THE SCHOOL OF PUBLIC POLICY

UNIVERSITY OF CALGARY

MASTER OF PUBLIC POLICY CAPSTONE PROJECT

The Regulatory Compact and the Treatment of Stranded Assets

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Capstone Executive Summary

This paper explores how transaction cost economics supports the regulatory compact and can provide guidance on the proper regulatory treatment of stranded assets. Stranded assets are regulated assets that are no longer used for utility service, but have not been fully depreciated. Traditional rate regulation has limited the amount of stranded asset risk exposure to utilities and pipeline companies. However, recent regulatory decisions in Canada have signaled that regulators may alter the way that they treat stranded costs, based on their interpretation of the *Calgary Stores Block* Supreme Court of Canada decision. Such a change, shifting the risk of stranded assets entirely to shareholders, could result in a major increase in business risk for utilities and energy infrastructure companies, increased rates for services and underinvestment in the industry. An analysis of transaction cost economics illuminates the importance of the regulatory compact, supporting the conclusion that prudently incurred stranded asset costs should be allowed full recovery. The paper ultimately provides policy recommendations for a legislative amendment supported by the economic theory of contracts entrenched in the implicit regulatory compact affecting utilities, regulators and ratepayers.

I. Introduction

The deregulation of the telecommunications, airline, railway and electricity industries has had profound societal implications influencing the regulated firms, consumers and taxpayers. As a result of technological advancements enabling competition in sectors of these regulated markets, economic and legal regulatory theory has had to evolve. An example of this theoretical evolution is the issue of who bears stranded cost risk, the firm's shareholders, the ratepayers or the government (ultimately the taxpayers). The regulatory treatment of stranded assets was extensively debated in academia once the generation sector of the electricity industry was deregulated. Traditionally electric utilities were vertically integrated, the regulators would approve rates based on the costs of providing the service, including generation, transmission, distribution and marketing. Any investments in the electricity sector would be evaluated on demand factors and the prudency standard. Technological advancements in electricity generation enabled competition thus negating the need for regulation in that specific sector of the supply chain.[1] As lower-cost generation suppliers entered the market, the previously regulated assets were rendered obsolete. Under a cost of service regulatory regime these sunk costs were prudently incurred and subject to full recovery, but became non-recoverable once the market was opened to competition.[2] The debate of stranded asset risk is anything but straightforward, it incorporates legal, economic and political factors which influence policy decisions. However, the application of transaction cost economics and contract theory can efficiently resolve the stranded asset issue.

Based on the interpretation of utility property rights established in the *Calgary Stores Block* Supreme Court of Canada decision, recent decisions by the Alberta Utilities Commission (AUC) and the National Energy Board (NEB) have indicated that regulators are shifting from the traditional treatment of stranded assets. The regulators have concluded that any gains or losses from regulated assets are to the account of the utility shareholders. These decisions could have adverse effects impacting the cost of capital of

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[1] Brennan, Timothy and James Boyd. "Stranded Costs, Takings, and the Law and Economics of Implicit Contracts." Discussion Paper 97-02 (1996). Pg. 6-8.

[2] Kahn, Alfred. "Introducing Competition to the Electricity Industry in Spain: the Role of Initial Conditions." Utilities Policy, Vol. 7 (1998). Pg. 15-22.

utilities, increasing rates and potentially deterring future capacity investment. Applying concepts derived from transaction cost economics, this paper argues that due to the required large sunk capital and asset specificity of pipelines and transmission lines (giving rise to opportunistic behavior), the regulator must protect the sunk investments of the regulated firm. Therefore, prudently incurred costs on regulated assets, that are found to be no longer used and useful, should be subject to full sunk cost recovery. Conversely, if the regulated asset, is found to be no longer used and useful and can be sold above net-book value, the proceeds should be allocated to the ratepayers. As the forthcoming sections of the paper will illustrate, the correct interpretation of the implicit regulatory compact supports this proposed framework.

This paper is composed of eight sections. The next section explores the evolution of the rationale for economic regulation from the neoclassical economic view to the new institutional view of transaction cost economics. The third section will define relevant terminology to the stranded asset issue and briefly outline potential recovery mechanisms. Next, the AUC's framework for the treatment of stranded assets will be explained, followed by the NEB's framework. Section six will establish the recommended framework for the regulatory treatment of stranded assets. The subsequent section will provide a case study analyzing the impacts of improper treatment of stranded costs. The eighth section will provide concluding remarks and policy recommendations.

II. Rationale for Economic Regulation

What is the rationale for regulating natural monopolies? To what extent do they need to be regulated? These were questions pondered by economists for several decades. Neoclassical economics first tackled the problem by prescribing price regulation where the goal was to minimize deadweight loss. The new institutional economists have observed how transaction costs impact the organization of certain industries and result in the establishment of specialized governance structures.[3] This section will outline both assessments, helping explain the rationale for economic regulation.

Neoclassical Economic Rationale for Regulation

In a perfectly competitive market the economies of scale are small relative to the market, output is homogeneous, perfect information exists and there are no entry and exit barriers. These assumptions imply that firms are price takers, thus the market sets the price based on supply and demand for the product or service. Firms price at marginal cost and allocative efficiency is satisfied. It is important to note that the mere non-existence of these principles in the market does not in itself justify regulation of the market. In practice, many markets violate some of the perfectly competitive market assumptions. The exercise of market power is contingent on the degree of violation and the extent that these violations persist. A firm has market power when it finds it profitable to raise price above marginal cost. This depends on the extent to which consumers can substitute to other suppliers.[4] Capital-intensive industries such as electric utilities, water utilities and pipelines, enjoy large economies of scale with their construction and operation. They are, in most cases, considered strong natural monopolies.[5] Therefore, these firms face a decreasing average cost making it more efficient to have one firm operating than having

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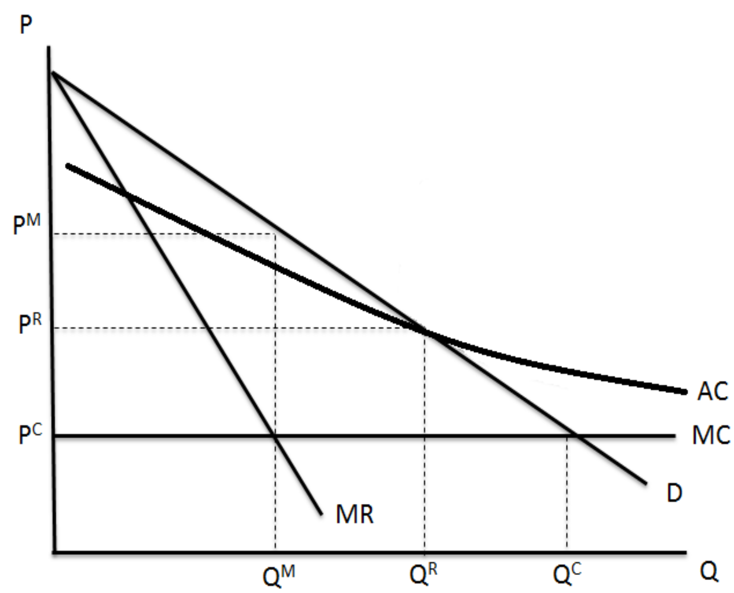
[3] Makholm, Jeff. "The Political Economy of Pipelines: A Century of Comparative Institutional Development." The University of Chicago Press (2012). Pg. 4-6

[4] Church, Jeffrey and Roger Ware. Industrial Organization: A Strategic Approach. New York: McGraw-Hill, 2000. Pg. 29.

[5] It could be the case that a firm is a weak natural monopoly. A weak natural monopoly materializes when economies of scale become exhausted. Thus, a weak natural monopoly faces rising average cost, making it unsustainable to set price equal to average cost and profitable to price at marginal cost (which exceeds average cost). For the purposes of this paper it is assumed that electric utilities and pipeline companies are strong natural monopolists as displayed by the strong natural monopoly model.

multiple firms competing in the market. These strong natural monopolies have cost functions which are characterized as subadditive. This means that, both the marginal cost and the average cost will be declining over the entire range of output, thus multiple firms cannot produce any output more cheaply than a single firm.[6] If the technology of production is subadditive then entry in the market is socially undesirable.[7] So, according to neoclassical theory, regulation is needed to restrict entry in the market and ensure that the natural monopoly does not exercise market power and increase prices, which harms consumers and generates a substantial deadweight loss. This was coined as *the public interest theory of regulation*.

According to the public interest theory of regulation, market failures, such as the creation of a monopoly, can be mitigated through regulation. Regulation can impose pricing constraints so that the outcome is as close as possible to an efficient outcome. Competitive markets are Pareto Efficient and thus both producer and consumer surplus is maximized.[8] Conversely, consider the following strong natural monopoly model:



6 Makholm, Jeff. "The Political Economy of Pipelines: A Century of Comparative Institutional Development." The University of Chicago Press (2012). Pg. 32

7 Church, Jeffrey and Robert Mansell. "Traditional and Incentive Regulation." The Van Horne Institute. 1995. Pg. 38.

8 Church, Jeffrey and Robert Mansell. "Traditional and Incentive Regulation." The Van Horne Institute. 1995. Pg. 33-35.

In this model there is only one producer of the good or service (a single product natural monopoly) and the producer has significant economies of scale (as indicated by the decreasing average cost curve being above the low and constant marginal cost curve). If this was a competitive market, the price would equal the marginal cost of the producer and allocative efficiency would be satisfied. The price level would be P^C and the quantity produced would be Q^C. However, the monopolist refuses to price at marginal cost because the firm would experience negative economic profits and thus would exit the industry. Equipped with market power by being the sole producer of the good, the monopolist can maximize its profits by setting price where its marginal cost equals its marginal revenue, price level P^M. Even though producer surplus increases, represented by the monopoly rent $(P^M - P^C)(Q^M)$, the consumer surplus drastically decreases as now consumers pay more for the good and receive less of it at quantity Q^M. Furthermore, the overall welfare in society decreases as is evident by the existence of the deadweight loss represented by the area:

$$DWL_M = \frac{(Q^C - Q^M)(P^M - P^C)}{2}$$

Therefore, the market left to its own devises will not produce the Pareto Optimal outcome, justifying government intervention in the market. A regulatory body can set the price equal to the firm's average cost and solve this problem. By employing the Ramsey price (setting prices equal to average cost) the regulator transfers some consumer surplus to the firm so that it breaks-even.[9] The price in the market becomes P^R and the quantity produced is Q^R. This is known as second-best pricing, as some deadweight loss still exists, however it is smaller than in the monopoly case:

$$DWL_M = \frac{(Q^C - Q^M)(P^M - P^C)}{2} \quad > \quad DWL_R = \frac{(Q^C - Q^R)(P^R - P^C)}{2}$$

[9] Named after the renowned early twentieth century philosopher, mathematician and economist Frank P. Ramsey.

Thus, welfare increases compared to the monopoly scenario as surplus is efficiently transferred to the firm so that it remains financially viable.[10]

To summarize, it is socially desirable for the regulator to restrict entry in markets where a firm has large economies of scale and subadditive cost functions. Since this restriction results in only one supplier of the good, the regulator must disallow pricing above average cost in order to minimize the deadweight loss in the market. Neoclassical economic foundations have applied mathematical logic to explain cost structures of natural monopolies and welfare impacts of their existence. However, there have been various economic developments that have expanded and challenged the public interest theory of regulation, as Makholm (2012) points out, "*Neoclassical economic theory has a tendency to assume away transaction costs. In a world without transaction costs, decision makers possess perfect foresight. They can effortlessly write complete, uncontroversial, binding contracts. In such a world, economic governance institutions play a neutral role in the efficiency of the productive process. It does not matter whether production is organized via prices in spot markets or within a vertically integrated firm. Such perspectives cannot help but impair the analysis of industries for which such costs are so important.*" The following part will examine the attributes that transaction cost economics has added to the theory of regulation.

<u>Transaction Cost Economics Rationale for Regulation</u>

New institutional economics examines institutions and how they interact within organizational arrangements, by abandoning neoclassical assumptions of perfect information and rationality it has identified the existence of transaction costs to acquiring information. In order to reduce risk and transaction costs, society has established institutions that oversee the writing and enforcing of constitutions, laws, contracts and regulations.[11] Transaction cost economics aims to recognize the variations of characteristics of transactions and how they impact the organizational arrangements that

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[10] Ibid., pg. 49.

[11] C. Menard and M. M. Shirley. "Introduction." Handbook of New Institutional Economics. Springer (2005). Pg.1-18.

govern trade in a capitalist economy.[12] Joskow (1991) defined these organizational arrangements as "*the vertical and horizontal expense of nonmarket organizations, the internal organization of firms, the determinants of the boundaries between firms and markets, and the structure of market transactions*." As it relates to the rationale for regulation, transaction cost economics allows us to focus on the individual sets of transactions between buyers and sellers, recognizing there are various organizational or contractual arrangements that can facilitate trade. Transaction costs are defined as costs associated with negotiating, reaching, and enforcing agreements between buyers and sellers. The Coase Theorem explains that if transaction costs were zero, all contracts would be complete, the gains from trade exhausted and efficiency reached.[13] In practice, transaction costs are not zero, the cost of forecasting uncertainties, writing legally binding contracts, monitoring and enforcing the contract are all substantial. Consequently, the nature of complex contractual transactions makes them incomplete. Herbert A. Simon refers to this as "bounded rationality".[14] Due to human nature's limited mental capacity, the transaction costs associated with complex contracts can never be eliminated, thus the greater the complexity and uncertainty of the transaction, the more costly it is and the more incomplete the contract becomes.[15]

Investment in natural monopolies such as pipelines or transmission lines requires a large sunk investment. Costs become sunk when they are dedicated to specialized productive activities, thus they cannot be used in alternative applications.[16] Capital assets such as pipelines and transmission lines exhibit high degrees of asset specificity, that is to

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[12] Joskow, Paul. "The Role of Transaction Cost Economics in Antitrust and Public Utility Regulatory Policies." Journal of Law, Economics, & Organization, Vol.7 (1991). Pg. 53.

[13] Church, Jeffrey and Roger Ware. Industrial Organization: A Strategic Approach. New York: McGraw-Hill, 2000. Pg. 73.

[14] Williamson, Oliver. "Transaction Cost Economics." Handbook of New Institutional Economics. (2008). Pg.46

[15] Church, Jeffrey and Roger Ware. Industrial Organization: A Strategic Approach. New York: McGraw-Hill, 2000. Pg. 74.

[16] Ibid., pg. 52.

say, that they are relationship-specific investments, which become less valuable if used in an alternative function.[17] Asset specificity fosters opportunistic behavior.

For example, assume a single supplier of natural gas discovers a significant field and needs to transport the gas to the marketplace. A separate company specializing in energy infrastructure can build a natural gas pipeline. Ex ante the two parties can negotiate the terms of trade, one will supply the gas and the other will transport it in exchange for a fee. Ex post, once the pipeline investment is sunk, if the supplier stops producing gas, the pipeline is essentially rendered useless due to its high degree of asset specificity. Moreover, the producer has an incentive to behave opportunistically and refuse to pay the established fee unless it is reduced, thereby expropriating the quasi-rents of its trading partner.[18] The infrastructure company has the same incentives to refuse to transport the gas to market unless the fee is increased, also in an attempt to capture quasi-rents. This risk of having your quasi-rents appropriated by the opportunistic behavior of your trading partner is known as the holdup problem.[19]

Economic literature concludes that the greater the investment idiosyncrasy, the degree of asset specialization required by the transaction, the greater the risk of quasi-rent expropriation.[20] A remedy for the holdup issue is to develop a binding contract between the upstream producer and midstream transportation provider. However, as was previously discussed, the associated transaction costs would be large and the contract likely incomplete, especially considering the lengthy expected life of pipeline assets. Another solution is vertical integration. The upstream producer could build its own pipeline or acquire the infrastructure firm and internalize the transaction costs. In the early twentieth century, most oil and gas companies were vertically integrated, owning all

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[17] Makholm, Jeff. "The Political Economy of Pipelines: A Century of Comparative Institutional Development." The University of Chicago Press (2012). Pg. 80-81.

[18] Quasi-rents are the difference between the value of the asset in its present use, the ex ante terms of trade, and its next best alternative use, its opportunity cost (Church and Ware, pg. 70).

[19] Church, Jeffrey and Roger Ware. Industrial Organization: A Strategic Approach. New York: McGraw-Hill, 2000. Pg. 72.

[20] Makholm, Jeff. "The Political Economy of Pipelines: A Century of Comparative Institutional Development." The University of Chicago Press (2012). Pg. 81.

of the facets of the supply chain. Nonetheless, vertical integration creates other problems. Internal transaction costs are existent as inevitable governance issues arise, it can give rise to anticompetitive incentives, and the final consumers cannot be vertically integrated.[21] Transaction cost economics points to the presence of regulatory agencies as institutions that can administer effective contracts and mitigate the adverse impacts of vertical integration and incomplete contracts.

Instead of two private firms attempting to develop a complete private contract, a regulatory agency can oversee a process that governs the ongoing relationship. Regulation is more efficient than private contracting if there is a large number of consumers served by the firm, and if there is a high degree of uncertainty, investment idiosyncrasy and asset specificity, as is the case with pipelines and transmission lines. The regulator can gather information, negotiate, adjust, monitor and enforce the terms of the long-term relationship between the consumers and the firm.[22] As Church and Ware (2000) point out, this "*least cost governance alternative minimizes the sum of transaction costs and the inefficiencies associated with incomplete contracting, especially those that arise from underinvestment in specific assets.*" The transaction costs are minimized by the regulator providing exclusive rights to serve to the firm, and the firm fulfilling its obligation to provide the service.

Furthermore, the regulator has to control the price and provide pricing flexibility.[23] In order to ensure an efficient level of investment in the industry, the regulator sets prices equal to average cost. Therefore, the regulator places a greater weight on the allowance of cost recovery and cost efficiency than achieving allocative efficiency. Specifically, the regulator approves rates, terms of service, expansions/abandonments, entry in the market and moderates disputes, resulting in

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[21] Biggar, Darryl. "Is Protecting Sunk Investments by Consumers a Key Rationale for Natural Monopoly Regulation?" Review of Network Economics. Vol. 8, Issue 2 (2009). Pg. 144.
[22] Church, Jeffrey and Roger Ware. Industrial Organization: A Strategic Approach. New York: McGraw-Hill, 2000. Pg. 766.
[23] Ibid., pg. 767.

decreased risk and a more efficient level of investment.[24]Many countries apply regulation to solve the holdup problem in the electric and natural gas transmission industry. However, by virtue of the regulator playing such a crucial role in this transactive relationship, it gives rise to potential regulatory holdup.

Regulators, in order to maximize total surplus, have an incentive to expropriate the firm's capital investment. Once a firm has made the sunk investment, the regulator could set rates equal to the firm's operating costs instead of long-run average cost, thereby lowering prices for consumers, increasing demand, output and gains from trade but disallowing the recovery of the firm's sunk investment. However, firms can anticipate this behavior, so they will either demand a higher rate of return to compensate for regulatory risk or not invest at all.[25] This is an outcome that reduces efficiency. History has shown that regulatory holdups affected investment decisions. Prior to World War I, in the United States, the Interstate Commerce Commission refused to allow railroads to raise rates to reflect inflation-related costs. These cost disallowances resulted in bankruptcies and decreases in quality of service, prompting a federal takeover of railroads. Evidence from the United States also shows that historically electric utilities have been reluctant to expand capacity due to regulator cost disallowances.[26]

In order to placate the utilities' trepidation of regulatory expropriation and encourage future investment, regulators must commit not to holdup firms. Legislative requirements to set just and reasonable tolls not only protect the consumers from the regulated firm acting opportunistically, but also protect the firm if the regulator acts opportunistically. In addition, the regulator can build a reputation for allowing the recovery of sunk costs. This reputation is not legislated, but can be examined in the context of the controversial regulatory compact.

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[24] Ibid., pg. 768.

[25] Ibid., pg. 768.

[26] Joskow, Paul. "The Role of Transaction Cost Economics in Antitrust and Public Utility Regulatory Policies." Journal of Law, Economics, & Organization, Vol.7 (1991). Pg. 69.

Regulatory Compact

The concept of the regulatory compact emerged in the twentieth century with respect to utility service provision. Fundamentally, a regulated natural monopoly is given the right to provide an *essential* public service in a specific area with *limited* competition. This service must be provided in a just, reasonable and non-discriminatory fashion. The firm has the *opportunity* to earn a fair return on its investment and recover all prudently incurred costs. Regulators, bound by their legislative statutes, ensure that market power is not abused by the natural monopoly. The regulatory compact attempts to balance the business interests of the firm and public interest of the consumers, by ensuring that the utility recovers its reasonable costs and in turn provides service reliably and economically.[27] In Alberta, utilities are subject to rate regulation, electric transmission and distribution utilities are bound by an obligation to serve and construct electric infrastructure, and section 36(d) of the Gas Utilities Act requires a similar obligation to serve for gas utilities.[28] Despite this obligation, the interpretation of the regulatory compact has been contentious.

Regulated firms tend to interpret the compact as guaranteed protection from any competition and guaranteed recovery of all prudently incurred costs. In contrast, ratepayers perceive it as protection from a natural monopoly's ability to exercise market power.[29] The Courts have described the "compact" as an evolving concept that is shaped by changes in economics, demographics, technology and policy.[30] Rose (1996) through his examination of the origins and content of the regulatory compact concluded that there is "*little basis for the claim that utilities are always entitled to cost recovery and a return on their investments. Indeed, a strong argument could be made that to be consistent with past treatment and the manner in which the compact has been interpreted by many states, full recovery of transition costs is what would be inconsistent. There is no "entitlement"*

[27] Ibid., pg. 67-68.

[28] Concentric Energy Advisors. "Stranded Cost Treatment for Alberta Utilities." January 16, 2013. Pg. 14.

[29] Rose, Kenneth. An Economic and Legal Perspective on Electric Utility Transition Costs. The National Regulatory Research Institute. July 1996. Pg. 42.

[30] The Court of Appeal of Alberta, FortisAlberta Inc v Alberta (Utilities Commission), 2015 ABCA 295. Pg. 3, para [10] – [12].

to "stranded" costs expressed or implied by the regulatory compact. The only entitlement granted was the revocable privilege to serve an exclusive territory. The obligation to serve stems from this privilege. The compact is not an agreement to pay all costs (prudent or otherwise) because of the obligation to serve. It is much more complex than simply - I am obligated to serve, therefore customers are obligated to pay all my costs." Contrary to Rose (1996), Sidak and Spulber (1996), explained that the regulatory compact warrants compensation for stranded costs arising from competition, while outlining entry controls, rate regulation and utility service obligations as the three main components of the regulatory compact. Baumol, Joskow and Kahn (1994) have perceived the regulatory compact as a contractual relationship that imposes a burden on utilities and an obligation on the state in a manner identical to a contract between private parties. Brennan and Boyd (1996) explain that due to the extreme cost of writing ex ante contracts that cover all future contingencies, judicial interpretation ex post is necessary. This interpretation should consider which party could best adapt to or insure against the risk that such a contingency could materialize.[31] Due to the fact that the regulatory compact is not legislatively defined, they label it as a "synonym for implicit contract."[32] Therefore, the compact is by no means a concrete concept, its interpretation and application varies with different agents, including the utilities, consumers, regulatory jurisdictions, and courts.

Since the regulatory compact was never officially legislated in writing, instead it has developed through various court cases and regulatory decisions, the compact should not be perceived as an explicit rule.[33] Rather it should be accepted as a broad regulatory contract, bargain or agreement, which allows for the re-balancing or re-negotiation of the terms of trade as circumstances change. By subscribing to the terms of the compact, the regulator can enhance its reputation of not expropriating the firm's investment. Breakdowns of the regulatory compact can have serious consequences such as "takings"

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[31] Brennan, Timothy and James Boyd. "Stranded Costs, Takings, and the Law and Economics of Implicit Contracts." Discussion Paper 97-02 (1996). Pg. 4.
[32] Ibid., pg. 12.
[33] Ibid., pg. 42.

of investors' property or regulatory holdup.[34] [35] Joskow (1991) has observed the following scenarios in which the regulatory compact breaks-down:

- excess capacity (driving average rates up when market conditions would imply that they should go down);
- when there is rapid inflation and high nominal interest rates (front-loading capital charges);
- when there is rapid cost-reducing or quality-improving technology (stranding undepreciated rate-base investment);
- when cross-subsidization that discriminates against large customers with good substitution possibilities is amplified by adverse cost-accounting realizations;
- when buyers are permitted to bypass the utility to take service at regulated rates from a proximate utility; and
- when competitors are allowed to enter the market to exploit differences between regulated rates and the stand-alone costs of providing subsets of services.[36]

The regulatory compact depends heavily on the absence of competitive alternatives and stable economic conditions, therefore its inherent instability and fragility increases the likelihood of a breakdown, resulting in regulatory hold-up.[37] As will be evident in forthcoming sections of this paper, the breakdown of the regulatory compact can have significant adverse effects on both the utility shareholders and the ratepayers. But first it is useful to examine some alternative theories of regulation that arose form transaction cost economics, which progress our understanding of the regulator's role in this transaction-specific relationship.

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[34] The term "takings" is from the Fifth Amendment of the U.S. Constitution, it states that private property shall not be taken for public use without just compensation (Brennan and Boyd, 1996).
[35] Garcia-Martin, Jose Antonio. "Stranded Costs: An Overview." Centre for Monetary and Financial Studies Working Paper No 0108. June 2001. Pg. 12.
[36] Joskow, Paul. "The Role of Transaction Cost Economics in Antitrust and Public Utility Regulatory Policies." Journal of Law, Economics, & Organization, Vol.7 (1991). Pg. 73.
[37] Ibid., pg. 73.

Alternative Theories of Regulation

Stigler (1971) in "The Theory of Economic Regulation" rationalized that since all economic actors are self-interested and seek to maximize their utility, the regulators must want to also maximize their own utility. [38] If, according to the public interest theory, we define a regulator's objective function as a maximization of consumer surplus and producer surplus, it will be reflected in the following manner;

$$U = CS + \alpha PS$$

The nonnegative variable α, determines the amount of influence consumers or firms will have on the regulator.[39] Stigler would argue that $\alpha > 1$, thus the regulator seeks to increase producer surplus. He explains this occurrence as capture theory, where the regulator can no longer be assumed to act in the public interest. Instead regulation institutes favorable business conditions for regulated firms to operate in, by providing them with subsidies, creating entry barriers, regulating prices and discouraging competition from substitute products. In return the firms can provide the politicians with funding and votes.[40] Therefore, the regulator becomes captured by the firms it is supposed to regulate.

Posner (1971) supplemented Stigler's analysis, by observing that regulation can also be used to distribute income among various consumer pressure groups. The regulator can achieve this distribution through cross-subsidization.[41] Conversely, a regulatory body could have an incentive to transfer surplus from producers to consumers. It could be the case that legislators are dependent on votes from specific constituencies that make up the regulated firm's customers. In this scenario, $\alpha < 1$. The regulator can accomplish this

[38] Stigler, George. "The Theory of Economic Regulation." The University of Chicago (1971).
[39] Guthrie, Graeme. "Regulating Infrastructure: The Impact on Risk and Investment." Journal of Economic Literature (2006): 925-972. Pg. 31.
[40] Church, Jeffrey and Roger Ware. Industrial Organization: A Strategic Approach. New York: McGraw-Hill, 2000. Pg. 769.
[41] Ibid., pg. 770.

transfer of surplus by setting output prices such that the regulated firm cannot recover its sunk costs.[42]

Biggar (2009), by analyzing empirical evidence, offered that the role of regulation is to protect the sunk investments made by the customers of the regulated firm. In Biggar's view, this explains why regulators continuously reject polices which would minimize deadweight loss such as marginal cost pricing, discriminatory pricing and Ramsey pricing, and instead encourage policies such as incremental tolling and pricing stability.[43] Extensive analysis of institutional economics has allowed the discipline to conclude that firms and consumers can demand regulation in order to maximize their individual utility, and the state, with its monopoly on legal coercion, supplies this regulation.

