effectiveness in six boiler capacity ranges to account for savings and cost differences for boilers with different capacities. Table 32 shows the boiler capacity bin ranges and the average capacity of the boilers within each bin, which was used to perform the calculations of cost effectiveness. The prototype is the average capacity boiler for each boiler capacity bin, as shown Table 32. Data on the capacity of installed boilers in California came from the statewide boiler inventory of local air district boiler permits developed as part of the Code Readiness program (Swanson & Staller, Steam Trap Fault Detection & Diagnostics in Existing Industrial Applications, 2025).

Table 32: Process Boiler Capacity Bins

Boiler Capacity Bin	Average Boiler Capacity Used for Calculations
10-15 MMBtu/h	12 MMBtu/h
15-25 MMBtu/h	19 MMBtu/h
25-50 MMBtu/h	33 MMBtu/h
50-100 MMBtu/h	71 MMBtu/h
100-200 MMBtu/h	143 MMBtu/h
200+ MMBtu/h	739 MMBtu/h

For both measures, boilers that operate infrequently throughout the year due to seasonal loads will experience lower savings. Due to this variance, the Statewide CASE Team also developed prototypes and calculated annual energy savings and cost effectiveness for boilers with seasonal loads separately from the more typical annual loads. Calculations for boilers operating annually assumed 6,500 operating hours per year at 40 percent load, and calculations for seasonal boilers assumed 2,400 operating hours per year (primarily August through October) at 80 percent load. To calculate statewide capacity, seasonal boilers were all boilers in canneries. Boilers used in all other industries were assumed to be year-round boilers.

Review finds no anticipated differences between new process boilers that are installed during the new construction, addition, or alteration of a building, so the same prototypes were used for new construction, additions, and alterations.

Existing Title 24, Part 6 requirements already cover process boilers and apply to new construction, additions, and alterations, so the Standard Design (i.e., baseline case) is compliant with the 2025 Title 24 requirements and representative of the non-compliant market. The Standard Design informs the baseline combustion efficiency estimate used in savings calculations. These requirements include combustion air positive shut-off for all process boilers with an input capacity of 2.5 MMBtu/h and above, variable speed drive for process boiler combustion air fans with motors 10 horsepower and greater, and stack oxygen concentrations at less than or equal to 3.0 percent by volume on a dry basis over firing rates of 20 to 100 percent for process boilers with an input capacity greater than 5.0 MMBtu/h.

The 2028 CASE Methodology Report provides details on estimating energy savings per prototypical building and unit.

Energy Savings Calculations

Flash Steam Recovery

The Proposed Design (i.e., measure case) was identical to the Standard Design in all ways except for the revisions that represent the proposed changes to the code. Specifically, the proposed conditions assume installation of blowdown flash steam recovery equipment.

Savings result from reducing the amount of flash steam that is vented to the atmosphere. The key equations used in a custom Microsoft Excel model developed for this savings analysis follow.

1. Fraction of condensate that vaporizes into flash steam:

$$x = \frac{h_{blowdown} - h_{f,LP}}{h_{fg,LP}}$$

where

$x = fraction\ of\ blowdown\ mass\ flow\ that\ flashes\ into\ steam$

$h_{blowdown} = enthalpy\ of\ boiler\ water h_{f,LP}$
$= enthalpy\ of\ saturated\ liquid\ at\ flash\ steam\ (lower)\ pressure$

$h_{fg,LP} = enthalpy\ of\ vaporization\ at\ flash\ steam\ (lower)\ pressure$

2. Flash steam mass flow:

$$\dot{\mathrm{m}}_{flash\ steam} = \dot{\mathrm{m}}_{blowdown} \cdot x$$

where

$\dot{\mathrm{m}}_{blowdown} = \text{mass flow of boiler blowdown}$

3. Live boiler steam energy saved from flash steam recovery:

$\dot{\mathrm{E}}_{recovered} = \dot{\mathrm{m}}_{flash\ steam} \cdot (h_{f,LP} - h_{makeup})$ where

$\dot{\mathrm{E}}_{recovered} = rate\ of\ recovered\ energy$

$\dot{\mathrm{m}}_{flash\ steam} = mass\ flow\ of\ flash\ steam$

$h_{makeup} = enthalpy\ of\ makeup\ water$

4. Fuel saved from flash steam recovery:

$$\dot{\mathrm{E}}_{fuel\ savings} = \frac{\dot{\mathrm{E}}_{recovered}}{\eta_{boiler}}$$

where

$\dot{\mathrm{E}}_{fuel\ savings} = boiler\ fuel\ savings$

$\eta_{boiler} = boiler\ system\ efficiency$

Consider a 50-MMBtu/h boiler that operates at 100 psig and has 1,800 lbm/h of blowdown flow. Assume flash steam is recovered at 8 psig and that makeup water is supplied at 65°F. All enthalpy values are taken for an elevation of sea level and sourced from the National Institute of Standards and Technology (NIST) Chemistry WebBook.

Fraction of blowdown that vaporizes into flash steam

$$x = \frac{h_{blowdown} - h_{f,LP}}{h_{fg,LP}}$$

where

$$h_{blowdown} = 309.2\,\frac{Btu}{lbm}\ saturated\ liquid\ enthalpy\ of\ boiler\ water\ at\ 100\ psig\ (114.7\ psia)$$

$$h_{f,LP} = 203.3\frac{Btu}{lbm}\ saturated\ liquid\ enthalpy\ at\ flash\ vessel\ pressure\ of\ 8\ psig\ (22.7\ psia)$$

$$h_{fg,LP} = 956.2\frac{Btu}{lbm}\ latent\ enthalpy\ at\ flash\ vessel\ pressure\ of\ 8\ psig\ (22.7\ psia)$$

Hence

$$x = \frac{309.2\ Btu/lbm - 203.3\ Btu/lbm}{956.2\ Btu/lbm}$$

$$x = 11.1\%$$

Flash steam mass flow

$$\dot{m}_{flash\ steam} = \dot{m}_{blowdown} \cdot x$$

$$\dot{m}_{flash\ steam} = 1{,}800\frac{lbm}{h} \cdot 11.1\%$$

$$\dot{m}_{flash\ steam} = 199.8\ lbm/h$$

Steam energy recovered

$$\dot{E}_{recovered} = \dot{m}_{flash\ steam} \cdot (h_{flash\ steam} - h_{makeup})$$

where

$$h_{makeup} = 33.0\frac{Btu}{lbm}, enthalpy\ of\ makeup\ water\ at\ 65°F$$

$$h_{flash\ steam} = 1{,}159.4\frac{Btu}{lbm} saturated\ vapor\ enthalpy\ at\ flash\ steam\ pressure$$

Hence

$$\dot{E}_{recovered} = 199.8\ \frac{lbm}{h} \cdot (1{,}159.4\frac{Btu}{lbm} - 33.0\frac{Btu}{lbm})$$

$$\dot{E}_{recovered} = 225{,}055\ Btu/h$$

Boiler fuel savings

$$\dot{E}_{fuel\ savings} = \frac{\dot{E}_{recovered}}{\eta_{boiler}}$$

where

$$\dot{E}_{fuel\ savings} = boiler\ fuel\ savings, calculated\ above$$

$$\eta_{boiler} = boiler\ system\ efficiency, 0.795, assumed$$

Hence

$$\dot{E}_{fuel\ savings} = \frac{225{,}055\ Btu/h}{0.795}$$

$$\dot{E}_{fuel\ savings} = 283{,}088\ Btu/h$$

Condensate Return

The Proposed Design (i.e., measure case) was identical to the Standard Design in all ways except for the revisions that represent the proposed changes to the code. Specifically, the proposed conditions assume installation of a condensate return system.

