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Attention: Docket ID No. PHMSA-2012-0082 (HM-251)

Re: Hazardous Materials: Rail Petitions and Recommendations to Improve the Safety of Railroad Tank Car Transportation (RRR)

The American Petroleum Institute (API) offers the following attached comments in response to the Department of Transportation (DOT) Pipeline and Hazardous Materials Safety Administration's (PHMSA) request for comments on Docket PHMSA-2012-0082 (HM-251). The American Petroleum Institute represents more than 600 companies involved in all aspects of the oil and natural gas industry including the exploration, production and transportation of crude oil.

Sincerely,

Robert L. Greco III

API Group Director
Downstream & Industry Operations

Attachment

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I. Introduction

API supports PHMSA's development of rules that will improve the safety of railroad operations and mitigate the consequences of train accidents. API supports a rule that ultimately focuses on two critical issues: improving the safety of rail transportation in North America through a holistic approach and supporting the continued growth of the U.S. energy renaissance.

According to the Association of American Railroads (AAR), 99.9977 percent of all rail hazmat shipments reach their destination without a release caused by a train accident.[1] We believe, however, that one accident is too many. To improve the safety of transportation of crude by rail, API has been actively engaged in collaborative efforts with crude by rail industry stakeholders to holistically address prevention efforts, tank car design, classification of crude oil, and emergency response.

In March 2011, the AAR Tank Car Committee, of which API is a member, petitioned PHMSA (P-1577) to adopt new tank car standards (CPC-1232). Directly after the submission of P-1577, the AAR Tank Car Committee established the T87.6 task force that reviewed the standard to determine if changes were necessary. The T87.6 task force was led by the FRA. Later that year, the industry adopted a revised CPC-1232 standard for tank cars ordered after October 1, 2011 that transport Packing Group I and II denatured fuel ethanol and crude oil. Industry began building tank cars to that specification, resulting in nearly 19,000 cars built to date and an additional 32,000 that will be built by the end of 2015. At that time, industry again petitioned the government to endorse the revised CPC-1232 standard. On July 11, 2012, the Chlorine Institute (CI), the American Chemistry Council (ACC), and API submitted P-1595 requesting PHMSA initiate an expedited rulemaking on regulatory requirements for tank cars carrying exclusively crude oil and ethanol. In this petition, it was noted that many materials within Packing Group I and II have different risks. On October 12, 2012, API once again petitioned PHMSA (P-1612), along with ACC, CI, and the Renewable Fuels Association, to expedite a rulemaking for new tank cars to provide regulatory certainty. API is encouraged that PHMSA is in a rulemaking process but requests that PHMSA develop a rule with a measured approach based on sound science and data.

In January, Secretary of Transportation Foxx issued a Call to Action in which the industry was asked to provide to the Administration data on crude oil moved by rail. API and its members submitted data on over 200 samples of Bakken and other crude oils to PHMSA. Since that time, at least two independent studies have been completed, both of which show that the industry is properly classifying the crude oil in accordance with the Hazardous Materials regulations. PHMSA's own analysis showed that "the current classification applied to Bakken crude is appropriate," and that "[b]ased on the data PHMSA collected, Bakken crude oil would be considered a "light sweet crude oil.""[2] Furthermore, PHMSA stated that "Bakken crude oil's gas content, flash point, boiling point, and vapor pressure are not outside the norm for light crude oils."[3] API believes it is important to educate stakeholders about these important conclusions.

As part of our continued efforts to provide information and improve safety, API also developed ANSI/API RP 3000, Classifying and Loading of Crude Oil into Rail Tank Cars. This API standard, which during its development, went through a public comment period in order to be designated as an American National Standard, addresses the proper classification of crude oil for rail transportation and quantity measurement for overfill prevention when loading crude oil into rail tank cars. The multidisciplinary

[1] "Freight Railroads Safely Moving Crude Oil," *Association of American Railroad*, December 5, 2013, https://www.aar.org/safety/Documents/Freight%20Railroads%20Safely%20Moving%20Crude%20Oil.pdf.
[2] Written Statement of Timothy P. Butters, Deputy Administrator, PHMSA, Before the Subcommittees on Energy and Oversight Committee on Science, Space, and Technology, U.S. House of Representatives, Sept. 9, 2014
[3] *Id.*

group that developed RP 3000 included a variety of stakeholders representing crude oil producers/suppliers, crude oil purchasers, rail road companies, rail tank car manufacturers, rail tank car lessors, classifiers of crude oil for transportation, crude oil testing laboratories, crude oil testing equipment manufacturers, and petrochemical terminal operators. In addition, PHMSA personnel have been directly involved and, like all other participants in the API standards development process, have been afforded every opportunity to make proposals on the content of RP 3000.

Additionally, the oil and rail industries joined together and created the Joint Working Group on Crude Oil Transportation by Rail (JWGCBR) to jointly identify, assess and address issues in prevention, mitigation, and emergency response to enhance the safety of crude by rail. As part of that effort, the members of API and AAR have jointly developed a response to PHMSA's proposed rail tank car standards. This joint response has been provided to PHMSA as part of this rulemaking with comments and suggestions directed towards improving the agency's recommended tank car design, tank car retrofit design, and implementation schedule. The results of that work are provided in joint comments between API and AAR and are referenced here. Also as part of that effort, API is creating a standard emergency response training program jointly with the railroad industry to be used to train First Responders. API is also commenting separately on the Department of Transportations Advanced Notice of Proposed Rulemaking, "Hazardous Materials: Oil Spill Response Plans for High-Hazard Flammable Trains."

API believes that with these efforts and with a comprehensive PHMSA rule, we can improve the safety of rail transportation in North America while supporting the continued growth of the U.S. energy renaissance.

II. U.S. Energy Renaissance

America is experiencing an energy revival. In 2013, the U.S. became the world's top producer of petroleum and natural gas, surpassing Russia and Saudi Arabia.[4] The continued growth of North American energy resources, however, is dependent upon a strong transportation infrastructure network. This transportation network requires all modes of transportation including rail, pipelines, barges, and trucks. Investment in building, maintaining and updating the oil and natural gas industry's transportation and storage infrastructure is not only crucial for energy growth, it is also crucial for U.S. economic growth, contributing up to $120 billion to the economy per year.[5] Additionally, investment in the infrastructure supports as many as 1.15 million jobs on an average annual basis.[6]

Due to new shale oil production, America's oil production grew by over 2.3 million barrels per day between 2007 and 2013 – more than any other country. Oil production in the Bakken region, one of the largest shale formations in the U.S., has increased by 20,000 barrels per day, month over month, from under 200,000 barrels per day in 2008 to nearly 1,200,000 barrels per day in 2014.[7] According to the U.S. Energy Information Administration (EIA), this record-setting level of production has "more than offset

[4] "Today in Energy," *U.S. Energy Information Administration*, October 2013, http://www.eia.gov/todayinenergy/detail.cfm?id=13251
[5] "Oil & Natural Gas Transportation & Storage Infrastructure: Status, Trends, & Economic Benefits," IHS Report for API, December 2013, http://www.api.org/~/media/Files/Policy/SOAE-2014/API-Infrastructure-Investment-Study.pdf
[6] "Oil & Natural Gas Transportation & Storage Infrastructure: Status, Trends, & Economic Benefits," IHS Report for API, December 2013, http://www.api.org/~/media/Files/Policy/SOAE-2014/API-Infrastructure-Investment-Study.pdf
[7] "Bakken Region Drilling Productivity Report," *Energy Information Administration*, August 2014

the rise in unplanned global supply disruptions over the past few years."[8] While supply disruptions in Libya, Iran, Nigeria, and Iraq plagued the global oil supply in 2013, U.S. production continued to increase and offset these disruptions. Onshore production has grown so significantly that the EIA states, "[r]ecent EIA forecasts of U.S. oil production undershot actual production because the pace of improvement in onshore drilling productivity has surpassed expectations."[9] As more supply disruptions erupt globally, sustained and continued growth in the U.S. energy renaissance is critical to maintaining U.S. energy security.

PHMSA's current proposals could stifle this energy renaissance and curtail substantial volumes of North American crude oil production. According to a study by ICF International, PHMSA's proposed regulations and timing would require extensive scrapping of the existing fleet of tank cars, forcing substantial volumes of crude oil, ethanol and other flammable products onto other, more expensive, modes of transportation and shutting-in some crude production due to a lack of tank cars. Higher transportation costs for crude oil could reduce incentives to invest in new production, combining with transportation constraints to reduce production by as much as 613,000 barrels per day. Higher costs for transporting ethanol and other petroleum products, along with a higher world oil price due to reduced North American production, could result in higher prices for consumers. ICF estimates consumer cost impacts could be in the range of $14.4 to $22.8 billion in the 2015 to 2024 period in a scenario where Keystone XL is approved. In a scenario where Keystone XL is not approved, constraints on crude oil, petroleum products and ethanol are more severe and potential consumer costs are estimated to increase to the range of $21.0 to $45.2 billion. Higher consumer costs reduce spending on other goods and services, reducing output and jobs in those sectors and negatively impacting GDP, which could drop by as much as $20.3 billion in 2019, even when the gains in rail car construction and other ancillary activities are included.[10] To limit impacts on consumers while producing meaningful improvements to safety, it is critical that PHMSA consider the broad impacts of regulations on domestic energy security and the impact on the energy infrastructure network.

With so much new domestic production and the need to move it to otherwise underserved markets, rail has played an increasingly critical role in the transportation of crude oil. In the Bakken, rail moves approximately 60 percent of the crude oil produced.[11] While refineries are planned for the Bakken region, the majority of crude oil will continue to move to refineries in other regions of the country, requiring the use of rail. Rail loading facilities for crude oil have been or are being developed in virtually every new production area of the U.S.[12]

The geographic diversity of the railroads, coupled with the non-traditional locations of unconventional resources, has led to a mutually beneficial partnership between the oil and rail industries as new resources are produced and transported. The Nation's railroads provide a critical piece of the infrastructure which will ensure the U.S. energy renaissance can continue to provide jobs, investments, and increased domestic energy security.

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[8] "Today in Energy," *Energy Information Administration*, August 27, 2014, http://www.eia.gov/todayinenergy/detail.cfm?id=17731

[9] Short-Term Energy Outlook Supplement: Uncertainties in the Short-Term Global Petroleum and Other Liquids Supply Forecast," *Energy Information Administration*, February 2014, http://www.eia.gov/forecasts/steo/special/pdf/2014_sp_01.pdf

[10] ICF, Forthcoming 2014, *Analysis of PHMSA Proposed Tank Car Design Regulations* (Working Title)

[11] "Monthly Update," North Dakota Pipeline Authority, September 12, 2014, https://ndpipelines.files.wordpress.com/2012/04/ndpa-monthly-update-september-12-2014.pdf.

[12] "Crude by Rail Facilities Map," BNSF, www.bnsf.com/customers/oil-gas/interactive-map/pdfs/BNSF-OG-Overview-Map.pdf

The oil and rail industries' commitment to safety, efficiency and environmentally responsible operations has allowed the continued production and movement of resources throughout North America. This commitment requires continuous effort and in light of several recent incidents involving crude oil shipped by rail, API has partnered with stakeholders including the railroads, tank car builders and lessors, shippers, producers, terminal operators, emergency responders, and regulators to maintain and improve the safe movement of products across the North American rail system. API supports regulations that will make measurable improvements to safety and support the continued growth of the American energy renaissance.

III. High-Hazard Flammable Train Definition

API has studied the challenges and implications of implementing a rule for high-hazard flammable trains (HHFT), as PHMSA proposes to define the term, and believes the approach is flawed. Railroads, not car owners, arrange trains, and Class I tracks are integrated with shortline and regional railroads, where cars are moved between trains based on destination. Railroads are unlikely to arrange a train to limit the number of flammable-liquid cars in that train. For example, a railroad may pick up 15 cars from one customer and 7 more from another that will make up a train. If either of these customers' cars were not modified to match the PG I or PG II requirements of the HHFT, then the entire train would be subject to the lower speed requirement. From the shipper's perspective, applying a speed restriction to manifest trains would be problematic since a shipper will not necessarily know whether the car will end up in an HHFT and therefore subject to new tank car requirements. Railroads would therefore likely require all shippers to modify all tank cars in case they are assigned to an HHFT.

For the shipper, it is important that the tank cars be fungible between different products and fields. It is impractical to manage the crude oil fleet in such a way that one tank car is specifically designated for one packing group. Therefore, it would be nearly impossible to use any tank car except a new or entirely retrofitted tank car that meets the PG I requirements, regardless of whether the product being moved was a PG I, II, or III.

It appears that PHMSA intended that the proposed rule apply only to unit trains: "this rule primarily impacts unit train shipments of ethanol and crude oil."[13] Further support is provided in the preamble where it states:

> "Approximately 68 percent of the flammable liquids transported by rail are comprised of crude oil or ethanol."
>
> "[T]here were over 400,000 carloads of crude oil originations by Class I railroads, or 37 times as many in the U.S."
>
> "In 2008 there were around 292,000 rail carloads of ethanol. In 2011, that number increased over 40 percent, to 409,000."

Additionally, Deputy Administrator Timothy P. Butters' testimony to Congress states:

> "Trains transporting this material [Bakken crude], referred to as unit trains, can contain more than 100 tank cars, carrying at least 2.5 million gallons within a single train. Unit trains only carry a single type

[13] "Hazardous Materials: Enhanced Tank Car Standards and Operational Controls for High-Hazard Flammable Trains," 79 Federal Register 148 (Aug. 1, 2014) p. 45,017.

of product… These trains often travel over a thousand miles from the Bakken region to refinery locations along the coasts."[14]

These statements show that the agency is clearly focused on improving the safety of the movement of ethanol and crude oil moved in large volumes. API supports regulating the movement of these commodities in unit trains but believes the proposed definition of a HHFT is incompatible with the goals of the proposed rule. Further, the HHFT approach is attempting to implement the key train concept which the railroads already implement in the OT-55.

API supports a rule focused on reducing the risk of transportation on unit trains where the highest risk reduction benefit can be achieved. We believe that applying PHMSA's proposed approach to manifest trains is counter to the intent of the proposed rule. However, applying PHMSA's approach to unit trains could achieve the Departments intended goal of increasing the safety of rail transportation for "certain trains transporting large volumes of flammable liquids" and ensuring that operations for those trains are achieved expeditiously. Such "certain trains" should be defined as a unit train and would meet the following criteria:

- dedicated source of power (locomotive)
- tank cars are nominated at least 30 days in advance by the shipper to the railroad
- single or gathered origin for placement into the train
- delivery to a single destination (or travels the majority of the trip as a single train)
- single commodity in Class 3, packing groups I, II or III

Such unit train movements meet the intention of the proposed rule and would provide the opportunity for a specific application to those trains of interest.

The approach of defining a unit train would have positive operational implications. As the cars are upgraded in a unit train, the speed restrictions could be lifted. Furthermore, as the fleet conditional probability of release (CPR) improves the speed restrictions could be lifted and the OT-55 speed limitations for key trains could be utilized.

The final rule should reflect what appears to have been PHMSA's intention that the operating restrictions only apply when shippers offer unit trains of flammable liquids. This is the only feasible way of implementing the HHFT concept.

IV. <u>Prevention</u>

In the Notice of Proposed Rulemaking (NPRM), PHMSA states "[t]he focus of this NPRM is on mitigating the damages of train accidents… PHMSA and FRA find that existing regulations and on-going rulemaking efforts—together with this NPRM's proposals for speed, braking, and routing—sufficiently address safety issues involving rail defects and human factors."[15] While API recognizes the importance of mitigating the impacts of accidents, we believe one accident is too many and that safety depends on preventing accidents.

a. <u>Prevention Joint Working Group</u>

[14] Written Statement of Timothy P. Butters, Deputy Administrator, The Pipeline and Hazardous Materials Safety Administration, U.S. Department of Transportation, Before the Subcommittees on Energy and Oversight Committee on Science, Space, and Technology, U.S. House of Representatives, September 9, 2014.
[15] "Hazardous Materials: Enhanced Tank Car Standards and Operational Controls for High-Hazard Flammable Trains," 79 Federal Register 148 (Aug. 1, 2014) p. 45026.

Through the JWGCBR, the Prevention subgroup agreed to work collaboratively to identify and implement proven practices to prevent the risks associated with moving crude oil by rail. The Prevention subgroup divided into four Task Teams focused on topics relating to the prevention of rail accidents: Inspection Technology, Safety Management and Safety Culture, Industry Standards and Best Practices and Training Programs. A large number of synergies and opportunities for sharing practices and principles were identified across the industries.