Priest (1992) explains the rationale for regulation in terms of voluntary exchange and contractual adaptation. Priest stated that, "*the motivation for the regulation of public utilities is more mundane than either the idealistic basis of the public interest theory or craven basis of the economic or capture theories.*"[44] According to Priest, utilities voluntarily accepted regulation in order to gain access to public rights-of-way. Both the municipal government and the utilities recognized that regulation would result in a reduction of transaction cost associated with long-term private contracting.[45] Further, Joskow (1991) elucidated on the evolution of regulation:

> *The evolution of public utility rate-making and accounting rules bears little if any relationship to the traditional static second-best pricing problem that appears in the academic literature. Instead, the evolution of these accounting and rate-making rules is more closely related to the standard transaction cost economics problem of finding a set of contracting rules that will induce efficient levels of investment,*

[42] Guthrie, Graeme. "Regulating Infrastructure: The Impact on Risk and Investment." Journal of Economic Literature (2006): 925-972. Pg. 32.

[43] Biggar, Darryl. "Is Protecting Sunk Investments by Consumers a Key Rationale for Natural Monopoly Regulation?" Review of Network Economics. Vol. 8, Issue 2 (2009). Pg. 130-136.

[44] Priest, George. "The Origins of Utility Regulation and the Theories of Regulation Debate." 36 J.L. & Econ. 289, 303 (1992).

[45] Ibid., pg. 303-304.

> *guard against holdups to support these investments, and provide for efficient adaptation to changing economic conditions. The development of twentieth century public-utility accounting and pricing rules was heavily influenced by concerns about encouraging efficient investment, supporting those investments with an adequate but not excessive stream of cash flows, and encouraging efficient operation of capital facilities. It was much less concerned with setting prices that matched exactly changing supply and demand conditions at every point in time.*[46]

Regulators are practically and politically minded people. Therefore, they seek to balance the interests of effectively organized groups. In Canada, that entails both the regulated firm and its consumers. If applied properly, the regulatory compact has the ability to act as a contractual tool to strike this balance and minimize transaction costs. Ex ante it can minimize negotiating and drafting costs, while ex post it minimizes the costs of unintended consequences of contract formulation and opportunistic behavior. Transaction cost economics prescribes this implicit regulatory contract as a means to safeguarding the recovery of sunk costs and thus minimizing the probability of a holdup. Regulators would be wise to comprehend and embrace it.

[46] Joskow, Paul. "The Role of Transaction Cost Economics in Antitrust and Public Utility Regulatory Policies." Journal of Law, Economics, & Organization, Vol.7 (1991). Pg. 70.

III. Relevant Terminology

This section will define some key regulatory concepts that will be used throughout this paper and briefly outline certain stranded cost recovery mechanisms.

Used and Useful Standard

An asset is found to be used and useful when it is actually being used to provide service and it is contributing to the provision of utility service.[47] The AUC has perceived the words "used or required to be used" in Section 37 of the Gas Utilities Act, as "*assets that are presently used, are reasonably used, and are likely to be used in the future to provide services.*"[48] The Commission further explained that if assets are used in an "operational sense" they are considered used and useful.[49]

This public interest and fair value theory[50] implies that assets which are no longer used and useful should be removed from rate base,[51] because consumers should not have to pay for something that is not employed for the provision of service.[52] The Commission agrees with this interpretation stating, "*the past or historical use of assets will not permit their inclusion in the rate base unless they continue to be used in the system*."[53]

Prudently Incurred Cost

A regulatory rule for allowable cost recovery, that considers the prudence of the original investment in assets in terms of the market circumstances and knowledge of the utility at the time of the investment.[54] The regulator assesses the prudency of the costs and approves items which are included in rate base for full recovery in conjunction with a

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[47] Jamison, Mark. Rate of Return: Regulation, University of Florida. Pg. 13.
[48] AUC Decision 2013-417. Utility Asset Disposition Proceeding. Pg. 33.
[49] Ibid., pg. 82.
[50] Fair value theory stems from the concept that ratepayers should be subject to just and reasonable rates. These rates must be non-discriminatory, meaning that, under substantially similar circumstances and conditions with respect to all service of the same description and over the same route, the rates be charged equally to all persons at the same rate.
[51] Rate base is the value of the assets that are used for the provision of service.
[52] Hoecker, James. Used and Useful: Autopsy of a Ratemaking Policy. Pg. 306.
[53] AUC Decision 2013-417. Utility Asset Disposition Proceeding. Pg. 33-34.
[54] Ontario Court of Appeal, Enbridge Gas Distribution Inc. v Ontario Energy Board (2006) 10 OAC 4 (Ont CA). Pg. 4, para [10].

depreciated original cost accounting system.[55] Once the revenue requirement is established, tolls are calculated and they act as the cost recovery mechanism for the provision of service.[56]

Stranded Asset

A stranded asset, also commonly referred to as stranded cost, stranded investment, stranded commitment or transition cost, is one that has lost its usefulness before the end of its depreciation period or expected economic life.[57] This predicament usually occurs due to extraordinary events, such as force majeure or market outcomes, leading to obsolescence and not routine retirement of the asset. Stranded assets can encompass both assets outside the course of ordinary business and assets that are used directly for the provision of the specific service. The Commission stated that this may include assets such as; obsolete property, property to be abandoned, overdeveloped property and facilities for future needs, and property used for non-utility purposes and surplus land.[58]

Therefore, stranded costs occur when a utility is unable to recover its fixed cost and related return on prudently invested capital in the stranded asset.[59] [60] This can arise as a result of changes in law, regulatory policy, market conditions, asset lives or asset productivity.[61] Similar to the contentious interpretation of the regulatory compact, stranded assets are perceived differently between utilities and ratepayers. Utilities believe that a stranded asset is one whose costs were prudently incurred and are recoverable

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[55] Joskow, Paul. "The Role of Transaction Cost Economics in Antitrust and Public Utility Regulatory Policies." Journal of Law, Economics, & Organization, Vol.7 (1991). Pg. 71.

[56] Revenue requirement is the amount of revenue that needs to be collected for the firm to cover its costs and a fair return on capital.

[57] Garcia-Martin, Jose Antonio. Stranded Costs: An Overview. Centre for Monetary and Financial Studies Working Paper No 0108. June 2001. Pg. 5.

[58] AUC Decision 2013-417. Utility Asset Disposition Proceeding. Pg. 77.

[59] Garcia-Martin, Jose Antonio. Stranded Costs: An Overview. Centre for Monetary and Financial Studies Working Paper No 0108. June 2001. Pg. 1.

[60] The Court of Appeal of Alberta, FortisAlberta Inc v Alberta (Utilities Commission), 2015 ABCA 295. Pg. 4-5, para [20] – [23].

[61] Concentric Energy Advisors. "Stranded Cost Treatment for Alberta Utilities." January 16, 2013. Pg. 6.

under a regulated environment, but not recoverable under a competitive environment.[62] Whereas ratepayers observe stranded assets as assets that are no longer used and useful and should therefore be removed from rate base.

Kahn (1998), defined stranded cost compensation as "*the remuneration of sunk costs incurred in a regulated regime, but not recoverable after the market has been opened to competition.*"[63] Sidak and Spulber, define stranded costs as "*the difference between the public utility's net revenue requirement under regulation and entry controls, and the net revenues earned by the utility from those stranded facilities in the competitive market.*"[64] The next part of the paper will briefly examine some potential stranded cost recovery mechanisms.

Cost Recovery Mechanisms

The purpose of this paper is not to assess the differences in equity and efficiency of previously proposed stranded cost recovery mechanisms, see Garcia Martin (2001) for a comprehensive analysis. However, it is important to provide a short overview of potential mechanisms that have been applied to stranded cost recovery, as they will be referred to throughout the paper.

A theoretical approach, which will be further explained in the recommended framework section of this paper, is for the regulator to allow the firm to engage in Ramsey pricing, since this price discrimination is an efficient mechanism for cost recovery.[65] This would enable the firm to achieve its revenue requirement while minimizing deadweight loss. An alternative, indirect method of salvaging stranded costs would be to establish a securitization mechanism. Securitization has been previously

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[62] RH-003-2011 National Energy Board Reasons for Decision. March 2013. pg. 28.

[63] Garcia-Martin, Jose Antonio. Stranded Costs: An Overview. Centre for Monetary and Financial Studies Working Paper No 0108. June 2001. Pg. 1.

[64] Sidak, Gregory & Spulber, Daniel. "Deregulatory Takings and Breach of the Regulatory Contract." 71 N.Y.U.L.Rev.851 (1996). Pg.921-922.

[65] Ramsey pricing involves the shifting of costs from shippers who face an elastic demand to shippers facing an inelastic demand. Such that, the inelastic demand market would face higher prices. This pricing scheme minimizes the loss in total surplus, since raising price in an inelastic market is more efficient than uniformly raising prices in all markets.

utilized, particularly in the deregulation of electricity markets.[66] It has been applied on more than 50 occasions in the United States and Canada over the past 15 years.[67] It is a mechanism that lowers the cost of capital through government-sponsored debt covering all the financing requirements of the utility's assets. Securitization requires government legislation, which would oblige the regulator to pass a financing order, creating a Special Purpose Entity to issue securitization bonds.[68] Subsequently, a surcharge, acting as a collection mechanism, would be imposed on ratepayers to feed into the Special Purpose Entity and service the securitization bonds, effectively recouping stranded asset costs.[69] The result of securitization is the same as Ramsey pricing, in the sense that shareholders will not be impacted, but the remaining inelastic system ratepayers will shoulder the stranded asset cost through the additional rate surcharge.

Various economists have suggested applying a two-part tariff over unit cost recovery.[70] The efficient access fee would be S/n per period per customer, where n represents homogenous consumers and S is the amount of stranded costs.[71] An additional proposition could be implementing an exit fee. Exit fees would be imposed on any consumers who want to de-contract, the fees are in-effect until the value of the asset is recovered. This would place the burden of stranded asset risk on precisely those consumers who are causing the asset to become stranded by de-contracting. In Order 888, the Federal Energy Regulatory Commission (FERC) approved an exit fee that was equal to the estimated utility revenue shortfall as a result of de-contracting.[72]

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[66] Michaels, Robert. Securitized Transaction Costs: Rethinking Who Wins and Who Loses. The Electricity Consumers Resource Council. 1998. Pg. 1-2.

[67] Concentric Energy Advisors. "Stranded Cost Treatment for Alberta Utilities." January 16, 2013. Pg. 19.

[68] RH-003-2011, TransCanada Pipelines Response to NEB Information Request 3.1 (b). February 6, 2012.

[69] RH-003-2011 National Energy Board Reasons for Decision. March 2013. pg. 46.

[70] A two-part tariff includes a combination of a fixed fee (access fee) and a per unit price (the usage charge).

[71] Garcia-Martin, Jose Antonio. Stranded Costs: An Overview. Centre for Monetary and Financial Studies Working Paper No 0108. June 2001. Pg. 29.

[72] Order No. 888 Federal Energy Regulatory Commission. Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities and Recovery of Stranded Costs by Public Utilities and Transmitting Utilities. Docket No. RM95-8-000 and Docket No. RM-94-7-001. April 24, 1996.

A simple option would be for the government to provide a direct transfer of funds to the utility equivalent to the value of the stranded asset. Ultimately this is an income tax recovery mechanism, which spreads the cost of stranded assets to the rest of society.[73] To properly comprehend the impact of an income tax transfer from the regulator to the firm, it is useful to analyze the change in welfare. As outlined in the previous section a regulator's objective function attempts to maximize both consumer and producer surplus, where:

$$U = CS + \alpha PS$$

If stranded assets are retained in rate base and Ramsey pricing is employed, the welfare function would be as follows:

$$W_1 = v(p) + \alpha[(p - c)*q(p) - F]$$

where v(p) is the consumer surplus, and the producer surplus is reflected by the firm's profit.[74] Now, suppose that the regulator is going to make a transfer to the firm equivalent to its stranded asset value. Since there is a deadweight loss associated with income tax transfers, (λ) will denote the social cost of public funds. Therefore, the new welfare function will be:

$$W_2 = v(p) - (1 + \lambda)T + \alpha[(p - c)*q(p) + T - F]$$

where T is equal to the transfer the firm receives from taxpayers, in this case the value of the stranded asset.[75] It is observed that $W_1 > W_2$. Therefore, an income tax transfer will result in *decreasing* consumer surplus and *increasing* producer surplus. However, the

73 Garcia-Martin, Jose Antonio. Stranded Costs: An Overview. Centre for Monetary and Financial Studies Working Paper No 0108. June 2001. Pg. 29.

74 Profit is the difference in the firm's revenue and costs (marginal and fixed costs).

75 Armstrong, Mark and David E. M. Sappington. "Developments in the Theory of Regulation." October 2005. Pg. 6-10.

policy decreases total surplus, as the deadweight loss created by taxation reduces welfare, theoretically violating the public interest mandate of the regulator.

Generally utility and energy infrastructure regulators have dealt with stranded asset costs as follows:

i. Identifying That an Asset is No Longer Used and Useful
   - The utility and the regulator determine certain assets are no longer required for the provision of service.

ii. Treatment of Stranded Asset
   - The Regulator must decide between three options of dealing with the asset:
     a. Retain the asset in rate base, allowing full recovery of depreciation and return.
     b. Remove the asset from rate base but allow continued recovery of at least depreciation and sometimes partial return by employing a recovery mechanism such as securitization.
     c. Deem the asset to be stranded, remove it from rate base and disallow any further cost recovery.

Traditional regulatory precedent has been option (a) or (b) above. However, recent regulatory decisions have indicated a shift in policy by enacting option (c), which poses new business risk to utilities.

IV. AUC Framework for Treatment of Stranded Assets

The treatment of stranded costs has historically been very controversial and expensive for both utilities and regulators. The level of complexity is exacerbated due to the involvement of conflicting objective functions between legislators, regulators, firms and ratepayers all attempting to impose their perspectives on issues of equity, efficiency and policy implementation.[76] Thus, the legislative history related to the stranded asset issue is quite cumbersome. This section will only focus on the legislative background and precedent in Alberta, which involves many actors including various Alberta Utilities, the City of Calgary, the Alberta Utilities Commission, the Court of Appeal of Alberta and the Supreme Court.

Development of Existing Legal Precedent

Prior to the precedent setting *Stores Block* Supreme Court decision, the regulator was able to distribute proceeds from the sale of a utility's asset according to the regulator's public interest mandate. The regulator would enforce the principle that all gains and losses on the disposition of utility assets were for the account of ratepayers.[77] Thus, there have been instances where utility customers were awarded all of the gains from the disposition of an asset.[78] Eventually, the TransAlta Formula was established and it allowed a division of gains between ratepayers and shareholders. [79] The regulator applied the TransAlta Formula once it was proven that the disposition of the asset would not cause harm to existing ratepayers (no harm test). However, if there was no financial gain on the sale of the asset, the utility would simply receive proceeds equal to the net book value of the asset. If the market value of the asset was less than the net book value,

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[76] Garcia-Martin, Jose Antonio. Stranded Costs: An Overview. Centre for Monetary and Financial Studies Working Paper No 0108. June 2001. Pg. 3.

[77] AUC Decision 2013-417. Utility Asset Disposition Proceeding. Pg. 83.

[78] The Regulator would apply the "no-harm test" to ensure that ratepayers were not adversely affected by the transaction. If the transaction caused harm, then the regulator would deny the application or offer the entire gains to the ratepayers as compensation.

[79] The Court of Appeal of Alberta, FortisAlberta Inc v Alberta (Utilities Commission), 2015 ABCA 295. Pg. 9, para [39].

ratepayers would continue to incur the loss. Thus, the regulator applied rational allocation procedures to deal with extraordinary asset dispositions.[80]

In 2001, ATCO Gas (AG) filed an application with the Alberta Energy and Utilities Board (EUB, predecessor of the AUC) for the approval of the sale of certain properties located in Calgary, known as Stores Block. The properties consisted of land and buildings, which were found to be no longer used and useful for the provision of service. The sale passed the no harm test and the market value of the land exceeded the net book value. AG proposed to distribute the entire proceeds from the sale to its shareholders, as the ratepayers would enjoy reduced rates due to the retirement and removal from rate base of the remaining book value of the sold assets.[81] However, the City of Calgary argued that customers should receive a portion of any gains from the sale. The Board decided to allocate the sale proceeds so that about one-third of the net proceeds went to AG and two-thirds to the ratepayers, in accordance with the TransAlta Formula.[82]

In response, AG appealed the decision to the Alberta Court of Appeal. The Court ruled that the EUB did not have jurisdiction to allocate the sale proceeds from the private property of a utility.[83] Subsequently, the City of Calgary obtained leave to appeal the Alberta Court decision to the Supreme Court.[84] In what became known as the *Calgary Stores Block* Decision, the Supreme Court, with a narrow 4-3 majority, also determined that the Board did not have the proper authority to alter the distribution of proceeds from the sale of a utility's private assets.[85]

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[80] Ibid., pg. 10, para [41].

[81] Supreme Court of Canada, ATCO Gas & Pipelines Ltd. *v.* Alberta (Energy & Utilities Board), [2006] 1 S.C.R. 140, 2006 SCC 4. para [8].

[82] Ibid., para [17].

[83] Ibid., para [18].

[84] Ibid., para [6].

[85] Stikeman Elliott LLP, Energy Law Update, *Supreme Court Limits Regulator's Jurisdiction over Proceeds of a Discarded Utility Asset Sale*, March 2006, pg.2

In 2008, the AUC commenced the Utility Asset Disposition (UAD) proceeding, which was intended to consider the potential rate related implications for Alberta utilities arising from the *Calgary Stores Block* Decision.[86] After a lengthy suspension of the proceeding due to outstanding Alberta Court of Appeal decisions,[87] the AUC re-commenced the Utility Asset Disposition proceeding on October 17, 2012, with the intention of establishing whether it is the utility or ratepayers that bear the risk of stranded assets.[88] Prior to analyzing the outcome of the UAD Decision, it is important to understand the perspective that the Alberta regulator had in regards to stranded asset risk. Due to the *Stores Block* precedent, various utilities challenged the Commission's rulings in regards to the traditional treatment of their assets. Thus, the Alberta Court of Appeal considered a number of cases that referenced *Stores Block*, the following table summarizes the major rulings.

Application	Regulator Ruling	Court of Appeal Ruling
Carbon (Decision 2007-005) – Following the deregulation of natural gas prices, ATCO Gas wanted to exclude a natural gas storage facility from its rate base, as all uses for the facility other than revenue generation were discontinued.	The EUB determined that the asset was still used and useful due to the fact it generated revenues and thus should remain in rate base.	The Court ruled that the EUB erred in law or jurisdiction because the asset no longer provided regulated service in an "operational sense." It stated that *Stores Block* supports the conclusion that ratepayers are not entitled to unregulated utility revenues. Thus, ATCO Gas was allowed to exclude the storage facility from rate base and enjoy the revenues generated from the asset.
Harvest Hills (Decision 2007 -	The EUB applied the no harm test	The Court ruled that according to

[86] AUC Decision 2013-417. Utility Asset Disposition Proceeding. Pg. 1.

[87] Leave to Appeal the Harvest Hills Decision and the Salt Cavern Letters was granted on November 12, 2008 in two separate decisions (ATCO Gas and Pipelines Ltd. v. Alberta (Energy and Utilities Board), 2009 ABCA 171, and ATCO Gas and Pipelines Ltd. v. Alberta (Utilities Commission), 2009 ABCA 246). *Carbon, Harvest Hills, Salt Caverns I and II* all sourced *Stores Block* as precedent in front of the Court of Appeal of Alberta to overturn the Regulator's initial decisions.

[88] AUC Decision 2013-417. Utility Asset Disposition Proceeding. Pg. 4, para [10].

101) – ATCO Gas was seeking to subdivide certain lands, it proposed that the portion used for utility purposes remain in rate base, while the remaining portion would be sold and proceeds allocated to the shareholders.	and found that financial harm would result to customers. Thus, it ruled that the proceeds should be placed in a deferral account and the disposition of it would be considered in the next rate case.	the principles established in *Stores Block*, the EUB is not allowed to appropriate the sale proceeds in order to subsidize rates. ATCO was allowed to sell the land and keep the proceeds.
Salt Caverns I and II (ATCO Pipelines 2008-2009 GRA) – ATCO Pipelines unilaterally excluded from rate base a portion of the assets comprising its salt cavern natural gas storage facility.	The AUC ruled that this unilateral exclusion constituted a disposition outside the ordinary course of business, requiring prior approval from the regulator. The Commission ordered ATCO to file an official application.	The Court ruled that the AUC once again violated its jurisdiction. It ruled that a unilateral withdrawal of an asset, found to be no longer used and useful, from rate base, without an accompanying sale, was not a disposition and does not require regulatory approval.

As a result of *Stores Block* and subsequent court decisions limiting and curtailing the regulator's legislative powers, the AUC established a set of 19 principles in its UAD Decision,[89] leading to the conclusion that utility shareholders are at risk for all stranded assets, and not the ratepayers. [90] Therefore, once an asset is considered no longer used and useful, it must be removed from rate base regardless of its remaining depreciation level. Hoping that the Court of Appeal would again overturn another AUC decision, the Alberta Utilities[91] appealed the Commission's UAD Decision. The Alberta Utilities attempted to challenge the legislative powers of the AUC in making such a drastic policy decision. The appellants stated that the Commission's interpretation and application to stranded assets subverts an established statutory principle of prudent cost recovery.[92] However, this time the Court of Appeal sided with the regulator and gave higher weight

89 See Appendix B.

90 Ibid., pg. 32, para [102].

91 Consists of 5 Electric Utilities (ATCO Electric, Enmax Power, EPCOR Distribution & Transportation, FrotisAlberta, AltaLink Management) and 2 Gas Utilities (ATCO Gas & Pipelines, AltaGas Utilties).

92 The Court of Appeal of Alberta, FortisAlberta Inc v Alberta (Utilities Commission), 2015 ABCA 295. Pg. 23, para [97].

to deference of the regulator's expertise in setting just and reasonable tolls.[93] Specifically, Justice Paperny concluded:

> In my view, the UAD decision represents a reasonable approach that is well within the statutory authority vested in the Commission and also one that is in keeping with the jurisprudence from the Supreme Court as further interpreted by this Court. Even in the absence of that jurisprudence, the legislation clearly gives the Commission the authority to make this particular choice. It is not a foregone conclusion that the Commission would have chosen to treat stranded assets differently in the absence of the *Stores Block* line of cases[94]… The entitlement to an opportunity to recover prudently incurred costs under this regime is not a guarantee. A policy that excludes stranded assets from rate base is not a derogation from the Commission's statutory powers if that policy is necessary to further the ultimate objective of the legislation - to achieve just and reasonable rates. Having regard to the legislation and the law of this province as set out in *Stores Block* and subsequent decisions of this Court, the conclusion reached by the Commission on this issue cannot be said to be unreasonable.[95]

For a more detailed, chorological explanation of events leading to the Alberta Court of Appeal Decision in regards to the Utility Asset Disposition proceeding, refer to Appendix A.

<u>Applicable Law to Stranded Assets in Alberta</u>

The primary piece of legislation outlining the Commission's statutory power related to stranded assets is the Gas Utilities Act (GUA). Specifically section 26(2) of the GUA states:

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[93] It should be noted that at the time of writing this paper, the Alberta Utilities are seeking a leave from the Supreme Court to appeal the Alberta Court of Appeal decision.

[94] Ibid., pg. 39, para [148].

[95] Ibid., pg. 44, para [169] and [170].

26 (2) No owner of a gas utility designated under subsection (1) shall

. . .

(d) without the approval of the Commission,

(i) sell, lease, mortgage or otherwise dispose of or encumber its property, franchises, privileges or rights, or any part of it or them, or

(ii) merge or consolidate its property, franchises, privileges or rights, or any part of it or them, and a sale, lease, mortgage, disposition, encumbrance, merger or consolidation made in contravention of this clause is void, but nothing in this clause shall be construed to prevent in any way the sale, lease, mortgage, disposition, encumbrance, merger or consolidation of any of the property of an owner of a gas utility designated under subsection (1) in the ordinary course of the owner's business.[96]

The Public Utilities Act contains an analogous provision pertaining to electric utilities.[97] The utilities argued that s 26 should be interpreted as a "secondary power" which only deals with exceptional circumstances and is outside the primary mandate of the regulator, which is to set just and reasonable tolls. The appellants further claimed that this Section only applies to the net gains on disposition of assets determined to be in excess of the utility's requirements and not to the recovery of prudently incurred costs.[98] The Court disagreed and stated that s 26 must be interpreted as part of the entire legislation, confirming it is an additional power that provides the Commission another tool to satisfy its public interest mandate.[99]

The utilities challenged the Commission's ratemaking powers by attempting to restrain them to s 36 and s 37 of GUA. The appellants allege that the UAD Decision

[96] Gas Utilities Act, RSA 2000, c G-5. Designated Gas Utilities, Section 26(2).
[97] The Court of Appeal of Alberta, FortisAlberta Inc v Alberta (Utilities Commission), 2015 ABCA 295. Pg. 9, para [37].
[98] Ibid., pg. 35, para [133].
[99] Ibid., pg. 35, para [134].

violated the regulatory compact. According to the gas utilities, s 36 and s 37 outline the regulatory compact, which permits them to earn a return on their capital, and all prudently incurred costs in all circumstances.[100]

> **Section 36 – Powers of Commission**
> The Commission, on its own initiative or on the application of a person having an interest, may by order ...
> (a) fix just and reasonable individual rates, joint rates, tolls or charges or schedules of them ... which shall be imposed, observed and followed afterwards by the owner of the gas utility,
> (b) fix proper and adequate rates and methods of depreciation, amortization or depletion in respect of the property of any owner of a gas utility ...
>
> **Section 37: Rate base**
> 37 (1) In fixing just and reasonable rates, tolls or charges, or schedules of them, to be imposed, observed and followed afterwards by an owner of a gas utility, the Commission shall determine a rate base for the property of the owner of the gas utility used or required to be used to provide service to the public within Alberta and on determining a rate base it shall fix a fair return on the rate base.
> (2) In determining a rate base under this section, the Commission shall give due consideration
> (a) to the cost of the property when first devoted to public use and to prudent acquisition cost to the owner of the gas utility, less depreciation, amortization or depletion in respect of each, and
> (b) to necessary working capital.
> (3) In fixing the fair return that an owner of a gas utility is entitled to earn on the rate base, the Commission shall give due consideration to all facts that in its opinion are relevant.[101]

[100] Ibid., pg. 32, para [122].

Furthermore, Subsection 4(3) of the Roles, Relationships and Responsibilities under the GUA states, "*A gas distributor is entitled to recover in its tariffs the prudent costs as determined by the Commission that are incurred by the gas distributor to meet the requirements of subsection (1).*"[102] The Utilities interpreted these sections as only requiring the used and useful standard for assets when setting an initial fair return standard. However, the return of prudent capital investment is perceived as an "absolute requirement" irrespective of the used and useful standard.[103] Justice Paperny, respectfully disagreed with the gas utilities:

> I do not read the language of the ratemaking provisions of the *GUA* to require (even if it may allow) the guaranteed cost recovery approach argued for by the appellants. The distinction the gas utilities wish to draw, that only the return on investment is tied to a requirement that the asset be used or required to be used, is not dictated by the language of s 36. Like the respondent Utilities Consumer Advocate, I think it preferable to read the two sections together. Section 36 provides that the Commission may fix just and reasonable rates and proper and adequate methods of depreciation. Read together with s 37, the Commission's mandate is to fix just and reasonable rates for the utility service received; there is no absolute obligation on utility ratepayers, under the *GUA* or at common law, to continue to pay for a service they are not actually receiving.

Policy/Legal Analysis

By examining the legislative record, it is evident that *Stores Block* was an anomaly. Traditionally, Courts have tended to apply a literal approach to making decisions concerning economic policy rather than getting involved in the policy-setting

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101 Ibid., pg. 33, para [124].