Energy savings from this measure were calculated in two components:

1. <u>Deaerator preheating savings</u>: Replacing cold make-up water with warm or hot returned condensate reduces the energy required to heat the deaerator.
2. <u>Blowdown reduction</u>: Replacing make-up water containing dissolved solids with condensate (which is effectively distilled water) reduces blowdown. Reducing blowdown reduces energy losses by reducing the total amount of feedwater that needs to be heated.

The estimated energy savings were based on the temperature difference between condensate and make-up water:

$$Energy\ Savings\ \left(\frac{Btu}{hr}\right) = \left(\dot{m}_{condp} - \dot{m}_{condb}\right) *\ c_p * (T_{con} - T_{mw})$$

where

$$\dot{m}_{condp} = proposed\ condensate\ flow\ (\frac{lbm}{hr})$$

$$\dot{m}_{condb} = baseline\ condensate\ flow\ (\frac{lbm}{hr})$$

$$T_{con} = temperature\ of\ condensate\ (°\mathrm{F})$$

$$T_{mw} = temperature\ of\ makeup\ water (°\mathrm{F})$$

$$c_p = constant - pressure\ specific\ heat\ capacity\ of\ water$$

Temperature losses due to condensate pipe length are accounted for in energy savings calculations. Insulation of condensate return pipes is already required by Title 24 Part 6.

The following equation was used to calculate energy savings due to decreased blowdown:

$$Blowdown\ Energy\ \left(\frac{Btu}{hr}\right) = (\dot{m}_{bdnb} - \dot{m}_{bdnp}) * (h_{bw} - h_{mw})$$

where

$$\dot{m}_{bdnb} = baseline\ blowdown\ flow\ rate\ in\ (\frac{lbm}{hr})$$

$$\dot{m}_{bdnp} = proposed\ blowdown\ flow\ rate\ in\ (\frac{lbm}{hr})$$

$$h_{bw} = specific\ enthalpy\ of\ boiler\ water\ (\frac{Btu}{lbm})$$

$$h_{mw} = specific\ enthalpy\ of\ makeup\ water\ (\frac{Btu}{lbm})$$

$$\dot{m}_{bdnb} = \frac{\dot{m}_{steam}}{COC - 1}$$

$$COC = cycles\ of\ concentration = \frac{C_b}{C_{fw}}$$

$$C_b = average\ conductivity\ of\ boiler\ water$$

$$C_{fw} = average\ conductivity\ of\ feedwater$$

Key Assumptions for Incremental Costs

Flash Steam Recovery First Costs

Table 33 below shows the breakdown of the flash steam recovery measure first costs for a boiler with an input capacity of 32.6 MMBtu/h. The Statewide CASE Team calculated first costs using a boiler load factor of 80 percent for both year-round and seasonal boilers as equipment is often sized for greater loads than actual operating loads.

Table 33: Flash Steam Recovery Incremental Cost Breakdown

Item	Cost Explanation	Item Cost or Quantity
Flash vessels	Linear extrapolation by load size of costs from a vendor stakeholder conversation in October 2024	$5,000
Pipe Diameter	2-inch diameter calculated by flash steam velocity calculation for active steam load; price obtained from RSMeans data	$51.78/linear foot (LF)
Total Schedule 40 Pipe Length (labor & materials)	Estimated 100 feet average linear length between deaerator and blowdown flash vessel	$5,178
Pipe insulation w/ all service jacket (labor & materials)	RSMeans data, fiberglass insulation with all service jacket: $45.36/LF	$4,536
Additional valves, strainers, and fittings (materials only)	Estimated to be 20 percent of total piping cost per engineering judgement	$1,036
Additional Install Labor	Estimated to be 20 percent of total project cost, including oversight, coordination, startup, and commissioning per engineering judgement	$3,150
Total Measure Cost		$18,900

Flash Steam Recovery Maintenance Costs

Table 34 below shows the breakdown of the discounted flash steam recovery measure maintenance costs for each boiler prototype. The costs are equivalent for year-round and seasonal boiler capacity. Maintenance costs include ten percent of the initial piping insulation costs, incurred twice, once in year 10 and once in year 20.

Table 34: Flash Steam Recovery Maintenance Costs by Boiler Capacity

Prototype Boiler Capacity (MMBtu/hr)	Total Discounted 30-Year Maintenance Costs
10-15	$5,887
15-25	$5,878
25-50	$6,723
50-100	$7,246
100-200	$8,150
200+	$13,431

Condensate Return

Table 36 shows the breakdown of the condensate return measure first costs for a boiler with an input capacity of 12 MMBtu/h. The Statewide CASE Team calculated first costs using a boiler load factor of 80 percent for both year-round and seasonal boilers as equipment is often sized for greater loads than actual operating loads. The Statewide CASE Team calculated the steam loads and amount of condensate returned for the boiler capacity corresponding with each boiler capacity bin and adjusted assumptions around pipe length and diameter and number of required fittings, elbows, tanks, valves, and pumps based on the steam load. When increasing boiler capacity, the Statewide CASE Team assigned a specific number of steam loads for the steam flow as seen in Table 35. The number of steam loads at the boiler informs the pipe length, pipe diameter, and number of pumps installed to comply with the proposed measure. The assumed pipe length was chosen to be 75 percent of the maximum cost-effective length from the code trigger table for the corresponding steam flow for each load.

Table 35. Steam Load Assumptions by Boiler Capacity

Prototype (MMBtu/hr)	Number of Steam Loads	Pipe Length (Ft)	Pipe Diameter (inches)
10-15	2	300	1.5
15-25	2	450	2.0
25-50	3	450	2.0
50-100	4	825	2.0
100-200	5	975	2.5
200+	12	975	3.5

Table 36: Condensate Return Incremental First Cost Breakdown

Item	Cost Explanation	Item Cost or Quantity
Pipe Diameter	Calculated at Pressure drop < 0.1 psig/100 LF for specific steam load	1.5 inches
Pipe Length	75% of maximum cost-effective length (400ft) obtained from code trigger table for a condensate load of 3gpm for an input capacity of 12MMBtu/h. Estimate of two loads for this steam load size.	300 feet per load
Pipe Cost	RSMeans data, 2025 Q2 for Vallejo, Calif.	$53.68/LF
Fittings, Elbows, Tanks and Valves	Estimated to be equivalent to piping costs. Tank costs are estimated at 50% of the total cost of fittings, elbows, tanks, and valves.	$53.68/LF
Total Labor Costs	Estimated to be 1.5 times the piping cost, based on costs from a recent Cascade Energy project in California	$80.52
Pump Cost	Linear extrapolation of RSMeans data, 2025 Q2 for Vallejo, Calif. Estimate of two pumps based on steam load size.	$10,001 per pump
Insulation Costs	RSMeans, fiberglass insulation with all service jacket for 2-inch insulation (1.5-inch pipe at 200°F	$20.89/LF
Total Cost per LF	Cost per LF for 300 feet	$238.77
Total Project Cost per Load	Cost for one load at 75% of max trigger table length (300 LF)	$71,630
Total Project Cost	Cost for two loads at 300 linear feet per load determined by steam load size	$143,260

Condensate Return Maintenance Costs

Table 37 below shows the breakdown of the discounted condensate return incremental maintenance costs for each prototype. The costs are equivalent for year-round and seasonal boiler capacity. Maintenance costs include pump replacement in year 10 and year 20, ten percent of the piping insulation incurred once in year 10 and once in year 20, and condensate return tank replacement in year 20.

