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Ms. Mary Nichols, Chair
California Air Resources Board
1001 I Street
Sacramento, CA 95814

Dear Ms. Nichols:

Below please find our detailed comments on the Appendices to the Draft Scoping Plan. We look forward to working closely with your staff to address both the technical and policy issues raised in our comments.

APPENDIX B: ACRONYMS AND GLOSSARY

Offsets: Should be defined as: **Offsets:** A represent reductions in greenhouse gas emissions, that, when measured and verified during a specified year, becomes an authorization to emit one ton of carbon dioxide equivalent, which can be used for compliance purposes or traded.

APPENDIX C: SECTOR OVERVIEWS AND EMISSION REDUCTION STRATEGIES

Cap and Trade Section
Major program design elements are taking shape in the Draft Scoping Plan, supported by appendices without many of the critical details, supporting analysis or underlying economic modeling, e.g., the system-wide cap and the general approach for distributing allowances. Proceeding in this manner is likely to raise concerns among industry and the public that the modeling will be dictated and shaped by a preferred program design, rather than following the more considered process of designing a program that is shaped and informed by the results of careful modeling.

As indicated by the detailed information provided in this document, as well as the extensive documentation within the academic community, it is unlikely that direct regulations will be as effective as a cap and trade program (C&T) in achieving the maximum feasible and cost-effective reductions. Many of the proposed direct reductions have either already been made, are duplicative across the program, or are not technologically feasible even at very high cost. The combination of direct regulatory measures and C&T is particularly troubling, and in fact runs counter to the very intent of market-based emissions control. While we support the use of direct regulatory measures without C&T in the transportation sector, overlapping requirements in the industrial sector unnecessarily raise costs to society while imposing a heavy administrative burden on affected sources. We urge ARB to avoid direct regulation of stationary sources under a C&T program.

The duplication and overuse of direct regulatory measures with an emissions cap will not only increase the cost of the program, but also inadvertently create uncertainty for the covered sectors. If the regulatory measures outlined in the draft scoping plan fail to achieve the state's projections for emissions reductions, there would be significant push within doubly-regulated sectors (such as the electricity sector which faces both an RPS and C&T obligations) to achieve compliance with the 365 MMTCO2e cap through the acquisition of allowances from the market. This 'high-demand' scenario -- which could unfold over a short period of time -- could significantly drive up prices and undermine the ability of industry to obtain allowances for continued operation, as occurred under RECLAIM. ARB itself cites on P. C-11 an EPA report indicating the overwhelming cost-effectiveness of cap-and-trade, but then goes on to state that a cap-and-trade program would be used only to 'compliment' (P. C-59) other direct regulatory measures to achieve additional reductions.

Also, ARB should focus on the statewide total emissions, rather than on localized GHG emissions. Section 38501(h) of AB 32 places equal emphasis on 'minimizing costs' and 'maximizing benefits'. The EPA report cited on C-11, showing no localized impacts from C&T under an analogous national program, is a strong example of why a broader statewide focus is appropriate. For example, ARB has focused more on the localized impacts of Combined Heat and Power (CHP), without providing data on the fact that CHP is a highly efficient technology that reduces the statewide net GHG emissions. The scoping plan should not imply that CO2 is a localized health hazard.

Transportation Section

We believe that it is critical for ARB to develop a separate appendix on the development of the LCFS rule as part of the scoping plan. There are numerous areas of deliberation that are required for the development of the LCFS and each of these will have impacts on the costs and effectiveness of the program. In particular, ARB must address the impact of land use change on the carbon intensity of biofuels. This is essential to provide appropriate direction to fuel providers on the types of fuels that will qualify for compliance with LCFS.

The fuel technology required for a successful LCFS does not yet exist. Developing these technologies and associated infrastructure will be a relatively high cost route to GHG reductions. As recognized in the Scoping Plan, the LCFS is best way to drive this technology forward rather than including transportation fuels in the cap and trade program where emitters will pursue lower cost reductions initially. However, given the cost of developing new technology, it is unclear how the cost of this program is identified as “zero.” We ask ARB to provide a more transparent explanation for this result, as with all other cost assessments included in the Appendices.