102 Subsection 4(3) Alta Reg. 186/2003 of the GUA.

103 The Court of Appeal of Alberta, FortisAlberta Inc v Alberta (Utilities Commission), 2015 ABCA 295. Pg. 33, para [123].

role.[104] However, *Stores Block's* misapplication of the regulatory compact is being used as a device for formulating regulatory economic policy. Even the Alberta Court of Appeal noted in its recent decision that had *Stores Block* been decided presently, the result might be different:

> A different conclusion on standard of review was reached by a slim majority of the Supreme Court in *Stores Block*, who applied a correctness standard to the Regulator's method of allocating proceeds from the disposition of assets (three members of the Court, in dissent, would have deferred to the Regulator's method as being part of its ratemaking authority). It is worth noting, however, that the decision in *Stores Block* preceded the Supreme Court's rethinking of standards of review in *Dunsmuir*, and preceded the direction in *ATA* that deference is presumed when a tribunal is interpreting and applying its home statute. Were *Stores Block* to be decided today, it is certainly possible that the majority approach on standard of review might more closely mirror that of the dissent. As Fraser CJA noted in the *ATCO Costs Appeal*, "that was then and this is now".[105]

In fact, Justice Binnie's dissenting judgment in *Stores Block* correctly applied the regulatory economic principles set out in the regulatory compact. He found that the Board did not confiscate AG's property, nor did it allocate proceeds to ratepayers. Rather, the regulator adjusted prospective rates to reflect the economics of the transaction. Justice Binnie perceived the Board's action as a normal exercise of its rate-making authority and its power to act in the public interest. He concluded, "*Perhaps not every regulator and not every jurisdiction would exercise the power in the same way, but the allocation of the gain on an asset ATCO sought to withdraw from the rate base was a decision the Board*

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104 The literal approach, also known as the plain meaning rule, dictates that statutes are to be interpreted using the ordinary meaning of the language of the statute. The literal approach prevents the courts from unjustifiably intervening in legislative, political or economic issues and potentially undermining the expertise of the regulator.
105 Ibid., pg. 22, para [92].

was mandated to make. It is not for the Court to substitute its own view of what is necessary in the public interest."[106] Woolley (2006), in her review of *Stores Block*, disapproved of the Court's interventionist approach. According to Woolley, the EUB, as the assigned tribunal for regulatory policy matters, would have never made the same mistake the court made when it ruled that utilities are responsible for losses and gains on regulated assets. The Court failed to appreciate the expertise of the regulator and the highly complex and technical regulatory problems associated with utility rate regulation. Woolley concluded by stating that public interest and democratic legitimacy are questioned when courts substitute their judgments for that of the regulator.[107] As a result of the decision and the Court's misunderstanding of the regulatory compact, Woolley recommended a legislative amendment explaining that "*the government should grant to the AUC the power that the Supreme Court would not, the power that the AUC will need to ensure just and reasonable rates and economic efficiency…*"[108]

Not only was there no legislative amendment subsequent *Stores Block*, but the Court of Appeal of Alberta continued to misapply the regulatory compact and limit the regulator's legislative powers as evinced by *Carbon, Harvest Hills* and *Salt Caverns*. In further evidence that agents act in utility maximization fashion, the utilities foolishly invoked *Stores Block* in order to reap excess profits in the short-term, without realizing the adverse long-term impacts.

In contrast, in the most recent Court of Appeal Decision regarding the UAD Decision, the Court deferred to the regulator's expertise. The Court stated that its ruling is not based on whether the appellants interpretation is reasonable, but rather whether the Commission's approach is reasonable.[109] Justifiably, the Court shifted the burden of

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106 Woolley, Alice. "Practical Necessity or Highly Sophisticated Opportunism? Judicial Review and Rate Regulation After ATCO Gas and Pipelines LTD. V. Alberta (Energy and Utilities Board)." University of Calgary. 44 Alta. L. Rev (2006-2007). Pg. 447-448.

107 Ibid., pg. 445-458.

108 Woolley, Alice. "The Importance of ATCO Gas and Pipelines: A Response to H. Martin Kay." The University of Calgary. 45 Alta. L. Rev. (2007-2008). Pg. 520.

109 The Court of Appeal of Alberta, FortisAlberta Inc v Alberta (Utilities Commission), 2015 ABCA 295. Pg. 24, para [101].

establishing proper regulatory principles, which balance the public interest of consumers and the profitability interests of firms, to the legislators and regulators. The Court explained that it is bound by *Stores Block* and subsequent decisions, and only a legislative amendment or a reversal of *Stores Block* by the Supreme Court could alleviate that.[110] Moreover, the Court, correctly this time, stated in its concluding remarks that this is a policy issue:

> The treatment of stranded assets is, at its foundation, a policy issue informed by public interest considerations. The Commission's policy choice, as expressed in the UAD decision, is a legitimate and defensible one, and well within its legislated power.
>
> One must also bear in mind that the questions raised have political and economic aspects. Courts are poorly positioned to opine on such matters. Judicial review considers the scope or breadth of jurisdiction, but by legislative design the selection of a policy choice from among a range of options lies with the Commission empowered and mandated to make that selection.[111]

Unfortunately, the UAD Decision was the wrong situation in which to defer to regulator expertise, as it attempted to legitimize the previous misinterpretations of the regulatory compact. During *Stores Block*, the Alberta Court of Appeal and the Supreme Court incorrectly assumed a policy-setting role by denying the regulator's method of allocating proceeds from the sale of a regulated asset. By intervening in the regulator's process, the Courts undermined the regulator's expertise in setting just and reasonable tolls. The consequences of the Courts' interventionist approach in *Stores Block* and subsequent Court of Appeal Decisions (*Carbon, Harvest Hills and Salt Caverns I and II*) resulted in the UAD proceeding. In the UAD Decision, the regulator attempted to incorporate the misguided principles from *Stores Block*, which violated the prudent cost

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110 Ibid., pg. 18, para [76].
111 Ibid., pg. 44, para [171] and [172].

recovery principle and establishment of just and reasonable tolls. After the utilities appealed the UAD Decision, the Alberta Court of Appeal had reason to intervene in the regulatory process, however instead it incorrectly gave deference to the regulator's expertise. Essentially, the Courts, both the Alberta Court of Appeal and the Supreme Court, intervened in the regulatory framework when they shouldn't have (*Stores Block* and subsequent decisions) and didn't intervene when they should have (*UAD Decision* incorporating the misguided principles from *Stores Block*). The following table summarizes this legal quandary:

	Pre Stores Block	**Stores Block**	**Post Stores Block**	**UAD Decision (Status Quo Policy)**
AB Court of Appeal Role	Deference to regulator expertise	Interventionist, undermined regulator expertise	Interventionist, undermined regulator expertise	Deference to regulator expertise
Supreme Court Role	Deference to regulator expertise	Interventionist, undermined regulator expertise	N/A	Undetermined, has opportunity to reverse *Stores Block* if appeal of the UAD Decision is accepted
Treatment of Stranded Cost	Prudently incurred costs allowed to remain in rate base for full recovery	Did not explicitly address stranded cost treatment	Did not explicitly address stranded cost treatment	Stranded cost are not allowed in rate base for recovery, shareholders at risk for stranded assets
Treatment of Stranded Benefits	Allocated according to TransAlta Formula: 1/3 to shareholders and 2/3 to ratepayers	Allocated 100% to shareholders	Allocated 100% to shareholders	Allocated 100% to shareholders
Violation of Just and Reasonable Standard	No	Yes	Yes	Yes

In light of all the facts, this would be an opportune time for a legislative amendment. Status quo with respect to stranded assets is not a reasonable public policy solution. The Alberta Court has clearly determined that the current legislation does not guarantee the recovery of prudently incurred costs in all circumstances, instead it merely offers an *opportunity* to earn a reasonable return.[112] As this paper will illustrate in the Recommended Framework section, if the "new" interpretation of the regulatory compact is systematically implemented it will have adverse effects on both the price levels and quantity of service provision. Stranded asset risk being imposed entirely on shareholders will increase the business risk faced by utilities. In turn, the cost of capital will increase, thereby increasing the price charged for the provision of service. In the longer term, the increased business risk could result in an under-investment in energy infrastructure affecting both the welfare of consumers and producers. If a legislative amendment is not a practical solution, then the Supreme Court has an opportunity to reverse *Stores Block* by approving the current Alberta Utilities leave for appeal of the Alberta Court of Appeal's UAD Decision.[113] The reversal to the period pre-*Stores Block,* where the regulator justifiably had the discretion to set the standards for the regulatory compact, is imperative in order to maintain consistency with Alberta's past legislative framework, ensuring adequate investment in utility and energy infrastructure industries.

[112] Ibid., pg. 39, para [147].

[113] In March 2016, the Alberta Utilities filed an application to seek leave from the Supreme Court to appeal the Alberta Court of Appeal Decision. A motion to extend the time to serve the application for leave to appeal was granted by the Supreme Court in April. The application is currently pending.

V. NEB Framework for Treatment of Stranded Assets

The NEB has traditionally applied the prudency standard when dealing with cost recovery cases. In the RH-2-76 Decision and the RH-1-77 Decision, the Board applied the used and useful standard and allowed the recovery of prudently incurred costs.[114] Specifically, the regulator used a two-part test to first determine if the asset was used and useful and then determine whether the investment was prudently incurred. The Board ruled that the investment was prudently incurred and thus accelerated the net book return of that investment. The Board did however, disallow part of the return on investment.[115] It is important to note, that the used and useful standard was only applied to the initial determination of rate base, and the full amount of depreciation expense was included in the utility's revenue requirement.[116] Historically, the NEB has correctly applied a fact-based judgment on the usefulness of the asset and allowed for the full recovery of the stranded costs and any related operating costs.

Following the *Stores Block* Decision, the NEB altered the way it applies the prudency standard, and aligned its framework with that of the AUC. Even though the federal regulator has not initiated an entire proceeding to determine the regulatory standards arising from *Stores Block*, it has given us a glimpse into how it perceives the controversial ruling. In its RH-003-2011 Decision, when explaining that TransCanada Pipelines would not be compensated for assets found to be no longer used and useful, the Board stated "*in our view, this conclusion is consistent with the principles set out in Stores Block. That case places the ultimate risk of asset ownership on the pipeline company and not its customers. We recognize that Stores Block does not specify how a regulator must calculate rate base or determine tolls. However, the Court made clear that the benefits and risks of asset ownership, realized upon the disposition of an asset,*

[114] RH-2-76 National Energy Board Reasons for Decision. In the Matter of Part II of a Public Hearing Respecting Tariffs and Tolls Charged by Interprovincial Pipe Line Limited. December 1977. RH-1-77 National Energy Board Reasons for Decision. In the Matter of an Application under Part IV of the National Energy Board Act of Trans Mountain Pipeline Company Ltd. January 1978.

[115] RH-003-2011 National Energy Board Reasons for Decision. March 2013. pg. 39.

[116] Concentric Energy Advisors. "Stranded Cost Treatment for Alberta Utilities." January 16, 2013. Pg. 17.

rests with the utility."[117] The interpretation of *Stores Block* by both the NEB and the AUC has ignored the broader principles of the regulatory compact and the regulators' traditional treatment of prudently incurred costs.

FERC Framework for Treatment of Stranded Assets

It is useful to briefly examine the FERC's treatment of stranded costs and application of the used and useful and prudency standards. The FERC has adopted the used and useful standard for determining which assets should be included in rate base, however it has noted that it is not required to apply this standard in all circumstances. Furthermore, the U.S. regulator has supported the recovery of prudently incurred costs. In the past, the used and useful standard has been employed to remove assets from rate base, but the regulator has always allowed full recovery of prudently incurred costs and sometimes even a partial return on equity while the asset is being depreciated. During appeal, courts have ruled that such treatment is part of the regulator's mandate to set just and reasonable tolls by appropriately balancing the competing interests of investors and ratepayers.[118]

Specifically, during the deregulation of the electricity industry, the FERC issued Order 888 explicitly stating that, "*the recovery of legitimate, prudent and verifiable stranded costs should be allowed*."[119] Similarly, the gas industry first experienced stranded cost issues once the decoupling of transport and merchant pipeline service took effect, thereby making the existing take-or-pay contracts uneconomic.[120] Initially, the FERC issued Orders 436, 500 and 528, all essentially outlining a sharing mechanism that would result in transition cost recovery from the local distribution companies, the end-

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117 RH-003-2011 National Energy Board Reasons for Decision. March 2013. pg. 41.

118 Concentric Energy Advisors. "Stranded Cost Treatment for Alberta Utilities." January 16, 2013. Pg. 18.

119 Order No. 888 Federal Energy Regulatory Commission. Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities and Recovery of Stranded Costs by Public Utilities and Transmitting Utilities. Docket No. RM95-8-000 and Docket No. RM-94-7-001. April 24, 1996. P.451.

120 These costs arose from fundamental regulatory and market changes. The contracts became uneconomic because the gas prices at the wellhead became deregulated. Thus, the long term contracts between the producers and pipeline companies were priced higher than the competitive market price, resulting in stranded costs.

customers and the pipeline shareholders. After officially mandating the decoupling of pipelines from merchant services and upon further analysis, the FERC issued Order No. 636, which allowed pipelines to recover the entire costs associated with the uneconomic take-or-pay agreements, sheltering the shareholders from any financial losses.[121] [122]

Moreover, the FERC has ruled on two noteworthy cases involving potential physical stranded assets. In the 1990's, the Transwestern Pipeline Company and the El Paso Natural Gas Company both experienced underutilization as California's consumers switched to sourcing cheaper natural gas from Alberta. The result was idled capacity and the consequence of dealing with potential stranded costs. [123] In both cases, the FERC allowed the companies to defer recovery of stranded asset cost by approving settlements, which, among various other provisions, instituted risk-sharing mechanisms, in the form of price cap tolling.[124] [125] Transwestern initiated its settlement proceeding, negotiating a ten-year toll cap with a shared cost surcharge that would allow for the recovery of 30% of fixed costs associated with de-contracted capacity.[126] Due to the nature of the price cap model allowing a utility to keep excess profits arising from cost reductions, Transwestern had an actual average ROE of 17.25% throughout the ten-year settlement period.[127] El Paso initially proposed an exit fee to recover future stranded costs associated with de-contracting, however the FERC rejected the proposal and encouraged El Paso to establish a risk sharing mechanism similar to the one proposed in Transwestern's settlement. Subsequently, El Paso applied a ten-year price cap as part of its risk sharing mechanism

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121 RH-003-2011 TCPL Response to NEB IR 3.1. February 6, 2012. Pg. 5-7.

122 The NEB issued a similar ruling in regards to the TOPGAS Program. It allowed TransCanada to recover its stranded costs arising from uneconomic take-or-pay contracts as a result of the de-coupling of merchant and transport service.

123 Makholm, Jeff. Hearing Order RH-001-2014 TCPL Application for Approval of 2013 to 2030 Settlement Agreement. Appendix B to the Joint Written Evidence of the Market Area Shippers. National Economic Research Associates Inc. July 2014. Pg. 20-21.

124 A price cap model sets a utility's price (revenue requirement and billing determinants) for a one year or greater time period. This means that a utility is at risk for cost variances and volume/revenue variances, but is allowed to keep excess profits from potential cost reductions or volume increases.

125 Transwestern Pipeline Co. 72 FERC P61,085 (RP95-271). Order Issued July 27, 1995.
El Paso Natural Gas Co. 79 FERC P61,085 (RP97-363). Order Issued April 16, 1997.

126 Foster Report No. 2040. "FERC Fully Approves Transwestern's Settlement Including Method to Share Costs of Reallocation of Capacity to be Relinquished by SOCALGAS in 1996." July 27, 1995.

127 Fosters Financial Reports.

that would obligate its customers to pay 35% of the sunk costs related to unsubscribed capacity. In order to reflect the high risk nature of the risk sharing model, the FERC approved an ROE of 14.5%.[128] The actual average ROE, excluding the outlier years with large deferred tax liabilities, over the ten-year settlement was 14.16%.[129]

In most cases the FERC has been able to properly balance the terms set out in the regulatory compact and the courts have been mindful of the regulator's expertise in setting just and reasonable tolls. The following section of the paper will provide the recommended framework for the treatment of stranded assets that Canada's regulatory and judicial institutions should uphold.

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[128] Foster Report No. 2127. "El Paso Settlement Offer to Resolve Rate and Capacity Turnback Issues Approved by FERC for Consenting Parties; Southern California Edison Severed from Settlement to Pursue Further Litigation." April 17, 1997.
[129] Fosters Financial Reports.

VI. Recommended Framework for the Treatment of Stranded Assets

The NEB and the AUC need to reconsider the long-term implications of their interpretation of *Stores Block*. This section of the paper will outline a recommended framework that the regulators should adopt, it begins with instructions for a legislative amendment, then explains the cost of capital impacts, afterwards it proposes an efficient mechanism for stranded cost recovery, and finally it offers instructions for the regulator's role in enforcing the framework.

<u>Legislative Amendment</u>

In the absence of the Supreme Court overturning *Stores Block*, a legislative amendment is necessary to avoid misinterpretations of the regulator's mandate in setting just and reasonable rates. The NEB Act, the Gas Utilities Act and the Public Utilities Act should be amended to include the following general instructions:

i. The Regulator determines if costs to be included in rate base were prudently incurred.

ii. Once an asset is part of rate base and is found to be no longer used and useful, it is classified as a stranded asset and treated in the following manner:

    a. If the market value of the asset is above the net book value, the firm should sell the asset and the goodwill (stranded benefits) would be allocated to the ratepayers.

    b. If the market value of the asset is below the net book value, the firm removes the asset from rate base and creates an account to recover the entire net-book value of sunk cost (remaining depreciation) and any associated decommissioning and abandonment costs. However, any return on investment associated with the asset should not be allowed from the date the asset is found no longer used and useful. Therefore, recovery

<u>of</u> the capital investment is permitted, but a rate of return *<u>on</u>* the capital investment is not, once an asset is found to no longer be used and useful.

The application of these provisions will ensure that proper tradeoffs are achieved between the utilities and its ratepayers. Removing the stranded asset from rate base and amortizing the undepreciated balance over a period of years is a fair approach, because allowing the full recovery of prudently incurred costs maintains the commitment of the regulatory compact. Equally, allocating stranded benefits to ratepayers and disallowing return on assets that are no longer used and useful ensures proper risk symmetry. Shareholders should not earn a return on uneconomic assets. Furthermore, ex ante, investors in regulated utilities invest in assets that generate stable, predictable and low returns, as opposed to speculative assets in which they hope market value increases over time. Since the shareholders are not responsible for losses due to unexpected asset retirement, they also shouldn't receive any benefits once the asset is found no longer used and useful for the provision of utility service.

<u>Cost of Capital Impacts</u>

A basic principle governing price regulation is for the regulator to set prices at levels that would prevent the regulated firm from capturing monopoly rents but allow it the opportunity to recover its investment and a fair return on that investment. This principle was established in the 1944 U.S. Supreme Court Decision, *Federal Power Commission et al. v. Hope Natural Gas Co.*. The *Hope* ruling settled the dispute over the appropriate valuation of regulatory assets. The new standard for determining just and reasonable rates was set as the Supreme Court ruled, "*return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and attract capital*."[130] Utilities viewed *Hope* as legal protection from regulatory holdup. This Decision has been cited in most common-law countries, and forms the basis for predictable cost recovery and

[130] Federal Power Commission et al. v. Hope Natural Gas Co., 320 U.S. 591 (1944). Pg. 603.

pricing of utility services.[131] Furthermore, the Supreme Court of Canada has also recognized the need to protect the rights of investors stating that, "*The duty of the Board was to fix fair and reasonable rates; rates which, under the circumstances, would be fair to the consumer on the one hand, and which, on the other hand, would secure to the company a fair return for the capital invested. By a fair return is meant that the company will be allowed as large a return on the capital invested in its enterprise (which will be net to the company) as it would receive if it were investing the same amount in other securities possessing an attractiveness, stability and certainty equal to that of the company's enterprise.*"[132]

These rulings have resulted in two important standards, the expected return in a regulated company should equal that available in other investments of the same risk, and this return needs to be adequate to ensure the financial integrity of the company so that it can attract future capital needed to provide the service. In fact, the NEB has recognized these standards and previously explained that a fair return on capital needs to meet *the comparable investment requirement*, *the financial integrity requirement* and *the capital attraction requirement*.[133]

Defining Risks Faced by Regulated Firms

In a free-market economy firms compete for capital. In a similar manner that labour or material prices are determined in the market by supply and demand forces, the price of capital is determined by the investor's required return or cost of capital. Specifically, this return required by investors is set in capital markets through the competition of firms issuing securities to fund their input factors of production. By purchasing these securities, investors delay consumption and expose their funds to risk. Therefore, the cost of capital is the compensation that investors require in order to postpone consumption and expose their capital to risk.[134] The level of risk varies from

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131 Makholm, Jeff. "The Political Economy of Pipelines: A Century of Comparative Institutional Development." The University of Chicago Press (2012). Pg. 129-130.

132 Northwestern Utilities Limited v. City of Edmonton, [1929] S.C.R. 186. Pg. 192-193.

133 National Energy Board RH-1-70, pg.5-7. National Energy Board RH-1-2008, pg. 6-7.

134 Morin, Rodger A. "New Regulatory Finance." Public Utilities Inc. (June, 2006). Pg. 20.

industry to industry, in general, in order to attract capital firms must offer an expected rate of return at least equal to what investors would expect on an alternative investment of equivalent risk.

Risk is defined as the likelihood that actual returns realized in the future from an investment will differ from expectations.[135] Therefore, the risk associated with capital intensive, long-lived assets, such as pipelines or transmission lines, can change over time due to a variety of factors. These factors are composed of business risks and financial risks. When investors calculate their required returns for a specific investment, they take into account the nominal risk-free rate and a risk premium specific to that investment. The nominal risk-free rate is composed of the real risk-free rate (a long-term government bond) and the rate of inflation expected by investors. The risk premium is composed of expected business and financial risks associated with the investment.[136]

Financial risk is concerned with the amount of debt employed in a firm's capital structure. Among various metrics, it takes into account a firm's leverage ratios, interest coverage ratios and credit ratings.[137] Interest rate risk and liquidity risk are a further concern to potential shareholders.[138]

Business risk is composed of variability (short-term) risks and fundamental (long-term) risks. *Variability risk* includes year-to-year variations in earnings or cash-flows. An example would be any variations in weather that increase the variability of earnings, but otherwise do not impact the long-term expected cash-flow stream. Another example is a force majeure event that affects the earnings in a single year. For electric utilities and pipelines, variability risk can be mitigated through the use of deferral accounts, which capture year-to-year cost variances and compensate the firm in the subsequent year (or compensate the ratepayers if the firm earns revenue above its cost of service or lowers its

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135 Ibid., pg. 57.
136 Ibid., pg. 36.
137 Ibid., pg. 46-47.
138 Ibid., pg. 36.

cost).[139] Since these risks are usually business-cycle related, long term investors do not place a great importance on them.[140]

Fundamental risk, in contrast, involves long-term uncertainties which can alter the entire structure of the industry. This includes supply risk, market risk, competition risk and regulatory risk. *Supply risk* addresses the risk that physical availability of competitively priced commodities could impact a firm's income earning capability. An example is the supply risk that local distribution companies (LDCs) faced following the deregulation of natural gas prices and its impact on the overall marketplace. *Market risk or demand risk* encompasses the size and growth rate of the market, the diversity of the consumer base and exogenous changes in the demand for the products and services of the firm. *Competition risk* is dependent on the availability of substitutes and the firm's relative standing in its major markets.[141] Examples include discoveries of new supply basins feeding competing infrastructure or approval of by-pass infrastructure resulting in direct competition. *Regulatory risk* refers to the quality and consistency of regulation applied to a regulated firm. Specifically, it measures the fairness and reasonableness of rate awards.[142]

Utilities and pipeline companies face a substantial amount of business risk related to uncontrollable external factors such as; seasonal demand patterns, the product's income and price elasticity, the degree of competition, the availability of substitutes, the risk of technological obsolescence and the degree and quality of regulation.[143] The nature of the capital being sunk and transaction-specific makes it difficult to redeploy should the

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139 Other cost recovery mechanisms include fuel adjustment clauses, purchased water adjustment clauses, environment-related capital expenditures, and purchased gas adjustment clauses. The financial community relies on these types of cost recovery mechanisms because they lower variability risk. In the absence of this protection, the regulated firm's credit profile would deteriorate, raising its cost of capital. (Morin, pg.40-41)

140 Written Evidence of Paul R. Carpenter for TCPL Business and Services Restructuring and Mainline 2012-2013 Tolls Application. Part D: Fair Return. The Brattle Group. September 1, 2011. Pg. 9.

141 Morin, Rodger A. "New Regulatory Finance." Public Utilities Inc. (June, 2006). Pg. 38-39.

142 Ibid., pg. 43.

143 Ibid., pg. 38.

fundamental risks begin to materialize. The extent to which investors will demand higher returns on investment depends on the ability to diversify these risks.[144]

Diversification of Risk

Risks that cannot be diversified away by means of holding a broad portfolio of securities constitute the most significant risk to equity investors. These risks are often referred to as "systemic risks," meaning that they are correlated with general changes in economic activity. Systemic risks faced by energy utilities include uncertainties in the demand and supply of transmission services affected by economic activity (i.e. incomes, prices and governmental policies).[145] Knight (1921) first distinguished the difference between risk and uncertainty in his work "*Risk, Uncertainty and Profit.*" *Knightian Uncertainty* recognizes that there are risks that cannot be measured and are not possible to calculate.[146] Knight concludes that in the absence of robust institutions, uncertainty is exacerbated. Therefore, institutional quality reflects the degree of uncertainty.[147] Regulatory bodies are one of the various societal institutions which are supposed to reduce investment uncertainty. Regulatory quality's impact on the level of uncertainty can be judged on the frequency of regulatory modifications, which affect the foreseeability of a regulator's course of action. Specifically, regulatory jurisdictions are evaluated on earnable return on equity, regulatory quality, and regulatory technique.[148] A regulator can decrease regulatory risk an investor faces by providing consistency and reliability that a fair return on and of capital will be earned over the lifetime of the firm's assets. Conversely, it could increase regulatory risk if investors believe that there is uncertainty with resect to the future regulatory treatment of the firm's business.[149] This increase in regulatory risk can have an adverse impact on investor decisions.

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[144] Written Evidence of Paul R. Carpenter for TCPL Business and Services Restructuring and Mainline 2012-2013 Tolls Application. Part D: Fair Return. The Brattle Group. September 1, 2011. Pg. 10.
[145] Ibid., pg. 8.
[146] Knight, Frank H. "Risk, Uncertainty and Profit." Houghton Mifflin Company. (1921). Pg. 19-20.
[147] Erbas, Nuri S. and Chera L. Sayers. "Institutional Quality, Knightian Uncertainty, and Insurability: A Cross-Country Analysis." IMF Working Paper. July 2006. Pg.4.
[148] Morin, Rodger A. "New Regulatory Finance." Public Utilities Inc. (June, 2006). Pg. 43.
[149] Written Evidence of Paul R. Carpenter for TCPL Business and Services Restructuring and Mainline 2012-2013 Tolls Application. Part D: Fair Return. The Brattle Group. September 1, 2011. Pg. 8.