The group developed several prevention action items for consideration. These action items are listed here.

- **Inspection Technology**
    - Continued exchange of information regarding inspection technologies between the railroad and petroleum industries through reciprocal participation in technology reviews hosted by these industries' research organizations, Transportation Technology Center, Inc. (TTC) and Pipeline Research Council International (PRCI), respectively.
    - Creation of a forum for non-destructive testing vendors from both the railroad and petroleum industries to exchange best practices.
    - Seek technologies which can integrate multiple types of track inspection data and rail traffic data and are capable of facilitating trend analysis both within and across the various data types.
    - Study various rail flaw detection technologies, examining how changes in the speed at which inspection equipment is operated affects the efficiency, effectiveness and repeatability of rail flaw detection.
    - Evaluation of technologies or practices which reduce or remove elements of operator dependency from the track inspection process to determine if such approaches would be of benefit in increasing the efficiency or throughput of detecting rail flaws.
- **Safety Culture and Safety Management**
    - Members of both the railroad and petroleum industry consider participation in safety culture conferences, which bring together expertise from various sectors (i.e. industry, academia, regulatory) to discuss safety culture, management and practices in an industrial setting.
    - Establishing a forum for continued sharing of information between the railroad and petroleum industries in the area of safety culture, safety management and training opportunities as they arise.
    - Transporters of crude oil review the content, structure and operation of existing or proposed Safety Management Systems (SMS) in related industries and consider the potential benefits associated with various elements in such systems as they pertain to further improving safety practices and potentially reducing transportation accidents, including those involving crude oil.
- **Industry Standards and Recommended Practices**
    - Recommended practices and guidance documents relating to the transport of hazardous materials by rail be updated with information relevant to the transport of crude oil by rail upon finalization of the PHMSA proposed rulemaking regarding "Enhanced Tank Car Standards and Operational Controls for High-Hazard Flammable Trains."
    - Continued exchange of information regarding the use of risk assessment practices in the transportation of crude oil across the railroad and petroleum industries.
- **Training Programs**
    - Creation of a training module aimed at crude oil shippers, offerers and workers at mid-stream transfer operations based on the information contained in the finalized API RP 3000 standard regarding classifying and loading of crude oil into rail tank cars.

- Encourage short-line rail operators who transport crude oil to take advantage of centralized, regional training centers to evaluate and potentially enhance the quality and uniformity of their training programs for various crafts

The work conducted by the Prevention Working Group and the subsequent action items represent a starting point for improving prevention efforts, but they are not an end point. API believes that there are many areas for potential improvement that are being explored and should be addressed. By reconsidering the acceptable level of risk for rail and for crude by rail routes in particular, API believes that we can further improve the safety of crude transportation by rail.

a. Notification to State Emergency Response Commissions

In the NPRM, PHMSA proposes codifying and clarifying the requirements of a May 7, 2014 Emergency Order. The Emergency Order requires each railroad transporting 1,000,000 gallons or more of Bakken crude oil in a single train in commerce within the U.S. provide certain information in writing to the SERC for each state in which it operates such a train.[16] API supports the railroads sharing information with local officials and emergency responders in compliance with DOT's requirements. The distribution of this information beyond what is required by DOT is being determined on a state-by-state basis by the railroad industry and state regulators. However, API does not support distinguishing Bakken crude oil from crude oil sourced from other locations.

There are multiple studies available to PHMSA on the properties of Bakken crude oil, including PHMSA's own "Operation Safe Delivery Update." None of the available data suggests that Bakken crude oil differs in degree of transportation risk from other crude oils that meet the criteria for Class 3, Packing Group I and II. On this basis, any regulatory action that distinguishes Bakken crude oil from other crude oils of Packing Group I and II should be considered arbitrary and without a rational basis. API recommends that application of special requirements, such as notification of SERCs, should be based on the properties of the relevant hazardous material and should not be based on place of origin.

Additionally, API sees no benefit in developing an STCC code number unique to Bakken crude oil. All of the studies confirm that Bakken crude oil is correctly classified as a Packing Group I or II flammable liquid. PHMSA has provided no data demonstrating that Bakken crude oil is materially different from other light crude oils produced in North America from a hazard perspective. The North American Emergency Response Guidebook provides the same guidance for crude oils of Packing Groups I, II and III and we are unaware of what would be gained by differentiating crude oils by geographical formation from an emergency response perspective. API further notes that STCC numbers are used by the railroads and shippers and are not widely understood by emergency response personnel. On that basis API sees no benefit in developing an STCC code number unique to Bakken crude oil.

b. Enhanced Braking

PHMSA requests information on three types of braking: Distributed Power, End-of-train devices, and Electronically Controlled Pneumatic Brakes.

API supports the use of Distributed Power on unit trains. Distributed Power is a system that places locomotives at points in the middle or end of a train to assist the train in crossing difficult grades or curves by providing additional power. Distributed power enables quicker application of standard air

[16] "Hazardous Materials: Enhanced Tank Car Standards and Operational Controls for High-Hazard Flammable Trains," 79 Federal Register 148 (Aug. 1, 2014) p. 45041.

brakes because it allows each locomotive to set the brakes simultaneously, rather than relying on the front locomotive to propagate pressure changes to the rear of the train. Brakes are set more quickly with distributed power, particularly when there are extra locomotive units in the middle of the train. Also, the additional power reduces the force between wheels and rails and can minimize wear on components that may lead to a derailment. Distributed power is a current practice in the industry and implementation throughout the system would be quick. Therefore, API supports the use of Distributed Power in unit train service.

API also supports the use of end-of-train devices, which are already broadly adopted and in use by the railroad industry. EOT devices mark the end of the train in place of a caboose and monitor brake pressure to ensure the integrity of the air brakes. EOT devices also transmit information to the locomotive about whether the end of the train has stopped or is moving forward or backwards. Some also have the capability to apply the brakes from an electronic signal from the locomotive. This signal moves from the rear end of the train forward, at the same time the locomotive engineer applies the brakes a the head end of the train. This type of operation shortens the time for all brakes to be applied.

Electronically Controlled Pneumatic Braking (ECP) technology has minimal safety impacts and therefore API instead recommends pursuing alternative enhanced braking technologies such as DP and EOT. Similar to tank car design, ECP is a mitigation technology and not a technology that will prevent a derailment. ECP, when built into a train network during development, has similar uses to traditional brake applications. However, retrofitting a fleet with ECP brakes is a lateral move and not a significant step forward for safety.

ECP requires all cars and locomotives in a train to be equipped with ECP so that each car receives the electronic transmission from the ECP system. Since ECP brakes can only be operated on a train where all cars are equipped with the technology, if ECP brakes were only required on unit trains, it would be necessary to have a dedicated fleet of tank cars for unit trains or it would require retrofitting the entire fleet of tank cars so that they were fungible. It would be highly unlikely for railroads to agree to manage trains such that tank cars would not fall under the ECP requirement. Therefore, the burden would fall on shippers of all flammable liquids to retrofit tank cars with ECP brakes. There is not a sufficient supply of shops or materials to retrofit or build all new cars with ECP brakes.

PHMSA likely underestimates the cost and availability of ECP brakes. Currently, there are only two providers of ECP brakes in North America. One provider currently manufactures about 300 to 400 car sets of ECP brakes per month, of which 100 percent are sold overseas. The second provider's production levels are similar. This equates to 7,200 to 9,600 sets per year of production between the two.[17] PHMSA's Option 1 could effectively require ECP brakes on all flammable service cars (88,000 cars by PHMSA's count[18]). Supplying this number of cars could mean increasing production by an order of magnitude (i.e. 10X). It would be reasonable to assume that this level of ramp-up could entail some price increases (as shops work with inefficiently small facilities and suppliers in the near-term) and some delays. Considering the lack of safety benefits and the challenges associated with ECP braking, API recommends evaluating alternative forms of braking.

c. Short Line and Regional Railroads

[17] AllTranstek, August 9, 2014
[18] RIA, Table TC4, page 78

Short line and regional railroads operate nearly 30 percent of the total U.S. railroad mileage, many of which are the first and last miles of service.[19] As such, short line and regional railroads are an important partner in the transportation network. Short line railroads who are not members of AAR are not included in the voluntary agreement between AAR and the Department of Transportation to enhance the safe transportation of crude oil by rail. API encourages FRA to evaluate whether further work needs to be conducted by the short line railroads to minimize risk and improve prevention efforts.

d. Speed Restrictions

PHMSA has proposed several options to limit the speed of trains carrying flammable liquids. While API understands that speed plays a role in the severity of derailments and should be reviewed accordingly, API urges PHMSA to carefully consider all the potential impacts of imposing blanket speed restrictions. Blanket speed restrictions that are imposed on all shipments regardless of the type of train involved can have negative effects on operations of entities nationwide, including railroads and shippers, responsible for the shipment of flammable liquids. Such restrictions could in turn have significant impact on the national economy and may not result in significant safety benefits.

e. Track Integrity

According to AAR TCC Task Force T87.6, broken rails result in the highest severity and frequency of derailments. Between 2001 and 2010, broken rails or welds caused more major derailments than any other factor, resulting in approximately 670 derailments. This exceeds the average from all other causes by over 7 times. The severity of these derailments is also far in excess of the average. The severity and frequency of derailments caused by broken rails or welds may be reduced by improving track maintenance and repair. PHMSA does not address track caused derailments in the NPRM, but nevertheless states that "existing regulations and on-going rulemaking efforts—together with this NPRM's proposals for speed, braking, and routing—sufficiently address safety issues involving rail defects and human factors." API encourages PHMSA and FRA to evaluate whether additional processes or standards regarding rail conditions would improve the safety of transporting flammable liquids by rail.

f. Derailment Reporting

PHMSA asks whether it should require reporting on every car carrying hazardous materials that derails, whether the car loses product or not. We believe PHMSA should collect this information to accurately understand the effectiveness of different kinds of cars in containing the materials they carry. Additionally, this would ensure consistent and complete data and allow PHMSA to improve incident reporting.

V. Mitigation

a. Analysis of PHMSA Proposals on Tank Car Design

API believes that PHMSA has not done a proper evaluation of the impacts of the proposed rule and encourages PHMSA to reconsider its conclusions. Specifically, PHMSA's analysis has led it to conclude that the proposed tank car designs and associated timelines would not have deleterious impact on the market for tank cars. This conclusion rests on PHMSA's assessment that no tank cars would be prematurely retired and that the rule would not impact the transportation of crude or ethanol. This is not the case. Indeed, PHMSA makes a number of errors regarding what would be involved in retrofitting existing

[19] ASLRRA, http://www.aslrra.org/our_members/America_s_Veterans___Short_Line_Railroads/

tank cars, the capacity to retrofit tank cars, and the ability of tank cars to be repurposed to Canadian oil sands trade. When these realities are taken into account, it is clear that shortages of retrofit shop capacity will likely lead to pre-mature scrapping of a large part of the existing fleet, jeopardizing the reliable use of rail for crude and ethanol transport with associated impacts on crude production and ethanol costs.

Under Executive Order (E.O.) 13211, DOT should have prepared a Statement of Energy Effects for the Office of Information and Regulatory Affairs, Office of Management and Budget (OMB). E.O. 13211 requires these detailed statements for "significant energy actions" – significant regulatory actions that: (1) have an annual effect on the economy of $100 million or more, or adversely affect the economy or productivity; or (2) raise novel legal or policy issues arising out of the President's priorities.[20] PHMSA's current proposals could have a significant adverse effect on the economy and productivity, as the proposed regulations and timing may require removing a significant number of existing tank cars from service, resulting in a shortage of tank cars. That shortage of tank cars could have a negative impact on crude oil production.[21] If oil production decreases, this could threaten the energy renaissance and domestic energy production, which is a high priority for the U.S. and one specifically identified multiple times by President Obama. By failing to prepare the required Statement of Energy Effects, PHMSA failed to provide OMB with critical information that would have significantly informed OMB's review of the proposed rule. Additionally, because E.O. 13211 requires publication with of the Statement of Energy Effects (or a summary thereof) in the NPRM itself, PHMSA has also deprived the public of the opportunity to fully understand the costs of the proposed rule and to provide PHMSA with comments on these costs. Finally, because PHMSA did not prepare the Statement of Energy Effects, it is questionable whether PHMSA truly understands the adverse effects that can result from its proposals.

The following section(s) retrace PHMSA's analysis 1) identifying critical errors which consistently bias the cost estimates downward, 2) presenting analysis by ICF International (ICF) which corrects for these errors and models the impact of the proposed rule on the rail market, oil production, consumer costs, and finally, GDP, then 3) examining the flaws in PHMSA's estimation of benefits stemming from the rule.

i. PHMSA underestimates the cost of the proposed rule

PHMSA makes a number of assumptions, calculations, and omissions that consistently bias the cost estimates downward. This is particularly problematic since by PHMSA's own calculations, the proposal does not pass a cost benefit test when historical accident rates are projected into the future. Only when accident rates that have no basis in history are deployed do two of PHMSA's nine options pass a cost benefit test. If costs were not consistently underestimated, it is likely that even those two options would not pass a cost benefit test. The following sections highlight the inconsistencies, omissions, and/or overly optimistic projections that PHMSA has made in calculating the costs of the proposal.

1. PHMSA underestimates the retrofitting challenge created by the proposed timeline

[20] In the NPRM, PHMSA states this this action is a "significant regulatory action" under Executive Order 12866; "Hazardous Materials: Enhanced Tank Car Standards and Operational Controls for High-Hazard Flammable Trains," 79 Federal Register 148 (Aug. 1, 2014) p. 45063.

[21] In Memoranda 01-27, "Guidance for Implementing E.O. 13211," OMB specifically notes that a "significant adverse effect" includes reductions in crude oil supply in excess of 10,000 barrels per day." ICF's estimated supply disruptions are above the 10,000 bpd threshold and could be large enough to impact world oil prices.

It is critical to ensure that the tank cars are retrofitted to a realistic standard on an achievable schedule that ensures that the retrofit workshop capacity is full but that the capacity is not exceeded. In the RIA (page 89), PHMSA implies that 22,061 tank cars can be retrofitted per year and that the phase-out timeline is sufficient to prevent shortages.[22] PHMSA appears not to have considered the challenges of undertaking such a large-scale program of retrofits, including the availability of labor and materials. Additionally, PHMSA both overestimates how many tank cars can be retrofitted (i.e. shop capacity) and underestimates how many tank cars would need retrofitting (i.e. size of the impacted fleet). Together, these errors result in a phase-out schedule that could leave over 86,000 tank cars needing to be scrapped or repurposed.[23]

a. **Challenges to large-scale retrofits**

In the last year, there has been an increase in tank car rail traffic of about 35 percent, but there has not been a repair facility of any significant size added to the infrastructure since the significant shale expansion started.[24] Most existing maintenance shops are not certified to do extensive repair.[25] Below is a list of potential bottlenecks to being able to achieve large-scale retrofits.

Potential lead times issues affecting retrofits[26]:

- Cleaning of tank cars is required prior to commencement of any work. Most of the retrofits discussed will be heavy in nature, and will necessitate a requalification event, regardless of the normal scheduled requalification cycle. The NPRM fails to take into account the associated costs related to cleaning, and the premature requalification. The capacity of the cleaning facilities is likely limited to about 16 to 20 cars per week at a tank car facility. Additional cleaning racks may be needed at repair facilities, or creation of cleaning facilities before the tank cars show up at a tank car facility.
- Shops in the U.S., Canada and Mexico are required to be certified by AAR to ensure that they are capable of retrofitting the tank cars. This may require AAR itself to expand resources to ensure the quality work at the new facilities is addressed.
- A shortage of raw materials will require that imports of materials and the quality of those materials are addressed. Further, the reliance on imports – due to an unreasonably short phase-out – deprives the U.S. the opportunity to expand production, and increase jobs, in those industries.
- Dual flow pressure relief devices (PRD) are still in the concept phase. PRD manufacturers have prototypes, but the valves are not AAR approved yet. Once they are approved, there will be a ramp-up time to get the valves into production. If a service trial is required by the AAR for these new valves, then production start dates may be delayed for the service trial (service trial for a new valve is 2 years).
- Full height head shields are manufactured like a tank car head and are either manufactured by cold or hot forming. Either method requires specific equipment that is costly, requires a very long lead time to procure and substantial investment that must be weighed against the short timeframe for which the retrofits will be required. Current tank car repair facilities do not have the ability to manufacture tank heads (while three of five tank car manufacturers do). If current

[22] 66,185 cars divided by 3 years equals 22,061 tank cars per year
[23] ICF, Forthcoming 2014, *Analysis of PHMSA Proposed Tank Car Design Regulations* (Working Title)
[24] RBN, 2014, "We Can Run Those Tank Cars for Miles and Miles and Miles – Bad Orders in the Crude-by-Rail Market"
[25] *Id*.
[26] AllTranstek, 2014, Memo to API "Lead times for retrofits 05-15-2014 Rev1"

production in the rail tank car industry does not have enough capacity, then additional capacity will be needed. Another possibility is to determine if non-AAR approved manufactures have capacity, such as ASME approved manufacturers.