Electricity and Natural Gas Section

We are pleased that ARB recognizes the benefits of combined heat and power (CHP), and understands that there are market barriers that require a multi-pronged approach to enhance the use of this technology in the state. We are concerned, however, that ARB is contemplating mandates for CHP, and we urge ARB to avoid such an approach. Decisions about industrial applications and processes are best addressed by operators. If industry can realize energy efficiencies – that is, if the application is right for the process— private industry will make the investment, assuming there are no exit barriers, that there is a home for excess power and there are no other significant unforeseen barriers to CHP.

Instead of direct regulation, the most straightforward approach for ARB to incent CHP while regulating the electricity sector is to establish a pass-through of GHG costs/charges in utility standard offer contracts. Alternatively, additional consideration is needed for the following proposals:

- CO2 reduction payment which could equal the reduction in overall GHG associated with the primary energy savings attributable to CHP (approximately 30 percent)
- A utility-provided incentive payment which could be equal to market for GHG CO2 on top of purchase price (really the same as pass through of GHG costs).

- Portfolio standard for CHPs which purchases any excess electricity produced to maximize energy efficiency by sizing CHP plant to meet thermal load. Purchase price must allow pass through of GHG costs, as the utility will surely pass these costs to their customers.

We believe these types of policies will be necessary to get the CHP plants built at the rate identified in the EPRI report, as well as to keep existing CHP sources from shutting down prematurely.

There is no discussion in the appendix regarding keeping existing CHP capacity in service. Many CHPs are now operating beyond their original contracts. There is a very real possibility that existing CHPs will need to be retired early- before 2020- , particularly if contracts are not completed. If that is the case, the power drain to the grid from the shutdown of these facilities will need to be made up somewhere. This will mean either more CHPs than the original estimate, or another source of power. To prevent this, the incentives for continued operation of existing CHPs should be considered early in the deliberations, and preferably set out in detail in the scoping plan.

ARB should focus on comparing emissions alternatives in its analysis of CHP. For example, the discussion on p. c-75 states that CHP will increase CO2, but ignores the fact that any combined cycle facility, or any other alternative plant built by a utility, will also increase CO2. ARB should remain cognizant of the steam needs of the industrial host in its analysis of CHP. It is important to note that once an existing CHP plant shuts down, the thermal host will find an alternative source for its steam and these alternatives are long term investments, usually either a major capital investment or a firm long term contract. Once that happens, it will be virtually impossible for the previously existing CHP to be restarted, even if portfolio standards are placed on the power company. The thermal host will have already invested in its new source of steam, and it will not be cost effective to return to CHP for steam.

Other technical comments:

- Footnote 33 acknowledges that the estimate quoted is low - there are gains from avoiding transmission losses. This information should be included in the text itself instead of being relegated to a footnote, preferably included as it should be included a bullet under additional benefits and costs on p c-75.
- Third ¶ on p c-73 strike "generally" from "natural gas generally use less fuel".
- Footnote 39 is troubling as cost and availability data for molten carbonate fuel cells is not easily accessible by stakeholders, and should be provided by ARB. Additionally, because it is unlikely that such technology has a wide application, it should not be established as a preferred option.
- ARB refers to an 85 percent load factor. That is low for applications of CHP in practice, where CHP facilities may run 350 to 360 days a year, which is a net load factor of greater than 92%.
- P. C-73: Footnote 35. This EPRI reference is not listed in the footnotes, and appears to be the entire basis for the 6.3 MMtonne reductions due to CHPs. Please provide additional reference details.

Green Buildings Section

In general, Chevron supports the need for a green buildings policy, and we encourage the state to aggressively develop an internal policy that will facilitate easy retrofitting as early as possible.