Regulatory Risk Increases Cost of Capital

To properly examine the adverse impacts of an increase in regulatory risk by the imposition of stranded asset risk on utility shareholders, it is important to understand how price regulation works. In a traditional cost-of-service model the regulator determines the prudence of a firm's cost of doing business (operating and capital costs, and a fair rate of return) and sets it equal to the firm's revenue requirement. The revenue stream that the firm earns is generated by the tolls it charges (P) and the quantity of the service provided (Q). The firm's operating costs (O) include expenses such as administrative expenses, maintenance, payroll and other labor costs, fuel, taxes, etc. The firm's capital costs (K) are contingent on the rate base (RB), the allowed rate of return (r), and depreciation (d).[150] The allowed rate of return consists of debt and equity financing. Debt financing is the rate charged by lenders (banks), the regulator often uses the weighted average interest rate on long-term debt as the return required for debt (r_d). Equity financing (r_e), the return shareholders expect on their investment, is more complex to determine. The return on equity (ROE), or the firm's opportunity cost of equity capital, is intended to reward investors with the same return they would earn on alternative investments of comparable risk.[151] Various versions of two commonly used models, the Capital Asset Pricing Model (CAPM) and the Discounted Cash-Flow Model (DCF), determine r_e.[152] Canadian regulators have relied more on the CAPM model. The model is defined as follows:

$$R_e = R_f + \beta(MERP)$$

R_f = risk-free rate

- Yield on long-term government bonds

MERP = Market Equity Risk Premium (R_m - R_{fh})

- Difference between average historical market returns and the historical risk-free rates

150 Church, Jeffrey and Roger Ware. Industrial Organization: A Strategic Approach. New York: McGraw-Hill, 2000. Pg. 843.
151 Ibid., pg. 844.
152 See Appendix C. for a breakdown of the models.

β = Beta

- Measures the market risk for a security
- $\beta = 1$, is the market portfolio of all investable assets
- $\beta < 1$, lower volatility than the market, or volatile non-correlation with the market
- $\beta > 1$, volatile asset, moves up and down with the market
- Beta is estimated using linear regression:
  - $r_a \approx \alpha + \beta r_b + \varepsilon$
  - $\beta = cov(r_a, r_b) / var(r_b)$
  - r_a is the return of the specific stock (asset) and r_b is the market return (benchmark)

During rate cases, economists, financial and accounting experts apply industry-specific data to these models to calculate the regulated firm's opportunity cost of equity capital and the appropriate mix of debt and equity that compose a firm's capital structure.[153] They further outline the aforementioned business and financial risks faced by the regulated firm. However, this process is highly subjective, and as Church and Ware (2000) note these models just disguise the bargaining game that is played between consumers and the firm, with the regulator acting as a referee. The regulator ensures that the r_e is not set too low so that the firm cannot attract future investment, but it also cannot be too high so the firm earns monopoly rents. [154] Nevertheless, the regulator uses these models to justify the allowed rate of return for the firm, which is a weighted average of r_d and r_e. The weighting is based on how much of the capital is financed through debt and how much is financed through equity. Therefore:

$$\text{Revenue Requirement} = \text{Cost of Service}$$
$$RR = K + O$$
$$K = r^*RB + d$$

153 Joskow, Paul. "Regulation of Natural Monopolies." Handbook of Law and Economics. August 29, 2006. Pg. 113.

154 Church, Jeffrey and Roger Ware. Industrial Organization: A Strategic Approach. New York: McGraw-Hill, 2000. Pg. 844.

$$r = d_T*r_d + e_T*r_e$$

$$P*Q = r*RB + O + d$$

$$P = \frac{(r*RB + O + d)}{Q}$$

This calculation clearly demonstrates how rate of return regulation functions. The regulator approves the firm's revenue requirement, which is based on its capital and operating costs, and a fair rate of return. Then, the price is set to essentially equal a firm's average historic cost.

Stranded asset risk reduces the expected rate base and expected cash flows, and increases the degree of variability in expected cash flows.[155] This results in an actual rate of return that is below the allowed rate of return. This point can be illustrated with the following example:[156]

$r_d = 10\%$ $d_T = 50\%$

$r_e = 15\%$ $e_T = 50\%$

RB = \$100 E = 50%*\$100 = \$50 D = 50%*\$100 = \$50

$r = d_T*r_d + e_T*r_e$

$r = 0.50*10\% + 0.50*15\% = 12.5\%$

K = r*RB

K = 12.5%*\$100 = \$12.50

In this case the Revenue Requirement (RR) is given by:

$RR = r_d*D + r_e*E$

RR = 0.10*\$50 + 0.15*\$50 = \$12.50

155 Pedell, Burkhard. "Regulatory Risk and the Cost of Capital: Determinants and Implications for Rate Regulation." Springer (2006). Pg.94.

156 For simplicity, this example does not include multiple time periods and the impact of depreciation rates on the recovery of rate base. The full example is demonstrated in Morin (2006, pg. 494-495).

In this example, the return on equity can be impacted by the following two scenarios:

Scenario #1: the regulator allows the recovery of all prudently incurred costs, and thus sets the rate base equal to the invested capital:

Revenue	\$12.50
Interest Expense	- \$5.00
Return on Equity	\$7.50

ROE = \$7.50/\$50 = 15%

Thus, the equity investor's actual return is equal to the approved return, which is equal to the cost of equity.

Scenario #2: the regulator disallows the recovery of prudently incurred cost, thus the rate base is less than the invested capital:

Assume that the initial capital invested was \$100, however, due to some unforeseen event the regulator finds that \$25 of the original investment is no longer used and useful, consequently the regulator sets the rate base at \$75.

K = 12.5%*\$75 = \$9.375

Revenue	\$9.375
Interest Expense	- \$5.00
Return on Equity	\$4.375

ROE = \$4.375/\$50 = 8.75%

In this case, the actual rate of return is below the allowed rate of return and the cost of equity, thus the investor suffers a loss.

Ultimately, the exclusion of assets from rate base undermines a utility's integrity. The utility credit ratings will get downgraded to reflect increased risk, thus the banks will charge a higher interest rate on debt. The firm's interest coverage, equity ratio and return on equity all suffer when a utility must write off its investment and reduce its equity by the amount of the disallowance.[157] The expectation that this disallowance might occur, further increases the cost of capital. Therefore, the result of shifting the risk of stranded assets entirely to shareholders will increase the regulated price as shareholders and debt issuers will need to be compensated for a perceived ex post increase in risk. This compensation will be reflected through an increase in the cost of capital (r), which increases the price (P).

To assess how the cost of capital increase is accounted for, recall the above-mentioned CAPM model. This model is intended to yield a cost of capital that compensates investors for undiversifiable risk associated with expected earnings. This measure of undiversifiable risk is computed through the beta (β) variable.[158] A number of risks that utilities are exposed to could increase the beta and hence the cost of capital, these include:

- Demand risk: unanticipated variability in demand and prices, caused by macroeconomic conditions, regulation, competition, and supply imbalances (fundamental risks).
- Cost risk: unanticipated variability in operating and financing costs caused by macroeconomic conditions, regulation, competition, and technological change.
- Leverage: the extent to which these demand and cost uncertainties are magnified by the operating cost and financial cost structures of the company.[159]

[157] Morin, Rodger A. "New Regulatory Finance." Public Utilities Inc. (June, 2006). Pg. 496.
[158] Kolbe, Lawrence A. and William B. Tye. "Compensation for the risk of stranded costs." Energy Policy. Vol. 24, No. 12. (1996). Pg. 1042.
[159] Morin, Rodger A. "New Regulatory Finance." Public Utilities Inc. (June, 2006). Pg. 86-87.

Morin (2006) outlined various empirical studies illustrating that investors' perception of regulatory behavior impacts the cost of capital, meaning that regulatory risk is not diversifiable. In fact several investment and research firms rate individual regulators based on their methods for regulating rates. The regulatory bodies that attract the most investment within their jurisdiction typically exhibit higher allowed rates of return, minimal regulatory lag, forward test year, inclusion of Construction Work In Progress (CWIP) in rate base, normalization of tax benefits, minimum uncertainty over the recovery of environmental compliance costs, minimal exposure to prudence reviews, and automatic fuel adjustment clauses.[160] Moreover, during the mid 1990s to mid 2000s period, it can be observed that U.S. electric utility betas escalated towards 1.0, reflecting the increased risk utilities faced due to restructuring, deregulation and increased competition.[161] Other research shows that increasing beta values are consistently associated with deteriorating bond ratings.[162] Therefore, if shareholders are solely at risk for stranded assets, then the beta will increase for the entire industry reflecting the variability of earnings due to the risk of the utilities not recovering all prudently incurred costs.

Currently the β for Canadian utilities is around 0.5, meaning that an investment in a regulated utility is less risky than the market average β of 1, and more risky than the risk-free rate with a β of 0.[163] As banks, equity analysts and investors begin to comprehend the impact of the status quo policy with respect to stranded assets, we can expect a gradual increase of β above the 0.5 level for the utility sector. With respect to stranded costs, Morin (2006) summarizes, "*if cost responsibility is assigned to shareholders, the risk of holding utility securities would increase substantially, reducing stock prices and bond ratings, and resulting in much higher capital costs.*"

160 Ibid., pg. 96-97.

161 Ibid., pg. 75.

162 Ibid., pg. 92.

163 Alberta Utilities Commission. 2013 Generic Cost Of Capital Proceeding. Decision 2191-D01-2015. March 23, 2015. Pg 24.

The notion that shareholders will demand a greater rate of return due to the exposure of stranded asset risk has already been observed. In the AUC's 2013 Generic Cost of Capital Proceeding (GCOC), Kathleen McShane, the expert witness for the Alberta Utilities, unsuccessfully attempted to provide the utilities with a 1.25% to 1.5% equity premium due to the increased risk exposure resulting from the UAD Decision.[164] The Commission rejected the claim that a risk premium is deserved. The regulator reasoned that utility credit spreads have not increased since the 2006 *Stores Block* and related AUC decisions.[165] But synthesizing and translating the related complex regulatory history and economic principles takes time. Research has shown that a random shock, which impacts the true beta, cannot be immediately measured by an estimated beta. This is the case because rising investor risk perceptions impact the stock price first, this in turn manufactures low betas.[166]

Moreover, bond-rating agencies have been found to be sluggish to changing market conditions. Typically other risk variables will change prior to a bond rating alteration. The bond adjustment usually occurs several months after investors have already responded to changes in the bond's quality.[167] The true implications of *Stores Block* are still unknown, the regulators have yet to apply the principles to a major cost disallowance. Furthermore, the UAD Decision has been appealed and the subsequent Court of Appeal decision is being challenged in the Supreme Court. The legislative and judicial process is far from finished. The rating agencies have taken note of this, the S&P stated;

> We expect many, if not all, of the regulated utilities to seek clarification and challenge aspects of the Alberta's GCOC decisions relating to stranded assets. Although we are not aware of any material assets exposed to stranding risk in the near term, exposing regulated utilities to stranded asset risk would weaken their

164 Alberta Utilities Commission. 2013 Generic Cost Of Capital Proceeding. Exhibit 42.02, McShane evidence for Alberta Utilities, page 6, lines 154-159.
165 Alberta Utilities Commission. 2013 Generic Cost Of Capital Proceeding. Decision 2191-D01-2015. March 23, 2015. Pg 69.
166 Morin, Rodger A. "New Regulatory Finance." Public Utilities Inc. (June, 2006). Pg. 80.
167 Ibid., pg. 92.

business risk profiles, and be a departure from what we view as a relatively low-risk environment for regulated utilities in Alberta.[168]

Banking analysts have also expressed concerns of the AUC's position on stranded assets.[169] In fact, the Alberta Utilities have requested that the AUC set 2016 approved ROE and equity ratios on an interim basis, because they believe the courts' future rulings, and rating agency commentary subsequent to the 2013 GCOC Decision will impact utility credit ratings. [170] This trend is likely to continue, and if regulators refuse to allow an increase in the ROE there could be serious underinvestment in Alberta's energy infrastructure. It would place the province's utilities at a disadvantage to other North American utilities when it comes to raising capital.

The importance of minimizing regulatory risk depends on the need for further investment under the regulatory framework. If an adequate amount of competition is expected in the future, then the market can be deregulated. However, this outcome requires a major technological change that lowers marginal costs and reduces the need for substantial, transaction-specific sunk costs and the extent of economies of scale. [171] This technological advancement has not emerged in the energy transmission sector.

Asymmetric Risk Faced by Regulated Firms

Another component of regulatory risk is the asymmetric risk that utilities face under rate of return regulation. Investors have the choice of where to allocate their funds based on the expected risk and return of the investment. Traditionally, investments in a regulated industry were considered *low risk* because the potential for a high return was capped by the fair return standard and the risk for incurring losses was insured by the cost-of-service model and prudency standard. In contrast, investments in an unregulated

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[168] Standard and Poor's, Industry Report Card: Growth Poses Biggest Challenge To An Otherwise Stable Canadian Midstream And Utility Sector, February 15, 2012. Pg 4.
[169] Scotia Bank, Fixed Income Research: Corporate Bond Morning Notes, February 23, 2012.
[170] Alberta Utilities Commission. 2016 Generic Cost Of Capital Proceeding. Decision 20371-D01-2015. July 8, 2015. Pg 2.
[171] Church, Jeffrey. "An Economic Analysis of the Alliance Pipeline." University of Calgary. October 1998. Pg. 13.

and competitive industry provide no guarantees as to what the return might be and any losses are to the account of shareholders. Hence, the return is usually greater in non-regulated industries compared to regulated utilities. This risk-reward spectrum allows investors to decide where to allocate their funds. If regulators continue to ignore the regulatory risk imposed by the non-recovery of stranded assets, while maintaining their current ceiling level on the utilities' possible return, the asymmetrical downside risk will create market distortions. Investors could potentially begin to re-direct their investments to less risky, but otherwise less productive, projects creating significant social costs.[172]

If regulation constrains profitability on the upside but not risk on the downside, the utility shareholders will essentially have a choice of either breaking-even or taking write-downs of prudently incurred capital. In fact, research suggests that regulated utilities exhibit a negatively skewed return distribution, meaning that, due to asymmetrical risk, the level of returns is likely to result in the utility earning less than its cost of capital. This is in contrast to firms which are not subject to asymmetric risk and have the potential to enjoy positively skewed return distribution by earning more than their cost of capital.[173] Morin explains "*an environment in which ratepayers obtain the benefits of successful operation or new technologies but investors bear the full costs of failure creates a game of "heads I win, tails you lose" and it increases risk while bringing with it the attendant increase in capital costs. If there is a finite probability of total ruin under bad conditions, but essentially no probability of correspondingly large positive returns under current regulatory practices, then the expected return for normal expected conditions would have to be substantially higher than for unregulated companies, and utilities would have to earn high returns in normal times to offset large losses when major problems occur.*"[174] Rational thought would lead to the conclusion that investors would be discouraged from placing significant investment in the regulated utility industry, because currently the regulatory risk outweighs the capped returns and the regulators are not willing to adequately compensate for this risk.

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[172] Williamson, Oliver. "Deregulatory Takings and Breach of the Regulatory Contract: Some Precautions." N.Y.U. Law Review. Pg.1015.

[173] Morin, Rodger A. "New Regulatory Finance." Public Utilities Inc. (June, 2006). Pg. 68.

[174] Morin, Rodger A. "New Regulatory Finance." Public Utilities Inc. (June, 2006). Pg. 497.

Asymmetric risk is exacerbated when a rate-regulated company is exposed to competition. Under traditional regulated conditions, a firm can expect to earn its allowed rate of return on average over the life-time of each investment. Introduction of competition in the market jeopardizes the ability of the regulated firm to earn its allowed rate of return and increases the probability that it will earn substantially less. Baumol, Joskow, and Kahn claim that this risk has placed utility investors in the same situation as junk bond investors, "*junk bonds have to offer interest rates higher than investors expect actually to realize, on average, to compensate for the fact that some of the bonds will default. Regulators have not done that; they have not deliberately permitted returns higher than the cost of capital on the successful investments: but that's what it would have taken to compensate investors for the risk that competition might now wipe out the unsuccessful ones.*"[175] Furthermore, Kolbe asserts that, "*the risks facing a rate-regulated company that is also exposed to competition are higher than they would be under either pure regulation or pure competition. Regulation sometimes restrains tolls in ways that competition would not, and competition sometimes restrains tolls in ways that regulation would not. The result can literally be the worst of both worlds.*"[176] By maintaining the status quo policy, ratepayers will be adversely impacted, as any near term benefits accruing to consumers from the disallowance of stranded cost recovery could be greatly offset by cost of capital increases for years to come.

Kolbe and Tye (1992) outline four policy options that could address the regulatory asymmetry problem:

i. Add an increment to the allowed return over and above the cost of capital to balance the negative asymmetry.
ii. Eliminate the asymmetry entirely by changing regulatory institutions.

[175] Baumol, William J., Paul L. Joskow, and Alfred E. Kahn, "The Challenge for Federal and State Regulators: Transition from Regulation to Efficient Competition in Electric Power," December 9, 1994, filed as Appendix A with the Edison Electric Institute's comments on the FERC 1994 Stranded Cost NOPR.
[176] Written Evidence of A. Lawrence Kolbe for TCPL Business and Services Restructuring and Mainline 2012-2013 Tolls Application. Part D: Fair Return. The Brattle Group. September 1, 2011. Pg. 5.

iii. Add a compensating item to the approved cost of service, akin to a fee for providing a risky service, to the revenue requirement.

iv. Adjust another cost recovery item by an amount sufficient to offset the asymmetry.[177]

The following section will consider if the historical cost of equity capital granted to the utilities actually compensates the shareholders for the asymmetric risk of stranded assets.

Does Historical Allowed Rate of Return Compensate Shareholders for Stranded Asset Risk?

Arguments have been made that the utilities' shareholders have already been compensated for the risk of stranded assets through historic approved rate of return.[178] Proponents of this theory claim that the potential for economic obsolescence has been embedded in the return structure of the utilities.[179] Rose (1996) argues that it could also be the case that regulators do not explicitly provide a risk premium when assessing the fair rate of return, but the efficient financial markets already take into account increased risk. Rose uses the following example to further his claim "*assume that competitive risk does increase significantly and the commission did not set the return high enough. Some stock and bond holders will sell securities and the price will drop, raising yield to equal the cost of capital. Similarly, if a commission set the return higher than necessary, prices will be bid up reducing yield. Commission policy obviously affects security prices, but financial markets determine the cost* of *capital.*"[180] This "automatic compensation theory" can be summarized as follows; as a result of past regulatory decisions, statements or experiences, the investors properly forecast they are at risk for stranded costs, these expectations are correctly reflected in an efficient market equilibrium which sets the price for utility securities and their expected rates of return, cost of capital experts study the

[177] Kolbe, Lawrence A. and William B. Tye. "The Fair Allowed Rate of Return with Regulatory Risk." Research in Law and Economics. (1992). Pg. 130.

[178] RH-003-2011 National Energy Board Reasons for Decision. March 2013. pg. 35.

[179] Written Evidence of Dr. Andrew Safir. Application for Approval of Restructuring and Mainline Final Tolls for 2012 and 2013. Recon Research Corporation. March 9, 2012. Pg. 37.

[180] Rose, Kenneth. An Economic and Legal Perspective on Electric Utility Transition Costs. The National Regulatory Research Institute. July 1996. Pg. 81.

markets and compute the increase in the cost of capital, the regulator properly revises the cost of capital to reflect all risks of which investors are aware and accordingly increases the revenue requirement in the next rate case, thus investors are automatically compensated for the risk of stranded costs in the cost of capital component of the revenue requirement.[181]

However, Kolbe and Tye (1996) argue that the cost of capital does not compensate investors for stranded cost risk. They assert that even if investors are fully cognizant of stranded asset risk, capital market prices fully reflect such risks, and regulators set the allowed rate of return equal to the true cost of capital, it is still mathematically impossible for investors to have been previously compensated for stranded asset risk.[182] [183] Cost of capital is defined in two ways; the *expected* rate of return prevailing in capital markets on alternative investments of equivalent risk, and the discount rate for determining the net present value of future uncertain cash flows by discounting their *expected* value. The authors state that the word "expected" is used in a statistical sense as the probability or weighted average of all possible outcomes. Since traditional regulatory practice is to equate the cost of capital to the allowed rate of return of a utility, the cost of capital does not itself offer compensation for the risk of stranded assets because it represents the average of; an expected return equal to the cost of capital if the event does not occur (cost of capital without stranded costs) and an expected return less than the cost of capital if the event does occur (cost of capital with stranded costs).[184] Kolbe and Tye conclude that the only way to compensate shareholders for the risk of stranded costs is to permit the utility to earn more than the cost of capital if no costs are stranded, therefore, "*fair compensation requires that the expected earnings during the prior period exceed the cost of capital by a risk premium over and above the cost of*

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[181] Kolbe, Lawrence A. and William B. Tye. "Compensation for the risk of stranded costs." Energy Policy. Vol. 24, No. 12. (1996). Pg. 1026.

[182] Ibid., pg. 1025.

[183] Kolbe and Tye (1996) also refute the "accidental compensation theory," which claims that the net result of past regulation turned out to *accidently* provide adequate return for stranded cost irrespective of regulatory mechanisms. This would mean that historical returns on utility stocks would have to overcompensate investors for their risks in general.

[184] Kolbe, Lawrence A. and William B. Tye. "Compensation for the risk of stranded costs." Energy Policy. Vol. 24, No. 12. (1996). Pg. 1029 - 1030.

capital that provides an additional return on capital equal to the expected losses from stranded costs."[185] They use the following example to illustrate the point:

Scenario #1: ROE without adequate compensation for stranded asset risk:

Allowed Rate of Return = Cost of Equity = 12.5%[186]
Probability that stranded assets will result in a loss of rate base = 25%
Amount of reduction to actual return on equity due to stranded cost = 30%

The *good outcome* is that the risk of stranded costs may never materialize, in which case the investors earn 12.5% return as the allowed rate of return intended.

The *bad outcome* is that the risk materializes and stranded assets are removed from rate base, in which case the investor receives an ROE of -17.5% (12.5% - 30%).

Under a cost-of-service model, the allowed rate of return is equal to the cost of equity capital, thus the weighted average of the expected rate of return is:

Expected Value = (probability of good outcome) x (payoff of good outcome) + (probability of bad outcome) x (payoff of bad outcome)

EV = (0.75)(12.5%) + (0.25)(-17.5%) = 5.0%

In this scenario the actual return that investors expect is below the allowed rate of return, thus the investors have not been compensated for stranded asset risk. In order to properly compensate the investors for the risk, as soon as the stranded cost risk arises, the allowed rate of return must be set above the cost of equity capital so that investors can expect to earn their cost of equity capital given the expected losses from stranded costs. This means that a risk premium above the cost of equity capital is needed.

185 Ibid., pg. 1030.
186 In this example, consistent with the automatic compensation theory, investors are fully cognizant of the stranded asset risk and this has been included in the utility's cost of equity.

Scenario #2: ROE with adequate compensation for stranded asset risk:

Risk Premium = (probability of bad outcome) x (amount of ROE reduction below the allowed rate of return)
OR
Risk Premium = allowed rate of return – expected value (cost of equity capital)

Risk Premium = (0.25)(30%) = 7.5%
OR
Risk Premium = 12.5% - 5% = 7.5%
With a risk premium of 7.5% above the cost of equity capital, investors are properly compensated for stranded asset risk:

ROE good outcome (adjusted allowed rate of return) = cost of capital + risk premium
ROE good outcome (adjusted allowed rate of return) = 12.5% + 7.5% = 20%

ROE bad outcome = 20% - 30% = -10%

Adjusted EV = (0.75)(20%) + (0.25)(-10%) = 12.5%

With the inclusion of a risk premium, the weighted average return investors can expect overall actually equals the cost of equity capital.[187]

This example demonstrates that in order to properly compensate shareholders for stranded asset risk, regulators would have to grant an approved ROE of 20% and keep on doing so, which is significantly more than the cost of equity capital already taking into account shareholder expectations of increased risk. Therefore, if regulators want to properly compensate investors for stranded asset risk, then both of the following components are necessary;

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[187] Kolbe, Lawrence A. and William B. Tye. "Compensation for the risk of stranded costs." Energy Policy. Vol. 24, No. 12. (1996). Pg. 1030 - 1032.

- an approval of adjustments (once shareholders have realized they are at risk for stranded assets) in cost of equity capital (as identified by the automatic compensation theory, in this example the increase to 12.5% ROE), and
- a risk premium (in this example the 7.5% premium).

The risk premium is very asset and circumstance specific. Its computation depends on the accurate forecast of the probability and quantifiable impact of future stranded assets (thus, the entire magnitude of stranded cost). Assessing the needed factors to determine the fair risk premium is not a trivial task. Kolbe and Tye (1996) outline regulatory repercussions, political acceptability and administrative feasibility as serious challenges. The authors further assume that utility management has experienced the same difficulty, explaining that "*utility executives may have understood the problem intuitively, but been no more able than the proponents of automatic compensation to sort out the reasons additional compensation was required. Given all these factors, it is not hard to understand, in our view, why the electric utility industry has not sought to bear these risks and to be compensated for these risks.*"[188] However, under the recommended framework, assuming this challenging undertaking of computing the stranded asset risk premium is completely avoided.[189] Therefore, allocating potential future stranded costs to ratepayers is reasonable, considering that the investors have never been adequately compensated for these risks.[190]

To summarize;

i. Since the beta variable reflects the historical relationship between asset returns, it does not automatically incorporate major changes in regulatory policy that

188 Ibid., pg. 1049.

189 There would also be substantial regulatory process cost saving, through the avoidance of cost of capital practitioners' fees for annual risk premium calculations.

190 Kolbe and Tye (1996) further show that even if we assume that the risk of stranded assets is fully diversifiable, thus there is no change in the cost of equity capital, shareholders will still need to be compensated. They explain that the risk of stranded costs still affects the future expected cash flows, which decreases the investment value. Indeed, they provide a counter-example to the automatic compensation theory, by proving that shareholders can still be impacted by stranded asset risk without the reflected change in the cost of equity capital. They conclude that the cost of equity capital cannot by itself compensate for asymmetric risk.

increase regulatory risk. Therefore, it is likely the case that the beta variable is incorrectly measuring the extent of regulatory risk as a result of a significant change in regulatory policy.[191]

ii. Even if it is assumed that the beta variable automatically adjusts and correctly incorporates the extent of regulatory risk, shareholders will still require a premium above the cost of equity capital to be compensated for stranded asset risk.

iii. Similar to the predicament of incomplete contracts, if an equilibrium beta is achieved, it will still be inherently incomplete due to the long-term uncertainties present in the marketplace. Transaction cost economics recognizes the existence of regulatory cost of capital proceedings as a platform for negotiations, which adjust the beta variable as risks change and unforeseen circumstances materialize.[192]

Stranded Benefits vs. Stranded Costs

In *Stores Block*, ultimately the stranded benefits were awarded to the shareholders. However, those assets were outside the course of ordinary business, the land that was sold had a market value over the net book value. Most of the assets utilized for ordinary utility service are considered a sunk cost. So the specific investment made in the asset is unlikely to have any value in their next-best alternative use.[193] This further creates an unbalanced risk-reward structure, as a regulated asset is much less likely to be classified a stranded benefit than a stranded cost. Furthermore, stranded benefits are

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[191] For example, it could be the case that a beta incorporating an old regulatory policy yields an ROE of 10%, however if a new policy is introduced and the risk of hold-up by the regulator increases, then the beta should increase and yield an ROE greater than 10%, for example 15%, reflecting the increase in risk. Since the calculation of beta is based on historical relationships this adjustment is not automatic.

[192] An example of a regulatory adjustment due to unforeseen circumstances is the NEB's abandonment of the generic formula for calculating ROE. In RH-2-94, the NEB established a general formula to calculate fair returns for pipelines under its jurisdiction. The ROE formula was based on the 10yr and 30yr Government of Canada Bond yields. After the 2008 financial market crash, governments undertook expansionary fiscal and monetary policies in order to stimulate the global economy. Expansionary monetary policies, such as quantitative easing, decreased interest rates. Subsequently, in 2009, the NEB's generic formula had to be discontinued due to depressed government bond yields generating abnormal results.

[193] Church, Jeffrey and Roger Ware. Industrial Organization: A Strategic Approach. New York: McGraw-Hill, 2000. Pg. 765.

usually much smaller in magnitude than the potential stranded costs. The net proceeds generated by the sale of the land in *Stores Block* was $6,550,000,[194] which is miniscule compared to the risk of not recovering a portion of $5 billion to $15 billion of sunk investment in an energy infrastructure project. Thus, the downside risk of a stranded cost outweighs the potential upside generated by a stranded benefit.

