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Developments in Newfoundland and Labrador Offshore Royalties: From Hibernia to Hebron and Back

This paper traces the historical development of the offshore oil and gas royalty regime for Newfoundland and Labrador, from the first negotiated private royalty agreement for the Hibernia project, through the application of both generic and project-specific regulatory schemes applicable to later projects, up to the Hibernia Southern Expansion. The variations in key provisions across the six major projects are reviewed, with regard to royalty structures, transportation cost eligibility, cost and production allocation, dispute settlement and legislative stability clauses. Finally, the prospect for application of innovations and solutions developed to date to future projects is considered.

L'article retrace l'histoire du développement du régime de redevances sur les hydrocarbures de la région extracôtière pour Terre-Neuve-et-Labrador depuis la première entente de redevances négociée pour le projet Hibernia; pour ce faire, il examine l'application de régimes réglementaires génériques et de régimes réglementaires spécifiques aux plus récents projets jusqu'à l'extension sud du réservoir Hibernia. Les différences entre les dispositions clés des six principaux projets sont passées en revue aux chapitres des structures de redevances, de l'admissibilité des frais de transport, de l'allocation des coûts et de la production, du règlement des différends et de la stabilité législative. Enfin, les auteurs examinent la possibilité d'appliquer à de futurs projets les innovations et les solutions élaborées jusqu'à maintenant.

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I. *Background*

The jurisdictional disputes between Canada and the Province of Newfoundland and Labrador (the Province) with respect to the Newfoundland and Labrador offshore area (the offshore area) have been chronicled elsewhere.[1] Under the current statutory scheme in the *Canada–Newfoundland Atlantic Accord Implementation Act*[2] (the *Federal Accord Act*), and the *Canada–Newfoundland and Labrador Atlantic Accord Implementation Newfoundland and Labrador Act*[3] (the *Provincial Accord Act* and, collectively with the *Federal Accord Act*, the *Accord Acts*), the *Federal Accord Act* imposes royalties on petroleum produced from the offshore area. The history of the negotiation and the nature of the *Accord Acts* has been discussed previously.[4] For our purposes it is sufficient to note that the *Accord Acts* constitute "mirror" legislation by Canada and

1. See Shawn Denstedt & RJ (Jack) Thrasher, "The *Accord Acts* Twenty Years Later" (2007) 30 Dal LJ 287 at 288-289 and authorities referenced there.
2. *Canada–Newfoundland Atlantic Accord Implementation Act*, SC 1987, c 3 [*Federal Accord Act*].
3. *Canada–Newfoundland and Labrador Atlantic Accord Implementation Newfoundland and Labrador Act*, RSNL 1990, c C-2 [*Provincial Accord Act*].
4. For a more detailed discussion of the framework and operation of the *Accord Acts* see Dendstedt & Thrasher, *supra* note 1 at 289-293.

the Province that creates a joint management regime for the exploration, development, and production of petroleum from the offshore area.

1. *Legislation*

Section 97(2) of the *Federal Accord Act* reserves, and makes "each holder of a share in a production licence" in the offshore area liable to pay, to the federal Crown the "royalties...that would be payable in respect of petroleum under the [Newfoundland and Labrador] *Petroleum and Natural Gas Act*[5] if the petroleum were produced from areas within the Province."[6] Section 97(4) of the *Federal Accord Act* makes the *Petroleum and Natural Gas Act* (the *P&NG Act*) and any regulations made under the *P&NG Act* apply to the offshore area and any references in the *P&NG Act* to the provincial Crown are deemed to be references to the federal Crown.[7]

Part II of the *P&NG Act* deals with royalties. There are two ways to impose royalties under Part II: (1) by regulation; and (2) by an agreement made by the Province under section 33 of the *P&NG Act*, which agreement prevails over regulations made under Part II where the agreement is inconsistent with those regulations.[8] Part II was amended extensively in 2001.[9] Section 47 of the *P&NG Act* provides that "leases issued after April 1, 1990" are subject to these amended royalty provisions, but that leases issued before April 1, 1990 are subject to the royalty "provisions... in force...before the..." amendments came into effect.[10]

Production Licence 1001 (PL1001), which comprises the Hibernia Development Project (Hibernia), was issued on 21 March 1990 and is the only production licence issued on or before 1 April 1990. Accordingly, PL1001 is subject to the provisions in the *P&NG Act* as they read before the 2001 amendments. All subsequent production licences issued in

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5. *Petroleum and Natural Gas Act*, RSNL 1990, c P-10 [*P&NG Act*].
6. *Federal Accord Act*, *supra* note 2, s 97(2).
7. *Ibid*, s 97(4)(a).
8. The relevant provisions of the *P&NG Act*, *supra* note 5, are ss 32 and 33:
   Royalty share
   32 Petroleum produced under a lease is subject to and an interest holder is liable for and shall pay royalty share to the Crown in an amount and in a manner prescribed by regulation.
   Royalty agreement
   33 (1) The Lieutenant-Governor in Council may make an agreement with an interest holder, with one or more holders of shares in a lease or with another person, including an agreement that is inconsistent with regulations made under this Part.
   (2) Where an agreement made under subsection (1) is inconsistent with regulations made under this Part the agreement shall prevail.
9. See *An Act to Amend the Petroleum and Natural Gas Act*, SNL 2001, c 41.
10. The term "lease" in the *Oil Royalty Regulations* must be interpreted by reference to s 30 of the pre-amendment *P&NG Act*. This provision states that for royalty purposes, "lease" includes a similar instrument issued under the *Provincial Accord Act*, *supra* note 3, which would include a production licence. *P&NG Act*, *supra* note 5, s 47.

respect of the offshore area will be subject to the royalty provisions in the *P&NG Act* as they read after the 2001 amendments (and any subsequent amendments).

2. *Hibernia*

Every premier of Newfoundland and Labrador since its joining Confederation attended the signing ceremony for Hibernia on 7 November 1990. It was a singular moment in the Province's history and ushered in a new era in its economic status.[11] Discovered in 1979, the Hibernia oil field is located in the Jeanne d'Arc Basin which underlies the northeast portion of the Grand Banks approximately 315 kilometers east southeast of St. John's in eighty metres of water.[12] The field contains approximately 1.395 billion barrels[13] of recoverable resource and is the fifth largest oil field

11. For an interesting discussion of the effects of the oil and gas industry on the economy of the Province up to 2007 see Wade Locke, "Offshore Oil and Gas: Is Newfoundland and Labrador Getting its Fair Share?" (2007) 99:3 Newfoundland Quarterly 8. See also the discussion of the benefits received by the Province from oil and gas development in Government of Newfoundland and Labrador, *Developing an Energy Plan for Newfoundland and Labrador: Public discussion paper* (St. John's: Department of Natural Resources, 2005), online: <http://www.nr.gov.nl.ca/nr/energy/plan/pdf/discussionpaper.pdf> at 1.

12. Like the Atlantic Accord itself, the financial assistance arrangements reached to proceed with the Hibernia project, despite low oil prices and other challenges, were a unique product of federal-provincial co-operation. Canada provided a variety of financial assistance measures including a \$1.66 billion primary guarantee facility to assist in financing for the project, a \$1.04 billion federal contribution to the eligible costs of the project, a \$175 million temporary financing facility to assist with cost overruns or if a proponent's cash flow after debt service was negative after production start-up, and a \$300 million interest assistance loan facility to assist with interest payments in times of low oil prices. Canada took project security in respect of the obligations of the proponents under the primary guarantee facility and an option on a net profits interest in the project. The Province provided \$95 million in contributions relating to costs of the construction site at Bull Arm and \$11 million in contributions for the gravity base structure construction in the Province as well as a commitment that, subject to each proponent maintaining a permanent establishment in the Province or the offshore area and allocating wages and salaries as agreed, the proponents' taxable income from the project would be taxed at the lesser of the provincial rate or the average of the rates of the other provinces and territories. For an analysis of the multiplier effects of the government assistance to Hibernia see James P Feehan & L Wade Locke, "Multiplier Effects and Governments Assistance to Energy Megaprojects: An Application to Hibernia" (1993) 5:1 Energy Studies Review 38, online: <http://digitalcommons.mcmaster.ca/ esr/vol5/iss1/3>.

13. This is the Canada–Newfoundland and Labrador Offshore Petroleum Board's (C-NLOPB) figure for proven and probable reserves as of 1 September 2011. See Canada–Newfoundland and Labrador Offshore Petroleum Board, "Petroleum Reserves and Resources Newfoundland Offshore Area" online: Canada–Newfoundland Petroleum Board <http://www.cnlopb.nl.ca/pdfs/disc_rr.pdf>.

discovered in Canada.[14] Hibernia utilizes a massive gravity base structure (GBS) that sits on the ocean floor, is designed to withstand iceberg impacts, and contains facilities for production operations from the field.

Despite the elaborate structure negotiated and enacted in relation to the *Accord Acts*, the first royalty relating to a petroleum development in the offshore area was not entirely of that lineage. In the negotiations leading to the execution of the *Hibernia Development Project Royalty Agreement* (the *HRA*), it was concluded that the royalty arrangements between the Province and the Hibernia proponents should be reflected in a so-called "private" royalty agreement—a binding contract between the province and the Hibernia proponents.[15] The Hibernia royalty is thus in large measure based upon a contract between the Province and the Hibernia proponents. Canada is not a party to the *HRA* and the agreement expressly states that it has not been entered into pursuant to any provision of the *Accord Acts* and has not been entered into pursuant to subsection 25(1)[16] or any other provision of the *P&NG Act*.

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14. The original proponents of Hibernia were Mobil Oil Canada Properties (now ExxonMobil Canada Properties) (28.125%), Chevron Canada Resources (21.875%), Petro-Canada Hibernia Partnership (25%) and Gulf Canada Limited (25%). Hibernia is operated by Hibernia Management and Development Company Ltd (HMDC), which is owned by the Hibernia proponents in the same proportions as their working interests in Hibernia. Gulf announced its withdrawal from Hibernia in 1991. Following intensive efforts by the other proponents and the federal and provincial governments, the Gulf interest was acquired by the three other original proponents and the following working interests were conveyed by them to Mobil Canada Hibernia Ltd, an affiliate of Mobil Canada Ltd (5%), Chevron Hibernia Holding Company Ltd, an affiliate of Chevron Canada Resources (5%), Murphy Atlantic Offshore Oil Company Limited (6.5%), and Canada Hibernia Holding Corporation (8.5%). Canada Hibernia Holding Corporation (CHHC) is a wholly owned subsidiary of Canada Development Investment Corporation (CDIC), a federal Crown corporation. CHHC was established in March 1993, for the sole purpose of holding, managing, administering, and operating Canada's 8.5% working interest in Hibernia.

In 1997, Petro-Canada and Norsk Hydro Canada Limited entered into a swap arrangement with respect to various North Sea and offshore area properties as a result of which Norsk Hydro Canada Limited (now Statoil Canada Ltd) acquired a five per cent interest in Hibernia.

15. The Province took security for the proponents' royalty obligations under the *HRA* and registered that security, together with a copy of the *HRA*, in the Registry of Deeds in St. Johns where it was publicly available for many years. Given the changes in the Province's registry system, it is not clear whether it is still available from that source. Hibernia Development Project (Canada), *Hibernia Development Project Royalty Agreement* (16 February 2010), online: Department of Natural Resources <www.nr.gov.nl.ca/nr/energy/petroleum/offshore/projects/hibernia_royalty_amending_agreement.pdf> [*HRA*]. For a general discussion of contracts with a provincial crown see Peter W Hogg & Patrick J Monahan, *Liability of the Crown*, 3d ed (Scarborough: Carswell, 2000). For a review of the Province's position on the various fiscal regimes negotiated with respect to the offshore are up to Hebron see Leah Fusco, "Offshore Oil: An Overview of Development in Newfoundland and Labrador," online: Memorial University of Newfoundland <http://www.ucs.mun.ca~oilpower/documents/NL%20oil%207-25-1.pdf>.

16. The predecessor to s 33(i) of the current *P&NG Act*, *supra* note 5.

Given that the *HRA* was not entered into pursuant to the *Accord Acts* or the *P&NG Act*, there was a royalty enacted in respect of Hibernia under the *P&NG Act* that would, in effect, "occupy the field" in relation to the structure under the *Accord Acts*. The relevant regulations under the *P&NG Act*[17] (the *Oil Royalty Regulations*) provide that each holder of a share in a lease issued under the *P&NG Act* before 1 April 1990 (as noted, only PL1001 falls into this category) must "pay to the [provincial] Crown a basic royalty...of $0.01 for each barrel of petroleum produced under the lease to which that holder...is entitled."[18] Under Sections 97(2) and 97(4) of the *Federal Accord Act*, this royalty is payable to the federal Crown. Petroleum produced from lands subject to PL1001 is therefore subject to the $0.01 per barrel basic royalty under the *Oil Royalty Regulations*, which is credited against the royalties payable to the Province under the *HRA*.[19]

3. *Terra Nova*

The next major offshore development in the offshore area after Hibernia was the Terra Nova Development Project (Terra Nova). The Terra Nova oil field was discovered in 1984 and is located approximately 350 kilometres east southeast of St. John's at a water depth of ninety to one hundred metres.[20] The field is estimated to contain over one billion barrels of oil in place, of which an estimated 419 million barrels are recoverable. Terra Nova was developed with a floating production, storage, and offloading vessel (an FPSO).

The history of the Terra Nova negotiations on the fiscal arrangements with the Province has been described elsewhere.[21] Despite several years of negotiations and an advanced document in the form of a private agreement along the lines of the *HRA*, there proved to be intractable differences between the parties on certain issues and the Province proceeded to enact a set of generic regulations in the form of the Newfoundland and Labrador

17. See CNLR 22/96 [*Oil Royalty Regulations*] and its predecessors, NLR 231/90 and NLR 264/90.
18. See *Oil Royalty Regulations*, *ibid*, s 3(1).
19. *HRA*, *supra* note 15, ss 1.3 & 24.15.
20. Suncor Energy Inc (formerly Petro-Canada) is the majority interest holder (33.99%) and operator of Terra Nova with the other interest holders being ExxonMobil Canada Properties (22%), Husky Oil Operations Ltd (12.51%), Murphy Oil Company Ltd (12%), Mosbacher Operating Ltd (3.5%), Statoil Canada Ltd (15%) and Chevron Canada Resources (1%). The very different approach to government assistance in Terra Nova and the consequent effects in terms of the work required to construct the facilities used in Terra Nova is described in Fusco, *supra* note 15 at 5-6. The estimated oil reserve figure given is the C-NLOPB's figure for proven and probable reserves as of 1 September 2011, see Canada–Newfoundland and Labrador Offshore Petroleum Board, *supra* note 13.
21. See RJ (Jack) Thrasher, "Newfoundland Generic Royalty Regime" (2003) 26 Dal LJ 365 at 366-367 and authorities referenced there.

Royalty Regulations, 2003 (the *Generic Royalty Regulations*)[22] to apply to Terra Nova and other post-Hibernia projects such as the White Rose Development Project (White Rose).

The Generic Royalty Regulations cannot impose a royalty payment directly in respect of the offshore area which is outside the legislative jurisdiction of the Province.[23] The Generic Royalty Regulations can, however, provide the basis for the calculation of a royalty payable to Canada in accordance with sections 97(2) and (4) of the *Federal Accord Act*.

As certain issues had been resolved in the Terra Nova negotiations in a different manner from the treatment of those issues under the *Generic Royalty Regulations*, there is a Part XIII in the *Generic Royalty Regulations* that applies only to Terra Nova.[24] The *Generic Royalty Regulations* other than Part XIII apply to White Rose.