- Besides the capacity to form heads, there is the potential problem of delivery of those heads due to their dimensions. The FWHA has a maximum width on trucks of 102 inches and the head shields would be of a greater diameter. Plate "C" maximum width is 128 inches. If Plate "C" maximum width was increased by two inches, which is proposed, the head shield would be just under 130 inches. This width would require over dimension permits, if available, or movement of the head shields via railcars.
- If tank cars need to have fittings nozzles replaced with one larger nozzle, then the tank car will have to have a section of the tank inserted with a formed section of tank. The larger nozzles themselves, will also take specialized equipment to roll. Similar to the head shields, new car manufacturers have this equipment readily available for new car production, however tank car repair facilities currently do not. The same construction capacity constraints for the Head Shields apply to these components. The NPRM's assumptions of out-of-service time of tank cars seems to assume these components are readily available. This incorrect assumption dramatically underestimates the lead times, and turn-around times of retrofitting tank cars.
- If the existing valves and fittings cannot be re-used when retrofitting nozzles, or if replacement valves are needed, then there could be long lead times for valves. The problem of retrofit cars competing with new cars production is again brought to light here. New cars production places standing orders months in advance to assure timely delivery. Retrofit cars will not be afforded this luxury. Castings for valve bodies can have long lead times (20-28 weeks), and the need will not be known until after the car arrives in shop.
- Trucks and bearings for 263,000 GRL cars may be needed and may not be available causing delays in the retrofit of the fleet.

Other bottle necks at tank car facilities:

- Current tank car requalification work load at facilities. This applies to all tank cars, which means crude oil cars will be vying for the same space as the rest of the tank car fleet. Historically, a typical turn time at a facility for a complete tank car requalification (without internal coating) was about 45 to 60 days. Currently, this same time is running about 90 to 120 days for the simple routine requalification without any major retrofit work being performed. Heavy repair projects will most likely take in excess of the 120 days.
- Since tank car facilities are trying to requalify more tank cars, additional shifts could be added. However, trained and qualified personnel may or may not be available and will take time to develop. These personnel include welders, NDT techs (nondestructive testing), mechanical, internal coating application and inspection, etc. Even if you can hire the workers, it takes time to teach and certify people to weld and perform NDT inspections. These types of people are required for some of the retrofit items, such as:
    - welding of jackets and jacket supports to the tank (certified welding and NDT inspection)
    - installation and welding of head shields to jackets
    - installation of valves (PRD and BV) (NDT inspection after installation)
    - installation of top fittings protection, which may require removal and application of the valves and fittings (certified welding and NDT inspection after installation)
    - adding insert valves
    - removing old safety valve or retrofitting the valves and moving the housing (welding and NDT inspection)
    - interior coating (application and inspection)
- If ECP brakes are required, these are very limited safety improvements for an extremely high cost.

- If coatings are needed, additional blasting, spraying, and drying booths will be needed.
- If a retrofit includes several linear feet of welds requiring stress relieving. This can be done by two methods:
    1. Utilizing local stress relieving equipment. Local stress relieving equipment incorporates ceramic blankets that cover the subject welds. A repair-car facility is not equipped to locally stress relieve large areas economically or in a timely fashion. The stress relieving will have to be done in sections or using stress relieving blankets. This method will dramatically increase out of service time, and costs.
    2. At some point, it ceases to be economically feasible to perform local stress relieving, in such cases unit stress relieving will be evaluated. Repair facilities do not have unit stress relieving ovens. Only facilities that manufacture new cars have these unit stress relieving ovens. It is impractical to assume retrofit cars will be shipped to new car facilities, and prepped for unit stress relieving, stress relieved, and then re-assembled.

b. **Challenges with access to sufficient quantities of materials**

If tank insert material would be needed for inserts, the availability of TC-128 steel is going to be limited. It is already in short supply for new car builds. Again, the final rule is necessary to determine how much, if any, of this material would be needed for inserts for top fitting modifications. A query of the steel producers would be necessary to determine availability of the material and the ability to have it delivered as a rolled plate to fit the tank diameter.

Though not covered in the rule, it is possible that when a tank is being retrofit, the company may choose to coat the interior of the tank. If this is option is chosen on a large scale, coating will become an issue as many shops are limited by blasting capacity. Additionally, if it is determined that interior coatings are required, there are shops that cannot perform this function. Additional certifications are necessary for coating work. Ovens may also be necessary for some coatings. Interior blast facilities may not be in place or capacity may be limited. This information would need to come from the individual shops as most of the facilities have not been certified under the new AAR requirements which allow for a detailed description of the shop capabilities.

The ability to do stress relief on inserts or jacket spacer application will be based on the final rule. Cars that are currently insulated should not be an issue. There could be designs approved that would not require welded jacket spacers. There is a lack of unit-stress relief oven capacity in the industry which could create challenges for implementation of the retrofit rule.

c. **PHMSA overestimates retrofit capacity**

PHMSA's estimate of the number of tank cars that can be retrofitted in a year is key to their finding that no tank cars will be prematurely retired. Unfortunately, PHMSA's estimate is unreasonably large and not supported by any of industry's estimates of retrofit capacity. Specifically, PHMSA implies that 22,061 tank cars can be retrofitted per year.[27] The basis for this assumption is not provided and it is far beyond the estimates of industry's capacity provided by AllTranstek and RSI.

[27] PHMSA RIA page 89. (66,185 cars divided by 3 years equals 22,061 tank cars per year) In case PHMSA is assuming newbuild shop capacity will be devoted to retrofits, API would like to remind PHMSA that forecasts are for newbuild shop capacity to be constrained even when the backlog of tank cars has been eliminated as other car types compete for shop space to build replacements for older cars (see Kloster, 2014).

AllTranstek conducted a study for API and estimated that there are approximately 221 facilities that are certified to repair tank cars and/or components of tank cars. Of these, 104 shops are classified as Class C facilities that are the only these shops that can repair or modify tank cars. The remaining approximate 111 shops are classified as Class F, G or L facilities, meaning they are only certified to remove, repair &/or replace tank car valves (F, G) and only Class L can apply coatings or linings to the interior of a tank car.

In Alltranstek's study, they received select information on the capabilities of 85 repair shops or 74 percent of the 104 CPC-1249 registered C shops (See Table 3). They estimated that 54 shops (52 percent of the 104 shops) can provide major retrofit services such as jacket, insulation and head shield installation. Based on the study data, they estimate that about 2,400 retrofits could be conducted in 2014. Applying a reasonable growth rate to this starting point, they estimate capacity could grow to 3,700 retrofits per year by 2018.

Table 3. Estimated Retrofit Shop Capacity for Next Five Years

	2014	2015	2016	2017	2018
Number of retrofit capable shops	54	56	58	60	62
Total number of potential annual retrofits	2,430	2,883	3,089	3,303	3,711
Average 3,100					

Source: AllTranstek

Separately, RSI conducted a survey of its members and the repair industry and estimated that approximately 5,700 cars could be retrofitted per year after a one year ramp up period.[28] This ramp-up does not include engineering activities (getting drawings, writing instructions, and getting AAR approvals). Since that time, RSI has indicated that their retrofit capacity is 6,400 cars per year.

The difference between the two estimates is significant[29] but more importantly, both estimates are much smaller than what PHMSA implies is available. The difference between the AllTranstek and RSI estimates, while large in percentage terms, is a mere 3,300 tank cars per year. Contrast this to the 15,661 tank car difference between RSI's largest estimate and PHMSA's estimate. PHMSA's estimate is clearly unreasonable and thus PHMSA's conclusion that there will be no premature retirement of tank cars. Moreover, to the extent that demand for rail cars cannot be met with retrofitted cars, new tank cars will need to be built to meet the demand, which is a much more costly alternative.

d. **PHMSA underestimates the size of the impacted fleet**

PHMSA's estimate of how fast the fleet can be retrofitted overestimates the capacity to retrofit cars and underestimates how many cars will need to be retrofitted. PHMSA states (RIA, page 89) that 66,185 cars would need to be retrofitted (Option 1). This severely underestimates the number of tank cars that would need to be retrofitted because it ignores the fleet of 'Other Flammables' and assumes jacketed cars could be transferred to Canadian oil sands trade.

[28] RSI, 2014, "2014-7-2 RSI Crude Oil Working Group Shop Capacity Study" [The 5,700 cars per year comes from RSI's statement that they have 103% of the capacity to do 462 cars per month.]

[29] It is likely that what drives the difference between the AllTranstek and the RSI estimates is how much capital expansion is anticipated, which is very uncertain.

i. PHMSA incorrectly assumes only tank cars in HHFT service will be covered by the proposed rule

PHMSA states that it endeavored to "provide a phase out period …that would ensure that sufficient time was provided to avoid a fleet shortage" (79 FR 45043). While avoiding a fleet shortage is a laudable goal, PHMSA's analysis excludes many tank cars that would inadvertently be forced to comply with the proposed rule. Specifically, PHMSA's analysis excludes the cars in 'other flammable' service .[30] API believes for the reasons outlined below that these cars will out of necessity need to comply with the proposed rule due to how it is written. As such, if PHMSA is trying to provide a phase-out period that does not result in a fleet shortage, it needs to account in its analysis for the fact that tank cars in 'other flammables' service will need to be retrofitted also and adjust the phase-out accordingly.

For estimating the number of tank cars that will need to be retrofitted, PHMSA must consider the total number of cars in flammable service that are moved in unit trains and large blocks because it is not practical for railroads to manage a mixed fleet of these cars to ensure that there are no more than 20 non-compliant cars in any given train. The shippers could limit the number of cars to be shipped but there is no way for the shipper to know if a train will be made up of additional cars that are not compliant. It would be up to the railroad to identify non-compliant cars and then structure their train operations to make sure there were no more than 20 in any given train en route from origin to destination. Manifest shipments are generally handled in at least 4 different trains en route from origin to destination and, even with all the rail mergers, 50% of shipments still move on more than one railroad so interline shipments would be handled in even more trains. Actions to limit the number of non-compliant cars would have to be taken multiple times for every manifest shipment.

Shippers are equally challenged in handling their fleet. The shippers do not assign tank cars to one production field. It is impractical to manage the crude oil fleet where one tank car may be loaded with PG II crude at the beginning of the month and loaded with a PG I crude at the end of the month. Managing these uncertainties would make it nearly impossible to run anything but completely new or retrofit tank cars that meet the PG I requirements, regardless of if the product being moved was PG I, II, or III.

In addition, the manufacture of many commodities, including flammable liquids, are often concentrated meaning the railroads would probably have to hold cars or run additional trains to keep the number of non-compliant cars under 20 on any given train. It is unlikely any railroad will try to manage their network to accommodate non-compliant cars. The assumption should be that all cars moved in unit trains will have to be retrofitted or replaced.

For the reasons provided above when estimating the number of tank cars that will need to be retrofitted, PHMSA must consider the total number of cars in flammable service that are moved in unit trains because it is not practical for railroads to manage a mixed fleet of these cars to ensure that there are no more than 20 non-compliant cars in any given train.

Given language in the proposed rule, this does not appear to be what PHMSA intended to happen under the rule. API holds that the PHMSA HHFT definition will have to be updated to clearly exclude the additional cars in other flammables service. This can be addressed by updating the HHFT definition more narrowly to identify the unit trains moving flammable liquids as described earlier in the comments.

ii. PHMSA makes incorrect assumptions regarding Canadian crude service

[30] PHMSA estimates this population of cars to number approximately 25,500. AAR estimates the population to be closer to 38,000.

The PHMSA proposal includes a statement that 23,000[31] tank cars will be moved into Canadian oil sands service. This assertion appears to be based on the unfounded assumption that "Alberta tar sands crude", which PHMSA never defines (is PHMSA referring to dilbit, synbit, railbit, purebit or some other blend?), is "a combustible rather than a flammable liquid" (RIA, page 81). This represents a profound lack of understanding of the Canadian crude oil market. As implied above, a variety of crude blends are moved by rail from Canada to the U.S. These include crude produced from shale formations as well as crudes derived from blending raw bitumen with other products (e.g. diluent to produce dilbit, railbit, or purebit depending on the ratio; synthetic oil to produce synbit). It is likely that the majority of these crude streams are flammable liquids, meaning that they cannot be transported in un-retrofitted cars.

Even if these cars could legally be deployed in the oil sands crude trade, they would still need retrofitting. Specifically, PHMSA acknowledges that oil sands crude must be heated to unload (RIA page 81). Accordingly, cars in this trade would, in general, need heating coils in addition to jackets and insulation. These cars thus would need to compete for shop space too.

2. **PHMSA incorrectly estimates cost of retrofits**

PHMSA's calculations regarding retrofit costs appear to be inaccurate. These include, but are not limited to, the following:

- PHMSA does not include the cost of Full Height Head Shields (FHHS) for retrofitting unjacketed cars, beyond a nominal $400 for the extra steel. This ignores the specialty equipment needed to shape such heads which is in short supply, transportation cost to move the FHHS to the retrofit shop, nor the extra labor needed to install them. This is inconsistent with the costs referenced in the rule that show the cost of a FHHS at $17,500 (RIA, Table TC6, page 83). This can add 65 percent to PHMSA's estimated cost of a retrofit.
- PHMSA indicates that it expects tank cars to upgrade allowing them to operate at 286,000 lbs GRL instead of 263,000 lbs GRL (RIA, page 87), but does not include the cost of upgrading trucks ($16,500, per RSI) on the DOT111 fleet to be able to operate at the heavier weight load.
- PHMSA does not include time and expense of requalification (RIA, page 80). The nature of the retrofits requires requalification therefore the time out of service and the costs that must be incurred (e.g. internal coatings on legacy tank cars) should be included in PHMSA's analysis.
- Even though PHMSA acknowledges that oil sands crude must be heated to unload (RIA page 81), PHMSA does not include the cost of retrofitting non-jacketed DOT111 tank cars with heating coils, saying instead that "only jackets and insulation are necessary".

Together, these errors mean that PHMSA's stated retrofit costs are low by anywhere from 65 percent to 162 percent.

3. **PHMSA makes incorrect assumptions regarding repurposing**

In general, PHMSA needs to be aware that there is limited opportunity to repurpose tank cars that are not retrofitted. Large General Purpose (GP) tank cars are – by definition – large. Repurposing these cars into lower gallonage segments (i.e. the 25.5k segment) would require light-loading which can lead to

[31] "As a result of this rule, PHMSA expects all DOT Specification 111 Jacketed and CPC-1232 Jacketed crude oil and ethanol cars (about 15,000) to be transferred to Alberta, Canada [oil sands] services. [And] some DOT unjacketed and CPC-1232 unjacketed cars (about 8,000) to [go to the same service]."

undesirable characteristics in train handling due to excessive product movement within the tank.[32] The non-ethanol/crude commodity base of the Large GP market already have the cars they need and there is no anticipated need to repurpose the cars to that fleet.

4. PHMSA improperly assumes industries supplying the rail industry have decreasing costs

PHMSA has made the assumption that costs will decline by 10 percent due to economies of scale. This is not realistic and we could not find support for this assumption. In fact, it is very likely the retrofit shops and their suppliers could experience diseconomies of scale if facilities are too small to efficiently handle the dramatic increase in orders. This would imply that costs could rise significantly until firms expand. Whether firms expand to take advantage of potential economies of scale remains to be seen. Seeing the retrofit demand as being short-term (relative to life of the capital being invested in), firms may opt not to expand. If that occurs, long-term elevated costs may result. Indeed, if increased demand meant costs would fall, then clearly, new tank car costs should be falling. However, that is not the case and is not expected to be the case going forward.[33]

5. PHMSA improperly assumes additional weight will not limit capacity

PHMSA acknowledges that "The additional safety features of the proposed new tank car standard could increase the weight of an unloaded tank car" and the "[a]dditional weight for the tank car could lead to a reduction in lading capacity per tank car" but assumes "there will not be less capacity in practice" because, in part, "new materials will restore the pre-DOT Specification 117 tare weight and cost no more than the materials in the DOT Specification 117." The TCC Task Forces on New Tank Steel have been trying for years to develop the next generation of steels to no avail. Also the "Next Gen" cars utilizing sandwich material, and other of the most innovative designs, may significantly increase puncture resistance, but they also increase weight. Further, these materials are not commercially viable at this time. The PHMSA approach would have limited impact for Option 3; however, the proposal to modify the 7/16" and 8/16" shell fleets (DOT-111 and CPC-1232) to meet the DOT-117 spec in Options 1 or 2, if it could be done at all, would have significant cost impacts without meaningful safety benefits.