Table 37. Condensate Return Maintenance Costs by Boiler Capacity

Prototype (MMBtu/hr)	Total Discounted 30-Year Maintenance Costs
10-15	$36,094
15-25	$45,337
25-50	$67,075
50-100	$120,193
100-200	$199,969
200+	$564,597

Appendix B: Purpose and Necessity of Proposed Code Changes

Introduction

The sections below provide the purpose and necessity of proposed changes to Title 24, Part 1; Title 24, Part 6; and the reference appendices. This section intends to provide the CEC with the information needed for the Initial Statement of Reasons.

Section 2.6 provides the marked-up code language for reference.

Flash Steam Recovery

Purpose and Necessity of Changes to Title 24, Part 1

No changes are proposed to Title 24, Part 1.

Purpose and Necessity of Changes to Title 24, Part 6

Section: 100.1

Purpose: The purpose of this change is to aid in the interpretation and implementation of new requirements for process boilers flash steam reduction in Title 24, Part 6, Section 120.6(d) by adding new definitions.

Necessity: This change adds definitions for Flash Steam and Pressurized Condensate Return. These definitions ensure clarity of the proposed condensate return requirements.

Section: 120.6(d)4

Purpose: The purpose of these changes is to create a requirement to recover flash steam from blowdown to the deaerator or another heating load. Flash steam contains thermal energy that, if not recovered and used for other purposes, is wasted. Reducing or repurposing flash steam will therefore save energy.

Necessity: These proposed changes are intended to reduce the energy consumption of steam systems. These adjustments align with the mandated cost-effective building design standards outlined in the California Public Resources Code, specifically Sections 25213 and 25402.

Purpose and Necessity of Changes to the Reference Appendices

There are no required updates to the reference appendices as a result of this measure.

Condensate Return

Purpose and Necessity of Changes to Title 24, Part 1

No changes are proposed to Title 24, Part 1.

Purpose and Necessity of Changes to Title 24, Part 6

Section: 100.1

Purpose: The purpose of this change is to aid in the interpretation and implementation of new requirements for process steam system condensate return in Title 24, Part 6, Section 120.6(l) by adding new definitions.

Necessity: This change adds definitions for Condensate Return System and Process Steam System. These definitions provide necessary clarity for the proposed additions to Title 24, Part 6, Section 120.6(l) that require the use of condensate return for process steam systems.

Section: 120.6(l)1

Purpose: The purpose of these changes is to require newly constructed process steam systems or newly added steam loads to possess condensate return, provided that the new system or added load is within a maximum linear length from a boiler or condensate sink. Condensate contains thermal energy which, if not returned to a boiler or condensate sink, would otherwise be wasted. Use of condensate return systems recovers this energy.

Necessity: These changes are intended to reduce process steam system energy consumption. These adjustments align with the mandated cost-effective building design standards outlined in the California Public Resources Code, specifically Sections 25213 and 25402.

Purpose and Necessity of Changes to the Reference Appendices

There are no proposed changes to the reference appendices.

Appendix C: Assumptions for Statewide Savings Estimates

Flash Steam Recovery

The Statewide CASE Team took the following steps to determine statewide savings from the proposed flash steam recovery measure.

To estimate statewide boiler capacities and counts by boiler capacity bins, the Statewide CASE Team leveraged statewide boiler inventory data developed as part of a Code Readiness project. This inventory is a nearly complete statewide boiler inventory that has over 9,000 equipment entries from local air quality management districts, which were collected and preprocessed by the Code Readiness project team in 2023 and 2024 (Swanson and Staller, Steam Trap Fault Detection & Diagnostics in Existing Industrial Applications 2025).

The Statewide CASE Team refined the statewide capacity for each capacity bin to account for Title 24 purview and requirement exceptions, making the following changes:

- Removed boilers with input capacities under 10 MMBtu/h and any units that were indicated to be hot water boilers or hot water heaters in the permit data.
- Removed oilfield and utility boilers, which are not in buildings and not subject to Title 24, Part 6 requirements.

9. Removed 5 percent of remaining boiler capacity to account for boilers without a pressurized deaerator, boilers with pressurized condensate return, and boilers with a linear length from the boiler to the serving deaerator greater than or equal to 100 feet, based on analysis of steam system operating pressures from IAC boiler audits;

10. Separated seasonal boilers from annual boilers by classifying boilers at major tomato and canned fruit and vegetable processers as seasonal boilers.

    a. The cannery capacity includes the capacity from major tomato and canned fruit and vegetable processers in the state. The Statewide CASE Team is not aware of other major facility types in California that would typically operate boilers seasonally.

The statewide capacity after these changes were made represents the Existing Boilers Stock. Boilers at or above 10 MMBtu/h in the healthcare, education, non-cannery food, refinery, and ‘all other’ sectors were included in the statewide capacity totals. The Statewide CASE Team plans to update inclusion of boilers from each industry according to ongoing conversations regarding Title 24 and process load applicability in these sectors.

To estimate the capacity of new process boilers installed annually from new construction and additions, the Statewide CASE Team calculated two IPGRs for boilers in California, one for annual boilers and one for seasonal boilers.

The Statewide CASE Team analyzed both national and state data to develop an IPGR for California. The IPGR from the 2022 Steam Trap Monitoring CASE Report was calculated using an average of the 10-year and 30-year compound annual growth rate (CAGR) of INDPRO, the national Federal Industrial Production Index (Johnson, Heinrichs Coakley 2020). However, the Statewide CASE Team determined that national trends would not provide an accurate representation of the California industrial production market. While California is the largest contributor to the U.S. manufacturing industry in terms of output and employment, it accounts for 14.5 percent of U.S. manufacturing output (Profozich 2022). A study performed by Beacon Economics for the California Manufacturing Network confirmed that California's manufacturing sector has grown at a faster rate compared the that of the US (Economics n.d.).

To more accurately estimate California's IPGR, the Statewide CASE Team met with Beacon Economics to discuss the availability of California-specific data on industrial production growth and the differences between California's manufacturing sector and the U.S. manufacturing sector as a whole. Beacon Economics provided a 2025 study demonstrating that California's manufacturing growth was not only faster than the rest of the United States, but California's manufacturing is also more productive (Beacon Economics 2025). The Statewide CASE Team investigated California real Gross Domestic Product (GDP) data from the U.S. Bureau of Economic Analysis (BEA) and California Federal Reserve Bank of St. Louis' Federal Reserve Economic Data (FRED) for industries classified as manufacturing per 2017 NAICS U.S. Bureau of Economic Analysis 2025 FRED 2025).

The Statewide CASE Team calculated the average of the 7-year CAGR and 10-year CAGR from both sources through 2024. The California real GDP manufacturing growth rate from BEA and FRED was similar at 2.25 percent and 2.74 percent, respectively. The data from BEA provided a more conservative growth rate and were selected for California IPGR calculations.