4. *White Rose*

White Rose is located on the eastern margin of the Jeanne d'Arc Basin, approximately 350 kilometres east of St. John's and within 50 kilometres of Hibernia and Terra Nova. The field is comprised of the North, West, and South Avalon pools.[25] The initial development focused on the South Avalon Pool in a water depth of 120 metres. Total recoverable oil reserves are estimated at 270 million barrels. White Rose was also developed with an FPSO.

5. *White Rose expansion*

The White Rose Expansion or White Rose Growth Project includes the North Amethyst Field, West White Rose, and South White Rose Extension. Nalcor Energy-Oil and Gas Inc (Nalcor), a wholly-owned subsidiary of

22. *Royalty Regulations, 2003* under the *Petroleum and Natural Gas Act* [*Generic Royalty Regulations*], NLR 71/03 [*Royalty Regulations*]. For one view of the purpose of the generic royalty regime see Fusco, *supra* note 15 at 9.

23. See *Reference Re Newfoundland Continental Shelf*, [1984] 1 SCR 86.

24. *Royalty Regulations*, *supra* note 22: these Terra Nova specific provisions include an extended period before the minister can exercise lien rights under s 20(4), the basic (s 73) and incremental (s 74) royalty rates applicable to Terra Nova, the Tier I and Tier II return allowance factors (s 75), provisions for deduction of basic royalty in calculating Tier II royalty payable in periods after Tier II payout when Tier I royalty is not payable (s 76), different cost limits for arm's length provisions (s 77), different fair market value levels for capital lease treatment (s 78), pre-development costs (s 79), additional Tier II return allowance (s 80), reference price provisions for sales of oil not at arm's length (ss 81-83), payable date for payment of overpayments (s 84), special disallowed cost rules (s 85), and an independent expert procedure for resolution of eligible cost disputes (s 86).

25. Husky Oil Operations Ltd is the majority interest holder (72.5%) and operator of White Rose with the other interest holder being Suncor Energy Inc (27.5%).

the Province's energy corporation, Nalcor Energy Inc, has a five per cent interest in the White Rose Growth Project.

North Amethyst is the first satellite field development at White Rose and was brought on production on 31 May 2009. It is also the first subsea tie-back project in Canada. It is estimated to hold 67.9 million barrels of recoverable oil.

6. *Hebron*

The Hebron Development Project (Hebron) has also had an interesting history. First discovered by Norcen Energy in 1981, it is the second largest resource to proceed to development in the offshore area after Hibernia.[26] Its reserves are a heavier quality of crude than found in Hibernia, Terra Nova, or White Rose that is technically more complex to recover and less profitable to develop, and in 2002 the development process for Hebron was suspended because of low oil prices.[27] At one point consideration was given to a pipeline to transport the Hebron crude to market, but that did not proceed.[28] The proponents are planning to use a GBS to produce from Hebron.

The initial phase of the Hebron negotiations with the Province was not successful. The Hebron proponents disbanded their project team in April 2006 and indicated they would not proceed with the development of Hebron at that time.[29] Premier Danny Williams indicated that the Province would require a 4.9% equity interest and a super-royalty in relation to Hebron and that the Province would pursue the acquisition of the interest of ExxonMobil (whom the Premier blamed for the failure to proceed with

26. Estimated recoverable reserves in Hebron are 400–700 million barrels of oil. Norcen Energy's interest was acquired by Chevron Canada Resources, which had a 28% interest and became the operator of Hebron despite the larger 37.9% interest held by ExxonMobil Canada Properties. The other parties were Petro-Canada (now Suncor Energy Inc) with a 23.9% interest and Norsk Hydro Canada (now Statoil Canada Ltd) with a 10.2% interest. On 22 August 2008, Chevron Canada Resources announced that it was relinquishing its operatorship of Hebron, which was assumed by ExxonMobil Canada effective 1 October 2008. See Chevron Corporation, "Chevron in Canada: Hebron Project Update," online: Chevron Corporation <http://www.chevron.ca/news/releases/2008-08_hebronupdate.asp>.

27. See Fusco, *supra* note 15 at 10.

28. See Brent Jang, "Chevron mulls undersea pipeline to revive Hebron oil project," *The Globe and Mail* (9 June 2004).

29. See Chevron Corporation, "Chevron Announces Plans to Suspend Hebron Activities" (3 April 2006), online: The Sir Robert Bond Papers <http://bondpapers.blogspot.com/2006/04/chevron-announces-plans-to-suspend.html>; James Stevenson, "Hebron Partners Suspend Heavy Oil Project in North Atlantic," *Resource Investor* (3 April 2006), online: Summit Business Media <http://www.resourceinvestor.com/News/2006/4/Pages/Hebron-Partners-Suspend-Heavy-Oil-Project-in-North.aspx>; "Hebron project 'over', partner Chevron says," *The National Post* (12 April 2006), online: Postmedia Network Inc <http://www.canada.com/nationalpost/ financialpost/story.html?id=ed4d9140-a208-4acb-ab4a-c312069ed0b0&k=6294>. For one view of the reason for the breakdown in the Hebron negotiations and the negative effects the Province's position on Hebron had on the investment climate in the offshore area at the time see Fusco, *supra* note 15 at 10-11.

the development) or perhaps fallow field legislation to ensure development on a timely basis if the proponents did not proceed with the development of Hebron.[30] The joint management regime in the offshore area under the *Accord Acts* means, however, that any such legislation would require federal action to implement and the federal government never publicly expressed any interest in pursuing such a course.

About the same time as the Hebron negotiations were unravelling, the Hibernia proponents submitted an application to the Canada-Newfoundland and Labrador Offshore Petroleum Board (C-NLOPB) in relation to an amendment to the Hibernia development plan that would permit them to drill and develop lands in the southern portion of PL1001 as well as additional lands further to the south and subject to production licence 1005 (PL1005) and exploration licence 1093 (EL1093). The C-NLOPB released a decision in January 2007 approving the application, subject to certain conditions. An approval of an amendment to a development plan is a fundamental decision under the *Accord Acts*, however, and requires the approval of both the federal and the provincial ministers.[31] By letter to the C-NLOPB dated 17 January 2007, the Minister of Natural Resources for the Province indicated that she did not approve of the C-NLOPB's decision as she did not have enough information. The Chairman and CEO of the C-NLOPB responded with a letter to the Minister dated 31 January 2007 and the Minister replied with her own letter of 2 February 2007 expressing her disappointment with the January 31st letter.[32]

Following the refusal by the provincial minister to approve the C-NLOPB's decision, negotiations with the Province on the fiscal regime for Hebron resumed in the spring of 2007. The parties concluded a memorandum of understanding dated 21 August 2007 (the *Hebron*

30. The Province had also proposed a requirement that an oil refinery be built in Newfoundland and Labrador that was later dropped. For a discussion of the policy and legal considerations of fallow fields initiatives in the East Coast offshore see Raymond E Quesnel, "Fallow Fields Initiatives and Canada's East Coast Offshore: Policy and Legal Considerations" (2007) 30 Dal LJ 457.

31. See *Federal Accord Act, supra* note 2, ss 31(1), 31(2), 139.

32. The first letter written by the Minister of Natural Resources can be found online: Government of Newfoundland and Labrador <http://www.releases.gov.nl.ca/releases/2007/nr/letterjan17.pdf>. The response to the Minister's letter by the Chairman and CEO of the C-NLOPB is discussed in Government of Newfoundland and Labrador, "Hibernia South Decision Should Not Delay Approvals" (2 February 2007), online: Government of Newfoundland and Labrador <http://www.releases. gov. nl.ca/releases/2007/nr/0202n11.htm>. The subsequent letter from the Minister of Natural Resources in response can be found online: Government of Newfoundland and Labrador <http://www.releases. gov.nl.ca/releases /2007/nr/0202letter.pdf>.

MOU)[33] that contemplated, among other matters, the acquisition of a 4.9% equity interest in the Hebron project by the Province through its energy corporation and an additional royalty of 6.5% payable on net revenues after Tier I payout if the monthly average West Texas Intermediate (WTI) prices exceed $50 (US) per barrel.

In September 2007, the Province released its energy plan: *Focusing Our Energy—Newfoundland and Labrador Energy Plan*.[34] The Energy Plan included proposals for both the acquisition of equity interests in future projects in the offshore area (ten per cent was the suggested interest) and a fiscal regime, including royalties, that was described in the Energy Plan as providing an "appropriate sharing of the downside risk" and "the upside potential, as well as clarity to potential investors."[35]

Following publication of the Energy Plan, the Province and the Hebron proponents continued to negotiate the Hebron fiscal arrangements, which were entered into on 20 August 2008. The Hebron fiscal arrangements mark an interesting intersection of the different approaches to royalties in the offshore area. The *Hebron MOU* contemplated a number of features that were a departure from the Generic Royalty Regulations. It was agreed that these features would be reflected in an agreement pursuant to section 33 of the *P&NG Act* that would be entered into between the Province and the Hebron proponents, including Nalcor. On 20 August 2008, the Province and the Hebron proponents entered into the *Hebron Fiscal Agreement*

33. See Government of Newfoundland and Labrador, "Equity, Improved Royalty Regime and Outstanding Local Benefits Highlights of Memorandum of Understanding for Hebron Development" (22 August 2007), online: Government of Newfoundland and Labrador <http://www.releases.gov.nl.ca/releases/2007/exec/0822n02.htm>.

34. Government of Newfoundland and Labrador, Department of Natural Resources, (St. John's, NL: Department of Natural Resources, 2007), online: Department of Natural Resources <www.nr.gov.nl.ca/nr/energy/plan/pdf/energy_report.pdf> [*Focusing our Energy*]. The Province had long chafed under the fact that the formula for federal-provincial equalization arrangements existing at the time Hibernia began producing took offshore oil revenues into account, with the result that what the Province gained from those oil revenues reduced what it would otherwise be entitled to in equalization payments. Like many of the achievements of the Province in recent years this was a lengthy battle, beginning with approaches by Premier Williams to Prime Minister Paul Martin in late 2003 and culminating with the announcement of the changes to redress this effect on 31 January 2005. Under the new arrangements contained in a sixteen year agreement between Canada and the Province, Canada agreed to make payments to the Province to offset reductions in equalization payments resulting from offshore oil revenues received by the Province. See Government of Newfoundland and Labrador, "Atlantic Accord 2005 News Releases" (14 February 2005), online: Department of Natural Resources <http://www.nr.gov.nl.ca/energyplan/EnergyReport.pdf>. See also Government of Newfoundland and Labrador, "Atlantic Accord 2005," online: Government of Newfoundland and Labrador <http://www.gov.nl.ca/atlanticaccord/>.

35. See *Focusing Our Energy*, *supra* note 34 at 18. What is a fair share is a notoriously difficult issue for energy producing provinces. For a 2007 discussion of the considerations relevant to the application of the fair share "test" and Newfoundland and Labrador's "government-take" compared to then comparables in other jurisdictions see Locke, *supra* note 11 at 10-11.

(*HFA*) which expressly provides that it is an agreement pursuant to section 33 of the *P&NG Act*.[36]

As noted, section 33 contemplates agreements by the Province with interest holders that are inconsistent with the *Generic Royalty Regulations* and stipulates that such agreements prevail over those regulations (and over any other regulations under Part II of the *P&NG Act*) where they are inconsistent.[37] The *HFA* provides that the *Generic Royalty Regulations*, as modified by the *HFA*, apply to Hebron and the Hebron proponents. The two major modifications made to the *Generic Royalty Regulations* by the *HFA* are: (i) the *Generic Royalty Regulations* applicable under the *HFA* are those that existed on 16 August 2007; and (ii) such version of the *Generic Royalty Regulations* is modified in accordance with the *HFA*. To the extent the *HFA* is inconsistent with the *Generic Royalty Regulations* as they exist from time to time in the future, the *HFA* prevails.

Since the *HFA* is an agreement under section 33 of the *P&NG Act*, if the *P&NG Act* applied directly to Hebron the royalty payable to the Province would be calculated in accordance with the *Generic Royalty Regulations*, as modified by the *HFA*. As a result, the royalty payable to Canada in respect of Hebron under sections 97(2) and (4) of the *Federal Accord Act* is calculated by reference to the *Generic Royalty Regulations*, as modified by the *HFA*. To comply with sections 97(2) and (4) of the *Federal Accord Act*, the royalty calculated in accordance with the *HFA* must be paid to Canada rather than to the Province. As with Terra Nova and White Rose, there was no need for a separate statutory royalty payable to Canada (such as the *Oil Royalty Regulations*) as that role was fulfilled by the *Generic Royalty Regulations*, as modified by the *HFA* in the case of Hebron.

7. *Hibernia Southern Extension*

The Hibernia Southern Extension Project (HSE) is an expansion of the Hibernia field that contains an estimated 215 million barrels of oil. An estimated 167 million barrels will be produced using a subsea tie-back and the remainder will be produced from the existing Hibernia GBS.[38]

Negotiations on the royalties applicable to HSE accelerated following the execution of the *HFA* and the other Hebron agreements. These

36. See Government of Newfoundland and Labrador, *Hebron Fiscal Agreement* (20 August 2008), online: Department of Natural Resources <http://www.nr.gov.nl.ca/nr/energy/petroleum/offshore/projects/hebron_fiscal_aggre.pdf> at 4.1 [HFA], and *P&NG Act*, *supra* note 5, s 33.
37. *Supra* note 22.
38. See Canada–Newfoundland and Labrador Offshore Petroleum Board, "Staff Analysis: Hibernia Development Plan Amendment" (2 September 2010), online: C-NLOPB <http://www.cnlopb.nl.ca/news/pdfs/hibsadev.pdf> at 26.

negotiations related to certain blocks in the southern portion of PL1001 that are entirely within PL1001 (the AA Blocks) and additional lands that underlie PL1001, PL1005, and EL1093 (the HSE Lands). The AA Blocks will be drilled and produced from the existing Hibernia gravity base structure while the HSE Lands will be drilled from both the Hibernia GBS and semi-submersible drilling rigs and will be produced using a subsea tie-back to the GBS.[39] The Province and the HSE proponents agreed that it would be preferable for all parties if all of the licences associated with Hibernia (PL1001, PL1005, and EL1093) were subject to the same royalty regime so that the calculation, payment and administration of royalties in respect of PL1001, PL1005 and EL1093 would be consistent in similar circumstances."[40] With PL1001 subject to the *HRA* and PL1005 and EL1093 subject to the *Generic Royalty Regulations* (as both licences were issued after 1 April 1990), this was not an easy task to accomplish.

As noted, the *HRA* is a private contract and expressly not entered into pursuant to any statutory provisions. On 16 February 2010, the Province and the Hibernia proponents (including Nalcor as the holder of the Province's equity interest in the HSE Lands) entered into an amendment to the *HRA* to provide for a new royalty structure in respect of the AA Blocks and that portion of the HSE Lands wholly contained within PL1001. As this new royalty structure is contained within the *HRA*, which remains a private contract between the Province and the Hibernia proponents, the new royalties prescribed in respect of such lands are payable directly to the Province in the same manner as all other royalties payable pursuant to the *HRA*.

The *HRA* only applies to PL1001, however, so the Province and the HSE proponents had to determine how to proceed with respect to that portion of the HSE Lands that are not contained within. Rather than entering into a new private contract with respect to PL1005 and EL1093 (in the same manner as the *HRA* with respect to PL1001, and which would have also likely required an expansion or duplication of the *Oil Royalty Regulations* so as to occupy the field for PL1005 and EL1093 as was done for PL1001), the Province and the HSE proponents agreed to proceed in a manner somewhat similar to what was done for Hebron. On 16 February 2010, the Province and the HSE proponents (again including Nalcor as the holder of the Province's equity interest in PL1005 and EL1093) also

39. *Ibid* at 19-39.