The green building efficiency proposals assumptions require more detail; otherwise, it is difficult to duplicate and verify the GHG reductions outlined in the Plan. A more detailed breakdown of green improvements that are under consideration, technology by technology, and the projected efficiency gains would be more transparent and would allow appropriate public review and comment. In fact, ARB should provide a range of savings and payback times, rather than providing values that appear to be for one best case scenario.

ARB mentions frequently that green building improvements are possible at little or no extra cost. This could be misleading because retrofits and higher efficiency levels may likely add noticeable extra costs. For example, the solar PV for a typical home can be up to $50,000 incremental cost. The baseline to which they are comparing is also harder to define, especially for new builds. Many new buildings today already incorporate a certain level of green attributes, but may not always qualify for LEED certification due to some issues that were not handled at the time of construction. Many projects can appear affordable if their cost is spread over many years … in some cases, beyond their useful life span. The key, however, is to devise a strategy that allows payback within a reasonable amount of time. Financing mechanisms that allow this are needed, and ARB should consider this in their analysis.

Finally, ARB states that, “In order to avoid double counting, the ARB is not counting any of the green building measures as "additional" GHG reductions, but this may change as ARB staff gains a better understanding of the interactions between the sector”. This appears to be inconsistent with the way all other efficiency measures are being treated. ARB should take additional time to find mechanisms to enable credits to be gained for efficiency projects in order to facilitate additional investments in this area. Otherwise, there is significant inconsistency in this approach as compared to other sectors.

Additional technical points:

- P. C-91: What Energy Star rating level is ARB targeting for State Buildings - 60, 74?
- P. C-93: ARB refers to 25.5 MMTCO2e in reductions from water and solid waste. Are these direct or indirect GHG reductions (e.g., less water means less pumping energy and less waste means less landfill gas emissions)?
- ARB states that there are 9,764 public schools in California. Additional detail is needed regarding which schools are included in this number (i.e., universities). Also, private schools seem to be omitted from consideration. ARB should prioritize all academic institutions based on GHG emissions, with the focus being first on largest emitters, and then moving down the list.
- In the section on existing homes, it appears ARB would place the upgrade burden on owners at the time of sale. ARB should also consider offering major incentives to the buyer, who many times ends up retrofitting the home in reality.
- Appendix C, Table 35: What are the assumptions used in estimating these reductions - lifetimes? Assuming conservative or aggressive programs? A range should be given unless these can be shown to be median costs.
- ARB should be careful in its focus on LEED as a way to reduce GHG emissions; increasing the LEED rating, for example, may not always reduce GHG, since some LEED credits are not related to energy usage.
- Additional detail is needed regarding how the State will budget and pay for these programs, as well as mechanisms to support home owner/home buyer programs.
- While we agree with the numbers presented on retro-commissioning, most retro-commissioning measures have a short life; in other words, you have to retro-commission the buildings every other year.

<u>Industry: Refineries Section</u>

Chevron’s refineries already have completed or soon will complete all of the suggested energy efficiency improvements listed on P. C-109. Chevron has had a comprehensive energy efficiency program in place since 1991, and our refineries are very energy efficient. We are already moving forward with additional reductions for projects at our Richmond refinery. It is critical that these early actions are recognized in the cap and trade program, are not mandated by ARB, and that ARB not seek to place mandatory requirements on top of a C&T program.

Existing regulations also minimize the opportunity to reduce emissions through direct regulation. For example:

- BAAQMD and SCAQMD flare minimization plan activities have taken refineries to essentially "no" flaring outside of startups, shutdowns, and upsets.
- Methane is already included in the Inspection and Maintenance (I&M) program under BAAQMD regulations. Refineries already have a rigorous I&M program, which includes valves, pumps, compressors, pressure relief valves, flanges, connectors and other piping components. There is no likely opportunity for material emissions reductions from an additional or enhanced I&M program.
- With respect to storage tanks, most liquids stored in tanks do not contain significant levels of methane. Tanks containing finished products with regulated levels of VOCs (e.g. gasoline) are already controlled under existing VOC programs, which specify tank seal construction, inspection and maintenance requirements. Furthermore, the presence of methane is very unlikely, since the finished products must meet vapor pressure and other product quality standards. This is in addition to the fuel production process itself, which removes methane.
- The potential emission reduction for methane also appears to be overestimated, given that nearly all valves are already included in some kind of I&M program. Furthermore, based on current costs of Chevron’s I&M program, the statewide cost for additional inspection and maintenance would likely be much higher than estimated by CARB. Overall, the cost effectiveness of increased or additional I&M programs for methane is very poor, at $20,000-$1,200,000/tonne of methane.