To further tailor this data to the proposed flash steam recovery measure, the Statewide CASE Team applied weights based on the proportion of boiler capacity in each of the main industry subsectors (i.e., food and beverage manufacturing, wood manufacturing, and total other manufacturing which is defined as all other manufacturing that was not food and beverage, wood, lumber, petroleum/refining, or other subsectors that burn byproduct waste), calculated from the statewide boiler inventory based on AQMD data to subsector-specific California real GDP BEA data. Boiler capacity from canneries was excluded from the weighted average for year-round boilers. The calculated weighted average IPGR for year-round boilers was 1.65 percent.

The growth rate for the seasonal facilities is best represented by the Food and Beverage Manufacturing IPGR of 0.46 percent, which was calculated from BEA real GDP data in 2017 chained dollars.

Statewide savings estimates were calculated using an IPGR of 1.65 percent for year-round boilers and 0.46 percent for seasonal boilers. The annual new construction and additions forecast is equivalent to the Existing Boiler Stock multiplied by the IPGR.

To estimate the capacity of new process boilers installed annually from alterations or replacements, the Statewide CASE Team calculated the replacement rate for boilers and applied it to Existing Boilers Stock. Boiler lifetimes range widely, with most estimates in the 25- to 40-year range (Van Wortswinkel Nijs 2010). The boiler replacement rate is based on a 30-year boiler lifetime, which means that 3.3 percent of the Existing Boiler Stock is replaced each year. The alterations forecast is therefore equivalent to the Existing Boiler Stock multiplied by 3.3 percent.

The Statewide CASE Team then multiplied the per-unit measure savings by the annual new construction and additions forecast and by the alterations forecast to get statewide savings, not accounting for natural market adoption.

The final statewide savings and cost estimates take the current market share rate into account. The Statewide CASE Team estimated current market adoption of flash steam recovery to be 10 percent of newly added qualifying boiler capacity based on interviews with boiler manufacturers and vendors and data from an analysis of IAC audit data from 64 boilers in 32 steam-using industrial plants from 2010 to 2022. The Statewide CASE Team may update this estimate based on additional stakeholder feedback from the upcoming public stakeholder workshop in March 2026.

The Statewide CASE Team applied this market share percentage to the statewide savings for the flash steam recovery measure to arrive at the final statewide savings estimate.

The energy impacts of the proposed code change do not vary by climate zone. The measure is not climate-dependent because the impact of the outdoor air temperature on the boiler's operation is minimal and does not materially impact estimated measure savings. Since savings do not vary by climate zone, the Statewide CASE Team used the statewide LSC hourly factors when calculating energy and LSC impacts.

Table show the percentages of statewide boiler capacity that would be impacted by the proposed code changes in 2029 among boilers with input capacities over 10 MMBtu/h. These percentages take into account the industries that are not impacted by Title 24, Part 6 and the exceptions for each measure, but not the estimated market share of compliance with the requirement. The Statewide CASE Team developed these estimates using the methods described in this section. No differences are found for affected boiler capacity by climate zone.

Table 38: Percentage of Statewide Boiler Capacity Impacted by Proposed Code Change in 2029, by Prototype – Flash Steam Recovery

Boiler Capacity Bin	New Construction and Additions Impacted (Percent Capacity)	Existing Boiler Capacity (Alterations) Impacted (Percent Capacity)
Year-Round Boiler 10-15 MMBtu/h	94%	2.83%
Year-Round Boiler 15-25 MMBtu/h	93%	2.79%
Year-Round Boiler 25-50 MMBtu/h	92%	2.76%
Year-Round Boiler 50-100 MMBtu/h	46%	1.39%
Year-Round Boiler 100-200 MMBtu/h	95%	2.85%
Year-Round Boiler 200+ MMBtu/h	28%	0.84%
Seasonal Boiler 10-15 MMBtu/h	95%	0.32%
Seasonal Boiler 15-25 MMBtu/h	95%	0.32%
Seasonal Boiler 25-50 MMBtu/h	95%	0.32%
Seasonal Boiler 50-100 MMBtu/h	95%	0.32%
Seasonal Boiler 100-200 MMBtu/h	95%	0.32%
Seasonal Boiler 200+ MMBtu/h	95%	0.32%

Tables Table 38Table 39, Table 40 present the projected new and existing process boiler capacity that the proposed code changes would respectively impact in 2029. The Statewide CASE Team developed these estimates using the methods described earlier in this section. The 2028 CASE Methodology Report includes additional information about the methodology and assumptions used to calculate statewide energy impacts.

Table 39: Estimated New Process Boiler Capacity Impacted by Proposed Flash Steam Recovery Code Change in 2029, by Climate Zone and Prototype (Million Btu/h)

Boiler Capacity Bin	CZ 1	CZ 2	CZ 3	CZ 4	CZ 5	CZ 6	CZ 7	CZ 8	CZ 9	CZ 10	CZ 11	CZ 12	CZ 13	CZ 14	CZ 15	CZ 16	All
Year-Round 10-15 MMBtu/h	0.17	2.07	11.84	5.45	1.50	9.29	6.14	13.01	16.16	12.52	2.61	19.96	14.20	2.29	2.00	0.85	120.07
Year-Round 15-25 MMBtu/h	0.00	1.83	10.75	4.88	1.91	10.79	3.66	15.38	18.87	13.18	2.19	23.93	23.77	4.12	3.29	1.47	140.02
Year-Round 25-50 MMBtu/h	0.98	2.33	13.91	6.92	2.94	13.28	4.76	13.58	19.99	12.32	2.79	36.11	29.85	4.62	1.86	1.85	168.09
Year-Round 50-100 MMBtu/h	0.00	1.43	23.06	4.03	1.03	2.14	2.13	3.44	3.93	3.54	1.49	125.23	186.25	4.04	1.63	0.73	364.12
Year-Round 100-200 MMBtu/h	0.00	2.72	15.15	7.08	0.00	3.93	0.00	5.59	7.35	4.19	2.76	44.89	37.00	9.18	2.57	2.05	144.46
Year-Round 200+ MMBtu/h	3.14	1.97	9.50	5.12	0.00	14.96	0.00	29.91	34.19	22.43	20.94	9.43	2.94	10.96	6.38	2.66	174.53
Seasonal 10-15 MMBtu/h	0.00	0.00	0.02	0.01	0.00	0.01	0.01	0.02	0.02	0.02	0.00	0.03	0.02	0.00	0.00	0.00	0.16
Seasonal 15-25 MMBtu/h	0.00	0.00	0.02	0.01	0.00	0.02	0.01	0.03	0.04	0.03	0.00	0.05	0.05	0.01	0.01	0.00	0.29
Seasonal 25-50 MMBtu/h	0.01	0.01	0.08	0.04	0.02	0.08	0.03	0.08	0.12	0.07	0.02	0.21	0.17	0.03	0.01	0.01	0.98
Seasonal 50-100 MMBtu/h	0.00	0.02	0.37	0.06	0.02	0.03	0.03	0.05	0.06	0.06	0.02	2.00	2.97	0.06	0.03	0.01	5.80
Seasonal 100-200 MMBtu/h	0.00	0.33	1.82	0.85	0.00	0.47	0.00	0.67	0.88	0.50	0.33	5.40	4.45	1.10	0.31	0.25	17.37
Seasonal 200+ MMBtu/h	0.39	0.25	1.19	0.64	0.00	1.88	0.00	3.76	4.29	2.82	2.63	1.18	0.37	1.38	0.80	0.33	21.91
TOTAL	**4.69**	**12.97**	**87.72**	**35.08**	**7.43**	**56.89**	**16.77**	**85.52**	**105.91**	**71.67**	**35.79**	**268.42**	**302.03**	**37.79**	**18.90**	**10.23**	1,157.80