A Non-jacketed DOT-111 is 263,000 gross railroad load (GRL) and when retrofit with a full height head shield, jacket and thermal blanket, will increase in weight by 10,000 to 12,000 pounds to approximately 286,000 pounds GRL. This weight increase does not impact carrying capacity of these cars. However, PHMSA has not accounted for the increased weight and decreased volume that a non-jacketed CPC-1232 will have once it is fully retrofitted with the same equipment. For both cars, they are adding more weight to the cars which results in more weight on the track when moving an empty car (e.g., 4,000 per 1/16th of an inch). The added weight for the CPC-1232 non-jacketed car reduces the carrying capacity by between 1,400 and 1,700 gallons[34] (calculate X pounds / 7 pounds/gallon). Not only are additional resources

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[32] Kloster, Dick "Challenges and Best Practices with Tank Car Procurement" Presentation at InfoNex Crude-by-Rail Conference, April 9, 2014 Calgary, AB

[33] Kloster, Dick "Challenges and Best Practices with Tank Car Procurement" Presentation at InfoNex Crude-by-Rail Conference, April 9, 2014 Calgary, AB

[34] 10,000 pounds divided by 7 pounds/gallon = 1,428 gallons in lost volume. The same calculation is done for 12,000 pounds and this provides a range of 4.6% to 5.5%.

expended to move the empty cars (motive power) but there is additional wear on the track which results in the need for additional inspections. Added weight of retrofit components on lower benefit features such as moving from 8/16th to 9/16th shell will put even more trains on the tracks, offsetting the marginal safety benefits of the thicker shell. The large weight increase and associated decrease in capacity should be accounted for when calculating the economic value of the tank car. An additional cost impact will result from some number cars built after 2003 that cannot be increased to 286k GRL without TFP, or M976 trucks.

6. **PHMSA draws incorrect conclusion regarding newbuild capacity for crude oil and ethanol tank cars**

PHMSA states that "Based on the RSI's presentation to the NTSB on tank car production capacity, it is anticipated that 33,800 tank cars could be manufactured per year." This would appear to be an incorrect interpretation of the RSI presentation. New tank cars are all built at manufacturing plants that are classified as Class A facilities. According to the AllTranstek study, currently, 5 of the 6 new rail car manufacturers build tank cars and together they operate ten facilities that manufacture tank cars, with 7 in the US, 2 in Mexico and 1 in Canada. Current total annual industry capacity to build new tank cars is ~34,000 cars. However, not all of this capacity is available for manufacturing cars in the crude oil and ethanol service. RSI states clearly in a June 16th presentation to OMB that "only 60% of the uncommitted tank cars would be available for crude oil and ethanol service. The remaining 40 percent are required to meet new car demand for other commodities." This reduces the annual quantity of crude oil and ethanol newbuilds to 20,400 cars. According to RSI, much of this capacity is needed to support new demand of crude and all this capacity is fully committed today into 2016.

7. **PHMSA incorrectly estimates the opportunity cost of the rule**

Opportunity cost of the rule is a function of how long a car will be out of service and the value it provided while in service. PHMSA consistently biased each component downward.

a. **PHMSA underestimates time out of service**

PHMSA does not appear to account for several processes that will keep cars out of service, increasing the opportunity cost of the rule such as time transporting the car to the shop and back, staging time[35], material procurement, material ordering and delivery, administrative time (estimate generations, economic evaluations, approvals) qualification inspection, qualification repair time, final inspection. So while time to conduct the immediate retrofit task could range from as little as 6 days (PRD and BOV) to as much as 46 days (non-jacketed legacy car under Option 1), total time out of service can total anywhere from 70 days to 155 days. In contrast, PHMSA estimates 56 to 84 days out of service.

Even if PHMSA does not consider all of these 'social costs'(e.g. requalification time – page 80), they impact the length of time a car is out of service and the subsequent availability of tank cars to haul crude oil and ethanol.

b. **PHMSA underestimates foregone value for removing a car from service**

[35] Staging time is the time sequencing cars through the shop, waiting to move from one queue to another. It is a main reason qualification work is taking 90 to 120 days currently.

API holds that the proper metric for foregone value is the lease rate that a tank car could have earned if it were in service. This is a measure of the market's willingness to pay for the marginal tank car and as such is the appropriate metric. If anything, the lease rate understates the lost value when a non-marginal number of cars are removed from service.

PHMSA bases its assessment on the lost value on the amortized cost of a tank car. While this could be justified under certain circumstances, as conducted, it results in biased results. First, PHMSA improperly assumes a longer than reasonable economic life of a tank car. API agrees with AAR that while the service life of a tank car is, at maximum, 50 years, the economic life is 30 to 40 years.[36] By choosing an unreasonably long life, PHMSA effectively lowers the implicit lost value of taking a car out of service. Secondly, PHMSA chose a cost of a tank car that does not appear to reflect market values. Accordingly, PHMSA arrives at $511 for the monthly value of a non-jacketed CPC-1232 tank car. Compare this to the lease rates for crude oil tank cars reported by RBN Energy, LLC in May of 2013.[37] At that time, they were reporting long term lease rates at $1,400/month and short term lease rates at $4,500/month.

8. **PHMSA's own cost calculations are internally inconsistent**

PHMSA's undiscounted costs for New Construction (see Tables TC13 and TC25) show lower newbuild costs than the supporting documentation (see Tables TC12 and TC24 respectively). The text and data table state that the incremental cost of a newbuild is $5,000 (Option 1) and $2,000 (Option 2). Yet, the total costs shown in the second column of Tables TC13 and TC25 imply a per unit costs differential of only $3,261 and $1,305 respectively. Both figures are 35 percent less than what is in Tables TC12 and TC24. This is important for two reasons. First, it is shows that the costs used in the cost benefit test are likely underestimated. Second, it casts doubt on the other calculations in the analysis (some of which cannot be easily verified).

9. **PHMSA does not account for growing crude by rail volumes**

PHMSA assumes virtually no increase in crude rail movements over the period of analysis. In contrast, ICF estimates significant production growth in U.S. oil fields such as the Bakken, Permian, and Niobrara as well as in Canada, with corresponding growth in crude rail movements. Specifically, in 2015, ICF estimates 635 thousand barrels per day more than PHMSA, and by 2020 about 1.26 million barrels per day more than PHMSA.[38] These numbers translate very roughly into a difference between ICF and PHMSA in rail car demand of 20,000 railcars in 2015 to 40,000 railcars in 2020. The quantity difference would be almost 2 million b/d more if KXL is denied.

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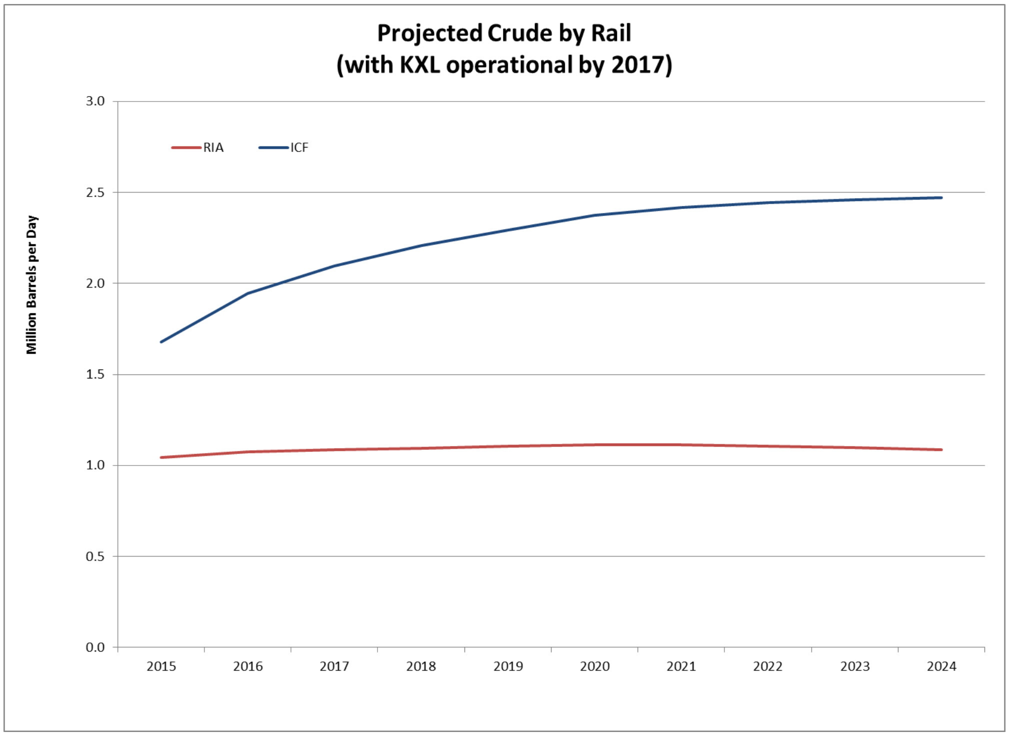
[36] Robert Fronczak Presentation to National Transportation Safety Board Safety Forum on Transportation of Crude Oil and Ethanol Washington, DC April 22, 2014

[37] "I Can See (Them) for Miles and Miles and Miles – The Tank Cars are Coming," RBN Energy, Blog posting 5/22/2013, https://rnbenergy.com.

[38] ICF, Forthcoming 2014, *Analysis of PHMSA Proposed Tank Car Design Regulations* (Working Title)



This difference has important implications. PHMSA's proposed phase-out is highly ambitious and only works when there are very optimistic assumptions. Any impacts resulting from a lack of time, a lack of retrofit capacity, and/or a lack of newbuild capacity are compounded when demand for Crude by Rail is growing instead of flat. Rising demand ensures that any minor glitch in transforming the fleet will have huge negative consequences.

ii. ICF's analysis finds proposed rule could have significant impact on the economy

According ICF International, PHMSA's current proposals threaten to curtail substantial volumes of North American crude oil production and may raise costs to consumers with subsequent negative impacts on employment and GDP.[39] ICF International developed, with input from the rail industry,[40] an economic model of tank car demand and the availability of tank cars under a business as usual (BAU) case as well as under PHMSA's three regulatory options over the 2014 to 2024 period ("study period"). The model corrects for many of the errors presented above and incorporates an assessment of: the existing fleet and its normal retirement outlook; retrofit and new build capacity, costs and timing; as well as the outlook for increased demand for crude movements by rail from the U.S. and Canada (assuming in one scenario KXL is approved and another where it is not). The model uses these inputs to determine the optimal economic path to meet the proposed regulations. In the event of insufficient qualified railcars, the model utilizes estimated costs of alternative options (e.g. pipeline, trucking, shut-in production) to reflect how the volume displaced by railcar shortages would be managed. The model outputs are used to estimate the broader economic impacts in terms of changes to consumer costs, GDP effects and job effects.

[39] Appendix 1 provides the full summary of the forthcoming report.
[40] Railway Supply Institute (RSI) and Alltranstek

1. Impact of PHMSA's Proposed Regulations – Petroleum Commodity Transport and Cost

The model results indicate that complying with the proposed regulations would not be possible without extensive scrapping of the existing legacy fleet in 2018 and 2019 and with the displacement of substantial volumes of crude oil, ethanol and other flammables on to alternative transportation modes – including trucking – for several years until new build capacity for railcars will allow the movement back to normal rail transport. Specifically, the model results indicate that the cost of retrofitting and the limited capacity to retrofit requires that the number of railcars needed to be scrapped or re-purposed is as follows (Table 4):

Table 4 – Railcars Scrapped/Repurposed

Railcars Scrapped or Repurposed	With KXL	Without KXL
Business as Usual	0[41]	0
Option 1	86,457	83,661
Option 2	84,631	83,682
Option 3	71,482	63,267

The inability to retrofit railcars in time for the proposed regulation dates requires substantial volumes of crude oil, ethanol and other flammables to be shifted to alternative, more costly means of transportation or in some cases result in shut in crude oil. The degree of impact increases should Keystone XL be denied, which requires an additional 700,000 barrels per day to be moved by rail above the base forecast increase (See Table 5).

Table 5 – Total Volumes Displaced by Year, in Thousand Barrels per Day (TBD) and Tank Cars (Cars)

	With Keystone XL						Without Keystone XL					
	Option 1		Option 2		Option 3		Option 1		Option 2		Option 3	
Year	TBD	Cars	TBD	Cars	TBD	Cars	TBD	Cars	TBD	Cars	TBD	Cars
2018	177	5,931	162	5,412	200	6,693	250	8,366	250	8,366	144	4,804
2019	530	21,953	467	19,697	198	7,675	1212	46,451	1157	44,379	482	20,359
2020	183	6,131	164	5,477	0	0	454	16,469	396	14,276	178	5,964
2021	0	0	0	0	0	0	85	2,844	5	176	0	0

No*te: This table shows amounts of crude oil and other flammable liquids that were expected to be transported by rail in the U.S. and Canada that will have to be transported by other means (or not produced) due to shortages of complaint rail tank cars. It also shows the minimum number of tank cars that would be needed to move those volumes.*

The cost implication of the proposed rule is substantial versus a BAU (See Table 6). For example, PHMSA's Option 1 has a cost above business as usual of $12.8 billion if KXL is approved and $22.8 billion if denied.

Table 6 – Annualized Costs, MM$ 2014-2024

[41] Excludes normal retirements over the period

		Total Annualized Cost			Annualized Cost vs BAU		
Annualized Cost, MM$	BAU	Option 1	Option 2	Option 3	Option 1	Option 2	Option 3
Keystone XL Approved	2,131	14,893	13,771	10,193	12,762	11,640	8,062
Keystone XL Denied	3,574	26,392	24,352	14,076	22,818	20,778	10,502

Note: This table shows the costs of new and retrofitted rail tank cars and, when needed, alternative modes of transportation or the opportunity cost of shutting in production of crude oil. The cost of new and retrofitted tank cars are "annualized" or spread out over the remaining lives of the cars. This table shows such annualized costs summed only over the years 2014 to 2024 for the U.S. and Canada.

2. **Impact of PHMSA's Proposed Regulations – Prices, GDP and Jobs**

There are several additional impacts the proposed regulations will have on the broader U.S. and Canadian economies. The impacts stem from increased rail transportation costs for crude oil, ethanol and other flammables, and a shift from rail transportation to much more expensive trucking costs and/or periods of shut in crude, particularly in the critical 2018-2019 period when the proposed regulations require use of new or retrofitted railcars. The higher transport costs for crude will reduce producer netbacks at the wellhead and reduce the incentives to invest in new productive capacity for crude oil. The resulting lower productive capacity, combined with possible transport bottlenecks that may force shut in of productive capacity for some periods of time, will reduce U.S. and Canadian oil production. The highest impact occurs in 2019 when combined U.S. and Canadian production could decline by as much as 613,000 barrels per day. Lower U.S. and Canadian oil production could, in turn, put upward pressure on world oil prices, which could be one source of higher prices for U.S. and Canadian consumers.

The other factors that could lead to higher prices for consumers will be higher shipping costs for petroleum products and higher shipping costs for ethanol that will be blended into gasoline. Such higher consumer costs reduce spending on non-energy consumer goods and services reducing output and jobs in those sectors. Potential higher consumer costs for gasoline and other petroleum products are estimated to be in the range of $14.4 to $22.8 billion in the 2015 to 2024 period in the scenario where Keystone XL is approved. In the scenario where Keystone XL is not approved, constraints on crude, petroleum products and ethanol are more severe and so potential consumer costs are estimated to increase even more to the range of $21.0 to $45.2 billion.