40. Hibernia Development Project (Canada), *Hibernia Development Project EL1093/PL1005 Royalty Agreement* (St. John's, NL: Department of Natural Resources, 2010) s 1.2(a) [*ELRA*], online: Department of Natural Resources <http://www.nr.gov.nl.ca>.

entered into the *Hibernia Development Project EL1093/PL1005 Royalty Agreement* (the *ELRA*) to provide for the royalty structure in respect of the external licences included in the HSE Lands—PL1005 and EL1093.

As with the *HFA*, the *ELRA* is an agreement entered into pursuant to section 33 of the *P&NG Act*. Unlike the *HFA*, which provides that the Generic Royalty Regulations, as modified by the *HFA*, will apply to Hebron, the *ELRA* takes a different approach. The parties to the *ELRA* agreed that the *ELRA* "comprehensively addresses the calculation, payment and administration [of] royalties in respect of...PL1005 and EL1093," is entered into pursuant to section 33(1) of the *P&NG Act* and is "inconsistent with the [Generic] Royalty Regulations...or any other regulation[s] promulgated [pursuant to] Part II of the [*P&NG*] *Act*."[41] As the *ELRA* was modelled on the *HRA* and the terms and conditions of the two agreements closely mirror each other, all of the Hibernia licences (PL1001, PL1005, and EL1093) are now subject to fundamentally the same royalty regime, even though PL1001 is subject to a private contract and PL1005 and EL1093 are subject to an agreement (that is expressly inconsistent with the *Generic Royalty Regulations*) pursuant to section 33 of the *P&NG Act*.

As a result, there are now six separate royalty regimes in the offshore area: (1) the private contract regime for Hibernia (including the AA Blocks and the portion of the HSE Lands that underlie PL1001) operating outside the *Accord Acts* as embodied in the *HRA* as amended in connection with HSE; (2) the *Oil Royalty Regulations* imposing the $0.01 per barrel basic royalty for Hibernia under the *P&NG Act* and "picked up" under the *Federal Accord Act*; (3) for Terra Nova, the *Generic Royalty Regulations* including the Terra Nova specific provisions in Part XIII; (4) for White Rose, the *Generic Royalty Regulations* excluding the provisions in Part XIII; (5) for Hebron, the combination of the *Generic Royalty Regulations* and a project specific agreement entered into pursuant to section 33 of the *P&NG Act* that crystallizes and modifies the *Generic Royalty Regulations* and prevails over the *Generic Royalty Regulations* and any other regulations under Part II of the *P&NG Act* to the extent of any inconsistency; and (6) for the portion of the HSE Lands that underlie PL1005 and EL1093, a section 33 agreement that supersedes the *Generic Royalty Regulations* and any other regulations promulgated pursuant to Part II of the *P&NG Act*.

41. *Ibid*, s 1.2(b), (c) and (d).

II. *Developments in Newfoundland and Labrador offshore royalties*
This section reviews the evolution of the royalty regime in the offshore area from the original Hibernia regime, through Terra Nova and White Rose, the publication of the Energy Plan and the entering into force of the *HFA*, and finally back to Hibernia with HSE. Specifically, this discussion focuses on key aspects of the royalty regime that have undergone significant changes in the course of that evolution: (i) the structure and characteristics of the royalties payable; (ii) the eligibility criteria for transportation costs to be deductible for royalty purposes; (iii) provisions that allocate costs and production between separate projects that make use of common infrastructure; (iv) dispute resolution provisions; and (v) legislative stability provisions.

1. *Royalty structures*

Hibernia
As noted, Canada, the Province and the Hibernia proponents agreed on a royalty regime for Hibernia that employed a combination of statutory and contractual royalties. A royalty of $0.01 per barrel of crude oil is prescribed by the *Oil Royalty Regulations* pursuant to the *P&NG Act* and became effective in respect of Hibernia under sections 97(2) and 97(4) of the *Federal Accord Act*.[42] This statutory royalty is paid to Canada pursuant to the *Federal Accord Act* and remitted to the Province. In addition, the Hibernia proponents pay contractual royalties to the Province pursuant to the *HRA*, which credits the statutory royalty paid to Canada under the Oil Royalty Regulations against the contractual royalties payable to the Province under the *HRA*.

The original *HRA* includes a three tier royalty structure in relation to Hibernia: (i) gross royalty; (ii) net royalty; and (iii) supplementary royalty. Gross royalty was the only royalty payable in the early years of Hibernia and escalated during such time from an initial rate of one per cent up to a maximum rate of five per cent. The original *HRA* provided that the maximum rate of five per cent would be achieved seventy-two months after production start-up, but the *HRA* was amended in 1999 to provide that the maximum rate of five per cent would be payable from the earlier of March 2004 or the time that Hibernia had produced 268 million barrels

42. See now CNRL 22/96 and its predecessors NL 231/90 and NL 264/90. NL 231/90 took a broader approach to the statutory royalty referring to the basic royalty as a gross royalty between one per cent and five per cent and an incremental royalty consisting of a net royalty of thirty per cent and a supplementary royalty of 12.5%, in each case to be calculated and paid in the time and manner ordered by the minister.

of crude oil.[43] Gross royalty is payable on the gross revenue of a proponent generated from the sale of crude oil produced by such proponent from Hibernia. No deductions for capital or operating costs or expenses are permitted in the calculation of gross royalty, although the *HRA* does allow for certain transportation related costs and expenses to be deducted in calculating gross revenue.[44]

Net royalty is the second tier of the Hibernia royalty structure. Generally speaking, net royalty at the rate of thirty per cent of net revenue (being the gross revenue and incidental revenue less a number of eligible costs, which include capital and operating costs, but do not include borrowing or financing costs, overhead of a proponent, certain taxes, and other disallowed costs) is payable by a proponent following the first time (net royalty payout) when the gross revenue of such proponent exceeds the aggregate of: (i) the amount of such proponent's eligible costs and expenses (including pre-development costs) compounded monthly at a rate of fifteen per cent per annum (referred to as "return allowance"); plus (ii) the amount of any gross royalty paid by such proponent. The net royalty return allowance is a form of return on investment allowed to the proponents that provides for a yearly return of fifteen per cent on the amount by which the net royalty cumulative eligible costs and expenses exceeds cumulative gross revenue. If eligible costs exceed revenues during any royalty period after net royalty payout, any excess will be carried forward, without net royalty return allowance, as an eligible cost and credited in the calculation of royalties in the subsequent royalty period. In any royalty period following net royalty payout, the gross royalty paid plus net royalty paid will not exceed the greater of five per cent of gross revenue or thirty per cent of net revenue.

Supplementary royalty is the third tier and is largely the same structure as net royalty, but the rate is 12.5% (over and above the thirty per cent net royalty) of net revenue and the return allowance rate is eighteen per cent per annum adjusted for changes in the *Consumer Price Index for Canada (All Items)*. Any eligible costs in excess of revenues in a period may be carried forward in a manner identical to that for the net royalty. If no net royalty is payable in a royalty period, the gross royalty paid is deducted

43. See the discussion of the Amending Agreement dated 1 September 1999 in Denstedt & Thrasher, *supra* note 1 at 329-330. For a suggestion that the handling and eventual resolution of this use actually led to a better royalty regime see Edward Hollett, "Hibernia spat led to better royalty regime" (30 January 2007), online: *The Sir Robert Bond Papers* <http://bondpapers.blogspot.com/search?q=Hibernia+Spat>.

44. See the "*Transportation cost eligibility*" section below for further discussion regarding deductible transportation costs.

from net revenue for the calculation of the supplementary royalty for that period.

Terra Nova

The royalty structure under the *Generic Royalty Regulations* is similar to the structure of the royalties payable under the *HRA* and consists of a basic royalty and a two-tier incremental royalty payable separately by each interest holder in a production licence, although the royalty rates and return allowance factors differ between the *HRA* and the *Generic Royalty Regulations*. For Terra Nova, Part XIII of the *Generic Royalty Regulations* provides a basic royalty rate of one to ten per cent of gross revenue depending on the aggregate volume of the interest holder's share of oil transferred at the loading point and whether simple payout or basic royalty payout had occurred,[45] and an incremental royalty in two tiers of thirty per cent and 12.5%, respectively. The basic royalty under the *Generic Royalty Regulations* is calculated on the interest holder's gross revenue for the month, which is its gross sales revenue minus certain eligible transportation costs under Part IX of the *Generic Royalty Regulations*. The Tier I and Tier II incremental royalties are calculated on the interest holder's net revenue, which is calculated in substantially the same manner as net revenue under the *HRA*. Payout and royalty payment obligations for the purposes of the incremental royalties under the *Generic Royalty Regulations* are calculated in a manner substantially similar to the net royalty and supplementary royalties under *HRA*.

White Rose

For White Rose and any other production licences issued after the Terra Nova production licences on 20 November 2001, the basic royalty rate under the *Generic Royalty Regulations* varies from one per cent to 7.5% and the incremental royalty rates are twenty per cent for Tier I and ten per cent for Tier II.

Hebron

Pursuant to the Energy Plan published after the entering into of the *Hebron MOU*, the Province sought to achieve a maximum royalty rate of fifty per cent with respect to any new projects in the offshore area. While

45. Simple payout occurs for an interest holder under a lease when its cumulative revenues exceed cumulative eligible costs and basic royalty paid, excluding any paid in kind. Basic royalty payout for an interest holder occurs when the sum of cumulative gross revenue and incidental revenue equals the sum of cumulative eligible costs, basic royalty return allowance and basic royalty paid, excluding any paid in kind. The basic royalty return allowance rate is calculated by a formula based on the long-term government bond rate.

the royalty regime in respect of the Hebron project does not include a maximum royalty rate of fifty per cent, it does mark the introduction of the so called "super-royalty," referred to in the *HFA* by the more pedestrian term "additional royalty," to the standard royalty structure applicable to the other projects in the offshore area.

Unlike the standard royalties (the gross royalty, net royalty and supplementary royalty under the *HRA* and the basic and the incremental Tier I and Tier II royalties under the *Generic Royalty Regulations*), the Hebron additional royalty is price sensitive—the 6.5% additional royalty is only payable for a month after Tier I payout when the arithmetic average of the price of crude oil for each day of that month is greater than US$50.00/ oil barrel (bbl). The determination of the price of crude oil for each day is based on the average range of prices of a marker crude (WTI light sweet crude oil) as published in Platt's *Crude Oil Marketwire* for such day.[46]

A price-sensitive royalty serves to bridge the gap between competing concerns of government and the proponents of a project—greater royalty revenue on the part of government and the economic viability of the project on the part of the proponents. In the Hebron context, the additional royalty delivers increased royalty revenue to the Province in a high-price environment without burdening the project with increased royalty obligations in a low-price environment when the economics of a project are least able to cope with increased royalty obligations. The Hebron basic royalty structure also provided that the basic royalty rate would not increase above one per cent until simple royalty payout had occurred.[47]

White Rose Expansion

The basic royalty and the Tier I and Tier II incremental royalties payable in relation to oil produced from the White Rose Expansion are those payable under the *Generic Royalty Regulations* excluding Part XIII. There is also an additional royalty of 6.5% of net revenue payable any time after Tier I payout when WTI crude oil trades above US $50 per barrel (not adjusted for inflation).

46. The WTI Price used for Hebron under the *HFA* is based on the average of the specified range of prices per barrel of WTI light sweet crude oil in US dollars, published in Platt's *Crude Oil Marketwire*. If Platt's *Marketwire* is no longer available, it is the specified price per barrel of such crude oil set forth in any successor publication widely used and generally accepted in the international petroleum industry. If there is no such price or publication, it is the price for comparable quality light sweet crude oil selected by the minister as a reasonable replacement in terms of quality and market for WTI, and notified to the proponents, subject to arbitration if the Hebron proponents disagree. See *Generic Royalty Regulations*, *supra* note 22, s 11.1, for the purpose of Hebron by paragraph (M) of Exhibit "C" to the *HFA*.

47. This was seen by the Province as downside protection—the basic royalty rate would not exceed one per cent until the proponent had recouped its costs.

HSE

Although HSE followed shortly after Hebron, the general royalty structure applicable to the AA Blocks and the HSE Lands is virtually identical to the royalty structure provided for under the original *HRA*. Indeed, the AA Blocks and that portion of the HSE Lands contained within PL1001 are subject to the *HRA* and have the same gross, net and supplementary royalties as are applicable to the rest of Hibernia. That portion of the HSE Lands contained within PL1005 and EL1093 are subject to the *ELRA*, but as discussed above the *HRA* and the *ELRA* are largely the same and so these HSE Lands also have the same gross, net and supplementary royalties. One important point, however, is that PL1005 and EL1093 are a separate project from Hibernia and, therefore, net royalty and supplementary royalty payouts (and the consequent payment of net and supplementary royalties) are calculated independently for PL1001, on the one hand, and for PL1005 and EL 1093 on the other.

In addition to the general Hibernia royalty structure, HSE also includes additional royalties for certain portions of PL1001 and for PL1005 and EL1093.[48] Unlike Hebron, however, which has a uniform additional royalty rate and price trigger for all lands included within the Hebron project, different additional royalty rates and royalty triggers apply to different portions of the HSE Lands as well as the AA Blocks:

- the AA Blocks have an additional royalty, the rate of which, rather than being dependent on a price trigger, varies depending on whether a particular proponent is paying supplementary royalty in respect of production from the AA Blocks—if a proponent is not paying supplementary royalty the additional royalty rate is 12.5% and if the proponent is paying supplementary royalty then the additional royalty rate is 7.5%;
- the portions of PL1001 included within HSE have an additional royalty that is both price sensitive and dependent on whether a proponent is paying supplementary royalty:
  - if a proponent is not paying supplementary royalty, the additional royalty rate is 7.5% at prices equal to or greater than US$50.00/bbl but less than US$70.00/bbl and 12.5% at prices equal to or greater than US$70.00/bbl; and

48. As well as the additional royalties, the AA Blocks and the HSE Lands are subject to the royalty structure described above in relation to the *HRA*, although PL1005 and EL1093 are ring-fenced separately from PL1001 for the purposes of calculating royalty obligations.

 - if a proponent is paying supplementary royalty, the additional royalty rate is 7.5% at prices equal to or greater than US$50.00/bbl; and
- PL1005 and EL1093 have an additional royalty that is solely price sensitive—2.5% at prices equal to or greater than US$50.00/bbl but less than US$70.00/bbl and 7.5% at prices equal to or greater than US$70.00/bbl.[49]

This complexity reflects the competing objectives of government and proponents with respect to additional royalties. A price-sensitive additional royalty is intended to deliver increased value to government when prices are high without compromising the project when prices are low. The varying royalty triggers and additional royalty rates described above are reflective of the differing economics of the development of various portions of the lands included within HSE, and such economics are in turn impacted by the traditional royalty structures applicable to such lands. Whether lands are more or less likely to become subject to a supplementary royalty obligation (and if so at what point in the development and exploitation of the lands) is significant when attempting to forecast the economic performance of a project and consequently determine and agree what additional royalty obligation such project can bear. In the offshore area, such additional royalty rates have been the subject of direct negotiations between the Province and the proponents of a project. The rates are agreed on a case-by-case basis and vary from project to project based on the economic viability of the project in question.

By comparison, Alberta has separate royalty regimes for oil sands and conventional oil. Price sensitivity features were introduced into these royalty regimes by the government of Alberta throughout the 1970s and 1980s. These features were implemented as a response to changing conditions in the industry "[i]n an [attempt] to level the 'playing field'" and recover a greater share of revenue from Alberta's resources.[50]

Alberta's current oil sands royalty regime is similar to that under the original *HRA* in that it provides for an initial gross royalty as well as a net royalty once a project achieves net revenue payout. As in Newfoundland and Labrador, this gross royalty is always payable; the concept of net revenue payout marks the commencement of net royalties, but following

49. The maximum royalty rate payable in respect of any lands included with HSE is fifty per cent when including net royalty, supplementary royalty and additional royalty.