Table 40: Estimated Existing Process Boiler Capacity Impacted by Proposed Flash Steam Recovery Code Change in 2029, by Climate Zone and Prototype (Million Btu/h)

Boiler Capacity Bin	CZ 1	CZ 2	CZ 3	CZ 4	CZ 5	CZ 6	CZ 7	CZ 8	CZ 9	CZ 10	CZ 11	CZ 12	CZ 13	CZ 14	CZ 15	CZ 16	All
Year-Round 10-15 MMBtu/h	0.34	4.18	23.86	10.97	3.02	18.73	12.38	26.23	32.56	25.23	5.27	40.23	28.63	4.61	4.04	1.70	241.99
Year-Round 15-25 MMBtu/h	0.00	3.69	21.67	9.83	3.86	21.75	7.37	30.99	38.03	26.55	4.42	48.23	47.90	8.30	6.63	2.97	282.18
Year-Round 25-50 MMBtu/h	1.97	4.69	28.04	13.94	5.93	26.76	9.60	27.36	40.29	24.84	5.62	72.78	60.15	9.31	3.76	3.72	338.75
Year-Round 50-100 MMBtu/h	0.00	2.89	46.47	8.13	2.08	4.32	4.29	6.93	7.92	7.13	3.01	252.39	375.35	8.15	3.28	1.48	733.81
Year-Round 100-200 MMBtu/h	0.00	5.49	30.54	14.26	0.00	7.93	0.00	11.26	14.82	8.44	5.56	90.47	74.56	18.49	5.18	4.14	291.14
Year-Round 200+ MMBtu/h	6.33	3.97	19.15	10.31	0.00	30.14	0.00	60.28	68.90	45.21	42.19	19.00	5.93	22.09	12.86	5.37	351.73
Seasonal 10-15 MMBtu/h	0.00	0.02	0.12	0.05	0.01	0.09	0.06	0.13	0.16	0.12	0.03	0.20	0.14	0.02	0.02	0.01	1.19
Seasonal 15-25 MMBtu/h	0.00	0.03	0.16	0.07	0.03	0.16	0.06	0.23	0.28	0.20	0.03	0.36	0.36	0.06	0.05	0.02	2.11
Seasonal 25-50 MMBtu/h	0.04	0.10	0.59	0.29	0.12	0.56	0.20	0.57	0.84	0.52	0.12	1.52	1.26	0.19	0.08	0.08	7.08
Seasonal 50-100 MMBtu/h	0.00	0.17	2.66	0.47	0.12	0.25	0.25	0.40	0.45	0.41	0.17	14.47	21.52	0.47	0.19	0.08	42.06

Seasonal 100-200 MMBtu/h	0.00	2.37	13.20	6.17	0.00	3.43	0.00	4.87	6.41	3.65	2.40	39.10	32.22	7.99	2.24	1.79	125.84
Seasonal 200+ MMBtu/h	2.86	1.79	8.64	4.65	0.00	13.61	0.00	27.21	31.10	20.41	19.05	8.58	2.68	9.97	5.80	2.42	158.76
TOTAL	**11.55**	**29.37**	**195.09**	**79.15**	**15.17**	**127.71**	**34.21**	**196.46**	**241.77**	**162.71**	**87.87**	**587.32**	**650.69**	**89.66**	**44.13**	**23.79**	**2,576.64**

Condensate Return

To determine statewide savings from the proposed condensate return measure, the Statewide CASE Team first assumed that statewide boiler capacities are a fair representation of steam system capacity. To estimate statewide boiler capacities and counts by boiler capacity bins, the Statewide CASE Team leveraged statewide boiler inventory data developed as part of a Code Readiness project. This inventory is a nearly complete statewide boiler inventory that has over 9,000 equipment entries from local air quality management districts, which were collected and preprocessed by the Code Readiness project team in 2023 and 2024 (Swanson & Staller, Steam Trap Fault Detection & Diagnostics in Existing Industrial Applications, 2025).

The Statewide CASE Team refined the statewide capacity for each capacity bin to account for Title 24 purview and requirement exceptions, making the following changes:

11 Removed boilers with input capacities under 10 MMBtu/h;

12 Removed oilfield and utility boilers, which are not subject to Title 24, Part 6 requirements;

13 Removed 10 percent of remaining boiler capacity to account for steam loads that would not qualify for the requirement via the code trigger table for the condensate return requirement;

14 Separated seasonal boilers from annual boilers by classifying boilers at major tomato and canned fruit and vegetable processers as seasonal boilers.

   a. The cannery capacity includes the capacity from major tomato and canned fruit and vegetable processers in the state. The Statewide CASE Team is not aware of other major facility types in California that would typically operate boilers seasonally.

The statewide capacity after these changes were made represents the existing boilers stock, which is a proxy for the existing capacity of statewide qualifying steam systems. Boilers at or above 10 MMBtu/h in the healthcare, education, and refinery sectors were included in the statewide capacity totals. The Statewide CASE Team plans to update inclusion of each boiler type according to ongoing conversations regarding Title 24 and process load applicability in these sectors.

To estimate the capacity of new steam loads installed annually, the Statewide CASE Team calculated four IPGRs for California: year-round new construction, year-round additions and alterations, seasonal new construction, and seasonal additions and alterations. The Statewide CASE Team analyzed both national and state data to develop the IPGRs. The IPGR from the 2022 Steam Trap Monitoring CASE Report was calculated using an average of the 10-year and 30-year compound annual growth rate (CAGR) of INDPRO, the national Federal Industrial Production Index (Johnson, Heinrichs, & Coakley, 2020). However, the Statewide CASE Team determined that national trends would not provide an accurate representation of the California industrial production market. While California is the largest contributor to the U.S. manufacturing industry in terms of output and employment, it accounts for just 14.5 percent of U.S. manufacturing output (Profozich, 2022). A study performed by Beacon Economics for the California Manufacturing Network confirmed that California's manufacturing sector has grown at a faster rate compared with that of the entire United States (Economics, n.d.).

To more accurately estimate California's IPGR, the Statewide CASE Team consulted with Beacon Economics to identify California-specific data on industrial production growth and the differences between California's manufacturing sector and the U.S. manufacturing sector as a whole. Beacon Economics provided a 2025 study demonstrating that California's manufacturing growth was not only faster than the rest of the United States, but California's manufacturing is also more productive (Beacon Economics, 2025). The Statewide CASE Team investigated California real Gross Domestic Product (GDP) data from the U.S. Bureau of Economic Analysis (BEA) and California Federal Reserve Bank of St. Louis' Federal Reserve Economic Data (FRED) for industries classified as manufacturing per 2017 North American Industry Classification System (NAICS) .