Additional technical comments:

P. C-109: The basis for the CARB staff estimate that 20% of existing boilers and heaters could be replaced is unclear. While this estimate may apply to other refineries in California, Chevron has modernized boilers and large heaters in Chevron's refineries to maximize efficiency. Driven by our comprehensive energy efficiency program, maintenance and operation of our process heaters and boilers is driven to maximize energy efficiency, while ongoing capital investment is directed to make step changes in energy efficiency as older facilities are replaced. Most steam produced at the El Segundo refinery comes from cogen units, hydrogen plants, or waste process heat exchangers. Many of the steam turbine drivers have been replaced with electric motors with variable frequency drives. These examples demonstrate why a cap-and-trade program with allocations that take early actions into account is preferable for reductions at industrial sites, rather than direct regulation.

P. C-109, 7th ¶: The large majority of US refineries participate in the Solomon ranking system to compare refinery energy efficiency and utilization. This system can form the basis for emissions allocation and control measures under a cap and trade program.

P. C-110: The estimated cost for refinery energy efficiency improvement seems low relative to CARB’s estimate that 20% of heaters and boilers could be modernized. Data from Chevron’s projects implies about two times this cost ($1.2 to 1.8 billion) if 20% of the heaters and boilers in California refineries are to be replaced. For example, replacement of a single 100 MMBtu/hr boiler will cost approximately $20 MM -$40MM.

P. C-110: Estimated total methane emissions from each of our refineries are less than 300 tonnes/year CO2e, or 0.0075% of a refinery's annual GHG emissions. The methane emissions estimate is based on very conservative emissions factors, so actual methane emissions are likely even lower than this estimate. Implementing measures to mitigate methane emissions would likely be very costly ($20,000-$1,200,000/tonne methane) and have a minimal effect on total refinery emissions.

One of the reduction strategies listed suggests that fugitive methane monitoring frequency be increased. As noted above, the total methane emissions from the Richmond refinery are less than 300 tons per year CO2e. Assuming the cost for a 10% increase in monitoring is approximately $300,000 per year, if the monitoring program eliminated all leakage, the cost would be $1000 per ton of CO2e, or $20,000 per ton of methane. As noted above, since methane emissions estimates are based on conservative factors, actual methane emissions reduction would likely be much lower than 300 tonnes/year CO2(e).

Table 28: The potential emission reductions from refinery energy efficiency process improvements are overestimated. Furthermore, based on data from our energy efficiency improvement program, and actual costs for recent boiler and heater projects, the net annualized cost provided in Table 28 appears to significantly underestimate actual costs for the refineries.

<u>Industry: Oil and Gas Production Section</u>

CARB's estimates that GHG emissions reductions can be achieved through repowering, retrofitting, replacing and/or repairing existing equipment likely overestimates potential reductions and underestimates potential costs. Chevron has installed and maintained energy efficient equipment, and conducts an ongoing maintenance and replacement program to maintain the highest levels of efficiency. We agree that energy efficiency standards should be applied to all production operations as appropriate. Chevron's SJVBU runs generators at high efficiency, controls/monitors O2 continuously, and keeps the generators well tuned. Emissions are checked regularly to ensure compliance with existing air quality regulations. The target GHG reduction of 0.5 to 1.5 MMTCO2E by 2020 is an overestimate which depends on the actual amount of fuel gas consumed and overall efficiency improvement opportunity. For example, the benefit associated with the 'economizer' is roughly a 1% fuel savings for every 10 DegF of temperature rise provided to the feedwater. The quoted 4 to 5 percent efficiency gains from adding the economizer would imply that there is a 200 to 250 DegF opportunity to reduce stack temperatures. Chevron SJVBU stack temperatures are typically lower, so this is not a potential GHG reduction opportunity for Chevron SJVBU production operations.