50. Alberta Energy, *Energy Economics: Understanding Royalties* (Edmonton: Alberta Energy, 2009), online: Government of Alberta <http://www.energy.alberta.ca/Org/pdfs/EnergyEconomic.pdf> at 6.

net revenue payout the aggregate royalty payable equals the greater of the gross royalty and the net royalty for the period in question.

Unlike the standard net royalty and supplementary royalty structure in the offshore area, in the case of Alberta oil sands projects, increases in royalty rates are based on market price as opposed to discrete royalty tiers with fixed rates at each tier (i.e., net royalty and supplementary royalty in the *HRA*). Prior to an oil sands project reaching net revenue payout, the gross royalty rate is indexed to the market price of a marker crude (WTI) with an initial rate of one per cent (when "[WTI] is less than or equal to US$55/bbl") up to a "maximum rate of nine per cent" ("when WTI [is equal to or greater than] [US]$120/bb1").[51] Once an oil sands project achieves net revenue payout, a net royalty is introduced, which ranges from twenty five up to forty per cent of net revenue for the period. This net royalty is also price-sensitive "when the price of WTI is less than or equal to $55/bbl," the rate is twenty five per cent, and the rate increases "linearly to a maximum of forty per cent when the price [of WTI is] $120/bbl" or more.[52]

In contrast, Alberta's conventional oil royalty regime does not include a minimum or basic royalty rate, nor is achieving "payout" a factor in determining the royalty rate. The royalty rates under Alberta's conventional oil royalty regime, however, are also largely based on market prices. With the exception of an initial five per cent royalty rate for new wells, the royalty rate for conventional oil is based solely on market price and well productivity. Currently, the minimum and maximum royalty rates for conventional oil are zero per cent and forty per cent, respectively, and these royalty rates are a composite of a price component and a volume component.[53] The price component is based on formulas that use the "par price" which is equal to the average wellhead price and set on a monthly basis. This component can be a negative value, no lower than four per cent, and has a maximum rate of thirty five per cent. The quantity component is based on formulas that use the monthly production of a well in cubic metres. This component can also be a negative value, no lower than twenty eight per cent, and has a maximum rate of thirty per cent. Although the composite royalty rate is based on the sum of the price component and the quantity component, the combined royalty rate cannot exceed forty per cent.

51. Canada's New West Partnership, *Oil and Gas Fiscal Regimes: Western Canadian Provinces and Territories* (Edmonton: Alberta Department of Energy, June 2011), online: Government of Alberta <http://www.energy.alberta.ca /Tenure/pdfs/FISREG.pdf> at 30.

52. *Ibid* at 31.

53. *Ibid* at 25.

In comparing the royalty regimes in the offshore area with Alberta's royalty regimes for both oil sands projects and conventional oil, both jurisdictions have taken a broadly similar approach with the inclusion of price-sensitive royalties in their respective royalty regimes, although Alberta introduced such measures earlier and makes greater use of this mechanic. The provinces differ, however, in their implementation of price-sensitive royalties. The standard royalty structure in the offshore area includes discrete tiers of net royalty that are not price sensitive with an additional royalty that is, while Alberta has essentially indexed all of its royalty rates to market prices in one way or another. Despite this difference in implementation, it is evident that both Newfoundland and Labrador and Alberta, as significant oil producing jurisdictions, have taken steps to deliver increased value to government while recognizing competing objectives and allowing projects to remain profitable even during periods of low prices.

2. *Transportation cost eligibility*

The original *HRA* prescribes four basic criteria that must be satisfied in order for a cost or expense to be deductible for the purposes of calculating royalties payable pursuant to the *HRA*. In general terms, the cost or expense must be:

(i) an actual cash payment;
(ii) directly attributable to the Hibernia project;
(iii) reasonable in relation to the circumstances under which it is incurred; and
(iv) charged to the joint account.

In addition to these basic criteria, there are a series of costs that are specifically disqualified for deduction. A cost must satisfy the eligibility criteria above and must not be disqualified in order to be deducted for the purposes calculating royalties.

For capital and operating costs with respect to projects in the offshore area, these eligibility criteria have remained essentially unchanged since the execution of the original *HRA*. The *Generic Royalty Regulations* reflect these principles and include provisions that are fundamentally the same, although the *Generic Royalty Regulations* also include an explicit prohibition with respect to any single cost being eligible for deduction with respect to more than one project in the offshore area.[54] These provisions of the *Generic Royalty Regulations* have not been significantly amended

54. *Generic Royalty Regulations*, *supra* note 22, s 63(1).

by way of any of the further agreements or regulations entered into or promulgated by the Province with respect to Terra Nova, White Rose, Hebron, or HSE. Consequently, all of the projects in the offshore area are subject to the same general eligibility criteria with respect to capital and operating costs incurred relating to the development of a project.

One obvious result of the eligibility criteria is that only cash costs are eligible to be deducted. While we expect that most of the proponents of the projects in the offshore area accrue costs for accounting purposes, for the purposes of calculating royalties such accrued costs are not eligible. Only once a cost has actually been incurred is a proponent entitled to deduct that cost for the purposes of calculating royalties.

Another more substantive result of the eligibility criteria is that costs are ring-fenced on a project-by-project basis. Pre-development, development and operating costs incurred in respect of a project are only deductible with respect to revenue generated from the sale of crude oil produced from that project (or allocated to, and see *Cost and Production allocations* below for further discussion on this point). Many of the companies active in the offshore area are participants in more than one project and are likely incurring costs in respect of the development of a new project (such as Hebron or HSE) while also generating revenue from existing projects (such as Hibernia, Terra Nova, or White Rose). Notwithstanding, such costs are not deductible in the current period against revenue from an existing project but rather are included for the purposes of determining when the tiers of net royalty or additional royalty may become payable with respect to such new project.

In Alberta, both conventional and oil sands development is ring-fenced in much the same manner. For conventional oil wells, once a well is completed it is assigned a unique well identifier and is then recognized as a separate and discrete "well event." Royalties are then calculated with respect to each separate well event.[55] For oil sands development, royalties are calculated with respect to a discrete project in fundamentally the same manner as in the Newfoundland and Labrador offshore area—costs incurred in respect of a project are aggregated for the purposes of determining if and when that project achieves net royalty payout.[56]

While there may have been discussion between the Province and industry participants regarding the elimination of the ring-fences around projects in the offshore area as a possible way to incent increased

55. *Petroleum Royalty Regulation, 2009*, Alta Reg 222/2008 [*Petroleum Royalty Regulation, 2009*].
56. *Oil Sands Royalty Regulation, 2009*, Alta Reg 223/2008 [*Oil Sands Royalty Regulation; 2009*].

exploration activities, only time will tell whether any such changes will be implemented (and if so, how).

While the general cost eligibility criteria with respect to capital and operating costs in the offshore area have remained largely unchanged for more than twenty years, the cost eligibility criteria for transportation costs have evolved quite significantly from the criteria included in the original *HRA*.

Hibernia—The Seeds of the Difficulties

As noted, the gross royalty on Hibernia is a percentage of the gross revenue of a proponent. Gross revenue is basically the sale price of the Hibernia crude sold after deducting certain transportation related charges. Each of the net and supplementary royalties on Hibernia is only payable after its specified payout has been reached and is based on net revenue, which is calculated by deducting from gross revenue certain costs that are eligible costs under the *HRA*. Transportation costs are thus fundamental to the calculation of gross revenue and net revenue for the purposes of determining the royalties payable under the *HRA*.

The original *HRA* divided the Hibernia project into a resource project (everything prior to delivery of Hibernia crude to tankers) and a tanker project (the transportation of Hibernia crude in tankers beneficially owned by the Hibernia proponents).[57]

While there is no obligation in the *HRA* for the Hibernia proponents to use a tanker project, the original *HRA* included detailed provisions with respect to cost eligibility for costs associated with the use of a tanker project to transport Hibernia crude to market. As originally envisioned, the participating interest of each Hibernia proponent in the tanker project would be the same as such proponent's participating interest in Hibernia, with the likely result that each such proponent's costs in relation to the tanker project would have closely approximated such proponent's use of the tanker project's transportation assets. The tanker project would arrange for sufficient transportation capacity to transport all Hibernia crude to the transshipment facility to be constructed at Whiffen Head in Newfoundland and Labrador and owned by Newfoundland Transhipment Ltd. (NTL). Under the original *HRA*, the eligibility criteria for costs incurred with respect to the tanker project were the same as the general eligibility criteria for costs incurred with respect to the Hibernia project, except that the cost had to be directly attributable to the tanker project.

57. See the definitions of "Project," "Resource Projects," and "Tanker Project" in Schedule "A" to the *HRA*: *ELRA*, *supra* note 40.

For better or for worse, there never was a tanker project for Hibernia. The MT Kometik was purchased by a subset of the Hibernia proponents and the MT Mattea was leased (pursuant to a long-term capital lease) by the others, and the interest of any such proponent in such aggregate transportation capacity is not necessarily equal to such proponent's participating interest in the Hibernia project.

Although there was no obligation in the original *HRA* that the Hibernia proponents have a tanker project, and the original *HRA* included provisions for the calculation of non-tanker project transportation costs, determining which provisions would be applicable to any particular transportation costs would depend on whether the transportation services were provided at arm's length to the relevant Hibernia proponent. The definition of arm's length under the *HRA* specifies that a service provided between Hibernia proponents or their affiliates will not be at arm's length. As each of the MT Kometik and the MT Mattea were wholly-owned or leased by some the Hibernia proponents (and the MT Vinland, on its arrival in the offshore area shortly before commencement of production from Terra Nova, was leased (among others) by the majority of the Hibernia proponents), almost all use by the Hibernia proponents of these tankers to transport Hibernia crude would be a non-arm's length transportation service under the *HRA*.

The end result is that, because of the actual ownership or chartering of these tankers, there were issues as to the applicability of the carefully negotiated provisions in the *HRA* relating to the deductibility of transportation costs. Given the lack of a tanker project and the fact that NTL was not acquired or operated by the resource project or a tanker project (which was the assumed basis for eligible cost treatment of transhipment costs under the *HRA*) for most of the producing life of Hibernia to date, the Hibernia proponents and the Province disagreed as to the proper calculation of eligible transportation costs. This disagreement was finally settled in February 2010 as one part of the agreements relating to HSE.

Regional Transportation System

In anticipation of production from Terra Nova, tanker pooling arrangements were entered into among most of the Hibernia and Terra Nova proponents with respect to capacity in the tankers available to transport crude produced from both projects. This pooling arrangement was not a contractual or legislative change with respect to transportation costs that would be eligible for royalty purposes, but it did affect the actual costs incurred by the Hibernia and Terra Nova participants for transportation. Although this pooling arrangement was not the first commercial arrangement relating to transportation among organizations active in the offshore area (and in fact there were additional arrangements entered into during the term of this pooling arrangement), it was the most expansive and significant arrangement relating to transportation.

While the specific terms of this pooling arrangement are not particularly relevant to (and are beyond the scope of) this paper, it is worth noting that this pooling arrangement changed one of the fundamental aspects of the cost structure that would have existed in respect of the tanker project. Pursuant to the pooling arrangement, the costs of each participant in the pooling arrangement were largely fixed and did not vary with the usage made by any particular participant of the transportation assets included in the pooling arrangement. Accordingly, there was a difficult calculation required to determine what portion of the pooled costs were attributable to particular voyages. The Province, not being a party to this pooling arrangement, was concerned with the lack of transparency and its limited understanding in relation to such transportation costs, and this concern fuelled the disagreement over eligible transportation costs.

As discussed, the *HRA* has a number of general requirements for eligible costs, including that they be charged to the joint account, and has a number of disqualifications of costs that prevent such costs from being deducted. The costs incurred in respect of transportation by a tanker that is not part of the tanker project (and particularly the costs associated with the tankers included within the pooling arrangement which included proponents from multiple projects), and for transshipment costs in respect of NTL, are not paid through the joint account. This was one more reason why the issue about whether such costs would be deductible for the purpose of calculating gross revenue continued as a matter of disagreement and dispute between the Hibernia proponents from 1997 to 2010.

Another concern for the Province in relation to transshipment costs was the fact that NTL was owned by some of the proponents or their affiliates and the costs established for NTL services include an element for return on capital to the owners of NTL. The Province did not accept this, despite the fact that the same fees were paid by any user of NTL, whether arm's length or not, and could thus be justified as fair market value.

Terra Nova

Given the existing issues under the *HRA*, the transportation and transshipment cost rules for Terra Nova were the subject of lengthy and vigorous debate during negotiations among the Terra Nova proponents and the Province. The Hibernia experience still rankled the Province; their sense was that Terra Nova was the first of many new projects and they evinced a desire to resolve some of the issues in a manner favourable to the

Province from a royalty standpoint. As discussed above, the negotiations between the Province and the Terra Nova proponents broke off and the royalty regime for Terra Nova was ultimately promulgated by the Province as the *Generic Royalty Regulations*. It can be speculated that a (not insignificant) contributing factor to this cessation of negotiations was the inability of the Province and the Terra Nova proponents to agree on the proper treatment of transportation costs for royalty purposes. In the end, however, the solution in Terra Nova did little to advance the resolution of these issues. Section 70 of the *Generic Royalty Regulations* (applicable to Terra Nova, White Rose and any other project subject to the generic regime) provides that "[a]n estimate of the eligible transportation costs for an interest holder for a period [would], after consultation with the interest holder, be determined by the minister [who would] notify the interest holder of [the] determination...before the beginning of th[at] period."[58] The minister was also to provide the interest holder, before such interest holder was required to file its annual reconciliation of royalty payments under section 32 of the *Generic Royalty Regulations*, of the minister's determination of the eligible transportation costs for the period.[59]

Misgivings have been expressed in other quarters about the result in the *Generic Royalty Regulations*.[60] The only publicly available assessment of the efficacy of this process is in a report of the Auditor General of Newfoundland and Labrador in January 2009 that states:

> *Terra Nova Project:* Contrary to the requirements of the *Royalty Regulations, 2003* the Department has not, in consultation with the project owners, developed any eligibility rules that would provide criteria to be used in determining what constitutes an eligible transportation cost. As a result, the Minister cannot provide the project owners with the Minister's determination of eligible transportation costs in accordance with the *Regulations*. The [seven] project owners have never provided actual transportation cost information with their annual reconciliations.[61]

58. *Supra* note 22, s 70.
59. See the discussion of these provisions in Thrasher, *supra* note 21 at 374-376.
60. *Ibid* at 375 and 407.
61. Auditor General of Newfoundland and Labrador, *Report of the Auditor General to the House of Assembly on Reviews of Departments and Crown Agencies for the Year Ended 31 March 2008* (St. John's: Auditor General, January 2009) at Part 2.15, online: Office of the Auditor General of Newfoundland and Labrador <http://www.ag.gov.nl.ca/ag/2008.htm> at 396. The Auditor General's report also had similar comments on the situation in White Rose, where the transportation provisions in section 70 of the *Generic Royalty Regulations* also applied.

Hebron

The issues with respect to the deductibility of transportation and transshipment costs were still outstanding at the time of the Hebron negotiations in 2007 and 2008. Like Hibernia, the development plan for Hebron contemplates the use of a gravity base structure and, despite a heavier quality of crude, would utilize similar tanker and transshipment arrangements to those employed for Hibernia, Terra Nova, and White Rose. Section 4.9 of the *HFA* contains certain agreements among the Province and the proponents (including Nalcor as the holder of the Province's equity interest in Hebron) with respect to transportation costs. In it the parties agree that section 70 of the *Generic Royalty Regulations* will have no application to oil produced from Hebron and that the transportation principles set forth in Exhibit "E" of the *HFA* (the *Hebron Transportation Principles*) are applicable to the royalty calculations under the *HFA*. The parties also acknowledge that the Province intends to amend the *Generic Royalty Regulations* to implement an eligible transportation cost system for oil produced from Hebron. The Province agrees that the transportation amendments applicable to Hebron oil will be consistent with the Hebron Transportation Principles and that until those transportation amendments are enacted the eligibility of transportation costs for Hebron oil will be determined in accordance with the Hebron Transportation Principles.