The Statewide CASE Team calculated the average of the 7-year CAGR and 10-year CAGR from both sources through 2024. The California real GDP manufacturing growth rate from BEA and FRED was similar at 2.25 percent and 2.74 percent, respectively. The data from BEA provided a more conservative growth rate and were selected for California IPGR calculations.

To further tailor this data to the proposed condensate return measure, the Statewide CASE Team applied weights based on the proportion of boiler capacity in each of the main industry subsectors (i.e., food and beverage manufacturing, wood manufacturing, and total other manufacturing which is defined as all other manufacturing that was not food and beverage, wood, lumber, petroleum/refining, or other subsectors that burn byproduct waste), calculated from the statewide boiler inventory based on AQMD data to subsector-specific California real GDP BEA data. Boiler capacity from canneries was excluded from the weighted average for year-round boilers. The calculated weighted average IPGR for year-round boilers was 1.65 percent. The growth rate for the seasonal boilers is best represented by the Food and Beverage Manufacturing IPGR of 0.46 percent, which was calculated from BEA real GDP data in 2017 chained dollars.

Because the condensate return measure does not apply to replacement boilers or steam systems, the Statewide CASE Team separated out estimates of new steam loads at new facilities from new steam loads added to existing facilities. The Statewide CASE Team then split out the year-round and seasonal IPGRs between growth at new facilities and growth at existing facilities. The Statewide CASE Team estimated that 90 percent of new steam load growth would occur at existing facilities and 10 percent of the growth would occur as new construction projects. Statewide savings estimates were calculated using the growth rates in Table 41.

Table 41: Estimated Industrial Production Growth Rates: Steam Loads

Steam Load Type	New Construction	Alterations and Alterations
Year-Round Steam Loads	0.17%	1.49%
Seasonal Steam Loads	0.05%	0.41%

The new construction and additions and alterations forecasts are equivalent to the Existing Steam Boiler Stock multiplied by the steam load IPGRs for each category. The Statewide CASE Team multiplied the per-unit measure savings by each forecast to get statewide savins. Natural market adoption is accounted for through the Standard Design assumptions as outlined in Appendix A.

The energy impacts of the proposed code changes do not vary by climate zone. The measures are not climate-dependent because the impact of the outdoor air temperature on steam system's operation is minimal and does not materially impact estimated measure savings. Since savings do not vary by climate zone, the Statewide CASE Team used the statewide LSC hourly factors when calculating energy and LSC impacts.

Tables Table 42, Table 43, and Table 44 show the percentages of statewide boiler capacity that would be impacted by the proposed code changes in 2029 among boilers with input capacities over 10 MMBtu/h. These percentages take into account the industries that are not impacted by Title 24, Part 6 and the exceptions for each measure, but not the estimated market share of compliance with the requirement. The Statewide CASE Team developed these estimates using the methods described in this section. No differences are found for affected boiler capacity by climate zone.

Table 42: Percentage of Statewide Boiler Capacity Impacted by Proposed Code Change in 2029, by Prototype – Condensate Return

Boiler Capacity Bin	New Construction Impacted (Percent Capacity)	Existing Boiler Capacity (Additions and Alterations) Impacted (Percent Capacity)
Year-Round Boiler 10-15 MMBtu/h	89%	1.32%
Year-Round Boiler 15-25 MMBtu/hB	88%	1.30%
Year-Round Boiler 25-50 MMBtu/h	85%	1.27%
Year-Round Boiler 50-100 MMBtu/h	43%	0.64%
Year-Round Boiler 100-200 MMBtu/h	63%	0.95%
Year-Round Boiler 200+ MMBtu/h	24%	0.36%
Seasonal Boiler 10-15 MMBtu/h	90%	0.37%
Seasonal Boiler 15-25 MMBtu/h	90%	0.37%
Seasonal Boiler 25-50 MMBtu/h	90%	0.37%
Seasonal Boiler 50-100 MMBtu/h	90%	0.37%
Seasonal Boiler 100-200 MMBtu/h	90%	0.37%
Seasonal Boiler 200+ MMBtu/h	90%	0.37%

Table 43 presents the projected new process boiler capacity that the proposed code changes would respectively impact in 2029. Table 44 shows the projected existing statewide boiler capacity that the proposed code changes would affect through additions and alterations in 2029. The Statewide CASE Team developed these estimates using the methods described earlier in this section. The 2028 CASE Methodology Report includes additional information about the methodology and assumptions used to calculate statewide energy impacts.

Table 43: Estimated New Process Boiler Capacity Impacted by Proposed Condensate Return Code Change in 2029, by Climate Zone and Prototype (Million Btu/h)

Boiler Capacity Bin	CZ 1	CZ 2	CZ 3	CZ 4	CZ 5	CZ 6	CZ 7	CZ 8	CZ 9	CZ 10	CZ 11	CZ 12	CZ 13	CZ 14	CZ 15	CZ 16	All
Year-Round 10-15 MMBtu/h	0.02	0.23	1.32	0.61	0.17	1.03	0.68	1.45	1.80	1.39	0.29	2.22	1.58	0.25	0.22	0.09	13.34
Year-Round 15-25 MMBtu/h	0.00	0.20	1.20	0.54	0.21	1.20	0.41	1.71	2.10	1.47	0.24	2.66	2.65	0.46	0.37	0.16	15.59
Year-Round 25-50 MMBtu/h	0.11	0.26	1.57	0.78	0.33	1.50	0.54	1.53	2.26	1.39	0.31	4.07	3.37	0.52	0.21	0.21	18.96
Year-Round 50-100 MMBtu/h	0.00	0.16	2.57	0.45	0.11	0.24	0.24	0.38	0.44	0.39	0.17	13.95	20.75	0.45	0.18	0.08	40.56
Year-Round 100-200 MMBtu/h	0.00	0.31	1.74	0.81	0.00	0.45	0.00	0.64	0.85	0.48	0.32	5.16	4.25	1.06	0.30	0.24	16.61
Year-Round 200+ MMBtu/h	0.45	0.28	1.36	0.73	0.00	2.14	0.00	4.28	4.89	3.21	3.00	1.35	0.42	1.57	0.91	0.38	24.97
Seasonal 10-15 MMBtu/h	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02
Seasonal 15-25 MMBtu/h	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.00	0.00	0.00	0.03
Seasonal 25-50 MMBtu/h	0.00	0.00	0.01	0.00	0.00	0.01	0.00	0.01	0.01	0.01	0.00	0.02	0.02	0.00	0.00	0.00	0.11
Seasonal 50-100 MMBtu/h	0.00	0.00	0.04	0.01	0.00	0.00	0.00	0.01	0.01	0.01	0.00	0.22	0.33	0.01	0.00	0.00	0.64
Seasonal 100-200 MMBtu/h	0.00	0.04	0.20	0.09	0.00	0.05	0.00	0.07	0.10	0.06	0.04	0.60	0.49	0.12	0.03	0.03	1.93
Seasonal 200+ MMBtu/h	0.04	0.03	0.13	0.07	0.00	0.21	0.00	0.42	0.48	0.31	0.29	0.13	0.04	0.15	0.09	0.04	2.43
TOTAL	**0.62**	**1.52**	**10.14**	**4.10**	**0.83**	**6.84**	**1.87**	**10.51**	**12.93**	**8.72**	**4.66**	**30.40**	**33.91**	**4.59**	**2.32**	**1.23**	**135.20**