As with refineries, upstream emissions reductions are also already addressed through existing regulation. For example, the possible gains are going to be an order of magnitude less than the stated CARB estimates since the LoNOX retrofits required have already been put into place. The LoNOX retrofits reduce both NOx and greenhouse gas emissions, because boilers redesigned to achieve LoNOX emissions and which are used near their design capacity, are more efficient than pre-retrofit boilers, resulting in lower fuel use per unit of steam.

Additional technical points:
The estimated costs for the target GHG reduction appear to be unreasonable. It would be helpful for the basis for the estimate to be clarified (how many boilers, ratings, target improvements, etc.). Without any additional specific details, it appears that the ARB estimate is off by one order of magnitude.

P. C-112 ¶. 6: The logic of this paragraph is unclear. As fields age, it takes more energy to produce the same amount of product. There must be distinction between heavy and light production to make a reasonable future projection.

P. C-113: The potential benefit of replacing internal combustion engines is minimal. Based on 2007 fuel use data, the estimated CO2 reduction, even if we take all of our engines completely out of service, which is not practical, the GHG reductions would be only 14,639 tonnes. Electrification would only change the geographic location of the emissions reductions, which could increase the amount of emissions statewide due to line loss. Also, the basis for CARB's estimated emission reduction and savings is unclear. Boiler replacement represents a significant capital cost – in the millions. Finally, both the potential reductions and negative net annualized cost estimates appear to be overstated.

Replacement and maintenance of pipeline components is very costly and not likely to yield cost-effective methane emissions reductions. Chevron Pipe Line company has invested in appropriate methane emissions reduction technology, such as elimination of pneumatic valves, installation of low-emission components and seals, and other practices and technologies recommended by EPA Natural Gas Star program. Pipelines are inspected quarterly per DOT regulations and gas is required to be odorized if it passes through any population. Thus, leaks are detected and repaired on the occasions when ppm or ppb levels of odorant (and gas) are apparent. Natural gas systems are less prone to leakage than refinery fuel gas or other systems, since natural gas is "dry" and contains only minute quantities of corrosive sulfur (usually < 4 ppm H2S/RSH).

General Combustion Section

CARB's estimate of 0.5 to 1.5 MMTCO2E is likely higher than the actual potential. It is not clear if this estimate double counts potential emission reductions from refinery, production and other industrial energy efficiency programs.

As part of Chevron's comprehensive energy efficiency program, oxygen trim systems are in place on all appropriate combustion devices. We monitor and maintain heaters and boilers to maximize efficiency, achieving up to 92% efficiency. We install and operate boilers and heaters within their optimum range, rather than operating large boilers and heaters at a reduced rate. Chevron already has plans in place to replace the lower efficiency boilers, and will continue our comprehensive energy efficiency program to maintain all equipment at optimum operating levels.

Other technical points:
P. C-116: The cost estimate for further replacement is very low. Replacement of a 100 MMBtu/hr boiler will cost approximately $20 MM -$40MM. Also, as described earlier in the refining section of these comments, ARB's estimated 4-5% efficiency improvement is overly high ; this is not likely to be an area of significant emission reduction. The estimates for potential emissions reductions and costs associated with boiler efficiency and engine electrification appear to be high.

Electrification of stationary engines might decrease direct emissions from a refinery or oil and gas production facility. However, total state emissions will be roughly equivalent or higher, since the power for the electrical drivers will need to be generated and transported to the facilities. Furthermore, the capital efficiency of the early replacement of these engines is very poor, contributing to a higher net annualized cost. CARB's estimate of the net annualized cost appears to be very low. It is not clear why there would be a cost savings for electrification, since there would still be a need to purchase the electricity, as well as the capital investment in electric drivers.