The *HFA* also provides that once the transportation amendments applicable to Hebron oil have been enacted, they will apply to the extent they are consistent with the Hebron Transportation Principles and the Hebron Transportation Principles will continue to apply with respect to the interpretation of the transportation amendments. Disputes relating to the Hebron Transportation Principles, the transportation amendments or any inconsistencies between them may be referred to arbitration under the *HFA*.[62]

The key elements of the Hebron Transportation Principles are as follows:

1. The general cost eligibility criteria under the *Generic Royalty Regulations* apply to tanker costs and transshipment costs other than the requirement that they not be a cost under another lease and the requirement that they be paid by the operator and shared among the interest holders in accordance with their working interest in the lease.
2. Eligible tanker costs for an owned or a capital lease shuttle tanker (one normally used to transport oil from the Hebron production

62. *HFA*, *supra* note 36, s 10.1.

facility to the NTL facility or direct to market) consist of operating costs plus a ten per cent uplift, depreciation calculated on a straight line basis over the remaining useful life of the tanker (not a unit of production basis as in the *HRA*) with a one per cent uplift on capital costs, and a return on capital of eight per cent on the undepreciated capital cost balance, calculated at mid-year.

3. Eligible tanker costs for an operating lease for a shuttle tanker resulting from a process with the required participation of arm's length bidders will be the operating lease costs and tanker operating costs directly related to operating the tanker, without uplifts. If the process did not have the requisite participation of arm's length bidders, or if the successful bidder was not at arm's length and the minister determines the process was not adequate, the eligible tanker costs will be determined in the same manner as a capital lease unless the minister permits deduction of the actual costs as allowed for an operating lease.
4. The annual cost of a tanker is allocated to the Hebron proponents collectively based on the days the tanker is used in Hebron service in relation to the total days the tanker is in service in the year. The costs so allocated to Hebron will be allocated among the Hebron proponents in accordance with an agreement containing specified formulae and provided to the Province prior to first oil.
5. NTL costs are fully deductible, without uplifts, unless the proponent paying them or its affiliate has an ownership interest in NTL, in which case there is a formula to reduce the return on capital component of the NTL costs.
6. Tanker costs for second leg tankers and replacement tankers are actual costs in arm's length situations and the lesser of actual costs and fair market value in non-arm's length situations.

The Hebron Transportation Principles represent a singular achievement in resolving the transportation and transshipment cost disputes among the proponents of the various projects in the offshore area and the Province and were the basis for dealing with these issues in the context of HSE.

HSE

Transportation cost provisions based on the Hebron Transportation Principles were included in the amendments to the *HRA* and in the *ELRA* entered into in February 2010 in connection with HSE. The amendments to the Hibernia transportation cost provisions in the *HRA* were made effective 1 July 2009 and the historic disagreement between the Province and the Hibernia proponents regarding eligible transportation costs was resolved.

The HSE transportation cost provisions are similar in certain respects to the transportation cost eligibility criteria included in the original *HRA*, but also differ in certain fundamental respects. The actual cost eligibility criteria and categories of ineligible costs are fundamentally the same—the Hebron Transportation Principles were based on such provisions as included in the *Generic Royalty Regulations*, which were originally based on such provisions as included in the original *HRA*, so there is now a high degree of similarity among all royalty regimes in the offshore area with respect to such provisions.

The HSE transportation cost provisions and the original *HRA* differ significantly with respect to the calculation of depreciation that is eligible for deduction in any given year and with respect to inter-project transportation cost allocations. The original *HRA* contemplated that the tankers included in a tanker project would be depreciated (for royalty purposes) on a unit of production basis relative to the Hibernia proved reserves. The entirety of such depreciation amount would be deductible in relation to Hibernia other than the amount attributable to any days where such tankers were actually used to transport crude oil from another project (such as Terra Nova).

In contrast, the HSE transportation cost provisions provide that any transportation assets used for the transportation of Hibernia crude oil are to be depreciated (for royalty purposes) on a straight line basis over the remaining useful life of such assets. For any given year, only that portion of the depreciation for that year that is proportionate to (i) the number of days (during that year) that such assets have been used for the transportation of Hiberia crude oil relative to (ii) the total number of days (during that year) that such assets have been used for the transportation of crude oil from any project, will be deductible in relation to Hibernia. In addition, this inter-project proration factor applies to almost all eligible transportation costs incurred in relation to Hibernia, including any transportation costs incurred with respect to any particular tankers that are used to transport Hibernia crude oil.

While it may not seem like these amendments would have a significant effect on royalties payable in relation to a project, they can make a dramatic difference. The change with respect to calculation of depreciation can significantly reduce the amount of depreciation that can be deducted for royalty purposes in relation to a project in the early years of such project when proved reserves remain low. Combine this with the new requirement that depreciation be prorated among all projects that make use of a transportation asset based on the relative usage of such asset by such projects, rather than a single project (i.e., Hibernia) deducting all of such depreciation except for the amount attributable to the days actually used by another project, and the amount of deductible depreciation can be greatly reduced. The most significant reduction in depreciation also occurs in the early years of a project, after significant pre-development costs have been incurred but while proved reserves remain low and likely prior to full scale production (and consequently revenue) being achieved. The longer that revenue (net of deductible transportation costs) remains lower than it might otherwise be (i.e., if more depreciation is deductible in relation to tankers used in connection with the project), the payout balances that determine the commencement of net royalty and supplementary royalty grow more quickly as a function of the compound interest applied to eligible costs when calculating such payout balances.

The transportation cost provisions implemented pursuant to HSE attempt to more equally distribute eligible transportation costs (including depreciation in relation to tankers) among projects in the offshore area that make use of the relevant tankers. By allocating eligible transportation costs among projects based on the use of tankers by the proponents of each such project, these new transportation cost provisions attempt to align royalty deductions with the use of the tankers, irrespective of the costs actually incurred in relation to such assets by any particular organization. Frustrated with the lack of transparency and understanding relating to the actual transportation costs incurred by each of the proponents of the different projects in the offshore area, the Province was ultimately successful in implementing (at least with respect to Hibernia and Hebron) a system that allocates eligible transportation costs based on the use of tankers, information that is more readily available to and more easily understood by the Province than the (at times complicated) commercial cost allocations among all of such proponents.

The treatment of transportation costs in the offshore area has progressed from the standoff in Hibernia as a result of the facts not fitting the anticipated tanker and transshipment arrangements dealt with in the *HRA*, to a seemingly ill-fated attempt to have the minister and the project proponents sort things out by a process of estimated and actual transportation costs under the *Generic Royalty Regulations* applicable to Terra Nova and White Rose, to a set of principles worked out in Hebron and forming part of the *HFA* as a basis for resolution of the decade-old differences, to a sophisticated set of transportation cost and allocation agreements in HSE that have put paid to the disputed items.[63]

3. *Cost and production allocations*

Hibernia

The allocation of costs and production between Hibernia and other projects in the offshore area under the *HRA* is dealt with in several ways. Costs relating to the acquisition or operation of facilities primarily for the exploration, production or other specified activities in relation to petroleum other than Hibernia crude or solution gas will not be eligible costs in respect of Hibernia unless the Province agrees in writing.[64] Resource project assets may not be used for the processing or storage of petroleum not produced pursuant to PL1001 unless the proponents and the Province (after notice and full particulars from the proponents of the proposed usage) have agreed as to the manner in which the revenues from such processing or storage are to be taken into account for the purpose of the *HRA*.[65]

Aside from these provisions (which ultimately require future agreement with the Province with respect to how to allocate costs between projects), the *HRA* only includes a fairly general cost allocation mechanic. Clause 29.4 of the *HRA* provides that where a cost is not entirely allocable to Hibernia, only the amount of the cost which is reasonably allocable to Hibernia will be potentially eligible for deduction.[66]

Terra Nova and White Rose

The *Generic Royalty Regulations* contain, in section 59, a more elaborate set of rules for the allocation of costs between production licences issued under the *Accord Acts* than is provided for under the *HRA*. These provisions look to the customary basis for the measurement of the capacity and usage of the service or asset whose costs are being allocated. If it is either volume

63. Following completion of this article, in 2013 the Generic Royalty Regulations were amended to add Part XI.1: *Transportation Costs re: April 1, 1990 to November 30, 2001 Leases*; NLR 35/13. Part XI.1 codifies definitional provisions for different categories of tankers, the general cost criteria and the allocation of eligible transportation costs in respect of leases in the offshore area subject to Part XI.1. The amendments incorporate the major elements of the variations described here, up to the innovations of the HSE agreements.

64. See *ELRA*, *supra* note 40 at clause 17.2.

65. For allocation of pre-development costs see *ibid* at clause 28.1.

66. There are provisions in the *HRA* that provide, where the result of a transaction is to artificially reduce the royalty share, or its value to the Province, for the calculation of "royalty share or [its] value…as if…the [transaction] had not taken place," with a right to arbitrate the extent, if any, of such reduction: *ibid* at clause 25.11.

or days, those will apply to the allocation as well. If it is neither, it is to be measured according to the industry practice for its measurement.[67]

If the cost to be allocated under the *Generic Royalty Regulations* is for a capital asset as defined by Canadian generally accepted accounting principles and good petroleum industry practices, the portion that can qualify as an eligible capital cost is the product obtained when the cost is multiplied by the percentage of expected use of the asset over the life of the production licence.[68]

The *Generic Royalty Regulations* also provide, in a provision that overrides any other provision of the regulations, that "[a] cost or part of a cost that has been claimed, deducted or included by an interest holder in a lease in [calculating] royalty share cannot be claimed, deducted or included by that interest holder or [any other] interest holder in a calculation of royalty under that or any other lease.[69]

Hebron

Under the *HFA* there are no modifications to the provisions of the *Generic Royalty Regulations* referred to above for the purposes of their application to Hebron. During the negotiations in respect of Hebron it was recognized that, in the future, additional lands could be developed by way of a tie-back to the Hebron facilities. Consequently, the *HFA* added provisions to the *Generic Royalty Regulations* for the purpose of their application to Hebron, to address cost allocations between an old lease and an adjacent lease in the context of a tie-back to the Hebron facilities. A new section 59.1 provides that section 59 of the *Generic Royalty Regulations* does not apply to transportation costs, to "old leases" (the lands described in the *HFA*) or to adjacent leases (any lease "from which the interest holders desire to utilize [any development] or infrastructure on the old leases" (referred to as "existing infrastructure") "for the production, offloading...

67. *Generic Royalty Regulations*, *supra* note 22, s 59(2).

68. See *ibid*, s 59(3). If that percentage of expected use changes after the asset has been acquired, an amount of incidental revenue or capital cost will accrue in the period of the change of use, depending on whether the period is greater or less than the previously determined period of use. See also *ibid*, s 59(5).

69. *Ibid*, s 15. See the discussion of this in Thrasher, *supra* note 21 at 382. See also the *P&NG Act*, *supra* note 5, s 37 where, in the opinion of the minister, the result of an action, agreement, arrangement, transaction or operation artificially or unduly reduces the amount of royalty share due to the Province, the royalty share is calculated as if the action, agreement, arrangement, transaction or operation had not occurred or had occurred at fair market value between parties dealing at arm's length. Subsection 37(2) makes the minister's decision subject to arbitration under the *Generic Royalty Regulations*, *supra* note 22.

or storage of oil from [the] [a]djacent [l]ease)," which are dealt with specifically in section 59.1.[70]

Where the interest holders of the old lease and adjacent lease are at arm's length[71] and they agree on the use of existing infrastructure by the interest holders of the adjacent lease, the eligible costs incurred by the holders of the old lease are eligible costs in the old lease and the revenue or other cost recovery charged by the interest holders of the old lease to the interest holders of the adjacent lease are incidental revenue in the old lease.[72] If the interest holders are not at arm's length, the minister has the discretion to either treat the costs and revenues as provided for in arm's length situations, if there is a collective request by the interest holders of both leases and such treatment is satisfactory to the minister.[73] If no such request is received or the minister does not approve a request, eligible capital costs incurred by the interest holders of the old lease for new capital improvements to the existing infrastructure required to handle oil from the adjacent lease are allocated between the two leases in proportion to their reasonable estimated future benefit for each lease. Eligible operating costs are allocated between the old lease and the new lease on the customary basis used in the industry, as provided under the *Generic Royalty Regulations*.[74]

There is a general provision added to the *Generic Royalty Regulations* for the purpose of their application to Hebron that makes the eligibility for royalty purposes of amounts actually charged by the interest holders in respect of such eligible capital and operating costs and reasonable capital recovery fees subject to review and revision by the minister if the minister believes that eligibility of the amount charged will have the effect of artificially increasing or decreasing royalties otherwise payable by the holders of the old lease and the adjacent lease compared to what would have occurred if the transaction was at arm's length.[75] In such cases, the minister may deem an alternative eligible amount for royalty calculation

70. See *Generic Royalty Regulations*, *ibid*, s 59.1 as added in Exhibit "C" of the *HFA*, *supra* note 36.
71. Under the *Generic Royalty Regulations* and the *HFA* "arm's length" has the meaning it has in s 251 of the *Income Tax Act*, RSC 1985 (5th Supp), c 1 with added provisions dealing with transactions between interest holders or their affiliates along the lines of what was in the definition of "arm's length" in *HRA* and a general discretionary power in the minister to determine things are not at arm's length (see s 16(2)). Subsection 59.1(b), added to the *Generic Regulations* applicable to Hebron by the *HFA*, provides that the interest holders of the old lease and adjacent lease are at "arm's length" if the interest holders of the old lease or their affiliates do not collectively hold a majority interest in the adjacent lease.
72. See *HFA*, *ibid*, s 59.1(d).
73. See *HFA*, *ibid*, s 59.1(e)(i).
74. See *Generic Royalty Regulations*, *supra* note 22, s 59(2) and the fact that under s 59.1(a) such eligible costs so allocated do not generate incidental revenue.
75. See *HFA*, *supra* note 36, s 59.1(e)(iii).

purposes, subject to the right of the interest holders to dispute that deemed amount.[76]

Finally, the provisions added to the *Generic Royalty Regulations* by the *HFA* for the purposes of their application to Hebron also provide that where the Province has promulgated regulations of general application for the allocation of costs and revenues between leases, the Hebron proponents collectively can elect, before first oil from an adjacent lease, to use those rules for allocating costs and revenues between the old lease and the adjacent lease.[77]

HSE

In the context of the HSE negotiations, the approval by the C-NLOPB of an amendment to the Hibernia development plan relating to the development of the HSE Lands expressly contemplates the development and exploitation of the *HSE Lands by way of a subsea tie-back to the Hibernia GBS*.[78] As a result, the Hibernia proponents and the Province recognized the need for detailed provisions with respect to allocations between PL1001 and the original Hibernia proponents on one hand and PL1005 and EL1093 and the proponents in respect of HSE on the other hand.

Even though the original Hibernia proponents and the HSE proponents are largely the same organizations, it is important to note that the participating interests of the different proponents vary between original Hibernia and HSE, particularly with the inclusion of Nalcor as an equity interest holder in respect of the HSE Lands. While perhaps a statement of the obvious, it is also important to note that crude produced from the HSE Lands will be produced into the Hibernia GBS, and there is no ability to segregate such crude from production from the remaining portions of PL1001 (the AA Blocks and the northern portion of PL1001) or to continuously measure any wells that are produced into the Hibernia GBS.