Equating Shareholder Return to the Risk-Free Rate and Impact of Recommended Framework

Various arguments have been made that investors, in cost-of-service utilities which are guaranteed to recover all prudently incurred costs, should receive a very low rate of return, equivalent to the risk-free rate.[195] The recommended framework, including a legislative amendment ensuring the recovery of prudently incurred costs, will drastically lower the fundamental business risk Canadian utilities face and eliminate the aforementioned asymmetric risk. However, this does not mean that the cost of equity capital will be the risk-free rate or that regulators should set the allowed rate of return equal to the risk-free rate.

It is important to recall that long-lived assets with very limited alternative uses, exhibit a large amount of internal risk. This implies that if they turn out to be less valuable than expected, there are not many mitigating mechanisms to avoid the associated losses. If they are more valuable than expected, competitive entry will erode any value going forward.[196] Rate regulation is intended to pass this high intrinsic risk to consumers in return for a lower market cost of capital and lower prices. This is done through mechanisms such as cost-of-service revenue protection, deferral accounts, rolled-in tolling for expansions and take-or-pay contracting to avoid volume variance risk.[197]

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194 Supreme Court of Canada, ATCO Gas & Pipelines Ltd. *v.* Alberta (Energy & Utilities Board), [2006] 1 S.C.R. 140, 2006 SCC 4. para [17].

195 For example see Rose (1996) or Maloney, Mccormick & Sauer (1997).

196 Written Evidence of A. Lawrence Kolbe for TCPL Business and Services Restructuring and Mainline 2012-2013 Tolls Application. Part D: Fair Return. The Brattle Group. September 1, 2011. Pg. 31.

197 Written Evidence of Paul R. Carpenter for TCPL Business and Services Restructuring and Mainline 2012-2013 Tolls Application. Part D: Fair Return. The Brattle Group. September 1, 2011. Pg. 45.

Transaction cost economics has defined this exchange as the regulatory bargain. In exchange for the exclusive right to provide affordable and consistent service, the utility is allowed to recover its sunk investment and earn a fair return on that investment. Regulators are supposed to act as arbitrators, which administer this long-term relationship based on sunk investments. If unforeseen circumstances and fundamental risks materialize, the regulator can mitigate opportunistic behavior and the hold-up problem. This framework is a less expensive option compared to the transaction costs associated with incomplete private contracting. Thus, by allowing the recovery of prudently incurred costs, the regulator would be fulfilling its role as arbitrator and minimizing the exposure to uncertainties and unforeseen risk.

Despite the drastic decrease in fundamental risk and the elimination of asymmetric risk arising from the recommended framework, the utility investors should not be subject to the risk-free rate. Financial and variability risk (through the potential disallowance of certain annual adjustment accounts affecting operating costs, such as fuel charges, interest rates or taxes), the risk of changes in the regulatory model (adopting performance-based regulation), and the risk of regulatory hold-up still exist. The magnitude of the risk premium required above the risk-free rate will depend on the extent that these risks can be diversified. If we assume that investors' expectations of increased risk due to stranded costs have not yet been captured by the cost of capital, then the beta variable should remain around its current levels once the recommended framework is adopted. If we assume that the current market data and CAPM models reflect the investors' increased risk due to stranded costs, then we can expect to observe a decrease in the beta variable due to the adoption of the recommended framework. However, in either case the beta would not be zero, as the risk-free rate proponents would suggest. The calculation of an appropriate risk premium over the risk-free rate, as a result of implementing the proposed framework, is beyond the scope of this paper and requires further market research.

Moreover, if the regulators adopted the recommended framework and set the allowed rate of return equal to the risk-free rate, then the regulated industry would struggle to attract any capital as investors would simply purchase government bonds and earn the same returns. Therefore, the fair return on a regulated asset should be lower than the average market return, but higher than the risk-free rate in order to attract adequate initial sunk investment. This portion of the premium over the risk-free rate can be thought of as a sunk liquidity premium, compensating investors for parking large amounts of capital in a sunk, long-term regulated asset. The alternative would be either deregulation or nationalization.

Being subject to a regulatory framework that does not properly adapt to increased fundamental risks will result in a disallowance of a reasonable opportunity to recover prudently incurred costs. In the long-term, this failure to protect investors will decrease the supply of capital and impact economic growth, creating an undercapitalized system of long-lived assets. In most developing countries, which face political instability and corruption, these types of long-lived assets are funded through the state (nationalized) and not by the private sector.[198] As is well documented in economic theory, nationalization is much more inefficient compared to proper regulation.

If the legislative amendment is adopted as outlined above, it will significantly reduce fundamental risk related to unforeseen circumstances, eliminate asymmetric risk, and if current cost of capital models have included the risk of stranded assets then it will reduce prices across the industry (if not, it will prevent prices from increasing). Historically it has been difficult to attract private investor capital to build energy infrastructure.[199] The status quo policy on the treatment of stranded assets and the regulator's refusal to acknowledge the created ex post regulatory risk, could debilitate decades of regulatory progress.

198 Private investors cannot diversify the extreme risk of holdup (equity expropriation) in countries with unstable political and democratic institutions.

199 Makholm, Jeff. "The Political Economy of Pipelines: A Century of Comparative Institutional Development." The University of Chicago Press (2012). Pg. 17.

Recovery of Stranded Costs

The recommended framework establishes that all prudently incurred sunk costs should be recovered. With the assumption that a utility is regulated under a cost of service model, the prescribed mechanism for cost recovery is the application of Ramsey pricing. Conventional economic theory of regulation has presented Ramsey pricing as the optimal pricing solution to minimizing deadweight loss. This part of the paper will explain the theoretical reasoning for the application of Ramsey pricing and offer comments on its practical implementation. It will also briefly comment on the appropriateness of cost recovery in the following scenarios; if a utility is regulated under Performance Based Regulation, such as a price-cap model, and in the extreme case, an exogenous demand shock materializes and the market becomes competitive.

Ramsey Pricing Defined

Public utilities offer products that are differentiated by customer class, geography, and time of delivery;[200] consider long-haul vs. short-haul service on a natural gas pipeline or the elasticity of demand of residential power consumers vs. industrial power consumers or consumption of electricity in the early morning vs. the afternoon. These are all examples of how natural gas or electricity consumption can constitute different products. In the rationale for economic regulation section of the paper, it was described that first-best pricing at marginal cost cannot be applied to a single product natural monopoly since it will result in negative economic profits.[201] Thus, the regulator can set prices equal to average cost (Ramsey Price) and achieve the second-best pricing solution. Ramsey prices will maximize total surplus subject to the constraint of the firm at least breaking even. The same scenario is observed with a multiproduct natural monopolist, however the existence of common costs complicates the second-best pricing solution for a multiproduct firm, because they give rise to economies of scope.[202] Thus in the multiproduct case, the price will not be set equal to average cost across all products, rather the prices will follow an inverse elasticity rule.

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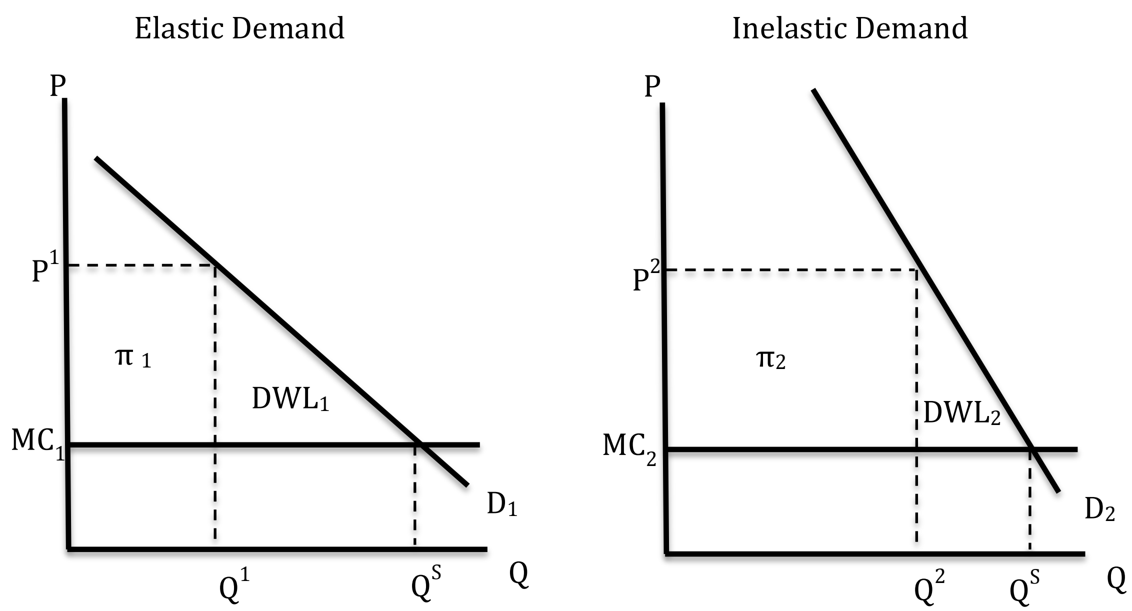
[200] Church, Jeffrey and Roger Ware. Industrial Organization: A Strategic Approach. New York: McGraw-Hill, 2000. Pg. 788.
[201] Assuming that it is a strong natural monopoly.
[202] Common costs are those that cannot be attributed to the provision of any specific product.

The inverse elasticity rule sets prices such that the difference between a product's price and its marginal cost varies inversely with the product's elasticity of demand. This means that the markets with relatively inelastic demand should have a higher price above marginal cost than the markets with relatively elastic demand.[203] In relatively inelastic markets, raising the price above marginal cost causes a lesser deadweight loss than raising the price in relatively elastic markets and therefore price discriminating in this fashion is more efficient than uniformly raising the price in all of the markets. The following model illustrates this relationship:



In this market a natural monopolist offers two products that have the same marginal costs of production, $MC_1 = MC_2$. The demand for product 1 is relatively elastic and the demand for product 2 is relatively inelastic. This diagram shows the impact of raising price above marginal cost by the same amount to P^1 and P^2. Increasing price, transfers consumer surplus to producer surplus in the form of economic rent (π), and decreases quantity from Q^s to Q^1 and Q^2, creating a deadweight loss (DWL). It can be observed that the effect of a price increase is more detrimental to total surplus in the elastic market, since the deadweight loss is bigger and the transfer to the producers is smaller. Thus,

203 Joskow, Paul. "Regulation of Natural Monopolies." Handbook of Law and Economics. August 29, 2006. Pg. 80.

$$DWL_1 = \frac{(Q^S - Q^1)\,(P^1 - MC^1)}{2} \quad > \quad DWL_2 = \frac{(Q^S - Q^2)\,(P^2 - MC^2)}{2}$$

And,

$$\pi_1 = (P^1 - MC^1)Q^1 \quad < \quad \pi_2 = (P^2 - MC^2)Q^2$$

This is the case because the elasticity of demand governs the quantity distortion arising from increased prices. This suggests that it is less costly to fund a firm's revenue requirement by increasing price in the inelastic market by more than in the elastic market, in this case increasing P^2 to a higher degree than P^1.[204]

Therefore, the Ramsey Rule proposes that a utility attempting to efficiently recover its stranded costs should increase rates for its inelastic ratepayers and decrease rates for its elastic ratepayers. Mathematically this procedure is given as follows:

$$\frac{P^1 - C^1}{P^1}\,\varepsilon_1 = \frac{P^2 - C^2}{P^2}\,\varepsilon_2$$

$$s.t.\ P^1 Q^1 + P^2 Q^2 - C(Q^1, Q^2) = F$$

Where, $\varepsilon_i = \dfrac{\%\Delta Q_i}{\%\Delta P_i}$

P^1 and P^2 are the respective prices, C^i represents marginal cost, ε_1 and ε_2 are the respective elasticities, $C(Q^1, Q^2)$ is the variable cost function, and F is the fixed cost.[205] If a multiproduct regulated firm is facing stranded costs it means that $P^1 Q^1 + P^2 Q^2 - C(Q^1, Q^2) < F$. Therefore it must increase prices above current levels in order to recover the

[204] Church, Jeffrey and Roger Ware. Industrial Organization: A Strategic Approach. New York: McGraw-Hill, 2000. Pg. 790-791.
[205] Church, Jeffrey and Robert Mansell. "Traditional and Incentive Regulation." The Van Horne Institute. 1995. Pg. 50-51.

entirety of its fixed costs.[206] Since market 1 is more elastic than market 2, then $\varepsilon_1 > \varepsilon_2$. Keeping in mind that $C^1 = C^2$, according to the Ramsey rule the firm should increase P^2 until all the stranded costs are recovered, reaching the second-best efficient solution.

Concerns with Ramsey Pricing Implementation

Despite the welfare-maximizing properties of Ramsey pricing, regulators have been reluctant to implement them. Opponents argue that implementation requires intensive information gathering which promotes asymmetric information, it is not Pareto improving, prices are not cost-based, and it discriminates on the basis of willingness to pay.[207]

Compiling information about the demand and cost functions a utility faces and calculating respective market elasticities requires access to detailed information, which might be costly to attain. Furthermore, strategic behavior by the regulated firm might lead to inaccurate reporting of demand and cost functions.[208] However, the regulatory process in Canada has become more rigorous with increasing transparency and accountability. Technological advancements in computer software have allowed for efficient recordkeeping and regulatory filing of costs. Rate case intervenors include highly sophisticated market participants and consumer advocate groups, which hire economic, engineering and accounting experts to determine costs and demand functions. Estimating the elasticity of demand or marginal costs cannot be too much more challenging than computing a fair return or a proper depreciation schedule or capital budgeting investment decisions which are all currently done as part of the regulatory process.

Absent a subsidization of the inelastic consumers, Ramsey pricing is not a Pareto improvement. Shifting from uniform pricing to Ramsey pricing will create winners and losers. The inelastic consumers can claim they are being held up, as this form of price

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[206] Stranded costs tend to materialize most frequently due to competition in the market leading to de-contracting of service. Thus increasing quantity (Q) is not an option and decreasing marginal cost (C) is not feasible because the marginal cost the natural monopoly faces is already minimal.

[207] Ibid., pg. 51-52.

[208] See VF Mechanism as example of how regulators can implement Ramsey prices without the ex ante knowledge of cost and demand functions.

discrimination aims to expropriate their sunk investment. However, the likelihood a firm would expropriate the value of a consumer's sunk investment depends on the impact of sunk investment on the elasticity of demand of the consumer.[209] Ideally a Ramsey pricing scheme would be established prior to the firm and consumers making sunk investments. Stranded costs often arise as a result of de-contracting of service, thus enforcing uniform pricing on elastic ratepayers might lead to further de-contracting, increasing the burden on inelastic consumers to a greater extent than Ramsey pricing would. At least with the application of Ramsey pricing the elastic consumers still continue to contribute quasi-rents to cover the fixed costs.

Regulators tend to be bound by the legislative requirement of setting just and reasonable prices. This includes prices that are cost-based and non-discriminatory. Ramsey pricing in this case is a form of third-degree price discrimination, as it discriminates on the willingness to pay of different ratepayer classes. However, stranded costs occur in *extraordinary* circumstances; when competition is introduced, new technology developed or force majeure events, meaning that Ramsey pricing will be applied in those specific cases in order for the firm to recover its prudently incurred costs. Along with cost-based and non-discriminatory principles, as part of the regulator's *just and reasonable* mandate, the regulator should ensure that the utility can recover its prudently incurred costs and attract future capital. Therefore the application of Ramsey pricing in the extraordinary events of stranded costs should not be interpreted as a definitive violation of the just and reasonable standard.

Cost Recovery Under Performance Based Regulation

Up to this point, it has been assumed that the utilities bearing the risk of stranded assets are regulated under a cost-of-service (COS) model. However, in various jurisdictions, incentive based or performance based regulation (PBR) has replaced the traditional rate of return or cost of service regulatory model. In fact, certain utilities under

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209 Biggar, Darryl. "Is Protecting Sunk Investments by Consumers a Key Rationale for Natural Monopoly Regulation?" Review of Network Economics. Vol. 8, Issue 2 (2009). Pg. 148.

the AUC's jurisdiction are regulated under PBR.[210] Incentive regulation attempts to de-couple regulated costs and prices, so that the regulated firm has incentives to reduce costs. PBR is intended to improve the performance of the regulated firm through the application of rewards or penalties beyond those existing in COS regulation.[211] PBR exposes a regulated firm to the risk of not recovering its revenue requirement, however it also rewards the regulated firm if it decreases its costs through an actual rate of return higher than the approved rate of return. A prominent mechanism for achieving the incentives under PBR is a price cap. Simply, a price cap establishes a fixed rate (usually for a period of five years, with a going-in-rate equivalent to the cost-of-service rate), which is adjusted annually by the rate of inflation less an offset of the total factor productivity variable, accounting for any industry-wide productivity improvements which are passed on to consumers through lower prices.[212] Therefore, the regulated firm is at risk for any cost and volume variances, but retains any increased profits (due to decreased cost or increased volume) above the initially established fixed rate.

It is easy to imagine the asymmetry created when recovery of all prudently incurred costs in rate base are guaranteed while a firm is under PBR. Rose (1996) explains that a distortion of intended incentives occurs if a regulator allows the utility to keep profits from efficiency gains, but simultaneously guarantees that any potential down-side loss from competition will be recovered from customers. However, the extent of the risk-reward asymmetry is exaggerated. If regulators guarantee the recovery of the net book value of prudently incurred sunk cost present in rate base, it does not mean that the utility will not be at risk of variances in operating costs such as administrative expenses, maintenance, payroll and other labor costs, fuel, taxes, etc. The risk-reward symmetry is still present with respect to decreases or increases in operating costs during

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[210] In 2010, the AUC established the Rate Regulation Initiative, intended to implement a form of PBR for electric and natural gas distribution companies, which were previously subject to cost of service regulation. Initially, the PBR mechanism would not apply to the electricity and natural gas services of transmission companies (which remain regulated under COS) or to retail electricity or natural gas sales. In 2012 (Decision 2012-237), the AUC approved a price-cap mechanism with cost of service going-in rates, for a period of five years for the electric distribution companies under its jurisdiction.

[211] Church, Jeffrey and Robert Mansell. "Traditional and Incentive Regulation." The Van Horne Institute. 1995. Pg. 87.

[212] Ibid., pg. 94-95.

the set term of the price cap, irrelevant of the risk for sunk capital cost recovery.[213] Furthermore, under the proposed framework, symmetry is present with respect to stranded benefits, because any benefits over net book value from the sale of a regulated asset would accrue to the ratepayers.

Assuming that the regulator adopts the recommended framework and allows the recovery of stranded costs, a different mechanism should be applied for utilities under PBR. Such a mechanism has been previously applied and it incorporates the price cap and profit sharing models.[214] The price cap formula is given as follows:

$$\Delta P_{it} = (PI_{(t-1)} - X_{(t-1)}) \pm Z_{(t-1)}$$

ΔP_{it}	=	percentage change in the price for customer class i in period t
$PI_{(t-1)}$	=	price index for latest reporting period (general inflation measure)
$X_{(t-1)}$	=	productivity offset from latest reporting data (total factor productivity)
$Z_{(t-1)}$	=	adjustment factor (captures stranded asset cost)

The regulator establishes the appropriate price ceiling for a specific period of time and adjusts it according to the price cap formula. Subsequently, the regulator would set an allowed cost of equity capital and a "dead-band" range around the estimated mean. This is reflected in the profit-sharing formula:

when $Y_e > Y_u$ then the utility is required to share excess profits with ratepayers:

$$Y = Y_u + g(Y_e - Y_u)$$

213 PBR can expose a utility to both volume and cost variance risk. Under the proposed framework a utility subject to PBR would no longer be exposed to volume risk, because the netbook value of stranded assets is allowed to be recovered. However, it would still be at risk for any cost variances. Therefore, the utility would recover its fixed costs, but could either; earn economic profits if it lowers its variable cost or suffer losses if its variable cost increases throughout the PBR term. Essentially, the utility would not have deferral account coverage for operating costs such as administrative expenses, maintenance, payroll, fuel and taxes, for the term of the PBR.

214 This mechanism was explained by Rose (1996). An Economic and Legal Perspective on Electric Utility Transition Costs. The National Regulatory Research Institute. July 1996. Pg. 94-100.

Y = rate of return on equity after price adjustment

Y_U = rate of return on equity at the upper boundary of the dead-band region

Y_L = rate of return on equity at the lower boundary of the dead-band region

Y_e = actual rate of return on equity

g = sharing ratio[215]

when $Y_e < Y_L$ then a symmetrical sharing of earnings occurs as ratepayers account for the earnings deficiency:

$$Y = Y_L + g(Y_e - Y_L)$$

when $Y_L \leq Y_e \leq Y_U$ then $Y = Y_e$, and the actual earnings are in the dead-band region and no sharing is necessary.

For example, if the dead-band region is determined to be between $Y_L = 5\%$ and $Y_U = 10\%$, and $g = 0.5$ and $Y_e = 15\%$ so the firm over-earns, then $Y = 10\% + 0.5(15\% - 10\%) = 12.5\%$. However, if $Y_e = 3\%$ so the firm under-earns, then $Y = 5\% + 0.5(3\% - 5\%) = 4\%$. And if Y_e is between 5% and 10% then the firm keeps its actual rate of return. The relationship between the Z factor in the price cap formula and the g variable in the profit-sharing formula is intended to be inversely proportional. So if the Z factor is high (meaning that most or all of the stranded costs are captured), then g is relatively low and the dead-band region is narrower. In such a case, the ratepayers bear the risk of stranded assets but they also receive a higher share of benefits from positive outcomes.[216] This model captures the cost-reduction incentives (exposure to variances in operating expense) while maintaining the prudency standard (Z factor allows for the recovery of prudently incurred sunk capital).

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[215] Equal to the share of the difference between the actual rate of return and the boundary rate of return, if g = 0 then Y_e is within the dead-band region.

[216] Rose, Kenneth. An Economic and Legal Perspective on Electric Utility Transition Costs. The National Regulatory Research Institute. July 1996. Pg. 102-103.

Exogenous Demand Shock

The prescribed cost recovery mechanisms are intended to be preventative measures, meaning that they are employed as mitigation or transitional mechanisms while some demand for the product or service still remains. However, in the case of an extreme exogenous demand shock, such as new technological advancements; making the products/services offered by the regulated firm entirely obsolete, or lowering costs and resulting in the deregulation of the industry, the former monopolist would not be able to apply a market power solution such as Ramsey pricing to recover its sunk cost.[217] In such a case, should stranded costs still be paid to the former monopolist?

According to Rose (1996), the goal should be to maximize dynamic efficiency, therefore the market should transition to full competition as quickly as possible and avoid compensating investors for stranded costs. Dynamic efficiency is reached in competitive markets, where consumers are choosing among various suppliers and producers are incentivized to reduce their cost of production. Rose explains that concerns of achieving dynamic efficiency should overpower concerns of static efficiency, because dynamic efficiency has more impact on social welfare.[218] Rose states that any attempt by the regulator to correct for static inefficiencies will only harm long-run efficiency, "*restricting the market's outcome (and its dynamic benefits) by supporting uncompetitive utilities (in the interest of static efficiency) only serves to delay the benefits of competition for consumers and hobbles potential competitors. The dynamic-efficiency gains from reduced costs, innovation, and lower prices to consumers, while difficult to predict, almost certainly outweigh any loss in static efficiency.*"[219] [220]

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217 As previously mentioned, in the electric generation industry, the regulated firms faced this doomsday scenario.

218 Rose, Kenneth. An Economic and Legal Perspective on Electric Utility Transition Costs. The National Regulatory Research Institute. July 1996. Pg. 30-31.

219 Ibid., pg. 32.

220 Interestingly, while Rose (1996) was establishing his argument that transition costs arising from the deregulation of the electric generation industry should not be recovered, he stated that infrastructure costs such as transmission and distribution should be sanctioned by regulators (as is argued in this paper). Rose supported an inclusion of an exit fee or a depreciation reserve to recover the cost of the stranded asset but not return on the asset, however, he stated that it would be unlikely that regulators would even consider denying cost recovery of transmission and distribution.

This argument against stranded cost recovery can once again be disputed on the basis of the asymmetry of the situation. For example, consider a firm that is regulated for decades because it is classified as a natural monopoly and thus subject to cost of service regulation, eliminating any possibility of earning economic rents. The asymmetry occurs once an exogenous shock permits the industry to become deregulated, and the firm is exposed to the same downside risk as a non-regulated firm, which had an opportunity to earn potential positive economic profits during periods of disequilibrium in the market.[221] If maximizing dynamic efficiency is the ultimate long-run goal, then the argument could be made that all industries should be deregulated and allowed to charge market-based rates, ignoring potential decades of monopoly rents and deadweight loss, because eventually technological change will lower marginal costs and entice sufficient market entry to eliminate the monopolist's rent. Despite this libertarian dream, there is enough economic research in the fields of industrial organization and regulatory economics to identify complete deregulation in all industries as imprudent. Imposing restrictive price regulation on the monopolist while it has market power, then, once its market power is gone, exposing the monopolist and its uneconomic assets to the rigors of a competitive market, would be an ideal outcome according to dynamic efficiency. But it would be hard to imagine any investors who would want to play this asymmetric game without the proper compensation for previous prudently incurred costs under regulation, which have now become uneconomic due to a major transformation of the industry.

Moreover, if the extent of the dynamic efficiency gain from a transition to competition is significant, it could be the case that a potential Pareto improvement can be achieved.[222] A potential Pareto improvement would mean that the winners from the transition to competition (entrant firms with lower marginal cost and consumers facing lower prices) can compensate the losers (the incumbent monopolist) and still be better

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[221] When regulators set the price equal to long-run average cost, the economic profits are zero, there is no economic rent available to the firm. In a non-regulated market it is possible to earn positive economic profits by charging market-based rates during periods of disequilibrium. The availability of economic rent creates incentives for new firms to enter the market. Thus, in the long-run, the equilibrium price will equalize quantity demanded and quantity supplied eliminating the availability of economic profits.

[222] A Pareto improvement is achieved when a reallocation of resources leads to increased efficiency and makes one participant better off without making anyone else worse off.

off. Brennan and Boyd (1996), further claim that the losers should be compensated for stranded costs so that they don't use their political power to impede efficient policies. Stranded cost payments to the formerly regulated firms would eliminate their incentives to oppose competition, and they would maximize their political efforts in support of competition because it maximizes net benefits in the economy.[223] Therefore, the allowance of recovery of stranded costs in the extreme situation of deregulation has the potential to result in a win-win situation for the ratepayers and the firm.

Role of the Regulator

The following section will provide suggestions for the regulator in the spirit of maintaining the sustainability of the recommended framework.

Understanding Objectives of the Regulatory Compact

Regulating in the public interest entails the promotion of safety, environmental protection and economic efficiency.[224] In the regulatory context, economic efficiency is comprised of allocative, productive and dynamic efficiency. Productive efficiency is reached when the regulated firm produces at the lowest cost over time. It has traditionally been associated with incentive-based (PBR) regulatory frameworks. Allocative efficiency, or marginal-cost pricing, is exhibited when the societal resources consumed in the provision of regulated service go to their highest valued use. Dynamic efficiency attempts to balance short-run and long-run investments, in making sure that the optimal amount of investment goes into the provision of the regulated service to meet the long-term interests of both the producers and consumers.[225] Transaction cost economics explains that investments in the energy infrastructure industry are transaction-specific, exhibiting high degrees of asset specificity and investment idiosyncrasy, giving rise to the holdup problem. Thus the industry participants require assurances that their sunk costs will not be expropriated. In order for the regulator to promote dynamic efficiency, it must

[223] Brennan, Timothy and James Boyd. "Stranded Costs, Takings, and the Law and Economics of Implicit Contracts." Discussion Paper 97-02 (1996). Pg. 22-23.