The net effect on gross domestic product (GDP) tends to be negative in that gains in some sectors (rail car construction and retrofits, oil pipeline services, barging and trucking) are offset by reduction in crude oil production and non-energy consumer goods. Likewise the effect on employment tends to be negative over the entire period, although the job gains in the rail car construction and retrofits are estimated to occur in the early years and are overtaken by job losses when the higher transport costs and constraints are fully felt. The net GDP losses are mostly occurring due to lost production of oil and exceed $20.3 billion per year in the peak year under the no-KXL scenario. Peak net job losses could be as high as 97,000 jobs in the no-KXL scenario and occur in oil production and non-energy consumer goods.

iii. **PHMSA's Cost Benefit is Not Supported**

Cost-benefit analysis is a well-established, systematic method of determining whether a proposed regulation costs society in terms of foregone resources more than it benefits society. The U.S. government has long-recognized the importance of all agencies conducting a cost-benefit analysis when promulgating new regulations. In 1993, President Clinton issued an Executive Order [No. 12866] instructing agencies to "assess all costs and benefits of available regulatory alternatives," adding that "[e]ach agency shall assess both the costs and benefits of the intended regulation and, recognizing that some costs and benefits are difficult to quantify, propose or adopt a regulation only upon a reasoned determination that the benefits of the intended regulation justify its costs."[42] The 1993 Executive Order was reaffirmed in 2011 when President Obama issued Executive Order 13563. The 2011 Executive Order again instructs agencies to issue regulations only when the benefits justify the costs and adds that the agency must also "tailor its regulations to impose the least burden on society, consistent with obtaining regulatory objectives, taking into account…the costs of cumulative regulations."[43]

Additionally, Congress has directed PHMSA itself to conduct these critical cost-benefit analyses for other areas under PHMSA's jurisdiction – for example, under the Accountable Pipeline Safety and Partnership Act of 1996, a statute that has the express stated goal of "reduc[ing] risk to public safety and the environment associated with pipeline transportation of…hazardous liquids",[44] which is a goal very similar to PHMSA's current goal of reducing risks associated with rail transportation of flammable liquids. The Act only permits the Secretary of DOT to issue a standard "*only upon* a reasoned determination that the benefits of the intended standard justify its costs" [emphasis added].[45] The Executive Orders and the Act demonstrate the necessity of conducting an accurate cost-benefit analysis and proceeding with a proposed rule only when the benefits outweigh the costs.

PHMSA's cost-benefit analysis demonstrates that the rule, as proposed, should not be promulgated. Out of the 9 proposal combinations considered, none of the 'low end' benefits are greater than the costs. Moreover, only 2 pass a cost-benefit test (i.e., have benefits exceeding costs) even when the upper end of the estimated benefits range are considered. (See Table 7, which calculates the "net benefits" of the proposals. Net benefits is defined as benefits minus costs)

Table 7. Net Benefit of the PHMSA Proposals ($ in millions)[46]

	Net Benefits	
Proposal	"Low" Benefits minus Cost	"High" Benefits minus Cost
PHMSA and FRA Design Standard + 40 MPH System Wide	($4,384)	($1,434)
PHMSA and FRA Design Standard + 40 MPH in 100K	($2,088)	$456
PHMSA and FRA Design Standard + 40 MPH in HTUA	($1,894)	$584
AAR 2014 Standard + 40 MPH System Wide	($4,478)	($2,238)
AAR 2014 Standard + 40 MPH in 100K	($2,190)	($382)
AAR 2014 Standard + 40 MPH in HTUA	($1,998)	($260)
CPC 1232 Standard + 40 MPH System Wide	($4,157)	($2,509)
CPC 1232 Standard + 40 MPH in 100K	($1,874)	($674)
CPC 1232 Standard + 40 MPH in HTUA	($1,683)	($556)

[42] *Regulatory Planning and Review*, Executive Order 12866 (Sept. 30, 1993).
[43] *Improving Regulation and Regulatory Review,* Executive Order 13563 (Jan. 18, 2011).
[44] S. 1505 (1996).
[45] *Id.* at Sec. 5.
[46] This table utilizes the data provided in Table 6 – "20 Year Benefits and Costs of Proopsoal Combinations of Proposed Regulatory Amendments 2015-2034" at Fed. Reg. Volume 79, p. 45022

Furthermore, API has serious concerns on the assumptions applied in the analysis which underestimates costs and applies unrealistic assumptions to quantify the potential benefits which has the overall effect of inflating benefits. The costs issues are addressed in preceding sections.

In particular with regard to the benefits, PHMSA both overestimates the potential damages from "lower consequence events" and arbitrarily assigns a cost and a frequency to "high consequence events" in the U.S.

In order to estimate the potential damages from lower consequence events, PHMSA multiplies an average of the gallons spilled per accident from 2006 through 2013 (83,602 gallons) by the per gallon cost of the Lynchburg incident ($300). This is then multiplied by the projected number of accidents in a given year to find the monetized damages in that year.[47] This method is flawed as a result assumptions made by PHMSA when determining inputs. The monetized damages in any given year will be overestimated as a result of the overestimated cost per gallon and the improperly calculated future accidents which includes all derailments on all track lines with and without releases.

PHMSA's trend calculation that is used to project the number of accidents in a given year uses poorly selected data that results in an overestimation of the accident frequency. The overestimation is generated in two ways. First, PHMSA's trend is calculated from derailment data from all commodities, rather than only derailments of crude oil and ethanol that resulted in releases. The agency justifies the use of this data by citing an inability to "capture all derailments of all trains carrying crude and ethanol."[48] However, PHSMA notes that only derailments that result in a release are included in the PHSMA database, because PHMSA requires an incident report to be filed if a hazardous material is released. FRA data lists all derailed trains that were carrying hazardous materials, but does not clarify the type of material. Given that PHMSA defines the "Vulnerability" portion of the risk calculation as "the probability of a release of flammable liquid…"[49] PHMSA's choice to include all derailments, regardless of release, overestimates the future releases by assuming that all derailments result in releases.

Similarly, PHMSA's derailment trend calculation is incorrectly based on all track data – mainline, yard, siding and industry. However, as PHSMA notes, the proposal will do little to mitigate derailments that occurred in rail yards, leading one to the conclusion that the trend should be built only on mainline derailments, such that only the actual benefits of the proposed regulations are captured. PHMSA notes "Mainline derailments have declined at a sharper rate than all derailments over the past 20 years," which would suggest that voluntary actions have had significant success in reducing the number of derailments. But, relying on input from subject matter experts, PHMSA concludes the data cannot be used as the trend would lead to a near zero projection by 2026, and faults recession sensitive data for the unlikely conclusion. The solution proposed by PHMSA is to use all track data – including derailments that will not be mitigated by the proposed regulations – even though this solution does not eliminate the effect of the recession on the derailment data.

PHMSA's second input to the damages equation, the incident cost per gallon, is also flawed, and leads to an overestimation of the annual potential damages. PHMSA used data from derailments of crude and ethanol trains from 2006 to 2013 to determine the quantity of product lost per derailment, and specifically excluded data from 2014 as the data may not yet be finalized.[50] The agency then determined that the most reliable cost data available were from two incidents in 2014, Lynchburg, VA and Lac-Mégantic, Quebec. PHMSA chose to use cost data associated with the Lynchburg, VA incident, despite having data from 40

[47] DOT, PHMSA, *Draft Regulatory Impact Analysis, Hazardous Materials: Enhanced Tank Car Standards and Operational Controls for High-Hazard Flammable Trains; Notice of Proposed Rulemaking*, July 2014, p. 35
[48] *Id.*, p. 22
[49] *Id.*, p. 21
[50] *Id.*, p. 25

mainline derailments involving crude oil and ethanol releases since 2006. As PHMSA notes, the average cost per gallon released for all 40 incidents from 2006 through 2013 was $14.13;[51] the cost per gallon released in the Lynchburg incident, according to CSX, was $300 per gallon[52] – more than 20 times the average for 2006 through 2013. Even including the Lynchburg data in the 2006-2013 dataset would only result in a cost per gallon released of approximately $16.67. PHMSA's estimate grossly overestimates the average cost per gallon released. PHMSA provides no convincing argument that the 2006 through 2013 data is flawed, apart from a belief in the agency that the reports filed "do not represent the full costs of an accident or the response."[53]

With respect to high consequence events, PHMSA believes that the full impact of the proposed rule can only be captured if events like the Lac-Mégantic are included in the benefit analysis. This is despite the fact that, as PHMSA states, "there have been no higher consequence events in the U.S."[54] Nonetheless, PHMSA assumes that 10 such events (nine similar to Lac-Mégantic and one five times more severe) will occur over the next 20 years. PHMSA provides no explanation for the number of events it has chosen to model and while the agency suggests that it calculated a range from zero to ten, with ten as the upper bound, only data for the upper bound case is provided. These assumptions are made without clear explanation, despite OMB guidelines on benefit-cost analysis recommending that any analysis "include a statement of the assumptions, the rationale behind them, and a review of their strengths and weaknesses."[55] In fact, the agency itself "believes that the occurrence of 10 such higher consequences events occurring in the U.S. is unlikely."[56]

The agency then uses the data collected from the Lac-Mégantic incident (including the 65 mph speed of the train) to calculate the estimated damages for nine of the higher consequence events. PHMSA uses this data, despite its own recognition that the speed of the train and the number of cars derailed are not likely to be seen in the U.S., given the agreed upon speed limit of 50 mph for crude and ethanol unit trains, and never having had a derailment of more than 31 cars. PHMSA offers the suggestion of scaling the data to fit an event more likely to occur in the U.S., but chose not to scale the data as the agency believes "extraordinary damages could have occurred even if the train in Lac-Mégantic had derailed at a slower speed,"[57] and, "extraordinary damages may have occurred even if the train in Lac-Mégantic had only involved 20 or 30 cars."[58] The flaw with the agency's logic is that they provide only a point estimate of the potential damages of nine Lac-Mégantic size incidents under the higher consequence event discussion. A range of data would have acknowledged that a higher consequence event could occur, yet be less damaging than the Lac-Mégantic incident – a possibility ignored by PHMSA. In fact, the only scaling performed by PHMSA was to scale up the damage of each of the nine incidents by increasing the population density around the tracks, citing available GIS data for the U.S.

PHMSA continues to push the higher bound, while providing no lower bound or greater range data, by including a single incident that is of even greater consequence than Lac-Mégantic in which the population density is five times denser than average. Again, PHMSA ignores OMB guidelines and does not provide sufficient rationale for this assumption.

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[51] *Id.*, p. 30
[52] *Id.*, p. 29
[53] *Id.*, p. 30
[54] *Id.*, p. 36
[55] OMB, *Memorandum for Heads of Executive Departments and Establishments*, Circular No. A-94 http://www.whitehouse.gov/omb/circulars_a094
[56] DOT, PHMSA, *Draft Regulatory Impact Analysis, Hazardous Materials: Enhanced Tank Car Standards and Operational Controls for High-Hazard Flammable Trains; Notice of Proposed Rulemaking*, July 2014, p. 37
[57] *Id.*, p. 39
[58] *Id.*, p. 40

PHMSA attempts to justify its assumptions and calculations using a Monte Carlo analysis. While a useful tool, the output from a Monte Carlo analysis is only as useful as its inputs are realistic. PHMSA continues to put its hand on the scale, by assuming that there will be 5 events, with the same fatality rate and non-medical cost as Lac-Mégantic (PHMSA again fails to scale the event to a more likely U.S. scenario). The Monte Carlo analysis provided by PHMSA is therefore irrelevant.

The final result of PHMSA's 'high consequence' analysis is an assumption that over a 20 year period, the following would occur: 1) 9 high consequence events with impacts greater than $1.15 billion per event and 2) 1 high consequence event with 5 times greater impact ($5.75 billion). Implicitly, PHMSA is assuming a Lac-Mégantic event, which has only occurred once, to occur ***every other year*** AND for an event ***roughly 5 times as destructive*** to occur once during that same time period. These assumptions, which only bump two of the nine proposals in the 'pass' category for the cost-benefit test, are based on nothing more than unjustified assertion.

iv. **Conclusion**

PHMSA has made considerable errors in its assessment of the costs of its proposed rule and its impact on many sectors of the economy. Additionally, PHMSA has erred in calculating the benefits associated with the rule. Accordingly, PHMSA's calculation of net benefits is seriously flawed. Moreover, it shows that the rule, as currently written, should not be promulgated. However, API believes strongly that public safety would be served by a rulemaking and, in the following section, offers specific changes to lessen the costs and improve the benefits of the rule.

b. **API and AAR Recommendations**

In response to the Call to Action, API and AAR developed a joint approach on tank car design that focused on how to mitigate the risks associated with a tank car derailment. The associations jointly agreed to the best design for retrofitting the existing fleet and for building new cars which substantially improves the puncture resistance and thermal protection of the tank cars when exposed to a pool fire. The API/AAR approach employs resources to mitigate the largest risks as quickly as possible while minimizing the effects to jobs and to U.S. energy security.

The details of the API and AAR approach are provided in the jointly submitted comments. Those comments include the following high level recommendations to the fleet.

- New tank cars would have a ½" shell with a jacket, thermal blanket, full-height head shields, an appropriately-sized pressure relief device, bottom-outlet handle protection, and top fittings protection.
- Legacy DOT-111 non-jacketed (not built to the CPC-1232 standards) tank cars would be retrofitted with jackets, thermal blankets, full-height head shields, appropriately-sized pressure relief devices, bottom-outlet handle protection, and valve protection.
- CPC-1232 non-jacketed cars would be retrofitted with jackets, thermal blankets, full-height head shields, appropriately-sized pressure relief devices, and bottom-outlet handle protection.
- Existing jacketed cars would be retrofitted with an appropriately-sized pressure relief device and bottom-outlet handle protection.
- Any cars that are retrofitted to these standards should be allowed to be used for their full life.
- The retrofit schedule for crude oil only would contain a retrofit deadline for legacy, non-jacketed DOT-111 tank cars three years after a ramp-up period for tank car facilities, with legacy, non-

jacketed CPC-1232 tank cars subject to a retrofit deadline six years after the ramp-up period, following the DOT-111 non-jacketed fleet.[59]

- The fleet retrofits could place a priority on crude oil and ethanol since they account for most of the unit train service for flammable liquids.

As provided below in Section b.ii, "Tank Car Retrofit Schedule," API recommends a schedule to accommodate the fact that PHMSA included ethanol and "other flammable liquids" in the proposed rule. API offers the following supplemental information in support of the API/AAR joint comments.

PHMSA's NPRM considers a number of factors for new tank car design in addition to shell thickness, such as full- height head shields and jackets. Based on a review of these factors, the API and AAR support an optimal design for new tank cars is PHMSA's proposed Option 2 with two modifications, including a slightly reduced shell thickness of 1/2" and a thermal blanket. A shell thickness of 1/2" falls within the parameters of the three options set forth in the NPRM: slightly thicker than PHMSA's proposed Option 3 (7/16") and only slightly thinner than PHMSA proposed Options 1 and 2 (9/16").

As stated in the joint comments, the 1/2" shell with the requirements provided above have a conditional probability of release (CPR) of 3.7%. All other things being equal (FHHS, TFP, bottom outlet handle), the CPR model shows a 0.8% difference between the 1/2" car and the 9/16" car proposed in PHMSA's Option 2, which during a derailment does not have a practical or meaningful difference. There is a similar difference in CPR when comparing the 1/2" car to the 7/16" car.

Looking at it differently, the CPR for a 1/2" car is 3.7%, which means that a tank car has a 96.3% chance of **not** releasing more than 100 gallons if the tank car is traveling at 26 mph. The 7/16" shell (all things being equal) is therefore 99.1% as effective as the 1/2" shell.[60] In contrast, the legacy DOT-111 non-jacketed 7/16" car is only 83.5% as effective as the proposed 1/2" jacketed car and thus why it should be retrofitted.[61] That car once retrofitted would be equivalent to the CPC-1232 jacketed tank car. The jacketed CPC-1232 car has a CPR of only 4.6% and would be equivalent to the PHMSA Option 3 tank car. The CPR model shows a 1.7% difference between the 9/16" shell and the 7/16" shell and therefore the performance characteristics are very similar. Further to the point, the jacketed 7/16" shell and the 8/16" shell provide 98.2% and 99.2%, respectively, of the benefit of a 9/16" shell.[62]

The added weight of a 9/16" would put even more trains on the tracks to move the same volume of product thus offsetting the marginal safety benefits of the thicker shell.[63]

With the modifications advanced by API and AAR, PHMSA's Option 2 with a 1/2" shell will achieve the similar level of safety as PHMSA's currently proposed Option 2, and exceed that of Option 3.

i. Impacts of increased shell thickness and adding jackets

[59] The retrofit schedule was based on crude oil only. AAR and API did not intend this time frame to govern all flammable liquids.