As discussed above, there are now four distinct royalty regimes operative in respect of Hibernia, inclusive of the HSE Lands: (i) the original Hibernia project lands remain subject to the *HRA*; (ii) the AA Blocks are subject to the *HRA* as well as an additional royalty; (iii) that portion of the HSE Lands that is contained within PL1001 is subject to the *HRA* as well as an additional royalty that is different and distinct from

76. See *HFA*, *ibid*, s 59.1(e)(iii).
77. See *HFA*, *ibid* at s 59.1(f).
78. See *Respecting the Amendment to the Hibernia Development Plan* (St. John's: Canada–Newfoundland Offshore Petroleum Board, 2010), online: Canada–Newfoundland and Labrador Offshore Petroleum Board <http://www.cnlopb.nl.ca/news/pdfs/dec1002e.pdf>.

the additional royalty applicable to the AA Blocks; and (iv) that portion of the HSE Lands that is contained in PL1005 and EL1093 are subject to the *ELRA*, which includes its own additional royalty provisions.

The end result is that for Hibernia, inclusive of the HSE Lands, the participating interest of each Hibernia proponent in crude oil produced from the original Hibernia project lands and the AA Blocks is different from the participating interest of each such proponent in crude oil produced from the HSE Lands. Furthermore, the royalty regime applicable to any of such crude oil will be one of four regimes depending on where such crude oil was produced from (original Hibernia project lands, AA Blocks, HSE Lands within PL1001 or HSE Lands within PL1005, and EL1093). Finally, in the absence of some form of allocation methodology, it would be impossible to determine whether any particular barrel of crude oil was produced from the original Hibernia project lands or the HSE Lands contained in PL1005 and EL1093, or somewhere in between.

Given this level of complexity it was necessary to address not only cost allocations between Hibernia and HSE but also production allocations to allow the Hibernia and HSE proponents to accurately determine their respective royalty obligations. Rather than including allocation methodologies in both the *HRA* and *ELRA*, which provisions would have had to be inter-connected from one agreement to the other as they both would have related to the Hibernia gravity base structure, allocation provisions with respect to all of these items were included in the separate *Hibernia Development Project Allocation Agreement* (the *Allocation Agreement*) entered into by the Province and the Hibernia proponents (including Nalcor as the holder of the Province's equity interest in the HSE Lands) on 16 February 2010.[79] The specifics of the detailed allocation provisions are beyond the scope of this paper, but a general discussion of these provisions follows.

As a general principle, costs that are solely for the benefit of the original Hibernia project lands or the AA Blocks (for the purposes of this discussion relating to Hibernia and HSE allocations, referred to as "Hibernia North"), on one side, or the HSE Lands, on the other side, are allocated entirely to

79. Hibernia, *Hibernia Development Project Allocation Agreement* (St. John's: Hibernia, 2010), online: Department of Natural Resources <www.nr.gov.nl.ca/nr/energy/petroleum/ offshore/projects/ hibernia_allocation_agreement.pdf> [*Allocation Agreement*].

Hibernia North or the HSE Lands, as applicable.[80] Operating costs related to operations of common benefit to Hibernia North and the HSE Lands (shared operating costs) are allocated between Hibernia North and the HSE Lands on an annual basis based on the annual production from each of Hibernia North and the HSE Lands relative to the aggregate production from both (see below for further discussion with respect to production allocations). While such shared costs will be allocated in the first instance based on an annual production forecast prepared by HMDC, following the end of each period there will be a reconciliation so that such costs are ultimately allocated based on annual production volumes.[81]

Capital costs relating to capital improvements that will be of common benefit to both Hibernia North and the HSE Lands (shared capital costs) are allocated between Hibernia North and the HSE Lands based on the estimated relative future benefit of the capital improvements to each such area. The default for the purposes of determining such relative future benefit is the remaining economically recoverable crude oil reserves in each such area, as determined by HMDC in accordance with good oilfield practice. Only with the agreement of all of the parties to the *Allocation Agreement*, including the Province, can shared capital costs be allocated on a basis other than *pro rata* in accordance with estimated remaining economically recoverable crude oil reserves.[82]

With respect to production allocations, pursuant to the *Allocation Agreement*, the total volume of crude oil produced into the Hibernia GBS will be allocated between the original Hibernia project lands, the AA Blocks and the HSE Lands on a well-by-well basis for each well producing from such areas. Even though there is common ownership of the original Hibernia project lands and the AA Blocks, because there are different royalty regimes applicable to these areas, production is separately allocated to these areas. The Hibernia facilities are not capable of continuously metering each of the producing wells, but the well-flow of each producing well is tested each month. The aggregate production volume is then allocated back to each producing well based on the well-flow test results of each well in accordance with flow system, calculation

80. The allocation methodologies described in this section are those provided for under the *HRA*, the *ELRA*, and the *Allocation Agreement* and solely relate to allocations for royalty purposes. The commercial cost and production allocations among the Hibernia and HSE proponents are provided for under separate contractual agreements among such proponents to which the Province is not a party. As this paper is focused on developments in royalties in the offshore area, such contractual arrangements are beyond the scope of this paper.

81. See *Allocation Agreement*, *supra* note 78, clause 18.2(a).

82. *Ibid* at 18.2(b).

and allocation procedures, which are required to be approved by the C-NLOPB.

The preceding paragraphs describe, in general terms, how costs and production are to be allocated between Hibernia North and the HSE Lands. Costs and production allocated to Hibernia North are further allocated among the Hibernia proponents in proportion to their participating interest in Hibernia. As discussed above, however, the HSE Lands include lands that underlie PL1001, PL1005 and EL1093 and in which different Hibernia and HSE proponents have different participating interests. That portion of the HSE Lands that is contained within PL1001 is part of Hibernia for royalty purposes and the royalties in respect of such lands are governed by the *HRA*, and that portion of the HSE Lands that is contained within PL1005 and EL1093 is part of HSE for royalty purposes and the royalties in respect of such lands are governed by the *ELRA*. Consequently, for all costs and production allocated to the HSE Lands, it is also necessary to allocate costs and production between the PL1001 portion of the HSE Lands and the PL1005 and EL1093 portion of the HSE Lands so that such costs and production can ultimately be allocated to the individual Hibernia and HSE proponents.

As required under the *Accord Acts*,[83] because the HSE Lands underlie PL1001, PL1005 and EL1093, the interest holders in such lands, the Province and Canada entered into a unit agreement with respect to such lands. As is customarily the case, pursuant to this unit agreement all unit costs and production of unitized substances are allocated between PL1001, PL1005 and EL1093, which are recognized as separate tracts under this unit agreement, in accordance with the tract participation ascribed to each such tract. Within each such tract, such costs and production are allocated to the interest holders of such tract in proportion to their respective participating interest in such tract. These allocations made pursuant to this unit agreement are adopted by the Allocation Agreement and are used for the purposes of calculating royalties under the *HRA* and the *ELRA*.

The end result of the allocation provisions discussed above is to allocate all Hibernia and HSE costs and production among the Hibernia and HSE proponents. Taken as a whole, the allocation provisions of the *Allocation Agreement* mark a step-change in the level of detail and complexity relative to that included in previous royalty regimes in the offshore area —they are the first of their kind and remain unique in the offshore area. If future development of the offshore area involves more tie-backs to existing projects, then we would expect to see the royalty

83. *Federal Accord Act*, *supra* note 2, s 167.

regimes for such projects adopting similarly detailed and prescriptive methodologies as the proponents of a project and the Province are all keenly interested in making sure that each proponent is paying no more and no less than its fair share of the royalty obligations associated with that project.

4. *Dispute resolution provisions*

Hibernia

The *HRA* contains a dispute resolution provision with an arbitration code based on the code contained in the *Commercial Arbitration Act* of Canada (which is in turn based on the UNCITRAL Model Law on International Commercial Arbitration).[84] The arbitration code is set forth in a Schedule to the *HRA* and clause 27.3 of the *HRA* provides certain agreements of the parties with respect to the procedures under the code.[85]

Clause 27.1 of the *HRA* only allows arbitration of the matters specified in the *Agreement* as being subject to arbitration that cannot be resolved by

84. *Commercial Arbitration Act*, RSC 1985, c 17, (2nd Supp). See the discussion of the federal Act and the provincial equivalents in Claude R Thomson & Annie MK Finn, "International Commercial Arbitration: A Canadian Perspective" (2002) 18:2 Arbitration International 205, online: <http:// adrchambersinternational.com/ publications.htm>. As Randy A Pepper observed: "The central philosophy of the Model Law is one of party autonomy, the guiding principles of which can be summarized as follows: (1) parties should be free to design the arbitral process as they see fit, but the arbitral process should be 'fair' to both parties; (2) parties who enter into valid arbitration agreements should be held to those agreements; (3) the arbitration tribunal should be neutral and as unbiased as possible, and should be empowered to determine its own jurisdiction; (4) the arbitration should proceed in confidence without substantial intervention by the courts; and (5) the resulting award should be readily enforceable subject to review only on the basis of a limited and specified list of fatal flaws in form or procedure." See Randy A Pepper, "Why Arbitrate: Ontario's Recent Experience with Commercial Arbitration" (1998) 36 Osgoode Hall LJ 807 at 811-812 and authorities there referenced.

85. These deal with giving notice in accordance with the provisions of the *HRA*, the relevant court being the Trial Division of the Supreme Court of Newfoundland or any court of appeal therefrom, the number of arbitrators being 3, one arbitration for disputes common to all proponents except in special circumstances such as sale price or revenues of a proponent, conduct of the arbitrations at St. John's, English as the language, the use of the laws in effect in the Province at the time the dispute arose and the authority of the arbitrator to decide *ex aequo et bono* or as an amiable compositor.

discussions among the parties involved.[86] It also postpones any right of action in any judicial proceedings on any matter expressly allowed to be submitted to arbitration under the *HRA* until after the conclusion of any arbitration or the expiration of the time within which the matter may be submitted to arbitration under the *HRA*.[87] Key among the matters subject to arbitration is the calculation of royalty share and any redetermination or recalculation by the Province in relation to elements used in this calculation.[88]

In recognition of its importance to the parties, there are detailed provisions in the *HRA* on the process and available information and

86. These include the Province's determination of similar treatment or similar circumstances in relation to its obligation to treat the proponents consistently under clause 6.2, whether the proponents' lifting agreement would adversely affect any calculation under the *HRA*, Provincial approval of the proponents' lifting agreement under clause 13.12, provisions to replace the joint account under clause 15.2, allocation to the production licence of the proceeds of any sale of the production licence and other assets under clause 16.5, whether the costs and revenues of any transshipment facility are treated consistently with other tanker project costs under the *HRA* as required by clause 17.5, the replacement for the supplementary royalty index pursuant to clause 21.6, the form of provincial lifting agreement (22.5), industry standard terms for the storage of royalty share taken in kind in transshipment facilities of the tanker project under clause 22.6, information determined by ENR Canada to be replacement information for unavailable or obsolete information required to determine the current oil price or the deflated current oil price under clause 23.3, any recalculation or redetermination by the Province of eligible costs or royalty share under clause 24.5, or any calculation by the Province in respect of an artificial transaction under clause 25.11: *supra* note 15. Definitions in the *HRA* that have aspects subject to arbitration include "Arm's Length" (on the Province's declaration, after discussion with the proponents, that certain circumstances are not at arm's length), "Project Withdrawal" (whether there has been a permanent and irrevocable decision, other than a Project Termination, by a proponent that it will discontinue its obligations to the project) and "Sale Price" (its determination).

87. Under clause 27.1, the time limit on submitting a disagreement on an arbitrable matter is either the time provided in the *HRA*, *ibid*, or, if no time is provided, within six months of a party having received notice from another party that the disagreement cannot be resolved by discussions among the affected parties.

88. Under clause 24.3 the Province has the right to redetermine any determination by a proponent for the purposes of any calculations pursuant to the *HRA*, *ibid*, and to recalculate any amount of any calculation or component of any calculation by a proponent of eligible costs, gross royalty, net royalty, or supplementary royalty. Under clause 24.5, after payment by a proponent of any amount resulting from such a recalculation or redetermination by the Province, a proponent can submit any disagreement it has with any recalculation or redetermination by the Province to arbitration with specified time limits.

evidence on an arbitration in respect of the sale price for Hibernia Crude under clause 24.5 of the *HRA*.[89]

Disputes under the *HRA* that are not subject to arbitration will be determined by other procedures agreed to by the parties or failing that by proceedings in the courts of the Province and all courts of appeal from those courts, to which the parties attorn.[90] The *HRA* is governed by and construed in accordance with the laws in force in the Province.[91]

Terra Nova and White Rose

The *Generic Royalty Regulations* applicable to Terra Nova and White Rose contain an arbitration provision in Part VI that also adopts as an arbitration code the code set out in the *Commercial Arbitration Act* of Canada. Subsection 48(2) makes the arbitration provisions in Part VI of the *Generic Royalty Regulations* an arbitration agreement under the code that prevails over the code in the event of any conflict.

Subsection 48(3) contains rules for the conduct of proceedings under the arbitration code, along the lines of what was provided in the *HRA*.[92]

Section 49 of the *Generic Royalty Regulations* provides for specific matters that may be submitted to arbitration under Part VI. As in the case of the *HRA* there is no general right to arbitrate issues under the *Generic Royalty Regulations*. Things that may be subject to arbitration include disputes with respect to the assessment or reassessment of royalty share, the calculation or eligibility of a royalty cost, certified predevelopment

89. Article XXXVII of the *ELRA*, *supra* note 40, deals with crude oil valuations and begins with the general statement in clause 37.1 that the sale price must reflect fair market value at the sale point taking into account specified factors. Clause 37.2 requires that each monthly summary submitted by a proponent to the Province include, for each sale price reported, the estimated landed price at the sale point of at least two widely-traded reference crude oils, quality adjusted for Hibernia crude. The Province can re-determine or recalculate the royalty share based upon the sale price reported by a proponent not reflecting fair market value and if it does so it must provide the proponent, at the time of the redetermination or recalculation, with an explanation of the reasons for doing so. The Province does not have to disclose any confidential information received by the Province with respect to the pricing of any other proponent, until the time of an arbitration pursuant to clause 24.5. For a much more detailed reference price committee process developed for Terra Nova see s 81 of Part XIII of the *Generic Royalty Regulations*, *supra* note 22 and the discussion in Thrasher, *supra* note 21 at 380-381. There is apparently no publicly available information on the creation, composition or operation of the reference price committee for Terra Nova.

90. *ELRA*, *supra* note 40, clause 38.2.

91. *Ibid*, clause 38.1.

92. An important difference is that, unlike under the *HRA*, *supra* note 15, the arbitrators under the *Generic Royalty Regulations*, *supra* note 22 do not have the authority to make an award *ex aequo et bono* or as an amiable compositor. For a discussion of this concept see Leon Trakman, "*Ex Aequo Et Bono*: De-Mystifying An Ancient Concept" (2008) 8 Chicago J Int'l L 621. In addition, the Minister and the interest holders can also agree on fewer than three arbitrators under the regulations (see s 48(2)(c)) and the parties can agree to hold the arbitration in a place in Newfoundland and Labrador other than St. John's (see s 48 (2)(d)).

costs, eligible transportation cost or incidental revenue, the calculation or inclusion of incidental revenue or tanker incidental revenue, the allocation of costs, fair market value, whether persons are dealing at arm's length, as well as the other matters specified under the *Generic Royalty Regulations*.[93]

Section 51 of the *Generic Royalty Regulations* contains a "baseball arbitration" or "final offer" provision for determination of the sale price for oil for royalty purposes in which the arbitrator is limited to awarding "the position of the minister [or the interest holder] made in a specific offer of settlement before the matter is referred to arbitration, as presented to the arbitrator before the hearing."[94]

Hebron

The *HFA* contains certain variations, for the purposes of the Hebron project, on the arbitration provisions in the *Generic Royalty Regulations*. It expressly permits arbitration under the *HFA* in respect of any matters that could be arbitrated under the *Generic Royalty Regulations*, as modified by the *HFA*. Such arbitration would be carried out pursuant to Part VI of the *Generic Royalty Regulations*, unless the parties otherwise agreed. The *HFA* does not modify any of the matters that are subject to arbitration under the *Generic Royalty Regulations* but adds several other matters that could be arbitrated.[95]

Any other matter under the *HFA* can also be arbitrated except for the specific items listed in section 10.1, which include provisions of the *Generic Royalty Regulations* revised for the purposes of Hebron under Exhibit "C" that are not subject to arbitration under the modified *Generic*

93. Other items subject to arbitration include disputes on the application of section 13, disputes under section 37 of the *Act* (which deals with artificial transactions), the provision of records and the extension of an audit period under s 45(2), specified decommissioning issues, the assessment of fair market value of insurance under s 63(2), the approval of reservoir risk amounts as contemplated under paragraph 68(1)(s), a determination of a "designated area" under paragraph 81(6)(b) and a determination by the minister under section 19 of adjustments with respect to commingled oil. For Terra Nova, a dispute between the minister and an interest holder with respect to whether an eligible cost is an eligible capital cost or an eligible operating cost may, before it is submitted to arbitration, be sent to an independent expert (a public accountant) with a substantial presence in Newfoundland and Labrador, on whose selection the parties must agree. See ss 86(1) and 49 of the *Generic Royalty Regulations*, *supra* note 22.