Table 44: Estimated Existing Process Boiler Capacity Impacted by Proposed Condensate Return Code Change in 2029, by Climate Zone and Prototype (Million Btu/h)

Boiler Capacity Bin	CZ 1	CZ 2	CZ 3	CZ 4	CZ 5	CZ 6	CZ 7	CZ 8	CZ 9	CZ 10	CZ 11	CZ 12	CZ 13	CZ 14	CZ 15	CZ 16	All
Year-Round 10-15 MMBtu/h	0.17	2.07	11.84	5.45	1.50	9.30	6.14	13.02	16.16	12.52	2.61	19.96	14.20	2.29	2.00	0.85	120.08
Year-Round 15-25 MMBtu/h	0.00	1.84	10.77	4.89	1.92	10.81	3.67	15.40	18.91	13.20	2.20	23.97	23.81	4.12	3.30	1.48	140.28
Year-Round 25-50 MMBtu/h	0.99	2.37	14.13	7.03	2.99	13.48	4.84	13.79	20.30	12.51	2.83	36.67	30.31	4.69	1.89	1.88	170.67
Year-Round 50-100 MMBtu/h	0.00	1.44	23.12	4.04	1.03	2.15	2.13	3.45	3.94	3.55	1.50	125.56	186.73	4.05	1.63	0.73	365.05
Year-Round 100-200 MMBtu/h	0.00	2.82	15.68	7.32	0.00	4.07	0.00	5.78	7.61	4.34	2.86	46.46	38.29	9.50	2.66	2.13	149.51
Year-Round 200+ MMBtu/h	4.05	2.53	12.23	6.59	0.00	19.26	0.00	38.51	44.02	28.89	26.96	12.14	3.79	14.11	8.21	3.43	224.71
Seasonal 10-15 MMBtu/h	0.00	0.00	0.02	0.01	0.00	0.01	0.01	0.02	0.02	0.02	0.00	0.03	0.02	0.00	0.00	0.00	0.16
Seasonal 15-25 MMBtu/h	0.00	0.00	0.02	0.01	0.00	0.02	0.01	0.03	0.04	0.03	0.00	0.05	0.05	0.01	0.01	0.00	0.29
Seasonal 25-50 MMBtu/h	0.01	0.01	0.08	0.04	0.02	0.08	0.03	0.08	0.12	0.07	0.02	0.21	0.17	0.03	0.01	0.01	0.98

Seasonal 50-100 MMBtu/h	0.00	0.02	0.37	0.06	0.02	0.03	0.03	0.05	0.06	0.06	0.02	2.00	2.97	0.06	0.03	0.01	5.80
Seasonal 100-200 MMBtu/h	0.00	0.33	1.82	0.85	0.00	0.47	0.00	0.67	0.88	0.50	0.33	5.40	4.45	1.10	0.31	0.25	17.37
Seasonal 200+ MMBtu/h	0.39	0.25	1.19	0.64	0.00	1.88	0.00	3.76	4.29	2.82	2.63	1.18	0.37	1.38	0.80	0.33	21.91
TOTAL	**5.61**	**13.68**	**91.27**	**36.93**	**7.48**	**61.56**	**16.86**	**94.56**	**116.35**	**78.49**	**41.96**	**273.62**	**305.15**	**41.35**	**20.86**	**11.10**	**1,216.81**

Appendix D: Environmental Analysis

Flash Steam Recovery

Potential Significant Environmental Effect of Proposal

The Statewide CASE Team has considered the environmental benefits and adverse impacts of its proposal, including but not limited to an evaluation of factors contained in the California Code of Regulations, Title 14, section 15064, and has determined that the proposal will not result in a significant effect on the environment.

Direct Environmental Impacts

Direct Environmental Benefits

Flash steam that is not recovered is vented to the atmosphere, wasting thermal energy and water. Flash steam recovery systems reduce energy and water consumption by using flash steam to serve low-pressure loads instead of down-regulating live boiler steam. Recovering flash steam will therefore save both energy and water. This process in turn reduces GHG emissions from the reduced need to produce that energy, typically by burning natural gas.

The direct environmental benefits of this proposal are demonstrated by the estimated energy reductions, as discussed in Sections 2.5.1 and 2.5.2. The data demonstrating water use benefits are discussed in section 2.5.3.

Direct Adverse Environmental Impacts

The Statewide CASE Team has not identified any direct adverse environmental impacts.

Indirect Environmental Impacts

Indirect Environmental Benefits

The reduction in energy consumption due to flash steam recovery would indirectly lead to improvements in local air quality. Combustion of natural gas produces NOx, a chemical precursor to ozone. Reducing the consumption of natural gas will therefore indirectly lead to reduced ozone (Chen, Omotesho, & Johnson, 2025).

In addition, reduced water consumption means that water utilities will spend less energy pumping water for distribution.

Finally, because people who live near industrial facilities dislike steam plumes and associate them with pollution, reduced steam venting provides an aesthetic benefit.

Indirect Adverse Environmental Impacts

The Statewide CASE Team has not identified any indirect adverse environmental impacts.

Mitigation Measures

The Statewide CASE Team has considered opportunities to minimize the environmental impact of the proposal, including an evaluation of "specific economic, environmental, legal, social, and technological factors" (Cal. Code Regs., tit. 14, § 15021). The Statewide CASE Team did not determine this measure would result in significant direct or indirect adverse environmental impacts and therefore did not develop any mitigation measures.

Reasonable Alternatives to Proposal

The Statewide CASE Team has considered alternatives to the proposal and determined that no alternate proposals would achieve the same impact of reduced boiler energy consumption.

Water Use and Water Quality Impacts Methodology

Recovering flash steam will reduce the amount of water that is lost to steam venting, saving water. The water savings are calculated using the difference in baseline and proposed blowdown flash steam mass flows. The quantity of water saved will vary depending on the site's size and operating characteristics.

Condensate Return

Potential Significant Environmental Effect of Proposal

The Statewide CASE Team has considered the environmental benefits and adverse impacts of its proposal, including but not limited to an evaluation of factors contained in the California Code of Regulations, Title 14, section 15064, and has determined that the proposal will not result in a significant effect on the environment.

Direct Environmental Impacts

Direct Environmental Benefits

Condensate return systems reduce water use by replacing fresh make-up water that would otherwise be needed for boiler feedwater. Fresh make-up water also requires additional heating from the boiler, so replacing fresh make-up water with condensate return also decreases boiler fuel consumption, which in turn reduces GHG emissions.

The data demonstrating energy benefits are discussed in section 3.5.1. The data demonstrating GHG benefits are discussed in section 3.5.2. The data demonstrating water use benefits are discussed in section 3.5.3.

Direct Adverse Environmental Impacts

The Statewide CASE Team has not identified any direct adverse environmental impacts that would result from the proposed changes.

Indirect Environmental Impacts

Indirect Environmental Benefits

This reduction in fuel consumption from returning condensate would also indirectly improve local air quality. Combustion of natural gas produces NOx, a chemical precursor to ozone. Reducing the consumption of natural gas will therefore indirectly lead to reduced ozone (Chen, Omotesho, & Johnson, 2025). In addition, reduced water consumption means that water utilities will spend less energy pumping water for distribution.

Indirect Adverse Environmental Impacts

The Statewide CASE Team has not identified any indirect adverse environmental impacts.