[60] A 1/2" shell (FHHS, TFP, Jacket, etc.) has a CPR of 3.70% or is 96.3% (100-3.7 =96.3) likely to survive an incident without a rupture. If the benchmark is the 1/2" shell, all things being equal, a 7/16" shell is 99.1% of the 1/2" performance = ((100 - 4.6 CPR)/96.3)

[61] A 7/16" shell without (FHHS, TFP, jacket, etc.) has a CPR of 19.6% or is 80.4% likely to survive an incident without a rupture. All things being equal, a 7/16" shell without a jacket is 83.5% as effective as the 1/2" car. (100-19.6)/96.3)

[62] A 9/16" shell has a CPR of 2.9 or is 97.1% likely to survive an incident without a rupture. A 1/2" shell is 99.2% as effective as the 9/16" shell -- (100-3.7)/97.1) --and a 7/16" shell with a jacket is 98.2% of a 9/16" performance or ((100-4.6)/97.1)

[63] ½"

The puncture and impact improvements that result from jacketing the fleet do not indicate a need to make all tank cars meet the new tank car specification as suggested in PHMSA's proposed rule. In support of this argument, Transport Canada has proposed allowing the existing CPC-1232 cars (both 8/16" without jackets and 7/16" with Jacket) to be allowed to be used for their useful life.

Even if the CPR showed that there was a need to retrofit the fleet to the impact standards of the new tank car design, it is unclear if the 7/16" shell can be modified to the impact performance of a 1/2" shell and if it could, it would provide minimal safety benefit. Further, according to the recently released study done by the FRA, the "energy to just cause puncture was calculated to be …the energy of a 12.1 mph impact…"[64] As provided in the PHMSA rule, the proposed side impact is 12 mph [65] which is the historical modeling of a 9/16" tank car. Historical modeling shows puncture resistance of a 7/16" tank at 9.3 mph.[66]

Additional information is provided above in Section V. a.i.5., "PHMSA improperly assumes additional weight will not limit capacity."

ii. Tank Car Retrofit Schedule

Today, there are approximately 143,000 tank cars in service in flammable liquid service. Of these cars, roughly 108,000 will be used in unit trains moving crude oil or ethanol after 2015. Modernization for improved safety of the entire fleet is, of course, the ultimate goal. However, this cannot be achieved over night and the capacity for rail car shops to retrofit the existing cars and to build new cars is finite. As will be shown in greater detail below shop capacity simply cannot modernize a fleet of 143,000 tank cars in 3 years. It cannot modernize 108,000 tank cars in this time. By RSI's estimate provided to API and AAR, 6,400 cars per year can be retrofitted and 20,000 new cars can be built per year for crude oil and ethanol service. Thus, to achieve the greatest enhancement of safety of rail transport, the final rule must *prioritize cars* to be retrofitted, provide *sufficient time* to achieve the retrofits and new builds, and preserve the energy security that is building in the U.S.

Accordingly, API proposes that the entire crude oil and ethanol fleet which are largely moved in unit trains be retrofit as follows (assuming effective date of the rule is January 1, 2015):

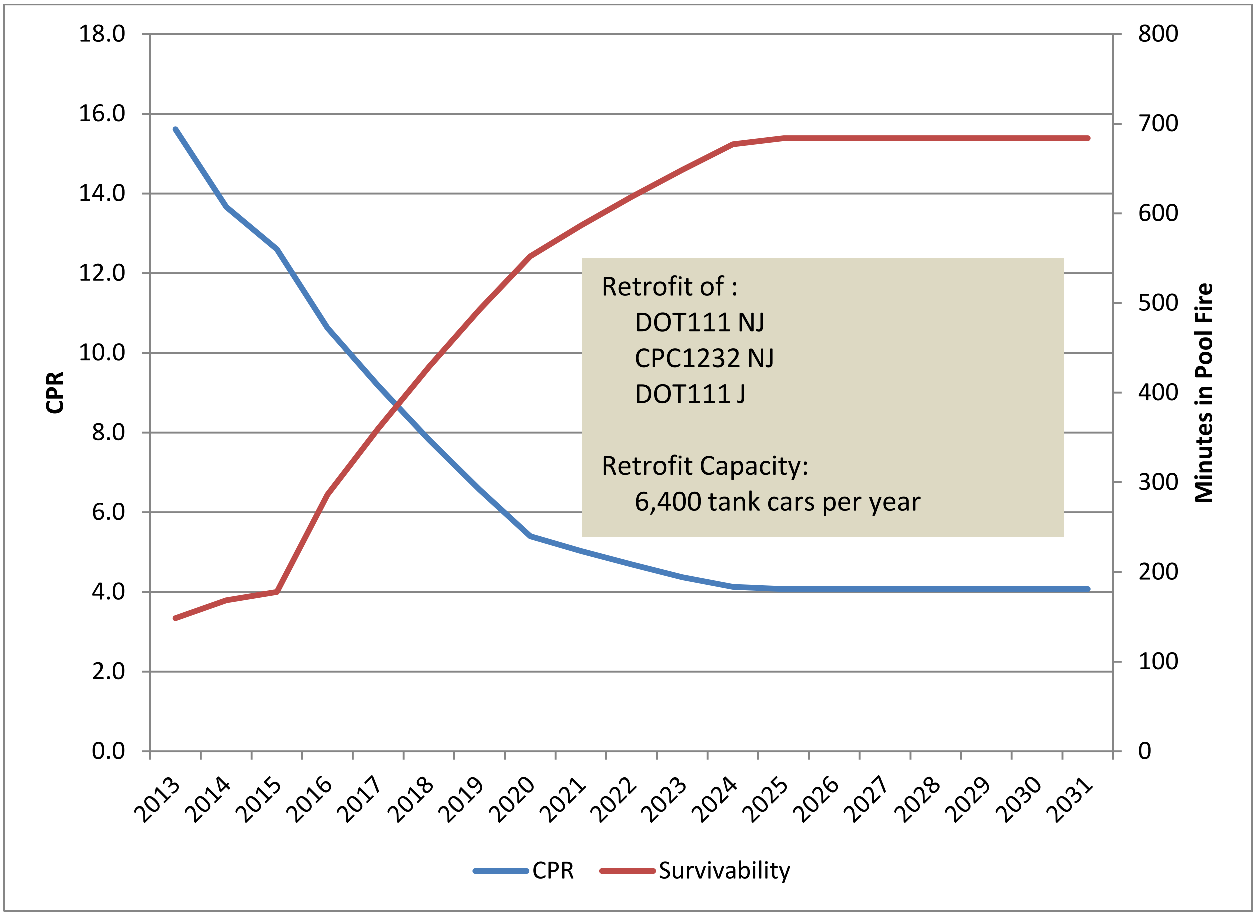
1. Begin the retrofits of the crude and ethanol fleet by starting first with tank cars used in unit train service to the standard explained in detail above
2. Retrofit, phase out or repurpose all ethanol and crude oil tank cars on the following schedule after which they would no longer be allowed to be used in that service.
    a) Legacy DOT-111 (not built to the CPC-1232 standards) Non-Jacketed (NJ) cars by December 2020.
    b) NJ cars built to the CPC-1232 standard (CPC-1232 NJ) cars by March 2024
    c) Legacy DOT-111 Jacketed cars by March 2025
3. The CPC-1232 non-jacketed fleet would be retrofit at the next shopping or qualification.
4. Retrofit schedule review should be conducted to determine how the retrofits are being done and consider what, if any, additional time may be necessary to complete the retrofits (more detail is provided above in Section V.a.ii., "PHMSA underestimates the retrofitting challenge created by the proposed timeline.")
5. Conduct an assessment in 2022 (two years in advance of the final phase out of CPC-1232 NJs) of the CPR of the then-existing tank cars that are in service in Class 3,

[64] "Full-Scale Shell Impact Test of a DOT-111 Tank Car,"U.S. DOT, Federal Railroad Administration, Office of Railroad Policy and Development, RR 14-29, August 2014
[65] "Hazardous Materials: Enhanced Tank Car Standards and Operational Controls for High-Hazard Flammable Trains," 79 Federal Register 148 (Aug. 1, 2014) p. 45077.
[66] *Id*., Table 18, p. 45054

Packing Group I, II to determine which retrofit elements, if any, and timeline are appropriate for tank cars that were not retrofitted under point (1) by time (2) herein.

This schedule is aggressive yet achievable. The seemingly longer time periods result in about 30% of the current fleet being scrapped with over 59,000 new cars being built. This timeline improves the safety and modernizes the entire fleet of cars which transport flammable liquids, addresses all cars in the fleet, prioritizes retrofitting of cars that are the core concern of the Department in light of the reality of limited shop capacity, and does so on an aggressive yet achievable timeline which enables continued strength of the U.S. and North American economy.

Figure 1. Changes in Crude and Ethanol Fleet Characteristics



iii. Retrofit Schedule Review

As stated in the AAR/API joint comments, there is a need to develop a retrofit review program.

> "The review would address available shop capacity, access to sufficient quantities of materials, availability of skilled labor, etc. and actual progress in manufacturing and retrofitting tank cars and consider what, if any additional time would be necessary to complete the retrofit schedule."

Further to that recommendation to PHMSA, retrofitting more than 108,000 tank cars is an extraordinarily large undertaking and would be six times larger than any retrofit previously undertaken. In the late

1970's the pressure car fleet was retrofit under HM-144 where roughly 17,000 tank cars were modified over a period of 4 years, or 4,250 retrofits per year.[67]

This schedule review would be overseen by the federal government and participation in the review would be required by any facility that was licensed to conduct a retrofit. The review would include at a minimum the following criteria:

- Available shop capacity
  - Ability to obtain permits for those facilities
  - Craning operations
  - Equipment to form and weld tank cars
  - Available track storage capacity
  - Existing shops that are at capacity and the expected expansions for new capacity?
  - What is the shop capacity of the lessors? Are those shops available to private owners?
- Access to sufficient quantities of materials (e.g., thermal blankets, full-head shields (availability, dimensions to deliver), valves, steel for jackets, wheels, bearings, etc.) (see challenges with access to materials below)
- Availability of skilled labor (see challenges of skilled labor below)
- Actual production rates. We propose a semi-annual (6- month) review) (e.g., number of completed tank cars completed and returned to service)
- Availability and cost of interim replacement capacity.

Additional challenges of this large scale retrofit and support for the need for a retrofit schedule review are provided above in Section V.a.i.1. "PHMSA underestimates the retrofitting challenge created by the proposed timeline."

VI. <u>Classification</u>

a. <u>Petroleum Crude Oil Definition</u>

In the NPRM, PHMSA uses the term "mined liquids and gases." This term is confusing and misleading; it is defined by neither PHMSA nor the FRA nor is it used by the affected industry. Dictionary definitions of "mining" indicate that the term typically refers to the act of digging into the earth for minerals. This is not the case with crudes, other than perhaps crude oils that are derived from open pit oil sand operations as in Canada. The rationale for including gases is unclear as the primary focus of the rule is on crude oil liquids. The term also suggests that these substances are in the same form as when they came from the earth, even though crude oil that is offered for transportation is substantially different from that produced at the wellhead because of the conditioning it undergoes. API recommends that PHMSA use the term "petroleum crude oil" in place of "mined liquids and gases." The term "petroleum crude oil" is the proper shipping name that is used for the crude oils that are the subject of this NPRM. The term "crude oil" is also already defined in ANSI/API RP 3000.

b. <u>Crude Oil Characteristics</u>

[67] HM-144 involved three classes of pressure cars, and each required something different for the retrofit. In the Federal Register dated 9/15/1977 the following information was reported as to how many cars were estimated to be involved.

PHMSA asks about the variability of crude oil properties across a region according to location, time, temperature and extraction methods. The degree of variability may differ from region to region. Based on PHMSA's own data, as well as that of other studies (e.g., the study completed by the North Dakota Petroleum Council), variability of Bakken crude oil appears to be fairly limited with most crude oil samples classified as PG I or PG II based on the measured initial boiling point values of crude oil samples being close to (i.e., somewhat above or below) the deciding threshold of the 95^{o}F. Furthermore, for purposes of the HMR, crude oil should be sampled and tested for classification in the form it is to be offered for transportation, not based on the location, time, temperature and extraction method of the crude oil, as these parameters do not provide relevant information for transportation classification purposes.

PHMSA also asks about the role of vapor pressure in the classification, characterization, and packaging selection process and whether regulatory changes to establish vapor pressure thresholds for packaging selection are necessary. A study carried out by the API Crude Oil Physical Properties Ad-hoc Group (COPP AHG) using the RSI-AAR Analysis of Fire Effects on Rail Cars (AFFTAC) model showed that different mixtures of hydrocarbons of different composition but with the same Reid vapor pressure (RVP) had diverse effects on a rail car in the event of a pool fire. It was therefore concluded that vapor pressure is a poor parameter for crude oil classification and for the behavior of crude oil in rail cars subjected to pool fires. Solely using vapor pressure as a classification criterion could lead to erroneous and dangerous results through misclassification. The API COPP AHG, with the participation of PHMSA, is continuing its research in this area and will provide recommendations based on sound science on whether vapor pressure thresholds for crude oil can be established for packaging selection.

c. Sampling and Testing Program

In the preamble PHMSA asks whether more or less specificity in 173.41(a) would aid compliance. API agrees with the approach being taken of establishing minimum requirements for a sampling and testing program for the purposes of classification. Voluntary consensus standards are an appropriate means of augmenting the minimum requirements in instances such as this and it is API's opinion that ANSI/API RP 3000, Classifying and Loading of Crude Oil into Rail Tank Cars, would provide the appropriate specificity to aid compliance if it were incorporated by reference in PHMSA's rulemaking.

PHMSA also asks whether the guidelines provide sufficient clarity. The provisions set out in §173.41(a) do not by themselves provide sufficient clarity. API RP 3000 appropriately provides considerably more detail; and §173.41(a) combined with RP 3000 provide the clarity that is needed. For this reason, API recommends incorporating RP 3000 by reference in PHMSA's rulemaking and additionally recognizing sampling and testing in accordance with RP 3000 as satisfying the requirements proposed in §173.41(a). API is submitting specific comments on selected elements in §173.41(a) as part of its response to this NPRM.

PHMSA asks what sampling and testing relief should be afforded offerors if they conservatively classify all crude oils as Packing Group I. It is API's opinion that offerors should exercise due diligence even if they were to classify all the crude oil they ship as PG I. Testing and sampling should still be required; however reduced sampling and testing would seem warranted. API RP 3000 addresses the situation of comingling of crude oils at rail transloading facilities where crudes oils already classified as PG I and II are mixed. In such a case, RP 3000 recommends a classification of PG I unless additional sampling and testing is performed.

API agrees that like any other hazardous material, it is essential that the person who offers crude oil for transportation properly classify it as required by §173.22. Recognizing the inherent potential for variation of crude oil properties, API has led in the development of a comprehensive industry voluntary consensus standard known as ANSI/API RP 3000, Classifying and Loading of Crude Oil into Rail Tank Cars (hereafter referred to as RP 3000). The multidisciplinary group which prepared RP 3000 has been broad based, made up of stakeholders representing crude oil producers/suppliers, crude oil purchasers, rail road companies, rail tank car manufacturers, rail tank car lessors, classifiers of crude oil for transportation, crude oil testing laboratories, crude oil testing equipment manufacturers, and petrochemical terminal operators. In addition, as noted in the HM-251 preamble, PHMSA personnel have been directly involved and, like all other participants in the API standards development process, have been afforded every opportunity to make proposals on the content of RP 3000. We appreciate PHMSA's recognition of the development work on RP 3000 and its willingness to consider incorporating RP 3000 into the regulations by reference. We note that incorporation would be in accord with the National Technology Transfer and Advancement Act of 1995 which mandates that all federal agencies use technical standards developed and adopted by voluntary consensus standards bodies, as opposed to using government-unique standards.

In view of PHMSA's active participation in the development of RP 3000 and its expressed willingness to incorporate RP 3000 into the regulations as a basis for crude oil classification, API assumes that PHMSA considers it appropriate guidance for correctly classifying crude oil. API appreciates that PHMSA endeavored to propose "minimum sampling and testing program" elements in §173.41(a) corresponding to provisions in RP 3000. In the case of the elements listed in §173.41(a), they differ in some respects from RP 3000. API is concerned that these differences may cause confusion and could potentially detract from our common goal of ensuring that crude oil offered for transportation is properly classified, particularly if RP 3000 were to be incorporated by reference into PHMSA's rulemaking. To avoid potential for confusion, API recommends that all of the elements listed in §173.41(a) closely correspond with provisions in RP 3000.