94. *Supra* note 22, s 51(2). For some insights into the utility of such a provision see Charles Rumbaugh, "Baseball Arbitration I", online: Superior Court of California, County of Santa Barbara <http://www.sbcadre.org/articles/0010.htm>.

95. These include whether measurement facilities and practices comply with the measurement standards established under s 18 of the *Generic Royalty Regulations*, *supra* note 22 and the reasonableness of the replacement for WTI selected by the minister under s 11.1(3) of the *Generic Royalty Regulations*, as modified by the *HFA*.

Royalty Regulations. They also include the provisions in sections 9.1 and 9.2 of the *HFA* on legislative and regulatory stability.[96]

Section 10.2 of the *HFA* stipulates that if a dispute arises that involves any issues common to both the *Hebron Benefits Agreement* (the *Benefits Agreement*), which has its own detailed arbitration provisions,[97] and the *HFA* there will be one arbitration of those disputes pursuant to the *Benefits Agreement* and all of the provisions of the *Benefits Agreement* shall apply to such arbitration.[98]

Certain provisions were added to the arbitration procedural provisions applicable to Hebron under the *Generic Royalty Regulations* as modified by the *HFA*. These include a role under the arbitration provisions for the ADR Institute of Canada (the Institute) or, if that body is not available, a similar body with similar standing as agreed to by the parties[99] and in the appointment of arbitrators under the *Generic Royalty Regulations* as modified by the *HFA* if the parties do not do so within a specified time.[100] The Institute is a non-profit organization that provides services in relation to the development and promotion of dispute resolution services in Canada and internationally.[101]

There are also a number of other provisions added in respect of arbitrations under the *Generic Royalty Regulations* as modified by the *HFA*. Decisions and awards by the arbitrators are determined by a majority vote.[102] Parties to an arbitration are to agree in advance as to the rules and procedures for the arbitration and, failing such agreement within a specified period, the arbitrators adopt the rules and procedures established by the Institute that apply to national matters, amended to be in compliance with the *Generic Royalty Regulations*, and promptly commence and

96. Other topics that may not be arbitrated under the *HFA*, *supra* note 36, are the provisions dealing with time limit for development (s 2.4), representations and warranties of the Province (s 3.6), pre-development costs (s 4.7(A)), and the non-application to Nalcor Oil and Gas Inc of the provisions of ss 8.2 (Separate Treatment) and 8.3 (Consistent Treatment) of the *HFA*.

97. *The Hebron Benefits Agreement* (St. John's: Hebron, 2008), online: Hebron Project <http://www.hebronproject.com/media/219/finalexecutedbenefits.pdf> [*Hebron Benefits Agreement*].

98. The arbitration provisions under the *Hebron Benefits Agreement* are more detailed and along the lines of what one would expect to see in a sophisticated commercial agreement: *Hebron Benefits Agreement*, *supra* note 93, Art 8, Exhibit "B."

99. Where there is an agreed arbitrator appointment procedure and a party fails to act as required under it or the parties are unable to reach an agreement expected of them under the procedure, a party can request the Institute to take the necessary measure. See Article 11(4)(a) and (b) of the code.

100. See para 48(3)(i) added to the *Generic Royalty Regulations*, *supra* note 22, by Exhibit "C" of the *HFA*, *supra* note 36.

101. For more information on the ADR Institute of Canada see online: <http://www.adrcanada.ca>.

102. See para 48(3)(i) added to the *Generic Royalty Regulations*, *supra* note 22, by Exhibit "C" of the *HFA*, *supra* note 36.

expeditiously conduct the arbitration proceedings.[103] An arbitration award is to be in writing, is binding on the parties and must deal with costs of the arbitration and other related matters.[104] There is no appeal on the merits from an arbitration award, and arbitrations conducted pursuant to the *Generic Royalty Regulations*, as modified for Hebron by the *HFA* are the final and exclusive forum for resolution of a dispute subject to arbitration, but nothing prevents a party from applying to court on matters that are subject to the jurisdiction of the courts under the Newfoundland and Labrador *Arbitration Act*.[105]

Finally, there are provisions added by the *HFA* to the *Generic Royalty Regulations* for Hebron dealing with the recognition and enforcement of arbitration awards,[106] excluding punitive or exemplary damages,[107] and confirming the arbitrators have no jurisdiction to amend or vary the terms of the *HFA* or the arbitration code.[108]

The HSE fiscal agreements (the amended *HRA*, the *ELRA* and the *Allocation Agreement*) all use the same arbitration code and related procedural provisions as were in the original *HRA* but these are now found in Schedule B of the *Allocation Agreement*. Each of the amended *HRA* and the *ELRA* makes those provisions applicable to any disagreement among the parties to it, as regards to any matter expressly allowed in that agreement, to be submitted to arbitration and the *Allocation Agreement* does the same with respect to any matter expressly allowed to be submitted to arbitration under that agreement and the royalty agreements.

The development of the dispute resolution provisions in the offshore area has moved from the initial adoption of the UNCITRAL-based code under the *Canadian Commercial Arbitration Act* in Hibernia (now applicable to all of the amended *HRA*, the *ELRA* and the *Allocation Agreement* in relation to HSE) through a maintenance of the code in the

103. See s 50(4) added to the *Generic Royalty Regulations*, *supra* note 22, by Exhibit "C" of the *HFA*, *supra* note 36.
104. See s 50(5) added to the *Generic Royalty Regulations*, *supra* note 22, by Exhibit "C" of the *HFA*, *supra* note 36.
105. See s 50(6) added to the *Generic Royalty Regulations*, *supra* note 22, by Exhibit "C" of the *HFA*, *supra* note 36. The relevant provisions of the Newfoundland and Labrador *Arbitration Act*, RSNL 1990, c A-14 for arbitrations under the *Generic Royalty Regulations* applicable to Hebron are s 13, which permits the court to remove an arbitrator who has misconducted himself and no award has been provided, and s 14, which permits the court to set aside an award where it has been improperly proceeded or the arbitrator has misconducted himself.
106. See s 50(7) added to the *Generic Royalty Regulations*, *supra* note 22, by Exhibit "C" of the *HFA*, *supra* note 36.
107. See s 50(8) added to the *Generic Royalty Regulations*, *supra* note 22, by Exhibit "C " of the *HFA*, *supra* note 36.
108. See s 50(9) added to the *Generic Royalty Regulations*, *supra* note 22, by Exhibit "C" of the *HFA*, *supra* note 36.

Generic Royalty Regulations with some additional features more common in a commercial agreement arbitration provision and a final offer arbitration process on price issues, to a much more commercially attuned set of arbitration provisions in the *HFA* and the *Generic Royalty Regulations* as modified by the *HFA* for the purpose of Hebron. The next step will hopefully be a series of amendments to the *Generic Royalty Regulations* that make these procedural and substantive improvements applicable to all arbitrations under the *Generic Royalty Regulations*. The issues subject to arbitration have expanded as well to the point where under the *HFA* they now encompass virtually every issue relevant to economic value including the calculation of royalty share and many other issues that arise under the *Generic Royalty Regulations* and in relation to the additional royalty in Hebron as well.

5. *Legislative stability clauses*

In a fiscal context, the purpose of a legislative stability clause is to give the proponents some assurance that the fiscal arrangements reflected in the agreements and the laws in effect at the time of entering into those agreements will be maintained, or at least not altered to the prejudice of those fiscal arrangements. This is important because the government party to the fiscal agreements can unilaterally amend the economic bargain reflected in the agreements and existing laws by changing those laws or their application.

In Canada, given the nature of our parliamentary democracy, there are at least two aspects to be considered in approaching such assurances when dealing with the federal or a provincial government:

(i) how far is the government party willing to go in providing such assurances; and
(ii) how effective are those assurances, given the nature of the parliamentary system.

The approach of Canadian courts to the capacity of a provincial government to provide such assurances and the limitations on their effect has been discussed in other contexts in relation to the offshore area.[109] The key principles from the relevant authorities in Canada can be summarized as follows:

1. A province has all the powers of a natural person to enter into a contract.

109. See the discussion of this area in Denstedt & Thrasher, *supra* note 1 at 327-329. We acknowledge the original research of our colleague Patrick Callaghan in relation to this portion of the paper.

2. Neither a minister nor a province itself can restrict the ability of the province to legislate in a manner inconsistent with a contract entered into by the province.
3. If a province breaches its contract with a party (even where it results from a proper exercise of its legislative authority) the province will be liable to the party in damages, unless:
   (a) the province, by clear and explicit legislation, denies the party such damages, or
   (b) the contract is unenforceable because it imposes an improper restriction on the administrative authority conferred by a statute on the province, or on someone representing the province, such as a minister.[110]

On the last principle, a contract with a province may be unenforceable if it could be breached by the proper exercise of discretionary authority conferred by a statute. The potential liability for breach of the contract constrains the exercise of the statutory authority intended to be exercised only with regard to the public good.

As noted, stabilization clauses[111] are intended to ensure that future changes to the laws, regulations and their interpretations applicable to a project in the offshore area at the time the fiscal agreements are entered into do not alter the agreements, and more specifically, the economic bargain negotiated in the agreements as they apply under existing laws. In other words, the agreement provisions, and the economic framework of the contract reflected in legislation and regulations existing at the time of entering into the project agreements, are "stabilized."

110. See *Pacific National Investments Ltd v Victoria (City)*, 2000 SCC 64, 193 DLR (4th) 385; *Happy Adventure Sea Products (1991) Ltd v Newfoundland & Labrador* (2006), 260 Nfld & PEIR 344 (Nfld CA). For a general treatise on the Crown's liability in contract see Hogg & Monahan, *supra* note 15 at 333.

111. We acknowledge the assistance of our colleague Riyaz Dattu whose insights contributed to the development of portions of this section of the paper.

There have been a number of papers and studies on stability provisions in international situations.[112] A key consideration in the negotiation of such provisions is what support can be found for the government's obligations in the stability clause from sources other than the contract.[113] In the offshore area, this could involve referring in the provision to relevant treaties or other international obligations, which is complicated if the only government party to the fiscal arrangements is the Province.[114]

Another important consideration in the effectiveness of legislative stability provisions is dispute resolution provisions in the contract that allow the proponents to seek final resolution of claims for breaches of the stability provisions in a forum or process consistent with international law principles and free of claims of government or sovereign immunity.

Sovereign immunity in relation to the fiscal agreements relating to the offshore area is dealt with in part by the Newfoundland and Labrador *Proceedings Against the Crown Act* (the PACA) which is intended to be a complete code governing proceedings against the Crown in right of Newfoundland and Labrador.[115]

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112. See Evaristus Oshionebo, "Stabilization Clauses in Natural Resource Extraction Contracts: Legal, Economic and Social Implications for Developing Countries" (2010) 10 Asper Rev Int'l Bus & Trade L 1; Andrea Shemberg, "Stabilization Clauses and Human Rights: A Research Project Conducted for IFC and the United Nations Special Representative to the Secretary General on Business and Human Rights" (11 March 2008), online: International Finance Corporation <http://www.ifc.org/ifcext/enviro.nsf/AttachmentsByTitle/p_Stabilization ClausesandHumanRights/$FILE/Stabilization+Paper.pdf>; and Nana A Hackman, "Ghana's Oil Policy Debate: Stabilization Clauses and the Freedom of Parliament To Impose New Taxes or Royalty," *KITE* (14 December 2009), online: KITEonline <http://kiteonline.net/index.php?option=com_content&view=article&id=170:ghanas-oil-policy-debate&catid=5: news-content&Itemid=5>. Each of these articles examine stabilization clauses in the developing countries context but have discussions relevant in assessing the effect of such clauses in any situation.

113. This would include such things as treaties, the North American Free Trade Agreement (NAFTA) and other international trade agreements or arrangements.

114. The federal government has the authority to enter into international treaties or agreements, such as NAFTA (see Library of Parliament, *Canada's Approach to the Treaty-Making Process* by Laura Barnett (Ottawa: Parliamentary Information and Research Service, 2008) at 1 and authorities referenced there, online: Parliament of Canada <http://www.parl.gc.ca/ Content/LOP/ResearchPublications/prb0845-e.pdf>). Given the Province's experience with NAFTA in relation to the Abitibi-Bowater matter (see, e.g., Alexandre Deslongchamps, "Canada to Pay AbitibiBowater C$130 Million in Newfoundland Nafta Dispute," *Bloomberg* (24 August 2010), online: <http://www.bloomberg.com/news/2010-08-24/canada-to-pay-abitibibowater-c-130-million-in-newfoundland-nafta-dispute.html>) and the NAFTA-based proceedings launched by ExxonMobil and Murphy Oil in relation to the research and development guidelines of the C-NLOPB in relation to Hibernia and Terra Nova (see Mobil Investments Canada Inc, "Notice of Intent to Submit a Claim to Arbitration under NAFTA Chapter 11" (3 August 2007), online: NAFTA Claims <http://www.naftaclaims.com/Disputes/Canada/Mobil/Mobil-Canada-NOI.pdf>), it would not be surprising if the Province, as a matter of policy, would resist explicit reference to NAFTA in a legislative stability provision.

115. *Proceedings Against the Crown Act*, RSNL 1990, c P-26 [*PACA*]. See Hogg & Monahan, *supra* note 15.

The *PACA* does leave some remaining immunities of the provincial Crown.[116] The difficulty in trying to deal with these remaining immunities in a contract with the Province is that it may not be possible for the Province to waive them along the lines of a standard sovereign immunity clause.[117]

In Hibernia, the legislative stability provisions focused on the general legislative and regulatory framework applicable to the project and are contained in the *Hibernia Development Project Framework Agreement* to which Newfoundland and Labrador, Canada and the Hibernia proponents are parties. Clause 4.4 of the *Hibernia Framework Agreement* provides:

> Canada and Newfoundland acknowledge that each of the Project Owners relies upon the good faith of each of Canada and Newfoundland, respectively, to maintain substantially the legislative and regulatory framework applicable to the Project as of the date of Closing, to the extent that doing so is in the public interest and, without limiting the generality of the foregoing, is consistent with governmental responsibilities, including responsibility for ensuring proper management of its resources, the protection and maintenance of public health and safety and protection of the environment. Each of the Project Owners acknowledges that Canada and Newfoundland rely upon the good faith of each of the Project Owners, respectively, to carry out its undertakings in respect of

116. The *PACA* preserves Crown immunity in specific instances such as proceedings in respect of a cause of action that is enforceable against a corporation or other agency owned or controlled by the Crown (paragraph 3(2)(d)), relief in the form of injunctions or specific performance (s 15(1)), orders for the recovery of property (s 16) and enforcement or execution proceedings to compel satisfaction of a judgment debt (ss 20 and 24(1)). In many of these instances there are other remedies available. Despite the Crown immunity for relief in the form of injunctions or specific performance, for example, the PACA provides that the court may instead make an order declaring the rights of the parties (s 15(1)). Similarly, declaratory relief is available instead of an order against the Crown for the recovery or delivery of property (s 16). Instead of enforcement and execution proceedings, the *PACA* imposes on the Minister of Finance a statutory duty to pay out of the Consolidated Revenue Fund to the person entitled to an amount under a court order for the payment of money by way of damages or otherwise (s 23(4)). At bottom, however, there are situations in which the remaining immunities of the Crown could represent a disadvantage to a person claiming against the Crown. For example, the bar of a claim against the Crown for liabilities of a Crown corporation under paragraph 3(2)(d) may prejudice a claimant where a piercing the corporate veil argument might have been available at common law. In addition, a declaration is a form of final relief, and is not available on a interlocutory basis, as an injunction could be.