Mitigation Measures

The Statewide CASE Team has considered opportunities to minimize the environmental impact of the proposal, including an evaluation of "specific economic, environmental, legal, social, and technological factors" (Cal. Code Regs., tit. 14, § 15021). The Statewide CASE Team did not determine that this measure would result in significant direct or indirect adverse environmental impacts and therefore did not develop any mitigation measures.

Reasonable Alternatives to Proposal

The Statewide CASE Team has considered alternatives to the proposal and determined that no alternate proposals would achieve the same impact of reduced boiler energy consumption.

Water Use and Water Quality Impacts Methodology

Returning condensate will reduce water consumption by reducing the amount of water that needs to be replaced in the boiler system. The water savings were calculated by adding the increase in condensate flow and the decrease in blowdown flow between the baseline and proposed cases. The quantity of water saved will vary depending on the site's size and operating characteristics.

Appendix E: Summary of Stakeholder Engagement

Introduction to Stakeholder Engagement

Collaborating with stakeholders who may be affected by proposed code changes is a core component of the Statewide CASE Team's process. The Statewide CASE Team engages interested parties to identify and address issues related to the proposals, with the goal of submitting recommendations to the CEC in this Draft CASE Report that reflect broad support. Public stakeholders provide valuable feedback on draft analyses and help identify and address adoption challenges, including cost effectiveness, market and technical barriers, compliance and enforcement, and potential impacts on human health or the environment. Some stakeholders also provide data that the Statewide CASE Team uses to support analyses.

This appendix summarizes the stakeholder engagement conducted by the Statewide CASE Team during the development and refinement of the report's recommendations.

Flash Steam Recovery and Condensate Return

Utility-Sponsored Stakeholder Meetings

Utility-sponsored stakeholder meetings provide an opportunity to learn about the Statewide CASE Team's role in the advocacy effort and to hear about specific code change proposals that the Statewide CASE Team is pursuing for the 2025 code cycle. The goal of these meetings is to solicit input on proposals from stakeholders early enough to ensure the proposals and the supporting analyses are vetted and have as few outstanding issues as possible. To promote transparency in the development of code change proposals, the Statewide CASE Team uses stakeholder meetings to solicit feedback on the following:

- Proposed code changes;
- Draft code language;
- Draft assumptions and results of analyses;
- Data to support assumptions;
- Compliance and enforcement; and
- Technical and market feasibility.

The Statewide CASE Team hosted one stakeholder meeting for the proposed process steam measures via webinar, as described in Table 45: Utility-Sponsored Stakeholder Meetings**Error! Reference source not found.**. Dates and links to event pages on Title24Stakeholders.com are provided in this section. Materials from each meeting, such as slide presentations, proposal summaries with code language, and meeting notes, are included in the bibliography section of this report.

Table 45: Utility-Sponsored Stakeholder Meetings

Meeting Name and Link to Materials	Meeting Date	Summary of Items Discussed
First Round of Process Steam Utility-Sponsored Stakeholder Meetings	Wednesday, October 29, 2025	• Proposal description • Market and technical considerations • Energy savings methodology and cost assumptions • Compliance verification
Second Round of Process Steam Utility-Sponsored Stakeholder Meetings	Tuesday, March 17	• Market and technical considerations • Energy savings methodology and assumptions • Cost assumptions

The first round of utility-sponsored stakeholder meetings began in October 2025 and served as an early forum to promote transparency and gather stakeholder feedback on measures under consideration by the Statewide CASE Team.

The objectives of the first round of stakeholder meetings were to solicit input on the scope of the 2025 code cycle proposals; request data and feedback on the specific approaches, assumptions, and methodologies for the energy impacts and cost-effectiveness analyses; and understand potential technical and market barriers. Initial draft code language was posted on Title24Stakeholders.com for public stakeholder review.

The second round of utility-sponsored stakeholder meetings will be held in March 2026 to provide updated details on proposed code changes. These meetings will introduce early results of energy, cost effectiveness, and incremental cost analyses and assumptions.

Utility-sponsored stakeholder meetings were open to the public. For each stakeholder meeting, two promotional emails were distributed from info@title24stakeholders.com. One email was sent to the full Title 24 Stakeholders listserv, which includes over 3,000 individuals. A second email targeted specific recipients based on their subscription preferences.

The Title 24 Stakeholders listserv is an opt-in service comprising participants from a diverse industries and trades, such as manufacturers, advocacy groups, local government, and building and energy professionals. Each meeting was announced on the Title 24 Stakeholders LinkedIn page and cross-promoted on the CEC LinkedIn page approximately two weeks in advance to engage individuals, organizations, and broader channels outside beyond the listserv. The Statewide CASE Team conducted extensive personal outreach to stakeholders identified in initial work plans who had not yet opted in to the listserv. Exported webinar meeting data captured attendance numbers, individual comments, and results from live attendee polls to help evaluate stakeholder participation and support.

Statewide CASE Team Communications

The Statewide CASE Team held personal communications over email and phone with numerous stakeholders when developing this report, listed in Table 46. Most stakeholders preferred to be anonymous.

Table 46: Engaged Stakeholders

Organization/ Individual Name	Market Role	Mentioned in CASE Report Sections
Anonymous Stakeholder 1	Boiler systems manufacturer	2.3.1.2 Market Challenges and Solutions 3.1.2 Benefits of Proposed Change 3.3.1.1 Current Market and Structure Availability
Anonymous Stakeholder 2	Boiler and steam system representative	3.3.1.1 Current Market and Structure Availability 3.3.2.3 Design and Construction Challenges and Solutions
Anonymous	Industrial energy benchmarking representative	Did not inform specific assumptions for the Draft CASE Report.
T. Berry	Sales representative, manufacturing equipment	3.3.2.1 Market Challenges and Solutions
R. Baker	California Technical Forum	Did not inform specific assumptions for the Draft CASE Report.
California Air Resources Board	Regulator	Did not inform specific assumptions for the Draft CASE Report, but supports updates to the flash steam measure that are under consideration.
Beacon Economics	Economic research and consulting firm	Appendix C: Assumptions for Statewide Savings Estimates.
Anonymous Stakeholder 3	Steam and water treatment services	Did not inform specific assumptions.
Anonymous Stakeholder 4	Controller manufacturer	Did not inform specific assumptions.
Anonymous Stakeholder 5	Government safety agency	2.1.5.2 Interactions with Other Regulations 2.2.1 Compliance Considerations

Anonymous Stakeholder 6	Manufacturer of thermal utility management systems	2.3.1.2 Market Challenges and Solutions

Engagement with ESJ communities

The Statewide CASE Team did not conduct stakeholder outreach specifically targeted towards ESJ communities. The proposed measures would have no direct impact on residential communities in California, and the only indirect anticipated impact is decreased exposure to air pollution due to reduced natural gas combustion at nearby industrial facilities.

Mass Email Cold Outreach

The Statewide CASE Team leveraged a list of organizations and emails from the California Directory of Manufacturers to send cold outreach emails to about 600 organizations believed to have process boilers or steam systems. The email invited respondents to participate in a conversational interview about or otherwise provide feedback on the proposed measures. Many of the email addresses were outdated at the time of sending, and the Statewide CASE Team did not receive responses from any stakeholders who wished to contribute to the process.