On this basis, API provides the following comments and recommended changes for selected paragraphs and subparagraphs in §173.41:

Proposed §173.41(a). In the proposed text, PHMSA would require that the listed "minimum sampling and testing program" elements are required to ensure that crude oil is properly "characterized" and classified in accordance with §173.22. API notes that "characterized" is a term that is not in the Hazardous Materials Regulations (HMR). While it is discussed in the NPRM preamble (page 45023, column 3), "characterized" is undefined in a HMR context. Contrary to the proposed §173.41(a) text, it is not used in §173.22 so that an offeror would not understand what is meant. API recommends that "characterized" be removed from the text in §173.41(a) so that it reads:

> "(a) General. ~~Mined gases and liquids, such as~~ Petroleum crude oil~~, extracted from the earth and~~ offered for transportation must be properly classed ~~and characterized~~ as prescribed in §173.22, in accordance with a sampling and testing program which specifies at a minimum:"

Proposed §173.41(a)(1). The proposed subparagraph lists factors that would need to be taken into account in specifying sampling and testing frequency. API notes that frequency should be based on factors influencing variability of crude oil as it is offered for transportation. Factors in the proposal dealing with conditions of crude oil as it is extracted may not be relevant. ANSI/API RP 3000 identifies the factors that may contribute to variability of crude oil properties for crude oil to be placed in transportation as:

- Historical consistency of the physical and chemical characteristics of the petroleum crude oil to be loaded;
- Stability of the petroleum crude oil to be loaded;
- Single source vs. multiple source(s);

- Pipeline specifications changes (tariff rules and regulations);
- Type of rail tank car loading facility (i.e., transload);
- New crude production or changes in crude oil production characteristics; and
- Variability of truck or pipeline receipts.

API recommends that the text of §173.41(a)(1) be revised by eliminating the proposed list of factors so that the subparagraph would read:

> "(1) A frequency of sampling and testing that accounts for any appreciable variability of the material, ~~including the time, temperature, method of extraction (including chemical use), and location of extraction~~;"

Proposed §173.41(a)(2). The expression "sampling along the supply chain" is a phrase not well understood in an HMR context and API recommends clarification. For crude oil, the supply chain begins when it is pumped from a wellhead storage tank into a means of conveyance and normally ends at a refinery where it is processed. Between those two points, it may be transported by other modes not subject to the HMR. Under §173.22, correct classification is required at the point crude oil is offered for transportation. For purposes of the HMR, it follows that crude oil, in the form to be offered for transportation, should be sampled for purposes of testing and classification. After crude oil is loaded for transport, its properties do not change from a classification perspective so that further sampling from a transport vehicle as it proceeds to its destination is unnecessary. In fact, in-transit sampling/testing could increase the risk of non-accidental release downstream of the loading point. Additional sampling and testing may also be needed at transloading facilities when crude oils of different packing groups are comingled. API recommends that the text of §173.41(a)(2) be clarified so that the requirement to sample is limited to points where it is offered for transportation for the purpose of "ensuring that the crude oil to be offered for transportation is correctly classified" and not to "understand the variability of the material during transportation". The following revised text is recommended:

> "(a)(2) Sampling prior to transportation, including at transloading facilities when mixing of crudes oils from diverse sources may affect classification ~~at various points along the supply chain to understand the variability of the material during transportation~~;"

Proposed §173.41(a)(3). The term "as packaged" suggests that sampling may only be performed after the crude oil has been loaded into a transport vehicle. In practice samples are frequently drawn from storage tanks prior to loading. Such sampling should also be deemed acceptable provided it produces representative samples of crude oil offered for transportation. On this basis API recommends that 173.41(a)(3) be revised to read:

> "(3) Sampling methods that ensure a representative sample of the entire mixture to be offered for transportation~~, as packaged,~~ is collected;"

Proposed §173.41(a)(4). It is not clear what PHMSA intends by "complete analysis". Complete analysis could mean measurement of many data points – including many not relevant to classification for transportation purposes. API understands that the testing should be limited to tests that contribute to correctly classifying crude oil and recommends that the text refer only to testing needed for ensuring regulatory compliance. As already noted above, "characterized" is an undefined term in the context of the HMR and API recommends that it not be retained. On this basis API recommends that proposed §173.41(a)(4) be revised to read as follows:

“(a)(4) Testing methods that enable ~~complete analysis,~~ classification~~, and characterization~~ of the material under the HMR.”

Proposed §173.41(a)(5). This proposed element would require a statistical analysis to justify the frequency of sampling and testing. ANSI/API RP 3000 provides a basis for sampling frequency through a qualitative approach and not on the basis of a statistical analysis. The approach is analogous to the “batching approach” described in the United Nations Globally Harmonized System of Classification and Labelling of Chemicals which may be applied in classifying mixtures in the case of hazards such as the toxic by inhalation hazard for liquids and gases. In essence, the batching approach would allow an untested batch of a mixture to be classified the same as a tested batch provided it is determined to be substantially equivalent. In addition, OSHA, under HCS 2012, authorizes an analogous “weight of evidence” approach for hazard classification of petroleum product streams, including crude oil.[68] API RP 3000 identifies the factors that may contribute to variability of crude oil properties and provides a basis for determining whether or not different batches may be considered substantially equivalent. They factors include:

- Historical consistency of the physical and chemical characteristics of the petroleum crude oil to be loaded;
- Stability of the petroleum crude oil to be loaded;
- Single source vs. multiple source(s);
- Pipeline specifications changes (tariff rules and regulations);
- Type of rail tank car loading facility (i.e., transload);
- New crude production or changes in crude oil production characteristics; and
- Variability of truck or pipeline receipts.

API recommends that this qualitative approach be authorized. We recommend that §173.41(a)(5) be amended to read as follows:

“(a)(5) ~~Statistical~~Quality control justification for sample frequencies.”

Proposed §173.41(a)(6). This provision calls for drawing duplicate samples. In normal practice a single sample is drawn unless closed sampling equipment is used. One portion of the sample is used for analysis and the other portion is retained, as appropriate. The retained portion of the sample is available for testing in the event of a problem with the portion of the sample used for testing. This is the procedure anticipated in ANSI/API RP 3000. Importantly, this procedure does not entail the drawing of duplicate samples for analysis. API recommends that this approach be authorized and on this basis recommends that §173.41(a)(6) be revised to read as follows:

"(6) Retention or duplicate samples, as appropriate, for quality assurance purposes;”

Proposed §173.41(a)(7). There are innumerable reasons for modifying a sampling and testing program. It is impractical and inappropriate to include such criteria within the program itself. API recommends that proposed 173.41(a)(7) be deleted.

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[68] Request for Interpretation of Application of OSHA's Amended Hazard Communication Standard (HCS 2012) to Combustible Dust; Request for Interpretation OSHA's Amended Hazard Communication Standard (HCS 2012) regarding Petroleum Streams; Request for Interpretation of OSHA's Amended Hazard Communication Standard (HCS 2012) about Hazards Not Otherwise Classified; Request for Interpretation of OSHA's Amended Hazard Communication Standard (HCS 2012) about classification criteria for Specific Target Organ Toxicity.

Proposed §173.41(b). The certification requirement is redundant and unnecessary. §172.204(a) already requires that an offeror certify that "the material is offered for transportation in accordance with this subchapter". If adopted in a final rule, §173.41(a) would be part of the relevant subchapter and, irrespective of proposed §173.41(b), the offeror certification required under §172.204 would include certification of classification in accordance with the sampling and testing program contained in §173.41(a). The proposed certification requirement is not included in any other requirement in the subchapter even though the offeror certification in 172.204 also affirms compliance with every other relevant provision in the subchapter. We see no basis for making specific mention of §173.41(a) for purposes of the §172.204 certification and we recommend that §173.41(b) be deleted from the rule.

Proposed §173.41(c). The second sentence of the proposed paragraph would require annual review of the sampling and testing program. API considers this level of detail overly prescriptive and without justification. API would propose that more discretion be provided by revising the proposed text to read:

> "The sampling and testing program must be reviewed ~~at least annually and~~ revised and/or updated as necessary to reflect changing circumstances."

The last sentence of subparagraph, as proposed, would require all employees to be notified whenever any change is made to the sampling and testing program even though such a change may not be relevant to some employees who are responsible for only a portion of the plan. In implementing the requirements, we would anticipate that some employees may only be provided those aspects of the plan relevant to their responsibilities. In such instances, it would be unnecessary for them to be apprised of a change not affecting their responsibilities. API recommends that only employees whose responsibilities are affected by a change should be required to be notified. We recommend that the last sentence be revised to read as follows:

> "When the sampling and testing program is updated or revised, all employees responsible for implementing ~~it~~ <u>an affected portion</u> must be notified, and all copies of the sampling and testing program must be maintained as of the date of the most recent revision."

d. <u>Crude Oil Wellhead Processing</u>

PHMSA does not provide additional flexibility by stipulating tank car requirements based on packing group. PHMSA states in its proposed rule that it provides "additional time for cars to meet the DOT Specification 117 performance standard if offerors take steps to reduce the volatility of the material."[69] However, even "over-stabilized" light crude will likely be a PG I or PG II flammable liquid, and offerors typically conservatively classify crude oil as Packing Group I, so there is no additional flexibility in this proposal.

Materials produced from an oil well include a mixture of gaseous and liquid hydrocarbons, water and other impurities. Hydrocarbons molecules exist as various weights, for example methane, ethane and propane. Separation of crude oil can occur at the wellhead through "field conditioning," at centralized facilities, or at downstream centralized locations with more complex Stabilization Units. At the wellhead, crude oil undergoes field conditioning which separates the crude oil to prepare it for market.

Hydrocarbons produced from the well normally flow to a vessel referred to as a "separator' where low boiling point hydrocarbons, or light ends (C1 through C5), are partially separated from the crude oil and

[69] "Hazardous Materials: Enhanced Tank Car Standards and Operational Controls for High-Hazard Flammable Trains," 79 Federal Register 148 (Aug. 1, 2014) p. 45061.

water. This separation occurs by means of a reduction in pressure and application of gravity. The recovered light ends are metered and delivered into a pipeline gathering system and shipped to a gas plant for further processing. In remote locations, where gas transportation and processing infrastructure are not available, the light ends may be burned as fuel or flared, if allowed by regulation.

From the separator, an emulsion, which is a crude oil and water mix, may then flow into a “heater-treater” which uses heat to achieve the partial separation of oil from water and any solids, at temperatures ranging from approximately 90 °F to 120 °F. Additional light ends may also be recovered from the crude in the heater-treater.

The separated water and oil are then delivered into their respective storage tanks and the crude is transported by pipe or truck to a rail or regional pipeline depot. The light ends would go into the gas transportation and processing infrastructure, burned as fuel, or flared, if allowed by regulation. Crude oil is sufficiently prepared for transportation by conventional separation equipment already at most well sites.

The amount of light ends removed from the crude oil can be somewhat modified by the choice of operating conditions at some stages in field conditioning. For example, higher heater-treater operating temperatures and residence times will increase the amount of light ends removed from the crude oil. However, this increase is limited and will not impact the Hazard Class designation of the material. Furthermore, it is important to note that all operating conditions must be carefully optimized to stay within equipment design limits and product quality and general operability constraints. For example, increasing heater-treater temperature to the upper end of the design limits can have the undesirable and unacceptable consequence of increasing internal tube failures and driving excessive amounts crude oil range material (C4+) into the gas stream. API is not currently aware of “better separators” that are capable of “shifting the product to a different Packing Group.”[70] Rather, most well sites already stabilize crude oil using conventional equipment operated within the equipment manufacturer’s specifications.

Additional removal of light ends can be achieved with more complex processing units which typically consist of a fired crude oil heater, a distillation column with reboiler, a product cooler, pumps and tankage (“Stabilization Unit”). The material is heated and reboiled in the distillation column to a bottom temperature of 200 °F to 400 °F (depending on the type of crude oil). Light ends (C1 to C5) are boiled overhead and compressed for fuel, condensed into natural gas liquids (“NGL”) and/or transported to a gas processing facility. Stabilization Units are most often used with condensate, which contains an elevated percentage of light ends by volume relative to crude oil, and may be further processed to achieve a mixture of heavier hydrocarbons to meet product composition specifications for commercial purposes. Data from NDPC’s study has shown that crude oil from the Bakken region has a API gravity range in the low 40’s which falls in the range of light crude oil, not condensate. Customized separation and Stabilization Units are selected for each operation based on a number of considerations, including crude composition, customer specifications and geographic location. Installation of a Stabilization Unit demands consideration of the disposition of the product streams, each of which requires significant infrastructure. Pipelines and processing plants must be available to move and further process the recovered light ends.

The primary function of field conditioning is to avoid excessive vapor emissions from storage and transport tanks or meet product specifications for commercial purposes. Removing the light end components can reduce the vapor pressure but the stabilized crude oil will still likely be a Hazard Class 3, PG I/II Flammable Liquid. If a greater portion of the light ends is removed in a stabilization step, the light

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[70] “Hazardous Materials: Enhanced Tank Car Standards and Operational Controls for High-Hazard Flammable Trains,” 79 Federal Register 148 (Aug. 1, 2014) p. 45061.

crude would still contain significant amounts of light gasoline (pentanes, hexanes, and other gasoline components) which has a low flash point. Consequently, if light crude oil were "over-stabilized" to a very low vapor pressure by removing essentially all of the propane (C3) and butanes (C4), the residual "dead oil" would still likely be a PG I or PG II Flammable Liquid.

Since "dead oil" will still likely be a PG I or PG II Flammable Liquid and offerors typically conservatively classify light crude oil as PG I, PHMSA's proposal does not "[provide] additional time for cars to meet the DOT Specification 117 performance standard." [71] Offerors cannot take steps to reduce the "volatility" of the material sufficient to classify the product in a different Packing Group. Field separators are currently used in the field to partially separate "light ends" and crude oil and water, not to achieve the types of reductions contemplated by the rule. In fact, even a more complicated Stabilization Unit cannot achieve this result. Additionally, given the variability in the tests required by DOT regulations for Packing Group assignments, many offerors have taken steps to classify flammable liquids in the most conservative terms to maximize precautions, classifying light crude oil as a PG I.

e. PHMSA Proposed Exceptions

The proposed exception for combustible liquids is not feasible and cannot incentivize producers to reduce the volatility of crude oil for continued use of the existing cars. First, if light crude oil were "over-stabilized" to a very low vapor pressure by removing essentially all of the propane (C3) and butanes (C4), the result would still likely be a PG I or PG II Flammable Liquid. Given the infeasibility of reducing a light crude oil to a combustible liquid, the current exception would not impact offerors of light crude oil. Moreover, the exception allowing offerors to reclassify a flammable liquid as a combustible was eliminated from use with the March 6, 2014 "Amended and Restated Emergency Order" which includes provisions requiring persons who offer bulk quantities of petroleum crude oil for transportation in commerce by rail to treat Class 3 petroleum crude oil as a PG I or PG II hazardous material only. Therefore, no Class 3 crude oil would be affected by the proposed exception. For the same reasons outlined above, the proposed exception for PG III materials cannot incentivize producers to reduce the volatility of crude oil for continued use of existing cars. Last, PHMSA asks what the impacts are on costs and safety benefits of degasifying crude oil to a combustible liquid or PG III level. As stated, even "over-stabilizing" light crude oil would likely not result in a crude oil being classified for transportation below a PG I or PG II.

PHMSA proposes to authorize the continued use of DOT Specification 111 tank cars for combustible liquid service. Due to the lower degree of risk, API recommends that combustible liquids as defined in §173.120(b) should be excluded from the definition of HHFTs.

VII. Conclusion

API stands ready and willing to work with PHMSA and other stakeholders to continue to improve the transportation of crude by rail. API supports a rulemaking that ultimately focuses on two critical issues: improving the safety of rail transportation in North America through a holistic approach and supporting the continued growth of the U.S. energy renaissance.

The transportation of domestic crude oil production by rail is critical to the renaissance of the United States economy and safety is critical to our industry. API stands ready and willing to consider and assess improvements to the transportation of crude by rail that are based on sound scientific, engineering, and cost/benefit principles. API will look forward to discussing these comments with PHMSA in the near future.

[71] "Hazardous Materials: Enhanced Tank Car Standards and Operational Controls for High-Hazard Flammable Trains," 79 Federal Register 148 (Aug. 1, 2014) p. 45061.

IMPACT OF PHMSA PROPOSED REGULATIONS - PETROLEUM COMMODITY TRANSPORT AND COST

ICF International developed an economic impact model to represent the existing fleet and its normal retirement outlook, retrofit and new build costs and capacities and demands for crude, ethanol and petrochemicals moved by rail over the 2014 to 2024 period ("study period"). The model uses these inputs to determine the optimal economic path to meet the proposed regulations. In the event of insufficient qualified railcars, the model utilizes estimated costs of alternative options (pipeline, trucking, shut-in production, etc.) to reflect how the volume displaced by railcar shortages would be managed. The model outputs are used to estimate the broader economic impacts in terms of changes to consumer costs, GDP effects and job effects.