[224] Section 1.1 of the NEB Filing Manual (2015).

[225] Makholm, Jeff. Hearing Order RH-001-2014 TCPL Application for Approval of 2013 to 2030 Settlement Agreement. Appendix B to the Joint Written Evidence of the Market Area Shippers. National Economic Research Associates Inc. July 2014. Pg. 25-26.

ensure the continuity and predictability of the regulated prices and service terms. The regulatory compact has acted as the contract which ensures this continuity and predictability. Regulators and courts have been quick to dismiss or quibble over the specifics of the regulatory compact, such as defining franchise areas or certificates of public convenience and necessity.[226] However, the economic doctrine of transaction costs would suggest that the regulators interpret the regulatory compact as a broad implicit contract, which ensures that the institutional relationships that motivate the building of energy infrastructure remain intact.

Moreover, due to the inherent incompleteness of long-term contracts the regulators must act as arbitrators in order to reduce associated transaction costs. They have the re-balancing power, in accordance with *the just and reasonable standard*, to oversee negotiations when the terms of trade change as a result of unforeseen circumstances. Therefore, the regulators should apply the lens of contract and understand the significance of the regulatory compact in aiding them to reduce transaction costs associated with sunk capital investments and long-term private contracts. It is necessary for dynamic efficiency.

Prudently Incurred Costs

Critics of the proposed framework will claim moral hazard problems exist. They believe utilities will have no incentive to limit investments and costs since they are guaranteed to recover them. Furthermore, they discredit the validity of a prudency standard administered by regulators during regulated proceedings. They explain that the regulated firm will have superior information about the industry's cost and demand characteristics compared to the regulatory agencies and consumers.[227] Also the regulator could be captured, and therefore act in the interests of the regulated firm. Williamson (1996) criticizes proponents of guaranteed prudent-cost recovery, stating that they "*invoke opportunism to support their argument that compensation should be paid for stranded investments. However, they ignore opportunism as it relates to the*

[226] RH-003-2011 National Energy Board Reasons for Decision. March 2013. pg. 38.
[227] Rose, Kenneth. An Economic and Legal Perspective on Electric Utility Transition Costs. The National Regulatory Research Institute. July 1996. Pg. 70-71.

transformation of regulation through capture."[228] Asymmetric information problems exist in regulatory practice, and regulatory capture is a possibility, however, these worries are greatly exaggerated.

The effectiveness of interest groups in the regulatory process has minimized the utilities' information advantage. The intervenors in a rate case are sophisticated market participants and consumer advocate groups. They understand the nature of the regulatory process and continuously monitor policy and regulatory developments. As previously stated, they have economic, financial, accounting and engineering experts at their disposal to keep the regulated firms honest. In many ways they have helped shape regulatory policies and outcomes. Makholm (2012) provides evidence of this from the U.S., he states;

> "*economic history of the development of a market in legal entitlements to gas transport in the United States would be incomplete without recognizing the sustained collective action on the part of gas distributors and their state and municipal allies who acted in the interest of their constituencies of many millions of local gas consumers. It is no overstatement to say that the creation of the competitive gas transport market in the United States owes its existence to these doughty gas distributors, acting over decades through adversarial litigation.*"[229]

With regards to future investments, the ratepayers are well-organized and sophisticated parties which comprehend that under the proposed framework they will ultimately be responsible for stranded costs. Thus, it would be logical to presume they will demand a prudent amount of capacity. The moral hazard problem of over-investment is mitigated by the ex ante allocation of stranded risk, the ratepayers receiving any stranded benefits

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[228] Williamson, Oliver. "Deregulatory Takings and Breach of the Regulatory Contract: Some Precautions." N.Y.U. Law Review. Pg.1014.

[229] Makholm, Jeff. "The Political Economy of Pipelines: A Century of Comparative Institutional Development." The University of Chicago Press (2012). Pg. 150.

and the disallowance of rate of return on assets classified as no longer used and useful. Therefore, the regulators can be assured that the intervenors will perform their due diligence in the next rate case, as they are no longer naïve victims of the monopolist.

Moreover, advancement in software technology and social media has increased regulatory transparency and access, and thus reduced the probability of regulatory capture. In Canada, any citizen that is directly affected or can offer expert evidence has the opportunity to participate in a regulatory hearing. The hearing room is open to the media and electorate for observation. All of the evidence and transcripts are posted online for viewing on regulator websites. Social media has mobilized various pressure groups and given them substantial power to voice their concerns. The impact of social media and pressure groups on regulated proceedings can be observed in the Keystone XL and Northern Gateway cases. In both proceedings the regulators ultimately approved the projects but subject to stringent and costly environmental conditions. Transparency and access to the regulatory process act as a check on the regulator's integrity and thus greatly reduce the likelihood of regulatory capture. Furthermore, Canada's democratic political system has built-in checks and balances. The legislative branch has the power to re-examine a regulator's decision and the judicial branch can overturn cases where the regulator violates the extent of its powers and jurisdiction.

Asymmetric information concerns and the possibility of regulatory capture will likely never be entirely eliminated. However, in Canada, these concerns should be secondary compared to achieving an efficient level of investment in energy infrastructure, because the magnitude of costs related to regulatory holdup risk outweigh the cost of asymmetric information concerns identified by the A-J effect.[230] Furthermore, as

[230] The A-J effect of Averch and Johnson (1962) explains that a firm under COS regulation is not cost minimizing. The firm has an incentive to increase the extent of its capital accumulation in order to expand the volume of its profits (gold-plating). The firm can achieve this because it has superior information related to its costs compared to the regulator. However, there has not been significant empirical evidence to support the claims of the A-J effect. Gilbert and Newbery (1994) analyzed electric utility investment data from the 70s and 80s, and concluded that utilities underinvested due to the risk of hold-up by the regulator. They argue that the COS model ensures efficient long-run investment, because it allows for the recovery of costs and thus reduces the risk of hold-up in a long-run repeated relationship with the regulator (Church and Ware, pg. 850).

described above, the asymmetric information concerns are mitigated by the involvement of sophisticated market participants in the regulatory process. The likelihood of regulatory capture is greatly reduced through increased transparency and access in the regulatory process, and a well-functioning political system of democratic institutions offering checks and balances.

Approval of Capacity Additions

An acute understanding of market conditions is imperative for the regulator to make prudent decisions related to capacity additions. Allowing duplicative capacity could result in adverse total surplus impacts, as the gains of the entrant and gains in consumer surplus, due to lower prices, could be smaller than the losses of the incumbent.[231] Allowing bypass without the sufficient long-term demand to support the capacity additions will increase the likelihood of stranded assets. An example of the regulator making a well-informed decision is the EUB's rejection of the Nova Gas Transmission Ltd. (NGTL) application to construct an extension that would serve consumers in the Fort Saskatchewan area, which was already being served by ATCO Pipelines. Alberta's regulator stated that this could strand ATCO Pipeline's assets and thus have negative implications for the remaining ATCO Pipeline ratepayers.[232] Regulators must continue to make such prudent decisions with regards to duplicative capacity in order to avoid future stranded costs.

Furthermore, the application of Ramsey pricing could incentivize inefficient entry. Using Ramsey pricing to recover stranded costs will result in the inelastic consumers paying rates in excess of the stand-alone cost-based rates. The regulator should be aware that this scenario might provide incentives for profitable but inefficient entry. If entry is permitted it should be done with the caveat that entrants internalize the costs that their entry imposes on the incumbent. This can be achieved through a surcharge

[231] For further analysis, see "business stealing effect" where private incentives for entry are not the same as the socially efficient incentives for entry.

[232] AEUB Decision 2002-058. Nova Gas Transmission Ltd. Application to Construct Fort Saskatchewan Extension and Scotford, Josephburg and Atotin Sales Meter Stations. July, 2, 2002.

mechanism embedded in the entrant's toll, which would cover any potential stranded costs of the incumbent as a result of the entry.

Upon approving an asset's inclusion in rate base, the regulator should enforce periodical depreciation studies. Thus, ensuring that depreciation rates correspond to the economic useful life of the regulated asset, and mitigating any strategic behavior of the regulated firm. Moreover, the regulator should require that greenfield projects and extensions/expansions are underpinned by shippers who have proper credit metrics and sign long-term contracts, i.e. 15 - 20 years and not 1 – 8 years. Periodic depreciation studies and long-term contracts would safeguard sunk costs with probable assurances of recovery.

Monitoring of Costs Through Diligent Filing Requirements

In order to ensure compliance, the regulatory body should institute periodic reviews and audits of assets in rate base. The AUC's recent initiative of asset monitoring requirements is a step in the right direction.[233] The regulators already have the legislative authority to require the utilities to make additional filings to verify the continued operational purpose of specific assets. The continuation of these monitoring initiatives will lead to increased costs of regulation. However, these costs should be miniscule compared to the potential long-run efficiency gains.

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[233] AUC Bulletin 2012-09. "Stakeholder consultation on AUC Rule 002: Service Quality and Reliability Performance Monitoring and Reporting for Owners of Electric Distribution Systems and for Gas Distributors." September 13, 2012.

VII. Case Study: TransCanada Pipelines Restructuring Proposal

The following section will examine a case study, which could provide some insight into the adverse effects of adopting the status quo policy on the treatment of stranded assets.

Application

On September 1st, 2011, TransCanada PipeLines Limited (TransCanada), NOVA Gas Transmission Ltd. (NGTL) and Foothills Pipe Lines Ltd. (Foothills) (collectively referred to as TransCanada) filed an application with the National Energy Board (NEB) for an approval to implement a proposed restructuring of the services on the TransCanada Mainline pipeline system (Mainline), the TransCanada Alberta System (currently referred to as the NGTL System) and the TransCanada Foothills System. The following map displays the pipeline systems:

The purpose of the restructuring proposal was to mitigate the increased business risk faced by the Mainline. The Mainline is a natural gas transmission system that extends from Empress, Alberta across Saskatchewan, Manitoba, and Ontario and through Québec, and ultimately connects to various downstream Canadian and international pipelines.[234] The Mainline was in an unprecedented position, as it faced the following fundamental business risks:[235]

- supply risk from the maturing Western Canadian Sedimentary Basin (WCSB) and West-coast LNG markets,
- market risk from the Marcellus shale basin, which is closer situated to Eastern markets,
- competitive risk from the Alliance Pipeline, and
- regulatory risk from the uncertainty of recovering potential stranded assets.

The manifestation of these risks placed TransCanada in a peculiar predicament. The firm was constrained by competition and experienced de-contracting. The Alliance pipeline system by-passed the Mainline and the development of the Marcellus shale made it cheaper to import natural gas from the Northeastern United States than from the WCSB. As a result, the Mainline began to experience reduced demand in its Eastern Canadian markets and its export markets to the United States. Facing decreasing throughput, TransCanada was in danger of not meeting its revenue requirement and uniformly increasing tolls was not an option. Since increasing the price charged for the provision of service would make the Mainline even more uncompetitive. This threat of an eventual "tolling spiral" prompted TransCanada to restructure its service offerings.[236]

Prior to engaging in the analysis of the Board's Restructuring Proposal Decision, it is useful to briefly summarize the historical regulatory decisions which ultimately impacted the Mainline rate base recovery.

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[234] RH-003-2011 National Energy Board Reasons for Decision. March 2013. pg. 5.
[235] Fundamental risk refers to long-term business risk as opposed to variability risk, which refers to short-term, year-to-year variations in earnings and cash flows.
[236] RH-003-2011 National Energy Board Reasons for Decision. March 2013. pg. 27.

Brief Outline of Past NEB Decisions Impacting the Recovery of Mainline Rate Base

The Mainline was built in the 1950s to connect Western Canadian supply with Eastern Canadian markets. This all-Canadian system was backed by government policy since its inception. In 1966, the Federal government made an agreement with TransCanada requiring the Mainline to transport at least 65% of its volume each year to Eastern Canada.[237] In 1970, the NEB first reviewed the Mainline's rate base, determining that all the assets previously constructed were used and useful.[238] During the 1972 to 1995 period, the Mainline tolls were generally established through annual toll hearings.[239] The Board explained that it is its responsibility to determine the optimal capacity of the nation's pipeline systems:

> Clearly it is the Board's responsibility to prevent the construction by any applicant of facilities that are in excess of those needed to meet its market requirements, because excessive facilities construction simply has a burden of unnecessary expense upon consumers of natural gas. Equally clear is the Board's responsibility to avoid creating a shortage of gas in a market area by refusing to approve the construction of sufficient facilities to deliver the gas which would otherwise be available to that market in the volumes desired.[240]

During the 1980s, the pressure was mounting from producers for the expansion of the Mainline. The GH-2-87 and GH-5-89 proceedings are evidence of the Board's approach to approving expansion facilities that are supported by supply and demand of markets, and thus economically feasible. This policy meant that there was a reasonable

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[237] Business and Services Restructuring and Mainline 2012-2013 Tolls Application. "Part B: Background. Section 2.0: The TransCanada Pipeline Systems." September 1, 2011. Pg.7-8.

[238] RH-1-70 Decision, TransCanada Rates Application Phase I, page 4-2.

[239] RH-1-2002 National Energy Board Reasons for Decision. July 2003. Pg. 1.

[240] National Energy Board Report to the Governor in Council, In the Matter of the Application under the National Energy Board Act, of TransCanada PipeLines Limited, April 1972, pages 5-13.

expectation that the facilities would be utilized throughout their lifespan and prudent costs would be recovered.[241]

Traditionally, the Mainline primarily offered long-term service that was underpinned by long-term firm service contracts. Occasionally the pipeline system would have excess capacity available, the unused firm capacity was re-packaged as a short-term service. This short-term service was made up of Interruptible Transportation (IT) and Short Term Firm Transportation (STFT). IT service was provided on a daily basis subject to capacity availability. STFT service was offered for a term of 14 days to nine months. In both cases, the capacity was allocated through an auction process with a set minimum floor price and a bidding mechanism based on a shipper's willingness to pay.[242]

The IT service (previously known as Authorized Overrun Interruptible Service) was first approved in RH-1-72, in order to contribute to the recovery of the fixed costs of the Mainline. Therefore, the revenues that were generated from IT service were credited to the pipeline's revenue requirement. Initially, the IT rate was set at 90% of the firm toll. In RH-2-75, the Board approved a 10% increase so that the IT rate would equal the firm rate. In RH-1-78, due to an excess of gas supply, TransCanada proposed that the IT service be based on the incremental costs associated with providing the short-term service, thereby lowering the rate. The Board approved the Application. In RH-3-86, the Board set the IT toll at a higher level than the FT toll (firm service), as it determined that the IT toll should be set high enough to discourage shippers from signing up for IT instead of contracting for firm service. In its RH-3-94 decision, the Board approved minimum and maximum rates for IT service. TransCanada was permitted to charge an IT floor price equal to 50% of the FT rate (equal to the incremental variable cost of providing the service) and an IT ceiling price equal to 200% of the FT toll. In subsequent decisions the ceiling for a maximum IT rate was removed.[243]

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[241] Business and Services Restructuring and Mainline 2012-2013 Tolls Application. "Part B: Background. Section 2.0: The TransCanada Pipeline Systems." September 1, 2011. Pg.7-8.
[242] RH-1-99 National Energy Board Reasons for Decision. April 2000. Pg. 1.
[243] Ibid., pg.2-4.

In RH-4-93, the Board approved the STFT service, with a contract term of a minimum of one month. In 1996, the Board set the STFT floor price equal to 100% of the FT toll and the price ceiling equal to 300% of the FT toll. In 1997, the ceiling was increased to 400% of the FT toll.[244]

In 1995, in the RH-2-94 Decision, along with establishing a general formula for calculating a fair return for pipelines under its jurisdiction, the Board addressed the business risk faced by the Mainline.[245] The Board determined that the equity thickness of the Mainline should be set at 30%. The Board stated that the Mainline was a low risk pipeline and was less risky than unregulated industrial companies.[246] Expansions for the Mainline's capacity continued into the 1990s with GH-3-96, GH-2-97 and GH-3-98, all decisions adding substantial volume, and supported by producers and the Board.[247] In the GH-3-96 Decision, the Board stated that "*TransCanada is in the best position to assess the risks associated with the individual projects underpinning an expansion of its facilities and, in particular, to determine the risk associated with the recovery of demand charges. The Board continues to believe that TransCanada should have the discretion to determine whether there is reasonable expectation of a long-term requirement for capacity expansion.*"[248] However, it was not until the beginning of the 21st century that TransCanada began to worry about potential underutilization. The approval of the Alliance pipeline, and the increased production of Marcellus shale lead to the substantial de-contracting of the Mainline.

The Alliance Pipeline Limited Partnership (Alliance) filed an application in 1997 to construct and operate a 2335 km natural gas pipeline from northeastern British Columbia and northwestern Alberta to the Chicago, Illinois area. The related capital cost

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244 Ibid., pg.2-4.

245 The NEB applied a variation of the CAPM formula and used the 10yr and 30yr Government of Canada Bond yields as the risk-free rate benchmark.

246 Generic Cost of Capital National Energy Board Decision RH-2-94. March 1995. Pg. 25.

247 Business and Services Restructuring and Mainline 2012-2013 Tolls Application. "Part B: Background. Section 2.0: The TransCanada Pipeline Systems." September 1, 2011. Pg.9.

248 GH-3-96 National Energy Board Reasons for Decision. November 1996. Pg. 45.

of the project was approximately $2 billion.[249] The project had significant commercial support as 37 shippers, accounting for 98 percent of the capacity, signed 15-year contracts.[250] The project offered producers another outlet to transporting their product to market. This increased competition in the market for gas transmission, leading to lower tolls, was touted as a social benefit. Furthermore, Alliance's shareholders stated that they were willing to accept full risk related to future underutilization of its applied-for-facilities. [251] This ensured that any future stranded costs would be to the account of Alliance shareholders and not its shippers.[252] However, intra-Alberta the project offered direct pipe-on-pipe competition with NGTL, and outside of Alberta, it competed with the Mainline. Instead of the incumbent pipeline companies vehemently opposing the construction of duplicative facilities, they decided to sign a competition accord.[253]

On April 7, 1998, an "*Agreement on Natural Gas Pipeline Regulation, Competition and Change to Promote a Competitive Environment and Greater Customer Choice*" (Competition Accord) was signed by Canadian Association of Petroleum Producers, NOVA Corporation, NOVA Gas Transmission Ltd., the Small Explorers and Producers Association of Canada, and TransCanada PipeLines Limited. The Accord had the following three guiding principles:

- support for competition and greater customer choice;
- the need to construct competitive incremental pipeline capacity from the WCSB by both new competitors and existing pipelines alike in a timely, safe, and cost-effective manner; and

[249] National Energy Board. Reasons for Decision GH-3-97 The Alliance Pipeline Project. November 1998. Pg. xiv.
[250] Ibid., pg. xvi.
[251] Ibid., pg. 13.
[252] Due to the increased risk, Alliance's approved ROE was 11.25%, by comparison, the Mainline's ROE at that time was 9.9% determined by the NEB's generic formula.
[253] Agreement on Natural Gas Pipeline Regulation, Competition and Change, To Promote a Competitive Environment and Greater Customer Choice. April 7, 1998.

- the need to effect regulatory changes that would provide existing and new pipelines equal opportunity to compete, recognizing that such competition is desirable and in the best interests of all industry stakeholders.[254]

In exchange for producer support for the TransCanada-NOVA merger, TransCanada signed the Competition Accord, resulting in the withdrawal of substantial portions of evidence, which NGTL and TransCanada had filed in commercial opposition to Alliance.[255] [256] Interestingly, as part of the agreement, NGTL secured a plan to include any costs related to underutilized capacity in its cost of service, within the first five years of Alliance coming into service.[257]

Deliberating on a project that has; substantial commercial support, minimal commercial opposition, the potential for increased competition, lower tolls and greater netbacks, and the Applicant's shareholders accepting all risk related to potential stranded assets, the NEB decided to approve Alliance in its GH-3-97 Decision. This decision was made despite the fact that Alliance by-passed existing transportation systems.

Around the same time frame, the Board approved the Vector Pipeline. In GH-5-98, Vector Pipeline Limited Partnership (Vector) applied for the construction and operation of a natural gas pipeline that would provide transmission service between the large market hub located at Joliet near Chicago, Illinois and the existing hub located at Dawn, Ontario. The estimated cost of the pipeline was $35.4 million.[258] The project was

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[254] The ambitious goal of the industry, to develop a new regulatory framework that promotes competition, drastically failed. The deadline for a new comprehensive regulatory model of December 31, 1998, was not met. It was clear that industry negotiations could not provide an optimal framework of "regulated competition." Due to the diverse and conflicting interests of the stakeholders involved, it was impossible to come to an agreement in regards to major regulatory principles such as the distribution of costs. In 2003, the parties ceased negotiations related to the Accord. (Restructuring Proposal Application, Part B. pg. 18)

[255] National Energy Board. Reasons for Decision GH-3-97 The Alliance Pipeline Project. November 1998. Pg. 6-7.

[256] NEB Hearing Order GH-001-2014. NEB IR No.1 to CAPP. November 8, 2013. Pg. 2.

[257] Agreement on Natural Gas Pipeline Regulation, Competition and Change, To Promote a Competitive Environment and Greater Customer Choice. April 7, 1998.

[258] GH-5-98 National Energy Board Reasons for Decision. March 1999. Chapter 1.

underpinned by four shippers who signed 10 or 15 year contracts, making up 83 percent of the available firm capacity. Vector's affiliates, Enbridge Inc. and CoEnergy Trading Company made up 85 percent of the contracted capacity.[259] According to the Precedent Agreements (PAs), Vector and its shippers (composed mainly of its affiliates) would bear any future risk related to unutilized capacity.[260] Even though Vector is a relatively minor pipeline, it still provided further competition to the Mainline. During the proceeding, TransCanada submitted that the Board has relaxed its public interest test when it comes to approving pipe-on-pipe competition, which can have adverse risk impacts on the entire network of existing pipelines. TransCanada stated that the Vector application was devoid of demand and supply market evidence traditionally required to justify new facilities. However, TransCanada, still under the "Competition Accord," did not suggest that the Board go back to detailed market studies and reject the Vector application, instead it wanted the Board to allow a "*level playing field to permit incumbent and new market entrants to compete fairly.*"[261]

In its decision, the Board explained that the project is in the public interest because the economic benefits of increased competition and transportation choice outweigh the costs. With respect to potential third party costs related to underutilization of incumbent pipelines, the Board stated, "*risk is an essential element of competition. It should be noted that it is generally incumbents that have a competitive advantage in offering expanded capacity, because they are able to expand in smaller increments than a greenfield pipeline and can normally "roll-in" tolls. TransCanada argued that some of its shippers could be harmed because of Vector. However, Vector does not expect a lengthy period of excess pipeline capacity in Eastern Canada. The Board finds no evidence of the certainty or magnitude of potential harm and is not persuaded that it would be significant.*"[262]

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[259] Ibid., Chapter 4, Section 4.3 – Transportation Contracts.
[260] Ibid., Chapter 4, Section 4.2 – Markets.
[261] Ibid., Chapter 6 – Other Public Interest Considerations.
[262] Ibid., Chapter 6 – Other Public Interest Considerations.

As a result of the Alliance and Vector decisions the Mainline began to experience some contract non-renewals. An increasing number of shippers opted to not sign firm service contracts, and instead used the short-term services (IT and STFT) offered on the Mainline. In the RH-1-99 proceeding, TransCanada attempted to use its market power, in order to recover a greater amount of its fixed costs, by gaining full discretion in setting the floor price for its IT and STFT services. The Board rejected the proposal because it felt that the underutilization of the Mainline and the migration from FT to IT service is not a serious long-term problem.[263] [264]

During the RH-1-2001 proceeding, TransCanada explained that competition and supply risk have increased for the Mainline since it was last evaluated in RH-2-94.[265] Despite its claim, TransCanada was again reassured that its worries of underutilization would be temporary and the producers claimed that the supply from the WCSB would catch up to the excess capacity of pipeline transportation now represented by the Mainline, Alliance and Vector pipelines.[266] Nevertheless, TransCanada increased its depreciation rate from 2.64% in 2000 to 2.74% in 2001 and 2.89% in 2002, to accelerate the recovery of its rate base.[267] The Board rejected any notion of TransCanada bearing the risk of future de-contracting, stating that the Mainline had not been traditionally exposed to this risk:

> The Board sees a clear distinction between risk sharing and the sharing of the realization of such risk. Absent clear evidence that TransCanada has been imprudent or that its actions have caused contract non-renewals, the Board is not inclined to impose, after the fact, the financial impact of the realization of a risk that TransCanada

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[263] RH-1-99 National Energy Board Reasons for Decision. April 2000. Pg. 7.

[264] The Board did not adjust the floor or the ceiling levels of the STFT rate. The regulator also refused to allocate any fixed costs to the IT toll, as TransCanada had requested. The Board concluded that the floor price for the IT rate should remain fixed at 80% of the FT rate and represent incremental variable costs.

[265] RH-1-2001 National Energy Board Reasons for Decision. November 2001. Pg.9-10.

[266] Business and Services Restructuring and Mainline 2012-2013 Tolls Application. "Part B: Background. Section 2.0: The TransCanada Pipeline Systems." September 1, 2011. Pg.10.

[267] RH-1-2001 National Energy Board Reasons for Decision. November 2001. Pg. 4.

has not traditionally borne. The Board notes that no party suggested that TransCanada has been imprudent. Further, the Board is of the view that no party provided compelling evidence supporting the view that TransCanada's actions have caused contract non-renewals or have contributed to their severity. On the contrary, most parties acknowledged that the majority of contract non-renewals resulted from shippers opting to ship gas on competing pipelines.[268]

The Board rejected risk-sharing proposals from some intervenors, including a proposal for an exit fee. The Board directed TransCanada to continue to allocate the full cost of the pipeline to its firm shippers using the cost of service model. With respect to future risk of underutilization, the Board hoped that the industry "Competition Accord" would come up with a workable business and regulatory model for TransCanada. The Board recognized that the traditional regulatory framework has changed and that regulatory solutions would differ between a monopoly environment and a competitive environment.[269]

Faced with continued firm service de-contracting, TransCanada applied to adjust its cost of capital in RH-4-2001. TransCanada was seeking an ROE of 12.50% on an equity component of 40% to reflect the increased business risk, which would have increased its cost of service by approximately $265 million.[270] The Board rejected TransCanada's proposal and instead approved an ROE of 9.61% for 2001 and 9.53% for 2002, in accordance with its RH-2-94 formula.[271] The Board did, however, increase the equity thickness from 30% to 33%, stating, "*the Board concludes that the level of business risk facing the Mainline has increased since 1994, although it remains low. The increased business risk primarily reflects an increase in the risk resulting from pipe-on-pipe competition and increased supply risk. Other sources of risk have not changed materially.*"[272] Perhaps in a moment of reflection the Board stated, "*the Mainline's ability*

[268] Ibid., pg. 13.
[269] Ibid., pg. 14-15.
[270] RH-4-2001 National Energy Board Reasons for Decision. June 2002. Pg. 1.
[271] Ibid., pg. 56.
[272] Ibid., pg. 28.

to recover its full cost of service would be put in jeopardy if its throughput declined to a point where the resulting tolls exceeded what the market could bear. While there is no indication that such an outcome is to be expected, the possibility that it may happen appears to have increased since 1994."[273] Furthermore, the NEB recognized that the regulatory regime has allowed increased competition, but that it again saw no evidence that prudently incurred costs would not be recovered. It concluded by stating that a cost of service model still provides the Mainline the opportunity to recover its prudently incurred costs.[274]

During the RH-1-2002 proceeding, among other things, TransCanada sought an increased depreciation rate of 3.65% for the Mainline.[275] This increase was supported by an extensive depreciation study, which would result in an $88.3 million increase of depreciation expense for the 2002 period.[276] The Board approved most of the aspects of the depreciation study and concluded that the composite depreciation rate should be approximately 3.42%.[277]

The Mainline's 2004 Tolls Application, proceeding RH-2-2004, reflected continued increases in business risk. TransCanada again submitted similar arguments and sought approval of an 11% ROE on a common equity ratio of 40%. The Board's RH-2-2004 Phase II Decision dealt with the cost of capital aspects.[278] The NEB rejected TransCanada's ROE proposal and once again set the approved ROE according to the RH-2-94 formula, 9.56%.[279] However, the Board did allow an increase of equity thickness from 33%, approved in RH-4-2001, to 36%.[280] The NEB concluded, "*the Board finds that, overall, the business risk to which the Mainline is exposed has increased since RH-*

273 Ibid., pg. 26.
274 Ibid., pg. 27.
275 RH-1-2002 National Energy Board Reasons for Decision. July 2003. Pg. 4.
276 Ibid., pg. 29.
277 Ibid., pg. 43.
278 RH-2-2004 Phase II National Energy Board Reasons for Decision. April 2005. Pg. 4.
279 Ibid., pg. 90.
280 Ibid., pg. 80.