117. See Hogg & Monahan, *supra* note 15 at 262, which is discussing estoppels but the result for waiver should be the same. There is some authority that suggests that if a province were sued outside the Province, the *PACA* would not apply (see *Athabasca Chipewyan First Nation v Canada*, [2001] AJ 609 (Alta CA)) and there could be a basis for arguing that a sovereign immunity waiver could be effective as the immunity there would be the common law immunity of the Crown only, not one based in statute.

the Project as set forth in Article VII.[118]

The restrictions on enforceability noted at the beginning of this section must be taken into account in assessing the effect of a provision such as clause 4.4 of the *Hibernia Framework Agreement* and the remedies in respect of its breach.

Clause 4.4 is framed as an acknowledgment of a reliance interest in relation to the good faith of the governments to maintain the legislative and regulatory framework applicable to the project at the date of closing, subject to the qualifications noted. If Canada or the Province introduced legislative changes that were found to constitute a breach of Section 4.4 of the *Hibernia Framework Agreement*, and the legislation did not expressly provide that the relevant Government was exempt from liability for the breach, there could be a basis for seeking damages for the breach. If Canada or the Province introduced regulatory changes in breach of Section 4.4, there could be a basis for seeking damages for the breach if the provision was not invalid for imposing an improper restriction on the regulatory authority under which the changes were imposed.

To establish a breach of clause 4.4 on the basis of changes to the legislative and regulatory framework would require that a proponent demonstrate, on a balance of probabilities, that: (i) the changes involved a failure to maintain substantially the legislative and regulatory framework applicable to the project as of the date of closing; (ii) maintaining the existing legislative and regulatory framework in the absence of the changes would have been in the public interest; and (iii) maintaining the existing legislative and regulatory framework in the absence of the changes would

118. Article V of the *Hibernia Framework Agreement*, entered into pursuant to s 3 of the *Hibernia Development Project Act*, SC 1990, c 41, also contains specific provisions with respect to a proponent's right to dispose of production from Hibernia in any domestic or international markets at the highest available price, with a right to compensation if Canada or the Province restrict or prohibits such access and a right to arbitrate aspects of determining such price. Clause 6.1 of the Hibernia Framework Agreement states that each proponent is permitted to produce oil from the project at rates consistent with good reservoir practices, subject to the actions of the C-NLOPB and the *Accord Acts*. Clause 6.2 exempts the project from any production pro-rationing and from all other similar programs restricting production of oil from the project.

have been consistent with governmental responsibilities including the responsibilities enumerated in Section 4.4.[119]

Terra Nova

At the time of negotiation of the *Terra Nova Royalty Agreement* the parties did contemplate provisions similar to those in Hibernia relating to legislative stability. The Province's Backgrounder on Terra Nova[120] in its description of the Terra Nova Letter of Intent entered into among the Province and the Terra Nova proponents on 5 August 1996 states:

> Government is willing to provide a commitment to maintain substantially the same legislative and regulatory framework applicable to the project as of the effective date of the agreements, provided that this is in the public interest and consistent with governmental responsibilities.

In the final analysis, with the Terra Nova royalty regime being implemented by the *Generic Royalty Regulations* rather than private agreement, the language on legislative stability does not appear to have found its way into any publicly available agreement between the Terra Nova proponents and the Province.

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119. Although not relating to the offshore area, the *Voisey's Bay Development Agreement between the Province of Newfoundland and Labrador*, (30 September 2002) contained a legislative stability provision in Clause 6.6:

> Legislative Framework
>
> 6.6.1 The Government represents to the Proponent (and acknowledges that the Proponent is relying upon such representation) that it shall maintain substantially the Legislative Framework for the duration of the Project, subject to legislative amendments contemplated in this Agreement and legislation of general application.
>
> The Government shall maintain the Legislative Framework consistent with this Agreement, subject to Governmental responsibilities, including the responsibility for ensuring proper management of the Province's resources, the protection and maintenance of public health and safety and the protection of the environment. The Government acknowledges that this Agreement is consistent with current public law and Governmental responsibilities.
>
> 6.6.2 The Proponent represents to the Government (and the Proponent acknowledges that the Government, in consideration of agreeing to maintain the Legislative Framework, has relied upon such representation) that the Proponent shall perform its obligations set out in this Agreement, the Instruments, the Exemption Orders, the Primary Production Order and the Mining Lease.

The "Legislative Framework" is defined as "the Applicable Laws of the Province in existence as of the date hereof applicable to the Project or any part thereof."

Here, the Province alone was giving the legislative stability assurances, they are framed as an obligation rather than an acknowledgment, and there is no mention of a good faith element. The language addresses the comfort relating to legislative stability in more definitive terms than those found in Section 4.4 of the Hibernia Framework Agreement but is careful to qualify it by reference to the obligations of the Province in its legislative and public policy role, albeit in narrower terms than those applicable in Hibernia. See <http://www.nr.gov.nl.cs/nr/royalties/legal.pdf>.

120. See Government of Newfoundland and Labrador, "Terra Nova Development Project News Release" (5 August 1996), online: <http://www.releases.gov.nl.ca/releases/1996/exec/0805n03.htm>.

White Rose and White Rose Expansion
We are not aware of any publicly available information on any legislative stability provisions in relation to White Rose or the White Rose Expansion.

Hebron
As noted, Hebron utilized a combination of modifications to the *Generic Royalty Regulations* as they existed on 16 August 2007, and the *HFA* under section 33 of the *P&NG Act*, to fashion the royalty arrangements for the project. This approach offered some interesting opportunities for legislative stability provisions.

Rather than taking an approach along the lines of Clause 4.4 of the *HRA*, Article 9 of the *HFA*, titled "Legislative and Regulatory Stability," states:

> 9.1 Royalty.
>
> The Province hereby covenants that other than the royalty regime imposed by the Royalty Regulations as modified by this Agreement, (a) no other royalty shall be imposed on the Proponents in respect of oil produced from the Lands; and (b) no additional tax, levy, fee or charge shall be imposed by the Province solely on a Development Project or on the Proponents solely in relation to their interest in the Lands.
>
> 9.2 Interests in the Lands.
>
> Notwithstanding the Energy Plan, or any other policy, regulation or legislation of the Province relating to energy resources, any working interest participation by the Province, its agent, or any provincially controlled corporation, in the Lands shall be limited to the interest acquired by OilCo, its successors or permitted assigns, in accordance with the Acquisition Agreement and the agreements to which OilCo, its successors or permitted assigns, becomes a party pursuant to the Acquisition Agreement.[121]

These provisions are not subject to arbitration under the *HFA*.[122] It is interesting that paragraph 9.1(a) is not limited to things imposed by the Province whereas paragraph 9.1(b) is.

The other legislative stability provisions in the *HFA* relate to a combination of crystallization and modification of aspects of the *Generic Royalty Regulations* and an agreement under section 33 of the *P&NG Act* as follows:

121. *HFA*, *supra* note 36.
122. See *ibid*, ss 10.1(6), 10.1(7).

1. The *HFA* provides that the *Generic Royalty Regulations* as they read on August 16, 2007, as modified by the *HFA*, would continue to apply to the Hebron project, subject only to amendments to those regulations that were permitted by the *HFA*.[123]
2. The revisions to the *Generic Royalty Regulations* resulting from the negotiated Hebron royalty arrangements are set forth in Exhibit "C" of the *HFA*.
3. Where a provision of the *HFA* is inconsistent with the *Generic Royalty Regulations* or "any other regulation promulgated under Part II of the *P&NG Act* the...provision of the [*HFA*]...prevail[s] to the extent necessary to give effect to the...provision."[124]
4. The *Generic Royalty Regulations* applicable on August 16, 2007, as modified in their application to Hebron by the *HFA*, continue to apply to the calculation of royalty payable by the proponents on oil produced from Hebron, except to the extent expressly permitted by specified sections of the *HFA*.[125] Changes to certain "provisions of the [*Generic Royalty Regulations*], as they existed on August 16, 2007 that are identified as "'[C]rystallized' in 'Exhibit D'" to the *Hebron Fiscal Agreement* do "not apply to the [Hebron] proponents in respect of royalties payable on [Hebron] oil" but changes to other provisions of those regulations identified as "administrative" in Exhibit "D" would apply to Hebron "unless the effect of a single amendment, or the net effect of more than one amendment introduced [at the same time], [could] be [shown by the Hebron] proponents to" exceed limits specified in the *HFA* for increases in costs to the proponents collectively or royalty revenues received by the Province.[126]

The effect of this approach is to crystallize the *Generic Royalty Regulations* applicable to Hebron, as modified by the *HFA*, except to the extent of future amendments expressly permitted by the *HFA*. All of this

123. See *ibid*, s 4.4.
124. See *ibid*, s 4.1. Because s 33 is a "supremacy clause"—it contemplates the making of enforceable agreements that are intended to be inconsistent with the royalty regulations under Part II of the *P&NG Act*—what is referred to as the "cool and objective" appraisal should be applied in identifying inconsistencies between the *HFA* and those royalty regulations. This approach finds an inconsistency where the two provisions cannot sensibly be read together, or the operation of one interferes with the operation of the other. See *Pagnan SpA v Trades Ocean Transportation SA*, [1987] 3 All ER 515 (CA); *Toronto Railway v Paget* (1909), 42 SCR 488; and *Tabernacle Permanent Building Society v Knight*, [1892] AC 298 (HL).
125. See HFA, *supra* note 36 at s 4.1.
126. See *ibid*, ss 4.3(B)(1) & 4.5. Disputes between the minister and the proponents as to the application of these limits are subject to arbitration.

is, of course, still subject to the restrictions on enforceability discussed at the outset of this section. Despite this, it represents an interesting variation on the more traditional approaches to legislative stability.

HSE

The amendments to the *HRA* resulting from the HSE agreements do not contain any additional provisions on legislative stability applicable to Hibernia. The *Hibernia Framework Agreement* continues to apply to the Hibernia project.

The *ELRA* contains the following provision in clause 40.1A:

> 40.1A Stability.
>
> The Province acknowledges that each of the Project Owners relies upon the good faith of the Province to maintain substantially the legislative and regulatory framework applicable to the Resource Projects as of the date of this Agreement, to the extent that doing so is in the public interest and, without limiting the generality of the foregoing, is consistent with governmental responsibilities, including responsibility for ensuring proper management of its resources, the protection and maintenance of public health and safety and the protection of the environment. Each of the Project Owners acknowledges that the Province relies upon the good faith of each of the Project Owners, respectively, to carry out its undertakings [in the Formal] Agreement[s].[127]

This basically parallels the effect, insofar as the Province's obligations are concerned, of clause 4.4 of the Hibernia Framework Agreement in relation to Hibernia.

In the result, the provisions dealing with legislative stability in the fiscal agreements relating to the offshore area have moved from a generic acknowledgment based on the good faith obligations of the respective governments party to the *Hibernia Framework Agreement* and qualified by other broad obligations of those Governments to act in the public interest, to the more precise obligations of the Province in the *HFA* with respect to the royalty regime and the acquisition of an interest in the project in relation to Hebron and the crystallization of the *Generic Royalty Regulations* as modified for the purpose of Hebron by the *HFA*. It is unlikely that provisions such as are found in the *HFA* would ever become part of the *Generic Royalty Regulations* but they do offer some guidance for future projects in which private contracts or section 33 contracts or their equivalent form a part of the royalty arrangements. All of these

127. *ELRA*, *supra* note 40 at 40.1A.

provisions continue to be subject to the restrictions on enforceability noted at the beginning of this section.

Conclusion

The offshore area has now seen six major developments for which royalty terms have been established—Hibernia, Terra Nova, White Rose, Hebron, the White Rose Expansion, and HSE.

The instruments containing the royalty rights of the Province have changed—from private agreement, to generic regulation, to generic regulation with a project specific addition, to a combination of generic regulation and a section 33 agreement, to a section 33 agreement alone. The structure of the royalty has changed as well—from a combination of gradated basic royalty and two tiers of net royalty in Hibernia, Terra Nova and White Rose, to that structure plus a price-triggered additional royalty in Hebron, the White Rose Expansion and HSE, with a variation on the trigger for the additional royalty in the AA Blocks development in the original Hibernia lands.

Perhaps the most significant changes have been in the treatment of transportation costs—from the tanker project cost of service and fair market value approach under the *HRA* that the parties were unable to implement effectively, to a seemingly unworkable process for ministerial determination under the *Generic Royalty Regulations* applicable to Terra Nova, White Rose, and the White Rose Extension, to a set of transportation and transshipment cost principles in Hebron, to specific detailed transportation and transshipment provisions in relation to HSE and the codification of such provisions in the *Generic Royalty Regulations*.[128]

Another feature of the royalty regimes that has had increased prominence as project development has continued in the offshore area is the provisions for allocation of costs between projects. Given the different royalty instruments applicable to the various projects that followed Hibernia in the offshore area and the fact that costs incurred in respect of a number of items such as transportation and transshipment are shared between several projects with different royalty rates and structures, the need for a more refined and specific set of allocation provisions becomes apparent. From general allocation language in the *HRA*, to more detailed provisions in the generic regulations, to specific provisions in Hebron, to an even more detailed and specific set of allocation arrangements in relation to HSE, this aspect of the royalty regime has evolved accordingly.

128. See *supra* note 63, with regard to the 2013 amendments to the *Generic Royalty Regulations* introduced following completion of this article.

The dispute resolution rights of persons obligated to pay royalties have also evolved—from the initial adoption of arbitration pursuant to the UNCITRAL-based *Commercial Arbitration Code* under the *Commercial Arbitration Act* of Canada in Hibernia and the *Generic Royalty Regulations* to further refinements on the scope and procedural incidents of such a process in Hebron, all the while moving towards an approach to the arbitration process more consistent with sophisticated commercial agreements.

On legislative stability provisions, in some instances there has been qualified general language with respect to the maintenance of the applicable fiscal regime, in others silence on the topic of the legislative and regulatory stability. In still other cases there have been specific assurances relating to the negotiated royalties and equity interests and portions of the royalty structure have been "fixed" or crystallized" by private agreement that overrides the royalty regulations in the event of inconsistency.

The developments in relation to royalties in the offshore area have seen increasing detail and innovation on some of these issues as the parties seek to fashion workable regimes that will address their respective concerns on determining a fair share for both sides, consistent with the benefits the individual projects provide to the people of Newfoundland and Labrador and the returns available to the proponents from their investments. The addition of the Province's energy corporation as an equity participant in Hebron, the White Rose Expansion and HSE projects has taken the Province's participation in these projects to a new level. It will be interesting to see whether this factor and the progress made in addressing these issues in the agreements reached on Hebron and HSE aids in resolving some of these issues under the *Generic Royalty Regulations* and gives the solutions reached broader potential scope in application to developments in the offshore area yet to come.