Key drivers of the model results include 1) the capacity to retrofit railcars to PHMSA's proposed Option 1, 2 and 3 standards; 2) the cost and time required to perform the retrofits; 3) the capacity to build new tank cars and their costs; and 4) the demand for crude oil movements by rail in the U.S. and Canada over the study period. Some of the assumptions used in this study differ from those used by PHMSA and lead to a more constrained market for tank car services. For example, we have estimated that the capacity to retrofit rail cars is lower, that the time and cost required to retrofit are greater, and that the demand for crude by rail service will be substantially higher than PHMSA's assumptions and would be even higher if Keystone XL is denied.[1] The ICF model determines the overall transportation cost to the oil/rail industry to deliver crude, ethanol and other flammables to the market in a "Business as Usual"[2] case as well as the three PHMSA proposed options, all under both a scenario that assumes KXL is approved (and operational in 2017) and a second scenario in which KXL is denied and the demand for transporting crude by rail is higher.

The model results indicate that based on input from the rail industry[3] on retrofit and new build capacity, costs and timing, as well as the outlook for increased demand for crude movements by rail from the U.S. and Canada, that the proposed regulations and timing would not be possible without extensive scrapping of the existing legacy fleet in 2018 and 2019. Furthermore, compliance would entail the displacement of substantial volumes of crude oil, ethanol and other flammables on to alternative transportation modes – including trucking – for several years until new build capacity for railcars will allow the movement back to normal rail transport.

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[1] ICF uses RSI's 7-2-2014 retrofit capacity estimate of 5,700 cars per year after a one year ramp-up, cost estimates –based on PHMSA and RSI estimates of individual enhancements- that are 65% to 160% greater than PHMSA's, and estimates of rail car demand which are roughly larger than PHMSA's by 20,000 railcars in 2015 to 40,000 railcars in 2020 (these figures would be even larger if KXL was not constructed).

[2] The "BAU" case assumes the same growth in demand for crude oil by rail (U.S. and Canada) and the same new build and retrofit capacities and costs and fleet retirements as the option cases, but assumes new railcar demands are met by CPC 1232 jacketed railcars.

[3] Railway Supply Institute (RSI) and AllTranstek

The model results indicate that the cost of retrofitting and the limited capacity to retrofit requires that the number of railcars needed to be scrapped or re-purposed is as follows (Table 1):

Table 1 – Railcars Scrapped/Repurposed

Railcars Scrapped or Repurposed	With KXL	Without KXL
Business as Usual	0[4]	0
Option 1	86,457	83,661
Option 2	84,631	83,682
Option 3	71,482	63,267

The inability to retrofit railcars in time for the proposed regulation dates requires substantial volumes of crude oil, ethanol and other flammables to be shifted to alternative, more costly means of transportation or in some cases result in shut-in of crude oil production. The degree of impact increases should Keystone XL be denied, which requires an additional 700,000 barrels per day to be moved by rail above the base forecast increase (See Table 2).

Table 2 – Total Volumes Displaced by Year, in Thousand Barrels per Day (TBD) and Tank Cars (Cars)

	With Keystone XL						Without Keystone XL					
	Option 1		Option 2		Option 3		Option 1		Option 2		Option 3	
Year	TBD	Cars	TBD	Cars	TBD	Cars	TBD	Cars	TBD	Cars	TBD	Cars
2018	177	5,931	162	5,412	200	6,693	250	8,366	250	8,366	144	4,804
2019	530	21,953	467	19,697	198	7,675	1212	46,451	1157	44,379	482	20,359
2020	183	6,131	164	5,477	0	0	454	16,469	396	14,276	178	5,964
2021	0	0	0	0	0	0	85	2,844	5	176	0	0

No*te: This table shows amounts of crude oil and other flammable liquids that were expected to be transported by rail in the U.S. and Canada that will have to be transported by other means (or not produced) due to shortages of complaint rail tank cars. It also shows the minimum number of tank cars that would be needed to move those volumes.*

The volumes which can no longer be moved by rail are alternatively moved by various means, including some crude by pipeline, but the movements are primarily by truck, including as much as 150,000 barrels per day ethanol and 150,000 barrels per day other flammables in the most constrained year (2019). These volumes, as well as a substantial volume of crude oil, must move long distances by truck to replace rail. In addition, for the cases without Keystone, a substantial volume of Canadian crude must be shut in in 2019 and 2020.

The cost implications of each of these cases is substantial versus a BAU case, which is based on meeting increased crude oil demand from the construction of new CPC 1232 jacketed crude cars. The table below summarizes the annualized cost of each option using cost and timing assumptions for retrofits and new builds and forecast commodity demand growth by rail and displaced volume alternatives developed by ICF International (See Table 3). For example, PHMSA's Option 1 has a cost above business as usual of $12.8 billion if KXL is approved and $22.8 billion if KXL is denied.

[4] Excludes normal retirements over the period

Table 3 – Annualized Costs in Million U.S. Dollars, 2014-2024

		Total Annualized Cost			Annualized Cost vs BAU		
Annualized Cost, MM$	BAU	Option 1	Option 2	Option 3	Option 1	Option 2	Option 3
Keystone XL Approved	2,131	14,893	13,771	10,193	12,762	11,640	8,062
Keystone XL Denied	3,574	26,392	24,352	14,076	22,818	20,778	10,502

Note: This table shows the costs of new and retrofitted rail tank cars and, when needed, alternative modes of transportation or the opportunity cost of shutting in production of crude oil. The cost of new and retrofitted tank cars are "annualized" or spread out over the remaining lives of the cars. This tables shows such annualized costs summed only over the years 2014 to 2024 for the U.S. and Canada.

IMPACT OF PHMSA PROPOSED REGULATIONS – PRICES, GDP, AND JOBS

There are several additional impacts the proposed regulations will have on the broader U.S. and Canadian economies. The impacts stem from increased rail transportation costs for crude oil, ethanol and other flammables, and a shift from rail transportation to much more expensive trucking costs and/or periods of shut-in crude, particularly in the critical 2018-2019 period when the proposed regulations begin to require use of new or retrofitted railcars. The shift is required due to the inability to retrofit the existing fleet in time due to limited shop capacity and the time to complete retrofits. The situation will be significantly worse if the Keystone XL pipeline is not approved, as this will require an additional 700,000 barrels per day, intended to be moved by pipeline, to be added to the crude by rail demand.

The higher transport costs for crude will reduce producer netbacks at the wellhead and reduce the incentives to invest in new productive capacity for crude oil. The resulting lower productive capacity, combined with possible transport bottlenecks that may force shut in of productive capacity for some period of time, will reduce U.S. and Canadian oil production. Lower U.S. and Canadian oil production will, in turn, put upward pressure on world oil prices, which could be one source of higher prices for U.S. and Canadian consumers.

The tables below show the expected changes to U.S. and Canadian oil production in barrels per day. The highest impact occurs in 2019 when the combined U.S. and Canadian production declines by as much as 613,000 barrels per day. These reductions in production adversely affect GDP and jobs and they put upward pressure on world oil prices, which the ICF modeling suggests could go higher by as much $1.35/bbl in the peak impact year.

Table 4 – Crude Oil Production Changes 2015-2024

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
U.S. Oil Production Changes (bpd)										
With Keystone XL										
Option 1	-	(1,693)	(3,191)	(7,870)	(17,552)	(26,483)	(31,566)	(34,097)	(35,094)	(34,114)
Option 2	-	(1,693)	(3,191)	(7,870)	(13,630)	(19,236)	(22,686)	(24,313)	(24,874)	(24,767)
Option 3	-	-	-	(3,880)	(9,222)	(12,642)	(14,401)	(15,308)	(15,627)	(15,564)
Without Keystone XL										
Option 1	-	(1,693)	(3,191)	(11,546)	(33,698)	(55,821)	(70,618)	(78,820)	(81,525)	(80,793)
Option 2	-	(1,693)	(3,191)	(11,546)	(33,698)	(55,821)	(70,618)	(78,820)	(81,525)	(80,793)
Option 3	-	-	-	(3,880)	(9,176)	(16,234)	(21,024)	(23,355)	(24,385)	(23,605)
Canadian Oil Production Changes (bpd)										
With Keystone XL										
Option 1	-	(2)	(38,028)	(41,230)	(34,626)	(21,927)	(4,173)	(3,164)	(2,129)	(1,243)
Option 2	-	(1)	(27,660)	(30,021)	(21,421)	(21,395)	(3,214)	(2,440)	(1,641)	(953)
Option 3	-	(1)	(18,675)	(20,497)	(10,498)	-	-	-	-	-
Without Keystone XL										
Option 1	-	(92)	(44,998)	(73,083)	(578,996)	(165,886)	(33,453)	(7,250)	(4,843)	(2,798)
Option 2	-	(93)	(44,998)	(73,082)	(523,160)	(145,681)	(31,070)	(4,697)	(3,121)	(1,801)
Option 3	-	(1)	(27,721)	(30,128)	(21,518)	(21,540)	(3,391)	(2,533)	(1,678)	(966)
U.S. + Can. Oil Production Changes (bpd)										
With Keystone XL										
Option 1	-	(1,696)	(41,219)	(49,100)	(52,177)	(48,410)	(35,739)	(37,261)	(37,223)	(35,357)
Option 2	-	(1,695)	(30,852)	(37,892)	(35,052)	(40,632)	(25,900)	(26,753)	(26,515)	(25,720)
Option 3	-	(1)	(18,675)	(24,378)	(19,720)	(12,642)	(14,401)	(15,308)	(15,627)	(15,564)
Without Keystone XL										
Option 1	-	(1,786)	(48,190)	(84,629)	(612,694)	(221,707)	(104,071)	(86,071)	(86,368)	(83,591)
Option 2	-	(1,786)	(48,189)	(84,628)	(556,858)	(201,502)	(101,689)	(83,517)	(84,646)	(82,594)
Option 3	-	(1)	(27,721)	(34,008)	(30,694)	(37,775)	(24,416)	(25,888)	(26,064)	(24,570)

Other factors that could lead to higher prices for consumers include higher shipping costs for petroleum products and higher shipping costs for ethanol that will be blended into gasoline. Such higher consumer costs reduce spending on non-energy consumer goods and services reducing output and jobs in those sectors. As shown in Table 5 below, potential higher consumer costs for gasoline and other petroleum products are estimated to be in the range of $14.4 to $22.8 billion in the 2015 to 2024 period in the scenario where Keystone XL is approved. In the scenario where Keystone XL is not approved, constraints on crude, petroleum products and ethanol are more severe and so potential consumer cost are estimated to increase even more to the range of $21.0 to $45.2 billion.

Table 5 – Changes to Consumer Costs Summed Over 2015-2024 Period ($Billion vs BAU)

Consumer Cost Changes $b 2015-24	With Keystone XL			Without Keystone XL		
	U.S.	Canada	Total	U.S.	Canada	Total
Option 1	$17.8	$5.0	$22.8	$37.6	$7.6	$45.2
Option 2	$16.6	$4.8	$21.4	$36.4	$7.5	$43.9
Option 3	$12.5	$1.9	$14.4	$16.4	$4.6	$21.0

Note: This table shows the higher cost of gasoline and petroleum products paid by U.S. and Canadian consumers over the period 2015 to 2024. These higher costs reflect higher world oil prices (due to lower U.S. and Canadian crude production), higher costs to move petroleum products to rail-dependent consumer markets and the higher cost of moving ethanol to consumer markets.

The net effect on gross domestic product (GDP) tends to be negative in that gains in some sectors (rail car construction and retrofits, oil pipeline services, barging and trucking) are offset by reductions in crude oil production and non-energy consumer goods. Likewise the effect on employment tends to be negative over the entire period, although the job gains in rail car construction and retrofits are estimated to occur in the early years and are overtaken by job losses when the higher transport costs and constraints are fully felt. The net GDP and job effects are shown in Table 6 and Table 7 for a multiplier effect of 1.3 (representing a tight economy with little slack) and a multiplier effect of 1.9 (representing a looser economy with available labor and capital that can accommodate economic expansion). The net GDP are mostly occurring due to lost production of oil and reach $20.3 billion per year in the peak year under the no-KXL scenario. Peak net job losses could be as high as 97,000 jobs in the no-KXL scenario and occur in oil production and non-energy consumer goods.

Table 6 – GDP Changes 2015-2024

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Lower Bound U.S. + Can. Oil GDP Changes (million U.S. dollars per year, multiplier effect=1.3)										
With Keystone XL										
Option 1	(9)	(676)	(2,537)	(2,818)	(2,947)	(2,864)	(2,658)	(2,725)	(2,787)	(2,773)
Option 2	(8)	(641)	(2,201)	(2,459)	(2,445)	(2,512)	(2,245)	(2,281)	(2,322)	(2,324)
Option 3	(20)	(99)	(1,132)	(1,788)	(1,715)	(1,501)	(1,528)	(1,543)	(1,559)	(1,577)
Without Keystone XL										
Option 1	(10)	(621)	(2,512)	(3,534)	(13,891)	(6,485)	(4,307)	(4,047)	(4,172)	(4,181)
Option 2	(8)	(587)	(2,410)	(3,412)	(12,673)	(5,956)	(4,126)	(3,857)	(3,995)	(4,017)
Option 3	(20)	(59)	(1,391)	(1,989)	(1,949)	(2,040)	(1,794)	(1,838)	(1,878)	(1,853)
Upper Bound U.S. + Can. Oil GDP Changes (million U.S. dollars per year, multiplier effect=1.9)										
With Keystone XL										
Option 1	(13)	(988)	(3,708)	(4,118)	(4,307)	(4,186)	(3,884)	(3,983)	(4,074)	(4,052)
Option 2	(12)	(937)	(3,217)	(3,594)	(3,573)	(3,672)	(3,281)	(3,334)	(3,394)	(3,397)
Option 3	(29)	(144)	(1,655)	(2,613)	(2,507)	(2,194)	(2,234)	(2,255)	(2,279)	(2,304)
Without Keystone XL										
Option 1	(15)	(907)	(3,671)	(5,165)	(20,303)	(9,478)	(6,294)	(5,915)	(6,098)	(6,111)
Option 2	(12)	(858)	(3,522)	(4,987)	(18,522)	(8,705)	(6,030)	(5,638)	(5,839)	(5,871)
Option 3	(29)	(87)	(2,033)	(2,906)	(2,848)	(2,981)	(2,621)	(2,686)	(2,745)	(2,708)

Table 7 – Employment Changes 2015-2024

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Lower Bound U.S. + Can. Oil Employment Changes (number of workers, multiplier effect=1.3)										
With Keystone XL										
Option 1	896	22,391	25,924	10,223	(334)	(10,916)	(13,697)	(16,338)	(13,595)	(16,122)
Option 2	836	20,489	25,993	10,407	(637)	(12,279)	(11,363)	(13,826)	(11,001)	(13,686)
Option 3	676	20,087	28,226	15,759	(17,035)	(10,825)	(8,061)	(10,426)	(7,833)	(9,504)
Without Keystone XL										
Option 1	893	22,449	24,571	(18,399)	(87,372)	(24,035)	(26,372)	(25,520)	(22,916)	(25,464)
Option 2	836	20,602	22,911	(19,736)	(79,990)	(23,686)	(27,983)	(24,926)	(22,172)	(24,825)
Option 3	676	19,816	25,910	(693)	1,738	(10,021)	(9,950)	(12,562)	(9,735)	(12,344)
Upper Bound U.S. + Can. Oil Employment Changes (number of workers, multiplier effect=1.9)										
With Keystone XL										
Option 1	(63)	(4,894)	(18,386)	(20,411)	(21,260)	(20,694)	(19,110)	(19,582)	(20,020)	(19,916)
Option 2	(60)	(4,655)	(16,062)	(17,928)	(17,786)	(18,258)	(16,251)	(16,506)	(16,801)	(16,811)
Option 3	(139)	(898)	(8,662)	(13,280)	(12,733)	(11,256)	(11,292)	(11,398)	(11,519)	(11,637)
Without Keystone XL										
Option 1	(72)	(4,513)	(18,213)	(25,369)	(97,032)	(45,760)	(30,527)	(28,733)	(29,606)	(29,668)
Option 2	(60)	(4,281)	(17,505)	(24,529)	(88,598)	(42,100)	(29,274)	(27,419)	(28,381)	(28,532)
Option 3	(139)	(627)	(10,452)	(14,671)	(14,351)	(14,985)	(13,128)	(13,436)	(13,725)	(13,551)