4-2001, as a result of increases in supply risk and competitive risk."[281] The Board refused to acknowledge increased regulatory risk, explaining, "*The regulatory model continues to provide the Mainline with a reasonable opportunity to recover its prudently incurred costs…While the Board acknowledges that regulators may be unable to protect the Mainline if tolls become uncompetitive, this has always been true and does not constitute a change in regulatory risk.*"[282] The Board did recognize that competitive forces might prevent the company from increasing its depreciation rates and expressed that if these risks are significant, the company could be appropriately compensated through the cost of capital.[283]

Around this time, improvements in drilling technology tapped into the vast resource of Marcellus shale gas in the United States. U.S. shale supplies grew from 1.4 Bcf/d[284] in 2004 to 13.7 Bcf/d in 2010, an increase of approximately 900 percent.[285] Subsequently, the Mainline lost over 1.5 Bcf/d of contracted volumes.[286] The following table displays the Mainline's throughput from 2000 to 2010:[287]

Year	Throughput (Bcf/d)[288]	Utilization Rate[289]
2000	6.8	97%
2001	6.0	86%
2002	6.4	91%
2003	5.9	84%
2004	5.7	81%
2005	6.3	90%

281 Ibid., pg. 47.

282 Ibid., pg. 45.

283 Ibid., pg. 46-47.

284 Abbreviation for billion cubic feet per day.

285 Written Evidence of Paul R. Carpenter for TCPL Business and Services Restructuring and Mainline 2012-2013 Tolls Application. Part D: Fair Return. The Brattle Group. September 1, 2011. Pg. 22.

286 Business and Services Restructuring and Mainline 2012-2013 Tolls Application. "Part B: Background. Section 2.0: The TransCanada Pipeline Systems." September 1, 2011. Pg.15.

287 Business and Services Restructuring and Mainline 2012-2013 Tolls Application. "Appendix C1: Throughput Study." Revised June 29, 2012. Pg.55.

288 The Western receipt points of the Mainline are used as the throughput proxy.

289 The Mainline's receipt capacity is 7 Bcf/d and is used as a 100% utilization proxy.

2006	6.1	87%
2007	5.7	81%
2008	5.2	74%
2009	4.3	61%
2010	3.4	48%

TransCanada had negotiated multiple toll settlements from 2005 until its RH-3-2011 Restructuring Proposal application, and introduced various services in an attempt to remain competitive.[290] Excluding an allowed equity thickness increase to 40% in 2007, the settlements followed the RH-2-94 ROE formula.[291] For the period of 2007 – 2011, TransCanada segmented its depreciation rate according to separate estimates of the economic lives of the Prairies line, the Northern Ontario line and the Eastern Triangle line of the Mainline system.[292] TransCanada applied higher depreciation rates for the Northern Ontario and Prairies lines than the Eastern Triangle line reflecting the utilization rates of the lines.[293] The approval of pipe-on-pipe competition and the discovery of new gas supplies closer to market have greatly increased TransCanada's business risk, and resulted in an unexpected worst-case scenario for both the firm and the federal regulator.

The aforementioned events led to the application of the Restructuring Proposal, which attempted to mitigate the increased business risk faced by the Mainline. The eventual Board decision dealt with many intricacies and issues. For the purposes of this paper, the focus will only be on the Board's perceived method of dealing with potential stranded assets.

<u>NEB View on Treatment of Stranded Assets in RH-003-2011</u>

TransCanada submitted that all of its Mainline assets, despite some underutilization, remain used and useful. However, due to the increased business risk facing the Mainline there is a chance that they could become stranded in the future.

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290 Ibid., pg. 17-21.
291 TransCanada PipeLines Limited 2007 Mainline Tolls Settlement Application. March 14, 2007. Pg.4.
292 Ibid., Settlement Section: pg. 4.
293 Ibid., Settlement Section: Appendix "B" Schedule of Depreciation Rates.

TransCanada believes that all costs included in the Mainline's rate base have been incurred prudently and that the firm should have the guarantee to recover the sunk costs and earn a return on those assets. Otherwise, a disallowance would be considered confiscatory and contrary to the regulatory compact. The Applicant warned that changing the terms of the regulatory compact, before an asset fully depreciates, due to changed business circumstances could substantially increase the entire industry's cost of capital. TransCanada further maintained that regulated companies face asymmetric downside risks that are much greater than their upside potential. Specifically, it stated "*an essential part of this "compact" was that one party cannot take advantages of cost-based tolls when the market could pay more and then abandon the agreement to its benefit when circumstances change...*"[294] Additionally, TransCanada claimed that there is no provision in either the NEB Act or the Gas Pipeline Uniform Accounting Regulations (GPUAR), which empowers the regulator to force a firm to write-down some of its assets.[295]

The intervenors disagreed with TransCanada's definition of the regulatory compact. They submitted that the regulatory compact does not protect a pipeline from adverse business conditions that impact its ability to recover all prudently incurred costs. Instead, they believe that the regulatory compact is there to protect the shippers from the potential abuse of market power by the pipeline. The intervenors referenced *Stores Block*, emphasizing that the pipeline owner bears all the risks of the assets it owns. Therefore, some intervenors demanded that certain underutilized assets be removed from rate base. They claimed that TransCanada has already been compensated for the risk of potential stranded assets through their historic rate of return, which has the potential for "economic obsolescence" embedded in the return structure.[296] Others proposed a securitization mechanism without a government backstop.[297] Another proposal was a cost sharing mechanism of underutilized assets, whereby the shareholders would take a write-down of

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294 RH-003-2011 National Energy Board Reasons for Decision. March 2013. pg. 33.
295 Ibid., pg. 26-28.
296 Ibid., pg. 35.
297 Ibid., pg. 47-48.

50% of the assets' value and the other 50% would be recovered through a securitization mechanism.[298]

The Board explained that it finds the regulatory compact "ill defined". The concept creates a fundamental flaw in setting just and reasonable tolls, because it means different things to different people. Thus, the Board prefers to rely on the prudency standard and the used and useful standard when setting just and reasonable tolls. However, the Board noted that the two regulatory standards can be in conflict, since "*the used and useful regulatory standard contemplates the potential disallowance of prudently incurred costs if the asset associated with that investment is not used and useful in providing service.*"[299] The Board also stated that Canadian courts have not reconciled the two in the context of NEB regulated pipelines. Ultimately, the regulator disagreed with the Applicant that all prudently incurred costs must be recovered. The NEB stated, "*we disagree with TransCanada's submission to the effect that the Board must approve tolls that allow recovery of all prudently incurred costs, even if the Board knew that those tolls could not be charged in the market. This would be an inefficient and non-sensical outcome*." The Board explained that allowing the recovery of all prudently incurred costs in all circumstances, would erode the management's responsibility for investment decisions and discourage the application of appropriate depreciation rates. Essentially, the regulator believes it would create inefficiencies in the energy infrastructure market and create a disincentive for a firm to find better uses for its assets.

The Board further disagreed with TransCanada's assertion that a disallowance would be confiscatory. The regulator explained that unlike the *Stores Block* case, the Board would not take any of TransCanada's property and redistribute it. Instead the firm would just not be compensated for owning those assets through tolls. The regulator feels that this maintains consistency with *Stores Block*, in that the ultimate risk of asset ownership is on the pipeline and not the ratepayers.

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298 Ibid., pg. 28-37.
299 Ibid., pg. 38.

Furthermore, the NEB stated that the Mainline's allowed cost of capital has always been above the risk-free rate, reflecting the embedded business risk, and that investors should have been aware that they could receive lower than expected returns. Regarding the Board's powers under the GPUAR, the regulator gave little consideration to the Applicant's claim. The regulator simply stated that the GPUAR does not constrain its authority under the NEB Act to set just and reasonable tolls.[300]

The NEB found practical flaws with the securitization proposals, as they did not include a government backstop. Besides, the Board decided to not disallow the currently underutilized Mainline costs. Therefore, it saw no value in lobbying the government to backstop a securitization mechanism for the Mainline. In fact, the Board clarified that it should be TransCanada who evaluates a securitization proposal and brings it in front of the Board when it sees fit.[301]

Analysis of NEB RH-003-2011 Decision

On the federal level there is no definitive regulatory precedent, such as the UAD Decision, related to the treatment of a pipeline's stranded assets. The RH-003-2011 Decision provides us with some degree of intuition as to how the NEB would handle stranded assets. The Board clearly stated that the prudency standard does not guarantee the recovery of all costs in all circumstances. The regulator expressed that it is not unfair for TransCanada to bear financial consequences of fundamental risk, since the company has been previously *awarded* a rate of return higher than the risk-free rate. As already explained in this paper, in cost of capital models, the risk-free rate is equivalent to the yield on a long-term government bond. An allowed rate of return is supposed to compensate investors in regulated natural monopolies by allowing them to earn a return equivalent to what they would earn on other similar risk investments. Therefore, it should not be compared to the risk-free rate (refer to previous section on compensation above the risk-free rate). Furthermore, government bonds have been greatly devalued since 2008 due to expansionary monetary policy and quantitative easing, this has drastically lowered

[300] Ibid., pg. 37-44.
[301] Ibid., pg. 45-50.

the risk-free rate. Therefore, the NEB decided to discontinue its formula for setting a fair return standard.[302] The following table provides the Mainline's allowed rate of return prior and post the Restructuring Proposal decision:[303]

Year	Mainline Approved ROE	Equity Ratio	NEB Formula ROE	LT Gov Bond Yield
2000	9.90%	30%	9.90%	6.00%
2001	9.61%	33%	9.61%	5.71%
2002	9.53%	33%	9.53%	5.63%
2003	9.79%	33%	9.79%	5.98%
2004	9.56%	36%	9.56%	5.68%
2005	9.46%	36%	9.46%	5.55%
2006	8.88%	36%	8.88%	4.78%
2007	8.46%	40%	8.46%	4.22%
2008	8.71%	40%	8.71%	4.55%
2009	8.57%	40%	8.57%	4.36%
2010	8.46%	40%	8.52%	4.30%
2011	8.08%	40%	8.08%	3.72%
2012	11.50%	40%	7.58%	3.06%
2013	11.50%	40%	7.23%	2.59%
2014	11.50%	40%	7.93%	3.52%
2015	10.10%	40%	7.64%	3.14%

As previously mentioned, it is evident that the Mainline's approved returns were based on the NEB ROE formula until the RH-003-2011 Decision. The NEB formula was established in 1995 and is mainly based on the CAPM model, as the regulator considered the risk-free rate and the market equity risk premium (MERP) in setting the fair return

[302] The NEB used an ROE formula based on the 10yr and 30yr Government of Canada Bond yields. The formula was discontinued in 2009 due to depressed government bond yields generating abnormal results.

[303] Mainline Quarterly Surveillance Reports. https://docs.neb-one.gc.ca/ll-eng/llisapi.dll?func=ll&objId=155521&objAction=browse&viewType=1

NEB Rate of Return on Common Equity. https://docs.neb-one.gc.ca/ll-eng/llisapi.dll?func=ll&objId=253088&objAction=browse&viewType=1.

standard.[304] The Board approved a 3% MERP.[305] Therefore, the NEB did not *award* the Mainline with higher returns until the increased market risk actually materialized and the Restructuring Proposal decision was in effect in 2012.[306] Kolbe (2011) calculated that the Mainline's overall risk corresponds to a cost of equity of 13.62% at a 40% deemed equity ratio. This calculation of a 13.62% ROE *does not* include an asymmetry risk premium over and above the cost of capital in order to actually compensate shareholders for stranded asset risk.[307] In the Restructuring Proposal decision, the Board approved an 11.50% ROE on 40% equity thickness. Not only did the Board not previously award the Mainline's shareholders for stranded risk, it still has not rewarded them by the proper amount, because it set the ROE at 11.50% without an asymmetry risk premium. This clearly *does not* compensate the shareholders for stranded asset risk.[308]

Moreover, the long-term return (1948-2010) on the S&P/TSX market averaged 12.3%.[309] So if investors had instead invested their money in the market, their returns would be higher on average. This point is sensible and important, the returns on average in the market are supposed to be higher since there is exposure to downside risk. Traditionally, due to the regulatory compact, investors could invest their funds into a low-risk utility and expect returns between 6%-10%. However, if the regulated asset is subjected to downside risk through stranded costs, limited opportunity of experiencing stranded benefits and no upside reward as it cannot charge market-based rates above the COS level, the investment in a utility becomes a lot less attractive compared to just investing in a diversified market portfolio aimed at yielding average market returns. In the long-run, if this added risk-exposure policy is preserved and the regulators do not

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304 CAPM = $r_f + \beta(\text{MERP})$

305 RH-2-94 NEB Decision Cost of Capital. March 1995. pg. 6.

306 The Board did allow a slight increase in equity thickness previously (2004 and 2007 rate hearings), reflecting some increases in risk.

307 Written Evidence of A. Lawrence Kolbe for TCPL Business and Services Restructuring and Mainline 2012-2013 Tolls Application. Part D: Fair Return. The Brattle Group. September 1, 2011. Pg. 8.

308 Refer to previous section to understand the proper level of compensation needed for stranded asset risk.

309 Written Evidence of Michael J. Vilbert in RH-003-2011. The Brattle Group. Workpaper #2 to Table No. MJV-9.

allow for a compensated increase in returns across the industry, there could be significant under-investment.

Furthermore, the Board has shifted the responsibility of avoiding lower returns exclusively onto TransCanada. The NEB suggested that the firm should redeploy or repurpose its assets, implicitly indicating that TransCanada should convert its underutilized natural gas assets to oil pipeline transportation (Energy East Project). [310] Also, the regulator stated that the shareholders should be able to foresee lower than expected returns in a regulated asset. Interestingly, the NEB avoided commenting on the approval of the construction of the Alliance and Vector pipelines and its effect on the competitive risk of the Mainline. Alliance enabled the continued replacement of long-haul contracts with short-haul contracts, which led to the displacement of long-haul supplies out of markets traditionally served by the Mainline and resulted in a reduction in Mainline throughput.[311] It can be argued that shareholders could not have foreseen the approval of pipe-on-pipe competition in a regulated natural monopoly environment. This would suggest that the Board also has some responsibility in sharing the future stranded costs of the Mainline. The Board declared, that "*no major NEB regulated natural gas transmission pipeline has been affected by market forces to the extent that the Mainline is now affected.*"[312] This statement might not be valid in the near future, since the Alliance pipeline is itself facing stranded asset risk amidst the continued growth and expansion of Marcellus Shale's market share.[313]

The Board believes that *Stores Block* clearly dictates that the benefits and risks of asset ownership are to the account of the pipeline company and not its customers. Moreover, the Board stated that it doesn't give much weight to the concept of regulatory compact. Specifically the regulator explained:

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[310] RH-003-2011 National Energy Board Reasons for Decision. March 2013. pg. 44.
[311] Ibid., pg. 157.
[312] Ibid., pg. 44.
[313] The impact of Alliance will be discussed later on in the paper.

> the regulatory compact as described by the Supreme Court of Canada in *Stores Block* is not directly applicable to TransCanada. The Mainline does not have a franchise area and TransCanada is not compelled by statute to provide service to customers in any area. Certificates of public convenience and necessity confer a right on TransCanada, not an obligation, to construct facilities for gas transportation service. As a result, we do not accept that the "regulatory compact" as described in *Stores Block* provides much assistance about how we should set tolls for the Mainline.[314]

The Board was able to defer any drastic action in RH-003-2011 as it concluded that the Mainline's fundamental risk has not materialized. Thus, the Board did not have to disallow any costs. In an outcome attempting to mirror the aforementioned El Paso and Transwestern risk sharing mechanisms, the NEB set the Mainline's toll below the COS-level to keep the asset competitive, allowed for discretionary pricing to offset revenue shortfalls, and increased the allowed rate of return to reflect the increased risk.[315]

The regulator anticipates that TransCanada's next toll hearing will deal with specific costs, at which point the regulator will administer the prudency standard and assess the sufficiency of TransCanada's management in diversifying the assets in the face of increasing competition when determining if costs should be disallowed from recovery in tolls.[316] Therefore, the NEB is going to eventually have to firmly rule on the stranded asset issue. This will create a federal-level precedent, which will surely include discussions over the regulatory compact, the interpretation of *Stores Block* and the AUC's recently established framework. Hopefully, the Board will consider the long-term implications of its impending decision.

[314] RH-003-2011 National Energy Board Reasons for Decision. March 2013. pg. 38.
[315] Discretionary pricing refers to the Board's decision to allow TransCanada to set the floor price for its short-term services (IT and STFT) at any level it wants to. In its Restructuring Proposal Decision, the Board decided to allow TransCanada to exercise its market power by charging unrestricted discretionary rates in order to aid in the recovery of its remaining fixed costs.
[316] Ibid., pg. 45-46.

Settlement with Eastern LDCs

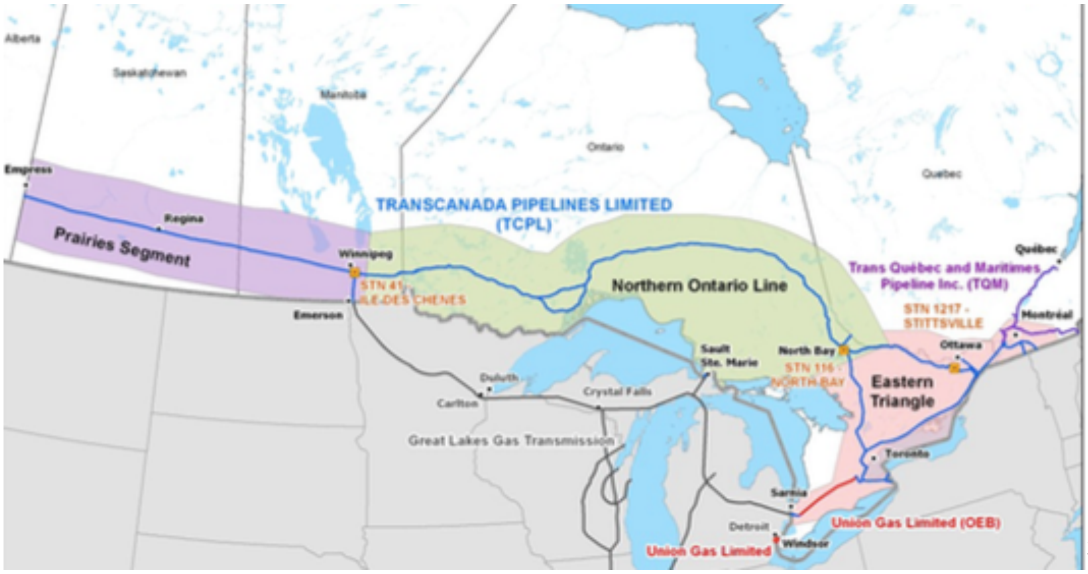
As a result of the RH-003-2011 Decision, both TransCanada and the intervenors were uncertain as to who would ultimately bear the risk of deferral accounts for revenue shortfalls associated with further long-haul de-contracting.[317] TransCanada additionally worried about its ability to recover future investment cost where there is new demand for capacity. The major Eastern Local Distribution Companies (LDCs)[318] were demanding an expansion of the Eastern Triangle facilities in order to source more gas from the Dawn hub and other eastern receipt points.[319] However, TransCanada did not have an incentive to expand its facilities due to cost recovery uncertainty. Facing this predicament, the LDCs and TransCanada negotiated a settlement that would provide the LDCs with additional capacity and mitigate the stranded cost risk faced by TransCanada.

The Board approved the Settlement in December 2014. Specifically, as part of the proposal, TransCanada will build additional capacity for short-haul shippers (with minimum 15-year contract terms) to satisfy the increasing supply from the Marcellus Shale basin. The pipeline company was allowed to apply a rolled-in tolling methodology for the expansion facilities. In a similar fashion to the 2007 segmentation of depreciation expense, the Settlement segments the Mainline by separating the short-haul (Eastern Triangle) rate base and cost from the long-haul (NOL and Prairies Lines). The following map displays the segmented regions; Prairies Lines (purple), NOL (green), and Eastern Triangle (pink)

[317] The Mainline now operates under a risk-adjusted cost-of-service model, however it still has deferral accounts which capture certain revenue shortfalls and cost variances.

[318] The LDCs include Enbridge Gas Distribution, Union Gas and Gaz Metro.

[319] Makholm, Jeff. Hearing Order RH-001-2014 TCPL Application for Approval of 2013 to 2030 Settlement Agreement. Appendix B to the Joint Written Evidence of the Market Area Shippers. National Economic Research Associates Inc. July 2014. Pg. 14.



[320]

TransCanada was able to mitigate some of its future stranded cost risk by establishing the Long-Term Adjustment Account[321] and the Bridging Amortization Account[322], which act as deferral accounts effectively cross-subsidizing the western (long-haul) part of the Mainline pipeline system until 2020.[323] The shippers on the Prairie and NOL lines will be isolated from costs related to the Eastern Triangle expansions, in addition the Eastern LDCs will pay for the revenue shortfalls arising from the underutilization of the Prairie and NOL segments of the Mainline through the aforementioned deferral accounts.[324] As a result the LDCs will face an increase from the

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[320] RH-003-2011 National Energy Board Reasons for Decision. March 2013. pg. 51.

[321] The Long-Term Adjustment Account contains the existing Mainline deferral account balance (TSA balance) and it aims to eliminate any and all variances between the actual and forecast Revenue Requirement and actual and forecast revenue during the period from January 1, 2015 to December 31, 2020. The account will be allocated 100% to the Eastern Triangle after December 31, 2020. The amortization of the account at the Eastern Triangle's composite depreciation rate will continue after the Term until the account balance equals zero. (Mainline 2013-2030 Settlement Application Section 3. Pg. 36)

[322] Bridging Contribution is the revenue shortfall allocated to the Eastern Triangle, Prairies and NOL segments after adjusting the Eastern Triangle short-haul tolls to recover costs of the Eastern Triangle and applying compliance tolls for the remaining paths. The shortfall allocated to the Prairies, NOL and Eastern Triangle long-haul are recovered in tolls from 2015–2020 and the shortfall allocated to Eastern Triangle short-haul is recovered in tolls from 2015–2030. (Mainline 2013-2030 Settlement Application Section 5. Pg. 54)

[323] RH-001-2014 National Energy Board Reasons for Decision. December 2014.

[324] Makholm, Jeff. Hearing Order RH-001-2014 TCPL Application for Approval of 2013 to 2030 Settlement Agreement. Appendix B to the Joint Written Evidence of the Market Area Shippers. National Economic Research Associates Inc. July 2014. Pg. 18.

tolling levels set in the RH-003-2011 Decision by 52% for Eastern Triangle short haul, 18% for Eastern Triangle long haul, and 12% for all others. Since the tolls the LDCs pay on the Mainline are “pass-through” costs, this means that Ontario consumers will effectively be subsidizing Manitoba and Saskatchewan consumers.[325] This is an interesting outcome, considering the Board does not usually approve tolls that could be construed as discriminatory.

In 2010, TransCanada filed an application for 2011 interim tolls essentially proposing a Ramsey pricing scheme, by instituting a Mainline Surcharge on the Alberta system shippers.[326] The tolling structure would have resulted in increased tolls for the inelastic Alberta shippers and decreased tolls for the long haul elastic Ontario Mainline shippers.[327] The Board rejected the proposal.[328] Furthermore, in the Restructuring Proposal (RH-3-2011), the Board rejected the Alberta System Extension, which attempted to use a “Transportation by Others” (TBO) mechanism to shift costs from the Mainline to the Alberta System, citing it was discriminatory and would unduly cross-subsidize the Mainline to enhance its competitiveness.[329] The 2014 Settlement’s unusual outcome is a result of the Board not allowing TransCanada to recover its fixed costs from inelastic shippers, instead it inadvertently shifted cost burdens from Alberta, Saskatchewan and Manitoba consumers onto Ontario consumers. The elastic Eastern LDCs should face the lowest rates (excluding the expansion costs) since they have been the ones de-contracting and accessing Marcellus shale, unfortunately for Ontario

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325 The LDCs themselves do not bear the costs of the subsidy, they pass on the costs to the retailers, who will in turn pass them on to final consumers.

326 TransCanada PipeLines Limited. Mainline Interim 2011 Tolls. December 9, 2010.

327 Due to the 2008 NGTL and ATCO Pipelines commercial integration, the Alberta shippers became highly inelastic. Intra-Alberta natural gas consumers have no alternative to the NGTL System (formerly known as the Alberta System). The remote Saskatchewan and Manitoba consumers have limited alternatives to the Mainline. Conversely, the Ontario consumers have become elastic, due to the development of Marcellus Shale and the construction of Alliance and Vector pipelines.

328 NEB Order. Application for Approval of Mainline Interim 2011 Tolls and Alberta System 2011 Interim Rates. December 23, 2010.

329 RH-003-2011 National Energy Board Reasons for Decision. March 2013. pg. 77.

consumers this is the result of a regulatory decision leading to adverse settlement negotiations between TransCanada and the Eastern LDCs.[330]

To further mitigate the risk of underutilized assets, TransCanada is repurposing part of the Mainline, as it officially filed an application with the NEB with respect to the Energy East project on October 2014. The project will convert approximately 3,000 km of existing TransCanada Mainline natural gas pipeline for oil transportation service.[331] The transfer of facilities from TransCanada to Energy East Pipeline Ltd. (subsidiary of TransCanada) includes a $500 million acquisition premium (not included in Energy East rate base, thus it constitutes a write-down for shareholders), which will further reduce the Mainline rate base.[332]

The Settlement and the Energy East project have greatly decreased the potential future risk of stranded assets on the Mainline. The risk-mitigating strategy employed by TransCanada was made possible due to market circumstances (assuming Energy East is approved and built). However, it did not come without some cost to TransCanada's shareholders including the $500 million acquisition premium and continued, although greatly minimized, stranded risk exposure on the Prairie and NOL lines (remaining rate base to recover post-2020 on the Prairie line will be approximately $1 billion).[333] The end result from the RH-003-2011 Decision and the Settlement is that TransCanada continues to face potential future stranded costs, compensated by a 10.1% ROE (which is not adequate to correctly compensate shareholders for stranded cost risk). [334] The Ontario

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[330] It would be interesting to compare the welfare of Ontario consumers in the following scenarios;

i. accessing gas from the WCSB with tolls set below COS, due to the application of Ramsey pricing and inelastic Alberta shippers cross-subsidizing long haul shippers (as TCPL originally proposed),
ii. accessing gas from Marcellus Shale with the trade-off between the Mainline expansion facilities cost and cross-subsidization of the Prairie and NOL lines cost (as is the current situation),
iii. maintaining the RH-003-2011 Decision tolls and signing long-term contracts on another system's expansion facilities or a greenfield expansion from the Marcellus Shale basin.

[331] Energy East Pipeline Ltd. Asset Transfer Application. Executive Summary. October 2014. Pg. 1.

[332] Ibid., pg. 3.

[333] RH-001-2014 National Energy Board Reasons for Decision. December 2014. Pg. 84.