P. C-116: Engines are addressed in the Oil and Gas production section as well as this section. The reductions may be double counted if they are attributed to policies under each section of the appendix. Also, a distinction is made in this section to differentiate engines over 50 HP. In the extraction section, ARB refers to "small internal combustion engine pumps" which may mean pumping unit engines/motors. Additional clarification is needed.

P. C-116: Fuel cells are neither well suited nor cost-effective for steam generation in refineries and oil and gas production, and do not necessarily reduce greenhouse gas emissions, since CO_2 is typically released when hydrogen is produced to run the fuel cell. Refineries require superheated steam at 800 psig, which fuel cells are not capable of generating, and are not a feasible replacement for boilers for steam generation in refineries.

Natural gas -fired high temperature fuel cells (Molten Carbonate Fuel Cells (MCFC), Solid Oxide Fuel Cells (SOFC)) and hydrogen-fed lower temperature fuel cells (Phosphoric Acid (electrolyte) Fuel Cells (PAFC), Proton Exchange Membrane Fuel Cells (PEMFC)) can be used to generate electricity directly. The waste heat can then be recovered for industrial process heat applications or in the case of MCFCs and SOFCs, combined with a turbine to generate more power. Today's fuel cells range in capacity from ~100 kWe to ~a few MWe and are used typically in distributed power applications. Thus, one would not replace a boiler or steam generator alone with a fuel cell, but rather a full power or CHP unit (e.g., gas-fired ICE, simple cycle gas turbine, microturbines, etc).

If combining power and heat, a fuel cell unit can reach efficiency of 85%, which, however, can be easily reached by current NG boilers or conventional CHP plants, even before considering the inefficiencies of hydrogen generation to support the fuel cell. Fuel cell CHP unit is very expensive, ~$10,000/kWe for PEMFC (or >$5,000/kWe for MCFC) as compared to $1,000-3,000/kWe for NG boiler (w/ steam turbine) and MTG based CHPs.

High GWP

The High GWP-gases section needs more clarity on where the burden of the reduction measure will fall. For example:

- For the Commercial and Industrial Refrigeration measure (C-147), it appears that most of the burden of compliance will fall on the manufacturer. However, it is unclear if owners of existing systems will need to purchase the new upgraded equipment or not.
- For the SF_6 rules (C150), the performance standard requirement appears to fall on the manufacturer. However, it is unclear who will be liable to comply with the related mandatory recovery rates and requirements for disposal. The rule should better clarify on whom the burden of the measure will fall at various stages of the equipment lifecycle.
- For the fire suppressant measure (C151), again, it is unclear where the burden will fall- on the manufacturers or the users.

Agriculture

In 2004 emissions from livestock waste were 6.9 MMtpa CO_2e and ARB estimates only 1 MMtpa can be mitigated by 2020. The ETAAC final report suggests that 3.1 MMtpa is technically feasible and previous work by ICF suggests that ~ 5 MMtpa could be mitigated. Additional detail is needed as to why ARB's estimate is so significantly lower.

The ARB cost estimates also seem too high, around one order of magnitude. For a dairy of 1000 head, ARB assumes the capital expense is $4-5.8 MM. For a 30% efficient conversion to electricity, 65% CH_4/30% CO_2 biogas, 80 scfd/cow, and 80% capacity factor, this would be equivalent to generating 130 kW continuously. This equates to an installed cost of $31,000/kW, whereas typical values are ~ $4000/kW. Their O&M costs are ~$0.13/kWh, whereas it is more likely to be estimated at $0.02/kWh.

ARB also did not estimate GHG reductions potential for making heat and power from agricultural residues, estimated at 8 MMtpa biomass available. While the appendix mentions that bioenergy will be tracked and accounted for in the energy sector, additional data is missing.

Sincerely,

Stephen D. Burns