[334] In RH-001-2014, the Board lowered the allowed rate of return to 10.1% to reflect the mitigated risks of the Settlement. However, the Mainline's actual ROE for 2014 was 13.06%, due to the ability

consumers face increased tolls due to the stand-alone costs of the Eastern Triangle expansion and the cross-subsidization of the Prairies and NOL lines. And the entire industry is uncertain as to how potential stranded costs will be dealt with once fundamental risks actually materialize.

Impact of Alliance

By assessing the Mainline's legislative record it becomes evident that had Alliance not been approved, the Mainline and the consumers would be better off.[335] The Mainline would have had a better opportunity to recover its prudently incurred costs, its business risk would have been relatively lower and thus yielded a lower cost of capital and lower tolls. It is true that the NEB could not have foreseen the development of Marcellus Shale, the sophisticated market participants, who signed long-term contracts on Alliance, and the Alliance investors, who accepted full exposure to potential stranded cost, did not expect it either. However, the Board has a duty to make decisions for the *public interest* and not solely approve projects because the markets enabled a transaction through underpinning financial commitments.

The Board should have recognized that the only reason Alliance was able to receive favorable financial commitments was because the contract renewals at the time were short-term and the contracts for existing systems were expiring (up for renewal) allowing shippers to exit the incumbent systems.[336] The Mainline traditionally offered long-term contracts of 15 years or more, and when excess capacity was available, short-term contracts of one to three years were offered. However, facilities were not built to accommodate short-term service. If additional capacity was needed for long-term service,

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to keep revenues generated from discretionary pricing (in the form of interruptible tolling service) allowing for an inflated ROE. The Mainline earned over $341 million in discretionary pricing revenue in 2014. (Mainline 2014 Quarterly Surveillance Reports)

335 MacAvoy (1998) calculated that Alliance would add more than $617 million in present discounted costs of providing service in Alberta due to its by-pass of NGTL. Doleman (2012) calculated that the costs of Alliance outweigh the benefits. The net cost of Alliance entering the market was between $2.28 billion and $3.96 billion. This calculation included the capital costs of the project, the deadweight loss of Mainline shippers (due to higher tolls) and the benefits of shipper netbacks.

336 Church, Jeffrey. "An Economic Analysis of the Alliance Pipeline." University of Calgary. October 1998. Pg. 26.

upon six months notice, a short-term shipper would have to either sign up as a long-term shipper or get bumped from the system (the bumping provision).[337]

Prior to the GH-2-87 proceeding, TransCanada removed the bumping provision from its tariff in response to shipper demands.[338] Subsequently, the Board changed the contract terms on the Mainline and ruled that contracts could range from; a one year minimum to any maximum with automatic rights of renewal subject to a six month notice period.[339] Due to the elimination of the bumping provision and implementation of renewal rights, TransCanada would begin to build facilities to accommodate short-term service demand. The Board's Decision introduced the concept of short-term contracts serving long-term markets.

In GH-5-89, TransCanada and its long-term shippers were concerned with the economic feasibility of expansion facilities that were underpinned by short-term contracts with flexible renewal rights. These parties were worried that the long-term shippers would face the entire risk of unutilized capacity costs if short-term shippers decided not to renew. Despite the expressed concerns of non-renewal, the Board reaffirmed its decision on the one year minimum term and the six month notice policy, stating that the "*existing tariff provisions have given shippers flexibility in choosing the term and form of transportation services to meet the particular circumstances of their long-term market requirements. The evidence also suggests that these tariff provisions, together with the removal of the bumping provision from TransCanada's tariff, have enhanced the development of a more market-oriented and competitive gas environment. Therefore, the Board is not persuaded that any changes to the existing short term contract and renewal rights provisions in TransCanada's tariff are warranted.*"[340] As the level of short-term contracts continued to increase, TransCanada again attempted to change the renewals policy (proposing an 18 month renewal period and an exit fee) in RH-4-93, but the Board

337 RH-3-86 Reasons for Decision. National Energy Board. May 1987. Chapter 10.1.1 – 10.1.3.
338 GH-2-87 Reasons for Decision. National Energy Board. July 1988. Pg. xv.
339 Ibid., pg. 83-86.
340 GH-5-89 Reasons for Decision. National Energy Board. November 1990. Chapter 4.1.

once again rejected the proposal justifying its decision with similar comments made in GH-5-89.[341]

In 1996, TransCanada first recognized the competition risk arising from the proposed Alliance project. [342] TransCanada noted that the ratio of short-term contracts was increasing due to the renewal policy and expressed concerns related to future pipeline underutilization.[343] In yet another attempt to alter the renewal policy, TransCanada proposed a Right Of First Refusal (ROFR) mechanism in RH-1-97. Among other detailed provisions, the ROFR attempted to increase the renewal period to 20 months and only allow for the building of new facilities if they were supported by a minimum of 10-year contract terms.[344] In order to appease CAPP's request, the Board chose to hear the dispute over contract renewal rights in a separate second phase proceeding, RH-3-97.[345] The RH-3-97 hearing never commenced as TransCanada requested that the Board adjourn the application *sine die*, and in 1999, TransCanada entirely withdrew the application stating that the concerns would be addressed as part of a broader industry discussion.[346] Subsequently, Alliance was approved and built, and the migration to short term contracting on the Mainline continued along with former Mainline shippers signing long-term contracts on the competing system.

In order to mitigate the risk from the Mainline's renewal policy and the competitive impact of Alliance, the Board should have approved Alliance on the condition that its investors internalize the costs that their entry creates on incumbent transmission systems. In fact, during the Alliance proceeding, Amoco proposed that Alliance set aside a contingency fund that would cover any future stranded costs on

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[341] RH-4-93 Reasons for Decision. National Energy Board. June 1994. Pg. 61.
[342] TransCanada Pipelines Limited. Annual Report 1996. Management's Discussion & Analysis. Pg. 18.
[343] TransCanada Pipelines Limited. Annual Report 1997. Management's Discussion & Analysis. Pg. 24.
[344] RH-3-97 TCPL Initial ROFR Evidence. National Energy Board. Pg. 8-9.
[345] RH-1-97 Reasons for Decision. National Energy Board. September 1997. Pg. 1-2.
[346] TransCanada Transmission. Contract Renewal Rights & Expansion Policy Requirements. July 19, 1999.

existing pipelines as a result of Alliance entering the market.[347] The Board rejected this proposition asserting:

> that Amoco's contingency fund suggestion was not supported by other parties. The Board finds that there is little merit in the suggestion, particularly given the willingness of the affected pipeline companies to negotiate a settlement. It is not clear that there will be any costs imposed on third party shippers on other pipelines. Without any certainty of these costs, the Board believes that it would be unfair to saddle Alliance with the onerous financial requirement to create a contingency fund.
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> Moreover, the Board agrees with those parties who argued that the Alliance Project will create benefits for third parties. Therefore, it would be unreasonable to require Alliance to compensate third party shippers for potential costs when these shippers may, in fact, receive indirect benefits from the Project due to potentially higher netbacks, greater choice, and the increased competition that will take place among gas transportation providers.[348]

The *affected pipeline companies settlement* the Board is referring to, is the previously mentioned "Competition Accord." Thus, the arrogance of the industry believing it can formulate a competitive regulatory model without fundamental technological change altering the entry barriers of large sunk costs, economics of scale/scope and long-term contracts, cannot be ignored. But the naivety of the regulator trusting that the industry could achieve such an unprecedented and complex task is puerile. Church (1998) warned that the fundamentals of gas transmission had not changed and that the reduction of regulatory oversight runs the risk of being counter-productive and resulting in unrestrained exercise of market power, inefficient transmission systems, and/or a lack of

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[347] GH-3-97 Reasons for Decision (The Alliance Pipeline Project). National Energy Board. November 1998. Pg. 36.
[348] Ibid., pg. 39.

investment and capacity. The establishment of the "Competition Accord" and the approval of Alliance are examples of this risk, which the entire industry (including the regulator) imprudently decided to embrace.

The impact on the Mainline has already been addressed, however Alliance itself now faces the risk of stranded assets, which its shareholders had voluntarily accepted. In 2015, the original contracts expired and that forced Alliance to negotiate a new proposal in a now more competitive environment. The result was that Alliance adopted a price cap model with an initial rate lower than the cost-of-service (COS) rate. Alliance proposed a 10-year levelized revenue requirement of approximately $368 million per year, yet it would only recover on average $206 million (56%) through its commercial support.[349] Furthermore, about 85% of the contracts signed on Alliance are under 5 years in length.[350] As of December 31, 2015 Alliance's total rate base is $1.342 billion.[351] Unlike in the Mainline RH-003-2011 Decision, in the RH-002-2014 Decision, the Board did not allow Alliance to set unlimited bid floor levels for seasonal and interruptible services which would have permitted Alliance to exercise market power in an effort to recover a larger portion of its sunk cost.[352] In a reassuring statement, reminiscent of the Board's comments in the RH-4-2001 Decision, the NEB concluded that Alliance should continue to be highly utilized in the near future, and that no evidence exists to suggest that firm contracts will not be renewed, or that by-pass infrastructure would be built, or that Alliance's competitiveness was eroding.[353] However, only time will tell if the fate of Alliance resembles that of the Mainline, Alliance's shareholders must be hoping history doesn't repeat itself.

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349 Ibid., pg. 16-17.

350 RH-002-2014 National Energy Board Reasons for Decision. July 2015. Pg. 17.

351 Alliance Pipeline Ltd. Quarterly Surveillance Report for the Month Ending December 31, 2015. February 29, 2016. Schedule 3.

352 This is perhaps an appropriate outcome as Alliance's shareholders voluntarily accepted future risk of stranded costs, therefore the regulatory compact does not apply in Alliance's case.

353 RH-002-2014 National Energy Board Reasons for Decision. July 2015. Pg. 52.

Mitigating the Current Situation

Almost all of the scenarios that Joskow (1991) identified for a breakdown of the regulatory compact were existent in the Mainline case:

Scenario of Regulatory Compact Breakdown	Mainline Case
Rapid cost-reducing technology	Technological advancements in horizontal drilling allowed for the increased production of Marcellus Shale
Competitors allowed to enter the market	NEB approval of Alliance and Vector pipelines
Buyers permitted to by-pass utility to take services from a proximate utility	Shippers with firm contracts up for renewal on the Mainline chose to not renew and instead signed long-term contracts on Alliance
Excess capacity	Mainline experienced de-contracting due to development of Marcellus Shale and approval of Alliance and Vector
Cross-subsidization discriminating against large customers with substitution possibilities	Elastic Ontario consumers subsidizing the Prairie and NOL portions of the Mainline[354]

Instead of the Board dismissing the vital concept of the regulatory compact, it should accept that mistakes were made leading to its breakdown and attempt to mitigate the current situation.

The Board shouldn't have approved Alliance and Vector without considering and assessing the tradeoff between an increase in allocative efficiency and a reduction in cost efficiency when entry is permitted in a regulated market. The Board shouldn't have trusted that industry could effectively negotiate a competitive regulatory framework where everyone "wins."

After the construction of Alliance and Vector, the Board should have either; guaranteed that the Mainline would be able to recover its prudent costs under the traditional regulatory framework (maintaining the RH-3-94 formula ROE) *or* it should

[354] It is important to note that this ability to discriminate against large consumers might not last long, as the elasticity of the consumers increases.

have ruled that the Mainline's shareholders bear the risk of stranded assets and properly compensated them for that risk through the escalation of its cost of capital and an additional risk premium. Rather, the Board chose to hope for the best-case scenario; that all the pipelines would have sufficient demand for capacity in the future.

In 2011, once the Mainline was in an unprecedented situation due to increased competition and loss of markets, the Board should have ignored the misinterpretations arising from *Stores Block* and allowed TransCanada to apply Ramsey pricing to recover its sunk costs from the inelastic Alberta consumers.

In examining the 2014 Settlement, the Board should have recognized that the Ontario consumers are burdened with subsidizing the underutilized portions of the Mainline, and that the approved rate of return does not begin to compensate shareholders for future stranded risk.

Despite the outcome of past NEB decisions, the Board still has an opportunity to learn from its previous experience and adopt the outlined recommended framework. Going forward, by applying the principles within the regulatory compact for stranded cost recovery, the Board can properly determine just and reasonable tolls; the pipelines would be guaranteed to recover the book value of their prudently incurred costs, as a result the cost of capital would be lower, and barring an extreme exogenous demand shock, the application of Ramsey pricing could efficiently recover any future stranded costs.

VI. Conclusion

Transaction cost economics has enlightened the traditional rationales for regulation. It has explained that regulation exists to provide administered relational contracts between the firm and its customers, decreasing transaction costs associated with incomplete private contracting. This arrangement depends on the exclusive provision of an essential service in return for the recovery of the significant sunk cost and a fair return to the firm providing the service. The regulator exists to govern this intricate relationship. Naturally, this relationship exposes the regulated firm to regulatory risk. A regulator can ex post, expropriate a firm's quasi-rents (capital investment) by instituting prices which equal marginal cost or allowing competitive entry in the market or adopting other policies which hinder the firm's ability to recover sunk costs. If this becomes the norm, investors in regulated firms, will anticipate these adversarial policies and will protect themselves by ultimately underinvesting or demanding a high rate of return. This will result in greater costs, capacity constraints and losses of efficiency. It is imperative to minimize exposure to regulatory risk if the market is to remain regulated, because exposure to regulatory risk will negate efficient expansion or replacement of sunk investments.[355]

The courts' interpretation and regulators' application of regulatory economic principles garnered from *Stores Block*, threatens to increase the regulatory risk traditionally faced by utilities and energy infrastructure firms. This paper recommends a legislative amendment, which specifies that regulated firms are guaranteed to recover all prudently incurred sunk costs and any stranded benefits should be distributed to the ratepayers. This framework creates a balanced treatment of stranded costs and benefits, which will be reflected in an appropriate level of fair return to the shareholders. It assures the regulator can achieve its public interest objectives by providing proper tradeoffs between producer and consumer surplus. Adversaries will claim that this policy recommendation creates an information asymmetry issue and is susceptible to regulatory capture. However, in practice these worries are greatly mitigated through the effective participation of interest groups, and the transparency and accessibility of the Canadian

[355] Church, Jeffrey and Roger Ware. Industrial Organization: A Strategic Approach. New York: McGraw-Hill, 2000. Pg. 766 - 769.

regulatory process. Furthermore, the regulator can enforce strict prudency standards. This can be achieved by:

- engaging in market studies which will investigate the supply-demand balance and inform if the proposed capacity additions will result in bypass or excess capacity in the market,
- considering the tradeoff between an increase in allocative efficiency and a reduction in cost efficiency if an entrant is permitted in a regulated market,
- requiring shippers/ratepayers to sign long-term contracts that will underpin greenfield projects and expansions/extensions,
- continuing to institute proper depreciation studies and mandating depreciation rate updates, and
- applying stricter cost and accounting filing requirements and monitoring.

The predicament over the proper treatment of stranded assets carries with it economic, legal, political and social consequences. At its core is the interpretation and application of the regulatory compact. The regulatory compact establishes the rules governing the relationship between the utility and the regulator. It should be safeguarded by judicial and legislative powers. As a result of recent judicial and legislative decisions, the regulatory compact in its current state does not *guarantee* the recovery of all prudently incurred costs and a reasonable return. It merely offers an *opportunity* for a utility to recover prudently incurred costs and earn a reasonable return. However, the premise of the compact is to limit competition. If competition arises in the market the *quid pro quo* for natural monopoly service provision is distorted. Due to the inherent regulated limitation on the upside of natural monopoly returns, it is rational to conclude that the regulatory compact would imply limited downside risk. But this has not been the policy enacted by the courts and regulators since *Stores Block*. The narrow and controversial Supreme Court decision has been used as a tool for irresponsible policy setting. This paper has cautioned that the misinterpretation of the regulatory compact has resulted in adverse changes to the traditional, principle-based, utility/regulator relationship. Utilities and pipeline companies will not invest in transaction-specific infrastructure if they do not have proper assurance of recovering their sunk costs, otherwise they will demand significant compensation to reflect increased business risk, which would increase costs across the entire industry. Joskow (1991) also warned against imprudent changes in the regulatory compact, "*the attributes of the traditional regulatory contract can only be understood by examining both its ex ante and ex post properties and by looking at the various provisions of the contract as an integrated whole. Changing one significant feature of the contract can undermine the viability of the entire relationship.*"[356]

Successful regulatory institutions support the regulatory compact through; effective legislation that protects a utility's private property, the establishment of just and reasonable rates for cost recovery, accessible and transparent regulatory proceedings, and unbiased judicial review of regulatory decisions. The courts and regulators should recognize that the status quo policy in regards to the treatment of stranded assets should be amended. It will ultimately restore the intentions of the regulatory compact and provide a more efficient societal outcome.

[356] Joskow, Paul. "The Role of Transaction Cost Economics in Antitrust and Public Utility Regulatory Policies." Journal of Law, Economics, & Organization, Vol.7 (1991). Pg. 73.

Appendix A.

Below is a chronological set of events leading to the AUC's Utility Asset Disposition Decision and recent Court of Appeal of Alberta decision related to stranded assets.

- *August 28, 2001* - ATCO Gas (AG) filed an application with the Alberta Energy and Utilities Board (EUB, predecessor to the AUC), for the approval of the sale of its properties located in Calgary known as Stores Block. The property consisted of land and buildings, the market land value exceeded the value of the buildings.

- *October 24, 2001* – The Board approved the sale of the property in Decision 2001 – 78.

- *March 21, 2002* – In Decision 2002-037, the Board allocated the net proceeds from the sale of the property, the shippers were awarded approximately two thirds of the value and AG received a third.

- *December 6, 2002* – AG appealed Decision 2002-037 to the Alberta Court of Appeal.

- *January 27, 2004* – The Alberta Court of Appeal decided that the Alberta Energy and Utilities Board did not have jurisdiction to allocate the sale proceeds from the private property of a utility. The Court determined that the Board's allocation of the proceeds of the sale to customers was taking the property of AG, and for the Board to do so it must have express or implied authority. Such authority would derive either from statute or common law, which the Board does not possess.

- *May 11, 2005* – The City of Calgary obtained leave to appeal the Alberta Court decision to the Supreme Court.

- *February 9, 2006* – In the Calgary Stores Block Decision, the Supreme Court determined that the Board did not have the proper authority to revise the distribution of proceeds from the sale of a utility's discarded assets. Effectively the Supreme Court ruled that the regulatory compact does not cancel the private nature of the utility or allow ratepayers to implicitly acquire ownership or control of the utility's assets by paying rates. The decision had important implications with regards to the interaction of regulatory powers with the private property rights of a utility and the scope of a regulator's condition-making power.[357]

- *April 2, 2008* - The AUC initiated the Utility Asset Disposition proceeding, which was intended to consider the potential rate related implications for Alberta utilities due to the Supreme Court's Calgary Stores Block Decision.

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[357] Stikeman Elliott LLP, Energy Law Update, Supreme Court Limits Regulator's Jurisdiction over Proceeds of a Discarded Utility Asset Sale, March 2006, pg.2.

- *April 11, 2008* – ATCO Utilities suggested that submissions in the Utility Asset Disposition Proceeding be deferred until the Alberta Court of Appeal rendered decisions in respect of several appeals of certain EUB decisions relating to AG Carbon natural gas storage facilities.

- *October 21, 2008* – ATCO Utilities filed a Motion requesting suspension of the Utility Asset Disposition proceeding.

- *November 28, 2008* – In Decision 2008-123, the AUC suspended the Utility Asset Disposition proceeding.

- *June 4, 2012* – In Decision 2012-154, with respect to a review and variance application of the 2011 generic cost of capital decision, the Commission noted that a stranded assets issue had arisen and directed that the matter be further considered in the suspended Utility Asset Disposition proceeding.

- *June 8, 2012* – In Decision 2012-156, in regards to a review and variance application of the ATCO Gas 2011-2012 General Rate Application Phase I decision, the Commission expressed that an issue with respect to production abandonment costs had arisen and also directed that the matter be further considered in the suspended Utility Asset Disposition proceeding.

- *October 17, 2012* – The AUC decided to recommence the Utility Asset Disposition proceeding to address Stores Block related matters. The Commission is also intending to begin a 2013 Generic Cost of Capital proceeding. The Utility Asset Disposition proceeding will establish whether it is the utility or the ratepayers that bear the risk of stranded assets and the applicability of those findings to the 2011 and 2012 test years. The 2013 GCOC proceeding will consider the impact of the risk determination and whether any adjustments to the fair return is required.

- *April 4, 2013* - The Commission indicated that following the filing of reply argument in the UAD proceeding, it will start deliberations.

- *November 26, 2013* – The Commission issues Decision 2013-417 (UAD Decision), concluding that shareholders are at risk for any stranded cost.

- *June 8, 2015* - Alberta Utilities appeal the UAD Decision to the Court of Appeal of Alberta.

- *September 18, 2015* - The Court of Appeal of Alberta dismisses the appeal, concluding that the AUC has the expertise and public interest mandate to determine just and reasonable tolls and thereby can decide how it should treat stranded costs.

- *April 21, 2016* – In March 2016, the Alberta Utilities filed an application to seek leave from the Supreme Court to appeal the Alberta Court of Appeal Decision. A motion to extend the time to serve the application for leave to appeal was granted by the Supreme Court in April. The application is currently pending.

Appendix B.

Below are the 19 AUC Principles established from *Stores Block*.

(a) The Commission derives its jurisdiction from its enabling statutes. The limits of the Commission's powers "are grounded in its main function of fixing just and reasonable rates (rate setting) and in protecting the integrity and dependability of the supply system." (*Stores Block*, para 7)

(b) The Commission will apply the "no harm test" in assessing an application for approval to dispose of a utility asset outside of the ordinary course of business under Section 26(2) of the *Gas Utilities Act* or Section 101(2) of the *Public Utilities Act*. (*Stores Block*, paras 13 and 77; *Harvest Hills*, para 31)

(c) Utility assets are the property of the utility. Customers do not obtain a property interest in utility assets by virtue of receiving, and paying for, utility service. (*Stores Block*, paras 63, 64 and 68)

(d) Utility shareholders are entitled to the net proceeds of disposition of an asset sold outside of the ordinary course of business. Shareholders receive any gain and must bear any financial loss arising upon disposition. "Ownership of the asset and entitlement to profits or losses upon its realization are one and the same." (*Stores Block*, paras 67, 39 and 70)

(e) "Shareholders have and they assume all risks as the residual claimants to the utility's profit." Utility "shareholders are the ones solely affected" when the actual profits or losses of a sale outside the ordinary course of business are realized; "the utility absorbs losses and gains, increases and decreases in the value of assets, based on economic conditions and occasional unexpected technical difficulties, but continues to provide certainty in service both with regard to price and quality." (*Stores Block* paras 68 and 69)

(f) The Commission may impose a condition to its approval of a disposition of a utility asset sold outside of the ordinary course of business which requires the utility to give "undertakings regarding the replacement of the assets and their profitability." It could also require as a "condition that the utility reinvest part of the sale proceeds back into the company in order to maintain a modern operating system that achieves the optimal growth of the system." (*Stores Block*, para 77)

(g) Para 77 of the *Stores Block* decision means that the Commission may impose a condition to its approval of a disposition of a utility asset sold outside of the ordinary course of business "if there was a close connection between the sale of the asset and the immediate resulting need to replace it." (*Harvest Hills*, para 35)

(h) Four criteria must be satisfied before the Commission may attach a condition to its approval of a disposition of a utility asset sold outside of the ordinary course of business:

(i) there must be a disposition of property by a utility
(ii) the sale must be outside of the ordinary course of business, giving rise to the jurisdiction of the Commission to review the transaction
(iii) there must be a close connection between the sale of the asset and the need to replace it
(iv) the need to replace the asset must be immediate, in other words the need to replace the asset must arise at the same time as the disposition (Decision 2011-450, para 300)

(i) Para 81 of the *Stores Block* decision, wherein the court commented on the ability of the EUB to convene "a hearing of the interested parties in order to modify and fix just and reasonable rates to give due consideration to any new economic data anticipated as a result of the sale," must be read in the context of the entire decision and the principle that ratepayers do not receive a property interest in utility assets. (Decision 2009-004, pages 14 and 15)

(j) The words "used or required to be used" in Section 37 of the *Gas Utilities Act* "are intended to identify assets that are presently used, are reasonably used, and are likely to be used in the future to provide services. Specifically, the past or historical use of assets will not permit their inclusion in the rate base unless they continue to be used in the system." (*Carbon*, paragraph 23)

(k) The "only reasonable reading of s. 37 is that the assets that are 'used or required to be used' to provide service are only those used in an operational sense." (*Carbon*, para 25; *Salt Caverns*, para 56)

(l) The Commission has "no jurisdiction to include in rate base, assets which were not being used or required to be used in providing service to the public, in an operational context." (*Salt Caverns*, para 14)

(m) The *Gas Utilities Act* "does not contain any provision or presumption that once an asset is part of the rate base, it is forever a part of the rate base regardless of its function. The concept of assets becoming 'dedicated to service' and so remaining in the rate base forever is inconsistent with the decision in *Stores Block*…." "Previous inclusion in the rate base is not determinative or necessarily important." (*Carbon*, para 29)

(n) "Past or historical use of assets does not permit their inclusion in rate base unless they continue to be used in the system." An "asset no longer used to operate the utility is no longer part of the rate base, whatever its history or earning capacity." (*Salt Caverns*, paras 14 and 54)

(o) Revenue generation alone is an insufficient basis upon which to include an asset in the rate base of a gas utility. Customers "have no interest in the profits, unregulated revenues, or unregulated businesses of the utility." (*Carbon*, para 30)

(p) The Commission has the responsibility to determine the rate base, including "what assets (still) are relevant utility investment on which the rates should give the company a return." (*Salt Caverns*, paras 30, 31 and 52)

(q) A gas utility may unilaterally withdraw an asset from rate base that it considers no longer used to provide service to the public within Alberta; provided that, should the utility act imprudently in removing an asset from rate base, the Commission may disallow recovery of the resulting financial impacts from customers. (*Salt Caverns*, paras 51 and 53)

(r) Gas utility assets that no longer have an operational purpose and are no longer used or required to be used by the utility in providing service to the public in Alberta, no matter what the historical use of such assets, should be removed from rate base and should not be reflected in customer rates. (Decision 2011-450, paras 312 and 315; Decision 2012-068, para 147)

(s) The effective date for removal of a gas utility asset from rate base and customer rates is the earlier of: (i) the date that the utility advises the Commission that the asset is no longer used or required to be used; or (ii) the date the Commission determines that an asset no longer has an operational purpose and is no longer used or required to be used to provide service to the public. (*Salt Caverns*, paras 28, 31, 51, 52, 53 and 56; Decision 2009-253, para 54; *Calgary Leave*, paras 23 and 25; Decision 2012-068, paras 146 and 147)

Appendix C.

Capital Asset Pricing Model (CAPM)

$$\mathbf{R_e = R_f + \beta(MERP)}$$

- R_f = risk-free rate
  - Yield on long-term government bonds

- MERP = Market Equity Risk Premium (R_m - R_{fh})
  - Difference between average historical market returns and the historical risk-free rates
- β = Beta
  - Measures the market risk for a security
  - $\beta = 1$, is the market portfolio of all investable assets
  - $\beta < 1$, lower volatility than the market, or volatile non-correlation with the market
  - $\beta > 1$, volatile asset, moves up and down with the market
  - Beta is estimated using linear regression:
    - $r_a \approx \alpha + \beta r_b + \varepsilon$
    - $\beta = \text{cov}(r_a, r_b) / \text{var}(r_b)$
    - r_a is the return of the specific stock (asset) and r_b is the market return (benchmark)

Discounted Cash Flow Model (DCF)

$$\mathbf{Re = (D_1 / P_0) + g}$$

- D_1 = the next expected dividend or D_0 (1+g), D_0 is the most recently paid dividend
- P_0 = current market share price
- g = the expected long-term average growth rate in dividends and earnings

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